APPENDIX D

PETROLEUM REFINERY CONSENT DECREE EMISSION REDUCTION ASSESSMENT FOR OZONE AND REGIONAL HAZE SIPS

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Petroleum Refinery Consent Decree Emission Reduction Assessment for Ozone and Regional Haze SIPs

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ACCRONYMS

BWON .....Benzene Waste Operations NESHAP

CO .....Carbon Monoxide

dscf.....Dry Standard Cubic Foot

dscm .....Dry Standard Cubic Meter

EPA .....United States Environmental Protection Agency

FCCU .....Fluid Catalytic Cracking Unit

FGR.....Flare Gas Recovery

LDAR.....Leak Detection and Repair

LDEQ.....Louisiana Department of Environmental Quality

NO_X.....Oxides of Nitrogen

NESHAP .....National Emission Standard for Hazardous Air Pollutants (class of regulations found in 40 CFR 61 and 40 CFR 63)

NSPS .....New Source Performance Standard (class of regulations found in 40 CFR 60)

NSR.....New Source Review

PM.....Particulate Matter

ppm .....Parts per Million

ppmvd .....Parts per Million by Volume on a Dry Basis

PSD .....Prevention of Significant Deterioration

SCR.....Selective Catalytic Reduction

SIP.....State Implementation Plan

SO_2 .....Sulfur Dioxide

SNCR .....Selective Non-Catalytic Reduction

SRP .....Sulfur Recovery Plant

SRU.....Sulfur Recovery Unit

TCEQ .....Texas Commission on Environmental Quality

VOC .....Volatile Organic Compounds

WGS.....Wet Gas Scrubber

1. INTRODUCTION

1.1 Purpose

The purpose of this Work Order is to assess petroleum refinery settlement agreement emission reductions for integration into ozone and regional haze State Implementation Plan (SIP) development programs. In addition to documentation of investigation methodologies and findings, the scope of this work order includes developing and delivering modeling files that will be used to create future base emission inventories for ozone and regional haze SIP modeling analyses.

1.2 Background Information

The Texas Commission on Environmental Quality (TCEQ) is currently developing modeling episodes for the Houston-Galveston-Brazoria (HGB) 8-hour Ozone SIP and a Regional Haze SIP. A crucial component of developing modeling episodes is the development of future base emission inventories. The EPA has reached multi-facility settlement agreements with several major petroleum refining companies with facilities in EPA Region 6 (Texas, Louisiana, Oklahoma, Arkansas and New Mexico). The EPA has indicated that these agreements will result in significant emissions reductions. TCEQ needs the nitrogen oxides (NO_X), volatile organic compound (VOC), sulfur oxides (SO_2), and particulate matter (PM) emission reductions associated with these agreements documented and analyzed for inclusion in their Ozone and Regional Haze SIPs.

1.3 EPA Petroleum Refinery Enforcement Initiative

Since the late 1990s, petroleum refineries have been the focus of an EPA enforcement initiative. This initiative alleges that, in general, petroleum refineries violated and/or continue to violate one or more of the following regulatory provisions:

1. Prevention of Significant Deterioration (PSD) requirements found at Part C of Subchapter I of the Clean Air Act (the Act) and the associated regulations (40 CFR 52.21) and Plan Requirements for Non-Attainment Areas at Part D of Subchapter I of the Act and the associated regulations (40 CFR 51, Appendix S and 40 CFR 52.24) for fuel gas combustion devices and fluid catalytic cracking unit (FCCU) catalyst regenerators for NO_X, SO_2, CO and PM.
2. New Source Performance Standards (NSPS) found at 40 CFR 60, Subparts A and J (petroleum refinery NSPS regulations) for sulfur recovery plants, fuel gas combustion devices and fluid FCCU catalyst regenerators.
3. Leak Detection and Repair (LDAR) requirements found at
   - 40 CFR 60, Subpart GGG;
   - 40 CFR 61, Subparts J and V; and

– 40 CFR 63, Subparts F, H and CC.

4. National Emission Standards for Hazardous Air Pollutants (NESHAP) for Benzene Waste Operations found at 40 CFR 61, Subpart FF.

A brief description of potentially affected process units is presented in Attachment A to this report.

In the interest of settling these allegations, without admitting to the alleged violations, many petroleum refiners have entered into consent decrees with EPA. Since March 2000, the EPA has entered into settlements with petroleum refiners that, collectively, represent nearly 80 percent of U.S. petroleum refining capacity. According to EPA, these settlements, covering 86 refineries in 25 states, will result in a reduction of approximately 80,000 tons per year of nitrogen oxides (NO_X) and 235,000 tons per year of sulfur dioxide (SO_2) upon full implementation.[1] The companies that have signed consent agreements with EPA are as follows:

- BP Exploration and Oil, Inc.
- Chevron USA Inc.
- CHS Inc. (Cenex)
- CITGO
- Coastal Eagle Point Oil Company (CEPOC)
- Conoco, Inc. (preconsolidation refineries only)
- ConocoPhillips
- Ergon Refining Inc.
- ExxonMobil Corporation
- Giant[2]
- Koch Industries[3]
- Lion Oil
- Marathon Ashland Petroleum LLC[4]
- Motiva Enterprises LLC / Equilon Enterprises LLC / Deer Park Refining (Shell)[5]

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[1] http://www.epa.gov/compliance/resources/cases/civil/caa/oil/index.html

[2] Giant Industries is now part of Western Refining, Inc.

[3] Koch Industries refineries operate as Flint Hills Resources, LP.

[4] Now operating as Marathon Petroleum Company LLC

[5] Equilon Enterprises LLC refineries in Martinez and Wilmington, California, and Anacortes, Washington, now operate under the Shell name. The Bakersfield, California refinery was sold to Big West Refining. No refineries currently operate under the Equilon name.

- Navajo Refining Company and Montana Refining Company[6]
- Sunoco
- Total Petrochemicals U.S.A.
- Valero Refining Company

Collectively, these companies own and operate 34 petroleum refineries in EPA Region 6 with a combined crude oil distillation capacity of approximately 4.3 million barrels per day (bbl/day). This represents approximately 87% of petroleum refining capacity in the five Region 6 states.

A summary of consent decree status by company is presented in Table 1-1. Companies with petroleum refineries located in EPA Region VI are shown in bold italics.

Table 1-1. Summary of Consent Decree Status

Company	Date of Lodging[1]	Affected EPA Region VI Refineries
BP	February 2001	Texas City, Texas
Cenex	October 2003	None
CEPOC	October 2003	None
Chalmette Refining	October 2005	Chalmette, Louisiana
Chevron	October 2003	None
CITGO	October 2004	Corpus Christi, Texas
		Lake Charles, Louisiana
Conoco	January 2002	Lake Charles, Louisiana
		Ponca City, Oklahoma
ConocoPhillips	February 2005	Belle Chasse, Louisiana
		Borger, Texas
		Sweeny, Texas
Ergon	October 2003	None
ExxonMobil	October 2005	Baton Rouge, Louisiana
		Baytown, Texas
		Beaumont, Texas
Giant (Western Refining)	August 2005	Bloomfield, New Mexico
		Gallup, New Mexico
Koch Industries	December 2000	Corpus Christi, Texas
Lion Oil	March 2003	El Dorado, Arkansas
Marathon	August 2001	Garyville, Louisiana

[6] Navajo Refining Company, L.P., is now a wholly-owned subsidiary of the Holly Corporation.

Table 1-1. Summary of Consent Decree Status

Company	Date of Lodging[1]	Affected EPA Region VI Refineries
		Texas City, Texas
Motiva / Shell	March 2001	Convent, Louisiana
		Deer Park, Texas
		Norco, Louisiana
		Port Arthur, Texas
Navajo (Holly Corp.)	January 2002	Artesia, New Mexico
Sunoco	June 2005	Tulsa, Oklahoma
Total	May 2007	Port Arthur, Texas
Valero	June 2005	Ardmore, Oklahoma
		Corpus Christi, Texas
		Houston, Texas
		Krotz Springs, Louisiana
		Norco, Louisiana (St. Charles Refinery)
		Port Arthur, Texas
		Sunray, Texas (McKee Refinery)
		Texas City, Texas
		Three Rivers, Texas

[1]Estimated dates of lodging based on Federal Register notices. Actual date of lodging is when the consent decree is lodged with the courts.

Figure 1-1 shows the location of Region 6 petroleum refineries that are part of a consent decree and the location of federal Class I areas.

EPA is continuing negotiations with other petroleum refiners. Therefore, it is possible that additional reductions in emissions from other EPA Region VI refineries may be realized as a result of this enforcement initiative.

Figure 1-1. Location of Petroleum Refineries in EPA Region VI

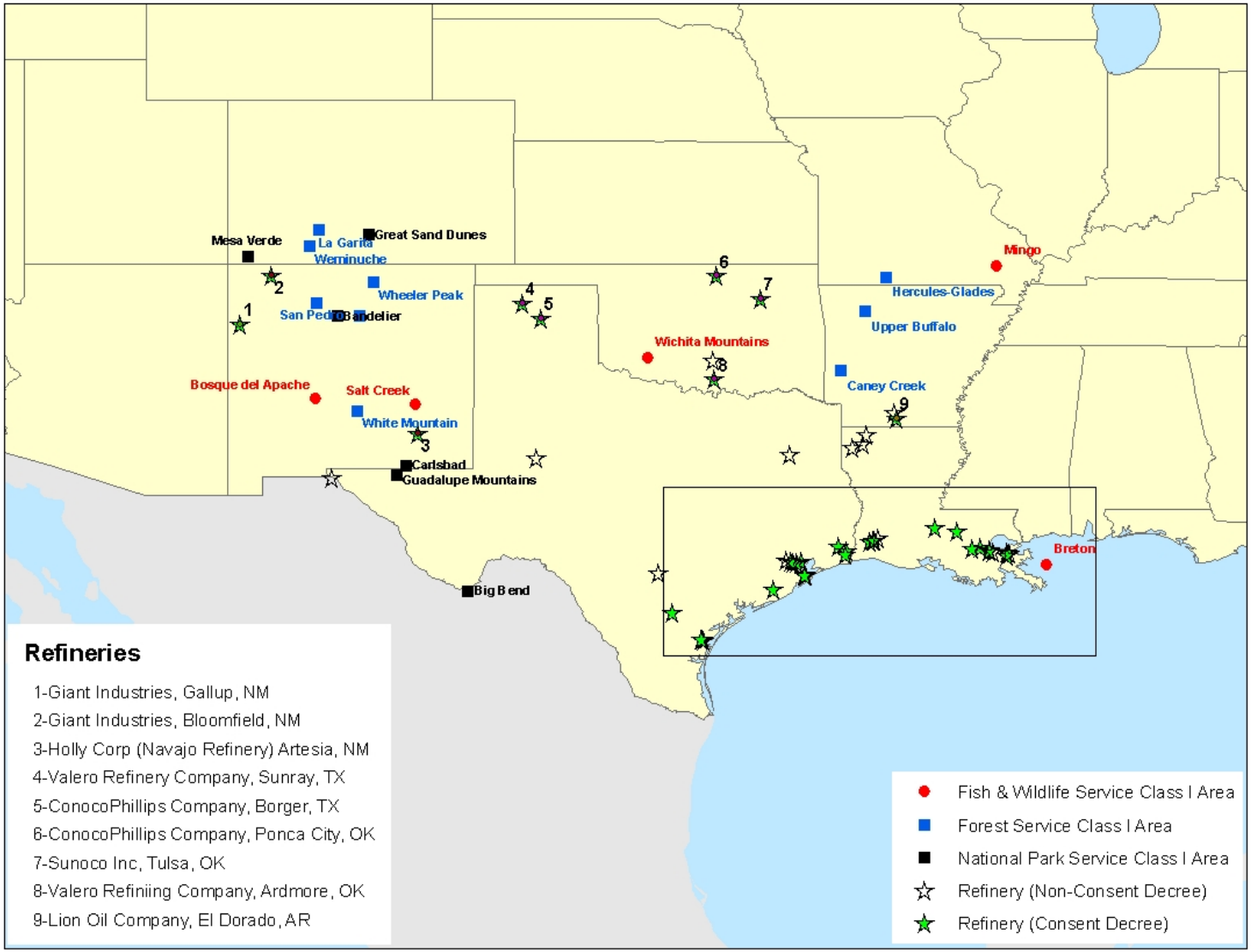
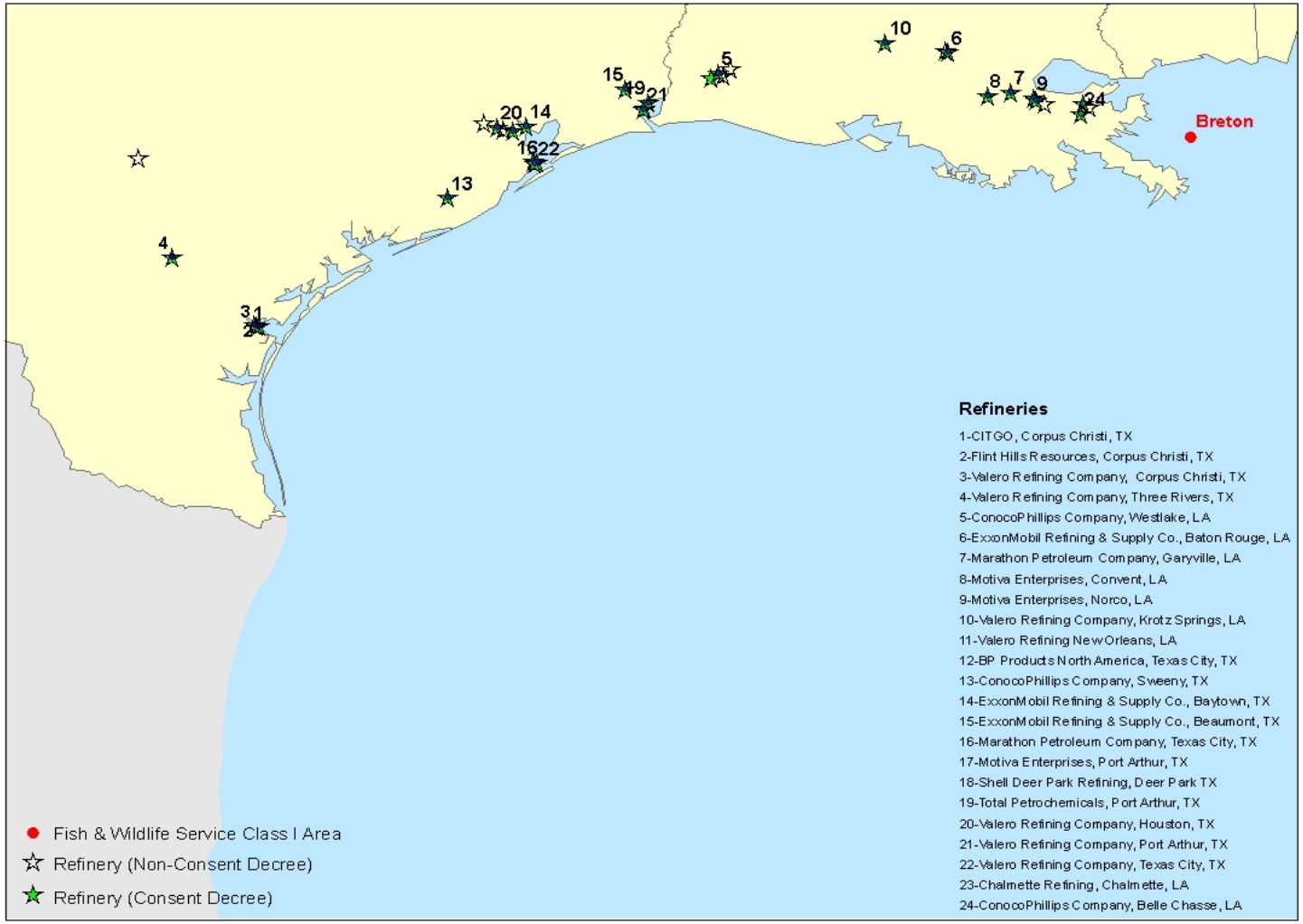


Figure 1-2. Location of Petroleum Refineries in EPA Region VI: Gulf Coast Insert



2. REFINERY CONSENT DECREE REQUIREMENTS AND EMISSION CHANGES

The various consent decrees negotiated between EPA and petroleum refiners are complex legal documents that contain numerous terms, conditions, stipulations and penalties. Presented within this section is a brief, simplified summary of consent decree requirements related to emissions of NO_X, SO_2, PM and VOC For a comprehensive treatment of the subject matter, the reader is referred to the consent decree (found at http://www.epa.gov/Compliance/resources/cases/civil/caa/oil/index.html) and associated semi-annual reports. The semi-annual reports are publicly-available documents and can be requested from EPA.

2.1 BP

2.1.1 Affected Refineries

BP owns and operates five refineries that are part of the consent decree. These refineries are as follows.

Refinery	Capacity (Barrels per Day)[7]
Carson (Los Angeles), California	265,000
Cherry Point (Ferndale), Washington	225,000
Texas City, Texas	417,000
Toledo, Ohio	131,000
Whiting, Indiana	410,000

Only the Texas City Refinery is located within EPA Region VI.

2.1.2 Consent Decree Requirements

2.1.2.1 Fluid Catalytic Cracking Units

To control emissions of NO_X, the consent decree specifies that BP is to install and begin operation of a selective catalytic reduction (SCR) system on Texas City FCCU 2 no later than December 31, 2005. The SCR unit is to achieve a NO_X limit of 20 ppmvd at 0% O_2 on a 365-day rolling average no later than July 1, 2006. It is our understanding that FCCU 2 is currently idled but retains its New Source Review (NSR) authorization.

The consent decree specifies use of a NO_X absorbing catalyst in conjunction with a low-NO_X combustion promoter to control emissions from Texas City Refinery FCCU 1 and FCCU 3. Compliance dates are December 31, 2001, for FCCU 3 and the end of the 2003 turnaround for FCCU 1. The final NO_X emission limits determined based on the results of optimization studies are as follows:

- For FCCU 1, a 365-day rolling average NO_X concentration of 40 ppmvd and a 7-day rolling average concentration of 80 ppmvd, both at 0% O_2. The compliance date is October 7, 2005.
- For FCCU 3, a 365-day rolling average concentration of 20 ppmvd and a 7-day rolling average concentration of 80 ppmvd, both at 0% O_2. applies if a SCR unit is installed. If SCR is not installed, then the NO_X limit is 30 ppmvd on a 365-day rolling average and 60 ppmvd on a 7-day rolling average, both at 0% O_2. The compliance date is July 1, 2007.

[7] Atmospheric crude oil distillation capacity (Source: Energy Information Administration, U.S. Refineries Operable Capacity, 2007, http://www.eia.doe.gov/neic/rankings/refineries.htm)

To control SO_2 emissions from FCCU 3, the consent decree specifies installation of a wet gas scrubber (WGS) or alternative control designed to achieve emission limits of 25 ppmvd or lower on a 365-day rolling average and 50 ppmvd or lower on a 7-day rolling average, both at 0% O_2. Compliance is to be achieved by July 1, 2007.

For FCCU 1, BP is to continue hydrotreatment of FCCU feed. Emissions from FCCU 2 are to be controlled through use of an SO_2 absorbing catalyst additive in conjunction with continued hydrotreatment of FCCU feed. Emission limits established through demonstrations are as follows.

- For FCCU 1, a 365-day rolling average SO_2 concentration of 50 ppmvd and a 7-day rolling average concentration of 150 ppmvd, both at 0% O_2. The compliance date is October 7, 2005.
- For FCCU 2, a 365-day rolling average SO_2 concentration of 126 ppmvd and a 7-day rolling average concentration of 250 ppmvd, both at 0% O_2. The compliance date is October 7, 2005.

2.1.2.2 Heaters and Boilers

The BP consent decree specifies the use of certain control methods to reduce NO_X emission from heaters and boilers at affected refineries by at least 9,632 tons per year.[8,9] Qualifying controls are as follows:

1. SCR or selective non-catalytic reduction (SNCR);
2. Current generation or next generation ultra-low NO_X burners (ULNB);
3. Other technologies which BP demonstrates to EPA's satisfaction should reduce NO_X emissions to 0.040 pounds of NO_X per MMBTU heat input or lower; or
4. Permanent shutdown of a combustion unit with surrender of its operating permit.

An annual heater and boiler update report describes BP's methods and progress toward the emission reduction target.

The consent decree specifies that BP will reduce SO_2 emissions from combustion devices by restricting H_2S in refinery fuel gas and by discontinuing and not commencing the burning of fuel oil except as provided for in the consent decree. As of the consent decree date of lodging, each heater and boiler that combusts refinery fuel gas is considered an affected facility and subject to the requirements of NSPS Subparts A and J. NSPS Subpart J (40 CFR 60.104(a)) establishes the

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[8] The numerical NO_X emission reduction target was established for the eight refineries included in the consent decree. Since then, BP has divested itself of refineries in Mandan, North Dakota; Salt Lake City, Utah; and Yorktown, Virginia. ENVIRON is not aware of how these divestitures affect the numerical emission reduction target for the remaining refinery portfolio.

[9] Compliance is determined by summing actual baseline emissions for the combustion sources listed in the consent decree and subtracting the sum of allowable emissions following implementation of the consent decree for those same combustion sources.

following sulfur emission limits for fuel gas combustion devices: "*No owner or operator subject to the provisions of this subpart shall: (1) Burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf)*."

2.1.2.3 Sulfur Recovery Plant

The BP consent decree specifies that the sulfur recovery plant (SRP) at the refinery is an affected facility with respect to NSPS Subparts A and J as of the consent decree date of lodging (January 2001). SO_2 limits per 40 CFR 60.104(a) are as follows: "*No owner or operator subject to the provisions of this subpart shall: . . . (2) Discharge or cause the discharge of any gases from any Claus sulfur recovery plant containing in excess of: (i) For an oxidation control system or a reduction control system followed by incineration, 250 ppm by volume (dry basis) of sulfur dioxide (SO_2) at zero percent excess air. (ii) For a reduction control system not followed by incineration, 300 ppm by volume of reduced sulfur compounds and 10 ppm by volume of hydrogen sulfide (H_2S), each calculated as ppm SO_2 by volume (dry basis) at zero percent excess air*."

2.1.2.4 Flares

The consent decree requires BP to prepare Hydrocarbon Pollution Minimization Plans (HCFPMP) for each refinery with the intent of reducing the number, duration and quantity of pollutants emitted through hydrocarbon flaring. These plans are due to EPA no later than two years following the date of lodging of the consent decree.

2.1.2.5 Benzene Waste Operations NESHAP Program Enhancements

The consent decrees contain numerous requirements related to Benzene Waste Operations NESHAP compliance and program enhancements. The consent decree, however, does not specify numerical emission targets or required numerical emission reductions.

2.1.2.6 Leak Detection and Repair Program Enhancements

The consent decrees specify certain enhancements to existing leak detection and repair (LDAR) programs at the BP refineries. This includes use of lower leak definitions. The consent decree, however, does not specify numerical emission targets or required numerical emission reductions.

2.1.2.7 Permitting

For emission limits and standards effective on the consent decree date of lodging, BP is to submit administratively-complete permit applications to incorporate these requirements into federally-enforceable New Source Review (NSR) permits within 12 months of the date of lodging. For those requirements effective after the date of lodging, BP is to submit administratively-complete permit

applications within 30 days of the effective date of the requirement.

2.1.3 Emissions Information

The summary of projected emissions and implementation dates is derived from the following sources of information:

- Consent decree,
- NO_X control plans, and
- Information provided by BP personnel.

It is important to note that the information provided by BP and the projected emissions presented within this document do not in and of themselves constitute enforceable commitments on the part of BP. Many of the requirements of the consent decree allow for flexibility in implementation. Until such time as the consent decree is closed (upon completion of all requirements), the methods and the location of the emission reductions, in certain cases, remain subject to change.

2.1.3.1 Fluid Catalytic Cracking Unit

BP provided the following information regarding contribution of the three FCCUs to their July 13, 2010, flexible permit cap.

Table 2.1-1. BP Texas City Refinery FCCU Flexible Permit Cap Contributions

FCCU	Cap Contribution (tons/year)		
	NO_X	SO_2	PM
1	695.39	1,185.19	197.10
2	386.00	657.89	118.26
3	1,262.36	2,151.51	378.43
Combined	2,343.75	3,994.59	693.79

BP notes, however, that the NO_X and SO_2 concentration limits specified by the consent decree are not incorporated into these cap contributions. Therefore, it should be assumed that emissions from the FCCUs will be significantly less than these calculated cap contributions.

A more realistic projection of FCCU NO_X and SO_2 emissions may be made using the following methodology.

(1) Coke Burn Rate (lbs/hour) = FCCU Throughput (bbl/day) x 0.75

(2) FCCU Exhaust = Coke Burn Rate (lbs/hour) x160 dscf/lb Coke Burned (Full Burn) <u>or</u>

FCCU Exhaust = Coke Burn Rate (lbs/hour) x 200 dscf/lb Coke Burned (Partial Burn)

(3) Mass Emission Rate (tons/year) = (PV/RT)(MW)(8760 hours/year)(1 ton/2000 lbs), where

P	=	1 atm
V	=	(FCCU Exhaust)[(Pollutant Concentration, ppmvd)/10^6]
R	=	0.7302 atm-ft^3/lbmole-°R
T	=	520°R
MW	=	Molecular Weight (NO_X = 46, SO_2 = 64)

Assuming a combined FCCU capacity of 179,300 bbl/day, [10] partial burn operation, and average annual NO_X and SO_2 concentrations equal to the highest limits allowed by the consent decree for any of the three FCCUs (40 ppmvd NO_X and 126 ppmvd SO_2), estimated emissions are as follows:

NO_X = 571 tons/year

SO_2 = 2,502 tons/year

With respect to PM emissions, the cap contributions listed in Table 2.1-1 compare favorably to the emissions estimated using Equation 1 and the NSPS limit of 1 lb/1,000 lbs coke burn: 134.5 lbs/hour or 589 tons/year.

Table 2.1-2 summarizes the emissions used in preparing the revised photochemical modeling emissions inventory files. Emissions were distributed among the FCCUs based on relative unit ratios calculated with the cap contributions of Table 2.1-1. For PM, the slightly higher cap contribution value as provided by BP personnel is used.

Table 2.1-2. BP Texas City Refinery FCCU Emissions Used in Revised Modeling Inventory

FCCU	Cap Contribution (tons/year)		
	NO_X	SO_2	PM
1	169.4	742.3	197.1
2	94.0	412.0	118.3
3	307.5	1347.5	378.4
Combined	570.9	2,501.8	693.7

In estimating emissions from the FCCUs for the photochemical modeling emissions inventory, use of average annual projected NO_X, SO_2 and PM emission rates is deemed appropriate for the following reasons.

1. It is ENVIRON's understanding that emissions from an FCCU are relatively constant.

[10] Source: Energy Information Administration (EIA), Form EIA-820, "Annual Refinery Report," 2007.

2. For the large number of FCCUs considered in a regional haze analysis, the collective emissions during any given period should, in aggregate, approach the annual average emission rate. Use of short-term emission limits might be appropriate for a single FCCU, but across the large number of FCCUs included in the photochemical modeling emissions inventory, use of short-term emission limits could result in a gross overestimation of portfolio emissions.

3. Compliance with the NSPS Subpart J emission limit – 1 lb PM per 1,000 lbs coke burned – is demonstrated using the average of three, one-hour test runs (EPA Method 5B or 5F). Therefore, annual PM emissions are calculated using a short-term emission rate.

2.1.3.2 Heaters and Boilers

BP has identified 29 Texas City Refinery heaters and boilers that are part of the NO_X control plan. Table 2.1-3 summarizes the emission rates from these units. The emissions compare to a baseline emission rate for these units of 4,031 tons per year.

Table 2.1-3. BP Texas City Refinery Heater and Boiler Emissions

Emission Unit	Max. Rated Capacity (MMBTU/hr)	NO_X Emission Rate (lb/MMBTU)	NO_X Emissions (tons/year)	SO_2 Emissions (tons/year)	Controls	Year Controlled
PS3A-101BA	331	0.04	63	38.2	LNB	2000
PS3A-101BB	331	0.04	63	38.2	LNB	2000
PRS4-B430	424	0.04	69	49.0	FGR	2000
AU2-B601	307	0.02	31	35.4	LNB	2000
UU3-308B	170	0.04	29	19.6	LNB	2000
PS3A-102BA	126	0.04	23	14.5	LNB	2000
PS3A-102BB	126	0.04	23	14.5	LNB	2000
DDU-B302	63	0.03	7	7.3	LNB	2000
ULC-101B	61	0.03	7	7.0	LNB	2000
DDU-B301	61	0.04	12	7.0	LNB	2000
COKR-B203	60	0.07	18	6.9	ULNB	2001
PS3B-401BC	299	0.04	52	34.5	ULNB	2002
PS3B-401BA	256	0.02	22	29.6	SCR + ULNB	2002
PS3B-401BB	256	0.02	22	29.6	SCR + ULNB	2002
PS3B-402BA	80	0	0	0	Shutdown	2002
PS3B-402BD	80	0	0	0	Shutdown	2002
PRS4-B420	1,399	0.015	92	161.5	SCR	2003
PS3B-402BE	154	0.02	13	17.8	SCR	2003
PRS4-B410	1,399	0.015	92	161.5	SCR	2004
HU2-101B C/D	618	0	0	0	Shutdown	2004
HU2-101A A/B	618	0	0	0	Shutdown	2004

Table 2.1-3. BP Texas City Refinery Heater and Boiler Emissions

Emission Unit	Max. Rated Capacity (MMBTU/hr)	NO_X Emission Rate (lb/MMBTU)	NO_X Emissions (tons/year)	SO_2 Emissions (tons/year)	Controls	Year Controlled
HU2-109C	150	0	0	0	Shutdown	2004
HU2-109A	150	0	0	0	Shutdown	2004
ISOM-B200	80	0	0	0	Shutdown	2006
ISOM-B1101	83	0	0	0	Shutdown	2006
UU3-303B	48	0	0	0	Shutdown	2006
UU4-B403	48	0	0	0	Shutdown	2006
PS3B-402BC	80	0	0	0	Shutdown	2002
PS3B-402BB	80	0	0	0	Shutdown	2002

SO_2 emissions are estimated using the NSPS Subpart J limit and the maximum rated capacity of the combustion units. As an example, SO_2 emissions for PS3A-101BA are estimated as follows:

PS3A-101BA SO_2 = [(331 x 10^6 BTU/hour)/(1,020 BTU/dscf)] x (0.1 gr H_2S/dscf) x (1 lb/7,000 gr) x (64 lbs SO_2/34 lbs H_2S) x (8,760 hrs/year) x (1 ton/2,000 lbs)

PS3A-101BA SO_2 = 38.2 tons/year

For heaters and boilers that are not part of the NO_X heater and boiler plan, emissions in the existing inventory are retained. This applies to NO_X, SO_2 and PM.

2.1.3.3 Sulfur Recovery Plant

Information on SRP emissions has not been provided. However, the consent decree specifies compliance with NSPS Subpart J emission limits as of the consent decree date of lodging. BP personnel have confirmed that the Texas City Refinery SRP was already in compliance with NSPS subpart J emission limits and no additional SO_2 emission reductions will be realized. Therefore, the emission rates in the current photochemical modeling emissions inventory are retained.

2.1.3.4 Flares

Information on flare emissions has not been provided. Therefore, the emission rates in the existing photochemical modeling emissions inventory are retained.

2.1.3.5 Leak Detection and Repair Program Enhancements

No estimate of VOC emission reductions resulting from implementation of enhanced LDAR programs is currently available. Therefore, the emission rates in the current photochemical modeling

emissions inventory are retained.

2.1.3.6 Summary of Emission Rates

Attachment C presents a summary of projected and calculated post-consent decree emission rates for the BP Texas City Refinery. This attachment provides the following information concerning units affected by the consent-decree:

(i) A description of each affected unit and its function, including associated unit identification numbers and emission point identifications;

(ii) Potential post-consent decree emission rates as projected by the refinery or calculated by ENVIRON given emission limits and unit design specifications, both for a short-term (tons/day) and long-term (tons/year) basis;

(iii) Actual emission rates (tons/day) for the year 2005.

In determining actual 2005 emission rates for those units covered by the consent decree at the BP Texas City Refinery, ENVIRON utilized emission inventory data as provided by the 2005 Texas AFS Format File (AFS File).

In order to properly correlate unit names as given by the consent decree to emission rates present in the AFS File, Facility Identification Numbers (FINs) and Emission Point Numbers (EPNs) were used for matching purposes. ENVIRON relied upon FINs provided by BP personnel to identify units within the AFS File. The NO_x, SO_2, VOC and PM_{10} emission rates from the AFS File associated with each unit FIN was then incorporated into the attachment. Fugitive VOC emissions were taken as the sum of VOC emissions resulting from the "Equipment Leak" category of the AFS File. The AFS File also supplied the corresponding EPN for each unit's FIN, and this EPN was then listed in the attachment. Non-zero AFS File emission rate values were given preference in the case that two emission rates for the same pollutant were provided for a single unit, one of which rates was listed as zero.

If a successful match was not made, ENVIRON assigned a FIN and EPN from the AFS File, along with the corresponding NO_x, SO_2, VOC and PM_{10} emission rates. Based on the emission point descriptions from the consent decree, ENVIRON attempted to select a FIN and EPN from among like sources, or units with similar functions and operations. For example, if an emissions unit was listed as a heater in the consent decree, then ENVIRON attempted to select a heater from the AFS File. These units' FINs and EPNs are indicated in bold red, italicized font.

In circumstances where emission rates from the AFS File were not present for a pollutant from a given unit, even if identified by FIN or EPN, the label "N.L." has been employed to mark emissions which were *not listed*.

2.2 Chalmette Refining

2.2.1 Affected Refineries

Chalmette Refining, L.L.C., is a joint venture between ExxonMobil and Petróleos de Venezuela S.A. (PDVSA). Chalmette Refining owns and operates one refinery that is part of the consent decree.

Refinery	Capacity (Barrels per Day)[11]
Chalmette, Louisiana	192,760

Refineries wholly-owned and operated by joint venture partner ExxonMobil are covered under a separate consent decree and are discussed in Section 2.5 of this report.

2.2.2 Consent Decree Requirements (FCCU)

2.2.2.1 Fluid Catalytic Cracking Unit

Chalmette Refining has one FCCU. An existing wet gas scrubber (WGS) controls emissions of SO_2. PM emissions are controlled by the WGS and existing third-stage separators. At the time of the consent decree, Chalmette Refining proposed using a Thermal DeNOx system and/or use of catalyst additives to control NO_X emissions. Final NO_X emission limits are 40 ppmvd on a 365-day rolling average basis and 80 ppmvd on a 7-day rolling average basis, both at 0% O_2. Chalmette Refining is to be in compliance with these limits no later than December 31, 2008.

Final SO_2 emission limits for the FCCU are as follows: 25 ppmvd on a 365-day rolling average and 50 ppmvd on a 7-day rolling average, both at 0% O_2. These limits are to be achieved no later than December 31, 2006.

With respect to PM, the Chalmette Refining FCCU is to comply with the NSPS Subpart J limit of 1.0 pound PM per 1,000 pounds of coke burned. This limit is to be achieved as of the consent decree entry date (October 2005).

In addition to the referenced requirements for the FCCU, the consent decree specifies that the FCCU catalyst regenerator is an affected facility subject to the requirements of NSPS Subparts A and J. SO_2 limits per 40 CFR 60.104(b) are as follows: "*Each owner or operator that is subject to the provisions of this subpart shall comply with one of the following conditions for each affected fluid catalytic cracking unit catalyst regenerator: (1) With an add-on control device, reduce sulfur dioxide emissions to the atmosphere by 90 percent or maintain sulfur dioxide emissions to the atmosphere less than or equal to 50 ppm by volume (ppmv), whichever is less stringent; or (2) Without the use of an add-on control device, maintain sulfur oxides emissions calculated as sulfur*

[11] Atmospheric crude oil distillation capacity (Source: Energy Information Administration, U.S. Refineries Operable Capacity, 2007, http://www.eia.doe.gov/neic/rankings/refineries.htm)

dioxide to the atmosphere less than or equal to 9.8 kg/Mg (20 lb/ton) coke burn-off; or (3) Process in the fluid catalytic cracking unit fresh feed that has a total sulfur content no greater than 0.30 percent by weight." Chalmette Refining is to comply with the NSPS SO_2 requirements no later than December 31, 2006.

PM limits per 40 CFR 60.102(a) are as follows: "*No owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any fluid catalytic cracking unit catalyst regenerator: (1) Particulate matter in excess of 1.0 kg/Mg (2.0 lb/ton) of coke burn-off in the catalyst regenerator*." Chalmette Refining is to comply with the NSPS PM emission limit as of the consent decree entry date (October 2005).

2.2.2.2 Combustion Units

The Chalmette Refining consent decree specifies the use of "qualifying controls" to reduce NO_X emission from Appendix A combustion units at the refinery by at least 380 tons per year.[12] Qualifying controls are as follows:

1. Selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR);
2. Current generation or next generation ultra-low NO_X burners (ULNB);
3. Other technologies which Chalmette Refining demonstrates to EPA's satisfaction should reduce NO_X emissions to 0.040 pounds of NO_X per MMBTU heat input or lower; or
4. Permanent shutdown of a combustion unit with surrender of its operating permit.

A NO_X control plan with annual updates describes Chalmette Refining's methods and progress toward the emission reduction target. The emission reductions are to be achieved no later than December 31, 2009.

The consent decree specifies that Chalmette Refining will reduce SO_2 emissions from combustion devices by restricting H_2S in refinery fuel gas and by discontinuing and not commencing the burning of fuel oil except as provided for in the consent decree. As of the consent decree entry date, each heater and boiler that combusts refinery fuel gas is an affected facility subject to the requirements of NSPS Subparts A and J. Combustion devices subject to a different schedule are identified in Appendix C to the consent decree. NSPS Subpart J (40 CFR 60.104(a)) establishes the following emission limits for fuel gas combustion devices: "*No owner or operator subject to the provisions of this subpart shall: (1) Burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf)*."

[12] Compliance is determined by summing actual baseline emissions for the combustion sources listed in the consent decree and subtracting the sum of allowable emissions following implementation of the consent decree for those same combustion sources.

2.2.2.3 Sulfur Recovery Plant

The Chalmette Refining consent decree specifies that all sulfur recovery plants (SRP) at the refinery are affected facilities with respect to NSPS Subparts A and J as of the consent decree entry date (October 2005). SO_2 limits per 40 CFR 60.104(a) are as follows: "*No owner or operator subject to the provisions of this subpart shall: . . . (2) Discharge or cause the discharge of any gases from any Claus sulfur recovery plant containing in excess of: (i) For an oxidation control system or a reduction control system followed by incineration, 250 ppm by volume (dry basis) of sulfur dioxide (SO_2) at zero percent excess air. (ii) For a reduction control system not followed by incineration, 300 ppm by volume of reduced sulfur compounds and 10 ppm by volume of hydrogen sulfide (H_2S), each calculated as ppm SO_2 by volume (dry basis) at zero percent excess air*."

2.2.2.4 Flares

The Chalmette Refining consent decree specifies that the following hydrocarbon flares are affected facilities and are to comply with the emission standards in NSPS Subparts A and J:

- Chalmette Refinery Flare 1, and
- Chalmette Refinery Flare 2.

NSPS Subpart J (40 CFR 60.104(a)) establishes the following emission limits for fuel gas combustion devices, including flares: "*No owner or operator subject to the provisions of this subpart shall: (1) Burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf)*." The compliance date is March 31, 2007, for both flares.

In the consent decree, Chalmette Refining committed to installing and operating a new flare gas recovery (FGR) system to serve Chalmette Refinery Flare 1. The FGR is to be installed and operational no later than December 31, 2006.

2.2.2.5 Benzene Waste Operations NESHAP Program Enhancements

The consent decrees contain numerous requirements related to Benzene Waste Operations NESHAP compliance and program enhancements. The consent decree, however, does not specify numerical emission targets or required numerical emission reductions.

2.2.2.6 Leak Detection and Repair Program Enhancements

To reduce fugitive emissions of VOC from process equipment, the consent decree requires Chalmette Refining to undertake certain LDAR program enhancements. These enhancements include compliance with the requirements of 40 CFR 60, Subpart GGG as of the consent decree entry date (October 2005). The consent decree, however, does not specify numerical emission targets or required numerical emission reductions.

2.2.2.7 Coke Barn Fugitive Emission Control Program

The Chalmette Refining consent decree includes provisions requiring an evaluation of fugitive PM emissions from the coke barn. As appropriate, additional control measures are to be implemented. However, the consent decree does not specify an emission limit or emission reduction target.

2.2.2.8 Permitting

For emission limits and standards effective on the consent decree entry date, Chalmette Refining is to submit administratively-complete permit applications to incorporate these requirements into federally-enforceable New Source Review (NSR) permits within 120 days of the entry date. For those requirements effective after the entry date, Chalmette Refining is to submit administratively-complete permit applications within 90 days of the effective date of the requirement.

2.2.3 Emissions Information

The summary of projected emissions and implementation dates is derived from the following sources of information:

- Consent decree, and
- Permit applications.

It is important to note that the information and projected emissions presented within this document do not in and of themselves constitute enforceable commitments on the part of Chalmette Refining. Many of the requirements of the consent decree allow for flexibility in implementation. Until such time as the consent decree is closed (upon completion of all requirements), the methods and the location of the emission reductions, in certain cases, remain subject to change.

2.2.3.1 Fluid Catalytic Cracking Unit

In March 2007, Chalmette Refining submitted a Part 70/PSD revision air permit application to the Louisiana Department of Environmental Quality (LDEQ). Among the purposes of the permit application is to incorporate certain requirements of the consent decree. These requirements include: a) designating the FCCU catalyst regenerator as an affected facility under 40 CFR 60 Subparts A and J; and b) incorporating the Thermal DeNOx project into the permit. Permitted emission rates following implementation of the proposed projects are extracted from the permit application and presented in Table 2.2-1.

In estimating emissions from the FCCU for use in the photochemical modeling emissions inventory, use of average annual projected NO_X, SO_2 and PM emission rates is deemed appropriate for the following reasons.

1. It is ENVIRON's understanding that emissions from an FCCU are relatively constant.

2. For the large number of FCCUs considered in a regional photochemical modeling analysis, the collective emissions during any given period should, in aggregate, approach the annual average emission rate. Use of short-term emission limits might be appropriate for a single FCCU, but across the large number of FCCUs included in the photochemical modeling emissions inventory, use of short-term emission limits could result in a gross overestimation of collective emissions.

3. Compliance with the NSPS Subpart J emission limit – 1 lb PM per 1,000 lbs coke burned – is demonstrated using the average of three, one-hour test runs (EPA Method 5B or 5F). Therefore, annual PM emissions are calculated using a short-term emission rate.

Table 2.2-1. Chalmette Refining FCCU Emissions

EPN	Description	Emission Rate (tons/year)		
		NO_X	SO_2	PM
45	FCC Heater (F-7801)	45.08	4.91	1.83
47	FCC Regenerator Flue Gas Scrubber Vent	160.50	53.79	73.37
48	FCC Regen Aux Burner (F-7802)	2.24	0.26	0.10

Actual and/or anticipated control approaches used to achieve the projected reductions in emissions are as follows.

- Use of WGS to reduce emissions of SO_2 and PM.
- Use of Thermal DeNOx to reduce emissions of NO_X.

2.2.3.2 Combustion Units

Appendix A to the Chalmette Refining consent decree identifies 31 combustion units rated greater than 40 MMBTU/hour. The collective maximum rated capacities (MRC) for these units are 4,008 MMBTU/hour and the collective 2000/2001 baseline NO_X emissions are 1,761 tons/year. As noted previously, the consent decree requires a reduction in NO_X emissions from combustion sources of no less than 380 tons/year. Therefore, projected NO_X emissions following the consent decree are: 1,761 – 380 = 1,381 tons/year

Since information on individual units, including emissions and anticipated control approaches, is not available, emissions are allocated among the combustion units as follows:

$$NO_X \text{ Allocation for Each Emission Unit} = (MRC_i/\Sigma\ MRC) \times \text{Total Projected } NO_X \text{ Emissions}$$

MRC_i is the maximum rated capacity for the individual emission unit and $\Sigma\ MRC$ is the sum of maximum rated capacities for all affected heaters and boilers at the refinery. As an example, NO_X emissions are allocated to Utilities Boiler F-402 (MRC = 320 MMBTU/hour) as follows:

$$F\text{-}402\ NO_X = (320/4{,}008) \times 1{,}381\ \text{tons/year} = 110.3\ \text{tons/year}$$

SO_2 emissions are estimated using the NSPS Subpart J limit and the maximum rated capacity of the combustion units. As an example, SO_2 emissions for Utilities Boiler F-402 are estimated as follows:

$$F\text{-}402\ SO_2 = [(320 \times 10^6\ \text{BTU/hour})/(1{,}020\ \text{BTU/dscf})] \times (0.1\ \text{gr}\ H_2S/\text{dscf}) \times (1\ \text{lb}/7{,}000\ \text{gr}) \times (64\ \text{lbs}\ SO_2/34\ \text{lbs}\ H_2S) \times (8{,}760\ \text{hrs/year}) \times (1\ \text{ton}/2{,}000\ \text{lbs})$$

$$F\text{-}402\ SO_2 = 37.0\ \text{tons/year}$$

2.2.3.3 Sulfur Recovery Plant

Information on SRP emissions has not been provided. However, the consent decree specifies compliance with NSPS Subpart J emission limits as of the consent decree Date of Entry (October 2005). Therefore, it is reasonable to assume that the Chalmette Refining SRP was already in compliance with NSPS subpart J emission limits and no additional SO_2 emission reductions will be realized. Therefore, the emission rates in the current photochemical modeling emissions inventory will be retained.

2.2.3.4 Flares

Information on flare emissions has not been provided. However, the consent decree specifies implementation of a flare gas recovery (FGR) system on Flare 1. Assuming the FGR system is sized to handle worst-case flows during normal operation, emissions from the flare *during normal operation* should be limited to pilot gas combustion – or very close to zero. For purposes of revising the photochemical modeling emissions inventory, we assume that emissions from Chalmette Refining Flare 1 are zero for NO_X, SO_2 and PM.

2.2.3.5 Leak Detection and Repair Program Enhancements

No estimate of VOC emission reductions resulting from implementation of enhanced LDAR programs is currently available. Therefore, the emission rates in the current photochemical modeling emissions inventory are retained.

2.2.3.6 Summary of Emission Rates

Attachment C presents a summary of projected and calculated post-consent decree emission rates for Chalmette Refining. This attachment provides the following information concerning units affected by the consent-decree:

(i) A description of each affected unit and its function, including associated unit identification numbers and emission point identifications;

(ii) Potential post-consent decree emission rates as projected by the refineries or calculated by ENVIRON given emission limits and unit design specifications, both for a short-term (tons/day) and long-term (tons/year) basis;

(iii) Actual emission rates (tons/day) for the years 2002, 2004 or 2005.

In determining actual 2004 emission rates for those units covered by the consent decree at the Chalmette Refinery, ENVIRON utilized emission inventory data as provided by the 2004 Louisiana AFS Format File (AFS File) and an emission point description database provided by the LDEQ (LDEQ database).[13]

In order to properly correlate unit names and/or descriptions as given by the consent decree to emission rates present in the AFS File, emission point descriptions were used for matching purposes. ENVIRON matched emission point descriptions from the consent decree with the corresponding emission point description from the LDEQ database. The LDEQ database contains a NEDS ID for each entry. The NEDS ID corresponds to the Point ID field in the AFS Format File. When a successful match was made between the consent decree and the LDEQ database, ENVIRON populated the Attachment C table with the corresponding Stack and Point IDs from the AFS File, along with the corresponding NO_x, SO_2, VOC and PM_{10} emission rates. If a successful match was not made, ENVIRON assigned a Stack and Point ID from the Louisiana AFS File, along with the corresponding NO_x, SO_2, VOC and PM_{10} emission rates. Based on the emission point descriptions from the consent decree, ENVIRON attempted to select a Stack and Point ID from among like sources, or units with similar functions and operations. For example, if an emissions unit was listed as a heater in the consent decree, then ENVIRON attempted to select a heater from the AFS File. These units' Stack and Point IDs are indicated in bold red, italicized font

In circumstances where emission rates from the AFS File were not present for a pollutant from a given unit, even if identified by Stack or Point ID, the label "N.L." has been employed to mark emissions which were *not listed*.

[13] Emission point description database was provided by Ms. Jackie Heber of LDEQ on August 28, 2007. According to Ms. Heber, the NEDS ID from this database corresponds to the Point ID field in the Louisiana AFS Format File.

2.3 CITGO

2.3.1 Affected Refineries

CITGO owns and operates six refineries that are part of the consent decree. These refineries are as follows.

Refinery	Capacity (Barrels per Day)[14]
Corpus Christi, Texas (East and West Refineries)	156,000
Lake Charles, Louisiana	429,500
Lemont, Illinois	167,000
Paulsboro, New Jersey	32,000
Savannah, Georgia	28,000

The three refineries shown in italics are located within EPA Region VI.

2.3.2 Consent Decree Requirements

2.3.2.1 Fluid Catalytic Cracking Units (FCCU)

The Corpus Christi East Refinery has two FCCUs, designated FCCU 1 and FCCU 2. The Lake Charles Refinery has three FCCUs, designated Unit A, Unit B and Unit C. NO_X emission limits specified by the consent decree are as follows.

Corpus Christi East Refinery FCCU 1: By December 31, 2006, CITGO is to convert Corpus Christi 1 to full burn operation or comply with concentration-based emission limits of 20 ppmvd NO_X (0% O_2, 365-day rolling average) and 40 ppmvd NO_X (0% O_2, 7-day rolling average). Additionally, CITGO is to implement a NO_X emission reduction program for Corpus Christi 1. This includes trials and demonstrations of low-NO_X combustion promoters and NO_X reducing catalyst additives. Final results of the demonstration are to be reported to EPA no later than September 30, 2013. Based on the results of the demonstrations, EPA will establish both short and long-term concentration-based NO_X emission limits. Compliance is upon issuance of final emission limits by EPA. As an alternative, CITGO may comply with concentration-based emission limits of 20 ppmvd on a 365-day rolling average and 40 ppmvd on a 7-day rolling average, both at 0% O_2.

Corpus Christi East Refinery FCCU 2: CITGO is to conduct a NO_X minimization study and demonstration at Corpus Christi 2. The final results of the demonstration are to be reported to EPA no later than August 31, 2007. Emission limits are to be established by EPA based on the demonstration and shall be between 20 ppmvd and 23 ppmvd, both at 0% O_2 and on a 365-day

[14] Atmospheric crude oil distillation capacity (Source: Energy Information Administration, U.S. Refineries Operable Capacity, 2007, http://www.eia.doe.gov/neic/rankings/refineries.htm)

rolling average. If the long-term limit is 20 ppmvd NO_X, the short-term limit will be 40 ppmvd NO_X at 0% O_2 on a 7-day rolling average. Compliance is upon issuance of final emission limits by EPA. As an alternative, CITGO may comply with concentration-based emission limits of 20 ppmvd on a 365-day rolling average and 40 ppmvd on a 7-day rolling average, both at 0% O_2.

Lake Charles Refinery Units A, B and C: CITGO is to implement a NO_X emission reduction program for the three Lake Charles Refinery FCCUs. This includes trials and demonstrations of low-NO_X combustion promoters and NO_X reducing catalyst additives. Final results of the demonstration are to be reported to EPA no later than September 30, 2010, for Units B and C and March 31, 2012, for Unit A. Based on the results of the demonstrations, EPA will establish both short and long-term concentration-based NO_X emission limits. Compliance is upon issuance of final emission limits by EPA. As an alternative, CITGO may comply with concentration-based emission limits of 20 ppmvd on a 365-day rolling average and 40 ppmvd on a 7-day rolling average, both at 0% O_2.

SO_2 emission limit requirements specified by the consent decree are as follows.

Lake Charles Refinery Units B and C: CITGO is to install and operate a wet gas scrubber (WGS) and comply with the following SO_2 emission limits: 25 ppmvd on a 365-day rolling average and 50 ppmvd on a 7-day rolling average, both at 0% O_2. The compliance dates are as follows.

- Lake Charles B: December 31, 2006
- Lake Charles C: December 31, 2007

Corpus Christi 1 and 2, Lake Charles Unit A: CITGO is to implement a program to reduce SO_2 emissions by using SO_2 reducing catalyst additives. Final results of the demonstrations are to be reported to EPA according to the following schedule.

- Corpus Christi 1: September 30, 2013
- Corpus Christi 2: March 31, 2010
- Lake Charles A: March 31, 2012

Based on the results of the demonstrations, EPA will establish both short and long-term concentration-based SO_2 emission limits. Compliance is upon issuance of final emission limits by EPA. As an alternative, CITGO may comply with concentration-based emission limits of 25 ppmvd on at365-day rolling average and 50 ppmvd on a 7-day rolling average, both at 0% O_2.

To control emissions of PM, CITGO is to install and operate WGSs and/or third-stage separators, or continue operation of existing electrostatic precipitators. PM emission limit requirements specified by the consent decree are as follows.

Lake Charles Refinery Units B and C: CITGO is to install and operate a WGS and comply with a PM emission limit of 0.5 lb per 1,000 pounds of coke burned on a 3-hour average basis. The compliance dates are as follows.

- Lake Charles B: December 31, 2006
- Lake Charles C: December 31, 2007

The consent decree has the option to establish PM emission limits based on source testing. The limits are to be no lower than 0.5 lb per 1,000 pounds of coke burned on a 3-hour average basis.

Corpus Christi 1 and 2, Lake Charles Unit A: At any time during the life of the consent decree, CITGO may accept a PM emission limit of 0.5 lb PM per 1,000 pounds of coke burned on a 3-hour average basis for the Corpus Christi 1, Corpus Christi 2 and Lake Charles Unit A FCCUs.

The consent decree specifies that the FCCU catalyst regenerators are affected facilities subject to the requirements of NSPS Subparts A and J, according to the following schedule:

FCCU	Effective Date for SO_2	Effective Date for PM
Corpus Christi FCCU 1	January 1, 2012	December 31, 2006
Corpus Christi FCCU 2	July 1, 2008	April 30, 2005
Lake Charles Unit A	January 1, 2010	March 31, 2010
Lake Charles Unit B	December 31, 2006	December 31, 2006
Lake Charles Unit C	December 31, 2007	December 31, 2007

SO_2 limits per 40 CFR 60.104(b) are as follows: "*Each owner or operator that is subject to the provisions of this subpart shall comply with one of the following conditions for each affected fluid catalytic cracking unit catalyst regenerator: (1) With an add-on control device, reduce sulfur dioxide emissions to the atmosphere by 90 percent or maintain sulfur dioxide emissions to the atmosphere less than or equal to 50 ppm by volume (ppmv), whichever is less stringent; or (2) Without the use of an add-on control device, maintain sulfur oxides emissions calculated as sulfur dioxide to the atmosphere less than or equal to 9.8 kg/Mg (20 lb/ton) coke burn-off; or (3) Process in the fluid catalytic cracking unit fresh feed that has a total sulfur content no greater than 0.30 percent by weight*." PM limits per 40 CFR 60.102(a) are as follows: "*No owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any fluid catalytic cracking unit catalyst regenerator: (1) Particulate matter in excess of 1.0 kg/Mg (2.0 lb/ton) of coke burn-off in the catalyst regenerator*."

2.3.2.2 Heaters and Boilers

The CITGO consent decree specifies the use of "qualifying controls" to reduce NO_X emission from combustion units at the six affected refineries by at least 50 percent from the baseline by June 30, 2011. Based on the list of affected boilers and heaters in Appendix C to the consent decree, the target

NO_X emission reduction is 4,949 tons per year.[15] Qualifying controls are as follows:

1. Selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR);
2. Current generation or next generation ultra-low NO_X burners (ULNB);
3. Other technologies which CITGO demonstrates to EPA's satisfaction should reduce NO_X emissions to 0.040 pounds of NO_X per MMBTU heat input or lower;
4. Permanent shutdown of a heater or boiler with revocation of its operating permit;
5. If current or next generation ULNB are technologically infeasible, CITGO may propose an alternative technology which CITGO demonstrates to EPA's satisfaction will reduce emissions to 0.055 lb/MMBTU or lower; and
6. In the case of the compressor engines at the Corpus Christi East Refinery, catalytic converters designed to achieve two grams of NO_X per Brake Horsepower per hour.

A NO_X control plan with annual updates describes CITGO's methods and progress toward the emission reduction target.

The consent decree specifies that CITGO will reduce SO_2 emissions from combustion devices by restricting H_2S in refinery fuel gas and by discontinuing and not commencing the burning of fuel oil except as provided for in the consent decree. As of the consent decree entry date (except as noted in Appendix E to the consent decree), each heater and boiler that combusts refinery fuel gas is an affected facility and subject to the requirements of NSPS Subparts A and J. NSPS Subpart J (40 CFR 60.104(a)) establishes the following emission limits for fuel gas combustion devices: "*No owner or operator subject to the provisions of this subpart shall: (1) Burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf)*."

2.3.2.3 Sulfur Recovery Plants

CITGO owns and operates Claus sulfur recovery plants (SRPs) at the Corpus Christi East, Corpus Christi West, and Lake Charles refineries. The consent decree specifies that SRPs are affected facilities with respect to NSPS Subparts A and J according to the following schedule:

Sulfur Recovery Plant	**NSPS Effective Date**
Corpus Christi East SRP	January 2, 2005
Corpus Christi West SRP	January 2, 2005
Lake Charles SRP	January 2, 2005

SO_2 limits per 40 CFR 60.104(a) are as follows: "*No owner or operator subject to the provisions of*

[15] Compliance is determined by summing actual baseline emissions for the combustion sources listed in the consent decree and subtracting the sum of allowable emissions following implementation of the consent decree for those same combustion sources.

this subpart shall: . . . (2) Discharge or cause the discharge of any gases from any Claus sulfur recovery plant containing in excess of: (i) For an oxidation control system or a reduction control system followed by incineration, 250 ppm by volume (dry basis) of sulfur dioxide (SO_2) at zero percent excess air. (ii) For a reduction control system not followed by incineration, 300 ppm by volume of reduced sulfur compounds and 10 ppm by volume of hydrogen sulfide (H_2S), each calculated as ppm SO_2 by volume (dry basis) at zero percent excess air."

2.3.2.4 Sulfuric Acid Plants

No later than December 31, 2006, the Lake Charles sulfuric acid plant shall be an affected facility, subject to the requirements of 40 CFR 60, Subparts A and H, and comply with an emission limit of 3.5 pounds SO_2 per ton of acid produced on a three-hour average basis.

2.3.2.5 Flares

The CITGO consent decree specifies that hydrocarbon flares (identified in Appendix B-1 of the consent decree) are affected facilities and are to comply with the emission standards found in NSPS Subparts A and J. NSPS Subpart J (40 CFR 60.104(a)) establishes the following emission limits for fuel gas combustion devices, including flares: "*No owner or operator subject to the provisions of this subpart shall: (1) Burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf)*." Appendix G to the consent decree specifies compliance dates for each flare.

- Corpus Christi East Refinery: December 2007
- Corpus Christi West Refinery: December 2006
- Lake Charles Refinery: December 2011

2.3.2.6 Benzene Waste Operations NESHAP Program Enhancements

The consent decrees contain numerous requirements related to Benzene Waste Operations NESHAP compliance and program enhancements. The consent decree, however, does not specify numerical emission targets or required numerical emission reductions.

2.3.2.7 Leak Detection and Repair Program Enhancements

The consent decree specifies certain enhancements to existing leak detection and repair (LDAR) programs at the CITGO refineries. This includes use of lower leak definitions. The consent decree, however, does not specify numerical emission targets or required numerical emission reductions.

2.3.2.8 Permitting

For emission limits and standards effective on the consent decree entry date, CITGO is to submit permit applications to incorporate these requirements into federally-enforceable New Source Review (NSR) permits no later than March 31, 2005. For those requirements effective after the entry date, CITGO is to submit a permit application within 30 days of the effective date of the requirement.

2.3.3 Emissions Information

The summary of projected emissions and implementation dates is derived from the following sources of information:

- Consent decree,
- Semi-annual reports,
- Permits,
- NO_X control plans, and
- Information provided by CITGO personnel.

It is important to note that the information provided by CITGO and the projected emissions presented within this document do not in and of themselves constitute enforceable commitments on the part of CITGO. Many of the requirements of the consent decree allow for flexibility in implementation. Until such time as the consent decree is closed (upon completion of all requirements), the methods and the location of the emission reductions, in certain cases, remain subject to change.

2.3.3.1 Fluid Catalytic Cracking Units

Tables 2.3-1, 2.3-2, and 2.3-4 present projected NO_X, SO_2 and PM emissions, respectively, for affected FCCUs at the Lake Charles and Corpus Christi East refineries. Projected PM emissions for the Corpus Christi East Refinery are not provided; therefore, emissions are estimated as follows.

(1) Coke Burn Rate[16] (lbs/hour) = FCCU Throughput (82,800 bbl/day) x 0.75

Coke Burn Rate = 62,100 lbs/hour

(2) FCCU PM Emissions = 62,100 lbs coke burned/hour x 1.0 lb PM/1,000 lbs coke burned

FCCU PM Emissions = 62.1 lbs/hour = 272.0 tons/year

FCCU Exhaust (dscf/hour) = Coke Burn Rate (lbs/hour) x 200 dscf/lb Coke Burned (Partial Burn)

[16] Source: Energy Information Administration (EIA), Form EIA-820, "Annual Refinery Report," 2007.

There are no FCCUs covered by the consent decree at the Corpus Christi West Refinery.

In estimating emissions from the FCCUs for the photochemical modeling emissions inventory, use of average annual projected NO_X, SO_2 and PM emission rates is deemed appropriate for the following reasons.

1. It is ENVIRON's understanding that emissions from an FCCU are relatively constant.

2. For the large number of FCCUs considered in a regional photochemical modeling analysis, the collective emissions during any given period should, in aggregate, approach the annual average emission rate. Use of short-term emission limits might be appropriate for a single FCCU, but across the large number of FCCUs included in the photochemical modeling emissions inventory, use of short-term emission limits could result in a gross overestimation of collective emissions.

Table 2.3-1. CITGO FCCU NO_X Emissions

Refinery	Projected Emissions by Year (tons)						
	2007	2008	2009	2010	2011	2012	2013
Lake Charles	1,590	1,590	1,090	815	815	815	815
Corpus Christi East	397	397	397	397	397	117	117

Table 2.3-2. CITGO FCCU SO_2 Emissions

Refinery	Projected Emissions by Year (tons)						
	2007	2008	2009	2010	2011	2012	2013
Lake Charles	2,782	2,782	2,782	932	932	932	932
Corpus Christi East	2,132	1,162	1,162	1,162	1,162	222	222

Table 2.3-3. CITGO FCCU PM Emissions

Refinery	Projected Emissions by Year (tons)						
	2007	2008	2009	2010	2011	2012	2013
Lake Charles	425	425	425	365	365	365	365
Corpus Christi East	272	272	272	272	272	272	272

Emissions are allocated among the site FCCUs using the ratio of actual emissions contained in the emissions inventories.

Actual and/or anticipated control approaches used to achieve the projected reductions in emissions are as follows.

Corpus Christi East Refinery:

- Use of low-NO_X combustion promoters and NO_X reducing catalyst additives for FCCU 1.
- Additional control measures, if any, for reduction NO_X emissions from FCCU 2 are not identified.
- Use of SO_2 reducing catalyst additives for FCCUs 1 and 2.
- Methods for reducing PM emissions, if any, are not identified.

Lake Charles Refinery:

- Use of low-NO_X combustion promoters and NO_X reducing catalyst additives for Units A, B and C.
- Use of WGS to reduce emissions of SO_2 and PM from Units B and C.
- Voluntary use of a WGS to control emissions of SO_2 and PM from Unit A.
- Methods for reducing PM emissions from Unit A, if any, are not identified.

2.3.3.2 Heaters and Boilers

Table 2.3-4 presents projected NO_X emissions for affected heaters and boilers at the Lake Charles and combined Corpus Christi East and West Refineries ("Corpus Christi"). CITGO has provided projections for the collective set of affected heaters and boilers as addressed within the NO_X control plan and Appendix C of the consent decree. Information on individual units, including emissions and anticipated control approaches has not been provided.

Table 2.3-4. CITGO Heater and Boiler NO_X Emissions

Refinery	Projected Emissions by Year (tons)						
	2007	2008	2009	2010	2011	2012	2013
Lake Charles	7,852	7,852	7,852	7,852	4,016	4,016	4,016
Corpus Christi	1,047	988	988	988	988	988	988

Control methods identified in the heater and boiler NO_X control plan for the Corpus Christi East Refinery include:

- Boiler shutdowns (Replacement Boiler B, Boiler 61-B1A, Boiler 61-B1C, PC Boiler 8 and PC Boiler 7);
- Installation of ULNB (No. 4 Platformer Reaction Heater); and

- Installation of catalytic converters (No. 4 Platformer Compressors).

Control methods identified for the Lake Charles Refinery include:

- Boiler shutdowns (Boiler B-3, Boiler B-3B, Boiler B-2, Boiler B-3A, Boiler B-3C, Boiler B-2A); Boiler 7) with subsequent installation of new boilers; and
- Installation of low-NO_X burners with flue gas recirculation (Boiler B-1, Boiler B-1A, Boiler B-1C, Boiler B-1B).

In revising the photochemical modeling emission inventory, heater and boiler NO_X emissions are allocated as follows:

$$NO_X \text{ Allocation for Each Emission Unit} = (MRC_i/\Sigma\ MRC) \times \text{Total Projected } NO_X \text{ Emissions}$$

MRC_i is the maximum rated capacity for the individual emission unit and $\Sigma\ MRC$ is the sum of maximum rated capacities for all affected heaters and boilers at the refinery. In the case of the Corpus Christi East and West Refineries, the sum of both refineries' maximum rated capacities is considered when allocating NO_X emissions for individual units at either site.

SO_2 emissions are estimated using the NSPS Subpart J limit and the maximum rated capacity of the combustion units.

2.3.3.3 Sulfur Recovery Plants

Information provided by CITGO indicates that the SRPs were in compliance with NSPS subpart J emission limits upon consent decree entry and no additional SO_2 emission reductions will be realized. Therefore, the emission rates in the current photochemical modeling emissions inventory are retained.

2.3.3.4 Sulfuric Acid Plant

Information on projected Lake Charles Refinery sulfuric acid plant emissions has not been provided. Therefore, the emission rates in the current photochemical modeling emissions inventory will be retained.

2.3.3.5 Flares

Information on projected flare emissions has not been provided. Therefore, the emission rates in the current photochemical modeling emissions inventory are retained.

2.3.3.6 Leak Detection and Repair Program Enhancements

No estimate of VOC emission reductions resulting from implementation of enhanced LDAR

programs is currently available. Therefore, the emission rates in the current photochemical modeling emissions inventory are retained.

2.3.3.7 Summary of Emission Rates

Attachment C presents a summary of projected and calculated post-consent decree emission rates for CITGO refineries. This attachment provides the following information concerning units affected by the consent-decree:

(i) A description of each affected unit and its function, including associated unit identification numbers and emission point identifications;

(ii) Potential post-consent decree emission rates as projected by the refineries or calculated by ENVIRON given emission limits and unit design specifications, both for a short-term (tons/day) and long-term (tons/year) basis;

(iii) Actual emission rates (tons/day) for the years 2004 or 2005.

In determining actual 2005 emission rates for those units covered by the consent decree at the CITGO Corpus Christi Refineries, ENVIRON utilized emission inventory data as provided by the 2005 Texas AFS Format File.

In order to properly correlate unit names as given by the consent decree to emission rates present in the AFS File, Facility Identification Numbers (FINs) and Emission Point Numbers (EPNs) were used for matching purposes. ENVIRON relied upon FINs provided by the CITGO consent decree and the CITGO 2006 Heater and Boiler Plan to identify units within the AFS File. The NO_x, SO_2, VOC and PM_{10} emission rates from the AFS File associated with each unit FIN was then incorporated into the attachment. Fugitive VOC emissions were taken as the sum of VOC emissions resulting from the "Equipment Leak" category of the AFS File. The AFS File also supplied the corresponding EPN for each unit's FIN, and this EPN was then listed in the attachment. Non-zero AFS File emission rate values were given preference in the case that two emission rates for the same pollutant were provided for a single unit, one of which rates was listed as zero.

If a successful match was not made, ENVIRON assigned a FIN and EPN from the AFS File, along with the corresponding NO_x, SO_2, VOC and PM_{10} emission rates. Based on the emission point descriptions from the consent decree, ENVIRON attempted to select a FIN and EPN from among like sources, or units with similar functions and operations. For example, if an emissions unit was listed as a heater in the consent decree, then ENVIRON attempted to select a heater from the AFS File. These units' FINs and EPNs are indicated in bold red, italicized font.

In determining actual 2004 emission rates for those units covered by the consent decree at the CITGO Lake Charles Refinery, ENVIRON utilized emission inventory data as provided by the 2004 Louisiana AFS Format File (AFS File) and an emission point description database provided by the

LDEQ (LDEQ database).[17]

In order to properly correlate unit names and/or descriptions as given by the consent decree to emission rates present in the AFS File, emission point descriptions were used for matching purposes. ENVIRON matched emission point descriptions from the consent decree with the corresponding emission point description from the LDEQ database. The LDEQ database contains a NEDS ID for each entry. The NEDS ID corresponds to the Point ID field in the AFS Format File. When a successful match was made between the consent decree and the LDEQ database, ENVIRON populated the Attachment C table with the corresponding Stack and Point IDs from the AFS File, along with the corresponding NO_x, SO_2, VOC and PM_{10} emission rates. If a successful match was not made, ENVIRON assigned a Stack and Point ID from the Louisiana AFS File, along with the corresponding NO_x, SO_2, VOC and PM_{10} emission rates. Based on the emission point descriptions from the consent decree, ENVIRON attempted to select a Stack and Point ID from among like sources. For example, if an emissions unit was listed as a heater in the consent decree, then ENVIRON attempted to select a heater from the AFS File.

In circumstances where emission rates from the AFS File were not present for a pollutant from a given unit, even if identified by FIN or EPN, or Stack or Point ID, the label "N.L." has been employed to mark emissions which were *not listed*.

[17] Emission point description database was provided by Ms. Jackie Heber of LDEQ on August 28, 2007. According to Ms. Heber, the NEDS ID from this database corresponds to the Point ID field in the Louisiana AFS Format File.

2.4 Conoco / ConocoPhillips

2.4.1 Affected Refineries

Two consent decrees were negotiated for the petroleum refineries currently owned and operated by ConocoPhillips. One consent decree covers the refineries owned and operated by Conoco, Inc., prior to the merger with the Phillips Petroleum company in 2002. The second consent decree covers the refineries of the merged ConocoPhillips that are not part of the Conoco consent decree. The ConocoPhillips Company is referred to as COPC in this report. COPC refineries that are a part of the consent decree are as follows.

Refinery	Capacity (Barrels per Day)[18]
Belle Chasse (Alliance), Louisiana	247,000
Billings, Montana	58,000
Borger, Texas[19]	146,000
Carson & Wilmington (LAR), California	139,000
Denver (Commerce City), Colorado[20]	62,000
Ferndale, Washington	96,000
Lake Charles (Westlake), Louisiana	239,400
Linden (Bayway), New Jersey	238,000
Ponca City, Oklahoma	194,000
Rodeo, California	76,000
Arroyo Grande (Santa Maria), California	44,200
Sweeny, Texas	247,000
Trainer, Pennsylvania	185,000
Wood River/Distilling West, Illinois[21]	306,000

The five refineries shown in italics are located within EPA Region VI. The Lake Charles and Ponca City refineries are covered by the Conoco consent decree. The Alliance, Borger and Sweeny refineries are covered by the ConocoPhillips consent decree.

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[18] Atmospheric crude oil distillation capacity (Source: Energy Information Administration, U.S. Refineries Operable Capacity, 2007, http://www.eia.doe.gov/neic/rankings/refineries.htm)

[19] Operating as WRB Refining LLC

[20] Sold to Suncor

[21] Operating as WRB Refining LLC

2.4.2 *Consent Decree Requirements*

2.4.2.1 Fluid Catalytic Cracking Units (FCCU)

The FCCU NO_X emission limit requirements specified by the consent decree are as follows.

Alliance Refinery: By December 31, 2012, COPC is to complete installation and begin operation of a scrubber-based NO_X emission reduction technology (SNERT) to achieve a NO_X concentration of no greater than 20 ppmvd on a 365-day rolling average at 0% O_2. Demonstrations are to be completed by March 31, 2015. Alternatively, by December 31, 2014, COPC can comply with NO_X concentration limits of no greater than 20 ppmvd on a 365-day rolling average and 40 ppmvd on a 7-day rolling average, both at 0% O_2.

Borger Refinery: There are two FCCUs at the Borger Refinery, FCCU 29 and FCCU 40. COPC is to complete installation and begin operation of an enhanced selective non-catalytic reduction (SNCR) system according to the following schedule.

- Borger FCCU 29: December 31, 2006
- Borger FCCU 40: December 31, 2012

Emission limits are to be proposed based on demonstrations. As an alternative to use of enhanced SNCR, COPC can convert the FCCUs to full-burn operation, utilize high-pressure hydrotreating, and commence implementation of a NO_X additives program. Emission limits would also be determined via demonstrations. At any time prior to May 31, 2012, COPC can comply with NO_X concentration limits of no greater than 20 ppmvd on a 365-day rolling average and 40 ppmvd on a 7-day rolling average, both at 0% O_2.

Lake Charles Refinery: COPC is to use low-NO_X combustion promoters and NO_X reducing catalyst additives to reduce emissions from the Lake Charles FCCU. Based on demonstrations, COPC is to propose 3-hour and 365-rolling average concentration limits for both FCCUs. Alternatively, by April 30, 2007, COPC can comply with NO_X concentration limits of no greater than 20 ppmvd on a 365-day rolling average and 40 ppmvd (0% O_2) on a 7-day rolling average, both at 0% O_2.

Ponca City Refinery: There are two FCCUs at the Ponca City Refinery, FCCU No. 4 and FCCU No. 5. COPC is to use low-NO_X combustion promoters and NO_X reducing catalyst additives to reduce NO_X emissions from these two units. Additionally, SNCR is to be installed on the FCCU No. 5 CO Boiler by no later than December 31, 2006. As identified in the second amendment to the consent decree, by October 31, 2005, COPC is to achieve a NO_X concentration of no greater than 40 ppmvd on a 365-day rolling average and 60 ppmvd on a 7-day rolling average for FCCU No. 4, both at 0% O_2. By no later than March 1, 2006, COPC is to comply with an interim NO_X emission limit of no greater than 46 ppmvd on a 365-day rolling average for FCCU No. 5. With respect to final emission limits for FCCU No. 5, based on demonstrations, COPC is to propose 3-hour and 365-day rolling average concentration limits.

Sweeny Refinery: There are two FCCUs at the Sweeny Refinery, FCCU 3 and FCCU 27. By December 31, 2009, COPC is to complete installation and begin operation of a selective catalytic reduction (SCR) system for FCCU 27 to achieve a NO_X concentration of no greater than 20 ppmvd on a 365-day rolling average at 0% O_2. By March 31, 2009, COPC is to begin use of NO_X reducing catalyst additives and low NO_X combustion promoters for FCCU 3. Based on demonstrations, COPC is to propose 7-day and 365-day rolling average concentration limits for FCCU 3. At any time prior to March 1, 2012, COPC can comply with NO_X concentration limits of no greater than 20 ppmvd on a 365-day rolling average and 40 ppmvd on a 7-day rolling average, both at 0% O_2.

SO_2 emission limit requirements specified by the consent decree are as follows.

Alliance Refinery: By December 31, 2009, COPC is to complete installation and begin operation of a wet gas scrubber (WGS) to achieve an SO_2 concentration emission limit of 25 ppmvd or lower on a 365-day rolling average basis and 50 ppmvd or lower on a 7-day rolling average basis, both at 0% O_2.

Borger Refinery: By December 31, 2006, for FCCU 29 and by December 31, 2015, for FCCU 40, COPC is to complete installation and begin operation of a WGS to achieve an SO_2 concentration emission limit of 25 ppmvd or lower on a 365-day rolling average basis and 50 ppmvd or lower on a 7-day rolling average basis, both at 0% O_2. As an alternative to installing WGS, COPC may comply with concentration-based emission limits of 20 ppmvd on a 365-day rolling average and 40 ppmvd on a 7-day rolling average, both at 0% O_2, on both FCCUs by the end of 2007.

Lake Charles Refinery: COPC is to use SO_2 adsorbing catalyst additives to reduce emissions from the Lake Charles FCCU. Based on demonstrations, COPC is to propose 7-day and 365-day rolling average concentration limits. Alternatively, by April 30, 2007, COPC can comply with SO_2 concentration limits of no greater than 25 ppmvd on a 365-day rolling average and 50 ppmvd on a 7-day rolling average, both at 0% O_2.

Ponca City Refinery: COPC is to use SO_2 adsorbing catalyst additives to reduce emissions from FCCU Nos. 4 and 5. Based on demonstrations, COPC is to propose 7-day and 365-day rolling average concentration limits. If these limits are greater than 25 ppmvd or 50 ppmvd for the 7-day and 365-day rolling averages, respectively, COPC is to install additional SO_2 controls in order to meet these limits by the following dates.

- Ponca City No. 4: December 31, 2008
- Ponca City No. 5: December 31, 2006

Sweeny Refinery: By June 30, 2006, COPC is to begin addition of SO_2 reducing catalyst additives to FCCU 3 and FCCU 27. Based on demonstrations, COPC is to propose 7-day and 365-day rolling average SO_2 concentration limits for FCCU 3. Alternatively, COPC can comply with SO_2 concentration limits of no greater than 25 ppmvd on a 365-day rolling average and 50 ppmvd on a 7-day rolling average, both at 0% O_2.

Particulate matter (PM) emission limit requirements specified by the consent decree are as follows.

Alliance Refinery: By December 31, 2009, COPC is to comply with emission limit of 0.5 pound PM per 1,000 pounds of coke burned on a 3-hour average basis.

Borger Refinery: By December 31, 2006, for FCCU 29 and by December 31, 2015, for FCCU 40, COPC is to install and operate a WGS to achieve a PM emission limit of 0.5 pound PM per 1,000 pounds of coke burned on a 3-hour average basis. As an alternative, if SO_2 limits are achieved prior to the end of 2007 without use of WGS, then the PM limit of 0.5 lb per 1,000 pounds of coke burned does not apply.

Lake Charles Refinery: By the date of lodging of the consent decree (December 20, 2001), the Lake Charles FCCU will continue to comply with a PM emission limit of 1 pound PM per 1,000 pounds of coke burned on a 3-hour average basis.

Ponca City Refinery: By December 31, 2008, FCCU No. 4 is to comply with a PM emission limit of 1 pound PM per 1,000 pounds of coke burned on a 3-hour average basis. By December 31, 2006, FCCU No. 5 will comply with a PM emission limit of 1 pound PM per 1,000 pounds of coke burned on a 3-hour average basis.

Sweeny Refinery: By December 31, 2009, COPC is to install and operate a new electrostatic precipitator (ESP) at FCCU 3 to achieve a PM emission limit of 0.5 pound PM per 1,000 pounds of coke burned on a 3-hour average basis.

The consent decree specifies that the FCCU catalyst regenerators are affected facilities subject to the requirements of NSPS Subparts A and J, according to the following schedule.

FCCU	Effective Date for SO_2	Effective Date for PM
Alliance FCCU	December 31, 2009	February 10, 2005
Borger FCCU 29	December 31, 2006	December 31, 2006
Borger FCCU 40	December 31, 2015	April 11, 2005
Lake Charles	January 2, 2004	January 2, 2004
Ponca City FCCU No. 4	January 2, 2004	December 31, 2008
Ponca City FCCU No. 5	January 2, 2004	December 31, 2006
Sweeny FCCU 3	June 30, 2006	December 31, 2009
Sweeny FCCU 27	June 30, 2006	April 11, 2006

SO_2 limits per 40 CFR 60.104(b) are as follows: "*Each owner or operator that is subject to the provisions of this subpart shall comply with one of the following conditions for each affected fluid catalytic cracking unit catalyst regenerator: (1) With an add-on control device, reduce sulfur dioxide emissions to the atmosphere by 90 percent or maintain sulfur dioxide emissions to the atmosphere less than or equal to 50 ppm by volume (ppmv), whichever is less stringent; or (2)*

Without the use of an add-on control device, maintain sulfur oxides emissions calculated as sulfur dioxide to the atmosphere less than or equal to 9.8 kg/Mg (20 lb/ton) coke burn-off; or (3) Process in the fluid catalytic cracking unit fresh feed that has a total sulfur content no greater than 0.30 percent by weight." PM limits per 40 CFR 60.102(a) are as follows: "*No owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any fluid catalytic cracking unit catalyst regenerator: (1) Particulate matter in excess of 1.0 kg/Mg (2.0 lb/ton) of coke burn-off in the catalyst regenerator*."

2.4.2.2 Combustion Units

Two separate consent decrees cover heaters and boilers at Conoco (pre-consolidation) and ConocoPhillips refineries. These consent decrees specify the implementation of a program to reduce NO_X emissions from controlled heaters, boilers and internal combustion engines (ICE) listed in Attachment 3 of the Conoco consent decree and Appendix B of the ConocoPhillips consent decree. The first amendment to the Conoco consent decree specifies a reduction in overall NO_X emissions of at least 1,443 tons per year from the affected refineries. The ConocoPhillips consent decree specifies a reduction in overall NOX emissions of at least 4,951 tons per year from the affected refineries.[22]

The consent decrees specify the use of "qualifying controls" to reduce NO_X emission from combustion units at the affected refineries. For combustion units other than internal combustion engines, qualifying controls are identified as follows:

1. Selective catalytic reduction (SCR);
2. Selective non-catalytic reduction (SNCR);
3. Current generation or next generation ultra low NO_X burners (ULNB);
4. Alternative NO_X control technologies that COPC demonstrates to EPA's satisfaction should reduce emissions to 0.040 pounds of NO_X per MMBTU heat input or lower; and
5. Permanent shutdown of a combustion unit with surrender of its operating permit;

For internal combustion engines, qualify controls include: a) permanent shutdown with surrender of the operating permit; b) installation of air-fuel ratio controllers; and c) installation of other new technologies that COPC demonstrates to EPA's satisfaction should reduce emissions by 80% or greater versus an uncontrolled ICE.

A NO_X control plan with annual updates describes COPC's methods and progress toward the emission reduction target. The emission reductions are to be achieved by July 31, 2009, for Conoco (pre-consolidation) refineries and by December 31, 2012, for ConocoPhillips refineries.

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[22] Compliance is determined by summing actual baseline emissions for the combustion sources listed in the consent decree and subtracting the sum of allowable emissions following implementation of the consent decree for those same combustion sources.

The consent decrees specify that COPC will reduce SO_2 emissions from combustion devices by restricting H_2S in refinery fuel gas and by discontinuing and not commencing the burning of fuel oil except as provided for in the consent decree. As of the date of lodging, each heater and boiler that combusts refinery fuel gas is an affected facility subject to the requirements of NSPS Subparts A and J. NSPS Subpart J (40 CFR 60.104(a)) establishes the following emission limits for fuel gas combustion devices: "*No owner or operator subject to the provisions of this subpart shall: (1) Burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf)*." COPC will discontinue burning fuel oil in all covered heaters and boilers at all refineries from the date of lodging of the consent decree.

2.4.2.3 Sulfur Recovery Plant

COPC owns and operates Claus sulfur recovery plants (SRPs) at each affected refinery. The consent decree specifies that all SRPs are affected facilities with respect to NSPS Subparts A and J according to the following schedule.

Refinery	**NSPS Applicability Date**
Alliance	February 10, 2005
Borger	February 10, 2005
Lake Charles	January 2, 2002
Ponca City	January 2, 2002
Sweeny	February 10, 2005

SO_2 limits per 40 CFR 60.104(a) are as follows: "*No owner or operator subject to the provisions of this subpart shall: . . . (2) Discharge or cause the discharge of any gases from any Claus sulfur recovery plant containing in excess of: (i) For an oxidation control system or a reduction control system followed by incineration, 250 ppm by volume (dry basis) of sulfur dioxide (SO_2) at zero percent excess air. (ii) For a reduction control system not followed by incineration, 300 ppm by volume of reduced sulfur compounds and 10 ppm by volume of hydrogen sulfide (H_2S), each calculated as ppm SO_2 by volume (dry basis) at zero percent excess air*."

2.4.2.4 Flares

COPC is to comply with the requirements of NSPS Subparts A and J according to the following schedule for flaring devices identified in the consent decrees.

Refinery	NSPS Applicability Date
Belle Chasse	December 31, 2011
Borger	December 31, 2011
Sweeny	December 31, 2011
Lake Charles Flares	December 31, 2006
Ponca City Flares	December 31, 2006

NSPS Subpart J (40 CFR 60.104(a)) establishes the following emission limits for fuel gas combustion devices, including flares: "*No owner or operator subject to the provisions of this subpart shall: (1) Burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf)*."

The Conoco consent decree requires that flares in delayed coker blowdown service at the Lake Charles and Ponca City refineries install flare gas recovery (FGR) systems to meet the requirements of NSPS Subparts A and J. FGR was to be installed on the Ponca City Refinery Coker Combo Flare by July 2002, and on the Lake Charles Refinery South Flare by March 31, 2006.

2.4.2.5 Benzene Waste Operations NESHAP Program Enhancements

The COPC consent decrees contain numerous requirements related to Benzene Waste Operations NESHAP compliance and program enhancements. The consent decree, however, does not specify numerical emission targets or required numerical emission reductions.

2.4.2.6 Leak Detection and Repair (LDAR) Program Enhancements

To reduce fugitive emissions of VOC from process equipment, the consent decrees require that COPC undertake certain LDAR program enhancements related to compliance with the requirements of 40 CFR 60, Subpart GGG; Part 61, Subparts J and V; Part 63, Subparts F, H and CC, by no later than 180 days after the date of lodging of the Conoco (pre-consolidation) consent decree and by September 30, 2005, for the ConocoPhillips consent decree. The consent decree, however, does not specify numerical emission targets or required numerical emission reductions.

2.4.2.7 Permitting

For emission limits and standards effective on the date of lodging of the Conoco consent decree, COPC is to submit permit applications to incorporate these requirements into federally-enforceable New Source Review (NSR) permits within 180 days of the date of lodging. For those requirements effective after the entry date, COPC is to submit a permit application within 90 days of the effective date of the requirement. For emission limits and standards effective on the date of lodging of the ConocoPhillips consent decree, COPC is to submit permit applications to incorporate these

requirements into federally-enforceable New Source Review (NSR) permits no later than June 30, 2005. For those requirements effective after the entry date, COPC is to submit a permit application within 90 days of the effective date of the requirement.

2.4.3 Emissions Information

The summary of projected emissions and implementation dates is derived from the following sources of information:

- Consent decree, and
- Information provided by ConocoPhillips personnel.

It is important to note that the information provided by ConocoPhillips and the projected emissions presented within this document do not in and of themselves constitute enforceable commitments on the part of ConocoPhillips. Many of the requirements of the consent decree allow for flexibility in implementation. Until such time as the consent decree is closed (upon completion of all requirements), the methods and the location of the emission reductions, in certain cases, remain subject to change.

2.4.3.1 Fluid Catalytic Cracking Unit

Following is a summary of FCCU emissions by refinery. Following the discussion, projected emissions are presented in Table 2.4-1.

Alliance Refinery: COPC personnel provided projections of annual FCCU emissions following implementation of consent decree emission limits. SCR, not SNERT (as identified in the consent decree), will be used to reduce emissions of NO_X. A WGS will be used to reduce emissions of SO_2 and PM. The WGS is scheduled for installation in 2009 while the SCR is scheduled to be fully operational and achieving the consent decree emission limits by 2014.

Borger Refinery: Final NO_X emissions have yet to be established for FCCUs 29 and 40. Therefore, COPC cannot provide projected NO_X emissions. COPC personnel have, however, provided 2005 and 2006 actual emissions for both FCCUs. The highest of the two years is used in the updated photochemical modeling inventory. With respect to SO_2, COPC has provided an estimated refinery-wide flexible permit emission cap of 3,602 tons per year following full consent decree implementation. This emission limit reflects the reduction in SO_2 emissions that have resulted or will result from achieving a 25 ppmvd concentration limit of each FCCU. An estimate of projected worst-case future emissions is made by subtracting 2006 actual SO_2 emissions from all other sources at the refinery (821 tons) from the cap and allocating based on 2006 actual emissions.

SO_2 Emissions for FCCU 29 = [(3602 – 821) tpy] x [3360/(3360 + 3339) tons] = 1,395 tpy

SO_2 Emissions for FCCU 40 = [(3602 - 821) tpy] x [3339/(3360 + 3339) tons] = 1,386 tpy

As for PM emissions, the higher of the 2005 and 2006 actual emissions are used as estimates of

projected emissions. Actual PM emissions, however, should decrease significantly following installation of a WGS on each FCCU.

Lake Charles Refinery: According to COPC personnel, the Lake Charles FCCU has already achieved the emission reductions required under the consent decree. To project future emissions, the highest actual annual emissions for the most recent three-year period (2004-2006) are used. For projected PM emissions, 2006 actual emissions are excluded. Per COPC, actual PM emissions for 2006 include emissions during upset events that are not representative of normal operations.

Ponca City Refinery: According to COPC personnel, the Ponca City FCCUs (Nos. 4 and 5) have already achieved the NO_X emission reductions required under the consent decree. To project future NO_X emissions, the highest actual annual emissions for the most recent two-year period (2005-2006) are used. For SO_2 and PM, COPC personnel provided projections of annual FCCU emissions following implementation of consent decree emission limits. A WGS is used to control emissions of SO_2 and PM from each FCCU. The WGS is to be installed and operational on FCCU 4 by 2008. The WGS on FCCU 5 is in place and operational.

Sweeny Refinery: COPC has provided an estimated refinery-wide flexible permit NO_X emission cap of 679 tons per year following full consent decree implementation. This emission limit reflects the reduction in NO_X emissions that have resulted or will result from installation of SCR on FCCU 27 and use of NO_X reducing catalyst additives and low-NO_X combustion promoters on FCCU 3. An estimate of projected worst-case future emissions is made by subtracting 2006 actual NO_X emissions from all other sources at the refinery, 475 tons, from the cap and allocating based on 2006 actual emissions.

$$NO_X \text{ Emissions for FCCU 3} = [(679 - 475) \text{ tpy}] \times [113/(113 + 430) \text{ tons}] = 42 \text{ tons/year}$$

$$NO_X \text{ Emissions for FCCU 27} = [(679 - 475) \text{ tpy}] \times [430/(113 + 430) \text{ tons}] = 162 \text{ tons/year}$$

Projections are not provided for SO_2 emissions. Therefore, actual 2006 SO_2 emissions are used in the photochemical modeling emissions inventory. With respect to PM emissions, a projection is provided for FCCU 3. For FCCU 27, actual emissions are used in the inventory. SCR will be used to control NO_X emissions from FCCU 27 by 2009. An electrostatic precipitator (ESP) will be used to control emissions of PM from FCCU 3 by 2009.

In estimating emissions from the FCCUs for the photochemical modeling emissions inventory, use of average annual projected NO_X, SO_2 and PM emission rates is deemed appropriate for the following reasons.

1. It is ENVIRON's understanding that emissions from an FCCU are relatively constant.
2. For the large number of FCCUs considered in a regional photochemical modeling analysis, the collective emissions during any given period should, in aggregate, approach the annual average emission rate. Use of short-term emission limits might be appropriate for a single FCCU, but

across the large number of FCCUs included in the photochemical modeling emissions inventory, use of short-term emission limits could result in a gross overestimation of portfolio emissions.

3. Compliance with the NSPS Subpart J emission limit – 1 lb PM per 1,000 lbs coke burned – is demonstrated using the average of three, one-hour test runs (EPA Method 5B or 5F). Therefore, annual PM emissions are calculated using a short-term emission rate.

Table 2.4-1. ConocoPhillips FCCU Emissions

FCCU	Emission Rate (tons/year)		
	NO_X	SO_2	PM
Alliance FCCU	102	176	191
Borger FCCU 29	788	1,395	477
Borger FCCU 40	495	1,386	385
Lake Charles FCCU	126	270	49
Ponca City FCCU 4	43	55	110
Ponca City FCCU 5	118	257	131
Sweeny FCCU 3	42	280	74
Sweeny FCCU 27	162	1,113	111

2.4.3.2 Combustion Units

Tables 2.4-2 through 2.4-6 identify heaters and boilers that are part of the Conoco and ConocoPhillips NO_X control plans. For comparative purposes, baseline emissions are as follows.

Table 2.4-2. ConocoPhillips Alliance Refinery Heater and Boiler Emissions

Emission Unit	Max. Rated Capacity (MMBTU/hr)	NO_X Emission Rate (lb/MMBTU)	Max. NO_X Emissions (tons/year)	Controls	Year Controlled
1291 / H-2/3	182	0.029	22.8	Burners	2004
1391 / H-1	342	0.050	74.9	Burners	2001
1391 / H-2/3	338	0.050	74.0	Burners	2001
1391 / H-4	192	0.050	42.0	Burners	2008
1791 / H-1	129	0.050	28.3	Burners	2010
1792 / H-1	167	0.050	36.6	Burners	2001
191 / H-1	900	0.019	72.9	SCR	2008
	210	0.000	0.0	Shutdown	2006
291 / H-1	128	0.050	27.9	Burners	2012
291 / H-2	101	0.050	22.0	Burners	2008
491 / H-1	180	0.050	39.4	Burners	2009

Table 2.4-2. ConocoPhillips Alliance Refinery Heater and Boiler Emissions

Emission Unit	Max. Rated Capacity (MMBTU/hr)	NO_X Emission Rate (lb/MMBTU)	Max. NO_X Emissions (tons/year)	Controls	Year Controlled
491 / H-2	226	0.050	49.5	Burners	2009
891 / H-1	240	0.000	0.0	Shutdown	2011

Table 2.4-3. ConocoPhillips Borger Refinery Heater and Boiler Emissions

Emission Unit	Max. Rated Capacity (MMBTU/hr)	NO_X Emission Rate (lb/MMBTU)	Max. NO_X Emissions (tons/year)	Controls	Year Controlled
CCH 10 U117	98	0.000	0.0	Shutdown	2011
CCH 28 U626	163	0.000	0.0	Shutdown	2011
CCU 9 U135	113	0.000	0.0	Shutdown	2011
HTR 19.03 T661	139	No Information Available.			
REB 29 N114	91	0.031	12.3	Burners	2012
HTR 11 C819	72	0.000	0.0	Shutdown	2008
REB 26 T116	91	0.031	12.3	Burners	2011
BLR 250#	362	0.000	0.0	Shutdown	2002
BLR 2.2 600#	150	0.000	0.0	Shutdown	2004
Engine 12E6	3	0.450	6.5	SCR	2008
Engine 55E1	6	0.000	0.0	Shutdown	2008
Engine 55E2	6	0.000	0.0	Shutdown	2008
Engine 55E3	6	0.000	0.0	Shutdown	2008
Engine 93E1	9	0.450	17.3	SCR	2003
Engine 93E3	9	0.450	17.3	SCR	2004
Engine 93E4	5	0.000	0.0	Shutdown	2002

Table 2.4-4. ConocoPhillips Lake Charles Refinery Heater and Boiler Emissions

Emission Unit	Max. Rated Capacity (MMBTU/hr)	NO_X Emission Rate (lb/MMBTU)	Max. NO_X Emissions (tons/year)	Controls	Year Controlled
B-3 LP Boiler	116	0.000	0.0	Shutdown	2003
B-4 LP Boiler	116	0.000	0.0	Shutdown	2003
B-6 HP Boiler	295	0.060	17.7	ULNB/FGR	2002
B-76001 Excel Boiler	348	Existing controls prior to consent decree.			
H-00014 Thermal Cracker	119	0.030	3.6	NGULNB	2004

Table 2.4-4. ConocoPhillips Lake Charles Refinery Heater and Boiler Emissions

Emission Unit	Max. Rated Capacity (MMBTU/hr)	NO_X Emission Rate (lb/MMBTU)	Max. NO_X Emissions (tons/year)	Controls	Year Controlled
H-00026 No. 1 Coker	84	0.030	2.5	NGULNB	2004
H-00046 No. 1 CTU	129	0.000	0.0	Shutdown	2005
H-01101 No. 3 CTU	290	Existing controls prior to consent decree.			
H-01103 No. 3 CVU	110	Existing controls prior to consent decree.			
H-01201 No. 4 HDS	40	Existing controls prior to consent decree.			
H-01202 No. 4 HDS	66	Existing controls prior to consent decree.			
H-11001 HDC H2 Htr.	83	Existing controls prior to consent decree.			
H-11002 HDC Heater	58	Existing controls prior to consent decree.			
H-11003 HDC Heater	43	Existing controls prior to consent decree.			
H-12003 HDF Heater	54	Existing controls prior to consent decree.			
H-16101 No. 10 Ref.	101	Existing controls prior to consent decree.			
H-16102 No. 10 Ref.	179	Existing controls prior to consent decree.			
H-16103 No. 10 Ref.	135	Existing controls prior to consent decree.			
H-16104 No. 10 Ref.	60	Existing controls prior to consent decree.			
H-16105 No. 10 Ref.	49	Existing controls prior to consent decree.			
H-20002 No. 2 CVU	165	Existing controls prior to consent decree.			
H-30001 No. 2 CVU	238	Existing controls prior to consent decree.			

Table 2.4-5. ConocoPhillips Ponca City Refinery Heater and Boiler Emissions

Emission Unit	Max. Rated Capacity (MMBTU/hr)	NO_X Emission Rate (lb/MMBTU)	Max. NO_X Emissions (tons/year)	Controls	Year Controlled
B-6 Main Power Boiler	210	0.00	0.00	Shutdown	2009
B-7 Main Power Boiler	286	0.280	0.00	Shutdown	2009
Cogen Duct Burners	560	0.000	0.00	Shutdown	2006
H-0001 No. 1 CTU CC	220	0.060	13.20	NGULNB	2004
H-0004 No. 4 CTU CC	173	0.040	6.91	NGULNB	2009
H-0015 No. 1 CTU CC	56	0.000	0.00	Shutdown	2004
H-0048 CRU Preheater	387	0.070	27.11	NGULNB	2005
H-0057 Alky Depropanizer	75	0.000	0.00	Shutdown	2008
H-0058 Alky Depropanizer	56	0.000	0.00	Shutdown	2008
H-0059 Alky Depropanizer	113	0.000	0.00	Shutdown	2008

Table 2.4-5. ConocoPhillips Ponca City Refinery Heater and Boiler Emissions

Emission Unit	Max. Rated Capacity (MMBTU/hr)	NO_X Emission Rate (lb/MMBTU)	Max. NO_X Emissions (tons/year)	Controls	Year Controlled
H-5001 No. 5 FCC Preheater	104	0.000	0.00	Shutdown	2007
H-6007 No. 3 CRU Preheater	124	0.070	8.67	NGULNB	2006
H-6014 No. 2 CVU Feed	69	0.050	3.45	NGULNB	2006
H-6015 No. 2 CVU Feed	121	0.050	6.06	NGULNB	2006

Table 2.4-6. ConocoPhillips Sweeny Refinery Heater and Boiler Emissions

Emission Unit	Max. Rated Capacity (MMBTU/hr)	NO_X Emission Rate (lb/MMBTU)	Max. NO_X Emissions (tons/year)	Controls	Year Controlled
HTR 11-36-1	67	No information available.		Burners	
HTR 11-36-5	70	No information available.		Burners	
HTR 14-36-3	88	No information available.		Burners	
HTR 14-36-4	53	No information available.		Burners	
HTR 25.1-36.1	500	0.035	76.7	SCR	2005
HTR 29.1-36-1	277	No information available.		Burners	
HTR 29.2-36-1	202	No information available.		Burners	
HTR 29.2-36-2	202	No information available.		Burners	
HTR 35-36-1	507	No information available.		Burners	

SO_2 emissions are estimated using the NSPS Subpart J limit and the maximum rated capacity of the combustion units. As an example, SO_2 emissions for Alliance Refinery heater 1291 / H-2/3 are estimated as follows:

$$1291 / H\text{-}2/3\ SO_2 = [(182 \times 10^6\ BTU/hour)/(1{,}020\ BTU/dscf)] \times (0.1\ gr\ H_2S/dscf) \times (1\ lb/7{,}000\ gr) \times (64\ lbs\ SO_2/34\ lbs\ H_2S) \times (8{,}760\ hrs/year) \times (1\ ton/2{,}000\ lbs)$$

$$1291 / H\text{-}2/3\ SO_2 = 21.0\ tons/year$$

For heaters and boilers that are not part of the NO_X heater and boiler plan, emissions in the existing inventories are retained. This applies to NO_X, SO_2 and PM.

2.4.3.3 Sulfur Recovery Plants

COPC has provided a summary of 2005 and 2006 SRP actual emissions. All COPC SRPs were in compliance with NSPS Subpart J limits as of the date of consent decree lodging. Therefore, no

additional emission controls are required and it is assumed that current actual emissions are reflective of anticipated future emissions. A summary of 2006 actual SO_2 emissions by refinery is presented in Table 2.4-7. Excluded are emissions associated with non-routine tail gas flaring events.

Table 2.4-7. ConocoPhillips SRP 2006 Actual Emissions

Refinery	2006 SO_2 Emissions (tons)
Alliance	41
Borger	79
Lake Charles	159
Ponca City	1
Sweeny	220

2.4.3.4 Flaring

COPC provided information regarding acid gas and hydrocarbon flaring incidents. However, insufficient information is available regarding routine flaring to project VOC, SO_2 and NO_X emissions. Therefore, no changes are made to the flare emissions currently contained within the photochemical modeling inventory. Exceptions are the Ponca City Refinery Coker Combo Flare and the Lake Charles Refinery South Flare. The consent decree required installation of flare gas recovery systems on those flares by 2002 and 2005, respectively. Therefore, after those dates there should be essentially no emission from those flares during routine operation.

2.4.3.5 Leak Detection and Repair Program Enhancements

No estimate of VOC emission changes resulting from implementation of enhanced LDAR programs is currently available. Therefore, the emission rates in the current photochemical modeling emissions inventory are retained.

2.4.3.6 Summary of Emission Rates

Attachment C presents a summary of projected and calculated post-consent decree emission rates for COPC refineries. This attachment provides the following information concerning units affected by the consent-decree:

(i) A description of each affected unit and its function, including associated unit identification numbers and emission point identifications;

(ii) Potential post-consent decree emission rates as projected by the refineries or calculated by ENVIRON given emission limits and unit design specifications, both for a short-term (tons/day) and long-term (tons/year) basis;

(iii) Actual emission rates (tons/day) for the years 2004 or 2005.

In determining actual 2005 emission rates for those units covered by the consent decree at the COPC Borger and Sweeny Refineries, ENVIRON utilized emission inventory data as provided by the 2005 Texas AFS Format File.

In order to properly correlate unit names as given by the consent decree to emission rates present in the AFS File, Facility Identification Numbers (FINs) and Emission Point Numbers (EPNs) were used for matching purposes. ENVIRON relied upon FINs provided by the COPC consent decree and information from COPC personnel to identify units within the AFS File. The NO_x, SO_2, VOC and PM_{10} emission rates from the AFS File associated with each unit FIN was then incorporated into the attachment. The AFS File also supplied the corresponding EPN for each unit's FIN, and this EPN was then listed in the attachment. Non-zero AFS File emission rate values were given preference in the case that two emission rates for the same pollutant were provided for a single unit, one of which rates was listed as zero.

If a successful match was not made, ENVIRON assigned a FIN and EPN from the AFS File, along with the corresponding NO_x, SO_2, VOC and PM_{10} emission rates. Based on the emission point descriptions from the consent decree, ENVIRON attempted to select a FIN and EPN from among like sources, or units with similar functions and operations. For example, if an emissions unit was listed as a heater in the consent decree, then ENVIRON attempted to select a heater from the AFS File. These units' FINs and EPNs are indicated in bold red, italicized font.

In determining actual 2004 emission rates for those units covered by the consent decree at the COPC Alliance and Lake Charles Refineries, ENVIRON utilized emission inventory data as provided by the 2004 Louisiana AFS Format File (AFS File) and an emission point description database provided by the LDEQ (LDEQ database).[23]

In order to properly correlate unit names and/or descriptions as given by the consent decree to emission rates present in the AFS File, emission point descriptions were used for matching purposes. ENVIRON matched emission point descriptions from the consent decree with the corresponding emission point description from the LDEQ database. The LDEQ database contains a NEDS ID for each entry. The NEDS ID corresponds to the Point ID field in the AFS Format File. When a successful match was made between the consent decree and the LDEQ database, ENVIRON populated the Attachment C table with the corresponding Stack and Point IDs from the AFS File, along with the corresponding NO_x, SO_2, VOC and PM_{10} emission rates. If a successful match was not made, ENVIRON assigned a Stack and Point ID from the Louisiana AFS File, along with the corresponding NO_x, SO_2, VOC and PM_{10} emission rates. Based on the emission point descriptions from the consent decree, ENVIRON attempted to select a Stack and Point ID from among like sources. For example, if an emissions unit was listed as a heater in the consent decree, then ENVIRON attempted to select a heater from the AFS File.

[23] Emission point description database was provided by Ms. Jackie Heber of LDEQ on August 28, 2007. According to Ms. Heber, the NEDS ID from this database corresponds to the Point ID field in the Louisiana AFS Format File.

In determining actual 2005 emission rates for those units covered by the consent decree at the COPC Ponca City Refinery, ENVIRON utilized emission inventory data as provided by the 2005 Oklahoma AFS Format File (AFS File).

In order to properly correlate unit names and/or descriptions as given by the consent decree to emission rates present in the AFS File, emission point descriptions were used for matching purposes. ENVIRON matched emission point descriptions from the consent decree with the corresponding emission point description from the AFS File (as listed in the sitename field). When a successful match was made between the consent decree and the AFS File, ENVIRON populated the Attachment C table with the corresponding Stack and Point IDs from the AFS File, along with the corresponding NO_x, SO_2, VOC and PM_{10} emission rates. If a successful match was not made, ENVIRON assigned a Stack and Point ID from the AFS File, along with the corresponding NO_x, SO_2, VOC and PM_{10} emission rates. Based on the emission point descriptions from the consent decree, ENVIRON attempted to select a Stack and Point ID from among like sources. For example, if an emissions unit was listed as a heater in the consent decree, then ENVIRON attempted to select a heater from the AFS File.

In circumstances where emission rates from the AFS File were not present for a pollutant from a given unit, even if identified by FIN or EPN, or Stack or Point ID, the label "N.L." has been employed to mark emissions which were *not listed*.

2.5 ExxonMobil

2.5.1 Affected Refineries

ExxonMobil owns and operates six refineries that are part of the consent decree. These refineries are as follows.

Refinery	Capacity (Barrels per Day)[24]
Baton Rouge, Louisiana	503,000
Baytown, Texas	562,500
Beaumont, Texas	348,500
Billings, Montana	60,000
Jolliet, Illinois	238,600
Torrance, California	149,500

The three refineries shown in italics are located within EPA Region VI. In addition to these six refineries, Chalmette Refining, L.L.C., is owned by ExxonMobil in a joint venture with Petróleos de Venezuela S.A. (PDVSA). Chalmette Refining is covered by a separate consent decree and is discussed in Section 2.2 of this report.

2.5.2 Consent Decree Requirements

2.5.2.1 Fluid Catalytic Cracking Units

NO_X emission limits specified by the consent decree are as follows.

Baton Rouge Refinery: The ExxonMobil Baton Rouge Refinery has two FCCUs, designated PCLA 2 and PCLA 3. As of the consent decree entry date, NO_X emissions are to be controlled from both Baton Rouge FCCUs. At the time of the consent decree, ExxonMobil proposed using a Thermal DeNOx system to control NO_X emissions. Long-term final NO_X emission limits are to be in the range of 50-60 ppmvd on a 365-day rolling average basis (0% O_2) and as close to 50 ppmvd as practicable. Short-term final NO_X emission limits are to be in the range of 100-120 ppmvd on a 7-day rolling average basis (0% O_2) and as close to 100 ppmvd as practicable. If final NO_X limits are greater than 50 ppmvd (long-term) or 100 ppmvd (short-term), then supplemental emission reductions are to be made from combustion units at the refinery in accordance with the table on page 22 of the consent decree. The compliance date is October 2006.

Baytown Refinery: The ExxonMobil Baytown Refinery has two FCCUs, designated FCCU 2 and

[24] Atmospheric crude oil distillation capacity (Source: Energy Information Administration, U.S. Refineries Operable Capacity, 2007, http://www.eia.doe.gov/neic/rankings/refineries.htm)

FCCU 3. At the time of the consent decree, ExxonMobil proposed use of a Thermal DeNOx system and/or use of a NO_X-reducing catalyst additive and/or use of a low-NO_X combustion promoter to control emissions of NO_X from FCCU 2. To control emissions of NO_X from FCCU 3, ExxonMobil proposed installing a scrubber-based emission control system. The weighted average of the emission limits for FCCU 2 and FCCU 3 are not to exceed 35 ppmvd on a 365-day rolling average and 70 ppmvd on a 7-day rolling average, both at 0% O_2. Individually, each FCCU is not to exceed 45 ppmvd on a 365-day rolling average and 90 ppmvd on a 7-day rolling average, both at 0% O_2. The compliance date is June 30, 2010.

Beaumont Refinery: The ExxonMobil Beaumont Refinery has a single FCCU. A WGS that commenced operation in 2004 controls emissions of SO_2 and PM. At the time of the consent decree, ExxonMobil proposed using a Thermal DeNOx System to control NO_X emissions. Long-term final NO_X emission limits are to be in the range of 50-60 ppmvd on a 365-day rolling average basis (0% O_2) and as close to 50 ppmvd as practicable. Short-term final NO_X emission limits are to be in the range of 100-120 ppmvd on a 7-day rolling average basis (0% O_2) and as close to 100 ppmvd as practicable. If final NO_X limits are greater than 50 ppmvd (long-term) or 100 ppmvd (short-term), then supplemental emission reductions are to be made from combustion units at the refinery in accordance with the table on page 22 of the consent decree. The compliance date is October 1, 2009.

With respect to SO_2 emissions, the consent decree establishes the following final limits.

Baton Rouge FCCUs: A single wet gas scrubber (WGS) that commenced operation in 1976 controls emissions of SO_2 and PM. SO_2 emission limits of 35 ppmvd on a 365-day rolling average and 70 ppmvd on a 7-day rolling average, both at 0% O_2, are to be achieved no later than January 1, 2006.

Baytown FCCU 2: A WGS that commenced operation in 1974 serves to control SO_2 and PM emissions from FCCU 2. A high-pressure hydrotreater lowers the sulfur content in a portion of the FCCU feed. SO_2 emission limits of 25 ppmvd on a 365-day rolling average and 50 ppmvd on a 7-day rolling average, both at 0% O_2, are to be achieved no later than December 31, 2009.

Baytown FCCU 3: A WGS that commenced operation in 1975 controls SO_2 and PM emissions from FCCU 3. SO_2 emission limits of 25 ppmvd on a 365-day rolling average and 50 ppmvd on a 7-day rolling average, both at 0% O_2, are to be achieved no later than the consent decree entry date.

Beaumont FCCU: 25 ppmvd on a 365-day rolling average and 50 ppmvd on a 7-day rolling average, both at 0% O_2, to be achieved no later than the consent decree entry date.

The consent decree specifies that the FCCU catalyst regenerators are affected facilities subject to the requirements of NSPS Subparts A and J, according to the following schedule.

FCCU	Effective Date for SO_2	Effective Date for PM
Baton Rouge PCLA 2	January 1, 2006	NA
Baton Rouge PCLA 3	January 1, 2006	NA
Baytown FCCU 2	December 31, 2009	December 31, 2009
Baytown FCCU 3	Date of Entry (12/13/2005)	Date of Entry (12/13/2005)
Beaumont FCCU	Date of Entry (12/13/2005)	Date of Entry (12/13/2005)

SO_2 limits per 40 CFR 60.104(b) are as follows: "*Each owner or operator that is subject to the provisions of this subpart shall comply with one of the following conditions for each affected fluid catalytic cracking unit catalyst regenerator: (1) With an add-on control device, reduce sulfur dioxide emissions to the atmosphere by 90 percent or maintain sulfur dioxide emissions to the atmosphere less than or equal to 50 ppm by volume (ppmv), whichever is less stringent; or (2) Without the use of an add-on control device, maintain sulfur oxides emissions calculated as sulfur dioxide to the atmosphere less than or equal to 9.8 kg/Mg (20 lb/ton) coke burn-off; or (3) Process in the fluid catalytic cracking unit fresh feed that has a total sulfur content no greater than 0.30 percent by weight*." PM limits per 40 CFR 60.102(a) are as follows: "*No owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any fluid catalytic cracking unit catalyst regenerator: (1) Particulate matter in excess of 1.0 kg/Mg (2.0 lb/ton) of coke burn-off in the catalyst regenerator*."

2.5.2.2 Combustion Units

The ExxonMobil consent decree specifies the use of "qualifying controls" to reduce NO_X emission from combustion units at the six affected refineries by at least 4,750 tons per year.[25] Qualifying controls are as follows:

1. Selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR);
2. Current generation or next generation ultra-low NO_X burners (ULNB);
3. Other technologies which ExxonMobil demonstrates to EPA's satisfaction should reduce NO_X emissions to 0.040 pounds of NO_X per MMBTU heat input or lower; or
4. Permanent shutdown of a combustion unit with surrender of its operating permit.

A NO_X control plan with annual updates describes ExxonMobil's methods and progress toward the emission reduction target. The emission reductions are to be accomplished no later than September 30, 2010.

[25] Compliance is determined by summing actual baseline emissions for the combustion sources listed in the consent decree and subtracting the sum of allowable emissions following implementation of the consent decree for those same combustion sources.

The consent decree specifies that ExxonMobil will reduce SO_2 emissions from combustion devices by restricting H_2S in refinery fuel gas and by discontinuing and not commencing the burning of fuel oil except as provided for in the consent decree. As of the consent decree entry date, each heater and boiler that combusts refinery fuel gas is an affected facility subject to the requirements of NSPS Subparts A and J. Combustion devices subject to a different schedule are identified in Appendix C to the consent decree. NSPS Subpart J (40 CFR 60.104(a)) establishes the following emission limits for fuel gas combustion devices: "*No owner or operator subject to the provisions of this subpart shall: (1) Burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf)*."

2.5.2.3 Sulfur Recovery Plants

The ExxonMobil consent decree specifies that all sulfur recovery plants (SRP) are affected facilities with respect to NSPS Subparts A and J according to the following schedule:

Sulfur Recovery Plant	**NSPS Effective Date**
Baton Rouge SRP	NA
Baytown SRP	Date of Entry (12/13/2005)
Beaumont SRP	Date of Entry (12/13/2005)

SO_2 limits per 40 CFR 60.104(a) are as follows: "*No owner or operator subject to the provisions of this subpart shall: . . . (2) Discharge or cause the discharge of any gases from any Claus sulfur recovery plant containing in excess of: (i) For an oxidation control system or a reduction control system followed by incineration, 250 ppm by volume (dry basis) of sulfur dioxide (SO_2) at zero percent excess air. (ii) For a reduction control system not followed by incineration, 300 ppm by volume of reduced sulfur compounds and 10 ppm by volume of hydrogen sulfide (H_2S), each calculated as ppm SO_2 by volume (dry basis) at zero percent excess air*."

While the consent decree does not establish the Baton Rouge sulfur recovery plant as an affected facility subject to NSPS Subparts A and J, it does establish essentially identical SO_2 emission limits with an effective date of the consent decree entry date.

2.5.2.4 Flares

The ExxonMobil consent decree specifies that hydrocarbon flares, identified in Appendix G of the consent decree, are affected facilities and shall comply with the emission standards in NSPS Subparts A and J according to a schedule in Appendix G of the consent decree. NSPS Subpart J (40 CFR 60.104(a)) establishes the following emission limits for fuel gas combustion devices, including flares: "*No owner or operator subject to the provisions of this subpart shall: (1) Burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf)*." Compliance dates are as follows.

Baton Rouge Refinery:	All flares in compliance as of the consent decree entry date (October 2005).
Baytown Refinery:	Ranging from the consent decree entry date to 24 months after the entry date (by October 2007).
Beaumont Refinery:	All flares in compliance 42 months after the consent decree entry date (by April 2009).

2.5.2.5 Benzene Waste Operations NESHAP Program Enhancements

The consent decrees contain numerous requirements related to Benzene Waste Operations NESHAP compliance and program enhancements. The consent decree, however, does not specify numerical emission targets or required numerical emission reductions.

2.5.2.6 Leak Detection and Repair Program Enhancements

To reduce fugitive emissions of VOC from process equipment, the consent decree requires ExxonMobil to undertake certain LDAR program enhancements. These enhancements include compliance with the requirements of 40 CFR 60, Subpart GGG, as of the consent decree entry date at the Baton Rouge, Baytown and Beaumont refineries. The consent decree, however, does not specify numerical emission targets or required numerical emission reductions.

2.5.2.7 Permitting

For emission limits and standards effective on the consent decree entry date, ExxonMobil is to submit administratively-complete permit applications to incorporate these requirements into federally-enforceable New Source Review (NSR) permits within 120 days of the entry date. For those requirements effective after the entry date, ExxonMobil is to submit administratively-complete permit applications within 90 days of the effective date of the requirement.

2.5.3 Emissions Information

The summary of projected emissions and implementation dates is derived from the following sources of information:

- Consent decree,
- Best Available Retrofit Technology modeling evaluations,
- NO_X control plans, and/or
- Information provided by ExxonMobil personnel.

It is important to note that the information provided by ExxonMobil and the projected emissions presented within this document do not in and of themselves constitute enforceable commitments on the

part of ExxonMobil. Many of the requirements of the consent decree allow for flexibility in implementation. Until such time as the consent decree is closed (upon completion of all requirements), the methods and the location of the emission reductions, in certain cases, remain subject to change.

2.5.3.1 Baton Rouge Refinery

Emission unit-specific information was not provided; however, ExxonMobil provided refinery-wide actual emissions (presented in Table 2.5-1). ExxonMobil personnel stated that projected emissions for 2007 should be representative of actual emissions for the next several years.

Table 2.5-1. ExxonMobil Baton Rouge Refinery Actual NO_X Emissions

Year	Refinery-Wide NO_X Emissions (Tons)
2002	3,583
2003	3,579
2004	3,056
2005	2,336
2006	2,247
2007	2,026

In revising the photochemical modeling emission inventory, refinery-wide NO_X emissions are allocated as follows:

NO_X Allocation for Each Emission Unit = (Unit Inventory Emissions/Total Inventory Emissions) x 2007 Total NO_X Emissions

No information is available on SO_2 and PM emissions. Therefore, the emission rates in the current photochemical modeling emissions inventory are retained.

2.5.3.2 Baytown Refinery

The ExxonMobil Baytown Refinery has a flexible permit with a plant-wide applicability limit. The permit allows ExxonMobil to adjust emissions at individual emission units as long as the refinery as a whole stays below the flexible permit emission cap. It is ExxonMobil's intent to continue to use the emissions flexibility allowed by the permit into the future.

Fluid Catalytic Cracking Unit: ExxonMobil has provided the following estimate of emissions for the two FCCUs at the Baytown Refinery:

- NO_X emissions of approximately 400 tons/year in 2010;
- SO_2 emissions similar to those represented in 2006 emissions inventory; and
- PM emissions approximately 25 tons/year less in 2010 than in 2006.

While not based upon information provided by ExxonMobil, worst-case FCCU SO_2 emissions can be estimated using information contained within the consent decree and the following methodology.

(1) Coke Burn Rate (lbs/hour) = FCCU Throughput (bbl/day)[26] x 0.75

(2) FCCU Exhaust = Coke Burn Rate (lbs/hour) x160 dscf/lb Coke Burned (Full Burn) <u>or</u>
FCCU Exhaust = Coke Burn Rate (lbs/hour) x 200 dscf/lb Coke Burned (Partial Burn)

(3) Mass Emission Rate (tons/year) = (PV/RT)(MW)(8760 hours/year)(1 ton/2000 lbs), where

P	=	1 atm
V	=	(FCCU Exhaust)[(SO_2 concentration of 25 ppmvd)/10^6]
R	=	0.7302 atm-ft^3/lbmole-°R
T	=	520°R
MW	=	Molecular Weight (SO_2 = 64)

Worst-case emissions of PM are estimated by multiplying the NSPS emission limit (1.0 lb per 1,000 lbs coke burned) by the estimated coke burn rate. Estimated ExxonMobil Baytown Refinery FCCU Emissions are presented in Table 2.5-2. Partial burn operation is assumed in estimating SO_2 emissions.

Table 2.5-2. ExxonMobil Baytown Refinery FCCU Emissions

FCCU	FCCU Capacity (bbl/day)	Emission Rate (tons/year)		
		NO_X	SO_2	PM
FCCUs 2 and 3	223,500	400	619	734

In estimating emissions from the FCCUs for the photochemical modeling emissions inventory, use of average annual projected NO_X, SO_2 and PM emission rates is deemed appropriate for the following reasons.

1. It is ENVIRON's understanding that emissions from an FCCU are relatively constant.
2. For the large number of FCCUs considered in a regional haze analysis, the collective emissions during any given period should, in aggregate, approach the annual average emission rate. Use of short-term emission limits might be appropriate for a single FCCU, but across the large number of FCCUs included in the photochemical modeling emissions inventory, use of short-term emission limits could result in a gross overestimation of portfolio emissions.
3. Compliance with the NSPS Subpart J emission limit – 1 lb PM per 1,000 lbs coke burned – is demonstrated using the average of three, one-hour test runs (EPA Method 5B or 5F). Therefore, annual PM emissions are calculated using a short-term emission rate.

[26] Source: Energy Information Administration (EIA), Form EIA-820, "Annual Refinery Report," 2007.

Combustion Units: As a result of large reductions in NO_X emissions already achieved due to requirements of the Houston/Galveston Area State Implementation Plan, ExxonMobil anticipates limited additional reductions, if any, from boilers and heaters at the Baytown Refinery due to the consent decree. ExxonMobil communicated that future emissions of criteria pollutants, including NO_X and SO_2, from heaters and boilers will be similar to those reported in the 2006 emissions inventory filing. Therefore, the emission rates in the current photochemical modeling emissions inventory are retained.

Sulfur Recovery Plant: The ExxonMobil Baytown Refinery has a reducing SRP that, during normal operation, should not emit SO_2. Therefore, the photochemical modeling emission inventory is modified to reflect no emissions from this unit.

Flares: ExxonMobil communicated that future emissions of criteria pollutants, including SO_2, from flares will be similar to those reported in the 2006 emissions inventory filing. Therefore, the emission rates in the current photochemical modeling emissions inventory are retained.

Leak Detection and Repair Program Enhancements: ExxonMobil communicated that they do not expect any change in VOC emissions from process equipment leaks as a result of the consent decree. Therefore, the emission rates in the current photochemical modeling emissions inventory are retained.

2.5.3.3 Beaumont Refinery

ExxonMobil Beaumont Refinery personnel provided copies of existing permit limits and permit limit changes that are pending. With respect to the combustion units, it should be noted that inclusion in this summary does not necessarily indicate that the individual emission unit is part of the consent decree settlement or that the listed emission rate necessarily reflects the final emission limit under the consent decree. ExxonMobil has until 2010 to achieve the combustion unit NO_X emission reductions required under the consent decree.

Fluid Catalytic Cracking Unit: ExxonMobil has proposed reductions in permit allowable emission rates from the Beaumont Refinery FCCU. Anticipated to take effect in 2009, the revised permit limits are presented in Table 2.5-3.

Table 2.5-3. ExxonMobil Beaumont Refinery FCCU Emissions

EPN	Description	Emission Rate (tons/year)		
		NO_X	SO_2	PM
06STK_003	FCCU Regenerator Scrubber Stack	619.9	431.2	655.8

In estimating emissions from the FCCUs for the photochemical modeling emissions inventory, use of average annual NO_X, SO_2 and PM emission rates is deemed appropriate for the following reasons.

1. It is ENVIRON's understanding that emissions from an FCCU are relatively constant.
2. For the large number of FCCUs considered in a regional haze analysis, the collective emissions during any given period should, in aggregate, approach the annual average emission rate. Use of short-term emission limits might be appropriate for a single FCCU, but across the large number of FCCUs included in the photochemical modeling emissions inventory, use of short-term emission limits could result in a gross overestimation of portfolio emissions.
3. Compliance with the NSPS Subpart J emission limit – 1 lb PM per 1,000 lbs coke burned – is demonstrated using the average of three, one-hour test runs (EPA Method 5B or 5F). Therefore, annual PM emissions are calculated using a short-term emission rate.

Combustion Units: ExxonMobil provided current permitted emission rates and proposed changes for combustion units at the refinery. This includes the proposed shutdown of Boiler No. 22 and The Isomerization Unit Stabilizer Reboiler Heater. [Note: Boilers 15-19 and 32 were shutdown in 2005.] Combustion unit emission rates are presented in Table 2.5-4.

Table 2.5-4. ExxonMobil Beaumont Refinery Combustion Unit Emissions

EPN	Description	Emission Rate (tons/year)		
		NO_X	SO_2	PM
04STK_001	Coker East Stack	31.10	9.21	11.13
04STK_002	Coker Mid Stack	32.32	9.57	11.57
04STK_003	Coker West Stack	30.22	8.95	10.82
04STK_004	Coker Far West Stack	38.79	9.57	2.42
05STK_001	Crude B Atm. Heater H-3101	344.27	40.16	17.50
05STK_002	Crude B Vacuum Heater H-3102	62.50	13.90	2.70
05STK_004	Crude B Heater H-2001	50.60	11.20	2.20
06STK_002	FCC Feed Preheater (B-2)	88.27	19.01	11.62
15STK_001	CHD1 Charge Heater (B-1)	42.18	12.49	3.16
16STK_001	B-1 Charge Heater	26.31	0.13	1.37
16STK_001	B-2 Stripper Reboiler	49.67	0.25	2.59
20STK_001	HDC 1st Stage West Furnace	4.38	1.53	0.59
20STK_002	HDC 1st Stage East Furnace	12.10	1.41	0.50
20STK_003	HDC 2nd Stage Furnace	12.10	1.41	0.50
20STK_004	HDC Stabilizer Reboiler Heater	49.93	11.65	4.99
20STK_005	HDC Splitter Reboiler Heater	19.15	4.58	2.05
25STK_001	Isom. Unit Pretreater Charge Heater	17.08	7.43	2.14
25STK_002	Isom. Unit Stabilizer Reboiler Heater	0	0	0
25STK_003	Isom. Unit Reactor Charge Heater	7.88	2.06	0.59

Table 2.5-4. ExxonMobil Beaumont Refinery Combustion Unit Emissions

EPN	Description	Emission Rate (tons/year)		
		NO_X	SO_2	PM
25STK_004	Isom. Unit Regeneration Heater	1.75	0.46	0.13
27STK_001	Pretreater Heater (H-3401)	48.36	10.1	7.8
27STK_002	Stripper Reboiler (H-3402)	36.62	9.42	5.74
27STK_003	Reformer Heater (H-3403 – H-3406)	216.81	28.78	6.45
27STK_004	Debutanizer Reboiler (H-3408)	23.65	10.03	7.32
28STK_001	PTR4 Rx Charge Heater	42.05	4.91	1.75
28STK_001	PTR4 Depentanizer Reboiler Heater	55.45	6.45	2.47
28STK_003	PTR4 Reformer Heater	326.14	36.12	27.16
28STK_003	PTR4 Debutanizer Reboiler	17.30	3.80	0.80
36STK_002	Atmospheric Heater (B1-A)	100.74	26.29	7.56
36STK_004	Atmospheric Heater (B1-B)	100.74	26.29	7.56
36STK_006	Vacuum Heater (B-2)	24.97	10.86	3.12
36STK_007	Vacuum Heater (B-3)	23.65	10.29	2.96
39STK_001	Extract Heater BA-1/BA-2	27.47	6.40	1.84
56STK_015	Boiler No. 15	0	0	0
56STK_016	Boiler No. 16	0	0	0
56STK_017	Boiler No. 17	0	0	0
56STK_018	Boiler No. 18	0	0	0
56STK_019	Boiler No. 19	0	0	0
56STK_022	Boiler No. 22	0	0	0
57STK_032	Boiler No. 32	0	0	0
57STK_033	Boiler No. 33	187.38	81.51	23.42
57STK_034	Boiler No. 34	187.38	81.51	23.42
61STK_001	Turbine 1 & Duct Burner	188.17	74.07	106.13
61STK_002	Turbine 2 & Duct Burner	188.17	74.07	106.13
61STK_003	Turbine 3 & Duct Burner	188.17	74.07	106.13

Sulfur Recovery Units: ExxonMobil provided current permitted emission rates for the Beaumont Refinery SRUs. These emission rates are summarized in Table 2.5-5.

Table 2.5-5. ExxonMobil Beaumont Refinery SRU Emissions

EPN	Description	Emission Rate (tons/year)		
		NO_X	SO_2	PM
32STK_001	SRU 2/3 Thermal Oxidizer	47.30	403.52	3.15

Flares: There are eight flares at the ExxonMobil Beaumont Refinery that are permitted under a flexible permit cap. Calculated contributions to the cap following a proposed amendment to the flexible permit are presented in Table 2.5-6.

Table 2.5-6. ExxonMobil Beaumont Refinery Flare Emissions

EPN	Emission Rate (tons/year)		
	NO_X	SO_2	PM
60FLR_001	7.81	463.82	0
60FLR_002	0.79	69.55	0
60FLR_003	11.91	506.90	0
60FLR_005	10.66	1,572.28	0
60FLR_006	14.28	174.02	0
60FLR_007	13.17	29.00	0
60FLR_008	9.44	544.52	0
60FLR_010	30.42	325.35	0

2.5.3.3 Summary of Emission Rates

Attachment C presents a summary of projected and calculated post-consent decree emission rates for the ExxonMobil refineries. This attachment provides the following information concerning units affected by the consent-decree:

(i) A description of each affected unit and its function, including associated unit identification numbers and emission point identifications;

(ii) Potential post-consent decree emission rates as projected by the refineries or calculated by ENVIRON given emission limits and unit design specifications, both for a short-term (tons/day) and long-term (tons/year) basis;

(iii) Actual emission rates (tons/day) for the years 2004 or 2005.

In determining actual 2005 emission rates for those units covered by the consent decree at the ExxonMobil Baytown and Beaumont Refineries, ENVIRON utilized emission inventory data as provided by the 2005 Texas AFS Format File.

In order to properly correlate unit names as given by the consent decree to emission rates present in the AFS File, Facility Identification Numbers (FINs) and Emission Point Numbers (EPNs) were used for matching purposes. ENVIRON relied upon FINs provided by ExxonMobil personnel to identify units within the AFS File. The NO_x, SO_2, VOC and PM_{10} emission rates from the AFS File associated with each unit FIN was then incorporated into the attachment. Fugitive VOC emissions were taken as the sum of VOC emissions resulting from the "Equipment Leak" category of the AFS File. The AFS File also supplied the corresponding EPN for each unit's FIN, and this EPN was then listed in the attachment. Non-zero AFS File emission rate values were given preference in the case that two emission rates for the same pollutant were provided for a single unit, one of which rates was listed as zero.

If a successful match was not made, ENVIRON assigned a FIN and EPN from the AFS File, along with the corresponding NO_x, SO_2, VOC and PM_{10} emission rates. Based on the emission point descriptions from the consent decree, ENVIRON attempted to select a FIN and EPN from among like sources, or units with similar functions and operations. For example, if an emissions unit was listed as a heater in the consent decree, then ENVIRON attempted to select a heater from the AFS File. These units' FINs and EPNs are indicated in bold red, italicized font.

In determining actual 2004 emission rates for those units covered by the consent decree at the ExxonMobil Baton Rouge Refinery, ENVIRON utilized emission inventory data as provided by the 2004 Louisiana AFS Format File (AFS File) and an emission point description database provided by the LDEQ (LDEQ database).[27]

In order to properly correlate unit names and/or descriptions as given by the consent decree to emission rates present in the AFS File, emission point descriptions were used for matching purposes. ENVIRON matched emission point descriptions from the consent decree with the corresponding emission point description from the LDEQ database. The LDEQ database contains a NEDS ID for each entry. The NEDS ID corresponds to the Point ID field in the AFS Format File. When a successful match was made between the consent decree covered unit and the LDEQ database, ENVIRON populated the Attachment C table with the corresponding Stack and Point IDs from the AFS File, along with the corresponding NO_x, SO_2, VOC and PM_{10} emission rates. If a successful match was not made, ENVIRON assigned a Stack and Point ID from the Louisiana AFS File, along with the corresponding NO_x, SO_2, VOC and PM_{10} emission rates. Based on the emission point descriptions from the consent decree, ENVIRON attempted to select a Stack and Point ID from among like sources. For example, if an emissions unit was listed as a heater in the consent decree, then ENVIRON attempted to select a heater from the AFS File.

In circumstances where emission rates from the AFS File were not present for a pollutant from a given unit, even if identified by FIN or EPN, or Stack or Point ID, the label "N.L." has been employed to mark emissions which were *not listed*.

2.6 Giant Industries (Western Refining)

2.6.1 Affected Refineries

Giant Industries, Inc. (Giant), a wholly-owned subsidiary of Western Refining, Inc., owns and operates two refineries that are part of the consent decree. These refineries are as follows.

Refinery	Capacity (Barrels per Day)[28]
Gallup, New Mexico (Ciniza Refinery)	20,800
Bloomfield, New Mexico (Bloomfield Refinery)	16,800

Both refineries are located within EPA Region VI.

2.6.2 Consent Decree Requirements

2.6.2.1 Fluid Catalytic Cracking Units (FCCU)

The consent decree specifies that Giant will implement a program to reduce or minimize NO_X and SO_2 emissions from the FCCUs at both the Ciniza and Bloomfield Refineries. If Giant elects to comply with Section VII of the consent decree (Emission Reductions from FCCUs after the Turnarounds Scheduled to Occur in 2009 and 2012) at the Ciniza FCCU during the turnaround scheduled to occur in 2009, then Giant will implement NO_X and SO_2 catalyst programs at the Bloomfield FCCU. The NO_X catalyst program involves the replacement of conventional platinum-based combustion promoter with an approved low-NO_X combustion promoter. The SO_2 catalyst program involves the use of SO_2 reducing catalyst additives. However, if Giant elects to comply with Section VII of the consent decree at the Bloomfield FCCU during the turnaround scheduled for 2009, then Giant will implement the O_2 program and the SO_2 catalyst program at the Ciniza FCCU. The O_2 program requires the conduct of an optimization study to ensure good combustion practices with a goal of reducing stack O_2 as much as feasible. Section VII specifies that Giant will accept NSPS applicability at the FCCU and achieve compliance with the following emission limits.

- NO_X: 20 ppmvd on a 365-day rolling average basis and 40 ppmvd on a 24-hour rolling average basis, each corrected to 0% oxygen.
- SO_2: 25 ppmvd on a 365-day rolling average basis and 50 ppmvd on a 7-day rolling average basis, each corrected to 0% oxygen, and
- PM: 1.0 pound PM per 1000 pounds of coke burned on a 3-hour average basis.

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[27] Emission point description database was provided by Ms. Jackie Heber of LDEQ on August 28, 2007. According to Ms. Heber, the NEDS ID from this database corresponds to the Point ID field in the Louisiana AFS Format File.

[28] Atmospheric crude oil distillation capacity (Source: Energy Information Administration, U.S. Refineries Operable Capacity, 2007, http://www.eia.doe.gov/neic/rankings/refineries.htm).

Giant is to achieve compliance with these emission limits no later than 60 days after startup after the turnaround scheduled to occur in 2009 at either refinery and no later than 60 days after startup of the FCCU after the turnaround currently scheduled to occur in 2012 at the remaining refinery, but not later than December 31, 2009, and December 31, 2012, respectively.

2.6.2.2 Heaters and Boilers

The consent decree specifies that Giant will implement a five-year program to reduce NO_X emissions from heaters and boilers listed in Appendix A to the consent decree by 50% in the aggregate on a refinery-by-refinery basis in the event that one refinery is permanently shutdown. The co-generation units at the Ciniza Refinery (Z-81-G/B104 and Z-81-G/B105) are not included in the NO_X emission reduction program. The consent decree specifies that Giant will install *qualifying controls* on covered heaters and boilers representing at least 50% of those units' total combined maximum heat input rate capacity in the aggregate, including at least 30% of the combined maximum heat input rate capacity at any one refinery. Qualifying controls include the permanent shutdown of a heater or boiler, the installation of next generation ultra low-NO_X burners (ULNB) or other such control technology which Giant demonstrates to the NMED should reduce NO_X emissions to 0.040 lb/MMBTU or lower. Giant must demonstrate compliance with the requirements of the consent decree by no later than June 30, 2010.

The consent decree specifies that Giant will reduce SO_2 emissions from all heaters and boilers at both refineries by restricting H_2S in refinery fuel gas and by discontinuing and not commencing the burning of fuel oil except as provided for in the consent decree. No later than June 30, 2007, all heaters and boilers are affected facilities subject to the requirements of NSPS Subparts A and J. NSPS Subpart J (40 CFR 60.104(a)) establishes the following sulfur emission limits for fuel gas combustion devices: "*No owner or operator subject to the provisions of this subpart shall: (1) Burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf)*."

2.6.2.3 Sulfur Recovery Plants

The sulfur recovery plants (SRPs) at the Ciniza and Bloomfield Refineries utilize a combination of chelation, oxidation, and precipitation for sulfur recovery, and by definition, are not Claus SRPs. As such, the SRPs are not affected facilities under 40 CFR Part 60, Subpart J. If Giant installs a Claus SRP with a capacity greater than 20 long tons per day (LTD), then the unit would be an affected facility under 40 CFR Part 60, Subpart J. SO_2 limits per 40 CFR 60.104(a) are as follows: "*No owner or operator subject to the provisions of this subpart shall: . . . (2) Discharge or cause the discharge of any gases from any Claus sulfur recovery plant containing in excess of: (i) For an oxidation control system or a reduction control system followed by incineration, 250 ppm by volume (dry basis) of sulfur dioxide (SO_2) at zero percent excess air. (ii) For a reduction control system not followed by incineration, 300 ppm by volume of reduced sulfur compounds and 10 ppm by volume of hydrogen sulfide (H_2S), each calculated as ppm SO_2 by volume (dry basis) at zero percent excess*

air."

2.6.2.4 Flares

The Giant consent decree specifies that the flares at the Ciniza and Bloomfield Refineries are affected facilities under 40 CFR Part 60 no later than June 30, 2006, for the Bloomfield Refinery and no later than June 30, 2007, for the Ciniza Refinery. NSPS Subpart J (40 CFR 60.104(a)) establishes the following emission limits for fuel gas combustion devices, including flares: "*No owner or operator subject to the provisions of this subpart shall: (1) Burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf)*."

2.6.2.5 Benzene Waste Operations NESHAP Program Enhancements

The consent decree specifies that Giant will continue compliance with all applicable requirements of the Benzene Waste Operations NESHAP (BWON) in addition to taking on several program enhancements to ensure compliance with applicable BWON requirements. As of the consent decree entry date, Giant believes that each refinery has a Total Annual Benzene (TAB) amount less than 10 megagrams per year (Mg/yr).

2.6.2.6 Leak Detection and Repair Program Enhancements

To reduce fugitive emissions of VOC from process equipment, the consent decree requires Giant to undertake certain LDAR program enhancements, including the development of a written refinery-wide LDAR program for each refinery. Specifically, this program will include an overall, refinery-wide leak rate goal that will be a target for achievement on a process-unit-by-process-unit basis. The consent decree, however, does not specify numerical emission targets or required numerical emission reductions.

2.6.2.7 Permitting

The consent decree requires Giant to submit applications and obtain revisions or modifications to NSR permits no later than 180 days before the deadline of a requirement of the consent decree for which a revision or modification to an NSR permit is required.

2.6.3 Emissions Information

Western Refining did not provide information regarding emission reductions at the Ciniza and Bloomfield refineries resulting from the Giant global consent decree. FCCU NO_X and SO_2 emissions can be estimated, however, using available information and the following methodology.

(1) Coke Burn Rate (lbs/hour) = FCCU Throughput (bbl/day)[29] x 0.75

(2) FCCU Exhaust (dscf/hour) = Coke Burn Rate (lbs/hour) x160 dscf/lb Coke Burned (Full Burn) or
FCCU Exhaust (dscf/hour) = Coke Burn Rate (lbs/hour) x 200 dscf/lb Coke Burned (Partial Burn)

(3) Mass Emission Rate (tons/year) = (PV/RT)(MW)(8760 hours/year)(1 ton/2000 lbs), where

P	=	1 atm
V	=	(FCCU Exhaust)[(Pollutant Concentration, ppmvd)/10^6]
R	=	0.7302 atm-ft^3/lbmole-°R
T	=	520°R
MW	=	Molecular Weight (NO_X = 46, SO_2 = 64)

Emissions of PM are calculated by multiplying the emission limit by the estimated coke burn rate. Estimated FCCU Emissions are presented in Table 2.6-1. Partial burn operation is assumed.

Table 2.6-1. Giant FCCU Emissions

FCCU	FCCU Capacity (bbl/day)	Emission Rate (tons/year)		
		NO_X	SO_2	PM
Bloomfield Refinery	6,500	10	18	21
Ciniza Refinery	11,500	18	32	38

2.6.3.1 Summary of Emission Rates

Insufficient information is available to estimate post-consent decree emissions from other categories of emission sources. Therefore, information contained within the current photochemical modeling emissions inventory is retained, and no changes are provided within Attachment C as with other refineries discussed herein.

[29] Source: Energy Information Administration (EIA), Form EIA-820, "Annual Refinery Report," 2007.

2.7 Koch Industries (Flint Hills Resources)

2.7.1 Affected Refineries

Flint Hills Resources, a wholly-owned subsidiary of Koch Industries, owns and operates three refineries that are part of the consent decree. These refineries are as follows.

Refinery	Capacity (Barrels per Day)[30]
Corpus Christi, Texas	288, 126
Pine Bend (Rosemont), Minnesota	279,300
North Pole, Alaska	210,000

The Corpus Christi Refinery consists of an East Plant and a West plant. Only the Corpus Christi refineries (in italics) are located within EPA Region VI.

2.7.2 Consent Decree Requirements

2.7.2.1 Fluid Catalytic Cracking Units (FCCU)

To control emissions of NO_X, the consent decree specifies that Flint Hills Resources will use low-NO_X absorbing catalyst additives in combination with selective non-catalytic reduction (SNCR) at the Corpus Christi West FCCU. SNCR is to be installed during the turnaround scheduled to begin no later than December 31, 2006. SNCR is to be installed on the Corpus Christi East FCCU during the turnaround scheduled to begin no later than December 31, 2008. The consent decree indicates that, at a minimum, the FCCUs must achieve an annual NO_X concentration of no more than 70 ppmvd (0% O_2).

Flint Hills Resources operates a wet gas scrubber (WGS) on both the Corpus Christi East and Corpus Christi West FCCUs. SO_2 emission limits are to be determined through optimization studies.

The consent decree specifies that the FCCU catalyst regenerators are affected facilities subject to the requirements of NSPS Subparts A and J. SO_2 limits per 40 CFR 60.104(b) are as follows: "*Each owner or operator that is subject to the provisions of this subpart shall comply with one of the following conditions for each affected fluid catalytic cracking unit catalyst regenerator: (1) With an add-on control device, reduce sulfur dioxide emissions to the atmosphere by 90 percent or maintain sulfur dioxide emissions to the atmosphere less than or equal to 50 ppm by volume (ppmv), whichever is less stringent; or (2) Without the use of an add-on control device, maintain sulfur oxides emissions calculated as sulfur dioxide to the atmosphere less than or equal to 9.8 kg/Mg (20 lb/ton) coke burn-off; or (3) Process in the fluid catalytic cracking unit fresh feed that has a total sulfur content no*

[30] Atmospheric crude oil distillation capacity (Source: Energy Information Administration, U.S. Refineries Operable Capacity, 2007, http://www.eia.doe.gov/neic/rankings/refineries.htm)

greater than 0.30 percent by weight." PM limits per 40 CFR 60.102(a) are as follows: "*No owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any fluid catalytic cracking unit catalyst regenerator: (1) Particulate matter in excess of 1.0 kg/Mg (2.0 lb/ton) of coke burn-off in the catalyst regenerator*." Flint Hills Resources is to comply with the NSPS requirements no later than January 1, 2001.

2.7.2.2 Heaters and Boilers

The Flint Hills Resources consent decree specifies implementation of a program to reduce NO_X emissions from heaters and boilers over 40 MMBTU/hr by:

1. Installing ultra-low NO_X burners (ULNB);
2. Demonstrating next generation ULNB; or
3. Use of an alternative emissions reduction technology.

An initial heater and boiler plan, to be updated annually, describes Flint Hills Resources' methods and progress toward meeting the requirements of the consent decree. NO_X emission controls are to be installed no later than December 31, 2006.

The consent decree specifies that Flint Hills Resources will reduce SO_2 emissions from combustion devices by restricting H_2S in refinery fuel gas and by discontinuing and not commencing the burning of fuel oil except as provided for in the consent decree. As of January 1, 2001 (except as noted in the consent decree), each heater and boiler that combusts refinery fuel gas is an affected facility subject to the requirements of NSPS Subparts A and J. NSPS Subpart J (40 CFR 60.104(a)) establishes the following sulfur emission limits for fuel gas combustion devices: "*No owner or operator subject to the provisions of this subpart shall: (1) Burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf)*."

2.7.2.3 Sulfur Recovery Plants

There are three sulfur recovery plants at the Corpus Christi Refinery: SRU#1 and SRU#2 at the West Plant and East SRU at the East Plant. The Flint Hills Resources consent decree specifies that all SRPs are affected facilities with respect to NSPS Subparts A and J. SO_2 limits per 40 CFR 60.104(a) are as follows: "*No owner or operator subject to the provisions of this subpart shall: . . . (2) Discharge or cause the discharge of any gases from any Claus sulfur recovery plant containing in excess of: (i) For an oxidation control system or a reduction control system followed by incineration, 250 ppm by volume (dry basis) of sulfur dioxide (SO_2) at zero percent excess air. (ii) For a reduction control system not followed by incineration, 300 ppm by volume of reduced sulfur compounds and 10 ppm by volume of hydrogen sulfide (H_2S), each calculated as ppm SO_2 by volume (dry basis) at zero percent excess air*."

2.7.2.4 Flares

The Flint Hills Resources consent decree specifies that the following hydrocarbon flares are affected facilities and are to comply with the emission standards in NSPS Subparts A and J:

- Corpus Christi West Plant Main Flare,
- Corpus Christi East Plant 36-inch Flare, and
- Other flares in the same service.

NSPS Subpart J (40 CFR 60.104(a)) establishes the following emission limits for fuel gas combustion devices, including flares: "*No owner or operator subject to the provisions of this subpart shall: (1) Burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf)*."

In the consent decree, Flint Hills Resources committed to installing and operating a new flare gas recovery (FGR) system at the East Plant. The FGR is to be installed and operational no later than December 31, 2003.

2.7.2.5 Benzene Waste Operations NESHAP Program Enhancements

The consent decree contains numerous requirements related to Benzene Waste Operations NESHAP compliance and program enhancements. The consent decree, however, does not specify numerical emission targets or required numerical emission reductions.

2.7.2.6 Leak Detection and Repair Program Enhancements

The consent decree specifies certain enhancements to existing leak detection and repair (LDAR) programs at the Corpus Christi Refinery. This includes use of lower leak definitions. These enhancements are to be implemented by January 1, 2001. The consent decree, however, does not specify numerical emission targets or required numerical emission reductions.

2.7.2.7 Permitting

The consent decree requires Flint Hills Resources to obtain federally-enforceable permits for the construction of pollution control equipment in a timely manner. Concentration limits are to be incorporated into NSR authorizations within 60 days of a determination of the final limit.

2.7.3 Emissions Information

The summary of projected emissions and implementation dates is derived from the following sources of information:

- Consent decree,
- NO_X control plan, and
- Information provided by Flint Hills Resources personnel.

It is important to note that the information provided by Flint Hills Resources and the projected emissions presented within this document do not in and of themselves constitute enforceable commitments on the part of Flint Hills Resources. Many of the requirements of the consent decree allow for flexibility in implementation. Until such time as the consent decree is closed (upon completion of all requirements), the methods and the location of the emission reductions, in certain cases, remain subject to change.

2.7.3.1 Fluid Catalytic Cracking Unit

According to Flint Hills Resources personnel, wet gas scrubbers were installed and operational on both the Corpus Christi West and East FCCUs prior to the consent decree. Therefore, there will be no reduction in actual SO_2 and PM emissions as a result of the consent decree. The flexible permit caps for the refineries will, however, be adjusted to reflect consent decree limits. SNCR has been installed on the West FCCU and will be installed on the East FCCU in 2008. The consent decree allows for an 18-month evaluation period after which concentration limits will be established. Emissions are projected assuming a NO_X concentration of 70 ppmvd is demonstrated attainable. Projected flexible cap contributions from the FCCUs are presented in Table 2.7-1.

Table 2.7-1. Flint Hills Resources FCCU Emissions

Refinery	Emissions (tons/year)		
	NO_X	SO_2	PM
Corpus Christi East	200	100	149
Corpus Christi West	360	162	236

In estimating emissions from the FCCU for the photochemical modeling emissions inventory, use of average annual projected NO_X, SO_2 and PM emission rates is deemed appropriate for the following reasons.

1. It is ENVIRON's understanding that emissions from an FCCU are relatively constant.
2. For the large number of FCCUs considered in a regional haze analysis, the collective emissions during any given period should, in aggregate, approach the annual average emission rate. Use of short-term emission limits might be appropriate for a single FCCU, but across the large number of FCCUs included in the photochemical modeling emissions inventory, use of short-term emission limits could result in a gross overestimation of portfolio emissions.
3. Compliance with the NSPS Subpart J emission limit – 1 lb PM per 1,000 lbs coke burned – is

demonstrated using the average of three, one-hour test runs (EPA Method 5B or 5F). Therefore, annual PM emissions are calculated using a short-term emission rate.

2.7.3.2 Combustion Units

Flint Hills Resources personnel provided a copy of their 2006 annual update to the heater and boiler NO_X control plan. From that plan the following information is derived.

- Fifteen heaters and boilers rated 40 MMBTU/hour or greater employed ULNB prior to the consent decree. There are no changes in emissions for these units.
- Following consent decree entry, next generation ULNB has been installed on 19 heaters and boilers. Of these, 18 units achieved a NO_X emission rate of 0.045 lb/MMBTU and one achieved a rate of 0.075 lb/MMBTU.
- Nine boilers have been permanently shutdown, replaced by either a 3rd party cogeneration unit or by three new boilers.
- Two process heaters were shutdown, two were derated to less than 40 MMBTU/hour and one was retrofitted with steam injection to achieve a NO_X emission rate of 0.045 lb/MMBTU.

Only two units remain to be addressed: the East Plant boilers. The current plan is to install a new boiler with SCR and shutdown the existing boilers.

Table 2.7-2 summarizes heater and boiler emissions following implementation of the consent decree. Emission information on units with UNLB installed prior to the consent decree is not available and those units are not addressed. For the two East Plant boilers under evaluation, it is assumed that the replacement boiler will have the same maximum rated capacity (MRC) of the combined existing boilers (479 MMBTU/hour) and will achieve a NO_X emission rate of 0.045 lb/MMBTU. Sulfur dioxide emissions are estimated using the NSPS Subpart J limit of 0.1 grains H_2S/dscf and the maximum rated capacities.

Table 2.7-2. Flint Hills Resources Heater and Boiler Emissions

Group	Combined MRC (MMBTU/hour)	NO_X Emission Rate (lb/MMBTU)	NO_X Emissions (tons/year)	SO_2 Emissions (tons/year)
ULNB Installed	2,743	0.045	541	327
	89	0.075	29	10
Shutdown	962	0	0	0
Under Evaluation	479	0.045	94	55

2.7.3.3 Sulfur Recovery Plant

The sulfur recovery units were in compliance with NSPS Subpart J limits as of the consent decree entry date. No change in actual or allowable emissions is projected. Permitted allowable emission rates are as follows.

West Plant SRU 1:	66 tons SO_2 per year
West Plant SRU 2:	63 tons SO_2 per year
East Plant SRU 1 & 2:	171 tons SO_2 per year

2.7.3.4 Flares

Flare gas recovery (FGR) has been in place at the West Plant with 1985. FGR is to be installed at the East Plant by the end of 2007. During "routine" operation, all of the gases going to the West Plant flare are recovered and recycled to the refinery. In support of this position, Flint Hills Resources noted that, during 2006, there were only 35.1 hours of actual process flaring. Once installed, flaring at the East Plant should similarly be reduced to "non-routine" periods of startup, shutdown, maintenance and/or malfunction.

During normal operations, emissions from flares employing FGR are limited to pilot gas combustion. For practical purposes, these emissions are zero. Therefore, emissions from the Flint Hills Resources flares are set to zero for NO_X, SO_2, PM and VOC in the photochemical modeling inventory.

2.7.3.5 Leak Detection and Repair Program Enhancements

No estimate of VOC emission changes resulting from implementation of enhanced LDAR programs is currently available. Therefore, the emission rates in the current photochemical modeling emissions inventory are retained.

2.7.3.6 Summary of Emission Rates

Attachment C presents a summary of projected and calculated post-consent decree emission rates for the Flint Hills Resources refineries. This attachment provides the following information concerning units affected by the consent-decree:

(i) A description of each affected unit and its function, including associated unit identification numbers and emission point identifications;

(ii) Potential post-consent decree emission rates as projected by the refineries or calculated by ENVIRON given emission limits and unit design specifications, both for a short-term (tons/day) and long-term (tons/year) basis;

(iii) Actual emission rates (tons/day) for the years 2004 or 2005.

In determining actual 2005 emission rates for those units covered by the consent decree at the Flint Hills Resources Corpus Christi Refineries, ENVIRON utilized emission inventory data as provided by the 2005 Texas AFS Format File.

In order to properly correlate unit names as given by the consent decree to emission rates present in the AFS File, Facility Identification Numbers (FINs) and Emission Point Numbers (EPNs) were used for matching purposes. ENVIRON relied upon FINs provided by the Flint Hills Resources consent decree, NO_x Control Plan, and information supplied by Flint Hills Resources personnel to identify units within the AFS File. The NO_x, SO_2, VOC and PM_{10} emission rates from the AFS File associated with each unit FIN was then incorporated into the attachment. Fugitive VOC emissions were taken as the sum of VOC emissions resulting from the "Equipment Leak" category of the AFS File. The AFS File also supplied the corresponding EPN for each unit's FIN, and this EPN was then listed in the attachment. Non-zero AFS File emission rate values were given preference in the case that two emission rates for the same pollutant were provided for a single unit, one of which rates was listed as zero.

If a successful match was not made, ENVIRON assigned a FIN and EPN from the AFS File, along with the corresponding NO_x, SO_2, VOC and PM_{10} emission rates. Based on the emission point descriptions from the consent decree, ENVIRON attempted to select a FIN and EPN from among like sources, or units with similar functions and operations. For example, if an emissions unit was listed as a heater in the consent decree, then ENVIRON attempted to select a heater from the AFS File. These units' FINs and EPNs are indicated in bold red, italicized font.

In circumstances where emission rates from the AFS File were not present for a pollutant from a given unit, even if identified by FIN or EPN, the label "N.L." has been employed to mark emissions which were *not listed*.

2.8 Lion Oil Company

2.8.1 Affected Refineries

Lion Oil Company (Lion Oil) owns and operates one refinery that is part of the consent decree. This refinery is listed below.

Refinery	Capacity (Barrels per Day)[31]
El Dorado, Arkansas	58,000

This refinery is located within EPA Region VI.

2.8.2 Consent Decree Requirements

2.8.2.1 Fluid Catalytic Cracking Unit (FCCU)

The Lion Oil El Dorado Refinery has one FCCU. To reduce NO_X emissions from its FCCU, the consent decree specifies that Lion Oil will install a LoTOx™ System on its FCCU or Lion Oil may opt to accept limits of 20 ppmvd on a 365-day rolling average and 40 ppmvd on a 24-hour rolling average for NO_X emissions. Lion Oil is to be in compliance with these limits no later than June 30, 2007.

To reduce SO_2 emissions from its FCCU, the consent decree specifies that Lion Oil will install and operate a Wet Gas Scrubber (WGS) at the El Dorado Refinery. Final SO_2 emission limits for the FCCU are as follows: 25 ppmvd or lower on a 365-day rolling average and 50 ppmvd on a 7-day rolling average, both corrected to 0% O_2. These limits are to be achieved no later than December 31, 2004.

The installation of the WGS, as stated above, will reduce the particulate matter (PM) emissions from the FCCU at the El Dorado Refinery. The El Dorado FCCU is to achieve an emission limit of 0.5 pound PM per 1,000 pounds of coke burned on a 3-hour average basis. This limit is to be achieved no later than December 31, 2004.

The FCCU regenerator at the El Dorado Refinery is an affected facility subject to compliance with the provisions of NSPS Subparts A and J for SO_2 and PM by no later than December 31, 2004. SO_2 limits per 40 CFR 60.104(b) are as follows: "*Each owner or operator that is subject to the provisions of this subpart shall comply with one of the following conditions for each affected fluid catalytic cracking unit catalyst regenerator: (1) With an add-on control device, reduce sulfur dioxide emissions to the atmosphere by 90 percent or maintain sulfur dioxide emissions to the*

[31] Atmospheric crude oil distillation capacity (Source: Energy Information Administration, U.S. Refineries Operable Capacity, 2007, http://www.eia.doe.gov/neic/rankings/refineries.htm)

atmosphere less than or equal to 50 ppm by volume (ppmv), whichever is less stringent; or (2) Without the use of an add-on control device, maintain sulfur oxides emissions calculated as sulfur dioxide to the atmosphere less than or equal to 9.8 kg/Mg (20 lb/ton) coke burn-off; or (3) Process in the fluid catalytic cracking unit fresh feed that has a total sulfur content no greater than 0.30 percent by weight." PM limits per 40 CFR 60.102(a) are as follows: "*No owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any fluid catalytic cracking unit catalyst regenerator: (1) Particulate matter in excess of 1.0 kg/Mg (2.0 lb/ton) of coke burn-off in the catalyst regenerator*."

2.8.2.2 Combustion Units

The Lion Oil consent decree specifies the implementation of an eight-year program to reduce NO_X emissions from controlled heaters, boilers and compressors listed in Appendix C of the consent decree, by at least 530 tons per year.[32] In order to achieve the lowest possible NO_X emissions, Lion Oil is to use the following control technologies:

1. Next generation ultra-low NO_X burners (ULNB);
2. Air fuel ratio controllers and catalytic converters;
3. Alternative NO_X control technologies which Lion Oil demonstrates to EPA's satisfaction should reduce emissions to 0.060 pounds of NO_X per MMBTU heat input or lower; or
4. Permanent shutdown of a combustion unit with surrender of its operating permit.

Lion Oil will reduce NO_X emissions from air compressor SN-841, G398TA by installing an air fuel ratio controller and a catalytic converter.

A NO_X control plan with annual updates describes Lion Oil's methods and progress toward the emission reduction target. The emission reductions are to be achieved no later than December 31, 2009.

As of the consent decree entry date, each heater and boiler that combusts refinery fuel gas is subject to the requirements of NSPS Subparts A and J. Combustion devices subject to a different schedule are identified in Appendix C to the consent decree. NSPS Subpart J (40 CFR 60.104(a)) establishes the following emission limits for fuel gas combustion devices: "*No owner or operator subject to the provisions of this subpart shall: (1) Burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf)*."

[32] Compliance is determined by summing actual baseline emissions for the combustion sources listed in the consent decree and subtracting the sum of allowable emissions following implementation of the Consent Decree for those same combustion sources.

2.8.2.3 Sulfur Recovery Plant

The Lion Oil El Dorado Refinery Sulfur Recovery Plant (SRP) is currently subject to the provisions of NSPS Subparts A and J. The El Dorado SRP will comply with 40 C.F.R. § 60.104(a)(2) for all periods of operation by no later than the consent decree entry date (March 11, 2003). SO_2 limits per 40 CFR 60.104(a) are as follows: "*No owner or operator subject to the provisions of this subpart shall: . . . (2) Discharge or cause the discharge of any gases from any Claus sulfur recovery plant containing in excess of: (i) For an oxidation control system or a reduction control system followed by incineration, 250 ppm by volume (dry basis) of sulfur dioxide (SO_2) at zero percent excess air. (ii) For a reduction control system not followed by incineration, 300 ppm by volume of reduced sulfur compounds and 10 ppm by volume of hydrogen sulfide (H_2S), each calculated as ppm SO_2 by volume (dry basis) at zero percent excess air*."

2.8.2.4 Flares

The Lion Oil consent decree specifies compliance with NSPS Subparts A and J SO_2 standards for the flares listed in Appendix B to the consent decree:

- Low Pressure Flare, and
- High Pressure Flare.

NSPS Subpart J (40 CFR 60.104(a)) establishes the following emission limits for fuel gas combustion devices, including flares: "*No owner or operator subject to the provisions of this subpart shall: (1) Burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf)*." The compliance date is March 11, 2003, for both flares.

To minimize and control acid gas and hydrocarbon flaring incidents at the El Dorado Refinery, Lion Oil has installed a flare gas recovery (FGR) system. According to the Lion Oil consent decree, flaring devices combusting refinery fuel gases shall either comply with the emission limit set forth by 40 C.F.R. § 60.104(a)(1) or be taken out of service. For both flares, the identified methods of compliance are implementation of corrective actions to minimize flaring incidents and continuous monitoring.

2.8.2.5 Benzene Waste Operations NESHAP Program Enhancements

The Lion Oil consent decree contains requirements related to Benzene Waste Operations NESHAP (BWON) compliance and program enhancements. The consent decree, however, does not specify numerical emission targets or required numerical emission reductions.

2.8.2.6 Leak Detection and Repair (LDAR) Program Enhancements

To reduce fugitive emissions of VOC from process equipment, the consent decree requires the Lion

Oil El Dorado Refinery to undertake certain LDAR program enhancements related to compliance with the requirements of 40 CFR 60, Subpart GGG; Part 61, Subparts J and V; Part 63, Subparts F, H and CC, by no later than December 31, 2004. The consent decree, however, does not specify numerical emission targets or required numerical emission reductions.

2.8.2.7 Permitting

For emission limits and standards effective on the consent decree entry date, Lion Oil is to submit administratively-complete permit applications to incorporate these requirements into federally-enforceable New Source Review (NSR) permits no later than June 30, 2003. For heaters and boilers using NO_X control technologies, Lion Oil will submit permit applications within 120 days of the startup. For other combustion units with requirements effective after the Date of Entry, Lion Oil is to submit administratively-complete permit applications within 60 days of the effective date of the requirement.

2.8.3 Emissions Information

Lion Oil did not provide information regarding projected emissions or emission reductions resulting from the consent decree. FCCU NO_X and SO_2 emissions can be estimated, however, using available information and the following methodology.

(1) Coke Burn Rate (lbs/hour) = FCCU Throughput (bbl/day)[33] x 0.75

(2) FCCU Exhaust (dscf/hour) = Coke Burn Rate (lbs/hour) x160 dscf/lb Coke Burned (Full Burn) <u>or</u>
FCCU Exhaust (dscf/hour) = Coke Burn Rate (lbs/hour) x 200 dscf/lb Coke Burned (Partial Burn)

(3) Mass Emission Rate (tons/year) = (PV/RT)(MW)(8760 hours/year)(1 ton/2000 lbs), where

P	=	1 atm
V	=	(FCCU Exhaust)[(Pollutant Concentration, ppmvd)/10^6]
R	=	0.7302 atm-ft^3/lbmole-°R
T	=	520°R
MW	=	Molecular Weight (NO_X = 46, SO_2 = 64)

Emissions of PM are calculated by multiplying the emission limit by the estimated coke burn rate. Estimated FCCU Emissions are presented in Table 2.8-1. Partial burn operation is assumed.

Table 2.8-1. Lion Oil FCCU Emissions

FCCU	FCCU Capacity (bbl/day)	Emission Rate (tons/year)		
		NO_X	SO_2	PM

[33] Source: Energy Information Administration (EIA), Form EIA-820, "Annual Refinery Report," 2007.

El Dorado Refinery	19,900	32	55	33

2.8.3.1 Summary of Emission Rates

Insufficient information is available to estimate post-consent decree emissions from other categories of emission sources. Therefore, information contained within the current photochemical modeling emissions inventory is retained, and no changes are provided within Attachment C as with other refineries discussed herein. However, considering the compliance dates contained within the consent decree, the following emission reductions required by the consent decree should have already been realized and should be reflected in the current photochemical modeling inventory.

- Sulfur Recovery Plant SO_2 emission reductions: March 11, 2003
- Flare SO_2 emission reductions: March 11, 2003
- LDAR program VOC emission reductions: December 31, 2004

2.9 Marathon Petroleum Company LLC

2.9.1 Affected Refineries

Marathon Petroleum Company LLC (MPC) owns and operates seven refineries that are part of the revised consent decree entered on August 31, 2005. The refineries were previously owned by joint venture Marathon Ashland Petroleum Company LLC until the 2004 purchase by Marathon Oil Corporation of Ashland's minority interest. Since then the refineries have operated as MPC. The refineries covered are listed below.

Refinery	Capacity (Barrels per Day)[34]
Canton, Ohio	73,000
Catlettsburg, Kentucky	222,000
Detroit, Michigan	74,000
Garyville, Louisiana	232,000
Robinson, Illinois	192,000
Texas City, Texas	72,000
St. Paul Park, Minnesota	70,000

The two refineries shown in italics are located within EPA Region VI.

2.9.2 Consent Decree Requirements

2.9.2.1 Fluid Catalytic Cracking Units (FCCU)

Each refinery has a single FCCU. NO_X emission limit requirements identified by the consent decree are as follows.

Garyville Refinery: The consent decree specifies the use of low-NO_X combustion promoters and NO_X reducing catalyst additives to reduce emissions. Based on optimization studies and demonstrations, MPC is to propose to EPA both short-term (24-hour or 7-day rolling average) and long-term (365-day rolling average) emission limits. MPC is to comply with these limits upon submittal of the demonstration report to EPA. The demonstration report is due to EPA by June 1, 2006.

Texas City Refinery: The consent decree specifies the installation and operation of a LoTOx™ system to achieve a NO_X concentration of no greater than 20 ppmvd on a 365-day rolling average and no greater than 40 ppmvd on a 7-day rolling average, both at 0% O_2. These provisions are to be implemented by December 31, 2007.

[34] Atmospheric crude oil distillation capacity (Source: Energy Information Administration, U.S. Refineries Operable Capacity, 2007, http://www.eia.doe.gov/neic/rankings/refineries.htm)

SO_2 emission limit requirements specified by the consent decree are as follows.

Garyville Refinery: As of the August 2001 date of lodging, MPC is to continue using the existing Wet Gas Scrubber (WGS) to achieve an SO_2 concentration emission limit of 25 ppmvd or lower on a 365-day rolling average basis and 50 ppmvd or lower on a 7-day rolling average basis, both at 0% O_2.

Texas City Refinery: By no later than March 1, 2005, the consent decree specifies use of a WGS to achieve SO_2 concentration emission limits of 25 ppmvd on a 365-day rolling average basis and 50 ppmvd on a 7-day rolling average basis, both at 0% O_2.

Particulate matter (PM) emission limit requirements specified by the consent decree are as follows.

Garyville Refinery: As of the date of lodging, the refinery is to comply with an emission limit of 1 pound PM per 1,000 pounds of coke burned on a 3-hour average basis. These limits are to be achieved using the existing WGS system.

Texas City Refinery: By March 31, 2003, the refinery will install and operate a WGS to achieve a PM emission limit of 1 pound PM per 1,000 pounds of coke burned on a 3-hour average basis.

The consent decree specifies that the FCCU catalyst regenerators are affected facilities subject to the requirements of NSPS Subparts A and J, according to the following schedule:

FCCU	**Effective Date for SO_2**	**Effective Date for PM**
Garyville	December 31, 2001	Date of Lodging
Texas City	June 30, 2003	August 30, 2003

SO_2 limits per 40 CFR 60.104(b) are as follows: "*Each owner or operator that is subject to the provisions of this subpart shall comply with one of the following conditions for each affected fluid catalytic cracking unit catalyst regenerator: (1) With an add-on control device, reduce sulfur dioxide emissions to the atmosphere by 90 percent or maintain sulfur dioxide emissions to the atmosphere less than or equal to 50 ppm by volume (ppmv), whichever is less stringent; or (2) Without the use of an add-on control device, maintain sulfur oxides emissions calculated as sulfur dioxide to the atmosphere less than or equal to 9.8 kg/Mg (20 lb/ton) coke burn-off; or (3) Process in the fluid catalytic cracking unit fresh feed that has a total sulfur content no greater than 0.30 percent by weight*." PM limits per 40 CFR 60.102(a) are as follows: "*No owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any fluid catalytic cracking unit catalyst regenerator: (1) Particulate matter in excess of 1.0 kg/Mg (2.0 lb/ton) of coke burn-off in the catalyst regenerator*."

2.9.2.2 Combustion Units

The MPC consent decree specifies the implementation of a program to reduce NO_X emissions from

controlled heaters, boilers and compressors listed in Appendix C of the consent decree by at least 3,886 tons per year from the seven affected refineries.[35] In order to achieve the lowest possible NO_X emissions, MPC will use one or any combination of the following control technologies:

1. Current generation ultra-low NO_X burners (ULNB);
2. Next generation ULNB;
3. Selective catalytic reduction (SCR);
4. Selective non-catalytic reduction (SNCR);
5. Alternative NO_X control technologies which MPC demonstrates to EPA's satisfaction should reduce emissions to 0.040 pounds of NO_X per MMBTU heat input or lower; or
6. Permanent shutdown of a combustion unit with surrender of its operating permit.

A NO_X control plan with annual updates describes MPC's methods and progress toward the emission reduction target. The emission reductions are to be achieved no later than December 31, 2008.

As of the consent decree entry date, each heater and boiler that combusts refinery fuel gas is an affected facility subject to the requirements of NSPS Subparts A and J. Appendix H to the consent decree and Appendix H in the First Amendment to the consent decree identifies those combustion units with differing compliance schedules. NSPS Subpart J (40 CFR 60.104(a)) establishes the following emission limits for fuel gas combustion devices: "*No owner or operator subject to the provisions of this subpart shall: (1) Burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf)*." MPC will discontinue burning fuel oil in all covered heaters and boilers at Texas City and Garyville Refineries.

With respect to PM emissions, heaters and boilers that are part of a PAL for PM shall limit PM emissions to 0.005 lb/MMBTU on a 365-day rolling average and 0.010 lb/MMBTU on a 24-hour rolling average.

2.9.2.3 Sulfur Recovery Plant

The MPC consent decree specifies that the Garyville sulfur recovery plant – Claus trains #20, #34 and #46 – is an affected facility subject to the requirements of NSPS Subparts A and J as of the date of lodging. MPC is to install an SRP at the Texas City Refinery no later than July 31, 2007. As of that date, the Texas City Refinery SRP will be an affected facility subject to the requirements of NSPS Subpart A and J. SO_2 limits per 40 CFR 60.104(a) are as follows: "*No owner or operator subject to the provisions of this subpart shall: . . . (2) Discharge or cause the discharge of any gases from any Claus sulfur recovery plant containing in excess of: (i) For an oxidation control system or a*

[35] Compliance is determined by summing actual baseline emissions for the combustion sources listed in the consent decree and subtracting the sum of allowable emissions following implementation of the consent decree for those same combustion sources.

reduction control system followed by incineration, 250 ppm by volume (dry basis) of sulfur dioxide (SO_2) at zero percent excess air. (ii) For a reduction control system not followed by incineration, 300 ppm by volume of reduced sulfur compounds and 10 ppm by volume of hydrogen sulfide (H_2S), each calculated as ppm SO_2 by volume (dry basis) at zero percent excess air ."

2.9.2.4 Flares

Hydrocarbon flaring devices listed in Appendix A to the consent decree are affected facilities with respect to NSPS Subparts A and J. Compliance is according to the following schedule.

Refinery	Flare	NSPS Effective Date
Garyville	South Flare	December 31, 2001
"	North Flare	December 31, 2001
"	Marine Vapor Recovery	September 7, 2000
Texas City	Marine Vapor Combustor	July 19, 2000
"	Alkylation Flare	July 19, 2000
"	WWTP Flare	July 19, 2000
"	Main Flare	December 31, 2007

NSPS Subpart J (40 CFR 60.104(a)) establishes the following emission limits for fuel gas combustion devices, including flares: "*No owner or operator subject to the provisions of this subpart shall: (1) Burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf)*."

2.9.2.5 Benzene Waste Operations NESHAP Program Enhancements

The MPC consent decree contains requirements related to Benzene Waste Operations NESHAP (BWON) compliance and program enhancements. The consent decree, however, does not specify numerical emission targets or required numerical emission reductions.

2.9.2.6 Leak Detection and Repair (LDAR) Program Enhancements

To reduce fugitive emissions of VOC from process equipment, the consent decree requires that the Texas City Refinery and the Garyville Refinery undertake certain LDAR program enhancements related to compliance with the requirements of 40 CFR 60, Subpart GGG; Part 61, Subparts J and V; Part 63, Subparts F, H and CC, by no later than 120 days after the date of lodging of the consent decree (August 30, 2001). The consent decree, however, does not specify numerical emission targets or required numerical emission reductions.

2.9.2.7 Permitting

MPC is to obtain required federally enforceable permits for the construction of pollution control systems. Permit applications are to be submitted in a timely fashion.

2.9.3 Emissions Information

The following summary of projected emissions and implementation dates is derived from one or more of the following sources of information:

- Consent decree,
- Semi-annual reports,
- NO_X control plans, and
- Information provided by MPC personnel.

It is important to note that the information provided by MPC and the projected emissions presented within this document do not in and of themselves constitute enforceable commitments on the part of MPC. Many of the requirements of the consent decree allow for flexibility in implementation. Until such time as the consent decree is closed (upon completion of all requirements), the methods and the location of the emission reductions, in certain cases, remain subject to change.

2.9.3.1 Fluid Catalytic Cracking Units

Projected FCCU emissions have not been provided for the Garyville Refinery. However, FCCU NO_X and SO_2 emissions can be estimated using available information and the following methodology.

(1) Coke Burn Rate (lbs/hour) = FCCU Throughput (bbl/day)[36] x 0.75

(2) FCCU Exhaust (dscf/hour) = Coke Burn Rate (lbs/hour) x160 dscf/lb Coke Burned (Full Burn) <u>or</u>
FCCU Exhaust (dscf/hour) = Coke Burn Rate (lbs/hour) x 200 dscf/lb Coke Burned (Partial Burn)

(3) Mass Emission Rate (tons/year) = (PV/RT)(MW)(8760 hours/year)(1 ton/2000 lbs), where

P	=	1 atm
V	=	(FCCU Exhaust)[(Pollutant Concentration, ppmvd)/10^6]
R	=	0.7302 atm-ft^3/lbmole-°R
T	=	520°R
MW =		Molecular Weight (NO_X = 46, SO_2 = 64)

[36] Source: Energy Information Administration (EIA), Form EIA-820, "Annual Refinery Report," 2007.

Emissions of PM are calculated by multiplying the emission limit by the estimated coke burn rate. Estimated FCCU Emissions are presented in Table 2.9-1. Partial burn operation is assumed.

With respect to the Texas City Refinery, MPC personnel provided copies of semi-annual reports and other information related to emissions from the Texas City FCCU. From this information it is determined that the LoTOx™ system was installed and began operation on February 10, 2007. The WGS was installed and began operation in February 2003. Those portions of the flexible permit emission caps attributable to the FCCU are not provided. Therefore, reported actual emissions for the period January-June 2007 are used to estimate annual actual emissions, shown in Table 2.9-1. Since the LoTOx™ system was operational for only part of the six-month reporting period, future actual

Table 2.9-1. Marathon Petroleum Company FCCU Emissions

Refinery	FCCU Capacity (bbl/day)	Emissions (tons/year)		
		NO_X	SO_2	PM
Garyville	131,000	417	363	430
Texas City	*	105	6	63

NO_X emissions may be lower.

*Estimation calculation employing FCCU capacity not used.

In estimating emissions from the FCCU for the photochemical modeling emissions inventory, use of average annual projected NO_X, SO_2 and PM emission rates is deemed appropriate for the following reasons.

1. It is ENVIRON's understanding that emissions from an FCCU are relatively constant.
2. For the large number of FCCUs considered in a regional haze analysis, the collective emissions during any given period should, in aggregate, approach the annual average emission rate. Use of short-term emission limits might be appropriate for a single FCCU, but across the large number of FCCUs included in the photochemical modeling emissions inventory, use of short-term emission limits could result in a gross overestimation of portfolio emissions.
3. Compliance with the NSPS Subpart J emission limit – 1 lb PM per 1,000 lbs coke burned – is demonstrated using the average of three, one-hour test runs (EPA Method 5B or 5F). Therefore, annual PM emissions are calculated using a short-term emission rate.

2.9.3.2 Heaters and Boilers

Tables 2.9-2 and 2.9-3 present, respectively, projected NO_X and SO_2 emissions heaters and boilers at the Garyville and Texas City refineries. This information is derived from Appendix C to the consent decree and the heater and boiler plan. Emissions are calculated using maximum rated capacities (MRC) and appropriate emission factors: those listed in the boiler and heater plan for NO_X and NSPS

Subpart J limits for SO_2. Only units that are part of the NO_X control plan (i.e. those rated at more than 40 MMBTU/hour) are included.

For both NO_X and SO_2, annual projections are used in revising the photochemical modeling emissions inventory.

Table 2.9-2. Marathon Petroleum Company Garyville Refinery Heater and Boiler Emissions

Emission Unit	MRC (MMBTU/hour)	CD Controls	NO_X EF (lb/MMBTU)	Emission Rate (tpy)	
				NO_X	SO_2
Platformer Heater	408	--	0.104	185.85	47.18
Boiler # 1	350	--	0.138	211.55	40.47
Crude Atm. Heater	286	LNB	0.050	62.63	33.07
Crude Atm. Heater	286	LNB	0.050	62.63	33.07
Hf Alky Iso. Reb.	268	LNB	0.040	46.95	30.99
ROSE Deasphalting	221	--	0.05	48.40	25.55
Plat. Interheater #5	210	--	0.14	128.77	24.28
FCC Charge Heater	170	ULNB	0.040	29.78	19.66
Crude Vacuum Htr.	138	ULNB	0.030	18.13	15.96
Crude Vacuum Htr.	138	--	0.122	73.74	15.96
Old Boiler #1	120	--	0.14	73.58	13.88
Old Boiler #2	120	--	0.14	73.58	13.88
HGO Charge Heater	99	--	0.12	52.03	11.45
HGO Reboiler Heater	78	--	0.12	41.00	9.02
Sat's Gas Hot Htr.	73	--	0.14	44.76	8.44
Dist. Hydro. Ch. Htr.	69	--	0.12	36.27	7.98
Dist. Hydro. Strip-Reb	62	--	0.12	32.59	7.17
Naphtha Hydro. Reb.	61	--	0.1	26.72	7.05
Plat. Debut. Reb.	61	--	0.12	39.38	7.05
Naphtha Hydro. Htr.	53	--	0.12	34.22	6.13

Table 2.9-3. Marathon Petroleum Company Texas City Refinery Heater and Boiler Emissions

Emission Unit	MRC (MMBTU/hour)	CD Controls	NO_X EF (lb/MMBTU)	Emission Rate (tpy)	
				NO_X	SO_2
Alky Heater	197	--	0.068	58.67	22.73
#5 Topper Htr.	182	ULNB	0.045	35.87	21.02
Boiler #1	77	Shutdown	--	0.00	0.00
Boiler #2	77	--	0.14	47.22	8.89
Boiler #3	77	--	0.14	15.20	8.89
Boiler #4	77	Shutdown	--	0.00	0.00

Table 2.9-3. Marathon Petroleum Company Texas City Refinery Heater and Boiler Emissions

Emission Unit	MRC (MMBTU/hour)	CD Controls	NO_X EF (lb/MMBTU)	Emission Rate (tpy)	
				NO_X	SO_2
Udex Stripper Htr.	63	Shutdown	--	0.00	0.00
Born Heater	62	--	0.04	10.86	7.14
Plat. Inter. Htr.	58	--	0.077	19.56	6.70
#4 Topper Htr.	50	--	0.056	12.26	5.78
Platformer Htr.	50	--	0.099	21.68	5.78
FCC GasCon – M7	--	Shutdown	--	0.00	0.00
FCC GasCon – M8	--	Shutdown	--	0.00	0.00
FCC GasCon – M9	--	Shutdown	--	0.00	0.00
FCC GasCon – M13	--	Shutdown	--	0.00	0.00
Plat. Comp. M-14	--	Elec. Motor	--	0.00	0.00
Plat. Comp. M-15	--	Elec. Motor	--	0.00	0.00

2.9.3.3 Sulfur Recovery Plants

The Garyville SRP was in compliance with NSPS Subpart J limits as of the consent decree entry date. Therefore, no change in actual or allowable emissions is projected. Information regarding permitted allowable emission rates has not been provided; therefore, the emission rates currently in the photochemical modeling inventory are retained.

The Texas City SRP began operation on May 25, 2007. Actual emissions data is not yet available. Information regarding permitted allowable emission rates or SRP contributions to the flexible permit SO_2 emission cap has not been provided. Therefore, this source is not added to photochemical modeling emissions inventory.

2.9.3.4 Flares

No projections of emission reductions are currently available for flares. Therefore, the emission rates currently in the photochemical modeling inventory are retained.

2.9.3.5 Leak Detection and Repair Program Enhancements

No estimate of VOC emission reductions resulting from implementation of enhanced LDAR programs is currently available.

2.9.3.6 Summary of Emission Rates

Attachment C presents a summary of projected and calculated post-consent decree emission rates for MPC refineries. This attachment provides the following information concerning units affected by the

consent-decree:

(i) A description of each affected unit and its function, including associated unit identification numbers and emission point identifications;

(ii) Potential post-consent decree emission rates as projected by the refineries or calculated by ENVIRON given emission limits and unit design specifications, both for a short-term (tons/day) and long-term (tons/year) basis;

(iii) Actual emission rates (tons/day) for the years 2004 or 2005.

In determining actual 2005 emission rates for those units covered by the consent decree at the MPC Texas City Refinery, ENVIRON utilized emission inventory data as provided by the 2005 Texas AFS Format File.

In order to properly correlate unit names as given by the consent decree to emission rates present in the AFS File, Facility Identification Numbers (FINs) and Emission Point Numbers (EPNs) were used for matching purposes. ENVIRON relied upon FINs provided by the MPC Consent Decree and 2007 Heater and Boiler NO_x Control Plan to identify units within the AFS File. The NO_x, SO_2, VOC and PM_{10} emission rates from the AFS File associated with each unit FIN was then incorporated into the attachment. Fugitive VOC emissions were taken as the sum of VOC emissions resulting from the "Equipment Leak" category of the AFS File. The AFS File also supplied the corresponding EPN for each unit's FIN, and this EPN was then listed in the attachment. Non-zero AFS File emission rate values were given preference in the case that two emission rates for the same pollutant were provided for a single unit, one of which rates was listed as zero.

If a successful match was not made, ENVIRON assigned a FIN and EPN from the AFS File, along with the corresponding NO_x, SO_2, VOC and PM_{10} emission rates. Based on the emission point descriptions from the consent decree, ENVIRON attempted to select a FIN and EPN from among like sources, or units with similar functions and operations. For example, if an emissions unit was listed as a heater in the consent decree, then ENVIRON attempted to select a heater from the AFS File. These units' FINs and EPNs are indicated in bold red, italicized font.

In determining actual 2004 emission rates for those units covered by the consent decree at the MPC Garyville Refinery, ENVIRON utilized emission inventory data as provided by the 2004 Louisiana AFS Format File (AFS File) and an emission point description database provided by the LDEQ (LDEQ database).[37]

In order to properly correlate unit names and/or descriptions as given by the consent decree to emission rates present in the AFS File, emission point descriptions were used for matching purposes. ENVIRON matched emission point descriptions from the consent decree with the corresponding

[37] Emission point description database was provided by Ms. Jackie Heber of LDEQ on August 28, 2007. According to Ms. Heber, the NEDS ID from this database corresponds to the Point ID field in the Louisiana AFS Format File.

emission point description from the LDEQ database. The LDEQ database contains a NEDS ID for each entry. The NEDS ID corresponds to the Point ID field in the AFS Format File. When a successful match was made between the consent decree and the LDEQ database, ENVIRON populated the Attachment C table with the corresponding Stack and Point IDs from the AFS File, along with the corresponding NO_x, SO_2, VOC and PM_{10} emission rates. If a successful match was not made, ENVIRON assigned a Stack and Point ID from the Louisiana AFS File, along with the corresponding NO_x, SO_2, VOC and PM_{10} emission rates. Based on the emission point descriptions from the consent decree, ENVIRON attempted to select a Stack and Point ID from among like sources. For example, if an emissions unit was listed as a heater in the consent decree, then ENVIRON attempted to select a heater from the AFS File.

In circumstances where emission rates from the AFS File were not present for a pollutant from a given unit, even if identified by FIN or EPN, or Stack or Point ID, the label "N.L." has been employed to mark emissions which were *not listed*.

2.10 Navajo Refining Company, L.L.C. (Holly Corporation)

2.10.1 Affected Refineries

Navajo Refining Company, L.L.C. (Navajo Refining), a wholly-owned subsidiary of Holly Corporation, owns and operates two refineries that are part of the consent decree. These refineries are as follows.

Refinery	Capacity (Barrels per Day)[38]
Artesia, New Mexico	84,000
Lovington, New Mexico	(Included in Artesia refining capacity)

Both refineries are located within EPA Region VI.

2.10.2 Consent Decree Requirements

2.10.2.1 Fluid Catalytic Cracking Units

To control emissions of NO_X, the consent decree specified that Navajo Refining will use NO_X reducing catalyst additives and low-NO_X combustion promoters at the Artesia FCCU. During the base line period, optimization period and demonstration period, Navajo determined the optimal addition rates of the NO_X reducing catalyst additives and low-NO_X combustion promoters at the Artesia FCCU Navajo Refining proposed to the EPA a concentration-based (ppmvd) NO_X emission limit based on 7-day rolling and 365-day rolling averages, corrected to 0% oxygen. Under no circumstances will this emission limit for the Artesia FCCU be greater than a concentration-based limit that would be equivalent to 34.9 lb/hr. Navajo must comply with the proposed limit immediately. EPA will use the data collected during the baseline period, optimization period and demonstration period to establish NO_X concentration-based limits. If EPA's limit is more stringent than the limit proposed by Navajo, then Navajo must comply with the more stringent limit within 30 days.

To reduce SO_2 and PM emissions, the consent decree specified that Navajo Refining install and operate a new wet gas scrubber (WGS) at the Artesia FCCU by December 31, 2003. Navajo Refining designed the WGS to achieve an SO_2 concentration of 25 ppmvd or lower on a 365-day rolling average basis and 50 ppmvd on a 7-day rolling average basis, each corrected to 0% oxygen. Navajo Refining designed the WGS to achieve an emission limit of 1.0 pound PM per 1000 pounds of coke burned on a 3-hour average basis. Navajo Refining complied with these emission limits by the December 31, 2003, deadline.

[38] Atmospheric crude oil distillation capacity (Source: Energy Information Administration, U.S. Refineries Operable Capacity, 2007, http://www.eia.doe.gov/neic/rankings/refineries.htm). Capacity is total capacity for both Artesia and Lovington Refineries.

In addition to the referenced requirements for the FCCUs, the consent decree specifies that the FCCU catalyst regenerators are affected facilities subject to the requirements of NSPS Subparts A and J. SO_2 limits per 40 CFR 60.104(b) are as follows: "*Each owner or operator that is subject to the provisions of this subpart shall comply with one of the following conditions for each affected fluid catalytic cracking unit catalyst regenerator: (1) With an add-on control device, reduce sulfur dioxide emissions to the atmosphere by 90 percent or maintain sulfur dioxide emissions to the atmosphere less than or equal to 50 ppm by volume (ppmv), whichever is less stringent; or (2) Without the use of an add-on control device, maintain sulfur oxides emissions calculated as sulfur dioxide to the atmosphere less than or equal to 9.8 kg/Mg (20 lb/ton) coke burn-off; or (3) Process in the fluid catalytic cracking unit fresh feed that has a total sulfur content no greater than 0.30 percent by weight*." PM limits per 40 CFR 60.102(a) are as follows: "*No owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any fluid catalytic cracking unit catalyst regenerator: (1) Particulate matter in excess of 1.0 kg/Mg (2.0 lb/ton) of coke burn-off in the catalyst regenerator*." Navajo Refining complied with the NSPS requirements by December 31, 2003.

2.10.2.2 Heaters and Boilers

The consent decree specifies that Navajo Refining will implement an eight-year program to reduce NO_X emissions from heaters and boilers listed in Appendix C to the consent decree by installing next generation ultra low-NO_X burners (ULNB) or alternative NO_X control technology. Instead of installing next generation ULNBs for Artesia Boilers B-7 and B-8, Navajo Refining designed and installed an alternative control technology that achieves a NO_X emission rate of less than 0.06 lb/MMBTU. Navajo Refining will install all NO_X controls according to the schedule in Appendix C to the consent decree. The last heaters scheduled for retrofit have a deadline of December 31, 2009.

Beginning in 2002, Navajo Refining will submit an annual report to the EPA and New Mexico Environment Department (NMED) about the progress of installation of NO_X control technology.

As of the date of lodging of the consent decree, each heater and boiler that combusts refinery fuel gas is an affected facility subject to the requirements of NSPS Subparts A and J. NSPS Subpart J (40 CFR 60.104(a)) establishes the following sulfur emission limits for fuel gas combustion devices: "*No owner or operator subject to the provisions of this subpart shall: (1) Burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf)*." Additionally, Navajo Refining agreed not to continue and/or commence burning fuel oil in heaters and boilers except under the provisions specified in the consent decree.

2.10.2.3 Sulfur Recovery Plants

There is one sulfur recovery plant (SRP) at the Artesia Refinery. No SRPs are in operation at the Lovington Refinery. The SRP at the Artesia Refinery consists of two units: one with a nominal processing capacity of 120 long tons per day (LTD) and the other with a processing capacity of 40

LTD of sulfur. The SRP is controlled by a single Tail Gas Unit (TGU). The Navajo Refining consent decree specifies compliance with NSPS Subparts A and J SO_2 standards for the SRP. SO_2 limits per 40 CFR 60.104(a) are as follows: "*No owner or operator subject to the provisions of this subpart shall: . . . (2) Discharge or cause the discharge of any gases from any Claus sulfur recovery plant containing in excess of: (i) For an oxidation control system or a reduction control system followed by incineration, 250 ppm by volume (dry basis) of sulfur dioxide (SO_2) at zero percent excess air. (ii) For a reduction control system not followed by incineration, 300 ppm by volume of reduced sulfur compounds and 10 ppm by volume of hydrogen sulfide (H_2S), each calculated as ppm SO_2 by volume (dry basis) at zero percent excess air*."

2.10.2.4 Flares

The Navajo Refining consent decree specifies compliance with NSPS Subparts A and J SO_2 standards for the following acid gas (AG) and/or hydrocarbon (HC) flares:

- Artesia North Plant Flare (AG/HC),
- Artesia South Plant Flare (HC),
- Artesia FCC Unit Flare (AG/HC),
- Artesia Alky/CCR Flare (AG/HC),
- Artesia GOHT Flare (HC), and
- Lovington LPG Flare (HC).

NSPS Subpart J (40 CFR 60.104(a)) establishes the following emission limits for fuel gas combustion devices, including flares: "*No owner or operator subject to the provisions of this subpart shall: (1) Burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf). The combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from this paragraph*."

2.10.2.5 Benzene Waste Operations NESHAP Program Enhancements

The consent decree specifies that Navajo Refining will continue compliance with all applicable requirements of the Benzene Waste Operations NESHAP (BWON) in addition to taking on several program enhancements to ensure compliance with applicable BWON requirements. As of the consent decree entry date, Navajo Refining believes that each refinery has a Total Annual Benzene (TAB) amount less than 10 megagrams per year (Mg/yr).

2.10.2.6 Leak Detection and Repair Program Enhancements

To reduce fugitive emissions of VOC from process equipment, the consent decree required Navajo

Refining to undertake certain LDAR program enhancements related to compliance with 40 CFR, Part 60, Subpart GGG; Part 61, Subparts J and V; Part 63, Subparts F, H, and CC; and applicable state LDAR requirements. The consent decree, however, did not specify numerical emission targets or required numerical emission reductions.

2.10.2.7 Permitting

The consent decree required Navajo Refining to submit permit applications no later than 180 days following the date of lodging of the consent decree to incorporate the emission limits, standards, and/or schedules required by the consent decree that are effective as of the date of lodging of the consent decree into federally-enforceable permits. No later than 30 days after the effective date or establishment of any remaining emission limits, standards, and schedules, Navajo Refining is to submit applications to make these federally enforceable.

2.10.3 Emissions Information

The summary of projected emissions and implementation dates is derived from the following sources of information:

- Consent decree,
- NO_X control plan, and
- Information provided by Navajo Refining personnel.

It is important to note that the information provided by Navajo Refining and the projected emissions presented within this document do not in and of themselves constitute enforceable commitments on the part of Navajo Refining. Many of the requirements of the consent decree allow for flexibility in implementation. Until such time as the consent decree is closed (upon completion of all requirements), the methods and the location of the emission reductions, in certain cases, remain subject to change.

2.10.3.1 Fluid Catalytic Cracking Units.

Navajo Refining provided post-consent decree potential emission rates NO_X, SO_2, and PM_{10} for the FCCU at its Artesia Refinery. These are presented in Table 2.10-1.

Table 2.10-1. Navajo Refining FCCU Emissions

Refinery	Post-Consent Decree Potential Emissions (tons per year)		
	NO_X	SO_2	PM_{10}
Artesia	152.87	61.02	109.50

2.10.3.2 Heaters and Boilers

Navajo Refining provided post-consent decree potential emission rates for NO_X and SO_2 for heaters and boilers at its Artesia and Lovington Refineries, except for Lovington boilers SG-1101A and SG-1101B and Artesia heater H-600. These sources have not yet been retrofitted with NO_X control technology. To calculate post-consent decree potential NO_X emission rates for the non-retrofitted sources, ENVIRON used the maximum rated capacity for each affected heater and boiler, derived from the consent decree, along with the NO_X emission limit from the consent decree (0.020 lb/MMBTU). Post-consent decree NO_X and SO_2 emission rates for the Artesia and Lovington heaters and boilers are presented in Table 2.10-2.

Table 2.10-2. Navajo Refining Heater and Boiler Emissions

Refinery	Post-Consent Decree Potential Emissions (tons per year)	
	NO_X	SO_2
Artesia	193.81	68.37
Lovington	11.4	13.78

2.10.3.3 Sulfur Recover Plant

Navajo Refining provided the post-consent decree potential emission rate for SO_2 for the Tail Gas Unit (TGU) at its Artesia Refinery. Post-consent decree potential emissions for SO_2 are 81.75 tpy.

2.10.3.4 Flares

Navajo Refining provided the post-consent decree potential emission rate for SO_2 for the flares at its Artesia and Lovington Refineries. Post-consent decree potential emissions of SO_2 from the Artesia and Lovington flares are 11.32 and 1.40 tpy, respectively.

2.10.3.5 Leak Detection and Repair Program Enhancements

No estimate of VOC emission reductions resulting from implementation of enhanced LDAR programs is currently available.

2.10.3.6 Summary of Emission Rates

Attachment C presents a summary of projected and calculated post-consent decree emission rates for the Navajo Refining Artesia and Lovington Refineries. This attachment provides the following information concerning units affected by the consent-decree:

(i) A description of each affected unit and its function, including associated unit identification numbers and emission point identifications;

(ii) Potential post-consent decree emission rates as projected by the refineries or calculated by ENVIRON given emission limits and unit design specifications, both for a short-term (tons/day) and long-term (tons/year) basis;

(iii) Actual emission rates (tons/day) for the years 2002, 2004 or 2005.

In determining actual 2002 emission rates for those units covered by the consent decree at the Artesia and Lovington Refineries, ENVIRON utilized emission inventory data as provided by the 2002 Western Regional Air Partnership (WRAP) IDA Format File (IDA File).

In order to properly correlate unit names and/or descriptions as given by the consent decree to emission rates present in the IDA File, source classification codes (SCCs) and heater/boiler maximum rated capacities (MRCs) were used for matching purposes. ENVIRON matched MRCs from the consent decree with the corresponding MRCs from the IDA File (as listed in the 'boilcap' field). When a successful match was made between the consent decree and the IDA File, ENVIRON populated the Attachment C table with the corresponding Stack and Point IDs from the IDA File, along with the corresponding NO_x, SO_2, VOC and PM_{10} emission rates. If a successful match was not made, ENVIRON assigned a Stack and Point ID from the IDA File, along with the corresponding NO_x, SO_2, VOC and PM_{10} emission rates. Based on the emission point descriptions from the consent decree and SCCs for each source, ENVIRON attempted to select a Stack and Point ID from among like sources. For example, if an emissions unit was listed as a heater in the consent decree, then ENVIRON attempted to select a heater from the IDA File.

In circumstances where emission rates from the IDA File were not present for a pollutant from a given unit, even if identified by Stack or Point ID, the label "N.L." has been employed to mark emissions which were *not listed*.

2.11 Shell Joint Ventures: Motiva and Deer Park Refining

2.11.1 Affected Refineries

Three consent decrees were negotiated for the petroleum refining entities in which the Shell Oil Company was sole owner or a principal joint venture partner. These include:

- Deer Park Refining Limited Partnership, a joint venture between Shell and PMI Norteamerica, S.A. de C.V., a subsidiary of Petróleos Mexicanos (Pemex);
- Equilon Enterprises LLC, a joint venture between Shell and Texaco; and
- Motiva Enterprises LLC, a joint venture between Shell and Saudi Refining, Inc.

Equilon Enterprises no longer exists. Current Shell and Motiva refineries that are part of the consent decrees are as follows.

Refinery	Capacity (Barrels per Day)[39]
Anacortes, Washington (Shell)	145,000
Convent, Louisiana (Motiva)	235,000
Deer Park, Texas (Deer Park Refining)	333,700
Martinez, California (Shell)	155,600
Norco, Louisiana (Motiva)	242,200
Port Arthur, Texas (Motiva)	285,000
Wilmington, California (Shell)	97,000

The four refineries shown in italics are located within EPA Region VI.

2.11.2 Consent Decree Requirements

2.11.2.1 Fluid Catalytic Cracking Units

Each refinery operates a single FCCU. NO_X emission limit requirements specified by the consent decrees are as follows.

- Convent Refinery: By September 30, 2001, Motiva Convent is to begin the addition of NO_X adsorbing catalyst. Based on the results of a catalyst optimization study, Motiva is to propose short and long-term NO_X emission limits to EPA.

[39] Atmospheric crude oil distillation capacity (Source: Energy Information Administration, U.S. Refineries Operable Capacity, 2007, http://www.eia.doe.gov/neic/rankings/refineries.htm)

- Deer Park Refining: By December 31, 2004, Deer Park Refining is to install and begin operation of a selective catalytic reduction (SCR) system or alternative technology to achieve a NO_X concentration of no greater than 20 ppmvd on a 365-day rolling average and no greater than 40 ppmvd on a 3-hour rolling average, both at 0% O_2.
- Norco Refinery: By December 31, 2004, Motiva Norco is to install and begin operation of a selective non-catalytic reduction (SNCR) system or acceptable alternative technology. Based on the results of an SNCR optimization study, Motiva is to propose short and long-term NO_X emission limits to EPA.
- Port Arthur Refinery: By September 30, 2001, Motiva is to begin the addition of NO_X adsorbing catalyst. Based on the results of a catalyst optimization study, Motiva is to propose short and long-term NO_X emission limits to EPA. Alternatively, Motiva can operate the FCCU so that NO_X emissions do not exceed 20 ppmvd on a 365-day rolling average and 40 ppmvd on a 3-hour rolling average. both at 0% O_2.

SO_2 emission limit requirements specified by the consent decrees are as follows.

- Convent Refinery: By December 31, 2006, Motiva is to install and begin operation of a wet gas scrubber (WGS) to control emissions of SO_2. The WGS is to achieve an SO_2 concentration emission limit of no greater than 25 ppmvd on a 365-day rolling average and no greater than 50 ppmvd on a 7-day rolling average, both at 0% O_2.
- Deer Park Refining: By December 31, 2003, Deer Park Refining is to install and begin operation of a WGS to control emissions of SO_2. The WGS is to achieve an SO_2 concentration emission limit of no greater than 25 ppmvd on a 365-day rolling average and no greater than 50 ppmvd on a 7-day rolling average, both at 0% O_2.
- Norco Refinery: By June 30, 2001, Motiva is to operate the FCCU so that SO_2 emissions do not exceed 25 ppmvd on a 365-day rolling average and 50 ppmvd on a 7-day rolling average, both at 0% O_2.
- Port Arthur Refinery: By June 30, 2001, Motiva is to operate the FCCU so that SO_2 emissions do not exceed 25 ppmvd on a 365-day rolling average and 50 ppmvd on a 7-day rolling average, both at 0% O_2. The Port Arthur Refinery is exempt from these limits during CO boiler outages until December 31, 2006.

The FCCU regenerators are affected facilities subject to the SO_2 and PM emission requirements of NSPS Subparts A and J according to the following schedule.

FCCU Regenerator	NSPS Effective Date (SO_2 and PM Limits)
Convent Refinery	December 31, 2006
Deer Park Refining	December 31, 2003
Norco Refinery	Upon Lodging (March 2001)
Port Arthur Refinery	December 31, 2006

SO_2 limits per 40 CFR 60.104(b) are as follows: "*Each owner or operator that is subject to the provisions of this subpart shall comply with one of the following conditions for each affected fluid catalytic cracking unit catalyst regenerator: (1) With an add-on control device, reduce sulfur dioxide emissions to the atmosphere by 90 percent or maintain sulfur dioxide emissions to the atmosphere less than or equal to 50 ppm by volume (ppmv), whichever is less stringent; or (2) Without the use of an add-on control device, maintain sulfur oxides emissions calculated as sulfur dioxide to the atmosphere less than or equal to 9.8 kg/Mg (20 lb/ton) coke burn-off; or (3) Process in the fluid catalytic cracking unit fresh feed that has a total sulfur content no greater than 0.30 percent by weight*." PM limits per 40 CFR 60.102(a) are as follows: "*No owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any fluid catalytic cracking unit catalyst regenerator: (1) Particulate matter in excess of 1.0 kg/Mg (2.0 lb/ton) of coke burn-off in the catalyst regenerator*."

2.11.2.2 Heaters and Boilers

A single consent decree covers heaters and boilers at Shell, Deer Park Refining, and Motiva refineries. The fifth amendment to the consent decree specifies an overall reduction in NO_X emissions of 5,103.25 tons/year from the refineries.[40] Compliance with the emission reductions is to be achieved by December 31, 2008.

For reference purposes only, per the first amendment to the heater and boiler consent decree, baseline NO_X emissions for 1998/1999 are as follows:

Deer Park Refining:	3,722 tons/year
Motiva Convent Refinery:	1,452 tons/year
Motiva Norco Refinery:	1,873 tons/year
Motiva Port Arthur Refinery:	2,674 tons/year

The consent decree requires the companies to submit a NO_X control plan to EPA no later than December 31, 2001. Annual updates are to be submitted by March 31 for the life of the consent

[40] Compliance is determined by summing actual baseline emissions for the combustion sources listed in the consent decree and subtracting the sum of allowable emissions following implementation of the consent decree for those same combustion sources.

decree. The control plan and annual updates are to describe the methods and progress of the NO_X emission reduction program.

Each heater and boiler that combusts refinery fuel gas is an affected facility and subject to the requirements of NSPS Subparts A and J. NSPS Subpart J (40 CFR 60.104(a)) establishes the following emission limits for fuel gas combustion devices: "*No owner or operator subject to the provisions of this subpart shall: (1) Burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf)*."

2.11.2.3 Sulfur Recovery Plants

The consent decrees specify that SRPs are affected facilities with respect to NSPS Subparts A and J according to the following schedule:

Sulfur Recovery Plant	Sulfur Recovery Units	NSPS Effective Date
Deer Park Refining SRP	5, 6, 7 and 8	Date of Lodging (March 2001)
Deer Park Refining SRP	3 and 4	September 30, 2002
Motiva Convent Refinery SRP	1, 2, 3, 4 and 5	Date of Lodging (March 2001)
Motiva Norco Refinery SRP	2 and 3	Date of Lodging (March 2001)
Port Arthur Refinery SRP	2, 3 and 4	Date of Lodging (March 2001)

SO_2 limits per 40 CFR 60.104(a) are as follows: "*No owner or operator subject to the provisions of this subpart shall: . . . (2) Discharge or cause the discharge of any gases from any Claus sulfur recovery plant containing in excess of: (i) For an oxidation control system or a reduction control system followed by incineration, 250 ppm by volume (dry basis) of sulfur dioxide (SO_2) at zero percent excess air. (ii) For a reduction control system not followed by incineration, 300 ppm by volume of reduced sulfur compounds and 10 ppm by volume of hydrogen sulfide (H_2S), each calculated as ppm SO_2 by volume (dry basis) at zero percent excess air*."

2.11.2.4 Flares

During 2001, Motiva and Deer Park Refining are to perform an audit and identify flares for which NSPS Subpart J applicability will be accepted. NSPS Subpart J (40 CFR 60.104(a)) establishes the following emission limits for fuel gas combustion devices, including flares: "*No owner or operator subject to the provisions of this subpart shall: (1) Burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf)*."

2.11.2.5 Benzene Waste Operations NESHAP Program Enhancements

The consent decrees contain numerous requirements related to Benzene Waste Operations NESHAP compliance and program enhancements. The consent decree, however, does not specify numerical

emission targets or required numerical emission reductions.

2.11.2.6 Leak Detection and Repair Program Enhancements

The consent decrees specify certain enhancements to existing leak detection and repair (LDAR) programs at the Shell and Motiva refineries. This includes use of lower leak definitions. The consent decrees, however, does not specify numerical emission targets or required numerical emission reductions.

2.11.2.7 Permitting

The consent decrees require that Motiva and Shell obtain federally-enforceable permits for the construction of pollution control equipment in a timely manner. Concentration limits are to be incorporated into NSR authorizations within 60 days of a determination of the final limit.

2.11.3 Emissions Information

The summary of projected emissions and implementation dates is derived from the following sources of information:

- Consent decree,
- NO_X control plans, and/or
- Information provided by Shell and/or Motiva personnel.

It is important to note that the information provided by Shell and Motiva and the projected emissions presented within this document do not in and of themselves constitute enforceable commitments on the part of Shell or Motiva. Many of the requirements of the consent decree allow for flexibility in implementation. Until such time as the consent decree is closed (upon completion of all requirements), the methods and the location of the emission reductions remain subject to change.

2.11.3.1 Fluid Catalytic Cracking Units

As noted previously, the consent decrees specify that, based on demonstrations, Motiva is to propose emission limits to EPA. It is our understanding that emission limits have been proposed for the Norco, Convent and Port Arthur refineries. However, EPA has yet to respond. Until such time as EPA approves them, the limits are not effective.

FCCU NO_X and SO_2 emissions are estimated using available information and the following methodology.

(1) Coke Burn Rate[41] (lbs/hour) = FCCU Throughput (bbl/day) x 0.75

(2) FCCU Exhaust (dscf/hour) = Coke Burn Rate (lbs/hour) x160 dscf/lb Coke Burned (Full Burn) or
FCCU Exhaust (dscf/hour) = Coke Burn Rate (lbs/hour) x 200 dscf/lb Coke Burned (Partial Burn)

(3) Mass Emission Rate (tons/year) = (PV/RT)(MW)(8760 hours/year)(1 ton/2000 lbs), where

P = 1 atm
V = (FCCU Exhaust)[(Pollutant Concentration, ppmvd)/10^6]
R = 0.7302 atm-ft^3/lbmole-°R
T = 520°R
MW = Molecular Weight (NO_X = 46, SO_2 = 64)

For the three Motiva refineries, a 40 ppmvd NO_X limit is assumed. The actual limits may be lower or higher than this value. Other limits are from the consent decree.

Emissions of PM are calculated by multiplying the emission limit by the estimated coke burn rate.

Table 2.11-1. Motiva / Deer Park Refining FCCU Emissions

Refinery	FCCU Capacity (bbl/day)	Emissions (tons/year)		
		NO_X	SO_2	PM
Deer Park Refining[1]	75,000	119	208	246
Motiva Convent Refinery[2]	92,000	234	204	302
Motiva Norco Refinery[1]	114,000	363	316	374
Motiva Port Arthur Refinery[2]	90,000	229	199	296

Estimated FCCU Emissions are presented in Table 2.11-1.

[1]Partial burn FCCU
[2]Full burn FCCU

In estimating emissions from the FCCU for the photochemical modeling emissions inventory, use of average annual projected NO_X, SO_2 and PM emission rates is deemed appropriate for the following reasons.

1. It is ENVIRON's understanding that emissions from an FCCU are relatively constant.
2. For the large number of FCCUs considered in a regional haze analysis, the collective emissions during any given period should, in aggregate, approach the annual average emission rate. Use of short-term emission limits might be appropriate for a single FCCU, but across the large

[41] Source: Energy Information Administration (EIA), Form EIA-820, "Annual Refinery Report," 2007.

number of FCCUs included in the photochemical modeling emissions inventory, use of short-term emission limits could result in a gross overestimation of portfolio emissions.

3. Compliance with the NSPS Subpart J emission limit – 1 lb PM per 1,000 lbs coke burned – is demonstrated using the average of three, one-hour test runs (EPA Method 5B or 5F). Therefore, annual PM emissions are calculated using a short-term emission rate.

2.11.3.2 Combustion Units

Tables 2.11-2 through 2.11-5 identify heaters and boilers that are part of the Shell / Motiva NO_X control plans.

Table 2.11-2. Deer Park Refining Heater and Boiler Emissions

Unit ID	Max. Rated Capacity (MMBTU/hr)	NO_X Emission Rate (lb/MMBTU)	NO_X Emissions (tons/year)	SO_2 Emissions (tons/year)	Controls	Year Controlled
FUT100	731.5	0	0	0	Shutdown	2004
FUT110	731.5	0	0	0	Shutdown	2004
FUT120	731.5	0	0	0	Shutdown	2004
FUT130	731.5	0	0	0	Shutdown	2004
H1170	65.0	0.035	10.0	7.5	ULNB	2002
H5100	324.0	0.04	56.8	37.4	ULNB	2000
H5101	324.0	0.04	56.8	37.4	ULNB	2000
H5301	250.0	0.02	21.9	28.9	SCR	2008
H5302	280.0	0.02	24.5	32.3	SCR + ULNB	2008
H5303	140.0	0.02	12.3	16.2	SCR + ULNB	2008
H5304	110.0	0.02	9.6	12.7	SCR + ULNB	2008
H5305	70.0	0.02	6.1	8.1	SCR	2008
H5350	35.0	0.02	3.1	4.0	SCR	2008
H5600	126.0	0.03	16.6	14.5	ULNB	1995
H613	138.0	0.04	24.2	15.9	ULNB	2000
H753	39.8	0	0	0	Shutdown	2004
H754	21.1	0	0	0	Shutdown	2005
H755	35.8	0	0	0	Shutdown	2004
H775	10.9	0	0	0	Shutdown	2005
H780	63.8	0	0	0	Shutdown	2004
H781	22.0	0	0	0	Shutdown	2005
H8	49.8	0	0	0	Shutdown	2004
H8610	1,597.2	0	0	0	Shutdown	2004
H8620	1,597.2	0	0	0	Shutdown	2004

Table 2.11-3 Motiva Convent Refinery Heater and Boiler Emissions

Unit ID	Max. Rated Capacity (MMBTU/hr)	NO_X Emission Rate (lb/MMBTU)	NO_X Emissions (tons/year)	SO_2 Emissions (tons/year)	Controls	Year Controlled
1F-201	165	0.04	28.9	19.1	ULNB	1999
1F-202	165	0.04	28.9	19.1	ULNB	1999
31F-801	345	0.04	60.4	39.8	ULNB+FGR	2005
31F-801 (Permit Mod)	345	0.04	60.4	39.8	ULNB+FGR	2005
31F-802	345	0.04	60.4	39.8	ULNB+FGR	2004
31F-802 (Permit Mod)	345	0.04	60.4	39.8	ULNB+FGR	2004
31F-803	345	0.04	60.4	39.8	ULNB+FGR	2006
4F-501	124	0.04	21.7	14.3	ULNB	1999
4F-502	130	0.04	22.8	15.0	ULNB	1999
6F-701	43	0	0	0	Shutdown	2004
7F-1	130	0.04	22.8	15.0	ULNB	2004

Table 2.11-4 Motiva Norco Refinery Heater and Boiler Emissions

Unit ID	Max. Rated Capacity (MMBTU/hr)	NO_X Emission Rate (lb/MMBTU)	NO_X Emissions (tons/year)	SO_2 Emissions (tons/year)	Controls	Year Controlled
11-73A/B	181.44	0.04	31.8	21.0	ULNB	2007
19-71	246.40	0.04	43.2	28.5	ULNB	2007
27/28-71	545.44	0.02	47.8	63.0	SCR	2008
30-71	222.32	0.04	39.0	25.7	ULNB	2007
31-71	222.32	0.04	39.0	25.7	ULNB	2007

Table 2.11-5 Motiva Port Arthur Refinery Heater and Boiler Emissions

Unit ID	Max. Rated Capacity (MMBTU/hr)	NO_X Emission Rate (lb/MMBTU)	NO_X Emissions (tons/year)	SO_2 Emissions (tons/year)	Controls	Year Controlled
HCU1	45.6	0.04	8.0	5.3	ULNB	1995
HCU1	57.0	0.04	10.0	6.6	ULNB	1995
HFU2	20.0	0	0	0	Shutdown	1999
HFU3	24.0	0	0	0	Shutdown	1999
HTU1	50.0	0.04	8.8	5.8	ULNB	1993

Table 2.11-5 Motiva Port Arthur Refinery Heater and Boiler Emissions

Unit ID	Max. Rated Capacity (MMBTU/hr)	NO_X Emission Rate (lb/MMBTU)	NO_X Emissions (tons/year)	SO_2 Emissions (tons/year)	Controls	Year Controlled
HTU2	64.0	0.04	11.2	7.4	ULNB	1996
HTU2	40.0	0.04	7.0	4.6	ULNB	1996
HTU3	60.0	0.04	10.5	6.9	ULNB	1994
HTU3	52.5	0.04	9.2	6.1	ULNB	1994
HTU4	23.79	0.04	4.2	2.7	ULNB	1998
HTU4LT	63.18	0.04	1.11	7.3	ULNB	1998
LCDU	37.0	0.04	6.5	4.3	ULNB	1993
MPU3	102.0	0.04	17.9	11.8	ULNB	1994
MPU3	44.0	0.04	7.7	5.1	ULNB	1994
MPU4	118.2	0.04	20.7	13.6	ULNB	1998
MPU4	60.0	0.04	10.5	6.9	ULNB	1998
MPU4	13.0	0.04	2.3	1.5	ULNB	1998
PS2	418.5	0	0	0	Shutdown	2004
PS2	418.5	0	0	0	Shutdown	2004
PS3	505.9	0	0	0	Shutdown	2004
SDU2	45.0	0	0	0	Shutdown	1998
SDU2	10.6	0	0	0	Shutdown	1998
SDU3	75.2	0	0	0	Shutdown	1998
SDU3	32.0	0	0	0	Shutdown	1998
VPS2	59.76	0.04	10.5	6.9	ULNB	2002
VPS2	59.76	0.04	10.5	6.9	ULNB	2002
VPS2	59.76	0.04	10.5	6.9	ULNB	2002
VPS2	59.76	0.04	10.5	6.9	ULNB	2002
VPS2	54.11	0.04	9.5	6.2	ULNB	2002
VPS2	54.11	0.04	9.5	6.2	ULNB	2002
VPS4	73.8	0.04	12.9	8.5	ULNB	1993

SO_2 emissions are estimated using the NSPS Subpart J limit and the maximum rated capacity of the combustion units. For heaters and boilers that are not part of the NO_X heater and boiler plan, emissions in the existing inventories are retained. This applies to NO_X, SO_2 and PM.

2.11.3.3 Sulfur Recovery Plants

The SRPs were in compliance with NSPS Subpart J limits as of the consent decree entry date. Therefore, no change in actual or allowable emissions is projected. Therefore, the emission rates currently in the photochemical modeling inventory are retained.

2.11.3.4 Flares

The following controls have been installed to reduce emissions from flares.

Deer Park Refining:

- A Central Processing Unit (CPU) replaced an Alky gas plant to prevent normal discharges to North and West Properties flares.
- Flare gas recovery (FGR) has been installed to prevent discharges to the Coker Flare during normal operation.

Motiva Convent Refinery:

- A FGR system has been installed to prevent discharges to Flares 1, 2, 3 and 4 during normal operation.

Motiva Norco Refinery:

- FGR has been installed to prevent discharges to the West Operations Flare during normal operation.

Motiva Port Arthur Refinery:

- FGR has been installed on all flares to prevent discharges during normal operation.

During normal operations, emissions from flares employing FGR are limited to pilot gas combustion. For practical purposes, these emissions are zero. Therefore, emissions from the Deer Park Refining and Motiva flares with FGR are set to zero for NO_X, SO_2, PM and VOC in the photochemical modeling inventory.

For other flares, the emission rates currently in the photochemical modeling inventory are retained.

2.11.3.5 Leak Detection and Repair Program Enhancements

No estimate of VOC emission changes resulting from implementation of enhanced LDAR programs is currently available. Therefore, the emission rates in the current photochemical modeling emissions inventory are retained.

2.4.3.6 Summary of Emission Rates

Attachment C presents a summary of projected and calculated post-consent decree emission rates for Motiva refineries. This attachment provides the following information concerning units affected by the consent-decree:

(iv) A description of each affected unit and its function, including associated unit identification numbers and emission point identifications;

(v) Potential post-consent decree emission rates as projected by the refineries or calculated by ENVIRON given emission limits and unit design specifications, both for a short-term (tons/day) and long-term (tons/year) basis;

(vi) Actual emission rates (tons/day) for the years 2004 or 2005.

In determining actual 2005 emission rates for those units covered by the consent decree at the Deer Park and Port Arthur Refineries, ENVIRON utilized emission inventory data as provided by the 2005 Texas AFS Format File.

In order to properly correlate unit names as given by the consent decree to emission rates present in the AFS File, Facility Identification Numbers (FINs) and Emission Point Numbers (EPNs) were used for matching purposes. ENVIRON relied upon FINs provided by the Motiva and Shell consent decree and Heater and Boiler Plan to identify units within the AFS File. The NO_x, SO_2, VOC and PM_{10} emission rates from the AFS File associated with each unit FIN was then incorporated into the attachment. Fugitive VOC emissions were taken as the sum of VOC emissions resulting from the "Equipment Leak" category of the AFS File. The AFS File also supplied the corresponding EPN for each unit's FIN, and this EPN was then listed in the attachment. Non-zero AFS File emission rate values were given preference in the case that two emission rates for the same pollutant were provided for a single unit, one of which rates was listed as zero.

If a successful match was not made, ENVIRON assigned a FIN and EPN from the AFS File, along with the corresponding NO_x, SO_2, VOC and PM_{10} emission rates. Based on the emission point descriptions from the consent decree, ENVIRON attempted to select a FIN and EPN from among like sources, or units with similar functions and operations. For example, if an emissions unit was listed as a heater in the consent decree, then ENVIRON attempted to select a heater from the AFS File. These units' FINs and EPNs are indicated in bold red, italicized font.

In determining actual 2004 emission rates for those units covered by the consent decree at the Convent and Norco Refineries, ENVIRON utilized emission inventory data as provided by the 2004 Louisiana AFS Format File (AFS File) and an emission point description database provided by the LDEQ (LDEQ database).[42]

In order to properly correlate unit names and/or descriptions as given by the consent decree to emission rates present in the AFS File, emission point descriptions were used for matching purposes. ENVIRON matched emission point descriptions from the consent decree with the corresponding emission point description from the LDEQ database. The LDEQ database contains a NEDS ID for each entry. The NEDS ID corresponds to the Point ID field in the AFS Format File. When a successful match was made between the consent decree and the LDEQ database, ENVIRON populated the Attachment C table with the corresponding Stack and Point IDs from the AFS File,

[42] Emission point description database was provided by Ms. Jackie Heber of LDEQ on August 28, 2007. According to Ms. Heber, the NEDS ID from this database corresponds to the Point ID field in the Louisiana AFS Format File.

along with the corresponding NO_x, SO_2, VOC and PM_{10} emission rates. If a successful match was not made, ENVIRON assigned a Stack and Point ID from the Louisiana AFS File, along with the corresponding NO_x, SO_2, VOC and PM_{10} emission rates. Based on the emission point descriptions from the consent decree, ENVIRON attempted to select a Stack and Point ID from among like sources. For example, if an emissions unit was listed as a heater in the consent decree, then ENVIRON attempted to select a heater from the AFS File.

In circumstances where emission rates from the AFS File were not present for a pollutant from a given unit, even if identified by FIN or EPN, or Stack or Point ID, the label "N.L." has been employed to mark emissions which were *not listed*.

2.12 Sunoco, Inc.

2.12.1 Affected Refineries

Sunoco, Inc. (Sunoco) owns and operates four refineries that are part of the consent decree. These refineries are as follows.

Refinery	Capacity (Barrels per Day)[43]
Marcus Hook, Pennsylvania/Claymont, Delaware	178,000
Philadelphia, Pennsylvania	335,000
Toledo, Ohio	160,000
Tulsa, Oklahoma	*85,000*

Only the Tulsa Refinery is located within EPA Region VI.

2.12.2 Consent Decree Requirements

2.12.2.1 Fluid Catalytic Cracking Unit

Currently, Sunoco does not operate a Fluid Catalytic Cracking Unit (FCCU) at the Tulsa Refinery.

2.12.2.2 Combustion Units

To reduce combustion unit NO_X emissions at the Tulsa Refinery, the consent decree specifies that Sunoco will install NO_X controls on heaters and boilers greater than 40 MMBTU/hr. The consent decree provides that Sunoco will select one or any combination of "Qualifying Controls" that include the following:

- Selective Catalytic Reduction (SCR) or Selective Non-Catalytic Reduction (SNCR),
- Current Generation or Next Generation Ultra-Low NO_x Burners,
- Other technologies that Sunoco demonstrates to EPA's satisfaction will reduce NO_x emissions from heaters and boilers to 0.040 lbs per MMBTU or lower, or
- Permanent shutdown of a heater or boiler with revocation of its operating permit.

On or before eight years from the consent decree entry date, Sunoco will use Qualifying Controls to reduce NO_X emissions from the heaters and boilers greater than 40 MMBTU/hr by at least 2,189 tons

[43] Atmospheric crude oil distillation capacity (Source: Energy Information Administration, U.S. Refineries Operable Capacity, 2007, http://www.eia.doe.gov/neic/rankings/refineries.htm)

per year (tpy) across all covered refineries. No later than four months after the consent decree entry date, Sunoco will submit a detailed NO_X Control Plan to the EPA with annual updates every 12 months thereafter.

By eight years from the consent decree entry date (June 15, 2005), the gas in the Tulsa Refinery's refinery fuel gas loop must meet the H_2S limit in NSPS Subpart J. NSPS Subpart J (40 CFR 60.104(a)) establishes the following emission limits for fuel gas combustion devices: "*No owner or operator subject to the provisions of this subpart shall: (1) Burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf)*." Also, Sunoco must recover at least 95% of the sulfur that is removed from the fuel gas.

2.12.2.3 Sulfur Recovery Plant

Currently, Sunoco does not operate a Sulfur Recovery Plant at the Tulsa Refinery.

2.12.2.4 Flares

On the following dates, the Sunoco consent decree specifies compliance with NSPS Subparts A and J SO_2 standards for three of the Refinery's four flares:

- Coker Flare, the Date of Entry (June 15, 2005),
- WPU Flare (FCCU Flare), the Date of Entry (June 15, 2005), and
- LEU/MEK Flare, Currently NSPS as of the Date of Entry.

The Tulsa Refinery's fourth flare, the #2 Plat Flare, is not subject to the requirements of the consent decree.

NSPS Subpart J (40 CFR 60.104(a)) establishes the following emission limits for fuel gas combustion devices, including flares: "*No owner or operator subject to the provisions of this subpart shall: (1) Burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf)*."

Sunoco will use one or any combination of the following NSPS Subpart J compliance methods for each Refinery Flare:

1. The operation and maintenance of a flare gas recovery (FGR) system to control continuous or routine combustion in the flare.
2. The operation of a continuous monitoring system or a predictive monitoring system approved by EPA.
3. The elimination of routes of continuous or intermittent, routinely-generated refinery fuel gases to a flare. The only gases permitted to reach the flares are upset gases, fuel gas released as a result of relief valve leakage, or gases released due to other emergency malfunctions.

2.12.2.5 Benzene Waste Operations NESHAP Program Enhancements

Currently, the Tulsa Refinery is not subject to the Benzene Waste Operations NESHAP (BWON) program enhancement requirements of the consent decree because it has a Total Annual Benzene (TAB) amount less than 10 megagrams per year (Mg/yr). Therefore, the Tulsa Refinery is not subject to the BWON Program Enhancement requirements of the consent decree unless and until it has a TAB equal to or greater than 10 Mg/yr.

2.12.2.6 Leak Detection and Repair Program Enhancements

To reduce fugitive emissions of VOC from process equipment, the consent decree requires Sunoco to undertake certain LDAR program enhancements related to compliance with 40 CFR, Part 60, Subpart GGG; Part 61, Subparts J and V; Part 63, Subparts F, H, and CC; and applicable state LDAR requirements. The consent decree, however, does not specify numerical emission targets or required numerical emission reductions.

2.12.2.7 Permitting

For emission limits and standards effective on the consent decree entry date, Sunoco is to submit administratively-complete permit applications to incorporate these requirements into federally-enforceable New Source Review (NSR) permits or other federally-enforceable permits (other than Title V permits) within 180 days of the entry date. For those requirements effective after the entry date, Sunoco is to submit administratively-complete permit applications within 90 days of the effective date of the requirement.

2.12.3 Emissions Information

The following summary of projected emissions and implementation dates is derived from one or more of the following sources of information:

- Consent decree, and/or
- Information provided by Sunoco personnel.

It is important to note that the information provided by Sunoco and the projected emissions presented within this document do not in and of themselves constitute enforceable commitments on the part of Sunoco. Many of the requirements of the consent decree allow for flexibility in implementation. Until such time as the consent decree is closed (upon completion of all requirements), the methods and the location of the emission reductions, in certain cases, remain subject to change.

2.12.3.1 Fluid Catalytic Cracking Units

Sunoco does not operate a Fluid Catalytic Cracking Unit at its Tulsa Refinery.

2.12.3.2 Heaters and Boilers

Sunoco did not provide projected NO_X or SO_2 emissions for affected heaters and boilers at the Tulsa Refinery. To calculate post-consent decree potential NO_X emission rates, ENVIRON used the maximum rated capacity for each affected heater and boiler, provided by Sunoco, along with the NO_X emission limit from the consent decree (0.040 lb/MMBTU). To calculate post-consent decree potential SO_2 emission rates, ENVIRON used the maximum rated capacity for each affected heater and boiler, provided by Sunoco, along with the NSPS Subpart J H_2S emission limit (0.1 grain per dry standard cubic foot).[44]

2.12.3.3 Sulfur Recovery Plant

Sunoco does not operate a Sulfur Recovery Plant at the Tulsa Refinery.

2.12.3.4 Flares

No projections of emission reductions are available for flares. Therefore, the emission rates in the current photochemical modeling emissions inventory are retained

2.12.3.5 Leak Detection and Repair Program Enhancements

No estimate of VOC emission reductions resulting from implementation of enhanced LDAR programs is available.

2.12.3.6 Summary of Emission Rates

Attachment C presents a summary of projected and calculated post-consent decree emission rates for the Sunoco Tulsa Refinery. This attachment provides the following information concerning units affected by the consent-decree:

(i) A description of each affected unit and its function, including associated unit identification numbers and emission point identifications;

(ii) Potential post-consent decree emission rates as projected by the refineries or calculated by ENVIRON given emission limits and unit design specifications, both for a short-term (tons/day) and long-term (tons/year) basis;

(iii) Actual emission rates (tons/day) for the years 2002, 2004 or 2005.

In determining actual 2005 emission rates for those units covered by the consent decree at the Sunoco Refinery, ENVIRON utilized emission inventory data as provided by the 2005 Oklahoma AFS Format File (AFS File).

In order to properly correlate unit names and/or descriptions as given by the consent decree to emission

rates present in the AFS File, emission point descriptions were used for matching purposes. ENVIRON matched emission point descriptions from the consent decree with the corresponding emission point description from the AFS File (as listed in the sitename field). When a successful match was made between the consent decree and the AFS File, ENVIRON populated the Attachment C table with the corresponding Stack and Point IDs from the AFS File, along with the corresponding NO_x, SO_2, VOC and PM_{10} emission rates. If a successful match was not made, ENVIRON assigned a Stack and Point ID from the AFS File, along with the corresponding NO_x, SO_2, VOC and PM_{10} emission rates. Based on the emission point descriptions from the consent decree, ENVIRON attempted to select a Stack and Point ID from among like sources. For example, if an emissions unit was listed as a heater in the consent decree, then ENVIRON attempted to select a heater from the AFS File.

In circumstances where emission rates from the AFS File were not present for a pollutant from a given unit, even if identified by Stack or Point ID, the label "N.L." has been employed to mark emissions which were *not listed*.

[44] We assume that 100% of fuel sulfur (H_2S) is converted to SO_2.

2.13 Total Petrochemicals U.S.A.

2.13.1 Affected Refineries

Total Petrochemicals U.S.A. (Total) owns and operates one refinery that is part of the consent decree.

Refinery	Capacity (Barrels per Day)[45]
Port Arthur, Texas	232,000

This refinery is located within EPA Region VI.

2.13.2 Consent Decree Requirements

2.13.2.1 Fluid Catalytic Cracking Unit

The consent decree specifies that Total is to limit NO_X emissions from any FCCU at the refinery to 30 ppmvd or less on a 365-day rolling average basis and 60 ppmvd NO_X or less on a 7-day rolling average basis at 0% O_2. At the time of the consent decree, Total intended to employ the use of Low-NO_X combustion promoters and NO_X-reducing catalyst additives in order to meet these limits. The limits are to be achieved no later than December 31, 2009.

As of the consent decree Date of Entry, Total is to limit emissions of SO_2 from any FCCU at the refinery to 25 ppmvd or less on a 365-day rolling average and 50 ppmvd or less on a 7-day rolling average at 0% O_2.

To control PM emissions from any FCCU at the Total Refinery, the consent decree specifies a limit of 0.5 pounds PM or less per 1000 pounds coke burned on a 3-hour average. The date of compliance is the consent decree Date of Entry (May 2007).

The consent decree specifies that the FCCU catalyst regenerators are affected facilities subject to the requirements of NSPS Subparts A and J. SO_2 limits per 40 CFR 60.104(b) are as follows: "*Each owner or operator that is subject to the provisions of this subpart shall comply with one of the following conditions for each affected fluid catalytic cracking unit catalyst regenerator: (1) With an add-on control device, reduce sulfur dioxide emissions to the atmosphere by 90 percent or maintain sulfur dioxide emissions to the atmosphere less than or equal to 50 ppm by volume (ppmv), whichever is less stringent; or (2) Without the use of an add-on control device, maintain sulfur oxides emissions calculated as sulfur dioxide to the atmosphere less than or equal to 9.8 kg/Mg (20 lb/ton) coke burn-off; or (3) Process in the fluid catalytic cracking unit fresh feed that has a total sulfur content no greater than 0.30 percent by weight*." PM limits per 40 CFR 60.102(a) are as follows: "*No owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the*

[45] Atmospheric crude oil distillation capacity (Source: Energy Information Administration, U.S. Refineries Operable Capacity, 2007, http://www.eia.doe.gov/neic/rankings/refineries.htm)

atmosphere from any fluid catalytic cracking unit catalyst regenerator: (1) Particulate matter in excess of 1.0 kg/Mg (2.0 lb/ton) of coke burn-off in the catalyst regenerator." The Total FCCU catalyst regenerator is to be in compliance with these emission limits as of the consent decree Date of Entry (May 2007).

2.13.2.2 Combustion Units

The consent decree provides that Total shall install NO_X control technology or otherwise limit NO_X emissions from the covered heaters and boilers listed in Appendix A to the consent decree. No later than December 31, 2013, the refinery-wide weighted-average NO_X emissions limit from all existing covered heaters and boilers is to be reduced to 0.040 lb/MMBTU. Total is to submit a compliance plan for existing heaters and boilers to EPA on or before December 31, 2007.

As of the consent decree entry date, each heater and boiler that combusts refinery fuel gas is an affected facility subject to the SO_2 emission limits of NSPS Subparts A and J. NSPS Subpart J (40 CFR 60.104(a)) establishes the following emission limits for fuel gas combustion devices: "*No owner or operator subject to the provisions of this subpart shall: (1) Burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf)*."

2.13.2.3 Sulfur Recovery Plant

Effective the Date of Entry, the Total consent decree specifies that the sulfur recovery plant (SRP) at the refinery is an affected facility with respect to NSPS Subparts A and J. SO_2 limits per 40 CFR 60.104(a) are as follows: "*No owner or operator subject to the provisions of this subpart shall: . . . (2) Discharge or cause the discharge of any gases from any Claus sulfur recovery plant containing in excess of: (i) For an oxidation control system or a reduction control system followed by incineration, 250 ppm by volume (dry basis) of sulfur dioxide (SO_2) at zero percent excess air. (ii) For a reduction control system not followed by incineration, 300 ppm by volume of reduced sulfur compounds and 10 ppm by volume of hydrogen sulfide (H_2S), each calculated as ppm SO_2 by volume (dry basis) at zero percent excess air*."

2.13.2.4 Flares

The Total consent decree specifies that the following hydrocarbon flares are affected facilities and are to comply with the emission standards in NSPS Subparts A and J as of the listed dates.

- North Flare: Date of Entry (May 2007)
- Middle Flare: 48 Months After Date of Entry (May 2009)
- South Flare: 48 Months After Date of Entry (May 2009)

NSPS Subpart J (40 CFR 60.104(a)) establishes the following emission limits for fuel gas combustion devices, including flares: "*No owner or operator subject to the provisions of this subpart shall: (1) Burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf)*."

2.13.2.5 Benzene Waste Operations NESHAP Program Enhancements

The consent decree specifies Total's compliance with the option set forth at 40 CFR Section 61.342(e) ("6 BQ Compliance Option"), along with all other applicable requirements of Benzene Waste Operations NESHAP. From March 31, 2007 until March 31, 2013, Total is required to achieve a standard at least thirty percent more stringent than that provided by 40 CFR Section 61.342(e). Total is specified to operate the refinery such that the benzene wastes described in 61.342(e) are equal to or less than 4.2 Mg/year ("4.2 BQ Compliance Option"). After March 31, 2013, Total will no longer be required to comply with the 4.2 BQ Compliance Option, though it will not deviate from the 6 BQ Compliance Option.

2.13.2.6 Leak Detection and Repair Program Enhancements

To reduce fugitive emissions of VOC from process equipment, the consent decree requires Total to undertake certain LDAR program enhancements. These enhancements include compliance with the requirements of 40 CFR 60, Subpart GGG, and will be presented in a written description of a Refinery-wide program developed by the consent decree entry date (May 2007). The consent decree, however, does not specify numerical emission targets or required numerical emission reductions.

2.13.2.7 Permitting

For emission limits and standards effective on the consent decree entry date, Total is to submit administratively-complete permit applications to incorporate these requirements into federally-enforceable New Source Review (NSR) permits within 180 days of the entry date. For those requirements effective after the entry date, Total is to submit administratively-complete permit applications within 180 days of the effective date of the requirement.

2.13.3 Emissions Information

The following summary of projected emissions and implementation dates is derived from one or more of the following sources of information:

- Consent decree, and/or
- Information provided by Total personnel.

It is important to note that the information provided by Total Petrochemicals and the projected emissions presented within this document do not in and of themselves constitute enforceable

commitments on the part of Total Petrochemicals. Many of the requirements of the consent decree allow for flexibility in implementation. Until such time as the consent decree is closed (upon completion of all requirements), the methods and the location of the emission reductions, in certain cases, remain subject to change.

2.13.3.1 Fluid Catalytic Cracking Units

Information provided by Total indicates that the FCCU is currently in compliance with the emission limits specified in the consent decree. FCCU NO_X and SO_2 emissions are estimated using available information and the following methodology.

(1) Coke Burn Rate (lbs/hour) = FCCU Throughput (bbl/day)[46] x 0.75

(2) FCCU Exhaust (dscf/hour) = Coke Burn Rate (lbs/hour) x160 dscf/lb Coke Burned (Full Burn) or
FCCU Exhaust (dscf/hour) = Coke Burn Rate (lbs/hour) x 200 dscf/lb Coke Burned (Partial Burn)

(3) Mass Emission Rate (tons/year) = (PV/RT)(MW)(8760 hours/year)(1 ton/2000 lbs), where

P = 1 atm
V = (FCCU Exhaust)[(Pollutant Concentration, ppmvd)/10^6]
R = 0.7302 atm-ft^3/lbmole-°R
T = 520°R
MW = Molecular Weight (NO_X = 46, SO_2 = 64)

Table 2.13-1. Total FCCU Emissions

Refinery	FCCU Capacity (bbl/day)	Emissions (tons/year)		
		NO_X	SO_2	PM
Port Arthur Refinery	78,000	186	216	128

Emissions of PM are calculated by multiplying the emission limit by the estimated coke burn rate. Estimated FCCU Emissions are presented in Table 2.13-1. Partial burn operation is assumed.

In estimating emissions from the FCCU for the photochemical modeling emissions inventory, use of average annual projected NO_X, SO_2 and PM emission rates is deemed appropriate for the following reasons.

1. It is ENVIRON's understanding that emissions from an FCCU are relatively constant.
2. For the large number of FCCUs considered in a regional haze analysis, the collective emissions

[46] Source: Energy Information Administration (EIA), Form EIA-820, "Annual Refinery Report," 2007.

during any given period should, in aggregate, approach the annual average emission rate. Use of short-term emission limits might be appropriate for a single FCCU, but across the large number of FCCUs included in the photochemical modeling emissions inventory, use of short-term emission limits could result in a gross overestimation of portfolio emissions.

3. Compliance with the NSPS Subpart J emission limit – 1 lb PM per 1,000 lbs coke burned – is demonstrated using the average of three, one-hour test runs (EPA Method 5B or 5F). Therefore, annual PM emissions are calculated using a short-term emission rate.

2.13.3.2 Combustion Units

Table 2.13-2 presents projected NO_X emissions for affected heaters and boilers at the Port Arthur Refinery. These emissions are calculated using the consent decree limit of 0.04 lb/MMBTU for all combustion units rated 40 MMBTU/hour or greater. The consent decree's heater and boiler listing provides each unit's maximum rated capacity.

Table 2.13-2. Total Combustion Units NO_X Emissions

NO_X Emission Limit per Unit (lb/MMBTU)	Refinery-wide Maximum Rated Capacity (MMBTU/hr)	Worst-Case NO_X Emissions (tons/year)
0.04	2,406.62	421.64

SO_2 emissions included in the updated photochemical modeling inventory are calculated using NSPS Subpart J emission limits and listed maximum rated capacities.

2.13.3.3 Sulfur Recovery Plants

Information provided by Total indicates that the SRP is currently in compliance with the emission limits specified in the consent decree. Insufficient information, however, is available to calculate post-consent decree maximum annual emission rates. Therefore, the emission rates in the current photochemical modeling emissions inventory are retained.

2.13.3.4 Flares

Information provided by Total indicates that the flares are currently in compliance with the emission limits specified in the consent decree. Insufficient information, however, is available to calculate post-consent decree maximum annual emission rates. Therefore, the emission rates in the current photochemical modeling emissions inventory are retained.

2.13.3.5 Leak Detection and Repair Program Enhancements

No estimate of VOC emission reductions resulting from implementation of enhanced LDAR programs is available.

2.13.3.6 Summary of Emission Rates

Attachment C presents a summary of projected and calculated post-consent decree emission rates for the Total refinery. This attachment provides the following information concerning units affected by the consent-decree:

(i) A description of each affected unit and its function, including associated unit identification numbers and emission point identifications;

(ii) Potential post-consent decree emission rates as projected by the refineries or calculated by ENVIRON given emission limits and unit design specifications, both for a short-term (tons/day) and long-term (tons/year) basis;

(iii) Actual emission rates (tons/day) for the years 2004 or 2005.

In determining actual 2005 emission rates for those units covered by the consent decree at the Total Port Arthur Refinery, ENVIRON utilized emission inventory data as provided by the 2005 Texas AFS Format File.

In order to properly correlate unit names as given by the consent decree to emission rates present in the AFS File, Facility Identification Numbers (FINs) and Emission Point Numbers (EPNs) were used for matching purposes. ENVIRON relied upon FINs provided by the Total consent decree to identify units within the AFS File. The NO_x, SO_2, VOC and PM_{10} emission rates from the AFS File associated with each unit FIN was then incorporated into the attachment. Fugitive VOC emissions were taken as the sum of VOC emissions resulting from the "Equipment Leak" category of the AFS File. The AFS File also supplied the corresponding EPN for each unit's FIN, and this EPN was then listed in the attachment. Non-zero AFS File emission rate values were given preference in the case that two emission rates for the same pollutant were provided for a single unit, one of which rates was listed as zero.

If a successful match was not made, ENVIRON assigned a FIN and EPN from the AFS File, along with the corresponding NO_x, SO_2, VOC and PM_{10} emission rates. Based on the emission point descriptions from the consent decree, ENVIRON attempted to select a FIN and EPN from among like sources, or units with similar functions and operations. For example, if an emissions unit was listed as a heater in the consent decree, then ENVIRON attempted to select a heater from the AFS File. These units' FINs and EPNs are indicated in bold red, italicized font.

In circumstances where emission rates from the AFS File were not present for a pollutant from a given unit, even if identified by FIN or EPN, the label "N.L." has been employed to mark emissions which were *not listed*.

2.14 Valero

2.14.1 Affected Refineries

Valero owns and operates 12 refineries that are part of the 2005 consent decree.[47] These refineries are as follows.

Refinery	Capacity (Barrels per Day)[48]
Ardmore, Oklahoma	87,400
Benicia, California	144,000
Corpus Christi, Texas (East & West Refineries)	142,000
Houston, Texas	83,000
Krotz Springs, Louisiana	80,000
McKee (Sunray), Texas	171,000
Paulsboro, New Jersey	160,000
St. Charles (Norco), Louisiana	185,000
Texas City, Texas	218,500
Three Rivers, Texas	93,000
Wilmington, California	6,300

The nine refineries shown in italics are located within EPA Region VI.

In August 2007, the EPA issued a press release stating that it had reached an agreement to reduce emissions from former Premcor refineries in Ohio, Tennessee and Texas that are now owned by Valero. This settlement includes the 260,000 bbl/day Valero refinery in Port Arthur.

2.14.2 Consent Decree Requirements

2.14.2.1 Fluid Catalytic Cracking Units (FCCU)

Each refinery has a single FCCU. NO_X emission limit requirements specified by the consent decree are as follows.

Houston and Texas City Refineries: By December 31, 2007, Valero is to install and begin operation

[47] The consent decree considers the Corpus Christi East Refinery and the Corpus Christi West Refinery as separate refineries.

[48] Atmospheric crude oil distillation capacity (Source: Energy Information Administration, U.S. Refineries Operable Capacity, 2007, http://www.eia.doe.gov/neic/rankings/refineries.htm)

of a LoTOx™ system or alternative to achieve a NO_X concentration of no greater than 20 ppmvd on a 365-day rolling average and no greater than 40 ppmvd on a 7-day rolling average, both at 0% O_2.

Port Arthur Refinery: By December 31, 2013, Valero is to achieve a final NO_X system-wide (former Premcor refineries only) concentration emission limit average of 33.4 ppmvd (at 0% O_2) on a 365-day rolling average. However, no covered FCCU, including the Port Arthur FCCU, is to have a permitted NO_X limit higher than 80 ppmvd at 0% O_2 on a 365-day rolling average.

St. Charles Refinery: By December 31, 2005, commence an optimization study on the existing high-efficiency regenerator oxygen control system in an effort to achieve a NO_X concentration of no greater than 20 ppmvd (0% O_2) on a 365-day rolling average and no greater than 40 ppmvd (0% O_2) on a 7-day rolling average.

All Refineries: By December 31, 2011, Valero is to achieve a system-wide (exclusive of Port Arthur and other former Premcor refineries) coke burn-weighted average of NO_X concentration emission limit of 33.4 ppmvd on a 365-day rolling average at 0% O_2.

SO_2 emission limit requirements specified by the consent decree are as follows.

Ardmore Refinery: By no later than the next scheduled turnaround (at the time of the consent decree anticipated to occur in 2005), Valero is to install and begin operation of a wet gas scrubber (WGS) to achieve an SO_2 concentration emission limit of no greater than 25 ppmvd on a 365-day rolling average and no greater than 50 ppmvd on a 7-day rolling average, both at 0% O_2.

Corpus Christi East Refinery: Valero is to implement an SO_2 absorbing catalyst additive protocol according to the description and schedule in Appendix E to the consent decree. Additionally, Valero has selected the Corpus Christi East Refinery for installation of a WGS to be installed during the anticipated 2010 turnaround. The WGS is to achieve an SO_2 concentration emission limit of no greater than 25 ppmvd on a 365-day rolling average and no greater than 50 ppmvd on a 7-day rolling average, both at 0% O_2.

Corpus Christi West Refinery: Within 60 days of the date of lodging of the consent decree (by August 2005), Valero is to achieve an SO_2 concentration emission limit of no greater than 25 ppmvd on a 365-day rolling average and no greater than 50 ppmvd on a 7-day rolling average, both at 0% O_2, at the Corpus Christi West FCCU.

Houston Refinery: By March 31, 2007, Valero is to install and begin operation of a WGS to achieve an SO_2 concentration emission limit of no greater than 25 ppmvd on a 365-day rolling average and no greater than 50 ppmvd on a 7-day rolling average, both at 0% O_2.

Krotz Springs Refinery: Valero is to implement an SO_2 absorbing catalyst additive protocol according to the description and schedule in Appendix E to the consent decree.

McKee Refinery: by June 30, 2006, Valero is to implement an SO_2 absorbing catalyst additive protocol according to the description and schedule in Appendix E to the consent decree.

Port Arthur Refinery: Upon the Date of Entry, Valero is to continue operation of a WGS at the Port Arthur Refinery FCCU and comply with an SO_2 concentration emission limit of no greater than 25 ppmvd on a 365-day rolling average and no greater than 50 ppmvd on a 7-day rolling average, both at 0% O_2.

St. Charles Refinery: By June 30, 2005, achieve an SO_2 concentration emission limit of no greater than 25 ppmvd on a 365-day rolling average and no greater than 50 ppmvd on a 7-day rolling average, both at 0% O_2.

Texas City Refinery: As of the consent decree entry date (June 2005), Valero is to continue operation of an existing WGS to achieve an SO_2 concentration emission limit of no greater than 25 ppmvd on a 365-day rolling average and no greater than 50 ppmvd on a 7-day rolling average, both at 0% O_2.

Three Rivers Refinery: By December 31, 2006, install and begin operation of a WGS to achieve an SO_2 concentration emission limit of no greater than 25 ppmvd on a 365-day rolling average and no greater than 50 ppmvd on a 7-day rolling average, both at 0% O_2.

The FCCU regenerators are affected facilities subject to the SO_2 emission requirements of NSPS Subparts A and J according to the following schedule.

FCCU Regenerator	**NSPS Effective Date**
Ardmore	December 31, 2005
Corpus Christi East	Upon Installation of WGS
Corpus Christi West	Date of Entry (June 2005)
Houston	March 31, 2007
Krotz Springs	June 30, 2010
McKee	December 31, 2009
Port Arthur Refinery	Date of Entry (est. August 2007)
St. Charles	Date of Entry (June 2005)
Texas City	Date of Lodging (June 2005)
Three Rivers	December 31, 2006

SO_2 limits per 40 CFR 60.104(b) are as follows: "*Each owner or operator that is subject to the provisions of this subpart shall comply with one of the following conditions for each affected fluid catalytic cracking unit catalyst regenerator: (1) With an add-on control device, reduce sulfur dioxide emissions to the atmosphere by 90 percent or maintain sulfur dioxide emissions to the*

atmosphere less than or equal to 50 ppm by volume (ppmv), whichever is less stringent; or (2) Without the use of an add-on control device, maintain sulfur oxides emissions calculated as sulfur dioxide to the atmosphere less than or equal to 9.8 kg/Mg (20 lb/ton) coke burn-off; or (3) Process in the fluid catalytic cracking unit fresh feed that has a total sulfur content no greater than 0.30 percent by weight."

With respect to PM, the consent decree limits PM emissions to 1.0 pound per 1,000 pounds, measured as a one-hour average over three, one-hour performance test runs. In addition, the refineries are subject to the PM emission requirements of 40 CFR 60 Subparts A and J according to the following schedule:

- 180 days from the consent decree Date of Entry (approx. December 2005): Corpus Christi West Refinery, Houston Refinery, McKee Refinery and Texas City Refinery.
- By December 31, 2006: Ardmore Refinery, Corpus Christi East Refinery, Krotz Springs Refinery, St. Charles Refinery, and Three Rivers Refinery.
- By 90 days from the Date of Entry (approx. December 1, 2007): Port Arthur Refinery.

PM limits per 40 CFR 60.102(a) are as follows: "*No owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any fluid catalytic cracking unit catalyst regenerator: (1) Particulate matter in excess of 1.0 kg/Mg (2.0 lb/ton) of coke burn-off in the catalyst regenerator*."

2.14.2.2 Heaters and Boilers

The consent decree commits Valero to achieving a final system-wide weighted average concentration limit for NO_X, exclusive of former Premcor refineries of 0.044 lb/MMBTU for heaters and boilers greater than 40 MMBTU/hr (listed in Appendix B to the consent decree) by December 31, 2011. For the former Premcor refineries, including the Port Arthur Refinery, Valero is to achieve this same final system-wide weighted average concentration limit for heaters and boilers greater than 40 MMBTU/hr by December 31, 2013.

Each heater and boiler that combusts refinery fuel gas is an affected facility subject to the SO_2 emission limits of NSPS Subparts A and J according to the following schedule:

- By 60 days after Date of Entry (approx. November 1, 2007): Port Arthur Refinery.
- By December 31, 2007: Corpus Christi West Refinery, Houston Refinery, Krotz Springs Refinery, St. Charles Refinery and Texas City Refinery.
- By December 31, 2010: Ardmore Refinery, Corpus Christi East Refinery, McKee Refinery and Three Rivers Refinery.

NSPS Subpart J (40 CFR 60.104(a)) establishes the following emission limits for fuel gas combustion

devices: "*No owner or operator subject to the provisions of this subpart shall: (1) Burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf)*."

2.14.2.3 Sulfuric Acid Plants

No later than December 31, 2007, Valero is to install and begin operation of a scrubber at the McKee Refinery Sulfuric Acid Plant to achieve: 1) at least a 90% reduction in SO_2 emissions and 2) the SO_2 standard in the NSPS for sulfuric acid plants (Subpart H). SO_2 limits per 40 CFR 60.82(a) are as follows: "*On and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain sulfur dioxide in excess of 2 kg per metric ton of acid produced (4 lb per ton), the production being expressed as 100 percent H_2SO_4.*"

2.14.2.4 Sulfur Recovery Plants

The Valero consent decree specifies that sulfur recovery plants (SRPs) are affected facilities with respect to NSPS Subparts A and J according to the following schedule:

Sulfur Recovery Plant	SRP Trains	NSPS Effective Date
Ardmore SRP	SRU No. 1	Date of Lodging (June 2005)
Corpus Christi East SRP	SRU Nos. 1 & 2	Date of Lodging (June 2005)
Corpus Christi West SRP	SRU Nos. 1, 2 & 3	Date of Lodging (June 2005)
Houston SRP	SRU B	December 31, 2006
McKee SRP	SRU Nos. 1 & 2	December 31, 2006
Port Arthur SRP	8 Claus Trains	Date of Entry (Est. August 2007)
St. Charles SRP	SRU Nos. 1 & 2	Date of Lodging (June 2005)
Texas City SRP	SRU Nos. 1 & 2	Date of Lodging (June 2005)
Texas City South Plant SRP	South Plant SRU	Date of Lodging (June 2005)
Three Rivers SRP	SRU No. 1	Date of Lodging (June 2005)

SO_2 limits per 40 CFR 60.104(a) are as follows: "*No owner or operator subject to the provisions of this subpart shall: . . . (2) Discharge or cause the discharge of any gases from any Claus sulfur recovery plant containing in excess of: (i) For an oxidation control system or a reduction control system followed by incineration, 250 ppm by volume (dry basis) of sulfur dioxide (SO_2) at zero percent excess air. (ii) For a reduction control system not followed by incineration, 300 ppm by volume of reduced sulfur compounds and 10 ppm by volume of hydrogen sulfide (H_2S), each calculated as ppm SO_2 by volume (dry basis) at zero percent excess air*."

2.14.2.5 Flares

The Valero and Premcor consent decrees specify compliance with NSPS Subparts A and J SO_2 standards for the flares identified in Appendix N of each consent decree. NSPS Subpart J (40 CFR 60.104(a)) establishes the following emission limits for fuel gas combustion devices, including flares: "*No owner or operator subject to the provisions of this subpart shall: (1) Burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf)*." All flares are to be in compliance by December 31, 2011.

2.14.2.6 Benzene Waste Operations NESHAP Program Enhancements

The consent decree contains numerous requirements related to Benzene Waste Operations NESHAP compliance and program enhancements. The consent decree, however, does not specify numerical emission targets or required numerical emission reductions.

2.14.2.7 Leak Detection and Repair Program Enhancements

The consent decree specifies certain enhancements to existing leak detection and repair (LDAR) programs at the Valero refineries. This includes use of lower leak definitions. The consent decree, however, does not specify numerical emission targets or required numerical emission reductions.

2.14.2.8 Permitting

For emission limits and standards effective on the consent decree Date of Entry, Valero is to submit permit applications to incorporate these requirements into federally-enforceable New Source Review (NSR) permits no later than December 31, 2005. For the Premcor refineries including the Port Arthur Refinery, permit applications for emission limits and standards effective on the Date of Entry are to be submitted no later than December 31, 2007. For those requirements effective after the entry date, Valero is to submit a permit application within 90 days of the effective date of the requirement.

2.14.3 Emissions Information

The following summary of projected emissions and implementation dates is derived from one or more of the following sources of information:

- Consent decree, and/or
- Information provided by Valero personnel.

It is important to note that the information provided by Valero and the projected emissions presented within this document do not in and of themselves constitute enforceable commitments on the part of Valero. Many of the requirements of the consent decree allow for flexibility in implementation. Until such time as the consent decree is closed (upon completion of all requirements), the methods and the

location of the emission reductions, in certain cases, remain subject to change.

2.14.3.1 Fluid Catalytic Cracking Units

Tables 2.14-1, 2.14-2, and 2.14-3 present projected NO_X, SO_2, and PM emissions, respectively, for each affected FCCU. Valero did not provide projected SO_2 emissions for the Port Arthur FCCU; therefore, 2005 actual emissions are retained in the updated photochemical modeling emissions inventory.

PM emission reductions are only projected for the Ardmore Refinery. The other FCCUs are in compliance with the NSPS Subpart J emission limit and no additional PM emission reductions are anticipated. For those FCCUs, PM emissions are estimated using the NSPS limit of 1 lb/1,000 pounds of coke burned and the maximum coke burn rates listed in the consent decree. Information is not available for the Port Arthur FCCU. Therefore, 2005 actual emissions are retained in the emission inventory.

Table 2.14-4 presents a summary of calculated PM emission rates.

Table 2.14-1. Valero FCCU NO_X Emissions

Refinery	Projected Emissions by Year (tons)							
	2005	2006	2007	2008	2009	2010	2011	2012
Ardmore	116	92	92	92	92	92	92	92
Corpus Christi East	155	155	155	155	155	155	27	27
Corpus Christi West	732	732	732	732	732	732	732	539
Houston	469	469	469	87	87	87	87	87
Krotz Springs	184	184	184	184	184	184	125	125
McKee	63	63	63	63	47	47	47	47
Port Arthur	--	--	799	799	799	799	799	492
St. Charles	1,157	1,157	984	984	984	984	151	151
Texas City	878	878	878	88	88	88	88	88
Three Rivers	88	88	88	88	88	66	66	66

Table 2.14-2. Valero FCCU SO_2 Emissions

Refinery	Projected Emissions by Year (tons)							
	2005	2006	2007	2008	2009	2010	2011	2012
Ardmore	412	45	45	45	45	45	45	45
Corpus Christi East	892	892	892	892	892	892	54	54
Corpus Christi West	58	58	58	58	58	58	58	58

Table 2.14-2. Valero FCCU SO_2 Emissions

Refinery	Projected Emissions by Year (tons)							
	2005	2006	2007	2008	2009	2010	2011	2012
Houston	4,130	4,130	4,130	146	146	146	146	146
Krotz Springs	804	804	804	804	804	804	402	402
McKee	1,034	1,034	1,034	1,034	1,034	517	517	517
St. Charles	174	174	174	174	174	174	174	174
Texas City	2,195	158	158	158	158	158	158	158
Three Rivers	198	198	32	32	32	32	32	32

Table 2.14-3. Valero FCCU PM Emissions

Refinery	Projected Emissions by Year (tons)							
	2005	2006	2007	2008	2009	2010	2011	2012
Ardmore	492	80	80	80	80	80	80	80

Table 2.14-4. Valero FCCU Calculated PM Emissions

Refinery	Maximum Coke Burn (lbs/hour)	PM Emission Rate (lbs/1,000 lbs Coke Burn)	PM emissions (lbs/hour)	PM Emissions (tons/year)
Corpus Christi East	14,700	1.0	14.7	64.4
Corpus Christi West	129,000	1.0	129.0	565.0
Houston	59,000	1.0	59.0	258.4
Krotz Springs	23,000	1.0	23.0	100.7
McKee	35,000	1.0	35.0	153.3
St. Charles	63,000	1.0	63.0	275.9
Texas City	60,000	1.0	60.0	262.8
Three Rivers	17,500	1.0	17.5	76.7

In estimating emissions from the FCCU for use in the photochemical modeling emissions inventory, use of average annual projected NO_X, SO_2 and PM emission rates is deemed appropriate for the following reasons.

1. It is ENVIRON's understanding that emissions from an FCCU are relatively constant.
2. For the large number of FCCUs considered in a regional photochemical modeling analysis, the collective emissions during any given period should, in aggregate, approach the annual average emission rate. Use of short-term emission limits might be appropriate for a single FCCU, but

across the large number of FCCUs included in the photochemical modeling emissions inventory, use of short-term emission limits could result in a gross overestimation of collective emissions.

3. Compliance with the NSPS Subpart J emission limit – 1 lb PM per 1,000 lbs coke burned – is demonstrated using the average of three, one-hour test runs (EPA Method 5B or 5F). Therefore, annual PM emissions are calculated using a short-term emission rate.

Actual and/or anticipated control approaches used to achieve the projected reductions in emissions are as follows.

Ardmore Refinery:

- Use of WGS to reduce emissions of SO_2 and PM.
- Improvements in FCCU regenerator and CO boiler to reduce emissions of NO_X.

Corpus Christi East Refinery:

- Use of WGS to reduce emissions of NO_X, and SO_2.

Corpus Christi West Refinery:

- Method of achieving project NO_X emission reductions has yet to be determined.

Houston Refinery:

- Use of LoTOx™ system to reduce emissions of NO_X.
- Use of WGS to reduce emissions of SO_2.

Krotz Springs Refinery:

- Method of achieving project NO_X emission reductions has yet to be determined.
- Use of SO_2 absorbing catalyst additive to reduce emissions of SO_2.

McKee Refinery:

- Method of achieving project NO_X emission reductions has yet to be determined.
- Use of SO_2 absorbing catalyst additive to reduce emissions of SO_2.

Port Arthur Refinery:

- Method of achieving project NO_X emission reductions has yet to be determined.
- Use of WGS to reduce emissions of SO_2.

St. Charles Refinery:

- Method of achieving project NO_X emission reductions has yet to be determined.

Texas City Refinery:

- Use of LoTOx™ system to reduce emissions of NO_X.
- Use of WGS to reduce emissions of SO_2.

Three Rivers Refinery:

- Method of achieving project NO_X emission reductions has yet to be determined.
- Use of WGS to reduce emissions of SO_2.

2.14.3.2 Heaters and Boilers

Table 2.14-5 presents projected NO_X emissions for affected heaters and boilers at each refinery. While not currently included in the consent decree, Valero provided NO_X emission projections for the Port Arthur Refinery as well. The projections are for the collective of affected heaters and boilers at each refinery as required for compliance with the consent decree. Information on individual units, including emissions and anticipated control approaches, is not provided.

Table 2.14-5. Valero Heater and Boiler NO_X Emissions

Refinery	Projected Emissions by Year (tons)							
	2005	2006	2007	2008	2009	2010	2011	2012
Ardmore	277	266	252	236	217	178	145	145
Corpus Christi East	995	862	737	622	515	373	288	288
Corpus Christi West	604	604	604	604	604	570	487	487
Houston	389	389	389	389	389	389	361	361
Krotz Springs	249	226	204	182	160	125	100	100
McKee	1,090	970	854	743	637	482	380	380
Port Arthur	--	--	1,192	1,229	935	935	935	935
St. Charles	805	709	619	533	451	337	264	264
Texas City	1,032	1,032	1,032	1,032	1,032	966	822	822
Three Rivers	328	328	328	328	328	297	250	250

In revising the photochemical modeling emission inventory, heater and boiler NO_X emissions are allocated as follows:

$$NO_X \text{ Allocation for Each Emission Unit} = (MRC_i/\Sigma\ MRC) \times \text{Total Projected } NO_X \text{ Emissions}$$

MRC_i is the maximum rated capacity for the individual emission unit and $\Sigma\ MRC$ is the sum of maximum rated capacities for all affected heaters and boilers at the refinery.

SO_2 emissions included in the updated photochemical modeling inventory are calculated using NSPS

Subpart J emission limits and maximum rated capacities. For both NO_X and SO_2, annual projections are used in revising the photochemical modeling emissions inventory.

2.14.2.3 Sulfuric Acid Plants

Valero provided the information shown in Table 2.14-6 on projected emission reductions at the McKee Refinery Sulfuric Acid Plant. Valero intends on achieving these emission reductions through use of a WGS.

Table 2.14-6. Valero Sulfuric Acid Plant SO_2 Emissions

Refinery	Projected Emissions by Year (tons)							
	2005	2006	2007	2008	2009	2010	2011	2012
McKee	803	803	803	65	65	65	65	65

Annual projections are used in revising the photochemical modeling emissions inventory.

2.14.3.4 Sulfur Recovery Plants

Table 2.14-7 presents projected emission reductions from SRPs at the Houston and McKee refineries. Valero intends on achieving these emission reductions through use of WGS. Other SRPs are thought to currently be in compliance with NSPS Subpart J emission limits; therefore, no additional SO_2 emission reductions will be realized. For those SRPs, the current actual emission rates are retained in the photochemical modeling emissions inventory.

Table 2.14-7. Valero Sulfur Recovery Plant SO_2 Emissions

Refinery	Projected Emissions by Year (tons)							
	2005	2006	2007	2008	2009	2010	2011	2012
Houston	187	187	27	27	27	27	27	27
McKee	466	466	13	13	13	13	13	13

Annual projections are used to estimate short-term emission rates for use in revising the photochemical modeling emissions inventory.

2.14.3.5 Flares

No projections of emission reductions are available for flares. Therefore, the emission rates in the current photochemical modeling emissions inventory are retained.

2.14.3.6 Leak Detection and Repair Program Enhancements

No estimate of VOC emission reductions resulting from implementation of enhanced LDAR programs is available.

2.14.3.7 Summary of Emission Rates

Attachment C presents a summary of projected and calculated post-consent decree emission rates for Valero refineries. This attachment provides the following information concerning units affected by the consent-decree:

(i) A description of each affected unit and its function, including associated unit identification numbers and emission point identifications;

(ii) Potential post-consent decree emission rates as projected by the refineries or calculated by ENVIRON given emission limits and unit design specifications, both for a short-term (tons/day) and long-term (tons/year) basis;

(iii) Actual emission rates (tons/day) for the years 2004 or 2005.

In determining actual 2005 emission rates for those units covered by the consent decree at the Valero Corpus Christi (East & West), Houston, McKee, Texas City and Three Rivers Refineries, ENVIRON utilized emission inventory data as provided by the 2005 Texas AFS Format File.

In order to properly correlate unit names as given by the consent decree to emission rates present in the AFS File, Facility Identification Numbers (FINs) and Emission Point Numbers (EPNs) were used for matching purposes. ENVIRON relied upon FINs provided by the Valero consent decree and information supplied by Valero personnel to identify units within the AFS File. The NO_x, SO_2, VOC and PM_{10} emission rates from the AFS File associated with each unit FIN was then incorporated into the attachment. Fugitive VOC emissions were taken as the sum of VOC emissions resulting from the "Equipment Leak" category of the AFS File. The AFS File also supplied the corresponding EPN for each unit's FIN, and this EPN was then listed in the attachment. Non-zero AFS File emission rate values were given preference in the case that two emission rates for the same pollutant were provided for a single unit, one of which rates was listed as zero.

If a successful match was not made, ENVIRON assigned a FIN and EPN from the AFS File, along with the corresponding NO_x, SO_2, VOC and PM_{10} emission rates. Based on the emission point descriptions from the consent decree, ENVIRON attempted to select a FIN and EPN from among like sources, or units with similar functions and operations. For example, if an emissions unit was listed as a heater in the consent decree, then ENVIRON attempted to select a heater from the AFS File. These units' FINs and EPNs are indicated in bold red, italicized font.

In determining actual 2004 emission rates for those units covered by the consent decree at the Valero Krotz Springs and St. Charles Refineries, ENVIRON utilized emission inventory data as provided by the 2004 Louisiana AFS Format File (AFS File) and an emission point description database provided

by the LDEQ (LDEQ database).[49]

In order to properly correlate unit names and/or descriptions as given by the consent decree to emission rates present in the AFS File, emission point descriptions were used for matching purposes. ENVIRON matched emission point descriptions from the consent decree with the corresponding emission point description from the LDEQ database. The LDEQ database contains a NEDS ID for each entry. The NEDS ID corresponds to the Point ID field in the AFS Format File. When a successful match was made between the consent decree and the LDEQ database, ENVIRON populated the Attachment C table with the corresponding Stack and Point IDs from the AFS File, along with the corresponding NO_x, SO_2, VOC and PM_{10} emission rates. If a successful match was not made, ENVIRON assigned a Stack and Point ID from the Louisiana AFS File, along with the corresponding NO_x, SO_2, VOC and PM_{10} emission rates. Based on the emission point descriptions from the consent decree, ENVIRON attempted to select a Stack and Point ID from among like sources. For example, if an emissions unit was listed as a heater in the consent decree, then ENVIRON attempted to select a heater from the AFS File.

In determining actual 2005 emission rates for those units covered by the consent decree at the Valero Ardmore Refinery, ENVIRON utilized emission inventory data as provided by the 2005 Oklahoma AFS Format File (AFS File).

In order to properly correlate unit names and/or descriptions as given by the consent decree to emission rates present in the AFS File, emission point descriptions were used for matching purposes. ENVIRON matched emission point descriptions from the consent decree with the corresponding emission point description from the AFS File (as listed in the sitename field). When a successful match was made between the consent decree and the AFS File, ENVIRON populated the Attachment C table with the corresponding Stack and Point IDs from the AFS File, along with the corresponding NO_x, SO_2, VOC and PM_{10} emission rates. If a successful match was not made, ENVIRON assigned a Stack and Point ID from the AFS File, along with the corresponding NO_x, SO_2, VOC and PM_{10} emission rates. Based on the emission point descriptions from the consent decree, ENVIRON attempted to select a Stack and Point ID from among like sources. For example, if an emissions unit was listed as a heater in the consent decree, then ENVIRON attempted to select a heater from the AFS File.

In circumstances where emission rates from the AFS File were not present for a pollutant from a given unit, even if identified by FIN or EPN, or Stack or Point ID, the label "N.L." has been employed to mark emissions which were *not listed*.

[49] Emission point description database was provided by Ms. Jackie Heber of LDEQ on August 28, 2007. According to Ms. Heber, the NEDS ID from this database corresponds to the Point ID field in the Louisiana AFS Format File.

3. NON-REFINERY CONSENT DECREE REQUIREMENTS AND EMISSION CHANGES

TCEQ has requested that, in addition to the petroleum refinery consent decree, ENVIRON evaluate anticipated emission reductions resulting from two additional consent decrees: Equistar and Rhodia. These consent decrees are discussed within this section.

3.1 Equistar Chemicals

3.1.1 Affected Facilities

EPA alleges that Equistar Chemicals, LP (Equistar), violated one or more of the following statues and the regulations promulgated there under at one or more of its olefins manufacturing plants.

1. The Clean Air Act
2. The Resource Conservation and Recovery Act
3. The Clean Water Act
4. The Emergency Planning and Community Right-to-Know Act
5. The Comprehensive Environmental Response, Compensation, and Liability Act

The olefins manufacturing plants in question are located in:

- *Channelview, Texas;*
- *Chocolate Bayou, Texas;*
- Clinton, Iowa;
- *Corpus Christi, Texas*;
- *Lake Charles, Louisiana* (this facility is currently shutdown);
- *La Porte, Texas;* and
- Morris, Illinois.

The five plants in italics are located in EPA Region VI.

On July 18, 2007, a consent decree between EPA and Equistar was lodged that will settle these alleged violations.

3.1.2 Consent Decree Requirements

Among others, the consent decree contains requirements related to Benzene Waste Operations NESHAPs (BWON), leak detection and repair (LDAR) programs, and flaring. Each is addressed separately.

3.1.2.1 BWON Program Enhancements

The consent decree identifies the Channelview and Chocolate Bayou facilities as having total annual benzene (TAB) quantities greater than 10 Megagrams (Mg). These facilities are currently complying with the option set forth in 40 CFR 61.342(c), utilizing the exemptions set for in 40 CFR 61.342(c)(2) and (c)(3)(ii) – also known as the "2 Mg Compliance Option." The LaPorte, Corpus Christi and Lake Charles facilities have reported TABs less than 10 Mg/year and are, therefore, exempt from BWON requirements. The consent decree specifies conduct of a review and verification of each facilities TAB and compliance status, with identification and implementation of corrective actions, if necessary. The review is to be completed no later than February 1, 2008. The consent decree, however, does not specify numerical emission targets or required numerical emission reductions.

3.1.2.2 LDAR Program Enhancements

To reduce fugitive emissions of VOC from process equipment, the consent decree requires Equistar to undertake LDAR program enhancements under 40 CFR Part 60, Subpart VV; Part 61, Subpart J; Part 63, Subparts F, G, H and UU; and applicable state and local LDAR requirements. Equistar is required by the consent decree to develop and maintain written program descriptions by January 1, 2008. By no later than December 31, 2010, Equistar is to perform an LDAR audit at each covered facility and to implement corrective actions identified during the course of the audit. The consent decree, however, does not specify numerical emission targets or required numerical emission reductions.

3.1.2.3 Flaring

Equistar is to implement good air pollution control practices for the flares listed in Appendix 1 to the consent decree. The consent decree also identifies a number of projects to be implemented with the intent of reducing flaring during startups and shutdowns. These projects include the following.

- Installation of piping to recycle propylene and ethylene back to the Deethanizer Unit inlet.
- To minimize flaring during olefins unit shutdowns, install piping to recycle methane purges back to the Charge Gas Compressor suction.

These projects are to be completed at covered facilities according to the following schedule.

Facility	Completion Date
Channelview	December 31, 2008
LaPorte	December 31, 2009
Chocolate Bayou	December 31, 2010
Corpus Christi	December 31, 2010

The consent decree, however, does not specify numerical emission targets or required numerical emission reductions.

3.1.3 Emissions Information

At this time, no information is available on emission reductions that may result from the flare gas recover projects identified in Section 3.1.2.3. As for LDAR enhancement requirements of the consent decree, it will take some time after implementation of the enhancements before monitoring and data collection efforts provide any information on improvements in actual emissions. Therefore, no changes are made to the current photochemical modeling emissions inventory.

3.2 Rhodia

3.2.1 Affected Facilities

EPA alleges that Rhodia violated one or more of the following at one or more of its sulfuric acid plants.

1. Prevention of Significant Deterioration (PSD) requirements found at Part C of Subchapter I of the Clean Air Act (the Act) and the associated regulations (40 CFR 52.21) and Plan Requirements for Non-Attainment Areas at Part D of Subchapter I of the Act and the associated regulations (40 CFR 51, Appendix S and 40 CFR 52.24).
2. New Source Performance Standards (NSPS) found at 40 CFR 60, Subparts A and H for sulfuric acid plants.
3. Title V operating permit requirements.
4. Federally-enforceable State Implementation Plans (SIPs) and other state rules.

The sulfuric acid plants in question are located in:

- *Baton Rouge, Louisiana*;
- *Baytown, Texas*;
- Carson, California (Dominguez Plant);
- Hammond, Indiana;
- *Houston, Texas*; and
- Martinez, California.

The three plants in italics are located in EPA Region VI.

On May 3, 2007, a consent decree between EPA and Rhodia Inc. was lodged that settles these alleged violations.

3.2.2 Consent Decree Requirements

3.2.2.1 Emission Limits

Among other requirements, the consent decree establishes short and long-term SO_2 emission limits at each affected facility. These limits are shown in Table 3.2-1.

Table 3.2-1. Rhodia SO_2 Emission Limits

Facility	Emission Limits (lbs SO_2 per ton 100% H_2SO_4 Produced)		Effective Date
	Short-Term	Long-Term	
Baton Rouge #1	3.00	1.90	May 1, 2012
Baton Rouge # 2	3.00	2.20	January 1, 2011
Baytown	3.00	2.20	January 1, 2009
Houston #2	3.00	1.90	April 1, 2014
Houston #8	3.00	1.70	July 1, 2009

Short-term limits are 3-hour rolling averages. Long-term limits are 365-day rolling averages.

As of the effective date of the consent decree, each sulfuric acid plant is to comply with the NSPS Subpart H emission limit of 0.15 lbs sulfuric acid mist per tone of 100% sulfuric acid produced.

3.2.2.2 New Source Performance Standards

As of the effective date for the SO_2 emission limits listed in Table 3.2-1, each sulfuric acid plant will be considered an affected facility for purposes of NSPS Subparts A and H. SO_2 limits per 40 CFR 60.82(a) are as follows: "*On and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain sulfur dioxide in excess of 2 kg per metric ton of acid produced (4 lb per ton), the production being expressed as 100 percent H_2SO_4.*" As shown in Table 3.2-1, the emission limits under the consent decree are approximately twice as stringent as the NSPS emission limits.

3.2.3 Emissions Information

The following summary of projected emissions and implementation dates is derived from one or more of the following sources of information:

- Consent decree,
- Permits, and/or

- Information provided by Rhodia personnel.

It is important to note that the information provided by Rhodia and projected emissions presented within this document do not in and of themselves constitute enforceable commitments on the part of Rhodia.

Table 3.2-2 presents calculated SO_2 emission rates for Rhodia's Texas facilities using the long-term emission rate and permitted production limits. In estimating annual emissions, 365 days per year operation is assumed. Production rates for the Baton Rouge plants are not available. Therefore, SO2 emissions following implementation of the consent decree have not been estimated.

Table 3.2-2. Rhodia SO_2 Emissions

Facility	Emission Limit (lbs SO_2 per ton H_2SO_4)	Production (tons H_2SO_4 per day)	SO_2 Emissions (tons/year)
Baytown	2.20	1,100	442
Houston #2	1.90	800	277
Houston #8	1.70	2,600	807

Attachment C presents a summary of projected and calculated post-consent decree emission rates for the Rhodia Baytown and Houston (#2 and #8) plants. This attachment provides the following information concerning units affected by the consent-decree:

(vii) A description of each affected unit and its function, including associated unit identification numbers and emission point identifications;

(viii) Potential post-consent decree emission rates as projected by the plant or calculated by ENVIRON given cap emission limits, both for a short-term (tons/day) and long-term (tons/year) basis;

(ix) Actual emission rates (tons/day) for the year 2005.

In determining actual 2005 emission rates for those units covered by the consent decree at the Rhodia plants, ENVIRON utilized emission inventory data as provided by the 2005 Texas AFS Format File (AFS File).

ENVIRON utilized calculated total annual SO_2 emissions given by Rhodia personnel to determine projected emissions based on relative emitting potentials from the 2005 AFS File. The cap annual emissions were proportionally distributed among all SO_2-emitting units listed in the AFS File for the Baytown and Houston plants. Unit Facility Identification Numbers (FINs) and Emission Point Numbers (EPNs) are provided as documented within the AFS File. In circumstances where emission rates from the AFS File were not present for a pollutant from a given unit, even if identified by FIN or EPN, the label "N.L." has been employed to mark emissions which were *not listed*.

4. ADDITIONAL CONSIDERATIONS

4.1 Flexible Permits

Most of the petroleum refineries in Texas operate under a flexible permit (30 TAC Chapter 116, Subchapter G). Flexible permits establish emission caps on a pollutant-by-pollutant basis for the collective of emission units covered by the permit. The caps are calculated based on application of current Best Available Control Technology (BACT0 at expected maximum capacity. The caps may also include an "insignificant emission factor" which is not to exceed 9.0% of the total emission cap. As stated in §116.716(e):

> *"An emission cap will be readjusted downward for any facility covered by a flexible permit if that facility becomes subject to any new state or federal regulation which would lower emissions or require an emission reduction. The adjustment will be made at the time the flexible permit is amended or altered."*

It is ENVIRON's understanding – confirmed in discussions with TCEQ Air Permits Division personnel – that additional emission reductions (above and beyond the BACT requirements of the flexible permit) resulting from a consent decree are not covered by this readjustment requirement. Consequently, permit allowable emission rates need not be reduced to reflect the emission reduction requirements of the consent decree. This may lead to the following situations.

1. *Permit allowable emission rates are now larger than the potential emissions of the refinery*. This creates uncertainty and confusion when trying to create an emissions inventory that reflects potential emissions since the permits are no longer a reliable source of potential emission rates.

2. *Emission reductions from some units at the refinery are offset by increases in emissions at other units*. The emission caps are set assuming application of BACT to all affected emission units. However, if emissions at some units are reduced beyond BACT, then the cap may be sufficient to allow the refinery to forgo implementation of BACT on other emission units.

4.2 Emissions Trading

Based upon ENVIRON's technical review of the consent decrees, while the language varies, all seem to contain general prohibitions against generation and use of emission reductions resulting from projects or emission controls required to comply with the consent decrees as netting reductions or emission offset credits in any PSD, major nonattainment and/or minor NSR permitting action. Specifically identified as being outside the scope of this prohibition are the following.

- Emission reductions at refinery units covered by the consent decree that are greater than the requirements of the consent decree may be used as netting reductions or as emission offset credits.
- Emission reductions at refinery units that are not covered by the consent decree may be used as netting reductions or as emission offset credits.

- Emission reductions resulting from installation of qualifying controls on combustion units that are not included in the overall reduction in emissions required by the consent decree may be used as netting reductions or as emission offset credits.
- Emission reductions resulting from projects required by the consent decree can be considered when determining whether a larger project, of which the consent decree-mandated reductions are but a part , triggers major NSR requirements.
- Emission reductions resulting from the consent decree may be used to demonstrate compliance with other rules and regulations designed to address regional haze or nonattainment status. A specific example listed is compliance with the Houston/Galveston Area (HGA) NO_X SIP. The consent decrees state that emission reductions required under the consent decree are not to be traded or sold.

Since the baseline period for the Mass Emission Cap and Trade (MECT) program, 1997-1999, was prior to any of the refinery consent decree-mandated emission reductions discussed within this report, NO_X allowance allocations at HGA refineries do not account for these emission reductions. To the extent that emission reductions under a consent decree reduce overall actual emissions, a source may not have to: a) reduce NO_X emissions at other emission units that it would have done otherwise; or b) purchase allowances from other sources that it would have purchased otherwise. Implementation of the consent decree emission reductions may also allow new projects that would otherwise not have happened due to insufficient availability of NO_X allowances. In summary it is possible, perhaps likely, that the consent decree process has not and will not lower overall NO_X emissions from stationary sources in the 8-county HGA.

4.3 MECT Cap

Regardless of emissions allowed under the consent decrees or flexible permits, NO_X emissions from all MECT program-affected sources in the 8-county Houston-Galveston-Brazoria (HGB) ozone nonattainment area are limited to the total number of allowances allocated.

4.4 Overly Conservative Emission Estimates

In discussions with petroleum refining personnel during the course of this project, it was determined that there are three areas where use of consent decree emission limits may result in a significant overestimation of emissions. These areas are:

1. SO_2 emissions from combustion units fired on refinery gas (including flares);
2. SO_2 emissions from sulfur recovery plants; and
3. PM emissions from FCCUs.

Some of the company representatives we spoke with during the course of this work were of the opinion that the sulfur content of refinery gas is typically much lower than that allowed by NSPS regulation. It was the experience of one individual that refineries processing sour crude will have H_2S concentrations in the refinery

gas anywhere between 25-50% of the NSPS limit (160 ppmv H_2S per dscf) and refineries processing sweeter crude will have H_2S concentrations less than 25% of the NSPS limit. However, unless they need to take restrictions to avoid triggering PSD review, refiners will seldom if ever request NSR permit limits for their combustion units fired on refinery gas that are lower than the NSPS limit. The same argument applies to sulfur recovery plants.

In the opinion of this individual, concentrations of SO_2 in the exhaust from an SRP are typically 50% or less of the NSPS limit (250 ppmvd SO_2 for a tail gas unit followed by incineration). As with combustion units, the refiner will only take more restrictive limits if required to avoid PSD review.

The consent decrees varied with respect to PM emission limits for FCCUs. Most set limits of 1 lb PM per 1,000 lbs coke burned. Others set the limit at 0.5 lb PM per 1,000 lbs coke burned. It the opinion of most refiners, FCCUs with WGS systems have actual emissions that are well below 0.5 lb PM per 1,000 lbs coke burned. However, as with SO_2 emissions from combustion units and SRPs, a refiner will not take a more stringent NSR permit limit unless required to do so as either part of a PSD best available control technology (BACT) review or to avoid PSD review.

Presented in Attachment D is a summary of how the consent decree emission limits summarized in this document compare to reported 2005 actual emissions. As can be seen, in many cases, reported actual emissions of SO_2 are much lower than the emission limits established under the consent decrees.

4.4 NSPS Subpart Ja

On May 14, 2007, proposed revisions to 40 CFR 60, Subpart J, and new standard 40 CFR 60, Subpart Ja – Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 – were published in the Federal Register.[50] The proposed Subpart Ja emission limits reflect, to a great extent, the emissions limits targeted by the consent decrees. Table 4.3-1 presents a simplified summary of proposed Subpart Ja emission limits.

Over time, it is expected that refineries that are not part of EPA's petroleum refinery enforcement initiative will be subject to the same emission limits through application of NSPS Subpart Ja requirements.

Table 4.3-1. Proposed NSPS Subpart Ja Emission Limits

Emission Unit	Emission Limit		
	NO_X	SO_2	PM
FCCUs & Fluid Coking Units[1]	- 80 ppmvd, 7-day rolling average, 0% O_2	- 50 ppmvd, 7-day rolling average, 0% O_2 - 25 ppmvd, 365-day rolling average, 0% O_2	- 0.5 lb/1,000 lbs coke burn-off

[50] 72 FR 92, pages 27178-27219

Table 4.3-1. Proposed NSPS Subpart Ja Emission Limits

Emission Unit	Emission Limit		
	NO_X	SO_2	PM
Sulfur Recovery Plant[2]		250 ppmvd SO_2 & total reduced sulfur (as SO_2), 12-hour rolling average, 0% O_2	
Fuel Gas Combustion Devices	- 80 ppmvd, 24-hour rolling average, 0% O_2[3]	- 20 ppmvd SO_2, 3-hour rolling average, 0% O_2 - 8 ppmvd SO_2, 365-day rolling average, 0% O_2	

[1] Option 1 for FCCUs and fluid coking units
[2] Capacity greater than 20 long tons per day
[3] Only applies to process heaters with a rated capacity of 20 MMBTU/hour or greater

5. RECOMMENDATIONS

ENVIRON's recommendations for continuing improvement of the photochemical modeling emissions inventory for petroleum refineries and others subject to EPA consent decree requirements are in two areas: 1) acquiring more accurate and complete data; and 2) reconciling the data collected with the existing photochemical emissions inventories.

5.1 Data Acquisition

The most significant challenge associated with the execution of this work order has been the acquisition of accurate and complete post-consent decree emissions data in timely manner. Should the TCEQ consider similar photochemical modeling emission inventory improvement projects in the future, we suggest the following.

1. *Consider submitting official information requests to the regulated entities*. Unofficial requests tend to be given a low priority, even when all parties agree that the goals are worthy. An official request, with the underlying knowledge that failure to respond could lead to an enforcement action, may result in additional effort being taken to ensure that the response is accurate and complete as well as timely.

2. *Be very specific with respect to the information requested*. For example, a request for "NO_X contributions from FCCU #1 to the annual flexible permit cap after installation of the SCR unit in 2012" is much more likely to result in the desired information in a timely fashion than a request for "emissions from your FCCUs following implementation of the consent decree."

3. *Allow sufficient time to respond to the request*. For large, complex corporations with many affected facilities, responding to what may be viewed as a relatively straightforward request for information may take a significant amount of time to assign, prepare, review and submit. It is worth noting that any request for information from a regulatory agency will probably be sent to legal counsel for review and consent before any response is prepared.

4. *Consider coordinating information requests with other states*. Regulatory agencies with jurisdiction will, most likely, be more effective in obtaining the desired emissions data. A cooperative effort could result in a better product that ultimately provides greater benefits to all parties.

5. *Consider replacing, supplementing and/or validating information received from the regulated entities through review of agency files*. All consent decrees reviewed during the course of this effort contain provisions requiring that the specified emission limits and control requirements be integrated in a timely fashion into NSR permits. NSR permit applications tend to be carefully prepared by the applicant and thoroughly reviewed by the TCEQ Air Permits Division or their counterparts in other states. The applications and resulting permits should be a rich source of detailed and accurate information regarding projects that have already been implemented. It is important to note that NSR permits may contain more stringent limits than required by the consent decrees. In these cases, use of

consent decree limits in preparing the photochemical modeling emissions inventory will result in an overestimation of potential emissions.

Another source of information might be semi-annual consent decree reports and annual NO_X control plan updates submitted to EPA. A word of caution is in order, though: reviewing regulatory agency files can be a very time consuming process. Also, accessing EPA files will almost certainly require filing a Freedom of Information Act request and waiting as much as several weeks before the files are made available for review.

5.2 Inventory Reconciliation

During the course of this project, ENVIRON determined that there is an 85-90% positive correlation between the emission sources contained within the existing photochemical modeling emission inventory (the AFS files provided to ENVIRON) and the sources listed in the petroleum refinery consent decrees. Discrepancies encountered include:

- Sources identified in the consent decrees that are missing from the modeling inventory;
- Sources in the modeling inventory that are not included in the list of existing and operational sources in the consent decrees; and
- Source identifiers (e.g. FIN and EPN) that do not match.

In addition to these discrepancies, there are cases where the reported post-consent decree emissions do not make sense when compared to the actual 2005 emissions contained within the inventory. A non-specific example is where actual 2005 emissions are much lower than post-consent decree emissions, even though the control devices required by the consent decree were not in place in 2005.

Potential avenues for reconciliation of these discrepancies include:

- *Working directly with the regulated entities to resolve discrepancies*. This could include making improvements to their emission inventory reporting process (e.g. adding new sources, removing no longer-existing sources, updating EPNs and FINs, etc.) or working to find the errors in the response to the request for post-consent decree emissions. It is expected that this approach would be resource intensive.

- *Working with the TCEQ Emissions Inventory Team to resolve discrepancies*. This could involve working with Emissions Inventory Team members to identify petroleum refiners and, as appropriate, other regulated entities where there is a discrepancy between consent decree-related information and emission inventory reports then developing and implementing a methodology for resolution of these discrepancies. Perhaps specific summaries could be prepared and sent to the regulated entities showing the discrepancies and directing them to resolve the differences.

ATTTACHMENT A

Description of Affected Refinery Process Units

DESCRIPTION OF AFFECTED REFINERY PROCESS UNITS

[The following is excerpted from Section 5.1, Petroleum Refining, of the USEPA document AP-42, Fifth Edition, *Compilation of Air Pollution Emission Factors, Volume 1: Stationary Point and Area Sources*, 1995. Additions and editorials are denoted by use of dark red print.]

General Description of a Petroleum Refinery

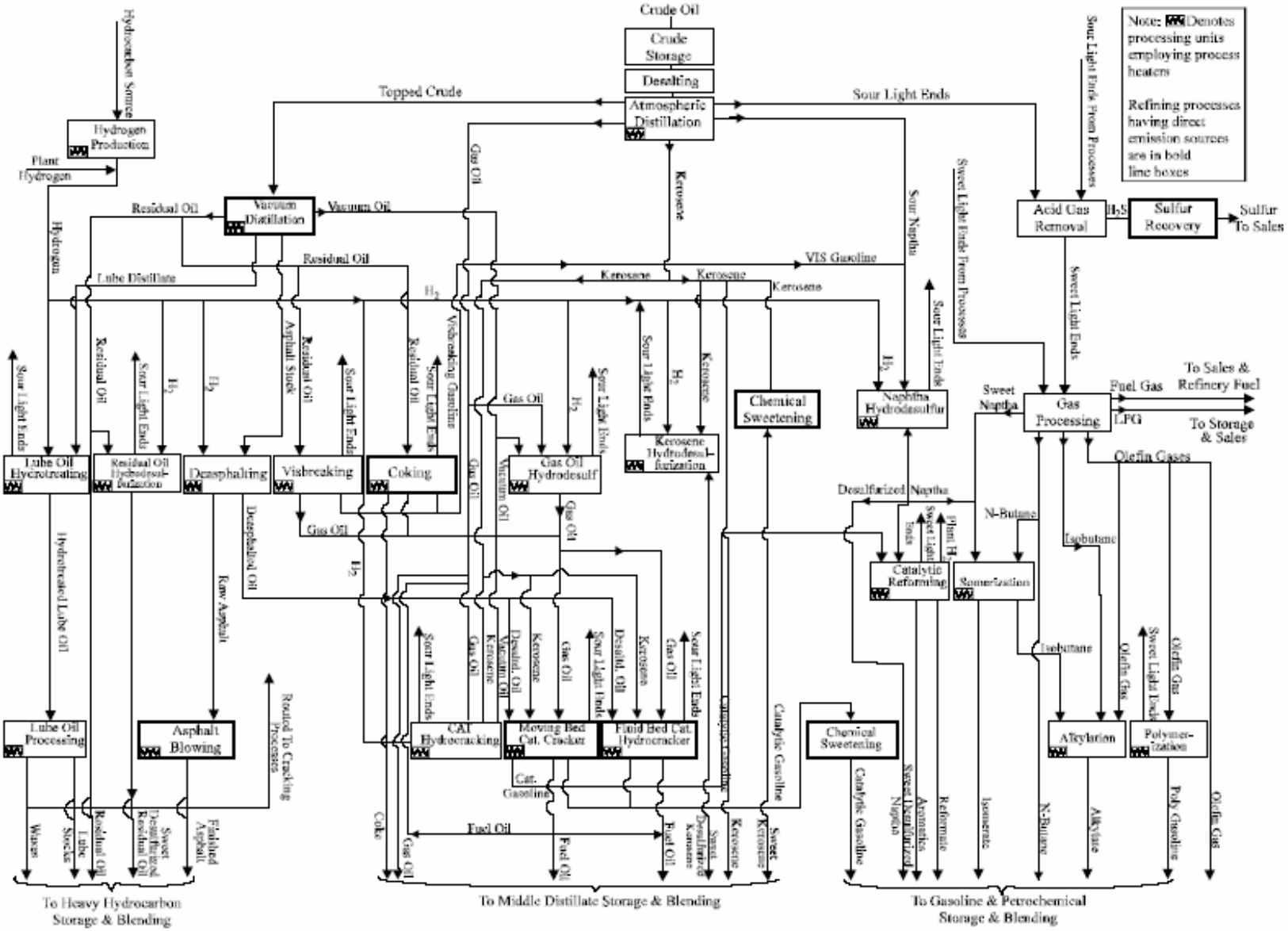
The petroleum refining industry converts crude oil into more than 2500 refined products, including liquefied petroleum gas, gasoline, kerosene, aviation fuel, diesel fuel, fuel oils, lubricating oils, and feedstocks for the petrochemical industry. Petroleum refinery activities start with receipt of crude for storage at the refinery, include all petroleum handling and refining operations, and they terminate with storage preparatory to shipping the refined products from the refinery. The petroleum refining industry employs a wide variety of processes. A refinery's processing flow scheme is largely determined by the composition of the crude oil feedstock and the chosen slate of petroleum products. The example refinery flow scheme presented in Figure 5.1-1 shows the general processing arrangement used by refineries in the United States for major refinery processes. The arrangement of these processes will vary among refineries, and few, if any, employ all of these processes. Petroleum refining processes having direct emission sources are presented on the figure in bold-line boxes. [Referenced Figure 5.1-1 is reproduced on the following page.]

Listed below are 5 categories of general refinery processes and associated operations:

1. Separation processes
2. Petroleum conversion processes
3. Petroleum treating processes
4. Feedstock and product handling
5. Auxiliary facilities

Separation Processes

The first phase in petroleum refining operations is the separation of crude oil into its major constituents using 3 petroleum separation processes: atmospheric distillation, vacuum distillation, and light ends recovery (gas processing). Crude oil consists of a mixture of hydrocarbon compounds including paraffinic, naphthenic, and aromatic hydrocarbons with small amounts of impurities including sulfur, nitrogen, oxygen, and metals. Refinery separation processes separate these crude oil constituents into common boiling-point fractions.



Source: USEPA, AP-42, Section 5, Figure 5.1-1.

Vacuum Distillation

Topped crude withdrawn from the bottom of the atmospheric distillation column is composed of high boiling-point hydrocarbons. When distilled at atmospheric pressures, the crude oil decomposes and polymerizes and will foul equipment. To separate topped crude into components, it must be distilled in a vacuum column at a very low pressure and in a steam atmosphere.

In the vacuum distillation unit, topped crude is heated with a process heater to temperatures ranging from 370 to 425°C (700 to 800°F). The heated topped crude is flashed into a multitray vacuum distillation column operating at absolute pressures ranging from 350 to 1400 kilograms per square meter (kg/m2) (0.5 to 2 pounds per square inch absolute [psia]). In the vacuum column, the topped crude is separated into common boiling-point fractions by vaporization and condensation. Stripping steam is normally injected into the bottom of the vacuum distillation column to assist the separation by lowering the effective partial pressures of the components. Standard petroleum fractions withdrawn from the vacuum distillation column include lube distillates, vacuum oil, asphalt stocks, and residual oils. The vacuum in the vacuum distillation column is usually maintained by the use of steam ejectors but may be maintained by the use of vacuum pumps.

The major sources of atmospheric emissions from the vacuum distillation column are associated with the steam ejectors or vacuum pumps. A major portion of the vapors withdrawn from the column by the ejectors or pumps is recovered in condensers. Historically, the noncondensable portion of the vapors has been vented to the atmosphere from the condensers. There are approximately 0.14 kg of noncondensable hydrocarbons per m3 (50 lb/103 bbl) of topped crude processed in the vacuum distillation column. A second source of atmospheric emissions from vacuum distillation columns is combustion products from the process heater. Process heater requirements for the vacuum distillation column are approximately 245 megajoules per cubic meter (MJ/m3) (37,000 British thermal units per barrel [Btu/bbl]) of topped crude processed in the vacuum column. Process heater emissions and their control are discussed below. Fugitive hydrocarbon emissions from leaking seals and fittings are also associated with the vacuum distillation unit, but these are minimized by the low operating pressures and low vapor pressures in the unit.

Control technology applicable to the noncondensable emissions vented from the vacuum ejectors or pumps includes venting into blowdown systems or fuel gas systems, and incineration in furnaces or waste heat boilers. These control techniques are generally greater than 99 percent efficient in the control of hydrocarbon emissions, but they also contribute to the emission of combustion products.

Conversion Processes

To meet the demands for high-octane gasoline, jet fuel, and diesel fuel, components such as residual oils, fuel oils, and light ends are converted to gasolines and other light fractions. Cracking, coking, and visbreaking processes are used to break large petroleum molecules into smaller ones. Polymerization and alkylation processes are used to combine small petroleum molecules into larger ones. Isomerization and reforming

processes are applied to rearrange the structure of petroleum molecules to produce higher-value molecules of a similar molecular size.

Catalytic Cracking

Catalytic cracking, using heat, pressure, and catalysts, converts heavy oils into lighter products with product distributions favoring the more valuable gasoline and distillate blending components. Feedstocks are usually gas oils from atmospheric distillation, vacuum distillation, coking, and deasphalting processes. These feedstocks typically have a boiling range of 340 to 540°C (650 to 1000°F). All of the catalytic cracking processes in use today can be classified as either fluidized-bed or moving-bed units.

The fluidized bed catalytic cracking (FCC) process uses a catalyst in the form of very fine particles that act as a fluid when aerated with a vapor. Fresh feed is preheated in a process heater and introduced into the bottom of a vertical transfer line or riser with hot regenerated catalyst. The hot catalyst vaporizes the feed, bringing both to the desired reaction temperature, 470 to 525°C (880 to 980°F) The high activity of modern catalysts causes most of the cracking reactions to take place in the riser as the catalyst and oil mixture flows upward into the reactor. The hydrocarbon vapors are separated from the catalyst particles by cyclones in the reactor. The reaction products are sent to a fractionator for separation. The spent catalyst falls to the bottom of the reactor and is steam stripped as it exits the reactor bottom to remove absorbed hydrocarbons. The spent catalyst is then conveyed to a regenerator. In the regenerator, coke deposited on the catalyst as a result of the cracking reactions is burned off in a controlled combustion process with preheated air. Regenerator temperature is usually 590 to 675°C (1100 to 1250°F). The catalyst is then recycled to be mixed with fresh hydrocarbon feed.

[The discussion provided in AP-42 on moving-bed catalytic cracking is excluded from this excerpt since these types of units are not part of the consent decrees and, to the best of ENVIRON's knowledge are not present at the affected refineries.]

Coking

Coking is a thermal cracking process used to convert low value residual fuel oil to higher value gas oil and petroleum coke. Vacuum residuals and thermal tars are cracked in the coking process at high temperature and low pressure. Products are petroleum coke, gas oils, and lighter petroleum stocks. Delayed coking is the most widely used process today, but fluid coking is expected to become an important process in the future.

In the delayed coking process, heated charge stock is fed into the bottom of a fractionator, where light ends are stripped from the feed. The stripped feed is then combined with recycle products from the coke drum and rapidly heated in the coking heater to a temperature of 480 to 590°C (900 to 1100°F). Steam injection is used to control the residence time in the heater. The vapor-liquid feed leaves the heater, passing to a coke drum where, with controlled residence time, pressure (1.8 to 2.1 kg/cm2 [25 to 30 psig]), and temperature (400°C [750°F]), it is cracked to form coke and vapors. Vapors from the drum return to the fractionator, where the thermal cracking products are recovered.

In the fluid coking process, typified by Flexicoking, residual oil feeds are injected into the reactor, where they are thermally cracked, yielding coke and a wide range of vapor products. Vapors leave the reactor and are quenched in a scrubber, where entrained coke fines are removed. The vapors are then fractionated. Coke from the reactor enters a heater and is devolatilized. The volatiles from the heater are treated for fines and sulfur removal to yield a particulate-free, low-sulfur fuel gas. The devolatilized coke is circulated from the heater to a gasifier where 95 percent of the reactor coke is gasified at high temperature with steam and air or oxygen. The gaseous products and coke from the gasifier are returned to the heater to supply heat for the devolatilization. These gases exit the heater with the heater volatiles through the same fines and sulfur removal processes.

From available literature, it is unclear what emissions are released and where they are released. Air emissions from thermal cracking processes include coke dust from decoking operations, combustion gases from the visbreaking and coking process heaters, and fugitive emissions. Emissions from the process heaters are discussed below. Fugitive emissions from miscellaneous leaks are significant because of the high temperatures involved, and are dependent upon equipment type and configuration, operating conditions, and general maintenance practices. Fugitive emissions are also discussed below. Particulate emissions from delayed coking operations are potentially very significant. These emissions are associated with removing the coke from the coke drum and subsequent handling and storage operations. Hydrocarbon emissions are also associated with cooling and venting the coke drum before coke removal. However, comprehensive data for delayed coking emissions have not been included in available literature.

Visbreaking

Topped crude or vacuum residuals are heated and thermally cracked (455 to 480°C, 3.5 to 17.6 kg/cm2 [850 to 900°F, 50 to 250 pounds per square inch gauge (psig)]) in the visbreaker furnace to reduce the viscosity, or pour point, of the charge. The cracked products are quenched with gas oil and flashed into a fractionator. The vapor overhead from the fractionator is separated into light distillate products. A heavy distillate recovered from the fractionator liquid can be used as either a fuel oil blending component or catalytic cracking feed.

Asphalt Blowing

The asphalt blowing process polymerizes asphaltic residual oils by oxidation, increasing their melting temperature and hardness to achieve an increased resistance to weathering. The oils, containing a large quantity of polycyclic aromatic compounds (asphaltic oils), are oxidized by blowing heated air through a heated batch mixture or, in a continuous process, by passing hot air countercurrent to the oil flow. The reaction is exothermic, and quench steam is sometimes needed for temperature control. In some cases, ferric chloride or phosphorus pentoxide is used as a catalyst to increase the reaction rate and to impart special characteristics to the asphalt.

Treating Processes

Petroleum treating processes stabilize and upgrade petroleum products by separating them from less desirable products and by removing objectionable elements. Undesirable elements such as sulfur, nitrogen, and oxygen are removed by hydrodesulfurization, hydrotreating, chemical sweetening, and acid gas removal. Treating processes, employed primarily for the separation of petroleum products, include such processes as deasphalting. Desalting is used to remove salt, minerals, grit, and water from crude oil feedstocks before refining. Asphalt blowing is used for polymerizing and stabilizing asphalt to improve its weathering characteristics.

Sweetening

Sweetening of distillates is accomplished by the conversion of mercaptans to alkyl disulfides in the presence of a catalyst. Conversion may be followed by an extraction step for removal of the alkyl disulfides. In the conversion process, sulfur is added to the sour distillate with a small amount of caustic and air. The mixture is then passed upward through a fixed-bed catalyst, counter to a flow of caustic entering at the top of the vessel. In the conversion and extraction process, the sour distillate is washed with caustic and then is contacted in the extractor with a solution of catalyst and caustic. The extracted distillate is then contacted with air to convert mercaptans to disulfides. After oxidation, the distillate is settled, inhibitors are added, and the distillate is sent to storage. Regeneration is accomplished by mixing caustic from the bottom of the extractor with air and then separating the disulfides and excess air. The major emission problem is hydrocarbons from contact of the distillate product and air in the "air blowing" step. These emissions are related to equipment type and configuration, as well as to operating conditions and maintenance practices.

Process Heaters

Process heaters (furnaces) are used extensively in refineries to supply the heat necessary to raise the temperature of feed materials to reaction or distillation level. They are designed to raise petroleum fluid temperatures to a maximum of about 510°C (950°F). The fuel burned may be refinery gas, natural gas, residual fuel oils, or combinations, depending on economics, operating conditions, and emission requirements. Process heaters may also use CO-rich regenerator flue gas as fuel.

Feedstock and Product Handling Operations

The refinery feedstock and product handling operations consist of unloading, storage, blending, and loading activities.

Auxiliary Facilities

A wide assortment of processes and equipment not directly involved in the refining of crude oil is used in functions vital to the operation of the refinery. Examples are boilers, waste water treatment facilities, hydrogen plants, cooling towers, and sulfur recovery units. Products from auxiliary facilities (clean water, steam, and process heat) are required by most process units throughout the refinery.

Utilities Plant

The utilities plant supplies the steam necessary for the refinery. Although the steam can be used to produce electricity by throttling through a turbine, it is primarily used for heating and separating hydrocarbon streams. When used for heating, the steam usually heats the petroleum indirectly in heat exchangers and returns to the boiler. In direct contact operations, the steam can serve as a stripping medium or a process fluid. Steam may also be used in vacuum ejectors to produce a vacuum.

Blowdown System

The blowdown system provides for the safe disposal of hydrocarbons (vapor and liquid) discharged from pressure relief devices. Most refining processing units and equipment subject to planned or unplanned hydrocarbon discharges are manifolded into a collection unit, called blowdown system. By using a series of flash drums and condensers arranged in decreasing pressure, blowdown material is separated into vapor and liquid cuts. The separated liquid is recycled into the refinery. The gaseous cuts can either be smokelessly flared or recycled.

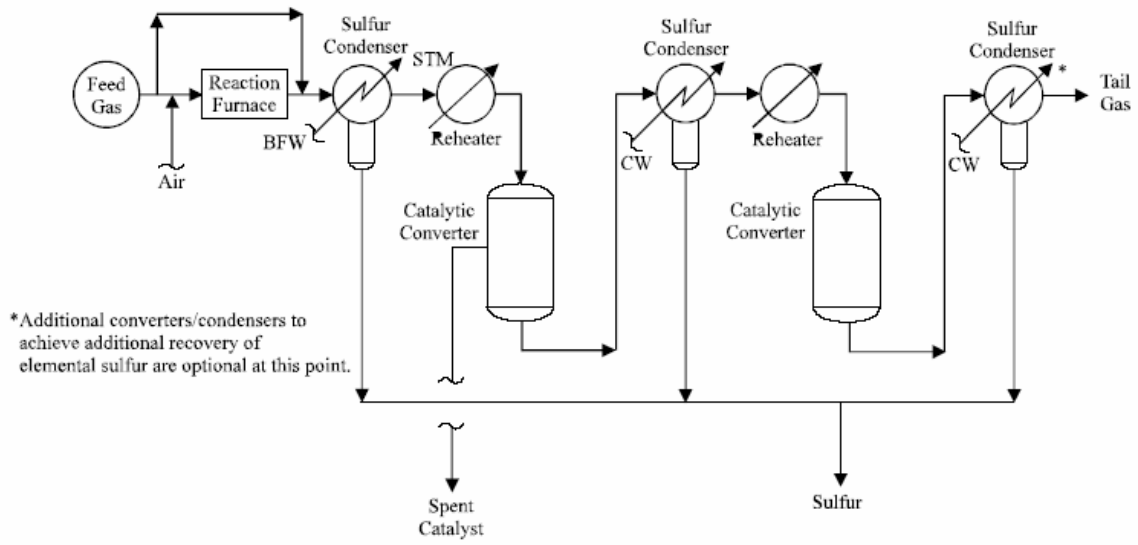
Uncontrolled blowdown emissions primarily consist of hydrocarbons but can also include any of the other criteria pollutants. The emission rate in a blowdown system is a function of the amount of equipment manifolded into the system, the frequency of equipment discharges, and the blowdown system controls.

Emissions from the blowdown system can be effectively controlled by combustion of the noncondensables in a flare. To obtain complete combustion or smokeless burning (as required by most states), steam is injected in the combustion zone of the flare to provide turbulence and air. Steam injection also reduces emissions of nitrogen oxides by lowering the flame temperature.

[The following is excerpted from Section 8.13, Sulfur Recovery, of USEPA's AP-42.]

Sulfur Recovery Plants

Sulfur recovery refers to the conversion of hydrogen sulfide (H2S) to elemental sulfur. Hydrogen sulfide is a byproduct of processing natural gas and refining high-sulfur crude oils. The most common conversion method used is the Claus process. Approximately 90 to 95 percent of recovered sulfur is produced by the Claus process. The Claus process typically recovers 95 to 97 percent of the hydrogen sulfide feedstream. Hydrogen sulfide, a byproduct of crude oil and natural gas processing, is recovered and converted to elemental sulfur by the Claus process. Figure 8.13-1 shows a typical Claus sulfur recovery unit. [The referenced Figure 8.13-1 is shown below.]



The process consists of multistage catalytic oxidation of hydrogen sulfide according to the following overall reaction:

$$(1)\ 2H_2S\ O_2 \rightarrow 2S\ 2H_2O$$

Each catalytic stage consists of a gas reheater, a catalyst chamber, and a condenser.

The Claus process involves burning one-third of the H_2S with air in a reactor furnace to form sulfur dioxide (SO_2) according to the following reaction:

$$(2)\ 2H_2S\ 3O_2 \rightarrow 2SO_2\ 2H_2O\ \text{heat}$$

The furnace normally operates at combustion chamber temperatures ranging from 980 to 1540°C (1800 to 2800°F) with pressures rarely higher than 70 kilopascals (kPa) (10 pounds per square inch absolute). Before entering a sulfur condenser, hot gas from the combustion chamber is quenched in a waste heat boiler that generates high to medium pressure steam. About 80 percent of the heat released could be recovered as useful energy. Liquid sulfur from the condenser runs through a seal leg into a covered pit from which it is pumped to trucks or railcars for shipment to end users. Approximately 65 to 70 percent of the sulfur is recovered. The cooled gases exiting the condenser are then sent to the catalyst beds. The remaining uncombusted two-thirds of the hydrogen sulfide undergoes Claus reaction (reacts with SO_2) to form elemental sulfur as follows:

$$(3)\ 2H_2S\ SO_2 \longleftrightarrow 3S\ 2H_2O\ \text{heat}$$

The catalytic reactors operate at lower temperatures, ranging from 200 to 315°C (400 to 600°F).

Alumina or bauxite is sometimes used as a catalyst. Because this reaction represents an equilibrium chemical reaction, it is not possible for a Claus plant to convert all the incoming sulfur compounds to elemental sulfur. Therefore, 2 or more stages are used in series to recover the sulfur. Each catalytic stage can recover half to

two-thirds of the incoming sulfur. The number of catalytic stages depends upon the level of conversion desired. It is estimated that 95 to 97 percent overall recovery can be achieved depending on the number of catalytic reaction stages and the type of reheating method used.

If the sulfur recovery unit is located in a natural gas processing plant, the type of reheat employed is typically either auxiliary burners or heat exchangers, with steam reheat being used occasionally. If the sulfur recovery unit is located in a crude oil refinery, the typical reheat scheme uses 3536 to 4223 kPa (500 to 600 pounds per square inch gauge [psig]) steam for reheating purposes. Most plants are now built with 2 catalytic stages, although some air quality jurisdictions require 3. From the condenser of the final catalytic stage, the process stream passes to some form of tailgas treatment process. The tailgas, containing H_2S, SO_2, sulfur vapor, and traces of other sulfur compounds formed in the combustion section, escapes with the inert gases from the tail end of the plant. Thus, it is frequently necessary to follow the Claus unit with a tailgas cleanup unit to achieve higher recovery.

In addition to the oxidation of H_2S to SO_2 and the reaction of SO_2 with H_2S in the reaction furnace, many other side reactions can and do occur in the furnace. Several of these possible side reactions are:

$$(4)\ CO_2\ H_2S \rightarrow COS\ H_2O$$

$$(5)\ COS\ H_2S \rightarrow CS_2\ H_2O$$

$$(6)\ 2COS \rightarrow CO_2\ CS_2$$

Fugitive Emissions

Fugitive emission sources include leaks of hydrocarbon vapors from process equipment and evaporation of hydrocarbons from open areas, rather than through a stack or vent. Fugitive emission sources include valves of all types, flanges, pump and compressor seals, process drains, cooling towers, and oil/water separators. Fugitive emissions are attributable to the evaporation of leaked or spilled petroleum liquids and gases. Normally, control of fugitive emissions involves minimizing leaks and spills through equipment changes, procedure changes, and improved monitoring, housekeeping, and maintenance practices.

ATTTACHMENT B

Description of Emission Control Technologies

DESCRIPTION OF EMISSION CONTROL TECHNOLOGIES

LoTOx™

The following is excerpted from the California Air Resources Board innovative clean air technologies website: http://www.arb.ca.gov/research/icat/projects/boc.htm. LoTOX™ is a scrubber-based NO_X emission reduction technology – or SNERT – as referenced in one or more consent decrees.

BOC Gases Low Temperature Oxidiation, or LoTOx™, System is a NO_X removal system that injects ozone into the flue gas stream to oxidize insoluble NO_X to soluble oxidized compounds. Ozone is produced on site and on demand by passing oxygen through an ozone generator. LoTOx™ is a low temperature system; therefore, it does not require heat input to maintain operational efficiency or to prevent the "slip" of treatment chemicals, such as ammonia, as is common with SCR and SNCR systems.

Ozone is produced in response to the amount of NO_X present in the flue gas generated by the process. The low operating temperature allows stable and consistent control regardless of variation in flow, load or NO_X content. There are no adverse effects of acid gases or particles on the LoTOx™ System, and some particles may even enhance the reaction by producing sites for nucleation of moisture and by catalyzing the oxidation reaction.

Ozone rapidly reacts with insoluble NO and NO_2 molecules to form soluble N_2O_5. The species N_2O_5 is highly soluble and will rapidly react with moisture in the gas stream to form nitric acid. The conversion of NO_X into the aqueous phase in the scrubber is rapid and irreversible, allowing nearly complete removal of NO_X. The nitric acid, along with unreacted N_2O_5 and nitrous acid formed by reaction of NO_2 with water, can be easily scrubbed out of the gas stream in a wet scrubber with water or neutralized with a caustic solution.

The rapid reaction rate of ozone with NO_X makes ozone highly selective for treatment of NO_X in the presence of other compounds such as CO and SO_X, resulting in a high ozone utilization efficiency for NO_X removal with no wasteful consumption of ozone by CO and SO_X.

Selective Catalytic Reduction (SCR)

The following is excerpted from USEPA Air Pollution Control Fact Sheet EPA-452/F-03-032.

The SCR process chemically reduces the NO_X molecule into molecular nitrogen and water vapor. A nitrogen based reagent such as ammonia or urea is injected into the ductwork, downstream of the combustion unit. The waste gas mixes with the reagent and enters a reactor module containing catalyst. The hot flue gas and reagent diffuse through the catalyst. The reagent reacts selectively with the NO_X within a specific temperature range and in the presence of the catalyst and oxygen.

Temperature, the amount of reducing agent, injection grid design, and catalyst activity are the main factors that determine the actual removal efficiency. The use of a catalyst results in two primary advantages of the

SCR process over the SNCR: higher NO_X control efficiency and reactions within a lower and broader temperature range. The benefits are accompanied by a significant increase in capital and operating costs. The catalyst is composed of active metals or ceramics with a highly porous structure. Catalysts configurations are generally ceramic honeycomb and pleated metal plate (monolith) designs. The catalyst composition, type, and physical properties affect performance, reliability, catalyst quantity required, and cost. The SCR system supplier and catalyst supplier generally guarantee the catalyst life and performance. Newer catalyst designs increase catalyst activity, surface area per unit volume, and the temperature range for the reduction reaction.

Catalyst activity is a measure of the NO_X reduction reaction rate. Catalyst activity is a function of many variables including catalyst composition and structure, diffusion rates, mass transfer rates, gas temperature, and gas composition. Catalyst deactivation is caused by:

- Poisoning of active sites by flue gas constituents,
- Thermal sintering of active sites due to high temperatures within reactor,
- Blinding/plugging/fouling of active sites by ammonia-sulfur salts and particulate matter, and
- Erosion due to high gas velocities.

As the catalyst activity decreases, NO_X removal decreases and ammonia slip increases. When the ammonia slip reaches the maximum design or permitted level, new catalyst must be installed. There are several different locations downstream of the combustion unit where SCR systems can be installed. Most coal-fired applications locate the reactor downstream of the economizer and upstream of the air heater and particulate control devices (hot-side). The flue gas in this location is usually within the optimum temperature window for NO_X reduction reactions using metal oxide catalysts. SCR may be applied after PM and sulfur removal equipment (cold-side), however, reheating of the flue gas may be required, which significantly increases the operational costs.

SCR is very cost-effective for natural gas fired units. Less catalyst is required since the waste gas stream has lower levels of NO_X, sulfur, and PM. Combined-cycle natural gas turbines frequently use SCR technology for NO_X reduction. A typical combined-cycle SCR design places the reactor chamber after the superheater within a cavity of the heat recovery steam generator system (HRSG). The flue gas temperature in this area is within the operating range for base metal-type catalysts.

SCR can be used separately or in combination with other NO_X combustion control technologies such as low-NO_X burners (LNB) and natural gas reburn (NGR). SCR can be designed to provide NO_X reductions year round or only during ozone season.

Selective Non-Catalytic Reduction (SNCR)

The following is excerpted from USEPA Air Pollution Control Fact Sheet EPA-452/F-03-031.

SNCR is based on the chemical reduction of the NO_X molecule into molecular nitrogen (N_2) and water vapor (H_2O). A nitrogen-based reducing agent (reagent), such as ammonia or urea, is injected into the post combustion flue gas. The reduction reaction with NO_X is favored over other chemical reaction processes at temperatures ranging between 1600°F and 2100°F (870°C to 1150°C), therefore, it is considered a selective chemical process.

Both ammonia and urea are used as reagents. Urea-based systems have advantages over ammonia based systems. Urea is non-toxic, less volatile liquid that can be stored and handled more safely. Urea solution droplets can penetrate farther into the flue gas when injected into the boiler, enhancing the mixing with the flue gas which is difficult in large boilers. However, urea is more expensive than ammonia. The Normalized Stoichiometric Ratio (NSR) defines the ratio of reagent to NO_X required to achieve the targeted NO_X reduction. In practice, more than the theoretical amount of reagent needs to be injected into the boiler flue gas to obtain a specific level of NO_X reduction.

In the SNCR process, the combustion unit acts as the reactor chamber. The reagent is generally injected within the boiler superheater and reheater radiant and convective regions, where the combustion gas temperature is at the required temperature range. The injection system is designed to promote mixing of the reagent with the flue gas. The number and location of injection points is determined by the temperature profiles and flow patterns within the combustion unit.

Certain applications are more suited for SNCR due to the combustion unit design. Units with furnace exit temperatures of 1550°F to 1950°F (840°C to 1065°C), residence times of greater than one second, and high levels of uncontrolled NOX are good candidates.

During low-load operation, the location of the optimum temperature region shifts upstream within the boiler. Additional injection points are required to accommodate operations at low loads. Enhancers can be added to the reagent to lower the temperature range at which the NO_X reduction reaction occurs. The use of enhancers reduces the need for additional injection locations.

Thermal DeNOx

The following is excerpted from http://www.cheresources.com/pollcontrolzz.shtml.

Similar to SCR, the ExxonMobil Thermal DeNOx process utilizes the NO_X/ammonia reaction. However, this process does not use a catalyst to aid the reaction. Rather, tightly controlled temperatures are used to steer the reactions. Optimum reaction temperatures are found between 1600°F (871°C) and 1800°F (981°C). Below

the optimum temperature range, ammonia does not fully react and can be released in the flue gas. Above the optimum temperature, the following competing reaction can begin to take place:

$$NH_3 + 5/4\ O_2 \text{ ---> } NO + 3/2\ H_2O$$

Ammonia is injected in a 2:1 molar ratio in this process.

Wet Gas Scrubber (WGS)

WGS systems used to control SO_2 and PM emissions from FCCUs are typically venturi scrubbers. The following is excerpted from USEPA Air Pollution Control Fact Sheet EPA-452/F-03-017.

A venturi scrubber accelerates the waste gas stream to atomize the scrubbing liquid and to improve gas-liquid contact. In a venturi scrubber, a "throat" section is built into the duct that forces the gas stream to accelerate as the duct narrows and then expands. As the gas enters the venturi throat, both gas velocity and turbulence increase. Depending upon the scrubber design, the scrubbing liquid is sprayed into the gas stream before the gas encounters the venturi throat, or in the throat, or upwards against the gas flow in the throat. The scrubbing liquid is then atomized into small droplets by the turbulence in the throat and droplet-particle interaction is increased. Some designs use supplemental hydraulically or pneumatically atomized sprays to augment droplet creation. The disadvantage of these designs is that clean liquid feed is required to avoid clogging.

After the throat section, the mixture decelerates, and further impacts occur causing the droplets to agglomerate. Once the particles have been captured by the liquid, the wetted PM and excess liquid droplets are separated from the gas stream by an entrainment section which usually consists of a cyclonic separator and/or a mist eliminator.

Current designs for venturi scrubbers generally use the vertical downflow of gas through the venturi throat and incorporate three features: (1) a "wet-approach" or "flooded-wall" entry section to avoid a dust buildup at a wet-dry junction; (2) an adjustable throat for the venturi throat to provide for adjustment of the gas velocity and the pressure drop; and (3) a "flooded" elbow located below the venturi and ahead of the entrainment separator, to reduce wear by abrasive particles. The venturi throat is sometimes fitted with a refractory lining to resist abrasion by dust particles.

ATTACHMENT C

Emission Summaries

Refinery EI Improvement Project
BP Texas City Refinery

Unit No.	Unit Type	FIN	EPN	Post-CD Potential Emission Rate (tpy)				Post-CD Potential Emission Rate (tpd)				2005 Actual Emission Rate (tpd)			
				NOX	SO2	VOC	PM	NOX	SO2	VOC	PM	NOX	SO2	VOC	PM10
FCCU 1	Fluidized Catalytic Cracking U	FCU1-FUGIT	94	169.37	742.28		197.10	0.46403	2.03364		0.54000	0.12687	0.26519	0.07502	0.14602
FCCU 2	Fluidized Catalytic Cracking U	FCU2-FUGIT	62	94.01	412.03		118.26	0.25757	1.12886		0.32400	0.27112	0.11316	0.03457	0.07081
FCCU 3	Fluidized Catalytic Cracking U	FCU3-FUGIT	34	307.46	1347.48		378.43	0.84236	3.69172		1.03679	1.09219	7.41327	0.1788	0.34898
PS3A-101BA				57.99	38.22			0.15888	0.10472						
PS3A-101BB	Furnace	***PS3A-101BAB***	***51***	57.99	38.22			0.15888	0.10472			0.216	0.041	0.022	0.031
PRS4-B430	Boiler	PRS4-B430	494	74.28	48.96			0.20352	0.13414			N.L.	N.L.	N.L.	0.000
AU2-B601	Furnace	AU2-B601	601	26.89	35.45			0.07368	0.09712			0.06329	0.01496	0.00803	0.01109
UU3-308B	Furnace	UU3-308B	169	29.78	19.63			0.08160	0.05378			0.03712	0.0087	0.00473	0.00653
PS3A-102BA	Furnace	PS3A102BAB	53	22.08	14.55			0.06048	0.03986			0.11648	0.01266	0.00689	0.00953
PS3A-102BB	Furnace	PS3A-102BB	54	22.08	14.55			0.06048	0.03986			N.L.	N.L.	N.L.	0.000
DDU-B302	Furnace	DDU-B302	395	8.28	7.27			0.02268	0.01993			0.01101	0.00418	0.00229	0.00317
ULC-101B	Furnace	ULC-101B	202	8.02	7.04			0.02196	0.01930			0.01412	0.00221	0.00116	0.0016
DDU-B301	Furnace	DDU-B301	394	10.69	7.04			0.02928	0.01930			0.01491	0.00418	0.00229	0.00317
COKR-B203	Furnace	COKR-B203	77	18.40	6.93			0.05040	0.01898			0.03113	0.00436	0.00239	0.0033
PS3B-401BC	Furnace	PS3B-401BC	44	52.38	34.53			0.14352	0.09459			0.07765	0.01962	0.01059	0.01464
PS3B-401BA	Furnace	PS3B-401BA	41	22.43	29.56			0.06144	0.08099			0.01496	0.01151	0.0062	0.00857
PS3B-401BB	Furnace	PS3B-401BB	42	22.43	29.56			0.06144	0.08099			0.01635	0.01448	0.0078	0.01077
PS3B-402BA	Furnace			0.00	0.00			0.00000	0.00000			N.L.	N.L.	N.L.	N.L.
PS3B-402BD	Furnace			0.00	0.00			0.00000	0.00000			N.L.	N.L.	N.L.	N.L.
PRS4-B420	Boiler	PRS4-B420	492	91.91	161.55			0.25182	0.44259			N.L.	N.L.	N.L.	0.000
PS3B-402BE	Furnace	PS3B-402BE	45	13.49	17.78			0.03696	0.04872			N.L.	N.L.	N.L.	0.000
PRS4-B410	Furnace	***PRS4-B410T***	***491***	91.91	161.55			0.25182	0.44259			N.L.	N.L.	N.L.	0.000
HU2-101B C/D	Furnace			0.00	0.00			0.00000	0.00000			N.L.	N.L.	N.L.	N.L.
HU2-101A A/B	Furnace			0.00	0.00			0.00000	0.00000			N.L.	N.L.	N.L.	N.L.
HU2-109C	Furnace			0.00	0.00			0.00000	0.00000			N.L.	N.L.	N.L.	N.L.
HU2-109A	Furnace			0.00	0.00			0.00000	0.00000			N.L.	N.L.	N.L.	N.L.
ISOM-B200	Furnace	ISOM-B200	197	0.00	0.00			0.00000	0.00000			0.0052	0.00061	0.00037	0.00051
ISOM-B1101	Furnace	ISOM-B1101	198	0.00	0.00			0.00000	0.00000			0.00975	0.00112	0.00061	0.00085
UU3-303B	Furnace	UU3-303B	163	0.00	0.00			0.00000	0.00000			N.L.	N.L.	N.L.	0.000
UU4-B403	Furnace	UU4-B403	214	0.00	0.00			0.00000	0.00000			N.L.	N.L.	N.L.	0.000
PS3B-402BC	Furnace			0.00	0.00			0.00000	0.00000			N.L.	N.L.	N.L.	N.L.
PS3B-402BB	Furnace			0.00	0.00			0.00000	0.00000			N.L.	N.L.	N.L.	N.L.
FUGITIVES	Equipment Leak													1.529	

Notes:
N.L. = not listed
Italics indicate that FIN and EPN are the best available matches based on information from consent decree and/or information provided by the refinery.

Refinery EI Improvement Project
CITGO Corpus Christi Refinery West Plant

Unit Description	Unit Type	FIN	EPN	Post-CD Potential Emission Rate (tpy)				Post-CD Potential Emission Rate (tpd)				2005 Actual Emission Rate (tpd)			
				NOX	SO2	VOC	PM	NOX	SO2	VOC	PM	NOX	SO2	VOC	PM10
WP COKER CHARGE HEATER	Boiler or Heater	521-H1	521-H1	18.09	7.66			0.04955	0.02099			0.14192	0.01645	0.01663	0.02298
WEST PLANT BOILER OR HEATER	Boiler or Heater	***546-H1***	***H-99***	9.01	3.82			0.02469	0.01046			0.40443	0.01744	0.01763	0.02525
WEST PLANT BOILER OR HEATER	Boiler or Heater	***546-H5***	***H-99***	8.26	3.50			0.02263	0.00958			0.01236	0.00068	0.00068	0.00094
WEST PLANT BOILER OR HEATER	Boiler or Heater	***527-H1***	***527-H1***	4.77	2.02			0.01306	0.00553			0.03406	0.00243	0.00245	0.00339
WP MDH REBOILER HEATER	Boiler or Heater	527-H2	527-H2	5.12	2.17			0.01403	0.00594			0.06789	0.05169	0.00489	0.00676
WP BOILER # 1	Boiler or Heater	561-B1	565-B1	6.16	2.61			0.01687	0.00714			0.05457	0.00279	0.00282	0.00389
WP BOILER # 2	Boiler or Heater	561-B2	565-B2	6.16	2.61			0.01687	0.00714			0.05804	0.0027	0.00272	0.00376
WEST PLANT BOILER OR HEATER	Boiler or Heater	***546-H2***	***H-99***	3.00	1.27			0.00822	0.00348			0.00	0.00	0.00	0.00
WP BOILER # 3	Boiler or Heater	561-B3	561-B3	6.16	2.61			0.01687	0.00714			0.04729	0.00258	0.0026	0.0036
NHT CAN HEATER	Boiler or Heater	547-H1	H-99	3.11	1.32			0.00851	0.00360			0.05044	0.00275	0.00278	0.00384
WEST PLANT BOILER OR HEATER	Boiler or Heater	***547-H2***	***H-99***	3.86	1.63			0.01057	0.00448			0.0237	0.00129	0.00131	0.0018
MEROX DISULFIDE SEPARATOR SPENT AIR VENT	Combustion Device											N.L.	N.L.	N.L.	N.L.
SULFUR RECOVERY PLANT	Sulfur Recovery Plant											N.L.	N.L.	N.L.	N.L.
WP AMINE FLARE	Flare	555-S9P	555-S9									0.0005	N.L.	N.L.	0
WP SRU FUGITIVES	Fugitives	553-FUG	553-FUG											0.01378	
WP SRU FUGITIVES	Fugitives	553-FUG	554-ME5											0.0285	
FUGITIVES	Equipment Leak	N.A.	N.A.											0.60503	

Notes:
N.L. = not listed
Italics indicate that FIN and EPN are the best available matches based on information from consent decree and/or information provided by the refinery.
The FIN and EPN listed do not necessarily correspond to the specified unit.

Refinery EI Improvement Project
CITGO Corpus Christi East Refinery

Unit Description	Unit Type	FIN	EPN	Post-CD Potential Emission Rate (tpy)				Post-CD Potential Emission Rate (tpd)				2005 Actual Emission Rate (tpd)			
				NOX	SO2	VOC	PM	NOX	SO2	VOC	PM	NOX	SO2	VOC	PM10
FCCU #1	Fluidized Catalytic Cracking Unit	38-C0B	F066	117.00	222.00		272.00	0.32055	0.60822		0.74521	0.77913	1.27834	0.01625	0.20233
FCCU #2	Fluidized Catalytic Cracking Unit	31-PR-1	31-PR-1									N.L.	N.L.	N.L.	N.L.
BOILER 61-B1B	Boiler	61-B1B	273A	0.00	0.00	0.00	0.00	0.00000	0.00000	0.00000	0.00000	0	0	0	0
BOILER 61-BIA	Boiler	61-B1A	272	0.00	0.00	0.00	0.00	0.00000	0.00000	0.00000	0.00000	0	0	0	0
BOILER 61-B1C	Boiler	61-B1C	274	0.00	0.00	0.00	0.00	0.00000	0.00000	0.00000	0.00000	0	N.L.	0	0
PC BOILER 8	Boiler	01-B8	252	0.00	0.00	0.00	0.00	0.00000	0.00000	0.00000	0.00000	0	0	0	0
PC BOILER 7	Boiler	01-B7	252	0.00	0.00	0.00	0.00	0.00000	0.00000	0.00000	0.00000	0.12268	0.00058	0.00529	0.00731
UTILITY BOILER E	Boiler or Heater	61-B3E	6100	113.08	36.95			0.30980	0.10124			0.12233	0.01131	0.00877	0.01212
CUMENE UNIT HEATER	Boiler or Heater	14-H1	356	42.40	13.86			0.11618	0.03796			0.11405	0.00809	0.00628	0.00867
REFINERY GAS COMBUSTION DEVICE	Boiler or Heater	***11-H1***	***292***	43.01	14.05			0.11782	0.03850			0.4049	0.03427	0.00078	0.03672
REFINERY GAS COMBUSTION DEVICE	Boiler or Heater	***11-H2***	***292***	40.99	13.39			0.11230	0.03670			0.12081	0.01023	0.00029	0.01096
REFINERY GAS COMBUSTION DEVICE	Boiler or Heater	***19-H1***	***222***	16.96	5.54			0.04647	0.01519			0.00575	0.00004	0.00032	0.00044
REFINERY GAS COMBUSTION DEVICE	Boiler or Heater	***19-H2***	***223***	14.70	4.80			0.04027	0.01316			0.00243	0.00002	0.00014	0.00019
REFINERY GAS COMBUSTION DEVICE	Boiler or Heater	***21-H1A***	***312***	141.35	46.19			0.38725	0.12654			0.01264	0.00264	0.00205	0.00283
REFINERY GAS COMBUSTION DEVICE	Boiler or Heater	***21-H1B***	***313***	18.66	6.10			0.05112	0.01670			0.00858	0.00265	0.00205	0.00284
REFINERY GAS COMBUSTION DEVICE	Boiler or Heater	***28-H1***	***102***	18.66	6.10			0.05112	0.01670			0.03992	0.00283	0.0022	0.00304
REFINERY GAS COMBUSTION DEVICE	Compressor Engine	***39-C1B***	***62***	20.99	6.86			0.05751	0.01879			0.05533	0.00002	0.00346	0.00139
REFINERY GAS COMBUSTION DEVICE	Compressor Engine	***39-C1A***	***63***	3.92	1.28			0.01075	0.00351			0.05533	0.00002	0.00346	0.00139
NO. 4 PLAT RX HTR (A, B, C, D)	Process Heater	29-H1A,B,C,D	82, 83, 84	89.19	29.15			0.24436	0.07985			0.0765	0.01358	0.01053	0.01455
NO. 4 PLAT COMPRESSSORS (4)	Compressor Engine	29-C4,5,6,3	166, 144, 145, 146	5.72	1.87			0.01568	0.00513			0.05512	0.00016	0.00752	0.00492
SULFUR RECOVERY PLANT	Sulfur Recovery Plant	51-V3, 52-SPIT, 53-U53, 54-V4	412									0.01423	0.11613	0.00078	0.00108
CUMENE DEPROPANIZER OFF-GAS	Refinery Gas Combustion											N.L.	N.L.	N.L.	N.L.
HYDRAR STABILIZER OH OFF-GAS	Refinery Gas Combustion											N.L.	N.L.	N.L.	N.L.
HYDRAR STRIPPER OFF-GAS	Refinery Gas Combustion											N.L.	N.L.	N.L.	N.L.
HYDRAR HYDROGEN	Refinery Gas Combustion											N.L.	N.L.	N.L.	N.L.
HYDRAR DEGASSING DRUM OFF-GAS	Refinery Gas Combustion											N.L.	N.L.	N.L.	N.L.
C4SHP DME STRIPPER OFF-GAS	Refinery Gas Combustion											N.L.	N.L.	N.L.	N.L.
TANKS 140 AND 141 VENTS	Refinery Gas Combustion											N.L.	N.L.	N.L.	N.L.
C5 MEROX DESULFIDE SEPARATOR SPENT AIR VENT	Refinery Gas Combustion											N.L.	N.L.	N.L.	N.L.
UNIBON RECYCLE HYDROGEN PURGE	Refinery Gas Combustion											N.L.	N.L.	N.L.	N.L.
MARINE EMISSION CONTROL	Refinery Gas Combustion											N.L.	N.L.	N.L.	N.L.
NESHAP FF INCINERATOR	Refinery Gas Combustion											N.L.	N.L.	N.L.	N.L.
CPI VAPOR COMBUSTOR	Refinery Gas Combustion											N.L.	N.L.	N.L.	N.L.
FLUOR FLARE	Flare	73-FLR442	F442									0	0	N.L.	0
CUMENE FLARE	Flare	73-FLR446	446									0	0	0	0
FUGITIVES	Equipment Leak	NA	NA									N.L.	N.L.	2.54587	N.L.

Notes:
N.L. = not listed

Refinery EI Improvement Project
CITGO Lake Charles Refinery

Unit No.	Unit Type	Stack ID	Point ID	Post-CD Potential Emission Rate (tpy)				Post-CD Potential Emission Rate (tpd)				2004 Actual Emission Rate (tpd)			
				NOX	SO2	VOC	PM10	NOX	SO2	VOC	PM10	NOX	SO2	VOC	PM10
FCCU A	Fluidized Catalytic Cracking Unit	*25*	*13*	0.70	0.75		0.40	0.0019	0.0021		0.0011	0.3479	1.3836	0.0055	0.3260
FCCU B	Fluidized Catalytic Cracking Unit	*26*	*14*	0.70	0.75		0.29	0.0019	0.0021		0.0008	0.3479	1.3836	0.0055	0.2356
FCCU C	Fluidized Catalytic Cracking Unit	*27*	*15*	0.84	1.06		0.30	0.0023	0.0029		0.0008	0.4219	1.9507	0.0055	0.2438
BOILER B-1, B-1A	Boiler	*22*	*00V*	312.07				0.8550				0.2014	0.0027	0.0041	0.0055
BOILER B-1C	Boiler	*23*	*00W*	216.09				0.5920				0.1973	0.0014	0.0041	0.0055
BOILER B-1B	Boiler	*24*	*00X*	186.27				0.5103				0.2137	0.0027	0.0041	0.0055
BOILER B-3, B-3B	Boiler	*52*	*25*	0.00	0.00	0.00	0.00	0.0000	0.0000	0.0000	0.0000	1.0096	0.0658	0.0178	0.0247
BOILER B-2	Boiler	*53*	*26*	0.00	0.00	0.00	0.00	0.0000	0.0000	0.0000	0.0000	1.2062	0.0301	0.0082	0.0219
BOIER B-3A, B-3C	Boiler	*54*	*27*	0.00	0.00	0.00	0.00	0.0000	0.0000	0.0000	0.0000	1.9027	0.0555	0.0144	0.0411
BOILER B-2A	Boiler	*55*	*28*	0.00	0.00	0.00	0.00	0.0000	0.0000	0.0000	0.0000	0.1548	0.0116	0.0027	0.0082
C-REFORMER B-501	Heater	*1*	*1*		7.64				0.0209			0.0507	0.0753	0.0027	0.0041
C-REFORMER B-502	Heater	*2*	*2*		7.64				0.0209			0.0205	0.2877	0.0027	0.0041
C-REFORMER B-503	Heater	*6*	*6*		26.94				0.0738			0.0247	0.0014	0.0014	0.0014
C-REFORMER B-504	Heater	*7*	*7*		26.94				0.0738			0.0288	0.0014	0.0014	0.0027
C-REFORMER B-505	Heater	*8*	*8*		26.94				0.0738			0.0315	0.0014	0.0014	0.0027
C-REFORMER B-506	Heater	*9*	*9*		7.64				0.0209			0.0055	N.L.	N.L.	N.L.
BOILER BF-1	Boiler	*56*	*29*		16.05				0.0440			0.0849	0.0096	0.0027	0.0068
BOILER BF-2	Boiler	*57*	*02A*		16.05				0.0440			0.1671	0.0123	0.0034	0.0096
BOILER BF-3	Boiler	*58*	*02B*		16.05				0.0440			0.1014	0.0075	0.0021	0.0055
BOILER BF-4	Boiler	*75*	*03R*		19.28				0.0528			0.0375	N.L.	0.0036	0.0068
BOILER BF-5	Boiler	*76*	*03S*									0.0507	0.0014	0.0068	0.0082
DUO-SOL FURNACE N-2A	Heater	*10*	*00A*		7.47				0.0205			0.0055	N.L.	N.L.	N.L.
DUO-SOL FURNACE N-2B	Heater	*11*	*00B*		7.47				0.0205			0.0233	0.0014	0.0014	0.0014
DUO-SOL FURANCE N-2C	Heater	*12*	*00E*		7.47				0.0205			0.1493	0.0014	0.0027	0.0041
DUO-SOL FURNACE S-1	Heater	*14*	*00G*									0.0055	N.L.	N.L.	N.L.
DUO-SOL FURNACE S-2	Heater	*15*	*00H*									0.0342	0.0014	0.0014	0.0027
DUO-SOL FURNACE P-2	Heater	*16*	*00J*									0.0192	N.L.	0.0014	0.0014
FURFURAL FURNACE BA-1, 2A & 2B	Heater	*17*	*00K*									0.0151	N.L.	0.0014	0.0014
FURFURAL FURNACE BA-3	Heater	*18*	*00P*									0.3068	0.0247	0.0123	0.0178
MEK-1 FURNACE BA-1 & 2	Heater	*19*	*00Q*									0.3945	0.0288	0.0151	0.0205
MEK-2 FURNACE BA-1 & 2	Heater	*20*	*00S*									N.L.	N.L.	0.0055	0.0192
MEK-2 FURNACE BA-3	Heater	*21*	*00T*									0.0014	N.L.	0.0014	0.0096
LUBE VACUUM BA-1	Heater	*31*	*19*									0.0027	N.L.	N.L.	N.L.
LUBE VACUUM BA-101	Heater	*32*	*01A*									0.0041	0.0014	N.L.	N.L.
TAME HYDROGEN	Heater	*33*	*01B*									0.0014	N.L.	N.L.	N.L.
FURNACE B-4	Heater	*34*	*01C*		52.72				0.1445			0.0397	0.0055	0.0027	0.0041
FURNACE B-104	Heater	*35*	*01D*		52.72				0.1445			0.0178	0.0014	0.0014	0.0014
BOILER B-5A	Boiler	*64*	*02I*		38.98				0.1068			0.0849	0.0082	0.0027	0.0027
BOILER B-5	Boiler	*65*	*02J*		38.98				0.1068			0.0767	0.0137	0.0027	0.0027
FURNACE B-403, 404, 405	Heater	*36*	*01E*		38.11				0.1044			0.0507	0.0068	0.0027	0.0041
FURNACE B-1,2,3,4,5	Heater	*38*	*01N*		28.29				0.0775			0.0082	0.0027	N.L.	N.L.
FURNACE B-102 - B-106	Heater	*39*	*01Q*		21.36				0.0585			0.0082	0.0027	N.L.	N.L.
FURNACE B-201	Heater	*40*	*01R*		18.34				0.0502			0.0356	0.0096	0.0014	0.0027
FURNACE B-202	Heater	*41*	*01S*		18.34				0.0502			0.0233	0.0068	0.0014	0.0014
A CAT FURNACE B-6	Heater	*42*	*01T*		18.04				0.0494			0.0562	0.0055	0.0027	0.0041
C CAT FURNACE B-6	Heater	*43*	*01U*		18.04				0.0494			0.0288	0.0027	0.0014	0.0027
FURNACE B-101	Heater	*44*	*01V*		13.04				0.0357			0.0329	0.0027	0.0014	0.0027
FURNACE B-201	Heater	*45*	*01W*		12.67				0.0347			0.0329	0.0027	0.0014	0.0027
FURNACE B-1C	Heater	*46*	*01X*		12.09				0.0331			0.1342	0.0219	0.0055	0.0082
FURNACE B-2C	Heater	*47*	*01Y*		11.34				0.0311			0.1041	0.0219	0.0055	0.0082
FURNACE B-102	Heater	*48*	*01Z*		10.16				0.0278			0.0096	0.0014	N.L.	0.0014
B CAN FURNACE B-6	Heater	*49*	*20*		9.40				0.0258			0.0630	0.0055	0.0027	0.0055
FURNACE BA-1	Heater	*50*	*21*	385.79	8.95			1.0570	0.0245			0.0630	0.0055	0.0027	0.0055
FURNACE BA-101	Heater	*51*	*22*	385.79	8.95			1.0570	0.0245			0.0247	0.0027	0.0014	0.0014
FURNACE B-201	Heater	*53*	*26*	376.33	8.73			1.0310	0.0239			1.2062	0.0301	0.0082	0.0219
FURNACE B-101	Heater	*54*	*27*	372.35	8.64			1.0201	0.0237			1.9027	0.0555	0.0144	0.0411
FURNACE B-101 & 2	Heater	*55*	*28*	372.35	8.64			1.0201	0.0237			0.1548	0.0116	0.0027	0.0082
FURNACE B-5	Heater	*56*	*29*	290.71	6.74			0.7965	0.0185			0.0849	0.0096	0.0027	0.0068
FURNACE B-406	Heater	*57*	*02A*	285.24	6.62			0.7815	0.0181			0.1671	0.0123	0.0034	0.0096
FURNACE B-402	Heater	*58*	*02B*	278.27	6.45			0.7624	0.0177			0.1014	0.0075	0.0021	0.0055
FURNACE B-202	Heater	*59*	*02C*	263.83	6.12			0.7228	0.0168			0.0260	0.0068	0.0014	0.0014
FURNACE B-2A	Heater	*60*	*02D*	221.52	5.14			0.6069	0.0141			0.0205	0.0055	0.0014	0.0014
FURNACE B-102	Heater	*61*	*02E*	215.54	5.00			0.5905	0.0137			0.0192	0.0055	0.0014	0.0014
FURNACE B-1 #1	Heater	*62*	*02F*	194.14	4.50			0.5319	0.0123			0.0685	0.0342	0.0068	0.0082
FURNACE B-1 #2	Heater	*63*	*02G*	194.14	4.50			0.5319	0.0123			0.0055	0.0027	N.L.	N.L.
B-700 WWT COMBUSTOR	Fuel Gas Combustion														
B-13 A-DOCK VAPOR COMBUSTOR	Fuel Gas Combustion														
B-14 B&C DOCK VAPOR COMBUSTOR	Fuel Gas Combustion														
VCU-01 FUEL LOADING RACK COMBUSTOR	Fuel Gas Combustion														
SULFUR RECOVERY PLANT	Sulfur Recovery Plant														
327B-11 FLARE C-REF/CK II	Flare	93	4K												
320B-12 FLARE UNICRACKER	Flare	94	4L												
399B-16 FLARE CFH	Flare														
360CB-701 (CB-11) PFU	Flare														
CA1001 CLAW	Flare														
B-104 COP/TIER II	Flare														
FUGITIVES	Fugitives	N/A	N/A												

Notes:
N.L. = not listed
Italics indicate that Stack ID and Point ID are the best available matches based on information from consent decree and/or information provided by the refinery.
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Refinery EI Improvement Project
ConocoPhillips Alliance Refinery

Unit Description	Unit Type	Unit ID	Stack ID	Point ID	Post-CD Potential Emission Rate (tpy)				Post-CD Potential Emission Rate (tpd)				2005 Actual Emission Rate (tpd)			
					NOX	SO2	VOC	PM	NOX	SO2	VOC	PM	NOX	SO2	VOC	PM10
Fluidized Catalytic Cracking Unit	Fluidized Catalytic Cracking Unit		10	10	102.00	176.00		191.00	0.27945	0.48219		0.52329	0.7452	4.0959	0.0027	0.4219
			11	11									0.8055	4.0959	0.0027	0.4274
1291	Heater	H-2/3	16	16	23.12	21.02			0.06334	0.05758			0.186301	0.035616	0.008219	0.010959
1391	Heater	H-1	17	17	74.90	39.49			0.20520	0.10820			0.049315	0.032877	0.005479	0.008219
1391	Heater	H-2/3	18	18	74.02	39.03			0.20280	0.10693			0.093151	0.063014	0.013699	0.016438
1391	Heater	H-4	19	19	42.05	22.17			0.11520	0.06074			0.421918	0.032877	0.005479	0.008219
1791	Heater	H-1	20	20	28.25	14.90			0.07740	0.04081			0.421918	0.032877	0.005479	0.008219
1792	Heater	H-1	21	20	36.57	19.28			0.10020	0.05283			0.153425	0.021918	0.005479	0.005479
191	Heater	H-1	2	2	74.90	103.92			0.20520	0.28473			0.330137	1.108219	0.0246575	0.0356165
191	Heater	H-1	2	2	0.00	0.00			0.00000	0.00000			0.330137	1.108219	0.0246575	0.0356165
291	Boiler	H-1	4	4	28.03	14.78			0.07680	0.04049			0.063014	0.016438	0.00274	0.005479
291	Heater	H-2	5	5	22.12	11.66			0.06060	0.03195			0.060274	0.016438	0.00274	0.005479
491	Heater	H-1	12	12	39.42	20.78			0.10800	0.05695			0.19726	0.024658	0.005479	0.008219
491	Heater	H-2	13	13	49.49	26.10			0.13560	0.07150			0.265753	0.038356	0.008219	0.010959
891	Heater	H-1	15	15	0.00	0.00			0.00000	0.00000			0.257534	0.041096	0.008219	0.010959
Sulfur Recovery Incinerator 591-D-21-X	Sulfur Recovery Unit	591	14	14		41.00				0.11233			0.013699	0.126027	N.L.	N.L.
Low Pressure Flare (coker)	Flare	308 D-1	23	23									0.052055	0.021918	0.106849	N.L.
High Pressure Flare	Flare	308 D-2	24	24									0.057534	0.024658	0.120548	N.L.
Marine Vapor Recovery Flare -- 406 D-15	Flare	5-90	33	33									0.008219	N.L.	0.019178	N.L.
Marine Vapor Recovery Flare -- 406 D-16	Flare	4-92	51	51									0.008219	N.L.	0.019178	N.L.

Notes:
N.L. = not listed

Refinery EI Improvement Project
ConocoPhillips Borger Refinery

Unit Description	Unit Type	FIN	EPN	Post-CD Potential Emission Rate (tpy)				Post-CD Potential Emission Rate (tpd)				2005 Actual Emission Rate (tpd)			
				NOX	SO2	VOC	PM	NOX	SO2	VOC	PM	NOX	SO2	VOC	PM10
Fluidized Catalytic Cracking Unit 29	Fluidized Catalytic Cracking Unit	*29-4*	*29H4*	788.00	1394.86		477.00	2.15890	3.82153		1.30685	0.10511	0.00025	0.00008	0.00686
Fluidized Catalytic Cracking Unit 40	Fluidized Catalytic Cracking Unit	*40-1*	*40H1*	495.00	1386.14		385.00	1.35616	3.79765		1.05479	0.08672	0.00585	0.00236	0.00326
Crude Charge Heater	Heater	*10-1*	*10H1*	0.00	0.00		0.00	0.00000	0.00000		0.00000	0.03486	0.01217	0.00132	0.00678
Rx Chg/Stab Reboiler	Boiler	*82-36*	*82B36*	34.40	1.37		2.32	0.09425	0.00377		0.00636	N.L.	N.L.	N.L.	0.00
Crude Charge Heater	Heater	*26-1*	*26HI*	0.00	0.00		0.00	0.00000	0.00000		0.00000	N.L.	N.L.	N.L.	0.00
Crude Charge Heater	Heater	*26-2*	*26H1*	0.00	0.00		0.00	0.00000	0.00000		0.00000	0.14207	0.00159	0.00067	0.00821
#1 Reheater	Heater	*19-4*	*19B2/19H4*	46.60	1.62		2.73	0.12767	0.00443		0.00749	0.0338	0.00322	0	0.00857
#2 and #3 Reheater	Heater	*19-1*	*19B1/19H1*	27.40	1.64		2.77	0.07507	0.00449		0.00758	0.16932	0.00014	0.00021	0.00995
Reformer Charge	Heater	*19-2*	*19B1/19H2*	70.50	2.87		4.85	0.19315	0.00786		0.01329	0.06261	0.00005	0.00007	0.00334
Naphtha HDS Charge	Heater	*19-3*	*19H3*	84.50	2.14		3.62	0.23151	0.00587		0.00992	0.19163	0.00575	0.00108	0.00775
Dist Rx Feed/Frac Feed	Heater	*19-5*	*19H5*	0.00	0.00		0.00	0.00000	0.00000		0.00000	0.0129	0.00338	0.00136	0.00188
Debutanizer Reboiler	Boiler	*81-14*	*81B14*	0.00	0.00		0.00	0.00000	0.00000		0.00000	N.L.	N.L.	N.L.	0.00
Steam Methane Reformer	Heater	*19-6*	*19H6*	115.80	8.03		13.56	0.31726	0.02199		0.03715	0.12288	0.02712	0.00198	0.00598
ARDS Chg. East	Heater	*42-1*	*42H1*	19.50	1.60		2.70	0.05342	0.00438		0.00739	0.04761	0.0008	0.00	0.00324
ARDS Chg. West	Heater	*42-2*	*42H2*	20.90	1.60		2.70	0.05726	0.00438		0.00739	0.04592	0.00273	0.00022	0.00339
Ethane Unit Superheater	Heater	*28-1*	*28H1*	0.00	0.00		0.00	0.00000	0.00000		0.00000	0.09209	0.02672	0.01077	0.01488
HDS Charge	Heater	*22-1*	*22H1*	20.10	0.89		1.50	0.05507	0.00244		0.00412	0.02943	0.00368	0.00148	0.00205
Col 45 Reboiler	Boiler	*85-1*	*85B1*	8.20	0.89		1.50	0.02247	0.00244		0.00412	2.09579	3.47661	0.2174	0.00
Debutanizer Reboiler	Boiler	*81-16*	*81B16*	0.00	0.00		0.00	0.00000	0.00000		0.00000	N.L.	N.L.	N.L.	0.00
Boiler	Boiler	*82-4*	*82B4*	9.80	9.30		15.71	0.02685	0.02548		0.04305	N.L.	N.L.	N.L.	0.00
Boiler	Boiler	*81-5*	*81B5*	0.00	0.00		0.00	0.00000	0.00000		0.00000	N.L.	N.L.	N.L.	0.00
Boiler	Boiler	*82-6*	*82B6*	0.00	0.00		0.00	0.00000	0.00000		0.00000	N.L.	N.L.	N.L.	0.00
Unit 12 Engine # 46	Internal Combustion Engine	12-E6	12000000									0.05553	0.00002	0.00041	0.00031
Unit 65 Engine # 1 (East)	Internal Combustion Engine	55-1	550									0.31048	0.00005	0.0011	0.00062
Unit 55 Engine # 2	Internal Combustion Engine	55-2	5500									0.09093	0.00005	0.00041	0.00062
Unit 65 Engine # 3 (West)	Internal Combustion Engine	55-3	55000									0.22337	0.00005	0.02246	0.00062
Unit 93 Engine # 37	Internal Combustion Engine	93-1	930									0.0174	0.00003	0.03991	0.00045
Unit 93 Engine # 39	Internal Combustion Engine	93-3	93000									0.02097	0.00003	0.00359	0.00045
Unit 93 Engine # 40	Internal Combustion Engine	93-4	930000									N.L.	N.L.	N.L.	0.00
Unit 34	SRP	34I1	34I1		0.87				0.00240			0.01775	0.00181	0.00122	0.00181
Unit 43	SRP	43I1	43I1		78.13				0.21404			0.027	0.1617	0.00138	0.00384
East Refinery Flare	0	*66FL1*	*66FL1*									0.00294	0.00001	0.01653	0
West Refinery Flare	0	*66FL2*	*66FL2*									0.00955	0.00223	0.09072	0
ARDS Flare	0	*66FL3*	*66FL3*									0.02891	0.03383	0.05195	0
Cat Flare	0	*66FL4*	*66FL4*									0.02366	0.02161	0.10414	0
NGL Non-Corrosive Flare	0	*66FL5*	*66FL5*									0	0	0	0
NGL Corrosive Flare	0	*66FL6*	*66FL6*									0.00044	0.3623	0.00009	0
AG Flare	0	*66FL7*	*66FL7*									N.L.	N.L.	N.L.	0
Derrick Flare	0	*66FL8*	*66FL8*									0.00455	0.02515	0.04387	0
FUGITIVES	Benzene Operations	NA	NA												
FUGITIVES	Fugitives	NA	NA												

Notes:
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Refinery EI Improvement Project
ConocoPhillips Lake Charles Refinery

Unit Description	Unit Type	Stack ID	Point ID	Post-CD Potential Emission Rate (tpy)				Post-CD Potential Emission Rate (tpd)				2004 Actual Emission Rate (tpd)			
				NOX	SO2	VOC	PM	NOX	SO2	VOC	PM	NOX	SO2	VOC	PM10
FCCU	Fluidized Catalytic Cracking Unit	*144*	*0SQ*	126.00	270.00		49.00	0.34521	0.73973		0.13425	N.L.	N.L.	0.035616	N.L.
B-3 LP Boiler	Boiler	*69*	*0C8*	0.00	0.00			0.00000	0.00000			N.L.	N.L.	0.00274	N.L.
B-4 LP Boiler	Boiler	*70*	*0C9*	0.00	0.00			0.00000	0.00000			N.L.	N.L.	0.00274	N.L.
B-6 HP Boiler	Boiler	*23*	*64*	17.70	34.06			0.04849	0.09333			0.021918	0.186301	0.093151	N.L.
B-76001 Excel Boiler	Boiler	*39*	*0A1*									N.L.	N.L.	0.005479	N.L.
H-00014 Thermal Cracker	Heater	*20*	*61*	3.57	13.74			0.00978	0.03765			0.024658	N.L.	N.L.	0.005479
H-00026 No. 1 Coker	Heater	*12*	*45*	2.52	9.70			0.00690	0.02657			0.013699	N.L.	N.L.	0.00274
H-00046 No. 2 CTU	Heater	*21*	*62*	0.00	0.00			0.00000	0.00000			0.035616	N.L.	0.00274	0.008219
H-01101 No. 3 CTU	Heater	*162*	*0TJ*									N.L.	N.L.	0.030137	N.L.
H-01103 No. 3 CVU	Boiler	*163*	*0TK*									N.L.	N.L.	0.010959	N.L.
H-01201 No. 4 HDS	Heater	*22*	*63*									0.019178	N.L.	N.L.	0.00274
H-01202 No. 4 HDS	Heater	*167*	*0TO*									N.L.	N.L.	0.010959	N.L.
H-11001 HDC H2 Heater	Heater	*43*	*0AB*									0.013699	N.L.	N.L.	0.00274
H-11002 HDC Heater	Heater	*54*	*0AO*									0.010959	N.L.	N.L.	0.00274
H-11003 HDC Heater	Heater	*55*	*0AP*									0.005479	N.L.	N.L.	N.L.
H-12003 HDF Heater	Heater	*45*	*0AD*									0.010959	N.L.	N.L.	0.00274
H-16101 No. 10 Reformer	Heater	*48*	*0AG*									0.057534	0.00274	0.00274	0.010959
H-16102 No. 10 Reformer	Heater	*49*	*0AI*									0.057534	0.00274	0.00274	0.016438
H-16103 No. 10 Reformer	Heater	*50*	*0AJ*									0.013699	0.00274	0.027397	N.L.
H-16104 No. 10 Reformer	Heater	*51*	*0AK*									0.052055	0.391781	N.L.	0.008219
H-16105 No. 10 Reformer	Heater	*52*	*0AL*									N.L.	N.L.	0.019178	0.005479
H-20002 No. 2 CVU	Heater	*46*	*0AE*									0.021918	0.00274	N.L.	0.005479
H-30001 No. 2 CVU	Heater	*47*	*0AF*									0.00274	N.L.	N.L.	N.L.
EP177 NO1 & 2 SULFUR PLANTS & TAILGAS UNIT	Sulfur Recovery Plant	146	0SS		101.18				0.27721			N.L.	N.L.	0.019178	N.L.
EP212 NO.4 SULFUR RECOVERY UNIT	Sulfur Recovery Plant	178	0UB		57.82				0.15841			N.L.	N.L.	0.010959	N.L.
South Flare	Flare	7	31	0.00	0.00	0.00		0.00000	0.00000	0.00000		0.005479	0.906849	0.027397	N.L.
FUGITIVES	Benzene Operations/Equipment Leak													0.3954	

Notes:
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Refinery EI Improvement Project
ConocoPhillips Ponca City Refinery

Unit Description	AEI ID	Stack ID	Point ID	Post-CD Potential Emission Rate (tpy)				Post-CD Potential Emission Rate (tpd)				2005 Actual Emission Rate (tpd)			
				NOX	SO2	VOC	PM	NOX	SO2	VOC	PM	NOX	SO2	VOC	PM10
FCCU 4	No. 4	5375	5375	43.00	55.00		110.00	0.11781	0.15068		0.30137	0.118516	0.548297	0.0125	0.380357
FCCU 5	No. 5	5376	5376	118.00	257.00		131.00	0.32329	0.70411		0.35890	0.325495	1.672582	N.L.	0.902582
B-6 Main Power Boiler	Main Power Plant Boiler	5370	5370	0.00	0.00		0.00	0.00000	0.00000		0.00000	0.082637	0.000962	0.000412	0.008077
B-7 Main Power Boiler	Main Power Plant Boiler	5371	5371	0.00	0.00		0.00	0.00000	0.00000		0.00000	0.22272	0.001676	0.000687	0.009176
Cogen Duct Burner	No. 1 Cogeneration Unit	5366	5366	0.00	0.00		0.00	0.00000	0.00000		0.00000	0.248159	0.006621	0.06044	0.024176
H-0001 No. 1 CTU CC	No. 1 CTU Crude charge heater	33697	34043	57.82	25.40		7.92	0.15840	0.06960		0.02171	0.007253	0.000549	0.001291	0.001786
H-0004 No. 4 CTU CC	No. 4 CTU Crude Charge Heater	5331	5331	30.27	19.95		6.22	0.08294	0.05467		0.01705	0.108984	0.006044	0.00978	0.013626
H-0015 No. 1 CTU CC	No. 1 CTU Crude Charge Heater	5333	5333	0.00	0.00		0.00	0.00000	0.00000		0.00000	0.031154	0.001016	0.000934	0.002335
H-0048 CRU Preheater	No. 2 CRU Reactor Preheater (H-48)	5349	5349	118.75	44.72		13.95	0.32533	0.12253		0.03822	0.185247	0.005989	0.013544	0.018819
H-0057 Alky Depropanizer	Alky. Depropanizer Heater (H-57)	5350	5350	0.00	0.00		0.00	0.00000	0.00000		0.00000	0.056731	0.001593	0.003104	0.004313
H-0058 Alky Depropanizer	Alky Depropanizer Heater (H-58)	5351	5351	0.00	0.00		0.00	0.00000	0.00000		0.00000	0.036044	0.000989	0.001978	0.002747
H-0059 Alky Depropanizer	Alky Depropanizer Heater (H-59)	5352	5352	0.00	0.00		0.00	0.00000	0.00000		0.00000	0.061676	0.001731	0.003379	0.004698
H-5001 No. 5 FCC Preheater	No. 5 FCC Feed Preheater (H-5001)	5354	5354	0.00	0.00		0.00	0.00000	0.00000		0.00000	0.278791	0.003681	0.005467	0.00761
H-6007 No. 3 CRU Preheater	No. 3 CRU Reactor Preheater (H-6007)	5356	5356	37.98	14.30		4.46	0.10406	0.03919		0.01222	0.247885	0.002253	0.006676	0.009258
H-6014 No. 2 CVU Feed	No. 2 CVU Feed Process (H-6014)	5360	5360	15.11	7.97		2.49	0.04140	0.02183		0.00681	0.066786	0.001291	0.003654	0.005082
H-6015 No. 2 CVU Feed	No. 2 CVU Feed Process (H-6015)	5367	5367	26.54	14.00		4.37	0.07272	0.03834		0.01196	0.156758	0.008571	0.072253	0.028901
No. 1 SRU	Sulfur Recovery Unit Tail Gas Vent	5385	5385		1.00				0.00274			N.L.	0.013077	N.L.	0.015467

Notes:
N.L. = not listed

Refinery EI Improvement Project
ConocoPhillips Sweeny Refinery

Unit Description	Unit Type	FIN	EPN	Post-CD Potential Emission Rate (tpy)				Post-CD Potential Emission Rate (tpd)				2005 Actual Emission Rate (tpd)			
				NOX	SO2	VOC	PM	NOX	SO2	VOC	PM	NOX	SO2	VOC	PM10
Fluidized Catalytic Cracking Unit 3	Fluidized Catalytic Cracking Unit	*3-95-3*	*3-95-3*	42.00	280.00		74.00	0.11507	0.76712		0.20274	0.58234	0.69228	0.00447	0.37945
Fluidized Catalytic Cracking Unit 27	Fluidized Catalytic Cracking Unit	*27.1-36-RE*	*27.1-36-RE*	162.00	1113.00		111.00	0.44384	3.04932		0.30411	1.23478	2.65743	0.00316	0.80640
FCC Charge Heater	Heater	3-36-4	3-36-4	15.40	0.23		1.58	0.04219	0.00062		0.00432	0.03112	0.00023	0.00036	0.00299
Crude Charge Heater	Heater	9-36-4	9-36-4	34.30	0.39		2.75	0.09397	0.00108		0.00753	0.07539	0.00116	0.00180	0.01476
Prefrac Reboiler Heater	Heater	11-36-1	11-36-1	3.60	0.12		0.87	0.00986	0.00034		0.00239	0.01020	0.00020	0.00032	0.00252
Reformer HDS Heater	Heater	11-36-5	11-36-5	2.30	0.13		0.91	0.00630	0.00036		0.00250	0.00634	0.00022	0.00035	0.00276
Reboiler Heater	Heater	14-36-3	14-36-3	3.30	0.16		1.15	0.00904	0.00045		0.00314	0.00935	0.00020	0.00033	0.00261
HDS Charge Heater	Heater	14-36-4	14-36-4	1.20	0.10		0.69	0.00329	0.00027		0.00189	0.00421	0.00010	0.00017	0.00132
Crude Charge Heater	Heater	25.1-36-1	25.1-36-1	65.90	0.76		5.30	0.18055	0.00207		0.01452	0.58649	0.00290	0.00451	0.03706
HDS Charge Heater	Heater	25.2-36-51	25.2-CS	74.70	0.08		0.59	0.20466	0.00023		0.00161	0.09786	0.00035	0.00054	0.00442
HDS Reboiler	Boiler	25.2-36-52	25.2-CS	17.50	0.12		0.81	0.04795	0.00032		0.00221	0.11303	0.00040	0.00062	0.00510
Charge Heater	Heater	26-36-1	26-CS	38.90	0.19		1.32	0.10658	0.00051		0.00360	N.L.	N.L.	N.L.	0.00000
Charge Heater	Heater	26-36-1.1	26.1-CS	53.70	0.19		1.32	0.14712	0.00051		0.00360	0.12082	0.00056	0.00088	0.00720
Recycle Gas Heater	Heater	26-36-2	25-72	17.50	0.08		0.53	0.04795	0.00021		0.00146	N.L.	N.L.	N.L.	0.00000
Recycle Gas Heater	Heater	26.36-2.1	26.1-CS	17.80	0.08		0.53	0.04877	0.00021		0.00146	0.02526	0.00013	0.00021	0.00170
Vacuum Charge Heater	Heater	29.1-36-1	29.1-36-1	29.40	0.52		3.61	0.08055	0.00141		0.00989	0.08725	0.00194	0.00683	0.02470
Coker Charge Heater	Heater	29.2-36-1	29.2-36-1	22.40	0.38		2.63	0.06137	0.00103		0.00721	0.06123	0.00129	0.00296	0.01642
Coker Charge Heater	Heater	29.2-36-2	29.2-36-2	22.10	0.38		2.63	0.06055	0.00103		0.00721	0.05999	0.00126	0.00290	0.01607
Isostripper Heater	Heater	30-36-1	30-36-1	6.90	0.17		1.19	0.01890	0.00046		0.00325	0.01956	0.00032	0.00049	0.00402
CCR Charge Heater	Heater	35-36-1	35-36-1	29.30	0.94		6.60	0.08027	0.00258		0.01809	0.14045	0.00276	0.00595	0.03522
SRU A	Sulfur Recovery Unit	*56-61-104*	*56-61-104*		177.09				0.48518			N.L.	2.65743	N.L.	N.L.
SRU B	Sulfur Recovery Unit	*56-61-152*	*56-61-152*		0.35				0.00096			0.00504	0.00525	N.L.	0.00068
SRU C	Sulfur Recovery Unit	*28.2-36-2*	*28.2-36-2*		42.56				0.11660			N.L.	0.63862	N.L.	N.L.
Unit 7 Flare	Flare	*28.1-61-10*	*28.1-61-10*									0.00037	0.00477	N.L.	0.00000
Units 11/14 Flare	Flare	*28.1-61-9*	*28.1-61-9*									0.00035	0.01026	0.00000	0.00000
Units 7/10D/18 Flare	Flare	*56-61-11*	*54-22-11*									N.L.	N.L.	N.L.	0.00000
Units 10abc/12/51 LP Flare	Flare	*56-61-1*	*56-61-1*									0.00621	0.00695	0.00003	0.00000
Units 10abc/12/68 HP Flare	Flare	*28.1-61-10*	*56-61-10*									N.L.	N.L.	N.L.	0.00000
Units 15/17/19 Flare	Flare	*56-61-11*	*56-61-11*									0.00051	0.00000	0.00021	0.00000
Expansion LP Flare	Flare	*56-61-16*	*56-61-16*									0.00258	0.00072	0.00035	0.00000
Expansion HP Flare	Flare	*56-61-17*	*56-61-16*									N.L.	N.L.	N.L.	0.00000
Unit 5 Flare	Flare	*56-61-17*	*56-61-17*									0.00072	0.26143	0.00007	0.00000
Unit 30 Flare	Flare	*56-61-19*	*56-61-19*									0.00035	0.01026	N.L.	0.00000
VDU/DCU Flare	Flare	*56-61-23*	*56-61-23*									0.01242	0.00005	0.00001	0.00000
DEA Stripper Flare	Flare	*56-61-3*	*56-61-3*									0.00252	0.01279	0.00001	0.00000
SW Stripper Flare	Flare	*56-61-4*	*56-61-4*									0.00168	0.00036	0.00044	0.00000
FUGITIVES	Benzene Operations/Equipment Leak	N.A.	N.A.											0.39540	

Notes:
N.L. = not listed
Italics indicate that FIN and EPN are the best available matches based on information from consent decree and/or information provided by the refinery.
The FIN and EPN listed do not necessarily correspond to the specified unit.

Refinery EI Improvement Project
ExxonMobil Baton Rouge Refinery

Unit Description	Unit Type	Stack ID	Point ID	Post-CD Potential Emission Rate (tpy)				Post-CD Potential Emission Rate (tpd)				2004 Actual Emission Rate (tpd)			
				NOX	SO2	VOC	PM	NOX	SO2	VOC	PM	NOX	SO2	VOC	PM10
0	0	1	5	127.39				0.34902				0.512329	N.L.	0.013699	0.019178
0	0	2	6	30.66				0.08399				0.123288	N.L.	0.005479	0.008219
0	0	3	7	85.84				0.23517				0.345205	0.013699	0.010959	0.016438
0	0	4	8	18.39				0.05039				0.073973	0.005479	0.005479	0.008219
PIPESTILL-7 F-1	0	5	10	32.02				0.08772				0.128767	0.032877	0.019178	0.027397
PIPESTILL-8 F-1	0	7	13	38.83				0.10638				0.156164	0.030137	0.019178	0.027397
PIPESTILL-8 VF-2	0	8	15	0.68				0.00187				0.00274	N.L.	N.L.	N.L.
PS-9 F-1 (ATMOS FURNACE)-2 STACKS	Furnace	9	16	35.42				0.09705				0.142466	0.032877	0.024658	0.035616
PS-9 F-1/F-2 AIR PREHEAT STACK	Furnace	10	19	24.52				0.06719				0.09863	0.010959	0.008219	0.013699
PS-9 F-2 (VACUUM FURNACE)	Furnace	11	20	35.42				0.09705				0.142466	0.016438	0.013699	0.019178
PS-10 F-1 (ATMOS FURNACE) 2-STACKS	Furnace	12	21	22.48				0.06159				0.090411	0.008219	0.008219	0.010959
PS-10 F-1/F-2 AIR PREHEAT STACK	Furnace	13	22	18.39				0.05039				0.073973	0.010959	0.008219	0.010959
PS-10 F-2 (VACUUM FURNACE)	Furnace	14	25	128.07				0.35088				0.515068	0.021918	0.016438	0.024658
PS-10 F-101 (ATMOSPHERE FURNACE) 2-STACKS	Furnace	15	26	29.29				0.08026				0.117808	0.019178	0.016438	0.021918
PS-10 F-101/F-102 AIR PREHEAT STACK	Furnace	16	27	3.41				0.00933				0.013699	N.L.	N.L.	N.L.
PS-10 F-102 (VACUUM FURNACE)-2STACKS	Furnace	17	31	25.21				0.06906				0.10137	0.016438	0.008219	0.010959
0	Furnace	18	32	31.34				0.08585				0.126027	0.013699	0.008219	0.010959
W COK F-101 (2-STACKS)	Furnace	19	33	14.99				0.04106				0.060274	0.010959	0.005479	0.008219
E COK F-1 (2-STACKS)	Furnace	20	34	17.71				0.04853				0.071233	0.013699	0.008219	0.010959
FE COK F501A	Furnace	21	35	1.36				0.00373				0.005479	N.L.	N.L.	N.L.
FE COK F501B	Furnace	22	36	0.68				0.00187				0.00274	N.L.	N.L.	N.L.
0	Furnace	23	37	6.13				0.01680				0.024658	0.00274	0.00274	0.00274
0	Furnace	24	39	21.12				0.05786				0.084932	0.00274	0.00274	0.005479
PCLA-2 PREHEAT FURNACE-F2	Furnace	25	40	8.86				0.02426				0.035616	0.00274	0.00274	0.00274
PCLA-3 PREHEAT FURNACE-F3	Furnace	26	41	14.99				0.04106				0.060274	0.019178	0.010959	0.016438
HCN F-201	Furnace	27	42	6.81				0.01866				0.027397	0.00274	0.00274	0.00274
PHLA-1 REGENERATION FURNACE F-105	Furnace	28	43	5.45				0.01493				0.021918	0.00274	0.00274	0.00274
PHLA-1 RECYCLE DRYER FURNACE F-301	Furnace	29	44	2.04				0.00560				0.008219	0.005479	N.L.	0.00274
PHLA-1 F401	Furnace	30	47	11.58				0.03173				0.046575	0.005479	N.L.	N.L.
PHLA-2 F1	Furnace	31	48	20.44				0.05599				0.082192	0.008219	0.005479	0.005479
PHLA-2 F2	Furnace	32	49	13.62				0.03733				0.054795	0.005479	N.L.	0.00274
PHLA-2 F-3	Furnace	33	50	9.54				0.02613				0.038356	0.041096	0.00274	0.005479
PHLA-2 F4	Furnace	34	51	35.42				0.09705				0.142466	0.010959	0.010959	0.013699
PHLA-2 F-5	Furnace	35	55	2.04				0.00560				0.008219	N.L.	N.L.	N.L.
PHLA-2 F-6	Furnace	36	59	4.09				0.01120				0.016438	N.L.	N.L.	0.00274
PHLA-2 F-7	Furnace	37	60	21.12				0.05786				0.084932	0.013699	0.008219	0.010959
RHLA-1 F-700	Furnace	38	61	21.80				0.05972				0.087671	0.008219	0.005479	0.010959
RHLA-2 F-600	Furnace	39	62	4.77				0.01306				0.019178	N.L.	N.L.	N.L.
FEED PREP F-30	Furnace	40	63	14.31				0.03919				0.057534	0.005479	0.00274	0.005479
FEED PREP F-30	Furnace	41	64	19.76				0.05413				0.079452	0.010959	0.005479	0.008219
HCLA F-101	Furnace	42	68	2.04				0.00560				0.008219	0.926027	N.L.	N.L.
HHLA-S F-201	Furnace	43	69	2.04				0.00560				0.008219	0.857534	N.L.	N.L.
1LEU F-301	Furnace	45	73	937.38				2.56817				3.769863	0.819178	0.013699	0.936986
4LEU EAST F-1	Furnace	47	76	2.04				0.00560				0.008219	0.00274	N.L.	0.00274
4LEU WEST F-1	Furnace	48	77	77.66				0.21277				0.312329	0.035616	1.20411	0.112329
2LEU DEC4 F-501	Furnace	51	81	10.90				0.02986				0.043836	0.005479	0.00274	0.005479
SOLVENT HYDROFINER F-1(IDLE)	Furnace	52	91	12.94				0.03546				0.052055	N.L.	0.065753	0.00274
1LEU F-401	Furnace	53	92	0.68				0.00187				0.00274	N.L.	0.00274	N.L.
0	Furnace	56	99	1.36				0.00373				0.005479	0.049315	0.005479	N.L.
0	Furnace	58	0A2	0.68				0.00187				0.00274	N.L.	N.L.	N.L.
LELA-E F-1	Furnace	60	0D8	5.45				0.01493				0.021918	0.00274	0.00274	0.005479
LELA-S F-3	Furnace	61	0D9	4.09				0.01120				0.016438	0.00274	0.00274	0.00274
LELA-S F-4	Furnace	62	0	1.36				0.00373				0.005479	N.L.	N.L.	N.L.
KDLA F-425	Furnace	63	0	1.36				0.00373				0.005479	N.L.	N.L.	N.L.
FUGITIVES	Benzene Operations/Equipment Leak														

Notes:
N.L. = not listed

Refinery EI Improvement Project
ExxonMobil Baytown Refinery

Unit Description	Unit Type	FIN	EPN	Post-CD Potential Emission Rate (tpy)				Post-CD Potential Emission Rate (tpd)				2005 Actual Emission Rate (tpd)			
				NOX	SO2	VOC	PM	NOX	SO2	VOC	PM	NOX	SO2	VOC	PM10
FCCU 2	Fluidized Catalytic Cracking Unit	*FCCU2F1A*	*FCCU2WGS*	193.23	584.12		543.56	0.52940	1.60032		1.48920	0.45789	0.57272	0.06276	0.48123
FCCU 3	Fluidized Catalytic Cracking Unit	*FCCU3S501A*	*FCCU3WGS*	206.77	34.64		190.64	0.56649	0.09489		0.52230	0.48997	0.03396	0.0207	0.16878
SCU 1	SRP	*SCU1*	*F102A/B*		0.00				0.00000			N.L.	N.L.	N.L.	0
SCU 2	SRP	*SCU2*	*F121*		0.00				0.00000			0.00	0.00	0.00	0.00
FUGITIVES	Fugitives	*NA*	*NA*									N.L.	N.L.	2.92	N.L.

Notes:
N.L. = not listed
Italics indicate that FIN and EPN are the best available matches based on information from consent decree and/or information provided by the refinery.
The FIN andEPN listed do not necessarily correspond to the specified unit.

Refinery EI Improvement Project
ExxonMobil Beaumont Refinery

Unit Description	Unit Type	FIN	EPN	Post-CD Potential Emission Rate (tpy)			Post-CD Potential Emission Rate (tpd)			2005 Actual Emission Rate (tpd)		
				NOX	SO2	PM	NOX	SO2	PM	NOX	SO2	PM10
FCCU Regenerator Scrubber	FCCU	06SCB#003	06STK_003	620	431	656	1.69836	1.18137	1.79671	2.10227	0.71795	0.369
Coker East Stack	Heater	04HTR#001	04STK_001	31	9	11	0.08521	0.02523	0.03049	0.06923	0.00234	0.0248
Coker Mid Stack	Heater	04HTR#002	04STK_002	32	10	12	0.08855	0.02622	0.03170	0.08091	0.00233	0.02414
Coker West Stack	Heater	04HTR#003	04STK_003	30	9	11	0.08279	0.02452	0.02964	0.06841	0.00197	0.02041
Coker Far West Stack	Heater	04HTR#004	04STK_004	39	10	2	0.10627	0.02622	0.00663	0.06831	0.00194	0.00427
Crude B Atm. Heater H-3101	Heater	05HTR#001	05STK_001	344	40	18	0.94321	0.11003	0.04795	0.64614	0.01638	0.03251
Crude B Vacuum Heater H-3102	Heater	05HTR#002	05STK_002	63	14	3	0.17123	0.03808	0.00740	0.11359	0.003	0.0051
Crude B Heater H-2001	Heater	05HTR#004	05STK_004	51	11	2	0.13863	0.03068	0.00603	0.08893	0.00239	0.00371
FCC Feed Preheater (B-2)	Heater	06HTR#002	06STK_002	88	19	12	0.24184	0.05208	0.03184	0.0148	0.00077	0.00284
CHD1 Charge Heater	Heater	15HTR#001	15STK_001	42	12	3	0.11556	0.03422	0.00866	0.05498	N.L.	0.00253
B-1 Charge Heater	Heater	16HTR#001	16STK_001	26	0	1	0.07208	0.00036	0.00375	0.02335	0.00017	0.00141
B-2 Stripper Reboiler	Boiler	16BLR#002	16STK_001	50	0	3	0.13608	0.00068	0.00710	0.0715	0.00043	0.00323
HDC 1st Stage West Furnace	Heater	20HTR#001	20STK_001	4	2	1	0.01200	0.00419	0.00162	0.00434	0.00043	0.00057
HDC 1st Stage East Furnace	Heater	20HTR#002	20STK_002	12	1	1	0.03315	0.00386	0.00137	0.00512	0.00022	0.00021
HDC 2nd Stage Furnace	Heater	20HTR#003	20STK_003	12	1	1	0.03315	0.00386	0.00137	0.00937	0.00028	0.00039
HDC Stabilizer Reboiler Heater	Heater	20HTR#004	20STK_004	50	12	5	0.13679	0.03192	0.01367	0.05653	0.00414	0.00752
HDC Splitter Reboiler Heater	Heater	20HTR#005	20STK_005	19	5	2	0.05247	0.01255	0.00562	0.0284	0.00132	0.00264
Isom. Unit Pretreater Charge Heater	Heater	25HTR#001	25STK_001	17	7	2	0.04679	0.02036	0.00586	0.05258	0.00082	0.00352
Isom. Unit Stabilizer Reboiler Heater	Heater	25HTR#002	25STK_002	0.00	0.00	0.00	0.00000	0.00000	0.00000	N.L.	N.L.	N.L.
Isom. Unit Reacter Charge Heater	Heater	25HTR#003	25STK_003	8	2	1	0.02159	0.00564	0.00162	0.00682	0.00011	0.00051
Isom. Unit Regeneration Heater	Heater	25HTR#004	25STK_004	2	0	0	0.00479	0.00126	0.00036	N.L.	N.L.	0
Pretreater Heater (H-3401)	Heater	27HTR#001	27STK_001	48	10	8	0.13249	0.02767	0.02137	0.04132	0.00118	0.0064
Stripper Reboiler (H-3402)	Heater	27HTR#002	27STK_002	37	9	6	0.10033	0.02581	0.01573	0.04777	0.00149	0.00747
Reformer Heater (H-3403 - H-3406)	Heater	27HTR#003	27STK_003	217	29	6	0.59400	0.07885	0.01767	0.23439	0.00193	0.00975
Debutanizer Reboiler (H-3408)	Boiler	27HTR#004	27STK_004	24	10	7	0.06479	0.02748	0.02005	0.02812	0.00165	0.00432
PTR4 Rx Charge Heater	Heater	28HTR#001	28STK_001	42	5	2	0.11521	0.01345	0.00479	0.12728	0.00317	0.00557
PTR4 Depentanizer Reboiler Heater	Heater	28HTR#002	28STK_001	55	6	2	0.15192	0.01767	0.00677	N.L.	N.L.	0
PTR4 Reformer Heater	Heater	28HTR#003	28STK_003	326	36	27	0.89353	0.09896	0.07441	0.47248	0.0176	0.07081
PTR4 Debutanizer Heater	Heater	28HTR#004	28STK_003	17	4	1	0.04740	0.01041	0.00219	N.L.	N.L.	0
Atmospheric Heater (B1-A)	Heater	36HTR#002	36STK_002	101	26	8	0.27600	0.07203	0.02071	0.08351	0.0022	0.01197
Atmospheric Heater (B1-B)	Heater	36HTR#004	36STK_004	101	26	8	0.27600	0.07203	0.02071	0.0832	0.00238	0.01247
Vacuum Heater (B-2)	Heater	36HTR#006	36STK_006	25	11	3	0.06841	0.02975	0.00855	0.11766	0.00105	0.00571
Vacuum Heater (B-3)	Heater	36HTR#007	36STK_007	24	10	3	0.06479	0.02819	0.00811	0.10574	0.00083	0.00448
Extract Heater BA-1/BA-2	Heater	39HTR#001	39STK_001	27	6	2	0.07526	0.01753	0.00504	0.03832	0.00067	0.00287
Boiler No. 15	Boiler	56BLR#015	56STK_015	0.00	0.00	0.00	0.00000	0.00000	0.00000	N.L.	0.00042	0.00292
Boiler No. 16	Boiler	56BLR#016	56STK_016	0.00	0.00	0.00	0.00000	0.00000	0.00000	0.05355	0.00082	0.00489
Boiler No. 17	Boiler	56BLR#017	56STK_017	0.00	0.00	0.00	0.00000	0.00000	0.00000	0.08571	0.00194	0.00859
Boiler No. 18	Boiler	56BLR#018	56STK_018	0.00	0.00	0.00	0.00000	0.00000	0.00000	0.00451	0.00023	0.00119
Boiler No. 19	Boiler	56BLR#019	56STK_019	0.00	0.00	0.00	0.00000	0.00000	0.00000	0.10211	0.0021	0.01027
Boiler No. 22	Boiler	56BLR#022	56STK_022	0.00	0.00	0.00	0.00000	0.00000	0.00000	0.1988	0.00239	0.12899
Boiler No. 32	Boiler	57BLR#032	57STK_032	0.00	0.00	0.00	0.00000	0.00000	0.00000	0.26978	0.00352	0.02032
Boiler No. 33	Boiler	57BLR#033	57STK_033	187	82	23	0.51337	0.22332	0.06416	0.28758	0.01263	0.04029
Boiler No. 34	Boiler	57BLR#034	57STK_034	187	82	23	0.51337	0.22332	0.06416	0.21102	0.0076	0.03058
Turbine 1 & Duct Burner	Turbine	61TRB#001	61STK_001	188	74	106	0.51553	0.20293	0.29077	0.19659	0.00367	0.04059
Turbine 2 & Duct Burner	Turbine	61TRB#002	61STK_002	188	74	106	0.51553	0.20293	0.29077	0.17372	0.02399	0.07098
Turbine 3 & Duct Burner	Turbine	61TRB#003	61STK_003	188	74	106	0.51553	0.20293	0.29077	0.16882	0.01597	0.04
SRU 2/3 Thermal Oxidizer	SRU	32TOX#001	32STK_001	47	404	3	0.12959	1.10553	0.00863	0.07523	0.21581	0.14569
CHD1 Flare	Flare	60FLR#001	60FLR_001	8	464	0.00	0.02140	1.27074	0.00000	0.02355	0.8811	0
CHD2 Flare	Flare	60FLR#002	60FLR_002	1	70	0.00	0.00216	0.19055	0.00000	0.00541	0.03167	0
High Pressure Flare	Flare	60FLR#003	60FLR_003	12	507	0.00	0.03263	1.38877	0.00000	0.07068	0.41199	0
Low Pressure Flare	Flare	60FLR#005	60FLR_005	11	1572	0.00	0.02921	4.30762	0.00000	0.03032	1.48709	0
No. 6 Flare	Flare	60FLR#006	60FLR_006	14	174	0.00	0.03912	0.47677	0.00000	0.02033	0.0277	0
No. 7 Flare	Flare	60FLR#007	60FLR_007	13	29	0.00	0.03608	0.07945	0.00000	0.03745	0	0
FCC Flare	Flare	60FLR#008	60FLR_008	9	545	0.00	0.02586	1.49184	0.00000	0.02663	0.25205	0
No. 10 Flare	Flare	60FLR#010	60FLR_010	30	325	0.00	0.08334	0.89137	0.00000	0.02593	0.22295	0
FUGITIVES	Fugitives	NA	NA	0.00	0.00	0.00	0.00000	0.00000	0.00000			
			TOTAL	**3,670**	**5,260**	**1,195**	**10.0534**	**14.4112**	**3.2747**	**7.0131**	**4.3968**	**1.1964**

N.L. = not listed
Italics indicate that the unit is not present in the AFS Inventory, as it has previously been shutdown.

Refinery EI Improvement Project
Navajo Artesia Refinery

				Post-CD Potential Emission Rate (tpy)				Post-CD Potential Emission Rate (tpd)				2002 Actual Emission Rate (tpd)			
Unit Description	Unit Type	Stack ID	Point ID	NOX	SO2	VOC	PM10	NOX	SO2	VOC	PM10	NOX	SO2	VOC	PM10
FCCREGEN	FCCU	021	021	152.87	61.02		109.50	0.4188	0.1672		0.3000	0.3715	4.5827	N.L	0.4694
B-7	Boiler	055	055	56.50	16.90			0.1548	0.0463			0.0387	0.0037	0.0001	0.0032
B-8	Boiler	056	056	56.50	16.90			0.1548	0.0463			0.0000	0.0000	0.0000	0.0000
H-20	Heater	009	009	18.30	6.13			0.0501	0.0168			0.0795	0.0032	N.L.	0.0083
H-601	Heater	065	065	15.40	6.13			0.0422	0.0168			0.0000	0.0000	0.0000	0.0000
H-600	Heater	039	039	7.71	6.60			0.0211	0.0181			0.0459	0.0030	N.L.	0.0078
H-352/H-353/H-354 (formerly 70-H1/H2/H3)	Heater			39.40	15.71			0.1079	0.0430						
H-473	Tail Gas Unit	041	041	28.47	81.75			0.0780	0.2240			0.0000	0.0000	0.0000	0.0000
Artesia Sulfur Pit	Sulfur Pit														
FL-400	Flare				0.54				0.0015						
FL-402	Flare				0.14				0.0004						
FL-403	Flare				10.24				0.0280						
FL-401	Flare				0.14				0.0004						
FL-404	Flare				0.27				0.0007						
FUGITIVES	Benzene Operations														
FUGITIVES	Fugitives														

Notes:
N.L. = not listed

Refinery EI Improvement Project
Koch Corpus Christi Refinery

Unit No.	Unit Type	FIN	EPN	Post-CD Potential Emission Rate (tpy)				Post-CD Potential Emission Rate (tpd)				2005 Actual Emission Rate (tpd)			
				NOX	SO2	VOC	PM	NOX	SO2	VOC	PM	NOX	SO2	VOC	PM10
WP FCCU	Fluidized Catalytic Cracking Unit	*01BF102*	*AA-4*	360.00	162.00		235.70	0.98630	0.44384		0.64575	0.97844	0.02309	0.00844	0.40811
EP FCCU	Fluidized catalytic Cracking unit	FG SCRUB	111	200.00	100.00		149.00	0.54795	0.27397		0.40822	0.76503	0.06377	0.01947	0.2636
CCR	Charge Heaters	39BA3902-5	JJ-2	146.64	85.91			0.40176	0.23537			0.09566	0.00757	0.02568	0.02164
MSTDP	Toluene Column Reboiler	33BA2	N-104	61.30	35.91			0.16794	0.09839			0.05933	0.00658	0.00461	0.02732
BTX RX 1	BTX Platformer	E21H1	35/36	25.62	15.01			0.07020	0.04113			0.00999	0.00084	0.00217	0.00299
BTX RX 2	BTX Platformer	E21H2	37/38	23.65	13.86			0.06480	0.03796			0.0131	0.00094	0.00241	0.00333
EAST BOILER	Utility	E10B5	22	0.00	0.00			0.00000	0.00000			0	0	0	0
EAST BOILER	Utility	E10B6	23	0.00	0.00			0.00000	0.00000			0	0	0	0
EAST BOILER	Utility	E10B7	24	0.00	0.00			0.00000	0.00000			0	0	0	0
HOT OIL HEATER	CCR	39BA3901	JJ-4	21.09	12.36			0.05778	0.03385			0.00721	0.00096	0.00345	0.00291
DEBUTANIZER REBOILER	Debutanizer Reboiler	02BA201	AA-18	16.56	9.70			0.04536	0.02657			0.01572	0.00168	0.00442	0.00611
#1 O-XYLENE REC COL REBOILER	Orthofrac	20BA2002	M5	14.59	8.54			0.03996	0.02341			0.02567	0.00159	0.00417	0.00576
REACTOR HEATER	MSTOP	33BA1	N-104B	14.19	8.31			0.03888	0.02278			0.00986	0.00066	0.00269	0.00372
SPLITTER REBOILER	Isom	*E29H417*	*E29H417*	10.51	6.93			0.02880	0.01898			0.00178	0.00004	0.0001	0.00014
HOT OIL (RAFFINATE) HEATER	Parex #1	*61BA1201*	*N-3*	11.43	6.70			0.03132	0.01835			0.01505	0.00162	0.00425	0.00587
DEPENTANIZER REBOILER	BTX Platformer	E21H3	33/34	10.84	6.35			0.02970	0.01740			0.00371	0.00028	0.00072	0.00099
A HEATER	DTH	*E23H101A*	*65A*	0.00	0.00			0.00000	0.00000			0.10774	0.00443	0.01141	0.01577
#2 COLUMN REBOILER	PMB	*29BF2902*	*Z-4*	0.00	0.00			0.00000	0.00000			0.05776	0.00109	0.00285	0.00394
HOT OIL (EXTRACT) HEATER	Parex #1	*61BA1202*	*N-3*	8.28	4.85			0.02268	0.01329			0.0105	0.00113	0.00297	0.00419
CHARGE HEATER	NHT	39BA3900	JJ-4									0.01609	0.00056	0.00203	0.00171
HOT OIL HEATER	Parex #2	31BA1	N-103	55.39	32.45			0.15174	0.08890			0.10554	0.00552	0.0145	0.02004
CRUDE HEATER	West Crude	40BA101	A103	41.59	24.36			0.11394	0.06675			0.18081	0.00101	0.00894	0.01235
VACUUM HEATER	West Crude	40BA401	A-103	17.54	10.28			0.04806	0.02816			0.07379	0.00041	0.00365	0.00504
CHARGE HEATER	No. 3 Isom	25BA2501	O-10	29.24	10.28			0.08010	0.02816			0.14852	0.00063	0.00315	0.00435
DEETHANIZER HEATER	Hydrocracker	26BA2603	II-7	15.18	8.89			0.04158	0.02436			0.07304	0.00137	0.00361	0.00499
#2 O-XYLENE REC COL REBOILER	Orthofrac	20BA2001	M-5	14.98	8.78			0.04104	0.02404			0.14132	0.00159	0.00419	0.00579
STABILIZER HEATER	Hydrocracker	26BA2604	II-7	13.99	8.20			0.03834	0.02246			0.03741	0.0007	0.00185	0.00256
O-XYLENE CRYSTALLIZER REBOILER	Orthofrac	20BA2004	M-5	15.97	9.35			0.04374	0.02563			0.13127	0.00148	0.00389	0.00538
B HEATER	DIH	*E23H301B*	*68*									0.02528	0.00054	0.00139	0.00192
No. 1 BOILER	Utilities	06BF651	R-1	0.00	0.00			0.00000	0.00000			0.05695	0.00119	0.00313	0.00433
No. 2 BOILER	Utilities	06BF652	R-2	0.00	0.00			0.00000	0.00000			0.04807	0.00101	0.00264	0.00365
No. 3 BOILER	Utilities	06BF653	R-3	0.00	0.00			0.00000	0.00000			0.05788	0.00121	0.00318	0.0044
No. 4 BOILER	Utilities	06BF654	R-4	0.00	0.00			0.00000	0.00000			0.05454	0.00114	0.003	0.00414
No. 5 BOILER	Utilities	06BF655	R-5	0.00	0.00			0.00000	0.00000			0.05489	0.00115	0.00302	0.00417
No. 6 BOILER	Utilities	06BF656	R-6	0.00	0.00			0.00000	0.00000			0.05362	0.00112	0.00295	0.00408
EAST BOILER	Utility	E10B8	94	47.11	27.60			0.12906	0.07561						
EAST BOILER	Utility	E10B9	94	47.11	27.60			0.12906	0.07561			0.52652	0.00606	0.01412	0.02158
HEATER	Heater	E0310F101	110									0.03168	0.00197	0.00675	0.00933
HEATER	Heater	*E23H301B*	*67*									0.02528	0.00054	0.00139	0.00192
AG FLARE	Flare	*V-6*	*V-6*	0.00	0.00		0.00	0.00000	0.00000		0.00000	0.00396	0.00194	0	0
REFINERY MAIN FLARE SYSTEM	Flare	*V-7*	*V-7*	0.00	0.00		0.00	0.00000	0.00000		0.00000	0.00396	0.00194	0	0
HYDROCARBON FLARE	Flare	*V-8*	*V-8*	0.00	0.00		0.00	0.00000	0.00000		0.00000	0.00248	0.00613	0.00001	0
EP HYDROCARBON FLARE	Flare	*FL-28*	*FL-28*	0.00	0.00		0.00	0.00000	0.00000		0.00000	0.00511	0.00076	0.0003	0
EP AG FLARE 1	Flare	AGFLARE1	FL-87	0.00	0.00		0.00	0.00000	0.00000		0.00000	0.00053	N.L.	0.00008	0
EP AG FLARE 2	Flare	AGFLARE2	FL-46	0.00	0.00		0.00	0.00000	0.00000		0.00000	0.00053	N.L.	0.00008	0
EP 36" FLARE	Flare	*FL-97*	*FL-97*	0.00	0.00		0.00	0.00000	0.00000		0.00000	0.0121	0.10427	0.00002	0
SRU # 1	Sulfur Recovery Plant	SRU NO.1	H-15A		66.00				0.18082			0.00381	0.01249	0.00053	0.00074
SRU # 2	Sulfur Recovery Plant	SRU NO.2	H-15B		63.00				0.17260			0.00544	0.07884	0.00083	0.0001
EAST SRU 1	Sulfur Recovery Plant	*SULFUR REC*	*F-SRU 1*		85.50				0.23425			0	0.00009	0.0003	0
EAST SRU 2	Sulfur Recovery Plant	*SULFUR REC*	*F-SRU 2*		85.50				0.23425			N.L.	0.00009	0.00122	0
FUGITIVE BENZENE WASTE EMISSIONS	Equipment Leak	N.A.	N.A.											0.76604	

Notes:
N.L. = not listed
Italics indicate that FIN and EPN are the best available matches based on information from consent decree and/or information provided by the refinery.
The FIN and EPN listed do not necessarily correspond to the specified unit.

Refinery EI Improvement Project
Marathon Oil Garyville Refinery

Unit Description	Unit Type	Unit ID	Stack ID	Point ID	Post-CD Potential Emission Rate (tpy)				Post-CD Potential Emission Rate (tpd)				2004 Actual Emission Rate (tpd)			
					NOX	SO2	VOC	PM10	NOX	SO2	VOC	PM10	NOX	SO2	VOC	PM10
86-74 FCCU REGENERATOR	Fluidized Catalytic Cracking Unit Reg	28	28	86	417.07	362.67		430.34	1.1427	0.9936		1.1790	0.635616	0.115068	0.041096	0.175342
Platformer Heater	Heater	12-1401	8	8	185.85	47.11			0.5092	0.1291			0.3370	0.0055	0.0192	0.0274
Boiler # 1	Boiler	42-1401	36	B3	211.55	40.42			0.5796	0.1107			0.3315	0.0192	0.0055	0.0027
Crude Atmospheric Heater	Heater	10-1401	2	2	62.63	33.03			0.1716	0.0905			0.1562	N.L.	N.L.	0.0247
Crude Atmospheric Heater	Heater	10-1402	3	3	62.63	33.03			0.1716	0.0905			0.1315	N.L.	N.L.	0.0219
Hf Alkyl Isostripper Reboiler	Boiler	27-1401 &1402	27	85	46.95	30.95			0.1286	0.0848			0.1123	N.L.	N.L.	0.0082
ROSE Deasphalting	Heater	7-1401	34	A3	48.40	25.52			0.1326	0.0699			0.0685	N.L.	N.L.	0.0082
Platformer Interheater	Heater	12-1403	29	89	128.77	24.25			0.3528	0.0664			0.2411	0.0027	0.0137	0.0164
FCC Charge Heater	Heater	25-1401	26	84	29.78	19.63			0.0816	0.0538			0.0685	0.0521	0.0137	0.0027
Crude Vacuum Heater	Heater	10-1403	4	4	18.13	15.94			0.0497	0.0437			0.0356	0.0027	0.0082	0.0110
Crude Vacuum Heater	Heater	10-1404	5	5	18.13	15.94			0.0497	0.0437			0.0438	0.0027	0.0082	0.0110
Old Boiler #1	Boiler	36-1601	*1*	*1*	73.58	13.86			0.2016	0.0380			0.1479	N.L.	0.0082	0.0110
Old Boiler #2	Boiler	36-1602	*31*	*93*	73.58	13.86			0.2016	0.0380			0.1507	N.L.	0.0082	0.0110
HGO Charge Heater	Heater	15-1401	12	12	52.03	11.43			0.1426	0.0313			0.2219	N.L.	N.L.	0.0055
HGO Reboiler Heater	Heater	15-1403	13	13	41.00	9.01			0.1123	0.0247			0.0959	N.L.	N.L.	0.0027
Sal's Gas Hot Heater	Heater	22-1401	30	92	44.76	8.43			0.1226	0.0231			0.0575	0.0603	0.0027	0.0055
Distillate Hydrotreater Charge Heater	Heater	14-1401	10	10	36.27	7.97			0.0994	0.0218			0.0247	N.L.	N.L.	0.0055
Distillate Hydrotreater Stripper Reboiler	Boiler	14-1402	11	11	32.59	7.16			0.0893	0.0196			0.0603	N.L.	N.L.	0.0055
Naphtha Hydrotreater Reboiler	Boiler	11-1402	7	7	26.72	7.04			0.0732	0.0193			0.0849	N.L.	0.0027	0.0055
Platformer Debutanizer Reboiler	Boiler	12-1402	9	9	32.06	7.04			0.0878	0.0193			0.0849	N.L.	0.0027	0.0055
Naphtha Hydrotreater Heater	Heater	11-1401	6	6	27.86	6.12			0.0763	0.0168			0.0575	N.L.	0.0027	0.0027
LSR Hydrotreater Charge Heater	Heater	100-82	32	A1	9.99	2.19			0.0274	0.0060			0.0137	N.L.	N.L.	N.L.
LSR Hydrotreater Reboiler	Boiler	101-85	33	A2	8.94	1.96			0.0245	0.0054			0.0082	N.L.	N.L.	N.L.
Thermal Drying Unit Heater	Heater		37	C7	2.10	0.46			0.0058	0.0013			0.0384	0.0055	0.0137	0.0055
SRP	Sulfur Recovery Plant		14	14	24.53	6.35			0.0672	0.0174			0.030137	0.038356	N.L.	0.00274
Fugitives	Equipment Leak	Fugitives	0	0									N.L.	N.L.	N.L.	N.L.

Notes:
N.L. = not listed
Italics indicate that Stack ID and Point ID are the best available matches based on information from consent decree and/or information provided by the refinery.
The Stack ID and Point ID listed do not necessarily correspond to the specified unit.

Refinery EI Improvement Project
Marathon Oil Texas City Refinery

Unit Description	Unit Type	FIN	EPN	Post-CD Potential Emission Rate (tpy)				Post-CD Potential Emission Rate (tpd)				2005 Actual Emission Rate (tpd)			
				NOX	SO2	VOC	PM	NOX	SO2	VOC	PM	NOX	SO2	VOC	PM10
FCCU	FCCU	P-93	ES12	104.51	6.36		62.50	0.2863	0.0174		0.1712	0.5495	0.02823	0.02539	0.17083
Alkyl Heater	Heater	H-8	ES20	58.67	22.75			0.1608	0.0623			0.11927	0.22317	0.00007	0.01336
#5 Topper Heater	Boiler	H-92	ES8A	35.87	21.02			0.0983	0.0576			0.34866	0.24872	0.01044	0.01443
Boiler # 1	Boiler	B-2A	ES13	0.00	0.00	0.00	0.00	0.0000	0.0000	0.0000	0.0000	0	0	0	0
Boiler # 2	Boiler	B-2B	ES13	40.47	8.89			0.1109	0.0244			0.18386	0.11329	0.00465	0.00643
Boiler # 3	Boiler	B-2C	ES13	40.47	8.89			0.1109	0.0244			0.18386	0.11329	0.00465	0.00643
Boiler # 4	Boiler	B-2D	ES13	0.00	0.00	0.00	0.00	0.0000	0.0000	0.0000	0.0000	0	0	0	0
UDEX Strippper Heater	Boiler	H-1	ES1/ES2	0.00	0.00	0.00	0.00	0.0000	0.0000	0.0000	0.0000	0	0	0	0
UDEX Born Heater	Heater	H-9	ES22	10.86	7.16			0.0298	0.0196			0.01678	0.06107	0.00236	0.00327
Platformer Interm Heater	Heater	H-2	ES3/ES4	19.56	6.70			0.0536	0.0183			0.0249	0.0308	0.00105	0.00145
#4 Topper Heater	Heater	H-6	ES9	12.26	5.77			0.0336	0.0158			0.04424	0.07626	0.00325	0.0045
Platformer Heater	Heater	H-3	ES5/ES6	21.68	5.77			0.0594	0.0158			0.03712	0.03425	0.00137	0.00189
FCC GasCon M-7	Gas-fired Reciprocating Compressor	E-5	ES30/ES31	0.00	0.00	0.00	0.00	0.0000	0.0000	0.0000	0.0000	0	0	0	0
FCC GasCon M-8	Gas-fired Reciprocating Compressor	E-4	ES28/ES29	0.00	0.00	0.00	0.00	0.0000	0.0000	0.0000	0.0000	0	0	0	0
FCC GasCon M-9	Gas-fired Reciprocating Compressor	E-3	ES26/ES27	0.00	0.00	0.00	0.00	0.0000	0.0000	0.0000	0.0000	0	0	0	0
FCC GasCon M-13	Gas-fired Reciprocating Compressor	E-6	ES32	0.00	0.00	0.00	0.00	0.0000	0.0000	0.0000	0.0000	0	0	0	0
M-15 Plat. Comp	Gas-fired Reciprocating Compressor	E-2	ES25	0.00	0.00			0.0000	0.0000			0.32587	0.00094	0.009	0.00362
M-14 Plat Comp	Gas-fired Reciprocating Compressor	E-1	ES24	0.00	0.00			0.0000	0.0000			0.31125	0.00094	0.009	0.00362
FCCU Superheater	Heater	B-1	ES11	15.33	4.04			0.0420	0.0111			0	0	0	0
TDU Salt Heater	Heater	P-70	ES70	1.75	0.46			0.0048	0.0013			N.L.	N.L.	N.L.	0
FCCU Air Preheat	Heater	H-94	ES12	24.09	6.35			0.0660	0.0174			0.00094	0.00219	0.00002	0.00031
Main Flare	Flare	***VDU-FLARE***	***ES60***									0.00003	0.00005	N.L.	0
Alkylation Flare	Flare	***P-1***	***ES16***									0.00504	0.00276	0.1151	0
Benzene Loading Combustor Flare	Flare	***P-200***	***ES17***									0.04328	0.01909	0.20341	0.00
Benzene Operations	Benzene Operations														
Fugitives	Equipment Leak														

Notes:
N.L. = not listed
Italics indicate that FIN and EPN are the best available matches based on information from consent decree and/or information provided by the refinery.
The FIN and EPN listed do not necessarily correspond to the specified unit.

Refinery EI Improvement Project
Motiva Convent Refinery

Unit Description	Stack ID	Point ID	Unit Type	Post-CD Potential Emission Rate (tpy)				Post-CD Potential Emission Rate (tpd)				2004 Actual Emission Rate (tpd)			
				NOX	SO2	VOC	PM	NOX	SO2	VOC	PM	NOX	SO2	VOC	PM10
FCCU	47	78	Fluidized Catalytic Cracking Unit	234.32	203.76		302.22	0.64198	0.55825		0.82800	0.369863	N.L.	0.005479	0.016438
1F-201	1	1	Heater	28.91	19.05			0.07920	0.05220			0.120548	0.00274	0.008219	0.019178
1F-202	2	2	Heater	28.91	19.05			0.07920	0.05220			0.123288	0.00274	0.008219	0.010959
31F-801	6	9	Boiler	60.44	39.84			0.16560	0.10914			0.621918	0.00274	0.013699	0.038356
31F-802	7	10	Heater	60.44	39.84			0.16560	0.10914			0.509589	0.00274	0.010959	0.030137
31F-803	8	11	Heater	60.44	39.84			0.16560	0.10914			0.509589	0.00274	0.010959	0.030137
4F-501	40	71	Heater	21.72	14.32			0.05952	0.03923			0.090411	N.L.	0.005479	0.016438
4F-502	41	72	Heater	22.78	15.01			0.06240	0.04113			0.090411	N.L.	0.005479	0.016438
6F-701	0	7	Heater	0.00	4.97			0.00000	0.01360			N.L.	N.L.	N.L.	N.L.
7F-1	5	8	Heater	22.78	15.01			0.06240	0.04113			0.147945	N.L.	0.005479	0.013699
TGTU #1 Incinerator Stack EIQ ID - 17AH-103	12	15	Sulfur Recovery Unit									0.009589	0.012329	0.00137	0.00137
TGTU #2 Incinerator Stack EIQ ID: 76H-101	18	33	Sulfur Recovery Unit									0.00137	0.041096	0.00411	0.005479
TGTU #3 Incinerator Stack EIQ ID: 77H-101	19	34	Sulfur Recovery Unit									0.00274	0.030137	0.00274	0.008219
TGTU #4 Incinerator Stack EIQ ID: 78H-101	20	35	Sulfur Recovery Unit									0.00274	0.047945	0.00137	0.010959
TGTU #5 Incinerator Stack EIQ ID: 82H-101	22	37	Sulfur Recovery Unit									0.00274	0.032877	0.00137	0.008219
Refinery Flare No. 1 - EIQ ID: 19F-3	0	F1	Flare	0.00	0.00	0.00	0.00	0.00000	0.00000	0.00000	0.00000	N.L.	N.L.	N.L.	N.L.
Refinery Flare No. 2 - EIQ ID: 19AH-901	0	F2	Flare	0.00	0.00	0.00	0.00	0.00000	0.00000	0.00000	0.00000	N.L.	N.L.	N.L.	N.L.
Refinery Flare No. 3 - EIQ ID: 19G-301	0	F3	Flare	0.00	0.00	0.00	0.00	0.00000	0.00000	0.00000	0.00000	N.L.	N.L.	N.L.	N.L.
Refinery Flare No. 4 - EIQ ID: 19G-302	0	F4	Flare	0.00	0.00	0.00	0.00	0.00000	0.00000	0.00000	0.00000	N.L.	N.L.	N.L.	N.L.
FUGITIVES	NA	NA	Fugitives												

N.L. = not listed

Refinery EI Improvement Project
Motiva Norco Refinery

Unit Description	Stack ID	Point ID	Unit Type	Post-CD Potential Emission Rate (tpy)				Post-CD Potential Emission Rate (tpd)				2004 Actual Emission Rate (tpd)			
				NOX	SO2	VOC	PM	NOX	SO2	VOC	PM	NOX	SO2	VOC	PM10
FCCU	*28*	*0A6*	Fluidized Catalytic Cracking Unit	362.95	315.61		374.49	0.99437	0.86467		1.02600	3.657534	0.309589	0.00274	0.079452
11-73 HEATER - CR-2 CAT REFORM FURNACE F-58A	16	57	Heater	31.79	20.95			0.08709	0.05740			0.178082	0.00274	0.00274	0.005479
11-73 HEATER - CR-2 CAT REFORM FURNACE F-58B	17	58	Heater	31.79	20.95			0.08709	0.05740			0.178082	0.00274	0.00274	0.005479
19-71 HEATER - DU-5 VAC FLASH CHARGE HTRS F-37/38	5	12	Heater	43.17	28.45			0.11827	0.07795			0.613699	0.005479	0.010959	0.016438
27-71 HEATER - HCU STEAM/METHANE REFORMER F-45A	10	19	Heater	47.78	62.98			0.13091	0.17256			0.536986	N.L.	0.010959	0.013699
28-71 HEATER - HCU STEAM/METHANE REFORMER F-45B	11	20	Heater	47.78	62.98			0.13091	0.17256			0.536986	N.L.	0.010959	0.013699
30-71 HEATER - CR-2 REFORM FURNACE F-53/54/55/57N	13	22	Heater	38.95	25.67			0.10671	0.07033			0.317808	0.00274	0.008219	0.010959
31-71 HEATER - CR-2 REFORM FURNACE F-53/54/55/57S	14	23	Heater	39.13	25.79			0.10719	0.07065			0.317808	0.00274	0.008219	0.010959
INCINERATOR - SULFUR RECOVERY UNIT #2	19	77	Sulfur Recovery Unit									0.008219	0.005479	N.L.	N.L.
INCINERATOR - SULFUR RECOVERY UNIT #3	26	0A0	Sulfur Recovery Unit									0.008219	0.021918	N.L.	N.L.
FLARE - WEST OPNS GROUND FLARE (FG-201)	24	93	Flare	0.00	0.00	0.00	0.00	0.00000	0.00000	0.00000	0.00000	0.043836	0.005479	0.038356	0.005479
FUGITIVES	NA	NA	Fugitives												

N.L. = not listed
Italics indicate that Stack ID and Point ID are not included in the AFS inventory.
The Stack ID and Point ID listed do not necessarily correspond to the specified unit.

Refinery EI Improvement Project
Motiva Port Arthur Refinery

Unit Description	Unit Type	FIN	EPN	Post-CD Potential Emission Rate (tpy)				Post-CD Potential Emission Rate (tpd)				2005 Actual Emission Rate (tpd)			
				NOX	SO2	VOC	PM	NOX	SO2	VOC	PM	NOX	SO2	VOC	PM10
FCCU	Fluidized Catalytic Cracking Unit	FCCU3	FCCU3	52.34	45.51		67.50	0.14338	0.12468		0.18493	0.01464	0.0023	0.00046	0.00252
HCU1	Heater	HCU1RAC1HT	SHCU1-1	1.82	1.20			0.00500	0.00329			0.0035	0.00093	0.00015	0.00119
HCU1	Heater	HCU1RAC2HT	SHCU1-2	2.28	1.50			0.00625	0.00412			0.00622	0.00065	0.00011	0.00084
HFU2	Heater	***N.L.***	***N.L.***	0.00	0.00	0.00	0.00	0.00000	0.00000	0.00000	0.00000	N.L.	N.L.	N.L.	N.L.
HFU3	Heater	***N.L.***	***N.L.***	0.00	0.00	0.00	0.00	0.00000	0.00000	0.00000	0.00000	N.L.	N.L.	N.L.	N.L.
HTU1	Heater	HTU1CHGHTR	SHTU1	2.00	1.32			0.00548	0.00361			0.00261	0.00053	0.00009	0.00068
HTU2	Heater	HTU2CHGHTR	SHTU2-1	2.56	1.69			0.00701	0.00462			0.06036	0.00283	0.00047	0.00364
HTU2	Reboiler	HTU 2 RBL	SHTU2-2	1.60	1.05			0.00438	0.00289			0.02681	0.00107	0.00018	0.00137
HTU3	Heater	HTU3CHGHTR	SHTU3-1	2.40	1.58			0.00658	0.00433			0.00522	0.00105	0.00017	0.00135
HTU3	Reboiler	HTU 3 RBL	SHTU3-1	2.10	1.38			0.00575	0.00379			0.00522	0.00105	0.00017	0.00135
HTU4	Reboiler	***SHTU4-1***	***SHTU4-1***	0.95	0.63			0.00261	0.00172			0.02484	0.00098	0.00028	0.00109
HTU4LT	Recycle Gas	***SHTU4-2***	***SHTU4-2***	2.53	1.67			0.00692	0.00456			0.01154	0.0009	0.00001	0.00088
LCDU	Heater	LCDU C HTR	LCDU1-2	1.48	0.98			0.00405	0.00267			0.02578	0.00033	N.L.	0.00088
MPU3	Heater	MPU3EXTHTR	SMPU3-2	4.08	2.69			0.01118	0.00737			0.02464	0.00319	0.00073	0.00569
MPU3	Heater	MPU3ROHTR	SMPU3-1	1.76	1.16			0.00482	0.00318			0.00884	0.00118	0.00027	0.0021
MPU4	Heater	MPU4EXTHTR	SMPU4	4.73	3.12			0.01295	0.00854			0.01485	0.00101	0.00021	0.00165
MPU4	Heater	MPU4ROHTR	SMPU4	2.40	1.58			0.00658	0.00433			0.00682	0.00032	0.00007	0.00052
MPU4	Heater	***SHTU4-3***	***SHTU4-3***	0.52	0.34			0.00142	0.00094			0.00654	0.00095	0.00004	0.00199
PS2	Boiler	BOILER 26	SPS2-6	0.00	0.00	0.00	0.00	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
PS2	Boiler	BOILER 27	SPS2-7	0.00	0.00	0.00	0.00	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
PS3	Boiler	BOILER 31	SPS3-1	0.00	0.00	0.00	0.00	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
SDU2	Heater	***N.L.***	***N.L.***	0.00	0.00	0.00	0.00	0.00000	0.00000	0.00000	0.00000	N.L.	N.L.	N.L.	N.L.
SDU2	Heater	***N.L.***	***N.L.***	0.00	0.00	0.00	0.00	0.00000	0.00000	0.00000	0.00000	N.L.	N.L.	N.L.	N.L.
SDU3	Heater	***N.L.***	***N.L.***	0.00	0.00	0.00	0.00	0.00000	0.00000	0.00000	0.00000	N.L.	N.L.	N.L.	N.L.
SDU3	Heater	***N.L.***	***N.L.***	0.00	0.00	0.00	0.00	0.00000	0.00000	0.00000	0.00000	N.L.	N.L.	N.L.	N.L.
VPS2	Heater	VPS2ATM1HT	SVPS2-1	2.39	1.58			0.00655	0.00432			0.0452	0.00184	0.00035	0.00276
VPS2	Heater	VPS2ATM2HT	SVPS2-1	2.39	1.58			0.00655	0.00432			0.0487	0.00219	0.00042	0.00328
VPS2	Heater	VPS2ATM3HT	SVPS2-1	2.39	1.58			0.00655	0.00432			0.04267	0.00198	0.00038	0.00297
VPS2	VPS2ATM4HT	VPS2ATM4HT	SVPS2-2	2.39	1.58			0.00655	0.00432			0.03565	0.00198	0.00038	0.00296
VPS2	VPS2VAC1HT	VPS2VAC1HT	SVPS2-1	2.16	1.43			0.00593	0.00391			0.02226	0.00146	0.00028	0.00219
VPS2	VPS2VAC2HT	VPS2VAC2HT	SVPS2-1	2.16	1.43			0.00593	0.00391			0.01948	0.00144	0.00028	0.00216
VPS4	VPS4NSRBL	***VPS4NSRBL***	***SVPS4-4***	2.95	1.95			0.00809	0.00533			0.01895	0.00248	0.00048	0.00372
SRP 2	TGTUINCINR	***TGTUINCINR***	***STGTU1***									0.01493	0.06285	0.00017	0.00131
SRP 3	STGTU2-1	***STGTU2-1***	***STGTU2-1***									0.01553	0.04434	0.00014	0.00109
SRP 4	STGTU2-2	***STGTU2-2***	***STGTU2-2***									0.0005	0.00001	0.00002	0.00018
	ARU NO2 FS	***ARU NO2 FS***	***EARU1&2***	0.00	0.00	0.00	0.00	0.00000	0.00000	0.00000	0.00000	0.00055	0	0	0
	CRU NO4 FS	***CRU NO4 FS***	***ECRU4***	0.00	0.00	0.00	0.00	0.00000	0.00000	0.00000	0.00000	0.00151	0	0.00197	0
	EDCU-1	***EDCU-1***	***EDCU-1***	0.00	0.00	0.00	0.00	0.00000	0.00000	0.00000	0.00000	0.00104	0.00019	0.00085	0
	EHTU	***EHTU***	***EHTU***	0.00	0.00	0.00	0.00	0.00000	0.00000	0.00000	0.00000	0.00055	0	0.00036	0
	FCCU NO2FS	***FCCU NO2FS***	***EFCCU1&2***	0.00	0.00	0.00	0.00	0.00000	0.00000	0.00000	0.00000	0.00137	0	0.00104	0
	FCCU NO3FS	***FCCU NO3FS***	***EFCCU3***	0.00	0.00	0.00	0.00	0.00000	0.00000	0.00000	0.00000	0.00077	0	0.00038	0
	HCU NO1 FS	***HCU NO1 FS***	***EHCU***	0.00	0.00	0.00	0.00	0.00000	0.00000	0.00000	0.00000	0.00058	0	0.00055	0
	VPS NO4 FS	***VPS NO4 FS***	***EVPS4***	0.00	0.00	0.00	0.00	0.00000	0.00000	0.00000	0.00000	0.00077	0.00055	0.00047	0
FUGITIVES	NA	NA	NA												

N.L. = not listed
Italics indicate that the unit is not present in the AFS Inventory, as it has previously been shutdown, or that FIN and EPN are the best available matches based on information from consent decree and/or information provided by the refinery.
The FIN and EPN listed do not necessarily correspond to the specified unit.

EI Improvement Project
Rhodia Specialty Chemicals, Baytown

Unit Description	Unit Type	FIN	EPN	Post-CD Potential Emission Rate (tpy)				Post-CD Potential Emission Rate (tpd)				2005 Actual Emission Rate (tpd)			
				NOX	SO2	VOC	PM	NOX	SO2	VOC	PM	NOX	SO2	VOC	PM10
FURNACE	Furnace	FURNACE	1		436.5306240				1.1959743			0.1110000	0.8564000	N.L.	0.0023000
SPENT-ACID	Spent Acid	SPENT-ACID	1		4.2154464				0.0115492			N.L.	0.0082700	0.0000000	0.0000000
FUGITIVES	Fugitives	FUGITIVES	FUGITIVES		1.2284433				0.0033656			0.0000000	0.0024100	0.0000000	0.0000000
FUG-TANKS	Fugitive Tanks	FUG-TANKS	FUG-TANKS		0.0152918				0.0000419			N.L.	0.0000300	0.0002300	0.0000000
FUG-BARGE	Fugitive Barge	FUG-BARGE	FUG-BARGE		0.0050973				0.0000140			N.L.	0.0000100	0.0000600	0.0000000
BARGESPTAC	Stack	BARGESPTAC	DOCKSCRSTK		0.0050973				0.0000140			N.L.	0.0000100	0.0043100	0.0000000
PACKGBOILR	Boiler	PACKGBOILR	PKGBOILSTK		0.00				0.0000000			0.0003000	0.0000000	0.0000200	0.0000200
SPENT-ACID	Scrubber	SPENT-ACID	EMSCRUBSTK		0.00				0.0000000			N.L.	0.0000000	0.0005700	0.0000000
BARGESPTAC	Dock	BARGESPTAC	BARGE-DOCK		0.00				0.0000000			N.L.	0.0000000	0.0004100	0.0000000
PREHTRFURN	Furnace	PREHTRFURN	PREHTRSTK		0.00				0.0000000			0.0000800	0.0000000	0.0000000	0.0000100

Notes:
N.L. = not listed

EI Improvement Project
Rhodia Houston Plant

Unit Description	Unit Type	FIN	EPN	Post-CD Potential Emission Rate (tpy)				Post-CD Potential Emission Rate (tpd)				2005 Actual Emission Rate (tpd)			
				NOX	SO2	VOC	PM	NOX	SO2	VOC	PM	NOX	SO2	VOC	PM10
U-8	FURNACE	U-8	101		632.11				1.73181			0.02458	16.08478	N.L.	0.05997
PIR-2	INCINERATOR	PIR-2	104		451.51				1.23701			0.16641	11.48913	N.L.	0.03409
U-8	FURNACE	U-8	FE1		0.11				0.00030			N.L.	0.00274	N.L.	0.00274
PIL-SO2	OTHER	PIL-SO2	FE10		0.11				0.00029			N.L.	0.00273	N.L.	0
PIR-2	INCINERATOR	PIR-2	FE-2		0.08				0.00023			N.L.	0.00215	0	0.00274
PIL-SO2	OTHER	PIL-SO2	123		0.04				0.00012			N.L.	0.0011	N.L.	0
SPENT-ACID	VERTICAL FIXED	SPENT-ACID	122		0.03				0.00008			N.L.	0.00077	0.24699	0
FUG-SA4	EQUIPMENT LEAK	FUG-SA4	FUG-SA4		0.00				0.00001			N.L.	0.00006	0.00005	0
FUG-SA 1	EQUIPMENT LEAK	FUG-SA 1	FUG-SA1		0.00				0.00001			N.L.	0.00005	0.00004	0
SA-BARGE	EQUIPMENT LEAK	SA-BARGE	SA-BARGE		0.00				0.00000			N.L.	0.00003	0	0
FUG-SA3	EQUIPMENT LEAK	FUG-SA3	FUG-SA3		0.00				0.00000			N.L.	0.00002	0.00001	0
B117	BOILER	B117	117		0.00				0.00000			0.01042	0.00002	0.0002	0.00045
FUG-SA2	EQUIPMENT LEAK	FUG-SA2	FUG-SA2		0.00				0.00000			N.L.	0.00001	0.00001	0
R-2-PREHTR	HEATER	R-2-PREHTR	128		0.00				0.00000			0.00034	0	0.00002	0.00003
SPENT-ACID	VERTICAL FIXED	SPENT-ACID	104		0.00				0.00000			N.L.	0	0	0
OLM-BARGE	MARINE	OLM-BARGE	125		0.00				0.00000			N.L.	0	0	0.00067

Notes:
N.L. = not listed
Italics indicate that FIN and EPN are the best available matches based on information from consent decree and/or information provided by the refinery.
The FIN andEPN listed do not necessarily correspond to the specified unit.

Refinery EI Improvement Project
Shell Deer Park Refinery

Unit Description	Unit Type	FIN	EPN	Post-CD Potential Emission Rate (tpy)				Post-CD Potential Emission Rate (tpd)				2005 Actual Emission Rate (tpd)			
				NOX	SO2	VOC	PM	NOX	SO2	VOC	PM	NOX	SO2	VOC	PM10
FCCU	Fluidized Catalytic Cracking Unit	***H5500***	***H5500A***	119.39	207.64		246.38	0.32710	0.56886		0.67500	0.82243	0.00679	0.01353	0.10548
FUT100	Boiler	FUT100	OPII	0.00	0.00			0.00000	0.00000			N.L.	N.L.	N.L.	0
FUT110	Boiler	FUT110	OPII	0.00	0.00			0.00000	0.00000			N.L.	N.L.	N.L.	0
FUT120	Boiler	FUT120	OPII	0.00	0.00			0.00000	0.00000			N.L.	N.L.	N.L.	0
FUT130	Boiler	FUT130	OPII	0.00	0.00			0.00000	0.00000			N.L.	N.L.	N.L.	0
H1170	Heater	H1170	H1170	9.96	7.51			0.02730	0.02056			0.00962	0.00107	0.00117	0.00329
H5100	Heater	H5100	H5100	56.76	37.41			0.15552	0.10250			0.07351	0.00657	0.01124	0.02149
H5101	Heater	H5101	H5101	56.76	37.41			0.15552	0.10250			0.07364	0.00671	0.01143	0.02192
H5301	Heater	H5301	CR3SCR	21.90	28.87			0.06000	0.07909			0.01176	N.L.	0.00401	0
H5302	Heater	H5302	CR3SCR	24.53	32.33			0.06720	0.08858			0.01552	N.L.	0.00527	0
H5303	Heater	H5303	CR3SCR	12.26	16.17			0.03360	0.04429			0.00554	N.L.	0.00195	0
H5304	Heater	H5304	CR3SCR	9.64	12.70			0.02640	0.03480			0.00429	N.L.	0.00156	0
H5305	Heater	H5305	CR3SCR	6.13	8.08			0.01680	0.02215			0.00473	N.L.	0.00102	0
H5350	Heater	H5350	CR3SCR	3.07	4.04			0.00840	0.01107			0.00108	N.L.	0.00037	0
H5600	Heater	H5600	H5600	16.56	14.55			0.04536	0.03986			0.04018	0.00246	0.00274	0.00763
H613	Heater	H613	H613	24.18	15.94			0.06624	0.04366			0.01625	0.00453	0.0051	0.0098
H753	Heater	H753	H753	0.00	0.00			0.00000	0.00000			N.L.	N.L.	N.L.	0
H754	Heater	H754	H754	0.00	0.00			0.00000	0.00000			N.L.	N.L.	N.L.	0
H755	Heater	H755	H755	0.00	0.00			0.00000	0.00000			N.L.	N.L.	N.L.	0
H775	Heater	H775	H775	0.00	0.00			0.00000	0.00000			N.L.	N.L.	N.L.	0
H780	Heater	H780	H780	0.00	0.00			0.00000	0.00000			N.L.	N.L.	N.L.	0
H781	Heater	H781	H781	0.00	0.00			0.00000	0.00000			N.L.	N.L.	N.L.	0
H8	Heater	H8	H8	0.00	0.00			0.00000	0.00000			N.L.	N.L.	N.L.	0
H8610	Heater	H8610	H8610	0.00	0.00			0.00000	0.00000			N.L.	N.L.	N.L.	0
H8620	Heater	H8620	H8620	0.00	0.00			0.00000	0.00000			N.L.	N.L.	N.L.	0
SRP 3	Sulfur Recovery Unit	***SP93301***	***H93301***									0.01482	0.01482	0.00011	0.00138
SRP 4	Sulfur Recovery Unit	***SP93701***	***H93701***									0.01537	0.01537	0.00011	0.00143
SRP 5	Sulfur Recovery Unit	SR5STACK	SR5STACK									N.L.	N.L.	N.L.	0
SRP 6	Sulfur Recovery Unit	SR6STACK	SR6STACK									N.L.	N.L.	N.L.	0
SRP 7	Sulfur Recovery Unit	SR7STACK	SR7STACK									N.L.	N.L.	N.L.	0
SRP 8	Sulfur Recovery Unit	SR8 STACK	SR8 STACK									N.L.	N.L.	N.L.	0
COKER FLARE	Flare	COKEFLARE	COKEFLARE	0.00	0.00		0.00	0.00000	0.00000		0.00000	N.L.	N.L.	N.L.	0
FUGITIVES	Fugitives	NA	NA									N.L.	N.L.	N.L.	N.L.

N.L. = not listed
Italics indicate that FIN and EPN are the best available matches based on information from consent decree and/or information provided by the refinery.
The FIN and EPN listed do not necessarily correspond to the specified unit.

Refinery EI Improvement Project
Sunoco Tulsa Refinery

Unit Description	AEI ID[1]	Stack ID[2]	Point ID[2]	Post-CD Potential Emission Rate (tpy)				Post-CD Potential Emission Rate (tpd)				2005 Actual Emission Rate (tpd)			
				NOX	SO2	VOC	PM10	NOX	SO2	VOC	PM10	NOX	SO2	VOC	PM10
#5 BH - #3&4 Boiler	106	6291	6291	67.28	44.34			0.1843	0.1215			0.4822	1.9184	0.0048	0.0147
#5 BH - #7 Boiler	109	6292	6292	30.48	20.09			0.0835	0.0550			0.0694	N.L.	0.0017	0.0027
#5 BH - #8 Boiler	110	6293	6293	29.96	19.75			0.0821	0.0541			0.1266	N.L.	0.0034	0.0050
#5 BH 0 #9 Boiler	111	6294	6294	31.36	20.67			0.0859	0.0566			0.1019	N.L.	0.0033	0.0054
Atmospheric Tower Heater (H-1)	201	6295	6295	63.77	42.03			0.1747	0.1152			0.2959	2.8521	0.0074	0.0081
#1 Vac Tower Heater (H2)	202	6296	6296	12.37	8.15			0.0339	0.0223			0.0759	0.8760	0.0021	0.0022
#2 Vac Tower Heater (H3)	203	6297	6297	8.02	5.29			0.0220	0.0145			0.0322	0.3355	0.0009	0.0010
Unifiner Charge Heater	206	6299	6299	6.43	4.24			0.0176	0.0116			0.0197	0.1594	0.0003	0.0003
Stripper Reboiler Heater	207	6300	6300	10.42	6.87			0.0286	0.0188			0.0315	0.2549	0.0006	0.0006
#2 Pit -1 Rx Chg Heater (PH1)	209	6302	6302	15.91	10.48			0.0436	0.0287			0.0744	0.6014	0.0014	0.0003
#2 Pit DeC4 Heater ID (PH3)	210	6303	6303	6.36	4.19			0.0174	0.0115			0.0239	0.1932	0.0004	0.0005
#2 Pit DeC5 Heater (PH4)	211	6304	6304	7.85	5.17			0.0215	0.0142			0.0134	0.1083	0.0002	0.0003
#2 Pit - #2 Rx Chg Heater (PH5)	212	6305	6305	11.44	7.54			0.0313	0.0207			0.2023	0.0000	0.0032	0.0035
#2 Pit - #3 Rx Chg Heater (PH6)	213	6306	6306	5.76	3.80			0.0158	0.0104			0.0841	N.L.	0.0007	0.0008
#2 Pit - #4 Rx Chg Heater (PH7)	214	6307	6307	4.49	2.96			0.0123	0.0081			0.0101	0.0695	0.0002	0.0002
Coker Drum Charge Heater B-1	225	6309	6309	8.85	5.83			0.0242	0.0160			0.0314	N.L.	0.0020	0.0010
Raffinate Mix Heater (H101)	242	6314	6314	3.92	2.59			0.0108	0.0071			0.0221	0.1818	0.0004	0.0004
Extract Mix Heater H-102	243	6315	6315	24.70	16.28			0.0677	0.0446			0.1080	1.5537	0.0034	0.0035
Hydrotreater Charge Heater H201	244	6316	6316	3.92	2.59			0.0108	0.0071			0.0352	0.2889	0.0007	0.0007
MEK - Wax Free Oil Heater	245	6317	6317	17.47	11.51			0.0479	0.0315			0.1052	N.L.	0.0026	0.0021
MEK Soft Wax Heater H-2	246	6318	6318	8.58	5.66			0.0235	0.0155			0.0430	0.2578	0.0010	0.0011
Perc. Filter Clay Heater	248	6319	6319	0.72	0.47			0.0020	0.0013			0.0027	N.L.	0.0001	0.0001
Coker Flare	268	6327	6327									0.0005	N.L.	0.0013	N.L.
WPU Flare (FCCU Flare)	266	6325	6325									0.0003	N.L.	0.0008	N.L.
LEU/MEK Flare	269	6328	6328									0.0002	N.L.	0.0006	N.L.
Benzene Operations	N/A	N/A	N/A												
Fugitives	N/A	N/A	N/A												

Notes:
N.L. = not listed
[1] AEI = Air Emission Inventory, ID provided by refinery
[2] The Sunoco Tulsa Refinery is Plant ID 1477.

Refinery EI Improvement Project
TOTAL Port Arthur Refinery Settlement Information

				Post-CD Potential Emission Rate (tpy)				Post-CD Potential Emission Rate (tpd)				2005 Actual Emission Rate (tpd)			
Unit Description	**Unit Type**	**FIN**	**EPN**	**NOX**	**SO2**	**VOC**	**PM**	**NOX**	**SO2**	**VOC**	**PM**	**NOX**	**SO2**	**VOC**	**PM10**
FCCU	FCCU	***55FCCURFGS***	***55FCCURFGS***	186.25	215.94		128.12	0.510271	0.591619		0.351	0.43608	0.22334	0.04279	0.38
No. 1 Crude	Heater	01ACU1H101	01ACU1H101	25.40	16.74			0.0696	0.045872			0.06238	0.00318	0.00622	0.00534
No.. 2 Crude	Heater	02ACU2H201	02ACU2H201	22.60	14.90			0.06192	0.040811			0.11595	0.00373	0.00337	0.006
No. 1 Crude	Heater	01ACU1202A	01ACU1202A	32.76	21.59			0.08976	0.05916			0.07551	0.00403	0.00214	0.01022
No. 1 Crude	Heater	01ACU1202B	01ACU1202B	32.76	21.59			0.08976	0.05916			0.09778	0.00367	0.00197	0.0094
Vacuum 1	Heater	01VACTH301	01VACTH301	18.40	12.12			0.0504	0.033218			0.05679	0.00211	0.00425	0.00364
Demex	Heater	10DEMEXH-2	10DEMEXH-2	11.23	7.40			0.030758	0.020272			0.01397	0.00112	0.00211	0.00496
Demex	Heater	10DEMEXH-4	10DEMEXH-4	13.84	9.12			0.03792	0.024993			0.05381	0.00211	0.00403	0.00348
Unibon	Heater	13UNIBH301	13UNIBH301	17.52	11.55			0.048	0.031636			0.02907	0.00134	0.00255	0.00219
NHT 1	Heater	17NHTHTRS	17NHTHTRS	9.92	6.54			0.027168	0.017906			0.06148	0.00249	0.00455	0.00627
NHT 1	Heater	17NHTHTRS	17NHTHTRS	12.09	7.97			0.03312	0.021829						
Reformer	Heater	17NHTHTRS	17NHTHTRS	22.28	14.68			0.061037	0.040229						
Reformer	Heater	17NHTHTRS	17NHTHTRS	25.25	16.64			0.069178	0.045594						
Reformer	Heater	17NHTHTRS	17NHTHTRS	13.93	9.18			0.03817	0.025157						
Reformer	Heater	17NHTHTRS	17NHTHTRS	9.85	6.49			0.026981	0.017783						
BTX	Heater	04BTXH-53	04BTXH-53	11.39	7.51			0.0312	0.020564			0.01775	0.00142	0.00268	0.00636
BTX	Heater	04BTXH-52	04BTXH-52	11.04	7.27			0.03024	0.019931			0.01414	0.00118	0.00214	0.00507
DHT 1	Heater	51DHT1H-1	51DHT1H-1	8.14	5.36			0.022291	0.014692			0.01603	0.00121	0.00115	0.00208
DHT 2	Heater	52DHT2H-1	52DHT2H-1	8.14	5.36			0.022296	0.014695			0.01285	0.00055	0.0009	0.00162
DHT 2	Heater	52DHT2H-2	52DHT2H-2	9.22	6.08			0.025262	0.01665			0.03071	0.00104	0.00153	0.00268
Condensate Heater	Heater	40CSPLTH-1	40CSPLTH-1	33.36	21.99			0.091397	0.060238			0.07904	0.006	0.00526	0.0214
Utility	Boiler	61BLRH300	61BLRSTACK	36.27	23.90			0.09936	0.065487			0.10532	0.00803	0.01277	0.01762
Utility	Boiler	61BLRH350	61BLRSTACK	36.27	23.90							N.L.	N.L.	N.L.	0
North Flare	Flare	41NORTHFLR	41NORTHFLR									0.01622	0.00044	0.04244	0
Middle Flare	Flare	53MIDFLARE	53MIDFLARE									0	0	0	0
South Flare	Flare	53SOUTHFLR	53SOUTHFLR									0	0	0	0
SRP	SRP	SRU-818	15SRUINCIN									N.L.	N.L.	N.L.	0
Fugitives	Fugitives	0	0												

Notes:
N.L. = not listed
Italics indicate that FIN and EPN are the best available matches based on information from consent decree and/or information provided by the refinery.
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Refinery EI Improvement Project
Valero Ardmore Refinery

Unit Description	Unit Type	Unit ID[1]	Stack ID[2]	Point ID[2]	Post-CD Potential Emission Rate (tpy)				Post-CD Potential Emission Rate (tpd)				2005 Actual Emission Rate (tpd)			
					NOX	SO2	VOC	PM10	NOX	SO2	VOC	PM10	NOX	SO2	VOC	PM10
FCCU	Fluidized Catalytic Cracking Unit	FCCU Flue Gas Scrubber	*331*	*331*	92.00	45.00		80.00	0.2521	0.1233		0.2192	0.4142	0.0671	N.L.	0.1748
SRU #1	Sulfur Recovery Plant	Sulfur Recovery Unit/Scot	*920*	*920*									0.0112	0.0004	0.0002	0.0004
EAST FLARE (CRUDE FLARE)	Hydrocarbon Flare	Atmospheric Flare for Crude	*922*	*922*									0.0004	0.0001	0.0000	0.0000
WEST FLARE	Hydrocarbon Flare	Flare 81001	*922*	*922*									0.0002	0.0000	0.0000	0.0004
OLD EAST FLARE	Hydrocarbon Flare	Atmospheric Flare for Crude	*922*	*922*									0.0062	0.4869	0.0128	0.0007
OLD WEST ALKYL FLARE	Hydrocarbon Flare	Atmospheric Flare for Platformer/Alkylat	*922*	*922*									0.0002	0.0000	0.0005	0.0015
HYDROGEN UNIT FEED PREHEATER	Heater	H-15001	6535	6535	28.71	37.74			0.0787	0.1034			0.0353	0.0005	0.0052	0.0070
CRUDE UNIT PREHEATER	Heater	H-102A	6493	6493	14.06	18.48			0.0385	0.0506			0.0353	0.0105	0.0068	0.0142
CRUDE UNIT PREHEATER	Heater	H-102B	6492	6492	11.86	15.59			0.0325	0.0427			0.0337	0.0093	0.0060	0.0133
DHDS UNIT FRACTIONATING TOWER REB.	Heater	H-603	6532	6532	11.03	14.49			0.0302	0.0397			0.0496	0.0062	0.0041	0.0053
FCCU FEED PREHEATER	Heater	H-201	6510	6510	9.20	12.09			0.0252	0.0331			0.1537	0.0062	0.0040	0.0055
PLATFORMER UNIT REACTOR #2 PREHEATER	Heater	H-403	6495	6495	8.67	11.40			0.0238	0.0312			0.0145	0.0003	0.0008	0.0043
PLATFORMER UNIT REACTOR #1 PREHEATER	Heater	H-404	6494	6494	4.26	5.60			0.0117	0.0153			0.0359	0.0008	0.0020	0.0027
PLATFORMER UNIT REACTOR #3 PREHEATER	Heater	H-405	6496	6496	4.46	5.87			0.0122	0.0161			0.0241	0.0005	0.0013	0.0018
VACUUM TOWER PREHEATER	Heater	H-103	6509	6509	9.01	11.85			0.0247	0.0325			0.0507	0.0051	0.0039	0.0038
CFHT UNIT REACTOR FEED PREHEATER	Heater	H-6501	6533	6533	8.09	10.63			0.0222	0.0291			0.0301	0.0042	0.0027	0.0036
PLANT UTILITY STEAM GENERATOR / BOILER	Boiler	B-802	6518	6518	7.90	10.38			0.0216	0.0284			0.0156	0.0013	0.0009	0.0010
PLANT UTILITY STEAM GENERATOR / BOILER	Boiler	B-803	6519	6519	7.63	10.02			0.0209	0.0275			0.0198	0.0017	0.0011	0.0013
PLANT UTILITY STEAM GENERATOR / BOILER	Boiler	B-801	6517	6517	6.37	8.37			0.0175	0.0229			0.0282	0.0021	0.0016	0.0021
ALKYLATION UNIT ISOSTRIPPER REBOILER	Heater	H-901	6500	6500	4.56	5.99			0.0125	0.0164			0.0351	0.0030	0.0019	0.0027
DHDS UNIT REACTOR FEED PREHEATER	Heater	H-601	6498	6498	4.43	5.82			0.0121	0.0159			0.0084	0.0019	0.0012	0.0009
CFHT UNIT FRACTIONATING TWR PREHEATER	Heater	H-6502	6534	6534	4.77	6.27			0.0131	0.0172			0.0163	0.0022	0.0014	0.0019
FUGITIVES	Fugitives		N/A	N/A												

Notes:
Italics indicate that Stack ID and Point ID are the best available matches based on information from consent decree and/or information provided by the refinery.
The Stack ID and Point ID listed do not necessarily correspond to the specified unit.
N.L. = not listed
[1] Unit ID is taken from consent decree.
[2] The Valero Ardmore Refinery is Plant ID 1534.

Refinery EI Improvement Project
Valero Corpus Christi East Refinery

Unit Description	Unit Type	FIN	EPN	Post-CD Potential Emission Rate (tpy)				Post-CD Potential Emission Rate (tpd)				2005 Actual Emission Rate (tpd)			
				NOX	SO2	VOC	PM	NOX	SO2	VOC	PM	NOX	SO2	VOC	PM10
FCCU	Fluidized Catalytic Cracking Unit	REG + CO	12-CO STK	27.00	54.00		64.39	0.074	0.148		0.176	0.38082	2.0437	0.02349	0.16888
SRU #1	Sulfur Recovery Plant	SRU1-INCIN	SRU1-INCIN									0.0079	0.04303	0.00104	0.00288
SRU #2	Sulfur Recovery Plant	SRU2-INCIN	SRU2-INCIN									0.01037	0.08271	0.00143	0.00875
COMPLEX 8 FLARE	Hydrocarbon Flare	***E.P. FLARE***	***EP-FLARE1***									0.02963	0	0.00001	0
COMPLEX 7 FLARE	Hydrocarbon Flare	***HCU-FLARE***	***HCU-FL1***									0.00014	0	0.00001	0
COMPLEX 6 FLARE	Hydrocarbon Flare	***REF2-FLARE***	***REF2-FL1***									0.0037	0.00045	0.00001	0
EP BOILER #5	Boiler	B-5	EP-B-5	24.82	30.84			0.068	0.085			0.10297	0.00147	0.0037	0.00512
WP #4 PLATFORMER CHARGE	Heater	H-3REF4A	39-H-3A	9.51	11.82			0.026	0.032			0.09104	0.00264	0.00638	0.00881
WP #4 PLATFORMER CHARGE	Heater	H-3REF4B	39-H-3B	10.26	12.75			0.028	0.035			0.02811	0.00139	0.00337	0.00466
WP #4 CRUDE CHARGE (H6)	Heater	H-6CRU4	8-H-6	27.91	34.69			0.076	0.095			0.06718	0.00611	0.015	0.01994
QP SMR HEATER	Heater	H-1SMR	Q10-H-01	23.51	29.21			0.064	0.080			0.27946	0.00119	0.00832	0.01406
WP #4 CRUDE CHARGE (H4)	Heater	H-4CRU4	8-H-4	13.89	17.26			0.038	0.047			0.15814	0.00358	0.00853	0.01178
#2 REFORMER HEATER REACTOR #1	Heater	H-125QREFA	QH-125									0.03567	0.00034	0.00219	0.00302
#2 REFORMER HEATER REACTOR #2, 3	Heater	H-125QREFB	QH-125									0.02819	0.00028	0.00173	0.00239
#2 REFORMER HEATER REACTOR #4, 5	Heater	H-125QREFC	QH-125	10.58	13.15			0.029	0.036			0.01618	0.00016	0.00099	0.00133
EP BOILER #1	Boiler	B-1	EP-B-1	12.41	15.43			0.034	0.042			0.07075	0.00105	0.00254	0.00351
EP BOILER #2	Boiler	B-2	EP-B-2	12.41	15.43			0.034	0.042			0.08279	0.00123	0.00298	0.00411
WP DELAYED COKER CHARGE	Heater	H-2COKE1	7-H-2	13.30	16.52			0.036	0.045			0.07091	0.00245	0.00553	0.00277
QP WEST BOILER	Boiler	B-4A	B-4	9.70	12.06			0.027	0.033			0.06792	0.00049	0.00296	0.00409
QP EAST BOILER	Boiler	B-5A	B-5	9.70	12.06			0.027	0.033			0.05476	0.0004	0.00236	0.00325
WP GOT CHARGE	Heater	H-1GOT1	44-H-1	11.12	13.82			0.030	0.038			0.02619	0.00165	0.00403	0.00557
EP #2 HDA RX CHARGE	Heater	H-1HDA2	24-H-1	11.54	14.34			0.032	0.039			N.L	N.L	N.L	0
WP BOILER #14	Boiler	B-14	WP-B-14	9.09	11.29			0.025	0.031			N.L	N.L	N.L	0
EP FCCU RAW OIL CHARGE	Heater	H-1FCCU1	12-H-1	7.84	9.75			0.021	0.027			0.02833	0.00052	0.00127	0.00176
WP #4 VACUUM CHARGE (H5)	Heater	H-5VAC4	8-H-5	7.11	8.83			0.019	0.024			0.01512	0.00056	0.00141	0.00194
EP NONENE HOT OIL HEATER	Heater	H-1NON1	23-H-1	7.09	8.81			0.019	0.024			N.L	N.L	N.L	0
CRUDE/VACUUM BACKUP	Heater	H-1CRU4	8-H-1	7.09	8.81			0.019	0.024			N.L	N.L	N.L	0
CRUDE/VACUUM BACKUP	Heater	H-2CRU4	8-H-2	7.09	8.81			0.019	0.024			N.L	N.L	N.L	0
EP VISBREAKER CHARGE HEATER @ SS	Heater	H-8VISBKR1	10-H-8	5.21	6.48			0.014	0.018			N.L	N.L	N.L	0
QP DEOCT. REBBOILER (#4 PLAT SPLITTER)	Heater	L-10QHDA	QL-10	5.70	7.09			0.016	0.019			0.0447	0.00038	0.00247	0.00341
QP HCU RX CHARGE	Heater	H-301HCU	Q11-H-301	5.55	6.89			0.015	0.019			0.069	0.00036	0.00314	0.00434
TOLUENE COL 2 HEATER	Heater	H-2LEF1	26-H-2	4.70	5.84			0.013	0.016			N.L	N.L	N.L	0
WP GOT FRAC. REB.	Heater	H-2GOT1	44-H-2	4.18	5.20			0.011	0.014			0.05668	0.00104	0.00255	0.00352
WP #4 HYDROBON CHARGE	Heater	H-1REF4	39-H-1	4.61	5.73			0.013	0.016			0.03995	0.00091	0.0022	0.00304
WP #4 PLAT. STAB. REB.	Heater	H-7REF4	39-H-7	3.61	4.49			0.010	0.012			0.04068	0.00093	0.00224	0.00309
WP #4 VACUUM CHARGE (H3)	Heater	H-3VAC4	8-H-3	4.28	5.32			0.012	0.015			0.00227	0.00022	0.00056	0.00077
QP #2 REFORMATE SPLITTER	Heater	H-4QNAPSPL	Q3-H-4	4.18	5.20			0.011	0.014			0.00296	0.00002	0.00016	0.00023
FUGITIVES	Equipment Leak	N.A.	N.A.											0.725	

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Refinery EI Improvement Project
Valero Corpus Christi West Refinery

Unit Name	Unit Type	FIN	EPN	Post-CD Potential Emission Rate (tpy)				Post-CD Potential Emission Rate (tpd)				2005 Actual Emission Rate (tpd)			
				NOX	SO2	VOC	PM	NOX	SO2	VOC	PM	NOX	SO2	VOC	PM10
FCCU (HOC)	Fluidized Catalytic Cracking Unit	24-ST-01	121	539.00	58.00		565.02	1.47671	0.15890		1.54800	1.13824	0.15426	0.19166	1.15949
SRU #1	Sulfur Recovery Plant	***SRU***	***121***									0.00737	0.11553	0.00086	0.0031
SRU #2	Sulfur Recovery Plant	***SCOT***	***121***									0.04696	0.40919	0.00634	0.04904
SRU #3	Sulfur Recovery Plant	***N.L.***	***N.L.***									N.L.	N.L.	N.L.	N.L.
BUP FLARE	Hydrocarbon Flare	MTBE FL-2	127									0.00002	N.L.	0	0
MAIN FLARE	Hydrocarbon Flare	MFL-1	126									0.00811	0.00049	0	0
GROUND FLARE	Hydrocarbon Flare	GF-1	158									0.01316	0.00057	0	0
SMR PRIMARY REFORMER	Heater	13-H-01 A	118									0.20914	0.01551	0.07277	0.05019
SMR AUXILARY BOILER	Boiler	13-H-01-C	118									0.06017	0.00765	0.01079	0.01491
SMR SUPER HEATER	Heater	13-H-01 B	118	159.14	168.82			0.43600	0.46252			0.0392	0.005	0.00705	0.00974
CORN PRODUCTS BOILER	Boiler	30-B-01	133	38.10	40.42			0.10438	0.11073			0.18111	0.00743	0.01034	0.01429
BUP BOILER	Boiler	30-B-03	163	30.26	32.10			0.08291	0.08795			0.12626	0.00797	0.01111	0.01535
HR BOILER	Boiler	30-B-02	153	26.56	28.18			0.07277	0.07719			0.14519	0.00527	0.00736	0.01017
OLEFLEX CHARGE HEATER	Heater	38-H-01	162									0.08102	0.00926	0.01291	0.01783
OLEFLEX INTERHEATER	Heater	38-H-02	162									0.03484	0.00401	0.00549	0.00758
OLEFLEX INTERHEATER	Heater	38-H-03	162	49.53	52.54			0.13569	0.14394			0.02547	0.00296	0.00399	0.00552
CRUDE HEATER	Heater	01-H-01	1	20.57	21.82			0.05636	0.05979			0.04228	0.00505	0.00705	0.00974
CRU NO. 1 INTERHEATER	Heater	49-H-02	152									0.08684	0.00626	0.00877	0.01212
CRU NO. 3 INTERHEATER	Heater	49-H-04	152									0.03502	0.00204	0.00462	0.00639
CRU CHARGE HEATER	Heater	49-H-01	152									0.0786	0.00565	0.00804	0.01111
CRU NO. 2 INTERHEATER	Heater	49-H-03	152	54.75	58.08			0.15001	0.15913			0.05813	0.00432	0.00588	0.00813
C8 SPLITTER REBOILER	Heater	49-H-91	49-H-91	16.65	17.67			0.04563	0.04840			0.01489	0.00203	0.00228	0.00314
C7 SPLITTER REBOILER	Heater	49-H-90	49-H-90	12.08	12.82			0.03310	0.03512			0.01088	0.00166	0.00186	0.00257
VACUUM HEATER	Heater	02-H-01	74	10.89	11.55			0.02982	0.03164			0.02637	0.00321	0.00438	0.00605
ALKYL FRAC REBOILER	Heater	31-H-01	117	10.89	11.55			0.02982	0.03164			0.04232	0.00357	0.00497	0.00686
DESALTER HEATER	Heater	11-H-01	114	10.89	11.55			0.02982	0.03164			0.02216	0.00351	0.00501	0.00693
HYDROCRACKER FRAC REBOILER	Heater	47-H-04	150	10.34	10.97			0.02833	0.03005			0.07895	0.00341	0.00638	0.00461
HYDROCRACKER RX-01 HEATER	Heater	47-H-01	150	8.93	9.47			0.02445	0.02594			0.04718	0.0021	0.00276	0.00381
REFORMATE SPLITTER HEATER	Heater	49-H-71	172	9.14	9.70			0.02505	0.02657			0.02988	0.00236	0.00322	0.00446
HDS HEATER	Heater	12-H-01 A	115A									0.01186	0.00195	0.00287	0.00396
HDS HEATER	Heater	12-H-01 B	115B	18.29	19.40			0.05010	0.05315			0.01159	0.00192	0.0028	0.00387
FUGITIVES	Equipment Leak	N.A.	N.A.											0.762	

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Refinery EI Improvement Project
Valero Houston Refinery

Unit No.	Unit Type	FIN	EPN	Post-CD Potential Emission Rate (tpy)				Post-CD Potential Emission Rate (tpd)				2005 Actual Emission Rate (tpd)			
				NOX	SO2	VOC	PM	NOX	SO2	VOC	PM	NOX	SO2	VOC	PM10
FCCU	Fluidized Catalytic Cracking Unit	42BB2101	42CB2001	87.00	146.00		258.42	0.23836	0.40000		0.70800	1.00868	7.94367	0.01444	0.22266
SRU B	Sulfur Recovery Plant	***46BC6325***	***46CB6301***		27.00				0.07397			0.02211	0.79257	0.01316	0.00159
DERRICK FLARE	Hydrocarbon Flare	***30FL1***	***30FL1***									0.01344	0.0055	0.12963	0
ISOMAX FLARE	Hydrocarbon Flare	***30FL2***	***30FL2***									0.01344	0.0055	0.12963	0
FCC FLARE	Hydrocarbon Flare	***30FL5***	***30FL5***									0.01344	0.0055	0.12963	0
COMB. ATM. TOWER FURNACE N.	Heater	23BC201	23BC201	111.94	41.57			0.30668	0.11389			0.01307	0.03271	0.02381	0.03287
BOILER 7	Boiler	81BF7	81BF7	35.76	13.28			0.09797	0.03638			N.L.	N.L.	N.L.	0
BOILER 12	Boiler	81BF12	81BF12	20.21	7.51			0.05537	0.02056			0.07032	0.00395	0.00268	0.0037
BOILER 14	Boiler	81BF14	81BF14	20.21	7.51			0.05537	0.02056			0.08257	0.00406	0.00305	0.00421
BOILER 15	Boiler	81BF15	81BF15	20.21	7.51			0.05537	0.02056			0.096	0.00435	0.00304	0.0042
BOILER 16	Boiler	81BF16	81BF16	20.21	7.51			0.05537	0.02056			0.07655	0.00407	0.00277	0.00383
PLATFORMER RERUN REB.	Heater	27BA1105	27BA1105	18.66	6.93			0.05111	0.01898			N.L.	N.L.	N.L.	0
COMB. VAC TOWER FURNACE (WEST)	Heater	23BA301	23BA301	18.66	6.93			0.05111	0.01898			0.05763	0.00407	0.003	0.00414
PLATFORMER RX. CHG. HTR.	Heater	27BA1100	27BA1100	18.35	6.81			0.05026	0.01867			0.05763	0.00407	0.003	0.00414
ROSE HOT OIL HTR.	Heater	44BA3002	44BA3002	18.35	6.81			0.05026	0.01867			0.04424	0.004	0.00287	0.00396
B UNIFINER RX. CHG. FURNACE	Heater	29BA1300	29BA1300	15.55	5.77			0.04259	0.01582			0.02805	0.00248	0.00162	0.00224
PSEUDOCUMENE REBOILER	Heater	37BA301	37BA301	15.55	5.77			0.04259	0.01582			0	0	0	0
VACUUM TOWER HTR. (EAST)	Heater	23BA302	23BA302	14.93	5.54			0.04089	0.01519			0.02281	0.0024	0.00165	0.00227
PLATFORMER RX. HTR. #1	Heater	27BA1103	27BA1103	12.44	4.62			0.03408	0.01265			0.03151	0.00225	0.00186	0.00257
FUGITIVES	Equipment leak	N.A.	N.A.											0.021	

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Refinery EI Improvement Project
Valero Krotz Springs Refinery

Unit Description	Unit Type	Stack ID	Point ID	Post-CD Potential Emission Rate (tpy)				Post-CD Potential Emission Rate (tpd)				2004 Actual Emission Rate (tpd)			
				NOX	SO2	VOC	PM10	NOX	SO2	VOC	PM10	NOX	SO2	VOC	PM10
FCCU	Fluidized Catalytic Cracking Unit	27	51	125.00	402.00		100.74	0.3425	2.2027		0.2760	0.3342	1.9452	0.0274	0.3178
CRUDE UNIT FLARE	Hydrocarbon Flare	32	56									0.0027	0.0055	0.0329	N.L.
FCC FLARE	Hydrocarbon Flare	31	55									0.0137	0.1260	0.1068	N.L.
B-8203 FCC BOILER	Boiler	29	53	18.44	18.31			0.0505	0.0502			0.0932	0.0027	0.0027	0.0110
H-2301 CRUDE HEATER	Heater														
H-2302 VACUUM HEATER	Heater	35	59	23.78	23.61			0.0651	0.0647			0.2849	0.0110	0.0027	0.0164
B-8202 FCC BOILER	Boiler	30	54	13.17	13.08			0.0361	0.0358			0.0438	0.0027	0.0027	0.0055
H-2001 REFORMER CHARGE HEATER	Heater	42	71	13.08	12.99			0.0358	0.0356			0.1205	0.0082	0.0027	0.0110
B-8003 ISOMERIZATION BOILER	Boiler	47	81	8.72	8.66			0.0239	0.0237			0.0822	0.0055	0.0055	0.0055
B-8201 MTBE BOILER	Boiler	46	80	8.72	8.66			0.0239	0.0237			0.0740	0.0027	0.0027	0.0055
H-4201 FCC CHARGE HEATER	Heater	37	62	5.23	5.20			0.0143	0.0142			0.0055	N.L.	N.L.	0.0027
B-8002 CRUDE HOLMAN BOILER	Boiler	43	72	5.09	5.06			0.0140	0.0139			0.0658	0.0027	0.0027	0.0027
B-8001 CRUDE ZURN BOILER	Boiler	28	52	3.77	3.74			0.0103	0.0103			0.0274	0.0027	N.L.	0.0027
FUGITIVES	Fugitives	N/A	N/A												

Notes:
N.L. = not listed

Refinery EI Improvement Project
Valero McKee Refinery

Unit No.	Unit Type	FIN	EPN	Post-CD Potential Emission Rate (tpy)				Post-CD Potential Emission Rate (tpd)				2005 Actual Emission Rate (tpd)			
				NOX	SO2	VOC	PM	NOX	SO2	VOC	PM	NOX	SO2	VOC	PM
FCCU	Fluidized Catalytic Cracking Unit	*V-5*	*V-5*	47.00	517.00		153.30	0.12877	1.41644		0.42000	0.00576	1.37526	0.00026	0.00036
SRU #1	Sulfur Recovery Plant	*V-16*	*V-16*		12.94				0.03546			0.00672	0.0346	0.00239	0.0005
SRU #2	Sulfur Recovery Plant	*V-22*	*V-22*		0.06				0.00016			0.00003	0.00325	0.00109	0.00392
SULFURIC ACID PLANT	Sulfuric Acid Plant	*V-20*	*V-20*		65.00				0.17808			0.37087	1.88141	0.02511	0.17208
REFINERY FLARE	Hydrocarbon Flare	*FL-1*	*FL-1*									0.02312	0.00315	0.00004	0
FCC FLARE	Hydrocarbon Flare	*FL-3*	*FL-3*									0.00926	0.00005	0.12085	0
HCU FLARE	Hydrocarbon Flare	*FL-4*	*FL-4*									0.00022	0.00005	0.00003	0
WASTEWATER TREATER FLARE	Hydrocarbon Flare	*FL-6*	*FL-6*									0.00003	0.00001	0	0
NO. 1 CRUDE CHARGE HEATER	Heater	H-1	H-1	32.82	36.01			0.08992	0.09866			0.3331	0.00903	0.01502	0.02075
NO. 2 CRUDE CHARGE HEATER (BORN)	Heater	H-41	H-41	23.10	25.35			0.06329	0.06944			0.11545	0.00887	0.01351	0.01866
NO. 1 CCR CHARGE HEATER 1	Heater	H-18/1													
NO. 1 CCR CHARGE HEATER 3	Heater	H-18/2													
NO. 1 CCR CHARGE HEATER 4	Heater	H-18/3	H-18	23.88	26.20			0.06542	0.07178			0.11037	0.00763	0.01256	0.01734
600# BOILER	Boiler	B-12	B-12	25.82	28.33			0.07073	0.07760			0.32872	0.00591	0.00909	0.01255
NO. 18 BOILER	Boiler	B-10	B-10	23.44	25.72			0.06423	0.07047			0.35066	0.00449	0.00737	0.01016
NO. 19 BOILER	Boiler	B-11	B-11	23.44	25.72			0.06423	0.07047			0.32242	0.00402	0.00678	0.00935
NO. 1 NH3 PRIMARY REFORMER HEATER	Heater	H-21	H-21	22.60	24.79			0.06191	0.06792			N.L.	N.L.	N.L.	0
NO. 3 REFORMER CHARGE HEATER 1	Heater	H-38/1													
NO. 3 REFORMER CHARGE HEATER 2	Heater	H-38/2													
NO. 3 REFORMER CHARGE HEATER 3	Heater	H-38/3	H-38	20.84	22.86			0.05709	0.06264			0.07962	0.00581	0.00953	0.01315
NO. 1 CCR REFORMER CHARGE HEATER 2	Heater	H-46	H-46	17.04	18.70			0.04669	0.05123			0.07646	0.00507	0.0083	0.01145
NO. 15 BOILER	Boiler	B-8	B-8	16.42	18.01			0.04498	0.04935			0.19386	0.00243	0.0041	0.00565
NO. 16 BOILER	Boiler	B-9	B-9	16.42	18.01			0.04498	0.04935			0.06807	0.00371	0.00617	0.00851
NO. 11 BOILER	Boiler	B-4	B-4	9.38	10.29			0.02569	0.02819			0.03914	0.00142	0.00235	0.00322
NO. 12 BOILER	Boiler	B-5	B-5	9.38	10.29			0.02569	0.02819			0.04283	0.00165	0.00256	0.00352
NO. 13 BOILER	Boiler	B-6	B-6	8.60	9.44			0.02357	0.02586			0.04115	0.00155	0.00247	0.00338
NO. 14 BOILER	Boiler	B-7	B-7	8.60	9.44			0.02357	0.02586			N.L.	N.L.	N.L.	0
NO. 2 VACUUM HEATER	Heater	H-26	H-26	7.87	8.64			0.02157	0.02366			0.03545	0.00281	0.0043	0.00593
NO. 10 BOILER (STANDBY)	Heater	B-3	B-3	7.81	8.57			0.02141	0.02349			0.05222	0.00206	0.00311	0.00428
HCU FRACTIONATION HEATER	Heater	H-8	H-8	7.41	8.13			0.02030	0.02227			0.02565	0.00184	0.00313	0.0043
NO. 2 CRUDE CHARGE HEATER	Heater	H-11	H-11	7.41	8.13			0.02030	0.02227			0.03431	0.00269	0.00416	0.00573
NO. 1 HYDROTREATER CHARGE HEATER	Heater	H-45	H-45	7.34	8.05			0.02010	0.02205			0.00983	0.00077	0.00123	0.00168
HCU RECYCLE HEATER	Heater	H-42	H-42	7.29	8.00			0.01998	0.02192			0.03238	0.00232	0.00393	0.00541
HCU DEC4 REBOILER HEATER	Heater	H-43	H-43	7.00	7.68			0.01919	0.02105			0.0305	0.00228	0.00371	0.0051
NO. 1 VACUUM CHARGE HEATER	Heater	H-2	H-2	6.95	7.62			0.01903	0.02088			0.03209	0.0023	0.0039	0.00537
NO. 4 HYDROTREATER CHARGE HEATER	Heater	H-36	H-36	6.70	7.35			0.01836	0.02015			0.0141	0.00106	0.00174	0.00239
NO. 1 PDA ASPHALT HEATER	Heater	H-40	H-40	6.37	6.99			0.01745	0.01914			0.04316	0.00128	0.002	0.00274
DIESEL HDU CHARGE HEATER	Heater	H-48	H-48	5.98	6.56			0.01639	0.01799			0.02377	0.00104	0.00166	0.00227
NO. 1 NAPHTHA REBOILER HEATER	Heater	H-3	H-3	5.00	5.48			0.01369	0.01502			N.L.	N.L.	N.L.	0
NO. 2 CRUDE HEATER (S. PETROCHEM)	Heater	H-9	H-9	4.98	5.46			0.01364	0.01496			0.04865	0.00148	0.00224	0.00308
GAS OIL FRACTIONATOR CHARGE HEATER	Heater	H-13	H-13	4.23	4.64			0.01158	0.01270			0.08421	0.00084	0.00148	0.00202
NO. 2 HYDROTREATER REBOILER	Heater	H-37	H-37	3.33	3.66			0.00914	0.01002			0.01136	0.00089	0.00141	0.00193
NO. 2 REFORMER STAB. REBOILER	Heater	H-39	H-39	2.55	2.79			0.00698	0.00766			0.02095	0.00065	0.001	0.00136
FUGITIVES	Equipment Leak	N.A.	N.A.									N.L.	N.L.	0.93976	N.L.

Notes:
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Refinery EI Improvement Project
Valero St. Charles Refinery

Unit Description	Unit Type	Unit ID	Stack ID	Point ID	Post-CD Potential Emission Rate (tpy)				Post-CD Potential Emission Rate (tpd)				2004 Actual Emission Rate (tpd)			
					NOX	SO2	VOC	PM10	NOX	SO2	VOC	PM10	NOX	SO2	VOC	PM10
FCCU	Fluidized Catalytic Cracking Unit	16-77 FCCU REGENEI	3	48	151.00	174.00		275.94	0.4137	0.4767		0.7560	2.2959	0.0493	0.0274	0.4685
SRU #1	Sulfur Recovery Plant	SRU/TO														
SRU #2	Sulfur Recovery Plant		34	U6									0.0438	0.0932	0.0027	0.0027
FLARE 1	Hydrocarbon Flare															
FLARE 2	Hydrocarbon Flare		36	0U8									0.0110	0.0055	0.0137	N.L.
CRUDE HEATER	Heater	F-72-703	7	56	48.45	60.97			0.1327	0.1670			0.3781	0.0082	0.0192	0.0274
COKER HEATER A	Heater	F-53-1A														
COKER HEATER B	Heater	F-53-1B														
COKER HEATER C	Boiler	F-53-1C														
COKER HEATER D	Heater	F-53-1D	37	0U9	33.77	42.49			0.0925	0.1164			0.1342	0.0055	0.0137	0.0192
BOILER	Boiler	B 401 C	***22***	***0F6***	22.39	28.18			0.0613	0.0772			0.0753	0.0027	0.0014	0.0137
BOILER	Boiler	B 401 D	***23***	***0F8***	22.39	28.18			0.0613	0.0772			0.0767	0.0027	0.0014	0.0137
VACUUM HEATER	Heater	F-52-1B			21.93	27.60			0.0601	0.0756			0.1205	0.0055	0.0110	0.0137
VAC HEATER (F-52-1A/B LIMIT IS 406 MM)	Heater	F-701	5	53	15.32	19.28			0.0420	0.0528			0.0110	N.L.	N.L.	N.L.
CRUDE HEATER	Heater	F-52-1A			17.43	21.94			0.0478	0.0601			N.L.	N.L.	N.L.	N.L.
CRUDE HEATER	Heater	F-704			12.75	16.05			0.0349	0.0440			N.L.	N.L.	N.L.	N.L.
BOILER	Boiler	B-804	4	52	11.84	14.90			0.0324	0.0408			0.1233	0.0110	0.0027	0.0027
BOILER	Boiler	B-19-04			8.08	10.16			0.0221	0.0278			N.L.	N.L.	N.L.	N.L.
BOILER	Boiler	B-19-03			8.08	10.16			0.0221	0.0278			N.L.	N.L.	N.L.	N.L.
KHT HEATER	Heater	F-33-01	***2***	***44***	7.25	9.12			0.0199	0.0250			0.0110	N.L.	N.L.	N.L.
DHT HEATER	Heater	15-02	***6***	***54***	6.79	8.54			0.0186	0.0234			0.0356	N.L.	0.0027	0.0027
NHT HEATER	Heater	H-39-02			5.51	6.93			0.0151	0.0190			N.L.	N.L.	N.L.	N.L.
KHT HEATER	Heater	F-33-02			4.86	6.12			0.0133	0.0168			N.L.	N.L.	N.L.	N.L.
NHT HEATER	Heater	H-39-01			4.59	5.77			0.0126	0.0158			N.L.	N.L.	N.L.	N.L.
DHT HEATER	Heater	H-15-01	***18***	***D6***	4.22	5.31			0.0116	0.0146			0.0164	N.L.	N.L.	0.0027
DHT HEATER	Heater	H-15-01B			4.22	5.31			0.0116	0.0146			N.L.	N.L.	N.L.	N.L.
NHT HEATER	Heater	H-39-03			4.13	5.20			0.0113	0.0142			N.L.	N.L.	N.L.	N.L.
FUGITIVES	Fugitives															

Notes:
Italics indicate that Stack ID and Point ID are the best available matches based on information from consent decree and/or information provided by the refinery.
The Stack ID and Point ID listed do not necessarily correspond to the specified unit.
N.L. = not listed

Refinery EI Improvement Project
Valero Texas City Refinery

Unit No. [a]	Unit Type	FIN	EPN	Post-CD Potential Emission Rate (tpy)				Post-CD Potential Emission Rate (tpd)				2005 Actual Emission Rate (tpd)			
				NOX	SO2	VOC	PM	NOX	SO2	VOC	PM	NOX	SO2	VOC	PM10
FCCU	Fluidized Catalytic Cracking U	G-001	EG-001	88	158		262.8	0.241	0.866		0.720	1.209	0.007	0.056	0.173
SRU #1	Sulfur Recovery Plant	**SRU/TGU**	**G-18-1403**									N.L.	N.L.	N.L.	0
SRU #2	Sulfur Recovery Plant	**G-170**	**EG-170**									N.L.	N.L.	0	0
SOUTH PLANT SRU	Sulfur Recovery Plant	**G-333**	**EG-18-140**									N.L.	N.L.	N.L.	0
FLARE NO. 1	Hydrocarbon Flare	FL-1	EFL-1									0.023	0.038	0.000	0.000
FLARE NO. 2	Hydrocarbon Flare	FL-2	EFL-02									0.025	0.404	0.000	0.000
FLARE NO. 3	Hydrocarbon Flare	FL-3	EFL-3									0.008	0.123	0.000	0.000
FLARE NO. 4	Hydrocarbon Flare	FL-4	EFL-4									0.016	0.321	0.000	0.000
FLARE NO. 5	Hydrocarbon Flare	FL-05	EFL-05									0.013	0.003	0.000	0.000
ROSE HEATER	Heater	H-44	EH-44	80.848278	36.60465			0.222	0.100			0.038	0.013	0.004	0.013
UTILITIES BOILER	Boiler	B-18	EB-18	69.626435	31.52388			0.191	0.086			0.060	0.015	0.004	0.013
NO. 3 CRUDE HEATER	Heater	H-16	EH-16&17	67.331058	30.48463			0.184	0.084			0.134	0.015	0.010	0.014
UTILITIES BOILER	Boiler	B-11	EB-11	57.384424	25.98122			0.157	0.071			0.225	0.006	0.001	0.006
NO. 1 REFORMER HEATER	Heater	H-8	EH-08	50.243252	22.748			0.138	0.062			N.L.	N.L.	N.L.	0.000
RESIDFINER TG TRAIN 1	Heater	H-39	EH-39	44.63233	20.20761			0.122	0.055			N.L.	N.L.	N.L.	0.000
RESIDFINER TG TRAIN 2	Heater	H-40	**EH-D4**	44.63233	20.20761			0.122	0.055			N.L.	N.L.	N.L.	0
TOPPERS HEATER	Heater	H-1	EH-01&02	42.591995	19.28384			0.117	0.053			N.L.	N.L.	N.L.	0.000
TOPPERS (A-76) HEATER	Heater	H-34	EH-34	41.826869	18.93742			0.115	0.052			0.014	0.006	0.001	0.006
TOPPERS HEATER	Heater	H-2	EH-01&02	37.491157	16.97439			0.103	0.047			N.L.	N.L.	N.L.	0.000
ALKYLATION UNIT	Heater	H-28	EH-28	34.175613	15.47326			0.094	0.042			0.016	0.006	0.004	0.005
RESIDFINER FEED PREP	Heater	**H-45**	**EH-45**	29.074775	13.16382			0.080	0.036			0.074	0.020	0.014	0.018
NO. 3 CRUDE HEATER	Heater	H-17	EH-16&17	26.524356	12.0091			0.073	0.033			0.000	0.008	0.006	0.008
RESIDFINER FRACTIONATOR	Heater	**H-46**	**EH-46**	26.269314	11.89362			0.072	0.033			0.055	0.013	0.009	0.012
DHT HEATER	Heater	H-50	EH-50	31.370152	14.20306			0.086	0.039			0.010	0.002	0.000	0.002
NO. 2 REFORMER HEATER	Heater	H-21	EH-REF2	24.739063	11.20079			0.068	0.031			0.000	0.008	0.006	0.008
NO. 2 REFORMER HEATER	Heater	H-20	EH-REF2	23.718895	10.7389			0.065	0.029			0.000	0.008	0.005	0.008
RVDU HEATER	Heater	H-29	EH-29	20.913435	9.46871			0.057	0.026			0.073	0.006	0.001	0.006
NO. 2 REFORMER HEATER	Heater	H-22	EH-REF2	17.852932	8.083045			0.049	0.022			0.000	0.003	0.003	0.004
NO. 2 REFORMER HEATER	Heater	H-19	ST	14.537388	6.581908			0.040	0.018			0.000	0.004	0.003	0.004
MDHT HEATER	Heater	H-32	EH-31&32	12.497052	5.658131			0.034	0.016			0.028	0.002	0.001	0.002
NO. 2 REFORMER HEATER	Heater	H-18	EH-REF2	11.986969	5.427187			0.033	0.015			0.226	0.002	0.001	0.002
NO. 2 REFORMER HEATER	Heater	H-23	EH-REF2	11.731927	5.311715			0.032	0.015			0.000	0.003	0.002	0.003
FUGITIVES	Equipment Leak	N.A.	N.A.											0.485	

Notes:
N.L. = not listed

Refinery EI Improvement Project
Valero Three Rivers Refinery

Unit No.	Unit Type	FIN	EPN	Post-CD Potential Emission Rate (tpd)				Post-CD Potential Emission Rate (tpd)				2005 Actual Emission Rate (tpd)			
				NOX	SO2	VOC	PM	NOX	SO2	VOC	PM	NOX	SO2	VOC	PM10
FCCU	Fluidized Catalytic Cracking Unit	*V-010*	*V-010*	66.00	32.00		76.65	0.181	0.088		0.210	0.13012	0.03228	0.00201	0.0258
SRU #1	Sulfur Recovery Plant	*V-008*	*V-008*									0.01673	0.02961	0.03064	0.00089
NO. 1 WEST PLANT FLARE	Hydrocarbon Flare	*FL-003*	*FL-003*									0	0	0	0
NO. 2 WEST PLANT FLARE	Hydrocarbon Flare	*FL-004*	*FL-004*									0	0	0	0
FCC FLARE	Hydrocarbon Flare	*FL-005*	*FL-005*									0	0.00099	0	0
HCU FLARE	Hydrocarbon Flare	*FL-006*	*FL-006*									0	0	0	0
WASTEWATER TREATER FLARE	Hydrocarbon Flare	*FL-501*	*FL-501*									0	0	0	0
BTX BOILER	Boiler	B-007	B-007	30.10	26.93			0.082	0.074			0.05763	0.00093	0.0105	0.01429
NO. 2 REFORMER CHARGE HEATER	Heater	H-030/1	H-030/1									0.02799	0.00083	0.00269	0.00365
NO. 2 REFORMER CHARGE HEATER	Heater	H-030/3	H-030/3									0.02269	0.00069	0.00219	0.00297
NO. 2 REFORMER CHARGE HEATER	Heater	H-030/4	H-030/4	27.08	24.23			0.074	0.066			0.02186	0.00066	0.00212	0.00286
BOILER 6F1-A	Boiler	B-004	B-004	23.79	21.29			0.065	0.058			0.12039	0.00202	0.0067	0.0091
BOILER 6F1-B	Boiler	B-004	B-004	0.00	0.00			0.000	0.000			0.12039	0.00202	0.0067	0.0091
NO. 1 CRUDE CHARGE HEATER	Heater	H-028	H-028	22.02	19.70			0.060	0.054			0.04791	0.00286	0.00796	0.01083
NO. 1 CRUDE CHARGE HEATER	Heater	H-036	H-036	22.02	19.70			0.060	0.054			0.06258	0.00365	0.01038	0.01413
NO. 1 REFORMER CHARGE HEATER	Heater	H-204	H-030									0.02186	0.00066	0.00212	0.00286
NO. 1 REFORMER CHARGE HEATER	Heater	H-205	H-033	12.44	11.13			0.034	0.030			0.00655	0.00037	0.00113	0.00152
NO. 2 REFORMER CHARGE HEATER	Heater	*H-202*	*H-032*	14.92	13.35			0.041	0.037			0.02839	0.00143	0.00474	0.00643
VACUUM CHARGE UNIT HEATER	Heater	*H-1401*	*H-016*	14.20	12.70			0.039	0.035			0.12781	0.00249	0.00706	0.00969
EAST PLANT BOILER	Boiler	B-006	B-006	14.05	12.57			0.039	0.034			0.05207	0.00181	0.00577	0.00789
HCU DEBUTANIZER REBOILER	Heater	H-035	H-035	8.16	7.30			0.022	0.020			0.01372	0.00074	0.00231	0.00313
STEAM BOILER (NEW)	Boiler	B-009	B-009	7.94	7.10			0.022	0.019			0.04751	0.00048	0.00527	0.00718
NAPHTHA SPLITTER REBOILER	Heater	*H-1102*	*H-014*	7.16	6.41			0.020	0.018			0.01293	0.00081	0.00218	0.00295
REFORMATE REBOILER HEATER	Heater	H-044	H-044	7.10	6.35			0.019	0.017			0.01065	0.00066	0.0018	0.00244
ALKY ISOSTRIPPER REBOILER HEATER	Heater	H-020	H-020	6.93	6.20			0.019	0.017			0.07013	0.00117	0.00395	0.00527
BOILER SP-5	Boiler	B-005	B-005	6.67	5.97			0.018	0.016			0.04057	0.00142	0.00455	0.0061
HCU RECYCLE HEATER	Heater	H-034	H-034	6.46	5.78			0.018	0.016			N.L.	0	N.L.	0
NO. 2 HDU CHARGE HEATER	Heater	H-037	H-037	5.62	5.03			0.015	0.014			0.00721	0.00041	0.00124	0.00167
STEAM/METHANE REFORMER HEATER	Heater	H-040	H-040	5.54	4.95			0.015	0.014			0.03104	0.00063	0.00192	0.00259
NO. 2 HDU REBOILER HEATER	Heater	H-038	H-038	5.24	4.69			0.014	0.013			N.L.	0	N.L.	0
F-2201 DMD HT H2 RECYCLE	Heater	H-041	H-041	2.56	2.29			0.007	0.006			0.003	0.00023	0.00055	0.00072
FUGITIVES	Equipment Leak	N.A.	N.A.											0.985	

Notes:
N.L. = not listed
Italics indicate that FIN and EPN are the best available matches based on information from consent decree and/or information provided by the refinery.
The FIN and EPN listed do not necessarily correspond to the specified unit.

ATTACHMENT D

Comparison of Post-Consent Decree to Reported Actual Emissions

Facility	Site	Total TPD Post-CD			Total TPD 2005			Projected vs. Actual Ratios			Notes
		NOX	SO2	PM10	NOX	SO2	PM10	NOX	SO2	PM10	
BP	*Texas City, TX*	3.29	8.70	1.90	2.12	7.93	0.67	1.55	1.10	2.83	Large difference in PM emissions for FCCU.
Chalmette	*Chalmette, LA*	4.25	1.40	0.21	4.59	3.87	0.49	0.93	0.36	0.42	
CITGO	*Corpus Christi (East), TX*	1.52	1.12	0.75	1.88	1.48	0.31	0.81	0.76	2.42	Large difference in PM emissions for FCCU.
CITGO	*Corpus Christi (West), TX*	0.20	0.09	0.08	0.90	0.10	0.08	0.23	0.85	1.00	
ConocoPhillips	*Alliance (Belle Chasse, LA)*	1.63	1.62	0.52	2.97	2.75	0.17	0.55	0.59	3.08	Can't identify cat cracker in AFS files.
ConocoPhillips	*Borger, TX*	4.77	7.92	2.51	4.11	4.18	0.09	1.16	1.90	26.45	Can't identify cat cracker in AFS files.
ConocoPhillips	*Lake Charles, LA*	0.41	1.33	0.13	0.37	1.50	0.07	1.12	0.89	1.81	Can't identify cat cracker in AFS files.
ConocoPhillips	*Ponca City, OK*	1.23	1.20	0.77	2.23	2.28	1.44	0.55	0.53	0.53	
ConocoPhillips	*Sweeny, TX*	1.81	4.43	0.60	3.30	6.97	1.37	0.55	0.64	0.44	
ExxonMobil	*Baton Rouge, LA*	5.55	3.11	1.45	8.15	3.11	1.45	0.68	1.00	1.00	
ExxonMobil	*Baytown, TX*	1.10	1.70	2.01	0.95	0.61	0.65	1.16	2.79	3.09	Large difference in PM and SO2 emissions for FCCUs.
ExxonMobil	*Beaumont, TX*	10.05	14.41	3.27	7.01	4.40	1.20	1.43	3.28	2.74	Large diference in SO2 emissions for flares, SO2 and PM for FCCU.
Navajo	*Artesia, NM*	1.03	0.61	0.30	0.54	4.59	0.49	1.92	0.13	0.61	
Koch	*Corpus Christi, TX*	3.35	2.59	1.05	4.06	0.35	0.90	0.83	7.35	1.17	Large difference in SRP SO2 emissions.
Marathon Oil	*Garyville, LA*	4.70	2.06	1.18	3.24	0.30	0.38	1.45	6.77	3.12	Large difference in PM and SO2 emissions for FCCU.
Marathon Oil	*Texas City, TX*	1.06	0.29	0.17	2.19	0.96	0.23	0.48	0.30	0.74	
Motiva	*Convent, LA*	1.48	1.13	0.83	2.60	0.18	0.23	0.57	6.32	3.66	Large difference in PM emissions for FCCU; no SO2 emissions reported for FCCU.
Motiva	*Norco, LA*	1.76	1.54	1.03	6.40	0.36	0.16	0.28	4.30	6.35	Large difference in PM and SO2 emissions for FCCU.
Motiva	*Port Arthur, TX*	0.28	0.22	0.18	0.52	0.14	0.05	0.54	1.53	3.67	Large difference in PM and SO2 emissions for FCCU.
Rhodia	*Baytown, TX*	0.00	1.21	0.00	0.11	0.87	0.00	0.00	1.40	1.00	
Rhodia	*Houston, TX*	0.00	2.97	0.10	0.20	27.58	0.10	0.00	0.11	1.00	
Shell	*Deer Park, TX*	1.22	1.16	0.68	1.11	0.06	0.17	1.10	19.85	3.91	Large difference in PM and SO2 emissions for FCCU.
Sunoco	*Tulsa, OK*	1.04	0.69	0.05	1.99	9.65	0.05	0.52	0.07	1.00	
Total	*Port Arthur, TX*	1.57	1.29	0.35	1.29	0.27	0.49	1.21	4.82	0.72	Large difference in SO2 emissions from FCCU and combustion units.
Valero	*Ardmore, OK*	0.65	0.65	0.22	1.02	0.61	0.25	0.64	1.06	0.88	
Valero	*Corpus Christi (East), TX*	0.86	1.13	0.18	1.91	2.20	0.30	0.45	0.51	0.59	
Valero	*Corpus Christi (West), TX*	2.81	1.57	1.55	2.71	0.79	1.45	1.04	1.98	1.07	
Valero	*Houston, TX*	1.23	0.84	0.71	1.65	8.82	0.29	0.74	0.10	2.42	Large difference in PM emissions for FCCU.
Valero	*Krotz Springs, LA*	0.62	2.47	0.28	1.15	2.12	0.38	0.54	1.17	0.72	
Valero	*McKee, TX*	1.17	2.77	0.42	3.02	3.38	0.37	0.39	0.82	1.14	
Valero	*St. Charles, LA*	1.14	1.39	0.76	3.32	0.18	0.57	0.34	7.56	1.33	Large difference in S)2 emissions for FCCU.
Valero	*Texas City, TX*	2.49	1.89	0.72	2.17	1.02	0.29	1.15	1.85	2.48	
Valero	*Three Rivers, TX*	0.87	0.70	0.21	1.10	0.09	0.15	0.79	7.80	1.36	Large difference in SO2 emissions from FCCU and combustion units.
TOTAL		**65.14**	**76.17**	**25.17**	**80.87**	**103.68**	**15.29**	**0.81**	**0.73**	**1.65**	