DRAFT

PERMIT to OPERATE 6708-R7

and

PART 70 OPERATING PERMIT 6708-R7

LOMPOC OIL AND GAS PLANT

PXP - LOMPOC POINT PEDERNALES STATIONARY SOURCE

3602 HARRIS GRADE ROAD
LOMPOC, CALIFORNIA

OWNER/OPERATOR

Plains Exploration & Production Co. (PXP)

Santa Barbara County
Air Pollution Control District

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ABBREVIATIONS/ACRONYMS

AP-42	USEPA's *Compilation of Emission Factors*
API	American Petroleum Institute
AQMM R&O	Air Quality and Meteorological Monitoring Protocol
ASTM	American Society for Testing Materials
ATC	Authority to Construct
BACT	Best Available Control Technology
BOEM	Bureau of Ocean Energy Management
bpd	barrels per day (1 barrel = 42 gallons)
Btu	British thermal unit
CAM	compliance assurance monitoring
CEMS	continuous emissions monitoring
CPP	cogeneration power plant
District	Santa Barbara County Air Pollution Control District
dscf	dry standard cubic foot
E100	emitters less than 100 ppmv
E500	emitters less than 500 ppmv
EQ	equipment
ESE	entire source emissions
EU	emission unit
°F	degree Fahrenheit
FID	facility identification
gal	gallon
gr	grain
HAP	hazardous air pollutant (as defined by CAAA, Section 112(b))
H_2S	hydrogen sulfide
I&M	Inspection & Maintenance
ISO	International Standards Organization
k	kilo (thousand)
l	liter
lb	pound
lbs/day	pounds per day
lbs/hr	pounds per hour
LACT	Lease Automatic Custody Transfer
LPG	liquid petroleum gas
LOGP	Lompoc Oil and Gas Plant
M	mega (million)
MACT	Maximum Achievable Control Technology
MM	million
MW	molecular weight
NAR	Nonattainment Review
NAROC	Non-alkane Reactive Organic Compound
NEI	net emissions increase
NGL	natural gas liquids
NG	natural gas
NH_3	ammonia
NSPS	New Source Performance Standards
NESHAP	National Emissions Standards for Hazardous Air Pollutants
O_2	oxygen
OCS	outer continental shelf
PM	particulate matter

PM_{10}	particulate matter less than 10 microns
PPM (vd or w)	parts per million (volume dry or weight)
PPHM	parts per hundred million
psia	pounds per square inch absolute
psig	pounds per square inch gauge
PRD/PSV	pressure relief device
PTO	Permit to Operate
RACT	Reasonably Available Control Technology
ROC	reactive organic compounds, same as “VOC” as used in this permit
RVP	Reid vapor pressure
scf	standard cubic foot
scfd (or scfm)	standard cubic feet per day (or per minute)
SIP	State Implementation Plan
SSID	stationary source identification
STP	standard temperature (60°F) and pressure (29.92 inches of mercury)
THC, TOC	total hydrocarbons, total organic compounds
tpq, TPQ	tons per quarter
tpy, TPY	tons per year
TVP	true vapor pressure
USEPA	United States Environmental Protection Agency
VE	visible emissions
VRS	vapor recovery system
WGI	Waste Gas Incinerator
w.c.	water column

1.0 Introduction

1.1 Purpose

General. The Santa Barbara County Air Pollution Control District (District) is responsible for implementing all applicable federal, state and local air pollution requirements which affect any stationary source of air pollution in Santa Barbara County. The federal requirements include regulations listed in the Code of Federal Regulations: 40 CFR Parts 50, 51, 52, 55, 60, 61, 63, 68, 70 and 82. The State regulations may be found in the California Health & Safety Code, Division 26, Section 39000 et seq. The applicable local regulations can be found in the District's Rules and Regulations. This is a combined permitting action that covers both the Federal Part 70 permit (*Part 70 Operating Permit No. 6708*) as well as the State Operating Permit (*Permit to Operate No. 6708*).

Santa Barbara County is designated as an ozone non-attainment area for the state ambient air quality standards. The County is also designated a non-attainment area for the state PM_{10} ambient air quality standard.

Part 70 Permitting. The initial Part 70 permit for the LOGP was issued October 17, 2000 in accordance the requirements of the District's Part 70 permit program. This is the fourth renewal of the Part 70 permit and may include additional applicable requirements and associated compliance assurance conditions. Also, this permit incorporates any Part 70 minor modifications since the last renewal, and is being issued as a combined Part 70 and District reevaluation permit.

The LOGP facility is a part of the *PXP - Lompoc/Point Pedernales Project* stationary source (SSID = 4632), which is a major source for VOC[1] and NO_x, Conditions listed in this permit are based on federal, state or local rules and requirements. Sections 9.A, 9.B and 9.C of this permit are enforceable by the District, the USEPA and the public since these sections are federally enforceable under Part 70. Where any reference contained in Sections 9.A, 9.B or 9.C refers to any other part of this permit, that part of the permit referred to is federally enforceable.

Pursuant to the stated aims of Title V of the CAAA of 1990 (i.e., the Part 70 operating permit program), this permit has been designed to meet two objectives. First, compliance with all conditions in this permit would ensure compliance with all federally-enforceable requirements for the facility. Second, the permit would be a comprehensive document to be used as a reference by the permittee, the regulatory agencies and the public to assess compliance.

Tailoring Rule. This reevaluation incorporates greenhouse gas emission calculations for the stationary source. On January 20, 2011, the District revised Rule 1301 to include greenhouse gases (GHGs) that are "subject to regulation" in the definition of "Regulated

[1] VOC as defined in Regulation XIII has the same meaning as reactive organic compounds as defined in Rule 102. The term ROC shall be used throughout the remainder of this document, but where used in the context of the Part 70 regulation, the reader shall interpret the term as VOC.

Air Pollutants". District Part 70 operating permits are being updated to incorporate the revised definition.

1.2 Facility/Project/Stationary Source Overview

1.2.1 Facility: PXP is owner and operator of the Lompoc Oil and Gas Plant. The facility is comprised of an oil dehydration and a gas processing plant. Crude oil from Platform Irene is dehydrated and shipped to the Santa Maria Refinery, via the Orcutt Pump Station, for final processing. Gas production from Platform Irene and the Lompoc Oil Field is treated to pipeline quality specifications, including removal of H_2S, and used as facility fuel or sold to Southern California Gas.

Project: The LOGP is part of the *PXP Point Pedernales Project*. The project was originally permitted in 1988 and included the LOGP, Platform Irene, associated pipelines, the Orcutt Pump Station, and the Santa Maria Refinery as established by the Santa Barbara County Planning and Development Department lead agency permit. The OPS and Santa Maria Refinery are part of the project but not part of the related stationary source.

Stationary Source: The LOGP is part of the *PXP Lompoc/Point Pedernales* stationary source. Originally, this was the Point Pedernales Stationary Source and consisted of the LOGP and Platform Irene only. However, the installation of the gas processing plant facilities resulted in the processing of gas from the Lompoc Oil Field at the LOGP. As a result, the District deemed the Lompoc Oil Field to be part of the same stationary source as the LOGP. As of the date of issuance of the gas processing plant permit (ATC 9522 issued 12/24/1996) the Lompoc Oil Field was included in the Point Pedernales Stationary Source and the stationary source was renamed *PXP Lompoc/Point Pedernales.*

The *PXP Lompoc/Point Pedernales Stationary Source* (SSID 4632) consists of the following facilities:

- La Purisima Lease (FID 3069)
- Lompoc Oil and Gas Plant (FID 3095)
- Jesus Maria "D" Lease (FID 3309)
- Orcutt Fee (FID 3310)
- Eefson Lease (FID 3802)
- Jesus Maria "A" Lease (FID 3832)
- Lompoc Fee (FID 3837)
- Hill Lease (FID 3839)
- Arkley Fee (FID 4117)
- Lompoc Internal Combustion Engines (FID 4218)
- Platform Irene (FID 8016)

1.2.2 1.2.2 Facility Permitting History: The following is the permit history for this facility:

PERMIT	FINAL ISSUED	PERMIT DESCRIPTION
PTO 06708	05/19/1988	See Permit

PERMIT	FINAL ISSUED	PERMIT DESCRIPTION
ATC 07549	06/02/1989	See Permit
PTO 07549	12/15/1989	See Permit
ATC Mod 07295 01	06/19/1990	See Permit
ATC 08357	05/23/1991	See Permit
PTO 08357	11/15/1991	See Permit
PTO 07295	01/29/1992	See Permit
ATC 08696	05/11/1992	See Permit
PTO 08696	06/11/1992	See Permit
ATC 08827	08/21/1992	See Permit
PTO 08827	09/09/1992	See Permit
Reeval 06708 R1	08/23/1994	1994 reevaluation of PTO 6708.
PTO Mod 06708 01	09/06/1994	See Permit
PTO Mod 06708 02	03/01/1995	See Permit
ATC 09200	06/08/1995	Installation of Gas Reinjection facilities at the HS&P.
ATC 09522	12/24/1996	Torch Gas Plant - entire facility formerly known as the HS&P, is now known as the Lompoc Oil and Gas Processing Plant.
PTO Mod 06708 05	04/02/1997	Permit modification to document several changes to PTO 6708 including, ERC swap, Qualification of BGP shutdown ERCs, ROC ethane adjustment, as well as several other minor changes.
PTO Mod 06708 06	07/07/1997	Revision to permit condition 42 - Storage Tank T-280 (100,000 bbl). to allow for increased tank level.
ATC Mod 09522 01	07/29/1997	Odorant injection facilities located at the HS&P. This project is associated with the Gas Plant Project (ATC 9522).
PTO Mod 06708 07	04/02/1998	Permit modification to eliminate the requirement to telemeter wet oil throughput rates to the District.
ATC Mod 09522 03	11/13/1998	LPG odorant station and increase of flare emissions from the gas plant. The LPG odorant station came in under ATC application 9522-02 and the flare emissions under -03. A single permit (ATC 9522-03) will be issued for both apps.
PTO Mod 06708 08	01/22/1999	Letter mod for revision of the DAS fee language.
ATC Mod 09522 04	02/03/1999	Application for use of correlation equations and consolidation with ATC 9200 and ATC 9522-01.
ATC/PTO 10146	07/01/1999	Modification to AAQM Station fee basis for APCD Charges.
PTO 09522	11/29/1999	PTO consolidating ATCs 9522, 9522-03 and 9522-04.
ATC/PTO Mod 09522 01	10/07/2000	Modify fuel gas sampling procedures so that they are consistent with Pt-70 permit.
PT-70/Reeval 06708 R3	10/17/2000	Part 70 Permit. See Pt70 PTO 9963.
PT-70 09963	10/17/2000	Part 70 permit application. See 6708.
Trn O/O 06708 02	02/27/2001	Transfer of operatorship from Torch to Nuevo
ATC/PTO 10341	12/20/2001	Pipeline H2S Increase. (PT70 10778)

PERMIT	FINAL ISSUED	PERMIT DESCRIPTION
ATC/PTO 10341	02/20/2002	Pipeline H2S Increase. (PT70 10778)
PT-70/Reeval 06708 R4	12/17/2003	Pt70 Reevaluation.
Trn O/O 06708 03	09/23/2004	Transfer of Owner/Operator from Nuevo to Plains Exploration & Production.
PTO 11867	12/19/2005	FW pump engines (2x) and One ES20 engine. FW: CAT 3406DI (430 bhp), CAT 3406DI (430 bhp), ES20 ?? at Lompoc O&G plant. M&T limited by NFPA hours use.
PTO Mod 06708 09	03/16/2006	Removal of Sigma W and VWS requirements from LOGP and Paradise Rd. AAQMS.
PT-70/Reeval 06708 R5	12/08/2006	Pt70 Permit Reevaluation.
ATC 13015	02/03/2009	Relocation of a pig trap in the Lompoc Field La Purisima Lease. See DOI 056. Note: Several emails were received revising this application. Latest was 12/22/2008, thus, original application submittal date was revised from 11/26/2008 to 12/22/2008.
ATC Mod 13015 01	04/09/2009	Permit modification was submitted for revisions to the fugitive I&M component count. ATC 13015-01 was not issued. The Fugitive I&M revisions were rolled into PTO 13015.
PTO 13015	04/09/2009	Relocation of a pig trap in the Lompoc Field La Purisima Lease. See DOI 056. Note: Several emails were received revising this application. Latest was 12/22/2008, thus, original application submittal date was revised from 11/26/2008 to 12/22/2008.
PT-70/Reeval 06708 R6	12/23/2009	Pt70 Permit Renewal.
PTO Mod 06708 10	08/31/2011	Permanent removal of a number of fugitive emission related components. See DOI 00068.

1.3 Emission Sources

The emissions from the LOGP facility come from the following sources: internal combustion engines, heater treaters, a flare, a sulfur recovery plant, various tanks, sumps, pumps and compressors, a thermal oxidizer and fugitive emission components. Section 4 of this permit provides the District's engineering analyses of these emission sources. Section 5 of this permit describes the allowable emissions from each permitted emissions unit and also lists the potential emissions from non-permitted emission units.

1.4 Emission Control Overview

Air pollution emission controls are utilized at the LOGP facility. The emission controls employed at the facility include:

- A Fugitive Inspection & Maintenance program for detecting and repairing leaks of hydrocarbons from piping components to reduce ROC emissions by approximately 80 percent, consistent with the BACT requirements of ATC 6708 and modifications thereof, NSPS KKK, and Rule 331.

- Use of a flare H_2S scrubber.
- Use of a thermal oxidizer for the combustion of waste gases.
- Use of pipeline quality natural gas as fuel gas for all gas combustion units.
- Use of a Sulferox sulfur removal system to reduce the sulfur in the produced gas.
- Use of Low-NO_x burners on the three heater treaters.
- Use of a vapor recovery system to collect hydrocarbon vapors from various tanks, sumps and drains.
- Use of carbon canisters to collect hydrocarbons and total reduced sulfur compounds at specified tanks, sumps and on vacuum trucks which service this equipment.

1.5 Offsets/Emission Reduction Credit Overview

Offsets: Emissions from the LOGP facility must be offset pursuant to the District's New Source Review regulation. Project ROC emissions increases are currently required to be offset based on District Rule 802 offset thresholds. Offsets were initially required for ROC, NAROC (non-alkane ROC) and NO_x. Section 7 details the offset requirements for the Point Pedernales Project.

1.6 Part 70 Operating Permit Overview

1.6.1 Federally-enforceable Requirements: All federally enforceable requirements are listed in 40 CFR Part 70.2 (*Definitions*) under "applicable requirements." These include all SIP-approved District Rules, all conditions in the District-issued Authority to Construct permits and all conditions applicable to major sources under federally promulgated rules and regulations. All permits (and conditions therein) issued pursuant to the OCS Air Regulation are federally enforceable. All these requirements are enforceable by the public under CAAA. (*see Section 3 for a list of the federally enforceable requirements)*

1.6.2 Insignificant Emissions Units: Insignificant emission units are defined under District Rule 1301 as any regulated air pollutant emitted from the unit, excluding HAPs, that are less than 2 tons per year based on the unit's potential to emit and any HAP regulated under section 112(g) of the Clean Air Act that does not exceed 0.5 ton per year based on the unit's potential to emit. Insignificant activities were listed in the Part 70 application with supporting calculations. Applicable requirements may apply to insignificant units.

1.6.3 Federal Potential to Emit: The federal potential to emit (PTE) of a stationary source does not include fugitive emissions of any pollutant, unless the source is: (1) subject to a federal NSPS/NESHAP requirement which was in effect as of August 7, 1980, or (2) included in the 29-category source list specified in 40 CFR 51.166 or 52.21. The federal PTE does include all emissions from any insignificant emissions units. (*See Section 5.4 for the federal PTE for this source)*

1.6.4 Permit Shield: The operator of a major source may be granted a shield: (a) specifically stipulating any federally-enforceable conditions that are no longer applicable to the source and (b) stating the reasons for such non-applicability. The permit shield must be based on a request from the source and its detailed review by the District. Permit shields cannot be indiscriminately granted with respect to all federal requirements. PXP made no requests for a permit shield.

1.6.5 Alternate Operating Scenarios: A major source may be permitted to operate under different operating scenarios, if appropriate descriptions of such scenarios are included in its Part 70 permit application and if such operations are allowed under federally-enforceable rules. PXP made no requests for alternative operating scenarios.

1.6.6 Compliance Certification: Part 70 permit holders must certify compliance with all applicable federally-enforceable requirements including permit conditions. Such certification must accompany each Part 70 permit application; and, be re-submitted annually on or before March 1st or on a more frequent schedule specified in the permit. A "responsible official" of the owner/operator company whose name and address is listed prominently in the Part 70 permit signs each certification. (*see Section 1.6.9 below)*

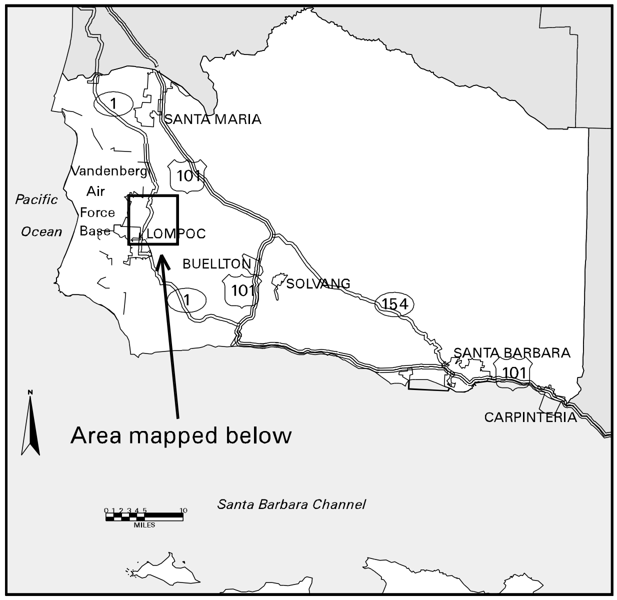
1.6.7 Permit Reopening: Part 70 permits are re-opened and revised if the source becomes subject to a new rule or new permit conditions are necessary to ensure compliance with existing rules. The permits are also re-opened if they contain a material mistake or the emission limitations or other conditions are based on inaccurate permit application data.

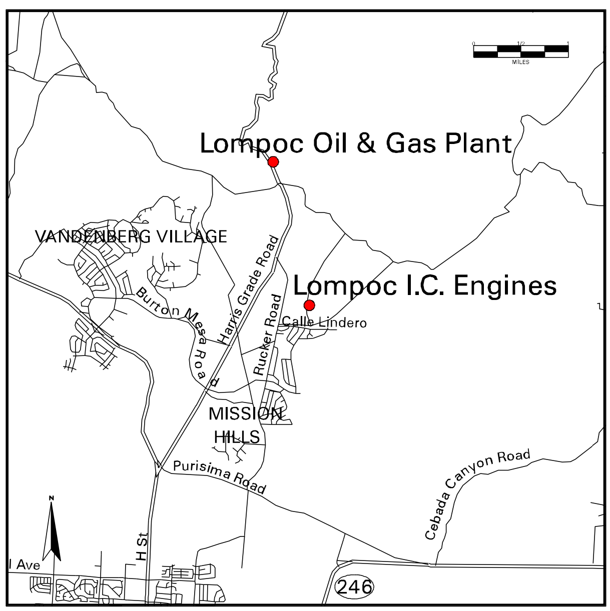
1.6.8 Hazardous Air Pollutants (HAPs): The requirements of Part 70 permits also regulate emission of HAPs from major sources through the imposition of maximum achievable control technology (MACT), where applicable. The federal PTE for HAP emissions from a source is computed to determine MACT or any other rule applicability. (*see Sections 4.15 and 5.0)*

1.6.9 Responsible Official: The designated responsible official and his mailing address is:

Mr. Thomas Goeres, Operations Manager
Plains Exploration & Production Company
201 South Broadway
Orcutt, California 93455

Figure 1.1 - Location Map





2.0 Description of Proposed Project and Process Description

2.1 Project and Process Description

2.1.1 Project Ownership: PXP is the owner and operator of the Lompoc oil and Gas Plant. PXP acquired ownership from Unocal in September 1994.

2.1.2 Geographic Location: The Lompoc Oil and Gas Plant Facility (LOGP) is located 2.7 miles northeast of the City of Lompoc at 3602 Harris Grade Road. The facility sits on a 22.5-acre parcel of land and is within the Lompoc Oil Field. See Figure 1.1 (Location Map) for additional detail.

2.1.3 Operations Overview: The Point Pedernales Project develops oil and gas production from the Point Pedernales Field and the Lompoc Oil Field. The Point Pedernales Field is located offshore on the outer continental shelf (OCS) approximately four miles west of Point Pedernales and is produced through wells and primary production equipment located on Platform Irene. Crude and gas production from Platform Irene is transported to shore through subsea pipelines and is treated at production facilities located at the LOGP. The Lompoc Field is adjacent to the LOGP and sends gas to the LOGP via pipeline. Crude oil is shipped from the LOGP to the Santa Maria Refinery via the OPS and gas is sold to Southern California Gas or used as fuel.

The LOGP facility consists primarily of two plants: the oil dehydration plant and the gas processing plant. Crude is dehydrated for shipment to the Santa Maria Refinery via the Orcutt Pump Station for final processing. Gas production is treated at the gas processing plant to pipeline quality specifications for use as facility fuel and sales to Southern California Gas.

2.1.4 Oil Processing Plant: *Oil Dehydration Plant.* The oil dehydration plant receives oil and water in the form of an emulsion through a 20"subsea pipeline from Platform Irene. The crude heat exchange and dehydration system heats the emulsion, separates the sour gas and free water from the emulsion in a free water knockout ("FWKO") and dehydrates the crude with either heater treater train "A", "B", or "C". Each heater treater is equipped with a Low-NO_x Alzeta Pyrocore burner. The heater treaters provide additional gas separation, free water removal and coalescence of entrained water particles to allow the oil to meet pipeline specifications.

2.1.4.1 *Produced Water Treating System:* The produced fluid flows from the dry crude/wet crude heat exchanger (E-200) to the gas oil separator (V-140). The gas oil separator serves a surge vessel and also removes gas from the liquid stream. The FWKO is designed to remove any free water from the produced fluid stream and to distribute the emulsion to each of the heater treaters. The FWKO also removes any gas that has evolved from the liquid system. Oil is routed to the heater treaters and oily water is routed to the water treatment system.

The purpose of the produced water treating system is to clean all produced water associated with the oil and gas processing. The water is collected from a variety of process sources including the FWKO, heater treaters and oil reclamation system. Oily water associated with crude and gas production is collected and transported to the wash tank (T-350). Oil rises to the top of the wash tank and is removed and pumped to the slop tank (T-420). Clean water from the wash tank is pumped to the clean water tank (T-400) via the clean water transfer pumps. Water from the clean water tank flows through SDU-400 to the water shipping pumps. The produced water is then pumped either to Platform Irene or the Lompoc field for offshore and onshore injection well disposal.

Flashed gas from these processes are routed to the LOGP's associated gas handling system and flow to the booster compressor for processing as facility gas in the gas processing system.

2.1.4.2 *Crude Oil Storage and Shipping*: Following treatment, crude oil is routed to the Shipping Vessel (V-250) which is a two-phase separator, using pressure to remove any gas still entrained in the crude. It also provides surge capacity to dampen the effects of variations in the production rates. The Automatic Custody Transfer (ACT) pumps transfer the dry crude from the Shipping Vessel to the ACT Unit (ACT-300) at the necessary pressure for custody transfer. If the shipping vessel is removed from service, all crude oil production must be diverted to the oil surge tank.

The Automatic Custody Transfer (ACT) Unit, ACT-300, processes dry crude from either the shipping vessel or the oil surge tank for transfer to the Santa Maria Refinery. The ACT Unit determines the net volume, maintains quality control and performs automatic sampling of the crude being sold. All controls affecting quantity and quality measurements are of a "Fail-safe" design. The design is such that mis-measurement will not occur in event of a power failure or failure of any of the system's component parts. Crude passing through the ACT Unit will either be shipped via the Shipping Pumps or will be diverted to the Reject Tanks to await further dehydration.

The Shipping Pumps, P-310 and P-315, bring the dry crude from ACT-300 up to shipping pressure so that it may be transported off-site via pipeline to the Santa Maria Refinery. The pumps are two identical three-rotor screw pumps each designed to transport 20 Mbpd. One pump is selected for operation and the other is to function as 100% spare.

The Reject Tanks, T-210 and T-220, provide storage capacity for wet crude until it can be sent back through the crude handling system to be dehydrated. The Reject Tanks are not utilized on a continuous basis during normal production. When utilized, they store wet crude from the Heater Treaters, Flare Scrubber, Oil Reclaimer or ACT Unit. Crude from the Reject Tanks are then pumped to the Shipping Vessel, V-250, for metering and shipment; to the Reclaim Oil Tank, T-450; or back to the FWKO for dehydration via the Reject Tank Pumps, P-230 and P-240.

The Oil Surge Tank, T-280, provides storage capacity when the incoming crude flow rate to the LOGP exceeds the shipping rate. The Oil Surge Tank is not utilized on a regular basis during normal production. If the Reject Tanks, T-210 and T-220, are full, wet crude from the Heater Treaters, Flare Scrubber Return Pumps, Oil Reclaimer and ACT Unit may be diverted into the Oil Surge Tank.

Associated with the Oil Surge Tank and an integral part of its operation is the Oil Surge Tank Pump (P-290). The pump transports crude from the Oil Surge Tank to the ACT Unit for metering and shipment; to the Reclaim Oil Tank, T-450; or back to the FWKO for dehydration.

2.1.4.3 *Crude Tank Blanketing and Vapor Recovery:* The vapor recovery and gas compression systems each consist of two independent trains. Each train of equipment is completely skid-mounted and is designed to handle 100% of the expected flow rate. The vapor recovery system collects, cools and compresses the vapors from the low-pressure sources (oil surge tank, shipping vessel, slops tank, etc.) in the process**.**

The vapor recovery system is designed to maintain a slightly positive pressure in the gas-gathering network. The pressure is maintained by adjusting the speed of the vapor recovery compressor and/or adding make-up gas to the system. The low-pressure tank vapors are cooled and scrubbed before entering the vapor recovery compressors (C-520A and C-520B). The vapor recovery compressor is a rotary vane unit designed to handle 465 Mscfd of hydrocarbon gas at near atmospheric pressure. The unit is designed to discharge the gas to the gas compression system at approximately 35 psig.

Because of the equipment layout at the facility, the vapor recovery network is divided into two headers: one 4 inch South vapor recovery header, and one 12 inch North vapor recovery header. The vapor sources that contribute to each of these headers are outlined in Table 1 below. The higher-pressure sources such as the heater treaters, FWKO, gas-oil separator, inlet scrubber, etc., are not continuous contributions to the vapor recovery system. These vessels are designed to be manually blown down to the vapor recovery system only during maintenance operations or when the vessel is taken out of service.

Vapor recovery blowcase V-610 is provided at a low point in the South vapor recovery header to remove any condensed vapors that may accumulate in the header. The blowcase is complete with the instrument and controls necessary to transfer the liquids to the FWKO.

Table 1

South Vapor Recovery Header	North Vapor Recovery Header	
Heater Treaters	Reject Tanks	Fuel Gas Scrubber
FWKO	Shipping Vessel	H_2S Scrubber
Gas/Oil Separator	Oil Surge Tank	Glycol Scrubber
Inlet Scrubber	Wash Tank	Fuel Gas Tower
Gas Pig Receiver	Clean Water Tank	
Oil Reclaimer	Slops Tank	
Condensate Storage Vessel	Sales Gas Pig Launcher	

2.1.4.1 *Flare:* The Flare system is designed for the incineration of process gas. The flare is located in the southeast corner of the plant, 80 feet from the plant's process equipment.

The flare system includes a gathering system consisting of a 6-inch header with laterals, flare scrubber, H_2S scrubber, flare blowcases, flare scrubber return pumps, ignition panel, flare meter, 40 feet guy wired stack and a multi-tipped flare. Gas enters the 6-inch flare header by blowdown, automatic safety relief and pressure control from high-pressure sources. The gas flows into the flare scrubber V-580 where entrained liquids drop out. The liquid is returned to the reject tanks via the flare scrubber return pumps P-590A/B. The gas continues to the flare line and exits the flare tip. At the tip the gas is ignited by a continuous burning pilot. Any liquid that accumulates in the flare stack, flare header or piping low points, drains to the flare blowcase V-585 which routes the liquids to the flare scrubber.

2.1.4.5 *Drain and Pump System*: The Oil Processing Plant is equipped with eight covered sumps. The sumps collect liquid from manual drains and sample boxes located throughout the facility. Pumps located on the sumps then transport the liquids back into the various systems. Each sump is located near the equipment that drains to it. The eight sumps and their corresponding areas are listed below:

Tag No.	Sump	Location
S-850	Flotation Unit Froth Sump	WEMCO
S-860	Control Building Lab Sump	Lab Building
S-870	Oil Surge Tank Sump	Oil Surge Tank
S-800	Inlet Sump	Heat Exchangers, Inlet Launcher and Receiver
S-810	Crude Dehydration Sump	Heater Treaters and Gas Handling Area
S-820	Water Treating Sump	Wash, Slop, and Clean Water Tank Area
S-830	Reject Tank Sump	Reject Tank Area
S-840	Outlet Sump	Outlet Launcher and Receiver Area

The sumps normally pump the liquids back to the slop tank. However, if the tank is full or out of service, each sump can pump into an alternate tank. The Flotation Unit Froth Sump, S-850, is tied into the vapor recovery system. S-850 is the only sump which is a completely closed system. All the other sumps are sealed and equipped with a vent line with a charcoal filter.

2.1.5 Gas Processing Plant

2.1.5.1 *Sulfur Recovery Unit:* Sulfur, H_2S, and CO_2 are removed from the inlet sour gas stream by means of the amine contactor (V-1210) and the Sulferox system. The amine contactor removes H_2S and CO_2 from the gas and the sweetened gas flows to the outlet scrubber (V-1215) before going to the refrigeration unit.

The gas stream then enters the sulfur extraction system. The sour gas enters an inlet knockout vessel which removes any entrained liquids or hydrocarbons. The acid gas flows through the Sulferox Contactor (V-1300), where H_2S in the acid gas is converted into sulfur. The sulfur press removes solid sulfur particles suspended in the liquid Sulferox solution. The suspended sulfur is converted to sulfur cake which is stored in bins prior to being transported off-site. Unreached CO_2 and trace hydrocarbons in the acid gas stream are routed to the thermal oxidizer for incineration.

2.1.5.2 *Thermal Oxidizer:* The thermal oxidizer incinerates trace hydrocarbons and sulfur compounds coming from the Sulferox system, spent air and tail gas streams and heats process oil in circulation. Combustion products are exhausted through a vent stack into the atmosphere.

2.1.5.3 *Low Temperature Separation (LTS) System:* The LTS system removes liquid hydrocarbons from the process gas stream. The gas entering the LTS system is first cooled by the gas-to-gas exchanger (E-1400). The gas then flows to the gas chiller (E-1405) where hydrate formation is inhibited by glycol injection, and then flows to the low temperature separator (V-1410). The gas is then reheated and leaves the LTS skid and flows to the sales gas compressors.

2.1.5.4 *Gas Compression:* Inlet gas is processed through the gas plant and the resultant sales gas enters the suction scrubber (V-1517) before flowing to the first stage of the gas compressor. The gas then travels through the cooling fan into the second stage scrubber (V-1507), and flows to the second stage compressor and the second half of the cooling fan. Prior to entering the sales gas line, the gas flows through scrubber V-1509.

If there is a plant shut down, inlet gas bypasses the gas processing system, flows through the compression system outlined above, and is routed to the gas injection well.

2.1.5.5 *Fractionation System:* The hydrocarbon liquids that dump from the LTS system flow to the top of the de-ethanizer tower. The de-ethanizer removes methane and ethane which is routed to the booster compressor for recompression. Hydrocarbons from the bottom of the de-ethanizer dump to the de-butanizer tower. B-P Mix (LPG) and gasoline are separated in this process. B-P mix flows through a condenser and reflex drum and gasoline flows through a reboiler and condenser, where both product streams are pumped to the storage tanks.

Gasoline is stored in tank V-1480 and the B-P mix is stored in tank V-1485. Tank V-1486 can be used to store either B-P mix or gasoline. Gasoline is pumped from the storage tank to be blended with crude oil and shipped to the refinery. B-P mix is pumped to the truck loading rack for truck pick-up out of the LOGP.

2.1.5.6 *Drain and Sump System:* The Gas Processing Plant is equipped with two sumps and one blowcase. The sumps and blowcase collect liquid from manual drains located near the equipment that drain into them. Pumps located on the sumps then transport the liquids back into various systems.

SYSTEM	FLOWS FROM	FLOWS TO
Amine Drain Sump	Amine Skid	Amine Surge Tank or the Produced Water tank at LOGP
Containment Area Sump (S-890)	Sulferox Storage Sulferox Skid Glycol Skid Amine Storage Thermal Oxidizer Seal Pots	Produced Water at HS&P Oil Side
Process Blowcase (V-880)	LTS Skid Glycol Skid Refrigeration Skids Amine Skids LPG Loading Skid	HS&P Oil Plant Condensate Tank

The Amine Drain Sump (S-895) is used to drain the amine skid. The charcoal filter, mechanical filter and process vessels on the amine skid drain to the amine sump. Vapors from the amine sump flow to vapor recovery. The sump is equipped with a low-level shut down switch set at 15%. The sump also has a high-level alarm set at 90%.

The amine drain sump can be operated automatically from the Central System, or in a manual mode from the field. Fluid from the amine drain sump can flow to the amine surge tank, or to the produced water line, at the operator's choice. The sump is also equipped with a level transmitter. The Containment Area Sump (S-890) is used to drain the following areas:

- Sulferox Storage Area
- Sulferox Skid
- Glycol Skid
- Amine Storage
- Thermal Oxidizer
- Seal Pots

Vapors from the sump flow through a charcoal filter to atmosphere. Fluids from the sump are pumped to the produced water system. The sump is equipped with a level transmitter, and a low and high level shut off switch.

The process blowcase gathers hydrocarbon fluids from various skids via a pressure drain system. When the blowcase fills up, it dumps to condensate tank V-490 at the HS&P Oil Plant. The blowcase is equipped with a low-level switch, high-level switch and a high-level alarm. Upon reaching its set point, solenoid valves are activated, which use blanket gas to push the fluid to the condensate tank V-490.

3.0 Regulatory Review

3.1 Rule Exemptions Claimed

District Rule 202 (*Exemptions to Rule 201*): PXP qualifies for a number of exemptions under this rule. An exemption from permit, however, does not grant relief from any applicable prohibitory rule unless specifically exempted by that prohibitory rule. The following exemptions are approved by the District:

- Section D.6 for emission *de minimis* increases. As of the issuance date of this permit, the *de minimis* increases for the Pt. Pedernales stationary source are 14.39 lb/day.
- Section D.8 for routine surface coating maintenance activities.
- Section D.14 for application of architectural coatings in the repair and maintenance of a stationary source.
- Section 202.U.2 for solvent application equipment and operations if the degreasing equipment contains unheated solvent and has a liquid surface area of less than 1 square foot and that the cumulative surface area of all the degreasers is less than 10 square feet.
- Section 202.U.3 for wipe cleaning using solvents as long as the solvents meet other applicable requirements and the use does not exceed 55 gallons per year.

District Rule 321 (*Solvent Cleaning Operations*): Pursuant to Section B.2, one Safety-Kleen cold solvent degreaser is exempt from all provisions of this rule, except for Section G.2.

District Rule 325 (*Crude Oil Production and Separation*): An exemption from section D.1 was granted on September 4, 1998 for the underground waste water tank. PXP shall comply with section E of this rule for this tank.

District Rule 331 (*Fugitive Emissions Inspection and Maintenance*): The following components are exempt from certain/all provisions of the rule:

- Components buried below ground (exempt from all requirements).
- Components totally contained or enclosed such that there are no ROC emissions into the atmosphere are exempt from Sections F.1, F.2, F.3 and F.7.
- Components, except components within gas processing plants, exclusively handling liquid and gaseous process fluids with an ROC concentration of 10 percent or less by weight, as determined according to test methods specified in Section H.2 are exempt from Sections F.1, F.2, F.3 and F.7.
- Components exclusively in heavy liquid service are exempt from Sections F.1, F.2, F.3 and F.7.
- Components that are unsafe-to-monitor, as documented and established in a safety manual or policy, and with prior written approval of the Control Officer are exempt from Sections F.1, F.2 and F.7.

District *Rule 333 - Control of Emissions from Reciprocating Internal Combustion Engines*: This rule applies to all engines with a rated brake horsepower of 50 or greater. The emergency standby IC engines at the facility include two firewater pump engines and one generator that are no longer exempt from permit. However, they are compression ignition emergency standby engines and are exempt from the provisions of the Rule per Section B.1.d.

District Rule 346 (*Loading of Organic Liquids*): Per Section B.4, the transfer of liquefied natural gas, propane, butane or liquefied petroleum gases (LPG) is exempt. PXP transports LPG by truck from this facility.

District Rule 359 (*Flares and Thermal Oxidizers*): Per Section B.2, the thermal oxidizer is exempt from all provisions of this rule except D.2 (Technology Standard) since the heating content of the waste gas stream is less than 300 Btu.

3.2 Compliance with Applicable Federal Rules and Regulations

3.2.1 40 CFR Parts 51/52{*New Source Review (Nonattainment Area Review and Prevention of Significant Deterioration*)}: The LOGP facility was permitted in May 1986 under District Rule 205.C. That rule was superseded by District Regulation VIII (*New Source Review*) in April 1997. Compliance with PTO 6708 requirements and Regulation VIII ensures that the LOGP facility will comply with the federal NSR requirements.

3.2.2 40 CFR Part 60 *{New Source Performance Standards}:* The following NSPS apply at the LOGP facility:

Subpart A	General Provisions
Subpart Kb	Standards of Performance for Volatile Organic Liquid Storage Vessels. The T-280 storage tank is subject to this subpart. Compliance is achieved by compliance with the requirements of 40 CFR §60.112b(a)(3) through the use of a closed vent system that meets the requirements of 40 CFR §60.18.
Subpart KKK	Standards of Performance for Equipment Leaks of VOC From Onshore Natural Gas Processing Plants. This standard applies to the Gas Processing Plant Only.
Subpart LLL	Standards of Performance for Onshore Natural Gas Processing; SO_2 Emissions.

3.2.3 40 CFR Part 61 *{NESHAP}:* This facility is not currently subject to the provisions of this Subpart.

3.2.4 40 CFR Part 63 *{MACT}:* On June 17, 1999, EPA promulgated Subpart HH, a National Emission Standards for Hazardous Air Pollutants (NESHAPS) for Oil and Natural Gas Production and Natural Gas Transmission and Storage. PXP submitted information in October 2000 indicating that the Oil Processing Plant at the LOGP qualified for the “black oil” exemption per section 63.760(e)(1) of the subpart and that the Gas Processing

Plant qualified for the “area source” exemption (reference June 3, 2002 letter from PXP). Thus, only the recordkeeping requirements specified in condition 9.B.14 apply.

3.2.5 Subpart ZZZZ *{NESHAP - Stationary Internal Combustion Engines}:* The revised National Emission Standard for Hazardous Air Pollutants (NESHAP) for reciprocating internal combustion engines (RICE) was published in the Federal Register on January 18, 2008. An affected source under the NESHAP is any existing, new, or reconstructed stationary RICE located at a major source or area source.

Notifications are not required for existing stationary emergency RICE.

Existing emergency standby compression ignition RICE must comply with the applicable operating limits by no later than May 3, 2013. The following engines on the platform are subject to this requirement: Emergency Generator (IDs 107189), and Emergency Firewater Pumps (IDs 107187 and 107188). The following operating requirements apply:

(1) change the oil and filter every 500 hours of operation or annually, whichever comes first;

(2) inspect the air cleaner every 1,000 hours of operation or annually, whichever comes first;

(3) inspect all hoses and belts every 500 hours of operation or annually, whichever comes first.

New stationary RICE that are subject to 40 CFR 60 Subpart IIII are not subject to any further requirements under 40 CFR 63 Subpart ZZZZ.

3.2.6 Subpart DDDDD *{Industrial/Commercial/Institutional Boilers and Process Heaters}*: The heater treaters at the LOGP are subject to this MACT, however there are no emission limits for these type units and they are exempt from the “work practice” requirements. There is a requirement to monitor for CO emissions if the units qualify as “reconstructed” equipment. “Reconstructed” equipment is defined as “..equipment for which the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable new source.” These heaters were equipped with Lo-NOx burners in 1991. Due to the unavailability of cost information from the source, boiler manufacturers (Lattner, Cleaver-Brooks) contacted by the District indicated that burner costs are no more than 40% of the total cost of a typical boiler. Based on this information, the District determined that these units did not satisfy the definition of reconstructed equipment for the purpose of this MACT.

3.2.7 Subpart EEEE *{Organic Liquid Distribution}:* Based on the MACT, the equipment at this facility is not subject to this subpart.

3.2.8 40 CFR Part 64 *{Compliance Assurance Monitoring}*: This rule became effective on April 22, 1998 and affects emission units at the source subject to a federally enforceable emission limit or standard that use a control device to comply with the emission standard, and either pre-control or post-control emissions exceed the Part 70 source emission thresholds. Compliance with this rule was evaluated and it was determined that no emission units at this facility are currently subject to CAM. Note, the emergency generator and firewater diesel engines and the flare do not use a control device to comply with a federally enforceable limit.

3.2.9 40 CFR Part 70 *{Operating Permits}:* This Subpart is applicable to LOGP. Table 3.1 lists the federally-enforceable District promulgated rules that are "generic" and apply to the facility. Table 3.2 lists the federally-enforceable District promulgated rules that are "unit-specific". These tables are based on data available from the District's administrative files and from PXP's Part 70 Operating Permit application. Table 3.4 includes the adoption dates of these rules.

In its Part 70 permit application (Form I), PXP certified compliance with all existing District rules and permit conditions. This certification is also required of PXP semi-annually. Issuance of this permit and compliance with all its terms and conditions will ensure that PXP complies with the provisions of all applicable Subparts.

3.3 Compliance with Applicable State Rules and Regulations

3.3.1 Division 26. Air Resources *{California Health & Safety Code}:* The administrative provisions of the Health & Safety Code apply to this facility.

3.3.2 California Administrative Code Title 17: These sections specify the standards by which abrasive blasting activities are governed throughout the State. All abrasive blasting activities at the LOGP facility are required to conform to these standards. Compliance is typically assessed through onsite inspections. However, CAC Title 17 does not preempt enforcement of any SIP-approved rule that may be applicable to abrasive blasting activities.

3.3.3 California Administrative Code Title 17 {Sections 93115}: These sections specify emission, operational, monitoring, and recordkeeping requirements for stationary diesel-fired compression ignition engines rated over 50 bhp. The firewater pumps and floodwater pump engines are required to conform to these standards. Compliance will be assessed through onsite inspections. These standards are not federally enforceable onshore.

3.4 Compliance with Applicable Local Rules and Regulations

3.4.1 Applicability Tables: In addition to Tables 3.1 and 3.2, Table 3.3 lists the non-federally enforceable District promulgated rules that apply to the LOGP facility. Table 3.4 lists the adoption date of all rules applicable to this permit at the date of this permit's issuance.

3.4.2 Rules Requiring Further Discussion: This section provides a detailed discussion regarding the applicability and compliance of certain rules. The following is a rule-by-rule evaluation of compliance for LOGP:

Rule 201 (Permits Required): This rule applies to any person who builds, erects, alters, replaces, operates or uses any article, machine, equipment, or other contrivance which may cause the issuance of air contaminants. The equipment included in this permit is listed in Attachment 10.6. An Authority to Construct is required to return any de-permitted equipment to service and may be subject to New Source Review.

Rule 210 - Fees: Pursuant to Rule 201.G, District permits are reevaluated every three years. This includes the re-issuance of the underlying permit to operate. Also included are the PTO fees. The fees for this facility are based on District Rule 210, Fee Schedule A; however Part 70 specific costs are based on cost reimbursement provisions (Rule 210.C). Attachment 10.3 presents the fee calculations for the reevaluated permit.

Rule 301 - Circumvention: This rule prohibits the concealment of any activity that would otherwise constitute a violation of Division 26 (Air Resources) of the California H&SC and the District rules and regulations. To the best of the District's knowledge, the permittee is operating in compliance with this rule.

Rule 302 - Visible Emissions: This rule prohibits the discharge from any single source any air contaminants for a period or periods aggregating more than three minutes in any one hour which is as dark or darker in shade than a reading of 1 on the Ringelmann Chart or of such opacity to obscure an observer's view to a degree equal to or greater than a reading of 1 on the Ringelmann Chart. Sources subject to this rule include: the thermal oxidizer and all diesel-fired piston internal combustion engines, regardless of exemption status. Improperly maintained diesel engines have the potential to violate this rule. Compliance will be assured by onsite inspections, proper operation and maintenance of all internal combustion engines and by visible emissions monitoring requirements for diesel engines.

Rule 303 (Nuisance): Rule 303 prohibits any source from discharging such quantities of air contaminants or other material in violation of Section 41700 of the Health and Safety Code which cause injury, detriment, nuisance or annoyance to any considerable number of persons or to the public or which endanger the comfort, repose, health or safety or any such persons or the public or which cause or have a natural tendency to cause injury or damage to business or property. Compliance with this rule is assessed through the District’s enforcement staff’s complaint response program. Based on the source's location, the potential for public nuisance is small.

Rule 304 - Particulate Matter, Northern Zone: The LOGP facility is considered a Northern Zone source. Platform Irene is also a Northern Zone source. This rule prohibits the discharge into the atmosphere from any source particulate matter in excess of 0.3 grain/scf. Sources subject to this rule include: the flare and all diesel-fired IC engines on the platform. Improperly maintained diesel engines have the potential to violate this rule. Compliance will be assured by requiring all engines to be maintained according to manufacturer maintenance schedules. Rule 359 addresses the need for the flare to operate in a smokeless fashion.

Rule 309 - Specific Contaminants: Under Section "A", no source may discharge sulfur compounds and combustion contaminants in excess of 0.2 percent as SO_2 (by volume) and 0.1 gr/scf (at 12% CO_2) respectively. All diesel powered piston IC engines have the potential to exceed the combustion contaminant limit if not properly maintained.

Rule 310 - Odorous Organic Compounds: This rule prohibits the discharge of H_2S and organic sulfides that result in a ground level impact beyond the property boundary in excess of either 0.06 ppmv averaged over 3 minutes and 0.03 ppmv averaged over 1 hour. The existing odor monitoring station currently monitors compliance with this rule as specified in condition 9.C.23 of this permit. There have been no incidents in the past three years.

Rule 311 - Sulfur Content of Fuels: This rule limits the sulfur content of fuels combusted at the LOGP facility to 0.5 percent (by weight) for liquids fuels and 50 gr/100 scf, calculated as H_2S, {796 ppmvd} for gaseous fuels. However, the LOGP is subject to the following additional limits for natural gas fuel: 0.25 gr/100 scf (4.0 ppm as H_2S at standard conditions) and total sulfur limit of 5.0 gr/100scf (80 ppmvd as H_2S at standard conditions). Compliance with this requirement is verified by continuous monitoring by a fuel gas H_2S analyzer (Houston-Atlas 722R). The flare relief system is not subject to this rule (see discussion under Rule 359).

Rule 317 - Organic Solvents: This rule sets specific prohibitions against the usage of both photo-chemically and non-photo-chemically reactive organic solvents (40 lb/day and 3,000 lb/day respectively). Solvents may be used at LOGP facilities during normal operations for degreasing by wipe cleaning and for use in paints and coatings in maintenance operations. There is the potential to exceed the limits under Section B.2 during significant surface coating activities. PXP is required to maintain records to ensure compliance with this rule.

Rule 321 - Solvent Cleaning Operations: This rule was revised to fulfill the commitment in the Clean Air Plans to implement requirements for solvent cleaning machines and solvent cleaning. The revised rule contains solvent reactive organic compounds (ROCs) content limits, revised requirements for solvent cleaning machines, and sanctioned solvent cleaning devices and methods. These provisions apply to solvent cleaning machines and wipe cleaning.

Rule 322 - Metal Surface Coating Thinner and Reducer: This rule prohibits the use of photo-chemically reactive solvents for use as thinners or reducers in metal surface coatings. PXP is required to maintain records during maintenance operations to ensure compliance with this rule.

Rule 323 - Architectural Coatings: This rule sets standards for the application of surface coatings. The primary coating standard that will apply to the lease is for Industrial Maintenance Coatings which has a limit of 250 grams ROC per liter of coating, as applied. The permittee will be required to comply with the Administrative requirements under Section F for each container on the lease.

Rule 324 - Disposal and Evaporation of Solvents: This rule prohibits any source from disposing more than one and a half gallons of any photo-chemically reactive solvent per day by means that will allow the evaporation of the solvent into the atmosphere. PXP is required to maintain records to ensure compliance with this rule.

Rule 325 - Crude Oil Production and Separation: This rule, adopted January 25, 1994, applies to equipment used in the production, gathering, storage, processing and separation of crude oil and gas prior to custody transfer. The primary requirements of this rule are contained in Sections D and E. Section D requires the use of vapor recovery systems on all tanks and vessels, including waste water tanks, oil/water separators and sumps. Section E requires that all produced gas be controlled at all times, except for wells undergoing routine maintenance. All production and test vessels and tanks are all connected to gas gathering systems and all relief valves are connected to the flare relief system. PXP has installed vapor recovery on all equipment subject to this rule. Compliance with this exemption will be verified by District inspections. Compliance with Section E is met by directing all produced gas to a sales compressor, injection well or to the flare relief system.

Rule 327 - Organic Liquid Cargo Tank Vessel Loading: There are no organic liquid cargo tank vessel loading operations associated with this project.

Rule 328 - Continuous Emissions Monitoring: This rule details the applicability and standards for the use of continuous emission monitoring systems ("CEMS"). There are no monitors at the LOGP that qualify as CEMs although some monitors have been subject to similar quality assurance standards. There is a significant number of process monitors (e.g., H_2S monitors, fuel use meters, etc.) are used to monitor process operating parameters and indirectly track emissions. These are subject to a District-approved *Process Monitor and Calibration Plan* as specified in permit condition 9.C.18**.**

Rule 330 - Surface Coating of Metal Parts and Products: This rule sets standards for many types of coatings applied to metal parts and products. In addition to the ROC standards, this rule sets operating standards for application of the coatings, labeling and recordkeeping. This rule only applies to metal parts and products which are not currently installed as appurtenances to the existing stationary structures. It is not anticipated that PXP will trigger the requirements of this rule. Compliance shall be based on site inspections.

Rule 331 - Fugitive Emissions Inspection and Maintenance: This rule applies to components in liquid and gaseous hydrocarbon service at oil and gas processing plants. PXP submitted an I&M Plan (*Fugitive Emissions Inspection and Maintenance Program for LOGP Process Facilities*) and received initial District approval of this Plan on January 26, 2000. Ongoing compliance with the many provisions of this rule will be assessed via facility inspection by District personnel using an organic vapor analyzer and through analysis of operator records.

Rule 333 - Control of Emissions from Reciprocating Internal Combustion Engines: This rule applies to all engines with a rated brake horsepower of 50 or greater that are fueled by liquid or gaseous fuels. The diesel-fired IC engines located at the facility are exempt per Rule 333.B.1.d.

Rule 342 - Control of Oxides of Nitrogen from Boilers, Steam Generators and Process Heaters: This rules sets emission standards for external combustion units with a rated heat input greater than 5.0 MMBtu/hr. The three heater treaters are subject to this rule. These units are required to meet an emissions standard established in ATC 8357 which is more stringent than the rule. Compliance is assessed through the monitoring, recordkeeping and reporting requirements listed in Section 9.C.1 of this permit.

Rule 343 - Petroleum Storage Tank Degassing: This rule applies to the degassing of any above-ground tank, reservoir or other container of more than 40,000 gallons capacity containing any organic liquid with a vapor pressure greater than 2.6 psia, or between 20,000 gallons and 40,000 gallons capacity containing any organic liquid with a vapor pressure greater than 3.9 psia. This rule applies to the oil surge tank (T-280) and the reject oil tanks (T-210, 220). Compliance is assessed based on the use of District-approved control devices and the recordkeeping and reporting requirements of the rule.

Rule 344 - Petroleum Sumps Pits and Well Cellars: This rule applies to sumps, pits and well cellars at facilities where petroleum is produced, gathered, separated, processed or stored. The ten sumps used at the LOGP facility are post-primary sumps with a surface area less than 1000 square feet, and are therefore exempt from the requirements of this rule, however, they are controlled by carbon canister.

Rule 346 - Loading of Organic Liquids: This rule applies to the transfer of organic liquids into an organic liquid cargo vessel. For this rule only, an organic liquid cargo vessel is defined as a truck, trailer or railroad car. PXP is exempt from this rule per Section B.4 (LPG and NGL). Further, the vacuum trucks are exempt from the provisions of Sections D, E and F pursuant to Section B.5.

Rule 352 - Natural Gas-Fired Fan-Type Central Furnaces and Small Water Heaters: This rule applies to new water heaters rated less than 75,000 Btu/hr and new fan-type central furnaces. It requires the certification of newly installed units.

Rule 353 - Adhesives And Sealants: This rule is applicable to any person who supplies, sells, offers for sale, manufactures, solicits the application of, or uses adhesives, adhesive bonding primers, adhesive primers, sealants, sealant primers, or any other primers, unless otherwise specifically exempted by this rule. Compliance with this rule will be demonstrated through inspections and recordkeeping.

Rule 359 - Flares and Thermal Oxidizers: This rule applies to flares for both planned and unplanned flaring events. Compliance with this rule has been documented. PXP uses a flare as well as thermal oxidizer to combust all gas plant waste gases. A detailed review of compliance issues is as follows:

§ D.1 - *Sulfur Content in Gaseous Fuels*: Part (a) limits the total sulfur content of all planned flaring from North County flares to 50 gr/100 cubic feet (796 ppmv) calculated as H_2S at standard conditions. Planned flaring is prohibited at the LOGP.

§ D.2 - *Technology Based Standard*: Requires all flares and thermal oxidizers to be smokeless and sets pilot flame requirements. PXP's flare and thermal oxidizer are in compliance with this section as determined through District inspection.

§ D.3 - *Flare Minimization Plan*: This section requires sources to implement flare minimization procedures so as to reduce SO_x emissions. PXP has fully implemented their *Flare Minimization Plan*.

Rule 505 - Breakdown Conditions: This rule describes the procedures that PXP must follow if they decide to apply for relief from enforcement action as provided by this rule. A breakdown condition is defined as an unforeseeable failure or malfunction of (1) any air pollution control equipment or related operating equipment which causes a violation of an emission limitation or restriction prescribed in the District Rules and Regulations, or by State law, or (2) any in-stack continuous monitoring equipment, provided such failure or malfunction:

a. Is not the result of neglect or disregard of any air pollution control law or rule or regulation;

b. Is not the result of an intentional or negligent act or omission on the part of the owner or operator;

c. Is not the result of improper maintenance;

d. Does not constitute a nuisance as defined in Section 41700 of the Health and Safety Code;

e. Is not a recurrent breakdown of the same equipment.

Rule 361 - Small Boilers, Steam Generators and Process Heaters: This rule sets emission standards for external combustion units with a rated heat input greater than 2.0 MMBtu/hr but less than 5.0 MMBtu/hr. There are no units located at this facility subject to this rule.

Rule 603 - Emergency Episode Plans: Section "A" of this rule requires the submittal of *Stationary Source Curtailment Plan* for all stationary sources that can be expected to emit more than 100 tons per year of hydrocarbons, nitrogen oxides, carbon monoxide or particulate matter. PXP submitted this plan on July 23, 1994. The Plan was updated on April 22, 1997 and December 12, 2000.

Rule 810 – Federal Prevention of Significant Deterioration: This rule was adopted January 20, 2011 to incorporate the federal Prevention of Significant Deterioration rule requirements into the District's rules and regulations. Future projects at the facility will be evaluated to determine whether they constitute a new major stationary source or a major modification.

3.5 Compliance History

This section contains a summary of the compliance history for this facility since the issuance of prior permit renewal and was obtained from documentation contained in the District's Administrative files.

3.5.1 *Facility Inspections*. Since the prior permit renewal, facility inspections were conducted on May 28, 2009, October 31, 2008, September 10, 2008, January 15, 2008, March 19, 2007 and November 6, 2007. With the exception of NOVs 8788 and 9127, listed below, each report indicates that the facility was operating in compliance with District rules and the conditions of this permit at the time of the inspections.

3.5.2 *Enforcement Actions:* The following enforcement actions were issued since the last permit reevaluation:

VIOLATION TYPE	NUMBER	ISSUE DATE	DESCRIPTION OF VIOLATION
MIN	9658	10/28/2011	Exceeding the number of leaks specified in Table 1, of Section F.2, for each inspection period for major gas leaks and/or liquid leaks, as determined by District or operator inspection.
NOV	9660	01/09/2012	Failure to correct a breakdown condition within 24 hours.
MIN	9728	07/24/2012	Operating with an open-ended line not sealed with a blind flange, plug, cap, or second closed valve at all times.

3.5.3 Variances: There were no variances granted to this facility since the last permit renewal.

Table 3.1 - Generic Federally-Enforceable District Rules

Generic Requirements	Affected Emission Units	Basis for Applicability
RULE 101: Compliance by Existing Installations	All emission units	Emission of pollutants
RULE 102: Definitions	All emission units	Emission of pollutants
RULE 103: Severability	All emission units	Emission of pollutants
RULE 201: Permits Required	All emission units	Emission of pollutants
RULE 202: Exemptions to Rule 201	Applicable emission units	Insignificant activities/emissions, per size/rating/function
RULE 203: Transfer	All emission units	Change of ownership
RULE 204: Applications	All emission units	Addition of new equipment of modification to existing equipment.
RULE 205: Standards for Granting Permits	All emission units	Emission of pollutants
RULE 206: Conditional Approval of Authority to Construct or Permit to Operate	All emission units	Applicability of relevant Rules
RULE 208: Action on Applications - Time Limits	All emission units. Not applicable to Part 70 permit applications.	Addition of new equipment of modification to existing equipment.
RULE 212: Emission Statements	All emission units	Administrative
RULE 301: Circumvention	All emission units	Any pollutant emission
RULE 302: Visible Emissions	All emission units	Particulate matter emissions
RULE 303: Nuisance	All emission units	Emissions that can injure, damage or offend.
RULE 304: PM Concentration - North Zone	Each PM source	Emission of PM in effluent gas
RULE 309: Specific Contaminants	All emission units	Combustion contaminants
RULE 311: Sulfur Content of Fuel	All combustion units	Use of fuel containing sulfur
RULE 317: Organic Solvents	Emission units using solvents	Solvent used in process operations.

Generic Requirements	Affected Emission Units	Basis for Applicability

RULE 321: Solvent Cleaning Operations	Emission units using solvents	Solvent used in process operations.
RULE 322: Metal Surface Coating Thinner and Reducer	Emission units using solvents	Solvent used in process operations.
RULE 323: Architectural Coatings	Paints used in maintenance and surface coating activities	Application of architectural coatings.
RULE 324: Disposal and Evaporation of Solvents	Emission units using solvents	Solvent used in process operations.
RULE 353: Adhesives and Sealants	Emission units using adhesives and sealants	Adhesives and sealants use.
RULE 505: Breakdown Conditions	All emission units	Breakdowns where permit limits are exceeded or rule requirements are not complied with.
RULE 603: Emergency Episode Plans	Stationary sources with PTE greater than 100 tpy	PXP Project PTE is greater than 100 tpy.
REGULATION VIII: New Source Review	All emission units	Addition of new equipment of modification to existing equipment. Applications to generate ERC Certificates.
REGULATION XIII (RULES 1301-1305): Part 70 Operating Permits	All emission units	PXP Project is a major source.

Table 3.2 - Unit-Specific Federally-Enforceable District Rules

Unit-Specific Requirements	Affected Emission Units	Basis for Applicability
RULE 325: Crude Oil Production and Separation	EQ Nos: 7-1, 7-2, 7-3, 7-4, 8-1, 8-2, 8-3, 8-4, 8-5, 8-6, 8-7, 8-8	All pre-custody production and processing emission units
RULE 331: Fugitive Emissions Inspection & Maintenance	EQ Nos: 4x.	Components emit fugitive ROCs.
RULE 342: Control of Oxides of Nitrogen from Boilers, Steam Generators and Process Heaters	EQ Nos: 1-1,1-2, 1-3	Rated greater than 5 MMBtu/hr
RULE 343: Petroleum Storage Tank Degassing	EQ Nos: 7-1, 7-2, 7-3, 7-4	Capacities greater than 40,000 gallons
RULE 359: Flares and Thermal Oxidizers	EQ Nos: 2-1	Used in petroleum service

Table 3.3 - Non-Federally-Enforceable District Rules

Requirement	Affected Emission Units	Basis for Applicability
RULE 210: Fees	All emission units	Administrative
RULES 310: Odorous Organics	All emission units	Emissions of Organic Sulfides
RULES 501-504: Variance Rules	All emission units	Administrative
RULES 506-519: Variance Rules	All emission units	Administrative

Table 3.4 – Adoption Dates of District Rules Applicable at Issuance of Permit

Rule No.	Rule Name	Adoption Date
Rule 101	Compliance by Existing Installations: Conflicts	June 1981
Rule 102	Definitions	March 17, 2011
Rule 103	Severability	October 23, 1978
Rule 201	Permits Required	June 19, 2008
Rule 202	Exemptions to Rule 201	June 21, 2012
Rule 203	Transfer	April 17, 1997
Rule 204	Applications	April 17, 1997
Rule 205	Standards for Granting Permits	April 17, 1997
Rule 206	Conditional Approval of Authority to Construct or PTO	October 15, 1991
Rule 208	Action on Applications - Time Limits	April 17, 1997
Rule 212	Emission Statements	October 20, 1992
Rule 301	Circumvention	October 23, 1978
Rule 302	Visible Emissions	June 1981
Rule 303	Nuisance	October 23, 1978
Rule 304	Particular Matter – Northern Zone	October 23, 1978
Rule 305	Particulate Matter Concentration - Southern Zone	October 23, 1978
Rule 309	Specific Contaminants	October 23, 1978
Rule 310	Odorous Organic Sulfides	October 23, 1978
Rule 311	Sulfur Content of Fuels	October 23, 1978
Rule 317	Organic Solvents	October 23, 1978

Rule No.	Rule Name	Adoption Date
Rule 321	Solvent Cleaning Operations	June 21, 2012
Rule 322	Metal Surface Coating Thinner and Reducer	October 23, 1978
Rule 323	Architectural Coatings	November 15, 2001
Rule 324	Disposal and Evaporation of Solvents	October 23, 1978
Rule 325	Crude Oil Production and Separation	July 19, 2001
Rule 326	Storage of Reactive Organic Compound Liquids	December 14, 1993
Rule 331	Fugitive Emissions Inspection and Maintenance	December 10, 1991
Rule 333	Control of Emissions from Reciprocating ICEs	April 17, 1997
Rule 342	Control of Oxides of Nitrogen (NOx) from Boilers, Steam Generators and Process Heaters	April 17, 1997
Rule 343	Petroleum Storage Tank Degassing	December 14, 1993
Rule 344	Petroleum Sumps, Pits and Well Cellars	November 10, 1994
Rule 353	Adhesives and Sealants	June 21, 2012
Rule 359	Flares and Thermal Oxidizers	June 28, 1994
Rule 360	Emissions of Oxides of Nitrogen from Large Water Heaters and Small Boilers	October 17, 2002
Rule 361	Small Boilers, Steam Generators and Process Heaters	January 17, 2008
``	Potential to Emit – Limitations for Part 70 Sources	January 20, 2011
Rule 505	Breakdown Conditions (Section A, B1 and D)	October 23, 1978
Rule 603	Emergency Episode Plans	June 15, 1981
Rule 801	New Source Review	April 17, 1997
Rule 802	Nonattainment Review	April 17, 1997
Rule 803	Prevention of Significant Deterioration	April 17, 1997
Rule 804	Emission Offsets	April 17, 1997
Rule 805	Air Quality Impact and Modeling	April 17, 1997
Rule 806	Emission Reduction Credits	April 17, 1997
Rule 810	Federal Prevention of Significant Deterioration	January 20, 2011
Rule 901	New Source Performance Standards (NSPS)	September 20, 2010
Rule 903	Outer Continental Shelf (OCS) Regulations	November 10, 1992

Rule No.	Rule Name	Adoption Date
Rule 1001	National Emission Standards for Hazardous Air Pollutants (NESHAPS)	October 23, 1993
Rule 1301	General Information	January 20, 2011
Rule 1302	Permit Application	November 9, 1993
Rule 1303	Permits	November 9, 1993
Rule 1304	Issuance, Renewal, Modification and Reopening	November 9, 1993
Rule 1305	Enforcement	November 9, 1993

4.0 Engineering Analysis

General

The engineering analyses performed for this permit were limited to the review of:

- emission factors and calculation methods for each emissions unit
- emission control equipment (including RACT, BACT, NSPS, NESHAP)
- emission source testing, sampling
- process monitors needed to ensure compliance.

Unless noted otherwise, default ROC/THC reactivity profiles from the District's document titled "*VOC/ROC Emission Factors and Reactivities for Common Source Types*" dated 7/13/98 (ver 1.1) were used to determine the non-methane, non-ethane fraction of THC.

4.1 Internal Combustion Equipment

Internal Combustion Engines. There are three emergency use internal combustion engines at this facility; two emergency firewater pumps and one emergency electrical generator. These units, previously exempt, were permitted under PTO 11867 on December 19, 2005. This permit was issued due to the March 17, 2005 revision to District Rule 202 {*Exemptions to Rule 201*} that resulted in the removal of the compression-ignited engine permit exemption for units rated over 50 brake horsepower (bhp). That exemption was removed to allow the District to implement the State's Airborne Toxic Control Measure for Stationary Compression Ignition Engines (DICE ATCM). The requirements of PTO 11867 were incorporated into the previous permit reevaluation.

Mass emission estimates for the electrical generator engine are based on the maximum allowed hours for maintenance and testing. Emissions are determined by the following equations:

E1, lb/day = Engine bhp * EF (g/bhp-hr) * Daily Hours (hr/day) * (lb/453.6 g)

E2, tpy = Engine bhp * EF (g/bhp-hr) * Annual Hours (hr/yr) * (lb/453.6g) *(ton/2000 lb)

The emission factors (EF) were chosen based on each engine's rating and age. Unless engine specific data was provided, default emission factors are used as documented on the District's webpage at http://www.sbcapcd.org/eng/atcm/dice/dice_efs.htm. Daily emissions are based on 2 hrs/day and annual emissions on 200 hours/yr.

The firewater pump engines identified in this permit must comply with NFPA 25. Since the NFPA 25 does not specify an upper limit on the hours to comply with the maintenance and testing requirements, in-use firewater pumps do not have a defined potential to emit restricting their operation. Thus, Table 5.0 of this permit does not include emission limits for the firewater pumps.

4.2 External Combustion Equipment

Heater Treaters. The NO_x, ROC and CO emission factors for the heater treaters are based on BACT as determined, verified and documented in ATC 8696. These are listed below. These BACT concentrations were verified and converted to lb/MMBtu emission factors using source test data obtained from 1991 and 1992 source test results. Heater treater emissions are based on the unit maximum rating and these lb/MMBtu emission factors. The SO_x emission factor is based on mass balance and a fuel sulfur limit of 80 ppmv. The PM_{10} emission factor is based on AP-42. The emission calculation methodology is as follows:

$$ER = [(EF \times SCFPP \times HHV) \div 10^6]$$

Where: ER = Emission rate (lb/period)
EF = Pollutant specific emission factor (lb/MMBtu)
SCFPP = gas flow rate per operating period (scf/period)
HHV = gas higher heating values per condition 9.C.1

Table 4.2 External Combustion Unit Emission Basis

					Values in lb/MMBtu unless other units indicated[1]				
District Ids	Unit IDs	Fuel	BACT Limit (ppmv)	MMBtu/hr, MMBtu/yr	NO_x	ROC	SOx	CO	PM
2155 2169 2170	Heater Treaters HT- 180A HT-180B HT-180C	PUC gas	NO_x = 22 ROC= 4 CO = 25 SO_x = 80[2] PM_{10}= 5 lb/MMscf	16.0 9000	0.0266	0.0017	0.0125	0.0184	0.0075

[1] Conversion to lb/MMBtu based on F-Factor of 8,550 DSCF/MMBtu and O_2 correction to 3% per source 1991/1992 source test results dated 7/18/91 and 2/18/92.
[2] The SO_x emission factor is based on the following equation: (0.169)(ppmv S)/(HHV)

4.30 Fugitive Hydrocarbon Sources

Oil Processing Plant

Emissions of reactive organic compounds from piping components such as valves, flanges and connections have been calculated using emission factors pursuant to District P&P 6100.061 (*Determination of Fugitive Hydrocarbon Emissions at Oil and Gas Facilities Through the Use of Facility Component Counts - Modified for Revised ROC Definition*) for components in gas/light liquid service. For components in oil service, emission factors are based on upon a Tecolote Research, Inc. analysis of oil plants, Modeling of Fugitive Hydrocarbon Emissions, E.B. Dumas and A.R Sjvold, Tecolote Research, Inc. January, 1986. This Tecolote THC factor (0.066) was adjusted for non-ethane ROC/THC (0.46) to establish the non-ethane emission factor. The component-leakpath was counted consisted with P&P 6100.061. This leakpath count is not the same as the "component" count required by District Rule 331. Both gas/light liquid and oil service components are present at this facility.

The number of emission leakpaths was determined by the operator and these data were verified by District staff by checking a representative number of P&IDs and by site checks. The current number of oil/emulsion component-leakpaths and gas/light-liquid component-leakpaths at the LOGP facility is listed in Table 5.1-1. The calculation methodology for the fugitive emissions is:

$$ER = [(EF \times CLP \div 24) \times (1 - CE) \times (HPP)]$$

where:	ER =	emission rate (lb/period)
	EF =	ROC emission factor (lb/clp-day)
	CLP =	component-leakpath (clp)
	CE =	control efficiency
	HPP =	operating hours per time period (hrs/period)

Emission control efficiency of 80% is credited to all components that are safe to monitor (as defined per Rule 331) due to the implementation of a District-approved Inspection and Maintenance program for leak detection and repair consistent with Rule 331 requirements. Unsafe to monitor components are not eligible for I&M control credit. Ongoing compliance is determined in the field by inspection with an organic vapor analyzer and verification of operator records.

BACT standards apply for Rule 331 components subject to NSR BACT provisions of that rule. Table 4.10-3 (*Rule 331 BACT Requirements*) list the specific BACT requirements for these components. More recent BACT determinations identify minor leak performance standards of 100 ppmv as methane (above background).

Gas Processing Plant

The fugitive emissions associated with the gas processing plant are based on the Correlation Equations (CE). The District has approved use of the Screening Value Range Factor (SVRF) correlation equation methodology for determination of fugitive emissions. SVRFs are component based factors that provide leak rate concentrations for each component type (oil and gas) within two specific concentration ranges; those "greater than" 10,000 ppm and those "less than" 10,000 ppm. The source must initially estimate the number of leaking components above and below 10,000 ppm that they anticipate will occur each quarter. This initial emissions estimate establishes the quarterly and annual fugitive emission limits as listed in this permit. The CE methodology is fully detailed in District Policy and Procedure 6100.072.1998 (Tier II Screening Value Range Factor).

As described above in section 1.2.2, the pig receiver on the gas transmission line formerly located at the La Purisima lease was relocated to the LOGP under ATC 13015. The emissions associated with this installation were calculated using the correlation equation methodology. Seventy-eight additional fugitive component were included with this installation and are reflected in the total number of components for which the correlation equation methodology serves as the emission basis. See Table 4.3.

Project Pipelines

The onshore pipeline segments associated with the LOGP are the gas and emulsion lines from the surf to the LOGP facility and the oil line from the LOGP to the Orcutt Pump Station. These pipelines fugitive emissions source only. The surf to LOGP gas pipeline has 90 gas and light liquid component-leakpaths associated with it. The surf to LOGP oil emulsion pipeline has 223 heavy liquid component-leakpaths associated with it. The LOGP to OPS pipeline has 113 heavy liquid component-leakpaths associated with it. The emissions from these pipelines are calculated using the emission factors described above for the oil processing plant. These emissions are listed in Table 5.4.

Service Type Component Type	Accessibility Group	Number of Components Screened			SVRFs for THC (Table SVRF-1)		THC Emissions by SVRF Range, and Total			ROC/THC Ratio	Total ROC Emissions		
					lb/comp-day		lb/day				lb/day	tpq	tpy
		<10K	>=10K	Total	<10K	>=10K	<10K	>=10K	total				
Gas/Light Liquid Service													
Valves	Access[2]	1221	5	1226	1.85E-03	7.33E+00	2.259	36.650	38.909	0.31	4.47	0.20	0.82
	Inaccess	82	1	83	1.85E-03	7.33E+00	0.152	7.330	7.482	0.31	2.32	0.11	0.42
	USM					7.33E+00		0.000	0.000	0.31	0.00	0.00	0.00
	USM-Bellows[2]	0	0	0	1.85E-03		0.000		0.000	0.31	0.00	0.00	0.00
PRDs	Assess	32	3	35	1.27E-02	9.76E+00	0.406	29.280	29.686	0.31	9.20	0.42	1.68
	Inassess	6	1	7	1.27E-02	9.76E+00	0.076	9.760	9.836	0.31	3.05	0.14	0.56
Others	Access	218	5	223	1.27E-02	9.76E+00	2.769	48.800	51.569	0.31	15.99	0.73	2.92
	Inaccess	4	1	5	1.27E-02	9.76E+00	0.051	9.760	9.811	0.31	3.04	0.14	0.56
	USM					9.76E+00		0.000	0.000	0.31	0.00	0.00	0.00
Connectors	Access	3168	7	3175	6.35E-04	1.37E+00	2.012	9.590	11.602	0.31	3.60	0.16	0.66
	Inaccess	723	2	725	6.35E-04	1.37E+00	0.459	2.740	3.199	0.31	0.99	0.05	0.18
Flanges	Access	1222	7	1229	1.48E-03	3.23E+00	1.809	22.610	24.419	0.31	7.57	0.35	1.38
	Inaccess	63	1	64	1.48E-03	3.23E+00	0.093	3.230	3.323	0.31	1.03	0.05	0.19
	USM					3.23E+00		0.000	0.000	0.31	0.00	0.00	0.00
Open-ended Lines	Access	0		0	1.27E-03		0.000		0.000	0.31	0.00	0.00	0.00
Pump/Compressor Seals	Access	16	0	16	3.07E-02	3.80E+00	0.491	0.000	0.491	0.31	0.15	0.01	0.03
Total: Gas/LL		**6755**	**33**	**6788**							**51.41**	**2.35**	**9.38**

NOTES:

1. Total includes ATC 9522 (original gas plant), ATC 9522-01 (sales gas odorant station), ATC 9522-03 (flare and odorant tank) and ATC 9200 (reinjection compressors).
2. Valves are monitored monthly and there are five anticipated >10k leakers/qtr, therefore, the tpq emission calculation for valves is as follows:
   5 @ > 10k for 30.4 days =1114.16 lbs THC
   1196 @ <10k for 30.4 days = 67.26 lb THC
   1201 @ <10k for 60.8 days = 135.09 lb THC
   Total = 1316.5 lb THC*0.31/ 91.25 = 4.47 lb/day = 0.20 tpq = 0.82 tpy.
3. USM-Bellows: The "<10K" factor may be applied to bellows seal valves for which OVA readings have been shown to be indistringuishable from background either in service or in a bench test approved by the District. See Attachment A "<10K" Components.

4.40 Flare

4.4.1 General: The smokeless, naturally aspirated flare, an NAO-Model 8NMJM, is equipped with a continuous pilot and electronic ignition and is rated at 625 MMBtu/hr. The flare system receives gas from the relief valves, vents and blowdown valves for emergency service. With the exception of the first five minutes of flaring, gas collected in the flare header system is routed to the H_2S scrubber prior to flaring. Design data indicates that the gas released during the first five minutes of flaring is pipeline quality gas used for purge and pilot.

Emission Factors: The emission factors are based on the most current update (Supplement D - March 1998) of AP-42, Chapter 3, Section 4. These factors are consistent with the Table 3.1.1 of the District's Flare Study Phase I Report (July 1991). The more conservative emission factor is used regardless of the most recent update. SO_2 is calculated by mass balance utilizing the reported total sulfur (calculated as ppmV H_2S) value of each flare event. Flare events for which a total sulfur analysis is not obtained, (e.g., failure of sample bomb) a total sulfur (reported as ppmV H_2S) default value of 500 ppmV shall be used.

A total annual flare volume of 959.80 Mscf/yr is used for the unplanned flare emission calculations and 100.00 Mscf/yr for planned flare emission calculations. An HHV of 1100 Btu/scf was used for these calculations.

Meters: Rotometers manufactured by Fischer & Porter (series 10A 1300) are used to meter the pilot and purge gas volumes. The mass flow meter, a LT81 Gas flow Transmitter manufactured by Fluid Components, Inc., is located in the flare gas line exiting the flare gas scrubber to measure the volume of flared gas. The operating range is 0.017 MMscfd to 15.0 MMscfd. The minimum detection limit is 707 scfh.

4.50 Thermal Oxidizer

4.5.1 General: The thermal oxidizer, located in the gas processing plant, serves as the emission control device for all process waste gases. The Epcon thermal oxidizer is rated at 12.0 MMBtu/hr designed for smokeless operation. The thermal oxidizer is designed to incinerate the ROCs associated with the CO_2 and regenerator waste gas streams and provide process heat to the gas plant. The process heat will be provided by a waste heat recovery unit that utilizes therminol as the heat medium.

The thermal oxidizer is designed for a minimum combustion chamber ROC waste gas residence time of 0.6 seconds. Based on an exhaust gas flow rate of 20,927 acfm, a combustion chamber design volume of 423 cubic feet, and a chamber operating temperature of 1500°F, the calculated residence time is 1.2 seconds.

A combustion chamber operating temperature range of 1400-1500°F is required to achieve a 98.5% ROC Destruction Rate Efficiency (DRE). Therefore, the combustion chamber operating temperature range of 1500°F is acceptable. The temperature will be continuously monitored for compliance with this temperature range to ensure the 98.5% ROC DRE.

The thermal oxidizer is equipped with a dilution air blower (3,000 scfm) which is required to avoid excessive combustion chamber operating temperatures that may damage the heat exchanger heating coils. The maximum anticipated waste gas volume to be combusted is approximately 800 scfm.

The thermal oxidizer is equipped with tail gas and spent air seal pots. These seal pots serve as safety devices related to the fuel gas supply however they also function as a NO_x control device. As such, they are considered control equipment. Condition 9.C.2 contains a requirement that minimum water levels be maintained in these vessels to assure compliance with NO_x emission limits.

4.5.2 Emission Factors: The emission factors are based on a BACT determination for ROC and manufacturers guarantees for NO_x, CO and PM_{10}. Manufacturer guarantees were used since they were more conservative than AP-42. The SO_x emission factor is based on the following equation: (0.169)(ppmv S)/(HHV). These factors are listed in Table 5.1-2. The emission calculation methodology is as follows:

$$ER = [(EF \times SCFPP \times HHV) \div 10^6]$$

where:

ER	= Emission rate (lb/period)
EF	= Pollutant specific emission factor (lb/MMBtu)
SCFPP	= gas flow rate per operating period (scf/period)
HHV	= gas higher heating values (per annual analysis)

4.5.4 Meters: A complete description of the thermal oxidizer's meters is documented in the District approved *Process Monitor Calibration and Maintenance Plan*.

4.6 Tanks/Sumps/Separators

4.6.1 General: The LOGP facility contains several tanks, sumps, separators and other vessels that have the potential to emit reactive organic compounds.

4.6.2 T-280 Surge Tank: This is a 100,000 barrel tank used periodically for excess surge capacity. Its use is limited to specific planned events and unplanned emergency events. This tank is connected to vapor recovery. Due to its limited use and nature of this use, it has not been assessed mass emissions, however, it is subject to NSPS subpart Kb. A subpart *Kb Operating Plan* is required to assure compliance with this subpart.

T-210 & T-220 Reject Oil Tanks: These two 3,000 barrel tanks are used for off-specification crude that does not meet pipeline specifications. These tanks are connected to vapor recovery. Due to their limited use and nature of this use, mass emissions have not been assessed, however, monitoring of the relief events is required per permit condition 9.C.6 to ensure that emissions are minimized.

Reclaim Oil Tank: This 500 barrel tank is used for off-specification crude that does not meet pipeline specifications. The tank is connected to vapor recovery. Due to its limited use and nature of this use, mass emissions have not been assessed, however, monitoring of the relief events is required per permit condition 9.C.6 to ensure that emissions are minimized.

Sumps: There are ten sumps at the LOGP. These are all post-primary sumps, are less than 1,000 square feet in surface area, and therefore are exempt from Rule 344. The sumps are covered and each is equipped with a carbon canister required to be changed out at 200 ppm ROC breakthrough. The calculations for the sumps are based on the CARB/KVB Report (*Emissions Characteristics of Crude Oil Production in California,* January 1983). The calculation is:

$$ER = [(EF \ x \ SAREA \div 24) \ x \ (1 - CE) \ x \ (HPP)]$$

where:	ER =	emission rate (lb/period)
	EF =	ROC emission factor (lb/ft^2-day)
	SAREA =	unit surface area (ft^2)
	CE =	control efficiency
	HPP =	operating hours per time period (hrs/period)

Compliance calculations for these emission units are the same (i.e., actual emissions equals permitted emissions).

Vessels: Vessels designed as pressure vessels (greater than 15 psig) are not assessed mass emission limits as it is assumed that the only potential emissions from those vessels are from fugitive emission components. All pressure vessels are connected to the facility's gas gathering system. All PSVs, vents, and blowdown valves are connected to either the gas gathering system or the flare relief system header.

4.6.3 Emission Controls: Emission controls are used on all tanks and sumps. The ROC controls used are vapor recovery or carbon canisters. Section 4.7 describes the vapor recovery systems in use at the facility. Each of the covered sumps is equipped with a carbon canister required to be changed out at 200 ppm ROC breakthrough based on monthly monitoring. In addition, NSPS Kb requires that the T-280 tank be operated at a vapor control efficiency of 95%.

4.7 Vapor Recovery Systems

4.7.1 General: The vapor recovery system consists of two independent trains. Each train of equipment is completely skid-mounted and is designed to handle 100% of the expected flow rate. The vapor recovery system collects, cools and compresses the vapors from the low-pressure sources (oil surge tank, shipping vessel, slops tank, etc.) in the process**.**

T-280 Surge Tank. Compliance with the vapor recovery efficiencies are based on monitoring the mass emissions emitted from the Oil Surge Tank. PXP records the actual mass emissions from tank venting by continuously monitoring the position of all PSVs (closed/open), tank pressure and time open for each PSV. This data, coupled with PSV manufacturer flow curves and actual tank headspace gas properties, is used to calculate the mass emissions during each PSV opening event. The specific calculation procedures and manufacturer data sheets/flow curves for each PSV is contained in the District-approved NSPS *Kb Operating Plan*.

4.9 Other Emission Sources

4.9.1 Pigging: The LOGP contains an oil emulsion pig receiver on the oil/water emulsion pipeline from Platform Irene, a gas pig receiver on the produced gas pipeline from Platform Irene and a gas pig receiver on the gas pipeline from the La Purisima lease. The receivers are bled to the vapor recovery unit prior to opening, however, there are a remaining few pounds of back pressure that are emitted when opened to the atmosphere. Emissions occur during the depressurization of the receiver units. The calculation per period and emission factors are calculated as follows:

$$ER = [V_1 \ x \ \rho \ x \ wt \ \% \ x \ EPP]$$

where:		
	ER =	emission rate (lb/period)
	V_1 =	volume of vessel (ft^3)
	ρ =	0.165 lb/ft^3 (density of oil vapors at actual conditions)
	ρ =	0.076 lb/ft^3 (density of gas vapors at actual conditions)
	wt % =	0.37 (weight percent ROC-TOC)
	EPP =	pigging events per time period (events/period)

4.9.2 General Solvent Cleaning/Degreasing: Solvent usage (not used as thinners for surface coating) occurring at the LOGP facility as part of normal daily operations includes cold solvent degreasing and wipe cleaning. Emissions are determined based on historic use records assuming that all the solvent used evaporates to the atmosphere. The solvent limits in Table 5.2 cannot be exceeded (excluding solvent activities that qualify for the maintenance exemption under Rule 202).

4.9.3 Surface Coating: Surface coating operations typically include normal touch-up activities. Entire facility painting programs are performed once every few years. Emissions are determined based on historic use records. Emission of PM/PM_{10} from paint overspray are not calculated due to the lack of established calculation techniques.

4.9.4 Abrasive Blasting: Abrasive blasting with CARB-certified sands may be performed as a preparation step prior to surface coating. The engines used to power the compressor may be electric or diesel fired. ICEs used for this purpose require a permit unless otherwise exempt. Particulate matter is emitted during this process. A general emission factor of 91 pound PM per 1000 pound of abrasive and 13 pound PM_{10} per pound abrasive is used (USEPA, 5^{th} Edition, Supplement D, Table 13.26-1, 9/97) to estimate emissions of PM and PM_{10}.

4.10 BACT/NSPS/NESHAP/MACT

4.10.1 BACT: Best Available Control Technology is required for certain emission units for NO_x, ROC and SO_x. The applicable BACT control technologies of this permit are listed in Table 4.10-1 and the corresponding BACT performance standards are listed in Table 4.10-2. Table 4.10-3 lists additional BACT requirements for the I&M FHC Program. Pursuant to District Policy and Procedure 6100.064, once an emission unit is subject to BACT requirements, then any subsequent modifications to that emissions unit or process is subject to BACT. This applies to both *de minimis* changes and equivalent replacements, regardless of whether or not such changes or replacements require a permit.

4.10.2 Rule 331 BACT Determinations: Pursuant to Sections D.4 and E.1.b of Rule 331, critical components are required to be replaced with BACT (or District-approved alternate BACT) in accordance with the District's NSR rule. These determinations are based on a case-by-case basis following the District's guidance document for determining BACT due to Rule 331. Rule 331 BACT determinations are documented in Table 4.10-4.

4.10.3 NSPS: Discussion of applicability and compliance with New Source Performance Standards is presented in Section 3 of this permit. An engineering analysis for the affected equipment is found in the sections above.

4.10.4 NESHAP: PXP has not identified any equipment or processes that are subject to an applicable National Emission Standard for Hazardous Air Pollutants.

4.10.5 MACT: A National Emission Standards for Hazardous Air Pollutants (NESHAPS) for Oil and Natural Gas Production and Natural Gas Transmission and Storage was promulgated on June 17, 1999. As described in section 3.2.4, the oil operations at this facility qualified for the black oil exemption and are required only to maintain the records specified in permit condition 9.B.14. The gas operations qualify as an "area source" and are not subject to the MACT.

4.11 Process Monitoring/CAM

4.11.1 Continuous Monitoring: The District reviewed the proposed facility to determine the emission sources and other parameters that must be monitored continuously to ensure permit compliance. There are no emission units that require *in-stack* emission monitoring or that otherwise qualify as Continuous Emissions Monitors (CEMs) although some monitors have been subject to similar quality assurance standards. Table 4.11 provides details on the continuous monitoring requirements for the Point Pedernales Project. Also, no emissions units were subject to CAM (see section 3.2.5).

Emission sources requiring continuous monitoring are the thermal oxidizer, gas processing plant sulfur emissions and H_2S content of the incoming platform gas. Besides pollutant emissions, process parameters, such as fuel gas flow rate & Production volumes, also require monitoring. The District may require additional monitors and redundant monitor system components in the future, if problems with the facility or monitoring operations that warrant additional monitoring develop.

	Table 4.10-1 – BACT CONTROL TECHNOLOGY POLLUTANT				
Source	**ROC**	**NO_x (as NO_2)**	**SO_x (as SO_2)**	**CO**	**PM/PM_{10}**
Heater Treaters	Use of pipeline quality natural gas as fuel.	Lo-NOx burners	Use of pipeline quality natural gas as fuel. Total sulfur content not to exceed 80 ppmv.		
Crude Oil Storage Tanks	Hard-piped closed vapor recovery system: 100% efficient excluding fugitives.				
<u>Tanks/Sumps</u>: (Oil Storage Tanks, Rerun Tanks, Oily Sludge Thickener, Backwash Sump)	Vapor recovery system (gas blanketed)				
<u>Sumps/Separators</u>: (Area Drain Oil/Water Separators, Open Drain Sumps)	Carbon Canister				
Thermal Oxidizer	Proper combustion practice. 0.6 sec residence time.				
Fugitive ROC	District-approved Inspection & Maintenance program for all onshore facilities: pressure relief devices in HC service vented to vapor control system or flare; dual mechanical pump seals for light liquid streams; closed purge sample systems for regularly sampled gaseous and light liquid streams; no open-ended lines.				
Flare	Use of pipeline quality natural gas for pilot		Use of pipeline quality natural gas for pilot.		
Vacuum Trucks	Carbon Canisters				
Depressurizing Vessels	Depressurize to vapor control system, flare, or equivalent and purge with pipeline quality gas				

	Table 4.10 - 2 BACT PERFORMANCE STANDARDS [2] POLLUTANT					
Source	ROC	NO_x (as NO_2)	SO_x (as SO_2)	CO	PM	PM_{10}
Heater Treaters	0.0017 lb/MMBtu	0.0266 lb/MMBtu	0.0125 lb/MMBtu	0.0184 lb/MMBtu	0.0198 lb/MMBtu	0.0075 lb/MMBtu
Fugitive ROC	Compliance with NSPS KKK requirements (as applicable) and Table 4.3					
Tanks/Sumps connected to vapor recovery systems	Hourly and Daily: 95% recovery efficiency (mass basis) Quarterly and Annual: 99.8% recovery efficiency (mass basis) NSPS Kb for the Oil Storage and Rerun Tanks.					
Sumps/Separators connected to carbon canisters	75% recovery efficiency (mass basis).					
Thermal Oxidizer	98.5% DRE or 10 ppm @ 3% O2.					

[2] BACT Performance Standards are not applicable during startup/shutdown periods for the equipment.

TABLE 4.10-3 - Rule 331 BACT REQUIREMENTS

Valves	All 2" valves and below shall be sealless. All other valves shall be equipped with low emissions packing. Socket welded valves where feasible. No open-ended valves unless double blocked or plugged.
Threaded Connections	Welded connections where feasible[2] Flanged gaskets rated at 150% of process pressure at process temperature Wafer type check valves where feasible
Relief Valves Monitoring	Route relief valves to closed vent system (e.g., vapor recovery) Utilize "soft-seat" designs Rupture disks for all relief valves in LPG, NGL and acid gas service equipped with indicator devices.
Pump Seals	Dual Mechanical Seals
Compressors Seals	Duel mechanical seals vented to vapor recovery system
Inspection and Maintenance Standards	Low-emission (i.e., graphite-packed) and Standard Valves: monthly monitoring of accessible valves. District Rule 331- Fugitive Inspection and Maintenance 40 CFR 60 Subpart KKK

Notes:

1. All ball valves two inches and below shall not require a sealless design due to technical unfeasibility but must be equipped with low-emissions packing.
2. A minimum of 50 % of total connections must be welded.
3. These requirements are in addition to District Rule 331 and permit requirements and apply to the gas plant only. Where a conflict may occur, the requirement more protective to air quality (as determined by the control Officer) shall apply.

Table 4.10-4 - Fugitive Hydrocarbon Component Emission BACT Requirements

Component Tag ID/Description	Technology	Performance Standard
ID# 9365.01	Alternate BACT - Repair and reinstall with Teflon Tape	100 ppmv

All continuously monitored parameters must be recorded on backup strip chart recorders unless this requirement is waived by the District. The required data will be consolidated and submitted to the District as required by Section 9.C. More frequent reporting may be required if the District deems this necessary. Minimum data reporting requirements must include the following:

- Summary of monitor downtime, including explanation and corrective action, and,

- Report on compliance with permit requirements, including any corrective action being taken.

Operator log entries, strip charts, and/or magnetic tapes or discs must be provided upon request by the District.

4.11.2 Process Monitor Calibration and Maintenance Plan: PXP is required to implement calibration and maintenance requirements for the process monitors identified in Table 4.11 as well as any process monitor not listed that is used to assess compliance, e.g., heater treater and thermal oxidizer fuel meters and surge tank level recorder according to the District-approved *Process Monitor Calibration and Maintenance Plan*, and all updates. This Plan takes into consideration manufacturer recommended maintenance and calibration schedules and may include other accuracy checks. Where manufacturer guidance is not available, the recommendations of comparable equipment manufacturers and good engineering judgment are to be utilized.

4.11.3 CAM: There are no emission units at this facility that are subject to the USEPA's Compliance Assurance Monitoring Assurance (CAM) rule.

Table 4.11

PROCESS PARAMETER MONITORING AND
REPORTING REQUIREMENTS FOR THE OIL PLANT

Location Number	Test Location	Parameter Monitored	Monitoring Method
OIL DEHYDRATION PLANT			
1	Gas Fired Equipment	Fuel Use [2,3]	Fuel meter
2	Flare Gas	Flow Rate [2, 3, 4, 6]	Process Flow Meter
3	Flare Pilot and Purge Gas	Flow Rate, [3, 7]	Process Flow Meter
4	Flare Pilot	Flameout Indicator [4]	Thermocouple
5	Pipeline-quality Oil Shipped to OPS	Volume [2,3]	Process Flow Meter
6	Gas Production	Volume (MMscfd) [2,3,5]	Process Flow Meter
7	Incoming OCS Gas	Volume and Mass Flow Rate [2,3,5]	Process Flow Meter
GAS PROCESSING PLANT			
1	Thermal Oxidizer Fuel	Fuel Use[2,3]	Fuel Meter
2	Thermal Oxidizer Combustion Temperature	Temperature[2,3]	Thermocouple
3	Acid Gas Flow rate	Flow Rate	Process Flow Meter
4	Tail Gas Flow rate	Flow Rate[2,3]	Process Flow Meter
5	Tail Gas/Regen Air H_2S Concentration	H_2S Content[7] (Daily)	Draeger (Detector Tube)
6	Regen Air Flow Rate	Flow Rate[2,3]	Process Flow Meter
7	Sour Gas flow Rate	Flow Rate[2,3]	Process Flow Meter
8	Sweet Gas Flow Rate	Flow Rate[2,3]	Process Flow Meter
9	Fuel/Sales Gas H_2S Concentration (Houston Atlas)	H_2S Content[2,3]	Tape Calorimeter

Notes to Table 4.11:

1. Parameters in addition to those listed shall be continuously monitored if deemed necessary by the District. If requested, data from monitoring shall be telemetered to the District on a real-time basis.
2. Permanent recording of parameter raw data is required using strip chart, circular chart, and/or computer or data logger. Permanent recording system shall be approved by the District.
3. Parameters must be monitored continuously and reported to the District semi-annually no later than September 1 and March 1 of each year. The District may request additional information to be presented in quarterly reports if necessary.
4. Equipped with in-plant alarm.

5. Production records shall be maintained through volume of oil and gas shipped.
6. Parameters shall be monitored and telemetered if records indicate that flaring frequency exceeds that assumed in this analysis.
7. Flow rates shall be read daily off the continuous monitor, and the rates logged on a daily basis, unless the District makes a determination that permanent continuous recording such as computer printout, strip chart or circular chart is required.

4.12 Source Testing/Sampling

Source testing and sampling are required in order to ensure compliance with permitted emission limits, BACT, NSPS, prohibitory rules, control measures and the assumptions that form the basis of this operating permit. Table Attachments 4.12-1 and 4.12-2 detail the emission units, pollutants and parameters, methods and frequency of required testing. PXP is required to follow the District *Source Test Procedures Manual* (May 24, 1990 and all updates).

All sampling and analyses are required to be performed according to District approved procedures and methodologies. Typically, the appropriate ASTM methods are acceptable. All sampling and analysis must be traceable by chain of custody procedures.

4.13 Operational and Regional Monitoring

4.13.1 <u>Regional Monitoring</u>: Pursuant to Condition E-4 of the County Development Plan PXP must install and operate monitors to provide data on regional ozone levels. These monitors must be installed and operated at locations specified by the District and according to the District Air Quality and Meteorological Monitoring (AQMM) Protocol (October, 1990 and subsequent District updates).

The sites identified in Table 4.13 shall provide information on ozone levels in regions of the air shed where PXP's Point Pedernales Project could reasonably be expected to contribute to the ozone levels. They include the LOGP facility and surrounding area and Paradise Road.

4.14 Odor Monitoring

4.14.1 Emissions from the operational phase of the project were reviewed to determine compliance with District Rules 205.A and 303, relating to the prevention of public nuisance as required by Section 41700 of the California Health and Safety Code. There is a potential for public nuisance due to emissions of hydrocarbons and reduced sulfur compounds which could occur during operation of the project facilities.

The two major odor sources are hydrogen sulfide (H_2S) from fugitive emissions and sulfur dioxide in the combustion gases. Based on predicted H_2S impacts resulting from Platform Irene activities (EIS/EIR Technical Appendix), no exceedances of the human detection threshold were predicted at the closest shoreline point. The EIS/EIR also forecasted that processing operations at the Lompoc facility would not cause exceedances of the human odor threshold (0.65 ug/m^3). This was based on extrapolations from the maximum modeled ROC level of 256 ug/m^3 and an onshore fugitive H_2S content of 24 ppm. Condition E-8 of the County Development Plan limits the gas used as fuel at the LOGP to an H_2S content of 0.25 gr/100 scf (pipeline quality). PXP was required to install continuous H_2S monitoring on the fuel gas line.

Subsequently, fugitive H_2S impacts were analyzed in ATC 7027 and 7295 to reflect an increased H_2S concentration of 10,000 ppmv and increased fugitive component counts. Table 6.5 presents the H_2S impacts based on modeling from ATC 7027 scaled to reflect the fugitive emissions as stated in a letter from the District to PXP dated February 15, 1991 regarding operational increment fees. The predicted H_2S concentrations are below both the state 1-hour standard and the District Rule 310 limitation but well above the H_2S odor threshold. PXP was required to install an ambient odor monitor to detect the odorous impacts of the facility on Highway 1 and the Mission Hills residential area. This monitor is located on PXP properties approximately one-quarter mile southeast of the LOGP facility (north east corner of section 2, Township 7N, Range 34W).

4.15 Part 70 Engineering Review: Hazardous Air Pollutant Emissions

Hazardous air pollutant emissions estimates from the different categories of emission units at the LOGP facility are discussed in section 5.7 and Table 5.6.

Table 4.12-1. Source Test Requirements: Thermal Oxidizer

Emission Points	Pollutants/Parameters	Test Methods
Inlet (CO_2 tail gas and regenerator air)	ROC (ppm, lb/hr and BTU content of the waste gas, total waste gas stream volume)	Flow meters FR1301 and FT-1330 EPA Method 19 (waste gas analysis)
Thermal Oxidizer Stack	Sampling Point Dtr. Stack Gas Flow Rate CO_2, O_2, Dry Mol Wt Moisture Content ROC ROC NO_x, CO SO_x	USEPA Method 1 USEPA Method 2 USEPA Method 3/CARB 100 USEPA Method 4 USEPA Method 18 USEPA Methods 7E or CARB 100 USEPA Method 6
Destruction Rate Efficiency (Waste gases)	ROC	USEPA Method 18 and the equation footnoted below.
Fuel Flow Rate	Std cubic feet NG	Plant Meter
Fuel Lineanalysis (NG)	Fuel gas analysis (NG)	ASTM D-3588 (NG)
Combustion chamber	Residence Time	Calculation (Engr. Evaluation)

Specific Requirements:

a. Source testing will consist of three forty minute runs.
b. All units to be reported at standard conditions (60°F and 1 atm).
c. Destruction efficiency is defined as: [100] [((lb/hr ROC)$_{in}$ - (lb/hr ROC)$_{out}$) / (lb/hr ROC)$_{in}$], where ROC$_{in}$= tail gas + regenerator air waste and ROC$_{out}$ = stack ROC.
d. The above listed test methods shall be used unless a proposed equivalent method is approved by the District.
e. Compliance with the thermal oxidizer ROC mass emission limit is based on 10 ppmv. Compliance will be deemed attained if the source tested lb/hr rate is equivalent to a 98.5% DRE or greater or ppm concentration ≤ 10 ppm, i.e, testing is required for ROC efficiency or ppm concentration.

Table 4.12-2. Source Test Requirements: Heater Treaters

Emission Points	Pollutants/Parameters	Test Methods
Heater Treater Exhaust Stacks	NO_x	USEPA Method 7E or CARB Method 100
	CO	USEPA Method 10 or CARB Method 100
	THC/ROC	USEPA Method 18
	O_2	CARB Method 100
	Stack Flow	USEPA Method 2 or 19
	Fuel Gas Flow	Plant Meter
	Fuel Gas Analysis	ASTM D - 3588-81 ASTM D - 1945-81

Specific Requirements:

a. The emission rates shall be based on EPA Methods 2 and 4, or Method 19 along with the heat input rate. Source testing will consist of three forty minute runs.
b. If Method 19 is used for emission rate calculation, then the fuel rate measurements during the test shall be based on a minimum 24-hour fuel meter chart setting for a Barton type fuel meter. Alternatively, a calibrated portable fuel meter (e.g., Roots meter) equipped with a pressure meter and a temperature gauge may be used for fuel measurement.
c. All units to be reported at standard conditions (60°F and 1 atm).
d. The above listed test methods shall be used unless a proposed equivalent method is approved by the District.

Table 4.13
REQUIREMENTS FOR OPERATIONAL and REGIONAL MONITORING

Parameters to be Monitored	LOGP	Paradise Road	LOGP Odor
$NO_x/NO/NO_2$	X	X	
Ozone	X	X	
PM_{10}			
H_2S			X
SO_2	X		
THC	X		
TRS			X
CO			
WS Avg.	X	X	X
WD Avg.	X	X	X
WS Resultant	X	X	X
WD Resultant	X	X	X
VWS			
Sigma W			
Sigma V			
Sigma Phi			
Sigma Theta	X	X	X
Int Temp.	X	X	X
Ext Temp.	X	X	X

5.0 Emissions

5.1 General

Emissions calculations are divided into "permitted", "exempt" and “entire source emissions (ESE)” categories. Permit exempt equipment is determined by District Rule 202. ESE emissions are the sum of all Point Pedernales Project emissions (excluding the Lompoc Oil Field) of ozone precursor (NO_x and ROC) pollutant. The permitted emissions for each emissions unit is based on the equipment's potential-to-emit (as defined by Rule 102). Section 5.2 details the permitted emissions for each emissions unit. Section 5.3 details the overall permitted emissions for the facility based on reasonable worst-case scenarios using the potential-to-emit for each emissions unit. Section 5.4 provides the federal potential to emit calculation using the definition of potential to emit used in Rule 1301. Section 5.5 details the ESE emissions for the stationary source (LOGP and Irene only). Section 5.6 provides the estimated emissions from permit exempt equipment. Section 5.7 provides the estimated HAP emissions from the LOGP facility. Section 5.8 provides the net emissions increase calculation for the facility and the stationary source. The emission tables include the symbols “-“ which denotes that no emission limit is applicable and “0” which denotes emissions less than 0.005.

5.2 Permitted Emission Limits - Emission Units

Each emissions unit associated with the facility was analyzed to determine the potential-to-emit for the following pollutants:

- Nitrogen Oxides (NO_x) [3]
- Reactive Organic Compounds (ROC)
- Carbon Monoxide (CO)
- Sulfur Oxides (SO_x) [4]
- Particulate Matter (PM) [5]
- Particulate Matter smaller than 10 microns (PM_{10})
- Greenhouse Gases (GHG)

Permitted emissions are calculated for both short term (hourly and daily) and long term (quarterly and annual) time periods. Section 4.0 (Engineering Analysis) provides a general discussion of the basic calculation methodologies and emission factors used. The reference documentation for the specific emission calculations, as well as detailed calculation spreadsheets, may be found in Section 4. Table 5.1-1 provides the basic operating characteristics. Table 5.1-2 provides the specific emission factors. Tables 5.1-3 and 5.1-4 show the permitted short-term and permitted long-term emissions for each unit or operation. In the table, the last column indicates whether the emission limits

[3] Calculated and reported as nitrogen dioxide (NO_2)

[4] Calculated and reported as sulfur dioxide (SO_2)

[5] Calculated and reported as all particulate matter smaller than 100 μm

are federally enforceable. Those emissions limits that are federally enforceable are indicated by the symbol “FE”.

5.3 *Permitted Emission Limits - Facility Totals*

The total potential-to-emit for all emission units associated with the facility was analyzed. This analysis looked at the reasonable worst-case operating scenarios for each operating period. The equipment operating in each of the scenarios are presented below. Unless otherwise specified, the operating characteristics defined in Table 5.1-1 for each emission unit are assumed. Table 5.2 shows the total permitted emissions for the facility.

Hourly/Daily Scenario:

- Internal Combustion Engines
- Heater Treaters
- Thermal Oxidizer
- Pigging Equipment
- Sumps
- Solvent Use
- Fugitives

Quarterly and Annual Scenario:

- Internal Combustion Engines
- Heater Treaters
- Thermal Oxidizer
- Flaring
- Pigging Equipment
- Sumps
- Solvent Use
- Fugitives

The total supply boat emission limits for the Point Pedernales Project are the emissions within the 25-mile platform radius and the emissions from the 25-mile radius to the county line. This total was determined during the original permitting of this project. See Table 5.4 of this permit and PTO 9106 Table 5.2.

There are no emissions limitations for the firewater pump engines as explained in Section 4.1 above.

5.4 *Part 70: Federal Potential to Emit for the Facility*

Table 5.3 lists the federal Part 70 potential to emit. Being a NSR source, all project emissions, except the oil plant fugitive emissions which are not subject to any applicable NSPS or NESHAP requirement, are included in the federal definition of potential to emit. For the LOGP facility, fugitives from equipment subject to NSPS KKK, Kb, and LLL are included in the federal PTE.

5.5 Entire Source Emissions (ESE)

PXP is required to mitigate all ozone precursor emissions (NO_x and ROC) from emission units associated with the Point Pedernales Project. The ESE is calculated based on the items listed below and includes all vessel emissions associated with trips between Platform Irene and the county line. The ESE table includes emissions associated with the Orcutt Pump Station (OPS) and the pipeline from the LOGP to the OPS (owned and operated by Conoco Phillips) since they are part of the Point Pedernales Project. The basis of the emissions associated with these facilities, as listed in Table 5.4 below, are provided in PTO 7511. Table 5.4 lists the ESE project emission totals.

- LOGP Permitted Emissions
- Platform Irene Permitted Emissions
- Orcutt Pump Station
- Pipelines

5.6 District Exempt Emission Sources/Part 70 Insignificant Emissions

Per Rule 202, maintenance activities such as painting and surface coatings qualify for a permit exemption, but may contribute to facility emissions. Insignificant emission units are defined under District Rule 1301 as any regulated air pollutant emitted from the unit, excluding HAPs, that are less than 2 tons per year based on the unit's potential to emit and any HAP regulated under section 112(g) of the Clean Air Act that does not exceed 0.5 ton per year based on the unit's potential to emit. The following emission units are exempt from permit per Rule 202, but are not considered insignificant emission units, since these exceed the insignificant emissions threshold:

- Solvents/Surface coating operations used during maintenance operations.

Table 5.5 presents the estimated annual emissions from these exempt equipment items, including those exempt items not considered insignificant.

5.7 Part 70: Hazardous Air Pollutant Emissions for the Facility

Total emissions of hazardous air pollutants (HAP) are computed for informational purposes only. Potential annual HAP emissions, based on the worst-case scenario listed in Section 5.3 are listed in Table 5.6.

5.8 Net Emissions Increase Calculation

The net emissions increase for this facility and the entire stationary source since November 15, 1990 (the day the federal Clean Air Act Amendments were adopted) are shown in the tables below.

Facility Emissions Summary
PXP Lompoc Oil & Gas Plant - FID 3095

I. This Projects "I" NEI-90

Permit	Date	NOx		ROC		CO		SOx		PM		PM10	
No.	Issued	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr

II. This Facility's "P1s"
Enter all facility "P1" NEI-90s below:

Permit	Date	NOx		ROC		CO		SOx		PM		PM10	
No.	Issued	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr
P8827	8/21/1992			85.44	15.61								
A9200	6/8/1995			9.26	1.69								
A9522-01	7/29/1997			0.33	0.06								
A9522-04	2/3/1999			40.33	7.36								
P9522		20.86	2.64	1.57	0.31	12.34	1.98	9.08	0.64	3.10	0.53	3.10	0.53
A13015	12/3/2009			0.045	0.008								
Totals		**20.86**	**2.64**	**136.98**	**25.04**	**12.34**	**1.98**	**9.08**	**0.64**	**3.10**	**0.53**	**3.10**	**0.53**

Notes: (1) Facility NEI from IDS.
(2) Totals only apply to permits for this facility ID. Totals may not appear correct due to rounding.
(3) Because of rounding, values in this table shown as 0.00 are less than 0.005, but greater than zero.

III. This Facility's "P2" NEI-90 Decreases
Enter all facility "P2" NEI-90s below:

Permit	Date	NOx		ROC		CO		SOx		PM		PM10	
No.	Issued	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr
Totals		**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

Notes: (1) Facility NEI from IDS.
(2) Totals only apply to permits for this facility ID. Totals may not appear correct due to rounding.
(3) Because of rounding, values in this table shown as 0.00 are less than 0.005, but greater than zero.

IV. This Facility's Pre-90 "D" Decreases
Enter all facility "D" decreases below:

Permit	Date	NOx		ROC		CO		SOx		PM		PM10	
No.	Issued	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr
Totals		**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

Notes: (1) Facility "D" from IDS.
(2) Totals only apply to permits for this facility ID. Totals may not appear correct due to rounding.
(3) Because of rounding, values in this table shown as 0.00 are less than 0.005, but greater than zero.

V. Calculated This Facility's NEI-90
Table below summarizes facility NEI-90 as equal to: I+ (P1-P2) -D

	NOx		ROC		CO		SOx		PM		PM10	
Term	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr
Project "I"	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
P1	20.86	2.64	136.98	25.04	12.34	1.98	9.08	0.64	3.10	0.53	3.10	0.53
P2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
D	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FNEI-90	**20.86**	**2.64**	**136.98**	**25.04**	**12.34**	**1.98**	**9.08**	**0.64**	**3.10**	**0.53**	**3.10**	**0.53**

Notes: (1) Resultant FNEI-90 from above Section I thru IV data.
(2) Totals only apply to permits for this facility ID. Totals may not appear correct due to rounding.
(3) Because of rounding, values in this table shown as 0.00 are less than 0.005, but greater than zero.

Stationary Source NEI-90 Calculations
PXP Point Pedernales Stationary Source

Facility No.	Facility Name	NOx		ROC		CO		SOx		PM		PM10	
		lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr
3069	La Purisima	0.00	0.00	25.47	4.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3095	Lompoc O&G Plant	20.86	2.64	136.98	25.04	12.34	1.98	9.08	0.64	3.10	0.53	3.10	0.53
3309	Jesus Maria "D"	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3310	Orcutt Fee	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3802	Eefson Lease	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3832	Jesus Maria "A"	0.00	0.00	2.75	0.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3837	Lompoc Fee	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3839	Hill Lease	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4417	Arkley Fee	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4218	Lompoc ICEs	5.04	0.96	0.24	0.05	1.20	0.21	0.48	0.07	0.00	0.00	0.00	0.00
8016	Platform Irene	0.07	1.62	4.80	0.90	0.09	0.02	0.11	0.02	0.01	0.00	0.01	0.00
Totals		**25.97**	**5.22**	**170.23**	**30.83**	**13.63**	**2.21**	**9.67**	**0.73**	**3.11**	**0.53**	**3.11**	**0.53**

Notes:
(1) Facility NEI from IDS.
(2) Totals only apply to permits for this facility ID. Totals may not appear correct due to rounding.
(3) Because of rounding, values in this table shown as 0.00 are less than 0.005, but greater than zero.

Table 5.1-1
PXP Lompoc Oil and Gas Plant: PTO 6708-R7
Operating Equipment Description

		Device Specifications				Usage Data			Maximum Operating Schedule			
Equipment Category	**Description**	**Fuel**	**% S**	**Size**	**Units**	**Capacity**	**Units**	**Load**	**hr**	**day**	**qtr**	**year**
Internal Combustion	Emergency Generator	D		598	Bhp	--	--	--	1.0	2	20	20
External Combustion	Heater Treater A	NG	0.0080	16	MMBtu/hr	0.140	MMBtu/yr	--	1.0	24	2,190	8,760
	Heater Treater B	NG	0.0080	16	MMBtu/hr	0.140	MMBtu/yr	--	1.0	24	2,190	8,760
	Heater Treater C	NG	0.0080	16	MMBtu/hr	0.140	MMBtu/yr	--	1.0	24	2,190	8,760
	Thermal Oxidizer	NG	0.0080	12	MMBtu/hr	0.105	MMBtu/yr	--	1.0	24	2,190	8,760
Flare	Purge and Pilot	PG	0.0080	45	scfh	0.059	MMBtu/hr	--	1.0	24	2,190	8,760
	Planned - continuous	--	--	--	--	--	--	--	--	--	--	--
	Planned - other	--	0.0796	--	--	0.100	MMscf/yr	--	--	--	1	1
	Unplanned	SG	0.0796	625	MMBtu/hr	0.959	MMscf/yr	--	--	--	0	1
Fugitive Emissions	Oil - controlled	--	--	5,441	comp-lp	--	--	--	1.0	24	2,190	8,760
	Oil - controlled 1/2" SS (connections)											
	Oil - controlled 1/2" SS (valves)											
(Oil Plant)	Gas - controlled (valves)	--	--	1,060	comp-lp	--	--	--	1.0	24	2,190	8,760
	Gas - controlled 1/2" SS (valves)											
	Gas - controlled (connections)	--	--	6,314	comp-lp	--	--	--	1.0	24	2,190	8,760
	Gas - controlled 1/2" SS (connections)											
	Gas - controlled (pumps)	--	--	4	comp-lp	--	--	--	1.0	24	2,190	8,760
	Gas - controlled (PRD)			43	comp-lp	--	--	--	1.0	24	2,190	8,760
	Gas - controlled (Compressors)	--	--	6	comp-lp	--	--	--	1.0	24	2,190	8,760
Oil Pipeline (SURF to LOGP)	Oil - controlled (valves)	--	--	222	comp-lp	--	--	--	1.0	24	2,190	8,760
	Oil - controlled (connections)	--	--	1	comp-lp	--	--	--	1.0	24	2,190	8,760
Gas Pipeline (SURF to LOGP)	Gas - controlled (valves)	--	--	89	comp-lp	--	--	--	1.0	24	2,190	8,760
	Gas - controlled (connections)	--	--	1	comp-lp	--	--	--	1.0	24	2,190	8,760
Pigging Equipment	Oil Receiver	--	--	32	cf	5	psig	--	1	1	92	366
	Gas Receiver	--	--	32	cf	5	psig	--	1	1	104	417
	Lompoc Field Gas Receiver	--	--	0.75	cf	5	psig	--	1	4	25	100
Sumps	S-800 (Inlet Sump)	--	--	12.5	ft2	--	--	--	1.0	24	2,190	8,760
	S-810 (Crude Dehydration Sump)	--	--	12.5	ft2	--	--	--	1.0	24	2,190	8,760
	S-820 (Water Treating Sump)	--	--	12.5	ft2	--	--	--	1.0	24	2,190	8,760
	S-830 (Reject Tank Sump)	--	--	12.5	ft2	--	--	--	1.0	24	2,190	8,760
	S-840 (Outlet Sump)	--	--	12.5	ft2	--	--	--	1.0	24	2,190	8,760
	S-850 (Flotation Unit Froth Sump)	--	--	12.5	ft2	--	--	--	1.0	24	2,190	8,760
	S-860 (Control Building Lab Sump)	--	--	12.5	ft2	--	--	--	1.0	24	2,190	8,760
	S-870 (Oil Surge Tank Sump)	--	--	12.5	ft2	--	--	--	1.0	24	2,190	8,760
	S-890 (Containment Area Sump)	--	--	12.5	ft2	--	--	--	1.0	24	2,190	8,760
	S-895 (Amine Sump)	--	--	12.5	ft2	--	--	--	1.0	24	2,190	8,760
Solvent Usage	Cleaning/degreasing	--	--	various		--	--	--	1.0	24	2,190	8,760

Table 5.1-2
PXP Lompoc Oil and Gas Plant: PTO 6708-R7
Equipment Emission Factors

		Emission Factors							
Equipment Category	**Description**	**NOx**	**ROC**	**CO**	**SOx**	**PM**	**PM10**	**GHG**	**Units**
Internal Combustion	Emergency Generator	14.05	1.02	3.03	0.18	0.98	0.98	556.58	g/bhp-hr
External Combustion	Heater Treater A	0.0266	0.0017	0.0184	0.0125	0.0075	0.0075	117.00	lb/MMBtu
	Heater Treater B	0.0266	0.0017	0.0184	0.0125	0.0075	0.0075	117.00	lb/MMBtu
	Heater Treater C	0.0266	0.0017	0.0184	0.0125	0.0075	0.0075	117.00	lb/MMBtu
	Thermal Oxidizer	0.0495	0.0043	0.038	0.0145	0.011	0.011	117.00	lb/MMBtu
Combustion	Purge and Pilot	0.068	0.0027	0.0333	0.102	0.0048	0.0048	117.00	lb/MMBtu
	Planned - continuous	0.068	0.0027	0.0333	0.102	0.0048	0.0048	117.00	lb/MMBtu
	Planned - other	0.068	0.0027	0.0333	0.102	0.0048	0.0048	117.00	lb/MMBtu
	Unplanned	0.068	0.0027	0.0333	0.102	0.0048	0.0048	117.00	lb/MMBtu
Fugitive Emissions	Oil - controlled	--	0.0304	--	--	--	--	--	lb/day-clp
	Oil - controlled 1/2" SS (connec	--	--					--	
	Oil - controlled 1/2" SS (valves)	--	--						
(Oil Plant)	Gas - controlled (valves)	--	0.4020	--	--	--	--	--	lb/day-clp
	Gas - controlled 1/2" SS (valves	--	--						
	Gas - controlled (connections)	--	0.0249	--	--	--	--	--	lb/day-clp
	Gas - controlled 1/2" SS (conne	--	--						
	Gas - controlled (pumps)	--	2.6070	--	--	--	--	--	lb/day-clp
	Gas - controlled (PRD)	--	0.6963	--	--	--	--	--	lb/day-clp
	Gas - controlled (Compressors	--	--	--	--	--	--	--	lb/day-clp
Oil Pipeline (SURF to LOGP)	Oil - controlled (valves)	--	0.0304	--	--	--	--	--	lb/day-clp
	Oil - controlled (connections)	--	0.0304	--	--	--	--	--	lb/day-clp
Gas Pipeline (SURF to LOGP)	Gas - controlled (valves)	--	0.4020	--	--	--	--	--	lb/day-clp
	Gas - controlled (connections)	--	0.0249	--	--	--	--	--	lb/day-clp
Pigging Equipment	Oil Receiver	--	0.061	--	--	--	--	--	lb/acf-evnt
	Gas Receiver	--	0.028	--	--	--	--	--	lb/acf-evnt
	Lompoc Field Pig Receiver		0.028	--	--	--	--	--	lb/acf-evnt
Sumps	S-800 (Inlet Sump)		0.013	--	--	--	--	--	lb/ft2-day
	S-810 (Crude Dehydration Sum	--	0.013	--	--	--	--	--	lb/ft2-day
	S-820 (Water Treating Sump)	--	0.013	--	--	--	--	--	lb/ft2-day
	S-830 (Reject Tank Sump)	--	0.013	--	--	--	--	--	lb/ft2-day
	S-840 (Outlet Sump)	--	0.013	--	--	--	--	--	lb/ft2-day
	S-850 (Flotation Unit Froth Sum	--	0.013	--	--	--	--	--	lb/ft2-day
	S-860 (Control Building Lab Su	--	0.013	--	--	--	--	--	lb/ft2-day
	S-870 (Oil Surge Tank Sump)	--	0.013	--	--	--	--	--	lb/ft2-day
	S-890 (Containment Area Sum	--	0.013	--	--	--	--	--	lb/ft2-day
	S-895 (Amine Sump)	--	0.013	--	--	--	--	--	lb/ft2-day
Solvent Usage	Cleaning/degreasing	--	various	--	--	--	--	--	lb/gal

Table 5.1-3
PXP Lompoc Oil and Gas Plant: PTO 6708-R7
Hourly and Daily Emissions

Equipment Category	Description	NOx lb/hr	NOx lb/day	ROC lb/hr	ROC lb/day	CO lb/hr	CO lb/day	SOx lb/hr	SOx lb/day	PM lb/hr	PM lb/day	PM10 lb/hr	PM10 lb/day	GHG lb/hr	GHG lb/day	Federally Enforceable
Internal Combustion	Emergency Generator	--	37.07	--	2.95	--	7.99	--	0.49	--	2.59	--	2.59	733.76	8,805.15	
External Combustion	Heater Treater A	0.43	10.21	0.03	0.65	0.29	7.07	0.20	4.80	0.12	2.88	0.12	2.88	1,872.00	44,928.00	FE
	Heater Treater B	0.43	10.21	0.03	0.65	0.29	7.07	0.20	4.80	0.12	2.88	0.12	2.88	1,872.00	44,928.00	FE
	Heater Treater C	0.43	10.21	0.03	0.65	0.29	7.07	0.20	4.80	0.12	2.88	0.12	2.88	1,872.00	44,928.00	FE
	Thermal Oxidizer	0.59	14.26	0.05	1.24	0.46	10.94	0.17	4.17	0.13	3.17	0.13	3.17	1,404.00	33,696.00	FE
Combustion	Purge and Pilot	0.00	0.10	0.00	0.00	0.00	0.05	0.01	0.15	0.00	0.01	0.00	0.01	6.94	166.54	FE
	Planned - continuous	--	--	--	--	--	--	--	--	--	--	--	--	--	--	
	Planned - other	--	--	--	--	--	--	--	--	--	--	--	--	--	--	
	Unplanned	--	--	--	--	--	--	--	--	--	--	--	--	--	--	
Fugitive Emissions	Oil - controlled	--	--	1.38	33.08	--	--	--	--	--	--	--	--	--	--	
	Oil - controlled 1/2" SS (connections)			--	--									--	--	
	Oil - controlled 1/2" SS (valves)			--	--											
(Oil Plant)	Gas - controlled (valves)	--	--	3.55	85.22	--	--	--	--	--	--	--	--	--	--	
	Gas - controlled 1/2" SS (valves)			--	--											
	Gas - controlled (connections	--	--	1.31	31.44	--	--	--	--	--	--	--	--	--	--	
	Gas - controlled 1/2" SS (connections)			--	--											
	Gas - controlled (pumps)	--	--	0.09	2.09	--	--	--	--	--	--	--	--	--	--	
	Gas - controlled (PRD)	--	--	0.25	5.99	--	--	--	--	--	--	--	--	--	--	
	Gas - controlled (Compresso	--	--	0.00	0.00											
Fugitive Emissions (Gas Processing Plant)	Gas - controlled	--	--	2.13	51.20	--	--	--	--	--	--	--	--	--	--	FE
Oil Pipeline (SURF to LOGI	Oil - controlled (valves)	--	--	0.06	1.35	--	--	--	--	--	--	--	--	--	--	FE
	Oil - controlled (connections)	--	--	0.00	0.01	--	--	--	--	--	--	--	--	--	--	FE
Gas Pipeline (SURF to LOC	Gas - controlled (valves)	--	--	0.30	7.16	--	--	--	--	--	--	--	--	--	--	FE
	Gas - controlled (connections	--	--	0.00	0.00	--	--	--	--	--	--	--	--	--	--	FE
Pigging Equipment	Oil Receiver	--	--	1.95	1.95	--	--	--	--	--	--	--	--	--	--	
	Gas Receiver	--	--	0.90	0.90	--	--	--	--	--	--	--	--	--	--	
	Lompoc Field Gas Receiver	--	--	0.02	0.08	--	--	--	--	--	--	--	--	--	--	
Sumps/Tanks/Separators	S-800 (Inlet Sump)	--	--	0.00	0.02	--	--	--	--	--	--	--	--	--	--	
	S-810 (Crude Dehydration Su	--	--	0.00	0.02	--	--	--	--	--	--	--	--	--	--	
	S-820 (Water Treating Sump)	--	--	0.00	0.02	--	--	--	--	--	--	--	--	--	--	
	S-830 (Reject Tank Sump)	--	--	0.00	0.02	--	--	--	--	--	--	--	--	--	--	
	S-840 (Outlet Sump)	--	--	0.00	0.02	--	--	--	--	--	--	--	--	--	--	
	S-850 (Flotation Unit Froth Su	--	--	0.00	0.02	--	--	--	--	--	--	--	--	--	--	
	S-860 (Control Building Lab S	--	--	0.00	0.02	--	--	--	--	--	--	--	--	--	--	
	S-870 (Oil Surge Tank Sump)			0.00	0.02	--	--	--	--	--	--	--	--	--	--	
	S-890 (Containment Area Sump)			0.00	0.02	--	--	--	--	--	--	--	--	--	--	
	S-895 (Amine Sump)			0.00	0.02	--	--	--	--	--	--	--	--	--	--	
Solvents	Cleaning/Degreasing	--	--	3.95	31.60	--	--	--	--	--	--	--	--	--	--	

Table 5.1-4
PXP Lompoc Oil and Gas Plant: PTO 6708-R7
Quarterly and Annual Emissions

		NOx		ROC		NAROC		CO		SOx		PM		PM10		GHG		Federally
Equipment Category	**Description**	**TPQ**	**TPY**	**TPQ**	**TPY**	**TPQ**	**TPY**	**TPQ**	**TPY**	**TPQ**	**TPY**	**TPQ**	**TPY**	**TPQ**	**TPY**	**TPQ**	**TPY**	**Enforceable**
Internal Combustion	Emergency Generator	0.46	0.46	0.04	0.04	--	--	0.10	0.10	0.01	0.01	0.03	0.03	0.03	0.03	7.34	7.34	
External Combustion	Heater Treater A	0.47	1.86	0.03	0.12	0.015	0.07	0.32	1.29	0.22	0.88	0.13	0.53	0.13	0.53	2,049.84	8,199.36	FE
	Heater Treater B	0.47	1.86	0.03	0.12	0.015	0.07	0.32	1.29	0.22	0.88	0.13	0.53	0.13	0.53	2,049.84	8,199.36	FE
	Heater Treater C	0.47	1.86	0.03	0.12	0.015	0.07	0.32	1.29	0.22	0.88	0.13	0.53	0.13	0.53	2,049.84	8,199.36	FE
	Thermal Oxidizer	0.65	2.60	0.06	0.23	--	--	0.50	2.00	0.19	0.76	0.14	0.58	0.14	0.58	1,537.38	6,149.52	FE
Combustion - Flare	Purge and Pilot	0.00	0.02	0.00	0.00	0.01	0.01	0.00	0.01	0.01	0.03	0.00	0.00	0.00	0.00	7.60	30.39	FE
	Planned - continuous	0.00	0.00	0.00	0.00	--	--	--	--	--	--	--	--	--	--	--	--	FE
	Planned - other	0.004	0.004	0.00	0.00	--	--	0.001	0.002	0.002	0.007	0.000	0.000	0.000	0.000	11.700	11.700	FE
	Unplanned	0.01	0.04	0.01	0.01	0.01	0.01	0.00	0.02	0.02	0.06	0.01	0.01	0.01	0.01	0.00	112.203	FE
Fugitive Emission	Oil - controlled	--	--	1.51	6.04	--	--	--	--	--	--	--	--	--	--	--	--	
	Oil - controlled 1/2" SS (connections)			--	--													
	Oil - controlled 1/2" SS (valves)			--	--													
	Gas - controlled (valves)	--	--	3.89	15.55	--		--	--	--	--	--	--	--	--	--	--	
	Gas - controlled 1/2" SS (valves)			--	--													
	Gas - controlled (connections)	--	--	1.43	5.74	--	--	--	--	--	--	--	--	--	--	--	--	
	Gas - controlled 1/2" SS (connections)			--	--													
	Gas - controlled (pumps)	--	--	0.10	0.38	--	--	--	--	--	--	--	--	--	--	--	--	
	Gas - controlled (PRD)	--	--	0.27	1.09	--	--	--	--	--	--	--	--	--	--	--	--	
	Gas - controlled (Compressors)	--	--	0.00	0.00	--	--	--	--	--	--	--	--	--	--	--	--	
Fugitive Emissions (Gas Processing Plant)	Gas - controlled	--	--	2.34	9.34	--	--	--	--	--	--	--	--	--	--	--	--	FE
Oil Pipeline (SURF to LOGP	Oil - controlled (valves)	--	--	0.06	0.25	--	--	--	--	--	--	--	--	--	--	--	--	FE
	Oil - controlled (connections)	--	--	0.00	0.00	--	--	--	--	--	--	--	--	--	--	--	--	FE
Gas Pipeline (SURF to LOG	Gas - controlled (valves)	--	--	0.33	1.31	--	--	--	--	--	--	--	--	--	--	--	--	FE
	Gas - controlled (connections)	--	--	0.00	0.00	--	--	--	--	--	--	--	--	--	--	--	--	FE
Pigging Equipment	Oil Receiver	--	--	0.09	0.36	--	--	--	--	--	--	--	--	--	--	--	--	
	Gas Receiver	--	--	0.05	0.19	--	--	--	--	--	--	--	--	--	--	--	--	
	Lompoc Field Gas Receiver	--	--	0.00	0.00	--	--	--	--	--	--	--	--	--	--	--	--	
Sumps	S-800 (Inlet Sump)	--	--	0.01	0.03	--	--	--	--	--	--	--	--	--	--	--	--	
	S-810 (Crude Dehydration Sump)	--	--	0.01	0.03	--	--	--	--	--	--	--	--	--	--	--	--	
	S-820 (Water Treating Sump)	--	--	0.01	0.03	--	--	--	--	--	--	--	--	--	--	--	--	
	S-830 (Reject Tank Sump)	--	--	0.01	0.03	--	--	--	--	--	--	--	--	--	--	--	--	
	S-840 (Outlet Sump)	--	--	0.01	0.03	--	--	--	--	--	--	--	--	--	--	--	--	
	S-850 (Flotation Unit Froth Sump)	--	--	0.01	0.03	--	--	--	--	--	--	--	--	--	--	--	--	
	S-860 (Control Building Lab Sump)	--	--	0.01	0.03	--	--	--	--	--	--	--	--	--	--	--	--	
	S-870 (Oil Surge Tank Sump)	--	--	0.01	0.03	--	--	--	--	--	--	--	--	--	--	--	--	
	S-890 (Containment Area Sump)	--	--	0.01	0.03	--	--	--	--	--	--	--	--	--	--	--	--	
	S-895 (Amine Sump)	--	--	0.01	0.03	--	--	--	--	--	--	--	--	--	--	--	--	
Solvent Usage	Cleaning/Degreasing	--	--	0.62	2.47	--	--	--	--	--	--	--	--	--	--	--	--	

Table 5.2
PXP Lompoc Oil and Gas Plant: PTO 6708-R7
Total Permitted Facility Emissions

A. PEAK HOURLY (lb/hr)

Equipment Category	NOx	ROC	NAROC	CO	SOx	PM	PM10	GHG
Combustion - ICEs	--	--	--	--	--	--	--	--
Combustion - Heater Treaters	1.28	0.08	--	0.88	0.60	0.36	0.36	5,616.00
Combustion - Thermal Oxidizer	0.59	0.05	--	0.46	0.17	0.13	0.13	1,404.00
Combustion - Flare	0.00	0.00	--	0.00	0.01	0.00	0.00	6.94
Fugitive Emissions (including pipelines	--	9.06	--	--	--	--	--	--
Pigging	--	2.87	--	--	--	--	--	--
Sumps	--	0.01	--	--	--	--	--	--
Solvent Usage	--	3.95	--	--	--	--	--	--
	1.87	16.03	--	1.34	0.78	0.49	0.49	7,026.94

B. PEAK DAILY (lb/day)

Equipment Category	NOx	ROC	NAROC	CO	SOx	PM	PM10	GHG
Combustion - ICEs	37.07	2.95	--	7.99	0.49	0.03	0.03	8,805.15
Combustion - Heater Treaters	30.64	1.96	--	21.20	14.40	8.64	8.64	134,784.00
Combustion - Thermal Oxidizer	14.26	1.24	--	10.94	4.17	3.17	3.17	33,696.00
Combustion - Flare	0.10	0.00	--	0.05	0.15	0.01	0.01	166.54
Fugitive Emissions (including pipelines	--	217.54	--	--	--	--	--	--
Pigging	--	2.93	--	--	--	--	--	--
Sumps	--	0.24	--	--	--	--	--	--
Solvent Usage	--	31.60	--	--	--	--	--	--
	82.07	258.46	0.00	40.18	19.21	11.84	11.84	177,451.70

C. PEAK QUARTERLY (tpq)

Equipment Category	NOx	ROC	NAROC	CO	SOx	PM	PM10	GHG
Combustion - ICEs	0.46	0.04	--	0.10	0.01	0.03	0.03	7.34
Combustion - Heater Treaters	1.40	0.09	0.05	0.97	0.66	0.39	0.39	6,149.52
Combustion - Thermal Oxidizer	0.65	0.06		0.50	0.19	0.14	0.14	1,537.38
Combustion - Flare	0.02	0.01	0.02	0.01	0.02	0.01	0.01	19.30
Fugitive Emissions (including pipelines	--	9.92	--	--	--	--	--	--
Pigging	--	0.14	--	--	--	--	--	--
Sumps	--	0.07	--	--	--	--	--	--
Solvent Usage	--	0.62	--	--	--	--	--	--
	2.53	10.95	0.07	1.57	0.88	0.58	0.58	7,713.54

D. PEAK ANNUAL (tpy)

Equipment Category	NOx	ROC	NAR	CO	SOx	PM	PM10	GHG
Combustion - ICEs	0.46	0.04	--	0.10	0.01	0.03	0.03	7.34
Combustion - Heater Treaters	5.59	0.36	0.20	3.87	2.63	1.58	1.58	24,598.08
Combustion - Thermal Oxidizer	2.60	0.23	--	2.00	0.76	0.58	0.58	6,149.52
Combustion - Flare	0.06	0.01	0.02	0.03	0.10	0.01	0.01	154.30
Fugitive Emissions (including pipelines	--	39.70	--	--	--	--	--	--
Pigging	--	0.54	--	--	--	--	--	--
Sumps	--	0.30	--	--	--	--	--	--
Solvent Usage	--	2.47	--	--	--	--	--	--
	8.71	43.64	0.22	5.99	3.50	2.20	2.20	30,909.23

Table 5.3
PXP Lompoc Oil and Gas Plant: PTO 6708-R7
Federal Potential to Emit

A. PEAK HOURLY (lb/hr)

Equipment Category	NOx	ROC	NAROC	CO	SOx	PM	PM10	GHG
Combustion - Heater Treaters	1.28	0.08	--	0.88	0.60	0.36	0.36	5,616.00
Combustion - Thermal Oxidizer	0.59	0.05	--	0.46	0.17	0.13	0.13	1,404.00
Combustion - Flare	0.00	0.00	--	0.00	0.01	0.00	0.00	6.94
Fugitive Components (Gas Plant)	--	2.14	--	--	--	--	--	
Pigging	--	2.93	--	--	--	--	--	
Pipelines	--	0.35	--	--	--	--	--	
Solvent Usage	--	458.00	--	--	--	--	--	
Platform Irene[1]	95.91	15.82	--	15.89	5.09	6.24	5.99	
Supply Boat Emissions (25 mi. to SBC li	--	--	--	--	--	--	--	
Exempt	--	--	--	--	--	--	--	
Total	1.87	463.56	--	1.34	0.78	0.49	0.49	7,026.94

B. PEAK DAILY (lb/day)

Equipment Category	NOx	ROC	NAROC	CO	SOx	PM	PM10	GHG
Combustion - Heater Treaters	30.64	1.96	--	21.20	14.40	8.64	8.64	134,784.00
Combustion - Thermal Oxidizer	14.26	1.24	--	10.94	4.17	3.17	3.17	33,696.00
Combustion - Flare	0.10	0.00	--	0.05	0.15	0.01	0.01	166.54
Fugitive Components (Gas Plant)	--	51.38	--	--	--	--	--	
Pigging	--	2.93	--	--	--	--	--	
Pipelines	--	8.52	--	--	--	--	--	
Solvent Usage	--	3,040.00	--	--	--	--	--	
Platform Irene	1,187.40	231.40	--	165.70	66.40	83.50	80.10	
Supply Boat Emissions (25 mi. to SBC li	--	--	--	--	--	--	--	
Exempt	--	--	--	--	--	--	--	
Total	1,232.40	3,337.43	--	197.89	85.12	95.31	91.91	168,646.54

C. PEAK QUARTERLY (tpq)

Equipment Category	NOx	ROC	NAROC	CO	SOx	PM	PM10	GHG
Combustion - Heater Treaters	1.40	0.09	0.05	0.97	0.66	0.39	0.39	6,149.52
Combustion - Thermal Oxidizer	0.65	0.06	--	0.50	0.19	0.14	0.14	1,537.38
Combustion - Flare	0.02	0.01	0.02	0.01	0.02	0.01	0.01	19.30
Fugitive Components (Gas Plant)	--	2.34	--	--	--	--	--	
Pigging	--	0.14	--	--	--	--	--	
Pipelines	--	0.39	--	--	--	--	--	
Solvent Usage	--	--	--	--	--	--	--	
Platform Irene [1]	7.37	0.45	--	1.86	0.62	0.75	0.72	
Supply Boat Emissions (25 mi. to SBC li	5	0.8	--	0.56	0.16	--	0.18	
Exempt	3.30	0.39	--	0.72	0.22	0.22	0.22	
Total	17.74	4.66	0.07	4.61	1.87	1.52	1.67	7,706.20

D. PEAK ANNUAL (tpy)

Equipment Category	NOx	ROC	NAROC	CO	SOx	PM	PM10	GHG
Combustion - Heater Treaters	5.59	0.36	0.20	3.87	2.63	1.58	1.58	24,598.08
Combustion - Thermal Oxidizer	2.60	0.23	--	2.00	0.76	0.58	0.58	6,149.52
Combustion - Flare	0.06	0.01	0.02	0.03	0.10	0.01	0.01	154.30
Fugitive Components (Gas Plant)	--	9.38	--	--	--	--	--	
Pigging	--	0.54	--	--	--	--	--	
Pipelines	--	1.55	--	--	--	--	--	
Solvent Usage	--	--	--	--	--	--	--	
Platform Irene [1]	29.48	1.81	--	7.43	2.48	3.00	2.88	
Supply Boat Emissions (25 mi. to SBC li	20.00	3.19	--	2.25	0.63	--	0.72	
Exempt	3.30	0.39	--	0.72	0.22	0.22	0.22	
Total	61.03	17.46	0.22	16.29	6.82	5.39	5.99	30,901.90

1. These are totals from PTO 9106 Table 5.2.
2. These are emissions between the county line and the 25 mi perimeter around Irene. They are not included in PTO 9106 since the OCS only includes the 25 mi. radius around the platform. The Point Ped source ESE total (and FPE) however includes these emissions. These are determined by subtracting the PTO 9106 Supply Boat emissions in Table 5.2 from the PTO 6708 (issued 8/94) Supply Boats line item emissions in Table 10.6-3. See Section 5.3 of this PTO for additional details.

Total supply boat emissions are obtained by adding PTO 9106 (Table 5.2) Supply Boat emissions and the *25 mi to SBC* line ab

Table 5.4
PXP Lompoc Oil and Gas Plant: PTO 6708-R7
Entire Source Emissions (ESE)

A. PEAK HOURLY (lb/hr)

Equipment Category	NOx	ROC	NAROC	CO	SOx	PM	PM10	GHG
Combustion - ICEs								
Combustion - Heater Treaters	1.28	0.08	--	0.88	0.60	0.36	0.36	5,616.00
Combustion - Thermal Oxidizer	0.59	0.05	--	0.46	0.17	0.13	0.13	1,404.00
Combustion - Flare	0.00	0.00	--	0.00	0.01	0.00	0.00	6.94
Fugitive Emissions (incld. surf to LOGP p	--	9.06	--	--	--	--	--	
Platform Irene (25 mi. emissions only)	95.91	15.82	--	15.89	5.09	6.24	5.99	
Supply Boat Emissions (25 mi. to SBC line	--	--	--	--	--	--	--	
Pigging	--	2.85	--	--	--	--	--	
Sumps	--	0.01	--	--	--	--	--	
Solvent Usage	--	3.95	--	--	--	--	--	
Orcutt Pump Station	--	--	--	--	--	--	--	
LOGP to OPS Pipeline	--	--	--	--	--	--	--	
Total	97.78	31.83	--	17.23	5.87	6.73	6.48	7,026.94

B. PEAK DAILY (lb/day)

Equipment Category	NOx	ROC	NAROC	CO	SOx	PM	PM10	GHG
Combustion - ICEs	37.07	2.95	--	7.99	0.49	0.03	0.03	8,805.15
Combustion - Heater Treaters	30.64	1.96	--	21.20	14.40	8.64	8.64	134,784.00
Combustion - Thermal Oxidizer	14.26	1.24	--	10.94	4.17	3.17	3.17	33,696.00
Combustion - Flare	0.10	0.00	--	0.05	0.15	0.01	0.01	166.54
Fugitive Emissions (incld. surf to LOGP p	--	217.54	--	--	--	--	--	
Platform Irene (25 mi. emissions only)	1,187.40	231.40	--	165.70	66.40	83.50	80.10	
Supply Boat Emissions (25 mi. to SBC line	--	--	--	--	--	--	--	
Pigging	--	2.85	--	--	--	--	--	
Sumps	--	0.24	--	--	--	--	--	
Solvent Usage	--	31.60	--	--	--	--	--	
Orcutt Pump Station	--	--	--	--	--	--	--	
LOGP to OPS Pipeline	--	--	--	--	--	--	--	
Total	1,269.47	489.78	0.00	205.88	85.61	95.34	91.94	177,451.70

C. PEAK QUARTERLY (tpq)

Equipment Category	NOx	ROC	NAROC	CO	SOx	PM	PM10	GHG
Combustion - ICEs								
Combustion - Heater Treaters	1.40	0.09	0.05	0.97	0.66	0.39	0.39	6,149.52
Combustion - Thermal Oxidizer	0.65	0.06	--	0.50	0.19	0.14	0.14	1,537.38
Combustion - Flare	0.02	0.01	0.02	0.01	0.02	0.01	0.01	19.30
Fugitive Emissions (incld. surf to LOGP p	--	9.92	--	--	--	--	--	
Platform Irene (25 mi. emissions only)[1]	7.37	0.45	--	3.47	2.33	1.27	1.17	
Supply Boat Emissions (25 mi. to SBC line	5	0.8	--	1.86	0.62	--	0.72	
Pigging	--	0.14	--	0.56	0.16	--	0.18	
Sumps	--	0.07	--	--	--	--	--	
Solvent Usage	--	0.62	--	--	--	--	--	
Lompoc Oil Field	0.24	0.14	--	--	--	--	--	
Orcutt Pump Station	0.41	1.06	--	3.41	0.16	0.16	0.16	
LOGP to OPS Pipeline		0.03						
Total	15.09	13.39	0.07	10.77	4.14	1.98	2.78	7,706.20

D. PEAK ANNUAL (tpy)

Equipment Category	NOx	ROC	NAROC	CO	SOx	PM	PM10	GHG
Combustion - ICEs	0.46	0.04	--	0.10	0.01	0.03	0.03	7.34
Combustion - Heater Treaters	5.59	0.36	0.20	3.87	2.63	1.58	1.58	24,598.08
Combustion - Thermal Oxidizer	2.60	0.23	--	2.00	0.76	0.58	0.58	6,149.52
Combustion - Flare	0.06	0.01	0.02	0.03	0.10	0.01	0.01	154.30
Fugitive Emissions (incld. surf to LOGP p	--	39.70	--	--	--	--	--	
Platform Irene (25 mi. emissions only)[1]	29.48	1.81	--	7.43	2.48	3.00	2.88	
Supply Boat Emissions (25 mi. to SBC line	20.00	3.19	--	2.25	0.63	--	0.72	
Pigging	--	0.54	--	--	--	--	--	
Sumps	--	0.30	--	--	--	--	--	
Solvent Usage	--	2.47	--	--	--	--	--	
Lompoc Oil Field	0.96	0.55	--	--	--	--	--	
Orcutt Pump Station	1.66	4.25	--	13.66	0.63	0.63	0.63	
LOGP to OPS Pipeline		0.13						
Total	60.81	53.57	0.22	29.33	7.24	5.83	6.43	30,909.23

1. These are totals from PTO 9106 Table 5.2.
2. These are emissions between the county line and the 25 mi perimeter around Irene. They are not included in PTO 9106 since the OCS only includes the 25 mi. radius around the platform. The Point Ped source ESE total (and FPE) however includes these emissions. These are determined by subtracting the PTO 9106 Supply Boat emissions in Table 5.2 from the PTO 6708 (issued 8/94) Supply Boats line item emissions in Table 10.6-3. See Section 5.5 of this PTO for additional details.
Total supply boat emissions are obtained by adding PTO 9106 (Table 5.2) Supply Boat emissions and the *25 mi to SBC* line above.
3. See PTO 7511 for OPS and LOGP to OPS pipeline emission totals.

Table 5.5
Lompoc Oil and Gas Plant: PTO 6708-R7
Estimated HAPs Emissions

HAP	lb/hr	lb/yr
Acetaldehyde	0.0203	0.6300
Acrolein	0.0015	0.3400
Benzene	0.0062	0.7200
Butadiene-1,3	0.0104	0.1000
Formaldehyde	0.0417	0.8600
H2S	0.0023	0.5000
Lead	0.0001	0.0000
Mercury	0.0001	0.0000
Methanol	0.0001	1.0500
Naphthalene	0.0008	1.1700
Toluene	0.0052	6.0600
Xylene	0.0020	2.4900
Total	0.0907	13.9200

6.0 Air Quality Impact Analyses

6.1 Modeling

Air quality impacts associated with the LOGP dehydration plant were analyzed in the project's EIS/EIR *(Union Oil Project/Exxon Project Shamrock and Central Santa Maria Basin Area EIS/EIR, Technical Appendix B, March 1985)* and in the District's Engineering Evaluations for ATC 6708, 7027, 7295, and 7549. A detailed summary of analyses performed for ozone (O_3), nitrogen dioxide (NO_2), total suspended particulate matter (TSP), particulate matter smaller than 10 microns (PM_{10}), carbon monoxide (CO), and sulfur dioxide (SO_2) was presented in ATC 6708. Due to subsequent ATC applications and modifications, additional air quality impact analyses were performed. No additional analyses were performed prior to the installation of the gas processing facilities since the emission increases were minimal.

6.1 <u>Compliance with Ambient Air Quality Standards</u>: Production phase air quality impacts associated with the LOGP dehydration plant were examined to determine compliance with ambient standards. Analyses were performed for NO_2, TSP, PM_{10}, CO, and SO_2 in the project's EIR/EIS. ATC 6708 presented the EIR/EIS results with additional 1-hour NO_2 analyses. ATC 7027 and 7549 required further analysis of NO_2 impacts. SO_2 impacts and a revised flaring analysis were also required as part of ATC 7027.

6.1.1 <u>Production Impacts from Onshore Facilities:</u> A summary of the air quality impacts associated with the onshore production phase of the LOGP dehydration plant is presented in Table 6-1. The table presents each pollutant and averaging time analyzed and the document from which the results were obtained. No ambient air quality standard violations were predicted for the onshore operations of the project, except for PM_{10} where the project contributed to annual background levels already exceeding the state standard. Because of the high background levels and lack of available mechanisms to mitigate projected violations, PXP was required to participate in a particulate matter reduction study specified in ATC 6708, Condition 58.

6.1.2 <u>Production Impacts From Platform Irene</u> Table 6-2 contains air quality impact results (obtained from the project EIS/EIR) for normal operation of Platform Irene and the EIS/EIR Area Study platforms. The total column values reflect the more recent onshore background measurements. No violations of standards are predicted during normal operation, except for PM_{10}. Project impacts, when added to existing background levels, would exceed the 24-hour and annual PM_{10} standards. Due to the high project and background levels and lack of available mechanisms to mitigate projected violations, PXP was required to participate in a background particulate reduction study as specified in Condition 58 of ATC 6708.

6.1.3 <u>Flaring Impacts From Onshore Facilities</u> Table 6-3 contains the flaring event impacts expected from the LOGP obtained from the project EIS/EIR, Table 9-4 and ATC 7027. The predicted impacts were based on the assumption that 41.7 Mscf of gas will be flared per event. However, during the ATC 6708 processing, PXP indicated that production would be halted under upset conditions, and that the expected amount of gas to be flared would be approximately 20 Mscf. Thus, no standard violations were anticipated from upset flaring events. Subsequently, ATC 7027 reevaluated the impacts from a flaring event based on the assumption of 42.5 Mscf of 10,000 ppm H_2S gas. A violation of the 1-hour SO_2 standard was predicted. To mitigate this, PXP was required to install a system to reduce the flare gas H_2S concentration to 3,745 ppmv averaged over one hour. Since that time however, District Rule 359 restricts flare gas H_2S concentrations to 796 ppmv.

6.1.4 Flaring Impacts From Platform Irene: Flaring impacts from Platform Irene were analyzed in the project EIS/EIR. The predicted impacts assumed that 400 Mscf of gas is flared per event. This represents flaring of the entire gas production for one hour. However, PXP indicated that production would be halted under upset conditions, and that the expected amount of gas to be flared in one hour would be less than the maximum scenario considered for modeling purposes. The modeling results (Table 6-3) show no violations of standards due to upset conditions at Platform Irene.

6.1.5 Gas Processing Plant: The Planning and Development Department required an addendum to the original Point Pedernales Project Environmental Impact Report for this project. This addendum, which indicated no significant impacts from this project modification, was approved by the Santa Barbara County Planning Commission on July 10, 1996.

6.1.6 Project Contribution To Ozone Formation: The potential for the project to contribute to ozone formation was examined in the project EIS/EIR. A photochemical pollutant analysis was conducted using the Trace model for a wide range of initial pollutant concentrations and trajectory paths. The results predicted a significant increase in ozone levels related to project emissions. Ozone levels in excess of the State standard (10.0 pphm) and Federal one-hour standard (12.0 pphm) were predicted for both facility operation and for upset conditions. No violations of the Federal standard were predicted with the mitigated final EIS/EIR project.

6.2 Increments

An increment analysis was performed for the LOGP on the pollutants NO_2, TSP, PM_{10}, CO, SO_2, and ROC as part of ATC 6708. An examination was first conducted to determine any existing increment consuming sources. It was determined that no existing sources had the potential to impact the same locations affected by the project. The results (Table 6-4) showed that no federal increment levels were exceeded. However, increment fees were required and submitted for NO_2 and ROC. Final payment was made March 16, 2006.

6.3 Vegetation and Soils Analysis

The predominant land use in the project area is agricultural. In the north county area, the major activities include livestock grazing, specialty cut flower cultivation, and dry farming of field crops (oats, hay, and wheat). The flood plains of the Santa Yñez and Santa Maria rivers and San Antonio Creek are productive croplands. Flower seed and vegetable crops are the major agricultural activities. Additional crops include alfalfa, corn, barley, walnuts, and wine grapes. Irrigated pasture land is the predominant activity in the Santa Maria Valley.

Vegetation in the project area includes native and introduced plants. Some of the native plants in the area are listed by the California Native Plant Society as rare and endangered, of limited geographic distribution, or as species for which more information is needed. Many of those same species are protected by federal or state legislation. Air pollutants, specifically ozone, sulfur dioxide, nitrogen dioxide, and combinations of the three, can injure vegetation at sufficient duration and concentrations. Exposure to ozone at various concentrations is presented in the Vegetation Impacts Table (Table 6-3A).

During the production phase, combined total emissions from the LOGP oil dehydration plant and the OPS are predicted to be 4.6 pounds per day of sulfur dioxide and 153 pounds per day of nitrogen oxides. Given the large project area over which the pollutants are dispersed, annual deposition of sulfates and nitrates onto the surrounding soils will be minimal. In addition, the alkalinity of the soils will ameliorate the effects of the minor decrease in pH expected from nitrate or sulfate deposition. No long term buildup of the deposited material is expected because of utilization of nitrates and sulfates by vegetation. Therefore, no impact on soils was predicted from the project emissions.

6.4 Potential to Impact Visibility and Opacity

A Level-1 visibility screening analysis was performed for the construction and operation phases of the project as part of ATC 6708. The methodology described in EPA's *Workbook for Estimating Visibility Impairment*, was used to calculate three contrast parameters -- plume contrast against sky (C1), plume contrast against terrain (C2) and change in sky/terrain contrast (C3). The San Rafael Wilderness Area, located approximately 45 km from the project site, is the closest Class I PSD area for which visibility analysis is required. The background visual range was assumed to be 25 km.

The analysis showed the values of the three contrast parameters are well below the critical value of 0.10. It also indicated that operational activities will have no significant effect on visibility in the San Rafael Wilderness Area. Furthermore, because of the substantial distance (45 km) between Platform Irene and Class I areas, no impact to Class I area visibility from normal operation of the platform is predicted.

6.5 Health Risk Assessment

The LOGP, formerly the Lompoc HS&P facility, was subject to the Air Toxics "Hot Spots" Program (AB 2588) since it is a source of air toxic emissions. As such, a health risk assessment (HRA) was performed for the HS&P facility by the District on November 9, 1995 under the requirements of the AB 2588 program. The HRA is based on 1992 emissions from the HS&P facility.

Based on the 1992 air toxics inventory, a cancer risk of about 0.1 per million, occurring on the sites property boundary, was estimated by the District for the HS&P facility. This cancer risk is primarily due to emissions of benzene emitted from various sources at the site. In addition, chronic and acute noncarcinogenic risks, or hazard indices, were estimated to be 0.008 and 0.2, respectively, and are mainly due to acrolein emissions. Less than one pound each of benzene and acrolein, the primary risk drivers, was released from emission sources at the HS&P facility during 1992. The risk projections for HS&P

are significantly less than the District's AB 2588 significance thresholds of 10 per million for cancer and 1.0 hazard index for noncancer risks.

6.6 Public Nuisance

Oil and gas processing facilities handling high sulfur content petroleum within Santa Barbara County have been the subject of numerous public complaints regarding odors and other related problems. It was important, therefore, to evaluate the potential for public nuisance from the LOGP facilities. Nuisance potential was initially analyzed in ATC 6708 and revised for ATC 7027 and 7295. This section summarizes much of the work performed for ATC 6708 with fugitive emissions updated to current levels.

Emissions from the operational phase of the project were reviewed to determine compliance with District Rules 205.A and 303, relating to the prevention of public nuisance as required by Section 41700 of the California Health and Safety Code. There is a potential for public nuisance due to emissions of hydrocarbons and reduced sulfur compounds which could occur during operation of the project related facilities. The two major odor sources are hydrogen sulfide (H_2S) from fugitive emissions and sulfur dioxide in the combustion gases.

Based on predicted H_2S impacts resulting from Platform Irene activities (EIS/EIR Technical Appendix), no exceedances of the human detection threshold were predicted at the closest shoreline point. The EIS/EIR also forecasted that processing operations at the Lompoc facility would not cause exceedances of the human odor threshold (0.65 $\mu g/m^3$). This was based on extrapolations from the maximum modeled ROC level of 256 $\mu g/m^3$ and an onshore fugitive H_2S content of 24 ppm. Condition E-8 of the County Development Plan limits the gas used as fuel at the LOGP to a sulfur content of 0.25 gr/100 scf (pipeline quality).

Subsequently, fugitive H_2S impacts were analyzed in ATC 7027 and 7295 to reflect an increased H_2S concentration of 10,000 ppmv and increased fugitive component counts. Table 6-5 presents the current H_2S impacts based on modeling from ATC 7027 scaled to reflect the current fugitive emissions as stated in a letter from the District to PXP dated February 15, 1991 regarding operational increment fees. The predicted H_2S concentrations are below both the state 1-hour standard and the District Rule 310 limitation but well above the H_2S odor threshold. PXP was required to install an ambient odor monitor to detect the odorous impacts of the facility on Highway 1 and the Mission Hills residential area. Several exceedances of the Rule 310 H_2S limit were recorded between 1995 and 1998 by this monitor, although to date, no public nuisance has been documented.

Table 6.1 – SUMMARY OF PRODUCTION PHASE MODELED IMPACTS FROM THE LOMPOC LOGP

POLLUTANT	AVERAGING TIME	PROJECT CONTRIBUTION (ug/m^3)	BACKGROUND (ug/m^3)	TOTAL (ug/m^3)	STANDARD (ug/m^3)
NO_2	1-Hour[c] Annual[a]	354.2 0.2	22.4 17.0	378.6 17.2	470 100
TSP	24-Hour[a] Annual[a]	2 < 0.1	165 64	167 64	260 75
PM_{10}	24-Hour[a] Annual[a]	2(4)[d] < 0.1	44 35	46(48)[d] 35	50 30
CO	1-Hour[a] 8-Hour[a]	114 63	14,880 5,494	14,994 5,557	23,000 10,000
SO_2	1-Hour[b] 3-Hour[b] 24-Hour[b] Annual[a]	22 12 1.6 0	139 63 18 5	161 75 19.6 5	655 1300 131 80

[a] Impacts for this averaging time and associated background values were obtained from ATC 6708, Project EIS/EIR.

[b] Impacts for this averaging time and associated background values were obtained from ATC 7027.

[c] Impacts for this averaging time and associated background values were obtained from ATC 7549.

[d] The 24-hour impacts in parentheses were extrapolated from the EIS/EIR results using updated emissions data in ATC 6708.

Table 6.2 – Modeled Impacts from Platform Irene

POLLUTANT	AVERAGING TIME	PROJECT CONTRIBUTION[a] (ug/m^3)	BACKGROUND[b] (ug/m^3)	TOTAL (ug/m^3)	STANDARD (ug/m^3)
NO_2	1-Hour Annual	226 0.7	22.4 17.0	248 18	470 100
TSP	24-Hour Annual	11 < 0.1	165 64	176 64	260 75
PM_{10}	24-Hour Annual	11 < 0.1	44 35	55 35	50 30
CO	1-Hour 8-Hour	71 39	14,880 5,494	4,951 5,533	23,000 10,000
SO_2	1-Hour 3-Hour 24-Hour Annual	21 16 9 < 0.1	139 63 18 5	160 79 27 5	655 1300 131 80

[a] Project contribution shown for drilling & Production obtained from the project EIS/EIR.
[b] Background values were updated for NO_2 and SO_2 in ATC 7027.

Table 6.3 - Total Flaring Impacts (Project Total)

IMPACT	1-HOUR NO_2 IMPACT (ug/m^3)	1-HOUR SO_2 IMPACT (ug/m^3)	3-HOUR SO_2 IMPACT (ug/m^3)	24-HOUR SO_2 IMPACT (ug/m^3)
Platform Irene	314[b]	132[b]	91[b]	39[b]
Lompoc LOGP	314[c]	1517[c]	80[b]	33[b]
Standards	470 (State)	655 (State)	1,300 (Federal Secondary)	131 (State) 365 (Federal Primary)

[a] These totals represent the project impact including background.
[b] These impacts were obtained from ATC 6708.
[c] These impacts were obtained from ATC 7027.

Table 6.3.a - Vegetation Impacts

POLLUTANT	CONCENTRATION	DURATION	EXAMPLES OF DAMAGE	SPECIES
O_3	0.02 ppm	8 hr	foliar injury	sensitive plants
	0.1 - 0.25 ppm	2 hr	foliar injury	sensitive plants
	0.1 - 0.25 ppm	1 hr	foliar injury	agricultural crops
SO_2	0.5 - 1.0 ppm	1 hr	visible injury	sensitive plants
	0.3 - 0.6 ppm	5 hr	visible injury	sensitive plants
	0.5 ppm	30 hr	Decreased shoot growth, necrosis	trees (ginkgo, pin oak, maple)
	0.63 ppm	3 hr	growth decrease	rye, oats
	1.0 - 2.0 ppm	1 hr	visible injury	maples, locusts, sweet gum, many crops
NO_2	0.58 ppm	1 hr	NO_2 sensitivity	mature white pines
	0.60 ppm	2 hr	Inhibition of photosynthesis	alfalfa and oat seedlings
	0.16 ppm	6 hr/day - 4 days	leaf necrosis	mature alfalfa
	1.0 ppm	4 hr	80% leaf necrosis	mature pinto beans

Table 6.4 - Maximum Project increment Consumed

POLLUTANT	AVERAGING TIME	INCREMENT CONSUMPTION (ug/m^3)	ALLOWABLE INCREMENT (ug/m^3)
NO_2	1-Hour[c] Annual[c]	309 0.7	100-470[b] 25-100[b]
TSP	24-Hour[c] Annual[c]	11 < 0.1	37 19
PM_{10}	24-Hour[c] Annual[c]	11 < 0.1	12-50[b]
CO	1-Hour[c] 8-Hour[c]	114 63	10,000 2,500
SO_2	3-Hour[c] 24-Hour[c] Annual[c]	16 9 < 0.1	512 91 20
ROC	3-Hour[d]	559	40-160[b]

[a] Operation of emergency equipment was not included in the air quality increment analysis for NO_2 and ROC increment consumption. However, operation of the firewater pump was included in the air quality impact analysis discussed in Section 6.1.

[b] Increment fee is imposed for impact above the lower end of the increment range.

[c] Increment consumption for this averaging time was obtained from ATC 6708.

[d] Increment consumption for this averaging time was obtained from the 2/15/91 District letter to PXP re: Revised Operational Increment Fee.

Table 6.5 - Maximum Project increment Consumed

POLLUTANT	AVERAGING TIME	PROJECT CONTRIBUTION (ug/m^3)	TOTAL (ug/m^3)	STANDARD (ug/m^3)	ODOR[e] THRESHOLD (ug/m^3)
H_2S	1-Hour	22[a]	22	42[b]	0.65
H_2S	3-Min	28[a,c]	28	84[d]	0.65

[a] These Impacts were scaled up from modeling results of ATC 7027.

[b] Corresponds to the California standard and District Rule 310 limitation.

[c] Three-minute impacts were derived from the one-hour impacts using the power-law methodology (turner, 1970).

[d] Corresponds to the District Rule 310 limitation.

[e] The human odor detection threshold of 0.65 ìg/m^3 for H_2S is assumed to be nearly instantaneous.

7.0 CAP Consistency, Offset Requirements and ERCs

7.1 General

Santa Barbara County is in attainment of the federal ozone standard but is in nonattainment of the state eight-hour ozone ambient air quality standard. In addition, the County is in nonattainment of the state PM_{10} ambient air quality standards. The County is either in attainment or unclassified with respect to all other ambient air quality standards. Therefore, emissions from all emission units at the stationary source and its constituent facilities must be consistent with the provisions of the USEPA and State approved Clean Air Plans (CAP) and must not interfere with maintenance of the federal ambient air quality standards and progress towards attainment of the state ambient air quality standards. Under District regulations, any modifications at this stationary source that result in an emissions increase of any nonattainment pollutant exceeding 25 lbs/day must apply BACT (NAR). Additional increases may trigger offsets at the source or elsewhere so that there is a net air quality benefit for Santa Barbara County. These offset threshold levels are 55 lbs/day for all non-attainment pollutants except PM_{10} for which the level is 80 lbs/day.

7.2 Clean Air Plan

The 2007 Clean Air Plan, adopted by the District Board on August 16, 2007, addressed both federal and state requirements, serving as the maintenance plan for the federal eight-hour ozone standard and as the state triennial update required by the Health and Safety Code to demonstrate how the District will expedite attainment of the state eight-hour ozone standard. The plan was developed for Santa Barbara County as required by both the 1998 California Clean Air Act and the 1990 Federal Clean Air Act Amendments.

On January 20, 2011 the District Board adopted the 2010 Clean Air Plan. The 2010 Plan provides a three-year update to the 2007 Clean Air Plan. As Santa Barbara County has yet to attain the state eight-hour ozone standard, the 2010 Clean Air Plan demonstrates how the District plans to attain that standard. The 2010 Clean Air Plan therefore satisfies all state triennial planning requirements

.7.3 Offset Requirements

District rules and regulations require that emissions from the entire project, when considered in conjunction with emission reductions for existing sources, result in a Net Air Quality Benefit. In addition, project emissions must be consistent with the AQAP and not interfere with reasonable further progress towards attainment and maintenance of ozone standards.

The E-6, E-9, and E-10 Conditions of the County Development Plan required emission reductions to compensate for all project emissions increases (Entire Source Emissions - ESE) from this project occurring within the District's jurisdiction. Further, they required mitigation of all onshore impacts caused by $NO_{x,}$ ROC and NAROC (non-alkane ROC) emissions from project sources located outside the District's jurisdiction. Total project emissions increases are mitigated by reducing existing sources of emissions on a 1:1

basis. Mitigation of the project emissions was required to maintain compliance with the 1986 County AQAP.

Originally, the project did not trigger the requirement to offset the facility emissions under District rules and regulations. However, several modifications to the facility have occurred since PTO 6708 was issued. These modifications resulted in emissions of reactive organic compounds (ROC) that exceeded the District's NSR offset trigger for nonattainment pollutants. All ROC ERCs therefore, were subject to applicable distance discounting ratios to ensure a net air quality benefit and reasonable further progress towards attainment of the ozone standard.

Furthermore, the Project is obligated via an Emission Reduction Agreement (ERA, dated August 11, 1986) to offset the Entire Source Emissions (ESE) for all project facilities. Per the ERA, emissions of ROC, NO_x, and NAROC have been offset at a minimum ratio of one-to-one.

Upon satisfaction of the requirements specified in the County Development Plan and the 1986 AQAP update, the District determined that the project would result in a Net Air Quality Benefit and would be consistent with the AQAP. The requirement to provide these ERCs is documented in the Emission Reduction Agreement (ERA, dated August 11, 1986) requiring PXP to offset the Entire Source Emissions (ESE) for all project facilities. Under the ERA, emissions of ROC, NO_x, and NAROC are to be offset at a minimum ratio of one-to-one. See the project file for a copy of this agreement.

7.3.1 Original Emission Reduction Credits: Project ERCs were originally provided by two sources. One source was the electrification of internal combustion engines (ICEs) and the installation of vapor recovery units. These ERCs were categorized as "constant" since they were quantified at the time of implementation and the amount of ERCs generated remain constant. They provided all of the required ROC ERCs but only a portion of the required NO_x ERCs. The total amount of "constant" ERCs provided by this equipment was 13.09 tpq NO_x and 46.03 tpq ROC (Table 7.a). At the time the swap agreement was executed, the Point Pedernales Project required a total of 19.146 tpq NO_x and 18.86 tpq ROC offsets.[6]

The remainder of the NO_x ERCs were provided by eighteen ICEs equipped with Pre-Stratified Charge (PSC) NO_x reduction control systems. These engines were source tested on an annual basis to confirm the amount of ERCs generated. Although only 6.05 tpq NO_x ERCs (19.146 tpq -13.096 tpq) were needed from these engines, they typically provide approximately 15.0-20.0 tpq NO_x ERCs. Since the amount of ERCs varied from year to year, this second source was categorized as "varying" ERCs (Table 7.a).

7.3.2 Battles Gas Plant ERC "Swap": Due to the expense of source testing and maintaining the PSC engines, the permittee sought to replace the second source of ERCs with another. In July 1996, the shutdown of the Battles Gas Plant (BGP) created a significant volume of

[6] PXP and Unocal executed an agreement for this "swap" of ERCs on July 5, 1995 based on the original amount of NO_x ERCs needed by the Project. PTO 6708-05, however, revised the Project NO_x liability and, therefore, the 19.146 tpq figure is not identical to the Project NO_x liability figure listed in Table 10.10-3 of this permit.

ERCs. Permittee entered into an agreement with Unocal (who owned the BGP ERCs at that time) to purchase sufficient NOx ERCs to replace ("swap") the existing NO_x ERCs generated by the PSC engines with BGP shutdown ERCs. As stated above, since only 6.05 tpq of NO_x ERCs are required, the agreement involved only the purchase of 6.05 tpq of NO_x ERCs. Table 7.b lists these BGP ERCs and represents the revised and most current amount and sources of ERCs provided to the Point Pedernales Project.

An Amendment to the original 1986 Emissions Reduction Agreement documenting this "swap" of NO_x ERCs was approved by the Santa Barbara Air Pollution Control Board on November 18, 1996. See the project file for a copy of this agreement.

TABLE 7.a – ORIGINAL PROJECT EMISSION REDUCTION CREDITS

Location	Owner After Sale	PTO Number	Constant or Varying	NO_x (tpq)	ROC[1] (tpq)	NAROC (tpq)
Cal Coast 1	PXP	8126	Varying	0.71	-0.14	-0.02
Cal Coast 2	PXP	8126	Varying	1.32	0.01	0.00
Cal Coast 3	PXP	8126	Varying	1.51	0.04	0.01
Cal Coast 5	PXP	8126	Varying	0.38	0.06	0.01
Cal Coast 6	PXP	8126	Varying	1.55	0.02	0.00
Cal Coast 8	PXP	8126	Varying	0.46	0.05	0.01
CC. Tran. P.	PXP	8126	Constant	0.26	0.00	0.00
Newlove 67	PXP	8126	Varying	0.66	0.05	0.01
Pinal 2	PXP	8126	Varying	0.09	-0.05	-0.01
J. Hopkins 1	PXP	8148	Varying	1.24	-0.02	0.00
J. Hopkins 3	PXP	8148	Varying	2.88	0.00	0.00
Cat Canyon 3	Saba	8150	Varying	0.30	-0.39	-0.06
Cat Canyon 5	Saba	8150	Varying	1.03	0.01	0.00
Cat Canyon 7	Saba	8150	Varying	0.41	0.04	0.01
Cat Canyon 11	Saba	8150	Varying	0.81	0.13	0.02
Cat Canyon 12	Saba	8150	Varying	2.15	-0.01	0.00
Cat Canyon 13	Saba	8150	Varying	0.20	-0.17	-0.20
Cat Canyon 14	Saba	8150	Varying	0.24	-0.13	-0.02
Silva 4	PXP	9139	Constant	0.186	0.00	0.00
Lompoc Comp.	PXP	7126-03	Constant	8.39	4.92	0.70
Lompoc 20	PXP	7126-03	Constant	3.03	0.11	0.02
Lompoc 53	PXP	7126-03	Constant	1.23	0.14	0.02
Lompoc Reboiler	PXP	7126-03	Constant	0.00	2.70	0.11
Orcutt Hill Reboiler	PXP	8174	Constant	0.00	7.30	0.31
Newlove Tank Bat.	PXP	8240	Constant	0.00	30.86	1.33
TOTAL VARYING				15.93	-0.50	-0.06
TOTAL CONSTANT				13.096	46.03	2.49
TOTAL				29.026	45.53	2.43
District CREDIT[1]				29.026	37.94	2.43

[1] ROC credit has been adjusted by District distance factors applicable at the time of permit issuance.

TABLE 7.b – CURRENT PROJECT EMISSION REDUCTION CREDITS

Location	Source	Control Measure	NOx (tpq)	ROC (tpq)	NAROC (tpq)
La Purisima Lease	Lompoc Compressor UP 55010	Electrification	8.39	4.92	0.70
La Purisima Lease	Lompoc 20 UP 11853	Electrification	3.03	0.11	0.02
La Purisima Lease	Lompoc 53 UP 11051	Electrification	1.23	0.14	0.02
La Purisima Lease	Lompoc Glycol Reboiler	Vapor Recovery	0.00	2.70	0.11
Newlove Lease	Newlove Tank Battery	Vapor Recovery	0.00	30.86	1.33
Orcutt Compressor Plant	Orcutt Hill Reboiler	Vapor Recovery	0.00	7.30	0.31
Silva Lease	ICE	Electrification	0.186	0.00	0.00
Cal Coast Lease	ICE	Electrification	0.26	0.00	0.00
Battles Gas Plant Shutdown	Marine Boilers	Shutdown	4.185	0.00	0.00
Battles Gas Plant Shutdown	Cooper #5	Shutdown	0.808	0.00	0.00
Battles Gas Plant Shutdown	Clark #18	Shutdown	0.741	0.00	0.00
Battles Gas Plant Shutdown	Clark #13	Shutdown	0.002	0.00	0.00
Battles Gas Plant Shutdown	Clark #14	Shutdown	0.049	0.00	0.00
Battles Gas Plant Shutdown	Clark #15	Shutdown	0.002	0.00	0.00
Battles Gas Plant Shutdown	Clark #19	Shutdown	0.052	0.00	0.00
Battles Gas Plant Shutdown	Clark #20	Shutdown	0.006	0.00	0.00
Battles Gas Plant Shutdown	Clark #21	Shutdown	0.024	0.00	0.00
Battles Gas Plant Shutdown	Clark #24	Shutdown	0.012	0.00	0.00
Battles Gas Plant Shutdown	Clark #25	Shutdown	0.007	0.00	0.00
Battles Gas Plant Shutdown	Clark #26	Shutdown	0.006	0.00	0.00
Orcutt Hill Field	Fox Injection	Shutdown	0.154	0.00	0.00
Sub Total (non-Battles)			13.096	46.03	2.49
Sub Total (Battles)			6.05	-	
TOTAL			19.14	46.03	2.49
PROJECT LIABILITY			17.38	9.89	0.79

Notes:

1. The Non-Battles ERC values are taken from the August 11, 1986 Emissions Reduction Agreement (Table 3) executed between Santa Barbara County, the District and PXP.

7.3.3 NEI Offsets: Under District NSR rules, PXP is required to provide offsets for the project's operational net emission increase for ROC only. In order to demonstrate a net air quality benefit, ROC offsets are adjusted to account for the distance between the project source and the offset source, i.e., 1:1.2 distance ratio as listed in Table 7.1-2.

Emission offsets for the operations phase are required to be in place, as specified in Table 7.1-2 and shall remain in place for the duration of the project as required by District rules and the conditions of this permit.

7.3.4 ESE Offsets: In order to make the finding of net air quality benefit and to assure reasonable further progress toward attainment of the federal ozone standard and to comply with FDP Condition XII-3.b, PXP is required to offset the Point Pedernales Project's Entire Source Emissions (ESE) for $NO_{x,}$ ROC and NAROC by reducing emissions at existing sources by an equal amount. PXP is required by this permit to offset the NO_x and ROC entire source emissions from the Point Pedernales Project at a ratio of 1 to 1. PXP has offset the maximum quarterly NO_x, ROC, and NAROC net emission increase associated with the operation of the Point Pedernales (as documented in Table 5.2) of this permit.

This requirement is necessary for the District to make the determination that the entire project provides a net air quality benefit to Santa Barbara County, does not impede reasonable further progress toward attainment of the ozone standards and is consistent with the District-approved AQAP. Tables 7.1-1, 7.1-2 and 7.1-3 include the offsets PXP is using to cover this ESE liability. Due to the nature of the ROC offsets, PXP has ROC offsets in excess of its ESE requirements however, there are no excess ESE or NEI ERCs available for future use.

7.3.5 Gas Processing Plant ERCs: With the exception of the ERCs described below, NO_x and ROC emissions from the gas processing plant are offset by ERCs from the shutdown of the Battles Gas Plant. These are listed in Tables 7.1-1 and 7.1-2.

7.3.6 Subsequent to installation of the gas plant, additional ERCs (0.01 tpq NO_x and 0.0008 tpq ROC) were required for a sales gas odorant station and increased flare NEI emissions at the LOGP permitted under Authority to Construct No. 9522-03. Authority to Construct/Permit to Operate (ATC/PTO 9971) was issued September 21, 1998 to replace two engines in the LOF with electric motors (Waukesha 140 - s/n: 11925 and Leroi 226 s/n: 10407). This action created 0.04 tons/quarter of NO_x ERCs, 0.006 tons/quarter of ROC ERCs and 0.08 tons/quarter of CO ERCs.

DOI No. 0005 and the associated ERC certificate No. 008-1003 were issued on September 21, 1998 and October 14, 1998, respectively, for the ERCs required to offset the emissions from the odorant station and flare. ERC Certificate 0015-1003 was issued for the remaining ERCs (0.03 tpq NOx, 0.005 tpq ROC and 0.08 tpq CO), subsequently renewed as ERC Certificate 109 and again as ERC #176 on November 14, 2008.

7.3.7 Lompoc Oil Field ERCs. Prior to the installation of the gas processing plant, the Lompoc Oil Field was a separate stationary source. Due to installation of the gas plant however, operations of the LOF and LOGP became interrelated to the extent that, as determined by the District, the LOF and the Point Pedernales Project constituted a single stationary source. As a result, the NEI (FNEI90) emissions associated with the LOF are required to be offset. These additional emissions are also offset with ERCs from the shutdown of the BGP. These ERCs are included in Tables 7.1-1 and 7.1-2.

7.3.8 Non-Stationary Source ERCs. The Santa Barbara County Planning and Development permit for this project required that emissions from the associated Santa Maria Refinery and Santa Maria Pump Station be offset. These are documented in PTO 9522 however, since these project components are not part of the PXP Lompoc/Point Pedernales Stationary Source, they have been omitted from the offset tables. See PTO 9522.

Table 7.1-1

PXP POINT PEDERNALES - Part 70/PTO 6708
PROJECT NO_x OPERATION EMISSIONS AND OFFSETS

OXIDES OF NITROGEN (NOx)

ESE EMISSIONS FROM PROJECT	TPQ	TPY
Entire Source Emissions (ESE) Liability[1,2]	18.71	74.86

EMISSION REDUCTION SOURCES[4]	Emission Reductions TPQ	TPY
La Purisima Lease	12.650	50.600
La Purisima Lease (ICE electrification)[5]	0.010	0.040
Battles Gas Plant - Marine boilers	4.185	16.740
Battles Gas Plant - Cooper #5	0.808	3.232
Battles Gas Plant - Clark #18	0.741	2.964
Battles Gas Plant - ICE #13	0.002	0.008
Battles Gas Plant - ICE #14	0.049	0.196
Battles Gas Plant - ICE #15	0.002	0.008
Battles Gas Plant - ICE #19	0.052	0.208
Battles Gas Plant - ICE #20	0.006	0.024
Battles Gas Plant - ICE #21	0.024	0.096
Battles Gas Plant - ICE #24	0.012	0.048
Battles Gas Plant - ICE #25	0.007	0.028
Battles Gas Plant - ICE #26	0.006	0.024
Orcutt Hill Field - Fox Injection	0.154	0.616
Cal Coast Transfer Pump	0.260	1.040
Silva Lease	0.186	0.744
Battles Gas Plant Shutdown Credit[6]	1.480	5.900
Total	20.634	82.516

Notes:

1. These are total ESE values as listed in Table 5.4 required to be offset at 1:1.
2. These include NEI emissions from the Lompoc Oil Field required to be offset. See section 5.8.
3. Project ESE emissions liability includes emissions from the OPS, however, this facility is now owned by Tosco. Offsets are provided by the BGP shut
4. The La Purisima, Orcutt hill Field, Cal Coast and Silva Lease ERC sources correspond to Table 3 of the August 11, 1986 Emissions Reduction Agree
as modified by the 11/18/96 Amendment to that agreement. This table has been reproduced as Table 7.b of this permit.
5. Two ICEs were electrified to generate NOx ERCs for the increased NOx emissions from additional unplanned flaring volumes at the gas plant.
See section 7.3.4 for details.
6. The new emissions from the installation of the gas plant and the NEI from the Lompoc Oil Field were offset by BGP shutdown credits.
PTO 9522 provides full details of this transaction. Note that the gas plant emissions are included in the above ESE liability value. The LOF emissions
value is taken from section 5.8.

Table 7.1-2

PXP POINT PEDERNALES - Part 70/PTO 6708

PROJECT OPERATION ROC EMISSIONS AND OFFSETS

REACTIVE ORGANIC COMPOUNDS (ROC)

PROJECT EMISSIONS	TPQ	TPY
Net Emissions Increase (NEI) Liability[1]	10.92	43.63
Entire Source Emissions (ESE) Liability[2,3]	18.91	75.02

	Emission Reductions		Distance	Offset Credit	
EMISSION REDUCTION SOURCES[4]	TPQ	TPY	Factor[5]	TPQ	TPY
La Purisima Lease	7.87	31.48	1.2	6.56	26.23
Newlove Tank Battery	30.86	123.44	1.2	25.72	102.87
Orcutt Compressor Plant - Reboiler	7.30	29.20	1.2	6.08	24.33
BGP Shutdown Credit[3]	2.63	10.5	1.2	3.15	12.6
TOTAL ROC	48.66	194.62		41.51	166.03

Notes:

1. These are NEI 79 figures and are requried to be offsets at a ratio of 2:1. They taken from Table 5.2. The emissions liability associated with the LOGP to OPS pipeline has been subtacted out since Tosco owns this pipeline is responsible for providing the offsets for it.
2. These are ESE figures and are taken from Table 5.4. The emissions associated with the LOGP to OPS pipeline have been subtracted out since Tosco owns this pipeline and is responsible for providing offsets for it.
3. The new emissions from the installation of the gas plant and the NEI from the Lompoc Oil Field were offset by BGP shutdown credits. PTO 9522 provides full details of this transaction. Note that the gas plant emissions are included in the above ESE liability value. The LOF emissions value is included in this total.
4. The La Purisima, Newlove Tank Battery and Orcutt Compressor Plant ERC sources correspond to Table 3 of the amended August 11, 1986 Emissions Reduction Agreement. This table has been reproduced as Table 7.b of this permit.
5. Project ROC emissions triggered APCD offset requirements hence, the 1.2:1 distance factor. Project NOx emissions did not trigger APCD offset requirements and are required by the lead agency (Planning and Development) only.

Table 7.1-3

PXP POINT PEDERNALES - Part 70/PTO 6708

PROJECT OPERATION ROC EMISSIONS AND OFFSETS

NON-ALKANE REACTIVE ORGANIC COMPOUNDS (NAROC)[1]

NEI EMISSIONS FROM PROJECT

	TPQ	TPY
Entire Source Emissions (ESE) Liability[2]	0.07	0.22

EMISSION REDUCTION SOURCES[3]	Emission Reductions TPQ	TPY
La Purisima Lease	0.85	3.4
Newlove Tank Battery	1.33	5.32
Orcutt Compressor Plant - Reboiler	0.31	1.24
TOTAL	2.49	9.96

Notes:

1. ERCs are valid only against the NEI/ESE emission liability for the equipment subject to this permit. Use of ERCs beyond those required to satisfy the current NEI/ESE are subject to the rules in effect at the time a project ATC application is deemed complete.
2. These are project emissions taken from Table 5.4 of this permit.
3. The La Purisima, Newlove Tank Battery and Orcutt Compressor Plant ERC sources correspond to Table 3 of the amended August 11, 1986 Emissi Reduction Agreement. This table has been reproduced as Table 7.b of this permit.

8.0 Lead Agency Permit Consistency

8.1 Prior Lead Agency Action

A Final Development Plan (FDP) for the *Union Oil Project/Exxon Project Shamrock and Central Santa Maria Basin Area Study EIS/EIR (issued 6/24/85)* was approved by the Santa Barbara County Board of Supervisors with the issuance of the *Union Final Staff Report (August 5, 1985)*. The approved plan contains "E-Conditions" which relate to air quality aspects of the Point Pedernales Project. The FDP conditions were revised via the county B-2 effectiveness review, and it is the revised conditions which are being addressed here. The following is a summary of these conditions and their relationship to the District's reevaluation of PTO 6708:

1. <u>FDP Condition E-1 (Statement of Scope)</u>: Indicates that the terms of the Lead Agency Permit do not authorize the violation of any local, state, or federal air quality rules and regulations.

2. <u>FDP Condition E-2 (Authority to Construct)</u>: Requires that prior to initiation of construction, including grading, of any facilities approved pursuant to this Development Plan, PXP shall obtain Authority to Construct from the County Air Pollution Control District. This was fulfilled by the original permit as well as all subsequent permits.

3. <u>FDP Condition E-3 (Curtailment Plan)</u>: Requirement for preparation and implementation for Curtailment Plans for the protection of ambient air quality standards:

4. The required curtailment plan was approved by the District in April, 1986. The District no longer requires operational phase curtailment plans. FDP Condition E-3 was modified as agreed upon by the Planning Commission on January 8, 1992, to reflect that curtailment plans apply to construction activities only. Instead, Emergency Episode Plans, required pursuant to District Rule 603 must be in effect for the operational phase of the project. *PXP's Emergency Episode Plan* was updated and approved in April, 1997.

5. <u>FDP Condition E-4 (Ambient Air Quality Stations):</u> Requires ambient air quality monitoring stations to examine onshore effects of construction and operation emissions. Section 5, *Project Emission Sources* and *Control Technology*, and Section 6, *Air Quality Impact Analysis*, and Condition 9.C.14 of this permit, *Ambient Air Quality Monitoring Program*, all identify the requirement for PXP to install and operate ambient air quality monitoring stations.

5\. <u>FDP Condition E-5</u> (Implementation of Air Pollution Control Procedures): Requires control measures relating to Class I and Class II Impact Areas according to the California Environmental Quality Act (CEQA) guidelines. Section 7 and permit conditions 9.C.9 and 9.C.10 of this permit specifies the emission mitigation measures that PXP shall maintain throughout the life of the project. PXP is in compliance with this condition.

6. FDP Condition E-6 (Mitigation of Project Emissions): Requires the mitigation of any project component that contributes to ozone standard violations. PXP implemented the ozone mitigation requirement for the project by entering into the Emission Reduction Agreement with the District and the County on August 11, 1986. This mitigation included offsetting ROC and NO_x at a minimum ratio of one-to-one for project components (including OCS sources and the Orcutt Pump Station).

7. FDP Condition E-7 (Submittal of Helicopter and Support Vessels Information to Planning and Development): This information was required prior to issuance to the Final Development Plan. PXP complied with this condition.

8. FDP Condition E-8 (Future Consolidation): Requires that no portion of the project, alone or in combination with any other existing and proposed facilities, would preclude future consolidation of oil and gas processing facilities at the Lompoc site. The FDP analysis assumed that gas produced at Platform Irene and processed at the LOGP would contain a maximum of 24 ppmv H_2S. The District confirmed that consolidation would not be precluded at this processing level if PXP used pipeline-quality gas (4 ppmv) in all fuel burning equipment at the LOGP. PXP agreed to this requirement, which was incorporated as Condition 18 (Heater Treater Operational and Emission Limits) of ATC 6708.

   Shortly after start-up of the facility, it became apparent that the H_2S content of produced gas was higher than the assumed value of 24 ppmv. After discussions with the District, PXP applied for a modification to ATC 6708 that would allow processing of gas with an H_2S content of up to 10,000 ppmv. District modeling analyses, performed as part of the ATC permit process, indicated that upset flaring of 10,000 ppmv gas would jeopardize the state one-hour SO_2 standard. This impact has been mitigated via District Rule 359 which limits the H_2S content of flare gas to 796 ppmv. PXP uses a flare scrubber to comply.

9. FDP Condition E-9 (Reasonable Further Progress Emissions Compliance and Effectiveness): Ensures that emissions from the project, including offshore facilities and mobile sources associated with the platforms, will not interfere with attainment of the ozone standard. This condition is essentially a requirement to mitigate all emissions associated with the project. As indicated above in section 7.0, PXP has complied with this condition.

10. FDP Condition E-10 (Emissions Offsets and Mitigation Strategies): Requires identification of the offset mitigation measures implemented. Section 7.0 provides a full discussion and details of these measures.

11. FDP Condition E-11 (Construction Air Quality Impacts Mitigation Plan): This condition is applicable to periods of construction only (e.g., as per ATC 6708). PXP is required to comply with the requirements of Condition E-11 only upon commencement of further construction activities. To date, PXP has complied with this condition.

12. FDP Condition E-12 (Modified LOGP - Fugitive Inspection and Maintenance Program): Requires PXP to implement a District-approved Fugitive I&M Program to the modified LOGP consistent with District rules and regulations. The "modified LOGP" is the LOGP modified to include the gas processing facilities. The facility is now called the Lompoc Oil and Gas Plant. PXP is in compliance with this requirement.

13. FDP Condition E-12 (Emissions Offsets for Modified LOGP): Specifies that the existing emission offset requirements, listed in Permit to Operate (PTO) 6708, Condition C.9 and C.10, be extended to include the modified LOGP with the exception of the NAROC requirements.

8.2 Lead Agency Action for PTO 6708 Renewal

Pursuant to CEQA Guidelines Section 15300.4 and Appendix A (*District List of Exempt Projects*) of the District's *Environmental Review Guidelines* document (10/95), the issuance of this Permit to Operate is exempt from CEQA.

9.0 Permit Conditions

This section lists the applicable permit conditions for the LOGP. Section A lists the standard administrative conditions. Section B lists 'generic' permit conditions, including emission standards, for all equipment in this permit. Section C lists conditions affecting specific equipment. Section D lists non-federally enforceable (i.e., District only) permit conditions. Conditions listed in Sections A, B and C are enforceable by the USEPA, the District, the State of California and the public. Conditions listed in Section D are enforceable only by the District and the State of California. Where any reference contained in Sections 9.A, 9.B or 9.C refers to any other part of this permit, that part of the permit referred to is federally-enforceable. In case of a discrepancy between the wording of a condition and the applicable federal or District rule(s), the wording of the rule shall control.

For the purposes of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any standard in this permit, nothing in the permit shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test had been performed.

9.A Standard Administrative Conditions

The following federally-enforceable administrative permit conditions apply to the LOGP:

A.1 **Condition Acceptance.** Acceptance of this operating permit by PXP shall be considered as acceptance of all terms, conditions, and limits of this permit. [*Re: ATC 6708*]

A.2 **Defense of Permit.** PXP agrees, as a condition of the issuance and use of this PTO, to defend at its sole expense any action brought against the District because of issuance of this permit. PXP shall reimburse the District for any and all costs including, but not limited to, court costs and attorney's fees which the District may be required by a court to pay as a result of such action. The District may, at its sole discretion, participate in the defense of any such action, but such participation shall not relieve PXP of its obligation under this condition. The District shall bear its own expenses for its participation in the action. [*Re: ATC 6708*]

A.3 **Reimbursement of Costs**. All reasonable expenses, as defined in District Rule 210, incurred by the District, District contractors, and legal counsel for the activities listed below that follow the issuance of this permit, including but not limited to permit condition implementation, compliance verification and emergency response, directly and necessarily related to enforcement of the permit shall be reimbursed by the permittee as required by Rule 210. Reimbursable activities include work involving: permitting, compliance, CEMS, modeling/AQIA, ambient air monitoring and air toxics.

A.4 **Access to Records and Facilities.** As to any condition that requires for its effective enforcement the inspection of records or facilities by the District or its agents, PXP shall make such records available or provide access to such facilities upon notice from the District. Access shall mean access consistent with California Health and Safety Code Section 41510 and Clean Air Act Section 114A. [*Re: ATC 6708*]

A.5 **Compliance.** Nothing contained within this permit shall be construed as allowing the violation of any local, state or federal rules, regulations, air quality standards or increments. [*Re: ATC 6708*]

A.6 **Injunctive Relief.** In addition to any administrative remedies or enforcement provided hereunder, the District may seek and obtain temporary, preliminary, or permanent injunctive relief to prohibit violation of the conditions set forth herein or to mandate the conditions set forth herein or to mandate compliance with the conditions herein. All remedies and enforcement procedures set forth herein shall be in addition to any other legal or equitable remedies provided by law. [*Re: ATC 6708*]

A.7 **Consistency with Analysis.** Operation under this permit shall be conducted consistent with all data, specifications and assumptions included with the application and supplements thereof (as documented in the District's project file), and the District's analyses under which this permit is issued as documented in the Permit Analyses prepared for and issued with this permit. [*Re: ATC 6708*]

A.8 **Consistency with State and Local Permits.** Nothing in this permit shall relax any air pollution control requirement imposed on the LOGP the State of California or the California Coastal Commission in any consistency determination for the Project with the California Coastal Act. [*Re: ATC 6708*]

A.9 **Compliance with Permit Conditions.**

(a) The permittee shall comply with all permit conditions in Sections 9.A, 9.B and 9.C.

(b) This permit does not convey property rights or exclusive privilege of any sort.

(c) Any permit noncompliance with sections 9.A, 9.B, or 9.C constitutes a violation of the Clean Air Act and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application.

(d) It shall not be a defense for the permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

(e) A pending permit action or notification of anticipated noncompliance does not stay any permit condition.

(f) Within a reasonable time period, the permittee shall furnish any information requested by the Control Officer, in writing, for the purpose of determining:

(i) compliance with the permit, or

(ii) whether or not cause exists to modify, revoke and reissue, or terminate a permit or for an enforcement action.

(g) In the event that any condition herein is determined to be in conflict with any other condition contained herein, then, if principles of law do not provide to the contrary, the condition most protective of air quality and public health and safety shall prevail to the extent feasible.

[*Re: 40 CFR Part 70.6.(a)(6), District Rules 1303.D.1]*

A.10 **Emergency Provisions.** The permittee shall comply with the requirements of the District, Rule 505 (Upset/Breakdown rule) and/or District Rule 1303.F, whichever is applicable to the emergency situation. In order to maintain an affirmative defense under Rule 1303.F, the permittee shall provide the District, in writing, a "notice of emergency" within 2 working days of the emergency. The "notice of emergency" shall contain the information/documentation listed in Sections (1) through (5) of Rule 1303.F. [*Re: 40 CFR 70.6(g), District Rule 1303.F*]

A.11 **Compliance Plan.**

(a) The permittee shall comply with all federally enforceable requirements that become applicable during the permit term in a timely manner.

(b) For all applicable equipment, the permittee shall implement and comply with any specific compliance plan required under any federally-enforceable rules or standards.

[*Re: District Rule 1302.D.2*]

A.12 **Right of Entry.** The Regional Administrator of USEPA, the Control Officer, or their authorized representatives, upon the presentation of credentials, shall be permitted to enter upon the premises where a Part 70 Source is located or where records must be kept:

(a) To inspect the stationary source, including monitoring and control equipment, work practices, operations, and emission-related activity;

(b) To inspect and duplicate, at reasonable times, records required by this Permit to Operate;

(c) To sample substances or monitor emissions from the source or assess other parameters to assure compliance with the permit or applicable requirements, at reasonable times. Monitoring of emissions can include source testing.

[*Re: District Rule 1303.D.2*]

A.13 **Severability.** In the event that any condition herein is determined to be invalid, all other conditions shall remain in force. [*Re: District Rules 103 and 1303.D.1*]

A.14 **Permit Life.** The Part 70 permit shall become invalid three years from the date of issuance unless a timely and complete renewal application is submitted to the District. Any operation of the source to which this Part 70 permit is issued beyond the expiration date of this Part 70 permit and without a valid Part 70 operating permit (or a complete Part 70 permit renewal application) shall be a violation of the CAAA, § 502(a) and 503(d) and of the District rules.

The permittee shall apply for renewal of the Part 70 permit no later than 180-days before the permit expiration date. Upon submittal of a timely and complete renewal application, the Part 70 permit shall remain in effect until the Control Officer issues or denies the renewal application. [*Re: District Rule 1304.D.1*]

A.15 **Payment of Fees.** The permittee shall reimburse the District for all its Part 70 permit processing and compliance expenses for the stationary source on a timely basis. Failure to reimburse on a timely basis shall be a violation of this permit and of applicable requirements and can result in forfeiture of the Part 70 permit. Operation without a Part 70 permit subjects the source to potential enforcement action by the District and the USEPA pursuant to section 502(a) of the Clean Air Act. [*Re: District Rules 1303.D.1 and 1304.D.11, 40 CFR 70.6(a)(7)*]

A.16 **Prompt Reporting of Deviations.** The permittee shall submit a written report to the District documenting each and every deviation from the requirements of this permit or any applicable federal requirements within 7 days after discovery of the violation, but not later than 180-days after the date of occurrence. The report shall clearly document 1) the probable cause and extent of the deviation 2) equipment involved, 3) the quantity of excess pollutant emissions, if any, and 4) actions taken to correct the deviation. The requirements of this condition shall not apply to deviations reported to District in accordance with Rule 505. *Breakdown Conditions*, or Rule 1303.F *Emergency Provisions*. [District Rule 1303.D.1, 40 CFR 70.6(a) (3)]

A.17 **Reporting Requirements/Compliance Certification.** The permittee shall submit compliance certification reports to the USEPA and the Control Officer every six months. These reports shall be submitted on District forms and shall identify each applicable requirement/condition of the permit, the compliance status with each requirement/condition, the monitoring methods used to determine compliance, whether the compliance was continuous or intermittent, and include detailed information on the occurrence and correction of any deviations (excluding emergency upsets) from permit requirement. The reporting periods shall be each half of the calendar year, e.g., January through June for the first half of the year. These reports shall be submitted by September

1 and March 1, respectively, each year. Supporting monitoring data shall be submitted in accordance with the “Semi-Annual Compliance Verification Report” condition in section 9.C. The permittee shall include a written statement from the responsible official, which certifies the truth, accuracy, and completeness of the reports. [*Re: District Rules 1303.D.1*, *1302.D.3*, *1303.2.c*]

A.18 **Federally-enforceable Conditions.** Each federally enforceable condition in this permit shall be enforceable by the USEPA and members of the public. None of the conditions in the District-only enforceable section of this permit are federally enforceable or subject to the public/USEPA review [*Re: CAAA, § 502(b)(6), 40 CFR 70.6(b*)]

A.19 **Recordkeeping Requirements**. The permittee shall maintain records of required monitoring information that include the following:

(a) The date, place as defined in the permit, and time of sampling or measurements;

(b) The date(s) analyses were performed;

(c) The company or entity that performed the analyses;

(d) The analytical techniques or methods used;

(e) The results of such analyses; and

(f) The operating conditions as existing at the time of sampling or measurement;

The records (electronic or hard copy), as well as all supporting information including calibration and maintenance records, shall be maintained for a minimum of five (5) years from date of initial entry by the permittee and shall be made available to the District upon request. [*Re: District Rule 1303.D.1.f, 40 CFR 70.6(a)(3)(ii)(A)*]

A.20 **Conditions for Permit Reopening.** The permit shall be reopened and revised for cause under any of the following circumstances:

(a) Additional Requirements: If additional applicable requirements (e.g., NSPS or MACT) become applicable to the source which has an unexpired permit term of three (3) or more years, the permit shall be reopened. Such a reopening shall be completed no later than 18 months after promulgation of the applicable requirement. However, no such reopening is required if the effective date of the requirement is later than the date on which the permit is due to expire, unless the original permit or any of its terms and conditions has been extended. All such re-openings shall be initiated only after a 30 day notice of intent to reopen the permit has been provided to the permittee, except that a shorter notice may be given in case of an emergency.

(b) Inaccurate Permit Provisions: If the District or the USEPA determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emission standards or other terms or conditions of the permit, the permit shall be reopened. Such re-openings shall be made as soon as practicable.

(c) Applicable Requirement: If the District or the USEPA determines that the permit must be revised or revoked to assure compliance with any applicable requirement including a federally enforceable requirement, the permit shall be reopened. Such re-openings shall be made as soon as practicable.

Administrative procedures to reopen a permit shall follow the same procedures as apply to initial permit issuance. Re-openings shall affect only those parts of the permit for which cause to reopen exists. If the permit is reopened, and revised, it will be reissued with the expiration date that was listed in the permit before the re-opening. [*Re: 40 CFR 70.7(f), 40 CFR 70.6(a)*]

A.21 **Risk Management Plan - Section 112r.** PXP shall comply with the requirements of 40 CFR 68 on chemical accident prevention provisions. The annual compliance certification must include a statement regarding compliance with this part, including the registration and submission of the risk management plan (RMP). [*Re: 40 CFR 68*]

9.B Generic Conditions

The generic conditions listed below apply to all emission units, regardless of their category or emission rates. These conditions are federally enforceable. Compliance with these requirements is discussed in Section 3. In case of a discrepancy between the wording of a condition and the applicable federal or District rule(s), the wording of the rule shall control.

B.1 **Circumvention (Rule 301).** A person shall not build, erect, install, or use any article, machine, equipment or other contrivance, the use of which, without resulting in a reduction in the total release of air contaminants to the atmosphere, reduces or conceals an emission which would otherwise constitute a violation of Division 26 (Air Resources) of the Health and Safety Code of the State of California or of these Rules and Regulations. This Rule shall not apply to cases in which the only violation involved is of Section 41700 of the Health and Safety Code of the State of California, or of District Rule 303. *[Re: District Rule 301]*

B.2 **Visible Emissions (Rule 302).** PXP shall not discharge into the atmosphere from any single source of emission any air contaminants for a period or periods aggregating more than three minutes in any one hour which is:

(a) As dark or darker in shade as that designated as No. 1 on the Ringlemann Chart, as published by the United States Bureau of Mines, or

(b) Of such opacity as to obscure an observer's view to a degree equal to or greater than does smoke described in subsection B.2(a) above.

For the equipment listed below, PXP shall determine compliance with this Condition as specified below:

Intermittent Flare or Thermal Oxidizer:

For planned flaring, a visible emissions inspection for a one-minute period shall be performed once per quarter during a planned flaring event. For each unplanned flaring event exceeding four hours in duration, a visible emissions inspection for a one-minute period shall be performed. For both planned and unplanned flaring, the date and start-time and end-time of each visible emissions inspection shall be recorded in a log. If visible emissions are detected during any inspection, then a USEPA Method 9 visible emission evaluation (VEE) shall immediately be performed. For planned flaring, the VEE shall be for a six-minute period or the duration of the flaring event, whichever is shorter. For unplanned flaring, the VEE shall be for six-minutes or the remaining duration of the flaring event beyond four hours, whichever is shorter. PXP staff certified in VEE shall perform the VEE and maintain logs in accordance with USEPA Method 9. The date and start-time and end-time of each visible emissions inspection shall be recorded in a log, along with a notation identifying whether visible emissions were detected District staff certified in visual emission evaluations shall determine compliance. *[Re: District Rule 302]*.

Diesel Fueled IC Engine(s):

Once per calendar quarter, PXP shall perform a visible emissions inspection for a one-minute period on each diesel engine when operating. The date and start-time and end-time of each visible emissions inspection shall be recorded in a log. If visible emissions are detected during any inspection, then a USEPA Method 9 visible emission evaluations (VEE) shall immediately be performed for a six-minute period. PXP staff certified in VEE shall perform the VEE and maintain logs in accordance with USEPA Method 9. The date and start-time and end-time of each visible emissions inspection shall be recorded in a log, along with a notation identifying whether visible emissions were detected.

B.3 **PM Concentration - Northern Zone (Rule 304).** PXP shall not discharge into the atmosphere, from any source, particulate matter in excess of 0.3 grain per cubic foot of gas at standard conditions. *[Re: District Rule 304]*

B.4 **Dust and Fumes - North Zone (Rule 306).** PXP shall not discharge into the atmosphere, from any source, particulate matter in excess of the concentrations listed in Table 306 (a) of Rule 306. *[Re: District Rule 306]*

B.5 **Specific Contaminants (Rule 309).** PXP shall not discharge into the atmosphere from any single source sulfur compounds and combustion contaminants (particulate matter) in excess of the applicable standards listed in Sections A through E of Rule 309. *[Re: District Rule 309]*.

B.6 **Sulfur Content of Fuels (Rule 311).** PXP shall not burn fuels with a sulfur content in excess of 0.5% (by weight) for liquid fuels and 796 ppmvd or 50 gr/100 scf (calculated as H_2S) for gaseous fuel. Compliance with this condition shall be based on continuous monitoring. *[Ref: District Rule 311]*

B.7 **Organic Solvents (Rule 317).** PXP shall comply with the emission standards listed in Rule 317.B. Compliance with this condition shall be based on PXP's compliance with Condition C.7 of this permit. *[Re: District Rule 317]*

B.8 **Metal Surface Coating Thinner and Reducer (Rule 322).** The use of photochemically reactive solvents as thinners or reducers in metal surface coatings is prohibited. Compliance with this condition shall be based on PXP's compliance with Condition C.7 of this permit and facility inspections. *[Re: District Rule 322]*

B.9 **Architectural Coatings (Rule 323).** PXP shall comply with the coating ROC content and handling standards listed in Section D of Rule 323 as well as the Administrative requirements listed in Section F of Rule 323. Compliance with this condition shall be based on PXP's compliance with Condition C.7 of this permit and facility inspections. *[Re: District Rules 323, 317, 322, 324]*

B.10 **Disposal and Evaporation of Solvents (Rule 324).** PXP shall not dispose through atmospheric evaporation of more than one and a half gallons of any photochemically reactive solvent per day. Compliance with this condition shall be based on PXP's compliance with Condition C.7 of this permit and facility inspections. *[Re: District Rule 324]*

B.11 **Adhesives and Sealants (Rule 353).** PXP shall not use adhesives, adhesive bonding primers, adhesive primers, sealants, sealant primers, or any other primers, unless the permittee complies with the following:

(a) Such materials used are purchased or supplied by the manufacturer or suppliers in containers of 16 fluid ounces or less; or alternately

(b) When PXP uses such materials from containers larger than 16 fluid ounces and the materials are not exempt by Rule 353.B.1, the total reactive organic compound emissions from the use of such material shall not exceed 200 pounds per year unless the substances used and the operational methods comply with Sections D, E, F, G, and H of Rule 353. Compliance shall be demonstrated by recordkeeping in accordance with Section B.2 and/or Section O of Rule 353. *[Re: District Rule 353]*

B.12 **Emergency Episode Plan.** During emergency episodes, PXP shall implement the *Emergency Episode Plan* approved December 12, 2000. The District may request an update to this Plan if equipment or operational changes occur.

B.13 **Oil and Gas MACT.** PXP shall comply with the requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPS) for Oil and Natural Gas Production and Natural Gas Transmission and Storage (promulgated June 17, 1999). At a minimum, PXP shall maintain records in accordance with 40 CFR Part 63, Subpart A, Section 63.10(b) (1) and (3). *[Re:* 40 CFR 63, Subpart HH*]*

B.14 **CARB Registered Portable Equipment.** State registered portable equipment shall comply with State registration requirements. A copy of the state registration shall be readily available whenever the equipment is at the facility. *[Re: District Rule 202]*

B.15 **Reciprocating Internal Combustion Engine NESHAP.** PXP shall comply with the requirements of the RICE NESHAP by the dates specified in the regulation. Prior to making any physical or operational changes to the engines subject to this regulation, PXP shall obtain an Authority to Construct from the District. [*Re:* 40 CFR 63, Subpart ZZZZ]

9.C Requirements and Equipment Specific Conditions

This section contains non-generic federally-enforceable conditions, including emissions and operations limits, monitoring, recordkeeping, and reporting for each specific equipment group. This section may also contain other non-generic conditions.

C.1 **Combustion Equipment.** The following equipment are included in this emissions unit category:

District Device No.	Name
2155	Heater Treater “A” (16.0 MMBtu/hr)
2169	Heater Treater “B” (16.0 MMBtu/hr)
2170	Heater Treater “C” (16.0 MMBtu/hr)

(a) Emission Limits: Mass emissions from the combustion equipment listed above shall not exceed the limits listed in Tables 5.1 and 5.2. In addition, the heater treater exhaust stack pollutant concentrations shall not exceed the concentration limits listed below. Compliance shall be based on the use of process monitors (e.g., fuel use meters) and the monitoring, recordkeeping and reporting conditions of this permit.

Concentration	NO_x	ROC	SO_x	CO	PM_{10}*
Ppmv @ 3.0% O_2	22.0	4.0	-	25.0	0.035
lb/MMBtu	0.02663	0.0017	0.0125	0.0184	5.0

* Units for PM_{10} are 0.035 gr/scf and 5.0 lb/MMscf

(b) Operational Limits: The following operational limits apply:

(i) Fuel heat input to each heater treater shall not exceed 16.0 MMBtu/hour. Total heat input to all heater treaters during any one hour shall not exceed 48.0 MMBtu/hr.

(ii) The heater treater shall not be operated in excess of the fuel heat input at which they were source tested and found to be in compliance.

Compliance with (a) and (b) above shall be based on the monitoring, recordkeeping and reporting requirements of this permit. Specifically, operational heat input shall be based upon District-approved fuel high heating value (HHV) as provided by PXP, and upon the 24-hour heater treater fuel gas usage meter charts. The HHV shall be based upon the semi-annual fuel gas sampling results.

(iii) Each heater treater shall be equipped with a totalizing fuel meter with recording chart.

(iv) PXP shall use only pipeline quality natural gas. The H_2S content shall not exceed 0.25 gr/100scf (4.0 ppmvd as H_2S at standard conditions) and the total sulfur shall not exceed 5.0 gr/100scf (80 ppmvd as H_2S at standard conditions).

(c) Monitoring: The following monitoring requirements shall apply:

(i) PXP shall monitor the fuel use for each equipment item for compliance with emission limits.

(ii) PXP shall perform biennial source testing of the heater treaters consistent with the requirements listed in Table 4.12-2 and the source testing condition of this permit.

(iii) PXP shall continuously monitor fuel gas H_2S content using a H_2S analyzer.

(iv) PXP shall collect semi-annual fuel samples and analyze for H_2S, TRS and HHV.

(d) Recordkeeping: The following records shall be maintained:

(i) Daily, monthly, and quarterly volume (MMscf and MMBtu consumed) of fuel gas burned in each heater treater;

(ii) Five (5) highest hourly fuel flow rates per quarter (including time and date) to each unit of fuel combustion equipment;

(iii) Five (5) highest hourly emissions by quarter, in units of lbs/hr of each criteria pollutant, including time and date, for each heater treater.

(iv) Semi-annual fuel sample analysis for fuel gas H_2S, TRS and HHV.

The fuel gas total sulfur content shall be assumed to be *80.0 ppmv (5.0* gr/100 scf), for the purpose of computing SO_x emissions to demonstrate compliance with the conditions in this permit.

(e) Reporting: On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the District. The report must list all data required by permit condition 9.C.12 (*Semi-Annual Compliance Verification Reports)* of this permit. *[Re: ATC 6708]*

C.2 **Thermal Oxidizer.** The following equipment are included in this emissions unit category:

District Device No.	Name
101647	Thermal Oxidizer (12.0 MMBtu/hr)

(a) Emission Limits: Mass emissions from the thermal oxidizer shall not exceed the limits listed in Tables 5.1 and 5.2. Compliance with this condition shall be based on the monitoring, recordkeeping and reporting conditions in this permit.

(b) Operational Limits: The following operational limits apply:

(i) Heat input to the thermal oxidizer shall not exceed 12.0 MMBtu/hr.

(ii) Tail gas and regenerator air from the Sulferox unit shall be combusted in the thermal oxidizer at all times the gas plant is operating.

(iii) Stack outlet emissions from the thermal oxidizer shall meet one of the following control limits:

a. A minimum ROC mass Destruction Rate Efficiency (DRE) of 98.5 percent, or

b. A maximum ROC outlet concentration of 10 part per million (by volume).

Except during startup and shutdown, the above standard shall be applicable over all operational scenarios. Compliance with this condition will be assessed through emission stack testing.

(iv) The combustion chamber temperature set-point shall be maintained between 1,450 and 1,550°F at all times except during startup and shutdown. PXP shall install, operate and properly maintain a monitoring device to permanently record the combustion chamber temperature for the purposes of assessing compliance.

(v) The minimum residence time of the waste gas streams in the combustion chamber shall be 0.6 seconds. Compliance with the residence time shall be determined during source testing and submitted with the source test results. Specifically, the combustion chamber volume (cubic feet) shall be divided through by the actual exhaust flow rate (cubic feet per second) observed during the source test.

(vi) PXP shall use pipeline quality natural gas. The H_2S content shall not exceed 0.25 gr/100scf (4.0 ppmvd as H_2S at standard conditions) and the total sulfur shall not exceed 5.0 gr/100scf (80 ppmvd as H_2S at standard conditions).

(vii) A minimum water level of one (1) foot shall be maintained in the tail gas and spent air seal pots at all times.

(c) Monitoring: The following monitoring requirements shall apply:

(i) PXP shall monitor the fuel use for the thermal oxidizer for compliance with heat input limits. The fuel gas HHV, as determined from quarterly analysis, shall be used for emission calculation purposes.

(ii) PXP shall perform annual source testing for ROC destruction efficiency and biennial source testing for NO_x, CO and SO_x. Source testing shall be consistent with the requirements listed in 4.12-1 and the source testing condition of this permit.

(iii) Continuous monitoring of the thermal oxidizer combustion chamber temperature.

(iv) A fuel meter on the fuel gas supply to the thermal oxidizer shall be used for metering fuel use. The fuel use log shall contain the meter coefficient being used to calculate flow volumes. This meter shall be included in the *LOGP Process Monitor Calibration and Maintenance Plan*.

(v) The water level of the tail gas seal pot (V-1546) and spent air seal pot (V-1545) shall be checked daily. Daily inspections shall continue until such time that PXP equips each vessel with an automatic liquid level monitoring system. This system shall include an alarm that alerts personnel in the control room when liquid levels fall below one foot in either of these vessels. This system shall be detailed in a formal plan and approved by the District prior to implementation.

(d) Recordkeeping: The following records shall be maintained:

(i) Daily, monthly and quarterly fuel gas (scfd) used by the thermal oxidizer.

(ii) five highest hourly thermal oxidizer fuel flow rates by quarter in units of MMBtu/hr.

(iii) thermal oxidizer combustion chamber continuous operating temperature.

(iv) daily liquid level checks of the tail gas and spent air seal pots.

(e) Reporting: On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the District. The report must list all data required by permit condition 9.C.12 (*Semi-Annual Compliance Verification Reports)* of this permit. *[Re: ATC 9522]*

C.3 **Flaring Activities.** The following equipment are included in this emissions unit category:

District Device No.	Name
101752	Flare (NAO - Model 8NMJM) 625 MMBtu/hr

(a) Emission Limits: Mass emissions from the flare shall not exceed the limits listed in Tables 5.1 and 5.2. Compliance with this condition shall be based on the monitoring, recordkeeping and reporting conditions in this permit.

(b) Operational Limits:

(i) *Flaring Volumes.*

a) Unplanned flaring at the LOGP shall not exceed the following limits:

- maximum hourly flare flow rate: 42.5 Mscfh
- maximum quarterly and annual flare flow rate: 239.95 Mscf/qtr and 959.80 Mscf/yr.

b) Planned flaring at the LOGP shall not exceed the following limits:

- continuous purge and pilot gas flow rate: 45.0 scfh
- maximum quarterly and annual flare flow rate: 100.00 Mscf/qtr and 100.00 Mscf/yr.

(ii) *Flare SO_2 Reduction.* Total sulfur content (calculated as H_2S at standard conditions, 60° F and 14.7 psia) of the gas flared at the LOGP shall not exceed 50 gr/100 scf (796 ppmV). During any flare event five (5) minutes or greater in duration PXP shall use the SO_2 scrubber system to reduce H_2S from the stack flare gas. Flare gas sampling shall conform to the following guidelines:

a) A third party gas sample analysis shall be required per b)3) below for all flare events greater than five (5) minutes in duration, except in certain circumstances described below.

b) The automatic sampler shall initiate sampling once the flare event exceeds five (5) minutes. Sampling procedures will be as follows:

1) Sampling by the automatic flare sampler will commence once a flare event exceeds five (5) minutes. The sampler stroke rate shall be set at approximately 9 cc/min. If the sample obtained is insufficient for analysis, District Breakdown procedures may be utilized, if appropriate.

2) Sampling may be on a continuous or periodic basis. Continuous sampling shall be defined as, "sampling which commences at five minutes into the flare event and continues throughout the flare event." The initial sample bomb shall be sized to accommodate a minimum of the initial 55 (fifty-five) minutes of

sampling. A separate sample bomb is required for each hour of flaring thereafter. Each distinct flare event triggers the sampling procedures described above and requires a new sample bomb. Periodic sampling shall be defined as, "one five minute sample commencing at five minutes, 30 minutes, 60 minutes into the flare event and at the end of each 60 minute period thereafter." If these samples represent a single flare event, the first three samples may be obtained in the same sample bomb. Each hourly sample thereafter shall be obtained in separate sample bombs for a single flare event. Each distinct flare event triggers the sampling procedures described above and requires a new sample bomb.

3) Sample analysis shall consist of a gas composition, density, BTU content, and analysis for total sulfur "calculated as ppmV H_2S." Chain of custody record procedures shall be implemented for flare gas sample canisters once the sample has been obtained. These chain of custody forms shall accompany the gas chromatographic analyses and shall be included in the quarterly report.

(iii) During any flaring event in which the SO_2 scrubber is used, PXP shall take all reasonable steps to assure optimum SO_x reduction efficiency. This shall include detector tube or other sampling of the scrubber outlet gas stream H_2S concentration and adjustment of the scrubber solution flow rate for maximum SO_x reduction efficiency for all flare events exceeding one hour. The flare gas H_2S removal system shall consist of a fresh H_2S scrubbing solution, tank, and pump, an H_2S scrubber with an upstream in-line mixer, and a spent H_2S scrubbing solution tank and pump. The system shall be able to process a minimum of 42.5 Mscfh.

To prevent a long period of flare gas scrubber solution unavailability, PXP shall maintain adequate scrubber solution for a complete change out onsite. Alternatively, PXP may demonstrate that a replacement solution can be obtained and changed within ten (10) working days.

(iv) *Flare Scrubber.* Flare events exceeding five minutes shall be routed through the flare scrubber.

(v) *Flare Purge/Pilot Fuel Gas Sulfur Limits.* The purge/pilot fuel gas combusted in the flare shall not exceed 0.25 gr/100scf (4.0 ppmvd as H_2S at standard conditions) and the total sulfur shall not exceed 5.0 gr/100scf (80 ppmvd as H_2S at standard conditions). Compliance shall be based on the monitoring, recordkeeping and reporting requirements of this permit.

(vii) *Rule 359 Technology Based Standards.*- PXP shall comply with the technology based standards of Section D.2 of Rule 359. Compliance shall be based on monitoring and recordkeeping requirements of this permit as well as District inspections.

(viii) *Flare Minimization/Flare Volume Monitoring Plans.* PXP shall comply with all aspects of the subject plans. These plans are hereby incorporated by reference as part of this permit.

(c) Monitoring: PXP shall monitor the following emission and process parameters for the flare relief system:

(i) *Flare Volumes.* The volumes of gas flared during each event shall be monitored by use of District-approved flare header flow meters. The meters shall be calibrated and operated consistent with the LOGP *Process Monitor Calibration and Maintenance Plan*.

(ii) *Purge/Pilot Gas.* PXP shall continuously monitor the volume of purge/pilot fuel gas.

(iii) *Flaring Sulfur Content.* The hydrogen sulfide content of produced gas combusted during flaring events shall be measured pursuant to condition C.3 (b)(ii) above.

(iv) *Pilot Flame Detection.* PXP shall continuously monitor each pilot to ensure that a flame is present at each pilot at all times.

(d) Recordkeeping: The equipment listed in this section are subject to all the recordkeeping requirements listed in District Rule 359.G. The following recordkeeping conditions apply to the flare:

(i) *Flare Event Logs.* All flaring events shall be recorded in a log. The log shall include: date; duration of flaring events (including start and stop times); quantity of gas flared; hydrogen sulfide content per third party analysis; value; reason for each flaring event, including the processing unit or equipment type involved and the type of event (planned or unplanned). The volumes of gas combusted and resulting mass emissions of all criteria pollutants for each type of event shall also be summarized for a cumulative summary for each day, quarter and year.

(ii) *Pilot/Purge Gas Volume.* The volume of pilot/purge fuel gas combusted in the flare shall be recorded on a weekly, quarterly and annual basis.

(e) Reporting: The equipment listed in this section are subject to all the reporting requirements listed in District Rule 359.H. On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the District. The report must list all data required by permit condition 9.C.12 (*Semi-Annual Compliance Verification Reports)* of this permit. *[Re: ATC 6708, ATC 9522]*

C.4 **Fugitive Hydrocarbon Emissions Components.** The following equipment are included in this emissions unit category:

District Device No.	Equipment
Gas Processing Plant	
2181	Components Gas/Gas Condensate Service
Oil Processing Plant	
8742	Component Leak-Paths in Gas/Gas Condensate Service
8744	Component Leak-Paths in Oil Service

(a) Emission Limits: Mass emissions from the gas/light liquid service (sub-total) and oil service (sub-total) components associated with the oil processing plant listed above shall not exceed the emissions limits listed in Tables 5.1 and 5.2. The mass emissions from the gas/light liquid service (sub-total) components associated with the gas processing plant listed above shall not exceed the emissions limits listed in Table 4.3.

(b) Operational Limits: Operation of the equipment listed in this section shall conform to the requirements listed in District Rule 331.D and E. Compliance with these limits shall be assessed through compliance with the monitoring, recordkeeping and reporting conditions in this permit. In addition PXP shall meet the following requirements:

(i) *VRS Use.* The vapor recovery and gas collection (VR&GC) systems at LOGP shall be in operation when equipment connected to these systems are in use. These systems include piping, valves, and flanges associated with the VR&GC systems. The VR&GC systems shall be maintained and operated to minimize the release of emissions from all systems, including pressure relief valves and gauge hatches.

(ii) *I&M Program.* The District-approved I&M Plan for PXP LOGP *{Fugitive Emissions Inspection and Maintenance Program for the Lompoc Oil and Gas Plant Facility - approved October 2001}* shall be implemented for the life of the project. The I&M Plan shall comply with all sections of Rule 331. The Plan, and any subsequent District approved revisions, is incorporated by reference as an enforceable part of this permit.

(iii) *Leakpath Count.* The total component and leakpath count listed in PXP's most recent I&M component and leakpath inventory shall not exceed the total component and leakpath count line item sub-totals listed in Table 5.1-1 by more than five percent. This five percent range is to allow for minor differences due to component counting methods and does not constitute allowable emissions growth due to the addition of new equipment.

(iv) *Venting.* All routine venting of hydrocarbons shall be routed to either the gas plant for processing, flare header, or other District-approved control device.

(v) *Rule 331 BACT.* PXP shall apply the BACT measures listed in Table 4.10-3 and Table 4.10-4 to the components listed in Table 4.10-4 pursuant to Rule 331. BACT, as defined in Table 4.10-4, shall be implemented for the life of the project.

(vi) *NSPS KKK.* PXP shall comply with the standards of 40 CFR 60.632, as applicable, for all gas plant fugitive I&M components.

(c) Monitoring: The equipment listed in this section are subject to all the monitoring requirements listed in District Rule 331.F, PXP's Fugitive I&M Plan and NSPS Subpart KKK (as applicable). The test methods in Rule 331.H and NSPS Subpart KKK shall be used, when applicable. In addition, PXP shall:

(i) Perform monthly monitoring of all valves located within the gas processing plant.

(ii) *Correlation Equations (CE).* The emissions from the gas processing plant components and the LOF gas pipeline pig receiver located at the LOGP (District #112278), are based on CE methodology). Assessing quarterly compliance with the emission limits developed by the CE Methodology (Table 4.3) shall be based on District Policy and Procedure 6100.072.1998 (*Tier II Screening Value Range Factor).*

(d) Recordkeeping: The equipment listed in this section are subject to all the recordkeeping requirements listed in District Rule 331.G and NSPS Subpart KKK, as applicable. In addition, PXP shall:

(i) *I&M Log.* PXP shall record in a log the following: a record of leaking components found (including name, location, type of component, date of leak detection, the ppmv or drop-per-minute reading, date of repair attempts, method of detection, date of re-inspection and ppmv or drop-per-minute reading following repair); a record of the total components inspected and the total number and percentage found leaking by component type; a record of leaks from critical components; a record of leaks from components that incur five repair actions within a continuous 12-month period; and, a record of component repair actions including dates of component re-inspections.

(ii) Separate and distinct records shall be maintained for the oil dehydration and gas processing plants.

(e) Reporting: The equipment listed in this section are subject to all the reporting requirements listed in District Rule 331.G and NSPS KKK, as applicable. On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the District. The report must list all data required by permit condition 9.C.12 (*Semi-Annual Compliance Verification Reports)* of this permit. *[Re: ATC 6708; ATC 9522]*

C.5 **Pigging Equipment.** The following equipment are included in this emissions category:

District Device No.	Name
101770	Oil Emulsion Pig Receiver
101769	Gas Pig Receiver
112278	Gas Pig Receiver (LOF)

(a) Emission Limits: Mass emissions from the pig receivers listed above shall not exceed the limits listed in Tables 5.1 and 5.2. Compliance with this condition shall be based on the monitoring, recordkeeping and reporting conditions in this permit.

(b) Operational Limits: Operation of the equipment listed in this section shall conform to the requirements listed in District Rule 325.E. Compliance with these limits shall be assessed through compliance with the monitoring, recordkeeping and reporting conditions in this permit. In addition PXP shall meet the following requirement:

(i) *Pig Openings.* Access openings to the pig receiver shall be kept closed at all times, except when a pipeline pig is being placed into or removed from the receiver.

(ii) *Venting of Pig Receivers.* The pig receivers shall be vented to the vapor recovery unit prior to opening to the atmosphere.

(c) Monitoring: n/a

(d) Recordkeeping: PXP shall record in a log the date of each pigging operation and the pressure inside the receiver prior to each opening.

(e) Reporting: On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the District. The report must list all data required by permit condition 9.C.12 (*Semi-Annual Compliance Verification Reports)* of this permit. *[Re: ATC 6708; 40 CFR 70.6]*

C.6 **Tanks/Sumps.** The following equipment are included in this emissions category:

District Device No.	Name	
TANKS		
101743	T-280 Oil surge Tank (Vapor Recovery)	
101742	T-210 Reject Oil Tank (Vapor Recovery)	
101743	T-220 Reject Oil Tank (Vapor Recovery)	
2173	T-450 Reclaim Oil Tank (Vapor Recovery)	
SUMPS		
8754	S-850 Flotation Unit Froth Sump TT Area Drain (Carbon Canister)	
8755	S-860 Control Building Lab Sump (Carbon Canister)	
8756	870 Oil Surge Tank Sump (Carbon Canister)	
8747	S-800 Inlet Sump (Carbon Canister)	
8749	S-810 Crude Dehydration Sump (Carbon Canister)	
8750	S-820 Water Treating Sump (Carbon Canister)	
8751	S-830 Reject Tank Sump (Carbon Canister)	
8752	S-840 Outlet Sump (Carbon Canister)	
8753	S-893 Process Drain Sump	
9858	S-895 Amine Drain Sump	

(a) Emission Limits: No federally enforceable emission limits.

(b) Operational Limits: All process operations from the tanks listed in this section shall meet the requirements of District Rule 325, Sections D, E, F and G. Compliance with these limits shall be assessed through compliance with the monitoring, recordkeeping and reporting conditions in this permit. In addition, PXP shall:

(i) *VRS Use*. The vapor recovery systems shall be in operation when the equipment connected to the VRS system at the facility are in use. The VRS system includes piping, valves, and flanges associated with each VRS system. Each VRS system shall be maintained and operated to minimize the release of emissions from all systems, including pressure relief valves and gauge hatches.

(ii) *Surge Tank T-280 (100,000 bbl).* Under the following limited circumstances, PXP may use the T-280 surge tank:

a) A tank level recorder is functioning at all times in order that the District may verify the volume of wet oil in the tank;

b) The tank shall remain gas blanketed and connected to a vapor recovery system at all times;

c) Use of the tank shall not include the period of time required to empty the tank following one of the events specified below. For the purpose of this condition, a tank level of 0-5 feet shall be considered empty;

d) Tank use shall be limited to the planned events listed below. During any planned event, the quantity of oil in the tank shall not exceed 75,000 bbl. With the exception of use for pigging, PXP shall inform the District, in writing, three (3) calendar days of any planned event use of the tank. Quarterly noticing for use during pigging operations shall be provided in writing within one (1) week of the beginning of each calendar quarter. This notice shall include the number of anticipated uses (for pigging) for the upcoming quarter:

Planned events are defined as follows:

(1) Pressure testing and maintenance of the pipelines between the LOGP and the Orcutt Pump Station (OPS) or the pipelines between the OPS and the Santa Maria Refinery;

(2) When the Conoco-Phillips Pipeline Company is required to ship exclusively from certain oil leases;

(3) Pigging Operations. The tank may be used during pigging operations. A single "pigging operation" may include one or more pigs;

(4) Planned events not addressed above but which qualify as such due to the nature of the event. This shall include but not be limited to, planned turnarounds at the Santa Maria Refinery, well treatment operations, chemical treatment of produced fluids, or establishing production from newly drilled wells.

e) Tank use shall be limited to the emergency events listed below. During any emergency event, the entire capacity of the tank (100,000 bbl) may be used in order to continue production without causing a shutdown of Platform Irene or the LOGP facility. PXP shall notify the District of the occurrence of any emergency event the next business day after the beginning of the event. Notification shall include the reason for the event and the anticipated duration. Should the event persist more than twenty-four (24) hours, PXP shall log the daily status of the event and will provide the District with a report summarizing the event when the tank reaches an empty condition. PXP shall not use the tank for emergency events more than fourteen (14) days per year. A record of the number of days the tank is used for emergency events shall be maintained onsite. Emergency events are defined as follows:

- Ruptures of pipelines between the OPS and the LOGP;
- Total shutdown of the Santa Maria Refinery.

f) The tank may be used during upset conditions defined as unplanned, non-emergency events which occur during periods of irregular operation at PXP facilities or the Santa Maria Refinery. Such conditions must adversely affect operations at the LOGP to the extent that PXP has no other reasonable alternative than use of this tank. Use of the tank during upset conditions will be limited to 75,000 barrels. PXP shall notify the District the next business day after the beginning of any upset event. Notification shall include the reason for the event and the anticipated duration. Should the event persist more than twenty-four (24) hours, PXP shall log the daily status of the event and will provide the District a report summarizing the event when the tank reaches an empty condition. PXP shall not use the tank for upset events more than fourteen (14) days per year. A record of the number of days the tank is used for all unplanned, non-emergency events shall be maintained onsite.

(iii) *NSPS Subpart Kb Operating Plan*. PXP shall operate the vapor recovery systems serving the T-280 Oil Surge Tank in accordance with the District-approved Kb Operating Plan (and all subsequent District-approved updates thereof). A copy of the Operating Plan shall be maintained onsite for the life of the project. The Operating Plan and its operating parameters are incorporated as an enforceable part of this permit.

(iv) *Tank Vent Monitoring.* The tank headspace high pressure transmitter PT-220 (for T-210 and T-220) shall be set to alarm at two inches water column (the design set point of the water seal hatch). Each recorded or audible alarm at two inches of water column shall be identified on the automated recordkeeping alarm printout and constitute a tank venting of the corresponding tank independent of whether a visual inspection was conducted. All venting shall constitute a violation of Rule 325. District Rule 505 (Breakdowns) is available for protection from enforcement action, if appropriate.

(v) *Carbon Canister Control Requirements*. Each carbon canister shall be maintained and operated to minimize the release of emissions of organic compounds and sulfur compounds. Each carbon canister shall achieve a minimum 75 percent (by mass) control efficiency for reactive organic compounds and sulfur compounds. During monitoring and source testing, compliance with the 75 percent control efficiency requirement is demonstrated if the outlet ROC concentration is maintained at or below 200 ppmv (as methane) using a calibrated organic vapor analyzer (OVA). See permit condition C.34 for carbon canister replacement requirements. When not in use, the inlet of each carbon canister shall be sealed with a leak-free (i.e., camlock or threaded) cap.

(c) Monitoring: The equipment listed in this section are subject to all the monitoring requirements of District Rule 325.H (for tanks), NSPS Subpart Kb (for T-280).

The test methods outlined in District Rule 325.G and NSPS Subpart Kb shall be used, as applicable. In addition, PXP shall:

(i) For the vapor recovery systems, monitor the parameters identified in the NSPS Kb Operating Plan.

(ii) Except as provided below, for each carbon canister control unit, monitor on a monthly basis the ROC emission concentration (as methane) at the outlet of each unit using a calibrated organic vapor analyzer (OVA).

(d) Recordkeeping: The equipment listed in this section is subject to all the recordkeeping requirements listed in District Rule 325.F (for tanks) and NSPS Subpart Kb (for T-280). PXP shall maintain hardcopy records for the information listed below:

(i) Log the parameters as required by the District-approved *NSPS Kb Operating Plan*.

(ii) For each carbon canister, log the results of every OVA check (including all test results and lab analyses).

(iii) All uses of the T-280 tank, the level and the reason and time in use.

(iv) All recorded or audible venting incidents as documented by the automated recording instrumentation linked to the pressure transmitters PT-220 and PT-280 (tanks T-210, T-220).

(e) Reporting: On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the District. The report must list all data required by permit condition 9.C.12 (*Semi-Annual Compliance Verification Reports)* of this permit. *[Re: ATC 6708]*

C.7 **Solvent Usage.** The following items are included in this emissions unit category: Photochemically reactive solvents, surface coatings and general solvents.

(a) Emission Limits: The following solvent emission limits are federally-enforceable for the entire stationary source:

Solvent Type	lbs/hour	lbs/day
Photochemically Reactive	8 lbs/hour	40 lbs/day
Non-Photochemically Reactive	450 lbs/hour	3,000 lbs/day

(b) Operational Limits: Use of solvents for cleaning/degreasing shall conform to the requirements of District Rules 317, 322, 323 and 324. Compliance with these rules shall be assessed through compliance with the monitoring, recordkeeping and reporting conditions in this permit and facility inspections.

(i) *Containers:* Vessels or containers used for storing materials containing organic solvents shall be kept closed unless adding to or removing material from the vessel or container.

(ii) *Materials:* All materials that have been soaked with cleanup solvents shall be stored, when not in use, in closed containers that are equipped with tight seals.

(iii) *Solvent Leaks:* Solvent leaks shall be minimized to the maximum extent feasible or the solvent shall be removed to a sealed container and the equipment taken out of service until repaired. A solvent leak is defined as either the flow of three liquid drops per minute or a discernible continuous flow of solvent.

(iv) *Reclamation Plan:* PXP shall comply with all requirements of the District-approved *Solvent Reclamation Plan* dated July 2002.

(c) Monitoring: none.

(d) Recordkeeping: PXP shall record in a log the following on a monthly basis for each solvent used: amount used; the percentage of ROC by weight (as applied); the solvent density; the amount of solvent reclaimed for District-approved disposal; whether the solvent is photochemically reactive; and, the resulting emissions to the atmosphere in units of pounds per month and pounds per day. Product sheets (MSDS or equivalent) detailing the constituents of all solvents shall be maintained in a manner readily accessible to District inspection.

(e) Reporting: On a semi-annual basis, a report detailing the previous six-month's activities shall be provided to the District. The report must list all data required by permit condition 9.C.12 (*Semi-Annual Compliance Verification Reports)* of this permit. [*Re: 40 CFR 70.6, District Rules 317, 322,323, 324*]

C.8 **Sulferox Sulfur Recovery Unit.** The following equipment is included in this emissions unit category:

District Device No.	Name
101615	Sulferox Sulfur Recovery Unit

(a) Emission Limits: Not Applicable.

(b) Operational Limits: All process operations from the equipment listed in this section shall meet the requirements of NSPS Subpart LLL. These requirements are detailed in PXP's *Subpart LLL Compliance Monitoring Plan*. Compliance shall be assessed through compliance with the monitoring, recordkeeping and reporting conditions in this permit and the compliance plan. The following additional requirements shall apply:

(i) *Sulfur Recovery Unit Removal Efficiency.* The sulferox unit shall comply with the continuous daily efficiency requirements specified in the New Source Performance Standards, 40 CFR Part 60 Subpart LLL. Specifically, the "calculated" seventy-four (74) percent sulfur reduction efficiency of this unit shall be achieved on a continuous basis. The "calculated" efficiency is defined and determined in accordance with the District-approved *Subpart*

LLL Compliance Monitoring Plan. PXP shall comply with all requirements of this plan. This plan is hereby incorporated as an enforceable part of this permit.

(ii) *Sulfur Cake Storage.* The sulfur cake produced by the Sulferox Unit shall be stored in a covered container, after filling is complete, and in such a manner as to reduce and minimize any potential odors. If sulfur cake odors are discernible at the LOGP property boundary, PXP shall submit a revised *Odor Mitigation Plan* to the District for review and approval. PXP shall implement this plan within sixty (60) days of District approval.

(c) Monitoring: PXP shall monitor the following process parameters:

(i) All the processing parameters listed in Table 2-1 of the District-approved *Subpart LLL Monitoring Plan* and any subsequent updates.

(ii) Continuously monitor the fuel gas H_2S content.

(iii) Perform annual total sulfur content measurements of the fuel gas using ASTM or other District-approved methods. PXP shall utilize District-approved sampling and analysis procedures.

(d) Recordkeeping: PXP shall maintain records of the parameters listed in section 9.C.8(c)(i) and (ii) above.

(e) Reporting: On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the District. The report must list all data required by permit condition 9.C.12 (*Semi-Annual Compliance Verification Reports)* of this permit. *[Re: ATC 9522]*

C.9 **Emissions Reduction Credits Dedicated to Specific Projects - ATC 9522-03.** DOI No. 0005 and the associated ERC certificate No. 008-1003 were issued on September 21, 1998 and October 14, 1998, respectively, for the ERCs required to offset project emissions associated with ATC 9522-03. These documents are hereby incorporated by reference as enforceable provisions of this permit. Copies of these documents are located in the ATC 9522-03 project file. A shift-in-load, as described in DOI No. 0005, shall invalidate the ERCs. All other ERCs associated with the gas plant were in place prior to adoption of Rule 806 requiring DOI and ERC certification documents. *[Re: ATC 9522]*

C.10 **Emission Offset Mitigation.** PXP shall offset all NEI at a minimum 1.2:1 ratio for ROC emissions resulting from the project. Emission reduction credits (ERCs) sufficient to offset the permitted quarterly ROC emissions shall be in place for the life of the project. Entire Source Emissions (ESE) of ROC, non-alkane ROC (NAROC), and oxides of nitrogen (NO_x) for the Point Pedernales Project shall be offset at a ratio of one-to-one per the Emission Reduction Agreement (ERA) between PXP, the District, and Santa Barbara County (dated August 11, 1986) and the November 18, 1996 Amendment to this agreement.

The NEI and ESE emissions and offsets for ROC, NAROC, and NO_x are listed in Tables 7.1, 7.2 and 7.3. The August 11, 1986 ERA and November 18, 1996 Amendment to this agreement are incorporated herein by reference as an enforceable part of this permit.

C.11 **Recordkeeping.** All records and logs required by this permit and any applicable District, state or federal rule or regulation shall be maintained for a minimum of five calendar years from the date of information collection and log entry at the LOGP facility. These records or logs shall be readily accessible and be made available to the District upon request. During this five year period, and pursuant to California Health & Safety Code Sections 42303 and 42304, such data shall be available to the District at LOGP within a reasonable time period after request by the District. This requirement applies to data required by this permit and archived by PXP's DCS, PI and any other data-storage systems including but not limited to charts and manual logs. With the exception of processing monitoring data, prior to archiving any required data from the data-storage system, PXP shall prepare written reports and maintain these reports in 3-ring binders at the LOGP facility. Failure to make such data available within the noted period shall be a violation of this condition. Further, retrieval of historical or archived data shall not jeopardize the logging of current data. *[Re: 40 CFR 70.6; District Rule 1303]*

C.12 **Semi-Annual Compliance Verification Reports.** Twice a year, PXP shall submit a compliance verification report to the District. Each report shall be used to verify compliance with the prior two calendar quarters. The first report shall cover calendar quarters 1 and 2 (January through June) and shall be submitted no later than September 1st. The second report shall cover calendar quarters 3 and 4 (July through December) and shall be submitted no later than March 1st Each report shall contain information necessary to verify compliance with the emission limits and other requirements of this permit (if applicable for that quarter). These reports shall be in a format approved by the District. All logs and other basic source data not included in the report shall be available to the District upon request. The second report shall also include an annual report for the prior four quarters. Pursuant to Rule 212, a completed *District Annual Emissions Inventory* questionnaire shall be included in the annual report or submitted electronically via the District Webpage. The report shall include the following information:

(a) *Thermal Oxidizer*.

(1) five highest hourly thermal oxidizer fuel flow rates and heat inputs by quarter in units of MMBtu/hr;

(2) the highest weekly thermal oxidizer combustion chamber continuous operating temperature;

(3) daily liquid level checks of the tail gas and spent air seal pots.

(4) Daily, monthly and quarterly fuel gas (scfd) fuel use for the thermal oxidizer.

(b) *Heater Treaters.*

(1) Five (5) highest hourly emissions by quarter, in units of lbs/hr heat input, of each criteria pollutant, including time and date, for each heater treater;

(2) five highest hourly fuel flow rates and heat inputs by quarter in units of MMBtu/hr for each heater treater;

(3) Daily, monthly, and quarterly volume of fuel gas used by each heater treater.

(c) *Fugitive Hydrocarbons*. Rule 331/Enhanced Monitoring fugitive hydrocarbon I&M program data (on a quarterly basis) for both the oil dehydration plant and gas plant maintained in separate and distinct reports:

(1) Inspection summary.

(2) Record of leaking components.

(3) Record of leaks from critical components.

(4) Record of leaks from components that incur five repair actions within a continuous 12-month period.

(5) Record of component repair actions including dates of component re-inspections.

(6) An updated FHC I&M inventory due to change in component list or diagrams.

(7) Listing of components installed as BACT as approved by the District.

(8) For valves monitored monthly, provide as a separate and identifiable part of the Leak Summary Table, records that the valves were monitored monthly and the following: plant, P&ID number, tag number, component, measured emission rates (ppmv and drop-per-minute), date inspected, date of repair, days to repair, and re-inspection data and results.

(d) *Flaring.*

(1) The date; duration of flaring events (including start and stop times); quantity of gas flared; hydrogen sulfide content per third party analysis; value; reason for each flaring event, including the processing unit or equipment type involved and the type of event. The volumes of gas combusted and resulting mass emissions of all criteria pollutants for each type of event shall also be summarized for a cumulative summary for each day, quarter and year. The volume of pilot/purge fuel gas combusted in the flare shall be recorded on a monthly, quarterly and annual basis.

(2) The results of the quarterly VEE inspections and any subsequent Method 9 inspections required by permit condition 9.B.2.

(e) *Pigging*. The number of pigging events per day, quarter and year.

(f) *Tanks and Sumps*.

(1) Monthly ppmv ROC monitoring results and frequency of carbon canisters change outs;

(2) All parameters required to be reported per the District-approved *NSPS Kb Operating Plan;*

(3) All uses of the T-280 tank, the reason, time in use and tank levels.

(4) Full documentation of all venting incidents.

(g) *Surface Coatings and Solvent Usage*. On a monthly basis the amount of surface coating/solvent used; the percentage of ROC by weight (as applied); the surface coating/solvent density; the amount of solvent reclaimed; whether the surface coating/solvent is photochemically reactive; and, the resulting emissions of ROC and photochemically reactive surface coatings/solvents to the atmosphere in units of pounds per month.

(h) *Sulfur Recovery Unit/Waste Gas Incinerator*. Daily sulferox unit efficiencies and all parameters listed in Appendix F of the *Subpart LLL Compliance Monitoring Plan.*

(i) On a monthly basis, monitor downtime for:

(1) all monitors providing data necessary to determine Sulferox Unit efficiency;

(2) all fuel gas meters for the heater treaters and thermal oxidizer.

(j) *Facility Throughput Data*.

(1) Volume (BOPD) of dry oil processed and pipeline-quality oil produced as determined by the LACT meter;

(2) Volume (MMscfd) of produced pipeline-quality fuel gas burned at the LOGP;

(3) Volume (MMscfd) of public utility fuel gas burned at the LOGP;

(4) volume of Lompoc Oil Field gas and Platform Irene gas processed through the LOGP each day;

(5) Volume (MMscf) of gas recovered from the oil treatment process and transported from the LOGP;

(6) Volume (MMscf) of gas transported from Platform Irene.

(k) Date, start and stop (clock) time, elapsed time of operation (minutes) and equipment identification for each piece of emergency generator and firewater pump equipment;

(l) Date, identification of equipment vacuumed, volume (bbls), description of material vacuumed and reason for the use of vacuum truck(s).

(m) Human Olfactory Verification and Odor Response Program:

(i) Date, time, location, and description of odor complaints;

(ii) Chronology of actions taken by PXP when odors are detected and isolated;

(iii) Chronology and note log for calls to the site. This log shall provide a written account of the events and actions taken to isolate odors, identify the sources, and any mitigation action(s) taken;

(iv) Date, time, location, and the results of independent laboratory analysis of samples taken.

(n) Date of application and/or disposal, material identification number(s), volume (gallons), ROC content (pounds per gallon), and Material Safety Data Sheet (MSDS) for all coating(s) and solvent(s) used;

(o) Date, start and stop (clock) time, vessel identification, and volume (scf) and type of gas released during purging of vessels containing ROC or sulfur compounds;

(p) Volume (gallons) and date of flare gas scrubbing solution replacement;

(q) Drain sump canister monthly reading and change out information;

(r) Records of engine maintenance conducted pursuant to Subpart ZZZZ.

(s) *General Reporting Requirements*.

(1) The results of the quarterly VEE inspections on diesel ICEs and any subsequent Method 9 inspections required by permit condition 9.B.2.

(2) On a quarterly basis, the emissions from each permitted emission unit for each criteria pollutant. Vessel emissions shall be reported for vessel trips between Platform Irene and the 25-mile radius around Platform Irene, as well as, vessel trips between Platform Irene and the Santa Barbara County line;

(3) On quarterly basis, the emissions from each exempt emission unit for each criteria pollutant and results of ROC breakthrough monitoring;

(4) Odorant delivery dates and volume delivered for the sales gas and LPG odorant stations;

(5) A summary of each and every occurrence of non-compliance with the provisions of this permit, District rules, NSPS and any other applicable air quality requirement;

(6) Semi-annual fuel gas analysis for determination of fuel gas H_2S, TRS and HHV;

(7) The amount, in units of long tons, and source (by monthly reports summarized quarterly) of sulfur shipped from the LOGP facility and the number and size of trucks used;

(8) Information as required under the Standards of Performance for New Stationary Sources (40 CFR, Part 60);

(9) A copy of the Rule 202 De Minimis Log for the stationary source;

(10) Results of all process stream analyses.
[Re: ATC 6708, ATC 9522; 40 CFR 70.6]

C.13 **BACT.** PXP shall apply emission control and plant design measures which represent Best Available Control Technology (BACT) to the operation of the LOGP facilities as described in Section 4.0 and Tables 4.10-1 through 4.10-4. BACT measures shall be in place and in operation at all times for the life of the project. *[Re: ATC 6708, ATC 9522]*

C.14 **Ambient Air Quality Monitoring Program.** PXP shall operate the monitoring stations listed in Table 4.13 of this document, for the life of the project or until such time as the APCO determines that the monitoring requirements have been satisfied. PXP shall monitor and report the parameters listed in Table 4.13 in accordance with the District Air Quality and Meteorological Monitoring (AQMM) Protocol (October, 1990, or subsequent District-approved updates). The 1990 AQMM Protocol and all subsequent updates and modifications prior to the issuance of this permit are hereby incorporated by reference as an enforceable part of this permit. This includes the site-specific District-approved monitoring plans submitted by PXP for the LOGP, (including Odor Monitoring) and the Paradise Road location as well as the Quality Assurance/Quality Control (QA/QC) Document (dated June, 1991, or subsequent District-approved updates), submitted by PXP. The QA/QC Document is incorporated herein by reference as an enforceable part of this permit. PXP shall be provided with an opportunity to comment on draft updates of the Monitoring Protocols prepared by the District. PXP shall respond in writing to District-identified deficiencies in the updates to the QA/QC Document within thirty (30) calendar days of receipt of the District's comments. Ambient and meteorological data shall conform to the time schedule specified in the District AQMM Protocol.

If deemed necessary by the District, PXP shall install additional monitoring stations to monitor upset/breakdown impacts. This requirement for additional monitoring stations may be appealed to the Air Pollution Control District Hearing Board by PXP, solely to review the justification for the additional stations.

Hourly averages of all air quality parameters shall be reported in the data summaries as one-hour clock averages. For the purpose of compliance with the state and federal standards and increments, data shall be calculated for all monitoring stations as follows: one hour clock averages based on five (5) minute intervals, except for H_2S and Total Reduced Sulfur (TRS) which will require three (3) minute intervals. These running hour calculations shall be initiated and reported within ninety (90) calendar days from the date of receipt of the written request from the District.

All data collected as required in Table 4.13, shall be telemetered to the District on a real-time basis. The term "real-time" shall be construed as to allow the District to poll data from PXP monitoring stations on demand.

If repeated instrument failures occur during the recording of elevated pollutant levels, or recurrent problems cause data recovery rates to fall below the specified monthly minimum recovery rates as identified in the AQMM Protocol, the District may require redundant analyzers. This requirement for redundant analyzer installation may be appealed to the Air Pollution Control District Hearing Board by PXP, solely to review the justification for the redundant monitors. *[PTO 6708-09]*

C.15 **Ambient Monitoring Station Data Review and Audit Fee.** As specified by condition 14 of this permit, PXP shall operate ambient monitoring stations and submit data to the District for quality assurance review and shall have the stations audited quarterly by District, or its contractor. In addition, PXP shall reimburse the District for the cost of this service. Effective July 1, 1999, PXP shall be assessed an annual fee, based on the District’s fiscal year, collected semi-annually.

Pursuant to Rule 210 III.A., PXP shall pay fees specified in Table C.15. The District will use this fee to pay staff costs to review and quality assure the monitoring data collected by PXP and the contractor or staff costs to audit the monitoring equipment. This fee shall not cover any District time necessary to issue or respond to any Notice of Violation, which will be billed on a reimbursable basis. Fees shall be due and payable pursuant to governing provisions of Rule 210, including CPI adjustments.

In the event that PXP consistently requires services in excess of those assumed in the March 27, 1998 letter (*Fixed Fee Proposal for Monitoring and DAS Costs*), the Control Officer may move PXP to a reimbursable method of payment, subject to provisions of Rule 210. In the event that the assumptions used to establish this fee substantially increase or decrease, District may revisit and adjust the fee based on documentation of cost of services.

The fees prescribed in this condition shall expire if and when the Board adopts an Ambient Monitoring Station Data Review and Audit Fee and such fee becomes effective.

Table C.15. FEES for DATA REVIEW and AUDIT [(a) (b)]

FEE DESCRIPTION	FEE
Monitoring Station Data Review and Audit Fee	
Data review and audit activities associated with data submitted from any monitoring station in Table 4.13 of this permit.	$33,854 annually
Data review and audit activities associated with data submitted from any odor station in Table 4.13 of this permit.	$16,926 annually

(a) All fees shall be due and payable pursuant to the governing provisions of Rule 210, including CPI adjustments.

(b) The fees in this table are based on the District's March 27, 1998 letter (*Fixed Fee Proposal for Monitoring and DAS Costs*) and may be updated pursuant to the requirements of this permit. *[Re: ATC 10146]*

C.16 **Source Testing.** The following equipment items are required to be source tested:

Heater Treaters: The heater treaters identified in Table 4.12-2 shall be source tested on a biennial basis. The test shall be completed by March 1 unless the District approves a later date to facilitate test plan approval.

Thermal Oxidizer: PXP shall conduct stack emission testing of air emissions and process parameters listed in Table 4.12-1. Source testing of the thermal oxidizer outlet ROC concentration and/or destruction rate efficiency shall be conducted annually for BACT compliance. NO_x and CO shall be tested biennially. The test shall be completed by March 1 unless the District approves a later date.

The permittee shall submit a written source test plan to the District for approval at least thirty (30) days prior to initiation of each source test. The source test plan shall be prepared consistent with the District's Source Test Procedures Manual (revised May 1990 and any subsequent revisions). The permittee shall obtain written District approval of the source test plan prior to commencement of source testing. The District shall be notified at least ten (10) calendar days prior to the start of source testing activity to arrange for a mutually agreeable source test date when District personnel may observe the test.

A source test for an item of equipment shall be performed on the scheduled day of testing (the test day mutually agreed to) unless circumstances beyond the control of the operator prevent completion of the test on the scheduled day. Such circumstances include mechanical malfunction of the equipment to be tested, malfunction of the source test equipment, delays in source test contractor arrival and/or set-up, or unsafe conditions on site. Except in cases of an emergency, the operator shall seek and obtain District approval before deferring or discontinuing a scheduled test, or performing maintenance on the equipment item on the scheduled test day.

Once the sample probe has been inserted into the exhaust stream of the equipment unit to be tested (or extraction of the sample has begun), the test shall proceed in accordance with the approved source test plan. In no case shall a test run be aborted except in the case of an emergency or unless approval is first obtained from the District. If the test cannot be completed on the scheduled day, then the test shall be rescheduled for another time with prior authorization by the District. Failing to perform or complete the source test of an equipment item on the scheduled test day without a valid reason and without District's prior authorization, except in the case of an emergency, shall constitute a violation of this permit. If a test is postponed due to an emergency, written documentation of the emergency event shall be submitted to the District by the close of the business day following the scheduled test day.

A test report shall be prepared and submitted to the District within forty-five (45) calendar days after test completion, or earlier if the District determines that special circumstances warrant earlier submittal. The test report shall be consistent in content and format with the approved source test plan and shall contain the following information:

(a) Summary of emission test results on volumetric (ppmv at 3% and 15% O_2), mass (lb/hour), and emission factor (lb/MMBtu) basis;

(b) Comparison of emission test results with permit limitations, including observed control efficiencies;

(c) Discussion of any problems, assumptions (including operating parameters and load), or uncertainties regarding the testing;

(d) Discussion of any measured parameters that do not meet permit limitations, proposed procedures to correct the problem, and schedule for retesting;

(e) Discussion of the QA/QC activities relative to the results of testing;

(f) Certification of accuracy of testing methods and results signed by representatives of PXP and the testing contractor;

(g) Raw data and calculation sheets as appendices;

(h) Summary of any maintenance procedures or adjustments to equipment being tested or associated control systems conducted in anticipation of the source test.

The timelines indicated above may be extended for good cause provided a written request is submitted to the District at least three (3) days in advance of the deadline, and approval for the extension is granted by the District. *[Re: ATC 6708; ATC 9522]*

C.17 **Process Stream Sampling and Analysis.** PXP shall sample and analyze by a third party, the following process streams. All process stream samples shall be taken according to District-approved ASTM methods and must follow traceable chain of custody procedures.

(a) Produced Gas: Sample taken at production separator outlet. Analysis for: HHV, total sulfur, hydrogen sulfide, composition. Samples to be taken on an annual basis.

(b) Produced Oil: Sample taken at outlet from production separator. Analysis for: API gravity; true vapor pressure (per Rule 325 methods). Samples to be taken on an annual basis.

(c) Fuel Gas: Analysis for: HHV on a semi-annual basis; analysis for total sulfur and H_2S to be taken on a semi-annual basis. H_2S shall be monitored on continuous basis as well.

(d) Produced Wastewater: Streams are analyzed for ROC content necessary to maintain compliance with Rule 325.B. Samples to be taken on an annual basis, if requested by the District.

All sampling and analyses are required to be performed according to District-approved procedures and methodologies. All sampling and analysis must be traceable by chain of custody procedures. *[Re: ATC 6708; ATC 9522; 40 CFR 70.6]*

C.18 **Process Monitor Calibration and Maintenance Plan.** PXP shall implement the *Process Monitor Calibration and Maintenance Plan*, dated July 22, 2003 or future approved updates. It shall include all design specifications, ranges, and manufacturer recommended maintenance and calibration procedures and frequencies for the following instruments associated with the gas processing plant including but not limited to:

(a) Thermal oxidizer natural gas fuel meter (FR-1521)

(b) Thermal Oxidizer combustion chamber temperature (TR-1524)

(c) Acid gas flow meter (FT-1300)

(d) Sour gas flow rate (FT-1285)

(e) Sweet gas flow rate (FT-1515)

(f) Fuel gas sulfur content (AI-1500)

(g) Tail gas flow rate (FR-1301)

(h) Regenerator air flow rate (FT-1330)

All monitors and meters used to determine facility compliance shall be included in this plan. *[Re: ATC 6708; ATC 9522]*

C.19 **Data Telemetry.** PXP shall telemeter monitoring data to the District as specified by Conditions C.14 (*Ambient Monitoring Requirements*) and C.23 (*Odor Monitoring*) of this permit. The data telemetry equipment shall be in place and functional for the life of the project consistent with the above-specified conditions. This telemetry equipment shall be compatible with the District's Central Data Acquisition System. *[Re: ATC 6708]*

C.20 **Mass Emission Limitations**. With the exception of sumps and solvents, mass emissions shall not exceed the values listed in Tables 5.1, 5.2 and 5.4. *[Re: ATC 6708;ATC 9522]*

C.21 **Facility Throughput Limitations.** The oil and gas processed at the LOGP shall be produced only from Platform Irene and the Lompoc Oil Field and shall not exceed the following rates:

(a) Pipeline-quality oil (less BS&W, corrected to 60˚ F): 25 MBOPD

(b) Oil evolved gas: 3.3 MMscfd

(c) Gas from Platform Irene: 12.0 MMscfd

(d) Inlet gas to the gas processing plant: 15.0 MMscfd

On a daily basis, PXP shall record in a log the volume of dry oil processed, the volume of platform gas processed and the volume of sour stripping gas processed. In addition, PXP shall log the volume of oil exported from the transportation terminal each day, summarized on a calendar quarter basis. *[Re: ATC 6708; ATC 9522]*

C.22 **Complaint Response**. PXP shall provide the District with the name, title, current address, and 24-hour telephone number of contact person(s) who shall be available to respond to complaints from the public concerning nuisance or odors. These contact person(s) shall aid the District staff, as requested by the District, in the investigation of any complaints received. PXP shall take actions necessary to correct the facility activity which is reasonably believed by PXP to have caused the complaint. PXP shall keep the District fully apprised of their assessment and resolution of the problem. *[Re: ATC 6708]*

C.23 **Odor Monitoring Program.** PXP shall operate, maintain, and report data from the ambient odor monitoring site located at the LOGP. This odor monitoring station shall be located on property owned or controlled by PXP. Sampling conducted at the station shall represent ambient conditions for purposes of enforcing the conditions of this permit. Any total reduced sulfides (TRS) data obtained at this station that exceeds 0.06 ppm (over a 3 minute averaging time) or 0.03 ppm (over a one hour averaging time), attributable to the LOGP, shall constitute a violation of this permit. PXP shall operate the odor monitoring station for the life of the project.

PXP shall monitor the parameters listed in Table 4.13 of this permit according to the revised Monitoring Plan, the Quality Assurance/Quality Control (QA/QC) Document (June, 1991) submitted by PXP, and the District's Air Quality and Meteorological Monitoring Protocol (October, 1990) and subsequent updates to these documents.

All data collected at the Odor Monitoring Station shall be telemetered to the District on a real-time basis. The term "real-time" shall be construed to allow the District to poll data from PXP monitoring stations on demand. Hourly averages of all air quality parameters shall be reported in the data summaries as one-hour clock averages. Data summaries shall include data to demonstrate compliance with District Rules 303 and 310 and County Ordinance 2832.

In the event that odor complaints or violation of Rule 310 occur and the District determines that the source of the odors can reasonably be attributed to operations at the LOGP, the District may require additional odor monitoring stations or other mitigation.

PXP shall implement a Human Olfactory Verification and Odor Response Program as specified in the District-approved monitoring plan (May, 1991). *[Re: ATC 6708;40 CFR 70.6]*

C.24 **NGL/LPG Loading Rack.** The NGL/LPG loading rack shall be equipped with a vapor return system. This system shall be capable of returning all vapors generated during the loading of the NGL and LPG to stationary tanks and trucks. The vapor return system shall be operated at all times the loading rack is in use. *[Re: ATC 9522]*

C.25 **Maximum H_2S Concentrations**. The maximum hourly H_2S concentration in the gas at the LOGP, as measured by existing monitors and sampling, shall not exceed the following limits:

(a) Facility maximum: 10,000 ppmv[7]

(b) Pipeline from Surf to the LOGP: 8,000 ppmv[8] *[Re: ATC/PTO 10341]*

C.26 **Vacuum Truck Use.** During vacuum truck use, PXP shall use a District approved carbon adsorption system (carbon canister) to reduce emissions of ROC and odorous compounds from the vacuum truck. The vacuum truck carbon canister shall be changed out after each 25 uses. Upon request by the District, PXP shall arrange for District personnel to observe, inspect and/or analyze carbon canister flow streams during vacuum truck use. When not in use, the inlet of each carbon canister shall be sealed with a leak-free (i.e., camlock or threaded) cap. *[Re: ATC 6708]*

C.27 **Emergency Generator Firewater Pumps.** The onshore diesel-fired firewater pumps and emergency generator shall not operate more than thirty (30) minutes each week except for the following:

(a) Emergencies requiring their use for longer periods of time;

(b) Annual performance drills;

(c) Quarterly performance drills.

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[7] Sorbent tube samples, taken on a daily basis on the overhead gas, will be used to demonstrate compliance.

[8] As measured daily by calorimetric tube per (PTO 9106 PC 9.C.15) and in accordance with the Point Pedernales Pipeline Sulfur Reporting Plan.

Only one piece of emergency equipment shall be operated at a time during weekly performance drills. Between 8:00 am and 5:00 PM pacific time, firewater pumps 960 and 970 may be operated simultaneously for two (2) hour periods to satisfy quarterly firewater performance drills as required by the Santa Barbara County Fire Department. No more than three (3) two-hour simultaneous test periods will be allowed in any one quarter. During annual performance drills, firewater pumps 960 and 970 may operate for a cumulative period of (8) hours each. During annual performance drills, these pumps shall not operate simultaneously nor shall any pump operate continuously more than three (3) hours. *[Re: ATC 6708]*

C.28 **Vessel Degassing.** Any pressure vessel not subject to District Rule 343 shall be depressurized by exhausting the gaseous contents into the vapor recovery system. Vessel purging shall be consistent with the *Vessel Degassing Plan*. PXP shall notify the District's PXP Project Manager at least eight (8) hours prior to any degassing or purging of any stationary tank, vessel, or containers which handle ROCs or sulfur compounds, except during emergencies or breakdowns. During degassing or purging of any vessel, it is to be filled with fluid it normally handles. The fluid level in the vessel will be drawn down while introducing PUC-quality gas or other inert gas (e.g., nitrogen) into it. *[Re: ATC 6708]*

C.29 **Diesel IC Engines - Particulate Matter Emissions.** To ensure compliance with District Rules 205.A, 302, 304, 309 and the California Health and Safety Code Section 41701, PXP shall implement the District-approved *IC Engine Particulate Matter Operation and Maintenance Plan*. This plan shall contain manufacturer recommended operational and maintenance procedures to ensure that emissions from all project diesel-fired engines are minimized. This Plan details the manufacturer recommended maintenance and calibration schedules for all project diesel-fired engines for the purpose of minimizing particulate emissions. Where manufacturer guidance is not available, the recommendations of comparable equipment manufacturers and good engineering judgment shall be utilized. *[Re: ATC 6708; 40 CFR 70.6]*.

C.30 **As-Built Drawings.** Upon request, PXP shall provide "as-built" drawings or acceptable facsimiles thereof, to the District or its agents. From time to time, the District shall review "as-built" drawings to determine conformance with the PTO, or with any other ATC application for this facility, submitted to the District. *[Re: ATC 6708]*

C.31 **Continuous Monitoring.** With the exception of Draeger tube sampling, the parameters listed in Table 4.11 shall be continuously monitored. Monitors shall be installed, maintained, and operated in accordance with the District-approved LOGP *Process Monitor and Calibration Plan*.

Sampling and analysis for total reduced sulfur shall occur quarterly. Additional continuous monitors or redundant systems may be required by the District if problems with facility or monitor operations develop which warrant additional monitoring.

C.32 **Central Data Acquisition System (DAS).** PXP shall connect the ambient and meteorological parameters and all other parameters required to be telemetered to the District, to the District central data acquisition system (DAS) as specified in permit condition 19 above. In addition, PXP shall reimburse the District for the cost of operating and maintaining the DAS. PXP shall be assessed an annual fee, based on the District's fiscal year, collected semi-annually.

Pursuant to Rule 210 III.A., PXP shall pay fees specified in Table C.32 below. The District shall use these fees to operate, maintain, and upgrade the DAS in proper running order. Fees shall be due and payable pursuant to governing provisions of Rule 210, including CPI adjustments.

All ongoing costs and anticipated future capital upgrades will be District's responsibility and will be accomplished within the above stated DAS fee. This fee is intended to cover the annual operating budget and upgrades of the DAS and is intended to gradually phase District into a share of the DAS costs (as outlined in the March 27, 1998, letter - *Fixed Fee Proposal for Monitoring and DAS Costs*). In the event that the assumptions used to establish this fee substantially increase or decrease, District may revisit and adjust the fee based on documentation of cost of services.

The fees prescribed in this condition shall expire if and when the Board adopts a Data Acquisition System Operation and Maintenance Fee schedule and such fee becomes effective. *[Re: ATC 6708]*

Table C.32 - Fees for Data Acquisition System Operation and Maintenance[(a) (b)]

FEE DESCRIPTION	FEE
DATA ACQUISITION SYSTEM OPERATION AND MAINTENANCE FEE	
Per ambient or meteorological parameter required by permit to be transmitted real-time to the District Central Data Acquisition System	$1,876.50 annually

(a) All fees shall be due and payable pursuant to the governing provisions of Rule 210, including CPI adjustments.

(b) The fees in this table are based on the District's March 27, 1998 letter (Fixed Fee Proposal for Monitoring and DAS Costs) and may be updated pursuant to Rule 210 and shall be effective when issued and shall not require a modification to this permit. *[Ref: ATC 6708]*

C.33 **Compressor Seal Venting Control.** All compressor seals in gaseous hydrocarbon service at the LOGP shall be dual mechanical seals vented to the vapor recovery system for the duration of the project. *[Re: ATC 6708]*

C.34 **Carbon Canisters**. The following provisions shall apply regarding use of carbon canisters:

<u>*LPG Odorant Tanks*</u>. Emissions from the sales gas and LPG odorant tanks shall be controlled by use of a carbon canisters emissions during refilling operations. During delivery of sales gas or LPG odorant, all vapors shall be routed through the carbon canister associated with the loading vehicle. PXP will maintain records of the test results

and change outs of the carbon canister filters. Testing for ROC breakthrough shall be conducted immediately following delivery of the odorant by either the truck owner/operator or PXP. The LPG odorant pump shall be operated on nitrogen and odorant tank pressure relief tank equipped with a rupture disk. The odorant pump associated with the sales gas odorant station shall be operated on compressed air. When not in use, the inlet of each carbon canister shall be sealed with a leak-free (i.e., camlock or threaded) cap.

<u>Sumps</u>. All sumps (with the exception of S-895) shall be equipped with a carbon canister. The ROC emissions from the exhaust of the carbon canister shall be checked monthly for breakthrough (200 ppm). An OVA, or other District-approved equipment, calibrated to methane, shall be used for this purpose. Within ten (10) calendar days of noting an ROC exhaust concentration level of 200 ppmv or greater, PXP shall replace the carbon canister. Failure to replace a carbon canister within 10 calendar days shall constitute a violation of this condition. When not in use, the inlet of each carbon canister shall be sealed with a leak-free (i.e., camlock or threaded) cap.
[Re: ATC 6708; ATC 9522; 40 CFR 70.6)]

C.35 **Pressure Relief Venting Control.** All pressure relief valves in gaseous hydrocarbon service at the LOGP shall be vented to the flare system. PXP shall maintain and operate for the duration of the project, a system that can handle the liquid discharges from relief valves at the gas-oil separator, the freewater knockout drum, and the heater treaters to a closed retention vessel at the LOGP. The closed retention vessel shall be large enough to accommodate the worst case liquid relief load and allow for the proper liquid/gas separation as determined by PXP and approved by the District. All gas releases from the retention vessel shall be routed to the LOGP flare.

C.36 **Fuel Gas Sulfur Monitoring.** Natural gas from the gas processing plant used as fuel shall be continuously monitored and recorded by a District-approved H_2S monitor for compliance with the sulfur limits listed above. This monitor shall be maintained per the procedures in the *Process Monitor Calibration and Maintenance Plan*. In addition, semi-annual fuel gas samples shall be collected and analyzed for H_2S and total reduced sulfur (TRS). Samples shall be analyzed in accordance with the procedures listed below. Lab sample data and continuous monitoring data shall be used to assess compliance with H_2S and TRS limits.

Analysis Procedures:

- Fuel gas samples shall be collected in Tedlar bags equipped with Teflon fittings.
- Fuel gas samples shall be analyzed for H_2S and TRS using EPA/CARB Method 15/16 no later than 24 hours after sample collection.
- Analytical apparatus shall be suitably constructed, configured, and operated to measure low concentrations of H_2S and TRS in a natural gas sample matrix according to Method 15/16 and good laboratory practice (GLP).
- Analytical apparatus shall be multipoint calibrated with NIST-traceable standards and calibration-checked with NIST-traceable standards according to Method 15/16 and GLP.

- Analytical results shall be documented and reported to PXP by the laboratory.

C.37 **Equipment Operation and Maintenance.** Operation under this permit shall be conducted in compliance with all data, specifications and assumptions included with the applications as documented in the District's project file (and supplements thereto) and the information in this reevaluated permit. *[Re: ATC 6708]*

C.38 **Diesel Internal Combustion Engines – NESHAP ZZZZ.** The equipment subject to this permit condition are one emergency standby electrical generator and two emergency standby firewater pumps in the Table below.

District Device No.	Name
107189	Emergency Diesel Generator (SN: 7BZ01677)
107187	Emergency Firewater Pump (SN 6TB02192)
107188	Emergency Firewater Pump (SN 6TB03520)

The following conditions apply:

a. *Engine Maintenance* - Existing non-emergency non-black start compression ignition reciprocating internal combustion engines (RICE) must comply with the following operating limits by no later than May 3, 2013:

(1) Change the oil and filter every 1,000 hours of operation or annually, whichever comes first. In place of changing the oil every 1,000 hours of operation or annually, the operator may analyze the oil of each engine every 1,000 hours of operation or annually, whichever occurs first. The analysis shall measure the Total Base Number, the oil viscosity, and the percent water content. The oil and filter shall be changed if any of the following limits are exceeded:

(a) The tested Total Base Number is less than 30 percent of the Total Base Number of the oil when new.

(b) The tested oil viscosity has changed by more than 20 percent from the oil viscosity when new.

(c) The tested percent water content (by volume) is greater than 0.5 percent.
[*ref: 40 CFR §63.6625*]

(2) Inspect the air cleaner every 1,000 hours of operation or annually, whichever comes first.

(3) Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first.

b. Starting May3, 2013 the following records shall be kept for each engine subject to Subpart ZZZZ:

(1) The date of each engine oil change and the number of hours of operation since the last oil change.

(2) The date and results of each oil analysis if the results of the oil analysis were used as the basis for not changing the oil every 1,000 hours or annually, whichever came first.

(3) The date of each engine air filter inspection and the number of hours of operation since the last air filter inspection. Indicate if the air filter was replaced as a result of the inspection.

(4) The date of each engine's hose and belts inspection and the number of hours of operation since the last hose and belt inspection. Indicate if any hose or belt was replaced as a result of the inspection.

9.D District-Only Conditions

D.1 **Mass Emission Limitations.** Mass emissions for the sumps and solvents shall not exceed the values listed in Tables 5.1, 5.2 and 5.4. *[Re: ATC 6708; ATC 9522]*

D.2 **Nuisance (Rule 303).** No pollutant emissions from any source at PXP shall create nuisance conditions. Operations shall not endanger health, safety or comfort, nor shall they damage any property or business. *[Re: District Rule 303]*

D.3 **Odorous Organic Sulfides (Rule 310).** PXP shall not discharge into atmosphere H_2S and organic sulfides that result in a ground level impact beyond the PXP property boundary in excess of either 0.06 ppmv averaged over 3 minutes and 0.03 ppmv averaged over 1 hour. *[Re: District Rule 310]*

D.4 **Standby/Emergency Diesel IC Engine.**
The equipment subject to this permit condition are one emergency standby electrical generator and two emergency standby firewater pumps in the Table below.

District Device No.	Name
107189	Emergency Diesel Generator (SN: 7BZ01677)
107187	Emergency Firewater Pump (SN 6TB02192)
107188	Emergency Firewater Pump (SN 6TB03520)

The following conditions apply:

(a) Emission Limitations**.** Mass emissions from the emergency diesel generator shall not exceed the values listed in Table 5.1-3 and 5.1-4. Emissions of PM and other pollutants shall not exceed the emissions standards listed in Table 5.1-2 of this permit. Compliance shall be based on the operational, monitoring, recordkeeping and reporting conditions of this permit.

(b) Operational Restrictions**.** The equipment permitted herein is subject to the following operational restrictions listed below. Emergency use operations, as defined in Section (d)(25) of the ATCM[9], have no operational hour's limitations:

i. Maintenance & Testing Use Limit: The stationary emergency standby diesel-fueled CI generator engine subject to this permit, except for in-use firewater pump engines, shall limit maintenance and testing[10] operations to no more than 2 hours per day and 20 hours per year.

ii. Impending Rotating Outage Use: The stationary emergency standby diesel-fueled CI generator engine subject to this permit may be operated in response to the notification of an impending rotating outage if all the

[9] As used in the permit, "ATCM" means Section 93115, Title 17, California Code of Regulations. Airborne Toxic Control Measure for Stationary Compression Ignition (CI) Engines
[10] "maintenance and testing" is defined in Section (d)(41) of the ATCM

conditions cited in Section (e)(2)(A)(2) or Section (e)(2)(B)(1) of the ATCM are met, as applicable.

iii. Fuel and Fuel Additive Requirements: Effective January 1, 2006, the permittee may only add fuel and/or fuel additives to the engines or any fuel tank directly attached to the engines that comply with Section (e)(1)(A) or Section (e)(1)(B) of the ATCM, as applicable. This provision may be delayed pursuant to the provisions of Section (c)(19) of the ATCM.

iv. Firewater Pumps: The stationary emergency standby diesel-fueled CI firewater pumps shall not operate more than the number of hours necessary to comply with the testing requirements of the current National Fire Protection Association (NFPA) 25 – "*Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems*".

(c) Monitoring**.** The equipment permitted herein is subject to the following monitoring requirements:

i. Non-Resettable Hour Meter: Each diesel-fueled CI engine subject to this permit shall have installed a non-resettable hour meter with a minimum display capability of 9,999 hours, unless the District has determined (in writing) that a non-resettable hour meter with a different minimum display capability is appropriate in consideration of the historical use of the engine and the owner or operator's compliance history.

(d) Recordkeeping**.** The permittee shall record and maintain the information listed below. Log entries shall be retained for a minimum of 36 months from the date of entry. Log entries made within 24 months of the most recent entry shall be retained on-site, either at a central location or at the engine's location, and made immediately available to the District staff upon request. Log entries made from 25 to 36 months from most recent entry shall be made available to District staff within 5 working days from request. Use of District Form ENF-92 (*Diesel-Fired Emergency Standby Engine Recordkeeping Form*) can be used for this requirement.

i. emergency use hours of operation.

ii. maintenance and testing hours of operation.

iii. hours of operation for emission testing to show compliance with Section (e)(2)(A)(3) or Section (e)(2)(B)(3).

iv. hours of operation for all uses other than those specified in items (i) - (iii) above along with a description of what those hours were for.

v. The owner or operator shall document fuel use through the retention of fuel purchase records that account for all fuel used in the engine and all fuel purchased for use in the engine, and, at a minimum, contain the following information for each individual fuel purchase transaction:

(1) identification of the fuel purchased as either CARB Diesel, or an alternative diesel fuel that meets the requirements of the Verification Procedure, or an alternative fuel, or CARB Diesel fuel used with

additives that meet the requirements of the Verification Procedure, or any combination of the above;

(2) amount of fuel purchased;

(3) date when the fuel was purchased;

(4) signature of owner or operator or representative of owner or operator who received the fuel;

(5) signature of fuel provider indicating fuel was delivered.

vi. hours of operation to comply with the requirements of the NFPA for healthcare facilities or firewater pumps.

(e) Reporting**.** By March 1st of each year, a written report documenting compliance with the terms and conditions of this permit and the ATCM for the previous calendar year shall be provided by the permittee to the District (Attn: *Annual Report Coordinator*). All logs and other basic source data not included in the report shall be made available to the District upon request. The report shall include the information required in the Recordkeeping Condition above.

(f) Temporary Engine Replacements - DICE ATCM**.** Any reciprocating internal combustion engine subject to this permit and the stationary diesel ATCM may be replaced temporarily only if the requirements (i-vi) listed herein are satisfied.

i. The permitted engine is in need of routine repair or maintenance.

ii. The permitted engine that is undergoing routine repair or maintenance is returned to its original service within 180 days of installation of the temporary engine.

iii. The temporary replacement engine has the same or lower manufacturer rated horsepower and same or lower potential to emit of each pollutant as the permitted engine that is being temporarily replaced. At the written request of the permittee, the District may approve a replacement engine with a larger rated horsepower than the permitted engine if the proposed temporary engine has manufacturer guaranteed emissions (for a brand new engine) or source test data (for a previously used engine) less than or equal to the permitted engine.

iv. The temporary replacement engine shall comply with all rules and permit requirements that apply to the permitted engine that is undergoing routine repair or maintenance.

v. For each permitted engine to be temporarily replaced, the permittee shall submit a completed *Temporary IC Engine Replacement Notification* form (Form ENF-94) within 14 days of the temporary engine being installed. This form shall be sent electronically to: *temp-engine@sbcapcd.org*.

vi. Within 14 days upon return of the original permitted engine to service, the permittee shall submit a completed *Temporary IC Engine Replacement Report* form (Form ENF-95). This form shall be sent electronically to: *temp-engine@sbcapcd.org*.

Any engine in temporary replacement service shall be immediately shut down if the District determines that the requirements of this condition have not been met. This condition does not apply to engines that have experienced a cracked block (unless under manufacturer's warranty), to engines for which replacement parts are no longer available, or new engine replacements {including "reconstructed" engines as defined in Section (d)(44) of the ATCM}. Such engines are subject to the provisions of New Source Review and the new engine requirements of the ATCM.

(g) Permanent Engine Replacements**.** Any E/S engine, firewater pump engine or engine used for an essential public service that breaks down and cannot be repaired may install a new replacement engine without first obtaining an ATC permit only if the requirements (i – v) listed herein are satisfied.

i. The permitted stationary diesel IC engine is an E/S engine, a firewater pump engine or an engine used for an essential public service (as defined by the District).

ii. The engine breaks down, cannot be repaired and needs to be replaced by a new engine.

iii. The facility provides "good cause" (in writing) for the immediate need to install a permanent replacement engine prior to the time period before an ATC permit can be obtained for a new engine. The new engine must comply with the requirements of the ATCM for new engines. If a new engine is not immediately available, a temporary engine may be used while the new replacement engine is being procured. During this time period, the temporary replacement engine must meet the same guidelines and procedures as defined in the permit condition above (*Temporary Engine Replacements - DICE ATCM*).
An Authority to Construct application for the new permanent engine is submitted to the District within 15 days of the existing engine being replaced and the District permit for the new engine is obtained no later than 180 days from the date of engine replacement (these timelines include the use of a temporary engine).

iv. For each permitted engine to be permanently replaced pursuant to the condition, the permittee shall submit a completed *Permanent IC Engine Replacement Notification* form (Form ENF-96) within 14 days of either the permanent or temporary engine being installed. This form shall be sent electronically to: *temp-engine@sbcapcd.org*. Any engine installed (either temporally or permanently) pursuant to this permit condition shall be immediately shut down if the District determines that the requirements of this condition have not been met.

(h) Notification of Non-Compliance. Owners or operators who have determined that they are operating their stationary diesel-fueled engine(s) in violation of the requirements specified in Sections (e)(1) and (e)(2) of the ATCM shall notify the District immediately upon detection of the violation and shall be subject to District enforcement action.

(i) Notification of Loss of Exemption. Owners or operators of in-use stationary diesel-fueled CI engines, who are subject to an exemption specified in Section (c) from all or part of the requirements of Section (e)(2), shall notify the District immediately after they become aware that the exemption no longer applies and pursuant to Section (e)(4)(F)(1) of the ATCM shall demonstrate compliance within 180 days after notifying the District.

(j) Enrollment in a DRP/ISC - January 1, 2005**.** Any stationary diesel IC engine rated over 50 bhp that enrolls for the first time in a Demand Response Program/Interruptible Service Contract (as defined in the ATCM) on or after January 1, 2005, shall first obtain a District Authority to Construct permit to ensure compliance with the emission control requirements and hour limitations governing ISC engines.

D.5 **External Combustion Units - Permits Required.**

(a) An ATC/PTO permit shall be obtained prior to installation of any grouping of Rule 360 applicable boilers or hot water heaters whose combined system design heat input rating exceeds 2.000 MMBtu/hr.

(b) An ATC permit shall be obtained prior to installation, replacement, or modification of any existing Rule 361 applicable boiler or water heater rated over 2.000 MMBtu/hr.

(c) An ATC shall be obtained for any size boiler or water heater if the unit is not fired on natural gas or propane except as provided for by District Rule 202.L.15 and L.16.

D.10 **Documents Incorporated by Reference:** The documents listed below, including any District-approved updates thereof, are incorporated herein and shall have the full force and effect of a permit condition for this operating permit. These documents shall be implemented for the life of the Project and shall be made available to District inspection staff upon request.

Fugitive Inspection and Maintenance Plan (October 2001)

Subpart LLL Compliance Monitoring Plan (September 1999)

Subpart Kb Operating Plan (July 2001)

Process Monitor Calibration and Maintenance Plan (July 2003)

IC Engine Particulate Matter Operation and Maintenance (December 2003)

Flare Minimization and Volume Monitoring Plan (December 2003)

Solvent Reclamation Plan (July 2002)

Vessel Degassing Plan (December 2003)

Emergency Episode Plan (December 2003

AIR POLLUTION CONTROL OFFICER

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Date

NOTES:

(a) Permit Reevaluation Due Date: December 2015
(b) Part 70 Operating Permit Expiration Date: December 2015