217/782-2113

CONSTRUCTION PERMIT – NSPS SOURCE

PERMITTEE

CITGO Petroleum Corporation
Attn: Claude Harmon
135th Street & New Avenue
Lemont, Illinois 60439-3659

Application No.: 01070060 I.D. No.: 197090AAI
Applicant's Designation: Date Received: July 23, 2001
Subject: Turnaround Project
Date Issued: November 13, 2001
Location: 135th Street & New Avenue, Lemont

Permit is hereby granted to the above-designated Permittee to CONSTRUCT emission source(s) and/or air pollution control equipment consisting of a turnaround project that may include various changes to the Crude Unit (Unit 111), FCC Unit (Unit 112) and the Sponge Coker Unit (Unit 113) as described in the above-referenced application. This Permit is subject to standard conditions attached hereto and the following special condition(s):

1.0 Unit Specific Conditions

1.1 Unit: Heaters

1.1.1 Description

Crude Unit

The Crude Unit separates incoming crude oil received by the refinery into various fractions based upon their boiling temperature by means of distillation.

Changes will be made to the Crude Unit to allow processing of heavier (more viscous) crude oils. The changes include increasing the capacity of heaters associated with the first stage distillation column, which operates at atmospheric pressure (crude atmospheric heaters). As part of this modification, these heaters will be reburnered with ultra-low NO_x burners.

Sponge Coker Unit

The Sponge Coker Unit uses a thermal cracking process to split the bottom fractions from the Crude Unit to increase the yield of higher-value, lighter liquid materials. These intermediate materials can be further refined in other process units (including the FCCU). The byproduct from this cracking process is a fuel grade form of carbon called “sponge coke”.

Improvements related to the compressor, cooling in the unit and charge pump drivers will be made to restore fresh feed capacity presently lost during warm weather operation. The Sponge Coker Heaters will be fired harder, but will remain within their existing capacity.

1.1.2 List of Emission Units and Air Pollution Control Equipment

Emission Unit	Description	Emission Control Equipment
111B-1A	Crude Atmospheric Heater A	Ultra-Low NO_x Burners
111B-1B	Crude Atmospheric Heater B	Ultra-Low NO_x Burners
113B-1	Sponge Coker Heater 1	Ultra-Low NO_x Burners
113B-2	Sponge Coker Heater 2	Ultra-Low NO_x Burners
113B-3	Sponge Coker Heater 3	Low NO_x Burners

1.1.3 Applicability Provisions and Applicable Regulations

a. “Affected heaters” for the purpose of these unit-specific conditions, are the heaters described in Conditions 1.1.1 and 1.1.2.

b. i. This permit is issued based upon affected heaters 111B-1A and 111B-1B (crude atmospheric heaters) being modified so that they are now subject to the NSPS for Petroleum Refineries, 40 CFR 60 Subparts A and J. The Illinois EPA administers the NSPS for subject sources in Illinois pursuant to a delegation agreement with the USEPA.

ii. The Permittee shall not burn in the affected heaters 111B-1A and 111B-1B (crude atmospheric heaters) any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 mg/dscm (0.10 gr/dscf) [40 CFR 60.104(a)(1)].

c. i. The Permittee shall not cause or allow the emission of smoke or other particulate matter, with an opacity greater than 20 percent, into the atmosphere from the affected heaters 111B-1A and 111B-1B (crude atmospheric heaters) except as provided below [35 IAC 212.122(a)].

ii. The emission of smoke or other particulate matter from the affected heaters 111B-1A and 111B-1B (crude atmospheric heaters) may have an opacity greater than 20 percent but not greater than 40 percent for a period or periods aggregating 3 minutes in any 60 minute period, providing that such opaque emission allowed during any 60 minute period shall occur from only one such emission unit located within a 305 m (1000 ft) radius from the center point of any other such emission unit owned or operated by such person, and provided further that such opaque emissions allowed from each such emission unit shall be limited to 3 times in any 24 hour period [35 IAC 212.122(b)].

d. Emission of nitrogen oxides into the atmosphere in any one hour period from the affected heaters 111B-1A and 111B-1B (crude atmospheric heaters) shall not exceed 0.3 lbs/mmBtu of actual heat input [35 IAC 217.141(a)].

1.1.4 Non-Applicability of Regulations of Concern

a. This permit is issued based on the affected heaters 111B-1A and 111B-1B (crude atmospheric heaters) not being subject to 40 CFR 60 Subpart Db, NSPS for Industrial-Commercial-Institutional Steam Generating Units because the affected heaters 111B-1A and 111B-1B (crude atmospheric heaters) are not steam generating units but rather process heaters.

b. This permit is issued based on the affected heaters not being subject to 35 IAC 212.206, 212.207, or 214.162 because the affected heaters do not burn liquid fuel.

c. This permit is issued based on the affected heaters 113B-1 and 113B-2 (sponge coker heaters) not being subject to 40 CFR 60 Subpart J, NSPS for Petroleum Refineries because the heaters were constructed prior to June 11, 1973 and are not being modified since the heaters will still be fired within their existing capacity. Note: affected heater 113B-3 is already subject to NSPS, Subpart J, as it was built in 1985.

1.1.5 Operational and Production Limits and Work Practices

a. With the exception of heater 113B-3, the affected heaters shall be equipped, operated, and maintained with ultra-low NO_x burners. Heater 113B-3 shall be equipped, operated, and maintained with low NO_x burners. These burners shall be operated and maintained in conformance with good air pollution control practices.

b. The firing rate of the affected heaters shall not exceed the following:

Heater	Firing Rate (mmBtu/Hr, Daily Average)
Crude Atmospheric Heater (111B-1A)	376.5
Crude Atmospheric Heater (111B-1B)	376.5
Sponge Coker Heater (113B-1)	88.8
Sponge Coker Heater (113B-2)	88.8
Sponge Coker Heater (113B-3)	88.8

c. These requirements and the emission limitations in Condition 1.1.6 become effective following completion of the Turnaround Project when the Crude Unit first begins to process heavier crude oils.

1.1.6 Emission Limitations

a. i. Emissions from affected heaters 111B-1A and 111B-1B (crude atmospheric heaters) each shall not exceed the following limits:

Pollutant	Emissions (Ton/Mo)	(Tons/Year)
NO_x	5.50	65.96
SO_2	2.97	35.61
CO	1.68	20.15
VOM	0.38	4.45
PM	1.03	12.29
PM_{10}	1.03	12.29

ii. Emissions from affected heaters 113B-1 and 113B-2 (sponge coker heaters) each shall not exceed the following limits:

Pollutant	Emissions (Tons/Mo)	(Tons/Year)
NO_x	1.69	20.23
SO_2	0.70	8.40
CO	2.67	32.03
VOM	0.18	2.10
PM	0.25	2.90
PM_{10}	0.25	2.90

iii. Emissions from affected heater 113B-3 (sponge coker heater) shall not exceed the following limits:

Pollutant	Emissions (Tons/Mo)	(Tons/Year)
NO_x	2.77	33.18
SO_2	0.70	8.40
CO	2.67	32.03
VOM	0.18	2.10
PM	0.25	2.90
PM_{10}	0.25	2.90

b. Compliance with annual limits shall be determined on a monthly basis from the sum of the data for the current month plus the preceding 11 months (running 12 month total).

1.1.7 Testing Requirements

a. Hydrogen Sulfide Testing.

In accordance with 40 CFR 60.8, within 60 days after achieving the maximum production rate at which the affected heaters 111B-1A and 111B-1B (crude atmospheric heaters) will be operated, but not later than 180 days after initial startup of the affected heaters 111B-1A and 111B-1B (crude atmospheric heaters) and at such other times as may be required by the Illinois EPA, the Permittee shall conduct performance test(s) in accordance with 40 CFR 60.106(e) and furnish the Illinois EPA a written report of the results of such performance test(s).

b. Nitrogen Oxides Testing.

i. Within 60 days after achieving the maximum production rate at which the modified crude unit will be operated, but not later than 180 days after initial startup, the nitrogen oxide (NO_x) emissions of the affected heaters 111B-1A and 111B-1B (crude atmospheric heaters) and either affected heater 113B-1, 113B-2 or 113B-3 (sponge coker heater) selected at random, shall be measured during conditions which are representative of maximum emissions.

ii. The following methods and procedures shall be used for testing of emissions, unless another method is approved by the Illinois EPA: Refer to 40 CFR 60, Appendix A, for USEPA test methods.

Location of Sample Points	USEPA Method 1
Gas Flow and Velocity	USEPA Method 2

Flue Gas Weight	USEPA Method 3
Moisture	USEPA Method 4
Nitrogen Oxides	USEPA Method 7

The Reference Method listed above refers to the base method or any of its “sub-methods”, e.g., Method 2 includes Methods 2, 2A, 2B, 2C, and 2D; Method 3 includes Methods 3 and 3A; and Method 7 includes Methods 7, 7A, 7B, 7C, 7D, and 7E.

1.1.8 Monitoring Requirements

a. The Permittee shall comply with the Monitoring requirements specified in 40 CFR 60.105 for the affected heaters 111B-1A and 111B-1B (crude atmospheric heaters) by installing, calibrating, maintaining and operating either of the following continuous monitoring systems:

i. An instrument for continuously monitoring and recording the concentration by volume (dry basis, zero percent excess air) of SO_2 emissions into the atmosphere from each heater. The monitor shall include an oxygen monitor for correcting the data for excess air; or

ii. An instrument for continuously monitoring and recording the concentration (dry basis) of H_2S in fuel gases before being burned in these heaters.

b. The Permittee shall determine compliance with the H_2S standard in 40 CFR 60.104(a)(1) as follows: Method 11, 15, 15A, or 16 shall be used to determine the H_2S concentration. The gases entering the sampling train should be at about atmospheric pressure. If the pressure in the refinery fuel gas lines is relatively high, a flow control valve may be used to reduce the pressure. If the line pressure is high enough to operate the sampling train without a vacuum pump, the pump may be eliminated from the sampling train. The sample shall be drawn from a point near the centroid of the fuel gas line [40 CFR 60.106(e)(1)].

c. The Permittee shall maintain records of the following items to demonstrate compliance with Condition 1.1.3(b)(ii):

i. For a SO_2 monitor on the affected heaters: a record of the concentration by volume (dry basis, zero percent excess air) of SO_2 emissions into the atmosphere; or

ii. For a H_2S monitor on the affected heaters: a record of the concentration (dry basis) of H_2S in fuel gases before being burned in the heaters.

1.1.9 Recordkeeping Requirements

The Permittee shall maintain records of the following items:

a. Firing rate of the affected heaters (mmBtu/hr on a daily average);

b. NO_x, CO, VOM, SO_2, PM and PM_{10} emissions from the affected heaters (tons/month and tons/year); and

c. Observations of opacity from affected heaters.

1.1.10 Reporting Requirements

a. The Permittee shall promptly notify the Illinois EPA, Compliance Section, of deviations of the affected heaters with the permit requirements as follows. Reports shall describe the probable cause of such deviations, and any corrective actions or preventive measures taken.

b. For the affected heaters 111B-1A and 111B-1B (crude atmospheric heaters), the Permittee shall comply with the reporting requirements specified in 40 CFR 60.107(d), (e) and (f) and 40 CFR 60.105(e)(3).

1.1.11 Operational Flexibility/Anticipated Operating Scenarios

N/A

1.1.12 Compliance Procedures

a. Compliance with the emission limitations specified in Conditions 1.1.3(c) is considered inherent in the normal operation of an affected heater firing refinery fuel gas.

b. Compliance with the emission limitations specified in Condition 1.1.3(d) is assured by the use of ultra-low NO_x burner technology in the affected heaters 111B-1A and 111B-1B (crude atmospheric heaters).

c. i. Compliance with the SO_2 limits in Condition 1.1.6(a) shall be based on the operating records required by Condition 1.1.9 and the sulfur content of refinery fuel gas as monitored in accordance with Condition 1.1.8.

ii. Compliance with the other emission limits in Condition 1.1.6(a)(i) for the affected heaters 111B-1A and 111B-1B (crude atmospheric heaters) shall be based on the operating records required by Condition 1.1.9 and appropriate emission factors:

Pollutant	Emission Factor (Lbs/mmBtu)
NO_x	0.04
CO	0.01222067
VOM	0.002696
PM/PM_{10}	0.00745098

iii. Compliance with the other emission limits in Condition 1.1.6(a)(ii) for the affected heaters 113B-1 and 113B-2 (sponge coker heaters) shall be based on the operating records required by Condition 1.1.9 and appropriate emission factors:

Pollutant	Emission Factor (Lbs/mmBtu)
NO_x	0.052
CO	0.08235294
VOM	0.00539216
PM/PM_{10}	0.00745098

iv. Compliance with the other emission limits in Condition 1.1.6(a)(iii) for the affected heater 113B-3 (sponge coker heater) shall be based on the operating records required by Condition 1.1.9 and the appropriate emission factors:

Pollutant	Emission Factor (Lbs/mmBtu)
NO_x	0.08532
CO	0.08235294
VOM	0.00539216
PM/PM_{10}	0.00745098

v. If available, results from representative stack tests in accordance with the methods described in 1.1.7(b)(ii) or in 40 CFR Part 60, Appendix A shall be used in lieu of these emission factors in condition 1.1.12(c)(i) through 1.1.12(c)(iv) to represent actual emissions.

1.2 Unit: FCCU

1.2.1 Description

<u>FCC Unit</u>

The fluid catalytic cracking unit (FCCU) converts an intermediate low grade fraction from the crude unit known as “gas-oil”, into more valuable lighter material by “cracking” the long chain molecules using a fine catalyst powder in a reactor. The reactor itself has no vents to the atmosphere. Internal cyclones separate the catalyst from the product so that coke formed on the catalyst during the process can be removed and the catalyst returned to the reactor.

In the regeneration step, the coke is removed from the catalyst by controlled combustion, which results in carbon monoxide (CO) and sulfur dioxide (SO_2). Primary and secondary cyclones separate most of the clean catalyst from the exhaust from the regenerator. The CO is burned in a boiler, which acts as a pollution control device (converting CO to CO_2). Any remaining catalyst fines which pass through the boiler are controlled by electrostatic precipitators (ESPs). The regenerated catalyst from the cyclones is reused. The FCCU regenerator’s cyclones will be improved. The cyclones are not control equipment but recover raw material. The main air blower will have an on-line cleaning system installed.

Because the modified crude unit will be able to process heavier crude oil, which would result in a gas oil containing more sulfur, and the sponge coker unit will be restoring lost capacity, the FCCU could realize an increase in SO_2 emissions. The FCCU will be adding de-SO_x catalyst additive into the catalyst blend to compensate for this potential increase in SO_2. This additive reduces the deposition of sulfur with the carbon on the catalyst so that more sulfur leaves with the various intermediate products and vapors from the FCCU, and is collected by the Sulfur Recovery Plant.

1.2.2 List of Emission Units and Air Pollution Control Equipment

Emission Unit	Description	Emission Control Equipment
Unit 112	FCC Unit	CO Boiler (112B-2) and ESPs (112P-1, 112P-2)

1.2.3 Applicability Provisions and Applicable Regulations

An "affected FCCU" for the purpose of these unit-specific conditions, is a FCCU as described in Conditions 1.2.1 and 1.2.2.

1.2.4 Non-Applicability of Regulations of Concern

a. This permit is issued based on the FCCU not being subject to 40 CFR 60 Subpart J, NSPS for Petroleum Refineries, because the FCCU was constructed prior to June 11, 1973 and is not being modified since the FCCU will continue to operate within its existing capacity.

b. i. This permit is issued based on the FCCU experiencing at most a negligible increase of PM and CO, as a result of the control measures that are present, so that the applicability of the federal rules for Prevention of Significant Deterioration (PSD), 40 CFR 52.21, is not triggered (See also Condition 3).

ii. This permit is issued based on the FCCU experiencing at most a negligible increase of NO_x as a result of the feed-stock substitution enabled by the upstream changes.

iii. Additional requirements may be established in the source's CAAPP permit to define the permitted emissions, after the emissions of the FCCU are tested under representative operating conditions (See also Condition 1.2.7).

1.2.5 Operational and Production Limits and Work Practices

a. The Permittee shall add de-SO_x catalyst into the catalyst blend. The de-SO_x catalyst will reduce SO_2 emissions.

b. These requirements and the emission limitations in Condition 1.2.6 become effective following completion of the Turnaround Project when the Crude Unit first begins to process heavier crude oils.

1.2.6 Emission Limitations

a. Emissions from catalyst regenerator 112D-1 shall not exceed the following limits.

Pollutant	Emissions (Tons/Mo)	Emissions (Tons/Year)
SO_2	1,139.56	13,675.00

b. Compliance with annual limits shall be determined on a monthly basis from the sum of the data for the current month plus the preceding 11 months (running 12 month total).

1.2.7 Testing Requirements

a. i. Within 180 days after resuming operation of the refinery, the NO_x, CO and PM emissions of the FCCU will be measured under representative operating conditions.

ii. Within 60 days after achieving the maximum production rate at which the FCCU will be operated following completion of the Turnaround Project, but not later than 180 days after completion of the project, the NO_x, CO, and PM emissions of the FCCU shall be measured during conditions which are representative of maximum emissions.

b. The following methods and procedures shall be used for testing of emissions, unless another method is approved by the Illinois EPA: Refer to 40 CFR 60, Appendix A, for USEPA test methods.

Location of Sample Points	USEPA Method 1
Gas Flow and Velocity	USEPA Method 2
Flue Gas Weight	USEPA Method 3
Moisture	USEPA Method 4
Particulate Matter	USEPA Method 5
Nitrogen Oxides	USEPA Method 7
Carbon Monoxide	USEPA Method 10

The Reference Method listed above refers to the base method or any of its “sub-methods”, e.g., Method 2 includes Methods 2, 2A, 2B, 2C, and 2D; Method 3 includes Methods 3 and 3A; and Method 7 includes Methods 7, 7A, 7B, 7C, 7D, and 7E.

1.2.8 Monitoring Requirements

The Permittee shall install, calibrate, maintain and operate the following continuous emissions monitoring systems:

A device to continuously monitor and record SO_2 emissions from the catalyst regenerator (measurement on each of the precipitator stacks (112P-1 and 112P-2)).

1.2.9 Recordkeeping Requirements

The Permittee shall maintain records of the following items to demonstrate compliance with Conditions 1.2.5 and 1.2.6:

a. Fresh feed to the FCCU (bbl/month and bbl/year);

b. De-SO_x catalyst additive usage rate (lb/month);

c. SO_2 emissions on a daily basis (tons/month and tons/year) from the CEM's on the FCCU;

1.2.10 Reporting Requirements

The Permittee shall promptly notify the Illinois EPA, Compliance Section, of deviations of the affected FCCU with the permit requirements as follows. Reports shall describe the probable cause of such deviations, and any corrective actions or preventive measures taken.

1.2.11 Operational Flexibility/Anticipated Operating Scenarios

N/A

1.2.12 Compliance Procedures

Compliance with the SO_2 emission limits in Condition 1.2.6(a) for the catalyst regenerator 112D-1 shall be demonstrated by continuous monitoring.

2a. This permit does not relax any requirements for the Crude Unit, FCC Unit or Sponge Coker Unit as set forth in the Clean Air Act Permit Program (CAAPP) permit for the source, CAAPP Permit 96030079.

b. General requirements of the CAAPP permit with respect to retention and availability of records or submission of reports shall apply to recordkeeping and reporting requirements established by this permit.

c. Operation of the enhanced units addressed in this permit is allowed for 270 days under this construction permit.

3. The source has addressed the applicability and compliance of 40 CFR 52.21, Prevention of Significant Deterioration (PSD) and 35 IAC Part 203, Major Stationary Sources Construction and Modification (See Attachments 1, 2 and 3). The limits established by this permit are intended to ensure that the modification addressed in this construction permit does not constitute a major modification pursuant to these rules.

4. Two copies of required reports and notifications concerning equipment operation or emissions, performance testing or a continuous monitoring system shall be sent to:

   Illinois Environmental Protection Agency
   Division of Air Pollution Control
   Compliance Section (#40)
   P.O. Box 19276
   Springfield, Illinois 62794-9276

   and one copy shall be sent to the Illinois EPA's regional office at the following address unless otherwise indicated:

   Illinois Environmental Protection Agency
   Division of Air Pollution Control
   9511 West Harrison
   Des Plaines, Illinois 60016

   Note: The Permittee must obtain an amended CAAPP permit to address the continued operation of the modified units covered under this permit. Information previously submitted in the construction permit application may be incorporated by reference into the application to amend the CAAPP permit.

If you have any questions on this permit, please contact Jason Schnepp at 217/782-2113.

Donald E. Sutton, P.E.
Manager, Permit Section
Division of Air Pollution Control

DES:JMS:jar

cc: Region 1

Attachment 1

PSD Applicability - NO_x Netting Analysis

Contemporaneous Time Period of November 1996 Through November 2001

Table I – Emissions Increases and Decreases Associated With The Proposed Modification

Item of Equipment	Past Actual (Tons/Yr)	Future Potential (Tons/Yr)	Emissions Change (Tons/Year)	Permit Number
Modified Heater 111B-1A	259.70	65.96	- 193.73	01070060
Modified Heater 111B-1B	249.01	65.96	- 183.05	01070060
Heater 113B-1	16.05	20.23	4.18	01070060
Heater 113B-2	15.68	20.23	4.55	01070060
Heater 113B-3	26.94	33.18	6.24	01070060
FCCU Cat. Regen. 112D-1	1,620.14	1,905.30	Neg.	01070060
		Total:	- 361.81	

Table II – Source-Wide Creditable Contemporaneous Emission Increases

Item of Equipment	Commencement of Operation Date	Emissions Increase (Tons/Year)	Permit Number
Vapor Recovery Unit w/Vapor Combustor	May 1998	14.80	98030075
Replacement Boiler (431B)	November 2001	70.89	01070039
	Total:	85.69	

Table III – Source-Wide Creditable Contemporaneous Emission Decreases

Item of Equipment	Commencement of Operational Change Date	Emissions Decrease (Tons/Year)	Permit Number
Heater 113B-1 - Installed Ultra-Low NO_x Burners	April 1998	27.71	98020008
Heater 111B-2 - Installed Ultra-Low NO_x Burners	February 2000	58.01	00010016
Boiler No. 19 Removed	November 2001	37.46	01070039
	Total:	123.18	

Table IV – Net Emissions Change

	(Tons/Year)
Increases and Decreases Associated With The Proposed Modification	- 361.81
Creditable Contemporaneous Emission Increases	85.69
Creditable Contemporaneous Emission Decreases	- 123.18
	- 399.30

Attachment 2

PSD Applicability - SO_2 Netting Analysis

Contemporaneous Time Period of November 1996 Through November 2001

Table I – Emissions Increases and Decreases Associated With The Proposed Modification

Item of Equipment	Past Actual (Tons/Yr)	Future Potential (Tons/Yr)	Emissions Change (Tons/Year)	Permit Number
Modified Heater 111B-1A	10.50	35.61	25.11	01070060
Modified Heater 111B-1B	10.06	35.61	25.55	01070060
Heater 113B-1	2.57	8.40	5.83	01070060
Heater 113B-2	2.51	8.40	5.89	01070060
Heater 113B-3	2.58	8.40	5.82	01070060
FCCU Cat. Regen. 112D-1	13,742.27	13,675.00	- 67.27	01070060
		Total:	0.93	

Table II – Source-Wide Creditable Contemporaneous Emission Increases

Item of Equipment	Commencement of Operation Date	Emissions Increase (Tons/Year)	Permit Number
Heater 113B-1 - Installed Ultra-Low NO_x Burners	April 1998	1.91	98020008
Heater 111B-2 - Installed Ultra-Low NO_x Burners	February 2000	6.47	00010016
Vapor Recovery Unit w/Vapor Combustor	May 1998	2.11	98030075
Replacement Boiler (431B)	November 2001	23.55	01070039
	Total:	34.04	

Table III – Source-Wide Creditable Contemporaneous Emission Decreases

Item of Equipment	Commencement of Operational Change Date	Emissions Decrease (Tons/Year)	Permit Number
Boiler No. 19 Removed	November 2001	4.91	01070039

Table IV – Net Emissions Change

	(Tons/Year)
Increases and Decreases Associated With The Proposed Modification	0.93
Creditable Contemporaneous Emission Increases	34.04
Creditable Contemporaneous Emission Decreases	- 4.91
	- 30.06

Attachment 3

Nonattainment NSR Applicability - VOM Netting Analysis

Contemporaneous Time Period of 1997 Through 2001

Table I – Emissions Increases and Decreases Associated With The Proposed Modification

Item of Equipment	Past Actual (Tons/Yr)	Future Potential (Tons/Yr)	Emissions Change (Tons/Year)	Permit Number
Modified Heater 111B-1A	0.18	4.45	4.27	01070060
Modified Heater 111B-1B	0.17	4.45	4.28	01070060
Heater 113B-1	1.66	2.10	0.44	01070060
Heater 113B-2	1.63	2.10	0.47	01070060
Heater 113B-3	1.70	2.10	0.40	01070060
FCCU Cat. Regen. 112D-1	Neg.	Neg.	0.00	01070060
		Total:	9.86	

Table II – Source-Wide Creditable Contemporaneous Emission Increases

Item of Equipment	Commencement of Operation Date	Emissions Increase (Tons/Year)	Permit Number
Heater 113B-1 - Installed Ultra-Low NO_x Burners	April 1998	0.47	98020008
Vapor Recovery Unit w/Vapor Combustor (335B-1)	May 1998	25.82	98030075
Ethanol Storage at Fuels Rack (335TK-ETOH)	July 1997	3.72	97050098
Replacement Boiler (431B)	November 2001	5.88	01070039
	Total:	35.89	

Table III – Source-Wide Creditable Contemporaneous Emission Decreases

Item of Equipment	Commencement of Operational Change Date	Emissions Decrease (Tons/Year)	Permit Number
Tank (331TK-050) - Installed Cover on Floating Roof	May 1999	12.44	99030103
Tank (331TK-406) - Installed Cover on Floating Roof	May 1999	9.49	99030103
Removed Fuels Loading Rack Vapor Recovery Unit	June 1998	6.58	98030075
Heater 111B-2 - Installed Ultra-Low NO_x Burners	February 2000	2.73	00010016
Boiler No. 19 Removed	November 2001	0.27	01070039
	Total:	31.51	

Table IV – Net Emissions Change

	(Tons/Year)
Increases and Decreases Associated With The Proposed Modification	9.86
Creditable Contemporaneous Emission Increases	35.89
Creditable Contemporaneous Emission Decreases	- 31.51
	14.24