GOVERNMENT OF THE VIRGIN ISLANDS OF THE UNITED STATES

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DEPARTMENT OF PLANNING AND NATURAL RESOURCES
DIVISION OF ENVIRONMENTAL PROTECTION
45 MARS HILL
FREDERIKSTED, ST. CROIX, VI 00840
PHONE: (340) 773-1082, FAX: (340) 692-9794

Part 70 Operating Permit

Permit Number: STX-TV-003-10
Effective Date: July 01, 2010

Facility Name: LIMETREE BAY TERMINALS LLC
Facility Address: One Estate Hope
Christiansted, V.I. 00820-5652

Mailing Address: One Estate Hope
Christiansted, V.I. 00820-5652

Parent/Holding Company: LIMETREE BAY TERMINALS LLC
Primary SIC: 2911

In accordance with the provisions of the Virgin Islands Rules & Regulations (VIR&R), Title 12 Chapter 09, Section 206-51 adopted pursuant to or in effect under the Act, the Permittee described above is issued a Part 70 Permit for:

LIMETREE BAY TERMINALS LLC
Christiansted, V.I.

This Permit is conditioned upon compliance with all provisions of the VIR&R Title 12 Chapter 09, Section 206-51 adopted or in effect under that Act, or any other condition of this Permit. Unless modified or revoked, this Permit expires five years after the effective date indicated above.

This Permit may be subject to revocation, suspension, modification or amendment by the Director for cause including evidence of noncompliance with any of the above; or for any misrepresentation made in the Title V Application dated December 2007; amendments to that Title V Application dated June 13, 2008 and October 10, 2008; any other applications upon which this Permit is based; supporting data entered therein or attached thereto; or any subsequent submittal or supporting data; or for any alterations affecting the emissions from this source.

This Permit is further subject to and conditioned upon the terms, conditions, limitations, standards, or schedules contained in or on the attached 235 pages, which pages are a part of this Permit. A copy of this Permit shall be kept on-site at the above named facility at all times.

Dawn L. Henry, Esq.
Commissioner

March 15, 2016
Date

GOVERNMENT OF THE UNITED STATES VIRGIN ISLANDS
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DEPARTMENT OF PLANNING AND NATURAL RESOURCES
45 Mars Hill, Frederiksted
St. Croix, U.S. Virgin Islands 00840-4474

Office of the Commissioner

Telephone: (340) 773-1082
Facsimile: (340) 773-1716

March 9, 2016

Sloan Schoyer
General Manager
HOVENSA, LLC
#1 Estate Hope
Christiansted, St. Croix USVI 00820-5652

Alberto Van Gurp
Limetree Bay Terminals, LLC
Authorized Representative
#1 Estate Hope
Christiansted, St. Croix USVI 00820-5652

Re: Request for Title V Administrative Amendment: Transfer of Permit STX-TV-003-10 from HOVENSA to Limetree Bay Terminals, LLC

Dear Mr. Schoyer and Mr. Gurp:

The Department of Planning and Natural Resources is in receipt of your correspondence dated January 26, 2016, requesting a Title V administrative amendment for the transfer of Permit STX-TV-003-10 from HOVENSA, LLC to Limetree Bay Terminals, LLC. This request, was made in accordance with Title 12, Chapter 9, Sections 206-21(c), 206-52(c), 206-81(a)(4) of the Virgin Islands Rules and Regulations. The aforementioned sections of the Virgin Islands Rules and Regulations allow for the following permits to be transferred and incorporated in STX-TV -003-10:

- STX-797-A-B-09 Permit to Operate Vacuum Enhanced Recovery (VER)s 3 & 4 issued on January 25, 2010;
- STX-557-F-08 Permit to Operate #1 Vacuum Unit Compressor issued on October 30, 2008;
- STX-557- N-Z-08 Permit to Operate the HOVENSA Wastewater Plant issued on January 18, 2008; and
- 4. STX-804-10 Permit to Construct West Sulfur Pit Vent Control issued on November 17, 2010.

HOVENSA, LLC and Hess Oil Virgin Islands Corp along with Limetree Bay Terminals, LLC are parties to an Asset Purchase Agreement (APA) dated January 4, 2016 shifting assets from HOVENSA to Limetree Bay Terminals. This transfer of assets includes the Title V permit.

The Department has determined that this transfer was carried out in agreement with 12 V.I.R & REGS § 206-52(c)(1995). Therefore, the request is hereby approved as of the date of this letter.

If there are any questions or concerns, please feel free to contact Norman Williams, Director of the Division of Environmental Protection at norman.williams@dpnr.vi.gov.

Best Regards,

Dawn L. Henry, Esq.
Commissioner, DPNR

Part 70 Operating Permit

Permit Number: _STX-TV-003-10
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In accordance with the provisions of the Virgin Islands Rules & Regulations (VIR&R), Title 12 Chapter 09, Section 206-51 adopted pursuant to or in effect under the Act, the Permittee described above is issued a Part 70 Permit for:

LIMETREE BAY TERMINALS LLC
Christiansted, V.I.

This Permit is conditioned upon compliance with all provisions of the VIR&R Title 12 Chapter 09, Section 206-51 adopted or in effect under that Act, or any other condition of this Permit. Unless modified or revoked, this Permit expires five years after the effective date indicated above.

This Permit may be subject to revocation, suspension, modification or amendment by the Director for cause including evidence of noncompliance with any of the above; or for any misrepresentation made in the Title V Application dated December 2007; amendments to that Title V Application dated June 13, 2008 and October 10, 2008; any other applications upon which this Permit is based; supporting data entered therein or attached thereto; or any subsequent submittal or supporting data; or for any alterations affecting the emissions from this source.

This Permit is further subject to and conditioned upon the terms, conditions, limitations, standards, or schedules contained in or on the attached 235 pages, which pages are a part of this Permit. A copy of this Permit shall be kept on-site at the above named facility at all times.

Dawn L. Henry, Esq.
Commissioner

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Note: Citations in brackets provide underlying regulatory authority for permit requirements.

PART 1.0 FACILITY DESCRIPTION

1.1 Site Determination

The LIMETREE BAY TERMINALS LLC refinery is located on approximately 1,500 acres in the Southern Industrial Complex on the south central coast of St. Croix, U.S. Virgin Islands. Figure 1 presents the general plot plan of the LIMETREE BAY TERMINALS LLC refinery.

1.2 Previous and/or Other Names

Operations at the facility began in 1965 under the Hess Oil Virgin Islands Corporation (HOVIC). On October 30, 1998, Amerada Hess Corporation, the parent company of HOVIC, and Petroleos de Venezuela, S.A. (PDVSA) formed a new corporation, HOVENSA L.L.C. (HOVENSA), which acquired ownership and operational control of the St. Croix refinery formerly known as HOVIC.

1.3 Overall Facility Process Description

LIMETREE BAY TERMINALS LLC's current design capacity is 545,000 barrels of crude oil per day. The refinery is capable of receiving and processing crude oil from all over the world (over 60 different types of crude oil have been processed at the facility), although the majority of its crude oil is received from Venezuela. The refinery consists of three separate processing complexes: the West Refinery, which was constructed in the late 1960s; the East Refinery, which was constructed in the early 1970s; and the Deep Conversion Complex, which includes the Fluid Catalytic Cracking Complex and the Delayed Coker Unit Complex. Former owner HOVENSA has also been constructing units that will enable the refinery to better produce lower sulfur fuels. Construction of the Low Sulfur Gasoline Unit has already been completed, and combustion turbine GT-13 and its duct-fired heat recovery stream generator (HRSG) are currently under construction. Construction of the Hydrogen Plant has not yet begun. Table 1 provides a list of the emissions units at LIMETREE BAY TERMINALS LLC.

The refinery operations begin by using atmospheric and vacuum distillation processes, where the crude oil is separated into various components. Figure 2 shows the refining processes. Light ends (fuel gas) are sent to the facility's fuel system, while naphtha, jet fuel, kerosene, and No. 2 oil are further processed to remove sulfur. The hydrogen sulfide gas generated from the desulfurization process is sent to the sulfur recovery plant to be treated by Claus units and Beavon tail gas treating units. The recovered sulfur is pelletized for sale. Desulfurized naphtha is sent to reforming units which upgrade the naphtha to higher octane gasoline components. Light reformates are sent to the aromatic recovery units which produce sales-grade pure benzene, toluene, and xylenes. Light straight run (LSR) pentanes from the crude distillation units are isomerized in the Penex process. Heavy atmospheric gas oil (HAGO) from the crude distillation units is blended into No. 6 oil. Bottom residues from atmospheric distillation are processed by the vacuum distillation units to form vacuum gas oil (VGO) and pitch (high sulfur (HS) No. 6 oil). The VGO is then desulfurized to produce low sulfur (LS) No. 6 oil. The pitch may be thermally cracked in the visbreaker unit to product distillates and residual tar (HS No. 6 oil) or in the delayed coker unit (DCU) to produce light products and petroleum coke.

In 1993, former owner HOVENSA brought online a state-of-the-art Fluid Catalytic Cracking unit (FCCU) which has a current charge rate of 165,000 barrels per day. The FCCU operates by cracking heavy gas oil and residual oils in the presence of a catalyst to yield lighter products, and is capable of producing over 130,000 barrels per day of gasoline that meets U.S. environmental standards. Former owner HOVENSA and now LIMETREE BAY TERMINALS LLC also operates a delayed coking unit

(Coker) that was brought on-line in August 2002. The coker uses lower cost heavy oils (oils with a higher sulfur content) to manufacture gasoline and heating oil.

The LIMETREE BAY TERMINALS LLC refinery operates 24 hours per day, 365 days per year, and has over 900 employees, as well as an additional 500 to 2,000 contract workers. The facility has its own fire department, security force, infirmary and ambulance, cafeteria, laboratories, and utilities.

LIMETREE BAY TERMINALS LLC operates a 45 to 60 foot deep harbor which is able to accommodate supertankers. All crude oil and most finished products are transported by means of tanker ships. The refinery typically has an overall storage capacity of over 30 million barrels of both crude and finished products.

1.4 Requirements for Individual Emission Units

Parts 3, 4, 5 and 6 of this permit specify the requirements that apply to emission units at the facility. Part 3 contains the emission and operational limitations, Part 4 contains the testing requirements, Part 5 contains the monitoring requirements, and Part 6 contains the recordkeeping and reporting requirements. Table 2 provides a summary by individual emission unit or emission unit grouping of the specific location within this Title V permit for each emission or operational limitation and locations of the testing, monitoring, recordkeeping and reporting requirements that apply to that emission or operational limitation.

Figure 1. Plot plan of LIMETREE BAY TERMINALS LLC Refinery (Source: December 2007 Title V Application)

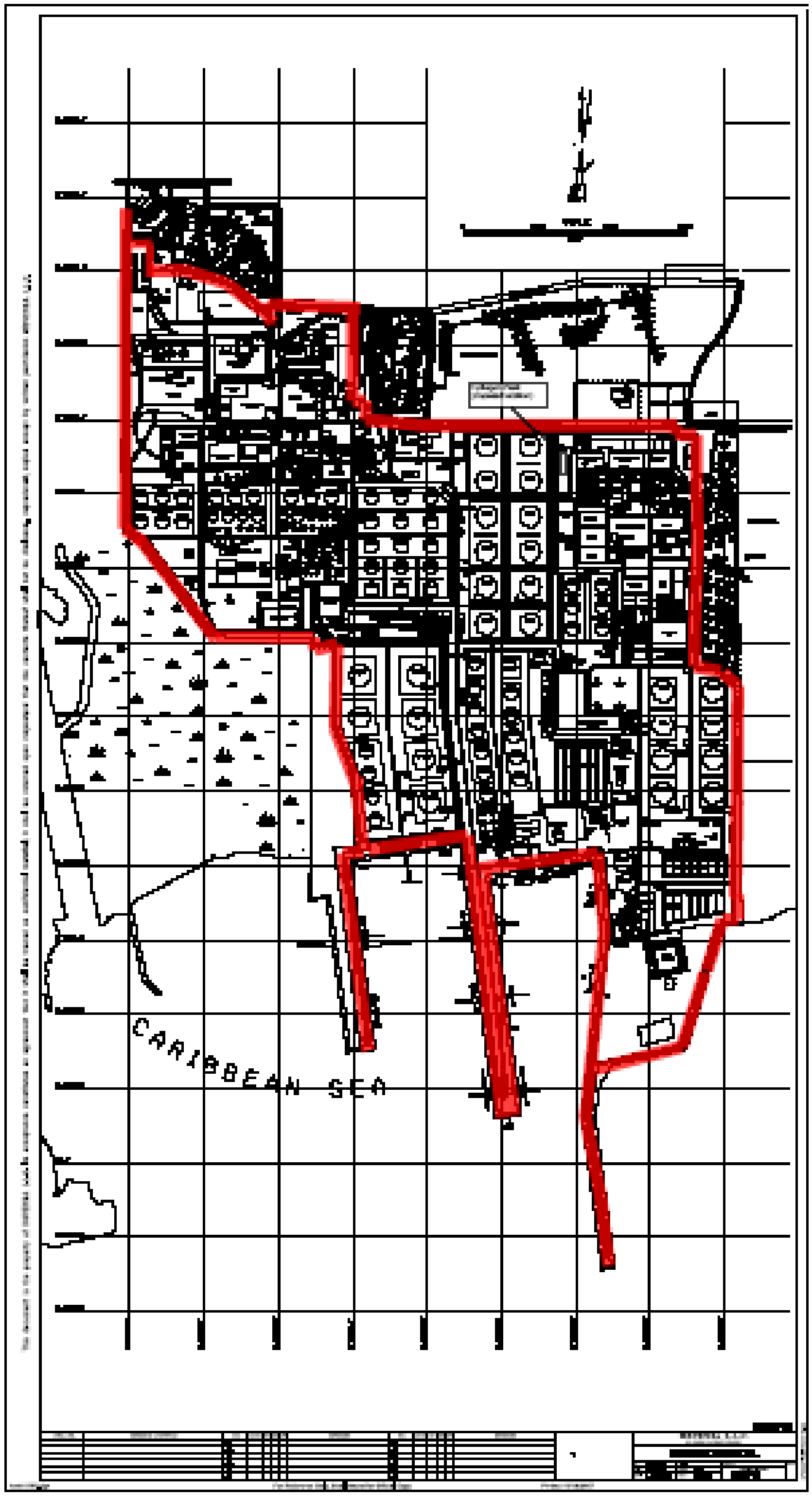


Table 1. LIMETREE BAY TERMINALS LLC Refinery Emission Units

Plant Area	Process Unit	Source ID(s)	Unit Description	Permit ID Group
Area I	#2 DU Fractionator	H-101	Heater	02
Area I	#2 DU Fractionator	H-104	Heater	02
Area I	#2 CDU	H-401A	Charge Heater	02
Area I	#2 CDU	H-401B	Charge Heater	02
Area I	#2 CDU	H-401C	Charge Heater	02
Area I	#3 CDU	H-1401A	Charge Heater	02
Area I	#1 VAC	H-1401B	Charge Heater	02
Area I	#3 DD	H-1500	Reactor Charge Heater	02
Area I	#3 DD	H-1501	Fractionator Reboiler Heater	02
Area I	#3 DD	C-1500A	Reciprocating Gas Compressor	03
Area I	#3 DD	C-1500B	Reciprocating Gas Compressor	03
Area I	#3 DD	C-1500C	Reciprocating Gas Compressor	03
Area I	Penex	H-200	Charge Heater	02
Area I	Penex	H-201	Fired Reboiler Heater	02
Area I	Penex	H-202	Hot Oil Heater	02
Area I	Penex	C-200A	Reciprocating Gas Compressor	03
Area I	Penex	C-200B	Reciprocating Gas Compressor	03
Area I	Penex	C-200C	Reciprocating Gas Compressor	03
Area I	#3 Amine	Unit No. 0920	Amine Unit	21
Area I	Utility Fractionation	H-160	Charge Heater	02
Area II	#2 Platformer	H-600	Unifining Charge Heater	02
Area II	#2 Platformer	H-601	Stripper Reboiler Heater	02
Area II	#2 Platformer	H-602	Platforming Charge Heater	02
Area II	#2 Platformer	H-603	Platforming No. 1 Interheater	02
Area II	#2 Platformer	H-604	Platforming No. 2 Interheater	02
Area II	#2 Platformer	H-605	Platforming No. 3 Interheater	02
Area II	#2 Platformer	H-606	Depentanizer Reboiler Heater	02
Area II	#2 DU	H-800A	Reactor Charge Heater	02

Plant Area	Process Unit	Source ID(s)	Unit Description	Permit ID Group
Area II	#2 DU	H-800B	Reactor Charge Heater	02
Area II	#2 DU	H-801	Stripper Heater	02
Area II	#2 VAC	H-2101	Charge Heater	02
Area II	#2 VAC	H-2102	Charge Heater	02
Area II	#2 Visbreaker	H-2185	Visbreaking Heater	02
Area II	#4 DD	H-2201A	Reactor Charge Heater	02
Area II	#4 DD	H-2201B	Reactor Charge Heater	02
Area II	#4 DD	H-2202	Stripper Reboiler Heater	02
Area II	#5 DD	H-2400	Charge Heater	02
Area II	#5 DD	H-2401	Reboiler Heater	02
Area II	#5 DD	C-2400A	Reciprocating Gas Compressor	03
Area II	#5 DD	C-2400B	Reciprocating Gas Compressor	03
Area II	Naphtha Fractionation	H-2501	Reboiler Heater	02
Area II	#2 Platformer	#2 Plat Vent	Plat No. 2 Catalyst Regen Vent	25
Area II	Hydrogen Concentration Unit	Unit No. 0801	Hydrogen Recovery	23
Area II	#1 Gas Recovery Unit	Unit No. 2300	Gas Stripper	22
Area III	#2 Sulfolane	H-4502	Benzene Column Reboiler Heater	02
Area III	#2 Sulfolane	H-4503	Toluene Column Reboiler Heater	02
Area III	#2 Sulfolane	H-4504	Xylene Column Reboiler Heater	02
Area III	#2 Sulfolane	H-4505	Raffinate Splitter Reboiler Heater	02
Area III	#5 CDU	H-3101A	Crude Charge Heater	02
Area III	#5 CDU	H-3101B	Crude Charge Heater	02
Area III	#6 CDU	H-4101A	Crude Charge Heater	02
Area III	#6 CDU	H-4101B	Crude Charge Heater	02
Area III	#2 Gas Recovery Unit	Unit No. 4850	Gas Stripper	22
Area III	Disulfide Handling	Unit No. 4810	Disulfide Washing, etc	24
Area III	Gas Treatment	Unit No. 3200	Gas Treating	22
Area III	Gas Treatment	Unit No. 4800	Gas Treating	22
Area III	Gas Treatment	Unit No. 5800	Gas Treating	22
Area IV	#3 Platformer	H-4401	Charge Heater	02
Area IV	#3 Platformer	H-4402	Fired Reboiler Heater	02
Area IV	#3 Platformer	H-4451	Charge Heater	02
Area IV	#3 Platformer	H-4452	Intermediate Heater	02
Area IV	#3 Platformer	H-4453	Intermediate Heater	02

Plant Area	Process Unit	Source ID(s)	Unit Description	Permit ID Group
Area IV	#3 Platformer	H-4454	Intermediate Heater	02
Area IV	#3 Platformer	H-4455	Fired Reboiler Heater	02
Area IV	#3 VAC	H-4201	Prestripper Heater	02
Area IV	#3 VAC	H-4202	Vacuum Heater	02
Area IV	#4 Platformer	H-5401	Charge Heater	02
Area IV	#4 Platformer	H-5402	Fired Reboiler Heater	02
Area IV	#4 Platformer	H-5451	Charge Heater	02
Area IV	#4 Platformer	H-5452	Intermediate Heater	02
Area IV	#4 Platformer	H-5453	Intermediate Heater	02
Area IV	#4 Platformer	H-5454	Intermediate Heater	02
Area IV	#4 Platformer	H-5455	Fired Reboiler Heater	02
Area IV	#6 DD	H-4601A	Reactor Charge Heater	02
Area IV	#6 DD	H-4601B	Reactor Charge Heater	02
Area IV	#6 DD	H-4602	Stripper Reboiler Heater	02
Area IV	#6 DD	C-4601A	Reciprocating Gas Compressor	03
Area IV	#6 DD	C-4601B	Reciprocating Gas Compressor	03
Area IV	#6 DD	C-4601C	Reciprocating Gas Compressor	03
Area IV	#7 DD	H-4301A	Reactor Charge Heater	02
Area IV	#7 DD	H-4301B	Reactor Charge Heater	02
Area IV	#7 DD	H-4302	Stripper Reboiler Heater	02
Area IV	#9 DD	H-5301A	Reactor Charge Heater	02
Area IV	#9 DD	H-5301B	Reactor Charge Heater	02
Area IV	#9 DD	H-5302	Stripper Reboiler Heater	02
Area IV	LSG Unit	H-4901	Charge Heater	02
Area IV	Hydrogen Plant[a]	See footnote a.	Hydrogen Plant Heater	02
Area IV	#3 Platformer	#3 Plat Vent	Plat No. 3 Catalyst Regen Vent	25
Area IV	#4 Platformer	#4 Plat Vent	Plat No. 4 Catalyst Regen Vent	25
Area V	Alkylation Unit	Unit No. 7200	Process Unit	14
Area V	Dimersol Unit	Unit No. 7300	Produce gasoline through catalytic reaction of light hydrocarbons	14
Area V	FCCU	STK-7051	Fluid Catalytic Cracking	16
Area V	Gas Concentration	Unit No. 7100	Process Unit	21

Plant Area	Process Unit	Source ID(s)	Unit Description	Permit ID Group
Area V	#6 Amine	Unit No. 7450	Process Unit	21
Area V	#6 Amine	Unit No. 7600	Process Unit	21
Area V	#7 Amine Unit	Unit No. 7460	Remove hydrogen sulfide from refinery gas and light hydrocarbons	21
Area V	Merox Unit	Unit No. 7500	Remove hydrogen sulfide and mercaptans	21
Area V	Sulfuric Acid Plant	STK-7801	Heater Stack	18
Area V	Sulfuric Acid Plant	H-7801	Process Air Heater	02
Area V	Sulfuric Acid Plant	H-7802	Converter Heater	02
Area V	Sulfuric Acid Plant	R-7801	Startup Heater	02
Area V	Sulfuric Acid Plant	STK-7802	Process Stack	18
Area VI	#1 SRU	Unit No. 1030	Sulfur Recovery Units	07
Area VI	#2 SRU	Unit No. 1040	Sulfur Recovery Units	07
Area VI	#1 SRU Incinerator	H-1032	Tail Gas Incinerator	07
Area VI	#2 SRU Incinerator	H-1042	Tail Gas Incinerator	07
Area VI	#1 Beavon	H-1061 (and T-1061)	Sulfur Recovery Units, Tail gas treatment	07
Area VI	#3 SRU	Unit No. 4740	Sulfur Recovery Units	07
Area VI	#2 Beavon	H-4761 (and T-4761)	Tail Gas Treatment	07
Area VI	#4 SRU	Unit No. 4750	Sulfur Recovery Units	07
Area VI	East Incinerator	H-4745	Tail Gas Incinerator	07
Area VI	# 1 Beavon	Beavon CT #1	Beavon CT #1	07
Area VI	# 2 Beavon	Beavon CT #2	Beavon CT #2	07
Area VI	Advanced Wastewater Treatment System	#1 API (Unit No. 1660)	Oil/Water Separator	13
Area VI	Advanced Wastewater Treatment System	#1 WEMCO	Induced Air Floatation Unit	13
Area VI	Advanced Wastewater Treatment System	#1 Lagoon	Aerated Lagoon	13
Area VI	Advanced Wastewater Treatment System	#2 API (Unit No. 1661)	Oil/Water Separator	13
Area VI	Advanced Wastewater Treatment System	#2 WEMCO	Induced air floatation unit	13
Area VI	Advanced Wastewater	#2 Lagoon	Aerated lagoon	13

Plant Area	Process Unit	Source ID(s)	Unit Description	Permit ID Group
	Treatment System			
Area VI	Advanced Wastewater Treatment System	West Benzene Stripper (STK-3510)	Air Stripper	13
Area VI	Advanced Wastewater Treatment System	#3 API (Unit No. 1662)	Oil/Water Separator	13
Area VI	Advanced Wastewater Treatment System	#3 WEMCO	Induced air floatation unit	13
Area VI	Advanced Wastewater Treatment System	#3 Lagoon	Aerated lagoon	13
Area VI	Advanced Wastewater Treatment System	East Benzene Stripper (STK-3530)	Air Stripper	13
Area VI	Advanced Wastewater Treatment System	#3 & 4 Sour Water Strippers (Unit No. 4720/30)	Steam Stripper	13
Area VI	Advanced Wastewater Treatment System	#5 Sour Water Stripper (Unit No. 7400)	Steam Stripper	13
Area VI	Advanced Wastewater Treatment System	#6 Sour Water Stripper	Steam Stripper	13
Area VI	Advanced Wastewater Treatment System	CPS Oil/Water Separator	Oil/Water Separator	13
Area VI	West Sulfur Storage Area	Materials Handling	Materials Handling	07
Area VI	East Sulfur Storage Area	Materials Handling	Materials Handling	07
Area VI	Refinery Flare System	#2 Flare (H-1105)	Gas burner	05
Area VI	Refinery Flare System	#3 Flare (H-1104)	Gas burner	05
Area VI	Refinery Flare System	#5 Flare (H-3351)	Gas burner	05
Area VI	Refinery Flare System	#6 Flare (H-3352)	Gas burner	05
Area VI	Refinery Flare System	#7 Flare (H-3301)	Gas burner	05
Area VI	Refinery Flare System	LPG Flare (STK 7921)	Gas burner, steam assisted	05
Area VI	Refinery Flare System	FCC Flare (L.P. Flare - STK 7941)	Gas burner, steam assisted	05
Area VI	Refinery Flare System	Ground Flare (H.P. Flare - STK 7942)	Gas burner	05
Area VII	Delayed Coker Unit	H-8501A	Coker process heater 1	02
Area VII	Delayed Coker	H-8501B	Coker process heater	02

Plant Area	Process Unit	Source ID(s)	Unit Description	Permit ID Group
	Unit		2	
Area VII	Delayed Coker Unit	TK-8501 (Hot pitch tank)	Fixed roof storage tank (pitch)	10
Area VII	Coker Complex	Coke handling, storage, and loading system	Transportation and breaking of solid coke between drums and dock	17
Area VII	Coker Complex	Tank TK-8511 and Residuals Recycling System	Tank TK-8511 and recycling system	17
Area VIII	Utility II	#1 Boiler (B-1151)	Boiler; Produces Steam	01
Area VIII	Utility II	#3 Boiler (B-1153)	Boiler; Produces Steam	01
Area VIII	Utility II	#4 Boiler (B-1154)	Boiler; Produces Steam	01
Area VIII	Utility II	#5 Boiler (B-1155)	Boiler; Produces Steam	01
Area VIII	Utility III	#6 Boiler (B-3301)	Boiler; Produces Steam	01
Area VIII	Utility III	#7 Boiler (B-3302)	Boiler; Produces Steam	01
Area VIII	Utility III	#8 Boiler (B-3303)	Boiler; Produces Steam	01
Area VIII	Utility III	#9 Boiler (B-3304)	Boiler; Produces Steam	01
Area VIII	Utility III	#10 Boiler (B-3701)	Boiler; Produces Steam	01
Area VIII	Powerhouse 1	GT No. 1 (G-1101E)	Turbine; Produces Electricity	04
Area VIII	Powerhouse 1	GT No. 2 (G-1101F)	Turbine; Produces Electricity	04
Area VIII	Powerhouse 1	GT No. 3 (G-1101G)	Turbine; Produces Electricity	04
Area VIII	Powerhouse 2	GT No. 4 (G-3404)	Turbine; Produces Electricity	04
Area VIII	Powerhouse 2	GT No. 5 (G-3405)	Turbine; Produces Electricity	04
Area VIII	Powerhouse 2	GT No. 6 (G-3406)	Turbine; Produces Electricity	04
Area VIII	Powerhouse 2	GT No. 7 (G-3407)	Turbine; Produces Electricity	04
Area VIII	Powerhouse 2	GT No. 8 (G-3408)	Turbine; Produces Electricity	04
Area VIII	Powerhouse 2	GT No. 9 (G-3409)	Turbine; Produces Electricity	04
Area VIII	Powerhouse 2	GT No. 10 (G-3410)	Turbine; Produces Electricity	04
Area VIII	GT No. 13 and Duct Burner	GT No. 13 (G-3413)	Turbine; Produces Electricity	04
Area VIII	GT No. 13 and	H-3413	Duct Burner;	02

Plant Area	**Process Unit**	**Source ID(s)**	**Unit Description**	**Permit ID Group**
	Duct Burner		Produces Steam	
Area IX	Tank	TK-1071	External Floating Roof	09
Area IX	Tank	TK-1151	Fixed Roof	10
Area IX	Tank	TK-1156	Internal Floating Roof	08
Area IX	Tank	TK-1157	Internal Floating Roof	08
Area IX	Tank	TK-1201	Fixed Roof	10
Area IX	Tank	TK-1202	Fixed Roof	10
Area IX	Tank	TK-1203	Fixed Roof	10
Area IX	Tank	TK-1206	Fixed Roof	10
Area IX	Tank	TK-1207	Fixed Roof	10
Area IX	Tank	TK-1208	Fixed Roof	10
Area IX	Tank	TK-1302	Fixed Roof	10
Area IX	Tank	TK-1626	Horizontal	11
Area IX	Tank	TK-1627	Horizontal	11
Area IX	Tank	TK-1628	Horizontal	11
Area IX	Tank	TK-1629	Horizontal	11
Area IX	Tank	TK-1630	Horizontal	11
Area IX	Tank	TK-1631	Horizontal	11
Area IX	Tank	TK-1632	Horizontal	11
Area IX	Tank	TK-1633	Horizontal	11
Area IX	Tank	TK-1653	Fixed Roof	10
Area IX	Tank	TK-1663	External Floating Roof	09
Area IX	Tank	TK-2653	Fixed Roof	10
Area IX	Tank	TK-2654	Fixed Roof	10
Area IX	Tank	TK-3208	Fixed Roof	10
Area IX	Tank	TK-3301	Fixed Roof	10
Area IX	Tank	TK-3302	Geodesic Dome	12
Area IX	Tank	TK-3304	Fixed Roof	10
Area IX	Tank	TK-3306	Fixed Roof	10
Area IX	Tank	TK-3384	Fixed Roof	10
Area IX	Tank	TK-3385	Fixed Roof	10
Area IX	Tank	TK-3386	Fixed Roof	10
Area IX	Tank	TK-4501	Internal Floating Roof	08
Area IX	Tank	TK-4502	Fixed Roof	10
Area IX	Tank	TK-4503	Internal Floating Roof	08
Area IX	Tank	TK-4725	External Floating Roof	09
Area IX	Tank	TK-4726	External Floating Roof	09
Area IX	Tank	TK-6801	External Floating Roof	09
Area IX	Tank	TK-6802	External Floating Roof	09
Area IX	Tank	TK-6803	External Floating	09

Plant Area	Process Unit	Source ID(s)	Unit Description	Permit ID Group
			Roof	
Area IX	Tank	TK-6804	External Floating Roof	09
Area IX	Tank	TK-6805	External Floating Roof	09
Area IX	Tank	TK-6806	External Floating Roof	09
Area IX	Tank	TK-6807	External Floating Roof	09
Area IX	Tank	TK-6808	External Floating Roof	09
Area IX	Tank	TK-6809	External Floating Roof	09
Area IX	Tank	TK-6810	Fixed Roof	10
Area IX	Tank	TK-6811	Fixed Roof	10
Area IX	Tank	TK-6812	Fixed Roof	10
Area IX	Tank	TK-6813	Fixed Roof	10
Area IX	Tank	TK-6814	External Floating Roof	09
Area IX	Tank	TK-6815	External Floating Roof	09
Area IX	Tank	TK-6816	External Floating Roof	09
Area IX	Tank	TK-6817	Fixed Roof	10
Area IX	Tank	TK-6818	Fixed Roof	10
Area IX	Tank	TK-6819	Fixed Roof	10
Area IX	Tank	TK-6820	Fixed Roof	10
Area IX	Tank	TK-6821	Fixed Roof	10
Area IX	Tank	TK-6822	Fixed Roof	10
Area IX	Tank	TK-6823	Fixed Roof	10
Area IX	Tank	TK-6824	Fixed Roof	10
Area IX	Tank	TK-6825	Fixed Roof	10
Area IX	Tank	TK-6831	Internal Floating Roof	08
Area IX	Tank	TK-6832	Internal Floating Roof	08
Area IX	Tank	TK-6833	External Floating Roof	09
Area IX	Tank	TK-6834	External Floating Roof	09
Area IX	Tank	TK-6835	External Floating Roof	09
Area IX	Tank	TK-6836	External Floating Roof	09
Area IX	Tank	TK-6837	External Floating Roof	09
Area IX	Tank	TK-6838	External Floating Roof	09
Area IX	Tank	TK-6839	External Floating Roof	09

Plant Area	Process Unit	Source ID(s)	Unit Description	Permit ID Group
Area IX	Tank	TK-6840	External Floating Roof	09
Area IX	Tank	TK-6841	Internal Floating Roof	08
Area IX	Tank	TK-6842	External Floating Roof	09
Area IX	Tank	TK-6843	Internal Floating Roof	08
Area IX	Tank	TK-6851	Fixed Roof	10
Area IX	Tank	TK-6852	Internal Floating Roof	08
Area IX	Tank	TK-6853	Fixed Roof	10
Area IX	Tank	TK-6854	Fixed Roof	10
Area IX	Tank	TK-6856	Fixed Roof	10
Area IX	Tank	TK-6858	Fixed Roof	10
Area IX	Tank	TK-6871	Fixed Roof with Carbon Canisters	10
Area Ix	Tank	TK-6872	Fixed Roof with Carbon Canisters	10
Area IX	Tank	TK-6873	Fixed Roof	10
Area IX	Tank	TK-6874	Fixed Roof with Carbon Canisters	10
Area IX	Tank	TK-6875	Fixed Roof	10
Area IX	Tank	TK-6876	Fixed Roof	10
Area IX	Tank	TK-6877	Fixed Roof	10
Area IX	Tank	TK-6881	Fixed Roof	10
Area IX	Tank	TK-6883	Fixed Roof	10
Area IX	Tank	TK-6884	Internal Floating Roof	08
Area IX	Tank	TK-6887	Fixed Roof	10
Area IX	Tank	TK-6888	Internal Floating Roof	08
Area IX	Tank	TK-700	Fixed Roof	10
Area IX	Tank	TK-701	Fixed Roof	10
Area IX	Tank	TK-702	Fixed Roof	10
Area IX	Tank	TK-7206	Fixed Roof	10
Area IX	Tank	TK-7207	Fixed Roof	10
Area IX	Tank	TK-7208	Fixed Roof	10
Area IX	Tank	TK-7209	Fixed Roof	10
Area IX	Tank	TK-7210	Fixed Roof	10
Area IX	Tank	TK-7211	Fixed Roof	10
Area IX	Tank	TK-7401	External Floating Roof	09
Area IX	Tank	TK-7402	External Floating Roof	09
Area IX	Tank	TK-7403	External Floating Roof	09
Area IX	Tank	TK-7404	External Floating Roof	09
Area IX	Tank	TK-7405	Fixed Roof	10

Plant Area	Process Unit	Source ID(s)	Unit Description	Permit ID Group
Area IX	Tank	TK-7406	Fixed Roof	10
Area IX	Tank	TK-7407	External Floating Roof	09
Area IX	Tank	TK-7408	External Floating Roof	09
Area IX	Tank	TK-7409	External Floating Roof	09
Area IX	Tank	TK-7410	External Floating Roof	09
Area IX	Tank	TK-7411	Fixed Roof	10
Area IX	Tank	TK-7412	Fixed Roof	10
Area IX	Tank	TK-7413	Fixed Roof	10
Area IX	Tank	TK-7414	Fixed Roof	10
Area IX	Tank	TK-7415	Fixed Roof	10
Area IX	Tank	TK-7416	Fixed Roof	10
Area IX	Tank	TK-7417	Internal Floating Roof	08
Area IX	Tank	TK-7418	Internal Floating Roof	08
Area IX	Tank	TK-7421	Fixed Roof	25
Area IX	Tank	TK-7422	Fixed Roof	25
Area IX	Tank	TK-7423	External Floating Roof	09
Area IX	Tank	TK-7424	External Floating Roof	09
Area IX	Tank	TK-7425	Internal Floating Roof	08
Area IX	Tank	TK-7426	Internal Floating Roof	08
Area IX	Tank	TK-7427	Fixed Roof	10
Area IX	Tank	TK-7428	Fixed Roof	10
Area IX	Tank	TK-7429	Fixed Roof	10
Area IX	Tank	TK-7430	Fixed Roof	10
Area IX	Tank	TK-7431	Internal Floating Roof	08
Area IX	Tank	TK-7432	Internal Floating Roof	08
Area IX	Tank	TK-7433	Internal Floating Roof	08
Area IX	Tank	TK-7434	Internal Floating Roof	08
Area IX	Tank	TK-7435	Fixed Roof	10
Area IX	Tank	TK-7436	Fixed Roof	10
Area IX	Tank	TK-7437	Fixed Roof	10
Area IX	Tank	TK-7438	Fixed Roof	10
Area IX	Tank	TK-7439	Fixed Roof	10
Area IX	Tank	TK-7440	Fixed Roof	10
Area IX	Tank	TK-7441	Internal Floating Roof	08
Area IX	Tank	TK-7443	External Floating	09

Plant Area	Process Unit	Source ID(s)	Unit Description	Permit ID Group
			Roof	
Area IX	Tank	TK-7444	External Floating Roof	09
Area IX	Tank	TK-7445	External Floating Roof	09
Area IX	Tank	TK-7446	Fixed Roof	10
Area IX	Tank	TK-7447	External Floating Roof	09
Area IX	Tank	TK-7448	Internal Floating Roof	08
Area IX	Tank	TK-7449	External Floating Roof	09
Area IX	Tank	TK-7451	Internal Floating Roof	08
Area IX	Tank	TK-7452	Internal Floating Roof	08
Area IX	Tank	TK-7453	Internal Floating Roof	08
Area IX	Tank	TK-7454	Internal Floating Roof	08
Area IX	Tank	TK-7455	External Floating Roof	09
Area IX	Tank	TK-7456	External Floating Roof	09
Area IX	Tank	TK-7501	Fixed Roof	10
Area IX	Tank	TK-7502	Fixed Roof	10
Area IX	Tank	TK-7503	Fixed Roof	10
Area IX	Tank	TK-7504	Fixed Roof	10
Area IX	Tank	TK-7505	Fixed Roof	10
Area IX	Tank	TK-7506	Fixed Roof	10
Area IX	Tank	TK-7507	External Floating Roof	09
Area IX	Tank	TK-7508	External Floating Roof	09
Area IX	Tank	TK-7509	External Floating Roof	09
Area IX	Tank	TK-7510	External Floating Roof	09
Area IX	Tank	TK-7511	External Floating Roof	09
Area IX	Tank	TK-7512	External Floating Roof	09
Area IX	Tank	TK-7513	External Floating Roof	09
Area IX	Tank	TK-7514	External Floating Roof	09
Area IX	Tank	TK-7515	External Floating Roof	09
Area IX	Tank	TK-7516	External Floating Roof	09

Plant Area	Process Unit	Source ID(s)	Unit Description	Permit ID Group
Area IX	Tank	TK-7517	External Floating Roof	09
Area IX	Tank	TK-7521	Internal Floating Roof	08
Area IX	Tank	TK-7522	Internal Floating Roof	08
Area IX	Tank	TK-7523	Internal Floating Roof	08
Area IX	Tank	TK-7524	Internal Floating Roof	08
Area IX	Tank	TK-7525	Internal Floating Roof	08
Area IX	Tank	TK-7526	Internal Floating Roof	08
Area IX	Tank	TK-7528	Internal Floating Roof	08
Area IX	Tank	TK-7601	Internal Floating Roof	08
Area IX	Tank	TK-7602	Internal Floating Roof	08
Area IX	Tank	TK-7603	Internal Floating Roof	08
Area IX	Tank	TK-7604	Internal Floating Roof	08
Area IX	Tank	TK-7605	External Floating Roof	09
Area IX	Tank	TK-7933	Fixed Roof	10
Area IX	Tank	TK-7934	Fixed Roof	10
Area IX	Tank	TK-7974	Internal Floating Roof	08
Area IX	Tank	D-1301	Horizontal	11
Area IX	Tank	D-1609	Horizontal	11
Area IX	Tank	D-1610	Horizontal	11
Area IX	Tank	D-1620	UST / Horizontal	11
Area IX	Tank	TK-8001	Internal Floating Roof	13
Area IX	Tank	TK-8002	Internal Floating Roof	13
Area IX	Tank	PRT1	Internal Floating Roof	08
Area IX	Tank	PRT2	Internal Floating Roof	08
Area IX	Tank	PRT3	Fixed Roof	10
Area IX	Tank	PRT4	Fixed Roof	10
Area IX	Tank	PRT5	Fixed Roof	10
Area IX	Tank	PRT6	Fixed Roof	10
Area IX	Tank	PRT7	Fixed Roof	10
Area IX	Tank	TK-6860	Fixed Roof	10
Area IX	Tank	TK-6859	Fixed Roof	10
Area IX	Tank	S-7974	External Floating	09

Plant Area	Process Unit	Source ID(s)	Unit Description	Permit ID Group
			Roof	
Area IX	Tank	S-7975	External Floating Roof	09
Area IX	Tank	UTT1	Fixed Roof	10
Area IX	Tank	TK-1118	Fixed Roof	10
Area IX	Tank	TK-1204	Fixed Roof	10
Area IX	Tank	TK-1205	Fixed Roof	10
Area IX	Tank	TK-1600	Fixed Roof	10
Area IX	Tank	TK-3201	Fixed Roof	10
Area IX	Tank	TK-3202	Fixed Roof	10
Area IX	Tank	TK-3204	Fixed Roof	10
Area IX	Tank	TK-3208	Fixed Roof	10
Area IX	Tank	TK-3209	Fixed Roof	10
Area IX	Tank	TK-7201	Fixed Roof	10
Area IX	Tank	TK-7301	Fixed Roof	10
Area IX	Tank	TK-7302	Fixed Roof	10
Area IX	Tank	TK-7542	Fixed Roof	10
Area IX	Tank	TK-7571	Fixed Roof	10
Area IX	Tank	TK-7943	Fixed Roof	10
Area IX	Tank	D-290	Horizontal	11
Area X	Seawater and Desalination Water Pumps	PD-1602	Seawater intake pump	15
Area X	Seawater and Desalination Water Pumps	PD-1603	Seawater intake pump	15
Area X	Seawater and Desalination Water Pumps	PD-1604	Seawater intake pump	15
Area X	Seawater and Desalination Water Pumps	PD-1605	Seawater intake pump	15
Area X	Seawater and Desalination Water Pumps	PD-1620	Seawater intake pump	15
Area X	Marine Loading (Docks 1 thru 9 and Dry Cargo Dock)	Unit No. 1600	Ship loading and unloading	06
Area X	Truck loading rack	Unit No. 1651	Dispense liquid and gaseous fuel to tank trucks	06
Area X	Fuel pumps	Gasoline Service Station	Dispense gasoline and diesel	20
Area X	Piping	Unit No. 1902	East/West fuel gas system	20
Area X	Piping	Unit No. 3303	East/West fuel gas system	20
Area X	Storage pile and	N/A	Sulfur storage and	06

Plant Area	Process Unit	Source ID(s)	Unit Description	Permit ID Group
	conveyor		ship loading	
Area X	Vapor Enhanced Recovery System	VER 1	Extracts liquids and air from groundwater wells to remediate contaminated soils and groundwater.	19
Area X	Vapor Enhanced Recovery System	VER 2	Extracts liquids and air from groundwater wells to remediate contaminated soils and groundwater.	19

[a]As of August 22, 2008, construction of this unit had not yet begun; thus, a heater ID number was not assigned.

Table 2. Summary of Locations of Emission or Operational Limits and Associated Requirements for Testing, Monitoring, Recordkeeping, and Reporting

Group	Description	Requirement for Emissions Units	Testing Requirement	Monitoring Requirement	Recordkeeping Requirement	Reporting Requirement
01	All Boilers	3.1.1.1	NA	5.2.2.1	NA	NA
		3.2.1.1	NA	5.2.1.4	NA	NA
01A	Boilers B-1151, B-1153, B-1154, B-1155	3.1.1.3.1	NA	5.2.1.5.1	NA	NA
		3.2.1.2.1	NA	5.2.1.5.2	NA	NA
		3.2.1.2.2	NA	5.2.1.5.2	NA	NA
		3.2.1.2.3	4.2.1.1.1	5.2.1.5.3	NA	5.3.1.1.1
01B	Boilers B-3301, B-3302, B-3303, B-3304	3.1.1.4.1	NA	5.2.1.6.2	NA	NA
		3.2.1.3.1	NA	5.2.1.6.2	NA	NA
		3.2.1.3.2	NA	5.2.1.6.2	NA	NA
		3.2.1.3.3	4.2.1.2.1	5.2.1.6.3	5.3.1.2.1	NA
01C	Boiler B-3701	3.2.1.4.1	NA	5.2.1.7.1	5.3.1.3.1	5.3.1.3.2
		3.2.1.4.2	4.2.1.3.1 4.2.1.3.2	5.2.1.7.2	5.3.1.3.1	5.3.1.3.2
		3.2.1.4.3	NA	5.2.1.7.3 5.2.1.7.4 5.2.1.7.5	5.3.1.3.3 5.3.1.3.4	NA
		3.2.1.4.4	NA	5.2.1.7.3 5.2.1.7.4 5.2.1.7.5	5.3.1.3.3 5.3.1.3.4	NA
		3.1.1.5.1 3.1.1.5.2 3.1.1.5.3 3.1.1.5.4 3.1.1.5.5	4.2.1.3.3 4.2.1.3.4 4.2.1.3.5 4.2.1.3.6 4.2.1.3.7 4.2.1.3.8	5.2.1.7.6 5.2.1.7.7 5.2.1.7.8 5.2.1.7.9	NA	5.3.1.3.5 5.3.1.3.6 5.3.1.3.7
02	All Heaters	3.2.2.1	NA	5.2.2.1	NA	NA
02A	Heaters H-101, H-104, H-401A, H-401B, H-401C, H-1401A, H-1401B, H-2101, H-2102, H-3101A,	3.1.2.1.1	NA	5.2.2.2.3	NA	NA
		3.1.2.1.2	NA	5.2.2.2.4	NA	NA
		3.2.2.1.1	NA	5.2.2.2.2	NA	NA
		3.2.2.1.2	NA	5.2.2.2.5	NA	NA

Group	Description	Requirement for Emissions Units	Testing Requirement	Monitoring Requirement	Recordkeeping Requirement	Reporting Requirement
	H-3101B, H-4101A, H-4101B, H-4201, H-4202	3.2.2.1.3	NA	5.2.2.2.5	NA	NA
		3.2.2.1.4	NA	5.2.2.2.3	NA	NA
		3.2.2.1.5	NA	5.2.2.2.5	NA	NA
		3.2.2.1.6	NA	5.2.2.2.5	NA	NA
		3.2.2.1.7	NA	5.2.2.2.5	NA	NA
		3.2.2.1.8	NA	5.2.2.2.5	NA	NA
		3.2.2.1.9	NA	5.2.2.2.5	NA	NA
		3.2.2.1.10	NA	5.2.2.2.6 5.2.2.2.7	5.3.2.1.1 5.3.2.1.2	5.3.2.1.3 5.3.2.1.4
		3.2.2.1.11	NA	5.2.2.2.5	NA	NA
02B	Heaters H-160, H-200, H-201, H-202, H-600, H-601, H-602, H-603, H-604, H-605, H-606, H-800A, H-800B, , H-801, H-1500, H-1501, H-2201A, H-2201B, H-2202, H-2400, H-2401, H-2501, H-4301A, H-4301B, H-4302, H-4401, H-4402, H-4451, H-4452, H-4453, H-4454, H-4455, H-4502, H-4503, H-4505, H-4601A, H-4601B, H-4602, H-5301A, H-5301B, H-5302, H-5401, H-5402, H-5451, H-5452, H-5453, H-5454, H-5455	3.1.2.2.1	NA	5.2.2.3.1	NA	NA
02C	Heater H-2185	3.2.2.2.1	NA	5.2.2.4.3	NA	NA
		3.2.2.2.3	NA	5.2.2.4.1	5.3.2.3.2	5.3.2.3.1
		3.2.2.2.4	NA	5.2.2.4.2	5.3.2.3.3	5.3.2.3.1
		3.2.2.2.5	NA	5.2.2.4.2	5.3.2.3.3	5.3.2.3.1
		3.2.2.2.6	4.2.2.1.1	5.2.2.4.3	NA	NA
		3.2.2.2.7	NA	5.2.2.4.4	5.3.2.3.4	NA

Group	Description	Requirement for Emissions Units	Testing Requirement	Monitoring Requirement	Recordkeeping Requirement	Reporting Requirement
				5.2.2.4.5	5.3.2.3.5	
		3.2.2.2.8	NA	5.2.2.4.5 5.2.2.4.6	5.3.2.3.4 5.3.2.3.5	NA
02D	Heater H-4901 (LSG Unit Heater) and Hydrogen Plant Heater	3.1.2.4.1	4.2.2.2.12	5.2.2.5.1	NA	NA
		3.2.2.3.7	NA	5.2.2.5.2	NA	NA
		3.2.2.3.10	NA	5.2.2.5.3 5.2.2.5.4	5.3.2.4.1	5.3.2.4.2
		3.2.2.3.11	4.2.2.2.13	5.2.2.5.3	5.3.2.4.1	5.3.2.4.2
		3.2.2.3.12	NA	5.2.2.5.3 5.2.2.5.4	5.3.2.4.1	5.3.2.4.3
		3.2.2.3.13	NA	5.2.2.5.5 5.2.2.5.6 5.2.2.5.7	5.3.2.4.3 5.3.2.4.4	NA
		3.2.2.3.14	NA	5.2.2.5.5 5.2.2.5.6 5.2.2.5.7	5.3.2.4.3 5.3.2.4.4	NA
		3.2.2.3.16	4.2.2.2.6 4.2.2.2.7	NA	NA	5.3.2.4.7 5.3.2.4.8
		3.2.2.3.17	4.2.2.2.6 4.2.2.2.7	NA	NA	5.3.2.4.7 5.3.2.4.8
		3.2.2.3.18	4.2.2.2.10	NA	NA	5.3.2.4.7 5.3.2.4.8
		3.2.2.3.19	4.2.2.2.10	NA	NA	5.3.2.4.7 5.3.2.4.8
		3.2.2.3.20	4.2.2.2.9	5.2.2.5.8	NA	5.3.2.4.7 5.3.2.4.8
		3.2.2.3.21	4.2.2.2.9	NA	NA	5.3.2.4.7 5.3.2.4.8 5.3.2.4.15
		3.2.2.3.22	4.2.2.2.9	NA	NA	5.3.2.4.8
		3.2.2.3.23	4.2.2.2.9	NA	5.3.2.4.1	5.3.2.4.8
		3.2.2.3.24	4.2.2.2.9	NA	5.3.2.4.1	5.3.2.4.8
		3.2.2.3.25	4.2.2.2.8	NA	NA	5.3.2.4.7

Group	Description	Requirement for Emissions Units	Testing Requirement	Monitoring Requirement	Recordkeeping Requirement	Reporting Requirement
						5.3.2.4.8
		3.2.2.3.26	4.2.2.2.8	NA	NA	5.3.2.4.7 5.3.2.4.8
		3.2.2.4.1	NA	5.2.2.6.1	NA	NA
		3.2.2.4.2	NA	NA	NA	5.3.2.5.1
		3.2.2.4.3	NA	5.2.2.6.2 5.2.2.6.3	5.3.2.5.2 5.3.2.5.3	NA
		3.2.2.4.4	NA	5.2.2.6.3 5.2.2.6.4	5.3.2.5.2 5.3.2.5.3	NA
		3.2.2.4.5	NA	5.2.2.6.4	NA	NA
		3.2.2.4.6	4.2.2.3.1 4.2.2.3.2	NA	NA	NA
		3.2.2.4.7	4.2.2.3.3	NA	NA	NA
		3.2.2.4.8	4.2.2.3.2	NA	NA	NA
		3.2.2.4.9	4.2.2.3.2	NA	NA	NA
		3.2.2.4.10	4.2.2.3.2	NA	NA	NA
		3.2.2.4.11	NA	5.2.2.6.5	NA	NA
02F	Incinerators H-1032, H-1042, H-4745	3.1.2.6.1	NA	5.2.2.7.3	5.3.2.6.1	NA
		3.1.2.6.2	NA	5.2.2.7.4	NA	NA
		3.2.2.5.1	NA	5.2.2.7.5	NA	NA
		3.2.2.5.2	NA	NA	NA	5.3.2.6.2
		3.2.2.5.4	NA	5.2.2.7.6	NA	5.3.2.6.3
		3.2.2.5.5	NA	NA	5.3.2.6.4	5.3.2.6.4
02G	Heaters H-8501A, H-8501B	3.1.2.7.2 3.1.2.7.3 3.1.2.7.4 3.1.2.7.5 3.1.2.7.6	NA	5.2.2.8.4 5.2.2.8.5 5.2.2.8.6 5.2.2.8.7	5.3.2.7.2 5.3.2.7.5 5.3.2.7.6	5.3.2.7.3 5.3.2.7.4 5.3.2.7.5 5.3.2.7.6
		3.2.2.6.1	NA	5.2.2.8.1 5.2.2.8.2 5.2.2.8.3	NA	5.3.2.7.1
		3.2.2.6.2	NA	5.2.2.8.1 5.2.2.8.2 5.2.2.8.3	NA	5.3.2.7.1

Group	Description	Requirement for Emissions Units	Testing Requirement	Monitoring Requirement	Recordkeeping Requirement	Reporting Requirement
03	All Compressors	3.1.3.1	NA	5.2.3.1	NA	NA
		3.2.3.1	4.2.3.1	5.2.3.2	5.3.3.1	5.3.3.2
04	Turbines	3.1.4.1	NA	5.2.4.1	NA	NA
04A	Turbines G-1101E, G-1101F, G-1101G, G-3404, G-3405, G-3406, G-3407, G-3408, G-3409, G-3410	3.1.4.2.1	NA	5.2.4.2.5	5.3.4.1.4	NA
		3.1.4.2.2 3.1.4.2.3 3.1.4.2.4 3.1.4.2.5 3.1.4.2.6 3.1.4.2.7 3.1.4.2.8 3.1.4.2.9 3.1.4.2.10 3.1.4.2.11 3.1.4.2.12	NA	5.2.4.2.21 5.2.4.2.22 5.2.4.2.23 5.2.4.2.24	5.3.4.1.23 5.3.4.1.24 5.3.4.1.25 5.3.4.1.28	5.3.4.1.26 5.3.4.1.27 5.3.4.1.29 5.3.4.1.30
		3.2.4.1.1	NA	5.2.4.2.3	NA	NA
		3.2.4.1.2	NA	5.2.4.2.4	NA	NA
		3.2.4.1.3	NA	5.2.4.2.4	NA	NA
		3.2.4.1.4	NA	5.2.4.2.4	NA	NA
		3.2.4.1.5	NA	5.2.4.2.6 5.2.4.2.7	5.3.4.1.1 5.3.4.1.3	5.3.4.1.2
		3.2.4.1.6	NA	5.2.4.2.6 5.2.4.2.7	5.3.4.1.1 5.3.4.1.3	5.3.4.1.2
		3.2.4.1.7	NA	5.2.4.2.9	5.3.4.1.4	5.3.4.1.5
		NA	NA	5.2.4.2.10	5.3.4.1.4 5.3.4.1.6	5.3.4.1.6
		3.2.4.1.8	NA	5.2.4.2.10	5.3.4.1.4 5.3.4.1.6	5.3.4.1.6
		3.2.4.1.9	NA	5.2.4.2.11	5.3.4.1.4 5.3.4.1.7	NA
		3.2.4.1.10	NA	5.2.4.2.12 5.2.4.2.13	5.3.4.1.8	NA
		3.2.4.1.11	NA	5.2.4.2.14	5.3.4.1.9	NA
		3.2.4.1.12	NA	5.2.4.2.16	5.3.4.1.4	5.3.4.1.10

Group	Description	Requirement for Emissions Units	Testing Requirement	Monitoring Requirement	Recordkeeping Requirement	Reporting Requirement
		3.2.4.1.13	NA	5.2.4.2.16	5.3.4.1.4	5.3.4.1.10
		3.2.4.1.14	4.2.4.1.4	5.2.4.2.17	5.3.4.1.4	NA
		3.2.4.1.15	NA	NA	5.3.4.1.4	5.3.4.1.11
		NA	NA	5.2.4.2.19	5.3.4.1.12	5.3.4.1.13
		3.2.4.1.16	NA	NA	NA	5.3.4.1.14
		3.2.4.1.17	NA	NA	NA	5.3.4.1.14
		3.2.4.1.19	NA	NA	NA	5.3.4.1.15
		3.2.4.1.21	4.2.4.1.5	NA	NA	5.3.4.1.16 5.3.4.1.14
04B	Turbine G-3413 (GT-13) and Associated Duct Burner H-3413	3.2.4.2.7	NA	5.2.4.3.4	5.3.4.2.2	NA
		3.2.4.2.8	NA	NA	5.3.4.2.4	NA
		3.2.4.2.14	4.2.4.2.1	5.2.4.3.5	5.3.4.2.3 5.3.4.2.7	5.3.4.2.7 5.3.4.2.8
		3.2.4.2.15	4.2.4.2.1	5.2.4.3.6 5.2.4.3.7 5.2.4.3.8 5.2.4.3.9 5.2.4.3.10 5.2.4.3.11 5.2.4.3.12 5.2.4.3.13	5.3.4.2.2 5.3.4.2.4	5.3.4.2.7 5.3.4.2.8
		3.2.4.2.16	4.2.4.2.1	5.2.4.3.5	5.3.4.2.2	NA
		3.2.4.2.17	NA	NA	5.3.4.2.2 5.3.4.2.3	NA
		3.2.4.2.18	4.2.4.2.7 4.2.4.2.20	NA	5.3.4.2.2 5.3.4.2.3	5.3.4.2.9
		3.2.4.2.19	4.2.4.2.8 4.2.4.2.20	NA	5.3.4.2.2 5.3.4.2.3	5.3.4.2.9
		3.2.4.2.20	4.2.4.2.11	NA	5.3.4.2.2 5.3.4.2.3	5.3.4.2.9
		3.2.4.2.21	4.2.4.2.10	5.2.4.3.3 5.2.4.3.6	5.3.4.2.2	5.3.4.2.9
		3.2.4.2.22	4.2.4.2.10	5.2.4.3.3 5.2.4.3.6	5.3.4.2.2	5.3.4.2.9

Group	Description	Requirement for Emissions Units	Testing Requirement	Monitoring Requirement	Recordkeeping Requirement	Reporting Requirement
		3.2.4.2.23	NA	NA	NA	5.3.4.2.12
		3.2.4.2.24	NA	5.2.4.3.3 5.2.4.3.7	5.3.4.2.2	5.3.4.2.11 5.3.4.2.12
		3.2.4.2.25	4.2.4.2.12	NA	5.3.4.2.2	5.3.4.2.9
		3.2.4.2.26	4.2.4.2.12	NA	5.3.4.2.2	5.3.4.2.9
		3.2.4.2.27	4.2.4.2.9	5.2.4.3.8	5.3.4.2.2	5.3.4.2.9
		3.2.4.2.28	4.2.4.2.13	NA	5.3.4.2.2	5.3.4.2.8
		3.2.4.2.29	NA	5.2.4.3.9 5.2.4.3.10 5.2.4.3.11	5.3.4.2.16 5.3.4.2.17	5.3.4.2.20
		3.2.4.2.30	NA	5.2.4.3.9 5.2.4.3.10 5.2.4.3.11	5.3.4.2.16 5.3.4.2.17	5.3.4.2.20
		3.2.4.2.31	4.2.4.2.22	5.2.4.3.13	NA	NA
		3.2.4.2.32	NA	5.2.4.3.14	NA	5.3.4.2.18
		3.2.4.2.33	NA	5.2.4.3.15	5.3.4.2.19	5.3.4.2.22 5.3.4.2.23
		NA	4.2.4.2.2 4.2.4.2.3 4.2.4.2.4 4.2.4.2.5 4.2.4.2.6 4.2.4.2.7 4.2.4.2.15 4.2.4.2.16 4.2.4.2.18 4.2.4.2.19 4.2.4.2.21	5.2.4.3.15	5.3.4.2.2	5.3.4.2.8 5.3.4.2.9 5.3.4.2.10 5.3.4.2.11 5.3.4.2.12 5.3.4.2.13 5.3.4.2.17 5.3.4.2.18
		3.2.5.1	NA	5.2.5.1	NA	NA
05	Flares	3.2.5.2	NA	5.2.5.2	5.3.5.1	5.3.5.4
		3.2.5.3	NA	5.2.5.3	5.3.5.3	5.3.5.6
		3.2.5.4	4.2.5.1	5.2.5.4	5.3.5.5	5.3.5.8
		3.2.5.5	NA	5.2.5.5 5.2.5.6	5.3.5.7 5.3.5.9	5.3.5.8 5.3.5.9

Group	Description	Requirement for Emissions Units	Testing Requirement	Monitoring Requirement	Recordkeeping Requirement	Reporting Requirement
		3.2.5.6	NA	5.2.5.5 5.2.5.6	5.3.5.7 5.3.5.9	5.3.5.8 5.3.5.9
06A	Truck Loading	3.1.6.1.2	NA	5.2.6.1.3	NA	5.3.6.1.7 5.3.6.1.8
		3.1.6.1.3	NA	5.2.6.1	NA	5.3.6.1.7 5.3.6.1.8
		3.1.6.1.4 3.1.6.1.5 3.1.6.1.6	NA	NA	5.3.6.1.10 5.3.6.1.11	5.3.6.1.9 5.3.6.1.12
		NA	4.2.6.1.1	NA	NA	5.3.6.1.7
06B	Marine Loading	3.1.6.2.1 3.1.6.2.2 3.1.6.2.3 3.1.6.2.4 3.1.6.2.5	NA	NA	5.3.6.2.8	5.3.6.2.7
		3.2.6.2.1	4.2.6.2.1 4.2.6.2.2 4.2.6.2.3	NA	5.3.6.2.1 5.3.6.2.2 5.3.6.2.3 5.3.6.2.5 5.3.6.2.6 5.3.6.2.8	5.3.6.2.4 5.3.6.2.7
		3.2.6.2.2	4.2.6.2.1 4.2.6.2.2 4.2.6.2.3		5.3.6.2.1 5.3.6.2.2 5.3.6.2.3 5.3.6.2.8	5.3.6.2.4 5.3.6.2.7
		3.2.6.2.3	4.2.6.2.1 4.2.6.2.2 4.2.6.2.3		5.3.6.2.2 5.3.6.2.3 5.3.6.2.5 5.3.6.2.6 5.3.6.2.8	5.3.6.2.4 5.3.6.2.7
		3.2.6.2.4	4.2.6.2.1 4.2.6.2.2 4.2.6.2.3		5.3.6.2.2 5.3.6.2.3 5.3.6.2.5 5.3.6.2.6	5.3.6.2.4 5.3.6.2.7

Group	Description	Requirement for Emissions Units	Testing Requirement	Monitoring Requirement	Recordkeeping Requirement	Reporting Requirement
					5.3.6.2.8	
07	Sulfur Recovery	3.1.7.1	NA	5.2.7.3	NA	NA
		3.1.7.2	NA	5.2.7.4	5.3.7.1	NA
		3.2.7.1	NA	5.2.7.5 5.2.7.7	5.3.7.2	NA
		3.2.7.2	NA	5.2.7.5 5.2.7.7	5.3.7.2	NA
		3.2.7.3	4.2.7.1	5.2.7.6 5.2.7.7	NA	5.3.7.4 5.3.7.5
08	Internal Floating Roof Tanks	3.2.8.1	NA	5.2.8.1	NA	5.3.8.1
		3.1.9.1	NA	5.2.9.1	5.3.9.7	5.3.9.1
09	External Floating Roof Tanks	3.2.9.1	NA	5.2.9.1	NA	5.3.9.1
		3.2.9.2	NA	5.2.9.1	NA	5.3.9.1
		3.2.9.3	NA	5.2.9.1	NA	5.3.9.1
		3.2.9.4	NA	5.2.9.1	NA	5.3.9.1
		3.2.9.5	NA	5.2.9.1	NA	5.3.9.1
10	Fixed Roof Tanks	3.1.10.1.1 3.1.10.1.2	NA	NA	5.3.10.1.5	NA
		3.2.13.2	NA	5.2.13.1	5.3.13.1	5.3.13.2
13	Wastewater Treatment	3.2.13.3	4.2.13.1 4.2.13.2	5.2.13.2	5.3.13.1	5.3.13.2
		NA	NA	NA	5.3.13.1	5.3.13.2
		3.2.13.4	4.2.13.3	5.2.13.3	5.3.13.1	5.3.13.2
		3.2.13.1	4.2.13.4	5.2.13.4	5.3.13.3	5.3.13.4
14	Alkylation and Dimersol Units	3.2.14.1	4.2.14.1	5.2.14.1	5.3.14.1 5.3.14.2	5.3.14.1 5.3.14.2
		3.2.14.3	4.2.14.2	5.2.14.2	5.3.14.3	5.3.14.3
		3.1.15.1	NA	5.2.15.1	NA	NA
15	Seawater Intake Pumps	3.1.15.2	NA	5.2.15.2	NA	NA
		3.2.15.1	NA	5.2.15.3	5.3.15.1	NA
16	FCCU	3.2.16.3	NA	5.2.16.1	NA	NA
		3.2.16.4	NA	5.2.16.1	NA	NA

Group	Description	Requirement for Emissions Units	Testing Requirement	Monitoring Requirement	Recordkeeping Requirement	Reporting Requirement
		3.2.16.5	NA	5.2.16.2	NA	NA
		3.2.16.6	4.2.16.1	5.2.16.3	NA	NA
		3.2.16.7	4.2.16.2	NA	NA	5.3.16.1
		3.2.16.8	4.2.16.3	NA	5.3.16.3	NA
		3.2.16.9	4.2.16.4	NA	NA	5.3.16.1
		3.2.16.10	4.2.16.5	5.2.16.4 5.2.16.12 5.2.16.13	NA	5.3.16.1 5.3.16.3 5.3.16.10
		3.2.16.11	4.2.16.5	5.2.16.4 5.2.16.12 5.2.16.13	NA	5.3.16.1 5.3.16.3 5.3.16.10
		3.2.16.12	4.2.16.5	5.2.16.4 5.2.16.12 5.2.16.13	NA	5.3.16.1 5.3.16.3 5.3.16.10
		3.2.16.13	NA	5.2.16.6 5.2.16.7 5.2.16.8 5.2.16.12 5.2.16.13	5.3.16.2 5.3.16.4	5.3.16.5 5.3.16.6
		3.2.16.14	NA	5.2.16.9 5.2.16.12 5.2.16.13	NA	5.3.16.3 5.3.16.10
		3.2.16.15	NA	5.2.16.9 5.2.16.12 5.2.16.13	NA	5.3.16.3 5.3.16.10
		3.2.16.16	NA	5.2.16.10 5.2.16.12 5.2.16.13	NA	5.3.16.3 5.3.16.10
		3.2.16.17	NA	5.2.16.10 5.2.16.12 5.2.16.13	NA	5.3.16.3 5.3.16.10
		3.2.16.18	NA	NA	NA	NA
		3.2.16.19	NA	5.2.16.11	NA	NA

Group	Description	Requirement for Emissions Units	Testing Requirement	Monitoring Requirement	Recordkeeping Requirement	Reporting Requirement
				5.2.16.12 5.2.16.13		
		3.2.16.20	4.2.16.6	5.2.16.14	NA	NA
		3.2.16.21	NA	5.2.16.14	NA	NA
		3.2.16.22	NA	NA	NA	NA
		3.2.16.23	NA	5.2.16.10	NA	5.3.16.3 5.3.16.10
		3.2.16.24	4.2.16.7	NA	NA	NA
		3.2.16.26	NA	5.2.16.18 5.2.16.19	NA	5.3.16.7 5.3.16.8
		3.2.16.27	NA	5.2.16.18 5.2.16.19	NA	5.3.16.3
		3.2.16.28	NA	5.2.16.19	5.3.16.15	5.3.16.16
		3.2.16.29	NA	5.2.16.20	NA	NA
		NA	4.2.16.8 4.2.16.9 4.2.16.10 4.2.16.11 4.2.16.12 4.2.16.13	5.2.16.20		5.3.16.9 5.3.16.13
17	Coker Complex	3.1.17.1	NA	5.2.17.1	NA	NA
		3.1.17.2	NA	NA	NA	5.3.17.1
		3.1.17.3	NA	5.2.17.2	5.3.17.2	5.3.17.3
		3.1.17.5	NA	5.2.17.3	5.3.17.2	5.3.17.3
		3.1.17.6 3.1.17.7 3.1.17.8 3.1.17.9 3.1.17.10 3.1.17.11 3.1.17.12 3.1.17.13 3.1.17.14 3.1.17.15	4.2.17.1	NA	NA	5.3.17.4

Group	Description	Requirement for Emissions Units	Testing Requirement	Monitoring Requirement	Recordkeeping Requirement	Reporting Requirement
		3.1.17.16 3.1.17.17				
18	Sulfuric Acid Plant Stack STK-7802	3.1.18.1	NA	5.2.18.1	NA	NA
		3.2.18.2	4.2.18.1	NA	NA	NA
		3.2.18.3	NA	5.2.18.2	NA	5.3.18.2
		3.2.18.4	4.2.18.2	NA	NA	NA
		3.2.18.5	4.2.18.3	NA	NA	NA
		3.2.18.6	4.2.18.4	NA	NA	NA
		3.2.18.7	NA	5.2.18.3	5.3.18.3	NA
		3.2.18.8	NA	5.2.18.4	5.3.18.4	5.3.18.5
19	Vapor Enhanced Recovery	3.1.19.1	NA	NA	NA	5.3.19.4 5.3.19.5
		3.1.19.2	NA	NA	NA	5.3.19.4 5.3.19.5
		3.1.19.3	NA	5.2.19.3	5.3.19.7 5.3.19.8	5.3.19.4 5.3.19.5
		3.1.19.4	NA	5.2.19.3	5.3.19.7 5.3.19.8	5.3.19.4 5.3.19.5
		3.1.19.5	NA	5.2.19.3	5.3.19.7 5.3.19.8	5.3.19.4 5.3.19.5
		3.1.19.6	NA	5.2.19.4	NA	5.3.19.4 5.3.19.5
		3.1.19.7	NA	5.2.19.4	NA	5.3.19.4 5.3.19.5
		3.1.19.8	NA	5.2.19.5	5.3.19.9	5.3.19.4 5.3.19.5
		3.1.19.9	NA	5.2.19.5	5.3.19.9	5.3.19.4 5.3.19.5
		3.1.19.10	NA	5.2.19.5	5.3.19.9	5.3.19.4 5.3.19.5
		3.1.19.11	NA	5.2.19.5 5.2.19.6	5.3.19.10	5.3.19.11
		3.1.19.12	NA	NA	NA	5.3.19.4 5.3.19.5

Group	Description	Requirement for Emissions Units	Testing Requirement	Monitoring Requirement	Recordkeeping Requirement	Reporting Requirement
		3.1.19.13	NA	NA	NA	5.3.19.4 5.3.19.5
		3.1.19.14	NA	5.2.19.1 5.2.19.2	5.3.19.1	5.3.19.2
		3.2.19.7	NA	5.2.19.1 5.2.19.2	5.3.19.1	5.3.19.2
25	Platformers	3.2.25.1	NA	5.2.25.1	5.3.25.1	5.3.25.1

PART 2.0 FACILITY WIDE REQUIREMENTS

2.1 Emission Limits

None.

2.2 Facility Wide Federal Applicable Requirements

2.2.1 National Emission Standard for Asbestos

If the Permittee owns or operates an active waste disposal site that receives asbestos-containing waste material from a source covered under 40 CFR 61.149 and 61.150 or 61.155, the Permittee shall meet the requirements pursuant to 40 CFR 61.154.

2.2.1.1 Either there must be no visible emissions to the outside air from any active waste disposal site where asbestos-containing waste material has been deposited or the requirements of paragraph (c) or (d) of 40 CFR 61.154 must be met.

2.2.1.2 Unless a natural barrier adequately deters access by the general public, either warning signs and fencing must be installed and maintained as required under this section, or the requirements of paragraph (c)(1) of 40 CFR 61.154 must be met.

2.2.1.3 The Permittee shall maintain waste shipment records for all asbestos-containing waste material received at the waste disposal site, and shall retain a copy of all records and reports required by this paragraph for at least five (5) years.

2.2.1.4 As soon as possible, and no longer than thirty (30) days after receipt of the waste from a waste generator other than the Permittee, the Permittee shall send a copy of the signed waste shipment record to the waste generator.

2.2.1.5 Upon closure of the waste disposal site, the Permittee shall comply with all the provisions of 40 CFR 61.151.

2.2.1.6 Upon closure of the facility, the Permittee shall submit a copy of records of asbestos waste disposal locations and quantities to the Administrator.

2.2.1.7 The Permittee shall furnish upon request, and make available during normal business hours for inspection by the Administrator, all records required under 40 CFR 61.154.

2.2.1.8 The Permittee shall notify the Administrator in writing at least 45 days prior to excavating or otherwise disturbing any asbestos-containing waste material that has been deposited at a waste disposal site and is covered.
[40 CFR 61 Subpart M]

2.2.2 1997 PSD Permit Requirements

2.2.2.1 The Permittee shall continuously monitor wind conditions in accordance with the Permittee's Meteorological Monitoring Plan dated September 5, 1991. Data on wind direction shall be monitored and recorded. The Permittee's meteorological station shall be audited semiannually by an independent party. Maintenance and calibration records shall be maintained.

[1997 PSD Permit II.VI.F]

2.2.2.2 The Permittee shall operate five ambient SO2 monitoring stations, two to the west of the refinery and three to the north of the refinery, for purposes relating to the Supplemental Control Scenario as delineated in this permit. These monitors shall record hourly average and 24-hour rolling average SO2 concentrations. In the event that monitoring data indicate an exceedance of the NAAQS, the Permittee shall report the exceedance to the EPA, and shall recommend corrective action and modifications to the Supplemental Control Scenario, to ensure protection of the NAAQS.

[1997 PSD Permit II.VI.G]

2.2.2.3 The Permittee shall develop and maintain a plan to monitor the residual and distillate fuel-oil usage. Such a plan must be approved by the EPA.

[1997 PSD Permit II.VI.H]

2.2.2.4 In the event that operational upsets or emergencies occur which result in Sulfur Recovery Unit Tail Gas being routed to the incinerator or process gases being routed to the flares, the Permittee shall discontinue the use of 1.0 wt. % sulfur fuel oil in all residual fuel oil burning sources until operations are returned to normal, in accordance with VIRR 12-09-204-45, FCCU PSD Permit Attachment II, Section IV(D), and condition 2.2.2.4.1.

[33 PTO (h), Permit No. 481-94, November 28, 1994]

2.2.2.4.1 Sulfur emissions from the Permittee flaring incidents during operational upsets:

a. 0-2.0 tons total SO2 emissions per calendar day (TPCD) are permitted from Permittee flaring incidents without switching from 1.0 to 0.5 wt. % sulfur fuel oil.
b. 2-30 tons total SO2 emissions per calendar day are permitted during Permittee flaring incidents, provided the Permittee immediately (within 4 hours) switches to burning 0.5 wt. % sulfur fuel oil and notifies the DPNR within 24 hours.
c. Greater than 30.0 tons total SO2 emissions in any calendar day from Permittee flaring will require immediate (within 4 hours) switch to burning 0.5% sulfur fuel oil and emergency release notification to the NRC and VIDPNR under CERCLA and SARA regulations (40 CFR parts 302 and 355).
d. All required fuel switches to 0.5 wt. % sulfur fuel oil will be for a minimum duration of 24 hours prior to resuming burning 1.5 wt. % sulfur fuel oil

[LIMETREE BAY TERMINALS LLC Air Emissions

Source Listing, Attachment 1, Note 4]

2.2.2.5 The Permittee shall submit a written report of excess emissions, the number of days operating under each operating scenario and operation of the Permittee supplemental control plan to EPA every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter and shall include the information specified below:

[1997 PSD Permit II.VII.B.b]

2.2.2.5.1 For excess emissions from the FCCU complex, provide the following information:

2.2.2.5.1.1The magnitude of excess emissions computed in accordance with 40 CFR Part 60.13 (h), all conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions.

2.2.2.5.1.2 Specific identification of each period of excess emissions that occurred during start- ups, shutdowns, and malfunctions of the affected facility.

2.2.2.5.1.3 The nature and cause of any malfunction of the affected facility (if known), and the corrective action taken or preventative measures adopted.

2.2.2.5.2 For apparent excess emissions due to CEM malfunction, provide the date and time identifying each period during which the continuous monitoring system was inoperative (not including zero and span checks), and the nature of the system repairs or adjustments.

2.2.2.5.3 When no excess emissions have occurred, or the continuous monitoring system(s) has not been inoperative, repaired or adjusted, such information shall be stated in the report.

2.2.2.5.4 For the existing fuel-consuming units, provide the number of days of operation for each operating scenario implemented during the reporting quarter.

2.2.2.5.5 For implementation of the Permittee's supplemental control plan, provide the date(s) and time(s) for each period that this plan was operational.

2.2.2.5.5.1 If the plan was triggered by SO2 monitoring data, provide the monitoring data.

2.2.2.5.5.2 If the plan was triggered by wind conditions, provide the wind data that resulted in plan implementation, as well as wind data for the duration and conclusion of plan implementation.

2.2.2.5.6 Each semiannual meteorological station audit report shall be submitted with the appropriate quarterly report.

2.2.2.6 The quarterly excess emission reports shall be sent to the following EPA official, and copies must be sent to the Chief of the Air Compliance Branch, EPA Region 2, and the Director of the Division of Environmental Protection, VIDPNR. The EPA address is:

Caribbean Division
Centro Europa Bldg., Suite 147
1492 Ponce de Leon Avenue
San Juan, Puerto Rico 00907

[1997 PSD Permit II.VII.B.c.]

2.2.2.7 The Permittee shall notify EPA and VIDPNR at least 30 days prior to actual testing.

[1997 PSD Permit II.X.C.]

2.2.2.8 The Permittee shall provide permanent sampling and testing facilities as may be required by the EPA to determine the nature and quantity of emissions from the FCCU. Such facilities shall conform with all applicable laws and regulations concerning safe construction and safe practice.

[1997 PSD Permit II.X.D.]

2.2.2.9 EPA reserves the right to require additional stack testing of the pollutants for which an emission limitation has been established in the 1997 PSD Permit.

[1997 PSD Permit II.X.E.]

2.2.2.10 The Permittee shall monitor and maintain records of the H_2S content of all refinery gas burned. The Permittee shall maintain records for a period of no less than 5 years.

[1997 PSD Permit (VI)(C)(h); 1997 PSD Permit (VI)(D)]

2.2.2.11 The Permittee shall report upsets/malfunctions, changes in operating scenarios, and implementation of the Permittee's supplemental control plan by telephone or facsimile within four (4) hours with a follow-up letter submitted within seven (7) calendar days to VIDPNR, upsets/malfunctions, changes in operating scenarios, and implementation of the HOVIC supplemental control plan.

[1997 PSD Permit VII.B.a.]

2.2.3 NESHAP for Site Remediation – 40 CFR 63, Subpart GGGGG

2.2.3.1 The Permittee shall comply with the applicable requirements of the Site Remediation NESHAP standards in 40 CFR 63.7880 through 63.7957.

[40 CFR 63.7880 through 63.7957]

2.2.4 ASTM Methods:

2.2.4.1 For applicable requirements that specify an ASTM Method, the Permittee may comply with either the applicable ASTM Method or a more recently published version.

2.2.5 Prevention of Accidental Releases (Section 112(r) of the 1990 CAAA)

2.2.5.1 The Permittee shall submit a Risk Management Plan (RMP) in accordance with the 40 CFR Part 68, when and if such requirement becomes applicable, by the date specified in Part 68.10 and shall certify compliance with the requirements of Part 68 as part of the annual compliance certification report.
[Section 112(r) of the CAAA of 1990]

2.2.6 Stratospheric Ozone Protection Requirements (Title VI of the CAAA of 1990):

2.2.6.1. If the Permittee performs any of the activities described below or as otherwise defined in 40 CFR Part 82, the Permittee shall comply with the standards for recycling and emissions reduction pursuant to 40 CFR Part 82, Subpart F, except as provided for motor vehicle air conditioners (MVACs) in Subpart B:

2.2.6.1.1 Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to 40 CFR 82.156.

2.2.6.1.2 Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to 40 CFR 82.158.

2.2.6.1.3 Persons performing maintenance, service, or repair, of appliances must be certified by an approved technician certification program pursuant to 40 CFR 82.161.

2.2.6.1.4 Persons disposing of small appliances, MVACs, and MVAC-like appliances must comply with record keeping requirements pursuant to 40 CFR 82.166. (Note: “MVAC-like appliance” is defined in 40 CFR 82.152.)

2.2.6.1.5 Persons owning commercial or industrial process refrigeration equipment must comply with the leak repair requirements pursuant to 40 CFR 82.156.

2.2.6.1.6 Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of the refrigerant purchased and added to such appliances pursuant to 40 CFR 82.166.

2.2.6.2 All records required to be maintained pursuant to 40 CFR 82.166 must be kept for a minimum of five years unless otherwise indicated.

2.2.6.3 Reclaimers must maintain records of the names and addresses of persons sending them material for reclamation and the quantity of the material sent to them for reclamation pursuant to 40 CFR 82.166.

2.2.6.4 If the Permittee performs a service on motor (fleet) vehicles and if this service involves an ozone-depleting substance (refrigerant) in the MVAC, the Permittee is subject to all the applicable requirements as specified in 40 CFR Part 82, Subpart B, Servicing of Motor Vehicle Air Conditioners. (The term “motor vehicle” as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed. The term “MVAC” as used in Subpart B does not include air-tight sealed refrigeration systems used for refrigerated cargo, or air conditioning systems on passenger buses using HCFC-22 refrigerant.)

2.2.6.5 Any person who transforms or destroys class I controlled substances who has submitted an IRS certificate of intent to transform or a destruction verification to the producer or importer of the controlled substance, must report the names and quantities of class I controlled substances transformed and destroyed for each control period within 45 days of the end of such control period.

2.2.7 Equipment Leaks, Wastewater System Components (Process Drains and Junction Boxes), and Miscellaneous Process Vents

2.2.7.1 The Permittee shall comply, as applicable, with the requirements, including monitoring, testing, recordkeeping, and reporting, of 40 CFR 60, Subpart GGG.

[40 CFR 60, Subpart GGG]

2.2.7.2 The Permittee shall comply with the requirements, as applicable, including periodic inspection, notification, repair, monitoring, recordkeeping, and reporting requirements, of 40 CFR 63, Subpart CC.

[40 CFR 63, Subpart CC]

2.2.7.3 The Permittee shall comply, as applicable, with the requirements, including monitoring, testing, recordkeeping, and reporting, of 40 CFR 63, Subparts F, G, and H.

[40 CFR 63.119 through 183]

2.2.7.4 The Permittee shall comply, as applicable, with the requirements, including monitoring, testing, recordkeeping, and reporting, of 40 CFR 60, Subpart QQQ and 40 CFR 61, Subpart FF.

[40 CFR 60, Subpart QQQ; 40 CFR 61, Subpart FF]

2.2.8 Special Exemptions – U.S. Virgin Islands

2.2.8.1 The Permittee has been granted an exemption to section 123 of the Clean Air Act. Specifically, the exemption waives the prohibition on the implementation of an Intermittent Control Strategy (ICS) based upon atmospheric conditions in order to set emission limitations. The emission limitations shall depend upon the sulfur content in the residual oil burned by the Permittee.

[40 CFR 69.41(a)]

2.2.8.2 The Permittee shall follow protocol for the ICS set forth in a PSD permit issued to the Permittee. The PSD permit shall include as a minimum, the conditions listed in sections 2.2.8.3, 2.2.8.4, 2.2.8.5, and 2.2.8.6,

[40 CFR 69.41(b)]

2.2.8.3 The Permittee shall maintain a meteorological tower on its property for the purpose of the ICS which meets the required EPA QA/QC operating specifications. At a minimum, the wind direction data will be monitored, collected, and reported as 1-hour averages, starting on the hour. If the average wind direction for a given hour is from within the designated sector, the wind will be deemed to have flowed from within the sector for that hour. Each "day" or "block period," for theses purposes will start at midnight and end the following midnight.

[40 CFR 69.41(b)(1)]

2.2.8.4 The Permittee shall maintain SO2 ambient monitors and collect ambient SO2 concentration data for the purpose of implementing the ICS at nearby locations approved by EPA and specified in the PSD permit. The ambient monitors shall follow the required EPA QA/QC operating specifications. At a minimum, the data will be collected according to EPA approved State and Local Ambient Monitoring Stations procedures found at 40 CFR 58.20, but will, for these purposes, be averaged by the hour, starting on the hour.

[40 CFR 69.41(b)(2)]

2.2.8.5 The switch to a lower sulfur fuel (0.5%) shall take place when sections 2.2.8.5.1 or 2.2.8.5.2 are met.

[40 CFR 69.41(b)(3)]

2.2.8.5.1 The winds blow from a 45 degree sector defined as 143 to 187 degrees inclusive, where zero degrees is due north, for at least 6 consecutive hours during a 24-hour block period or any 12 non-consecutive hours during a 24-hour block period.

[40 CFR 69.41(b)(3)(i)]

2.2.8.5.2 One of the Permittee's ICS monitors measures an average ambient SO2 concentration that is 75% of the 24-hour NAAQS during any rolling 24-hour average (75% of the 24-hour NAAQS = 274 ug/m3 or 0.105 ppm).

[40 CFR 69.41(b)(3)(ii)]

2.2.8.6 The switch back to higher sulfur fuel (1.0%) may occur if the conditions in sections 2.2.8.6.1, 2.2.8.6.2, and 2.2.8.6.3 are met.

[40 CFR 69.41(b)(4)]

2.2.8.6.1 If the ICS was triggered by condition 2.2.8.5.1, the switch back may occur when the winds blow outside the sector listed in the condition 2.2.8.5.1 for at least 3 consecutive hours following the period during which the winds were blowing inside the sector.

[40 CFR 69.41(b)(4)(i)]

2.2.8.6.2 If the ICS was triggered by condition 2.2.8.5.2, the switch back may occur after all of the Permittee's ICS ambient monitors measure a 24-hour average concentration which is less than 75% of the NAAQS for at least on 24-hour block period following any occurrence when the monitor measured the concentration which was 75% of the NAAQS.

[40 CFR 69.41(b)(4)(ii)]

2.2.8.6.3 If the ICS was triggered by both conditions 2.2.8.5.1 and 2.2.8.5.2, the switch back may occur when both of the conditions in 2.2.8.6.1 and 2.2.8.6.2 are met.

[40 CFR 69.41(b)(4)(iii)]

2.2.8.7 The protocol may be modified by EPA to protect against exceedances of the sulfur dioxide NAAQS.

[40 CFR 69.41(c)]

2.2.8.8 In the event that there is an exceedance of the NAAQS, the Permittee shall report the exceedance to EPA and recommend corrective action as well as amendments to the protocol to ensure the protection of the NAAQS.

[40 CFR 69.41(d)]

2.2.8.9 The Permittee shall comply with all fuel switching requirements contained in the Permittee's PSD permit.

[40 CFR 69.41(e)]

2.2.8.10 This exemption shall take effect only in the event that a final PSD permit modification becomes effective.

[40 CFR 69.41(f)]

2.2.8.11 The Administrator may terminate the exemption through rulemaking procedures upon determining that the Permittee's use of the ICS is causing or contributing to an exceedance of the NAAQS.

[40 CFR 69.41(g)]

2.3 Facility Wide Territorial Implementation Plan (TIP) Requirements

None.

2.4 Facility Wide Standards Not Covered by a Federal or TIP Rule and Not Instituted as an Emission Cap or Operating Limit

2.4.1 Air Pollution Nuisances Prohibited

2.4.1.1 The Permittee shall not permit, cause, suffer, or allow open burning except under the circumstances stipulated in 12-09-204-21(a), (b), (c), and (d).

[VIRR 12-09-204-21]

2.4.1.2 The Permittee shall not cause or permit the discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance, annoyance to persons or to the public or which endanger the comfort, repose, health, or safety of any such persons or the public or which cause or have tendency to cause injury or damage to business or property.

[VIRR 12-09-204-27(a)]

2.4.2 Storage of Petroleum and Other Volatile Products

2.4.2.1 The Permittee shall not store in any stationary tank of more than 65,000 gallons capacity, any petroleum or volatile product or mixture of product having a vapor pressure 2.0 psia or greater under actual storage conditions, unless such tank, reservoir or other container is a pressure tank maintaining working pressures sufficient at all times to prevent hydrocarbon vapor or gas loss to the atmosphere, or is designed and equipped with a vapor loss control device, properly installed, in good working order, and in operation as specified in Sections a, b, and c in VIRR-12-09-204-24.

[VIRR 12-09-204-24]

2.4.3 Fugitive Emissions

2.4.3.1 The Permittee shall not cause but take all reasonable precautions to prevent dust from any operation, process, handling, transportation or storage facility from becoming airborne. Reasonable precautions that should be taken to prevent dust from becoming airborne include, but are not limited to, the following:

2.4.3.1.1 The use, where possible, of water or suitable chemicals for control of dust in the demolition of existing buildings or structures, construction operations, the grading of roads or the clearing of land;

2.4.3.1.2 The application of asphalt, water, or suitable chemicals on dirt roads or roads under construction, materials, stockpiles, and other surfaces that can give rise to airborne dust;

2.4.3.1.3 The installation and use of hoods, fans, and fabric filters to enclose and vent the handling of dusty materials. Adequate abatement methods can be employed during sandblasting or other similar operations;

2.4.3.1.4 The covering, at all times when in motion, of open bodied trucks transporting materials likely to give rise to airborne dust;

2.4.3.1.5 The conduct of agricultural practices, such as the filling of land and the application of fertilizers, in such a way as to prevent dust from becoming airborne;

2.4.3.1.6 The paving or roadways and their maintenance in a clean condition;

2.4.3.1.7 The prompt removal of earth or other material from paved streets onto which earth or other material has been transported by trucking or earth-moving equipment, by erosion by water, or by other means;

2.4.3.1.8 The planting of shrubs or trees as a natural barrier, or the installation of metal sheet fences as artificial barriers; and

2.4.3.1.9 The seeding or planting of grass on exposed terrains.

[VIRR 12-09-204-25(a)]

2.4.3.2 No person shall cause or permit the discharge of visible emissions of fugitive dust beyond the boundary line of the property on which the emissions originate.

[VIRR 12-09-204-25(c)]

2.4.4 Sulfur Compound Emission Control

2.4.4.1 The Permittee shall not let, permit, suffer, or allow any emission of sulfur oxides which results in ground level concentrations of sulfur oxides at any given point in excess of 0.5 ppm (volume) in any three hour period or average exposure in excess of 0.14 ppm (volume) of sulfur oxide in any 24-hour period. These limitations shall not apply to ground level concentrations occurring on the property from which such emission occurs, provided such property, from the emission point to the point of any such concentration is controlled by the person responsible for such emission.

[VIRR 12-09-204-26(a)(1)]

2.4.4.2 The Permittee shall not cause or permit the emission of hydrogen sulfide from any premises in such a manner and amounts that the concentrations attributable to such emissions in the ambient air at any occupied place beyond the premises on which the source is located exceed 0.03 ppm by volume for any averaging period of thirty (30) or more minutes on more than two (2) occasions in any five (5) days.

[VIRR 12-09-204-26(b)(1)]

2.4.5 Upset, Breakdown, or Scheduled Maintenance

2.4.5.1 In the event that any source, air pollution control equipment or related equipment breaks down, malfunctions, ruptures, leaks, or is rendered partially or totally inoperative such that releases of an air contaminant are in excess of allowable emission limits, the Permittee shall within four (4) hours, report to the Commissioner such failure or incident and provide all pertinent available facts, including the estimated duration of the incident. The Commissioner shall be notified in writing not later than one (1) week after the incident. This report shall include specific data concerning the affected source, air pollution control equipment and other related equipment, date, hour and duration of the incident, and corrective measures taken or to be taken.

[VIRR 12-09-204-29(a)]

2.4.5.2 If the malfunction which causes excess air pollution extends or will extend for more than twenty-four (24) hours, the Commissioner may require that the affected facility can only be operated to the end of a cycle or within forty-eight (48) hours after the malfunction occurs, whichever is sooner, at which time it shall be shut down for repairs. Nevertheless, if the malfunction causes the emission of contaminants into the ambient air in quantities that pose an imminent danger to the public, the affected installation or facility shall immediately cease operations or shall act as specified in its approved emergency response plan pursuant to Section 204-33(c).

[VIRR 12-09-204-29(b)]

2.4.5.3 At all times, including periods of startup, shutdown, and malfunction, the Permittee shall, to the extent practicable, maintain and operate any NSPS affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

[40 CFR 60.11(d)]

2.4.6 Circumvention

2.4.6.1 The Permittee shall not build, erect, install, or use any article, machine, equipment, or other contrivance, the sole purpose of which is to dilute or conceal an emission without resulting in a reduction in the total release of air contaminants into the atmosphere. Increase in stack height or construction so as to increase stack exit velocity of gases shall not constitute a violation of this condition.

[VIRR 12-09-204-30]

2.4.7 Duty to Report Discontinuance or Dismantlement

2.4.7.1 The Permittee has a duty to report any discontinued or dismantled fuel burning, combustion, or process equipment or device under the jurisdiction of this Title V Operating Permit to the Department within thirty (30) days the permanent discontinuance or dismantlement of such equipment or device.

[VIRR 12-09-204-31]

2.4.8 Emergency Air Pollution Plan

2.4.8.1 The Permittee is required to have an emergency plan pursuant to this section which must be consistent with adequate safety practices, and which provides for the reduction or retention of the emission from the plant during periods classified by the Commissioner as air pollution alerts, warnings, or emergencies. The Permittee must make this plan available to any representative of the Commissioner at any time.

[VIRR 12-09-204-33(b)(3)]

2.4.8.2 The emergency response plan shall include the information specified in VIRR 12-09-204-3(c)(2)(A) through (L).

[VIRR 12-09-204-33(c)(2)]

2.4.8.3 When the Commissioner declares an air pollution alert, warning or emergency, and determines that such condition requires immediate action for the protection of the health of human beings, the Commissioner will order persons causing or contributing to the atmospheric pollution to reduce their emissions in order to eliminate such condition, or to immediately discontinue the emission of pollutants.

[VIRR 12-09-204-33(b)(1)]

2.4.8.4 The Permittee shall prepare and submit to the Commissioner together with the application for a permit to construct, or permit to operate, whichever is applicable, an emergency response plan according to the provisions set forth in VIRR 12-09-204-33(c)(2). In the case of a renewal of a permit to operate, an emergency response plan will be required only if the Commissioner has not already approved an existing plan, or if there is a change in the process or operation that would give rise to a new potential source of emissions, releases or leaks of sufficient magnitude to present a hazard to human health.

[VIRR 12-09-204-33(c)(1)]

2.4.9 Reports, Sampling, and Analysis of Waste Fuels A and B

2.4.9.1 If the Permittee is burning waste fuel regulated under Section 12-09-204-37, the Commissioner may require the Permittee to: sample, analyze, and measure quantities of all waste fuel received and/or burned; monitor emissions and/or operations; and maintain records of the quantity of Waste Fuel B received and the names and addresses of waste fuel suppliers for three (3) calendar years..

[VIRR 12-09-204-40(a)]

2.4.9.2 The Permittee, if required to maintain and retain records pursuant to this section, must make such records available for inspection by the Commissioner or his representative during normal business hours. Such person(s) must furnish copies of such records to the Commissioner or representative upon request.

[VIRR 12-09-204-40(d)]

2.4.9.3 Sampling and analysis of waste fuel samples must be carried out in accordance with methods acceptable to the Commissioner. A list of acceptable methods may be obtained from any office of the Department.

[VIRR 12-09-204-40(e)]

2.4.10 Existing Air Contamination Sources for Waste Fuel

2.4.10.1 Any person who owns or operates an existing air contamination source in which waste fuel is being burned must either: possess a valid certificate to operate meeting the requirements of subdivision (a) of VIRR 12-09-204-38; or submit a complete application for an amended permit to operate for burning waste fuel. If a permit to operate is denied, the owner and/or operator must discontinue burning waste fuel within forty-five (45) days of receipt of the denial. Note: LIMETREE BAY TERMINALS LLC has a current VIDPNR permit (VI Special Waste Permit No. STX C-002) for combustion of waste fuels in the boilers that meets the intent of this requirement.

[VIRR 12-09-204-41(a)]

2.4.11 Permit Availability

2.4.11.1 This permit to operate shall be maintained readily available at all times on the operating premises.

[VIRR 12-09-206-20(d)]

2.4.12 Fee Assessment and Payment:

2.4.12.1 The Permittee shall calculate and pay an annual permit fee to the Division. The amount of fee shall be determined each year in accordance with the applicable rules and regulations.

[VIRR 12-09-206-93]

2.4.12.2 The Permittee must submit an annual payment based on the facility's actual emission rates in tons per year. The fee amount for annual emissions is $50.00 per ton of regulated pollutant emitted.

[VIRR 12-09-206-93]

2.4.12.3 The Permittee shall be assessed a penalty for failure to pay annual emission fees, within thirty days of receipt of invoice for annual emissions, which shall accrue at the rate of ten percent per month on the outstanding balance, compounded monthly.

[VIRR 12-09-206-93(f)]

PART 3.0 REQUIREMENTS FOR EMISSION UNITS

Table 2 in Part 1 provides a summary by individual emission unit or emission unit grouping of the specific location within this Title V permit for each emission or operational limitation and for the testing, monitoring, recordkeeping, and reporting requirements that apply to that emission or operational limitation.

3.1 Equipment Emission Caps and Operating Limits (V.I. Requirements)

3.1.1 Group 01 – Boilers

3.1.1.1 For all boilers except B-1155, B-3303, and B-3304, the Permittee shall not discharge into the atmosphere, any air contaminant(s) with opacity greater than or equal to 20% for any time period, except for a period or periods aggregating not more than 3 minutes in any 30 minutes when opacity shall be less than or equal to 40%.

[VIRR 12-09-204-22(a) and (b)]

3.1.1.2 For Boilers B-1155, B-3303, and B-3304, the Permittee shall ensure compliance with the continuous emission monitoring requirements contained in VIRR 12-09-204-35(d).

[VIRR 112-09-204-35(d)]

3.1.1.3 Group 01A – Boilers B-1151, B-1153, B-1154, and B-1155

3.1.1.3.1 The allowable particulate emission rate for each boiler is as follows, where $E = 1/P^{0.22}$ and P = heat input in mmBtu/hr:

B-1151: E = 0.30 lb/mmBtu
B-1153: E = 0.30 lb/mmBtu
B-1154: E = 0.30 lb/mmBtu
B-1155: E = 0.26 lb/mmBtu

[VIRR 12-09-204-23(b)(4)]

3.1.1.4 Group 01B – Boilers B-3301, B-3302, B-3303, and B-3304

3.1.1.4.1 The allowable particulate emission rate for each boiler is as follows, where $E = 1/P^{0.22}$ and P = heat input in mmBtu/hr:

B-3301: E = 0.30 lb/mmBtu
B-3302: E = 0.30 lb/mmBtu
B-3303: E = 0.26 lb/mmBtu
B-3304: E = 0.26 lb/mmBtu

[VIRR 12-09-204-23(b)(2) and (4)]

3.1.1.5 Group 01C – Boiler B-3701

3.1.1.5.1 Boiler B-3701 (#10 Boiler) shall be limited to burning refinery gas or propane with H_2S content less than 75 ppmv, averaged over any 3-hour period. The emission rate of SO2 from the boiler shall not exceed 2.6 lbs/hr based on a 365- day rolling average.

[STX-557-I-00 (II)(E), September 18, 2000]

3.1.1.5.2 The Permittee shall equip Boiler B-3701 with ultra-low NOx burners. The emission rate of NOx from the boiler shall not exceed 0.07 lb/mmBtu and 15.8 lbs/hr, based on the average value of three (3) successive test runs using EPA Reference Method 7E, or the NSPS Method, whichever testing method is determined to be the most stringent at the time of the test.

[STX-557-I-00 (II)(F), September 18, 2000]

3.1.1.5.3 The emission rate of CO from Boiler B-3701 shall not exceed 15.8 lbs/hr, based on the average value of three (3) successive test runs using EPA Reference Method 10 or the NSPS Method, whichever testing method is determined to be the most stringent at the time of the test.

[STX-557-I-00 (II)(G), September 18, 2000]

3.1.1.5.4 The emission rate of VOC from Boiler B-3701 shall not exceed 1.1 lbs/hr based on 365-days rolling average.

[STX-557-I-00 (II)(H), September 18, 2000]

3.1.1.5.5 The emission rate of PM/PM10 from Boiler B-3701 shall not exceed 0.7 lbs/hr based on 365-days rolling average.

[STX-557-I-00 (II)(I), September 18, 2000]

3.1.2 Group 02 – Heaters

3.1.2.1 Group 02A – Heaters H-101, H-104, H-401A, H-401B, H401C, H-1401A, H-1401B, H-2101, H-2102, H-3101A, H-3101B, H-4101A, H-4101B, H-4201, H-4202

3.1.2.1.1 The allowable particulate matter emission rates for these heaters (based on $E=1/P^{0.22}$, where P = heat input in mmBtu/hr) are:

H-101: E = 0.34 lb/mmBtu
H-104: E = 0.36 lb/mmBtu
H-401A: E = 0.33 lb/mmBtu
H-401B: E = 0.33 lb/mmBtu
H-401C: E = 0.33 lb/mmBtu
H-1401A: E = 0.29 lb/mmBtu
H-1401B: E = 0.30 lb/mmBtu
H-2101: E = 0.32 lb/mmBtu
H-2102: E = 0.32 lb/mmBtu
H-3101A: E = 0.28 lb/mmBtu
H-3101B: E = 0.28 lb/mmBtu
H-4101A: E = 0.28 lb/mmBtu
H-4101B: E = 0.28 lb/mmBtu
H-4201: E = 0.30 lb/mmBtu
H-4202: E = 0.30 lb/mmBtu

[VIRR 12-09-204-23(b)(4)]

3.1.2.1.2 The Permittee shall not discharge into the atmosphere, any air contaminant(s) with opacity greater than or equal to 20% for any time period, except for a period or periods aggregating not more than 3 minutes in any 30 minutes when opacity shall be less than or equal to 40%.

[VIRR 12-09-204-22(a) and (b)]

3.1.2.2 Group 02B – Heaters H-160, H-200, H-201, H-202, H-600, H-601, H-602, H-603, H-604, H-605, H-606, H-800A, H-800B, H-801, H-1500, H-1501, H-2201A, H-2201B, H-2202, H-2400, H-2401, H-2501, H-4301A, H-4301B, H-4302, H-4401, H-4402, H-4451, H-4452, H-4453, H-4454, H-4455, H-4502, H-4503, H-4504, H-4505, H-4601A, H-4601B, H-4602, H-5301A, H-5301B, H-5302 H-5401, H-5402, H-5451, H-5452, H-5453, H-5454, H-5455

3.1.2.2.1 The Permittee shall not discharge into the atmosphere, any air contaminant(s) with opacity greater than or equal to 20% for any time period, except for a period or periods aggregating not more than 3 minutes in any 30 minutes when opacity shall be less than or equal to 40%.

[VIRR 12-09-204-22(a) and (b)]

3.1.2.3 Group 02C – Heater H-2185

None.

3.1.2.4 Group 02D – Heaters H-4901 (LSG Unit Heater) and Hydrogen Plant Heater

3.1.2.4.1 The Permittee shall not discharge into the atmosphere, any air contaminant(s) with opacity greater than or equal to 20% for any time period, except for a period or periods aggregating not more than 3 minutes in any 30 minutes when opacity shall be less than or equal to 40%.

[VIRR 12-09-204-22(a) and (b)]

3.1.2.5 Group 02E – Heaters H-7801, H-7802, and R-7801 and Stack STK-7801

None.

3.1.2.6 Group 02F – Incinerators H-1032, H-1042, and H-4745

3.1.2.6.1 The Permittee shall comply with the applicable requirements of VIRR 12-09-204-45.

[VIRR 12-09-204-45]

3.1.2.6.2 Opacity shall be less than 20%.

[VIRR 12-09-204-22(a)]

3.1.2.6.3 The Permittee shall comply with the applicable requirements of VIRR 12-09-204-23(c).

[VIRR 12-09-204-23(c)]

3.1.2.7 Group 02G – Heaters H-8501A and H-8501B

3.1.2.7.1 The Permittee shall not discharge into the atmosphere, any air contaminant(s) with opacity greater than or equal to 20% for any time period, except for a period or periods aggregating not more than 3 minutes in any 30 minute period when opacity shall be less than or equal to 40%.

[VIRR 12-09-204-22(a) and (b)]

3.1.2.7.2 The process heaters shall be limited to burning refinery gas or propane with an H_2S content less than 75 parts per million by volume (ppmv) average over a 3-hour rolling period. The emission rate of SO2 from each heater shall not exceed 2.2 lbs/hr based on a 365-day rolling average.

[STX-557A-E-02(III)(A), June 4, 2002]

3.1.2.7.3 Each heater shall be equipped with ultra-low NOx burners. The emission rate of NOx from each heater shall not exceed 0.07 lb/mmBtu and 13.7 lb/hr, based on the average of three (3) successive test runs using EPA Reference Method 7E, or the NSPS Method, whichever testing method is determined to be the most stringent at the time of the test. The test protocol must be approved by the VIDPNR.

[STX-557A-E-02(III)(B), June 4, 2002]

3.1.2.7.4 The emission rate of CO from each heater shall not exceed 5.9 lb/hr, based on the average of three (3) successive test runs using EPA Reference Method 10, or the NSPS Method, whichever testing method is determined to be the most stringent at the time of the test. The test protocol must be approved by the VIDPNR.

[STX-557A-E-02(III)(C), June 4, 2002]

3.1.2.7.5 The emission rate of VOC from each heater shall not exceed 1.0 lb/hr based on a 365-day rolling average.

[STX-557A-E-02(III)(D), June 4, 2002]

3.1.2.7.6 The emission rate of PM/PM10 from each heater shall not exceed 0.6 lb/hr based on a 365-day rolling average.

[STX-557A-E-02(III)(E), June 4, 2002]

3.1.3 Group 03 – Compressor Engines

3.1.3.1 The Permittee shall not discharge into the atmosphere, any air contaminant(s) with opacity greater than or equal to 20% for any time period, except for a period of not more than 3 minutes during start-up when opacity shall be less than or equal to 40%.

[VIRR 12-09-204-28(b)(i) and (ii)]

3.1.3.2 The two compressor engines located at #5DD (C-2400A and C-2400B) and the three compressors at the Penex Unit (C-200A, C-200B, and C-200C) shall be equipped with catalytic converters prior to startup of the coker.

[STX-557A-E-02(IX)(A), June 4, 2002]

3.1.3.3 The catalytic converters installed on C-2400A and C-2400B shall reduce the NOx emissions to 0.67 lbs/mmBtu average over a calendar quarter.
[STX-557A-E-02(IX)(B), June 4, 2002]

3.1.3.4 The catalytic converters installed on C-2400A and C-2400B shall reduce the CO emissions to 2.40 lbs/mmBtu average over a calendar quarter.
[STX-557A-E-02(IX)(C), June 4, 2002]

3.1.3.5 The catalytic converters installed on C-200A, C-200B, and C-200C shall reduce the NOx emissions to 0.86 lbs/mmBtu average over a calendar quarter.
[STX-557A-E-02(IX)(D), June 4, 2002]

3.1.3.6 The catalytic converters installed on C-200A, C-200B, and C-200C shall reduce the CO emissions to 7.06 lbs/mmBtu average over a calendar quarter.
[STX-557A-E-02(IX)(E), June 4, 2002]

3.1.4 Group 04 – Combustion Turbines

3.1.4.1 For all combustion turbines except G-3410, the Permittee shall not discharge into the atmosphere, any air contaminant(s) with opacity greater than or equal to 20% for any time period, except for a period or periods aggregating not more than 3 minutes in any 30 minute period when opacity shall be less than or equal to 40%.
[VIRR 12-09-204-22(a) and (b)]

3.1.4.2 Group 04A – Turbines G-1101E, G-1101F, G-1101G, G-3404, G-3405, G-3406, G-3407, G-3408, G-3409, G-3410

3.1.4.2.1 The allowable particulate matter emission rate for each turbine is as follows, where $E = 1/P^{0.22}$ and P = heat input in mmBtu/hr:

G-1101E: E = 0.29 lb/mmBtu
G-1101F: E = 0.29 lb/mmBtu
G-1101G: E = 0.29 lb/mmBtu
G-3404: E = 0.29 lb/mmBtu
G-3405: E = 0.29 lb/mmBtu
G-3406: E = 0.29 lb/mmBtu
G-3407: E = 0.29 lb/mmBtu
G-3408: E = 0.27 lb/mmBtu
G-3409: E = 0.27 lb/mmBtu
G-3410: E = 0.10 lb/mmBtu
[VIRR 12-09-204-23(b)(2) and (4)]

3.1.4.2.2 The Permittee shall only combust the following fuels in GT No. 9 (G-3409): gaseous fuels – refinery grade propane and refinery grade butane; and liquid fuels – distillate fuel oil with a maximum of 0.2% sulfur by weight.
[STX-557-J-K-05(A)(1), November 22, 2005]

3.1.4.2.3 For G-3409, the Permittee shall combust liquid fuels up to a maximum of 266,304 MMBtu per year, as calculated on a 12-month rolling basis.
[STX-557-J-K-05(A)(2), November 22, 2005]

3.1.4.2.4 NOx emission limitations for GT No. 9 shall be as follows:

3.1.4.2.4.1 NOx emissions during gaseous and/or liquid firing shall not exceed 42 ppmv, dry, corrected to 15% oxygen, or 57.0 lbs/hr on a block -hour average, whichever is more stringent.

3.1.4.2.4.2 Annual NOx emissions shall not exceed 150.2 tpy as calculated on a 12-month rolling basis.

3.1.4.2.4.3 Except during startups and shutdowns, the Permittee shall use steam injection at all times to control NOx emissions. The optimum steam to fuel ratio established for butane firing is 1.58, for propane firing is 1.47, and for distillate oil firing is 1.44.
[STX-557-J-K-05(B)(1), November 22, 2005]

3.1.4.2.5 CO emission limitations for GT No. 9 shall be as follows:

3.1.4.2.5.1 CO emissions during gaseous fuel firing shall not exceed 206.5 ppmvd, corrected to 15% oxygen, or 94.0 lbs/hr, on a block-hour average whichever is more stringent.

3.1.4.2.5.2 CO emissions during liquid fuel firing shall not exceed 242 ppmvd, corrected to 15% oxygen, or 111.0 lbs/hr, on a block-hour average whichever is more stringent.

3.1.4.2.5.3 CO emissions during combination fuel firing shall not exceed the prorated gaseous and liquid fuel emissions as determined by the flow rate of each fuel type.

3.1.4.2.5.4 CO emissions shall not exceed 44.1 tpy as calculated on a 365-day rolling basis.

3.1.4.2.5.5 GT No. 9 shall be operated except during periods of startups and shutdowns, at loads greater than 50%.
[STX-557-J-K-05(B)(2), November 22, 2005]

3.1.4.2.6 PM10 emissions limitations for GT No. 9 shall be as follows:

3.1.4.2.6.1 Emissions of PM10 during gaseous fuel firing shall not exceed 2.5 lbs/hr.

3.1.4.2.6.2 Emissions of PM10 during liquid fuel firing shall not exceed 9.5 lbs/hr.

3.1.4.2.6.3 PM10 Emissions during combination fuel firing shall not exceed the prorated gaseous and liquid fuel emissions as determined by the flow rate of each fuel type.
[STX-557-J-K-05(B)(3), November 22, 2005]

3.1.4.2.7 For the purposes of this permit, startup shall be defined as the establishment of 11 MW load to the turbine and operation of the steam injection system. The startup process shall not exceed one hour. Shutdown shall be defined as the removal of electrical load to the turbine. The shutdown process shall not exceed one hour.
[STX-557-J-K-05(C)(1), November 22, 2005]

3.1.4.2.8 The maximum annual heat input of GT No. 9 shall not exceed 304 mmBtu/hr.
[STX-557-J-K-05(C)(2), November 22, 2005]

3.1.4.2.9 For fuels that are intermediately stored in tanks for combustion by GT No. 9, the Permittee shall determine the sulfur content, through laboratory analysis, each time there is a transfer of fuel to the storage tanks.
[STX-557-J-K-05(C)(4), November 22, 2005]

3.1.4.2.10 Emissions in excess of the applicable emission limits, during periods of startup and shutdowns, shall not be considered a violation of the applicable emission limit.
[STX-557-J-K-05(D)(7), November 22, 2005]

3.1.4.2.11 The Permittee shall continuously calculate the NOx and CO mass emission rates for GT No. 9. The calculated emission rates shall be used to determine compliance with the NOx and CO mass emission rate limits contained in sections 3.1.4.2.4 and 3.1.4.2.5.
[STX-557-J-K-05(D)(8), November 22, 2005]

3.1.4.2.12 At all times, including periods of startup, shutdown, and malfunction, the Permittee shall, to the extent practicable, maintain and operate the GT No. 9 in a manner consistent with good air pollution control practices for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to EPA and/or VIDPNR, which may include, but is not limited to, monitoring results, review of operating and maintenance procedures, and inspection of the facility.
[STX-557-J-K-05(D)(9), November 22, 2005]

3.1.4.3 Group 04B – G-3413 (GT No. 13) and Associated Duct Burner H-3413

3.1.4.3.1 The allowable particulate matter emissions rate for GT-13 (G-3413) is: E = 0.10 lb/mmBtu. [This requirement will be met through compliance with condition 3.2.4.2.20]
[VIRR 12-09-204-23(b)(2)]

3.1.5 Group 05 – Flares

None.

3.1.6 Group 06 – Loading

3.1.6.1 Group 06A – Truck Loading

3.1.6.1.1 The Permittee shall install all monitors, recorders, and meter devices, as required by this permit, prior to operation of the equipment, unless otherwise stated.
[STX-557-H-00(III)(G), September 18, 2000]

3.1.6.1.2 The emissions from the Vapor Recovery Unit (VRU) shall not exceed 35 mg Total Organic Compounds/L of gasoline loaded.
[STX-557-H-00(III)(C), September 18, 2000]

3.1.6.1.3 The VRU shall not cause any air contaminant, including an air contaminant detectable by the sense of smell, to be present in the outdoor atmosphere in such quantity and duration which is, or tends to be injurious to human health or welfare, animal or plant life or property, except in areas over which the owner or operator has exclusive use or occupancy.
[STX-557-H-00(V)(B), September 18, 2000]

3.1.6.1.4 The Permittee shall load all jet fuel, gasoline (regular and premium), and diesel into tank trucks by submerged fill pipe. Vapors displaced during loading shall be collected by the vapor collection system and routed to the Vapor Recovery Unit (VRU) prior to discharge through stack. [Condition based on September 7, 2007 former owner HOVENSA Letter to DPNR recommending elimination of specified stack height.]
[Truck Loading Facility Permit No. 414-96(h), July 25, 1996]

3.1.6.1.5 The normal operating hours of the terminal shall be eight (8) hours per day and six (6) days per week. In the event of unforeseen customer needs, the Permittee may deviate from the normal operating hours.
[Truck Loading Facility Permit No. 414-96(i), July 25, 1996]

3.1.6.1.6 The Permittee shall develop Standard Operating Procedures (SOPs) on the operation of the terminal while loading tank and propane trucks to ensure operation in a manner consistent with good air pollution control practice for minimizing emissions.
[Truck Loading Facility Permit No. 414-96(m), July 25, 1996]

3.1.6.2 Group 06B – Marine Loading

3.1.6.2.1 The Permittee shall comply with 40 CFR 61, Subpart A and Subpart BB.
[Marine Vapor Control System Permit No. 412-96(h), July 25, 1996]

3.1.6.2.2 All benzene emissions collected from the vapor collection system shall be vented through the Thermal Destructor Unit (H-4745) located on the No. 2 Beavon (SRU Tail Gas Processing Unit).
[Marine Vapor Control System Permit No. 412-96(i), July 25, 1996]

3.1.6.2.3 Loading and unloading of benzene will be limited to marine vessels.
[Marine Vapor Control System Permit No. 412-96(j), July 25, 1996]

3.1.6.2.4 VIDPNR reserves the right to inspect the Permittee's facilities. The Permittee shall give VIDPNR whatever aid is necessary to perform said inspections in a safe and timely manner.
[Marine Vapor Control System Permit No. 412-96(g), July 25, 1996]

3.1.6.2.5 The Permittee shall develop Standard Operating Procedures (SOPs) to ensure that the Thermal Destructor Unit is operated in a manner consistent with good air pollution control practice for minimizing emissions.
[Marine Vapor Control System Permit No. 412-96(l), July 25, 1996]

3.1.7 Group 07 – Sulfur Recovery, including Stacks

3.1.7.1 Opacity shall be less than 20%.
[VIRR 12-09-204-22(a)]

3.1.7.2 The Permittee shall comply with the applicable requirements of VIRR 12-09-204-45.
[VIRR 12-09-204-45]

3.1.8 Group 08 – Internal Floating Roof Tanks

None.

3.1.9 Group 09 – External Floating Roof Tanks

3.1.9.1 Prior to startup of the coker, Tanks TK-6815 and TK-6839 shall be equipped with sleeves on the slotted guide poles. Tanks TK-6815 and 6839 shall be limited to storing material with maximum annual average true vapor pressure less than 12.0 psia. Tank TK-6815 shall be limited to an annual throughput of 508,000,000 gallons. Tank TK-6839 shall be limited to an annual throughput of 821,600,000 gallons.
[STX-557A-E-02(VIII)(A), June 4, 2002]

3.1.9.2 The Permittee shall inspect the gauge pole sleeves annually and every time the tanks are taken out of service (i.e., emptied and degassed):

3.1.9.2.1 The gauge pole sleeve system shall be physically inspected annually from the tops of the floating roofs. These inspections shall involve physical examination for loose, damaged, or defective components, and measurement of the gaps between the gauge poles and the pole liners.

3.1.9.2.2 The entire gauge pole sleeve system shall be physically inspected every time the tank is taken out of service.

3.1.9.2.3 Signs of a broken, worn, damaged, defective, misplaced or detached seal, gasket, line or part that may result in the loss of seal integrity of the gauge pole sleeve control system shall be considered a failure of the control system. The Permittee shall make repairs to the system as soon as practicable, but no later than 15 days after the date that the failure is discovered during an annual inspection or before the tank is returned to service during an empty and degas inspection.
[STX-557A-E-02(VIII)(B), June 4, 2002]

3.1.10 Group 10 – Fixed Roof Tanks

3.1.10.1 Group 10A – Fixed Roof Tanks PRT3, PRT4, PRT5, PRT6, PRT7, TK-1151, TK-1201, TK-1202, TK-1203, TK-1206, TK-1207, TK-1208, TK-1302, TK-1653, TK-2653, TK-2654, TK-3208, TK-3301, TK-3304, TK-3306, TK-3384, TK-3385, TK-3386, TK-4502, TK-6810, TK-6811, TK-6812, TK-6813, TK-6817, TK-6818, TK-6819, TK-6820, TK-6821, TK-6822, TK-6823, TK-6824, TK-6825, TK-6851, TK-6853, TK-6854, TK-6856, TK-6858, TK-6859, TK-6860, TK-6873, TK-6875, TK-6876, TK-6877, TK-6881, TK-6883, TK-6887, TK-700, TK-701, TK-702, TK-7206, TK-7207, TK-7208, TK-7209, TK-TK-7210, TK-7211, TK-7301, TK-7405, TK-7406, TK-7411, TK-7412, TK-7413, TK-7414, TK-7415, TK-7416, TK-7421, TK-7422, TK-7427, TK-7428, TK-7429, TK-7430, TK-7435, TK-7436, TK-7437, TK-7438, TK-7439, TK-7440, TK-7446, TK-7501, TK-7502, TK-7503, TK-7504, TK-7505, TK-7506, TK-7933, TK-7934, UTT1, TK-8501

3.1.10.1.1 Tank TK-8501 shall store only pitch. The emission rate of VOC from the tank shall not exceed 7.3 tons per year.
[STX-557A-E-02(IV)(A), June 4, 2002]

3.1.10.1.2 Tank TK-8501 shall be subject to 40 CFR 60, Subpart Kb, 60.110b. However, TK-8501 shall be exempt from the control requirements under Subpart Kb because it is restricted from storing material with a true vapor pressure greater than 0.5 psia.
[STX-557A-E-02(IV)(B), June 4, 2002]

3.1.10.2 Group 10B - Affected Units: TK-1204, TK-1205, TK-8001, TK-8002

None.

3.1.11 Group 11 – Horizontal Tanks TK-1626, TK-1627, TK-1628, TK-1629, TK-1630, TK-1631, TK-1633, D-1301, D-1609, D-1610, D-1620

None.

3.1.12 Group 12 – Geodesic Dome Tanks

None.

3.1.13 Group 13 – Wastewater Treatment

None.

3.1.14 Group 14 – Alkylation and Dimersol Units

None.

3.1.15 Group 15 – Seawater Intake Pumps

3.1.15.1 The allowable particulate matter emission rates for these pumps (based on $E=1/P^{0.22}$, where P = heat input in mmBtu/hr) are:

PD-1602: E = 0.86lb/mmBtu
PD-1603: E = 0.86 lb/mmBtu
PD-1604: E = 0.86 lb/mmBtu
PD-1605: E = 0.86 lb/mmBtu
PD-1620: E = 0.94 lb/mmBtu

[VIRR 12-09-204-23(b)(4)]

3.1.15.2 The Permittee shall not discharge into the atmosphere, any air contaminant(s) with opacity greater than or equal to 20% for any time period, except for a period of not more than 3 minutes during start-up when opacity shall be less than or equal to 40%.

[VIRR 12-09-204-28(b)(i) and (ii)]

3.1.16 Group 16 – FCCU (including STK-7051)

3.1.16.1 For STK-7051, the Permittee shall ensure compliance with the continuous emission monitoring requirements contained in VIRR 12-09-204-35(d).

[VIRR 12-09-204-35(d)]

3.1.16.2 For a period of five years after startup of the FCCU Turbo Expander, the Permittee shall determine, on a rolling 12-month basis, annual emission increases from Boilers 6 through 10 which result from increased steam production attributable to the loss of steam from the FCCU flue gas coolers (FGC) waste boilers (WHB). In order to comply with 40 CFR 52.21(r)(6) and to properly determine if emissions increases are attributable to the use of the FCCU Turbo Expander, the Permittee will use the following methodology:

3.1.16.2.1 On a monthly basis, the 12-month rolling total emissions will be calculated using heat input to the boilers and emission factors from the following sources: first priority, CEMS data (where available); second priority, 40 CFR 60 stack test data (where available); third priority, AP-42 factors (sources without CEMS or stack test data).

3.1.16.2.2 In instances where the increase from the baseline actual emissions to the total actual emissions exceeds the projected emissions increases NOx – 108.9 tpy; CO – 20.5 tpy; VOC – 1.9 tpy; PM – 17.0 tpy; PM10 – 15.1 tpy; SO2 – 178.0 tpy; and H2SO4 – 8.4 tpy), and the increase is above the significance level, calculations will be performed to determine what portion of the emissions increase is attributable to the use of the FCCU Turbo Expander using the following methodology:

3.1.16.2.2.1 Annual average 600-pound steam production from the FCCU FGC WHB will be determined for the time period used in the determination of the baseline actual emissions from Boilers 6 through 10.

3.1.16.2.2.2 On a monthly basis, the 12-month rolling total actual steam production from the FCCU FGC WHB will be determined.

3.1.16.2.2.3 Emission increases attributable to the use of the FCCU Turbo Expander shall be determined using the difference between the baseline steam production and actual steam production (adjusted for any periods of reduced production due to reduced FCCU throughput or other operational anomalies in the FCCU) in the FCCU FGC WHB, the average heat input to steam production ratio from Boilers 6 through 10, and the average emissions factors for Boilers 6 through 10, with all averages determined according to actual heat input ratios.

[STX-557-J-K-05(C)(6), November 22, 2005]

3.1.17 Group 17 – Coker Complex

3.1.17.1 The Permittee shall comply with the applicable requirements of VIRR 12-09-204-23(d) [Particulate Emissions From Industrial Process Equipment].

[VIRR 12-09-204-23(d)]

3.1.17.2 The Residuals Recycling System (Tank 8511) shall not cause any air contaminant, including an air contaminant detectable by the sense of smell, to be present in the outdoor atmosphere in such quantity and duration which is, or tends to be injurious to human health or welfare, animal or plant life or property, or would unreasonably interfere with the enjoyment of life or property, except in areas over which the owner or operator has exclusive use or occupancy.

[STK-557-K-05(V)(B), May 11, 2005]

3.1.17.3 For the Residuals Recycling System (Tank 8511), the granulated activated carbon (GAC) emissions control system shall operate at a minimum removal efficiency of 96%.

[STK-557-K-05(II)(F), May 11, 2005]

3.1.17.4 The Permittee shall limit the contents of Tank 8511 to slurry for injection into the Delayed Coker Unit. The slurry will consist of various refinery residual solids and water (such as stripped sour water, service water, or desalinated water).

[STK-557-K-05(II)(I), May 11, 2005]

3.1.17.5 The GAC emission control system for Tank 8511 shall be composed of three (3) GAC canisters placed in series which are designed to remove hydrocarbons.
[STK-557-K-05(II) (G) and (H), May 11, 2005]

3.1.17.6 The crude oil capacity of the refinery shall not exceed 525,000 barrels per calendar day (BPD).
[STX-557A-E-02(II)(B), June 4, 2002]

3.1.17.7 The charge rate to the coker shall not exceed 21,170,000 barrels on a 365 day rolling average.
[STX-557A-E-02(II)(C), June 4, 2002]

3.1.17.8 The wastewater conveyance system shall incorporate traps and shall be enclosed wherever feasible.
[STX-557A-E-02(V)(B), June 4, 2002]

3.1.17.9 Dual mechanical pump and compressor seals shall be used where feasible.
[STX-557A-E-02(V)(C), June 4, 2002]

3.1.17.10 All coke drum drop operations shall maintain a material moisture content of greater than or equal to 4.8% based on an annual average. All coke drum drop operations shall be limited to emissions rates of 900 lb/yr of PM and 300 lb/yr of PM10.
[STX-557A-E-02(VI)(A), June 4, 2002]

3.1.17.11 All coke crusher drop operations shall maintain a material moisture content of greater than or equal to 4.8% based on an annual average. All coke crusher drop operations shall be limited to emission rates of 900 lb/yr of PM and 300 lb/yr of PM10.
[STX-557A-E-02(VI)(B), June 4, 2002]

3.1.17.12 All coke drop operations to the ship shall maintain a material moisture content of greater than of equal to 4.8% based on an annual average. All coke drop operations to the ship shall be limited to emission rates of 900 lb/yr of PM and 300 lb/yr of PM10.
[STX-557A-E-02(VI)(C), June 4, 2002]

3.1.17.13 All coke storage dome vents shall be limited to emission rates of 90 lb/yr of PM and 30 lb/yr of PM10.
[STX-557A-E-02(VI)(D), June 4, 2002]

3.1.17.14 All material in the coke crusher shall maintain a material moisture content of greater than or equal to 4.8% based on an annual average. All operations in the coke crusher shall be limited to 9,450 lb/yr of PM and 4,500 lb/yr of PM10.
[STX-557A-E-02(VI)(E), June 4, 2002]

3.1.17.15 The enclosed handling system shall be routinely inspected and maintained.
[STX-557A-E-02(VI)(F), June 4, 2002]

3.1.17.16 The tank vent dust collection systems shall be routinely inspected and maintained.

[STX-557A-E-02(VI)(G), June 4, 2002]

3.1.17.17 In the event of a breakdown of the enclosed handling system or during maintenance of the system, the Permittee shall follow the following requirements for the handling of petroleum coke in order to prevent the emission of fugitive particulate matter:

3.1.17.17.1 In the event of breakdown/maintenance of the enclosed handling system, all alternate coke drop operations involving the transfer of petroleum coke, shall be subject to the material moisture content percentages and fugitive particulate emission rates contained in this permit.

[STX-557A-E-02(VII)(A), June 4, 2002]

3.1.17.17.3 Every such vehicle shall be provided with a means of covering the petroleum coke to be hauled and of keeping such waste completely and securely within the hauling body.

[STX-557A-E-02(VII)(C), June 4, 2002]

3.1.17.17.4 The hauling body shall be provided with a tight metal permanent cover having adequate opening fitted with smoothly operating loading and unloading doors, or shall be provided with heavy tarpaulin or other canvas cover fitted with proper eyes, grommets, the ropes and hooks whereby the cover can be held securely over the petroleum coke so as to preclude its leakage, spillage or wind disbursement.

[STX-557A-E-02(VII)(D), June 4, 2002]

3.1.17.17.5 No vehicle, other than one with permanent cover, shall be loaded with petroleum coke to a level above the side wall height.

[STX-557A-E-02(VII)(E), June 4, 2002]

3.1.17.17.6 No vehicle shall be loaded with petroleum coke in such a manner which will permit the petroleum coke to spill, leak, be wind disbursed or otherwise leave the hauling body whether or not the vehicle is in motion.

[STX-557A-E-02(VII)(F), June 4, 2002]

3.1.17.17.7 When vehicles used for the transport of petroleum coke are loaded, no driver, owner or superintendent having charge or control of any such vehicle shall keep or allow such vehicle to be parked to consume an unreasonable amount of time in unloading, or when not engaged in loading and unloading the vehicle, allow the lid or covering of the vehicle to be otherwise than securely closed, nor allow such vehicle to be otherwise than securely covered.

[STX-557A-E-02(VII)(G), June 4, 2002]

3.1.18 Group 18 – Sulfuric Acid Plant Stack STK-7802

3.1.18.1 The Permittee shall not discharge into the atmosphere, any air contaminant(s) with opacity greater than or equal to 20% for any time period.
[VIRR 12-09-204-22(a)]

3.1.18.2 For STK-7082, the Permittee shall ensure compliance with the continuous emission monitoring requirements contained in VIRR 12-09-204-35(d).
[VIRR 12-09-204-35(d)]

3.1.19 Group 19 – Vapor Enhanced Recovery

3.1.19.1 The maximum design flow rate of VER #1 shall be 200 cubic feet per minute.
[STX-557-G-01(II)(F), September 6, 2001]

3.1.19.2 The maximum design flow rate of VER #2 shall be 300 cubic feet per minute.
[STX-557-G-01(II)(G), September 6, 2001]

3.1.19.3 For the Thermal/Catalytic Oxidizer Modes: The maximum influent concentration of hydrocarbons to be treated by the oxidizer shall be 198,429 ppmv.
[STX-557-G-01(II)(A), September 6, 2001]

3.1.19.4 For the Thermal/Catalytic Oxidizer Modes: The VOC from the oxidizer shall not exceed 55.4 lbs/day.
[STX-557-G-01(II)(B), September 6, 2001]

3.1.19.5 For the Thermal/Catalytic Oxidizer Modes: The oxidizer shall operate at a minimum destruction removal efficiency (DRE) of 99%.
[STX-557-G-01(II)(K), September 6, 2001]

3.1.19.6 For the Thermal/Catalytic Oxidizer Modes: The oxidizer shall be operated at a minimum temperature of 1400 degrees F during thermal mode.
[STX-557-G-01(II)(G), September 6, 2001]

3.1.19.7 For the Thermal/Catalytic Oxidizer Modes: The oxidizer shall be operated at a minimum temperature of 600 degrees F during catalytic mode.
[STX-557-G-01(II)(I), September 6, 2001]

3.1.19.8 For the Activated Carbon Mode: The activated carbon absorber shall operate at a minimum DRE of 95%.
[STX-557-G-01(II)(D), September 6, 2001]

3.1.19.9 For the Activated Carbon Mode: The maximum influent concentration of hydrocarbons to be treated by the activated carbon unit shall be 500 ppmv.
[STX-557-G-01(II)(A), September 6, 2001]

3.1.19.10 For the Activated Carbon Mode: The VOC from the activated carbon absorber shall not exceed 2.0 lbs/day.
[STX-557-G-01(II)(E), September 6, 2001]

3.1.19.11 The Permittee shall install all monitors, recorders, and meter devices, as required by this permit, prior to operation of the equipment, unless otherwise stated.

[STX-557-G-01(III)(A), September 6, 2001]

3.1.19.12 The VER system shall not cause any air contaminant, including an air contaminant detectable by the sense of smell, to be present in the outdoor atmosphere in such quantity and duration which is, or tends to be, injurious to human health or welfare, animal or plant life or property, except in areas over which the Permittee has exclusive use or occupancy.

[STX-557-G-01(V)(B), September 6, 2001]

3.1.19.13 The Permittee shall follow the startup procedure (case-by-case basis) whenever there is an exceedance of conditions in this permit applicable to the VER units, or the VER unit has been shut down for more than seven working days.

[STX-557-G-01(II)(D), September 6, 2001]

3.1.19.14 The Permittee shall not discharge into the atmosphere, any air contaminant(s) with opacity greater than or equal to 20% for any time period.

[VIRR 12-09-204-22(a)]

3.1.19.15 The Permittee shall comply with the applicable requirements of VIRR 12-09-204-23(c).

[VIRR 12-09-204-23(c)]

3.1.20 Group 20 – Gasoline Service Station and Fuel Gas System

None.

3.1.21 Group 21 – Amine Units, Merox Unit, and Gas Concentration

None.

3.1.22 Group 22 – Gas Treating and Stripping

None.

3.1.23 Group 23 – Hydrogen Recovery

None.

3.1.24 Group 24 – Disulfide Handling

None.

3.1.25 Group 25 – Platformers

None.

<u>3.2</u> <u>Equipment Federal Requirements</u>

3.2.1 Group 01 – Boilers

3.2.1.1 For boilers B-1151, B-1153, B-1154, B-1155, B-3301, B-3302, B-3303, and B-3304, maximum sulfur content in residual fuel oil shall not exceed 0.5% by weight under the supplemental control operating scenario and 1.0% by weight under the reduced fuel-use or normal operating scenarios.
[1997 PSD Permit (III)(C)(c), (d), and (e)]

3.2.1.2 Group 01A – Boilers B-1151, B-1153, B-1154, and B-1155

3.2.1.2.1 For boilers B-1151, B-1153, B-1154, and B-1155, the Permittee is allowed a combined maximum residual fuel usage of 1,082 bbls per calendar day and 355,437 bbls per calendar year under the reduced fuel-use operating scenario, and 2,261 bbls per calendar day and 742,739 bbls per calendar year under the normal operating scenario.
[1997 PSD Permit (III)(C)(d) and (e)]

3.2.1.2.2 For boiler B-1155, the Permittee is allowed a maximum residual fuel usage of 760 bbls per calendar day and 249,660 bbls per calendar year under the reduced fuel-use operating scenario, and 592 bbls per calendar day and 194,472 bbls per calendar year under the normal operating scenario.
[1997 PSD Permit (III)(C)(d) and (e)]

3.2.1.2.3 For boiler B-1155, the Permittee shall comply with the requirements of 40 CFR 60.42 (Standard for particulate matter[PM]), 40 CFR 60.43 (Standard for sulfur dioxide [SO_2]) and 40 CFR 60.44 (Standard for nitrogen oxide [NOx]), as applicable.
[40 CFR 60.40 - 60.44]

3.2.1.3 Group 01B – Boilers B-3301, B-3302, B-3303, and B-3304

3.2.1.3.1 The Permittee is allowed a combined maximum residual fuel usage of 1,506 bbls per calendar day and 494,721 bbls per calendar year under the reduced fuel use operating scenario, and 3,325 bbls per calendar day and 1,092,263 bbls per calendar year under the normal operating scenario.
[1997 PSD Permit (III)(C)(d) and (e)]

3.2.1.3.2 For Boilers B-3301 and B-3302 only, the Permittee is allowed a combined maximum residual fuel oil usage of 800 bbls per calendar day and 262,800 bbls per calendar year under the reduced fuel use operating scenario, and 1,138 bbls per calendar day and 373,833 bbls per calendar year under the normal operating scenario.
[1997 PSD Permit (III)(C)(d) and (e)]

3.2.1.3.3 For Boilers B-3303 and B-3304 only, the Permittee shall comply with the requirements of 40 CFR 60.42 (Standard for Particulate Matter [PM]), 40 CFR 60.43 (Standard for Sulfur Dioxide [SO_2]), and 40 CFR 60.44 (Standard for Nitrogen Oxides [NOx]), as applicable.

[40 CFR 60.40-60.44]

3.2.1.4 Group 01C – Boiler B-3701

3.2.1.4.1 The Permittee shall comply with the applicable requirements of 40 CFR 60, Subpart Db. (PM standards do not apply to gas-fired boilers.)

[40 CFR 60.40b-49b]

3.2.1.4.2 Maximum nitrogen oxide (NOx) emission limits, expressed as NO2, shall be less than or equal to 0.20 lb/MMBtu (natural gas and high heat release rate).

[40 CFR 60.44b(1)(ii)]

3.2.1.4.3 The Permittee shall not combust any fuel gas that contains H_2S in excess of 0.1 gr/dscf.

[40 CFR 60.104(a)(1)]

3.2.1.4.4 For the purpose of reports under 40 CFR 60.7(c), excess emissions shall be defined as all rolling 3-hour periods during which the average concentration of H_2S as measured by the H_2S continuous monitoring system under 40 CFR 60.105(a)(4) exceeds 230 mg/dscm (0.10 gr/dscf).

[40 CFR 60.105(e)(3)(ii); 40 CFR 60.7(c)]

3.2.2 Group 02 – Heaters

3.2.2.1 Group 02A – Heaters H-101, H-104, H-401A, H-401B, H401C, H-1401A, H-1401B, H-2101, H-2102, H-3101A, H-3101B, H-4101A, H-4101B, H-4201, H-4202

3.2.2.1.1 Maximum sulfur content in residual fuel oil shall not exceed 0.5% by weight under the supplemental control operating scenario and 1.0% by weight under the reduced fuel-use or normal operating scenarios.

[1997 PSD Permit (III)(C)(c), (d), and (e)]

3.2.2.1.2 For H-101 and H-104, the Permittee is allowed a combined maximum residual fuel usage of 446 bbls per calendar day and 146,511 bbls per calendar year under the reduced fuel-use operating scenario, and 415 bbls per calendar day and 136,327 bbls per calendar year under the normal operating scenario.

[1997 PSD Permit (III)(C)(d) and (e)

3.2.2.1.3 For H-401A, H-401B, and H-401C, the Permittee is allowed a combined maximum residual fuel oil usage of 996 bbls per calendar day and 327,186 bbls per calendar year under the reduced fuel-use operating scenario, and 282 bbls per calendar day and 92,637 bbls per calendar year under the normal operating scenario.

[1997 PSD Permit (III)(C)(d) and (e)]

3.2.2.1.4 For H-1401A and H-1401B, the Permittee is allowed a combined maximum residual fuel oil usage of 408 bbls per calendar day and 134,028 bbls per calendar year under the reduced fuel-use operating scenario, and 0 bbls per calendar day and 0 bbls per calendar year under the normal operating scenario.

[1997 PSD Permit (III)(C)(d) and (e)]

3.2.2.1.5 For H-2101 and H-2102, the Permittee is allowed a combined maximum residual fuel oil usage of 842 bbls per calendar day and 276,597 bbls per calendar year under the reduced fuel-use operating scenario, and 1,154 bbls per calendar day and 379,089 bbls per calendar year under the normal operating scenario.

[1997 PSD Permit (III)(C)(d) and (e)]

3.2.2.1.6 Vacuum Unit Heaters H-2101 and H-2102 shall be limited to burning only refinery fuel gas, propane, butane, and/or No. 6 fuel oil.

[GT-10 PSD Permit (IX)(1)]

3.2.2.1.7 The Permittee shall limit its combustion of No. 6 fuel oil in #2 Vacuum Unit Heaters H-2101 and H-2102 to a maximum of 260 barrels per calendar day total.

[GT-10 PSD Permit (IX)(2)]

3.2.2.1.8 For H-3101A and H-3101B, the Permittee is allowed a combined maximum residual fuel oil usage of 1,260 bbls per calendar day and 413,910 bbls per calendar year under the reduced fuel-use operating scenario, and 1,210 bbls per calendar day and 397,485 bbls per calendar year under the normal operating scenario.

[1997 PSD Permit (III)(C)(d) and (e)]

3.2.2.1.9 For H-4101A and H-4101B, the Permittee is allowed a combined maximum residual fuel oil usage of 1,260 bbls per calendar day and 413,910 bbls per calendar year under the reduced fuel-use operating scenario, and 1,210 bbls per calendar day and 397,485 bbls per calendar year under the normal operating scenario.

[1997 PSD Permit (III)(C)(d) and (e)]

3.2.2.1.10 For H-3101A, H-3101B, H-4101A, and H-4101B, the Permittee shall not combust any fuel gas that contains H_2S in excess of 0.1 gr/dscf.

[40 CFR 60.104(a)(1)]

3.2.2.1.11 For H-4201 and H-4202, the Permittee is allowed a combined maximum residual fuel oil usage of 1,035 bbls per calendar day and 339,998 bbls per calendar year under the reduced fuel-use operating scenario, and 1,273 bbls per calendar day and 418,181 bbls per calendar year under the normal operating scenario.

[1997 PSD Permit (III)(C)(d) and (e)]

3.2.2.2 Group 02C – Heater H-2185

3.2.2.2.1 The maximum heat input for the H-2185 heater shall be 250 mmBtu/hr (HHV).

[1997 PSD Permit (III)(B)]

3.2.2.2.2 Visbreaker #2 heater shall be limited to burning only refinery fuel gas or LPG with H_2S content less than or equal to 0.1 gr/dscf.

[40 CFR 60.104(a)(1); 1997 PSD Permit (III)(B)]

3.2.2.2.3 Opacity must be less than 17%, except for 3 minutes in any 30 minute period during which opacity is less than or equal to 40%.

[1997 PSD Permit (III)(B)(f)]

3.2.2.2.4 NOx emissions shall be less than or equal to 0.2 lbs/mmBtu, 50.3 lbs/hr, 219 tons per year, 148 ppmv on a dry basis corrected to 7% oxygen. The compliance with the ppmv, lb/mmBtu, and lb/hr limits shall be demonstrated based on a block-hour average, and with the tons per year limit, based on a calendar year period.

[1997 PSD Permit (III)(B)(c)]

3.2.2.2.5 The Permittee shall use low NOx burners to control NOx emissions.

[1997 PSD Permit (III)(A)(c)(2)]

3.2.2.2.6 SO_2 emissions shall be less than or equal to 4.42 lbs/hr (3-hour rolling average), 19.38 tpy (calendar year total), 13 ppmv (3-hour rolling average) on a dry basis corrected to 7% oxygen. CO emissions shall be less than or equal to 10.2 lbs/hr (365-day rolling average), 45.1 tpy (calendar year total), 50 ppmv (365-day rolling average) on a dry basis corrected to 7% oxygen. PM/PM10 emissions shall be less than or equal to 0.1 lbs/mmBtu (365-day rolling average), 25 lb/hr (365-day rolling average), 110 tpy (calendar year total). VOC emissions shall be less than or equal to 1.6 lbs/hr (365-day rolling average), 7 tpy (calendar year total), 15 ppmv (365-day rolling average) as methane on a dry basis corrected to 7% oxygen.

[1997 PSD Permit (III)(B)(a), (b), (d), and (e)]

3.2.2.2.7 The Permittee shall not combust any fuel gas that contains H_2S in excess of 0.1 gr/dscf.

[40 CFR 60.104(a)(1)]

3.2.2.2.8 For the purpose of reports under 40 CFR 60.7(c), excess emissions shall be defined as all rolling 3-hour periods during which the average concentration of H_2S as measured by the H_2S continuous monitoring system under 40 CFR 60.105(a)(4) exceeds 230 mg/dscm (0.10 gr/dscf).

[40 CFR 60.105(e)(3)(ii); 40 CFR 60.7(c)]

3.2.2.3 Group 02D – Heaters H-4901 (LSG Unit Heater) and Hydrogen Plant Heater

3.2.2.3.1 The LSFP PSD Permit shall become invalid if construction: (A) has not commenced (as defined in 40 CFR 52.21(b)(9)) within 18 months of the effective date of the permit; (B) is discontinued for a period of 18 months or more; or (C) is not completed within a reasonable time.

[LSFP PSD Permit I)

3.2.2.3.2 The Permittee shall notify the Regional Administrator (RA) in writing of the anticipated date of initial startup (as defined in 40 CFR 60.2) of each facility of the source not more than sixty (60) days nor less than thirty (30) days prior to such date. The Permittee shall notify the RA in writing of the actual date of both commencement of construction and startup within fifteen (15) days after such date.

[LSFP PSD Permit II]

3.2.2.3.3 All equipment, facilities, and systems installed or used to achieve compliance with the terms and conditions of the LSFP PSD Permit, shall at all times be maintained in good working order and be operated as efficiently as possible so as to minimize air pollutant emissions. The Permittee shall demonstrate initial and continuous compliance with the operating, emission and other limits according to the performance testing and compliance assurance and all other requirements of the LSFP PSD Permit.

[LSFP PSD Permit III]

3.2.2.3.4 For pollution control equipment, each unit shall continuously operate in accordance with its design specified parameters. This includes continuously operating all proposed control devices in a manner consistent with good air pollution control practice for minimizing emissions.

[LSFP PSD Permit IX.1]

3.2.2.3.5 The LSG unit heater shall have a maximum design heat input rate of 87.3 mmBtu/hr based on the higher heating value (HHV) of the fuel.

[LSFP PSD Permit VI.B.1]

3.2.2.3.6 The Hydrogen Plant heater shall have a maximum design heat input rate of 259.4 mmBtu/hr, HHV.

[LSFP PSD Permit VI.B.4]

3.2.2.3.7 On and after the date of initial performance testing required by the LSFD PSD Permit, the total number of startup cycles for the LSG Unit heater and for the Hydrogen Plant heater shall not exceed 12 starts each during any consecutive 365 day rolling period. The duration of each startup and shutdown shall not exceed 76 hours and 24 hours, respectively.

[LSFP PSD Permit VI.B.8 and VI.B.9]

3.2.2.3.8 Exhaust gases from the LSG unit heater shall be directed to a single stack that rises 212.8 feet above grade with a flue diameter of 4.8 feet.

[LSFP PSD Permit VI.B.10]

3.2.2.3.9 Exhaust gases from the Hydrogen Plant heater shall be directed to a single stack 65.6 feet above grade with a flue diameter of 4.3 feet.
[LSFP PSD Permit VI.B.11]

3.2.2.3.10 The LSG unit heater shall only burn refinery gas and/or LPG with a maximum hydrogen sulfide content of 0.1 gr/dscf averaged over any 3-hour period and 75 ppmvd averaged over any 24-hour period.
[LSFP PSD Permit VII.B.1]

3.2.2.3.11 The Hydrogen Plant heater shall be limited to burning refinery gas, LPG and/or purge gas with a maximum hydrogen sulfide content of 0.1 gr/dscf averaged over any 3-hour period and 75 ppmvd averaged over any 24-hour period.
[LSFP PSD Permit VII B.2]

3.2.2.3.12 For the LSG unit heater, the continuous emission monitoring systems required by the LSFP PSD permit shall be on-line and in operation 95% of the time when the emissions sources are operating.
[LSFP PSD Permit III]

3.2.2.3.13 The Permittee shall not combust any fuel gas that contains H_2S in excess of 0.1 gr/dscf.
[40 CFR 60.104(a)(1)]

3.2.2.3.14 For the purposes of reports under 40 CFR 60.7(c), excess emissions shall be defined as all rolling 3-hour periods during which the average concentration of H_2S as measured by the H_2S continuous monitoring system under 40 CFR 60.105(a)(4) exceeds 230 mg/dscm (0.10 gr/dscf).
[40 CFR 60.105(e)(3)(ii); 40 CFR 60.7(c)]

3.2.2.3.15 Startup and shutdown for the LSG unit heater and the Hydrogen Plant heater shall be defined as follows: Startup shall be defined as the initial firing of the equipment after its refractory dry-out operation has been completed and ending at the time when the inlet temperature to the SCR has been maintained at 600°F or above for a period of two hours; Shutdown is defined as the period of time beginning with the SCR inlet temperature falling below 600°F and ending with the cessation of fuel firing in the unit's burners.
[LSFP PSD Permit VI.B.7]

3.2.2.3.16 PM/PM-10 emissions from the LSG unit heater shall not exceed 0.82 lbs/hr and 3.6 tons/year.
[LSFP PSD Permit VIII.B.1.a]

3.2.2.3.17 PM/PM-10 emissions from the Hydrogen Plant heater shall not exceed 3.0 lbs/hr and 13.2 tons/year.
[LSFP PSD Permit VIII.B.1.b]

3.2.2.3.18 SO_2 emissions from the LSG unit heater shall not exceed 2.1 lbs/hr averaged over any 3-hour period, 23.0 lbs over any 24-hour period and 4.2 tons/year.

[LSFP PSD Permit VIII.B.2.a]

3.2.2.3.19 SO_2 emissions from the Hydrogen Plant heater shall not exceed 6.2 lbs/hr averaged over any 3-hour period, 68.5 lbs over any 24-hour period and 12.5 tons/year.

[LSFP PSD Permit VIII.B.2.b]

3.2.2.3.20 NOx emissions from the LSG unit heater shall not exceed 0.61 lbs/hr and 0.007 lb/mmBtu averaged over any 3-hour period, 2.4 lbs/hr during periods of SCR system startup, and 2.7 tons/year as calculated on a 365-day rolling basis.

[LSFP PSD Permit VIII.B.3.a]

3.2.2.3.21 NOx emissions from the Hydrogen Plant heater shall not exceed 2.2 lbs/hr and 0.0085 lb/mmBtu averaged over any 3-hour period, 10.4 lbs/hr and 0.04 lb/mmBtu during periods of SCR system startup. Annual NOx emissions from the Hydrogen Plant heater shall not exceed 9.6 tons/year as calculated on a 365-day rolling basis.

[LSFP PSD Permit VIII.B.3.b and c]

3.2.2.3.22 The LSG unit heater shall be equipped with ultra low NOx burners and SCR to control NOx emissions. These control devices shall be utilized at all times the heater is operating except during startup and shutdown.

[LSFP PSD Permit VI.B.3]

3.2.2.3.23 The Permittee shall utilize ultra low NOx burners and SCR to control NOx emissions from the Hydrogen Plant heater at all times except during startup and shutdown.

[LSFP PSD Permit VI.B.6 and IX.4]

3.2.2.3.24 For the Hydrogen Plant heater, placement of the SCR control should be downstream of the low NOx burners

[LSFP PSD Permit VI.B.6]

3.2.2.3.25 CO emissions from the LSG unit heater shall not exceed 0.04 lb/mmBtu averaged over any 365-day period.

[LSFP PSD Permit VIII.B.4.a]

3.2.2.3.26 CO emissions from the Hydrogen Plant heater shall not exceed 0.04 lb/mmBtu averaged over any 365-day period.

[LSFP PSD Permit VIII.B.4.b]

3.2.2.4 Group 02E – Heaters H-7801, H-7802, and R-7801 and Stack STK-7801

3.2.2.4.1 The maximum combined heat input shall be limited to 30 million Btu per hour.

[1997 PSD Permit (III)(A)]

3.2.2.4.2 The heaters shall be limited to burning refinery gas or propane as fuel (during all operations), with a hydrogen sulfide content not to exceed 0.1 gr/dscf, averaged over any 3-hour period.
[1997 PSD Permit (III)(A); 40 CFR 60.104(a)(1)]

3.2.2.4.3 The Permittee shall not combust any fuel gas that contains H_2S in excess of 0.1 gr/dscf.
[40 CFR 60.104(a)(1)]

3.2.2.4.4 For the purpose of reports under 40 CFR 60.7, excess emissions shall be defined as all rolling 3-hour periods during which the average concentration of H_2S as measured by the H_2S continuous monitoring system under 40 CFR 60.105(a)(4) exceeds 230 mg/dscm (0.10 gr/dscf).
[40 CFR 60.105(e)(3)(ii); 40 CFR 60.7(c)]

3.2.2.4.5 SO_2 emission shall not exceed 0.73 lbs/hr (3-hour rolling average), 3.2 tons/year (calendar year), 11 ppmv (3-hour rolling average) on a dry basis corrected to 7% oxygen.
[1997 PSD Permit (III)(A)]

3.2.2.4.6 PM/PM10 emissions shall not exceed 0.1 lbs/mmBtu of heat input, 3.1 lbs/hr, 13.4 tons/year.
[1997 PSD Permit (III)(A)]

3.2.2.4.7 NOx emission shall not exceed 0.14 lbs/mmBtu of heat input, 4.2 lbs/hr, 18.4 tons/year, 96 ppmv on a dry basis corrected to 7% oxygen.
[1997 PSD Permit (III)(A)]

3.2.2.4.8 The Permittee shall utilize low NOx burners to control NOx emissions.
[1997 PSD Permit (III)(A)(c)]

3.2.2.4.9 CO emissions shall not exceed 0.03 lbs/mmBtu of heat input, 0.9 lbs/hr, 3.9 tons/year, 32 ppmv on a dry basis corrected to 7% oxygen.
[1997 PSD Permit (III)(A)]

3.2.2.4.10 VOC emissions shall not exceed 0.07 lbs/hour 0.32 tons/year, or 5 ppmv as methane on a dry basis corrected to 7% oxygen.
[1997 PSD Permit (III)(A)]

3.2.2.4.11 The opacity shall not exceed 17 percent, as determined by continuous monitoring, except for 3 minutes in any consecutive 30 minute period during which 40 percent shall not be exceeded. In each report quarter, a 95% quality data availability shall be maintained for all opacity monitors.
[1997 PSD Permit (III)(A); 1997 PSD Permit (VI)(E)]

3.2.2.4.12 Unit start-up: The sulfuric acid plant process heaters H-7801, H-7802, and R-7801 are exempt from the concentration emission limits for CO and VOC as described in the requirements above, for maximum of 1-hour during start-up of the unit(s). This exemption shall be only afforded 8 times per year (based on a 365-day rolling average). Start-up of a process heater begins with the introduction of feed to the unit, and concludes when minimum, stable temperatures are achieved.

[1997 PSD Permit (III)(A)]

3.2.2.5 Group 02F – Incinerators H-1032, H-1042, and H-4745

3.2.2.5.1 The Permittee shall limit SO_2 emissions from all incinerators associated with each pair of sulfur recovery units to a total of 30 tons per day.

[1997 PSD Permit (IV)(D)]

3.2.2.5.2 Except as provided below, the Permittee shall vent all tail gas from the sulfur recovery units to the Beavon units at all times.

3.2.2.5.2.1 The Permittee shall vent the tail gas from the sulfur recovery units in the following manner when one of the two Beavon units is not operating:

(a) Transfer all acid gas streams (which may originate at the amine treating unit, sour water stripper, other gas sweetening processes, etc.), excluding that from the acid plant, to the sulfur recovery units associated with the operating Beavon unit.

(b) Vent excess tail gas to any of the three existing incinerators when the operating Beavon unit is charged to capacity. The Permittee shall provide written justification to the EPA describing the nature of the venting and provide planned mitigation procedures to the EPA for prior approval.

3.2.2.5.2.2 The Permittee shall vent all Claus Plant tail gas to any of the three existing incinerators when neither Beavon unit is operating. The Permittee shall provide written justification to the EPA describing the nature of the outage and provide planned mitigation procedures to the EPA for prior approval.

[1997 PSD Permit (IV)(A), (B), and (C)]

3.2.2.5.3 The Permittee shall comply with the following when either one or both Beavon units are not operating and tail gas is being vented to an incinerator: (a) Discontinue the use of 1.0 percent sulfur fuel-oil and revert to the use of 0.5 percent sulfur fuel-oil in all new and existing residual oil-burning sources within the plant; (b) In no event shall tail gas not be vented to the Beavon units for more than 30 days per calendar year, with a maximum of 14 continuous days.

[1997 PSD Permit (IV)(D)]

3.2.2.5.4 For H-1032 and H-1042, the Permittee shall not discharge or cause the discharge of any gases into the atmosphere from any Claus sulfur recovery plant containing in excess of 250 ppm by volume (dry basis) of sulfur dioxide (SO_2) at zero percent excess air.
[40 CFR 60.104(a)(2)(ii)]

3.2.2.5.5 For H-4745, the Permittee shall comply with the applicable requirements of 40 CFR 61, Subpart BB.
[40 CFR 61.300-305]

3.2.2.5.6 When operating H-4745 to comply with condition 3.2.7.4, the Permittee shall maintain the daily average combustion zone temperature at or above 1,023°F and the daily average O2 concentration above 0.15% as determined by performance test.
[OMM Plan for East Sulfur Recovery; 40 CFR 63, Subpart UUU, Table 35]

3.2.2.6 Group 02G – Heaters H-8501A and H-8501B

3.2.2.6.1 The Permittee shall not combust any fuel gas that contains H_2S in excess of 0.1 gr/dscf.
[40 CFR 60.104(a)(1)]

3.2.2.6.2 For the purpose of reports under 40 CFR 60.7(c), excess emissions shall be defined as all rolling 3-hour periods during which the average concentration of H_2S as measured by the H_2S continuous monitoring system under 40 CFR 60.105(a)(4) exceeds 230 mg/dscm (0.10 gr/dscf).
[40 CFR 60.105(e)(3)(ii); 40 CFR 60.7(c)]

3.2.3 Group 03 – Compressor Engines

3.2.3.1 For compressors engines C-200A, C-200B, C-200C, C-2400A, and C-2400B only, the Permittee shall either (a) reduce formaldehyde emissions from each stack by 76%, or (b) limit the concentration of formaldehyde in each stack to 350 ppbvd or less corrected to 15% O_2. The Permittee shall comply with the requirements of 40 CFR 63.6600 through 63.6665, as applicable.
[40 CFR 63.6600 through 63.6665]

3.2.4 Group 04 – Combustion Turbines

3.2.4.1 Group 04A – Turbines G-1101E, G-1101F, G-1101G, G-3404, G-3405, G-3406, G-3407, G-3408, G-3409, G-3410

3.2.4.1.1 The maximum sulfur content in the distillate fuel oil shall not exceed 0.2% by weight under the reduced fuel-use or normal operating scenarios.
[1997 PSD Permit (III)(D)(c) and (d)]

3.2.4.1.2 The Permittee is allowed a combined maximum distillate fuel oil usage of 4,800 bbls per calendar day and 1,576,800 bbls per calendar

year under the reduced fuel-use operating scenario, and 5,427 bbls per calendar day and 1,782,770 bbls per calendar year under the normal operating scenario.
[1997 PSD Permit (III)(D)(c) and (d)]

3.2.4.1.3 For G-1101E, G-1101F, and G-1101G, the Permittee is allowed a combined maximum distillate fuel oil usage of 1,800 bbls per calendar day and 591,300 bbls per calendar year under the reduced fuel-use operating scenario, and 1,539 bbls per calendar day and 505,562 bbls per calendar year under the normal operating scenario.
[1997 PSD Permit (III)(D)(c) and (d)]

3.2.4.1.4 For G-3404, G-3405, G-3406, G-3407, G-3408, G-3409, and G-3410, the Permittee is allowed a combined maximum distillate fuel oil usage of 4,000 bbls per calendar day and 1,314,000 bbls per calendar year under the reduced fuel-use operating scenario, and 3,888 bbls per calendar day and 1,277,208 bbls per calendar year under the normal operating scenario.
[1997 PSD Permit (III)(D)(c) and (d)]

3.2.4.1.5 The Permittee shall not combust any fuel gas that contains H_2S in excess of 0.1 gr/dscf.
[40 CFR 60.104(a)(1)]

3.2.4.1.6 For the purpose of reports under 40 CFR 60.7(c), excess emissions shall be defined as all rolling 3-hour period during which the average concentration of H_2S as measured by the H_2S continuous monitoring system under 40 CFR 60.105(a)(4) exceeds 230 mg/dscm (0.10 gr/dscf).
[40 CFR 60.105(e)(3)(ii); 40 CFR 60.7(c)]

3.2.4.1.7 NOx Emission Standard. The Permittee shall not cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of: STD = 0.0150 x 14.4/Y + F, where: STD = allowable ISO corrected (if required as given in 40 CFR 60.335(b)(1)) NOx emission concentration (percent by volume at 15 percent oxygen and on a dry basis); Y = manufacturer's rated heat rate at manufacturer's rated peak load (kilojoules per watt hour), or actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour, and F = NOx emission allowance for fuel-bound nitrogen as defined in 40 CFR 60.332(a)(4). Note: For G-3409 and G-3410, compliance with the NOx related permit conditions 3.1.4.2.4.1 and 3.2.4.1.12.1, respectively, shall constitute compliance with these NSPS Subpart GG NOx requirements.
[40 CFR 60.332(a)(2); 40 CFR 60.332(d);
GT-10 PSD Permit (XII)(8)]

3.2.4.1.8 Stationary gas turbines with a heat input greater than or equal to 10.7 gigajoules per hour (10 million Btu/hour) when fired with natural gas are exempt from the NOx emission standard in condition 3.2.4.1.7 when being fired with an emergency fuel.

[40 CFR 60.332(k)]

3.2.4.1.9 SO_2 Emission Standard. The Permittee shall comply with the following: (a) the Permittee shall not cause to be discharged into the atmosphere from any stationary gas turbine any gases which contain sulfur dioxide in excess of 0.015 percent by volume at 15 percent oxygen and on a dry basis; or (b) the Permittee shall not burn in any stationary gas turbine any fuel which contains total sulfur in excess of 0.8 percent by weight (8000 ppmw).

[40 CFR 60.333; GT-10 PSD Permit (XII)(8)]

3.2.4.1.10 For G-3410, the Permittee shall only combust the following fuels: (i) refinery grade propane, (ii) refinery grade butane, (iii) distillate fuel oil less than 0.2% sulfur by weight.

[GT-10 PSD Permit (VII)(1)]

3.2.4.1.11 For G-3410, the Permittee shall combust liquid fuels up to a maximum of 876 hours per year, as calculated on a 365-day rolling total basis.

[GT-10 PSD Permit (VII)(2)]

3.2.4.1.12 Nitrogen Oxides (NOx). For G-3410:

3.2.4.1.12.1 NOx emissions, during gaseous and/or liquid fuel firing, shall not exceed 42 ppmdv corrected to 15% oxygen on a block-hour average, or 57.0 lbs/hour, whichever is more stringent.

3.2.4.1.12.2 Annual NOx emissions shall not exceed 150.2 tons per year as calculated on a 365-day rolling basis.

3.2.4.1.12.3 Except during startups and shutdowns, the Permittee shall use steam injection at all times to control NOx emissions. The optimum steam to fuel ratio will be established during the performance testing and will be incorporated in the VIDPNR operating permit (see Attachment D).

[GT-10 PSD Permit (VIII)(1)]

3.2.4.1.13 Carbon Monoxide (CO). For G-3410:

3.2.4.1.13.1 CO emissions, during gaseous fuel firing, shall not exceed 206.5 ppmdv corrected to 15% oxygen on a block-hour average, or 94.0 lbs/hour, whichever is more stringent.

3.2.4.1.13.2 CO emissions, during liquid fuel firing, shall not exceed 242 ppmdv corrected to 15% oxygen on a block-hour average, or 111 lbs/hour, whichever is more stringent.

3.2.4.1.13.3 CO emissions shall not exceed 44.1 tons per year as calculated on a 365-day rolling basis.

3.2.4.1.13.4 CO emissions, during combination fuel firing, shall not exceed the prorated gaseous and liquid fuel emissions as determined by the flow rate of each fuel type.

[GT-10 PSD Permit (VIII)(2)]

3.2.4.1.14 Particulate Matter under 10 Microns (PM10). For G-3410:

3.2.4.1.14.1 Emissions of PM10, during gaseous fuel firing, shall not exceed 2.5 lbs/hour.

3.2.4.1.14.2 Emissions of PM10, during liquid fuel firing, shall not exceed 9.5 lbs/hour.

3.2.4.1.14.3 PM10 emissions, during combination fuel firing, shall not exceed the prorated gaseous and liquid fuel emissions as determined by the flow rate of each fuel type.

3.2.4.1.14.4 For G-3410, PM10 emissions in excess of the applicable emission limit during periods of startup and shutdown, shall not be considered a violation of the applicable emission limit.

[GT-10 PSD Permit V(III)(3) and (X)(7)]

3.2.4.1.15 For G-3410, opacity of emissions shall not exceed 10 percent (six-minute average) except for one six-minute set per hour which shall not exceed 25 percent.

[GT-10 PSD Permit (VIII)(3)(d)]

3.2.4.1.16 For G-3410, the Permittee shall submit a written report of all excess emissions to EPA for every calendar quarter. In each quarterly report, the Permittee shall maintain 95% quality data availability for the opacity monitor and all gaseous monitors.

[GT-10 PSD Permit (X)(5) and (11)]

3.2.4.1.17 For G-3410, emissions in excess of the applicable emission limit during period of startup and shutdown, shall not be considered a violation of the applicable emission limit.

[GT-10 PSD Permit (X)(7)]

3.2.4.1.18 For G-3410, startup and shutdown shall be defined as:

3.2.4.1.18.1 Startup – The establishment of a 12.5 MW load to the turbine and operation of the steam injection system. The startup process shall not exceed one hour.

3.2.4.1.18.2 Shutdown – The removal of electrical load to the turbine. The shutdown process shall not exceed one hour.

[GT-10 PSD Permit (X)(8)]

3.2.4.1.19 For G-3410, the Permittee shall continuously calculate the NOx and CO mass emission rates.

[GT-10 PSD Permit (X)(9)]

3.2.4.1.20 At all times, including periods of startup, shutdown, and malfunction, the Permittee shall, to the extent practicable, maintain and operate the GT No. 10 (G-3410) in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to EPA and/or VIDPNR which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the facility.

[GT-10 PSD Permit (X)(10)]

3.2.4.1.21 The maximum heat input of GT No. 10 (G-3410) shall not exceed 325 mmBtu/hour.

[GT-10 PSD Permit (XII)(1)]

3.2.4.1.22 GT No. 10 (G-3410) shall not be operated below 50% load (12.5 MW), except during startups and shutdowns.

[GT-10 PSD Permit (XII)(2)]

3.2.4.1.23 For G-3410, the Permittee shall determine the total heat content (higher heating value in Btu) of each fuel fired during each hour. Heat input shall be calculated from the total fuel flow and the heating value (in Btu per cubic foot or per gallon) of that fuel. The fraction of an hour of use of each fuel shall be calculated as the ratio of the heating value of that fuel to the total heating value of all fuels used during the hour.

[GT-10 PSD Permit (XII)(7)]

3.2.4.1.24 For G-3410, the Permittee shall meet all other applicable federal, state, and local requirements, including those contained in the Virgin Islands State Implementation Plan (VISIP).

[GT-10 PSD Permit (XII)(9)]

3.2.4.2 Group 04B – G-3413 (GT No. 13) and Associated Duct Burner H-3413

3.2.4.2.1 The LSFP PSD Permit shall become invalid if construction: (a) has not commenced (as defined in 40 CFR 52.21(b)(9)) within 18 months of the effective date of the permit; (b) is discontinued for a period of 18 months or more; or (c) is not completed within a reasonable time.

[LSFP PSD Permit I]

3.2.4.2.2 All equipment, facilities, and systems installed or used to achieve compliance with the terms and conditions of the LSFP PSD Permit shall at all times be maintained in good working order and be operated as efficiently as possible so as to minimized air pollutant emissions. The Permittee shall demonstrate initial and continuous compliance with the operating, emission and other limits according to the performance testing and compliance assurance and all other requirements of the LSFP PSD Permit.

[LSFP PSD Permit III]

3.2.4.2.3 Each unit (G-3413 and H-3413) shall continuously operate in accordance with its design specified parameters. This includes continuously operating all proposed control devices in a manner consistent with good air pollution control practice for minimizing emissions.

[LSFP PSD Permit IX.1]

3.2.4.2.4 Combustion turbine No. 13 (GT No. 13 or G-3413) shall have a maximum design heat input rate of 356.0 mmBtu/hr, based on the higher heating value of the fuel.

[LSFP PSD Permit VI.A.1]

3.2.4.2.5 The Heat Recovery Steam Generator (HRSG) duct burner (H-3413) shall combust refinery gas and/or LPG and shall have a maximum design heat input rate of 270.1 mmBtu/hr, HHV.

[LSFP PSD Permit VI.A.3]

3.2.4.2.6 Startup of GT No. 13 (G-3413) and the associated duct burner (H-3413) shall not commence until the existing compressor engines in the Nos. 2 and 4 Distillate Desulfurizer Units (C-800A, C-800B, C-800C, C-2201A, C-2201B, and C-2201C) are permanently removed from service.

[LSFP PSD Permit VI.A.2]

3.2.4.2.7 The HSRG shall not be bypassed more than 720 hours per year, as calculated on a 12-month rolling basis.

[LSFP PSD Permit VI.A.4]

3.2.4.2.8 For the purposes of the LSFP PSD Permit, startup and shutdown shall be defined as:

3.2.4.2.8.1 Startup for GT No. 13 (G-3413) is defined as the period beginning with the initial firing of fuel in the combustion turbine combustor and ending at the time when the load has increased to 60% of peak rated load and, with the exception of HRSG bypass, the SCR system has reached its design operating temperature. The duration of the startup shall not exceed 4 hours for any given cold startup (greater than 72 hours since shutdown), 2 hours for any given warm startup (10 to 72 hours since shutdown), and 1.5 hours for any given hot startup (less than 10 hours since shutdown).

3.2.4.2.8.2 Shutdown for GT No. 13 (G-3413) is defined as the period of time beginning with the load decreasing from 60% of peak rated load and ending with the cessation of operation of fuel flow to the combustion turbine. The duration of any shutdown shall not exceed one hour.

3.2.4.2.8.3 During startup and shutdown of GT No. 13 (G-3413), the Permittee shall comply with all mass emission limits except for NOx which shall be limited to 95 ppmvd at 15% oxygen averaged over a 4 hour time period for cold starts, a 2 hour time period for warm starts, a 1.5 hour time period for hot starts, and a 1 hour time period for shutdown. The Permittee shall also comply with the opacity limit during each startup and shutdown. The total number of cold, warm, and hot startup-shutdown cycles for GT No. 13 (G-3413) shall be limited to 12, 24, and 72, respectively, during any consecutive 12-month period.

[LSFP PSD Permit VI.A.5.c]

3.2.4.2.9 At all times, including during periods of startup, shutdown, and malfunction, the Permittee shall, to the extent practicable, maintain and operate the combustion turbine including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to EPA and/or VIDPNR which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the plant.

[LSFP PSD Permit VI.A.6]

3.2.4.2.10 The GT No. 13 HRSG (G-3413) stack shall be 79 feet above grade with a flue diameter of 9.9 feet.

[LSFP PSD Permit VI.A.7]

3.2.4.2.11 The GT No. 13 (G-3413) bypass stack shall be 76 feet above grade with a flue diameter of 10.6 feet.

[LSFP PSD Permit VI.A.8]

3.2.4.2.12 GT No. 13 (G-3413) shall only burn refinery gas and/or LPG and/or distillate oil.

[LSFP PSD Permit VII.A.2]

3.2.4.2.13 The duct burner (H-3413) associated with GT No. 13 shall only burn refinery gas and/or LPG as fuel.

[LSFP PSD Permit VII.A.2]

3.2.4.2.14 The refinery gas and LPG burned in G-3413 and H-3413 shall have a maximum hydrogen sulfide content of 0.1 gr/dscf averaged over any 3-hour period and 75 ppmvd averaged over any 24-hour period.
[LSFP PSD Permit VII.A.3]

3.2.4.2.15 The continuous emission monitoring systems required by the LSFP PSD Permit shall be on-line and in operation 95% of the time when the emissions sources are operating.
[LSFP PSD Permit III]

3.2.4.2.16 The sulfur content of the distillate oil burned in GT No. 13 (G-3413) shall not exceed 0.05 percent by weight.
[LSFP PSD Permit VII.A.4]

3.2.4.2.17 The maximum amount of distillate oil burned in GT No. 13 (G-3413) shall not exceed 74,947 bbls during any consecutive 12-month period.
[LSFP PSD Permit VII.A.5]

3.2.4.2.18 Mass Emission Rates of PM.

3.2.4.2.18.1 The gas fired mass emission rate of PM in the exhaust gas during supplemental firing of the HRSG shall not exceed 20.5 lb/hr and 0.033 lb/mmBtu.

3.2.4.2.18.2 The gas fired mass emission rate of PM in the exhaust gas with no supplemental firing of the HRSG shall not exceed 3.4 lb/hr and 0.0096 lb/mmBtu.

3.2.4.2.18.3 The oil fired mass emission rate of PM in the exhaust gas during supplemental firing of the HRSG shall not exceed 33 lb/hr and 0.053 lb/mmBtu.

3.2.4.2.18.3 The oil fired mass emission rate of PM in the exhaust gas with no supplemental firing of the HRSG shall not exceed 7.5 lb/hr and 0.021 lb/mmBtu.
[LSFP PSD Permit VIII.A.1.a through d]

3.2.4.2.19 Mass Emission Rates of PM-10.

3.2.4.2.19.1 The gas fired mass emission rate of PM-10 in the exhaust gas during supplemental firing of the HRSG shall not exceed 22.9 lb/hr and 0.037 lb/mmBtu.

3.2.4.2.19.2 The gas fired mass emission rate of PM-10 in the exhaust gas with no supplemental firing of the HRSG shall not exceed 5.8 lb/hr and 0.016 lb/mmBtu.

3.2.4.2.19.3 The oil fired mass emission rate of PM-10 in the exhaust gas during supplemental firing of the HRSG shall not exceed 41.0 lb/hr and 0.066 lb/mmBtu.

3.2.4.2.19.4 The oil fired mass emission rate of PM-10 in the exhaust gas with no supplemental firing of the HRSG shall not exceed 15.4 lb/hr and 0.043 lb/mmBtu.
[LSFP PSD Permit VIII.A.2.a through d]

3.2.4.2.20 Mass Emission Rates of SO_2.

3.2.4.2.20.1 The gas fired mass emission rate of SO_2 in the exhaust gas during supplemental firing of the HRSG shall not exceed 15.0 lb/hr and 0.024 lb/mmBtu averaged over any 3-hour period and 6.9 lb/hr and 0.011 lb/mmBtu averaged over any 24-hour period.

3.2.4.2.20.2 The gas fired mass emission rate of SO_2 in the exhaust gas with no supplemental firing of the HRSG shall not exceed 8.5 lb/hr and 0.024 lb/mmBtu averaged over any 3-hour period and 3.9 lb/hr and 0.011 lb/mmBtu averaged over any 24-hour period.

3.2.4.2.20.3 The oil fired mass emission rate of SO_2 in the exhaust gas during supplemental firing of the HRSG shall not exceed 25.4 lb/hr and 0.041 lb/mmBtu averaged over any 3-hour period and 21.9 lb/hr and 0.035 lb/mmBtu averaged over any 24-hour period.

3.2.4.2.20.4 The oil fired mass emission rate of SO_2 in the exhaust gas with no supplemental firing of the HRSG shall not exceed 18.9 lb/hr and 0.053 lb/mmBtu averaged over any 3-hour period.
[LSFP PSD Permit VIII.A.4.c and d]

3.2.4.2.21 The concentration of NOx in the exhaust gas during gaseous fuel firing shall not exceed 13 ppmvd corrected to 15% oxygen and 0.0497 lbs mmBtu. The concentration of NOx in the exhaust gas during fuel oil firing shall not exceed 20 ppmvd, corrected to 15% oxygen and 0.0761 lbs/mmBtu.
[LSFP PSD Permit VIII.A.5.a and b]

3.2.4.2.22 For GT No. 13 (G-3413), the Permittee shall install and continuously operate (except during startup and shutdown periods) a steam injection system and monitor the steam to fuel ratio to ensure proper control of NOx emissions. In addition to steam injection, the Permittee shall operate a Selective Catalytic Reduction (SCR) system for NOx control except during startup and shutdown. The duct burner (H-3413) associated with GT No. 13 shall utilize low NOx burner(s) and SCR to control NOx emissions.
[LSFP PSD Permit IX.2]

3.2.4.2.23 The Permittee shall conduct a performance demonstration study of the SCR system to determine the lowest NOx concentration from GT

No. 13 (G-3413) and the associated duct burner (H-3413) that is feasible. Such study shall commence immediately after the initial performance test for NOx and shall be completed within 18 months.
[LSFP PSD Permit VIII.A.5.c]

3.2.4.2.24 The concentration of NOx in the exhaust gas during periods when the HRSG is bypassed shall not exceed 42 ppmvd, corrected to 15% oxygen and 0.1601 lbs/mmBtu.
[LSFP PSD Permit VIII.A.5.d]

3.2.4.2.25 The mass emission rate for H_2SO_4 in the exhaust gas during gaseous fuel firing shall not exceed 14.5 lb/hr and 0.023 lb/mmBtu.
[LSFP PSD Permit VIII.A.6.a]

3.2.4.2.26 The mass emissions rate for H_2SO_4 in the exhaust gas during oil firing shall not exceed 28.3 lb/hr and 0.045 lb/mmBtu.
[LSFP PSD Permit VIII.A.6.b]

3.2.4.2.27 Total CO emissions from GT No. 13 (G-3413) and its associated duct burner (H-3413) shall not exceed 196 tons per year as calculated on a 365-day rolling basis.
[LSFP PSD Permit VIII.A.7]

3.2.4.2.28 Opacity of emissions shall not exceed 10% except for one period of not more than 6 minutes in any 60-minute interval when the opacity shall not exceed 25%.
[LSFP PSD Permit VIII.A.8]

3.2.4.2.29 The Permittee shall not combust any fuel gas that contains H_2S in excess of 0.1 gr/dscf.
[40 CFR 60.104(a)(1)]

3.2.4.2.30 For the purposes of reports under 40 CFR 60.7(c), excess emissions shall be defined as all rolling 3-hour periods during which the average concentration of H_2S as measured by the H_2S continuous monitoring system under 40 CFR 60.105(a)(4) exceeds 230 mg/dscm (0.10 gr/dscf).
[40 CFR 60.105(e)(3)(ii); 40 CFR 60.7(c)]

3.2.4.2.31 For any individual drain system or aggregate facility that became an affected facility under 40 CFR Part 60, Subpart QQQ as a result of the petroleum refinery modification authorized by LSFP PSD Permit, the Permittee shall comply with the requirements of 40 CFR 60.692-1 to 60.692-7 and with 40 CFR 60.693-1 and 60.693-2, as applicable, except during periods of startup, shutdown, or malfunction.
[LSFP PSD Permit, 40 CFR 60, Subpart QQQ - 60.692-1 through 60.692-7, 60.693-1, and 60.693-2]

3.2.4.2.32 The Permittee shall comply with the emission standards for NOx and SO_2 in accordance with 40 CFR 60.4320 through 60.4330, as applicable. [Compliance with condition 3.2.4.1.12.1 for NOx emissions and condition 3.2.4.2.22 for SO_2 emissions will provide for compliance with this condition.]

[40 CFR 60, Subpart KKKK - 60.4320 through 60.4330]

3.2.4.2.33 When 40 CFR Part 63, Subpart YYYY applies to G-3413 (per 63.6095), the Permittee shall limit the concentration of formaldehyde in the stack to 91 ppbvd or less corrected to 15 % O_2. The Permittee shall comply with the requirements of 40 CFR 63.6080 through 63.6165, as applicable.

[40 CFR 63, Subpart YYYY - 63.6080 through 63.6165]

3.2.5 Group 05 – Flares

3.2.5.1 For the #2 Flare (H-1105), #3 Flare (H-1104), #5 Flare (H-3351), #6 Flare (H-3352), #7 Flare (H-3301), FCC LP Flare, and LPG Flare, the flares shall be designed for and operated with no visible emissions, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours. Flares shall be operated with a flame present at all times.

[40 CFR 60.18]

3.2.5.2 For the #6 Flare, the Permittee shall comply with all applicable requirements of 40 CFR 63, Subpart F.

[40 CFR 63.100 through 107]

3.2.5.3 For the #6 Flare, the Permittee shall comply with the applicable requirements of 40 CFR 63, Subpart G.

[40 CFR 63.110 through 153]

3.2.5.4 For the #6 Flare, the Permittee shall comply with all applicable leak detection and repair requirements of 40 CFR 63, Subpart H.

[40 CFR 63.160 through 183]

3.2.5.5 For the FCC LP Flare and the LPG Flare, the Permittee shall not combust any fuel gas that contains H_2S in excess of 0.1 gr/dscf.

[40 CFR 60.104(a)(1)]

3.2.5.6 For the FCC LP Flare and the LPG Flare, for the purposes of reports under 40 CFR 60.7(c), excess emissions shall be defined as all rolling 3-hour periods during which the average concentration of H_2S as measured by the H_2S continuous monitoring systems under 40 CFR 60.105(a)(4) exceeds 230 mg/dscm (0.10 gr/dscf).

[40 CFR 60.105(e)(3)(ii); 40 CFR 60.7(c)]

3.2.6 Group 06 – Loading

3.2.6.1 Group 06A – Truck Loading

3.2.6.1.1 The Permittee shall comply with the EPA-approved June 29, 1998 ‘Emissions Averaging Implementation Plan’ for truck loading.

[40 CFR 63.653(d)(1)]

3.2.6.2 Group 06B – Marine Loading

3.2.6.2.1 The Permittee shall equip each loading rack with a vapor collection system that is: designed to collect all benzene vapors displaced from tank trucks, railcars, or marine vessels during loading; and designed to prevent any benzene vapors collected at one loading rack from passing through another loading rack to the atmosphere.
[40 CFR 61.302(a)]

3.2.6.2.2 The Permittee shall install a control device and reduce benzene emissions routed to the atmosphere through the control device by 98 weight percent.
[40 CFR 61.302(b)]

3.2.6.2.3 The Permittee shall limit the loading of marine vessels to those vessels that are vapor tight and shall ensure that each marine vessel is loaded as determined by paragraph 3.2.6.2.3.1.

3.2.6.2.3.1 The Permittee shall ensure that each marine vessel is loaded with the benzene product tank below atmospheric pressure (i.e., at negative pressure). If the pressure is measured at the interface between the shoreside vapor collection pipe and the marine vessel vapor line, the pressure measured according to the procedures in 40 CFR 61.303(f) must be below atmospheric pressure.
[40 CFR 61.302(e)]

3.2.6.2.4 The Permittee shall ensure that the maximum normal operating pressure of the marine vessel's vapor collection equipment shall not exceed 0.8 times the relief set pressure of the pressure-vacuum vents. This level is not to be exceeded when measured by the procedures specified in section 4.2.6.2.2.
[40 CFR 61.302(j)]

3.2.7 Group 07 – Sulfur Recovery

3.2.7.1 The Permittee shall limit sulfur concentration emissions from both Beavon units (T-1061 and T-4761) to no more than 50 ppmv H_2S dry at 0% oxygen as determined by a continuous monitor.
[1997 PSD Permit (IV)(G)]

3.2.7.2 The compliance with the H_2S limit above shall be determined based on a 12-hour rolling average.
[40 CFR 60.105(e)(4)]

3.2.7.3 For T-1061, the Permittee shall not discharge or cause the discharge of any gases into the atmosphere from any Claus sulfur recovery plant containing in excess of 300 ppm by volume of reduced sulfur compounds and 10 ppm by volume of H_2S, each calculated as ppm SO_2 by volume (dry basis) at zero percent excess air. Compliance with these H_2S and TRS limits shall be determined based on a 12-hour rolling average.

[40 CFR 60.104(a)(2)(ii); 40 CFR 60, Subpart UUU]

3.2.7.4 For T-4761, the Permittee shall not discharge or cause the discharge of any gases into the atmosphere from any Claus sulfur recovery plant containing in excess of 300 ppm by volume of reduced sulfur compounds (dry basis) at zero percent excess air, in accordance with the Operations, Maintenance, and Monitoring Plan for East Sulfur Recovery. Compliance with this TRS limit shall be determined based on a 12-hour rolling average.

[40 CFR 60, Subpart UUU]

3.2.8 Group 08 – Internal Floating Roof Tanks

The requirements of this section apply only to internal floating roof storage vessels defined as "Group 1" under 40 CFR 63, Subparts F and G (HON) or Subpart CC (Refinery NESHAP).

3.2.8.1 The Permittee shall comply with the requirements specified in paragraphs 3.2.8.1.1 through 3.2.8.1.4. (Note: The intent of paragraphs 3.2.8.1.1 and 3.2.8.1.2 is to avoid having a vapor space between the floating roof and the stored liquid for extended periods. Storage vessels may be emptied for purposes such as routine storage vessel maintenance, inspections, petroleum liquid deliveries, or transfer operations. Storage vessels where liquid is left on walls, as bottom clingage, or in pools due to floor irregularity are considered completely empty.)

3.2.8.1.1 The internal floating roof shall be floating on the liquid surface at all times except when the floating roof must be supported by the leg supports during the periods specified in paragraphs 3.2.8.1.1.1 through 3.2.8.1.1.3.

3.2.8.1.1.1 During the initial fill.

3.2.8.1.1.2 After the vessel has been completely emptied and degassed.

3.2.8.1.1.3 When the vessel is completely emptied before being subsequently refilled.

[40 CFR 63.119(b)(1); 40 CFR 63.646(a)]

3.2.8.1.2 When the floating roof is resting on the leg supports, the process of filling, emptying, or refilling shall be continuous and shall be accomplished as soon as practical.

[40 CFR 63.119(b)(2); 40 CFR 63.646(a)]

3.2.8.1.3 Each internal floating roof shall be equipped with a closure device between the wall of the storage vessel and the roof edge. Except as provided in paragraph 3.2.8.1.3.4, the closure device shall consist of one of the devices listed in paragraph 3.2.8.1.3.1, 3.2.8.1.3.2, and 3.2.8.1.3.3.

3.2.8.1.3.1 A liquid-mounted seal as defined in 40 CFR 63.111.

3.2.8.1.3.2 A metallic shoe seal as defined in 40 CFR 63.111.

3.2.8.1.3.3 Two seals mounted one above the other so that each forms a continuous closure that completely covers the space between the wall of the storage vessel and the edge of the internal floating roof. The lower seal may be vapor- mounted, but both must be continuous seals.

3.2.8.1.3.4 If the internal floating roof is equipped with a vapor-mounted seal as of July 15, 1994 (December 31, 1992 for HON Group 1), the requirement for one of the seal options specified in paragraphs 3.2.8.1.3.1, 3.2.8.1.3.2, and 3.2.8.1.3.3 does not apply until the earlier of the dates specified in paragraphs 3.2.8.1.3.4.1 and 3.2.8.1.3.4.2.

3.2.8.1.3.4.1 The next time the storage vessel is emptied and degassed.

3.2.8.1.3.4.2 No later than 10 years after August 18, 1995 (April 22, 1994 for HON Group 1).

[40 CFR 63.119(b)(3); 40 CFR 63.646(a)]

3.2.8.1.4 Automatic bleeder vents are to be closed at all times when the roof is floating, except when the roof is being floated off or is being landed on the roof leg supports.

[40 CFR 63.119(b); 40 CFR 63.646(a)]

3.2.8.1.5 Storage vessels (tanks) regulated under 40 CFR 63 (HON) shall also be subject to 40 CFR 63.119(b)(5) and (6).

[40 CFR 63.119(b)(5) and (6)]

3.2.8.1.6 The following paragraphs 3.2.8.1.6.1, 3.2.8.1.6.2, and 3.2.8.1.6.3 of this section apply to Group 1 storage vessels subject to 40 CFR 63 Subpart CC at existing sources.

[40 CFR 63.646(f)]

3.2.8.1.6.1 If a cover or lid is installed on an opening on a floating roof, the cover or lid shall remain closed except when the cover or lid must be open for access.

[40 CFR 63.646(f)(1)]

3.2.8.1.6.2 Rim space vents are to be set to open only when the floating roof is not floating or when the pressure beneath the rim seal exceeds the manufacturer's recommended setting.

[40 CFR 63.646(f)(2)]

3.2.8.1.6.3 Automatic bleeded vents are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports.
[40 CFR 63.646(f)(3)]

3.2.8.1.7 If a Group 1 external floating roof storage vessel that has been converted to an internal floating roof storage vessel is subject to HON, the Permittee shall comply with 40 CFR 63.119(d)(1) and (d)(2).
[40 CFR 63.119(d)(1) and (2)]

3.2.8.1.8 If a Group 1 external floating roof storage vessel that has been converted to an internal floating roof storage vessel is subject to 40 CFR 63 Subpart CC, the Permittee shall comply with 40 CFR 63.119(d)(1)
[40 CFR 63.646(c); 40 CFR 63.119(d)(1)]

3.2.9 Group 09 – External Floating Roof Tanks

The requirements of this section apply only to external floating roof storage vessels defined as “Group 1” under 40 CFR 63, Subparts F and G (HON) or Subpart CC (Refinery NESHAP).

3.2.9.1 Each external floating roof shall be equipped with a closure device between the wall of the storage vessel and the roof edge.

3.2.9.1.1 Except as provided in paragraph 3.2.9.1.4, the closure device is to consist of two seals, one above the other. The lower seal is referred to as the primary seal and the upper seal is referred to as the secondary seal.

3.2.9.1.2 Except as provided in paragraph 3.2.9.1.4, the primary seal shall be either a metallic shoe seal or a liquid-mounted seal.

3.2.9.1.3 Except during the inspections required by section 5.2.9, both the primary seal and the secondary seal shall completely cover the annular space between the external floating roof and the wall of the storage vessel in a continuous fashion.

3.2.9.1.4 If the external floating roof is equipped with a liquid-mounted or metallic shoe primary seal as of July 15, 1994 (December 31, 1992 for HON Group 1 tanks), the requirement for a secondary seal in paragraph 3.2.9.1.1 does not apply until the earlier of the dates specified in paragraphs 3.2.9.1.4.1 and 3.2.9.1.4.2.

3.2.9.1.4.1 The next time the storage vessel is emptied and degassed.

3.2.9.1.4.2 No later than 10 years after August 18, 1995 (April 22, 1994 for HON Group 1 tanks).

3.2.9.1.5 If the external floating roof is equipped with a vapor-mounted primary seal and a secondary seal as of July 15, 1994 (December 31, 1992 for HON Group 1 tanks), the requirement for a liquid-mounted or metallic shoe primary seal in paragraph 3.2.9.1.2 does not apply until the earlier of the dates specified in paragraphs 3.2.9.1.5.1 and 3.2.9.1.5.2.

3.2.9.1.5.1 The next time the storage vessel is emptied and degassed.

3.2.9.1.5.2 No later than 10 years after August 18, 1995 (April 22, 1994 for HON Group 1 tanks).

[40 CFR 63, Subpart CC]

3.2.9.2 Each external floating roof on a storage vessel subject to the HON shall meet the specifications listed in paragraphs 3.2.9.2.1 through 3.2.9.2.12.

3.2.9.2.1 Except for automatic bleeder vents (vacuum breaker vents) and rim space vents, each opening in the noncontact external floating roof shall provide a projection below the liquid surface except as provided in paragraph 3.2.9.1.12.

3.2.9.2.2 Except for automatic bleeder vents, rim space vents, roof drains, and leg sleeves, each opening in the roof is to be equipped with a gasketed cover, seal or lid which is to be maintained in a closed position (i.e., no visible gap) at all times except when the cover or lid must be open for access. Covers on each access hatch and each gauge float well shall be bolted or fastened so as to be air-tight when they are closed.

3.2.9.2.3 Automatic bleeder vents are to be closed at all times when the roof is floating, except when the roof is being floated off or is being landed on the roof leg supports.

3.2.9.2.4 Rim space vents are to be set to open only when the roof is being floated off the roof leg supports or when the pressure beneath the rim seal exceeds the manufacturer's recommended setting.

3.2.9.2.5 Automatic bleeder vents and rim space vents are to be gasketed.

3.2.9.2.6 Each roof drain that empties into the stored liquid is to be provided with a slotted membrane fabric cover that covers at least 90 percent of the area of the opening.

3.2.9.2.7 Each unslotted guide pole well shall have a gasketed sliding cover or a flexible fabric sleeve seal.

3.2.9.2.8 Each unslotted guide pole shall have on the end of the pole a gasketed cap which is closed at all times except when gauging the liquid level or taking liquid samples.

3.2.9.2.9 Each slotted guide pole well shall have a gasketed sliding cover or a flexible fabric sleeve seal.

3.2.9.2.10 Each slotted guide pole shall have a gasketed float or other device which closes off the liquid surface from the atmosphere.

3.2.9.2.11 Each gauge hatch/sample well shall have a gasketed cover which is closed at all times except when the hatch or well must be open for access.

3.2.9.2.12 If each opening in a noncontact external floating roof except for automatic bleeder vents (vacuum breaker vents) and rim space vents does not provide a projection below the liquid surface as of July 15, 1994, the requirement for providing these projections below the liquid surface does not apply until the earlier of the dates specified in paragraphs 3.2.9.2.12.1 and 3.2.9.2.12.2.

3.2.9.2.12.1 The next time the storage vessel is emptied and degassed.

3.2.9.2.12.2 No later than 10 years after April 22, 1994.

[40 CFR 63, Subpart G]

Note: The intent of paragraphs 3.2.9.3 and 3.2.9.4 is to avoid having a vapor space between the floating roof and the stored liquid for extended periods. Storage vessels may be emptied for purposes such as routine storage vessel maintenance, inspections, petroleum liquid deliveries, or transfer operations. Storage vessels where liquid is left on walls, as bottom clingage, or in pools due to floor irregularity are considered completely empty.

3.2.9.3 The external floating roof shall be floating on the liquid surface at all times except when the floating roof must be supported by the leg supports during the periods specified in paragraphs 3.2.9.3.1 through 3.2.9.3.3.

3.2.9.3.1 During the initial fill.

3.2.9.3.2 After the vessel has been completely emptied and degassed.

3.2.9.3.3 When the vessel is completely emptied before being subsequently refilled.

[40 CFR 63.119(c)(3); 40 CFR 63.646(a)]

3.2.9.4 When the floating roof is resting on the leg supports, the process of filling, emptying, or refilling shall be continuous and shall be accomplished as soon as practical.

[40 CFR 63.119(c)(4); 40 CFR 63.646(a)]

3.2.9.5 The following paragraphs 3.2.9.5.1, 3.2.9.5.2, and 3.2.9.5.3 apply to Group 1 storage vessels subject to 40 CFR Part 63, Subpart CC at existing sources:

3.2.9.5.1 If a cover or lid is installed on an opening on a floating roof, the cover or lid shall remain closed except when the cover or lid must be open for access.

3.2.9.5.2 Rim space vents are to be set to open only when the floating roof is not floating or when the pressure beneath the rim seal exceeds the manufacturer's recommended setting.

3.2.9.5.3 Automatic bleeder vents are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports.

[40 CFR 63.646(f)]

3.2.10 Group 10 – Fixed Roof Tanks

3.2.10.1 Group 10A – Fixed Roof Tanks PRT3, PRT4, PRT5, PRT6, PRT7, TK-1151, TK-1201, TK-1202, TK-1203, TK-1206, TK-1207, TK-1208, TK-1302, TK-1653, TK-2653, TK-2654, TK-3208, TK-3301, TK-3304, TK-3306, TK-3384, TK-3385, TK-3386, TK-4502, TK-6810, TK-6811, TK-6812, TK-6813, TK-6817, TK-6818, TK-6819, TK-6820, TK-6821, TK-6822, TK-6823, TK-6824, TK-6825, TK-6851, TK-6853, TK-6854, TK-6856, TK-6858, TK-6859, TK-6860, TK-6873, TK-6875, TK-6876, TK-6877, TK-6881, TK-6883, TK-6887, TK-700, TK-701, TK-702, TK-7206, TK-7207, TK-7208, TK-7209, TK-TK-7210, TK-7211, TK-7301, TK-7405, TK-7406, TK-7411, TK-7412, TK-7413, TK-7414, TK-7415, TK-7416, TK-7421, TK-7422, TK-7427, TK-7428, TK-7429, TK-7430, TK-7435, TK-7436, TK-7437, TK-7438, TK-7439, TK-7440, TK-7446, TK-7501, TK-7502, TK-7503, TK-7504, TK-7505, TK-7506, TK-7933, TK-7934, UTT1, TK-8501

None.

3.2.10.2 Group 10B - Affected Units: TK-1204, TK-1205, TK-8001, TK-8002 (Subject to 40 CFR 60, Subpart EEEE)

None.

3.2.11 Group 11 – Horizontal Tanks TK-1626, TK-1627, TK-1628, TK-1629, TK-1630, TK-1631, TK-1633, D-1301, D-1609, D-1610, D-1620

None.

3.2.12 Group 12 – Geodesic Dome Tanks

None.

3.2.13 Group 13 – Wastewater Treatment

3.2.13.1 For oil-water separators with floating roofs, the Permittee shall meet the requirements in 40 CFR 60.693-2(a), as applicable. For portions of the oil-water separator where it is infeasible to construct and operate a floating roof, such as over the weir mechanism, the Permittee shall operate a fixed roof

vented to a vapor control device and shall meet the requirement in 40 CFR 61.347 applicable to the fixed roof. (Requirements for the closed-vent systems and control devices may be found in section 3.2.13.3.)
[40 CFR 60, Subpart QQQ; 40 CFR 61.347 and 61.352; 40 CFR 63.647]

3.2.13.2 For oil-water separators with fixed roofs, the Permittee shall comply with the requirements in 40 CFR 61.347. (Requirements for the closed-vent systems and control devices may be found in section 3.2.13.3.)
[40 CFR 60, Subpart QQQ; 40 CFR 61.347; 40 CFR 63.647]

3.2.13.3 For closed vent systems associated with wastewater system components (i.e., WEMCO Units and oil-water separators), the Permittee shall properly design, install, operate, and maintain the closed-vent system and control device in accordance with the following requirements:

3.2.13.3.1 The closed-vent system shall:

3.2.13.3.1.1 Be designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in 40 CFR 61.355(h).

3.2.13.3.1.2 Vent systems that contain any bypass line that could divert the vent stream away from a control device used to comply with the provisions of this subpart shall install, maintain, and operate according to the manufacturer's specifications a flow indicator that provides a record of vent stream flow away from the control device at least once every 15 minutes, except as provided in 40 CFR 61.349 (a)(1)(ii)(B).

3.2.13.3.1.2.1 The flow indicator shall be installed at the entrance to any bypass line that could divert the vent stream away from the control device to the atmosphere.

3.2.13.3.1.2.2 Where the bypass line valve is secured in the closed position with a car-seal or a lock-and-key type configuration, a flow indicator is not required.

3.2.13.3.1.3 All gauging and sampling devices shall be gas-tight except when gauging or sampling is taking place.

3.2.13.3.1.4 For each closed-vent system complying with 40 CFR 61.349(a) of this section, one or more devices which vent directly to the atmosphere may be used on the closed-vent system provided each device remains in a closed, sealed position during normal operations except when the device needs to open to prevent physical damage or permanent deformation of the closed-vent system resulting from malfunction of the unit in accordance with good engineering and safety practices for handling flammable, explosive, or other hazardous materials.

3.2.13.3.2 Closed-vent systems and control devices shall comply with the standards in 40 CFR 61.349, as applicable.

3.2.13.3.3 Each closed-vent system and control device associated with wastewater system components shall be operated at all times when waste is placed in the waste management unit vented to the control device except when maintenance or repair of the waste management unit cannot be completed without a shutdown of the control device.
[40 CFR 60, Subpart QQQ; 40 CFR 61.349; 40 CFR 63.647]

3.2.13.4 For each waste stream subject to Subpart FF which is managed in a wastewater treatment system, the Permittee shall treat the waste stream in accordance with the following requirements:

3.2.13.4.1 The owner or operator shall design, install, operate, and maintain a treatment process that either:

3.2.13.4.1.1 Removes benzene from the waste stream to a level less than 10 parts per million by weight (ppmw) on a flow-weighted annual average basis,

3.2.13.4.1.2 Removes benzene from the waste stream by 99 percent or more on a mass basis, or

3.2.13.4.1.3 Destroys benzene in the waste stream by incinerating the waste in a combustion unit that achieves a destruction efficiency of 99 percent or greater for benzene.

3.2.13.4.2 Each treatment process complying with paragraph 3.2.13.4.1.1 or 3.2.13.4.1.2 shall be designed and operated in accordance with the appropriate waste management unit standards specified in 40 CFR 61.343 through 61.347. For example, if a treatment process is a tank, then the owner or operator shall comply with 40 CFR 61.343.

3.2.13.4.3 For the purpose of complying with the requirements specified in paragraph 3.2.13.4.1.1, the intentional or unintentional reduction in the benzene concentration of a waste stream by dilution of the waste stream with other wastes or materials is not allowed.

3.2.13.4.4 An owner or operator may aggregate or mix together individual waste streams to create a combined waste stream for the purpose of facilitating treatment of waste to comply with the requirements of paragraph 3.2.13.4.1 except as provided in paragraph 3.2.13.4.5.

3.2.13.4.5 If an owner or operator aggregates or mixes any combination of process wastewater, product tank drawdown, or landfill leachate subject to 40 CFR 61.342(c)(1) together with other waste streams to create a combined waste stream for the purpose of facilitating management or treatment of waste in a wastewater treatment system, then the wastewater treatment system shall be operated in accordance with paragraph (b) of 40 CFR 61.348. These provisions apply to above-ground wastewater treatment systems as well as those that are at or below ground level.

[40 CFR 61.348 (a)]

3.2.13.4.6 If the Permittee aggregates or mixes individual waste streams as defined in paragraph 3.2.13.4.5 for management and treatment in a wastewater treatment system shall comply with the following requirements:

3.2.13.4.6.1 The owner or operator shall design and operate each waste management unit that comprises the wastewater treatment system in accordance with the appropriate standards specified in 40 CFR 61.343 through 61.347.

3.2.13.4.6.2 The provisions of paragraph 3.2.13.4.6.1 do not apply to any waste management unit that the owner or operator demonstrates to meet the following conditions initially and, thereafter, at least once per year:

3.2.13.4.6.2.1 The benzene content of each waste stream entering the waste management unit is less than 10 ppmw on a flow-weighted annual average basis as determined by the procedures specified in 40 CFR 61.355(c); and

3.2.13.4.6.2.2 The total annual benzene quantity contained in all waste streams managed or treated in exempt waste management units comprising the facility wastewater treatment systems is less than 1 Mg/yr (1.1 ton/yr). For this determination, total annual benzene quantity shall be calculated as follows:

(a) The total annual benzene quantity shall be calculated as the sum of the individual benzene quantities determined at each location where a waste stream first enters an exempt waste management unit. The benzene quantity discharged from an exempt waste management unit shall not be included in this calculation.

(b) The annual benzene quantity in a waste stream managed or treated in an enhanced biodegradation unit shall not be included in the calculation of the total annual benzene quantity, if the enhanced biodegradation unit is the first exempt unit in which the waste is managed or treated. A unit shall be considered enhanced biodegradation if it is a suspended-growth process that generates biomass, uses recycled biomass, and periodically removes biomass from the process. An enhanced biodegradation unit typically operates at a food-to-microorganism ratio in the range of 0.05 to 1.0 kg of biological oxygen demand per kg of biomass per day, a mixed liquor suspended solids ratio in the range of 1 to 8 grams per liter (0.008 to 0.7 pounds per liter), and a residence time in the range of 3 to 36 hours.

[40 CFR 61.348 (b)]

3.2.13.4.7 Except as specified in paragraph 3.2.13.4.7.3, if the treatment process or wastewater treatment system unit has any openings (e.g., access doors, hatches, etc.), all such openings shall be sealed (e.g., gasketed, latched, etc.) and kept closed at all times when waste is being treated, except during inspection and maintenance.

3.2.13.4.7.1 Each seal, access door, and all other openings shall be checked by visual inspections initially and quarterly thereafter to ensure that no cracks or gaps occur and that openings are closed and gasketed properly.

3.2.13.4.7.2 Except as provided in 40 CFR 61.350, when a broken seal or gasket or other problem is identified, first efforts at repair shall be made as soon as practicable, but not later than 15 calendar days after identification.

3.2.13.4.7.3 If the cover and closed-vent system operate such that the treatment process and wastewater treatment system unit are maintained at a pressure less than atmospheric pressure, the owner or operator may operate the system with an opening that is not sealed and kept closed at all times if the following conditions are met:

3.2.13.4.7.3.1 The purpose of the opening is to provide dilution air to reduce the explosion hazard;

3.2.13.4.7.3.2 The opening is designed to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppmv above background, as determined initially and thereafter at least once per year by the methods specified in 40 CFR 61.355(h); and

3.2.13.4.7.3.3 The pressure is monitored continuously to ensure that the pressure in the treatment process and wastewater treatment system unit remain below atmospheric pressure.
[40 CFR 61.348 (e)]

3.2.13.4.8 The Administrator may request at any time an owner or operator demonstrate that a treatment process or wastewater treatment system unit meets the applicable requirements specified in 3.2.13.4.1 through 3.2.13.4.5 or 3.2.13.4.6 by conducting a performance test using the test methods and procedures as required in 40 CFR 61.355.
[40 CFR 61.348(f)]

3.2.13.5 The requirements of Section 3.2.13.4 shall not apply to waste streams exempt from 40 CFR 61.342(c)(1) pursuant to 40 CFR 61.342(c)(2) and (c)(3).
[40 CFR 61.342(c)(2) and (c)(3)]

3.2.14 Group 14 – Alkylation and Dimersol Units

3.2.14.1 For distillation unit vent streams, the Permittee shall comply with the requirements of 40 CFR 60.660, as applicable.
[40 CFR 60.660]

3.2.14.2 In lieu of the above monitoring requirements, the Permittee may instead comply with EPA-approved alternative monitoring requirements, as applicable, in accordance with provisions of 40 CFR 60.13(i).
[40 CFR 60.13(i)]

3.2.14.3 For reactor process vent streams, the Permittee shall comply with the requirements of 40 CFR 60.700, as applicable.
[40 CFR 60.700]

3.2.15 Group 15 – Seawater Intake Pumps

3.2.15.1 The following distillate oil-fired units have no limits on the amount of 0.2% sulfur distillate fuel oil that can be burned on a daily or annual basis: P-1602 (standby pump seawater intake), P-1603 (standby pump seawater intake), P-

1604 (standby pump seawater intake), P-1605 (standby pump seawater intake), and P-1620 (standby pump desalination water).

[1997 PSD Permit (III)(D)(e)]

3.2.16 Group 16 – FCCU

3.2.16.1 For STK-7051, the LSFP PSD Permit shall become invalid if construction: (a) has not commenced (as defined in 40 CFR 52.21(b)(9)) within 18 months of the effective date of the permit; (b) is discontinued for a period of 18 months or more; or (c) is not completed within a reasonable time.

[LSFP PSD Permit I]

3.2.16.2 For STK-7051, all equipment, facilities, and systems installed or used to achieve compliance with the terms and conditions of the LSFP PSD Permit shall at all times be maintained in good working order and be operated as efficiently as possible so as to minimize air pollutant emissions. The Permittee shall demonstrate initial and continuous compliance with the operating, emission and other limits according to the performance testing and compliance assurance and all other requirements of the LSFP PSD Permit.

[LSFP PSD Permit III]

3.2.16.3 The maximum annual throughput to the FCCU shall not exceed 58,400,000 bbls as calculated on a 365-day rolling basis.

[LSFP PSD Permit VI.C.1]

3.2.16.4 The maximum daily throughput to the FCCU shall not exceed 165,000 barrels per calendar day.

[LSFP PSD Permit VI.C.2]

3.2.16.5 The maximum coke burn-off rate shall be limited to 115,500 pounds per hour.

[LSFP PSD Permit VI.C.3]

3.2.16.6 For STK-7051, the FCCU shall only use low sulfur content feedstock with a maximum sulfur content of 0.6 percent by weight.

[LSFP PSD Permit VII.C.1]

3.2.16.7 For STK-7051, PM emissions shall not exceed 0.5 pounds per 1,000 pounds of coke burn-off, 57.75 lbs/hr and 252.9 tons/year. Compliance shall be determined in accordance with the procedures in condition 4.2.16.7 [Compliance with this condition is expected to provide for compliance with the NSPS Subpart J limit for particulate matter of 1.0 kg/Mg (1.0 lb/1,000 pounds) of coke burn-off in the catalyst regenerator required by 40 CFR 60.102(a)(1) as determined by the 40 CFR 60.106(b)].

[LSFP PSD Permit VIII.C.1; 40 CFR 60.102(a)(1)]

3.2.16.8 For the 3 Turbo Expander Maintenance Vents, the Permittee shall not discharge or cause the discharge into the atmosphere from the fluid catalytic cracking unit catalyst regenerator particulate matter in excess of 1.0 kg/Mg (2.0 lb/ton) of coke burn-off in the catalyst regenerator. In lieu of the particulate matter testing requirements in 40 CFR 60.106, the Permittee may instead comply with EPA-approved alternative monitoring requirements for flue gas

monitoring, as applicable, in accordance with provisions of 40 CFR 60.13(i).
[40 CFR 60.102(a)(1)]

3.2.16.9 For STK-7051, PM-10 emissions from the FCCU regenerator exhaust shall not exceed 1.0 pounds per 1,000 pounds of coke burn-off, 115.5 lbs/hr and 505.9 tons/year.
[LSFP PSD Permit VIII.C.2]

3.2.16.10 For STK-7051:

(a) The concentration of SO_2 in the FCCU stack shall not exceed 16 ppmv on a dry basis, corrected to 0% oxygen, when averaged over any consecutive 365-day period.

(b) The concentration of SO_2 in the FCCU stack shall not exceed 25 ppmv on a dry basis, corrected to 0% oxygen, when averaged over any consecutive 7-day period.

(c) The venturi scrubber must reduce SO_2 emissions to the atmosphere by at least 90%.

(d) The emission rate of SO_2 from the FCCU shall not exceed 214.9 lb/hr on a rolling 3-hour basis and 237 tons/year during each consecutive 12-month period.
[LSFP PSD Permit VII.C.3.a through d]

3.2.16.11 For STK-7051, the Permittee shall comply with applicable requirements (a) and (b) above, or applicable requirement (c) above, whichever is less stringent.
[1997 PSD Permit (I)(B)(b)]

3.2.16.12 For STK-7051, the continuous emission monitoring systems required by the LSFP PSD Permit shall be on-line and in operation 95% of the time when the emissions sources are operating.
[LSFP PSD Permit III]

3.2.16.13 For STK-7051, the Permittee shall reduce SO_2 emissions to the atmosphere by 90 percent or maintain SO_2 emissions to the atmosphere less than or equal to 50 ppm by volume (ppmv), whichever is less stringent.
[40 CFR 60.103(a)]

3.2.16.14 For STK-7051, the maximum concentration of NOx in the FCCU exhaust, as determined by continuous monitoring, shall not exceed 25 ppmvd corrected to 0% oxygen, when averaged over any consecutive 365-day period.
[LSFP PSD Permit VIII.C.4.a]

3.2.16.15 For STK-7051, the emissions rate of NOx from the FCCU shall not exceed 266 tons per year.
[LSFP PSD Permit VIII.C.4.b]

3.2.16.16 For STK-7051, the Permittee shall limit CO emissions to 432 ppmv on a dry basis corrected to 7% oxygen on a block-hour average, as determined by continuous monitoring.

[LSFP PSD Permit VIII.C.5.a]

3.2.16.17 For STK-7051, for any 1-hour period, the emission rate of CO from the FCCU shall not exceed 738.6 lbs/hr and 3,235.0 tons/year.

[LSFP PSD Permit VII.C.5.b]

3.2.16.18 For STK-7051, the Permittee shall limit VOC emissions to 20 ppmv on a dry basis corrected to 7% oxygen, 12.1 lbs/hr and 52.7 tons/year.

[LSFP PSD Permit VIII.C.6.a]

3.2.16.19 For STK-7051, the EPA reserves the right to require continuous emission monitoring for VOC.

[LSFP PSD Permit VIII.C.6.b]

3.2.16.20 For STK-7051, the average opacity as measured by a visual observation shall not exceed 20 percent, except for one six minute period in any one hour.

[LSFP PSD Permit VIII.C.7.b]

3.2.16.21 For the 3 Turbo Expander Maintenance Vents, the Permittee shall not discharge or cause the discharge into the atmosphere from any fluid catalytic cracking unit catalyst regenerator gases exhibiting greater than 30 percent opacity, except for one six-minute average opacity reading in any one hour period. In lieu of the opacity monitoring requirements in 40 CFR 60.106 which apply to STK-7051 and the 3 Turbo Expander Maintenance Vents, the Permittee may instead comply with EPA-approved alternative monitoring requirements for flue gas monitoring, as applicable, in accordance with provisions of 40 CFR 60.13(i).

[40 CFR 60.102(a)(2)]

3.2.16.22 The Permittee shall assure efficient scrubber operation by measuring and maintaining the pressure drop across the venturi scrubber throat.

[LSFP PSD Permit VIII.C.7.a]

3.2.16.23 The FCCU is exempt from the concentration limits for CO and VOC, as described above, for a maximum of 8 hours during startup of the unit. This exemption shall be afforded 3 times per year (based on a 365-day rolling average). Startup of the FCCU begins with the introduction of feed to the reactor and concludes when a stable regenerator combustion temperature of 1,280 degrees Fahrenheit has been achieved.

[LSFP PSD Permit VIII.C.8]

3.2.16.24 The FCCU coke burn-off rate shall be calculated in accordance with condition 4.2.16.7.

[LSFP PSD Permit X.2]

3.2.16.25 For pollution control equipment, each unit shall continuously operate in accordance with its design specified parameters. This includes continuously operating all proposed control devices in a manner consistent with good air pollution control practice for minimizing emissions.

[LSFP PSD Permit IX.1]

3.2.16.26 For the 3 Turbo Expander Maintenance Vents – The Permittee shall not discharge or cause the discharge into the atmosphere from any fluid catalytic cracking unit catalyst regenerator any gases that contain carbon monoxide (CO) in excess of 500 ppm by volume (dry basis). In lieu of these carbon monoxide monitoring requirements, the Permittee may instead comply with EPA-approved alternative monitoring requirements for flue gas monitoring, as applicable, in accordance with provisions of 40 CFR 60.13(i).

[40 CFR 60.103(a)]

3.2.16.27 For the 3 Turbo Expander Maintenance Vents – The Permittee shall, 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. In lieu of those sulfur dioxide monitoring requirements, the Permittee may instead comply with EPA-approved alternative monitoring requirements for flue gas monitoring, as applicable, in accordance with provisions of 40 CFR 60.13(i).

[40 CFR 60.104(b)(2); 40 CFR 60.13(i)]

3.2.16.28 For STK-7051 and the Turbo Expander Maintenance Vents, the Permittee shall comply with the requirements of 40 CFR 63, Subpart UUU, by complying with the procedures of the Operation, Monitoring, and Maintenance (OMM) Plan.

[40 CFR 63.1561 through 1577]

3.2.16.29 The Permittee shall monitor fugitive emissions from the FCCU complex in accordance with the requirements of 40 CFR 60, Subpart GGG, Fugitive Equipment Leaks from Petroleum Refineries. The Permittee shall utilize dual mechanical pump and compressor seals wherever possible.

[1997 PSD Permit (V)(A) and (D)]

3.2.17 Group 17 – Coker Complex

None.

3.2.18 Group 18 – Sulfuric Acid Plant

3.2.18.1 The Permittee shall limit the production of the sulfuric acid plant to a maximum of 320 tons per calendar day.

[1997 PSD Permit (II)(A)]

3.2.18.2 The emission rate of SO_2 from the sulfuric acid plant shall not exceed 4 pounds per ton of acid produced, 45.8 pounds per hour, 201 tons per year.

[1997 PSD Permit (II)(B)]

3.2.18.3 The concentration of SO_2 in the stack gas from the sulfuric plant shall not exceed 375 ppmv on a dry basis corrected to 7% oxygen, as determined by continuous monitoring.

[1997 PSD Permit (II)(B)]

3.2.18.4 The emission rate of NOx from the sulfuric acid plant shall not exceed 12.2 pounds per hour (as NO_2), 200 ppmv on a dry basis corrected to 7% O2, 53.4

tons per year.

[1997 PSD Permit (II)(C)]

3.2.18.5 The emission rate of sulfuric acid mist (H_2SO_4) and SO_3 (as defined by NSPS) from the acid plant shall not exceed 0.15 pounds per ton of acid produced, 2.0 pounds per hour, 8.8 tons per year.

[1997 PSD Permit (II)(D)]

3.2.18.6 The opacity shall not exceed 10 percent as determined by visual emission observation made in accordance with RM 9.

[1997 PSD Permit (II)(E)]

3.2.18.7 Unit Start-up: The sulfuric acid plant is exempt for the SO_2 hourly mass emissions limit and the SO_2 concentrations limit as described in the 1997 PSD Permit (II)(B) for a maximum of 4 hours during start-up of the unit. The SO_2 hourly mass emission rate shall not exceed the PSD permitted limit of 45.8 pounds per hour, based on a 3-hour rolling average. This start-up exemption shall only be afforded 8 times per year (based on a 365-day rolling average). Start-up of the sulfuric acid plant begins with the introduction of acid gas or spent acid to the unit, and concludes when the fourth conversion bed achieves a stable temperature above 780°F.

[1997 PSD Permit (II)(F)]

3.2.18.8 The Permittee shall comply with the applicable standards in 40 CFR 60, Subpart H.

[40 CFR 60.80 through 60.85]

3.2.19 Group 19 – Vapor Enhanced Recovery

3.2.19.1 The Permittee shall not combust any fuel gas that contains H_2S in excess of 0.1 gr/dscf.

[40 CFR 60.104(a)(1)]

3.2.19.2 For the purpose of reports under 40 CFR 60.7(c), excess emissions shall be defined as all rolling 3-hour periods during which the average concentration of H_2S as measured by the H_2S continuous monitoring system under 40 CFR 60.105(a)(4) exceeds 230 mg/dscm (0.10 gr/dscf).

[40 CFR 60.105(e)(3)(ii)]

3.2.20 Group 20 – Gasoline Service Station and Fuel Gas System

None.

3.2.21 Group 21 – Amine Units, Merox Unit, and Gas Concentration

None.

3.2.22 Group 22 – Gas Treating and Stripping

None.

3.2.23 Group 23 – Hydrogen Recovery

None.

3.2.24 Group 24 – Disulfide Handling

None.

3.2.25 Group 25 – Platformers

3.2.25.1 The Permittee shall comply with the requirements of 40 CFR 63, Subpart UUU by complying with the procedures of the current Operation, Maintenance, and Monitoring Plans for the #2, #3, and #4 Platformers.
[40 CFR 63.1561 through 1577]

3.3 Equipment TIP Requirements

None.

3.4 Equipment Standards Not Covered by a Federal or TIP Rule and Not Instituted as an Emission Cap or Operating Limit

None.

3.5 Operating Scenarios

None.

PART 4.0 REQUIREMENTS FOR TESTING

4.1 General Testing Requirements

None.

4.2 Specific Testing Requirements

Table 2 in Part 1 provides a summary by individual emission unit or emission unit grouping of the specific location within this Title V permit for each emission or operational limitation and for the testing, monitoring, recordkeeping and reporting requirements that apply to that emission or operational limitation.

4.2.1 Group 1 – Boilers

4.2.1.1 Group 01A - Boilers B-1151, B-1153, B-1154, and B-1155

4.2.1.1.1 For B-1155, the Permittee shall comply, as applicable, with the testing requirements of 40 CFR 60, Subpart A and 40 CFR 60.46 (NSPS Subpart D - Test Methods and Procedures), as applicable.

[40 CFR 60, Subpart A; 40 CFR 60.46]

4.2.1.2 Group 01B – Boilers B-3301, B-3302, B-3303, and B-3304

4.2.1.2.1 For B-3303 and B-3304, the Permittee shall comply, as applicable, with the testing requirements of 40 CFR 60, Subpart A and 40 CFR 60.46 (NSPS Subpart D - Test Methods and Procedures), as applicable.

[40 CFR Part 60, Subpart A; 40 CFR 60.46]

4.2.1.3 Group 01C – Boiler B-3701

4.2.1.3.1 Compliance with the NOx emission limit shall be determined on a 30-day rolling average basis.

[40 CFR 60.44b(i)]

4.2.1.3.2 Compliance with the NOx emission standard in NSPS Subpart Db shall be determined through performance test as required under 40 CFR 60.8, and by using the continuous system for monitoring NOx and O2 under 40 CFR 60.48(b).

[40 CFR 60.46b(c) and (e)]

4.2.1.3.3 The emission rate of NOx from Boiler B-3701 shall be based on the average value of three (3) successive test runs using EPA Reference Method 7E, or the NSPS Method, whichever testing method is determined to be the most stringent at the time of the test.

[STX-557-I-00 (II)(F), September 18, 2000]

4.2.1.3.4 The emission rate of CO from Boiler B-3701 shall be based on the average value of three (3) successive test runs using EPA Reference Method 10 or the NSPS Method, whichever testing method is determined to be the most stringent at the time of the test.

[STX-557-I-00 (II)(G), September 18, 2000]

4.2.1.3.5 The Permittee shall conduct stack tests for NOx from the boiler to demonstrate that the ultra-low burners achieve the emission limits in section 3.1.1.4.2. These stack tests shall be in accordance with the test methods published in 40 CFR 60, Appendix A.

[STX-557-I-00 (IV)(A), September 18, 2000]

4.2.1.3.6 The Permittee shall conduct stack tests for CO from the boiler to demonstrate that the emission limits in section 3.1.1.4.3 can be achieved. These stack tests shall be in accordance with the test methods published in 40 CFR 60, Appendix A.

[STX-557-I-00 (IV)(B), September 18, 2000]

4.2.1.3.7 The Permittee shall conduct all tests within 60 days after achieving maximum production rate at which the facility will normally be operated, but no later than 180 days after initial startup.

[STX-557-I-00 (IV)(C), September 18, 2000]

4.2.1.3.8 The Permittee shall notify VIDPNR in writing at least 30 days prior to actual testing.

[STX-557-I-00 (IV)(D), September 18, 2000]

4.2.1.3.9 For NOx, the Permittee shall perform a stack test during the initial term of the Permittee's Title V operating permit. This requirement shall not apply if a stack test using EPA or VIDPNR approved reference methods has been performed within 2 years of the issuance date of this Title V permit. The Permittee shall retest after the initial term of the Permittee's Title V operating permit to the extent required by (i) the provisions of the applicable local or federal preconstruction permit, or (ii) VIRR Title 12, Chapter 9, or (iii) once during each five year period following the initial term of the Permittee's Title V permit. In lieu of the testing requirement, the Permittee may use alternative compliance monitoring methods approved by VIDPNR or required by current or future applicable requirements.

[VIRR 12-206-71(a)(3)(b)]

4.2.1.3.10 For CO, the Permittee shall perform a stack test during the initial term of the Permittee's Title V operating permit. This requirement shall not apply if a stack test using EPA or VIDPNR approved reference methods has been performed within 2 years of the issuance date of this Title V permit. The Permittee shall retest after the initial term of the Permittee's Title V operating permit to the extent required by (i) the provisions of the applicable local or federal preconstruction permit, or (ii) VIRR Title 12, Chapter 9. In lieu of the testing requirement, the Permittee may use alternative compliance monitoring methods approved by VIDPNR or required by current or future applicable requirements.

[VIRR 12-206-71(a)(3)(b)]

4.2.2 Group 2 – Heaters

4.2.2.1 Group 02C – Heater H-2185

4.2.2.1.1 For CO, PM/PM10, and VOC emissions, the Permittee shall perform a stack test during the initial term of the Permittee's Title V permit. This requirement shall not apply if a stack test using EPA or VIDPNR approved reference methods has been performed within 2 years of the issuance date of the Permittee's Title V permit. The Permittee shall retest after the initial term of the Title V permit to the extend required by (1) the provisions of the local or federal preconstruction permit listed as the source of the limit in the applicable requirement, or (2) VIRR Title 12, Chapter 9. In lieu of the testing requirement, the Permittee may use alternative compliance monitoring methods approved by the VIDPNR or required by current or future applicable requirements.

[VIRR 12-09-206-71(a)(3)(B)]

4.2.2.2 Group 02D – Heater H-4901 (LSG Unit Heater) and Hydrogen Plant Heater

4.2.2.2.1 The Permittee shall conduct performance tests for the LSG unit heater and for the Hydrogen Plant heater. Within 60 days after achieving the maximum production rate of each unit, but no later than 180 days after initial startup as defined in 40 CFR 60.2 and once every five years thereafter (with the exception of those pollutants for which a CEM is required), the Permittee shall submit the results for PM, PM-10, NOx, CO, SO_2 ,and H_2SO_4 .

[LSFP PSD Permit XI.A.1]

4.2.2.2.2 Three test runs shall be conducted for the LSG unit heater and for the Hydrogen Plant heater and compliance shall be based on the average emission rate of these runs.

[LSFP PSD Permit XI.A.2]

4.2.2.2.3 At least At least 60 days prior to actual testing, the Permittee shall submit to the EPA a Quality Assurance Project Plan detailing methods and procedures to be used during the performance stack testing. A Quality Assurance Project Plan that does not have EPA approval may be grounds to invalidate any test and require re-test.

[LSFP PSD Permit XI.A.3]

4.2.2.2.4 The Permittee shall use the following test methods, or a test method which would be applicable at the time of the test and detailed in a test protocol approved by EPA.

[LSFP PSD Permit XI.A.4]

4.2.2.2.5 Performance tests to determine the stack gas velocity, sample area, volumetric flow rate, molecular composition, excess air of flue gases, and moisture content of flue gas shall be conducted using 40 CFR 60, Appendix A, Methods 1, 2, 3, and 4.

[LSFP PSD Permit XI.A.4.a]

4.2.2.2.6 Performance tests for the emissions of PM shall be conducted using 40 CFR 60, Appendix A, Method 5.

[LSFP PSD Permit XI.A.4.b]

4.2.2.2.7 Performance tests for the emissions of PM-10 shall be conducted using 40 CFR 51, Appendix M, Method 201 (exhaust gas recycle), Method 201A (constant flow rate) or Method 5, and Method 202. PM-10 emissions shall be the sum of noncondensable emissions determined using Method 201, 201A or Method 5 and condensable emissions determined using Method 202.

[LSFP PSD Permit XI.A.4.c]

4.2.2.2.8 Performance tests for the emissions of CO shall be conducted using 40 CFR 60, Appendix A, Method 10.

[LSFP PSD Permit XI.A.4.d]

4.2.2.2.9 Performance test for the emissions of NOx shall be conducted using 40 CFR 60, Appendix A, Method 7E.

[LSFP PSD Permit XI.A.4.e]

4.2.2.2.10 Performance tests for the emissions of SO_2 shall be conducted using 40 CFR 60, Method 6 or 6C.

[LSFP PSD Permit XI.A.4.f]

4.2.2.2.11 Performance tests for the emissions of H_2SO_4 shall be conducted using 40 CFR 60, Appendix A, Method 8.

[LSFP PSD Permit XI.A.4.g]

4.2.2.2.12 Permittee shall conduct performance tests for the visual determination of the opacity of emissions from the stack using 40 CFR Part 60, Appendix A, Method 9 and the procedures stated in 40 CFR 60.11, or using a Continuous Opacity Monitoring system meeting the requirements of 40 CFR 60.

[LSFP PSD Permit XI.A.4.h]

4.2.2.2.13 Compliance with the sulfur content standards for liquid and gaseous fuels shall be determined using the testing methods established in 40 CFR 60.335(b)(10) except for refinery fuel gas which shall be monitored for H_2S using the methodology specified in 40 CFR 60 Subpart J.

[LSFP PSD Permit XII.2]

4.2.2.2.14 Test results indicating that emissions are below the limits of detection shall be deemed to be in compliance.

[LSFP PSD Permit XI.A.5]

4.2.2.2.15 Additional performance tests may be required at the discretion of the EPA or VIDPNR for any or all of the above pollutants.

[LSFP PSD Permit XI.A.6]

4.2.2.2.16 For performance test purposes, sampling ports, platforms and access shall be provided by the Permittee on each unit in accordance with 40 CFR 60.8(e).

[LSFP PSD Permit XI.A.7]

4.2.2.2.17 Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test.

[LSFP PSD Permit XI.A.9]

4.2.2.2.18 For the Hydrogen Plant heater and LSG Unit heater, the Permittee shall conduct performance evaluations of the continuous monitoring system during the initial performance testing required under the LSFP PSD permit or within 30 days thereafter in accordance with the applicable performance specifications in 40 CFR 60, Appendix B and 40 CFR 52, Appendix E. The Permittee shall notify the Regional Administrator (RA) at least 15 days in advance of the date upon which demonstration of the monitoring system(s) performance will commence.

[LSFP PSD Permit X.7]

4.2.2.3 Group 02E – Heaters H-7801, H-7802, and R-7801 and Stack STK-7801

4.2.2.3.1 The Permittee shall determine PM/PM10 emissions according to EPA Reference Method (RM) 5 based on the average value of 3

successive test runs using a test protocol approved by EPA.
[1997 PSD Permit (III)(A)]

4.2.2.3.2 For PM, CO, and VOC, the Permittee must perform a stack test during the initial term of its Title V permit. This requirement shall not apply if a stack test using EPA or VIDPNR approved reference methods has been performed within 2 years of the issuance date of the Permittee's Title V permit. The Permittee shall retest after the initial term of its Title V permit to the extent required by (i) the provisions of the local or federal preconstruction permit listed as the source of the limit or (ii) VIRR Title 12, Chapter 9. In lieu of the testing requirement, the Permittee may use alternative compliance monitoring methods approved by the VIDPNR or required by current or future applicable requirements.
[VIRR 12-09-206-71(a)(3)(B)]

4.2.2.3.3 For NOx, the Permittee must perform a stack test during the initial term of its Title V permit. This requirement shall not apply if a stack test using EPA or VIDPNR approved reference methods has been performed within 2 years of the issuance date of the Permittee's Title V permit. The Permittee shall retest after the initial term of its Title V operating permit to the extent required by (i) the provisions of the local or federal preconstruction permit listed as the source of the limit, or (ii) VIRR Title 12, Chapter 9, or (iii) once during each five year period following the initial term of its Title V permit. In lieu of the testing requirement, the Permittee may use alternative compliance monitoring methods approved by the VIDPNR or required by current or future applicable requirements.
[VIRR 12-09-206-71(a)(3)(B)

4.2.2.4 Group 02F – Incinerators H-1032, H-1042, and H-4745

See sections 4.2.6.2.1 and 4.2.7.3.

4.2.2.5 Group 02G – Heaters H-8501A and H-8501B

4.2.2.5.1 For NOx, the Permittee shall perform a stack test during the initial term of the Permittee's Title V operating permit. This requirement shall not apply if a stack test using EPA or VIDPNR approved reference methods has been performed within 2 years of the issuance date of this Title V permit. The Permittee shall retest after the initial term of the Permittee's Title V operating permit to the extent required by (i) the provisions of the applicable local or federal preconstruction permit, or (ii) VIRR Title 12, Chapter 9, or (iii) once during each five year period following the initial term of the Permittee's Title V permit. In lieu of the testing requirement, the

Permittee may use alternative compliance monitoring methods approved by VIDPNR or required by current or future applicable requirements.

[VIRR 12-206-71(a)(3)(b)]

4.2.2.5.2 For CO, VOC, and PM/PM10, the Permittee shall perform a stack test during the initial term of the Permittee's Title V operating permit. This requirement shall not apply if a stack test using EPA or VIDPNR approved reference methods has been performed within 2 years of the issuance date of this Title V permit. The Permittee shall retest after the initial term of the Permittee's Title V operating permit to the extent required by (i) the provisions of the applicable local or federal preconstruction permit, or (ii) VIRR Title 12, Chapter 9. In lieu of the testing requirement, the Permittee may use alternative compliance monitoring methods approved by VIDPNR or required by current or future applicable requirements.

[VIRR 12-206-71(a)(3)(b)]

4.2.3 Group 3 – Compressor Engines

4.2.3.1 For C-200A, C-200B, C-200C, C-2400A, and C-2400B, the Permittee shall comply with the performance testing requirements, as applicable, in 40 CFR 63.6610 through 63.6640, and 63.6665, as applicable.

[40 CFR 63, Subpart ZZZZ - 63.6610 through 63.6640, and 63.6665]

4.2.3.2 The Permittee shall test the catalytic converters installed on the two compressor engines located on #5DD and the three compressors located at the Penex Unit once a quarter (calendar quarter) to certify compliance with permit conditions.

[STX-557-A-E-02(X)(J), June 4, 2002]

4.2.4 Group 4 – Combustion Turbines

4.2.4.1 Group 04A – Turbines G-1101E, G-1101F, G-1101G, G-3404, G-3405, G-3406, G-3407, G-3408, G-3409, and G-3410

4.2.4.1.1 For G-3410, within 60 days after achieving the maximum production rate of GT No. 10 (G-3410), but no later than 180 days after initial startup as defined in 40 CFR 60.2, and at such other times as specified by EPA, the Permittee shall conduct performance tests for SO_2, NOx, PM10, CO, and opacity. All performance tests shall be conducted at the operating capacity of the unit being tested, except for CO, and/or other loads specified by EPA. Test results indicating that emissions are below the limits of detection shall be deemed to be in compliance. Additional performance tests may be required at the discretion of the EPA or VIDPNR for any or all of the above pollutants. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test.

[GT-10 PSD Permit (XI)(1), (4), (5), and (8)]

4.2.4.1.2 For performance test purposes for G-3410, sampling ports, platforms, and access shall be provided by the Permittee on the combustion exhaust system in accordance with 40 CFR 60.8(e).

[GT-10 PSD Permit (XI)(6)]

4.2.4.1.3 The steam or water to fuel ratio or other parameters that are continuously monitored shall be monitored during the performance test required under 40 CFR 60.8, to establish acceptable values and ranges.

[40 CFR 60.334(g)]

4.2.4.1.4 For G-3410, for PM, the Permittee must perform a stack test during the initial term of its Title V permit. This requirement shall not apply if a stack test using EPA or VIDPNR approved reference methods has been performed within 2 years of the issuance date of the Permittee's Title V permit. The Permittee shall retest after the initial term of its Title V permit to the extent required by (i) the provisions of the local or federal preconstruction permit listed as the source of the limit or (ii) VIRR Title 12, Chapter 9. In lieu of the testing requirement, the Permittee may use alternative compliance monitoring methods approved by the VIDPNR or required by current or future applicable requirements.

[VIRR 12-09-206-71(a)(3)(B)]

4.2.4.1.5 For G-3410, if a performance test is required by EPA or VIDPNR, the Permittee shall use the following test methods, or a test method which would be applicable at the time of the test and detailed in a test protocol approved by EPA:

4.2.4.1.5.1 Stack gas velocity, sample area, volumetric flowrate, molecular composition, excess air of flue gases, and moisture content of flue gas shall be conducted using 40 CFR 60, Appendix A, Methods 1, 2, 3, and 4.

4.2.4.1.5.2 SO_2 testing shall be conducted using 40 CFR 60, Appendix A, Method 20.

4.2.4.1.5.3 NOx testing shall be conducted using 40 CFR 60, Appendix A, Method 20.

4.2.4.1.5.4 PM10 testing shall be conducted using 40 CFR 51, Appendix M, Method 201 (exhaust gas recycle) and Method 202 or Method 201A (constant flow rate) and Method 202.

4.2.4.1.5.5 CO testing shall be conducted using 40 CFR 60, Appendix A, Method 10.

4.2.4.1.5.6 Opacity testing shall be conducted using 40 CFR 60, Appendix A, Method 9 and the procedures stated in 40 CFR 60.11.

[GT-10 PSD Permit (XI)(3)]

4.2.4.1.6 For G-3409, for NOx, the Permittee shall perform a stack test during the initial term of the Permittee's Title V operating permit. This requirement shall not apply if a stack test using EPA or VIDPNR approved reference methods has been performed within 2 years of the issuance date of this Title V permit. The Permittee shall retest after the initial term of the Permittee's Title V operating permit to the extent required by (i) the provisions of the applicable local or federal preconstruction permit, or (ii) VIRR Title 12, Chapter 9, or (iii) once during each five year period following the initial term of the Permittee's Title V permit. In lieu of the testing requirement, the Permittee may use alternative compliance monitoring methods approved by VIDPNR or required by current or future applicable requirements.

[VIRR 12-206-71(a)(3)(b)]

4.2.4.1.7 For G-3409, for CO and PM10, the Permittee shall perform a stack test during the initial term of the Permittee's Title V operating permit. This requirement shall not apply if a stack test using EPA or VIDPNR approved reference methods has been performed within 2 years of the issuance date of this Title V permit. The Permittee shall retest after the initial term of the Permittee's Title V operating permit to the extent required by (i) the provisions of the applicable local or federal preconstruction permit, or (ii) VIRR Title 12, Chapter 9. In lieu of the testing requirement, the Permittee may use alternative compliance monitoring methods approved by VIDPNR or required by current or future applicable requirements.

[VIRR 12-206-71(a)(3)(b)]

4.2.4.2 Group 04B – G-3413 (GT. No. 13) and Associated Duct Burner H-3413

4.2.4.2.1 Compliance with the sulfur content standards for liquid and gaseous fuels shall be determined using the testing methods established in 40 CFR 60.335(b)(10) except for refinery fuel gas which shall be monitored for H_2S using the methodology specified in 40 CFR 60, Subpart J.

[LSFP PSD Permit XII.2]

4.2.4.2.1.1 Liquid fuel samples shall be collected and analyzed initially and annually.

[40 CFR 60.4365(b)]

4.2.4.2.2 The Permittee shall conduct performance tests for GT No. 13 (G-3413). Within 60 days after achieving the maximum production rate of each unit, but no later than 180 days after initial startup as defined in 40 CFR 60.2, and once every five years thereafter (with the exception of those pollutants for which a CEM is required), the Permittee shall submit the results of the performance tests for PM, PM-10, NOx, CO, SO_2, and H_2SO_4. All performance tests shall be conducted at base load conditions, with and without firing the HRSG (for GT No. 13 (G-3413)), 60% load conditions and/or other loads specified by EPA.

[LSFP PSD Permit XI.A.1]

4.2.4.2.3 Three test runs shall be conducted for each load condition and compliance shall be based on the average emission rate of these runs.

[LSFP PSD Permit XI.A.2]

4.2.4.2.4 At least At least 60 days prior to actual testing, the Permittee shall submit to the EPA a Quality Assurance Project Plan detailing methods and procedures to be used during the performance stack testing. A Quality Assurance Project Plan that does not have EPA approval may be grounds to invalidate any test and require re-test.

[LSFP PSD Permit XI.A.3]

4.2.4.2.5 The Permittee shall use the following test methods, or a test method which would be applicable at the time of the test and detailed in a test protocol approved by EPA.

[LSFP PSD Permit XI.A.4]

4.2.4.2.6 Performance tests to determine the stack gas velocity, sample area, volumetric flow rate, molecular composition, excess air of flue gases, and moisture content of flue gas shall be conducted using 40 CFR 60, Appendix A, Methods 1, 2, 3, and 4.

[LSFP PSD Permit XI.A.4.a]

4.2.4.2.7 Performance tests for the emissions of PM shall be conducted using 40 CFR 60, Appendix A, Method 5.

[LSFP PSD Permit XI.A.4.b]

4.2.4.2.8 Performance tests for the emissions of PM-10 shall be conducted using 40 CFR 51, Appendix M, Method 201 (exhaust gas recycle), Method 201A (constant flow rate) or Method 5, and Method 202.

PM-10 emissions shall be the sum of noncondensible emissions determined using Method 201, 201A or Method 5 and condensable emissions determined using Method 202.
[LSFP PSD Permit XI.A.4.c]

4.2.4.2.9 Performance tests for the emissions of CO shall be conducted using 40 CFR 60, Appendix A, Method 10.
[LSFP PSD Permit XI.A.4.d]

4.2.4.2.10 Performance test for the emissions of NOx shall be conducted using 40 CFR 60, Appendix A, Method 7E.
[LSFP PSD Permit XI.A.4.e]

4.2.4.2.11 Performance tests for the emissions of SO_2 shall be conducted using 40 CFR 60, Method 6 or 6C.
[LSFP PSD Permit XI.A.4.f]

4.2.4.2.12 Performance tests for the emissions of H_2SO_4 shall be conducted using 40 CFR 60, Appendix A, Method 8.
[LSFP PSD Permit XI.A.4.g]

4.2.4.2.13 Permittee shall conduct performance tests for the visual determination of the opacity of emissions from the stack using 40 CFR Part 60, Appendix A, Method 9 and the procedures stated in 40 CFR 60.11, or using a Continuous Opacity Monitoring system meeting the requirements of 40 CFR 60.

[LSFP PSD Permit XI.A.4.h]

4.2.4.2.14 Compliance with the sulfur content standards for liquid and gaseous fuels shall be determined using the testing methods established in 40 CFR 60.335(b)(10) except for refinery fuel gas which shall be monitored for H_2S using the methodology specified in 40 CFR 60 Subpart J.
[LSFP PSD Permit XII.2]

4.2.4.2.15 Test results indicating that emissions are below the limits of detection shall be deemed to be in compliance.
[LSFP PSD Permit XI.A.5]

4.2.4.2.16 Additional performance tests may be required at the discretion of the EPA or VIDPNR for any or all of the above pollutants.
[LSFP PSD Permit XI.A.6]

4.2.4.2.17 For performance test purposes, sampling ports, platforms and access shall be provided by the Permittee on each unit in accordance with 40 CFR 60.8(e).

[LSFP PSD Permit XI.A.7]

4.2.4.2.18 Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test.

[LSFP PSD Permit XI.A.9]

4.2.4.2.19 The Permittee shall conduct performance evaluations of the continuous monitoring system during the initial performance testing required under the LSFP PSD permit or within 30 days thereafter in accordance with the applicable performance specifications in 40 CFR 60, Appendix B and 40 CFR 52, Appendix E. The Permittee shall notify the Regional Administrator (RA) at least 15 days in advance of the date upon which demonstration of the monitoring system(s) performance will commence.

[LSFP PSD Permit X.7]

4.2.4.2.20 Within 120 days after achieving normal operation of GT No. 13 (G-3413), the Permittee shall perform PM and PM-10 testing on GT No. 13 using EPA Reference Method 5 for PM and Methods 201A and 202 for PM-10. Within 60 days of performing the test, LIMETREE BAY TERMINALS LLC shall submit a test report to EPA and propose new PM/PM-10 limits which will be less than or equal to the values identified in 3.2.4.2.20 and 3.2.4.2.21. Upon approval, and if applicable, EPA will administratively amend the LSFP PSD Permit to reflect the new limit(s).

[LSFP PSD Permit VIII.A.3]

4.2.4.2.21 The Permittee shall comply with the performance testing requirements, as applicable, in 40 CFR 60.4333 through 60.4370, 60.4380, 60.4385, and 60.4400 through 60.4415.

[40 CFR 60, Subpart KKKK]

4.2.4.2.22 For G-3413, the Permittee conduct performance tests for formaldehyde initially and annually. The Permittee may bypass the oxidation catalyst during startups, shutdowns, and malfunctions. The oxidation catalyst may be bypassed during normal operation only when G-3413 is 100% gas-fired. The Permittee shall comply with the requirements of 40 CFR 63.6105 through 63.6140 and with 63.6165, as applicable.

[40 CFR 63, Subpart YYYY – 63.6105 through 63.6140, and 63.6165]

4.2.5 Group 5 – Flares

4.2.5.1 For the #6 Flare, the Permittee shall comply with the testing requirements, test methods, and procedures in 40 CFR 63.162 through 180, as applicable.
[40 CFR 63.162 through 180]

4.2.6 Group 6 – Loading Racks

4.2.6.1 Group 06A – Truck Loading

4.2.6.1.1 Within six months of the VRU startup, the Permittee shall conduct a stack test under normal loading conditions in accordance with EPA approved test methods in 40 CFR Part 60, Appendix A. [Condition was satisfied by performance test conducted on Marc h 28, 2001].
[STX-557-H-00(III)(A), September 18, 2000]

4.2.6.2 Group 06B – Marine Loading

4.2.6.2.1 The procedures for determining compliance with 40 CFR 61.302(b) for the incinerator are as follows:

4.2.6.2.1.1 All testing equipment shall be prepared and installed as specified in the appropriate test methods.

4.2.6.2.1.2 The time period for a performance test shall be not less than 6 hours, during which at least 300,000 liters of benzene are loaded. If the throughput criterion is not met during the initial 6 hours, the test may be either continued until the throughput criterion is met, or resumed the next day with at least another 6 complete hours of testing.

4.2.6.2.1.3 An emission testing interval shall consist of each 5-minute period during the performance test. For each interval: the reading from each measurement instrument shall be recorded; Method 1 or 1A of 40 CFR 60, Appendix A, as appropriate, shall be used for selection of the sampling site; the volume exhausted shall be determined using Method 2, 2A, 2C, or 2D of 40 CFR 60, Appendix A, as appropriate; and the average benzene concentration upstream and downstream of the control device in the vent shall be determined using Method 25A or Method 25B of 40 CFR 60, Appendix A, using benzene as the calibration gas. The average benzene concentration shall correspond to the volume measurement by taking into account the sampling system response time.

4.2.6.2.1.4 The mass emitted during each testing interval shall be calculated as follows:

$$M_i = FKV_SC$$

where:

M_i=Mass of benzene emitted during testing interval i, kg
V_s=Volume of air-vapor mixture exhausted, m^3 at standard conditions
C=Benzene concentration (as measured) at the exhaust vent, ppmv
K=Density, (kg/m^3 benzene), standard conditions
K=3.25 for benzene
F=Conversion factor, (m^3 benzene/m^3 air)(1/ppmv)
F=$10/^{-6}/$
s=Standard conditions, 20 °C and 760 mm Hg

4.2.6.2.1.5 The benzene mass emission rates before and after the control device shall be calculated as follows:

$$E = \frac{\sum_{i=1}^{n} M_i}{T}$$

where:

E=Mass flow rate of benzene emitted, kg/hr.
M_i=Mass of benzene emitted during testing interval i, kg.
T=Total time of all testing intervals, hr.
n=Number of testing intervals.

4.2.6.2.1.6 The percent reduction across the control device shall be calculated as follows:

$$R = \frac{E_b - E_a}{E_b}(100)$$

where:

R=Control efficiency of control device, %.
E_b=Mass flow rate of benzene prior to control device, kg/hr.
E_a=Mass flow rate of benzene after control device, kg/hr.
[40 CFR 61.304(a)]

4.2.6.2.2 For the purpose of determining compliance with section 3.2.6.2.4, the following procedures shall be used:

4.2.6.2.2.1 Calibrate and install a pressure measurement device (liquid manometer, magnehelic gauge, or equivalent instrument), capable of measuring up to the relief set pressure of the pressure-vacuum vents.

4.2.6.2.2.2 Connect the pressure measurement device to a pressure tap in the affected facility's vapor collection system, located as close as possible to the connection with the marine vessel.

4.2.6.2.2.3 During the performance test, record the pressure every 5 minutes while a marine vessel is being loaded, and record the highest instantaneous pressure that occurs during each loading cycle.

[40 CFR 61.304(d)]

4.2.6.2.3 Immediately prior to a performance test required for determination of compliance with section 3.2.6.2.2, all potential sources of vapor leakage in the affected facility's vapor collection system equipment shall be inspected for detectable emissions as required in 40 CFR 61.302(k). The monitoring shall be conducted only while a vapor-tight tank truck, railcar, or marine vessel is being loaded. All identified leaks in the terminal's vapor collection system shall be repaired prior to conducting the performance test.

[40 CFR 61.304(e)]

4.2.7 Group 7 – Sulfur Recovery

4.2.7.1 For T-1061, the Permittee shall comply with applicable test methods and procedures in 40 CFR 60.106(f)(2) and (3).

[40 CFR 60.106(f)]

4.2.7.2 The Permittee shall comply with the test methods and procedures in 40 CFR 63, Subpart UUU as specified in the OMM Plan for West Sulfur Recovery (for T-1061 and bypass lines).

[OMM Plan for West Sulfur Recovery]

4.2.7.3 The Permittee shall comply with the test methods and procedures in 40 CFR 63, Subpart UUU as specified in the OMM Plan for East Sulfur Recovery (for T-4761, H-4745, and bypass lines).

[OMM Plan for East Sulfur Recovery]

4.2.8 Group 8 – Internal Floating Roof Tanks

None.

4.2.9 Group 9 – External Floating Roof Tanks

None.

4.2.10 Group 10 – Fixed Roof Tanks

None.

4.2.11 Group 11 – Horizontal Tanks

None.

4.2.12 Group 12 – Geodesic Dome Tanks

None.

4.2.13 Group 13 – Wastewater Treatment

4.2.13.1 The Permittee shall demonstrate that each control device, except for a flare, achieves the appropriate conditions specified in section 3.2.13.2 by using one of the following methods:

4.2.13.1.1 Engineering calculations in accordance with requirements specified in 40 CFR 61.356(f); or

4.2.13.1.2 Performance tests conducted using the test methods and procedures that meet the requirements specified in 40 CFR 61.355.

[40 CFR 61.349 (c)]

4.2.13.2 The Administrator may request at any time that an owner or operator demonstrate that a control device meets the applicable conditions specified in section 3.2.13.2 by conducting a performance test using the test methods and procedures as required in 40 CFR 61.355.

[40 CFR 61.349 (e)]

4.2.13.3 For waste streams subject to the requirements of section 3.2.13.4, the Permittee shall demonstrate that each treatment process or wastewater treatment system unit achieves the appropriate conditions specified in sections 3.2.13.4.1 through 3.2.13.4.5 or 3.2.13.4.6 in accordance with the following requirements:

4.2.13.3.1 Engineering calculations in accordance with requirements specified in 40 CFR 61.356(e); or

4.2.13.3.2 Performance tests conducted using the test methods and procedures that meet the requirements specified in 40 CFR 61.355.

[40 CFR 61.348 (c)]

4.2.13.4 The Permittee shall comply, as applicable, with the performance test requirements of 40 CFR 60.695 and 60.696.

[40 CFR 60, Subpart QQQ; 40 CFR 60.696]

4.2.14 Group 14 – Alkylation and Dimersol Units

4.2.14.1 For distillation unit vent streams, the Permittee shall comply with EPA-approved alternative monitoring requirements for Alkylation and Dimersol NSPS Subpart NNN affected facilities in accordance with provisions of 40 CFR 60.13.

[40 CFR 60.13(i)]

4.2.14.2 For reactor process vent streams, the Permittee shall comply with the requirements of 40 CFR 60.704, as applicable.

[40 CFR 60.704]

4.2.15 Group 15 – Seawater Intake Pumps

None.

4.2.16 Group 16 – FCCU

4.2.16.1 For STK-7051, compliance with the sulfur content standard for the FCCU feed shall be determined using the testing methods established in 40 CFR 60.106(j).

[LSFP PSD Permit XII.3]

4.2.16.1.1 Liquid feed samples shall be collected and analyzed daily.

[VIRR 12-09-206-71(a)(3)(B)]

4.2.16.2 For STK-7051, performance tests for the emissions of PM shall be conducted using 40 CFR 60, Appendix A, Method 5B or 5F.

[LSFP PSD Permit XI.B.1.b]

4.2.16.3 For STK-7051, the Permittee shall determine compliance with the particulate matter limit and the coke burn-off rate in 40 CFR 60.102 (a)(1) according to the methods and equations in 40 CFR 60.106(b).

[40 CFR 60.106(b)]

4.2.16.4 For STK-7051, performance tests for the emissions of PM-10 shall be conducted using 40 CFR 60, Appendix A, Method 5B or 5F or Method 201 or 201A in 40 CFR 51, Appendix M; and 40 CFR 51, Appendix M, Method 202. PM-10 emissions shall be the sum of noncondensible emissions determined using Method 5B, 5F, 201, or 201A and condensable emissions determined using Method 202.

[LSFP PSD Permit XI.B.1.c]

4.2.16.5 For STK 7051, performance tests for the emissions of SO_2 shall be conducted using 40 CFR 60, Method 6 or 6C. Such tests shall be conducted simultaneously, upstream and downstream of the venturi scrubber.

[LSFP PSD Permit XI.B.1.a]

4.2.16.6 For STK-7051, performance tests for the visual determinations of the opacity of emissions from the stack shall be conducted using 40 CFR 60, Appendix A, Method 9 and the procedures stated in 40 CFR 60.11.

[LSFP PSD Permit XI.B.1.d]

4.2.16.7 The FCCU coke burn-off rate shall be calculated from the FCCU regenerator flue gas composition. The flue gas will be analyzed daily by EPA RM 3/3A or an equivalent analytical method approved by EPA. The flue gas will be analyzed for the following parameters: CO, CO_2, O_2, and inerts (Ar, N_2). The water content will be determined by a psychometric chart. These data shall be input to the unit's computer and be used to calculate the coke burn-off rate for determining compliance with condition 3.2.16. 7 by the following steps:

4.2.16.7.1 Continuously measure the air flow to the regenerator.

4.2.16.7.2 Calculate dry air flow rate with psychometric chart.

4.2.16.7.3 Adjust the regenerator flue gas oxygen analysis for argon (if GC method used). Argon is inert and should not be included in the oxygen balance calculations (see section 4.2.16.7.5 below).

4.2.16.7.4 Calculate the coke carbon content by knowing that 1 mol carbon is burned for each mol of CO or CO_2 produced. The CO and CO_2 concentrations are determined by analysis of flue gas.

4.2.16.7.5 Calculate coke hydrogen content by an oxygen balance between the regenerator air concentration and the flue gas excess oxygen content.

4.2.16.7.6 Calculate the hourly coke burn-off rate by adding the coke carbon and hydrogen contents. The daily average coke burn-off shall be calculated and reported as a rolling average for any 24-hour period.

[LSFP PSD Permit X.2.a through f]

4.2.16.8 Within 60 days after achieving the maximum production rate of the FCCU, but no later than 180 days after the compressor engines in the Nos. 2 and 4 Distillate Desulfurizer Units are permanently removed from service, and once every five years thereafter, the Permittee shall conduct and submit the results of the performance tests for SO_2, PM and PM-10 in accordance with the test methods specified in this subsection (or a test method which would be applicable at the time of the test and detailed in a test protocol approved by EPA).

[LSFP PSD Permit XI.B.1]

4.2.16.9 Three test runs shall be conducted and compliance shall be based on the average emission rate of these runs.

[LSFP PSD Permit XI.B.2]

4.2.16.10 Test results indicating that emissions are below the limits of detection shall be deemed to be in compliance.

[LSFP PSD Permit XI.B.4]

4.2.16.11 Additional performance tests may be required at the discretion of the EPA or VIDPNR for any or all of the above pollutants.

[LSFP PSD Permit XI.B.5]

4.2.16.12 For performance test purposes, sampling ports, platforms, and access shall be provided by the Permittee on each unit in accordance with 40 CFR 60.8(e).

[LSFP PSD Permit XI.B.6]

4.2.16.13 Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test.

[LSFP PSD Permit XI.B.8]

4.2.17 Group 17 – Coker Complex

4.2.17.1 The Permittee shall conduct all formal performance tests in accordance with the following

4.2.17.1.1 The Permittee shall conduct stack tests at the coker complex on all affected pollutants in accordance with the test methods published in 40 CFR 60, Appendix A. The Permittee shall conduct all tests within 60 days after achieving shakedown, but no later than 180 days after initial start-up.

[STX-557A-E-02(XI)(A), June 4, 2002]

4.2.17.1.2 The Permittee shall obtain all approvals of stack test protocols. The Permittee shall submit to the EPA a detailed description of the sampling point locations, sampling equipment, sampling and analytical procedures, data reporting forms, quality assurance procedures, and operating conditions for such tests.

[STX-557A-E-02(XI)(B), June 4, 2002]

4.2.17.1.3 The Permittee shall notify EPA and VIDPNR at least 30 days prior to actual testing.

[STX-557A-E-02(XI)(C), June 4, 2002]

4.2.17.1.4 The Permittee shall provide permanent sampling and testing facilities as may be required by the EPA to determine the nature and quantity of emissions from each unit. Such facilities shall conform with all applicable laws and regulations concerning safe construction and safe practice.

[STX-557A-E-02(XI)(D), June 4, 2002]

4.2.17.1.5 The EPA reserves the right to require additional stack testing of the pollutants of which an emission limitation has been set in permit no. STX-557A-E-02.

[STX-557A-E-02(XI)(E), June 4, 2002]

4.2.18 Group 18 – Sulfuric Acid Plant Stack STK-7802

4.2.18.1 The Permittee shall determine SO_2 emissions according to EPA Reference Method (RM) 6C based on the average value of 3 successive test runs, or the NSPS Method which would be applicable at the time of the test following a test protocol approved by EPA.

[1997 PSD Permit (II)(B)]

4.2.18.2 The Permittee shall determine NOx emissions according to EPA Reference Method (RM) 7E based on the average value of 3 successive test runs, or the NSPS Method which would be applicable at the time of the test following a test protocol approved by EPA.

[1997 PSD Permit (II)(C)]

4.2.18.3 The Permittee shall determine sulfuric acid mist and SO_3 emissions (as defined by 40 CFR 60) according to EPA Reference Method (RM) 8 based on the average value of 3 successive test runs, or the NSPS Method which would be applicable at the time of the test following a test protocol approved by EPA.

[1997 PSD Permit (II)(D)]

4.2.18.4 The Permittee shall make annual visual emission observations in accordance with RM 9.

[1997 PSD Permit (II)(E)]

4.2.19 Group 19 – Vapor Enhanced Recovery

None.

4.2.20 Group 20 – Gasoline Service Station and Fuel Gas System

None.

4.2.21 Group 21 – Amine Units, Merox Unit, and Gas Concentration

None.

4.2.22 Group 22 – Gas Treating and Stripping

None.

4.2.23 Group 23 – Hydrogen Recovery

None.

4.2.24 Group 24 – Disulfide Handling

None.

4.2.25 Group 25 – Platformers

4.2.25.1 The Permittee shall comply with the applicable test methods and procedures in the current Operations, Maintenance, and Monitoring Plans for #2, #3, and #4 Platformers during catalyst regenerations.

[40 CFR 63, Subpart UUU – 63.1566 and 63.1567]

PART 5.0 REQUIREMENTS FOR MONITORING (Related to Data Collection)

Table 2 in Part 1 provides a summary by individual emission unit or emission unit grouping of the specific location within this Title V permit of each emission or operational limitation and of the testing, monitoring, recordkeeping, and reporting requirements that apply to that emission or operational limitation.

5.1 General Monitoring Requirements

None.

5.2 Specific Monitoring Requirements

5.2.1 Group 1 – Boilers

5.2.1.1 For all boilers, the Permittee shall perform daily visual observations for opacity.

[VIRR 12-09-206-71(a)(3)(B)]

5.2.1.2 For all boilers except B-3701, the Permittee shall monitor the H_2S content of all refinery gas burned.

[1977 PSD Permit (VI)(C)(h)]

5.2.1.3 The analysis (including colorimetric tubes) of daily grab samples from collection points (or other representative sample locations) in the refinery fuel gas system may be used to comply with this requirement. Analysis shall only be required for refinery fuel gas and shall not be required for propane, butane, and other gases at the refinery that are inherently low in H_2S.

[VIRR 12-09-206-71(a)(3)(B)]

5.2.1.4 For all boilers, the Permittee shall monitor the sulfur content of all fuel oil burned.

[1997 PSD Permit (VI)(C)(g)]

5.2.1.5 Group 01A – Boilers B-1151, B-1153, B-1154, B-1155

5.2.1.5.1 The Permittee shall verify that the sulfur content of the oil is low enough (using applicable AP-42 emission factors) to ensure compliance with the allowable PM emission rate in section 3.1.1.2.1, or use another approved emissions measurement method.

[VIRR 12-09-206-71(a)(3)(B)]

5.2.1.5.2 The Permittee shall monitor fuel oil usage for each operating scenario.

[1997 PSD Permit (VI)(C)]

5.2.1.5.3 For B-1155, the Permittee shall comply, as applicable, with the monitoring requirements of 40 CFR 60, Subpart A and 40 CFR 60.45 (NSPS Subpart D – Emissions and Fuel Monitoring).

[40 CFR 60 Subpart A; 40 CFR 60.45]

5.2.1.6 Group 01B – Boilers B-3301, B-3302, B-3303, B-3304

5.2.1.6.1 The Permittee shall verify that the sulfur content of the oil is low enough (using applicable AP-42 emission factors) to ensure compliance with the allowable PM emission rate in 3.1.1.3.1, or use another approved emissions measurement method.

[VIRR 12-09-206-71(a)(3)(B)]

5.2.1.6.2 The Permittee shall verify that the sulfur content of the oil is low enough to ensure compliance with the allowable PM emission rate in section 3.1.1.3.1, or use another approved emissions measurement method.

[VIRR 12-09-206-71(a)(3)(B)]

5.2.1.6.3 The Permittee shall monitor fuel oil usage for each operating scenario.

[1997 PSD Permit (VI)(C)]

5.2.1.6.4 For Boilers B-3303 and B-3304 only, the Permittee shall comply, as applicable, with the monitoring requirements of 40 CFR 60, Subpart A and 40 CFR 60.45 (NSPS Subpart D – Emissions and Fuel Monitoring), as applicable.

[40 CFR 60, Subpart A; 40 CFR 60.45]

5.2.1.7 Group 01C – Boiler B-3701

5.2.1.7.1 The Permittee shall comply, as applicable, with the monitoring requirements in 40 CFR 60, Subpart Db.

[40 CFR 60.47b through 60.48b]

5.2.1.7.2 Compliance with the NOx emission standard shall be determined through performance tests as required under 40 CFR 60.8, and by using the continuous system for monitoring NOx and O2 under 40 CFR 60.48(b).

[40 CFR 60.46b(c) and (e)]

5.2.1.7.3 The Permittee shall continuously monitor the H_2S in the fuel gases before being burned in a combustion device. The continuous emission monitor shall meet the requirements in 40 CFR 60.105 and 40 CFR 60.106.

[40 CFR 60.105(a)(4)]

5.2.1.7.4 In lieu of the above H_2S monitoring requirements, the Permittee may instead comply with EPA-approved alternative monitoring requirements or exemption from monitoring for combusted fuel gas streams, as applicable, in accordance with provisions of 40 CFR 60.13(i) or 60.105(b).

[40 CFR 60.13(i); 40 CFR 60.105(b)]

5.2.1.7.5 In lieu of 40 CFR 60, Subpart J span requirements, the Permittee may use a lower span, per Appendix B of 40 CFR 60.

[40 CFR 60]

5.2.1.7.6 The fuel gas supply to Boiler B-3701 shall be equipped with a continuous H_2S analyzer.

[STX-557-I-00 (III)(A), September 18, 2000]

5.2.1.7.7 The Permittee shall calibrate and test the H_2S analyzer in accordance with EPA performance and siting specifications of 40 CFR 60, Appendix B, Performance Specifications 1-4.

[STX-557-I-00 (III)(B), September 18, 2000]

5.2.1.7.8 The Permittee shall equip the H_2S analyzer with data recording equipment to ensure that the fuel gas supply to the boiler is recorded on a continuous basis.

[STX-557-I-00 (III)(C), September 18, 2000]

5.2.1.7.9 The boiler shall demonstrate compliance with monitoring, recording, and reporting as required by 40 CFR 60, Subpart J for petroleum refineries, 40 CFR 60.100, et seq.

[STX-557-I-00 (III)(E), September 18, 2000]

5.2.2 Group 2 – Heaters

5.2.2.1 For all heaters except H-4901, the Hydrogen Plant heater, H-8501A, H-8501B, and H-3413, the Permittee shall monitor and maintain records of the H_2S content of all refinery gas burned.

[1997 PSD Permit (VI)(C)(h)]

5.2.2.2 Group 02A – Heaters H-101, H-104, H-401A, H-401B, H-401C, H-1401A, H-1401B, H-2101, H-2102, H-3101A, H-3101B, H-4101A, H-4101B, H-4201, H-4202

5.2.2.2.1 The Permittee shall verify that the sulfur content of the oil is low enough (using applicable AP-42 emission factors) to ensure compliance with the allowable PM emission rate in Section 3.1.2.1.1, or use another approved emissions measurement method.

[VIRR 12-09-206-71(a)(3)(B)]

5.2.2.2.2 The Permittee shall monitor the sulfur content of all fuel oil burned.
[1997 PSD Permit (VI)(C)(g)]

5.2.2.2.3 The Permittee's compliance with the 1997 PSD Permit requirements for particulate matter emissions shall constitute compliance with the allowable particulate matter emissions under section 3.1.2.1.1 of this permit.
[VIRR 12-09-206-71(a)(3)(B)]

5.2.2.2.4 The Permittee shall perform daily visual observations for opacity.
[VIRR 12-09-206-71(a)(3)(B)]

5.2.2.2.5 The Permittee shall monitor fuel oil usage for each operating scenario.
[1997 PSD Permit (VI)(C)]

5.2.2.2.6 For H-3101A, H-3101B, H-4101A, and H-4101B, the Permittee shall continuously monitor the H_2S in the fuel gases before being burned in a combustion device. The continuous emission monitor shall meet the requirements in 40 CFR 60.105 and 40 CFR 60.106.
[40 CFR 60.105(a)(4)]

5.2.2.2.7 For H-3101A, H-3101B, H-4101A, and H-4101B, in lieu of the above H_2S monitoring requirements, the Permittee may instead comply with EPA-approved alternative monitoring requirements or exemption from monitoring for combusted fuel gas streams, as applicable, in accordance with provisions of 40 CFR 60.13(i) or 60.105(b).
[40 CFR 60.13(i); 40 CFR 60.105(b)]

5.2.2.3 Group 02B – Heaters H-160, H-200, H-201, H-202, H-600, H-601, H-602, H-603, H-604, H-605, H-606, H-800A, H-800B, H-801, H-1500, H-1501, H-2201A, H-2201B, H-2202, H-2400, H-2401, H-2501, H-4301A, H-4301B, H-4302, H-4401, H-4402, H-4451, H-4452, H-4453, H-4454, H-4455, H-4502, H-4503, H-4504, H-4505, H-4601A, H-4601B, H-4602, H-5301A, H-5301B, H-5302 H-5401, H-5402, H-5451, H-5452, H-5453, H-5454, H-5455

5.2.2.3.1 The Permittee shall perform daily visual observations for opacity.
[VIRR 12-09-206-71(a)(3)(B)]

5.2.2.4 Group 02C – Heater H-2185

5.2.2.4.1 The Permittee shall monitor opacity continuously by a Continuous Opacity Monitor (COM).
[1997 PSD Permit (III)(B)(f); 1997 PSD Permit (VI)(A)]

5.2.2.4.2 The Permittee shall use a Continuous Emissions Monitor (CEM) to monitor NOx and O2.

[1997 PSD Permit (VI)(A)]

5.2.2.4.3 The Permittee shall monitor fuel usage.

[VIRR 12-09-206-71(a)(3)(B)]

5.2.2.4.4 The Permittee shall continuously monitor H_2S (in lieu of SO_2 as provided for in 60.105(a)(4)) in the fuel gases before being burned in a combustion device. The continuous emission monitor shall meet the requirements in 40 CFR 60.105 and 40 CFR 60.106. as required under 40 CFR 60 Subpart J for H_2S. The Permittee shall calculate compliance with the SO_2 limit using the H_2S data.

[VIRR 12-09-206-71(a)(3)(B); 40 CFR 60.105(a)(4)]

5.2.2.4.5 In lieu of the above H_2S monitoring requirements, the Permittee may instead comply with EPA-approved alternative monitoring requirements or exemption from monitoring for combusted fuel gas streams, as applicable, in accordance with provisions of 40 CFR 60.13(i) or 60.105(b).

[40 CFR 60.13(i); 40 CFR 60.105(b)]

5.2.2.5 Group 02D – Heater H-4901 (LSG Unit Heater) and Hydrogen Plant Heater

5.2.2.5.1 While firing gaseous fuels, the Permittee shall conduct monthly opacity observations at the heater's emission point in accordance with 40 CFR 60, Appendix A, Method 9. The opacity observations shall be made at the point of greatest opacity in that portion of the plume where condensed water vapor is not present. Alternatively, the Permittee may install and operate a Continuous Opacity Monitoring System (COMS) that meets the requirements of 40 CFR 60.

[LSFP PSD Permit IX.5]

5.2.2.5.2 The Permittee shall track the number of starts in each period and the duration of each startup and shutdown.

[VIRR 12-09-206-71(a)(3)(B)]

5.2.2.5.3 The Permittee shall verify that the sulfur content of the fuels being burned meets the specifications outlined in sections 3.2.2.4.2.

[LSFP PSD Permit XII.1]

5.2.2.5.4 Compliance with the sulfur content standards for liquid and gaseous fuels shall be determined using the testing methods established in 40 CFR 60.335(b)(10) except for refinery fuel gas which shall be monitored for H_2S using the methodology specified in 40 CFR 60

Subpart J.

[LSFP PSD Permit XII.2]

5.2.2.5.5 The Permittee shall continuously monitor the H_2S in the fuel gases before being burned in a combustion device. The continuous emission monitor shall meet the requirements in 40 CFR 60.105 and 40 CFR 60.106.

[40 CFR 60.105(a)(4)]

5.2.2.5.6 In lieu of the above H_2S monitoring requirements, the Permittee may instead comply with EPA-approved alternative monitoring requirements or exemption from monitoring for combusted fuel gas streams, as applicable, in accordance with provisions of 40 CFR 60.13(i) or 60.105(b).

[40 CFR 60.13(i); 40 CFR 60.105(b)]

5.2.2.5.7 In lieu of 40 CFR 60 Subpart J span requirements, the Permittee may use a lower span, per Appendix B of 40 CFR 60.

[40 CFR 60]

5.2.2.5.8 Prior to conducting the initial performance tests required by section 4.2.2.2 and thereafter, the Permittee shall install, calibrate, maintain, and operate a CEM to measure and record stack gas NOx (as measured as NO_2) concentrations on the LSG unit heater stack and on the Hydrogen Plant heater stack. These systems shall meet all applicable EPA monitoring performance specifications (including but not limited to 40 CFR 60.13 and 40 CFR 60, Appendix B, Performance Specification 2, and Appendix F).

[LSFP PSD Permit X.4]

5.2.2.6 Group 02E – Heaters H-7801, H-7802, and R-7801 and Stack STK-7801

5.2.2.6.1 The Permittee shall monitor combined heat input to the heaters.

[VIRR 12-09-206-71(a)(3)(B)]

5.2.2.6.2 The Permittee shall continuously monitor the H_2S in the fuel gases before being burned in a combustion device. The continuous emission monitor shall meet the requirements in 40 CFR 60.105 and 40 CFR 60.106.

[40 CFR 60.105(a)(4)]

5.2.2.6.3 In lieu of the above H_2S monitoring requirements, the Permittee may instead comply with EPA-approved alternative monitoring requirements or exemption from monitoring for combusted fuel gas streams, as applicable, in accordance with provisions of 40 CFR 60.13(i) or 60.105(b).

[40 CFR 60.13(i); 40 CFR 60.105(b)]

5.2.2.6.4 The Permittee shall continuously monitor SO_2 emissions as required by 40 CFR 60, Subpart J. The Permittee shall calculate compliance with the SO_2 limit using the H_2S data.

[VIRR 12-09-71(a)(3)(B)]

5.2.2.6.5 The Permittee shall monitor opacity continuously by a Continuous Opacity Monitor (COM).

[1997 PSD Permit (III)(A)(f); 1997 PSD Permit (VI)(A)]

5.2.2.6.6 The Permittee shall install and operate a continuous O_2 monitor.
[1997 PSD Permit (VI)(A)]

5.2.2.7 Group 02F – Incinerators H-1032, H-1042, and H-4745

5.2.2.7.1 The Permittee shall monitor the H_2S content of all refinery gas burned.

[1997 PSD Permit (VI)(C)(h)]

5.2.2.7.2 The analysis (including colorimetric tubes) of daily grab samples from collection points (or other representative sample locations) in the refinery fuel gas system may be used to comply with this requirement. Analysis shall only be required for refinery fuel gas and shall not be required for propane, butane, and other gases at the refinery that are inherently low in H_2S.

[VIRR 12-09-206-71(a)(3)(B)]

5.2.2.7.3 The Permittee shall comply, as applicable, with the monitoring requirements as required in VIRR 12-09-204-45.

[VIRR 12-09-204-45]

5.2.2.7.4 The Permittee shall make daily visual observations for opacity.

[VIRR 12-09-206-71(a)(3)(B)]

5.2.2.7.5 The Permittee shall operate in compliance a continuous emission monitoring system for SO_2/H_2S at the outlet of the sulfur recovery unit(s) in accordance with the Quality Assurance Plan.

[1997 PSD Permit (IV)(E)]

5.2.2.7.6 For H-1032 and H-1042, the Permittee shall install, calibrate, maintain, and operate an instrument for continuously monitoring and recording the concentration (dry basis, zero percent excess air) of SO_2 emissions into the atmosphere. The monitor shall include an oxygen monitor for correcting the data for excess air. The Permittee shall comply with all monitoring requirements in 40 CFR

60.105(a)(5).

[40 CFR 60.105(a)(5)]

5.2.2.7.7 For the East Incinerator:

5.2.2.7.7.1 The Permittee shall install, calibrate, maintain, and operate according to manufacturer's specifications a temperature monitoring device equipped with a continuous recorder and having an accuracy of ±1 percent of the combustion temperature being measured expressed in degrees Celsius or ±0.5°C, whichever is greater. Where an incinerator other than a catalytic incinerator is used, Permittee shall install a temperature monitoring device in the firebox.

[40 CFR 61.303(a)]

5.2.2.7.7.2 The Permittee shall do one or a combination of the following if using a vent system that contains valves that could divert a vent stream from a control device:

5.2.2.7.7.2.1 Install a flow indicator immediately downstream of each valve that if opened would allow a vent stream to bypass the control device and be emitted, either directly or indirectly, to the atmosphere. The flow indicator shall be capable of recording flow at least once every 15 minutes.

5.2.2.7.7.2.2 Monitor the valves once a month, checking the position of the valves and the condition of the car seal, and identify all times when the car seals have been broken and the valve position has been changed (*i.e.*, from opened to closed for valves in the vent piping to the control device and from closed to open for valves that allow the stream to be vented directly or indirectly to the atmosphere)

[40 CFR 61.303(g)]

5.2.2.7.8 For H-4745, the Permittee shall comply, as applicable, with the monitoring requirements as required in 40 CFR 61, Subpart BB. The Permittee shall install, calibrate, maintain, and operate according to manufacturer’s specifications a temperature monitoring device equipped with a continuous recorder and having an accuracy of ± 1 percent of the combustion temperature being measured expressed in degrees Celsius or ±0.5°C, whichever is greater.

[40 CFR 61.303-304]

5.2.2.7.9 For H-4745, the Permittee shall monitor for temperature and oxygen (in a continuous parameter monitoring system for TRS) as required in the 40 CFR 60, Subpart UUU O&M Plan for East Sulfur Recovery.

[OMM Plan for East Sulfur Recovery; 40 CFR 63 Subpart UUU, Table 31, 3(ii)]

5.2.2.8 Group 02G – Heaters H-8501A and H-8501B

5.2.2.8.1 The Permittee shall continuously monitor the H_2S in the fuel gases before being burned in a combustion device. The continuous emission monitor shall meet the requirements in 40 CFR 60.105 and 40 CFR 60.106.

[40 CFR 60.105(a)(4)]

5.2.2.8.2 In lieu of the above H_2S monitoring requirements, the Permittee may instead comply with EPA-approved alternative monitoring requirements or exemption from monitoring for combusted fuel gas streams, as applicable, in accordance with provisions of 40 CFR 60.13(i) or 60.105(b).

[40 CFR 60.13(i); 40 CFR 60.105(b)]

5.2.2.8.3 In lieu of 40 CFR 60 Subpart J span requirements, the Permittee may use a lower span, per Appendix B or 40 CFR 60.

[40 CFR 60]

5.2.2.8.4 The fuel gas supply to H-8501A and H-8501B shall be equipped with continuous H_2S analyzers.

[STX-557A-E-02(X)(A), June 4, 2002]

5.2.2.8.5 The H_2S analyzers shall be calibrated and tested in accordance with EPA performance and siting specifications of 40 CFR 60, Appendix B, Performance Specifications 1-4.

[STX-557A-E-02(X)(B), June 4, 2002]

5.2.2.8.6 All coker fugitive emission sources are subject to 40 CFR 63, Subpart CC. The Permittee shall demonstrate compliance with the fugitive emission requirements of 40 CFR 63, Subpart CC.

[STX-557A-E-02(X)(K), June 4, 2002]

5.2.2.8.7 The coker process heaters are subject to and shall demonstrate compliance with the monitoring, recording, and reporting requirements of 40 CFR 60, Subpart J for petroleum refineries, 60.100 et seq.

[STX-557A-E-02(X)(L and M), June 4, 2002]

5.2.3 Group 03 – Compressor Engines

5.2.3.1 The Permittee shall make daily visual observations for opacity.
[VIRR 12-09-206-71(a)(3)(B)]

5.2.3.2 For C-200A, C-200B, C-200C, C-2400A, and C-2400B, for formaldehyde, the Permittee shall comply with the emissions monitoring requirements, as applicable, in 40 CFR 63, Subpart ZZZZ, 63.6610 through 63.6640, and 63.6665.
[40 CFR 63, Subpart ZZZZ]

5.2.4 Group 04 – Combustion Turbines

5.2.4.1 For all combustion turbines, the Permittee shall make daily visual observations of opacity.
[VIRR 12-09-206-71(a)(3)(B)]

5.2.4.2 Group 04A - Turbines G-1101E, G-1101F, G-1101G, G-3404, G-3405, G-3406, G-3407, G-3408, G-3409, G-3410

5.2.4.2.1 The Permittee shall monitor the H2S content of all refinery gas burned.
[1997 PSD Permit (VI)(C)(h)]

5.2.4.2.2 The analysis (including colorimetric tubes) of daily grab samples from collection points (or other representative sample locations) in the refinery fuel gas system may be used to comply with this requirement. Analysis shall only be required for refinery fuel gas and shall not be required for propane, butane, and other gases at the refinery that are inherently low in H2S.
[VIRR 12-09-206-71(a)(3)(B)]

5.2.4.2.3 The Permittee shall monitor the sulfur content of all fuel oil burned.
[1997 PSD Permit (VI)(C)(g)]

5.2.4.2.4 The Permittee shall monitor fuel usage for each operating scenario.
[1997 PSD Permit (VI)(C)]

5.2.4.2.5 The Permittee's compliance with the 1997 PSD Permit requirements for particulate matter emissions shall constitute compliance with the allowable particulate emissions under section 3.1.4.2.1 of this permit.
[VIRR 12-09-206-71(a)(3)(B)]

5.2.4.2.6 The Permittee shall continuously monitor the H_2S in the fuel gases before being burned in a combustion device. The continuous emission monitor shall meet the requirements of 40 CFR 60.105 and

60.106.

[40 CFR 60.105(a)(4)]

5.2.4.2.7 In lieu of the above H_2S monitoring requirements, the Permittee may instead comply with EPA-approved alternative monitoring requirements or exemption from monitoring for combusted fuel gas streams, as applicable, in accordance with provisions of 40 CFR 60.13(i) or 60.105(b).

[40 CFR 60.13(i); 40 CFR 60.105(b)]

5.2.4.2.8 The Permittee using water or steam injection to control NOx emissions shall install, calibrate, maintain, and operate a system to continuously monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine. As an alternative, the Permittee may install, certify, maintain, operate, and quality-assure a CEMS consisting of NOx and O_2 monitors. (As an alternative, a CO_2 monitor may be used to adjust the measured NOx concentrations to 15 percent O_2 as specified in 40 CFR 60.334.) If the Permittee chooses to use a NOx CEMS, the CEMS shall be installed, certified, maintained, and operated per 40 CFR 60.334 (b)(1) through (3). [Note: For G-3409 and G-3410, compliance with the NOx monitoring sections 5.2.4.2.19.1 and 5.2.4.2.13.1, respectively, shall constitute compliance with these NSPS Subpart GG NOx requirements.]

[40 CFR 60.334(a) and (b); GT-10 PSD Permit (XII)(8)]

5.2.4.2.9 The Permittee shall monitor the nitrogen content of the fuel combusted in each turbine, if the Permittee claims an allowance for fuel bound nitrogen (i.e., if an F-value greater than zero is being or will be used by the Permittee to calculate STD in 40 CFR 60.332). The nitrogen content of the fuel shall be determined using methods described in 40 CFR 60.335(b)(9) or an approved alternative, when fuel is transferred to the storage tank.

[40 CFR 60.334(h)(2); 40 CFR 60.334(i)]

5.2.4.2.10 The steam or water to fuel ratio or other parameters that are continuously monitored shall be monitored and recorded during the performance test required under 40 CFR 60.8, to establish acceptable values and ranges.

[40 CFR 60.334(g)]

5.2.4.2.11 The Permittee shall monitor the total sulfur content of the fuel being fired in each turbine. The sulfur content of the fuel must be determined using the total sulfur methods described in 40 CFR 60.335(b)(10) according to the frequency of determination specified in 40 CFR 60.333(i)(2). Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than 0.4 weight percent (4,000 ppmw), ASTM D4084-82, 94, D5504-01, D6228-98, or Gas Processors Association Standard 2377-86 may be used. The Permittee may elect not to monitor the total sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in 40 CFR 60.331(u). Notwithstanding the requirements in 40 CFR 60.333(i)(2), the Permittee may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply in accordance with the provisions of 40 CFR 60.334(i)(3).

[40 CFR 60.334(h)(1), (h)(3), (i)(3) and (i)(3)]

5.2.4.2.12 The Permittee shall monitor flows for all fuels fired by GT-10 (unit number G-3410).

[GT-10 PSD Permit (XII)(6)]

5.2.4.2.13 For G-3410, for fuels that are intermediately stored in tanks, the Permittee shall determine the sulfur content, through laboratory analysis, each time there is a transfer of fuel to the storage tanks.

[GT-10 PSD Permit (XII)(4)]

5.2.4.2.14 For G-3410, for purposes of compliance with conditions 3.2.4.1.12 and 3.2.4.1.13, when liquid and gaseous fuels are co-fired during the hour, the equivalent amount of time for liquid fuel consumption is taken as the ratio of the heat content of the liquid fuel to the heat content of the total fuel for that hour independent of the total load. For instance, if 70 mmBtu of liquid fuel and 210 mmBtu of gaseous fuel were used in an hour (at about 90% load), the time of liquid fuel usage would be 70/(70+210) = 0.25 hours.

[GT-10 PSD Permit (VII)(2)]

5.2.4.2.15 The Permittee shall install, calibrate, maintain, and operate the following continuous monitoring systems in the GT 10 (unit G-3410) exhaust stack:

5.2.4.2.15.1 CEM systems to measure stack gas NO (as measured NO2) and opacity concentrations. The systems shall meet EPA monitoring performance specifications (40 CFR 60.13 and 40 CFR 60, Appendix B, Performance Specifications 1, 2, and 3, and 40 CFR 60, Appendix F).

5.2.4.2.15.2 A CEM system to measure CO and a continuous monitoring system to measure oxygen. These systems, at a minimum, shall meet EPA monitoring performance specifications of 40 CFR 60, Appendix B, Performance Specifications 3 and 4, and 40 CFR 60, Appendix F.

[GT-10 PSD Permit (X)(1)]

5.2.4.2.16 For G-3410, the Permittee shall monitor the emissions by a CEM system for NOx and for CO. The Permittee shall continuously calculate the NOx and the CO mass emission rates for GT No. 10 (unit G-3410). The emission rate (in lb/mmBtu) of the monitored NOx and CO concentrations shall be determined using EPA Method 19 procedures. Mass emissions of NOx and of CO (in lb/hr and tons/year) shall be calculated by multiplying the emission rate by the hourly heat input.

[GT-10 PSD Permit (X)(9); GT-10 PSD Permit (XII)(7)]

5.2.4.2.17 For G-3410, the Permittee shall monitor opacity concentrations through the use of a COMS. The system shall meet EPA monitoring performance specifications 40 CFR 60.13 and 40 CFR 60, Appendix B, Performance Specifications 1, 2, and 3, and 40 CFR 60, Appendix F.

[GT-10 PSD Permit (X)(1)]

5.2.4.2.18 The Permittee shall use reasonable best efforts, taking into account operating conditions and equipment condition, to maintain the optimum steam to fuel ratios set forth in the GT-10 PSD Permit and/or established during the performance testing.

[VIRR 12-09-206-71(a)(3)(B)]

5.2.4.2.19 Not less than 90 days prior to the startup of the GT No. 10 (unit G-3410), the Permittee shall submit to the EPA a Quality Assurance Project Plan (QAPP) for the certification of the CEM systems. CEM performance testing may not begin until the QAPP has been approved by EPA.

[GT-10 PSD Permit (X)(2)]

5.2.4.2.20 The Permittee shall calibrate, maintain, and operate the following continuous monitoring systems at the GT No. 9 (G-3409) exhaust stack:

5.2.4.2.20.1 CEMS systems to measure stack gas NOx (reported as NO2). The system shall meet EPA monitoring performance specifications in 40 CFR 60.13, 40 CFR 60, Appendix B, Performance Specification 2 and 3, and Appendix F.

5.2.4.2.20.2 A CEM system to measure CO and a continuous monitoring system to measure oxygen. These systems, at a minimum, shall meet EPA monitoring performance specifications of 40 CFR 60, Appendix B, Performance Specifications 3 and 4, and 40 CFR 60, Appendix F.

[STX-557-J-K-05(D)(1), November 22, 2005]

5.2.4.2.21 Not less than 90 days prior to the date of startup of the steam1injection system on GT No. 9, the Permittee shall submit to the EPA a Quality Assurance Project Plan (QAPP) for the certification of the CEM systems. CEM performance testing may not begin until the QAPP has been approved by EPA.
[STX-557-J-K-05(D)(2), November 22, 2005]

5.2.4.2.22 The Permittee shall notify EPA and VIDPNR 15 days in advance of the date upon which demonstration of the CEM system performance will commence (40 CFR 60.13(c)). This date shall be no later than 60 days after the startup and commencement of normal operations of the steam injection system on GT No. 9.
[STX-557-J-K-05(D)(3), November 22, 2005]

5.2.4.2.23 The Permittee shall monitor and record the fuel consumption and the ratio of the steam to fuel being fired in GT No. 9.
[STX-557-J-K-05(C)(3), November 22, 2005]

5.2.4.3 Group 04B – G-3413 (GT. No. 13) and Associated Duct Burner H-3413

5.2.4.3.1 While firing gaseous fuels, the Permittee shall conduct monthly opacity observations in accordance with 40 CFR 60, Method 9. The opacity observations shall be made at the point of greatest opacity in that portion of the plume where condensed water vapor is not present. Alternatively, the Permittee may install and operate a COMS that meets the requirements of 40 CFR 60.
[LSFP PSD Permit IX.5]

5.2.4.3.2 While firing distillate oil fuel, the Permittee shall conduct daily opacity observations in accordance with 40 CFR 60, Method 9. The opacity observations shall be made at the point of greatest opacity in that portion of the plume where condensed water vapor is not present. Alternatively, the Permittee may install and operate a COMS that meets the requirements of 40 CFR 60.
[LSFP PDS Permit IX.6]

5.2.4.3.3 The Permittee's compliance with the requirements in section 3.2.4.2.18 for maximum sulfur content of the distillate oil burned shall constitute compliance with the allowable particulate matter emissions under section 3.1.4.3.1 of this permit.
[VIRR 12-09-206-71(a)(3)(B)]

5.2.4.3.4 The Permittee shall determine the number of hours per 12-month period during which the HRSG is bypassed.

[VIRR 12-09-206-71(a)(3)(B)]

5.2.4.3.5 The Permittee shall verify that the sulfur content of the fuels being burned meets the specifications outlined in sections 3.2.4.2.16 through 3.2.4.2.18.

[LSFP PSD Permit XII.1]

5.2.4.3.6 Prior to conducting the initial performance tests required by Section XI of the LSFP PSD Permit and thereafter, the Permittee shall install, calibrate, maintain, and operate a CEM to measure and record stack gas NOx (as measured as NO_2) concentrations on the GT No. 13/HRSG stack. These systems shall meet all applicable EPA monitoring performance specifications (including but not limited to 40 CFR 60.13 and 40 CFR 60, Appendix B. Performance Specification 2, and Appendix F).

[LSFP PSD Permit X.4]

5.2.4.3.7 Prior to conducting the initial performance tests required by Section XI of the LSFP PSD Permit and thereafter, the Permittee shall install, calibrate, maintain, and operate a continuous monitoring system to measure and record fuel flow rate and steam to fuel ratios from the combustion turbine. These systems shall meet all applicable EPA monitoring performance specifications.

[LSFP PSD Permit X.5]

5.2.4.3.8 Prior to conducting the initial performance tests required by Section XI of the LSFP PSD Permit and thereafter, the Permittee shall install, calibrate, maintain, and operate a CEM to measure and record stack gas CO concentrations from GT No. 13 (G-3413). The system shall meet all applicable EPA monitoring performance specifications (including but not limited to 40 CFR 60.13 and 40 CFR 60, Appendix B, Performance Specification 4, and Appendix F).

[LSFP PSD Permit X.3]

5.2.4.3.9 The Permittee shall continuously monitor the H_2S in the fuel gases before being burned in a combustion device. The CEM shall meet the requirements in 40 CFR 60.105 and 60.106.

[40 CFR 60.105(a)(4)]

5.2.4.3.10 In lieu of the above H_2S monitoring requirements, the Permittee may instead comply with EPA-approved alternative monitoring requirements or exemption from monitoring for combusted fuel gas streams, as applicable, in accordance with provisions of 40 CFR 60.13(i) or 60.105(b).

[40 CFR 60.13(i); 40 CFR 60.105(b)]

5.2.4.3.11 In lieu of Subpart J span requirements, the owner or operator may use a lower span, per Appendix B of 40 CFR 60.

[40 CFR 60]

5.2.4.3.12 The Permittee shall comply, as applicable, with the monitoring requirements of 40 CFR 60.695 and 60.696.

[40 CFR 60, Subpart QQQ - 60.695 and 60.696]

5.2.4.3.13 The Permittee shall comply with the emissions monitoring requirements, as applicable, in 40 CFR 60.4333 through 60.4370, 60.4380, 60.4385, and 60.4400 through 60.4415 (40 CFR 60, Subpart KKKK).

[40 CFR 60, Subpart KKKK]

5.2.4.3.14 For G-3413, except when the bypass stack is being used, the Permittee shall continuously monitor the inlet temperature to the catalyst. Except during startups, shutdowns, and malfunctions as specified in 40 CFR 63.6105(a), the Permittee shall maintain the 4-hour rolling average of the inlet temperature within the range suggested by the catalyst manufacturer. The Permittee shall comply with the requirements of 40 CFR 63.6105 through 63.6140 and with 63.6165, as applicable (40 CFR 63, Subpart YYYY).

[40 CFR 63.6105 through 63.6140; 40 CFR 63.6165]

5.2.4.3.15 For G-3413, the Permittee shall install and continuously operate (except during startup and shutdown periods) a steam injection system and monitor the steam to fuel ratio to ensure proper control of NOx emissions.

[LSFP PSD Permit IX.2]

5.2.5 Group 5 – Flares

5.2.5.1 For the #2 Flare (H-1105), #3 Flare (H-1104), #5 Flare (H-3351), #6 Flare (H-3352), #7 Flare (H-3301), FCC LP Flare, and LPG Flare, the Permittee shall use EPA Reference Method (RM) 22 to determine compliance with visible emissions. The observation period is 2 hours and shall be performed according to Method 22. The Permittee shall monitor the presence of a flare pilot flame using a thermocouple or any other equivalent device to detect the presence of a flame.

[40 CFR 60.18(f); 63.11(b)(5)]

5.2.5.2 For the #6 Flare, the Permittee shall comply with the monitoring requirements of 40 CFR 63, Subpart F, as applicable.

[40 CFR 63.100 through 107]

5.2.5.3 For the #6 Flare, the Permittee shall comply, as applicable, with the monitoring

requirements as required in 40 CFR 63, Subpart G.
[40 CFR 63.110 through 153]

5.2.5.4 For the #6 Flare, the Permittee shall comply with the monitoring, test methods, and procedures in 40 CFR 63.162 through 180, as applicable.
[40 CFR 63.162 through 180]

5.2.5.5 For the FCC LP and HP Flares and the LPG Flare, the Permittee shall continuously monitor the H_2S in the fuel gases before being burned in a combustion device. The continuous emission monitor shall meet the requirements in 40 CFR 60.105 and 60.106.
[40 CFR 60.105(a)(4)]

5.2.5.6 For the FCC LP and HP Flares and the LPG Flare, in lieu of the above H_2S monitoring requirements, the Permittee may instead comply with EPA-approved alternative monitoring requirements or exemption from monitoring for combusted fuel gas streams, as applicable, in accordance with provisions of 40 CFR 60.13(i) or 60.105(b).
[40 CFR 60.13(i); 40 CFR 60.105(b)]

5.2.6 Group 6 – Loading Racks

5.2.6.1 Group 06A - Truck Loading

5.2.6.1.1 The Permittee shall demonstrate that the emissions from the emission points proposed to be included in the average will not result in greater hazard or, at the option of the State or local permitting authority, greater risk to human health or the environment than if the emission points were controlled according to the provisions in 40 CFR 63.643 through 63.647, 63.650, and 63.651. [Permittee’s June 9, 1998 Emission Averaging Implementation Plan was approved by EPA satisfying this condition.]
[40 CFR 63.652(k)]

5.2.6.1.2 The Permittee shall maintain and calibrate, in a manner consistent with the manufacturer’s specifications, all monitors, meters, hydrocarbon analyzers, and recorders.
[STX-557-H-00(III)(G), September 18, 2000]

5.2.6.1.3 Regeneration of the carbon adsorption beds shall be based on manufacturer’s recommendation of the elapsed time required to ensure regeneration of the beds before any breakthrough considering the carbon loading properties of the Vapor Recovery Unit and the VRU test results. [Condition based on May 9, 2007 former owner HOVENSA Letter to DPNR with recommended revised carbon bed turnover procedure based on set time interval as recommend by manufacturer following installation rather than continuous inlet

monitor as initial required in Permit to Operate.]
[STX-557-H-00(III)(D), September 18, 2007]

5.2.6.1.4 The Permittee shall monitor the VRU's valves and pumps in light liquid service, using Method 21, according to 40 CFR 60, Subpart VV.
[STX-557-H-00(III)(F), September 18, 2000]

5.2.6.2 Group 06B – Marine Loading

None.

5.2.7 Group 7 – Sulfur Recovery

5.2.7.1 The Permittee shall monitor the H_2S content of all refinery gas burned.
[1997 PSD Permit (VI)(C)(h)]

5.2.7.2 The analysis (including colorimetric tubes) of daily grab samples from collection points (or other representative sample locations) in the refinery fuel gas system may be used to comply with this requirement. Analysis shall only be required for refinery fuel gas and shall not be required for propane, butane, and other gases at the refinery that are inherently low in H_2S.
[VIRR 12-09-206-71(a)(3)(B)]

5.2.7.3 The Permittee shall make daily visual observations of opacity.
[VIRR 12-09-206-71(a)(3)(B)]

5.2.7.4 The Permittee shall comply, as applicable, with the monitoring requirements as required in VIRR 12-09-204-45.
[VIRR 12-09-204-45]

5.2.7.5 The Permittee shall operate in compliance a continuous emissions monitoring system to track the H_2S concentration, flowrate, and temperature at the Beavon stacks.
[1997 PSD Permit (IV)(H)]

5.2.7.6 For T-1061, an instrument for continuously monitoring and recording the concentration of reduced sulfur and O_2 emissions into the atmosphere shall be installed, calibrated, maintained, and operated by the Permittee, except as provided in 40 CFR 60.105(a)(6)(ii). The reduced sulfur emissions shall be calculated as SO_2 (dry basis, zero percent excess air). The Permittee shall comply with all the monitoring requirements in 40 CFR 60.105(a)(6).
[40 CFR 60.105(a)(6)]

5.2.7.7 For T-1061, T-4761, and bypass lines, the Permittee shall comply with the monitoring requirements of 40 CFR 63, Subpart UUU, as applicable, by following the procedures outlined in the OMM Plans for East and West Sulfur Recovery.

[40 CFR 63.1572 through 63.1576]

5.2.8 Group 8 – Internal Floating Roof Tanks

The requirements of this section apply only to internal floating roof storage vessels defined as "Group 1" under 40 CFR 63, Subparts F and G (HON) or Subpart CC (Refinery NESHAP).

5.2.8.1 To demonstrate compliance with section 3.2.8.1 (storage vessel equipped with a fixed roof and internal floating roof) or a storage vessel equipped with an external floating roof converted to an internal floating roof, the Permittee shall comply with the requirements in paragraphs 5.2.8.1.1 through 5.2.8.1.7.

5.2.8.1.1 The Permittee shall visually inspect the internal floating roof, the primary seal, and the secondary seal (if one is in service), according to the schedule specified in paragraphs 5.2.8.1.2 and 5.2.8.1.3.

5.2.8.1.2 For vessels equipped with a single-seal system, the Permittee shall perform the inspections specified in paragraphs 5.2.8.1.2.1 and 5.2.8.1.2.2.

5.2.8.1.2.1 Visually inspect the internal floating roof and the seal through manholes and roof hatches on the fixed roof at least once every 12 months after initial fill, or at least once every 12 months after the compliance dates specified in (a) 40 CFR 63.640(h) through (m) for tanks in this category covered by Subpart CC, and (b) 40 CFR 63.100 of Subpart F for tanks in this category covered by Subpart G.

5.2.8.1.2.2 Visually inspect the internal floating roof, the seal, gaskets, slotted membranes, and sleeve seals (if any) each time the storage vessel is emptied and degassed, and at least once every 10 years after the compliance dates specified in (a) 40 CFR 63.640(h) through (m) for tanks in this category covered by Subpart CC, and (b) 40 CFR 63.100 of Subpart F for tanks in this category covered by Subpart G.

5.2.8.1.2.3 For the Group 1 storage vessels in this category that are subject to 40 CFR 63 Subpart CC, the Permittee is not required to visually inspect gaskets, slotted membranes, and sleeve seals.

[40 CFR 60.646(e)]

5.2.8.1.3 For vessels equipped with a double-seal system as specified in section 3.2.8.1.3.3, the Permittee shall perform either the inspection required in paragraph 5.2.8.1.3.1 or the inspections required in both paragraphs 5.2.8.1.3.2 and 5.2.8.1.3.3.

5.2.8.1.3.1 The Permittee shall visually inspect the internal floating roof, the primary seal, the secondary seal, gaskets, slotted membranes, and sleeve seals (if any) each time the storage vessel is emptied and degassed and at least once every 5 years after the compliance dates specified in (a) 40 CFR 63.640(h) through (m) for tasks in this category covered by Subpart CC, and (b) 40 CFR 63.100 of Subpart F for tanks in this category covered by Subpart G; or

5.2.8.1.3.2 The Permittee shall visually inspect the internal floating roof and the secondary seal through manholes and roof hatches on the fixed roof at least once every 12 months after initial fill, or at least once every 12 months after the compliance dates specified in (a) 40 CFR 63.640(h) through (m) for tasks in this category covered by Subpart CC, and (b) 40 CFR 63.100 of Subpart F for tanks in this category covered by Subpart G; and

5.2.8.1.3.3 Visually inspect the internal floating roof, the primary seal, the secondary seal, gaskets, slotted membranes, and sleeve seals (if any) each time the vessel is emptied and degassed and at least once every 10 years after the compliance dates specified in (a) 40 CFR 63.640(h) through (m) for tasks in this category covered by Subpart CC, and (b) 40 CFR 63.100 of Subpart F for tanks in this category covered by Subpart G.

5.2.8.1.3.4 For the Group 1 storage vessels in this category that are subject to 40 CFR 63 Subpart CC, the Permittee is not required to visually inspect gaskets, slotted membranes, and sleeve seals.

[40 CFR 60.646(e)]

5.2.8.1.4 If during the inspections required by paragraph 5.2.8.1.2.1 or 5.2.8.1.3.2, the internal floating roof is not resting on the surface of the liquid inside the storage vessel and is not resting on the leg supports; or there is liquid on the floating roof; or the seal is detached; or there are holes or tears in the seal fabric; or there are visible gaps between the seal and the wall of the storage vessel, the Permittee shall repair the items or empty and remove the storage vessel from service within 45 calendar days. If a failure that is detected during inspections required by paragraph 5.2.8.1.2.1 or 5.2.8.1.3.2 cannot be repaired within 45 calendar days and if the vessel cannot be emptied within 45 calendar days, the Permittee may utilize up to 2 extensions of up to 30 additional calendar days each. Documentation of a decision to utilize an extension shall include a description of the failure, shall document that alternate storage capacity is unavailable, and shall specify a schedule of actions that will ensure that the control equipment will be repaired or the vessel will be emptied as soon as practical.

5.2.8.1.5 Except as provided in paragraph 5.2.8.1.6, for all the inspections required by paragraphs 5.2.8.1.2.2, 5.2.8.1.3.1 and 5.2.8.1.3.3, the Permittee shall notify the Administrator in writing at least 30 calendar days prior to the refilling of each storage vessel to afford the Administrator the opportunity to have an observer present.

5.2.8.1.6 If the inspection required by paragraph 5.2.8.1.2.2, 5.2.8.1.3.1 or 5.2.8.1.3.3 is not planned and the Permittee could not have known about the inspection 30 calendar days in advance of refilling the vessel, the Permittee shall notify the Administrator at least 7 calendar days prior to the refilling of the storage vessel. Notification may be made by telephone and immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, the notification including the written documentation may be made in writing and sent so that it is received by the Administrator at least 7 calendar days prior to refilling.

5.2.8.1.7 If during the inspections required by paragraph 5.2.8.1.2.2, 5.2.8.1.3.1 or 5.2.8.1.3.3, the internal floating roof has defects; or the primary seal has holes, tears, or other openings in the seal or the seal fabric; or the secondary seal has holes, tears, or other openings in the seal or the seal fabric; or the gaskets no longer close off the liquid surface from the atmosphere; or the slotted membrane has more than 10 percent open area, the Permittee shall repair the items as necessary so that none of the conditions specified in this paragraph exist before refilling the storage vessel with organic HAP.
[40 CFR 63.120(a)]

5.2.9 Group 9 – External Floating Roof Tanks

The requirements of this section apply only to external floating roof storage vessels defined as "Group 1" under 40 CFR 63, Subparts F and G (HON) or Subpart CC (Refinery NESHAP).

5.2.9.1 To demonstrate compliance with section 3.2.9 (storage vessel equipped with an external floating roof), the Permittee shall comply with the requirements specified in paragraphs 5.2.9.1.1 through 5.2.9.1.10.

5.2.9.1.1 Except as provided in paragraph 5.2.9.1.7, the Permittee shall determine the gap areas and maximum gap widths between the primary seal and the wall of the storage vessel, and the secondary seal and the wall of the storage vessel according to the frequency specified in paragraphs 5.2.9.1.1.1 through 5.2.9.1.1.3.

5.2.9.1.1.1 For an external floating roof vessel equipped with primary and secondary seals, measurements of gaps between the vessel wall and the primary seal shall be performed during the hydrostatic testing of the vessel or by the compliance dates specified in (a) 40 CFR 63.640(h) through (m) for tasks in this category covered by Subpart CC, and (b) 40 CFR 63.100 of Subpart F for tanks in this category covered by Subpart G, whichever occurs last, and at least once every 5 years thereafter.

5.2.9.1.1.2 For an external floating roof vessel equipped with a liquid-mounted or metallic shoe primary seal and without a secondary seal as provided for in section 3.2.9.1.4 measurements of gaps between the vessel wall and the primary seal shall be performed by the compliance dates specified in (a) 40 CFR 63.640(h) through (m) for tasks in this category covered by Subpart CC, and (b) 40 CFR 63.100 of Subpart F for tanks in this category covered by Subpart G and at least once per year thereafter, until a secondary seal is installed. When a secondary seal is installed above the primary seal, measurements of gaps between the vessel wall and both the primary and secondary seals shall be performed within 90 calendar days of installation of the secondary seal, and according to the frequency specified in paragraphs 5.2.9.1.1.1 and 5.2.9.1.1.3 thereafter.

5.2.9.1.1.3 For an external floating roof vessel equipped with primary and secondary seals, measurements of gaps between the vessel wall and the secondary seal shall be performed by the compliance dates specified in (a) 40 CFR 63.640(h) through (m) for tasks in this category covered by Subpart CC, and (b) 40 CFR 63.100 of Subpart F for tanks in this category covered by Subpart G and at least once per year thereafter.

5.2.9.1.1.4 If any storage vessel ceases to store organic HAP for a period of 1 year or more, or if the maximum true vapor pressure of the total organic HAPs in the stored liquid falls below the values defining Group 1 storage vessels specified in table 5 or table 6 of 40 CFR 63, Subpart G (or, for Subpart CC Group 1 storage vessels for the values defining those vessels in the definition of 40 CFR 63.641), for a period of 1 year or more, measurements of gaps between the vessel wall and the primary seal, and gaps between the vessel wall and the secondary seal shall be performed within 90 calendar days of the vessel being refilled with organic HAP.

5.2.9.1.2 Except as provided in paragraph 5.2.9.1.7, the Permittee shall determine gap widths and gap areas in the primary and secondary seals (seal gaps) individually by the procedures described in paragraphs 5.2.9.1.2.1 and 5.2.9.1.2.2.

5.2.9.1.2.1 Seal gaps, if any, shall be measured at one or more floating roof levels when the roof is not resting on the roof leg supports.

5.2.9.1.2.2 Seal gaps, if any, shall be measured around the entire circumference of the vessel in each place where an 0.32 centimeter (1/8inch) diameter uniform probe passes freely (without forcing or binding against the seal) between the seal and the wall of the storage vessel. The circumferential distance of each such location shall also be measured.

5.2.9.1.2.3 The total surface area of each gap described in paragraph 5.2.9.1.2.2 shall be determined by using probes of various widths to measure accurately the actual distance from the vessel wall to the seal and multiplying each such width by its respective circumferential distance.

5.2.9.1.3 The Permittee shall add the gap surface area of each gap location for the primary seal and divide the sum by the nominal diameter of the vessel. The accumulated area of gaps between the vessel wall and the primary seal shall not exceed 212 square centimeters per meter of vessel diameter and the width of any portion of any gap shall not exceed 3.81 centimeters.

5.2.9.1.4 The Permittee shall add the gap surface area of each gap location for the secondary seal and divide the sum by the nominal diameter of the vessel. The accumulated area of gaps between the vessel wall and the secondary seal shall not exceed 21.2 square centimeters per meter of vessel diameter and the width of any portion of any gap shall not exceed 1.27 centimeters. These seal gap requirements may be exceeded during the measurement of primary seal gaps as required by paragraphs 5.2.9.1.1.1 and 5.2.9.1.1.2.

5.2.9.1.5 The primary seal shall meet the additional requirements specified in paragraphs 5.2.9.1.5.1 and 5.2.9.1.5.2.

5.2.9.1.5.1 Where a metallic shoe seal is in use, one end of the metallic shoe shall extend into the stored liquid and the other end shall extend a minimum vertical distance of 61 centimeters above the stored liquid surface.

5.2.9.1.5.2 There shall be no holes, tears, or other openings in the shoe, seal fabric, or seal envelope.

5.2.9.1.6 The secondary seal shall meet the additional requirements specified in paragraphs 5.2.9.1.6.1 and 5.2.9.1.6.2.

5.2.9.1.6.1 The secondary seal shall be installed above the primary seal so that it completely covers the space between the roof edge and the vessel wall except as provided in paragraph 5.2.9.1.4.

5.2.9.1.6.2 There shall be no holes, tears, or other openings in the seal or seal fabric.

5.2.9.1.7 If the Permittee determines that it is unsafe to perform the seal gap measurements required in paragraphs 5.2.9.1.1 and 5.2.9.1.2 or to inspect the vessel to determine compliance with paragraphs 5.2.9.1.5 and 5.2.9.1.6 because the floating roof appears to be structurally unsound and poses an imminent or potential danger to inspecting personnel, the Permittee shall comply with the requirements in either paragraph 5.2.9.1.7.1 or 5.2.9.1.7.2.

5.2.9.1.7.1 The Permittee shall measure the seal gaps or inspect the storage vessel no later than 30 calendar days after the determination that the roof is unsafe, or

5.2.9.1.7.2 The Permittee shall empty and remove the storage vessel from service no later than 45 calendar days after determining that the roof is unsafe. If the vessel cannot be emptied within 45 calendar days, the Permittee may utilize up to 2 extensions of up to 30 additional calendar days each. Documentation of a decision to utilize an extension shall include an explanation of why it was unsafe to perform the inspection or seal gap measurement, shall document that alternate storage capacity is unavailable, and shall specify a schedule of actions that will ensure that the vessel will be emptied as soon as practical.

5.2.9.1.8 The Permittee shall repair conditions that do not meet requirements listed in paragraphs 5.2.9.1.3, 5.2.9.1.4, 5.2.9.1.5, and 5.2.9.1.6 (i.e., failures) no later than 45 calendar days after identification, or shall empty and remove the storage vessel from service no later than 45 calendar days after identification. If during seal gap measurements required in paragraph 5.2.9.1.1 and 5.2.9.1.2 or during inspections necessary to determine compliance with paragraphs 5.2.9.1.5 and 5.2.9.1.6 a failure is detected that cannot be repaired within 45 calendar days and if the vessel cannot be emptied within 45 calendar days, the Permittee may utilize up to 2 extensions of up to 30 additional calendar days each. Documentation of a decision to utilize an extension shall include a description of the failure, shall document that alternate storage capacity is unavailable, and shall specify a schedule of actions that will ensure that the control equipment will be repaired or the vessel will be emptied as soon as practical.

5.2.9.1.9 The Permittee shall notify the Administrator in writing 30 calendar days in advance of any gap measurements required by paragraph 5.2.9.1.1 and 5.2.9.1.2 to afford the Administrator the opportunity to have an observer present.

5.2.9.1.10 The Permittee shall visually inspect the external floating roof, the primary seal, secondary seal, and fittings each time the vessel is emptied and degassed.

5.2.9.1.10.1 If the external floating roof has defects; the primary seal has holes, tears, or other openings in the seal or the seal fabric; or the secondary seal has holes, tears, or other openings in the seal or the seal fabric; or the gaskets no longer close off the liquid surface from the atmosphere; or the slotted membrane has more than 10 percent open area, the Permittee shall repair the items as necessary so that none of the conditions specified in this paragraph exist before filling or refilling the storage vessel with organic HAP.

5.2.9.1.10.2 Except as provided in paragraph 5.2.9.1.10.3, for all the inspections required by paragraph 5.2.9.1.10, the Permittee shall notify the Administrator in writing at least 30 calendar days prior to filling or refilling of each storage vessel with organic HAP to afford the Administrator the opportunity to inspect the storage vessel prior to refilling.

5.2.9.1.10.3 If the inspection required by paragraph 5.2.9.1.10 is not planned and the Permittee could not have known about the inspection 30 calendar days in advance of refilling the vessel with organic HAP, the Permittee shall notify the Administrator at least 7 calendar days prior to refilling of the storage vessel. Notification may be made by telephone and immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the written documentation may be made in writing and sent so that it is received by the Administrator at least 7 calendar days prior to the refilling.

5.2.9.1.10.4 For the Group 1 storage vessels in this category that are subject to 40 CFR 63 Subpart CC, the Permittee is not required to visually inspect gaskets, slotted membranes, and sleeve seals.

[40 CFR 63.120(b); 40 CFR 60.646(e)]

5.2.10 Group 10 – Fixed Roof Tanks

5.2.10.1 Group 10A - Fixed Roof Tanks PRT3, PRT4, PRT5, PRT6, PRT7, TK-1151, TK-1201, TK-1202, TK-1203, TK-1206, TK-1207, TK-1208, TK-1302, TK-1653, TK-2653, TK-2654, TK-3208, TK-3301, TK-3304, TK-3306, TK-3384, TK-3385, TK-3386, TK-4502, TK-6810, TK-6811, TK-6812, TK-6813, TK-6817, TK-6818, TK-6819, TK-6820, TK-6821, TK-6822, TK-6823, TK-6824, TK-6825, TK-6851, TK-6853, TK-6854, TK-6856, TK-6858, TK-6859, TK-

6860, TK-6873, TK-6875, TK-6876, TK-6877, TK-6881, TK-6883, TK-6887, TK-700, TK-701, TK-702, TK-7206, TK-7207, TK-7208, TK-7209, TK-TK-7210, TK-7211, TK-7301, TK-7405, TK-7406, TK-7411, TK-7412, TK-7413, TK-7414, TK-7415, TK-7416, TK-7421, TK-7422, TK-7427, TK-7428, TK-7429, TK-7430, TK-7435, TK-7436, TK-7437, TK-7438, TK-7439, TK-7440, TK-7446, TK-7501, TK-7502, TK-7503, TK-7504, TK-7505, TK-7506, TK-7933, TK-7934, UTT1, TK-8501

None.

5.2.10.2 Group 10B - Tanks TK-1204, TK-1205, TK-8001, TK-8002 (Subject to 40 CFR 63, Subpart EEEE)

None.

5.2.11 Group 11 – Horizontal Tanks TK-1626, TK-1627, TK-1628, TK-1629, TK-1630, TK-1631, TK-1633, D-1301, D-1609, D-1610, D-1620

None.

5.2.12 Group 12 – Geodesic Dome Tanks

None.

5.2.13 Group 13 – Wastewater Treatment

5.2.13.1 For oil/water separators (i.e., API and CPS units), the Permittee shall comply with the following requirements:

5.2.13.1.1 For oil/water separators with floating roofs, the Permittee shall comply with the monitoring requirements in 40 CFR 60.696(d), as applicable. (For portions of the oil/water separator equipped with a fixed roof vented to a vapor control device, monitoring requirements may be found in sections 5.2.13.1.2 for the fixed roof, and in 5.2.13.2 for the closed vent system and control device.)
[40 CFR 60, Subpart QQQ; 40 CFR 61.352; 40 CFR 63.647]

5.2.13.1.2 For oil/water separators with fixed roofs, the Permittee shall comply with all applicable monitoring requirements in 40 CFR 61.347. (Monitoring requirements for the closed-vent system and control device may be found in section 5.2.13.2).
[40 CFR 60, Subpart QQQ; 40 CFR 61.347; 40 CFR 63.647]

5.2.13.2 For closed vent systems associated with wastewater system components (i.e., WEMCO Units and oil/water separators), the Permittee shall:

5.2.13.2.1 Each closed-vent system and control device shall be visually inspected initially and quarterly thereafter. The visual inspection shall include inspection of ductwork and piping and connections to covers and control devices for evidence of visible defects such as holes in ductwork or piping and loose connections.

[40 CFR 61.349 (f)]

5.2.13.2.2 Except as provided in 40 CFR 61.350, if visible defects are observed during an inspection, or if other problems are identified, or if detectable emissions are measured, a first effort to repair the closed-vent system and control device shall be made as soon as practicable but no later than 5 calendar days after detection. Repair shall be completed no later than 15 calendar days after the emissions are detected or the visible defect is observed.

[40 CFR 61.349 (g)]

5.2.13.2.3 The owner or operator of a control device that is used to comply with the provisions of 40 CFR 61, Subpart FF, shall monitor the control device in accordance with 40 CFR 61.354(c).

[40 CFR 61.349 (h)]

5.2.13.3 For Benzene strippers:

5.2.13.3.1 The Permittee shall monitor the unit in accordance with the applicable requirements in 40 CFR 61.354.

[40 CFR 61.348 (g)]

5.2.13.4 The Permittee shall comply, as applicable, with the monitoring and performance test requirements of 40 CFR 60.695 and 60.696.

[40 CFR 60.695 and 60.696]

5.2.14 Group 14 – Alkylation and Dimersol Units

5.2.14.1 For distillation unit vent streams compliance with 40 CFR 60 Subpart NNN, the Permittee shall comply with an EPA-approved alternative monitoring requirements for Alkylation and Dimersol affected facilities in accordance with provisions of 40 CFR 60.13(i).

[40 CFR 60.13(i); 40 CFR 60.663]

5.2.14.2 For reactor process vent streams, the Permittee shall comply with the requirements of 40 CFR 60.703, as applicable.

[40 CFR 60.703]

5.2.15 Group 15 – Seawater Intake Pumps

5.2.15.1 The Permittee's compliance with section 3.2.15.1 requirements for particulate matter emission shall constitute compliance with the allowable particulate matter emissions under section 3.1.15.1 of this permit.

[VIRR 12-09-206-71(a)(3)(B)]

5.2.15.2 The Permittee shall make daily visual observations of opacity.

[VIRR 12-09-206-71(a)(3)(B)]

5.2.15.3 The Permittee shall monitor the sulfur content of all fuel oil burned.
[1997 PSD Permit (VI)(C)(g)]

5.2.16 Group 16 – FCCU

5.2.16.1 The Permittee shall keep logs and update them daily to record the daily fresh feed rate (barrels).
[LSFP PSD Permit XIII.1.a]

5.2.16.2 The Permittee shall keep logs and update them daily to record the daily coke burn-off rate in units of 1,000 pounds per hour and hours of operation for the FCCU regenerator.
[LSFP PSD Permit XIII.1.b]

5.2.16.3 The Permittee shall keep logs and update them daily to record the sulfur content of the feed to the FCCU complex.
[LSFP PSD Permit XIII.1.a]

5.2.16.4 The FCCU complex shall be equipped with operable continuous emission monitors to measure the following pollutants and/or operating parameters: SO_2 (inlet and outlet of the venturi gas scrubber). These monitors shall comply with EPA performance and siting specifications pursuant to 40 CFR 60, Appendix B, Performance Specification 2. EPA reserves the right to require the auditing of the CEMS by independent agents.
[LSFP PSD Permit X.1]

5.2.16.5 The FCCU complex shall be equipped with operable continuous emission monitors to measure the following pollutants and/or operating parameters: O2 (outlet of the venture gas scrubber). These monitors shall comply with EPA performance and siting specifications pursuant to 40 CFR 60, Appendix B, Performance Specifications 3 or 4. EPA reserves the right to require the auditing of the CEMS by independent agents.
[LSFP PSD Permit X.1]

5.2.16.6 For STK-7051, the Permittee shall also comply, as applicable, with the monitoring requirements in 40 CFR 60.105. A minimum of 22 valid days of data shall be obtained every 30 successive calendar days. The CEMS performance evaluation and QA/QC shall be performed in accordance with the requirements of 40 CFR 60.105(a)(12)(i) and (ii).
[40 CFR 60.105]

5.2.16.7 For STK-7051, compliance with the SO_2 limits in section 3.2.16.13 shall be determined daily on a 7-day rolling average basis using procedures outlined in 40 CFR 60.106.
[40 CFR 60.106]

5.2.16.8 For STK-7051, in lieu of Subpart J span requirements, the Permittee may use a lower span, per Appendix B of 40 CFR 60.

[40 CFR 60]

5.2.16.9 The FCCU complex shall be equipped with operable continuous emission monitors to measure the following pollutants and/or operating parameters: NOx. These monitors must comply with EPA performance and siting specifications pursuant to 40 CFR 60, Appendix B, Performance Specification 2. EPA reserves the right to require the auditing of the CEMS by independent agents.

[LSFP PSD Permit X.1]

5.2.16.10 The FCCU complex shall be equipped with operable continuous emission monitors to measure the following pollutants and/or operating parameters: CO. These monitors must comply with EPA performance and siting specifications pursuant to 40 CFR 60, Appendix B, Performance Specification 4. EPA reserves the right to require the auditing of the CEMS by independent agents.

[LSFP PSD Permit X.1]

5.2.16.11 For STK-7051, the Permittee shall keep logs and update them daily to record the FCCU scrubber water feed rate.

[LSFP PSD Permit XIII.1.c]

5.2.16.12 The FCCU complex shall be equipped with an operable continuous monitor to measure the pollutants and/or operating parameters: CO, O_2, NO_x, SO_2 (inlet and outlet of the venture gas scrubber for SO_2), regenerator temperature, and pressure across the venturi scrubber throat.

[LSFP PSD Permit X.1; 1997 PSD Permit (VI)(A)]

5.2.16.13 The Permittee shall install, calibrate, and test each CEM and recorder listed in section 5.2.16.12. Monitors must comply with EPA performance and siting specifications pursuant to 40 CFR 60, Appendix B, Specifications 1-4. Equipment specifications, calibration, and operating procedures, and data evaluation and reporting procedures shall be submitted to EPA in Performance Specifications Test Protocol. EPA reserves the right to require the auditing of the CEMs by independent agents.

[LSFP PSD Permit X.1; 1997 PSD Permit (VI)(B)]

5.2.16.14 The Permittee shall comply, as applicable, with the continuous opacity monitoring requirements of 40 CFR 60.105(a)(1). In lieu of these monitoring requirements, the Permittee may instead comply with EPA-approved alternative monitoring requirements for opacity monitoring, as applicable, in accordance with provisions of 40 CFR 13(i).

[40 CFR 60.105(a)(1); 40 CFR 60.13(i)]

5.2.16.15 The Permittee shall keep logs and update them daily to record any adjustments and maintenance performed on the combustion turbine unit, the heaters and/or the FCCU.

[LSFP PSD Permit XIII.1.i]

5.2.16.16 The Permittee shall keep logs and update them daily to record any adjustments and maintenance performed on monitoring systems.

[LSFP PSD Permit XIII.1.j]

5.2.16.17The Permittee shall keep logs and update them daily to record the following: the beginning, duration, and completion of startup episodes for the FCCU complex, along with the reason(s) for the prior shutdown.

[LSFP PSD Permit XIII.1.d]

5.2.16.18 The FCCU complex shall be equipped with an operable continuous monitor to measure the following operating parameter: regenerator temperature.

[LSFP PSD Permit X.1]

5.2.16.19 For the 3 Turbo Expander Maintenance Vents, the Permittee shall adhere to the testing and monitoring procedures in 40 CFR 60.106 for opacity, PM, and CO. In lieu of these monitoring requirements, the Permittee may instead comply with EPA-approved alternative monitoring requirements for flue gas monitoring, as applicable, in accordance with provisions of 40 CFR 60.13(i).

[40 CFR 60.106; 40 CFR 60.13(i)]

5.2.16.20 For STK-7051 and the Turbo Expander Vents, the Permittee shall comply with the monitoring requirements of 40 CFR 63, Subpart UUU, as applicable. The Permittee shall follow the procedures outlined in the OMM Plan.

[40 CFR 63.1572 through 1573]

5.2.16.21 For the 3 Turbo Expander Maintenance Vents, the Permittee shall adhere to the testing and monitoring procedures in 40 CFR 60.106(i). In lieu of these sulfur dioxide monitoring requirements, the Permittee may instead comply with EPA approved alternative monitoring requirements for flue gas monitoring, as applicable, in accordance with provisions of 40 CFR 60.13(i).

[40 CFR 60.106(i); 40 CFR 60.13(i)]

5.2.17 Group 17 – Coker Complex

5.2.17.1 The Permittee shall determine annual PM and PM-10 emissions from the coke handling system.

[VIRR 12-09-206-71(a)(3)(B)]

5.2.17.2 For the Residuals Recycling System: The Permittee shall monitor the GAC emission control system every working day for the determination of breakthrough between the first and second canisters.

[STK-557-K-05(III), May 11, 2005]

5.2.17.3 The Permittee shall inspect the control devices for Tank 8511 once a month in between the carbon canisters, which are in series.
[STK-557-K-05(III), May 11, 2005]

5.2.18 Group 18 – Sulfuric Acid Plant Stack STK-7802

5.2.18.1 The Permittee shall monitor the daily tons of sulfuric acid produced.
[1997 PSD Permit (VI)(C)(c)]

5.2.18.2 SO_2 emissions shall be monitored by Continuous Emissions Monitors (CEMs) for SO_2 and O_2.
[1997 PSD Permit (VI)(A)]

5.2.18.3 The Permittee shall monitor sulfuric acid plant start-up events.
[VIRR 12-09-206-71(a)(3)(B)]

5.2.18.4 The Permittee shall comply, as applicable, with the monitoring requirements as required in 40 CFR 60, Subpart H.
[40 CFR 60.84]

5.2.19 Group 19 – Vapor Enhanced Recovery

5.2.19.1 The Permittee shall continuously monitor the H_2S in the fuel gases before being burned in a combustion device. The continuous emission monitor shall meet the requirements of 40 CFR 60.105 and 60.106.
[40 CFR 60.105(a)(4)]

5.2.19.2 In lieu of the above H_2S monitoring requirements, the Permittee may instead comply with EPA-approved alternative monitoring requirements or exemption from monitoring for combusted fuel gas streams, as applicable, in accordance with provisions of 40 CFR 60.13(i) or 60.105(b).
[40 CFR 60.13(i); 40 CFR 60.105(b)]

5.2.19.3 For the Thermal/Catalytic Oxidizer Modes: The oxidizer shall have continuous temperature monitors with automatic shutdown of the system. The automatic shutdown system shall be designed to inactivate the system upon detection of a temperature below 1300 degrees F or a temperature above 1600 degrees F during thermal mode.
[STX-557-G-01(II)(F) and (H) (modified), September 6, 2001]

5.2.19.4 The automatic shutdown system shall be designed to inactivate the system upon detection of a temperature below 500 degrees F or a temperature above 1250 degrees F during catalytic mode.
[STX-557-G-01(II)(F) and (J), September 6, 2001]

5.2.19.5 The Permittee shall maintain and calibrate, in a manner consistent with the manufacturer's specifications, all monitors, meters, hydrocarbon analyzers, and recorders as required by this permit.

[STX-557-G-01(III)(A), September 6, 2001]

5.2.19.6 The Permittee shall locate all monitors, recorders, and meters required in this permit in a manner which allows easy access and visibility. VIDPNR may require the relocation of the monitor or remote readout equipment.

[STX-557-G-01(III)(B), September 6, 2001]

5.2.20 Group 20 – Gasoline Service Station and Fuel Gas System

None.

5.2.21 Group 21 – Amine Units, Merox, and Gas Concentration

None.

5.2.22 Group 22 – Gas Treating and Stripping

None.

5.2.23 Group 23 – Hydrogen Recovery

None.

5.2.24 Group 24 – Disulfide Handling

None.

5.2.25 Group 25 – Platformers

5.2.25.1 The Permittee shall comply with the monitoring requirements of 40 CFR 63, Subpart UUU, as applicable, and shall follow the monitoring procedures outlined in the current Operation, Maintenance, and Monitoring Plans for the #2, #3, and #4 Platformers.

[40 CFR 63.1572 through 1573]

5.3 Recordkeeping and Reporting Requirements (associated with Specific Monitoring Requirements)

5.3.1 Group 1 – Boilers

5.3.1.1 Group 01A – Boilers B-1151, B-1153, B-1154, and B-1155

5.3.1.1.1 For B-1155, the Permittee shall comply, as applicable, with the recordkeeping and reporting requirements of 40 CFR 60, Subparts A and D. The Permittee shall submit excess emission reports on a semiannual basis.

[40 CFR 60, Subpart A; 40 CFR 60.7(c)]

5.3.1.1.2 The Permittee shall report to VIDPNR changes and alterations in operations that result in an increase in regulated emissions.

[33 PTO (c), Permit No. 481-94, November 28, 1994]

5.3.1.1.3 The Permittee shall allow VIDPNR to inspect its facility during reasonable hours. The inspection shall be conducted in a timely manner, in the presence of, and with full assistance and cooperation of LIMETREE BAY TERMINALS LLC management. VIDPNR shall issue an advanced verbal request for the use of cameras and vocal recording devices.

[33 PTO (f), Permit No. 481-94, November 28, 1994]

5.3.1.1.4 The Permittee shall sample fuel oil sources as regulated under PSD permits for nitrogen and sulfur concentrations and maintain these data for not less than five years. The Permittee shall analyze sulfur usage. Fuel oil sulfur concentrations shall be in compliance with VIRR 12-09-204 and 206, as amended.

[33 PTO (g), Permit No. 481-94, November 28, 1994]

5.3.1.1.5 The Permittee shall initiate operation, maintenance, and fuel consumption records and shall keep these records on a daily and cumulative basis. The Permittee shall keep one log for each operating area which shall contain information regarding the operation and maintenance of each permitted unit in the areas listed in the LIMETREE BAY TERMINALS LLC Air Emission Source Listing. The Permittee may store fuel consumption data electronically. The Permittee shall make available the logs and data for inspection by VIDPNR and EPA upon request.

[33 PTO (i), Permit No. 481-94, November 28, 1994]

5.3.1.2 Group 01B – Boilers B-3301, B-3302, B-3303, and B-3304

5.3.1.2.1 For B-3303 and B-3304, the Permittee shall comply, as applicable, with the recordkeeping and reporting requirements of 40 CFR 60, Subparts A and D. The Permittee shall submit excess emission reports on a semiannual basis.

[40 CFR 60, Subparts A and D]

5.3.1.2.2 The Permittee shall report to VIDPNR changes and alterations in operations that result in an increase in regulated emissions.

[33 PTO (c), Permit No. 482-94, November 28, 1994]

5.3.1.2.3 The Permittee shall allow VIDPNR to inspect its facility during reasonable hours. The inspection shall be conducted in a timely manner, in the presence of, and with full assistance and cooperation of LIMETREE BAY TERMINALS LLC management. VIDPNR shall issue an advanced verbal request for the use of cameras and vocal recording devices.

[33 PTO (f), Permit No. 482-94, November 28, 1994]

5.3.1.2.4 The Permittee shall sample fuel oil sources as regulated under PSD permits for nitrogen and sulfur concentrations and maintain these data for not less than five years. The Permittee shall analyze sulfur concentrations in other regulated fuel oils on each tank prior to usage. Fuel oil sulfur concentrations shall be in compliance with VIRR 12-09-204 and 206, as amended.

[33 PTO (g), Permit No. 482-94, November 28, 1994]

5.3.1.2.5 The Permittee shall initiate operation, maintenance, and fuel consumption records and shall keep these records on a daily and cumulative basis. The Permittee shall keep one log for each operating area which shall contain information regarding the operation and maintenance of each permitted unit in the areas listed in the LIMETREE BAY TERMINALS LLC Air Emission Source Listing. The Permittee may store fuel consumption data electronically. The Permittee shall make available the logs and data for inspection by VIDPNR and EPA upon request.

[33 PTO (i), Permit No. 482-94, November 28, 1994]

5.3.1.3 Group 01C – Boiler B-3701

5.3.1.3.1 The Permittee shall comply, as applicable, with recordkeeping requirements as required in 40 CFR 60, Subparts A and Db.

[40 CFR 60, Subparts A and Db; 40 CFR 60.49b(d)]

5.3.1.3.2 The Permittee shall comply, as applicable, with the reporting requirements as required in 40 CFR 60 Subparts A and Db. The reporting period for the reports required under this subpart is each 6 month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30^{th} day following the end of the reporting period.

[40 CFR 60, Subpart A; 40 CFR 60.49b]

5.3.1.3.3 The Permittee shall continuously record the H_2S concentration (dry basis) in the fuel gas.

[40 CFR 105(a)(4); 40 CFR 60.107]

5.3.1.3.4 In lieu of the above H_2S monitoring requirements, the Permittee may instead comply with EPA-approved alternative monitoring requirements or exemption from monitoring for combusted fuel gas streams, as applicable, in accordance with provisions of 40 CFR 60.13(i) or 60.105(b).

[40 CFR 60.13(i); 40 CFR 60.105(b)]

5.3.1.3.5 The Permittee shall submit the results of the NOx and CO emission rate test runs on the boiler to the VIDPNR within 60 days of test completion.

[STX-557-I-00 (III)(D), September 18, 2000]

5.3.1.3.6 The Permittee shall within four (4) hours report to VIDPNR via telephone and/or fax upon determination of any non-compliance of operating requirements directly related to emission limits, or any non-compliance specified in the sections of this permit that reference permit no. STX-557-I-00.

[STX-557-I-00 (V)(A), September 18, 2000]

5.3.1.3.7 The Permittee shall report within four (4) hours to the VIDPNR via telephone and/or fax, any operation of the equipment covered by the sections of this permit that reference permit no. STX-557-I-00 which may cause off-property effects, including odors.

[STX-557-I-00 (V)(C), September 18, 2000]

5.3.2 Group 2 – Heaters

5.3.2.1 Group 02A – Heaters H-101, H-104, H-401A, H-401B, H-401C, H-1401A, H-1401B, H-2101, H-2102, H-3101A, H-3101B, H-4101A, H-4101B, H-4202, H-4202

5.3.2.1.1 For H-3101A, H-3101B, H-4101A, and H-4101B, as applicable, the Permittee shall continuously record the H_2S concentration (dry basis) in the fuel gas.

[40 CFR 60.105(a)(4); 40 CFR 60.107]

5.3.2.1.2 For H-3101A, H-3101B, H-4101A, and H-4101B, in lieu of the above H_2S recording requirements, the Permittee may instead comply with EPA-approved alternative monitoring requirements or exemption from monitoring for combusted fuel gas streams, as applicable, in accordance with provisions of 40 CFR 60.13(i) or 60.105(b).

[40 CFR 60.13(i); 40 CFR 60.105(b)]

5.3.2.1.3 The Permittee shall comply, as applicable, with the quarterly excess emissions reporting requirements as required in 40 CFR 60.7.

[40 CFR 60.7]

5.3.2.1.4 For the purpose of reports under 40 CFR 60.7(c), excess emissions shall be defined as all rolling 3-hour periods during which the average concentration of H_2S as measured by the H_2S continuous monitoring system under 40 CFR 60.105(a)(4) exceeds 230 mg/dscm (0.10 gr/dscf).

[40 CFR 60.105(e)(3)(ii); 40 CFR 60.7(c)]

5.3.2.1.5 The Permittee shall report to VIDPNR changes and alterations in operations that result in an increase in regulated emissions.

[33 PTO (c), Permit Nos. 326-94, 332-94, 333-94, 343-94, 352-94, 468-94, and 469-94, November 28, 1994]

5.3.2.1.6 The Permittee shall allow VIDPNR to inspect its facility during reasonable hours. The inspection shall be conducted in a timely manner, in the presence of, and with full assistance and cooperation of LIMETREE BAY TERMINALS LLC management. VIDPNR shall issue an advanced verbal request for the use of cameras and vocal recording devices.

[33 PTO (f), Permit Nos. 326-94, 332-94, 333-94, 343-94, 352-94, 468-94, and 469-94, November 28, 1994]

5.3.2.1.7 The Permittee shall sample fuel oil sources as regulated under PSD permits for nitrogen and sulfur concentrations and maintain these data for not less than five years. The Permittee shall analyze sulfur concentrations in other regulated fuel oils on each tank prior to usage. Fuel oil sulfur concentrations shall be in compliance with VIRR 12-09-204 and 206, as amended.

[33 PTO (g), Permit Nos. 326-94, 332-94, 333-94, 343-94, 352-94, 468-94, and 469-94, November 28, 1994]

5.3.2.1.8 The Permittee shall initiate operation, maintenance, and fuel consumption records and shall keep these records on a daily and cumulative basis. The Permittee shall keep one log for each operating area which shall contain information regarding the operation and maintenance of each permitted unit in the areas listed in the LIMETREE BAY TERMINALS LLC Air Emission Source Listing. The Permittee may store fuel consumption data electronically. The Permittee shall make available the logs and data for inspection by VIDPNR and EPA upon request.

[33 PTO (i), Permit Nos. 326-94, 332-94, 333-94, 343-94, 352-94, 468-94, and 469-94, November 28, 1994]

5.3.2.2 Group 02B – Heaters H-160, H-200, H-201, H-202, H-600, H-601, H-602, H-603, H-604, H-605, H-606, H-800A, H-800B, H-801, H-1500, H-1501, H-2201A, H-2201B, H-2202, H-2400, H-2401, H-2501, H-4301A, H-4301B, H-4302, H-4401, H-4402, H-4451, H-4452, H-4453, H-4454, H-4455, H-4502, H-4503, H-4504, H-4505, H-4601A, H-4601B, H-4602, H-5301A, H-5301B, H-5302 H-5401, H-5402, H-5451, H-5452, H-5453, H-5454, H-5455

5.3.2.2.1 The Permittee shall report to VIDPNR changes and alterations in operations that result in an increase in regulated emissions.
[33 PTO (c), Permit Nos. 328-94, 331-94, 335-94, 342-94, 350-94, 351-94, 466-94, 467-94, 470-94, 471-94, 472-94, 473-94, 477-94, 478-94, November 28, 1994]

5.3.2.2.2 The Permittee shall allow VIDPNR to inspect its facility during reasonable hours. The inspection shall be conducted in a timely manner, in the presence of, and with full assistance and cooperation of LIMETREE BAY TERMINALS LLC management. VIDPNR shall issue an advanced verbal request for the use of cameras and vocal recording devices.
[33 PTO (f), Permit Nos. 328-94, 331-94, 335-94, 342-94, 350-94, 351-94, 466-94, 467-94, 470-94, 471-94, 472-94, 473-94, 477-94, 478-94, November 28, 1994]

5.3.2.2.3 The Permittee shall initiate operation, maintenance, and fuel consumption records and shall keep these records on a daily and cumulative basis. The Permittee shall keep one log for each operating area which shall contain information regarding the operation and maintenance of each permitted unit in the areas listed in the LIMETREE BAY TERMINALS LLC Air Emission Source Listing. The Permittee may store fuel consumption data electronically. The Permittee shall make available the logs and data for inspection by VIDPNR and EPA upon request.
[33 PTO (i), Permit Nos. 328-94, 331-94, 335-94, 342-94, 350-94, 351-94, 466-94, 467-94, 470-94, 471-94, 472-94, 473-94, 477-94, 478-94, November 28, 1994]

5.3.2.3 Group 02C – Heater H-2185

5.3.2.3.1 The Permittee must submit quarterly excess emissions reports to VIDPNR and EPA in accordance with the quarterly excess emissions reporting requirements as required in 40 CFR 60.7. The Permittee shall report upsets/ malfunctions, changes in operating scenarios, and implementation of the HOVIC supplemental control plan by telephone or facsimile within four (4) hours, with a follow-up letter submitted within seven (7) calendar days to VIDPNR.
[1997 PSD Permit (VII); 40 CFR 60.7]

5.3.2.3.2 In each report quarter, the Permittee shall maintain a 95% quality data availability for the opacity monitor. The Permittee shall have a quality assurance plan coupled with a calibration and maintenance program.

[1997 PSD Permit (VI)(D) and (E)]

5.3.2.3.3 In each report quarter, the Permittee shall maintain a 90% quality data availability for all gaseous monitors. The Permittee shall have a quality assurance plan coupled with a calibration and maintenance program.

[1997 PSD Permit (VI)(D) and (E)]

5.3.2.3.4 The Permittee shall continuously record the H_2S concentration (dry basis) in the fuel gas.

[40 CFR 105(a)(4); 40 CFR 60.107]

5.3.2.3.5 In lieu of the above H_2S recording requirements, the Permittee may instead comply with EPA-approved alternative monitoring requirements or exemption from monitoring for combusted fuel gas streams, as applicable, in accordance with provisions of 40 CFR 60.13(i) or 60.105(b).

[40 CFR 60.13(i); 40 CFR 60.105(b)]

5.3.2.3.6 The Permittee shall report to VIDPNR changes and alterations in operations that result in an increase in regulated emissions.

[33 PTO (c), Permit No. 139-94, November 28, 1994]

5.3.2.3.7 The Permittee shall allow VIDPNR to inspect its facility during reasonable hours. The inspection shall be conducted in a timely manner, in the presence of, and with full assistance and cooperation of LIMETREE BAY TERMINALS LLC management. VIDPNR shall issue an advanced verbal request for the use of cameras and vocal recording devices.

[33 PTO (f), Permit No. 139-94, November 28, 1994]

5.3.2.3.8 The Permittee shall initiate operation, maintenance, and fuel consumption records and shall keep these records on a daily and cumulative basis. The Permittee shall keep one log for each operating area which shall contain information regarding the operation and maintenance of each permitted unit in the areas listed in the LIMETREE BAY TERMINALS LLC Air Emission Source Listing. The Permittee may store fuel consumption data electronically. The Permittee shall make available the logs and data for inspection by VIDPNR and EPA upon request.

[33 PTO (i), Permit No. 139-94, November 28, 1994]

5.3.2.4 Group 02D – Heater H-4901(LSG Unit Heater) and Hydrogen Plant Heater

5.3.2.4.1 The Permittee shall keep logs and update them daily to record all fuel sampling results verifying that the sulfur content meets the requirements in sections 3.2.2.3.10 and 3.2.2.3.11.

[LSFP PSD Permit XIII.1.f]

5.3.2.4.2 The Permittee shall comply, as applicable, with the reporting requirements as required in 40 CFR 60.107. The Permittee shall submit excess emission reports on a quarterly basis. For the purpose of reports, excess emissions shall be determined and reported in terms of 3-hour rolling and 24-hour rolling average concentrations of H_2S.

[40 CFR 60.7; 40 CFR 60.107]

5.3.2.4.3 The Permittee shall continuously record the H_2S concentration (dry basis) in the fuel gas.

[40 CFR 60.105(a)(4); 40 CFR 60.107]

5.3.2.4.4 In lieu of the above H_2S monitoring requirements, the Permittee may instead comply with EPA-approved alternative monitoring requirements or exemption from monitoring for combusted fuel gas streams, as applicable, in accordance with provisions of 40 CFR 60.13(i) or 60.105(b).

[40 CFR 60.13(i); 40 CFR 60.105(b)]

5.3.2.4.5 The Permittee shall keep logs and update them daily to record any adjustments and maintenance performed on the combustion turbine unit, the heaters, and/or the FCCU.

[LSFP PSD Permit XIII.1.i]

5.3.2.4.6 The Permittee shall keep logs and update them daily to record any adjustments and maintenance performed on monitoring systems.

[LSFP PSD Permit XIII.1.j]

5.3.2.4.7 The Permittee shall submit a written report to EPA of the results of all emission testing within 60 days of the completion of the performance test, but in any event, no later than 180 days after initial startup as defined in 40 CFR 60.2, and once every five years thereafter (with the exception of those pollutants for which a CEM is required).

[LSFP PSD Permit XI.A.1; LSFP PSD Permit XI.A.8]

5.3.2.4.8 At least 60 days prior to actual testing, the Permittee shall submit to EPA a Quality Assurance Project Plan detailing methods and procedures to be used during the performance stack testing. A Quality Assurance Project Plan that does not have EPA approval may be grounds to invalidate any test and require a re-test.

[LSFP PSD Permit XI.A.3]

5.3.2.4.9 Any failure of air pollution control equipment, process equipment, or of a process to operate in a normal manner which results in an increase in emissions above any allowable emission limit stated in the LSFP PSD permit and any corrective actions and/or preventative measures taken on any unit must be reported by telephone within 24 hours to: Director, Caribbean Environmental Protection Division, U.S. Environmental Protection Agency, Centro Europa Building, Suite 417, Ponce de Leon Avenue, San Juan, Puerto Rico 00907.

[LSFP PSD Permit XIV.1.g]

5.3.2.4.10 The U.S. EPA's Air Compliance Branch shall be notified in writing within fifteen (15) days of any such failure described in section 5.3.2.4.7. This notification shall include a description of the malfunctioning equipment or abnormal operation; the date of the initial failure; the period of time over which emissions were increase due to the failure; the cause of the failure; the estimated resultant emission in excess of those allowed under the LSFP PSD Permit; and the methods used to restore normal operations. Compliance with this malfunction notification provision shall not excuse or otherwise constitute a defense to any violations of the LSFP PSD permit or of any law or regulations which such malfunction may cause.

[LSFP PSD Permit XIV.1.h]

5.3.2.4.11 All reports and Quality Assurance Project Plans required by the LSFP PSD Permit shall be submitted to: Director, Caribbean Environmental Protection Division, U.S. Environmental Protection Agency, Centro Europa Building, Suite 417, Ponce de Leon Avenue, San Juan, Puerto Rico 00907.

[LSFP PSD Permit XIV.2]

5.3.2.4.12 Copies of all reports and Quality Assurance Project Plans shall also be submitted to: (a) Chief, Air Programs Branch – Permitting Section, U.S. Environmental Protection Agency, Region 2, 290 Broadway, New York, NY 10007; and (b) Director, Division of Environmental Protection, Virgin Islands Department of Planning and Natural Resources, 45 Mars Hill, Frederiksted, VI 00840-4744.

[LSFP PSD Permit XIV.3]

5.3.2.4.13 For Heater H-4901 and the Hydrogen Plant heater, the Permittee shall submit a written report to EPA of the results of all monitor performance specification evaluations conducted on the monitoring system(s) within 60 days of the completion of the tests. The monitoring systems must meet all the requirements of the applicable performance specification test in order for the monitors to be certified.

[LSFP PSD Permit X.8]

5.3.2.4.14 For Heater H-4901 and the Hydrogen Plant heater, the Permittee shall submit a written report of all excess emissions to EPA for every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each quarter.

[LSFP PSD Permit XIV.1]

5.3.2.4.15 For Heater H-401 and the Hydrogen Plant heater, all quarterly reports shall include the information specified below:

(a) The magnitude of excess emissions computed in accordance with 40 CFR 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions.

(b) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions for the combustion units. The nature and cause of any malfunction (if known) and the corrective action taken or preventive measures adopted shall also be reported.

(c) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

(d) When no excess emissions have occurred or the monitoring systems have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

(e) Results of quarterly monitor performance audits, as required by 40 CFR 60, Appendix F (including the Data Assessment Report) and all information required by the reporting requirements in 40 CFR 60.7 including excess emissions and CEMS downtime summary sheets.

[LSFP PSD Permit XIV.1.a through e]

5.3.2.5 Group 02E – Heaters H-7801, H-7802, and R-7801 and Stack STK-7801

5.3.2.5.1 The Permittee shall submit quarterly excess emissions reports to VIDPNR and EPA in accordance with the quarterly excess emissions reporting requirements as required in 40 CFR 60.7.

[1997 PSD Permit (VII); 40 CFR 60.7]

5.3.2.5.2 The Permittee shall continuously record the H_2S concentration (dry basis) in the fuel gas.

[40 CFR 60.105(a)(4); 40 CFR 60.107]

5.3.2.5.3 In lieu of the above H_2S monitoring requirements, the Permittee may instead comply with EPA-approved alternative monitoring requirements or exemption from monitoring for combusted fuel gas streams, as applicable, in accordance with provisions of 40 CFR 60.13(i) or 60.105(b).

[40 CFR 60.13(i); 40 CFR 60.105(b)]

5.3.2.5.4 The Permittee shall record the beginning, duration, the completion of start-up episodes, and the reason(s) for the prior shutdown of the sulfuric acid plant process heaters.

[1997 PSD Permit (VI)(C) and (D)]

5.3.2.5.5 In each report quarter, the Permittee shall maintain a 95% quality data availability for the opacity and O_2 monitors. The Permittee shall have a quality assurance plan coupled with a calibration and maintenance program.

[1997 PSD Permit (VI)(D) and (E)]

5.3.2.5.6 For STK 7801, the Permittee shall report to VIDPNR changes and alterations in operations that result in an increase in regulated emissions.

[33 PTO (c), Permit No. 479-94, November 28, 1994]

5.3.2.5.7 For STK-7801, the Permittee shall allow VIDPNR to inspect its facility during reasonable hours. The inspection shall be conducted in a timely manner, in the presence of, and with full assistance and cooperation of LIMETREE BAY TERMINALS LLC management. VIDPNR shall issue an advanced verbal request for the use of cameras and vocal recording devices.

[33 PTO (f), Permit No. 479-94, November 28, 1994]

5.3.2.5.8 For STK-7801, the Permittee shall initiate operation, maintenance, and fuel consumption records and shall keep these records on a daily and cumulative basis. The Permittee shall keep one log for each operating area which shall contain information regarding the operation and maintenance of each permitted unit in the areas listed in the LIMETREE BAY TERMINALS LLC Air Emission Source Listing. The Permittee may store fuel consumption data electronically. The Permittee shall make available the logs and data for inspection by VIDPNR and EPA upon request.

[33 PTO (i), Permit No. 479-94, November 28, 1994]

5.3.2.6 Group 02F – Incinerators H-1032, H-1042, and H-4745

5.3.2.6.1 The Permittee shall comply, as applicable, with the recordkeeping requirements as required in VIRR 12-09-204-45.

[VIRR 12-09-204-45]

5.3.2.6.2 If excess tail gas is vented to any of the three existing incinerators when the operating Beavon unit is charged to capacity, the Permittee shall provide written justification to the EPA describing the nature of the venting and provide planned mitigation procedures to the EPA for prior approval. If all Claus Plant tail gas is vented to any of the three existing incinerators when neither Beavon unit is operating, the Permittee shall provide written justification to the EPA describing the nature of the outage and provide planned mitigation procedures to the EPA for prior approval.

[1997 PSD Permit (IV)(A), (B) and (C)]

5.3.2.6.3 For the purpose of reports under 40 CFR 60.7(c) for H-1032 and H-1042, periods of excess emission that shall be determined and reported are defined as follows: all 12 hour periods during which the average concentration of SO_2 as measure by the SO_2 continuous monitoring system under 40 CFR 60.105(a)(5) exceeds 250 ppm (dry basis, zero percent air). The Permittee shall submit excess emission reports on a quarterly basis.

[40 CFR 60.105(e)(4)(i); 40 CFR 60.7(c)]

5.3.2.6.4 For H-4745, the Permittee shall comply, as applicable, with the recordkeeping and reporting requirements as required in 40 CFR 61 Subpart BB.

[40 CFR 61.305]

5.3.2.6.5 The Permittee shall report to VIDPNR changes and alterations in operations that result in an increase in regulated emissions.

[33 PTO (c), Permit No. 480-94, November 28, 1994]

5.3.2.6.6 The Permittee shall allow VIDPNR to inspect its facility during reasonable hours. The inspection shall be conducted in a timely manner, in the presence of, and with full assistance and cooperation of LIMETREE BAY TERMINALS LLC management. VIDPNR shall issue an advanced verbal request for the use of cameras and vocal recording devices.

[33 PTO (f), Permit No. 480-94, November 28, 1994]

5.3.2.6.7 The Permittee shall initiate operation, maintenance, and fuel consumption records and shall keep these records on a daily and cumulative basis. The Permittee shall keep one log for each operating area which shall contain information regarding the operation and maintenance of each permitted unit in the areas listed in the LIMETREE BAY TERMINALS LLC Air Emission Source Listing. The Permittee may store fuel consumption data electronically. The Permittee shall make available the logs and data

for inspection by VIDPNR and EPA upon request.
[33 PTO (i), Permit No. 480-94, November 28, 1994]

5.3.2.6 Group 02G – Heaters H-8501A and H-8501B

5.3.2.7.1 The Permittee shall comply, as applicable, with the quarterly excess emissions reporting requirements as required in 40 CFR 60.7.
[40 CFR 60.7; 40 CFR 60.105(e)]

5.3.2.7.2 For the H_2S analyzers required by 5.2.2.8.4, the Permittee shall submit to the VIDPNR in a Performance Specification Testing Protocol equipment specifications, calibration, and operating procedures and data evaluation and reporting procedures
[STX-557A-E-02(X)(B), June 4, 2002]

5.3.2.7.3 The H_2S analyzers shall be equipped with data recording equipment to ensure that the fuel gas supply to the coker process heaters (H-8501A and H-8501B) is recorded on a continuous basis. The Permittee shall record the H_2S content records in a VIDPNR approved method.
[STX-557A-E-02(X)(C), June 4, 2002]

5.3.2.7.4 The Permittee shall report to the VIDPNR any exceedance of H_2S content in fuel gas supplied to H-8501A and H-8501B in writing within three (3) days of its occurrence. The report shall include but not be limited to H_2S content of all fuel, the quantity of fuel and the corrective actions taken to bring this process back into compliance.
[STX-557A-E-02(X)(D), June 4, 2002]

5.3.2.7.5 The Permittee shall submit quarterly and annual report to the VIDPNR reporting all reporting all exceedances of the permit conditions of the H_2S content of all fuel gas supplied to H-8501A and H-8501B.
[STX-557A-E-02(X)(E), June 4, 2002]

5.3.2.7.6 The Permittee shall submit to the VIDPNR the results of the NOx emission rate test runs and the CO emission rate test runs on H-8501A and H-8501B.
[STX-557A-E-02(X)(F) and (G), June 4, 2002]

5.3.2.7.7 The coker process heaters are subject to and the Permittee shall demonstrate compliance with monitoring, recording, and reporting as required by 40 CFR 60, Subpart J for petroleum refineries, 60.100 et. seq.
[STX-557A-E-02(X)(L) and (M), June 4, 2002]

5.3.3 Group 03 – Compressor Engines

5.3.3.1 For C-200A, C-200B, C-200C, C-2400A, and C-2400B, for formaldehyde, the Permittee shall comply with the recordkeeping requirements, as applicable, in 40 CFR 63, Subpart ZZZZ, 63.6655 through 63.6665, as applicable.

[40 CFR 63, Subpart ZZZZ]

5.3.3.2 For C-200A, C-200B, C-200C, C-2400A, and C-2400B, for formaldehyde, the Permittee shall comply with the reporting requirements, as applicable, in 40 CFR 63, Subpart ZZZZ, 63.6645, 63.6650, and 63.6665. Reports shall be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the semiannual reporting period.

[40 CFR 63, Subpart ZZZZ; 40 CFR 63.6650(b)(4)]

5.3.3.3 The Permittee shall report to VIDPNR changes and alterations in operations that result in an increase in regulated emissions.

[33 PTO (c), Permit Nos. 328-94, 331-94, 350-94, and 373-94, November 28, 1994]

5.3.3.4 The Permittee shall allow VIDPNR to inspect its facility during reasonable hours. The inspection shall be conducted in a timely manner, in the presence of, and with full assistance and cooperation of LIMETREE BAY TERMINALS LLC management. VIDPNR shall issue an advanced verbal request for the use of cameras and vocal recording devices.

[33 PTO (f), Permit Nos. 328-94, 331-94, 350-94, and 373-94, November 28, 1994]

5.3.3.5 The Permittee shall initiate operation, maintenance, and fuel consumption records and shall keep these records on a daily and cumulative basis. The Permittee shall keep one log for each operating area which shall contain information regarding the operation and maintenance of each permitted unit in the areas listed in the LIMETREE BAY TERMINALS LLC Air Emission Source Listing. The Permittee may store fuel consumption data electronically. The Permittee shall make available the logs and data for inspection by VIDPNR and EPA upon request.

[33 PTO (i), Permit Nos. 328-94, 331-94, 350-94, and 373-94, November 28, 1994]

5.3.3.6 The Permittee shall report the results of the tests on the catalytic converters installed on the two compressor engines located on #5DD and the three compressors at the Penex Unit to VIDPNR no later than 60 days after the last day of the quarter.

[STX-557-A-E-02(X)(J), June 4, 2002]

5.3.4 Group 04 – Combustion Turbines

5.3.4.1 Group 04A - Turbines G-1101E, G-1101F, G-1101G, G-3404, G-3405, G-

3406, G-3407, G-3408, G-3409, G-3410

5.3.4.1.1 The Permittee shall continuously record the H_2S concentration (dry basis) in the fuel gas.

[40 CFR 60.105(a)(4); 40 CFR 60.107]

5.3.4.1.2 The Permittee shall comply, as applicable, with the quarterly excess emissions reporting requirements as required in 40 CFR 60.7.

[40 CFR 60.7]

5.3.4.1.3 In lieu of the above H_2S recordkeeping and reporting requirements, the Permittee may instead comply with EPA-approved alternative monitoring requirements or exemption from monitoring for combusted fuel gas streams, as applicable, in accordance with provisions of 40 CFR 60.13(i) or 60.105(b).

[40 CFR 60.13(i); 40 CFR 60.105(b)]

5.3.4.1.4 If the Permittee elects to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content or fuel nitrogen under this Subpart, the Permittee shall submit reports of excess emissions and monitor downtime, in accordance with 40 CFR 60.7(c). Excess emissions shall be reported for all periods of unit operation, including startup, shutdown, and malfunction. For the purposes of reports required under 40 CFR 60.7(c), periods of excess emissions and monitor downtime that shall be reported are defined in 40 CFR 60.334(j). In lieu of the above requirements, the Permittee may instead comply with custom schedule(s) for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply, as applicable, in accordance with provisions of 40 CFR 60.334(i)(3).

[40 CFR 60.334(i)(3); 40 CFR 60.334(j)]

5.3.4.1.5 The Permittee shall comply, as applicable, with the recordkeeping and reporting requirements in 40 CFR 60, Subparts A and GG.

[40 CFR 60.7; 40 CFR 60.330 through 60.335]

5.3.4.1.6 The sulfur content of the fuel oil shall be recorded each time fuel oil is transferred to the storage tank.

[40 CFR 60.334(i)]

5.3.4.1.7 For G-3410, the Permittee shall determine and record daily the sulfur content of the liquid fuels that are directly transferred from a process unit.

[GT-10 PSD Permit (XII)(5)]

5.3.4.1.8 The Permittee shall monitor and record the fuel consumption and the ratio of the steam to fuel being fired in GT No. 10 (unit G-3410).
[GT-10 PSD Permit (XII)(3)]

5.3.4.1.9 For G-3410, the Permittee shall submit a written report of all excess emissions to EPA for every calendar quarter. Excess emissions shall be defined as: (1) any one hour period during which the average emissions of NOx or of CO, as measured by the CEM systems exceeds the corresponding mass or concentration emission limits set for NOx or for CO in the GT-10 PSD Permit; (2) any rolling 365-day period during which the total emissions of NOx or of CO as measured by the CEM system exceeds the corresponding annual emissions limit in the GT-10 PSD Permit.
[GT-10 PSD Permit (X)(5)]

5.3.4.1.10 For G-3410, for opacity, excess emissions shall be defined as any 6-minute period during which the average opacity, as measured by the CEM system, exceeds 10% opacity, except for one 25% opacity per each one-hour period.
[GT-10 PSD Permit (X)(5)]

5.3.4.1.11 For G-3410, the Permittee shall maintain a file of all measurements, including CEM system performance evaluations, all CEM systems or monitoring device calibration checks, adjustments and maintenance performed on these systems or devices, and all other information required by 40 CFR 60 recorded in a permanent form suitable for inspection.
[GT-10 PSD Permit (X)(6)]

5.3.4.1.12 The Permittee shall notify EPA 15 days in advance of the date upon which demonstration of the CEM system performance will commence (40 CFR 60.13(c)). This date shall be no later than sixty days after the GT No. 10 (G-3410) startup. The Permittee shall submit a written report to EPA of the results of all monitor performance specification tests conducted on the monitoring systems within 45 days of the completion of the tests. The continuous emission monitors must meet all the requirements of the applicable performance specification test in order for the monitors to be certified.
[GT-10 PSD Permit (X)(3) and (4)]

5.3.4.1.13 For G-3410, all quarterly reports shall be postmarked by the 30th day following the end or each quarter and shall include the following information:

(a) The magnitude of excess emissions computed in accordance with

40 CFR 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions.

(b) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions for the GT No. 10 unit. The Permittee shall also report the nature and cause of any malfunction (if known) and the corrective action taken or preventive measures adopted.

(c) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

(d) When no excess emissions have occurred or the CEM system has not been inoperative, repaired, or adjusted, such information shall be stated in the report.

(e) Results of quarterly monitor performance audits, as required in 40 CFR 60, Appendix F.

[GT-10 PSD Permit (X)(5)]

5.3.4.1.14 For G-3410, the Permittee shall submit to EPA for approval the proposed methodology for the calculation of the NOx and CO mass emission rates at the same time the Quality Assurance Project Plan is submitted. The calculated mass emission rates shall be used to determine compliance with the NOx and CO mass emission rate limits.

[GT-10 PSD Permit (X)(9)]

5.3.4.1.15 For G-3410, at least 60 days prior to actual testing, the Permittee shall submit to the EPA a Quality Assurance Project Plan detailing methods and procedures to be used during the performance stack testing. A Quality Assurance Project Plan that does not have EPA approval may be grounds to invalidate any test and require a re-test.

[GT-10 PSD Permit (XI)(2)]

5.3.4.1.16 For G-3410, the Permittee shall submit results of emission testing to EPA within 60 days after completion of performance tests.

[GT-10 PSD Permit (XI)(7)]

5.3.4.1.17 For G-3410, all reports required by the GT-10 PSD Permit shall be submitted to:

Chief, Air Compliance Branch
Division of Enforcement and Compliance Assistance
U.S. Environmental Protection Agency
Region 2
290 Broadway – 21st Floor

New York, New York 10007-1866

Copies of the reports required by the GT-10 PSD Permit shall be submitted to:

Region 2 CEM Coordinator
U.S. Environmental Protection Agency
Region 2
Air and Water QA Team
Monitoring and Assessment Branch
2890 Woodbridge Avenue – MS-102
Edison, New Jersey 08837-3679

Director, Division of Environmental Protection
Virgin Islands Department of Planning and Natural Resources
45 Mars Hill
Frederiksted, VI 00840-4744

[GT-10 PSD Permit (XII)(10)]

5.3.4.1.18 The Permittee shall report to VIDPNR changes and alterations in operations that result in an increase in regulated emissions.

[33 PTO (c), Permit No. 484-94, November 28, 1994]

5.3.4.1.19 The Permittee shall allow VIDPNR to inspect its facility during reasonable hours. The inspection shall be conducted in a timely manner, in the presence of, and with full assistance and cooperation of LIMETREE BAY TERMINALS LLC management. VIDPNR shall issue an advanced verbal request for the use of cameras and vocal recording devices.

[33 PTO (f), Permit No. 484-94, November 28, 1994]

5.3.4.1.20 The Permittee shall sample fuel oil sources as regulated under PSD permits for nitrogen and sulfur concentrations and maintain these data for not less than five years. The Permittee shall analyze sulfur concentrations in other regulated fuel oils on each tank prior to usage. Fuel oil sulfur concentrations shall be in compliance with VIRR 12-09-204 and 206, as amended.

[33 PTO (g), Permit No. 484-94, November 28, 1994]

5.3.4.1.21 The Permittee shall initiate operation, maintenance, and fuel consumption records and shall keep these records on a daily and cumulative basis. The Permittee shall keep one log for each operating area which shall contain information regarding the operation and maintenance of each permitted unit in the areas listed in the LIMETREE BAY TERMINALS LLC Air Emission Source Listing. The Permittee may store fuel consumption data

electronically. The Permittee shall make available the logs and data for inspection by VIDPNR and EPA upon request.
[33 PTO (i), Permit No. 484-94, November 28, 1994]

5.3.4.1.22 The Permittee shall record the fuel consumption and the ratio of the steam to fuel fired in GT No. 9 (G-3409).
[STX-557-J-K-05(C)(3), November 22, 2005]

5.3.4.1.23 The Permittee shall include the information referenced in condition 5.3.4.1.22, in any report to the Administrator as required under 40 CFR 52.21(r)(6)(v).
[STX-557-J-K-05(C)(7), November 22,2005]

5.3.4.1.24 For G-3409, the Permittee shall record daily the sulfur content of the liquid fuels that are directly transferred from a process unit.
[STX-557-J-K-05(C)(5), November 22, 2005]

5.3.4.1.25 For G-3409, the Permittee shall submit a written report to VIDPNR of the results of all monitor performance specification tests conducted on the monitoring system(s) within 45 days of the completion of the tests. The continuous emission monitors shall meet all the requirements of the applicable performance specifications test in order for the monitors to be certified.
[STX-557-J-K-05(D)(4), November 22, 2005]

5.3.4.1.26 For G-3409, the Permittee shall submit a written report of all excess emissions to VIDPNR for every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each quarter and shall include the information specified in the sections of this permit that reference section (D)(5) of permit no. STX-557-J-K-05.
[STX-557-J-K-05(D)(5), November 22, 2005]

5.3.4.1.27 For G-3409, the Permittee shall maintain a file of all measurements, including CEM system performance evaluations, all CEM system or monitoring device calibration checks, adjustments and maintenance performed on these systems or devices, and all other information required by 40 CFR 60 recorded in a permanent form suitable for inspections.
[STX-557-J-K-05(D)(6), November 22, 2005]

5.3.4.1.28 For G-3409, in each quarterly report, the Permittee shall maintain 95% data availability for all gaseous monitors.
[STX-557-J-K-05(D)(10), November 22, 2005]

5.3.4.1.29 The Permittee shall submit all reports required under permit STX-557-J-K-05 to the following:

Director, Division of Environmental Protection
Virgin Islands Department of Planning and Natural Resources

45 Mars Hill
Frederiksted, VI 00840-4744

U.S. Environmental Protection Agency
Region 2 – Caribbean Environmental Protection Division
Centro Europa Building
1492 Ponce De Leon Avenue, Suite 417
San Juan, PR 00907-4127

[STX-557-J-K-05(D)(11)]

5.3.4.2 Group 04B - G-3413 (GT. No. 13) and Associated Duct Burner H-3413

5.3.4.2.1 The Regional Administrator (RA) shall be notified in writing of the anticipated date of initial startup (as defined in 40 CFR 60.2) of each facility of the source not more than sixty (60) days nor less than thirty (30) days prior to such date. The RA shall be notified in writing of the actual date of both commencement of construction and startup within fifteen (15) days after such date.

[LSFP PSD Permit II]

5.3.4.2.2 The Permittee shall keep logs and update them daily to record the daily barrels of No. 2 fuel oil fired in the combustion turbine totaled with the barrels of oil fired in the combustion turbine for the last 364 consecutive days.

[LSFP PSD Permit XIII.1.e]

5.3.4.2.3 The Permittee shall keep logs and update them daily to record all fuel sampling results verifying that the sulfur content meets the requirements in sections 3.2.4.2.13, 3.2.4.2.14, 3.2.4.2.16, 3.2.4.2.18, and 3.2.4.2.19 of this Title V permit.

[LSFP PSD Permit XIII.1.f]

5.3.4.2.4 The Permittee shall keep logs and update them daily to record the beginning, duration, and completion of each startup and shutdown for GT No. 13 (G-3413).

[LSFP PSD Permit XIII.1.g]

5.3.4.2.5 The Permittee permit shall keep logs and update them daily to record the total pounds of NOx, as measured by the CEM, for each startup and shutdown for GT No. 13 (G-3414).

[LSFP PSD Permit XIII.1.h]

5.3.4.2.6 The Permittee permit shall keep logs and update them daily to record any adjustments and maintenance performed on the combustion turbine unit and monitoring systems.

[LSFP PSD Permit XIII.1.i and XIII.1.j]

5.3.4.2.7 The Permittee shall comply, as applicable, with the reporting requirements as required in 40 CFR 60.107. The Permittee shall submit excess emission reports on a quarterly basis. For the purpose of reports, excess emissions shall be determined and reported in terms of 3-hour rolling and 24-hour rolling average concentrations of H_2S.

[40 CFR 60.107]

5.3.4.2.8 The Permittee shall submit a written report to EPA of the results of all emission testing within 60 days of the completion of the performance test, but in any event, no later than 180 days after initial startup as defined in 40 CFR 60.2, and once every five years thereafter (with the exception of those pollutants for which a CEM is required).

[LSFP PSD Permit XI.A.1; LSFP PSD Permit XI.A.8]

5.3.4.2.9 Within 60 days of performing the PM and PM-10 tests, the Permittee shall submit a test report to EPA and propose new PM/PM-10 limits which will be less than or equal to the values identified in sections 3.2.4.2.18 and 3.2.4.2.19 of this Title V permit. Upon approval, and if applicable, EPA will administratively amend the LSFP PSD Permit to reflect the new limit(s).

[LSFP PSD Permit VIII.A.3]

5.3.4.2.10 The Permittee shall submit a written report to EPA of the results of all monitor performance specification evaluations conducted on the monitoring system(s) within 60 days of the completion of the test. The monitoring systems must meet all the requirements of the applicable performance specification test in order for the monitors to be certified.

[LSFP PSD Permit X.8]

5.3.4.2.11 Within 60 days of study completion as referenced in condition 3.2.4.2.25, the Permittee shall submit a report with the results of the performance demonstration of the SCR system and propose a new NOx limit which will be less than or equal to the limits established in section 3.2.4.2.22.2 of this Title V permit. If approved by EPA, EPA will administratively amend the LSFP PSD Permit to reflect the new NOx limit(s). If EPA determines that a lower limit is appropriate, EPA will re-propose the LSFP PSD Permit for the purposes of modifying this condition.

[LSFP PSD Permit VIII.A.5.c]

5.3.4.2.12 Not less than 90 days prior to the date of startup of the combustion turbine, the Permittee shall submit a written report to EPA of a Quality Assurance Project Plan for the certification of the combustion turbine's monitoring systems. Performance evaluation of the monitoring systems may not begin until the Quality Assurance Project Plan has been approved by EPA.

[LSFP PSD Permit X.6]

5.3.4.2.13 At least 60 days prior to actual testing, the Permittee shall submit to the EPA a Quality Assurance Project Plan detailing methods and procedures to be used during the performance stack testing. A Quality Assurance Project Plan that does not have EPA approval may be grounds to invalidate any test and require a re-test.

[LSFP PSD Permit XI.A.3]

5.3.4.2.14 The Permittee shall submit a written report of all excess emissions to EPA every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each quarter and shall include the information specified below:

[LSFP PSD Permit XIV.1]

(a) The magnitude of excess emissions computed in accordance with 40 CFR 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions.

[LSFP PSD Permit XIV.1.a]

(b) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions for the combustion units. The nature and cause of any malfunction (if known) and the corrective action taken or preventive measures adopted shall also be reported.

[LSFP PSD Permit XIV.1.b]

(c) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

[LSFP PSD Permit XIV.1.c]

(d) When no excess emissions have occurred or the monitoring systems have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

[LSFP PSD Permit XIV.1.d]

(e) Results of quarterly monitor performance audits, as required in 40 CFR 60, Appendix F (including the Data Assessment Report) and all information required by the reporting requirements in 40 CFR 60.7 including excess emissions and CEMS downtime summary sheets.

[LSFP PSD Permit XIV.1.e]

5.3.4.2.15 Any failure of air pollution control equipment, process equipment, or of a process to operate in a normal manner which results in an increase in emissions above any allowable emission limit stated in the LSFP PSD Permit and any corrective actions and/or preventive measures taken on any unit must be reported by telephone within 24 hours to:

Director, Caribbean Environmental Protection Division
U.S. Environmental Protection Agency
Centro Europa Building, Suite 417
Ponce de Leon Avenue
San Juan, Puerto Rico 00907

[LSFP PSD Permit XIV.1.g]

5.3.4.2.16 The U.S. EPA's Air Compliance Branch shall be notified in writing within fifteen (15) days of any such failure described in section 5.3.4.2.12. This notification shall include a description of the malfunctioning equipment or abnormal operation; the date of the initial failure; the period of time over which emissions were increased due to the failure; the cause of the failure; the estimated resultant emissions in excess of those allowed under this permit; and the method utilized to restore normal operations. Compliance with this malfunction notification provision shall not excuse or otherwise constitute a defense to any violations of this permit or of any law or regulations which such malfunction may cause.

[LSFP PSD Permit XIV.1.h]

5.3.4.2.17 All reports and Quality Assurance Project Plans required by this LSFP PSD permit shall be submitted to:

Director, Caribbean Environmental Protection Division
U.S. Environmental Protection Agency
Centro Europa Building, Suite 417
Ponce de Leon Avenue
San Juan, Puerto Rico 00907

[LSFP PSD Permit XIV.2]

5.3.4.2.18 Copies of all reports and Quality Assurance Project Plans shall also be submitted to:

Chief, Air Programs Branch – Permitting Section
U.S. Environmental Protection Agency
Region 2

290 Broadway
New York, New York 10007

Director, Division of Environmental Protection
Virgin Islands Department of Planning and Natural Resources
45 Mars Hill
Frederiksted, VI 00840-4744

[LSFP PSD Permit XIV.3]

5.3.4.2.19 The Permittee shall continuously record the H_2S concentration (dry basis) in the fuel gas.

[40 CFR 60.105(a)(4); 40 CFR 60.107]

5.3.4.2.20 In lieu of the above H_2S monitoring requirements, the Permittee may instead comply with EPA-approved alternative monitoring requirements or exemption from monitoring for combusted fuel gas streams, as applicable, in accordance with provisions of 40 CFR 60.13(i) or 60.105(b).

[40 CFR 60.13(i); 40 CFR 60.105(b)]

5.3.4.2.21 The Permittee shall comply with the recordkeeping and reporting requirements, as applicable, in 40 CFR 60.4375 and 60.4395. The Permittee shall submit reports semiannually on the 30th day following each 6-month reporting period.

[40 CFR 60, Subpart KKKK]

5.3.4.2.22 The Permittee shall comply, as applicable, with the recordkeeping requirements in 40 CFR 63.6155, 63.6160, 63.6165, and requirements in any EPA-approved alternative monitoring plan for formaldehyde emissions during catalyst bypasses.

[40 CFR 63, Subpart YYYY]

5.3.4.2.23 The Permittee shall comply, as applicable, with the reporting requirements in 40 CFR 63.6145, 63.6150, and 63.6165. The Permittee shall report compliance status semiannually, according to the requirements of 40 CFR 63.6150.

[40 CFR 63, Subpart YYYY]

5.3.5 Group 05 – Flares

5.3.5.1 For the #6 Flare, the Permittee shall comply with the recordkeeping requirements of 40 CFR 63, Subpart F, as applicable. All applicable records shall be maintained in such a manner that they can be readily accessed. The most recent 6 months of records shall be retained on site or shall be accessible from a central location by computer or other means that provides access within 2 hours after a request. The remaining four and one-half years of records may be retained offsite.

[40 CFR 63.103]

5.3.5.2 For the #6 Flare, the Permittee shall comply with the reporting requirements of 40 CFR 63, Subpart F, as applicable.

[40 CFR 63.103]

5.3.5.3 For the #6 Flare, the Permittee shall comply, as applicable, with the recordkeeping requirements as required in 40 CFR 63, Subpart G.

[40 CFR 63.110 through 153]

5.3.5.4 For the #6 Flare, the Permittee shall comply, as applicable, with the reporting requirements as required in 40 CFR 63, Subpart G.

[40 CFR 63.110 through 153]

5.3.5.5 For the #6 Flare, the Permittee shall comply with the recordkeeping requirements of 40 CFR, Subpart H, as applicable.

[40 CFR 63.181]

5.3.5.6 For the #6 Flare, the Permittee shall comply with the reporting requirements of 40 CFR 63, Subpart H, as applicable. The Permittee shall submit the periodic report semiannually.

[40 CFR 63.182]

5.3.5.7 For the FCC LP Flare and the LPG Flare, the Permittee shall continuously record the H_2S concentration (dry basis) in the fuel gas.

[40 CFR 60.105(a)(4); 40 CFR 60.107]

5.3.5.8 For the FCC LP Flare and the LPG Flare, the Permittee shall comply, as applicable with the quarterly excess emissions reporting requirements as required in 40 CFR 60.7.

[40 CFR 60.7]

5.3.5.9 For the FCC LP Flare and the LPG Flare, in lieu of the above H_2S recordkeeping and reporting requirements, the Permittee may instead comply with EPA-approved alternative monitoring requirements or exemption from monitoring for combusted fuel gas streams, as applicable, in accordance with provisions of 40 CFR 60.13(i) or 60.105(b).

[40 CFR 60.13(i); 40 CFR 60.105(b)]

5.3.5.10 For H-1104, H-1105, H-3351, H-3352, and H-3301, the Permittee shall report to VIDPNR changes and alterations in operations that result in an increase in regulated emissions.

[33 PTO (c), Permit No. 485-94, November 28, 1994]

5.3.5.11 For H-1104, H-1105, H-3351, H-3352, H-3301, STK-7921, STK-7941, and

STK-7942, the Permittee shall allow VIDPNR to inspect its facility during reasonable hours. The inspection shall be conducted in a timely manner, in the presence of, and with full assistance and cooperation of LIMETREE BAY TERMINALS LLC management. VIDPNR shall issue an advanced verbal request for the use of cameras and vocal recording devices.
[33 PTO (f), Permit No. 485-94, November 28, 1994]

5.3.5.12 For H-1104, H-1105, H-3351, H-3352, H-3301, STK-7921, STK-7941, and STK-7942, the Permittee shall initiate operation, maintenance, and fuel consumption records and shall keep these records on a daily and cumulative basis. The Permittee shall keep one log for each operating area which shall contain information regarding the operation and maintenance of each permitted unit in the areas listed in the LIMETREE BAY TERMINALS LLC Air Emission Source Listing. The Permittee may store fuel consumption data electronically. The Permittee shall make available the logs and data for inspection by VIDPNR and EPA upon request.
[33 PTO (i), Permit No. 485-94, November 28, 1994]

5.3.6 Group 06 – Loading Racks

5.3.6.1 Group 06A – Truck Loading

5.3.6.1.1 The Permittee shall keep the records specified in 40 CFR 63.654(i).
[40 CFR 63.654(i)]

5.3.6.1.2 The Permittee of an existing source who elects to comply with 40 CFR 63.654 (g) and (h) by using emissions averaging for any emission points shall submit an Implementation Plan. [Permittee's Emission Averaging Implementation Plan approved by EPA Administrator on June 29, 1998]

5.3.6.1.2.1 The Implementation Plan shall be submitted to the Administrator and approved prior to implementing emissions averaging. This information may be submitted in an operating permit application, in an amendment to an operating permit application, in a separate submittal, in a Notification of Compliance Status Report, in a Periodic Report or in any combination of these documents. If the Permittee submits the information specified in this section at different times, and/or in different submittals, later submittals may refer to earlier submittals instead of duplicating the previously submitted information.

5.3.6.1.2.2 The Implementation Plan shall include the information specified below for all points included in the average.

5.3.6.1.2.2.1 The identification of all emission points in the planned emissions average and notation of whether each emission point is a Group 1 or Group 2 emission point as defined in 40 CFR 63.641.

5.3.6.1.2.2.2 The projected annual emission debits and credits for each emission point and the sum for the emission points involved in the average calculated according to 40 CFR 63.652. The annual projected credits must be greater than the projected debits, as required under 40 CFR 63.652(e)(3).

5.3.6.1.2.2.3 The specific control technology or pollution prevention measure that will be used for each emission point included in the average and date of application or expected date of application.

5.3.6.1.2.2.4 The specific identification of each emission point affected by a pollution prevention measure. To be considered a pollution prevention measure, the criteria in 40 CFR 63.652(j)(1) must be met. If the same pollution prevention measure reduces or eliminates emissions from multiple emission points in the average, the Permittee must identify each of these emission points.

5.3.6.1.2.2.5 A statement that the compliance demonstration, monitoring, inspection, recordkeeping, and reporting provisions in 40 CFR 63.654(a), (b), and (c) that are applicable to each emission point in the emissions average will be implemented beginning on the date of compliance.

5.3.6.1.2.2.6 Documentation of the information listed below for each emission point included in the average:

- The values of the parameters used to determine whether each emission point in the emissions average is Group 1 or Group 2.
- The estimated values of all parameters needed for input to the emission debit and credit calculations in 40 CFR 63.652 (g) and (h). These parameter

values or, as appropriate, limited ranges for the parameter values, shall be specified in the source's Implementation Plan as enforceable operating conditions. Changes to these parameters must be reported in the next Periodic Report.

- The estimated percentage of reduction if a control technology achieving a lower percentage of reduction than the efficiency of the reference control technology, as defined in 40 CFR 63.641, is or will be applied to the emission point.
- The anticipated nominal efficiency if a control technology achieving a greater percentage emission reduction than the efficiency of the reference control technology is or will be applied to the emission point. The procedures in 40 CFR 63.652(i) shall be followed to apply for a nominal efficiency.

[40 CFR 63.653(d)(vii)(B); 40 CFR 63.653(d)(ix); 40 CFR 63.654(d)]

5.3.6.1.3 The Permittee shall submit a Notification of Compliance Status report covering the truck loading rack as provided in 40 CFR 63.654(f). The information required by the NCS report may instead be submitted in an operating permit application, in a separate submittal, or in an amendment to the operating permit application. For emission points included in an emissions average, the Notification of Compliance Status report shall include the values of the parameters needed for input to the emission credit and debit equations in 40 CFR 63.652(g) and (h), calculated or measured according to the procedures in 40 CFR 63.652(g) and (h), and the resulting credits and debits for the first quarter of the year. The first quarter begins on the compliance date specified in 40 CFR 63.640.

[40 CFR 63.654(f)]

5.3.6.1.4 The Permittee shall submit quarterly reports for all emission points included in an emissions average. The quarterly reports shall be submitted no later than 60 calendar days after the end of each quarter. The first report shall be submitted with the Notification of Compliance Status report no later than 150 days after the compliance date specified in 40 CFR 63.640. The quarterly reports shall include the information required by 40 CFR 63.654(g)(8)(ii).

[40 CFR 63.654]

5.3.6.1.5 Other reports shall be submitted as required by 40 CFR Part 63 Subpart A and as specified in 40 CFR 63.654(h).

[40 CFR 63, Subpart A; 40 CFR 63.654(h)]

5.3.6.1.6 Within 45 days of the stack test completion, as required by condition 4.2.6.1.1, the Permittee shall submit a report with the test results to VIDPNR.

[STX-557-H-00(III)(B), September 18, 2000]

5.3.6.1.7 For the monitors, meters, hydrocarbon analyzers, and recorders required by condition 5.2.6.1.2, the Permittee shall make all specifications available to VIDPNR representatives upon request.

[STX-557-H-00(III)(H), September 18, 2000]

5.3.6.1.8 The Permittee shall with four (4) hours report to VIDPNR via telephone and/or fax upon determination of any noncompliance of operating requirements directly related to emission limits, or any noncompliance specified in the sections of this permit that reference the conditions of Permit No. STX-557-H-00.

[STX-557-H-00(IV)(A), September 18, 2000]

5.3.6.1.9 The Permittee shall submit to VIDPNR within 7 days a written report detailing the nature of the noncompliance of operating requirements, and the corrective actions instituted to bring the system into compliance.

[STX-557-H-00(IV)(B), September 18, 2000]

5.3.6.1.10 The Permittee shall report to VIDPNR any physical change or changes in operation which increase the amount of air pollutants or process production.

[Truck Loading Facility Permit No. 414-96, July 25, 1996]

5.3.6.1.11 The Permittee shall maintain records on the daily hours of operations and type and quantity of fuel loaded.

[Truck Loading Facility Permit No. 414-96, July 25, 1996]

5.3.6.1.12 The Permittee shall make all records and any associated logs available for inspection by EPA and VIDPNR upon request.

[Truck Loading Facility Permit No. 414-96, July 25, 1996]

5.3.6.1.13 VIDPNR reserves the right to inspect the Permittee's facilities. The Permittee shall give VIDPNR whatever aid is necessary to perform said inspections in a safe and timely manner.

[Truck Loading Facility Permit No. 414-96, July 25, 1996]

5.3.6.2 Group 06B – Marine Loading

5.3.6.2.1 The Permittee shall keep an up-to-date, readily accessible record of the following data measured during each performance test, and also include the following data in the report of the initial performance test required under 40 CFR 61.13.

5.3.6.2.1.1 Where the Permittee is complying with section 3.2.6.2.2 through use of an incinerator:

5.3.6.2.1.1.1 The average firebox temperature of the incinerator, measured at least every 2 minutes during a loading cycle if the total time period of the loading cycle is less than 3 hours and every 15 minutes if the total time period of the loading cycle is equal to or greater than 3 hours. The measured temperature shall be averaged over the loading cycle.

5.3.6.2.1.1.2 The percent reduction of benzene determined as specified in 40 CFR 61.304(a) achieved by the incinerator.

5.3.6.2.1.1.3 The duration of the loading cycle.

[40 CFR 61.305(a)(1)]

5.3.6.2.1.2 The Permittee shall submit with the initial performance test an engineering report describing in detail the vent system used to vent each affected vent stream to a control device. This report shall include all valves and vent pipes that could vent the stream to the atmosphere, thereby bypassing the control device, and identify which valves are car-sealed opened and which valves are car-sealed closed.

[40 CFR 61.305(a)(5)]

5.3.6.2.2 The Permittee shall keep up-to-date, readily accessible continuous records of the equipment operating parameters specified to be monitored as well as up-to-date, readily accessible records of periods of operation during which the parameter boundaries established during the most recent performance test are exceeded. The Administrator may at any time require a report of these data. Periods of operation during which the parameter boundaries established during the most recent performance tests are exceeded are defined as follows:

5.3.6.2.2.1 For thermal incinerators, all loading cycles during which the average combustion temperature was more than 28 °C (50 °F) below the average loading cycle combustion temperature during the most recent performance test at which compliance with section 3.2.6.2.2 was determined.

[40 CFR 61.305(b)(1)]

5.3.6.2.3 If a vent system containing valves that could divert the emission stream away from the control device is used, the Permittee shall keep for at least 2 years up-to-date, readily accessible continuous records of:

5.3.6.2.3.1 All periods when flow is indicated if flow indicators are installed.

5.3.6.2.3.2 All times when maintenance is performed on car-sealed valves, when the car seal is broken, and when the valve position is changed (i.e., from open to closed for valves in the vent piping to the control device and from closed to open for valves that vent the stream directly or indirectly to the atmosphere bypassing the control device) if valves are monitored.

[40 CFR 61.305(c)]

5.3.6.2.4 The Permittee shall submit to the Administrator quarterly reports of the following information. The Permittee shall submit the initial report within 90 days after the effective date of this subpart or 90 days after startup for a source that has an initial startup date after the effective date.

5.3.6.2.4.1 Periods of operation where there were exceedances of monitored parameters recorded under 40 CFR 61.305(b).

5.3.6.2.4.2 All periods recorded under section 5.3.6.2.3.1 when the vent stream is diverted from the control device.

5.3.6.2.4.3 All times recorded under section 5.3.6.2.3.2 when maintenance is performed on car-sealed valves, when the car seal is broken, and when the valve position is changed.

[40 CFR 61.305(f)]

5.3.6.2.5 The Permittee shall keep the vapor-tightness documentation required under section 3.2.6.2.3 on file at the affected facility in a permanent form available for inspection.

[40 CFR 61.305(g)]

5.3.6.2.6 The Permittee shall update the documentation file required under condition 3.2.6.2.3 (40 CFR 61.302(e)) for each marine vessel at least once per year to reflect current test results as determined by the appropriate method. The Permittee shall include, as a minimum, the following information in this documentation: (1) test title; (2) marine vessel owner and address; (3) marine vessel identification number; (4) testing location; (5) date of test; (6) tester name and signature; (7) witnessing inspector: name, signature, and affiliation; and (8) test results.

[40 CFR 61.305(h)]

5.3.6.2.7 The Permittee shall report by telephone all scheduled maintenance that will cause visible emission or other violations and all upset conditions and breakdown situations that will cause or have caused visible emission and other violations. In addition, the Permittee shall establish and maintain a log of all the above occurrences stating date,

time, cause of occurrence, corrective action taken, etc. This log shall be available for inspection by VIDPNR and EPA upon request.
[Marine Vapor Control System Permit No. 412-96(f), July 25, 1996]

5.3.6.2.8 The Permittee shall maintain records of the date and duration of each benzene transfer, the name of vessel loaded, the weight percent of benzene loaded, and the amount of benzene loaded (liters). These records shall be available for inspection by VIDPNR and EPA upon request.
[Marine Vapor Control System Permit No. 412-96(k), July 25, 1996]

5.3.7 Group 07 – Sulfur Recovery

5.3.7.1 The Permittee shall comply, as applicable, with the recordkeeping requirements as required in VIRR 12-09-204-45.
[VIRR 12-09-204-45]

5.3.7.2 The Permittee shall maintain an operation log specifically for the Claus plants and the Beavon units (T-1061 and T-4761). Such logs shall be made available upon request. The Permittee shall record exceedance of the emission limitations of the 1997 PSD Permit that apply to the tail gas treatment system, as determined by continuous monitoring. The Permittee shall also maintain a 90% quality data availability for all gaseous monitors in each report quarter.
[1997 PSD Permit (IV)(F); 1997 PSD Permit (VI)(C), (D), and (E)]

5.3.7.3 For T-1061, for the purpose of reports under 40 CFR 60.7(c), periods of excess emissions that shall be determined and reported are defined as follows: all 12 hour periods during which the average concentration of reduced sulfur (as SO_2) as measured by the reduced sulfur continuous monitoring system under 40 CFR 60.105(a)(6) exceeds 300 ppm.
[40 CFR 60.105(e)(4)(ii)]

5.3.7.4 The Permittee shall submit excess emission reports on a quarterly basis to VIDPNR and EPA.
[40 CFR 60.7(c); 1997 PSD Permit (VII)]

5.3.8 Group 8 – Internal Floating Roof Tanks

The requirements of this section apply only to internal floating roof storage vessels defined as "Group 1" under 40 CFR 63, Subparts F and G (HON) or Subpart CC (Refinery NESHAP).

5.3.8.1 The Permittee who elects to comply with section 3.2.8.1 by using a fixed roof and an internal floating roof or with an external floating roof converted to an internal floating roof shall submit, as part of the Periodic Report required under 40 CFR 63.152(c), the results of each inspection conducted in accordance with 40 CFR 63.120(a) in which a failure is detected in the control equipment.

5.3.8.1.1 For vessels for which annual inspections are required under paragraphs 5.2.8.1.2.1 or 5.2.8.1.3.2, the specifications and requirements listed in paragraphs 5.3.8.1.1.1 through 5.3.8.1.1.3 apply.

5.3.8.1.1.1 A failure is defined as any time in which the internal floating roof is not resting on the surface of the liquid inside the storage vessel and is not resting on the leg supports; or there is liquid on the floating roof; or the seal is detached from the internal floating roof; or there are holes, tears, or other openings in the seal or seal fabric; or there are visible gaps between the seal and the wall of the storage vessel.

5.3.8.1.1.2 Except as provided in paragraph 5.3.8.1.2, each Periodic Report shall include the date of the inspection, identification of each storage vessel in which a failure was detected, and a description of the failure. The Periodic Report shall also describe the nature of and date the repair was made or the date the storage vessel was emptied.

5.3.8.1.1.3 If an extension is utilized in accordance with paragraph 5.2.8.1.4, the Permittee shall, in the next Periodic Report, identify the vessel; include the documentation specified in paragraph 5.2.8.1.4; and describe the date the storage vessel was emptied and the nature of and date the repair was made.

5.3.8.1.2 For vessels for which inspections are required under 5.2.8.1.2.2, 5.2.8.1.3.1 or 5.2.8.1.3.3, the specifications and requirements listed in paragraphs 5.3.8.1.2.1 and 5.3.8.1.2.2 apply.

5.3.8.1.2.1 A failure is defined as any time in which the internal floating roof has defects; or the primary seal has holes, tears, or other openings in the seal or the seal fabric; or the secondary seal (if one has been installed) has holes, tears, or other openings in the seal or the seal fabric; or the gaskets no longer close off the liquid surface from the atmosphere; or the slotted membrane has more than 10 percent open area.

5.3.8.1.2.2 Each Periodic Report required under 40 CFR 63.152(c) shall include the date of the inspection, identification of each storage vessel in which a failure was detected, and a description of the failure. The Periodic Report shall also describe the nature of and date the repair was made.

[40 CFR 63.122(d)]

5.3.8.2 For Group 1 storage vessels subject too 40 CFR 63 Subpart CC, the reporting requirements of section 5.3.8.1 shall be modified as provided in 40 CFR 63.646(b) through (l). The Permittee shall comply with the reporting requirements of 40 CFR 63.654(e).

[40 CFR 63.646; 40 CFR 63.654(e)]

5.3.8.3 For Group 1 storage vessels subject to 40 CFR 63, Subpart G, the Permittee shall keep the records specified in 40 CFR 63.123. For Group 1 storage vessels subject to 40 CFR 63, Subpart CC, the Permittee shall keep the records specified in 40 CFR 63.123, except as specified in 40 CFR 63.654(i)(1)(i) through (i)(1)(iv).

[40 CFR 63.123; 40 CFR 63.654]

5.3.8.4 For TKs 4501, 4503, 6831, 6832, 6841, 6843, 6852, 6884, 6888, 7417, 7418, 7425, 7426, 7433, 7434, 7441, 7451, 7452, 7453, 7454, 7455, 7521, 7522, 7523, 7524, 7525, 7526,7528, 7601, 7602, 7603, 7604, and 7974, the Permittee shall report to VIDPNR (as required in Federal and Territorial regulations) changes and alterations in operations that result in an increase in regulated emissions.

[Storage Tank Permit Nos. 489-95, 490-95, 491-95, and 492-95, February 28, 1995]

5.3.8.5 For TKs 4501, 4503, 6831, 6832, 6841, 6843, 6852, 6884, 6888, 7417, 7418, 7425, 7426, 7433, 7434, 7441, 7451, 7452, 7453, 7454, 7455, 7521, 7522, 7523, 7524, 7525, 7526,7528, 7601, 7602, 7603, 7604, and 7974, the Permittee shall allow VIDPNR to inspect its facility during reasonable hours. The inspection shall be conducted in a timely manner, in the presence of, and with full assistance and cooperation of LIMETREE BAY TERMINALS LLC management. VIDPNR shall issue an advanced verbal request for the use of cameras and vocal recording devices.

[Storage Tank Permit Nos. 489-95, 490-95, 491-95, and 492-95, February 28, 1995]

5.3.8.6 For TKs 4501, 4503, 6831, 6832, 6841, 6843, 6852, 6884, 6888, 7417, 7418, 7425, 7426, 7433, 7434, 7441, 7451, 7452, 7453, 7454, 7455, 7521, 7522, 7523, 7524, 7525, 7526,7528, 7601, 7602, 7603, 7604, and 7974, the Permittee shall keep tank service records (types and quantities of liquids stored) on a daily and cumulative basis. The Permittee shall maintain inspection and maintenance records for all hydrocarbon and volatile organic storage tanks listed above. The Permittee shall make available these records for inspection by VIDPNR and EPA upon request.

[Storage Tank Permit Nos. 489-95, 490-95, 491-95, and 492-95, February 28, 1995]

5.3.8.7 For TKs 7601, 7602, 7603, 7604, and 7605, the Permittee shall operate these storage tanks in accordance with the requirements for internal floating roof tanks in 40 CFR 60, Subparts A and Ka, as applicable.

[Storage Tank Permit Nos. 489-95, 490-95, 491-95, and 492-95, February 28, 1995]

5.3.8.8 For TKs 7417, 7418, 7433, 7434, and 7974, the Permittee shall operate these storage tanks in accordance with the requirements for internal floating roof tanks in 40 CFR 60, Subparts A and Kb, as applicable.

[Storage Tank Permit Nos. 489-95, 490-95, 491-95, and 492-95, February 28, 1995]

5.3.9 Group 9 – External Floating Roof Tanks

The requirements of this section apply only to external floating roof storage vessels defined as "Group 1" under 40 CFR 63, Subparts F and G (HON) or Subpart CC (Refinery NESHAP).

5.3.9.1 The Permittee shall meet the periodic reporting requirements specified in paragraphs 5.3.9.1.1, 5.3.9.1.2, and 5.3.9.1.3.

5.3.9.1.1 The Permittee shall submit, as part of the Periodic Report required under 40 CFR 63.654(g), documentation of the results of each seal gap measurement made in accordance with section 5.2.9.1 in which the requirements of paragraphs 5.2.9.1.3, 5.2.9.1.4, 5.2.9.1.5, 5.2.9.1.6 are not met. This documentation shall include the information specified in paragraphs 5.3.9.1.1.1 through 5.3.9.1.1.4.

5.3.9.1.1.1 The date of the seal gap measurement.

5.3.9.1.1.2 The raw data obtained in the seal gap measurement and the calculations described in paragraphs 5.2.9.1.3 and 5.2.9.1.4.

5.3.9.1.1.3 A description of any condition specified in paragraphs 5.2.9.1.5 and 5.2.9.1.6 that is not met.

5.3.9.1.1.4 A description of the nature of and date the repair was made, or the date the storage vessel was emptied.

5.3.9.1.2 If an extension is utilized in accordance with paragraphs 5.2.9.1.7 or 5.2.9.1.8, the Permittee shall, in the next Periodic Report, identify the vessel; include the documentation specified in paragraph 5.2.9.1.7.2 or 5.2.9.1.8, as applicable; and describe the date the vessel was emptied and the nature of and date the repair was made.

5.3.9.1.3 The Permittee shall submit, as part of the Periodic Report required under 40 CFR 63.654(g), documentation of any failures that are identified during visual inspections required by paragraph 5.2.9.1.10. This documentation shall meet the specifications and requirements in paragraphs 5.3.9.1.3.1 and 5.3.9.1.3.2.

5.3.9.1.3.1 A failure is defined as any time in which the external floating roof has defects; or the primary seal has holes, or other openings in the seal or the seal fabric; or the secondary seal has holes, tears, or other openings in the seal or the seal fabric; or the gaskets no longer close off the liquid surface from the atmosphere; or the slotted membrane has more than 10 percent open area.

5.3.9.1.3.2 Each Periodic Report required under 40 CFR 63.654 shall include the date of the inspection, identification of each storage vessel in which a failure was detected, and a description of the failure. The periodic report shall also describe the nature of and date the repair was made.

[40 CFR63.122(e)]

5.3.9.2 For Group 1 storage vessels subject to 40 CFR 63, Subpart CC, the reporting requirements of section 5.3.9.1 shall be modified as provided in 40 CFR 63.646(b) through (l). The Permittee shall comply with the reporting requirements of 40 CFR 63.654(e).

[40 CFR 63.646; 40 CFR 63.654(e)]

5.3.9.3 For Group 1 storage vessels subject to 40 CFR 63, Subpart G, the Permittee shall keep the records specified in 40 CFR 63.123. For Group 1 storage vessels subject to 40 CFR 63, Subpart CC, the Permittee shall keep the records specified in 40 CFR 63.123, except as specified in 40 CFR 63.654(i)(1)(i) through (i)(1)(iv).

[40 CFR 63.123; 40 CFR 63.654]

5.3.9.4 For TKs 4725, 4726, 6801, 6802, 6803, 6804, 6805, 6806, 6807, 6808, 6809, 6814, 6815, 6816, 6833, 6834, 6835, 6836, 6837, 6838, 6839, 6842, 7401, 7402, 7403, 7404, 7405, 7406, 7407, 7408, 7409, 7410, 7425, 7424, 7443, 7444, 7445, 7446, 7447, 7449, 7507, 7508, 7509, 7510, 7511, 7512, 7513, 7514, 7515, 7516, and 7517, the Permittee shall report to VIDPNR (as required in Federal and Territorial regulations) changes and alterations in operations that result in an increase in regulated emissions.

[Storage Tank Permit Nos. 489-95, 490-95, 491-95, and 492-95, February 28, 1995]

5.3.9.5 For TKs 4725, 4726, 6801, 6802, 6803, 6804, 6805, 6806, 6807, 6808, 6809, 6814, 6815, 6816, 6833, 6834, 6835, 6836, 6837, 6838, 6839, 6842, 7401, 7402, 7403, 7404, 7405, 7406, 7407, 7408, 7409, 7410, 7425, 7424, 7443, 7444, 7445, 7446, 7447, 7449, 7507, 7508, 7509, 7510, 7511, 7512, 7513, 7514, 7515, 7516, and 7517, the Permittee shall allow VIDPNR to inspect its facility during reasonable hours. The inspection shall be conducted in a timely manner, in the presence of, and with full assistance and cooperation of LIMETREE BAY TERMINALS LLC management. VIDPNR shall issue an advanced verbal request for the use of cameras and vocal recording devices.

[Storage Tank Permit Nos. 489-95, 490-95, 491-95, and 492-95, February 28, 1995]

5.3.9.6 For TKs, 4725, 4726, 6801, 6802, 6803, 6804, 6805, 6806, 6807, 6808, 6809, 6814, 6815, 6816, 6833, 6834, 6835, 6836, 6837, 6838, 6839, 6842, 7401, 7402, 7403, 7404, 7405, 7406, 7407, 7408, 7409, 7410, 7425, 7424, 7443, 7444, 7445, 7446, 7447, 7449, 7507, 7508, 7509, 7510, 7511, 7512, 7513, 7514, 7515, 7516, and 7517, the Permittee shall keep tank service records (types and quantities of liquids stored) on a daily and cumulative basis. The Permittee shall maintain inspection and maintenance records for all hydrocarbon and volatile organic storage tanks listed above. The Permittee shall make available these records for inspection by VIDPNR and EPA upon request.

[Storage Tank Permit Nos. 489-95, 490-95, 491-95, and 492-95, February 28, 1995]

5.3.9.7 The Permittee shall record the material throughput of tanks TK-6815 and TK-6839 shall be recorded as necessary to ensure compliance with condition 3.1.9.1 of this permit.

[STX-557A-E-02(X)(I), June 4, 2002]

5.3.10 Group 10 – Fixed Roof Tanks

5.3.10.1 Group 10A – Fixed Roof Tanks PRT3, PRT4, PRT5, PRT6, PRT7, TK-1151, TK-1201, TK-1202, TK-1203, TK-1206, TK-1207, TK-1208, TK-1302, TK-1653, TK-2653, TK-2654, TK-3208, TK-3301, TK-3304, TK-3306, TK-3384, TK-3385, TK-3386, TK-4502, TK-6810, TK-6811, TK-6812, TK-6813, TK-6817, TK-6818, TK-6819, TK-6820, TK-6821, TK-6822, TK-6823, TK-6824, TK-6825, TK-6851, TK-6853, TK-6854, TK-6856, TK-6858, TK-6859, TK-6860, TK-6873, TK-6875, TK-6876, TK-6877, TK-6881, TK-6883, TK-6887, TK-700, TK-701, TK-702, TK-7206, TK-7207, TK-7208, TK-7209, TK-TK-7210, TK-7211, TK-7301, TK-7405, TK-7406, TK-7411, TK-7412, TK-7413, TK-7414, TK-7415, TK-7416, TK-7421, TK-7422, TK-7427, TK-7428, TK-7429, TK-7430, TK-7435, TK-7436, TK-7437, TK-7438, TK-7439, TK-7440, TK-7446, TK-7501, TK-7502, TK-7503, TK-7504, TK-7505, TK-7506, TK-7933, TK-7934, UTT1, TK-8501

5.3.10.1.1 Each storage vessel listed above which is subject to 40 CFR 63.646 shall keep the following record: If a storage vessel is determined to be Group 2 because the weight percent total organic HAP of the stored liquid is less than or equal to 4 percent, the Permittee shall retain a record of any data, assumptions, and procedures used to make this determination.

[40 CFR 63.654(i)(1)(iv)]

5.3.10.1.2 Except for Tanks 1206, 1207, 1208, 1653, 2653, 2654, 6859, 6860, 7301, and 8501, the Permittee shall report to VIDPNR (as required in Federal and Territorial regulations) changes and alterations in operations that result in an increase in regulated emissions.

[Storage Tank Permit Nos. 489-95, 490-95, 491-95, and 492-95, February 28, 1995]

5.3.10.1.3 Except for Tanks 1206, 1207, 1208, 1653, 2653, 2654, 6859, 6860, 7301, and 8501, the Permittee shall allow VIDPNR to inspect its facility during reasonable hours. The inspection shall be conducted in a timely manner, in the presence of, and with full assistance and cooperation of LIMETREE BAY TERMINALS LLC management. VIDPNR shall issue an advanced verbal request for the use of cameras and vocal recording devices.

[Storage Tank Permit Nos. 489-95, 490-95, 491-95, and 492-95, February 28, 1995]

5.3.10.1.4 Except for Tanks 1206, 1207, 1208, 1653, 2653, 2654, 6859, 6860, 7301, and 8501, the Permittee shall keep tank service records (types and quantities of liquids stored) on a daily and cumulative basis. The Permittee shall maintain inspection and maintenance records for all hydrocarbon and volatile organic storage tanks covered by these storage tank permits. The Permittee shall make available these records for inspection by VIDPNR and EPA upon request.

[Storage Tank Permit Nos. 489-95, 490-95, 491-95, and 492-95, February 28, 1995]

5.3.10.1.5 The Permittee shall record and maintain records documenting the material stored in the hot pitch storage tank (TK-8501) in accordance with 40 60 CFR, Subpart Kb, 60.115b.or TK 8501,

[S STX-557A-E-02(X)(H), June 4, 2002]

5.3.10.2 Group 10B - Tanks TK-1204, TK-1205, TK-8001, TK-8002 (Subject to 40 CFR 63, Subpart EEEE)

5.3.10.2.1 For each storage tank having a capacity of less than 18.9 cubic meters (5,000 gallons), the Permittee must keep documentation that verifies that each storage tank is not required to be controlled. The documentation must be kept up-to-date (i.e., all such emission sources at a facility are identified in the documentation regardless of when the documentation was last compiled) and must be in a form suitable and readily available for expeditious inspection and review according to 40 CFR 63.10(b)(1), including records stored in electronic form in a separate location. The documentation may consist of identification of the tanks on a plant site plan or process and instrumentation diagram (P&ID).

[40 CFR 63.2343 (a)]

5.3.10.3 For TKs 7206, 7207, 7208, 7209, 7210, 7211, 7414, 7501, 7502, 7503, 7504, 7933, and 7934, the Permittee shall operate these storage tanks in accordance with the requirements for fixed roof tanks in 40 CFR 60 Subparts A and Kb, as applicable.

[Storage Tank Permit Nos. 489-95, 490-95, 491-95, and 492-95, February 28, 1995]

5.3.11 Group 11 – Horizontal Tanks TK-1626, TK-1627, TK-1628, TK-1629, TK-1630, TK-1631, TK-1633, D-1301, D-1609, D-1610, D-1620

5.3.11.1. Each storage vessel listed above which is subject to 40 CFR 63.646 shall keep the following record: If a storage vessel is determined to be Group 2 because the weight percent total organic HAP of the stored liquid is less than or equal to 4 percent, the Permittee shall retain a record of any data, assumptions, and procedures used to make this determination.

[40 CFR 63.654(i)(1)(iv)]

5.3.11.2 The Permittee shall report to VIDPNR (as required in Federal and Territorial regulations) changes and alterations in operations that result in an increase in regulated emissions.

[Storage Tank Permit Nos. 489-95 and 491-95, February 28, 1995]

5.3.11.3 The Permittee shall allow VIDPNR to inspect its facility during reasonable hours. The inspection shall be conducted in a timely manner, in the presence of, and with full assistance and cooperation of LIMETREE BAY TERMINALS LLC management. VIDPNR shall issue an advanced verbal request for the use of cameras and vocal recording devices.

[Storage Tank Permit Nos. 489-95 and 491-95, February 28, 1995]

5.3.11.4 The Permittee shall keep tank service records (types and quantities of liquids stored) on a daily and cumulative basis. The Permittee shall maintain inspection and maintenance records for all hydrocarbon and volatile organic storage tanks listed above. The Permittee shall make available these records for inspection by VIDPNR and EPA upon request.

[Storage Tank Permit Nos. 489-95 and 491-95, February 28, 1995]

5.3.12 Group 12 – Geodesic Dome Tanks

5.3.12.1. Each storage vessel listed above which is subject to 40 CFR 63.646 shall keep the following record: If a storage vessel is determined to be Group 2 because the weight percent total organic HAP of the stored liquid is less than or equal to 4 percent, the Permittee shall retain a record of any data, assumptions, and procedures used to make this determination.

[40 CFR 63.654(i)(1)(iv)]

5.3.13 Group 13 – Wastewater Treatment

5.3.13.1 The Permittee shall comply, as applicable, with the recordkeeping requirements as required in 40 CFR 61, Subpart FF.

[40 CFR 61.356]

5.3.13.2 The Permittee shall comply, as applicable, with the reporting requirements as required in 40 CFR 61.357. These requirements include submittals of the following reports: annual reports, and quarterly monitoring and inspections reports.

[40 CFR 61.357]

5.3.13.3 The Permittee shall comply, as applicable, with the recordkeeping requirements as required in 40 CFR 60.697.

[40 CFR 60.697]

5.3.13.4 The Permittee shall comply, as applicable, with the reporting requirements as required in 40 CFR 60.698. The Permittee shall submit reports semiannually.

[40 CFR 60.698]

5.3.13.5 For STK-3510 and STK-3530, the Permittee shall report to VIDPNR (as required in Federal and Territorial regulations) changes and alterations in operations that result in an increase in regulated emissions.

[33 PTO (c), Permit No. 487-94, November 28, 1994]

5.3.13.6 For STK 3510 and STK-3530, the Permittee shall allow VIDPNR to inspect its facility during reasonable hours. The inspection shall be conducted in a timely manner, in the presence of, and with full assistance and cooperation of LIMETREE BAY TERMINALS LLC management. VIDPNR shall issue an advanced verbal request for the use of cameras and vocal recording devices.

[33 PTO (f), Permit No. 487-94, November 28, 1994]

5.3.13.7 For STK-3510 and STK-3530, the Permittee shall initiate operation, maintenance, and fuel consumption records and shall keep these records on a daily and cumulative basis. The Permittee shall keep one log for each operating area which shall contain information regarding the operation and maintenance of each permitted unit in the areas listed in the LIMETREE BAY TERMINALS LLC Air Emission Source Listing. The Permittee may store fuel consumption data electronically. The Permittee shall make available the logs and data for inspection by VIDPNR and EPA upon request.

[33 PTO (i), Permit No. 487-94, November 28, 1994]

5.3.14 Group 14 – Alkylation and Dimersol Units

5.3.14.1 For distillation unit vent streams, the Permittee shall comply, as applicable, with recordkeeping and reporting requirements as required by 40 CFR 60.665.

[40 CFR 60.665]

5.3.14.2 In lieu of the above requirements, the Permittee may instead comply with EPA-approved monitoring requirements, as applicable, in accordance with 40 CFR 60.13(i).

[40 CFR 60.13(i)]

5.3.14.3 For reactor process vent streams, the Permittee shall comply with the recordkeeping and reporting requirements of 40 CFR 63.705, as applicable.
[40 CFR 60.705]

5.3.15 Group 15 – Seawater Intake Pumps

5.3.15.1 The Permittee shall maintain all records for a period of five years after the date of record, and shall make these records available for inspection by the EPA and VIDPNR, upon request.
[1997 PSD Permit (VI)(D)]

5.3.15.2 The Permittee shall report to VIDPNR (as required in Federal and Territorial regulations) changes and alterations in operations that result in an increase in regulated emissions.
[33 PTO (c), Permit No. 486-94, November 28, 1994]

5.3.15.3 The Permittee shall allow VIDPNR to inspect its facility during reasonable hours. The inspection shall be conducted in a timely manner, in the presence of, and with full assistance and cooperation of LIMETREE BAY TERMINALS LLC management. VIDPNR shall issue an advanced verbal request for the use of cameras and vocal recording devices.
[33 PTO (f), Permit No. 486-94, November 28, 1994]

5.3.15.4 The Permittee shall sample fuel oil sources as regulated under PSD permits for nitrogen and sulfur concentrations and maintain these data for not less than five years. The Permittee shall analyze sulfur concentrations in other regulated fuel oils on each tank prior to usage. Fuel oil sulfur concentrations shall be in compliance with VIRR 12-09-204 and 206, as amended.
[33 PTO (g), Permit No. 486-94, November 28, 1994]

5.3.15.5 The Permittee shall initiate operation, maintenance, and fuel consumption records and shall keep these records on a daily and cumulative basis. The Permittee shall keep one log for each operating area which shall contain information regarding the operation and maintenance of each permitted unit in the areas listed in the LIMETREE BAY TERMINALS LLC Air Emission Source Listing. The Permittee may store fuel consumption data electronically. The Permittee shall make available the logs and data for inspection by VIDPNR and EPA upon request. .
[33 PTO (i), Permit No. 486-94, November 28, 1994]

5.3.16 Group 16 – FCCU (including STK-7051)

5.3.16.1 For STK-7051, (in addition to the requirements of section 4.2.16.8) the Permittee shall submit a written report to EPA of the results of all emission testing (required by the LSFP PSD Permit) within 60 days of the completion of the performance test, but in any event, no later than 180 days after startup.

[LSFP PSD Permit XI.B.7]

5.3.16.2 The Permittee shall record the average coke burn-off rate (1,000 lbs per hour) and hours of operation daily.

[LSFP PSD Permit XIII.1.b.; 40 CFR 60.105(c)]

5.3.16.3 The Permittee shall submit a written report of all excess emissions to EPA for every calendar quarter. All quarterly reports shall be postmarked by the 30^{th} day following the end of each quarter.

[LSFP PSD Permit XIV.1]

5.3.16.4 For STK-7051, the CEMS required by 40 CFR 60.105(a) shall be operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, or malfunction, except for continuous monitoring system breakdowns, repairs, calibration adjustments, and zero and span adjustments.

[40 CFR 60.105(a)(11)]

5.3.16.5 For STK-7051 and the 3 Turbo Expander Maintenance Vents, the Permittee shall comply, as applicable, with the reporting requirements in 40 CFR 60.107. In addition to the excess emissions reporting requirements in section 5.3.16.10, the Permittee shall comply, as applicable, with the SO2 excess emissions reporting requirements in 40 CFR 60.107. The Permittee shall submit excess emission reports for SO_2 at least on a quarterly basis, but no less frequently than semi-annually.

[40 CFR 60.107; 40 CFR 60.107(e); LSFP PSD Permit XIV.1]]

5.3.16.6 For STK-7051 and the 3 Turbo Expander Maintenance Vents, the Permittee shall submit a signed statement certifying the accuracy and completeness contained in the reports submitted as required under 40 CFR 60.107 and section 5.3.16.10.

[40 CFR 60.107(g)]

5.3.16.7 The Permittee shall comply, as applicable, with the reporting requirements in 40 CFR 60.7. The Permittee shall submit excess emission reports for CO on a quarterly basis.

[40 CFR 60.7(c)]

5.3.16.8 For the purpose of reports under 5.3.16.10, periods of excess emissions that shall be determined and reported are defined as all 1-hour periods during which the average CO concentration as measured by the CO continuous monitoring system exceeds: (1) 500 ppm, and (2) 432 ppmv on a dry basis corrected to 7% oxygen.

[40 CFR 60.105(e)(2); LSFP PSD Permit VIII.C.5.a]

5.3.16.9 At least 60 days prior to actual testing, the Permittee shall submit to the EPA a

Quality Assurance Project Plan detailing methods and procedures to be used during the performance stack testing. A Quality Assurance Project Plan that does not have EPA approval may be grounds to invalidate any test and require a re-test.

[LSFP PSD Permit XI.B.3]

5.3.16.10 The excess emissions report shall include the following information:

(a) The magnitude of excess emissions computed in accordance with 40 CFR 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions.
(b) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions for the combustion units. The nature and cause of any malfunction (if known) and the corrective action taken or preventive measures adopted shall also be reported.
(c) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.
(d) When no excess emissions have occurred or the monitoring systems have not been inoperative, repaired, or adjusted, such information shall be stated in the report.
(e) Results of quarterly monitor performance audits, as required in 40 CFR 60, Appendix F (including the Data Assessment Report) and all information required by the reporting requirements in 40 CFR 60.7 including excess emissions and CEMS downtime summary sheets.

[LSFP PSD Permit XIV.1.a through e]

5.3.16.11 Any failure of air pollution control equipment, process equipment, or of a process to operate in a normal manner which results in an increase in emissions above any allowable emission limit stated in the LSFP PSD permit and any corrective actions and/or preventive measures taken on any unit must be reported by telephone within 24 hours to:

Director, Caribbean Environmental Protection Division
U.S. Environmental Protection Agency
Centro Europa Building, Suite 417
Ponce de Leon Avenue
San Juan, Puerto Rico 00907

[LSFP PSD Permit XIV.1.g]

5.3.16.12 In addition, the U.S. EPA's Air Compliance Branch shall be notified in writing within fifteen (15) days of any such failure described in section 5.3.16.11. This notification shall include a description of the malfunctioning equipment or abnormal operation; the date of the initial failure; the period of time over which emissions were increased due to the failure; the cause of the failure; the estimated resultant emissions in excess of those allowed under this permit; and the method utilized to restore normal operations. Compliance with this malfunction notification provision shall not excuse or otherwise constitute a defense to any violations of this permit or of any law or regulations which such malfunction may cause.

[LSFP PSD Permit XIV.1.h]

5.3.16.13 All reports and Quality Assurance Project Plans required by the LSFP PSD Permit shall be submitted to:

Director, Caribbean Environmental Protection Division
U.S. Environmental Protection Agency
Centro Europa Building, Suite 417
Ponce de Leon Avenue
San Juan, Puerto Rico 00907

[LSFP PSD Permit XIV.2]

5.3.16.14 Copies of all reports and Quality Assurance Project Plans shall also be submitted to:

Chief, Air Programs Branch – Permitting Section
U.S. Environmental Protection Agency
Region 2
290 Broadway
New York, New York 10007

Director, Division of Environmental Planning
Virgin Islands Department of Planning and Natural Resources
45 Mars Hill
Frederiksted, VI 00840-4744

[LSFP PSD Permit XIV.3]

5.3.16.15 The Permittee shall comply with the recordkeeping requirements of 40 CFR 63, Subpart UUU, as specified in the OMM Plan for the FCCU.

[40 CFR 63.1576]

5.3.16.16 The Permittee shall comply with the reporting requirements of 40 CFR 63, Subpart UUU, as applicable. The Permittee shall submit reports semiannually by July 31st or January 31st, as applicable, following the end of each six month period.

[40 CFR 63.1574 through 1576]

5.3.16.17 For STK-7051, the Permittee shall report to VIDPNR (as required in Federal and Territorial regulations) changes and alterations in operations that result in an increase in regulated emissions.

[33 PTO (c), Permit No. 479-94, November 28, 1994]

5.3.16.18 For STK-7051, the Permittee shall allow VIDPNR to inspect its facility during reasonable hours. The inspection shall be conducted in a timely manner, in the presence of, and with full assistance and cooperation of LIMETREE BAY TERMINALS LLC management. VIDPNR shall issue an advanced verbal request for the use of cameras and vocal recording devices.
[33 PTO (f), Permit No. 479-94, November 28, 1994]

5.3.16.19 For STK-7051, the Permittee shall initiate operation, maintenance, and fuel consumption records and shall keep these records on a daily and cumulative basis. The Permittee shall keep one log for each operating area which shall contain information regarding the operation and maintenance of each permitted unit in the areas listed in the LIMETREE BAY TERMINALS LLC Air Emission Source Listing. The Permittee may store fuel consumption data electronically. The Permittee shall make available the logs and data for inspection by VIDPNR and EPA upon request..
[33 PTO (i), Permit No. 479-94, November 28, 1994]

5.3.17 Group 17 – Coker Complex

5.3.17.1 For the Residuals Recycling System: The Permittee shall notify VIDPNR in writing within 7 days and by phone and/or telefax within 4 hours of any operation of the residuals recycling system equipment which may cause off-property effects, including odors.
[STK-557-K-05(IV)(C), May 11, 2005]

5.3.17.2 For the Residuals Recycling System: The Permittee shall maintain an operating log for the air pollution control devices for a period of no less than 5 years. The log shall track dates of inspections, breakthrough, replacement, and any other events associated with the devices.
[STK-557-K-05(III)(C) and (D), May 11, 2005]

5.3.17.3 For the Residuals Recycling System: The Permittee shall notify VIDPNR via telephone and/or telefax within 24 hours of any noncompliance with the operating requirements. The Permittee shall submit a written report within 7 days detailing the nature of the noncompliance and the corrective measures instituted to bring the system back into compliance.
[STK-557-K-05(IV)(A) and (B), May 11, 2005]

5.3.17.4 The Permittee shall report to VIDPNR any physical change or changes in operation of the units covered by Permit STX-557A-E-02 which increases the amount of air pollutants or process production.
[STX-557A-E-02(II)(D), June 4, 2002]

5.3.17.5 For the Residuals Recycling System: The VIDPNR reserves the right to inspect the Permittee's facilities, and the Permittee shall give the VIDPNR whatever aid is necessary to perform said inspections in a safe and timely manner.

[STX-557A-E-02(II)(E), June 4, 2002]

5.3.18 Group 18 – Sulfuric Acid Plant Stack STK-7802

5.3.18.1 The Permittee shall submit quarterly excess emissions reports to VIDPNR and EPA by the 30^{th} day following the end of the calendar quarter.

[1997 PSD Permit (VII)]

5.3.18.2 The Permittee shall record, pursuant to condition 3.2.18.7, the beginning, duration, the completion of start-up episodes, and the reason(s) for the prior shutdown of the sulfuric acid plant.

[1997 PSD Permit (VI)(C) and (D)]

5.3.18.3 The Permittee shall maintain records of all data required to determine compliance with the emission standards, emission monitoring, and testing requirements in 40 CFR 60, Subpart H.

[40 CR 60.80 through 60.85]

5.3.18.4 In addition to the quarterly reporting requirement in section 5.3.18.2, the Permittee shall comply, as applicable, with the reporting requirements in 40 CFR 60, Subpart A.

[40 CFR 60, Subpart A]

5.3.18.5 For STK-7802, the Permittee shall report to VIDPNR (as required in Federal and Territorial regulations) changes and alterations in operations that result in an increase in regulated emissions.

[33 PTO (c), Permit No. 479-94, November 28, 1994]

5.3.18.6 For STK-7802, the Permittee shall allow VIDPNR to inspect its facility during reasonable hours. The inspection shall be conducted in a timely manner, in the presence of, and with full assistance and cooperation of LIMETREE BAY TERMINALS LLC management. VIDPNR shall issue an advanced verbal request for the use of cameras and vocal recording devices.

[33 PTO (f), Permit No. 479-94, November 28, 1994]

5.3.19 Group 19 – Vapor Enhanced Recovery

5.3.19.1 The Permittee shall continuously record the H_2S concentration (dry basis) in the fuel gas.

[40 CFR 60.105(a)(4); 40 CFR 60.107]

5.3.19.2 The Permittee shall comply, as applicable, with the quarterly excess emissions reporting requirements as required in 40 CFR 60.7.

[40 CFR 60.7]

5.3.19.3 In lieu of the above H_2S recordkeeping and reporting requirements, the Permittee may instead comply with EPA approved alternative monitoring requirements or exemption from monitoring for combusted fuel gas streams, as applicable, in accordance with provisions of 40 CFR 60.13(i) or 60.105(b).
[40 CFR 60.13(i); 40 CFR 105(b)]

5.3.19.4 The Permittee shall report to VIDPNR via telephone and/or fax within four (4) hours upon determination of any noncompliance of operating requirements directly related to emission limits, or any non-compliance specified in the sections of this permit that reference the conditions of Permit No. STX-557-G-01.
[STX-557-G-01(IV), September 6, 2001]

5.3.19.5 Within 7 days, the Permittee shall submit to VIDPNR a written report detailing the nature of the noncompliance of operating requirements directly related to emissions limits, and the corrective actions instituted to bring the system into compliance.
[STX-557-G-01(IV), September 6, 2001]

5.3.19.6 Upon startup at each site, the Permittee shall record the volumetric flowrate through the VER.
[STX-557-G-01(II)(C)(1), September 6, 2001]

5.3.19.7 For the Thermal/Catalytic Oxidizer Mode: Upon startup at each site, the Permittee shall record the TO-3 analysis of the influent and effluent vapor stream to identify the specific hydrocarbons and verify 99% control destruction removal efficiency (DRE).
[STX-557-G-01(II), September 6, 2001]

5.3.19.8 For the Thermal/Catalytic Oxidizer Mode: During routine operation, the Permittee shall record the following for every working day: (1) influent volumetric flow rate and (2) influent hydrocarbon concentration.
[STX-557-G-01(II), September 6, 2001]

5.3.19.9 For the Activated Carbon Mode: Upon startup at each site, the Permittee shall record the hydrocarbon effluent concentration (ppmv) to verify 95% DRE, and the TO-14 analysis of the influent vapor stream to identify the specific hydrocarbons.
[STX-557-G-01(II), September 6, 2001]

5.3.19.10 The Permittee shall enter all records in a permanently bound logbook with numbered pages.
[STX-557-G-01(III), September 6, 2001]

5.3.19.11 The Permittee shall make all specifications available to representative of VIDPNR upon request.

[STX-557-G-01(III), September 6, 2001]

5.3.20 Group 20 – Gasoline Service Station and Fuel Gas System

None.

5.3.21 Group 21 – Amine Units, Merox, and Gas Concentration

None.

5.3.22 Group 22 – Gas Treating and Stripping

None.

5.3.23 Group 23 – Hydrogen Recovery

None.

5.3.24 Group 24 – Disulfide Handling

None.

5.3.25 Group 25 – Platformers

5.3.25.1 The Permittee shall comply with the recordkeeping and reporting requirements of 40 CFR 63, Subpart UUU, as applicable for the #2, #3, and #4 Platformers. The Permittee shall submit reports semiannually by July 31st or January 31st, as applicable, following the end of each six month period.

[40 CFR 63.1574 through 1576]

PART 6.0 OTHER RECORDKEEPING AND REPORTING REQUIREMENTS

6.1 General Recordkeeping and Reporting Requirements

None.

6.2 Specific Recordkeeping and Reporting Requirements

Table 2 in Part 1 provides a summary by individual emission unit or emission unit grouping of the specific location within this Title V permit for each emission or operational limitation and for the testing, monitoring, recordkeeping and reporting requirements that apply to that emission or operational limitation.

6.2.1 Group 1 – Boilers

The Permittee shall maintain records for at least five years.

[VIRR 12-09-206-71(a)(4)(b)]

6.2.2 Group 2 – Heaters

The Permittee shall maintain records for at least five years.

[VIRR 12-09-206-71(a)(4)(b)]

6.2.3 Group 3 – Compressor Engines

The Permittee shall maintain records for at least five years.

[VIRR 12-09-206-71(a)(4)(b)]

6.2.4 Group 4 – Combustion Turbines

The Permittee shall maintain records for at least five years.

[VIRR 12-09-206-71(a)(4)(b)]

6.2.5 Group 5 – Flares

The Permittee shall maintain records for at least five years.

[VIRR 12-09-206-71(a)(4)(b)]

6.2.6 Group 6 – Loading Racks

The Permittee shall maintain records for at least five years.

[VIRR 12-09-206-71(a)(4)(b)]

6.2.7 Group 7 – Sulfur Recovery

The Permittee shall maintain records for at least five years.

[VIRR 12-09-206-71(a)(4)(b)]

6.2.8 Group 8 – Internal Floating Roof Tanks

The Permittee shall maintain records for at least five years.
[VIRR 12-09-206-71(a)(4)(b)]

6.2.9 Group 9 – External Floating Roof Tanks

The Permittee shall maintain records for at least five years.
[VIRR 12-09-206-71(a)(4)(b)]

6.2.10 Group 10 – Fixed Roof Tanks

The Permittee shall maintain records for at least five years.
[VIRR 12-09-206-71(a)(4)(b)]

6.2.11 Group 11 – Horizontal Tanks

The Permittee shall maintain records for at least five years.
[VIRR 12-09-206-71(a)(4)(b)]

6.2.12 Group 12 – Geodesic Dome Tanks

None.

6.2.13 Group 13 – Wastewater Treatment

The Permittee shall maintain records for at least five years.
[VIRR 12-09-206-71(a)(4)(b)]

6.2.14 Group 14 – Alkylation and Dimersol Units

The Permittee shall maintain records for at least five years.
[VIRR 12-09-206-71(a)(4)(b)]

6.2.15 Group 15 – Seawater Intake Pumps

The Permittee shall maintain records for at least five years.
[VIRR 12-09-206-71(a)(4)(b)]

6.2.16 Group 16 – FCCU

The Permittee shall maintain records for at least five years.
[VIRR 12-09-206-71(a)(4)(b)]

6.2.17 Group 17 – Coker Complex

The Permittee shall maintain records for at least five years.
[VIRR 12-09-206-71(a)(4)(b)]

6.2.18 Group 18 – Sulfuric Acid Plant Stacks

The Permittee shall maintain records for at least five years.

[VIRR 12-09-206-71(a)(4)(b)]

6.2.19 Group 19 – Vapor Enhanced Recovery

The Permittee shall maintain records for at least five years.

[VIRR 12-09-206-71(a)(4)(b)]

6.2.20 Group 20 – Gasoline Service Station and Fuel Gas System

None.

6.2.21 Group 21 – Amine Units, Merox, and Gas Concentration

None.

6.2.22 Group 22 – Gas Treating and Stripping

None.

6.2.23 Group 23 – Hydrogen Recovery

None.

6.2.24 Group 24 – Disulfide Handling

None.

6.2.25 Group 25 – Platformers

The Permittee shall maintain records for at least five years.

[VIRR 12-09-206-71(a)(4)(b)]

PART 7.0 OTHER SPECIFIC REQUIREMENTS

7.1 Alternative Requirements
(White Paper #2)

None.

7.2 Insignificant Activities

See Attachment B for the list of Insignificant Activities in existence at the facility at the time of permit issuance.

7.3 Temporary Sources

None.

7.4 Short-term Activities
(White Paper #1)

None.

7.5 Compliance Schedule/Progress Reports

See Compliance Schedules in Attachment D. Progress reports shall be submitted on the same schedule as provided for the six-month deviation report in Section 8.13.1.

[VIRR 112-09-206-71(b)(A)]

7.6 Emissions Trading
[VIRR 12-09-206-65(c); VIRR 12-09-206-65(d)]

None.

7.7 Operational Flexibility

7.7.1 The Permittee may make Section 502(b)(10) changes as defined in 40 CFR 70.2 without requiring a permit revision, if the changes are not modifications under any provisions of Title I of the Federal Act and the changes do not exceed the emissions allowable under the permit.

a. For each such change, the Permittee shall notify the Department at least seven (7) days in advance. The notice shall include a brief description of the change within the permitted facility, the date on which the change will occur, any change in emissions, and any permit term or condition that would no longer apply as a result of the change.

b. Provisions for operational flexibility do not preclude the Permittee's obligation to comply with all applicable requirements.

. [VIRR 12-09-206-65(a)]

7.8 Off-Permit Changes

7.8.1 The Permittee may make changes that are not addressed or are prohibited by this permit, other than those described in condition 7.9.2 below, without a permit revision, provided the following requirement is met:

a. Each such change shall meet all applicable requirements and shall not violate any existing permit term or condition.

b. The Permittee must provide contemporaneous written notice to the Division of each such change, except for changes that qualify as insignificant or are exempt under VIRR 12-09-206-65 or this permit. Such written notice shall describe each such change, including the date, any change in emissions, pollutants emitted, and any applicable requirement that would apply as a result of the change.

c. The change shall not qualify for the permit shield in condition 8.16.

d. The Permittee shall keep a record describing changes made at the source that result in emissions of a regulated air pollutant subject to an applicable requirement, but not otherwise regulated under the permit, and the emissions resulting from those changes.

e. The source shall obtain any permits required.

[VIRR 12-09-206-65(b)]

7.8.2 The Permittee shall not make, without a permit revision, any changes that are not addressed or prohibited by this permit, if such changes are modifications under any provision of Title I of the Clean Air Act.

[VIRR 12-09-206-65(b)]

PART 8.0 GENERAL PROVISIONS

8.1 Terms and References

8.1.1 Terms not otherwise defined in the permit shall have the meaning assigned to such terms in the referenced regulation.

8.1.2 When more than one condition in this permit applies to an emission unit and/or the entire facility, the most stringent shall take precedence.

8.2 EPA Authorities

8.2.1 Except as identified as "Territory-only enforceable" or "local-only enforceable" requirements in this permit, all terms and conditions contained herein shall be enforceable by the EPA and citizens of the United States under the Clean Air Act, as amended, 42 U.S.C. 7401, et seq. Terms and conditions that are "territory-only enforceable" or "local-only enforceable" are not subject to VIRR 12-09-206-70 through 206-73, and 206-80 through 206-83, except section 206-71(c).
[VIRR 12-09-206-71(c)]

8.2.2 Nothing in this permit shall alter or affect the authority of the EPA to obtain information pursuant to Section 114 of the Clean Air Act.
[VIRR 12-09-206-71(e)(3)(C)]

8.2.3 Nothing in this permit shall alter or affect the authority of the EPA to impose emergency orders pursuant to Section 303 of the Clean Air Act.
[VIRR 12-09-206-71(e)(3)(A)]

8.3 Duty to Comply

8.3.1 The Permittee shall comply with all conditions of this operating permit. Any permit noncompliance constitutes a violation of the Federal Clean Air Act and the Virgin Islands Rules and Regulations and is grounds for enforcement action; for permit termination revocation and reissuance, or modification; or for denial of a permit renewal application. [VIRR 12-09-206-71(a)(7)(A)]

8.3.2 The Permittee shall not use as a defense in an enforcement action the contention that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.
[VIRR 12-09-206-71(a)(7)(B)]

8.3.3 The Permittee shall affix such permit to operate, an approved facsimile, or other approved identification bearing the permit number upon the article, machine, equipment, or other contrivance in such a manner as to be clearly visible and accessible. In the event that the article, machine, equipment, or other contrivance is so constructed or operated that the permit to operate cannot be so placed, then the permit should be maintained readily available at all times at the facility.
[VIRR 12-09-206-20(d)]

8.3.4 Nothing in this permit shall alter or affect the liability of the Permittee for any violation of applicable requirements, prior to or at the time of permit issuance.

[VIRR 12-09-206-71(e)(3)(B)]

8.4 Fee Assessment and Payment

8.4.1 The Permittee shall calculate and pay an annual permit fee to the Division. The amount of fee shall be determined each year in accordance with the applicable laws and regulations.
[VIRR 12-09-206-93]

8.4.2 The Permittee must submit an annual payment based on the facility's actual emission rates in tons per year.
[VIRR 12-09-206-93(c)(2)]

8.4.3 The Permittee shall be assessed a penalty for failure to pay annual emission fees, within thirty days of the due date, which shall accrue at the rate of ten percent (10%) per month on the outstanding balance, compounded monthly.
[VIRR 12-09-206-93(f)]

8.5 Permit Renewal and Expiration

8.5.1 This permit shall remain in effect for five (5) years from the date of issuance. The permit shall become null and void after the expiration date unless a timely and complete renewal application has been submitted to the Division at least six (6) months, but no more than eighteen (18) months, prior to the expiration date of the permit.
[VIRR 12-09-206-74(a) and VIRR 12-09-206-71(a)(2)]

8.5.2 Permits being renewed are subject to the same procedural requirements, including those for public participation and affected State and EPA review that apply to initial permit issuance.
[VIRR 12-09-206-74(a)]

8.5.3 If the Permittee has submitted a timely and complete application for a permit renewal consistent with VIRR 12-09-206-62, the permit shall not expire until the renewal permit has been issued or denied.
[VIRR 12-09-206-74(b)]

8.5.4 Failure of the Commissioner to act on a permit application shall not be deemed issuance by default.
[VIRR 12-09-206-73(a)(8)]

8.6 Transfer of Permit

8.6.1 The Permittee shall transfer this permit only in accordance with VIRR 12-09-206-52.
[VIRR 12-09-206-52(b)]

8.7 Property Rights

8.7.1 This permit shall not convey property rights of any sort, or any exclusive privilege.
[VIRR 12-09-206-71(a)(7)(D)]

8.8 Submissions

8.8.1 Reports, test data, monitoring data, notifications, annual certifications, and requests for revision and renewal shall be submitted to:

Director of the Virgin Islands Department of Planning and Natural Resources
Environmental Protection Division
45 Mars Hill
Frederiksted, St. Croix 00840-4474

8.8.2 Any records, compliance certifications, and monitoring data required by the provisions in this permit to be submitted to the EPA shall be sent to:

Director, Caribbean Environmental Protection Division
U.S. Environmental Protection Agency
Region 2 Office
Centro Europa Building, Suite 417
1492 Ponce De Leon Avenue
Santurce, PR 00907-4127

8.8.3 Any application form, report, or compliance certification submitted pursuant to this permit shall contain a certification by a responsible official of its truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

[VIRR 12-09-206-64(a)]

8.8.4 Unless otherwise specified, all submissions under this permit shall be submitted to the Division only.

8.9 Duty to Provide Information

8.9.1 All information contained in permit applications, except that which is claimed confidential in accordance with the Virgin Islands Air Pollution Control Act, shall be public. The contents of the permit itself are not entitled to confidentiality.

[VIRR 12-09-206-62(d)]

8.9.2 The Permittee shall furnish to the Department, within a reasonable time, any information that the Department may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the Permittee shall also furnish to the Department copies of records that the Permittee is required to keep by this permit or, for information claimed to be confidential, the Permittee may furnish such records directly to the Administrator, if necessary, along with a claim of confidentiality.

[VIRR 12-09-206-71(a)(7)(E)]

8.10 Permit Revision and Reopening

8.10.1 The permit must be reopened before the expiration date and revised accordingly under the following circumstances:

a. New/additional applicable requirements become applicable to the Permittee with three (3) or more years remaining in the permit term. Permits with three (3) or more years remaining prior to the expiration date shall be reopened to incorporate any newly promulgated section 112 standard. The reopening shall be completed within eighteen (18) months after promulgation of the applicable requirement.
[VIRR 12-09-206-83(a)(1)(A)]

b. The EPA or the Commissioner identifies mistakes or inaccurate statements made in establishing emissions standards or other terms or conditions.
[VIRR 12-09-206-83(a)(1)(B)]

c. The permit must be revised or revoked to ensure compliance with applicable requirements.
[VIRR 12-09-206-83(a)(1)(C)]

8.10.2 Procedures used to reopen and issue a permit shall follow the same procedures as applicable to initial permit issuance and shall affect only those parts of the permit for which cause to reopen exists.
[VIRR 12-09-206-83(a)(2)]

8.10.3 The Commissioner shall notify the Permittee at least thirty (30) days in advance of the date the permit is to be reopened, except that the Commissioner may provide a shorter time period in the case of an emergency.
[VIRR 12-09-206-83(a)(3)]

8.10.4 All permit conditions remain in effect until such time as the Director takes final action. The filing of a request by the Permittee for any permit revision, revocation, reissuance, or termination, or of a notification of planned changes or anticipated noncompliance, shall not stay any permit condition.
[VIRR 12-09-206-71(a)(7)(C)]

8.10.5 A permit revision shall not be required for certain defined changes that contravene permit terms or conditions or make them inapplicable without requiring a permit revision. Such changes may not include changes that violate applicable requirements or contravene permit terms and conditions that are monitoring, recordkeeping, reporting, or compliance certification requirements.
[VIRR 12-09-206-65(b)(1)]

8.10.6 A permit revision shall not be required for changes that are part of an approved economic incentive, marketable permit, emission trading, or other similar program or process for change that is specifically provided for in this permit.
[VIRR 12-09-206-71(a)(9)]

8.11 Severability

8.11.1 Any condition or portion of this permit that is challenged, becomes suspended or is ruled invalid as a result of any legal or other action shall not invalidate any other portion or condition of this permit.
[VIRR 12-09-206-71(a)(6)]

8.12 Excess Emissions Due to an Emergency

8.12.1 An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under the permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventative or required maintenance, careless or improper operation, or operator error.

[VIRR 12-09-204-20(p)]

8.12.2 An emergency shall constitute an affirmative defense to an action brought for noncompliance with the technology-based emission limitations, if the Permittee demonstrates, through properly signed contemporaneous operating logs or other relevant evidence that:

a. An emergency occurred and the Permittee can identify the cause(s) of the emergency;

b. The permitted facility was at the time of the emergency being properly operated;

c. During the period of the emergency, the Permittee took all reasonable steps to minimize levels of emissions that exceeded the emissions standards or other requirements in the permit; and

d. The Permittee submitted written notice of the emergency to the Division within two (2) working days of the time when emission limitations were exceeded due to the emergency. This notice must contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.

[VIRR 12-09-206-71(d)]

8.12.3 In an enforcement proceeding, the Permittee seeking to establish the occurrence of an emergency shall have the burden of proof.

[VIRR 12-09-206-71(d)(2)]

8.12.4 The emergency conditions listed above are in addition to any emergency or upset provisions contained in any applicable requirement.

[VIRR 12-09-206-71(d)(3)]

8.13 Compliance Requirements

8.13.1 Six Month Deviation Report

The Permittee shall submit to VIDPNR a six-month deviation report. The report shall include any deviations from required monitoring, not including information for monitoring which has other reporting schedules specified in this permit. Normally, continuous monitoring reporting is done quarterly. Reports must be submitted by August 31st for the period January 1 – June 30, and by February 28th for the period July 1 – December 31.

[VIRR 12-09-206-71(a)(5)(A)]

8.13.2 Compliance Certification

The Permittee shall provide an annual written certification to the Division and to the EPA of compliance with the conditions of this permit, by the end of the first calendar quarter after the previous calendar year reporting period. The certification shall include, but not be limited to, the following elements:

a. A statement of the methods used for determining compliance, including a description of monitoring, recordkeeping, and reporting requirements and test methods.

b. A schedule requiring the submission of compliance certification on an annual basis during the permit term or more frequently if specified by the underlying applicable requirements, or the Commissioner or his designated representative.

c. A statement indicating the Permittee's compliance status with any applicable enhanced monitoring and compliance certification requirements of the Act.
: [VIRR 12-09-206-64(c); VIRR 12-09-206-71(b)(5)]

8.13.3 Inspection and Entry

Upon presentation of credentials and other documents as may be required by law, the Permittee shall allow authorized representatives of the Division to perform the following:

a. Enter upon the Permittee's premises where a Part 70 source is located or an emissions-related activity is conducted, or where records must be kept under the conditions of this permit;

b. Have access to and copy, at reasonable times, any records that must be kept under the conditions of this permit;

c. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit; and

d. Sample or monitor any substances or parameters at any location during operating hours for the purpose of assuring permit compliance, compliance with applicable requirements, or as otherwise authorized by the Clean Air Act.
[VIRR 12-09-206-91; VIRR 12-09-206-71(b)(2)]

8.13.4 Schedule of Compliance

a. For applicable requirements with which the Permittee is in compliance, the Permittee shall continue to comply with those requirements.
[VIRR 12-09-206-63(b)(3)(A)]

b. For applicable requirements that will become effective during the permit term, the Permittee shall meet such requirements on a timely basis unless a more detailed schedule is expressly required by the applicable requirement.
[VIRR 12-09-206-63(b)(3)(B)]

c. The Permittee shall provide a schedule of compliance for applicable requirements with which the source is not in compliance at the time of permit issuance that includes a schedule of remedial measures including an enforceable sequence of actions with milestones leading to compliance with any applicable requirements for which the source will be in noncompliance at the time of permit issuance.
[VIRR 12-09-206-63(b)(3)(C)]

8.14 Permit Shield

8.14.1 Compliance with the conditions of this permit shall be deemed compliance with any applicable requirements as of the date of permit issuance, provided that such applicable requirements are included and specifically identified in the permit, or the Department, in acting on the permit application or revision, determines in writing that other requirements specifically identified are not applicable to the Permittee, and the permit includes the determinations or a concise summary thereof.
[VIRR 12-09-206-63(e)(1)]

8.14.2 Any permit that does not expressly state that a permit shield exists shall be presumed not to provide such a shield.
[VIRR 12-09-206-63(e)(2)]

8.15 Visible Emissions

8.15.1 Notwithstanding other conditions in this permit, fuel-burning facilities may discharge into the atmosphere air contaminant(s) with opacity equal to or less than 40% for a period or periods aggregating not more than three (3) minutes in any thirty (30) minutes.
[VIRR 12-09-204-22(b)]

8.16 Fuel-burning Equipment

8.16.1 For units other than those listed in sections 3.1 and 3.2, the Permittee shall not cause, let,

Million Btu/hour		Maximum Allowable Particulate Emission Rate (lbs/hr-mmbtu)
50 or less	-	0.30
50 up to 250	-	0.20
250 up to 10,000	-	0.10

suffer, permit, or allow the emission of particulate matter from any fuel-burning equipment to exceed the following: for heat input value of 50 million Btu or less, 0.30 ppm per hour per million Btu; for heat input value of 50 to 250 million Btu, 0.20 ppm per hour per million Btu; for heat input value of 250 to 10,000 million Btu, 0.10 ppm per hour per million Btu; and for heat input value of 10,000 million Btu or more, 0.09 ppm per hour per million Btu.
[VIRR 12-09-204-23(b)(2)]

8.16.2 Facilities that commenced construction prior to August 1, 1986 may emit particulate matter in quantities less than or equal to the quantity set forth in the following formula: $E = 1.0/p^{0.22}$ where E = allowable emission rate in pounds per million Btu and p = total heat input in million Btu/hr.
[VIRR 12-09-204-23(b)(4)]

8.17 Sulfur Dioxide

8.17.1 For units other than those listed in sections 3.1 and 3.2, the Permittee shall not:

a. burn distillate fuel oil containing more than 0.3 percent sulfur by weight if its total combined rated heat input capacity exceeds 8 million Btu per hour; and

b. burn residual fuel oil containing more than 1.5 percent sulfur by weight in any fuel burning source.

[VIRR 12-09-204-26(a)(2)]

8.18 Stack Testing and Monitoring

8.18.1 Any person responsible for the discharge of sulfur compounds in the form of gases, vapors, or liquid particles through a stack or chimney into the atmosphere shall, when requested by the Department, provide the facilities and necessary equipment for determining the combined quantity of such sulfur compounds being discharged and shall conduct stack tests using methods approved by the Division. The aforementioned does not apply if the total volume of gases discharged is less than 1,000 cfm at standard conditions. The data shall be maintained for a period of not less than one year.

[VIRR 12-09-204-26(c)(1) and (c)(2)]

Attachment A

LIST OF ABBREVIATIONS AND ACRONYMS

AMP	Alternative Monitoring Plan
ASTM	American Society for Testing and Materials
BACT	Best Available Control Technology
Bbl	barrel
BPD	barrels per calendar day
Btu	British Thermal Unit
CAAA	Clean Air Act Amendments
CDU	crude distillation unit
CEM	continuous emission monitor
CEMS	Continuous Emission Monitoring System
CFR	Code of Federal Regulations
CIM	continuous inlet monitor
CMS	Continuous Monitoring System(s)
CO	carbon monoxide
COM	continuous opacity monitor
COMS	Continuous Opacity Monitoring System
CPMS	Continuous Parameter Monitoring System
CS2	carbon disulfide
dcsf/dscm	dry standard cubic foot/dry standard cubic meter
DCU	delayed coker unit
DD	distillate desulfurizer
DRE	destruction removal efficiency
DU	distillate unifier
EAP	Emergency Action Plan
EFR	external floating roof
EPA	United States Environmental Protection Agency
ERP	Emergency Response Plan
FCC	fluid catalytic cracking
FCCU	fluid catalytic cracking unit
FGC	flue gas cooler
gr	grain(s)
GRU	gas recovery unit
GT	gas turbine
H_2 (H2)	hydrogen
H_2O (H2O)	water
H_2S (H2S)	hydrogen sulfide
H_2SO_4	sulfuric acid
HAGO	heavy atmospheric gas oil
HAP	hazardous air pollutant
HCFC	hydrochlorofluorocarbon
HCl	hydrogen chloride
HHV	higher heating value
HOVIC	Hess Oil Virgin Islands Corporation
HRSG	heat recovery steam generator
ICS	Intermittent Control Strategy
IFR	internal floating roof
lb/hr	pounds per hour

lb/mmBtu	pounds per million Btu
LDRP	leak detection repair program
LHV	lower heating value
LPG	liquefied petroleum gas
LPS	low pressure separator
LSFP	Low Sulfur Fuel Project
LSG	low sulfur gasoline
LSR	light straight run
MACT	Maximum Achievable Control Technology
MMBtu	million British thermal units
mmBtu	million British thermal units
MVAC	motor vehicle air conditioner
MW	megawatt
N/A	Not Applicable
NAAQS	National Ambient Air Quality Standards
NCS	Notification of Compliance Status
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO_X	nitrogen oxides
NSPS	New Source Performance Standards
O_2	oxygen
OMM	Operation, Monitoring, and Maintenance
OSHA	Occupational Safety and Health Administration
PLAT	platformer
PM	particulate matter
PM-10/PM10	particulate matter less than 10 micrometers in diameter
ppm	parts per million
ppmv	parts per million by volume
ppmvd	parts per million, volumetric dry
ppmw	parts per million by weight
PSD	Prevention of Significant Deterioration
Psia	absolute pressure per square inch
PTE	potential to emit
QA/QC	quality assurance/quality control
QAPP	Quality Assurance Project Plan
RA	Regional Administrator
RACT	Reasonably Available Control Technology
RFG	refinery fuel gas
RM	(EPA) reference method
RMP	Risk Management Plan
scf	standard cubic feet
scfm	standard cubic feet per minute
SCR	selective catalytic reduction
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SO2/SO_2	sulfur dioxide
SOCMI-HON	Synthetic Organic Chemical Manufacturing Industry – Hazardous Organic NESHAP
SOP	standard operating procedure
SRU	sulfur recovery unit
TDS	total dissolved solids
tpd	tons per day
TIP	Territorial Implementation Plan

tpy	tons per year
TVP	True Vapor Pressure
USC	United States Code
VAC	vacuum unit
VER	Vapor Enhanced Recovery System
VIDPNR	Virgin Islands Department of Planning and Natural Resources
VIRR	U.S. Virgin Islands Rules and Regulations
VIS	visbreaker
VISIP	Virgin Islands State Implementation Plan
VOC	volatile organic compound
VRU	vapor recovery unit
WGS	wet gas scrubber
WHB	waste heat boiler

Attachment B

INSIGNIFICANT ACTIVITIES CHECKLIST

NOTE: Attachment B contains information regarding insignificant emission units/activities in existence at the facility at the time of permit issuance. Future modifications or additions of insignificant emission units/activities may not necessarily cause this attachment to be updated.

INSIGNIFICANT ACTIVITIES CHECKLIST		
Category	**Description of Insignificant Activity/Unit**	**Quantity**
A - Fuel Use-Related	1. Production of hot water for in-house, non-process use.	
	2. Space heater (natural gas, propane fueled only).	
	3. Retail restaurant (on-site cafeteria) fuel use.	
B - Plant Upkeep-Related	1. Housekeeping (paint building, re-tar roof).	
	2. Activities not related to process (copy machine, document printers, housekeeping, physical plant maintenance.	
C - Laboratories	1. Lab equipment used exclusively for chemical and physical analyses (using occupational safety and health definition - attached).	
	2. Lab equipment used for desktop experiments.	
D - Furnaces, Boilers, Incinerators	1. Infrared electric ovens.	
	2. Fuel-burning equipment of less than 500,000 Btu/hr capacity, except where total capacity of equipment exceeds 2 MMBtu/hr when operated by one stationary source.	
E - Materials Handling	1. Batch mixers with rated capacity of five (5) cubic feet or less that are not covered by Part 60 (NSPS) requirements.	
	2. Construction grading of surface areas not exceeding a total of twenty five (25) contiguous acres for not more than one (1) year.	
F - Fabrication Operations	1. Equipment used to inspect metal products.	
	2. Equipment used exclusively for forging, pressing, drawing, spinning, or extruding hot or cold metals.	
	3. Equipment used exclusively to mill or grind coatings and molding compounds where all materials charged are in paste form.	
	4. Mixers, blenders, roll mills, or claendars for rubber or plastics for which no materials in powder are added and in which no organic solvents, diluents, or thinners are used.	
G - Finishing Operations	1. Closed tumblers used for cleaning or debarring products without abrasive blasting, and open tumblers with a batch capacity of one thousand pounds (1000 lbs.) or less.	
	2. Equipment for washing or drying fabricated glass or metal products, if no VOCs are used in the process and no gas, oil or solid fuel is burned.	
H - Storage and Distribution (except petroleum products)	1. Aqueous fertilizer storage tanks.	
I - Water Treatment	1. Stacks or vents to prevent escape of sewer gases through plumbing traps.	
J - Cleaning Operations	1. Commercial laundries (except dry cleaners) not using liquid or solid fuel.	
	2. Alkaline/phosphate and associated burners.	
K - Domestics Activities, Excluding the Burning of Tires, Tire By-Products, or Contaminated Wood	1. Emissions from, or construction or modifications of, residential structures.	
	2. Refrigeration systems, including associated activities.	
	3. Comfort air conditioning or ventilation systems not used to remove air contaminants generated by or released from specific units of equipment.	
	4. Outdoor kerosene heaters.	
	5. Space heaters operating by direct heat transfer.	
	6. Recreational fireplaces.	
	7. Barbeque pits and cookers.	
L - Miscellaneous	1. Repairs and maintenance not involving structural repairs where no new permanent facilities are installed, where the repairs or maintenance does not increase air emissions.	
	2. Safety devices, if associated with a permitted emission source.	
	3. Non-production-related repair and maintenance coating, cleaning, decreasing operations that do not exceed 145 gal/yr.	
	4. Flares to indicate danger to the public.	
	5. Equipment used exclusivley for packaging lubricants or greases.	
	6. Equipment used for hydraulic or hydrostatic testing.	
	7. Brazing, soldering, or welding equipment.	
	8. Blueprint copiers and photographic processes.	
	9. Equipment used exclusively for melting or applying wax.	
	10. Non-asbestos equipment used exclusively for bonding and lining to brake shoes.	

Attachment B (continued)

DESCRIPTION OF INSIGNIFICANT ACTIVITY[1]	**QUANTITY**
Mobile Sources except MVACs	
Ship and barges	
Onsite Laboratories	
Portable Generators	
Portable Engines	
Small or Limited Use Engines < 500 hp or 100 hrs/yr operation)	
Portable Welding Machines	
Miscellaneous Portable Equipment	
Plant Maintenance	
Service Barges	
Service Station	
Cafeteria	
Housing Camps – Rec. Hall	
LPG Spheres	
Miscellaneous storage tanks with no applicable requirements	
Landfarms	
PTU Storage Area	

[1] Source: Former owner HOVENSA Title V Application, December 2007, Section 2.5

Attachment C

LIST OF REFERENCES

1. The Virgin Islands Air Pollution Control Act Rules and Regulations Title 12, Chapter 09. All Rules cited herein that begin with 12-09 are the Virgin Islands Air Quality Rules.

2. Title 40 of the Code of Federal Regulations; specifically 40 CFR Parts 50, 51, 52, 60, 61, 63, 64, 68, 70, 72, 73, 75, 76 and 82. All rules cited with these parts are Federal Air Quality Rules.

3. **Compilation of Air Pollutant Emission Factors, AP-42, Fifth Edition, Volume I: Stationary Point and Area Sources.** This information may be obtained from EPA's TTN web site at *www.epa. gov/ttn/chief /ap42.html.*

4. The Clean Air Act (42 U.S.C. 7401 et seq.).

5. White Paper for Streamlined Development of Part 70 Permit Applications, July 10, 1995 (White Paper #1).

6. White Paper Number 2 for Improved Implementation of the Part 70 Operating Permits Program, March 5, 1996 (White Paper #2).

7. Title V Permit Application (w/Attachments), former owner HOVENSA, December 2007.

8. Title V Permit Application – Update No. 1, Letter from Kathleen C. Antoine (former owner HOVENSA) to Nadine Noorhasan (VIDPNR), June 13, 2008.

9. Title V Permit Application – Update No. 2, Letter from Kathleen C. Antoine (former owner HOVENSA) to Nadine Noorhasan (VIDPNR), October 10, 2008.

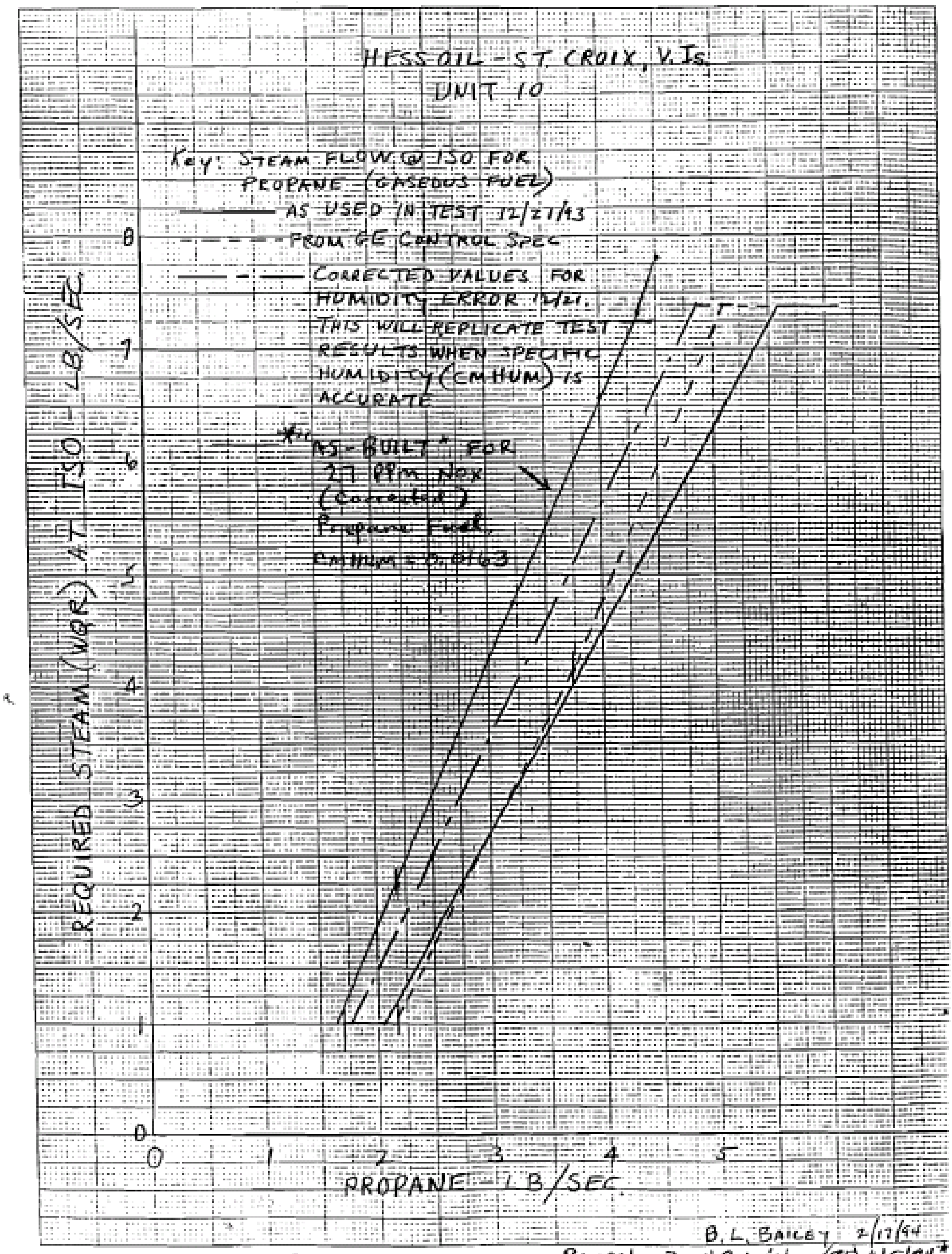
10. GT No. 10 PSD Permit Conditions, August 15, 2007.

11. Former owner HOVENSA Low Sulfur Fuels Project, Final Permit, June 5, 2008.

12. Final Prevention of Significant Deterioration of Air Quality (PSD) Permit, Hess Oil Virgin Islands Corporation (HOVIC) Refinery Modification, December 12, 1997.

Attachment D

OPTIMUM STEAM TO FUEL RATIO FOR G-3410



Attachment E

COMPLIANCE SCHEDULES

- Schedules 1 – 9
- Schedule 11
- Schedule 14
- Schedule CD
- Schedule 16
- Schedule 18