Santa Barbara County
Air Pollution Control District
Our Vision: Clean Air

PROPOSED

PERMIT to OPERATE No. 5651
and
PART 70 OPERATING PERMIT No. 5651

EXXON – SYU PROJECT
LAS FLORES CANYON

12000 CALLE REAL, GOLETA
SANTA BARBARA COUNTY, CA

OPERATOR

Exxon Company, U.S.A.

OWNERSHIP

Exxon Company, U.S.A.

Santa Barbara County
Air Pollution Control District

October 19, 1999

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ABBREVIATIONS/ACRONYMS

AP-42	USEPA's *Compilation of Emission Factors*
APCD	Santa Barbara County Air Pollution Control District
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
bpd	barrels per day (1 barrel = 42 gallons)
Btu	British thermal unit
CAM	compliance assurance monitoring
CEMS	continuous emissions monitoring
CPP	cogeneration power plant
DCS	Distributed Control System
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
HRSG	Heat Recovery Steam Generator
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
LFC	Las Flores Canyon
LPG	liquid petroleum gas
M	mega (million)
MACT	Maximum Achievable Control Technology
MM	million
MW	molecular weight
NAR	Nonattainment Review
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
NSCR	non-selective catalytic reduction
O_2	oxygen

OCS	outer continental shelf
OTP	Oil Treating Plant
PI	Process Information System
PM	particulate matter
PM_{10}	particulate matter less than 10 microns
POPCO	Pacific Offshore Pipeline Company
ppm(vd or w)	parts per million (volume dry or weight)
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)
SCR	Selective Catalytic Reduction
SIP	State Implementation Plan
SGTP	Stripping Gas Treating Plant
SOV	Stabilizer Overhead Vapor
SSID	stationary source identification
STP	standard temperature (60°F) and pressure (29.92 inches of mercury)
SYU	Santa Ynez Unit
THC, TOC	total hydrocarbons, total organic compounds
TGCU	Tail Gas Cleanup Unit
tpq, TPQ	tons per quarter
tpy, TPY	tons per year
TT	Transportation Terminal
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 (APCD) 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 APCD's Rules and Regulations.

The County is designated as an ozone nonattainment area for both the state and federal ambient air quality standards. The County is also designated a nonattainment area for the state PM_{10} ambient air quality standard.

Part 70 Permitting. The issuance of this Part 70 permit for the Las Flores Canyon facility satisfies the permit issuance requirements of the APCD's Part 70 operating permit program. The Las Flores Canyon facility is a part of the *Exxon - Santa Ynez Unit ("SYU") Project* stationary source (SSID = 1482), which is a major source for VOC[1], NO_x, CO, SO_x and PM_{10}. 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 APCD, 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. Conditions listed in Section 9.D are "APCD-only" 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..

1.2 Stationary Source/Facility Overview

1.2.1 Stationary Source/Facility Overview: The Las Flores Canyon facility is part of the *Exxon – SYU Project* stationary source. The facility is comprised of an oil plant, a stripping gas plant, an NGL/LPG loading facility, a cogeneration power plant and a pipeline transportation terminal. The *Exxon - SYU Project* stationary source consists of the following 5 facilities:

- Platform Harmony (FID= 8018)
- Platform Heritage (FID= 8019)
- Platform Hondo (FID= 8009)

[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.

- Las Flores Canyon Oil and Gas Plant (FID= 1482)
- POPCO Gas Plant (FID= 3170)

1.2.2 Facility New Source Review Overview: The Las Flores Canyon facility was originally permitted under ATC 5651 in November of 1987. Since that time, ATC 5651 was modified numerous times. The APCD Permit to Operate for LFC was recently issued in January of 1999. A brief description of each modification, including the date of issuance, follows:

ATC 5651-01	12/05/91	Increase in NO_x OCS construction emissions by 549 tons.
ATC 5651-02	07/15/91	Temporary decommissioning of the LFC2 ambient air quality monitoring station during the onshore construction period.
ATC 5651-03	07/09/93	Installation of back-up gas sweetening unit; revise thermal oxidizer pilot and purge rates; allow for use of helicopters in lieu of crew boats.
ATC 5651-04	04/06/94	Extension of the Source Compliance Demonstration Period to August 8, 1994.
ATC 5651-05	01/25/95	Re-qualification of SO_x ERCs to meet Rule 359 liabilities; removal from permit of the Marine Terminal and associated equipment.
ATC 5651-06	02/17/95	Application to modify Best Available Control Technology was withdrawn by Exxon.
ATC 5651-08	06/30/94	Extension of the Source Compliance Demonstration Period to October 30, 1994.
Letter Mod	08/11/94	Eliminated ROC Monitoring at Stations LFC Sites 1 and 10.
ATC 5651-09	10/26/94	Extension of the Source Compliance Demonstration Period to May 31, 1995.
ATC 5651-10	05/31/95	Extension of the Source Compliance Demonstration Period to December 15, 1995.
ATC 5651-11	12/15/95	Extension of the Source Compliance Demonstration Period to July 31, 1996.
ATC 5651-12	07/31/96	Extension of the Source Compliance Demonstration Period to January 31, 1997.
ATC 5651-14	01/31/97	Extension of the Source Compliance Demonstration Period to July 31, 1997.

ATC 5651-15	07/31/97	Extension of the Source Compliance Demonstration Period to January 31, 1998.
ATC 9651	12/18/96	Implementation of an Enhanced Hydrocarbon I&M Program on selected valves to generate emission reduction credits.
ATC 9651-01	11/17/97	Modification to reduce the number of valves subject to the Enhanced Hydrocarbon I&M Program.
ATC/PTO 9826	01/21/98	Implementation of an Enhanced Hydrocarbon I&M Program on selected valves to generate emission reduction credits.
ATC 5651-16	01/31/98	Extension of the Source Compliance Demonstration Period to July 31, 1998.
ATC 9917	07/15/98	Modification to post-construction monitoring requirements to allow for the shut down of Site 10 near UCSB.
ATC 5651-18	07/16/98	Extension of the Source Compliance Demonstration Period to October 30, 1998 or issuance of PTO 5651, whichever is earlier.
ATC 5651-19	10/30/98	Extension of the Source Compliance Demonstration Period to January 28, 1999 or issuance of PTO 5651, whichever is earlier.
ATC 5651-17	01/27/99	Significant modification of ATC 5651 to incorporate changes in assumptions, operations and emission factors. This permit was superceded by PTO 5651 on the day of issuance.
PTO 5651	01/27/99	The APCD operating permit for LFC. All prior ATC permits were superceded by this permit.
ATC/PTO 5651-01	05/27/99	This combined ATC/PTO permit addressed operation of ambient monitors, revisions to certain parametric monitoring requirements, use of emergency firewater/floodwater pump engines and changes to the use of the Demulsifier tank.
ATC/PTO 10172	09/21/99	This combined ATC/PTO permit addressed use of larger crew and supply boats, allowed combustion of ammonia in the thermal oxidizer, revised compliance mechanisms for carbon canisters and the Equalization Tank scrubber and addressed testing and maintenance activities for the gas turbine/steam generator.

1.3 Emission Sources

The emissions from the Las Flores Canyon facility come from numerous sources, such as: a cogeneration gas turbine, a heat recovery steam generator, oil storage tanks, a sulfur plant, various sumps, pumps and compressors, a thermal oxidizer and piping components. Section 4 of this permit provides the APCD's engineering analysis 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 Las Flores Canyon facility. The emission controls employed at the facility include:

- An Inspection & Maintenance program for detecting and repairing leaks of hydrocarbons from piping components and the shipping pumps to reduce ROC emissions by approximately 80 percent, consistent with the BACT requirements of ATC 5651 and modifications thereof, NSPS KKK and Rule 331.

- Use of water injection, low-NO_x burners and Selective Catalytic Reduction (ammonia injection) at the Cogeneration Power Plant.

- 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 3-stage Claus process with a Flexsorb SE tail gas cleanup unit.

- Use of vapor recovery on two 270,000 barrel oil storage tanks.

- Use of Low-NO_x burners and NSCR at the sulfur recovery unit tail gas incinerator.

- Use of vapor recovery systems to collect hydrocarbon vapors from various tanks, sumps, separators and drains.

- Use of carbon canisters to collect hydrocarbons and total reduced sulfur compounds at specified tanks, sumps, separators, drains and on vacuum trucks which service this equipment.

- Use of vapor recovery, a venturi scrubber, carbon canisters and a gas sweetening unit (SulfaTreat) to eliminate hydrogen sulfide emissions from specified tanks, sumps, separators and drains.

- Use of turbo-charging, inter-cooling and ignition timing retard on crew and supply boat engines (or equivalent technology).

1.5 Offsets/Emission Reduction Credit Overview

Offsets: Emissions from the Las Flores Canyon facility must be offset pursuant to the APCD’s New Source Review regulation. Offsets are required for ROC, NO_x, SO_x, PM and PM_{10}.

Section 7 details the offset requirements for the Santa Ynez Unit Project. In addition, Exxon is required via their Lead Agency permit to offset all SYU Expansion Project emissions of ozone precursor pollutants (i.e., ROC and NO_x). These are known as Entire Source Emissions (ESE) offsets.

ERCs: Exxon has generated 1.56 tons per year of ROC ERCs in order to offset emission increases from compressor skid projects at Platforms Harmony and Heritage (PTO 9640 and PTO 9634 respectively). In addition, on January 20, 1998 Exxon obtained ERC Certificate No. 0004 for 0.18 tpq of ROCs assigned to increased ROC fugitive emissions from gas pipeline project topsides tie-ins at Platforms Harmony and Heritage (ATC 9827, ATC 9828) respectively.

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 APCD Rules, all conditions in the APCD-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 Tables 3.1 and 3.2 for a list of federally enforceable requirements)*

1.6.2 Insignificant Emissions Units: Equipment or activities exempted from permitting under APCD Rule 202 are considered as insignificant emissions units. The guidance under the USEPA's White Paper II, Sections C.2.c and C.2.d, applies to insignificant emission 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, 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 APCD. Permit shields cannot be indiscriminately granted with respect to all federal requirements. Exxon has made a request for a permit shield. Table 1.1 summarizes the permit shield granted to Exxon.

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. Exxon made no request for permitted alternative operating scenarios.

Exxon lists their main operating scenario as: "The LFC facilities are an oil and gas processing plant (SIC 1311), which produces products such as crude oil, gas, propane, mixed butane, sulfur and electrical power. The facility also produces byproducts from crude oil and gas production. Normal facility operations include periods of startup, shutdown and turnaround. Periodically, malfunctions may occur."

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. Each certification is signed by a "responsible official" of the owner/operator company whose name and address is listed prominently in the Part 70 permit. (*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. This permit is expected to be re-opened in the future to address new monitoring rules, if the permit is revised significantly prior to its first expiration date. *(see Section 4.11.3, CAM Rule).*

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 5.5)*.

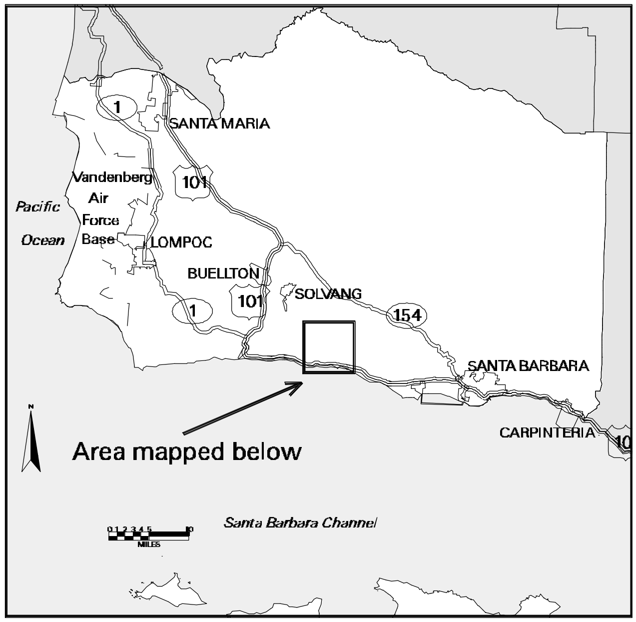
1.6.9 Responsible Official: The designated responsible official and their mailing address is:

Mr. Jeffrey J. Woodbury
Production Manager
Exxon Company, U.S.A. (a division of Exxon Corporation)
Post Office Box 61707
1555 Poydras Street
New Orleans, LA 70161-1707

Telephone: (504) 561-4222
.

Figure 1.1 - Location Map

Santa Ynez Unit Project - (onshore)



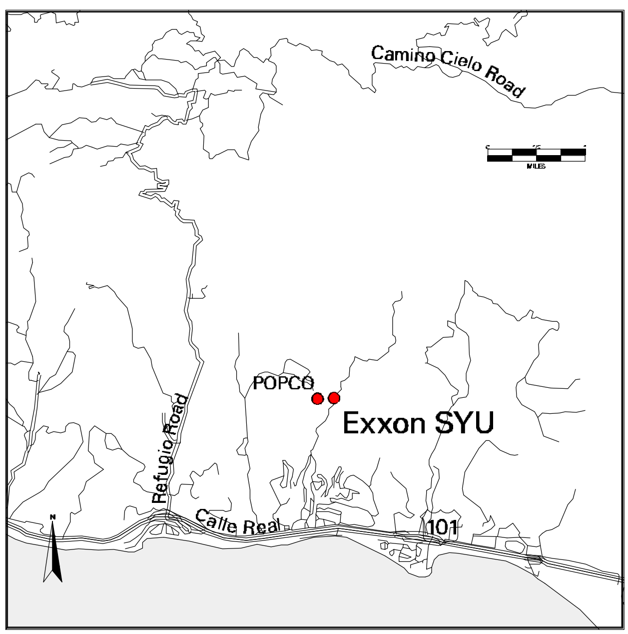
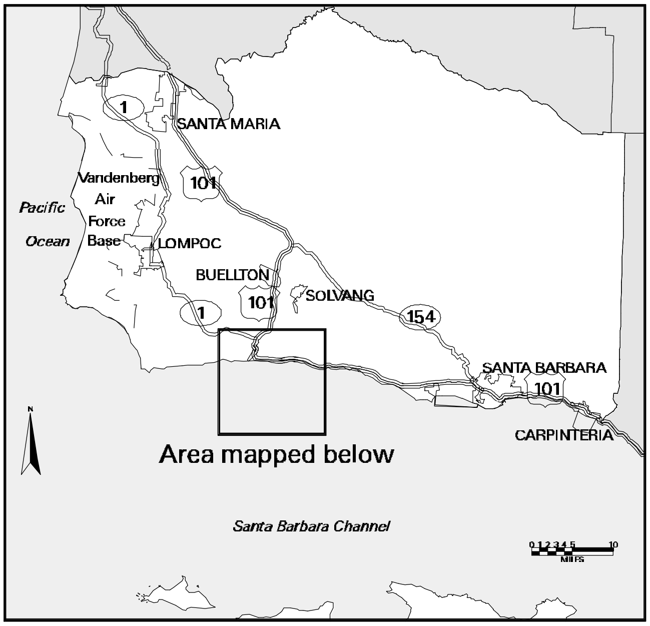


Figure 1.1 - Location Map (continued)

Exxon Santa Ynez Unit Project - (offshore)



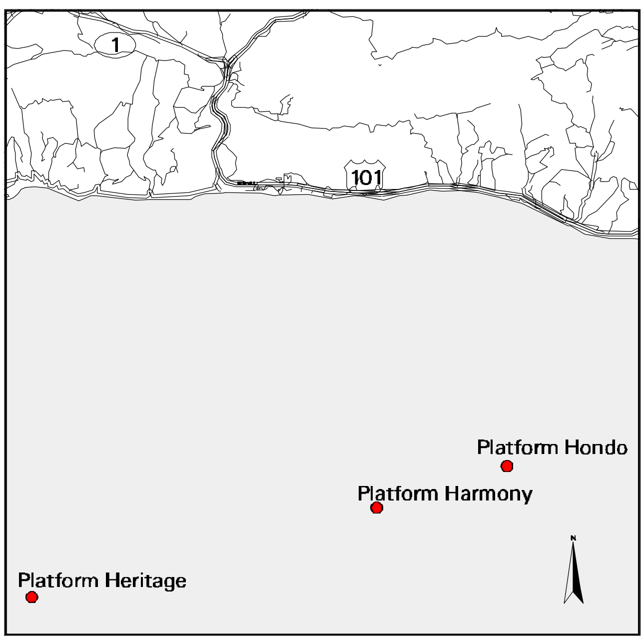


TABLE 1.1 – PERMIT SHIELD FOR EXXON LAS FLORES CANYON

APPLICABLE RULE/REGULATION	AFFECTED EMISSION UNIT(S)	JUSTIFICATION FOR GRANTING PERMIT SHIELD
APCD Rule 328.H.1	SGTP Waste Gas Incinerator (EQ No. 12-2)	Section H.1 requires NOx to be reported at 3% oxygen. Table 4.2a (*BACT Performance Standards*) defines a NO_x standard for the WGI to be reported at 2% oxygen. Compliance determinations based on the 2% readings is deemed adequate for ensuring compliance with Section H.1
APCD Rule 342.E.3	CPP Heat Recovery Steam Generator (EQ No. 1-2)	Section E.3 prohibits the use of anhydrous ammonia. APCD memo dated March 8, 1994 clarifies that this Section does not apply to facilities that received approval to use anhydrous ammonia prior to the date of rule adoption (March 10, 1992). Exxon received approval in 1987.
40 CFR 60.42b NSPS Db	CPP Heat Recovery Steam Generator (EQ No. 1-2)	This Section's standard for sulfur dioxide does not apply since the emissions unit is only fired on natural gas.
40 CFR 60.43b NSPS Db	CPP Heat Recovery Steam Generator (EQ No. 1-2)	This Section's standard for particulate matter does not apply since the emissions unit is only fired on natural gas.
40 CFR 60.44b NSPS Db	CPP Heat Recovery Steam Generator (EQ No. 1-2)	This section establishes a NO_x limit of 0.20 lb/MMBtu using 30 day rolling average. APCD BACT requirements for NO_x in Table 4.2a require a limit of 0.03 lb/MMBtu averaged over 15-minutes. Compliance with the APCD's BACT requirements (during Normal Operations Mode and HRSG Only Mode) ensures compliance with the applicable NSPS requirement.
40 CFR 60.48b(h) NSPS Db	CPP Heat Recovery Steam Generator (EQ No. 1-2)	This section exempts a source from the requirements to install and operate a NO_x CEMS if it is subject to the standards of Section 60.44b(a)(4). Since Exxon is subject to Section 60.44b(a)(4), this Section 60.48b(h) does not apply. [2]
40 CFR 60.334(b)(2) NSPS GG	CPP Gas Turbine (EQ No. 1-1)	Compliance with the requirement of daily monitoring of the sulfur content of the natural gas fuel is accomplished via the use

[2] This does not exempt Exxon from their NSR/PSD permit requirements to install and operate the NO_x CEMS required pursuant to ATC 5651.

APPLICABLE RULE/REGULATION	**AFFECTED EMISSION UNIT(S)**	**JUSTIFICATION FOR GRANTING PERMIT SHIELD**
		of a continuous H_2S monitor along with quarterly sample for total sulfur.
40 CFR 60.630 NSPS KKK	CPP/SGTP/TT Fugitive Hydrocarbon Emission Components (EQ No. 3-x and 4-x)	This NSPS only applies to gas processing facilities (SGTP) and all associated vapor recovery equipment feeding the SGTP (whether inside the gas plant or not).

2.0 Description of Proposed Project and Process Description

2.1 Project and Process Description

2.1.1 Project Ownership: Exxon is the major owner and operator of the Santa Ynez Unit offshore and onshore facilities.

2.1.2 Geographic Location: The onshore facilities are located in Las Flores Canyon (LFC) approximately 20 miles west of Santa Barbara, California in the southwestern part of Santa Barbara County. The Exxon property consists of a pie-shaped piece of property, approximately 1500 acres, starting on the north side of Highway 101 and continuing to the north. Of this area, approximately 110 acres have been cleared with 34 acres containing facilities and the remainder left as open space. A paved road about 1.5 miles long from Calle Real, the frontage road off Highway 101, provides access to the facility.

Within the Exxon property, approximately 17 acres is leased to Pacific Offshore Pipeline Company (POPCO) to operate a natural gas treating facility. In addition, small areas are provided for installation of utility connections by Southern California Gas Company (SCG) and Southern California Edison Company (SCE) as well as a pump station by the All American Pipeline Company for crude transportation.

The Exxon property is located within the western part of the Transverse Ranges physiographic province of Southern California. This region is characterized by predominately east-west oriented topographic and structural elements. The canyons area is predominately rural in character, with some agricultural and industrial uses present.

2.1.3 Facility Description: The Santa Ynez Unit (SYU) Project develops production from three platforms (Platforms Hondo, Harmony and Heritage) located offshore California in the Santa Barbara Channel. The production is transported to shore through a subsea pipeline and treated in new production facilities located in Las Flores Canyon (LFC). Overall recovery from the development totals approximately 500 million barrels of crude oil and almost one trillion cubic feet of natural gas.

The onshore facility is subdivided into the following plants:

- Oil Treating Plant (OTP)
- Stripping Gas Treating Plant (SGTP)
- Transportation Terminal (TT)
- Cogeneration Power Plant (CPP)

The onshore facilities receive the produced crude/water/gas emulsion from the offshore platforms via the 20-inch emulsion pipeline and produced gas from the platforms via the POPCO transportation system. The onshore facilities produce oil, propane, butane, and sulfur products for sale and fuel quality gas for process needs and power generation of process heat and electricity.

The recovered produced water is treated to acceptable standards and returned to Harmony for release to the ocean.

An overview of the SYU offshore/onshore facilities is shown in Figures 2.1, 2.2, 2.3 and 2.4 and Table 2.1. The data shown in the figures and table are not enforceable. See Section 9 of this permit for what is enforceable. Rates provided for key streams represent design base case conditions.

2.1.3.1 Oil Treating Plant (OTP): The Oil Treating Plant, located at the north end of LFC, receives oil and water in the form of an emulsion from the offshore platforms. The OTP dehydrates, stabilizes, and sweetens the crude oil to meet product specifications. The separated, produced water is filtered, degassed and biologically treated with both anaerobic and aerobic bacteria to reduce dissolved oil and grease so that it is suitable for ocean disposal.

Two oil treating trains each with a daily capacity of 50 KBPD of treated oil are installed with a third train to be constructed in the future. The utility support systems and plant layout are designed to support 125 KBPD on an annual average basis or 140 KBPD on a stream day basis. Two water treating trains with a 60 KBPD capacity are installed. One future train will increase capacity to 90 KBPD of water.

2.1.3.2 Transportation Terminal (TT): The Transportation Terminal, located southeast of the OTP, consists of two 270 KB storage tanks, 3 pipeline booster pumps and support facilities necessary to store oil received from the OTP and ship through the All American Pipeline system. The booster pumps are designed to ship crude at various rates up to 300 KBPD.

Also located in the Transportation Terminal are the water outfall pipeline pig launcher and emulsion pipeline pig receiver.

2.1.3.3 Stripping Gas Treating Plant (SGTP):

The Stripping Gas Treating Plant, located on the west side of the OTP just north of the POPCO plant, processes up to 21 MSCFD of gas from the OTP, and Hondo, Heritage and/or Harmony Platforms, to produce a sweet fuel gas for use in the onshore facilities, Natural gas liquids (NGLs) and sulfur are also produced.

The recovered NGL products are sweetened and fractionated to produce up to 2900 BPD of a sales quality propane and 2600 BPD of a mixed butane product. Acid gases from the fuel gas amine system, NGL sweetening system and OTP water treating system are treated in a sulfur recovery unit (combination Claus and tail gas units) to produce up to 20 LT/D specification sulfur product. A small quantity of acid gas remaining after cleanup in the tail gas unit is incinerated.

2.1.3.4 Cogeneration Power Plant (CPP): The 49 MW Cogeneration Power Plant, located on the east side of the OTP, consists of a natural gas fueled GE Frame 6 Gas Turbine Generator with a rated output of 39 MW and a non-condensing steam turbine rated at 10 MW. The CPP generates electric power to supply both the onshore facilities and the offshore platforms.

Heat from the gas turbine exhaust is recovered in a waste Heat Recovery Steam Generator (HRSG) to generate steam to supply the LFC process heat requirements. This system can also be supplementary fired with fuel gas to provide heat to maintain operations when the turbine is down.

The SYU power plant operates in parallel with the SCE utility system. SCE provides emergency backup and supplemental power during peak demand periods. This tie-in also provides the flexibility to sell power to SCE when the plant generating capacity exceeds the SYU power demand.

2.1.4 Process Description: The onshore processing systems, which are described below, have been divided into the following areas:

- Oil Treating Plant (OTP)
- Produced Water Treating System (WTS)
- Transportation Terminal (TT)
- Stripping Gas Treating Plant (SGTP)
- Cogeneration Power Plant (CPP)

2.1.4.1 Oil Treating Plant: The OTP oil facilities have been divided into the following process systems:

- Emulsion Metering and Rerun System
- Crude Heat Exchange and Dehydration
- Crude and Condensate Stabilization, Gas Compression
- Thermal Oxidizer

Figure 2.2 shows a simplified block flow diagram of the Oil Treating Plant.

2.1.4.1.1 Emulsion Metering and Rerun System: The Emulsion Metering and Rerun System measures the volume of inlet emulsion received from the offshore emulsion pipeline system and distributes the emulsion to the two parallel oil treating trains. The metered emulsion is combined with any recycle from the crude rerun tanks and sent to the crude heat exchangers. Two 30 KBPD rerun tanks are available to temporarily store or rerun any excess production or off spec product.

2.1.4.1.2 Crude Heat Exchange and Dehydration: The Crude Heat Exchange and Dehydration System heats the emulsion to approximately 220°F, separates the sour gas and free water from the emulsion in a free water knockout (FWKO) and dehydrates the crude with electrostatic treaters. The FWKO in each train is sized to handle 50 KBPD oil and 40 KBPD water. Separated water is sent to the produced water treating system, flashed gas is sent to the condensate stabilizer and the emulsion to the electrostatic emulsion treaters for further water removal. Each train has two electrostatic emulsion treaters in parallel which dehydrate the emulsion to 1 percent BS&W to meet product specifications.

2.1.4.1.3 Crude and Condensate Stabilization, Gas Compression: The Crude and Condensate Stabilization/Gas Compression System serves to sweeten and stabilize the crude to meet product specifications and recover NGLs from the inlet stream. The crude stabilizer receives the sour dehydrated crude from the emulsion treaters and strips H_2S, light gases and NGL components from the crude, stabilizing the crude to the required vapor pressure. Sweet stabilized bottom produced from the crude stabilizer is metered in the sweet crude ACT unit before flowing to the Transportation Terminal. The gas from the crude stabilizer overhead is compressed in two stages to approximately 350 psig. Hot gas from the second stage of compression along with the condensed interstage liquids flow to a condensate stabilizer. This stabilizer removes most of the H_2S and lighter components from the condensate for processing in the SGTP and recycles the heavy ends (mostly C5+) back to the crude stabilizers.

2.1.4.1.4 <u>Thermal Oxidizer</u>: The Thermal Oxidizer located east of the OTP burns waste gases from the four flare systems: low pressure (LP) flare, high pressure (HP) flare, acid gas (AG) flare and ammonia tank pressure relief. The Thermal Oxidizer is designed to handle varying flow rates with smokeless combustion. Combustion occurs at multiple burners near grade level inside a protective wind fence. Burners for the four different flare systems are arranged in several stages, each with its own pilot. The first stage is sized for low flaring rates with additional stages automatically added as the flaring rates increase. A flare gas sampling system is also provided to capture representative samples of the gases flared in the LP, HP and AG systems.

Each of the LP, HP and AG flare systems is made up of a network of flare collection headers, a flare scrubber, and a flare liquid pump. The flare headers collect the discharged vapors for each system from appropriate relief valves, pressure control valves, and manual blow down valves on tanks and vessels located in the process units. The flare scrubber separates any liquid from the gas prior to discharge to the Thermal Oxidizer. Liquids are pumped to the closed drain system or the Rerun Tanks.

2.1.4.2 <u>Produced Water Treating System (WTS)</u>: The produced water treating system is located within the OTP. It treats the produced water removed from the oil/water emulsion as well as miscellaneous process waste water streams. The system is designed to handle a feed stream containing an average of 260 mg/l of dissolved oil and grease plus significant amounts of dissolved solids, sulfides, carbon dioxide, biodegradable materials and suspended solids. The final liquid effluent is designed to contain only trace contaminants well within the NPDES discharge limits.

The produced water treating system facilities have been divided into the following process areas:

- Free Oil Removal
- Degassing
- Equalization and Anaerobic Treating
- Aeration and Clarification
- Sludge Removal and Handling System

Figure 2.2 shows a simplified flow diagram of the WTS.

2.1.4.2.1 <u>Free Oil Removal</u>: The Free Oil Removal system removes entrained oil and solids from the produced water by passing it through two Pressurized Plate Separators (PPS) operating in parallel. Oil dumps intermittently to the closed drain system. Solids, accumulating in coned bottoms of the PPS, are discharged to the Oily Sludge Thickener. Water exiting the PPS, containing less than 50 mg/l free oil and 50 mg/1 suspended solids, feeds two Media Filters that operate in parallel and further reduce the oil and suspended solids to approximately 10 mg/l each. The Oily Sludge

Thickener bottoms can be blended back into the crude stream or sent to the Sludge Removal and Handling System.

2.1.4.2.2 Degassing: The Degassing system removes dissolved sulfur compounds to allow proper operation of the downstream biological treatment systems. The Degassing unit is designed as a single train for a produced water rate of up to 90 KBPD. The incoming water feed is acidified to a pH of 5.8 and fed to a Vacuum Flash Tower operating at -10 psig which reduces the hydrogen sulfide to 50 ppm or less. Flashed sour vapors are sent to the SGTP Sulfur Recovery Unit. The hot Vacuum Flash effluent water flows to the Equalization Tank.

2.1.4.2.3 Equalization and Anaerobic Treating: The Equalization and Anaerobic treating area converts soluble grease, oil and organic acids, through bacterial digestion, to a gas mixture composed of methane, carbon dioxide, hydrogen sulfide and water vapor. Water from the Equalization Tank is neutralized to 7.0-8.0 pH, cooled to approximately 100°F and mixed with appropriate nutrients prior to entering the Anaerobic Filter. In the anaerobic filter, water flows up through a packed core in contact with resident bacteria. The gas produced by the bacteria is released to the Vapor Recovery System for further processing. Some of the exit water is continuously recycled back to the Anaerobic Filter with the remainder sent to the Aeration Basin for aerobic biological treatment.

2.1.4.2.4 Aeration and Clarification: The Aeration and Clarification Area removes 90% of the remaining soluble contaminants in the water by means of biological oxidation (biox). The water is contacted with new and recycled aerobic microorganisms (activated sludge) in two highly aerated Aeration Basins. The overflow passes through the two Clarifiers (large retention basins) where activated sludge and water are separated.

Effluent water from the Clarifier is collected in the Outfall Batch Tank. This treated water is transferred to the Harmony Platform for discharge to the ocean.

The activated sludge settles to the bottom of the Clarifiers where it is continuously withdrawn and recycled back to the Aeration Basins. A slip stream of sludge is sent to the Sludge Removal and Handling System.

2.1.4.2.5 Sludge Removal and Handling System: The Sludge Removal and Handling System uses centrifuges to de-water the biox sludge removed from the Clarifiers and oily sludge from the Free Oil Removal portion of the plant. The oil sludge cake is discharged into tote bins vented to carbon canisters for truck transfer to an approved disposal site. The liquid from the centrifuge is recycled and mixed with the water feed to the Aeration System.

2.1.4.3 Transportation Terminal: The TT facilities have been divided into the following process systems:

- Crude Oil Storage and Shipping
- Crude Tank Blanketing and Vapor Recovery

Figure 2.2 shows a simplified block flow diagram of the TT.

2.1.4.3.1 Crude Oil Storage and Shipping: Treated crude oil can be either stored in two crude storage tanks or sent directly to the pipeline booster pumps. The tanks are cone roof type with an internal floating roof containing blanket gas in the vapor space.

The crude can be heated to maintain the appropriate viscosity by recirculating crude product via the pipeline booster pumps through the pipeline heater and back to the tanks. Mixers are provided in the crude storage tanks to maintain any sediment and water in suspension.

Treated crude oil from the OTP is received in the transportation terminal on a continuous basis. Three centrifugal pipeline booster pumps rated at 50 psig discharge are provided to ship crude at rates up to 300 KBPD. One to two pumps are normally required with the third pump as a standby spare.

2.1.4.3.2 Crude Tank Blanketing and Vapor Recovery: The crude tank blanketing and vapor recovery system will maintain the pressure (between 0.3" and 1.3" water column) in the vapor space between the floating roof and the external fixed cone roof. Vapor is made up from the fuel gas system as needed. When there is a displacement of vapor, it is routed to the tank vapor recovery compressor. Compressed vapors are transferred to the OTP vapor recovery unit for further compression and ultimate treatment in the SGTP.

2.1.4.4 Stripping Gas Treating Plant: The SGTP facilities have been divided into the following process systems:

- Gas Separation and Cooling
- Deethanizer System
- Fuel Gas Sweetening
- NGL Sweetening
- Depropanizer System, Propane Drying and NGL Storage
- Sulfur Recovery Unit
- Waste Gas Incinerator

Figure 2.3 shows a simplified block flow diagram of the SGTP.

2.1.4.4.1 Gas Separation and Cooling: The gas separation and cooling system separates the liquids out of both the transported platform gas and the sour OTP gas prior to sending these feed streams to the Deethanizer. The sour transported platform gas from the POPCO pipeline flows through an expansion valve where the pressure is dropped from 900 psig to 345 psig thereby cooling the gas to about 18°F. Liquids that condense are separated and sent to the deethanizer, with the gas sent to the fuel gas sweetening unit. The sour OTP gas is cooled; the condensed liquids are separated and sent to the deethanizer, with the gas going to the fuel gas sweetening unit.

2.1.4.4.2 Deethanizer System: The deethanizer system separates the light end components, (i.e., H_2S, methane, ethane, and carbon dioxide), from the NGLs in the inlet feed. The deethanizer tower is used to control the light end composition of the NGL propane product and the heating value of the fuel gas. The deethanizer overhead product combines with the raw conditioned gas from the gas separation and cooling system and proceeds to the fuel gas sweetening process. The deethanizer bottom product (NGL product) is sent to the NGL sweetening system.

2.1.4.4.3 Fuel Gas Sweetening: The fuel gas sweetening system removes contaminants from the sour gas to obtain sweet gas for use in the onshore facilities. The design rate for the system is approximately 15 MSCF/D with backup and supplemental sweet pipeline gas available from the local utility (Southern California Gas Company). The gas is sweetened in a 30 tray amine contactor where the amine solvent absorbs carbon dioxide, hydrogen sulfide, and other sulfur compounds. The sweetened gas leaving the top of the amine contactor then goes to the fuel and blanket gas systems. The rich amine, containing the acid gas compounds, is regenerated and recirculated, with the resulting acid gas sent to the sulfur recovery unit.

2.1.4.4.4 NGL Sweetening: The NGL sweetening system removes the carbon dioxide, hydrogen sulfide, carbonyl sulfides (COS), and mercaptans from the raw NGL (Deethanizer bottoms). The NGL sweetening process consists of a COS conversion step followed by treatment in an NGL amine contactor where most of the H_2S and CO_2 is removed. The NGLs from the contactor are further treated by a COS polishing step to remove any remaining COS. The rich amine is regenerated and recirculated with the resulting acid gases sent to the sulfur recovery unit. The treated NGLs then enters a caustic pre-wash tower followed by a Merox (catalyzed caustic) contactor tower to remove any mercaptans. The sweetened NGL then goes to the depropanizer.

2.1.4.4.5 Depropanizer System Propane Drying and NGL Storage: The depropanizer system separates the treated sweet NGL into a commercial grade propane and a mixed butane spec product in a 26 tray tower. The mixed butane product (containing up to 20% propane) is sent directly to storage, while the propane product goes through a molecular sieve drier where any water is removed before going to storage. Four 88,000 gallon pressurized NGL storage tanks are provided. Normally two of the tanks will be used for propane and two for the mixed butanes. In addition, there is a 21,000 gallon vessel for off-spec liquids. Two truck loading stations, designed for handling 250 gpm each, are available for loading propane or mixed butanes.

2.1.4.4.6 Sulfur Recovery Unit: The Sulfur Recovery Unit (SRU), consisting of a Claus Unit and a Tail Gas Cleanup Unit, followed by a Waste Gas Incinerator, is designed to recover 99.9% of the sulfur in the inlet gas under full load conditions and produce a specification sulfur product for sale. The recovered molten sulfur is stored in a sulfur tank at the SGTP and periodically pumped into sulfur trucks. The SRU is designed for high turndown (approximately 1 LT/D to design rate of 20 LT/D) due to the expected variations in operations. Recovery will decline at levels below the design rates.

The Claus Unit, which converts hydrogen sulfide (H_2S) to sulfur, contains a Combustor, three Claus Reactor Beds, Sulfur Condensers and Waste Heat Recovery Systems. Concentrated acid gas from the Tail Gas Cleanup Unit enters the SRU combustor where a portion of the H_2S is burned to form sulfur dioxide (SO_2). In the Claus reaction H_2S and SO_2 react to form sulfur and water. The hot combustor gas is cooled to recover waste heat and sulfur and then cycled through the three catalytic reactor beds where the reaction continues. On each pass, the gas is cooled to condense any produced sulfur prior to being reheated and entering the next stage. The gas from the last condenser is sent to the Tail Gas Cleanup Unit for further removal of any remaining sulfur compounds.

The Tail Gas Cleanup Unit (TGCU) converts all of the sulfur compounds in the received gas to H_2S, recovers the H_2S in an amine system and recycles the concentrated acid gas back to the Claus Unit. Gas entering the TGCU from the Claus unit is combusted and hydrogenated in a reactor bed to convert the non-H_2S sulfur compounds to H_2S. The gases are cooled to recover waste heat, contacted with a mild caustic solution to remove any traces of SO_2 and then combined with feed acid gas from the fuel gas and LPG amine units. The combined stream is treated in a 12 tray amine contactor to remove the H_2S. The concentrated acid gas from the amine regenerator is combined with acid gas from the OTP water treating unit (vacuum tower) and recycled back to the Claus Unit. The gas exiting the tail gas amine contactor contains mostly CO_2 and water vapor with trace amounts of hydrocarbons and sulfur compounds and is sent to the waste gas incinerator.

2.1.4.4.7 Waste Gas Incinerator: The waste gas incinerator oxidizes trace amounts of hydrocarbons and sulfur compounds contained in the TGCU waste gas and the Merox system vent gas to an environmentally acceptable gas that can be dispersed to the atmosphere. The incinerator is designed for a H_2S and hydrocarbon destruction efficiency greater than 99.9% using a minimum of auxiliary firing to minimize NO_x emissions. A thermal De-NO_x system is included to further reduce NO_x emissions by reacting ammonia with the hot flue gases.

2.1.4.5 Cogeneration Power Plant: The Cogeneration Power Plant (CPP) facilities have been divided into the following process systems:

- Gas Turbine Generator
- Heat Recovery Steam Generator
- Steam Turbine/Generator
- Steam Distribution System

Figure 2.4 shows a simplified block flow diagram of the CPP.

2.1.4.5.1 Gas Turbine/Generator: The Gas Turbine/Generator installed in the CPP is a General Electric (GE) Industrial type, Frame 6 simple cycle, single shaft unit rated at 39MW. The turbine drives a G. E. 3600 RPM, 47.9 MVA rated synchronous generator. The gas turbine fuel is natural gas from the SGTP or the local utility.

For NO_x control, the gas turbine is equipped with a steam injection manifold system. An exhaust bypass damper is provided to vent exhaust to the atmosphere for turbine startup and to allow operation of the HRSG using duct burners when the turbine is down.

2.1.4.5.2 Heat Recovery Steam Generator (HRSG): The exhaust from the turbine/generator enters the HRSG where steam is produced to meet the LFC process heat requirements. A duct burner section located upstream of the HRSG may be supplementally fired with fuel gas to provide additional heat when necessary or generate adequate heat to maintain operations when the turbine is down. For the latter case, two auxiliary air blower fans provide the combustion air for the duct burners.

The HRSG also includes a Selective Catalytic Reduction (SCR) section which uses ammonia and a catalyst to reduce NO_x by 80%.

2.1.4.5.3 Steam Turbine/Generator: The CPP includes a non-condensing back pressure steam turbine driving an 1800 RPM, 11.5 KVA rated 0.85 power factor synchronous generator unit rated at approximately 10MW.

The steam turbine utilizes 700 psig superheated steam from the HRSG and exhausts the steam to the 65 psig process heating system. Excess 700 psig superheated steam is by-passed around the turbine/generator to the 65 psig process level.

2.1.4.5.4 Steam Distribution System: The steam distribution system for the CPP is composed of four systems:

- 700 psig superheated steam for the steam turbine
- 700 psig saturated steam for process heating
- 65 psig saturated steam for process heating
- 20 psig saturated steam for process heating

This steam is distributed throughout the process facilities to supply system requirements. Heat recovery within the SRU also contributes to the generation of steam for the 65 psig and 20 psig systems.

2.1.5 Emission Source Description: There are four emission source "stacks" in Las Flores Canyon. They are:

- CPP HRSG Bypass Stack
- CPP HRSG Main Stack
- SGTP Incinerator Stack
- OTP Thermal Oxidizer Stack

Table 2.1 lists the high/low/normal ranges of significant operating parameters relating to each of the emission sources.

Exxon's application – specifically "Option B Onshore and Nearshore Facilities, Volume I Exhibits A, C & D: Facilities Technical Data and Volume II Air Emissions Analysis" – provides the detailed descriptions of all the processes and equipment subject to permit.

2.2 Detailed Process Equipment Listing

Due to the complexity of the LFC facility, this permit does not specifically list all emission units. Instead, the equipment permitted to operate under this permit are incorporated by reference to the following documents:

- Exxon Las Flores Canyon Mechanical (Major) Equipment List; Revision 2; 10/23/90.
- Exxon Las Flores Canyon Process Flow Diagrams; dated prior to December 1, 1998.
- Exxon Las Flores Canyon Piping & Instrument Diagrams; dated prior to December 1, 1998.

Only those equipment items that have a potential to emit air contaminants, as determined by the APCD, are subject to this operating permit. These documents are maintained as part of the APCD's administrative file.

In addition, the APCD has permitted the following equipment:

- ATC/PTO 5651-01 (5/27/99). Two 500 gallon demulsifier tanks and associated carbon canister units (55 gallon drum design). These tanks are connected at all times to a carbon canister unit. The tanks are not filled on-site.

- ATC/PTO 10172 (09/21/99). Crew and supply boats. See Tables Q and P in Attachment 10.

TABLE 2.1
STACK GAS DESCRIPTIONS

The following lists the expected low/high/norm ranges of significant operating parameters based on available equipment manufacturers' data. Each line item is independent of the others (e.g., low NO_x may not occur under the same conditions as low CO). The pressure in all stacks at the flow measurement point is essentially atmospheric and no pressure correction is applied. The data herein are not enforceable. See Section 9 of this permit for what data is enforceable.

Parameter	Low	High	Norm
Cogen Plant Main HRSG Stack			
Moisture Vol % Wet	5.79	14.35	11.91
Flow (Dry) MSCFH	10.7	13.7	12.8
Temp Deg. F.	304	491	326
Velocity Ft./Sec	41	68	53
Cogen Plant Bypass Stack			
O_2 vol % dry	14.95	19.10	19.06
Moisture Vol % Wet	2.58	10.75	2.94
Flow (Dry) MSCFH	10.9	13.4	11.3
Temp Deg. F.	528	1035	528
Velocity F./Sec.	51	104	53
SGTP Incinerator Stack			
O2 Vol % Dry	2	2	2
Moisture vol % Wet	12	16	12
Flow (Dry) KSCFH	140	274	274
Temp Deg. F.	1750	1750	1750
Velocity Ft./Sec.	33	63	63
OTP Thermal Oxidizer			
HP Header Flow KSCFH	0.0	555	0
LP Header Flow KSCFH	1.6	183	0
AG Header Flow KSCFH	0.5	109	0
NH3 Header Flow KSCFH	0.04	7.0	0
Stack Temp Deg. F.	Ambient	1800	Ambient
Stack Velocity Ft./Sec.	0	110	0
Stack Flow Klb/h	0	6611	0

Figure 2.1 - Exxon SYU Offshore/Onshore Facility Overview

Figure 2.2 - SYU Oil Treating Plant and Transportation Terminal Block Flow Diagram

Figure 2.3 - SYU Stripping Gas Treating Plant Flow Diagram

Figure 2.4 - Cogeneration Power Plant Flow Diagram

3.0 Regulatory Review

3.1 Rule Exemptions Claimed

⇒ APCD Rule 202 (*Exemptions to Rule 201*): Exxon 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 APCD:

- As of November 6, 1998, the *de minimis* increases (per Section D.6) are zero.

- Section D.8 for routine surface coating maintenance activities.

- Section F.1.d for two diesel internal combustion engines driving emergency firewater pumps rated at 216 and 221 bhp respectively and one diesel internal combustion engine driving an emergency floodwater control pump for the area drain sumps rated at 230 bhp (Model No. 103445-1, Tag No. LFC-07). Each engine is operated less than 51 minutes/day, 50 hr/qtr and 200 hrs/yr.

- Section H.3 for all portable abrasive blasting equipment (excluding IC engines that are subject to Section F of Rule 202).

- Section V.2 for the storage of diesel fuel.

- Section V.3 for lube oil storage tanks.

⇒ APCD Rule 311 (*Sulfur Content of Fuels*): Based on the exemption in Section A.1 for the manufacturing of sulfur or sulfur compounds, the sulfur recovery unit is exempt from the standards in this rule.

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

⇒ APCD Rule 325 (*Crude Oil Production and Separation*): Per Section B.3, the following emission units are exempt from Sections D.1 and D.2 of the rule:

- SGTP Area Drain Separator (ABH-4406)
- SGTP Open Drain Sump (ABH-4407)
- OTP Open Drain Sump (ABH-1413)
- OTP Area Drain Oil/Water Separator (ABH-1415)
- OTP Equalization Tank (ABJ-1424)
- OTP Centrate Tank (ABJ-1443)
- TT Area Drain Oil/Water Separator (ABH-3402)

Per Section B.5, the following five emission units are exempt from all requirements of the rule:

- OTP Clear Backwash Makeup Tank (MBJ-1104)
- OTP Backwash Collection Tank (ABJ-1421)
- OTP AF Gas Separator (MBF-1108)
- OTP Anaerobic Filter (MBM-1109)
- OTP VF Tower Feed Drum (MBD-1138)
- OTP Closed Drain Sump (MBH-1152)
- TT Closed Drain Sump (MBH-3107)
- SGTP Closed Drain Sump (MBH-4166)

⇒ APCD Rule 326 (*Storage of Reactive Organic Compound Liquids*): Per Section B.1.b, the following three emission units are exempt from all provisions of the rule:

- Diesel Storage Tank (ABJ-1416)
- SOV Compressor Lube Tank (ABJ-1417)
- VR Compressor Lube Tank (ABJ-1419)

⇒ APCD 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)
- One half inch and smaller stainless steel tube fittings that have been determined to be leak free by the Control Officer (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.

⇒ APCD Rule 333 (*Control of Emissions From Reciprocating Internal Combustion Engines*): Section B.1.b exempts engines that are exempt from permit per Rule 202 from all the requirements of this rule.

⇒ APCD Rule 344 (*Petroleum Sumps, Pits and Well Cellars*): The following emission units are exempt from all provisions of the rule:

- ABH-1413, OTP Open Drain Sump (B.1)
- ABH-1442, OTP Backwash Sump (B.1)
- ABH-4407, SGTP Open Drain Sump (B.1)

- MBH-3107, TT Closed Drain Sump (B.1)
- MBH-4164, SGTP Ethylene Glycol Drain Sump (B.1)
- MBH-4166, SGTP Closed Drain Sump (B.1)
- MBH-4168, SGTP Fuel Gas Amine Drain Sump (B.1)
- MBH-4169, SGTP LPG Amine Drain Sump (B.1)
- MBH-4170, SGTP TG Amine Drain Sump (B.1)
- MDB-4171, SGTP Waste Caustic Drain Sump (B.1)
- ABJ-3401A, TT Oil Storage Tank Containment Device (B.1)
- ABJ-3401B, TT Oil Storage Tank Containment Device (B.1)
- ZBH-4501, TT Emergency Curtailment Basin (B.1)
- ABJ-1425, OTP Aeration Tank A (B.2)
- ABJ-1426, OTP Aeration Tank B (B.2)
- ABJ-1428, OTP Clarifier A (B.2)
- ABJ-1429, OTP Clarifier B (B.2)
- ABJ-1431, OTP Outfall Batch Tank (B.2)
- ABJ-1450, OTP Skim Tank (B.2)
- ABH-1414, OTP Area Drain Sump (B.1, B.4)
- ABH-3403, TT Area Drain Sump (B.1, B.4)
- ABH-4405, SGTP Area Drain Sump (B.1, B.4)
- ABH-1415, OTP Area Drain Separator (B.1, B.4)
- ABH-3402, TT Area Drain Separator (B.1, B.4)
- ABH-4406, SGTP Area Drain Separator (B.1, B.4)

⇒ APCD Rule 346 (*Loading of Organic Liquids*): Per Section B.4, the transfer of liquefied natural gas, propane, butane or liquefied petroleum gases.

⇒ APCD Rule 359 (*Flares and Thermal Oxidizers*): Per Section B.2, the acid gas flare header is exempt from all requirements, except Section D.2.

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 Las Flores Canyon facility was permitted in November 1987 under APCD Rule 205.C. That rule was superseded by APCD Regulation VIII (*New Source Review*) in April of 1997. Compliance with PTO 5651 requirements and Regulation VIII ensures that the LFC 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 Las Flores Canyon facility:

Subpart A	General Provisions
Subpart Db	Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units
Subpart Kb	Standards of Performance for Volatile Organic Liquid Storage Vessels. The ATC/PTO 5651-01 modification of the TVP limit of 11 psia for the Oil Storage

tanks to an average value triggered the requirements of 40 CFR §60.112b(b) (since this would allow short-term exceedances). Compliance is achieved by compliance with the requirements of 40 CFR §60.112b(a)(3) through the use of a closed vent system and control device (Thermal Oxidizer) that meets the requirements of 40 CFR §60.18.

Subpart GG	Standards of Performance for Stationary Gas Turbines
Subpart KKK	Standards of Performance for Equipment Leaks of VOC From Onshore Natural Gas Processing Plants
Subpart LLL	Standards of Performance for Onshore Natural Gas Processing; SO_2 Emissions

Attachment 10.6 provides an NSPS compliance report.

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*}: At the time of public review, this facility was not subject to the provisions of this Subpart. However, compliance will be assessed once an applicable MACT standard is promulgated.

3.2.5 40 CFR Part 64 {*Compliance Assurance Monitoring*}: This rule became effective on April 22, 1998. Compliance with this rule is not required until the next Part 70 permit renewal or significant permit revision.

3.2.6 40 CFR Part 70 {*Operating Permits*}: This Subpart is applicable to Las Flores Canyon. Table 3.1 lists the federally-enforceable APCD promulgated rules that are "generic" and apply to the facility. Table 3.2 lists the federally-enforceable APCD promulgated rules that are "unit-specific". These tables are based on data available from the APCD's administrative files and from Exxon's Part 70 Operating Permit application. Table 3.4 includes the adoption dates of these rules.

In its Part 70 permit application (Forms I and J), Exxon certified compliance with all existing APCD rules and permit conditions. This certification is also required of Exxon semi-annually. Issuance of this permit and compliance with all its terms and conditions will ensure that Exxon 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 Las Flores Canyon 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.

3.4 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 APCD promulgated rules that apply to the Las Flores Canyon 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 more detailed discussion regarding the applicability and compliance of certain rules.

The following is a rule-by-rule evaluation of compliance for Las Flores Canyon:

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 SBCAPCD rules and regulations. To the best of the APCD's knowledge, Exxon 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, the TGCU Incinerator 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 requiring all engines to be maintained according to manufacturer maintenance schedules per the APCD-approved *IC Engine Particulate Matter Operation and Maintenance Plan*.

Rule 303 - Nuisance: This rule prohibits Exxon from causing a public nuisance due to the discharge of air contaminants. To date, there are no nuisance complaints that can be attributable to operation of the Las Flores Canyon facilities. All nuisance complaints are investigated by the APCD and follow the guidelines outlined in Policy & Procedure I.G.2 (*Compliance Investigations*). This rule is included in the SIP.

Rule 305 - Particulate Matter, Southern Zone: The LFC facility is considered a Southern Zone source. This rule prohibits the discharge into the atmosphere from any source particulate matter in excess of specified concentrations measured in gr/scf. The maximum allowable concentrations are determined as a function of volumetric discharge, measured in scfm, and are listed in Table 305(a) of the rule. Sources subject to this rule include: the thermal oxidizer, the TGCU Incinerator and all diesel-fired IC engines. 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 per the APCD-approved *IC Engine Particulate Matter Operation and Maintenance Plan*. Rule 359 addresses the need for the thermal oxidizer 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. Sulfur emissions due to planed flaring events will comply with the SO_2 limit. Flaring of acid gas may not comply with the SO_2 limit, however, and Exxon will need to obtain variance relief in such cases. All diesel powered piston IC engines have the potential to exceed the combustion contaminant limit if not properly maintained (see discussion on Rule 305 above for compliance).*)*

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. No measured data at the fence line exists to confirm compliance with this rule, however the consolidated odor monitoring station (*LFC Odor*) will be placed at the fence line and future data will be available. Further, the APCD has not recorded any odor complaints from this facility.

Rule 311 - Sulfur Content of Fuels: This rule limits the sulfur content of fuels combusted at the LFC facilities to 0.5 percent (by weight) for liquids fuels and 15 gr/100 scf (calculated as H_2S) {or 239 ppmvd} for gaseous fuels. Exxon, as part of the BACT determination for ATC 5651 is required to use diesel fuel with a sulfur content not exceeding 0.2 percent (wt. basis). In addition, all fuel gas is required to have a sulfur content not exceeding 24 ppmv (as S). Compliance with this requirement is continuously monitored by the fuel gas H_2S Analyzer (A-40055A) and quarterly sampling. 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 LFC 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. Exxon is required to maintain records to ensure compliance with this rule.

Rule 318 - Vacuum Producing Devices or Systems – Southern Zone: This rule prohibits the discharge of more than 3 pounds per hour of organic materials from any vacuum producing device or system, unless the organic material emissions have been reduced by at least 90 percent. Exxon states that there are no emission units subject to this rule.

Rule 321 - Control of Degreasing Operations: This rule sets equipment and operational standards for degreasers using organic solvents. The Safety-Kleen cold solvent degreaser is exempt from all rule provisions, except Section G.2.

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. Exxon is required to maintain records during maintenance operations to ensure compliance with this rule.

Rule 323 - Architectural Coatings: This rule sets standards for many types of architectural coatings. The primary coating standard that will apply to the platform is for Industrial Maintenance Coatings which has a limit of 340 gram ROC per liter of coating, as applied. Exxon is required to comply with the Administrative requirements under Section F for each container at LFC.

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. Exxon 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, except for the relief devices on the Oil Storage and Rerun Tanks. Exxon has installed vapor recovery on all equipment subject to this rule. Compliance with this exemption will be verified by APCD inspections. Compliance with Section E is met by directing all produced gas to a sales compressor, injection well or to the flare relief system. In addition, the distance pieces on the SOV and VR compressors are subject to Section E. Compliance is met by a combination of vapor recover and carbon canister on the distance piece/seal system.

Rule 326 - Storage of Reactive Organic Liquids: This rule applies to equipment used to store reactive organic compound liquids with a vapor pressure greater than 0.5 psia. The Demulsifier Tank (300 bbl capacity) stores demulsifier agents with a vapor pressure of 0.8 psia; Section D.1 applies. Per the BACT requirements of this permit, the Demulsifier Tank is connected to an APCD-approved carbon canister system.

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

Rule 328 - Continuous Emissions Monitoring: This rule details the applicability and standards for the use of continuous emission monitoring systems ("CEMS"). Process monitoring systems (e.g., fuel use meters) are used to track emissions. CEMS are required for the CPP and SGTP as outlined in Section 4.11 and the tables in Attachment 10.1. A number of process variables are also continuously monitored to assess compliance with the applicable requirements. Exxon operates the CEMS and process monitors consistent with their CEMS Plan (approved 10/22/93 and all subsequent APCD-approved updates).

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 Exxon 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. Exxon has submitted an I&M Plan (*Fugitive Emissions Inspection and Maintenance Program for Las Flores Canyon Process Facilities*) and received APCD approval of this Plan on July 20, 1993. Ongoing compliance with the many provisions of this rule will be assessed via facility inspection by APCD 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. However, per Section B.1.b any engine exempt from the requirement to obtain a permit under Rule 202 is also exempt from this rule (see Section 3.1 above). The only IC engines at the LFC facilities are two emergency firewater pump engines and the emergency floodwater pump engine that are exempt from permit. Compliance with the terms of the B.2 exemption are based on use of a non-resettable hour meter. Use of any other IC engine is subject to the provisions of this rule, if applicable.

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 Heat Recovery Steam Generator ("HRSG") is subject to this rule. All requirements of this rule are complied with due to the prior requirement of BACT via ATC 5651. Pursuant to an APCD directive, Section E.3 does no apply facilities that used anhydrous ammonia to comply with BACT standards prior to the adoption of this rule. Compliance is assessed through the monitoring, recordkeeping and reporting requirements listed in Section 9.C 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 Storage Tanks and the Rerun Tanks. The *Petroleum Storage Tank Degassing Plan* was approved by the APCD on December 15, 1994. Compliance is assessed based on the use of APCD-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 sumps used at the LFC facility are post-primary sumps with a surface area less than 1000 square feet, and are thus exempted from the requirements of this rule.

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. Exxon is exempt from this rule per Section B.4. Further, the vacuum trucks are exempt from the provisions of Sections D, E and F pursuant to Section B.5.

Rule 353 – Adhesives and Sealants: This rule applies to the use of adhesives, adhesive bonding primers, adhesive primers, sealants, sealant primers, or any other primers. Compliance shall be based on site inspections.
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. Exxon uses a thermal oxidizer to combust all waste gases, as well as an Incinerator in the Tail Gas Cleanup Unit in the SGTP. The TGCU Incinerator is exempt from the provisions of this Rule pursuant to Section B.1. The acid gas flare header is exempt pursuant to Section B.2. 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 South County flares to 15 gr/100 cubic feet (239 ppmv) calculated as H_2S at standard conditions. Under Section D.1.b, Exxon obtained an exemption from the sulfur content standard. Offsets are in place to mitigate the additional SO_x emissions from planned flaring (all SO_x emissions were required to be offset per ATC 5651). Section 7 of this permit describes the source of ERCs.

§ D.2 - Technology Based Standard: Requires all thermal oxidizers to be smokeless and sets pilot flame requirements. Exxon's thermal oxidizer is in compliance with this section as determined through APCD inspection.

§ D.3 - Flare Minimization Plan: This section requires sources to implement flare minimization procedures so as to reduce SO_x emissions. The Planned Flaring volume is 19 million standard cubic feet per month. Exxon has fully implemented their Flare Minimization Plan.

Rule 505 - Breakdown Conditions: This rule describes the procedures that Exxon must follow when a breakdown condition occurs to any emissions unit associated with any LFC facility. 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 APCD 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 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. The APCD approved Exxon's *Emergency Episode Plan* on May 20, 1993.

3.5 Compliance History

This section contains a summary of the compliance history for this facility and was obtained from documentation contained in the APCD's Administrative file.

3.5.1 Variances: Exxon has sought variance relief per Regulation V and received two Regular (R) Variances, one Interim (I) Variance and two Emergency Variances since the original permit was issued:

14-91R: Granted 6/5/91. Rule 205.c.b.5, ATC 5651 Condition 49. Due to construction of pipelines and power cables at LFC, monitoring station LFC 4 was unable to meet the required 90% monthly data recovery rate.   This 90-day variance allowed this station to continue monitoring without satisfying the data recovery rate requirement.

38-96E: Granted 8/26/96. Rule 206, ACT 5651 Condition 44. The Ace High crew boat was unable to meet the 80% per month data recovery rate required by *APCD's Data Reporting Protocol for Crew and Supply Boat Activity Monitoring* Sec. 3.4. This variance allowed the boat to operate without meeting this requirement.

39-96I: Granted 9/10/96. Rule 206, ACT 5651 Condition 44. The Ace High crew boat was unable to meet the 80% per month data recovery rate required by *APCD's Data Reporting Protocol for Crew and Supply Boat Activity Monitoring* Sec. 3.4. This variance allowed the boat to operate without meeting this requirement.

40-96R: Granted 10/02/96. Rule 206, ATC 5651 Condition 44. The Ace High crew boat was unable to meet the 80% per month data recovery rate required by *APCD's Data Reporting Protocol for Crew and Supply Boat Activity Monitoring* Sec. 3.4. This variance allowed the boat to operate without meeting this requirement. The boat was eventually removed from service.

12-98E: Granted 3/31/98. Rule 206, ATC 5651 Condition 51. The access road to monitoring station LFC2 was washed out by heavy rains, making on-time performance of the 1Q98 quarterly station audit impossible. This variance order removed the need for the 1Q98 audit. The road was restored and the 2Q98 audit was completed on time.

18-99E: Granted 09/02/99. Rule 206, ATC 5651 Condition 9.C.18. The continuous in-line heating value analyzer was providing erratic BTU values (the Applied Automation BTU Analyzer (AIT-40622)). Exxon was unable to fix the analyzer within the timelines allocated within the APCD's Rule 505 (Breakdowns).

24-99N: Granted 10/06/99. Rule 206, PTO 5651 Condition 9.C.7.a. Exxon was granted a 90 day variance from their permitted mass emission limits if solvents through the end of 1999. Exxon had exceeded their annual limit for solvent emissions and was granted a variance to use solvents for the remainder of the calendar year for essential laboratory requirements.

17-99R: Granted 10/06/99. Rule 359 D.2.b.3, PTO 5651 Condition 9.C.2(b)(iv). Exxon was granted a variance from certain provisions of Rule 359 (*Flares and Thermal Oxidizers*). Specifically, Exxon is in violation of District Rule 359 D.2.b.3 due to the recurrent failures of pilots serving the facility's Thermal Oxidizer unit (equipment ID number EAW-1601).
Rule 359 D.2.b.3 requires the flame (in the pilot) to be operating at all times when combustible gases are vented through the Thermal Oxidizer. The requirements of Rule 359.D are incorporated into this permit in Permit Condition 9.C.2.(b)(iv). Permit condition 9.C.50 incorporates the requirements of the Hearing Board Variance and temporarily relieves Exxon of the requirement to comply with Rule 359 D.2.b.3 and Permit Condition 9.C.2.(b)(iv) until June 30, 2000.

3.5.2 Violations: The last facility inspections occurred during July 1998 and December 9, 1998. The inspector reported that the facility was not in compliance with all APCD rules and permit conditions. Violations of NSPS Kb, Rule 328, Rule 325 and Rule 331 were documented.

As of January 1999 fifteen Notice of Violations (NOVs) and eight Administrative Infraction Documents (AI Doc) have been issued since the original permit was issued:

NOV No. 1823: Violation of Rule 205.C. Issued 06/12/88. Specifically, required marine vessel fuel monitoring data was not submitted within the required time frame. The data was submitted late. Resolved Date: 2/23/1989.

NOV No. 2247: Violation of Rule 205.C. Issued 9/8/89. Specifically, Exxon failed to provide certificate for construction equipment for a piece of fuel-consuming equipment of greater than 50 HP. Resolved Date: 11/10/1989.

NOV No. 2254: Violation of Rule 205.C. Issued 10/4/89. Specifically, Exxon failed to meet the required data recovery rate for certain meteorological parameters at monitoring site LFC 4 during March 1989. Resolved Date: 2/15/1990.

NOV No. 2631: Violation of Rule 302. Issued 5/8/90. Specifically, a violation of the visible emissions rule was documented. Resolved Date: 8/6/1990.

NOV No. 5013: Violation of Rule 206. Issued 1/10/95. Specifically, Exxon failed to meet the permit requirements of ATC 5651 Condition 51 at monitoring station LFC 1 due to low data recovery rates, absent biweekly precision checks, improperly timed span checks, and quarterly calibration using a non-certified transfer standard. Resolved Date: 5/2/1995.

NOV No. 5016: Violation of Rule 206. Issued 6/22/95. Specifically, Exxon failed to meet monitoring requirements of ATC 5651 Condition 51 for quarterly PM10 multi-point calibrations for 4Q94. Resolved Date: 8/8/1996.

NOV No. 5017: Violation of Rule 206. Issued 6/22/95. Specifically, Exxon failed to meet the minimum data recovery requirements for certain monitoring station parameters required by ATC 5651 Condition 51 for the January 1995 monitoring month. Resolved Date: 8/8/1996.

NOV No. 5018: Violation of Rule 206. Issued 6/22/95. Specifically, Exxon failed to meet the minimum data recovery requirements for certain monitoring station parameters required by ATC 5651 Condition 51 for the February 1995 monitoring month. Resolved Date: 8/8/1996.

AI Doc No. 5019: Violation of Rule 505. Issued 7/24/95. Specifically, Exxon failed to provide notification of a breakdown. Resolved Date: 7/24/95.

NOV No. 5172: Violation of Rule 206. Issued 12/11/95. Exceeded total mass emission limits of SO_2 per Condition #17. Resolved Date: 3/7/1996.

NOV No. 5173: Violation of Rule 206. Issued 12/12/95. Using equipment with a diesel fuel sulfur content exceeding the limit established by the permit. Resolved Date: 3/7/1996.

NOV No. 5174: Violation of Rule 206. Issued 2/29/96. Failure to meet minimum data recovery requirements for ambient air quality for March, May, August, September and October of 1995. Resolved Date: 8/8/1996.

NOV No. 5179: Violation of Rule 331. Issued 6/21/96. Two PRDs exceeded 10,000 ppmv threshold at Rerun Tank ABJ-1401B. Resolved Date: 8/26/1996.

AI Doc No. 5520: Violation of Rule 505. Issued 3/12/97. Failure to submit breakdowns #6243, #6244 within the allotted time of 7 days after repairs. Resolved Date: 3/12/1997.

AI Doc No. 5524: Violation of Rule 206. Issued 10/02/97. Monitoring violation. Resolved Date: 7/29/1997.

AI Doc No. 5528: Violation of Rule 212. Issued 11/04/97. Failure to submit 1996 Annual Emission Fee Statement to the APCD. Resolved Date: 11/04/1997.

AI Doc No. 5537: Violation of Rule 206. Issued 2/17/98. Failure to meet data recovery rates; LFC 1 THC, DRR less than 80 percent for July, August, September, October 1997. Was originally issued as NOV No. 5536, made an AI Doc. Resolved Date: 2/17/1998.

AI Doc No. 6151: Violation of Rule 505. Issued 4/21/98. Late submittal of initial breakdown #6686. Resolved Date: 4/21/1998.

AI Doc No. 6152: Violation of Rule 505. Issued 4/21/98. Late submittal of initial breakdown #6687. Resolved Date: 4/21/1998.

NOV No. 5956: Violation of Rule 328. Issued 8/03/98. Using a calibration gas mixture that did not meet the specification in 40 CFR, Part 51, Appendix P, Section 3.3, and Part 60, Appendix B, Performance Specification 2, Section 2.1 for the daily calibrations of the analyzer installed to continuously monitor turbine stack outlet concentrations of NO_x.

NOV No. 5957: Violation of Rule 901. Issued 8/03/98. Failure to submit for approval, an Operating Plan for the Oil Storage Tanks and the Rerun Tanks as required by 40 CFR, Part 60, Subpart Kb, Sections 60.113b(c) (et seq.).

AI Doc No. 5958: Violation of Rule 325. Issued 8/03/98. Failing to perform the analysis of the crude oil vapor pressure using the test methods specified in Rule 325.

NOV No. 5991: Violation of Rule 331.D.3. Issued 12/17/98. A gaseous leak was detected at the open end of a 2-inch line.

3.5.3 Significant Historical Hearing Board Actions/NOVs: There are no significant *historical* Hearing Board actions or NOVs.

Table 3.1 - Generic Federally-Enforceable APCD 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 305: PM Concentration – South Zone	Each PM source	Emission of PM in effluent gas
RULE 309: Specific Contaminants	All emission units	Combustion contaminants
RULE 310: Odorous Org. Sulfides	All emission units	Emission of organic sulfides
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.

RULE 318: Vacuum Producing Devices – Southern Zone	All systems working under vacuum	Operating pressure

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	Exxon SYU 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	Exxon SYU Project is a major source.

Table 3.2 - Unit-Specific Federally-Enforceable APCD 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, 6-1, 8-1, 8-2, 8-3, 8-4, 8-5, 8-6, 8-7, 8-8, 8-9, 14-1, 14-2	All pre-custody production and processing emission units
RULE 326: Storage of Reactive Organic Compounds	EQ Nos: 10-1	Stores ROCs with vapor pressure greater than 0.5 psia
RULE 328: Continuous Emission Monitors	EQ Nos: 1-1, 1-2, 12-1, 12-2	Section C and NSPS

Unit-Specific Requirements	Affected Emission Units	Basis for Applicability
RULE 331: Fugitive Emissions Inspection & Maintenance	EQ Nos: 3-x, 4-x.	Components emit fugitive ROCs.
RULE 342: Control of Oxides of Nitrogen from Boilers, Steam Generators and Process Heaters	EQ Nos: 1-2	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 344: Petroleum Sumps, Pits and Well Cellars	EQ Nos: 8-4, 8-5, 8-8, 9-1, 9-2, 9-3	Used in petroleum service
RULE 359: Flares and Thermal Oxidizers	EQ Nos: 2-1	Used in petroleum service

Table 3.3 - Non-Federally-Enforceable APCD Rules

Requirement	Affected Emission Units	Basis for Applicability
RULE 210: Fees	All emission units	Administrative
RULES 501-504: Variance Rules	All emission units	Administrative
RULES 506-519: Variance Rules	All emission units	Administrative

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

Rule No.	Rule Name	Adoption Date
Rule 101	Compliance by Existing Installations: Conflicts	June 1981
Rule 102	Definitions	January 21, 1999
Rule 103	Severability	October 23, 1978
Rule 201	Permits Required	April 17, 1997
Rule 202	Exemptions to Rule 201	April 17, 1997
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 Permit to	October 15, 1991

Rule No.	Rule Name	Adoption Date
	Operate	
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 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 318	Vacuum Producing Devices or Systems - Southern Zone	October 23, 1978
Rule 321	Solvent Cleaning Operations	September 18, 1997
Rule 322	Metal Surface Coating Thinner and Reducer	October 23, 1978
Rule 323	Architectural Coatings	July 18, 1996
Rule 324	Disposal and Evaporation of Solvents	October 23, 1978
Rule 325	Crude Oil Production and Separation	January 25, 1994
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 Internal Combustion Engines	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	August 19, 1999
Rule 359	Flares and Thermal Oxidizers	June 28, 1994
Rule 505	Breakdown Conditions (Section A, B1 and D)	October 23, 1978

Rule No.	Rule Name	Adoption Date
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 901	New Source Performance Standards (NSPS)	May 16, 1996
Rule 903	Outer Continental Shelf (OCS) Regulations	November 10, 1992
Rule 1001	National Emission Standards for Hazardous Air Pollutants (NESHAPS)	October 23, 1993
Rule 1301	General Information	September 18, 1997
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

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4.0 Engineering Analysis

4.1 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, CEMS
- process monitors needed to ensure compliance.

Unless noted otherwise, default ROC/THC reactivity profiles from the APCD'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. The results of source testing for the CPP and SGTP since startup are summarized in Attachment 10.8

4.2 Cogeneration Power Plant

4.2.1 General: The primary stationary combustion sources in Las Flores Canyon are located in the Cogeneration Power Plant ("CPP"). The CPP consists of a 39.0 MW (ISO) General Electric Model PG 6531B gas-fired turbine generator and a 9.8 MW Shin Nippon steam turbine. The CPP generators produce electrical power at 13,800 volts to serve the power needs of the LFC facility as well as Exxon's three offshore platforms. Exxon also provides additional power to the local grid. The maximum heat input to the gas turbine is 463 MMBtu/hr.

Also part of the CPP is a 345 MMBtu/hr Entec Heat Recovery Steam Generator ("HRSG") that is equipped with John Zink Co. Low-NO_x burners. The HRSG recovers waste heat from the gas turbine as well as its own burners' heat to supply up to 250,000 lbs/hr of steam to satisfy the needs of Exxon's LFC facility.

NO_x emissions are controlled through the use of steam injection in the gas turbine and Selective Catalytic Reduction (ammonia injection) on the combined gas turbine/HRSG exhaust stream. Steam injection is designed to achieve a 50 percent level of control for NO_x. The SCR reactor uses Babcock-Hitachi plate-type catalyst and ammonia injection to achieve a 80 percent control efficiency of NO_x and has a maximum exhaust flow capacity of 1.2 million pounds per hour. The primary fuel source for the CPP is treated natural gas from the Stripping Gas Treating Plant. Secondary fuel is purchased from the gas company. The gas turbine is equipped with a bypass stack that is used when the SCR unit is not operational.

4.2.2 Operating Modes: Operations of the CPP are separated into three modes:

- *Normal Operations Mode*. Includes the majority of CPP operations. Normal operations are defined as operations with a gas turbine load greater than 75 percent of the ISO rating of 39.0 MW (i.e., greater than 29.25 MW). CPP operations outside this mode can only occur during the other two modes described below. During this mode, the gas turbine and the HRSG are limited to a combined maximum heat input of 605.140 MMBtu/hr.

Emissions from the gas turbine bypass stack are based on a leakage rate not exceeding 1 percent of the gas turbine exhaust.

- *HRSG Only Mode*. During this mode, the HRSG operates alone in order to supply steam to the LFC facility. The SCR unit is operational. The gas turbine does not operate in HRSG Only Mode.

- *Startup/Shutdown Mode*. This mode covers both warm and cold startup scenarios and shutdowns. Warm startups occur when the gas turbine goes down, with the HRSG still online, and the SCR unit still "warm". In this case, the gas turbine can be brought back online rather quickly. During a cold startup, more time, up to 2 hours, is needed to bring the SCR unit up to temperature. It takes 1 hour at a turbine power output of up to 20-22 MW to heat the SCR up to a temperature of 570 ºF, and another hour at the same power output in order to produce a sufficient quantity and quality of steam for steam injection for NO_x control. Once the SCR reaches operating temperature, Exxon is required to initiate ammonia injection, and the CPP is ramped up to Normal Operations Mode.

  During the Startup Mode, the combined gas turbine/HRSG is limited to a maximum heat input of 309 MMBtu/hr and power output of 22 MW. During the Startup Mode, gas turbine exhaust will be emitted directly to atmosphere via the bypass stack at the initial phase of startup and then through the main CPP stack for the remainder of the startup process.

  Shutdown is defined as the one hour operating period immediately preceding gas turbine and/or HRSG burner flame out.

  Operations in the Planned Startup/Shutdown Mode are limited to 2 hours per day and 18 hours per year.

4.2.3 Emission Factors: Except as discussed below, emission factors for the CPP remain unchanged from ATC 5651 (issued November 1987). The basis for the emission factors is discussed in Section 2.3 of the APCD's Technical Support Document titled *Net Emissions Increase/Entire Source Emissions* (February 29, 1988). The following changes to the emission factors were approved in ATC 5651-17:

- The mass balance emission factor for SO_x (as SO_2) emissions changed from 0.0033 lb/MMBtu to 0.0034 lb/MMBtu. This is due to a change in the default HHV of the fuel gas from 1236 Btu/scf to 1200 Btu/scf.

- The categories of Case A, B, C and D were eliminated and replaced with the operating modes discussed above in Section 4.2.2.

- Case A (Full Turbine Load) is roughly equivalent to the new *Normal Operations Mode* and covers all operating loads. Normal Operations Mode emission factors are now applicable at all loads above 75 percent of the ISO gas turbine rating. The NO_x, ROC and CO emission factors are all updated to reflect tandem operations of the gas turbine and the HRSG. A weighted average method was used to establish the new emission factors. See Attachment 10.3 for the emission factor derivation method. The PM and PM_{10} emission factors were proposed by Exxon in order to minimize the PM offset liability.

- Case B (Turbine Startup) is roughly equivalent to the new *Startup/Shutdown Mode*. The combined heat input to the gas turbine/HRSG is now 309 MMBtu/hr (22 MW). Emission factors for NO_x changed based on SCDP data to accommodate a peak hourly rate of 90 lb/hr. The ROC emission factor is changed to 0.0953 lb/MMBtu to accommodate the Rule 102 change in the definition of ROC and the PM emission factor is changed to 0.0279 lb/MMBtu to ensure that Rule 309 limits are not exceeded.

- Case C (Turbine Down) is roughly equivalent to the new *HRSG Only Mode*. There were no changes in HRSG loads. The CO and ROC emission factors were revised to 0.297 lb/MMBtu and 0.0095 lb/MMBtu respectively, and are applicable at all loads. Further, the CO emissions are limited to 17 lb/hr at all loads.

- Case D (Turbine Idling) no longer exists as the CPP is not operated in an idling mode.

4.2.4 Emission Controls: The emission controls for the CPP remain unaffected by this permit modification. A full description of the CPP emission control systems may be found in Appendix C.6 of Exxon's ATC application document *Option B – Onshore and Nearshore Facilities/ Volume II – Exhibit B: Air Emissions Analysis*. In summary, the emission controls consist of:

- Steam injection at the gas turbine to reduce NO_x emissions by 50 percent at a minimum water-to-fuel ratio of 0.6.

- Low-NO_x burner design for the HRSG burners.

- Selective Catalytic Reduction ("SCR") system to reduce inlet NO_x emissions from the combined gas turbine and HRSG exhaust stream by a minimum of 80 percent using a minimum NH_3/NO_x (inlet) ratio of 1.0. Ammonia slip is designed not to exceed 10 ppmv, however the permit allows up to 20 ppmv.

4.3 Fugitive Hydrocarbon Sources

Emissions of reactive organic compounds from piping components such as valves, flanges and connections have been calculated using emission factors pursuant to APCD 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 and using Exxon specific emission factors for the components in oil service (as applied for in ATC 5651). The component-leakpath was counted consisted with P&P 6100.061. This leakpath count is not the same as the "component" count required by APCD Rule 331. Both gas/light liquid and oil service components are present at this facility.

The number of emission leakpaths were determined by the operator and these data were verified by APCD staff by checking a representative number of P&IDs and by site checks. A total of 9,963 oil/emulsion component-leakpaths and 30,739 gas/light-liquid component-leakpaths exist at the LFC facility. The calculation methodology for the fugitive emissions is:

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

<u>where</u>:	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)

Differing emission control efficiencies are credited to all components that are safe to monitor (as defined per Rule 331) due to the implementation of an APCD-approved Inspection and Maintenance program for leak detection and repair consistent with Rule 331 requirements. The control efficiencies vary: for bellows seal valves – 100%; for Low Emission Valves (LEV) – 90%; for monthly monitoring of valves – 84%; for monthly monitoring of LEV – 92%; and 80% for the remainder of the safe-to-monitor components. 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 4-2b (*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).

Exxon has classified a large number of components as "emitters less than 500 ppmv" (E500). Component-leakpaths classified as E500 are assigned a mass emission control efficiency of 85 percent. E500s are defined as component-leakpaths associated with closed vent systems (e.g., vapor recovery systems) for which screening values are maintained at or below 500 ppmv as methane, monitored per EPA Reference Method 21. For such E500s, screening values above background trigger the Rule 331 repair process per the minor leak schedule.

4.4 Crew and Supply Boats

Exxon utilizes both crew boats and supply boats in support of the SYU Project. These vessels are primarily permitted under the OCS operating permits for each of Exxon's three platforms. A portion of each crew boat trip, however, occurs within state waters. Supply boats enter state territorial waters only during times when severe weather conditions create a safety hazard at which times the boat seeks shelter at Cojo Anchorage near Government Point. The supply boats are permitted for use within state waters for up to two and a half percent of their total usage. As required under APCD rules, emissions from the crew and supply boats are included in the LFC permit. Crew boat operations occur from the Ellwood Pier to each of Exxon's three OCS platforms. Supply boat operations occur from Port Hueneme to each of Exxon's three OCS platforms.

For crew and supply boats, Exxon has identified two types of vessels. One type is for dedicated project usage and the main engines are controlled for NO_x. These are denoted as Dedicated Project Vessels (DPV). The other type is used as a spot-charter, and the main engines may be controlled or uncontrolled for NO_x. The crew and supply boat spot-charter trips are limited to 10 percent of actual crew boat trips. Compliance is based on a comparison of the actual fuel use.

The crew boat M/V Broadbill is used for emissions liability calculations as the typical crew boat. This boat is equipped with four 510 bhp main diesel-fired IC engines (Detroit Diesel 12VA71). Auxiliary diesel-fired engines on this boat include two 131 bhp diesel-driven generators (Detroit Diesel 3-71). These auxiliary engines are not controlled for NO_x.

The supply boat Sea Tide is used for emissions liability calculations as the typical supply boat. This boat is equipped with two 1,200 bhp main diesel-fired IC engines (DD 12V149 DDEC). Auxiliary diesel-fired engines on this boat include two 200 bhp diesel-driven generators (DD 8V-71), one 200 bhp bow thruster (DD 6-71). These auxiliary engines are not controlled for NO_x.

The permit assesses emission liability for main engines based solely on a single emission factor (the cruise mode). For engines with the controls listed above, a full load NO_x emission factor of 8.4 g/bhp-hr (337 lb/1000 gallons) is used. Sulfur oxide emissions are based on mass balance calculations assuming 0.20 weight percent sulfur diesel fuel. Other boat main engine emission factors are taken from USEPA, AP-42 (Volume II). For the auxiliary engines, emission factors are taken from USEPA, AP-42 (Volume I). Uncontrolled NO_x main engine emission factors for spot-charter crew and supply boat usage are assumed to be 14 g/bhp-hr (561 lb/1000 gallons). The calculation methodology for the crew and supply boat main engine emissions is:

$$ER = [(EF \times EHP \times BSFC \times EL \times TM) \div (10^3)]$$

<u>where</u>:	ER =	emission rate (lbs per period)
	EF =	full load pollutant specific emission factor (lb/1000 gallons)
	EHP =	engine max rated horsepower (bhp)
	BSFC =	engine brake specific fuel consumption (gal/bhp-hr)
	EL =	engine load factors (percent of max fuel consumption)
	TM =	time in mode (hours/period)

The calculations for the auxiliary engines are similar, except that a 50 percent engine load factor for the auxiliary engines is utilized and that auxiliary engines are generally assumed to be uncontrolled at 600 lb/1000 gal. Compliance with the main engine controlled emission rates shall be assessed through emission source testing. Ongoing compliance with all mass emission rates will be assessed through implementation of a APCD-approved Boat Monitoring and Reporting Plan. This Plan will be required to follow the APCD *Data Reporting Protocol for Crew and Supply Boat Activity Monitoring* document (dated June 21, 1991 and subsequent updates). The requirements include: fuel usage meters on the main and auxiliary engines, a Global Positioning System (or equivalent location device) and a data gathering system. Alternative data collection and reporting methods that are equivalent in accuracy and reliability may be proposed by Exxon as part of the Boat Monitoring and Reporting Plan.

4.5 Thermal Oxidizer

4.5.1 General: The thermal oxidizer, located in the oil plant, serves as the emission control for all process waste gases. The John Zink Co. Model ZTOF-BC thermal oxidizer is designed for smokeless operation and receives waste gases from three header systems: high pressure header, low pressure header and acid gas header. In addition, the PSV from the ammonia storage tank is piped to the thermal oxidizer via the ammonia flare header, and there is an acid gas enrichment fuel line. The gases from each header are combusted in separate burners. The thermal oxidizer is a refractory lined stack with burners near the base. The stack is designed as a radiation barrier and to provide a natural convection air flow to enhance the combustion process. Steam injection is available at the base of the stack to eliminate smoking, if needed. The pilot system is comprised of: a ring of 28 pilots with each flame pilot present at all times - a thermocouple is used at each pilot to detect the presence of the flame.

The thermal oxidizer is 115 feet high with outside diameters of 72 feet for the radiation barrier and 36 feet for the stack. The thermal oxidizer is rated at 3193 MMBtu/hr with the following capacities: high pressure header 24 million scfd (163,327 lb/hr); low pressure header 10.34 million scfd (49,980 lb/hr); acid gas header 5.25 million scfd (15,962 lb/hr); pilot & purge 1,948 scfh; and, acid gas enrichment gas 1.25 million scfd.

Potential flaring emissions from the high pressure header are minimized through the use of a "jumper" line to the second stage of the OTP vapor recovery compressor. At low flow events, valving bypasses the thermal oxidizer. When the load of the OTP compressors (8.8 million scfd) is about to be reached, the valving is set to re-direct the gas to the thermal oxidizer.

4.5.2 Operating Modes: This permit categorizes all flaring activities into one of the following four categories:

- *Purge and Pilot* - Up to 1948 scfh of sales gas is used to maintain pilot flames and to purge the thermal oxidizer. Per APCD P&P 6100.004, this category is included in all emission scenarios (i.e., hourly, daily, quarterly and annual).

- *Planned Continuous* - This category includes all continuous flaring events. The volume is based on one-half the minimum detection limits of each of the three flare header flow meters. The sulfur content of 500 ppmv is based on the exemption granted to Exxon under Rule 359. Per APCD P&P 6100.004, this category is included in all emission scenarios.

- *Planned Other* - This category includes planned infrequent flaring events such as purging of vessels for maintenance, sulfur plant catalyst change-outs, condensate stabilizer maintenance and crude stabilizer maintenance. This category includes operations occurring a maximum of four times per year. Per APCD P&P 6100.004, emissions from this category are included only in the quarterly and annual emission scenarios.

- *Unplanned Other* - This category includes unplanned frequent flaring events such as releases from pressure relief valves and flaring of off-spec gas that occur more than 4 times per year from the same cause from the same processing unit or equipment type. This category also includes unplanned infrequent flaring events such as failure of processing equipment that occur no more than 4 times per year from the type of event from the same cause from the same processing unit or equipment type. Per APCD P&P 6100.004, emissions from this category are included only in the quarterly and annual emission scenarios.

The spreadsheet *therm_ox.xls* in Attachment 10.3 documents the basis and assumptions used for all thermal oxidizer emission calculations.

4.5.3 Emission Factors: The emission factors are based on AP-42, Chapter 3, Section 4. The most current update (Supplement D - March 1998) is used. The emission factors are consistent with the Table 3.1.1 of the APCD's Flare Study Phase I Report (July 1991) for Enclosed Thermal Oxidizer, except that the most recent AP-42 factors are used. The SO_x emission factor is determined using the equation: (0.169)(ppmv S)/(HHV)[3]. The calculation methodology for the flare emissions is:

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

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 value (Btu/scf)

To meet the requirements of Rule 359 Exxon will use purge and pilot gas which complies with the rule limit of 239 ppmv and has obtained APCD approval to offset all other planned SO_x emissions. Exxon's fuel gas does not exceed a total sulfur content of 24 ppmv.

4.5.4 Meters: The low pressure, high pressure and acid gas headers are each equipped with two volumetric flow meters, one for high range and one for low range. In addition, one flow meter each is in place for the ammonia header, ammonia header purge line, pilot gas line and acid gas enrichment fuel line. A thorough description of the thermal oxidizer's meters may be found in Appendix D-13 (*LFC Flare Gas Measurement, Sampling & Emission Calculation*) of the APCD-approved CEM Plan. To establish the allowable Planned Continuous flaring volumes, the low flow cutoff of each meter is required. Continuous flaring is assumed for the volumes up to this low flow cutoff point. Via their CEM Plan, Exxon is using the low flow cutoff value based on manufacturer minimum velocity detection limits (0.25 fps). Since the high pressure flare is connected to the OTP vapor recovery compressor it is assumed to have no minimum low flow cutoff. The initial low flow cutoff values are: 1414 scfh for the LP flare meter and 245 scfh for the acid gas flare header.

4.6 Tanks/Sumps/Separators

4.6.1 General: The LFC facility contains several tanks, sumps, separators and other vessels that have the potential to emit reactive organic compounds. This permit categorizes these emissions units as belonging to one of four groups. Group A includes the tanks subject to NSPS Kb (i.e., the two Oil Storage Tanks and the two Rerun Tanks). Group B includes equipment whose emissions are subject to Rule 325 and where the emissions are determined using the KVB method of service type and surface area (i.e., oil/water separators, open drain sumps, backwash sump, oily sludge

[3] Reference: *SOx Emission Factors for Gaseous Fuels*, SBCAPCD, January 31, 1997

thickener, equalization tank) and where each unit is controlled via vapor recovery of carbon canister. Group C includes area drain sumps. Group D includes the 300 bbl Demulsifier Tank that is subject to Rule 326 as well as the two new 500 gallon demulsifier tote tanks.

The primary tanks are the two 270,000 barrel Oil Storage Tanks (with a working capacity of 254,591 barrels each) in the TT and the two 30,000 barrel Rerun Tanks in the OTP. Prior to being stored, NGL is injected into the treated oil from the OTP to raise the vapor pressure to a maximum of 11 psia at the oil storage tank at a temperature of 100 ºF. Through use of its DCS system, Exxon controls the maximum rate at which the NGLs are injected (i.e., the spike rate) to minimize/eliminate PSV releases from these tanks.

Permit exempt tanks include diesel storage tanks and lube oil tanks. Attachment 10.4 contains a summary table of all the affected process units in this category and identifies applicability of Rules 325, 326, 331 and 344 as well as the types of controls used. A complete description of the use and design of each tank, sump, separator and vessel may be found in Exxon's permit application material.

4.6.2 Emission Calculations:

GROUP A

Oil Storage Tanks: Emission calculations are based on USEPA Chapter 7 (5^{th} Edition) equations. A spreadsheet (*tk_3401a.xls*) for the Oily Storage tanks maybe found in Attachment 10.3. Emissions and throughput for each tank are identical. The emissions are calculated to allow each tank to handle the entire permitted throughput for the facility. The tanks are treated as fixed roof tanks only. The internal floating roof is not considered an emission control device. Compliance with the mass emission limits and the vapor recovery efficiency requirements are based on monitoring the actual emissions released via the tank's PSVs (see Section 4.8).

Rerun Tanks: Emission calculations are based on USEPA Chapter 7 (5^{th} Edition) equations. A spreadsheet (*tk_1401a.xls*) for the Rerun tanks maybe found in Attachment 10.3. Emissions are based on operations of the tank in off-spec/reject oil mode. Compliance with the mass emission limits and the vapor recovery efficiency requirements are based on monitoring the actual emissions released via the tank's PSVs (see Section 4.8).

GROUP B AND GROUP C

Sumps, Separators, Equalization Tank, Oily Sludge Thickener: Emissions from the sumps, separators, Equalization Tank and the Oily Sludge Thickener are based on emission factors from APCD P&P 6100.060. This P&P uses the CARB/KVB Report (*Emissions Characteristics of Crude Oil Production in California,* January 1983) to estimate emissions for this type of equipment. The calculation is:

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

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).

<u>GROUP D</u>

Demulsifier Tank: Emission calculations are based on USEPA Chapter 7 (5^{th} Edition) equations. A spreadsheet (*tk_1402.xls*) for the Demulsifier tank may be found in Attachment 10.3. Compliance calculations are based on throughput and TVP data using the AP-42 equations. The two 500 gallon demulsifier tanks may be used in lieu of the 300 bbl tank. Their emissions are assumed to be equal to or less than the 300 bbl tank.

<u>GROUP E</u>

Chemical Storage Tote Tanks: Portable tote tanks are used to deliver various chemicals to the plant's facilities. These tote tanks only dispense liquids. Some of these tote tanks contain ROCs and are not exempt under Rule 202. The emissions from these tanks are assumed to be very small and are assigned a default mass emissions rate of 0.10 tpy (200 lb/yr). To ensure that these emissions are maintained at these levels and to address BACT, all permitted tote tanks containing ROC compounds where the fluid vapor pressure is greater than 0.5 psia must be kept closed at all times and must be equipped with a functional PSV valve.

<u>OTHER NON-GROUPED UNITS</u>

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 that gas gathering system or the flare relief system header.

4.6.3 <u>Emission Controls</u>: Emission controls are used for Group A, B and D units. The ROC controls used are vapor recovery or carbon canisters. The Equalization Tank uses a caustic packed bed venturi scrubber with mist eliminator for removing hydrogen sulfide and carbon canisters for removing residual hydrogen sulfide and ROCs. Section 4.8 describes the vapor recovery systems in use at the facility. In addition, NSPS Kb requires that Exxon operate the vapor recovery systems in accordance with the parameters identified in a vapor recovery system *Operating Plan*.

The carbon canister units are identical units each designed to hold 1,000 pounds of carbon. The carbon used is designed to handle petroleum hydrocarbon vapor streams. A control efficiency of 75 percent ROC (by mass) is assumed for each unit. Monitoring of each unit is required throughout the year to ensure that each unit is effective at removing ROC at all times.

The Equalization Tank has the potential to emit large quantities of hydrogen sulfide (up to 100 pounds per hour based on 15,000 ppm). The venturi scrubber uses a 4 percent caustic solution in a packed bed design. The scrubber uses the venturi principle to draw up to 360 acfm of tank vapors and requires that the circulation pump run at all times during use. The outlet from the scrubber is routed to two carbon canisters (in a parallel arrangement) to remove residual hydrogen sulfide and to control ROCs. The scrubber is designed to achieve a control efficiency of 99.9 percent (mass basis) in removing hydrogen sulfide (15 ppmw or 13 ppmv).

4.7 Sulfur Recovery Unit/Tail Gas Cleanup Unit and Incinerator

4.7.1 General: Acid Gas Sulfur Recovery and Tail Gas Cleanup is accomplished by a three-catalytic stage Claus Plant with steam reheat, followed by a selective amine type Tailgas Cleanup Unit (TGCU). The TGCU contains two sections, a hydrogenation section and an amine absorption/regeneration sections which recycles acid gas to the Claus Plant. This amine section is also used to enrich the acid gas produced in the Fuel Gas and LPG Amine Units by selective removal of H_2S, thereby providing a rich H_2S acid gas feed to the Claus Plant.

4.7.2 Waste Gas Incinerator – Design/Controls: The Waste Gas Incinerator is designed to combust two sulfur-laden waste streams. The primary stream is Tail Gas from the TGCU Amine Contactor (MAF-4152) from the TGCU Amine Absorption process. The second stream is spent air/fuel gas from the Disulfide Oil Separator (MDB-4137) from the Merox process. Both streams pass through gas/vent scrubbers to knock out entrained liquids and are then combusted in the Incinerator. The Incinerator is custom designed for a hydrocarbon destruction efficiency of greater than 99.9 percent. In order to reduce NO_x emissions, it is also designed for a minimum requirement of auxiliary firing. NO_x is further reduced by the use of Low-NO_x burners and Thermal DeNO_x (ammonia injection). The Thermal DeNO_x process operates by mixing NH_3 with NO_x-containing flue gases in an effective temperature range for a certain residence time. The Incinerator has been designed to achieve a temperature of 1750 ^oF and maintain this temperature for at least 0.5 seconds after NH_3 is injected. The use of Thermal DeNO_x in this configuration (with Low-NO_x burners) achieves a minimum 50 percent reduction in NO_x emissions. CEMS are installed to continuously monitor emissions of NO_x and SO_x. In addition, the H_2S inlet concentration from the TGCU Amine Contactor is continuously monitored.

4.7.3 Waste Gas Incinerator – Emission Calculations: Emissions of SO_x (as SO_2) are documented in the spreadsheet named *incin.xls* and Attachment 10.3. The two inlet streams and fuel gas enrichment stream are calculated separately. Scenario S1 addresses the true material balance based on process design parameters. Scenario S2 takes the true material balance data and inflates the result by 28 percent (as documented in the March 21, 1986 letter from Exxon to the APCD). Permitted emissions of SO_x are based on operations with and without the Merox process. Emission of NO_x (as NO_2) are based on manufacturer data.

4.8 Vapor Recovery Systems

4.8.1 General: The LFC facility has a number of vapor recovery systems designed to collect low pressure vapors from tanks, sumps, drains, separators and other process units. Vapor recovery systems in the SGTP and TT are themselves routed to the main LFC vapor recovery system in the OTP. Figure 4.1 shows a block diagram of the emission units connected to the OTP vapor recovery system. The vapor recovery systems are assigned a control efficiency of 95 percent for short-term and 99.8 percent for long term emission scenarios. For vessels that are designated as pressure vessels (by design), vapor recovery is assumed to be 100 percent. Compliance with the vapor recovery efficiencies are based on monitoring the mass emissions emitted from the Oil

Storage Tanks and Rerun Tanks. Exxon records the actual mass emissions from these tanks 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 APCD-approved NSPS Kb *Operating Plan*. Non-compliance with any of the daily, quarterly or annual mass emission rates from the Oil Storage or Rerun Tanks is also assumed as non-compliance with the vapor recovery system control efficiencies.

4.8.2 Oil Treating Plant: The OTP vapor recovery system collects excess vapors from tanks and equipment containing organic compounds and acid gas operating below the SOV compressor suction pressure of 35 psig. The system has a suction scrubber, two compressors, and a recycle cooler. One compressor is sized for normal vapor flow rate. The second compressor is sized for the normal flow rate plus the vapor flow rate from the Rerun Tanks when all the inlet crude emulsion is diverted from the Inlet Emulsion Meter Drum. The larger compressor starts automatically on high suction pressure. The OTP compressors discharge to the inlet of the SOV Suction Cooler.

4.8.3 Stripping Gas Treating Plant: The vapor recovery system in the SGTP consists of a low pressure header collection system and a vapor recovery compressor that discharges into the vapor recovery system of the Oil Treating Plant. Another vapor recovery system is used to collect vapors from the LPG loading and storage operation. A vapor balance line is used between the LPG trucks and LPG Storage Bullets. Each of the LPG Storage Bullets is tied to the vapor recovery system which recovers excess vapors and routes them to the Oil Treating Plant compression system. A low pressure vapor recovery line is used to reduce emissions during the coupling operation between the LPG loading arm and the LPG trucks that is directly tied to the OTP vapor recovery system.

4.8.4 Cogeneration Power Plant: The CPP 6-inch fuel gas line is connected to the OTP vapor recovery system. The 1-inch vapor recovery line is valved to a normally closed position and is used for maintenance purposes.

4.8.5 Transportation Terminal: The Crude Storage Tanks' vapor spaces are connected by a vapor transfer line. This line allows transfer of vapor between the tanks during filling, tank emptying, and barometric and thermal value changes in the vapor space. A pressure controller on the common line senses low pressure (below 0.6" w.c.) and allows gas from the Blanket Gas Header to enter the line and provide gas blanketing. Another pressure controller on the common line senses high pressure (above 1" w.c.) and releases excess vapors to the TT Tank Vapor Compressors suction header. Flashed vapor from the Closed Drain Sump, together with excess blanket gas collects at the TT Tank Vapor Compressor suction scrubber. This vessel is maintained at a vacuum of 5 psi (9.7 psia) by the TT Tank Vapor Compressors. The collected vapors are compressed to a pressure of 5 psig which is sufficient to transfer the vapors to the OTP vapor recovery system.

4.9 Other Emission Sources

4.9.1 Pigging: The transportation terminal contains an oil emulsion pig receiver. Pipeline pigging operations originate from Platform Hondo. After the pigging operation is complete, the receiver is purged with sweet fuel gas and bled down to 1 psig (the maximum vapor recovery suction pressure) prior to opening to the atmosphere. The calculation per period is:

$$ER = [V_1 \; x \; r \; x \; wt \, \% \; x \; EPP]$$

where:	ER =	emission rate (lb/period)
	V_1 =	volume of vessel (ft^3)
	ρ =	density of vapor at actual conditions (lb/ft^3)
	wt % =	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 LFC facility as part of normal daily operations includes cold solvent degreasing and wipe cleaning. Mass balance emission calculations are used assuming that all the solvent used evaporates to the atmosphere.

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 mass balance calculations assuming that all solvents evaporate to the atmosphere. 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. 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, 5th Edition, Supplement D, Table 13.26-1, 9/97) to estimate emissions of PM and PM_{10}.

4.9.5 Compressor Vents: The three SOV compressors and two VR compressors are each equipped with dual sealing systems that are connected to vapor recovery via the distance piece of each compressor. There are potential emissions on the back end of each distance piece/seal system. As such, each compressor system (SOV and VR) collects these vapors through a common vent system and directs the vapors to a carbon canister system. Based on estimates from Exxon, the ROC emissions (post-carbon) from each vent are not expected to exceed 0.10 lb/hr.

4.10 BACT/NSPS/NESHAP/MACT

4.10.1 BACT: Best Available Control Technology is required for all emission units for NO_x, ROC, CO, SO_x, PM and PM_{10}. The applicable BACT control technologies of this permit are listed in Table 4.1 and the corresponding BACT performance standards are listed in Table 4.2. Table 4.3 lists the BACT requirements for the I&M FHC Program. In addition, chemical tote tanks containing ROCs where the fluid vapor pressure is greater than 0.5 psia must be closed at all times and must be equipped with a functional PSV valve.

Pursuant to APCD 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, components are required to be replaced with BACT in accordance with the APCD's NSR rule. These BACT determinations are based on a case-by-case basis following the APCD's guidance document for determining BACT due to Rule 331. Rule 331 BACT determinations are documented in Table 4.2b.

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

4.10.5 MACT: As of the date of public review, MACT provisions have yet to be promulgated for this source type.

4.11 CEMS/Process Monitoring/CAM

4.11.1 CEMS: The APCD reviewed the proposed facility to determine the emission sources and other parameters that must be monitored continuously to ensure permit compliance. Attachment 10.1 provides details on the CEM requirements for the SYU Project. In order for the APCD to assess facility operation status and to ensure major emission sources are operating properly, selected monitor data are telemetered to the APCD offices on a real-time basis. Both calculated and raw data is telemetered in accordance with APCD specifications for the life of the project, as required by the applicable permit conditions.

Major emission sources requiring continuous monitoring are the Cogeneration Power Plant, the WGI Incinerator and the Thermal Oxidizer. Besides pollutant emissions, process parameters, such as fuel gas flow rate and stack temperature, also require monitoring. Detailed data are required on the gas turbine operation, SCR emission control system for the turbine, sulfur recovery unit, and the transportation terminal vapor control system, to ensure that emission controls are operating as specified in the applicable Permit Conditions. Detailed information on the Thermal Oxidizer is required to monitor facility breakdown circumstances and to inventory emissions associated with flaring events. The APCD may require additional continuous emission monitors and redundant monitor system components in the future, if problems with the facility or monitoring operations that warrant additional monitoring develop.

The monitors must meet the requirements set forth in APCD Rule 328 and the Code of Federal Regulations (CFR), 40 CFR Parts 51, 52 and 60. These must be installed in accordance with manufacturer's specifications, and EPA requirements as specified in the CFR.

Exxon must obtain the APCD's approval of any modifications/updates to the CEMS Plan (approved 10/22/93 and all subsequent APCD-approved updates). Exxon is required to follow the APCD *Continuous Emission Monitoring Protocol Manual* (10/22/92 and all updates).

All continuously monitored parameters must be recorded on backup strip chart recorders unless this requirement is waived by the APCD. The required data will be consolidated and submitted to the APCD as required by Section 9.C. More frequent reporting may be required if the APCD deems this necessary. Minimum data reporting requirements must be consistent with APCD Rule 328 and must include the following:

- Hourly data summaries for each parameter;
- 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 APCD.

4.11.2 Process Monitoring: In many instances, ongoing compliance beyond a single (snap shot) source test is assessed by the use of process monitoring systems. Examples of these monitors include: engine hour meters, fuel usage meters, water injection mass flow meters, flare gas flow meters and hydrogen sulfide analyzers. Once these process monitors are in place, it is important that they be well maintained and calibrated to ensure that the required accuracy and precision of the devices are within specifications. At a minimum, the following process monitors - as well as any process monitor not listed that is used to assess compliance - will be required to be calibrated and maintained in good working order:

- Crew and Supply Boat Diesel Fuel Use Meters (main and auxiliary engines)
- Flare Header Flow Meters (Low Pressure, High Pressure, Purge/Pilot, Acid Gas, Acid Gas Fuel Enrichment, Ammonia)
- Hour Meters (emergency firewater pumps IC engines)
- CPP (fuel flow meters, water injection meter, ammonia injection meter, SCR inlet temperature indicator, gas turbine electrical meter, steam turbine electrical meter)
- OTP (oil and gas production flow meters, Thermal Oxidizer pilot sensors)
- TT (PSV proximity switches)
- WGI Incinerator (ammonia injection meter, combustion chamber temperature indicator, flow meter, H_2S analyzer on inlet)
- Fuel Gas System (H_2S analyzer)

Exxon shall implement calibration and maintenance requirements for the process monitors identified above (as well as any process monitor not listed that is used to assess compliance) according to the CEMS Plan (approved 10/22/93 and all updates). This Plan takes into consideration manufacturer recommended maintenance and calibration schedules. Where manufacturer guidance is not available, the recommendations of comparable equipment manufacturers and good engineering judgement are to be utilized.

4.11.3 CAM: *Exxon – SYU Project* is a major source that is subject to the USEPA's Compliance Assurance Monitoring (CAM) rule (40 CFR 64). Any emissions unit at the facility with uncontrolled emissions potential exceeding major source emission thresholds for any pollutant is subject to CAM provisions. Exxon must submit a compliance plan to the APCD for this rule at the time of Part 70 permit renewal or before if the permit is reopened due to a significant permit change.

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. Attachment 10.2 details the emission units, pollutants and parameters, methods and frequency of required testing. Exxon is required to follow the APCD *Source Test Procedures Manual* (May 24, 1990 and all updates).

Section 9 details the sampling that is required. All sampling and analyses are required to be performed according to APCD 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 Regional Monitoring: As required by permit condition XII-6 in the County's Final Development Plan, Exxon must install and operate monitors to provide data on regional ozone levels. These monitors must be installed and operated at locations specified by the APCD and according to a APCD-approved *Air Quality and Meteorological Regional and Operation (AQMRO) Monitoring Plan* (approved 6/22/93 and updates).

The sites identified in Table 4.4 shall provide information on ozone levels in regions of the airshed where Exxon's SYU project could reasonably be expected to contribute to the ozone levels. They include the Nojoqui area of Gaviota Pass, Carpinteria, Las Flores Canyon and at El Capitan.

Exxon will share the costs of operating the Nojoqui monitoring site while the GTC Gaviota marine terminal is operating. If GTC ceases operation of the terminal, Exxon will be responsible for operating all parameters required of Exxon at this monitoring site. Exxon will share the costs of operating the Carpinteria monitoring site while the Point Arguello Project is operating. If the Point Arguello Project ceases operation, Exxon will be responsible for operating all parameters required of Exxon at this monitoring site.

Exxon will share no less than 25 percent of costs for operating the APCD's El Capitan monitoring station, reimbursable to the APCD.

4.13.2 Operational Monitoring: Exxon shall operate the LFC1 post-construction monitoring site to provide data on the impacts of the SYU facilities operation. This station is also a regional ozone monitoring site. The parameters to be monitored at these sites are identified in Table 4.5. These monitors must be installed and operated at locations specified by the APCD and according to a APCD-approved *AQMRO Monitoring Plan* (approved 6/22/93 and updates).

4.14 Odor Monitoring

Exxon shall implement the APCD-approved *Odor Monitoring Plan* (approved 6/22/93 and all updates) for ambient odor monitoring and a human olfactory verification program for the life of the

SYU Project. The site identified in Table 4.5, *LFC Odor*, shall provide the following information: H_2S, wind speed, wind direction, and shelter temperature. Up to two additional monitors may be required to be installed by Exxon to monitor odorous emissions emanating from the Las Flores Canyon facilities and offshore operations if the APCD determines that odor thresholds are being exceeded. Other odor-related pollutant -specific monitoring equipment may be added to the stations, if deemed necessary by the APCD.

4.15 Part 70 Engineering Review: Hazardous Air Pollutant Emissions

Hazardous air pollutant emissions from the different categories of emission units at the Las Flores Canyon facility are based on emission factors listed in USEPA AP-42. Where no emission factors are available, the HAP fractions from the ARB VOC Speciation Manual – Second Edition (August 1991) are used in conjunction with the ROC emission factor for the equipment item in question.

Potential HAP emissions from each emissions unit at the Las Flores Canyon facility are listed in Section 5.

	Table 4.1 – BACT CONTROL TECHNOLOGY POLLUTANT				
Source	**ROC**	**NO_x (as NO_2)**	**SO_x (as SO_2)**	**CO**	**PM/PM_{10}**
CPP Gas Turbine	Use of pipeline quality natural gas as fuel. Proper combustor operation (e.g., tuning)	Steam injection and SCR (90 percent overall control)	Use of pipeline quality natural gas as fuel. Total sulfur content not to exceed 24 ppmv.	Proper combustor operation (e.g., tuning)	Use of pipeline quality natural gas as fuel. Proper combustor operation (e.g., tuning)
CPP Heat Recovery Steam Generator (HRSG)	Use of pipeline quality natural gas as fuel. Proper combustor operation (e.g., tuning)	Low-NOx burner design and SCR (90 percent overall control)	Use of pipeline quality natural gas as fuel. Total sulfur content not to exceed 24 ppmv.	Proper combustor operation (e.g., tuning)	Use of pipeline quality natural gas as fuel. Proper combustor operation (e.g., tuning)
SGTP – Sulfur Recovery	Use of pipeline quality natural gas in TGCU incinerator. Proper combustor operation (e.g., tuning)	Low-NOx burner design and Thermal DeNOx on TGCU Incinerator	3-Stage Claus Process with Flexsorb SE tail gas cleanup unit (99.9 percent overall sulfur control)	Use of pipeline quality natural gas in TGCU incinerator. Proper combustor operation (e.g., tuning)	Use of pipeline quality natural gas in TGCU incinerator. Proper combustor operation (e.g., tuning)
Tanks/Sumps: (Oil Storage Tanks, Rerun Tanks, Oily Sludge Thickener, Backwash Sump)	Vapor recovery system (gas blanketed)				
Equalization Tank, Demulsifier Tank, Compressor Vents	Carbon Canister		H_2S: Venturi Scrubber with caustic solution (Equalization Tank only)		
Sumps/Separators: (Area Drain Oil/Water Separators, Open Drain Sumps)	Carbon Canister				
Thermal Oxidizer	Use of pipeline quality natural gas in for pilot, purge and Acid Gas Enrichment Fuel. Proper combustor operation (e.g., tuning)	Use of pipeline quality natural gas in for pilot, purge and Acid Gas Enrichment Fuel. Proper combustor operation (e.g., tuning)	Use of pipeline quality natural gas as fuel. Total sulfur content not to exceed 24 ppmv.	Use of pipeline quality natural gas in for pilot, purge and Acid Gas Enrichment Fuel. Proper combustor operation (e.g., tuning)	Use of pipeline quality natural gas in for pilot, purge and Acid Gas Enrichment Fuel. Proper combustor operation (e.g., tuning)

	Table 4.1 – BACT CONTROL TECHNOLOGY POLLUTANT				
Source	**ROC**	**NO_x (as NO_2)**	**SO_x (as SO_2)**	**CO**	**PM/PM_{10}**
NGL Loading and Storage	Vapor balance line between loading trucks and storage bullets and vapor recovery on the LPG loading arm.				
Fugitive ROC	APCD-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.				
Vacuum Trucks	Carbon Canisters				
Depressurizing Vessels	Depressurize to vapor control system, flare, or equivalent and purge with pipeline quality gas		For the SGTP, venting through amine contactor (TGCU) for H_2S control		
Crew and Supply Boats		Use of turbo charging/inter-cooling and ignition timing retard or equivalent.			
Solvents	Low VOC/Water Based solvents where feasible				

	Table 4.2a – BACT PERFORMANCE STANDARDS [4] POLLUTANT					
Source	ROC	NO_x (as NO_2)	SO_x (as SO_2)	CO	PM	PM_{10}
CPP Gas Turbine [5, 4]	0.0026 lb/MMBtu	0.0300 lb/MMBtu	0.0034 lb/MMBtu	0.0216 lb/MMBtu at loads between 75% and 100%. 17 lb/hr at all loads	0.0198 lb/MMBtu	0.0158 lb/MMBtu
CPP Gas Turbine and HRSG Operating in Tandem [3, 4]	0.0055 lb/MMBtu	0.0272 lb/MMBtu	0.0034 lb/MMBtu	0.0260 lb/MMBtu at loads between 75% and 100%. 17 lb/hr at all loads	0.0163 lb/MMBtu	0.0130 lb/MMBtu
CPP HRSG Only [3, 4]	0.0095 lb/MMBtu	0.0300 lb/MMBtu	0.0034 lb/MMBtu	0.297 lb/MMBtu at all loads. 17 lb/hr at all loads	0.0050 lb/MMBtu	0.0040 lb/MMBtu
SGTP – Sulfur Recovery Unit (Claus and Tail Gas Unit)			99.9 percent (mass basis) sulfur removal efficiency at design throughput rate or 100 ppmv H_2S in feed to incinerator (whichever is more stringent)			
SGTP – TGCU Incinerator (w/Merox Vent) [6, 7]	0.0040 lb/MMBtu	0.12 lb/MMBtu and 38 ppmvd at 2% O_2	0.37 lb/MMBtu and 87 ppmvd at 2% O_2	0.092 lb/MMBtu	0.078 lb/MMBtu	0.0624 lb/MMBtu

[4] BACT Performance Standards are not applicable during startup/shutdown periods for the equipment.
[5] In addition to source testing, compliance with NO_x and CO BACT Performance Standards shall be demonstrated through use of CEMS and process flow monitoring data as required by the applicable Permit Condition in Section 9.C.
[6] "lb/MMBtu" standards are based on contribution of heating value from the fuel gas on a HHV basis.

	Table 4.2a – BACT PERFORMANCE STANDARDS [4] POLLUTANT					
Source	ROC	NO_x (as NO_2)	SO_x (as SO_2)	CO	PM	PM_{10}
SGTP – TGCU Incinerator (w/out Merox Vent) [4, 5]	0.0040 lb/MMBtu	0.12 lb/MMBtu and 38 ppmvd at 2% O_2	0.34 lb/MMBtu and 79 ppmvd at 2% O_2	0.092 lb/MMBtu	0.078 lb/MMBtu	0.0624 lb/MMBtu
Fugitive ROC	Compliance with NSPS KKK requirements (as applicable) and Table 4.3					
Tanks/Sumps connected to vapor recovery systems	<u>Hourly and Daily</u>: 95% recovery efficiency (mass basis) <u>Quarterly and Annual</u>: 99.8% recovery efficiency (mass basis) NSPS Kb for the Oil Storage and Rerun Tanks					
Equalization Tank Demulsifier Tank, Compressor Vents	75% recovery efficiency (mass basis)		<u>H_2S</u>: 99.9 percent recovery efficiency (mass basis) of H_2S and 13 ppmvd (Equalization Tk only)			

[7] In addition to source testing, compliance with NO_x and SO_x BACT Performance Standards shall be demonstrated through use of CEMS and process flow monitoring data as required by the applicable Permit Condition in Section 9.C.

	Table 4.2a – BACT PERFORMANCE STANDARDS [4] POLLUTANT					
Source	ROC	NO_x (as NO_2)	SO_x (as SO_2)	CO	PM	PM_{10}
Sumps/Separators connected to carbon canisters	75% recovery efficiency (mass basis)					
Thermal Oxidizer – Flaring					Compliance with 40 CFR 60.18 5-minute opacity limits	Compliance with 40 CFR 60.18 5-minute opacity limits
Thermal Oxidizer – Purge/Pilot and Acid Gas Enrichment Fuel	0.0054 lb/MMBtu	0.098 lb/MMBtu	0.0034 lb/MMBtu	0.0824 lb/MMBtu	0.0075 lb/MMBtu	0.0075 lb/MMBtu
NGL Loading and Storage	<u>Hourly and Daily</u>: 95% recovery efficiency (mass basis) <u>Quarterly and Annual</u>: 99.8% recovery efficiency (mass basis)					
Vacuum Trucks	75% recovery efficiency (mass basis)					
Crew and Supply Boats (main engines)		337 lb/1000 gallons				

TABLE 4.2b – Rule 331 BACT Requirements

Component Tag ID/Description	Technology	Performance Standard
RK- 6228 / Other: 4" flange set on fuel gas line to cogen unit in small compartment east of flow valve compartment.	Gasket rated at 150% of actual process pressure at process temperature	1000 ppm as methane above ambient, monitored per EPA Reference Method 21
RK-6191 / Other: Jr. Orifice fitting On FE 2501-1 fuel gas line (6") to cogeneration unit.	Gasket rated at 150% of actual process pressure at process temperature	1000 ppm as methane above ambient, monitored per EPA Reference Method 21
KW-4669 / Other: 12" spectacle flange on condensate stabilizer MBA-1133.	Gasket rated at 150% of actual process pressure at process temperature	1000 ppm as methane above ambient, monitored per EPA Reference Method 21
RK-4725 / Other: threaded connection on Flow Element 10212. Outlet gas from condensate gas stabilizer reflux drum (MBD-134).	Replaced existing flow measurement device with new manufacturer unit.	1000 ppm as methane above ambient, monitored per EPA Reference Method 21
KW-322 / Other: 1" plug on finfan HAL 4255 at SGTP. Unable to bring emission rate to less than 500 on this NDE fitting, so requested critical status.	Gasket rated at 150% of actual process pressure at process temperature	1000 ppm as methane above ambient, monitored per EPA Reference Method 21
RK-2028 / Valve: ½" needle valve in gas service on 3/8" tubing line from methanol injection line that feeds into the 6" line from the Platform Gas Flash Separator MBD-4102 to Refrigerant subcooler HBG-4250. Design conditions: 345 psig @ 18 deg F.	Low Emission Valve design	100 ppm as methane above ambient, monitored per EPA Reference Method 21
RK-4725 / 1/4" - 3/8" threaded nipple on Peco senior orifice meter on the outlet gas line from the Condensate Stabilizer Reflux Drum. Replace existing senior orifice meter with a replacement unit mfg'd by Daniel Flow Products.	Gasket rated at 150% of actual process pressure at process temperature	100 ppm as methane above ambient, monitored per EPA Reference Method 21

Component Tag ID/Description	Technology	Performance Standard
RK-6191/ 6" 300 series junior orifice fitting on the fuel gas system to the Gas Turbine Generator in the CPP, which operates at a pressure of 285 psig and temp of 155 degrees F.	Gasket rated at 150% of actual process pressure at process temperature	100 ppm as methane above ambient, monitored per EPA Reference Method 21
RK-6205 / Flange downstream of orifice plate on fuel gas line to gas turbine generator.	Gasket rated at 150% of actual process pressure at process temperature	100 ppm as methane above ambient, monitored per EPA Reference Method 21
RK-1770 / 3/4" threaded pipe connection to a coupling on the side of the Deethanizer (MBA-4112) in the SGTP.	Gasket rated at 150% of actual process pressure at process temperature	100 ppm as methane above ambient, monitored per EPA Reference Method 21
KW-322 / 1" plug on finfan HAL 4255 at SGTP. Unable to bring emission rate to less than 500 on this NDE fitting, so requested critical status.	Gasket rated at 150% of actual process pressure at process temperature	100 ppm as methane above ambient, monitored per EPA Reference Method 21

Table 4.3
Fugitive Hydrocarbon Inspection and Maintenance (I&M) Program

	GAS COMPONENTS [A]	OIL COMPONENTS [B]
Leak Definition	Gaseous: 10,000 ppm [C. D] Liquid: any indication	Gaseous: 10,000 ppm [E] Liquid: any indication
Valve Monitoring [F,G]	Monthly/Quarterly	Monthly/Quarterly
Relief Valve Monitoring	Vented to vapor control system	Quarterly
Pump Monitoring	Dual Seals, monthly [H]	Monthly
Connections Monitoring [I, J]	Quarterly	Quarterly
Open-Ended Lines	Capped	Capped
Compressors [K]	Vented to vapor recovery system	Not applicable
Repair Requirements [L, M, N]	First attempt within 5 calendar days. Repair within 15 calendar days..	First attempt within 5 calendar days. Repair within 15 calendar days.
Recordkeeping and Reporting Requirements [O]	Similar to NSPS Subpart KKK	Similar to NSPS Subpart KKK

NOTE: These requirements are in addition to APCD Rule 331 and permit requirements. Where a conflict may occur, the requirement more protective to air quality (as determined by the Control Officer) shall apply.

TABLE 4.3 (continued)

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a Similar to Standards of Performance for New Stationary Sources (NSPS); Equipment Leaks of VOC from Onshore Natural Gas Processing Plants; Final Rule, 40 CFR Part 60, FR Vol. 50, No. 121, June 24, 1985. Applicable to equipment in VOC service (that is, contains or contacts a process fluid that is at least 10 percent VOC by weight at 150°F) or in wet gas service (that is, contains or contacts inlet gas before the plant extraction process).

b Applicable to oil components in heavy hydrocarbon Liquid service (that is, contains or contacts a process fluid that is less than 10 percent VOC by weight at 150°C).

<u>Gas Components Leak Detection</u>

c Gaseous and Light hydrocarbon Liquid component Leakage monitoring will be determined by a hydrocarbon analyzer which uses the flame ionization detection method, and additionally by visual inspection.

d Calibration of the hydrocarbon analyzer will be similar to NSPS requirements.

<u>Heavy Hydrocarbon Liquid Leak Detection</u>

e Heavy hydrocarbon liquid component leakage monitoring will be determined by visual inspection. Monitoring with a hydrocarbon analyzer may be required.

<u>Valves</u>

f Reductions in fugitive emissions due to the implementation of the APCD I&M Programs assume that all valves are accessible to monthly/quarterly monitoring.

g The monthly/quarterly valve monitoring program required by the APCD is similar to that of the NSPS valve monitoring program.

<u>Pumps</u>

h The APCD I&M program on pumps with dual mechanical seals is similar to that required by NSPS on pumps with single seals. This also includes single seals on the sweet crude oil prover sample pump, PBE-1349, PBH-3334 and PBE-3335.

<u>Connections</u>

i The same record keeping and reporting procedures as NSPS are also required for connections; alternatively, a procedure approved by the Air Pollution Control Officer can be used.

j It is assumed that the total connection count includes all connections required for the venting of relief valves to a vapor control system, the capping of open-ended lines, and the conversion of sampling to a closed purge system.

<u>Compressors</u>

k The APCD fugitive emissions calculation assumes no emissions from compressor seals which are required by BACT to be vented to a vapor control system. The APCD assumes that a leak detection program around the compressors will be part of the I&M program to insure that the vent system is operating properly and that no emissions from the compressors are occurring.

<u>Repair Requirements</u>

l Repair requirements follow NSPS requirements.

m It is assumed that spare parts and maintenance personnel are available when necessary for repair.

n Emissions reduction credit will not be applicable to leaking components that are not repaired within the requirements of this program. For repairs made at process turnarounds, emissions reduction credit will be based on the statistical frequency of process turnarounds or shutdowns.

<u>Record Keeping and Reporting Requirements</u>

p Record keeping and reporting requirements follow the most stringent of NSPS requirements.

<u>Component Accessibility</u>
Note: Credit will be adjusted consistent with NSPS as stated in 40 CFR Part 60.

Table 4.4

REQUIREMENTS FOR OPERATIONAL and REGIONAL MONITORING

Parameters to be Monitored	Nojoqui Pass [1]	Carpinteria [2]	El Capitan [3]	LFC1 [4]
$NO_x/NO/NO_2$	X	X	X	X
Ozone	X	X	X	X
PM_{10}				X [5]
H_2S				
SO_2				X
THC				X
CO				X
WS Avg.	X	X	X	X
WD Avg.	X	X	X	X
WS Resultant	X	X	X	X
WD Resultant	X	X	X	X
VWS	X	X	X	X
Sigma W	X	X	X	X
Sigma V				
Sigma Phi				
Sigma Theta	X	X	X	X
Int Temp.	X	X	X	X
Ext Temp.	X	X	X	X

1 Currently operated by GTC.
2 Currently operated by Chevron.
3 Currently operated by the APCD.
4 Currently operated by Exxon
5 Co-located PM_{10} site.

Table 4.5

REQUIREMENTS FOR ODOR MONITORING

Parameters to be Monitored	LFC Odor [1]
H_2S	X
TRS	
WS Avg.	X
WD Avg.	X
WS Result	X
WD Result	X
Sigma Theta	X
Int Temp.	X
Ext. Temp.	X

1 This station shall be located at the property boundary.

FIGURE 4.1 – LFC VAPOR RECOVERY SYSTEM BLOCK DIAGRAM

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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 APCD Rule 202. ESE emissions are the sum of all SYU Expansion Project emissions 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 provides the estimated HAP emissions from the Las Flores Canyon facility. Section 5.6 provides the estimated emissions from permit exempt. Section 5.7 details the ESE emissions for the stationary source. Section 5.8 provides the net emissions increase calculation for the facility and the stationary source. In order to accurately track the emissions from a facility, the APCD uses a computer database. Attachment 10.7 contains the APCD’s documentation for the information entered into that database.

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) [8]
- ⇒ Reactive Organic Compounds (ROC)
- ⇒ Carbon Monoxide (CO)
- ⇒ Sulfur Oxides (SO_x) [9]
- ⇒ Particulate Matter (PM) [10]
- ⇒ Particulate Matter smaller than 10 microns (PM_{10})

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 and Attachment 10.3. Table 5.1-1 provides the basic operating characteristics. Table 5.1-2 provides the specific emission factors. The SO_x emission factors from the Waste Gas Incinerator, all emission factors for the Thermal Oxidizer, the Oil Storage Tanks, the Rerun Tanks and the Demulsifier Tank are found the detailed spreadsheet for these emission units in Attachment 10.4. Tables 5.1-3 and 5.1-4 shows the permitted short-term and permitted long-term emissions

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

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

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

for each unit or operation. In the table, the last column indicates whether the emission limits are federally enforceable. Those emissions limits that are federally enforceable are indicated by the symbol "FE". Those emissions limits that are APCD-only enforceable are indicated by the symbol "A". Emissions data that are shown for informational purposes only are not enforceable (APCD or federal) and are indicated by the symbol "NE".

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:

- CPP Hourly: Startup/Shutdown Mode (NO_x, ROC, CO), CPP Normal Operations Mode (SO_x, PM, PM_{10})
  CPP Daily: CPP Normal Operations Mode
- Waste Gas Incinerator (Startup/Shutdown/Maintenance Mode)
- Thermal Oxidizer (Planned Continuous and Pilot/Purge)
- Crew Boats (Spot Charter and auxiliary engines)
- Supply Boats (Spot Charter and auxiliary engines)
- Pigging Equipment
- Tanks/Sumps/Separators (1 Oil Storage Tank and 1 Rerun Tank)
- Solvent Use (hourly based on daily emissions across a maximum of 8 hours)
- Fugitives
- Compressor Vents

Quarterly and Annual Scenario:

- CPP Startup/Shutdown Mode, CPP Normal Operations Mode, HRSG Only Mode
- Waste Gas Incinerator (w/Merox Vent)
- Thermal Oxidizer (All Flaring Scenarios)
- Crew Boats (Main Boat, Spot Charter and auxiliary engines)
- Supply Boats (Main Boat, Spot Charter and auxiliary engines)
- Pigging Equipment
- Tanks/Sumps/Separators (1 Oil Storage Tank and 1 Rerun Tank)
- Solvent Use
- Fugitives
- Compressor Vents

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 fugitive emissions that are not subject to any applicable NSPS or NESHAP requirement., are counted in the federal definition of potential to emit. For the Las Flores Canyon facility, fugitives from equipment subject to NSPS KKK, Kb, GG and LLL are included in the federal

PTE. For ease of processing, Exxon has agreed to accept the assumption that all fugitives from the Las Flores Canyon facility are part of the federal PTE.

5.5 Part 70: Hazardous Air Pollutant Emissions for the Facility

Total emissions of hazardous air pollutants (HAP) are computed for informational purposes only. HAP emission factors are shown in Table 5.6-1. Potential annual HAP emissions, based on the worst-case scenario listed in Section 5.3 above, are shown in Table 5.6-2.

5.6 Exempt Emission Sources/Part 70 Insignificant Emissions

Equipment/activities exempt pursuant to Rule 202 include maintenance operations involving surface coating. Under the APCD's Part 70 regulation, equipment/activities that are exempt under Rule 202 are considered insignificant units emissions. In addition, *insignificant activities* such as maintenance operations using paints and coatings, contribute to the facility emissions. Table 5.4 list these exempt emissions units and the expected emissions. These are emission estimates only. They are not limitations.

5.7 Entire Source Emissions (ESE)

Exxon is required to mitigate all ozone precursor emissions (NO_x and ROC) from emission units associated with the Santa Ynez Expansion Project [11]. The ESE is calculated based on the following:

- Las Flores Canyon Permitted Emissions
- Las Flores Canyon Phase III Oil and Phase III Wastewater
- Las Flores Canyon Exempt Emissions
- Platform Harmony Permitted Emissions
- Platform Harmony Exempt Emissions
- Platform Heritage Permitted Emissions
- Platform Heritage Exempt Emissions

Table 5.5 lists the ESE emissions.

5.8 Net Emissions Increase Calculation

All emissions from permitted equipment at the Las Flores Canyon facilities contribute to the Net Emissions Increase Calculation (NEI). The NEI for LFC is the same as shown in Table 5.2.

[11] Platform Hondo and the POPCO gas plant emissions are not included in ESE emissions as they were not part of the SYU Expansion Project.

Table 5.1-1: Operating Equipment Description

Table 5.1-1: continued

Table 5.1-2: Emission Factors

Table 5.1-2: continued

Table 5.1-3: Short-Term Permitted Emissions

Table 5.1-3: continued

Table 5.1-4: Long-Term Permitted Emissions

Table 5.1-4 continued

Table 5.2: Facility Permitted Emissions

Table 5.3: Federal Potential to Emit

Table 5.4: Permit Exempt Emissions

Table 5.5: SYU Expansion Project ESE

Table 5.6-1: HAP Emission Factors

Table 5.6-2: HAP Emissions

6.0 Air Quality Impact Analyses

6.1 Modeling

A detailed modeling analysis was performed with the issuance of ATC 5651 (11/19/87) and ATC 5651-17 (1/27/99). This operating permit summarizes the key results of those analyses.

The following sub-sections summarize the operational impacts predicted by the models.

6.1.1 Compliance with Ambient Air Quality Standards: Inert pollutant concentrations from operation of the Exxon Santa Ynez Unit (SYU) Development onshore and associated offshore facilities were estimated using the OCDCPM model and the Industrial Source Complex (ISCST) model for the updated modeling. The OCDCPM model is a hybrid of the Offshore and Coastal Dispersion (OCD) model developed by the Minerals Management Service (MMS), and the Environmental Protection Agency's (EPA) COMPLEX I and MPTER air quality simulation models. Production emissions for both offshore and onshore sources were analyzed in accordance with the APCD's Modeling Protocol. The following pollutants were analyzed for compliance with the ambient air quality standards:

- Nitrogen dioxide (NO_2);
- Total suspended particulate matter (TSP);
- Particulate matter smaller than 10 microns (PM_{10});
- Carbon monoxide (CO);
- Sulfur dioxide (SO_2);
- Reactive organic compounds (ROC);
- Hydrogen sulfide (H_2S); and
- Sulfates (SO_4)

Photochemical modeling to determine project-specific ozone (O_3) impacts was not carried out as part of the ATC process. However, analyses in the Supplemental EIR for ATC 5651 (11/19/87) that used the TRACE photochemical model, concluded that project emissions of the precursor pollutants, NO_x and ROC, could result in significant increases in ozone. These potential impacts have been addressed through Exxon's commitment of appropriate NO_x and ROC offsets as discussed in Section 7.0.

Pre-construction monitoring data collected for one year at Las Flores Canyon Sites A and B were used to establish background pollutant levels. For NO_x, a revised background value was used for the 1-hour standard analysis that reflects more current information. Air quality data collected at other monitoring sites in the general area of the proposed project were used to fill in values missing from the Las Flores Canyon data set for certain pollutants. These background data were reviewed as part of the ATC analysis. Table 6.1 shows the background air quality values.

The background levels of O_3 and NO_2 (one-hour averages) were used to estimate project NO_2 impacts by the Ozone Limiting Method (*Cole and Summerhays, 1979*).

Existing emission sources were reviewed to determine whether any would affect the area of the proposed project during its installation or operation. The existing POPCO gas treating plant was identified as an existing source emitting CO, NO_2, SO_2, ROC, PM_{10}, and TSP. POPCO was modeled according to APCD procedures.

6.1.2 Production Impacts from Onshore Project Components: Impacts from the stripping gas treating facility, the oil treating plant, the cogeneration power plant, the transportation terminal and the emission increases associated with increased throughput at the existing POPCO gas treating plant were evaluated using the OCDCPM model as specified in the Modeling Protocol. Emission sources assessed for short-term standard compliance included normal production activities at each facility (including the CPP Startup/Shutdown Mode) and tests of emergency equipment (fire water pumps) at the Exxon facility. All anticipated annual flaring emissions were included in the analyses which were performed to assess compliance with annual standards. Concentrations were predicted for an array of receptors placed outside the property line of the facility. The internal spacing of the receptors was 125 to 250 meters. Table 6.1 shows the onshore production phase impacts.

Emissions from Exxon's proposed onshore production facilities will not cause standard exceedances during routine operations; however, onshore production emissions of PM_{10} will contribute to an existing exceedance of the state PM_{10} (24-hour) standard. To address this exceedance, Exxon has participated in a particulate concentration reduction and mitigation study and is required to implement control measures resulting from this study to the maximum extent feasible.

Sulfate impacts from the proposed project were also examined. Sulfate formation in the atmosphere results from a complex series of reactions involving sulfur oxide (SO_x) emissions, airborne concentrations of oxidizing species, relative humidity, and metal catalysts, among other factors. The rate of oxidation of SO_2 to sulfate in urban areas such as Los Angeles has been shown to vary from a few percent per hour to levels in excess of 10 percent per hour (*Levy A, et al, 1986*). For this analysis, a sulfur conversion rate of 6 percent per hour (*Bay Area Air Quality Management District, 1986*) was used. Modeled results were added to the maximum ambient 24-hour SO_4 background measured at El Capitan Beach between March 1985 and February 1986, and that total was compared to the state 24-hour SO_4 standard of 25 ug/m^3. The maximum ambient 24-hour background at the El Capitan monitor during this period was 16.0 ug/m^3.

Modeling results indicated a maximum onshore project-related 24-hour SO_2 impact of 34 ug/m^3. This value was converted to a 24-hour sulfate impact of 2.0 ug/m^3. After addition of a background concentration of 16 ug/m^3, the maximum expected sulfate concentration would be 18.0 ug/m^3. This maximum is below the state 24-hour sulfate standard of 25 ug/m^3.

The ISCST model was used to determine peak ambient H_2S concentrations from components of the proposed project containing sour gas. Maximum concentrations of 23 ug/m^3 were predicted. This concentration is below the California standard of 42 ug/m^3.

6.1.4 Production Impacts from Offshore Project Components: Two scenarios were analyzed for Exxon's offshore production. The first included operations at the nearshore marine terminal. That scenario, however, is no longer applicable since Exxon de-permitted the tankering option of ATC 5651 in 1995. The second scenario included drilling and production at the platforms. A cumulative scenario was also modeled, since Platform Harmony lies almost directly offshore of two permitted projects: GTC's Gaviota marine terminal and the Point Arguello Project's Gaviota oil and gas facility.

Impacts from drilling and production at Platforms Harmony and Heritage were evaluated using the reasonable worst-case meteorological data set prescribed by the Modeling Protocol. These maximum onshore concentrations, which Table 6.2 summarizes, are due to emissions from Platform Harmony alone.

Cumulative emissions associated with operations at the Point Arguello Project's facility in Gaviota as well as the GTC Interim Marine Terminal near Gaviota were modeled with drilling/production emissions from Platform Harmony. Table 6.3 gives the maximum predicted concentrations using the offshore one-hour meteorological data set. Background levels reported in Table 6.3 reflect those expected in the Gaviota area. These levels are reported in the ATC for the Gaviota Interim Marine Terminal (*Gaviota Terminal Company, Final Decision Document, Authority to Construct Permit, 1987*). Platform Harmony emissions were predicted to contribute 54 percent of the concentration at the worst-case receptor. The maximum pollutant contributions from the cumulative projects includes emissions from the old GTC marine terminal as well as emissions from the new GTC facility. Since the older marine terminal was built prior to the PSD baseline, only the emissions from the terminal expansion occurring after the baseline will consume PSD increment. The PSD increment consumption analysis is given in Section 6.2.

6.1.5 Unplanned Flaring from Onshore Project Components: Four scenarios for flaring from onshore facilities were identified for modeling. These scenarios include combinations of possible events identified in the emission calculations. They are expected to result in worst-case impacts and include:

(a) Stripping gas treating plant shutdown caused by refrigeration unit failure. A refrigeration unit shutdown would result in the loss of cooling in the Deethanizer Tower overhead condenser. Since reflux would no longer be condensed, the tower and reflux drum pressure would begin to increase. Flaring would then occur to release pressure from the tower and its associated equipment. This event is expected to occur once a year and would result in flaring 63.5 KSCF of gas with a sulfur content of 3.6 percent by volume. This scenario represents the worst-case flaring event for the oil treating plant.

(b) Sulfur plant shutdown at the stripping gas treating facility. A sulfur plant shutdown can be caused by an air blower failure, a low liquid level in the waste heat reclaimer, a combustor flame failure, etc. In such circumstances, sour gas feed would be blocked off from the sulfur plant, causing a pressure increase in the upstream tail gas treating solvent regenerator and tail gas unit sour water stripper. The pressure control system on the regenerator would automatically divert the sour off-gas directly to the thermal oxidizer. The regenerator would continue to operate manually. This event is expected to occur once every three months and to result in flaring 18.5 KSCF of gas with a sulfur content of 67.9 percent by volume. This is the worst-case scenario for the stripping gas treating plant.

(c) Scheduled maintenance flaring. Scheduled maintenance is expected during the purging of the stripping gas treating plant. This would occur four times a year and would result in the flaring of 600 KSCF per event. Once a year, a 100-KSCF flaring event would result from scheduled maintenance of the crude and condensate stabilizer at the oil treating plant.

(d) Off-spec fuel gas production at the stripping gas treating facility. Off-spec fuel gas production could be caused by a loss of treating solvent circulation due to solvent pump failure, solvent flow control valve closure, loss of solvent regenerator heat, etc. The failure of the gas treating system would result in off-spec fuel gas, which would be flared rather than routed to the cogeneration power plant and the oil treating plant. This event is estimated to occur twice a year and would result in the flaring of 162.5 KSCF of gas. The gas would have an average sulfur content of 3.3 percent by volume. This unplanned flaring event is the largest volume that would be flared.

Maximum predicted concentrations from onshore flaring events were modeled by using the OCDCPM model with the Las Flores Canyon meteorological data set. The predicted levels for the four onshore scenarios are reported in Tables 6.4 through 6.7. In all four scenarios, exceedances of the state 1-hour SO_2 standard are predicted. Exceedance of the federal 3-hour and 24-hour SO_2 standards are also predicted for Scenarios (b) and (d). PM_{10} emissions will be insignificant contributors to existing California standard exceedance, while no exceedances are predicted for NO_2 or CO. In order to mitigate these projected air quality standard exceedances, Exxon is required to fund a study to identify feasible measures to reduce flaring emissions.

6.1.6 Unplanned Flaring from Offshore Project Components: Emergency flaring at the platform was evaluated with the OCDCPM model using the worst-case offshore meteorological data set described earlier in Section 6.1.1. This is expected to occur 48 times a year and would result in flaring 260.5 KSCF of gas, with a sulfur content of 2.8 percent by volume. Table 6-8 indicates that exceedances of the state 1-hour and 24-hour SO_2 standards are predicted to occur. Contribution to the existing PM_{10} standard exceedance would be insignificant. No standard exceedance would occur for NO_2 or CO.

6.1.7 Consolidation in Las Flores Canyon: Condition XII-3a of the FDP requires that Exxon demonstrate that the consolidation of facilities at specified throughputs in Las Flores Canyon is feasible without violating AAQS. ARCO oil and gas company submitted an ATC application to the District in July 1986 for oil and gas processing facilities to be consolidated with Exxon's and POPCO's facilities in Las Flores Canyon. Since ARCO's facilities when combined with Exxon were a close match to the specified operating limits in the FDP condition, the ARCO facility was modeled to show compliance with the condition. Although ARCO's application was subsequently deemed incomplete, modeling this project also meets the District requirements to perform an AQIA that includes all reasonably foreseeable projects.

The ARCO emission rates were obtained from the most recent ATC application tables dated 21 May 1987. The ARCO stack parameters and locations were primarily obtained from ATC application tables dated 22 February 1987 and personal communication from R. MacArthur, SAI.

Table 6.9, which shows the results, indicates that no standard violations are expected to occur. Due to the background levels, the state 24-hr PM_{10} standard is exceeded; however, the federal standard would not be violated.

6.2 Increments

This section discusses increment consumption during the operation phase. Project components within APCD jurisdiction (both onshore and offshore) consume increment for NO_2, SO_2, TSP, PM_{10}, CO, and ROC. Emergency equipment that operates on an intermittent basis for a limited period of time was not included in increment consumption calculations. This category includes firewater pump tests as well as unscheduled flaring events. CPP Startup/Shutdown operations are also not included.

When conducting increment consumption analysis, all new emissions occurring after the baseline date must be included as already consuming part of the available increment. For SO_2 and PM, the PSD baseline date in Santa Barbara County is 7 August 1978. Since the POPCO facility was constructed in 1983, all of the permitted (60 MSCFD) SO_2 and PM emissions from the facility must be included in the increment analysis. However, for CO, NO_2, ROC, and PM_{10}, the baseline date is 1 January 1984. Consequently, only the potential increases from the initial processing level (30 MSCFD) to the total permitted level (60 MSCFD) must be included in the analysis as part of the increment consumed to date.

Table 6.10 shows the results of the increment consumption analysis for the Exxon SYU expansion project. This table reports the maximum increments from the Exxon project emissions. The required fees will be reduced by 10 percent per year in accordance with APCD rules. Increment fees cannot be used in place of other fees required under APCD Rules and Regulations.

In addition to the increment analysis done for Las Flores Canyon, a cumulative analysis was done for sources in the Gaviota area. A portion of the emissions included in the cumulative analysis would also consume PSD increment. This cumulative scenario was modeled for offshore production impacts and included emissions from Platform Harmony, the GTC marine terminal and the Chevron Gaviota Plant. Emissions from both the existing GTC marine terminal and the proposed expansion were included in the analysis for compliance with AAQS. However, the existing GTC marine terminal was constructed prior to the PSD baseline date for SO_2 and TSP, so do not consume increment. If emissions from the existing GTC terminal are excluded, then applicable increment consumption values would be 114 ug/m3 for 3-hour SO_2, 65 ug/m^3 for 24-hour SO_2, 16 ug/m^3 annual SO_2, 27 ug/m^3 24-hour TSP and 11 ug/m^3 annual TSP. None of these concentrations exceed the applicable PSD limits for SO_2 or TSP.

6.3 Vegetation and Soils Analysis

Use of the land in the general area of the project includes cattle forage and growth of specialty and row crops. Studies have indicated that at sufficient concentration and duration, ambient air pollutants, specifically SO_2 and NO_2, can injure vegetation. For SO_2, injury thresholds range from 1300-2600 ug/m^3 for one hour for sensitive plants and greater than 5200 ug/m^3 for more resistant plants. The maximum hourly ambient concentration of SO_2 expected during operation of the facility would be approximately 523 ug/m^3, which is below the thresholds cited above.

The maximum hourly NO_2 for operation was predicted to be 814 ug/m^3. As stated in the previous ATC, leaf symptoms have been observed at 3007-4887 ug/m^3 NO_2 for 2-day exposures and 37,588 ug/m3 NO_2 for 1-hour exposures. Thus, the predicted concentration is well below the injury threshold and no vegetation injury is expected.

The effect of SO_2 and NO_x emissions on soils was examined. During production, total project emissions were estimated to be 341 tons/yr and 337 tons/yr for SO_2 and NO_x, respectively. Deposition on the surrounding soil will be minimal, based on the large project area over which the pollutants are dispersed and the distance from offshore sources to shore. The pronounced alkalinity of the soils will ameliorate the effects of the minor decrease in pH expected from sulfate or nitrate deposition. No long-term buildup of deposition products is expected because of use of these compounds by existing vegetation. No heavy metals or other toxic substances are anticipated to be emitted from the Exxon facilities. Thus, the project is not anticipated to cause any adverse impacts on surrounding soils.

6.4 Potential to Impact Visibility and Opacity

A level-1 methodology as described in EPA's Workbook for Estimating Visibility Impairment was used to calculate visibility impacts for the project. This methodology estimates 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 35 km from the project site, is the closest Class I PSD area for which a visibility analysis is required. The background visual range for this area was assumed to be 25 km. Operation emissions from both the nearshore and onshore project components were included in the estimate of visibility impacts.

The analysis showed that the values of the three constant parameters are well below the critical screening value of 0.10 (C1=0.016, C2=0.012, and C3=.000). These results indicate that the activities will have no significant effects on visibility in the San Rafael Wilderness Area.

Opacity impacts were also examined. During the production and operation phase, opacity violations could potentially result from flaring, sand blasting, or firewater pump operation. The potential for these exceedances will be minimized through the use of smokeless flares and through proper maintenance procedures. Sand-blasting operations must use certified materials. Potential opacity violations from other combustion sources will be minimized with maintenance and inspection programs.

6.5 Health Risk Assessment

The *Exxon – Santa Ynez Unit* stationary source is subject to the Air Toxics 'Hot Spots' Program (AB 2588). As required by AB 2588, a health risk assessment (HRA) for the Las Flores Canyon source was prepared by the APCD on March 28, 1995. The HRA is based on 1993 emissions and was prepared by the APCD at the request of Exxon.

Based on the 1993 air toxics emission inventory, a cancer risk of 6 per million at the property boundary (UTM location 771981 East, 3818027 North) was estimated for the Exxon-Las Flores Canyon Stationary Source. The risk is primarily due to benzene and carcinogenic polycyclic aromatic hydrocarbon (PAH) emissions from a thermal oxidizer. Emissions of hydrazine also contribute to the cancer risk estimate. Hydrazine is emitted from a steam generation/steam injection system. The 1993 facility-wide annual emissions of benzene, PAH and hydrazine were 180, 15.1 and 1.71 pounds per year, respectively.

In addition, an acute non-cancer hazard index of 0.3 and a chronic non-cancer hazard index of 0.1 have been estimated by the APCD (both under the significance threshold of 1.0). The acute and chronic risks are due to ammonia emissions and their effect on the respiratory system endpoint. About 18.3 tons per year, and a maximum of 5.5 pounds per hour of ammonia were emitted from the *Exxon – Santa Ynez Unit* stationary source in 1993.

6.6 Public Nuisance

Historically, oil and gas processing facilities handling high sulfur crude oil within the County of Santa Barbara have been the subject of numerous public complaints regarding odors and other related public nuisance factors. Based on these experiences, it was considered necessary to evaluate the potential for public nuisance from the proposed facility. Emissions from the operation phases of the project were reviewed to determine compliance with APCD Rules 205.A and 303, which relate to the prevention of public nuisance as required by Section 41700 of the State Health and Safety Code.

Emissions of reduced sulfur compounds during facility operation have the potential to cause a public nuisance. Sources of the reduced sulfur compounds are the amine units, the sulfur recovery unit, the tail gas cleanup unit, and fugitive emissions from gas and oil handling facilities.

Additionally, operations involving piping for handling sour gas with an H_2S content greater than 825 ppm will trigger classification as a "Potentially Hazardous Emission Area" in accordance with County Ordinance 2832. For petroleum operations in such potentially hazardous emission areas, a plan for detecting and monitoring emissions is required and operations must be conducted so that the ambient H_2S concentration does not exceed the values set forth in Ordinance 2832 for the protection of public health. Ordinance 2832 is also triggered by petroleum facilities "in the vicinity of any residence or place of public gathering which could affect the safety or well being of others." Places of public gathering in the vicinity of Exxon facilities include Refugio and El Capitan State Beaches. However, reduced sulfur concentrations substantially lower than those specified in the Ordinance can cause a public nuisance.

In Section 6.1.3 of ATC 5651 (11/19/87), the predicted level of H_2S (23 ug/m^3) was below the state standard of 42 ug/m^3. However, this peak level would exceed the human odor threshold of 0.7 ug/m3 (*SCAQMD EIR Handbook, Appendix M*). Thus, it is likely that odors will be detectable from the facility. As a result, an odor monitoring program as specified in Section 9.C and as described in Section 4.14 is required.

Table 6.1 – Maximum Concentrations from Onshore Production Facilities in Las Flores Canyon (ug/m^3)

Pollutant	Averaging Time	Project Contribution	Background	Total	Ambient Standard	Location, (km) X	Y
NO_2	1-hr	431	14	445	470	771.00	3,819.50
	Annual	12	6	18	100	771.99	3,818.02
PM_{10}	24-hr	12	61	73 [(a)]	50	772.59	3,818.91
	Annual	2	24	26	30	772.11	3,818.15
CO	1-hr	1,583	2,629	4,212	23,000	772.55	3,819.12
	8-hr	598	1,966	2,564	10,000	772.35	3,818.53
SO_2	1-hr	304	133	437	655	771.00	3,819.50
	3-hr	294	100	394	1,300	771.05	3,819.50
	24-hr	47	28	75	131	771.05	3,819.62
	Annual	11	5	16	80	771.99	3,818.02
SO_4	24-hr	2	16	18	25	771.08	3,819.62
H_2S	1-hr	23	-- [(b)]	23	42	771.19	3,820.00

(a) Project contribution of PM_{10} adds to an existing California standard exceedance. However, predicted levels are below federal standard of 150 ug/m^3.

(b) H_2S background was assumed to be negligible.

(c) Maximum 1-hour NO_x impact due to CPP Startup/Shutdown operations.

(d) SO_2 1-hour, 3-hour and 24-hour values linear scaled from original modeling results.

(e) NO_x 1-hour remodeled per ATC/PTO 5651-01 (5/27/99).

Table 6.2 – Maximum Concentrations from Platform Emissions (ug/m^3)

Pollutant	Averaging Time	Project Contribution	Background	Total	Ambient Standard	Location, (km) X	Y
NO_2	1-hr	359	45	404	470	758.81	3,818.05
	Annual	36	6	42	100	758.81	3,818.05
PM_{10}	24-hr	12	61	73 [(a)]	50	758.81	3,818.05
	Annual	3	24	27	30	758.81	3,818.05
CO	1-hr	87	2,629	2,716	23,000	758.81	3,818.05
	8-hr	61	1,966	2,007	10,000	758.81	3,818.05
SO_2	1-hr	26	133	159	655	758.81	3,818.05
	3-hr	24	100	124	1,300	758.81	3,818.05
	24-hr	10	28	38	131	758.81	3,818.05
	Annual	3	5	8	80	758.81	3,818.05

(a) Project contribution of PM_{10} adds to an existing California standard exceedance. However, predicted levels are below federal standard of 150 ug/m^3.

Table 6.3 – Maximum Cumulative Onshore Concentrations [(a)] (ug/m^3)

Pollutant	Averaging Time	Project Contribution[(b)]	Background[(c)]	Total	Ambient Standard	Location, (km) X	Y
NO_2	1-hr	289	70	359	470	756.52	3,818.80
PM_{10}	24-hr	38	58	96[(d)]	50	756.52	3,818.80
CO	1-hr	340	8,000	8,340	23,000	756.46	3,819.00
	8-hr	306	2,663	4,935	10,000	756.46	3,819.00
SO_2	1-hr	270	47	317	655	755.42	3,820.00
	3-hr	189	35	224	1,300	755.42	3,820.00
	24-hr	108	10	118	131	755.42	3,820.00

(a) Scenario includes Platform Harmony production as well as operation of the GTC marine terminal and Chevron USA oil and gas treating facilities near Gaviota.

(b) Includes contribution from existing GTC marine terminal, which do not consume PSD increment.

(c) Background values monitored in the Gaviota area and used in the GTC and Chevron ATC permitting analysis.

(d) Project contribution to PM_{10} adds to an existing California standard exceedance. However, predicted levels are below the federal AAQS of 150 ug/m^3.

Table 6.4 – Maximum Concentrations for Onshore Flaring Scenario A (ug/m^3)

Pollutant	Averaging Time	Project Contribution	Background	Total	Ambient Standard	Location, (km) X	Y
NO_2	1-hr	130	45	175	470	772.41	3,818.63
PM_{10}	24-hr	< 1	61	61[(a)]	50	772.41	3,818.63
CO	1-hr	9	2,629	2,638	23,000	772.41	3,818.63
	8-hr	1	1,966	1,967	10,000	772.41	3,818.63
SO_2	1-hr	1,432	133	1,565	655	772.41	3,818.63
	3-hr	477	100	577	1,300	772.41	3,818.63
	24-hr	60	28	88	131	772.41	3,818.63

(a) Project contribution to PM_{10} adds to an existing California standard exceedance. However, predicted levels are below the federal AAQS of 150 ug/m^3.

Table 6.5 – Maximum Concentrations for Onshore Flaring Scenario B (ug/m^3)

Pollutant	Averaging Time	Project Contribution	Background	Total	Ambient Standard	Location, (km) X	Y
NO_2	1-hr	64	45	109	470	772.12	3,817.90
PM_{10}	24-hr	< 1	61	61[(a)]	50	772.12	3,817.90
CO	1-hr	16	2,629	2,645	23,000	772.12	3,817.90
	8-hr	2	1,966	1,968	10,000	772.12	3,817.90
SO_2	1-hr	52,308	133	52,441	655	772.12	3,817.90
	3-hr	17,436	100	17,536	1,300	772.12	3,817.90
	24-hr	533	28	561	131	772.12	3,817.90

(a) Project contribution to PM_{10} adds to an existing California standard exceedance. However, predicted levels are below the federal AAQS of 150 ug/m^3.

Table 6.6 – Maximum Concentrations for Onshore Flaring Scenario C (ug/m^3)

Pollutant	Averaging Time	Project Contribution	Background	Total	Ambient Standard	Location, (km) X	Y
NO_2	1-hr	171	45	216	470	772.41	3,818.63
PM_{10}	24-hr	< 1	61	61[(a)]	50	771.28	3,821.33
CO	1-hr	16	2,629	2,645	23,000	772.41	3,818.63
	8-hr	2	1,966	1,968	10,000	772.41	3,818.63
SO_2	1-hr	577	133	710	655	772.41	3,818.63
	3-hr	192	100	292	1,300	772.41	3,818.63
	24-hr	24	28	52	131	771.28	3,821.33

(a) Project contribution to PM_{10} adds to an existing California standard exceedance. However, predicted levels are below the federal AAQS of 150 ug/m^3.

Table 6.7 – Maximum Concentrations for Onshore Flaring Scenario D (ug/m^3)

Pollutant	Averaging Time	Project Contribution	Background	Total	Ambient Standard	Location, (km) X	Y
NO_2	1-hr	360	45	405	470	772.41	3,818.63
PM_{10}	24-hr	< 1	61	61[(a)]	50	772.18	3,818.39
CO	1-hr	28	2,629	2,657	23,000	772.41	3,818.63
	8-hr	4	1,966	1,970	10,000	772.35	3,818.53
SO_2	1-hr	3,911	133	4,044	655	772.41	3,818.63
	3-hr	1,304	100	1,404	1,300	772.41	3,818.63
	24-hr	163	28	191	131	772.18	3,818.39

(a) Project contribution to PM_{10} adds to an existing California standard exceedance. However, predicted levels are below the federal AAQS of 150 ug/m^3.

Table 6.8 – Maximum Concentrations for Offshore Flaring Scenario (ug/m^3)

Pollutant	Averaging Time	Project Contribution	Background	Total	Ambient Standard	Location, (km) X	Y
NO_2	1-hr	387	45	432	470	771.24	3,818.13
PM_{10}	24-hr	< 1	61	61[(a)]	50	771.24	3,818.13
CO	1-hr	48	2,629	2,677	23,000	771.24	3,818.13
	8-hr	6	1,966	1,972	10,000	771.24	3,818.13
SO_2	1-hr	5,690	133	5,823	655	771.24	3,818.13
	3-hr	1,896	100	1,996	1,300	771.24	3,818.13
	24-hr	237	28	265	131	771.24	3,818.13

(a) Project contribution to PM_{10} adds to an existing California standard exceedance. However, predicted levels are below the federal AAQS of 150 ug/m^3.

Table 6.9 – Maximum Concentrations from Consolidated Onshore Facilities[(a)] (ug/m^3)

Pollutant	Averaging Time	Project Contribution	Background	Total	Ambient Standard	Location, (km) X	Y
NO_2	1-hr	392	45	437	470	771.08	3,819.37
	Annual	45	6	51	100	772.11	3,818.15
PM_{10}	24-hr	13	61	74[(b)]	50	771.19	3,820.13
	Annual	4	24	26	30	771.99	3,818.02
CO	1-hr	1,583	2,629	4,212	23,000	772.59	3,819.16
	8-hr	629	1,966	2,595	10,000	772.35	3,818.53
SO_2	1-hr	346	133	479	655	772.59	3,818.91
	3-hr	282	100	382	1,300	772.11	3,818.15
	24-hr	51	28	79	131	772.59	3,818.91
	Annual	15	5	20	80	772.11	3,818.15

(a) This scenario includes Exxon, POPCO, (60 MSCFD gas production rate) and ARCO facilities in Las Flores Canyon.

(b) Project contribution to PM_{10} adds to an existing California standard exceedance. However, predicted levels are below the federal AAQS of 150 ug/m^3.

Table 6.10 – Increment Analysis (ug/m^3)

Pollutant	Averaging Time	Project Maximum Increment Consumed	Increment Consumed to Date (1993)[a]	Total Increment Consumed	Allowable Increment
NO_2	1-hr	363.0[b]	0.0	363.0	100-470[d]
	Annual	7.0[c]	5.0	12.0	25-100[d]
TSP	24-hr	13.5[c]	0.6	14.1	37
	Annual	3.0[c]	0.1	3.1	19
PM_{10}	24-hr	10.8[c]	0.3	11.1	12-50
CO	1-hr	1,471.0[c]	7.0	1,573.0	10,000
	8-hr	590.0[c]	2.0	594.0	2,500
SO_2	3-hr	105.0[c]	172.0	277.0	512
	24-hr	19.0[c]	26.0	45.0	91
	Annual	5.6[c]	6.7	12.3	20
ROC	3-hr	457.0[c]	0.2	457.2	40-160[d]

(a) Increment consumed to date includes contributions from both the existing POPCO facility and contributions from emissions increases associated with increasing production to permitted capacity.

(b) Maximum project increment consumption due to nearshore marine terminal operations.

(c) Maximum project increment consumption due to onshore production sources.

(d) Increment fee is based on maximum increment consumption by project contribution above lower end of increment range.

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7.0 CAP Consistency, Offset Requirements and ERCs

7.1 General

The Exxon Santa Ynez stationary source is located in an ozone nonattainment area. Santa Barbara County is nonattainment for both the federal and state ozone ambient air quality standards. In addition, the County is nonattainment for the state PM_{10} ambient air quality standard. 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 progress towards attainment of federal and state ambient air quality standards. Under APCD regulations, any modifications at Las Flores Canyon (or the Santa Ynez Unit stationary source) that result in an emissions increase of any nonattainment pollutant exceeding 25 lbs/day must apply BACT (NAR). Any additional increases of ROC, NO_x, SO_x, PM or PM_{10} require emission offsets at the source or elsewhere so that there is a net air quality benefit for Santa Barbara County. These offset threshold levels for these pollutants (55 lbs/day for all non-attainment pollutants except PM_{10} for which the level is 80 lbs/day) already are exceeded.

7.2 Clean Air Plan

Santa Barbara County does not meet the current hourly federal ambient ozone standard of 0.12 ppm or the state hourly ambient ozone standard of 0.09 ppm. The APCD has submitted the 1998 Clean Air Plan (Final, 12/98) to the USEPA through the State of California Air Resources Board. The 1998 CAP, if approved by the USEPA, will be incorporated into the California State Implementation Plan (SIP). The CAP demonstrates a Rate-of-Progress and how the county will attain the ambient ozone standards by 1999 through the application of emission controls on all pollution sources.

7.3 Offset Requirements

7.3.1 <u>NEI Offsets</u>: Under APCD rules, Exxon is required to provide offsets for the project's operational net emission increase for NO_x, ROC, PM, PM_{10} and SO_2. In order to demonstrate a net air quality benefit, offsets have been adjusted to account for the distance between the project source and the offset source.

Exxon shall offset the maximum quarterly NO_x, ROC, SO_x, PM_{10} and PM net emission increase associated with the operation of the SYU Project as documented in Table 5.2 of this permit. Emission offsets for the operations phase are required to be in place, as specified in Tables 7.1, 7.2, 7.3 and 7.4, and shall remain in place for the duration of the project as required by APCD rules and the conditions of this permit.

7.3.2 <u>ESE Offsets</u>: 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, Exxon is required by this permit to offset the SYU Expansion Project's Entire Source Emissions (ESE) for NO_x and ROC by reducing emissions at existing sources by an equal amount. Exxon is required by this permit to offset the NO_x and ROC entire source emissions from the SYU Project at a ratio of 1 to 1. This requirement is necessary for the APCD 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 APCD-approved AQAP. Table 7.5 provides a listing of the offsets that Exxon is using to cover its NO_x and ROC ESE liability. Due to the large offset ratios required for the NEI liability, Exxon has offsets in excess of its ESE requirements. Table 7.6 shows how these excess offsets will be used. There are no excess ESE or NEI ERCs available for future use.

7.4 Emission Reduction Credits

7.4.1 ATC 9651, PTO 9651: Exxon has generated 1.56 tons per year of ROC ERCs in order to offset emission increases from compressor skid projects at Platforms Harmony and Heritage (PTO 9640 and PTO 9634 respectively). These ERCs were created by implementation of an Enhanced Fugitive Hydrocarbon I&M Program – monthly monitoring of valves. ATC 9651 and PTO 9651 were issued to ensure the reductions were enforceable. The requirements of those permits are included in this permit.

7.4.2 DOI No. 0002/ERC Certificate No. 0004: On January 20, 1998 Exxon obtained ERC Certificate No. 0004 (DOI No. 0004) for 0.18 tpq of ROCs. These ERCs were assigned to increased ROC fugitive emissions from gas pipeline project topsides tie-ins at Platforms Harmony and Heritage (ATC 9827, ATC 9828) respectively. The APCD issued ATC/PTO 9826 to ensure that the modifications (an Enhanced Fugitive Hydrocarbon I&M Program – monthly monitoring of valves) were enforceable. The Certificate was retired from the Source Register in whole on January 20, 1998. The requirements of that permit are included in this permit.

Table 7.1 - NO_x Project Emissions and Offsets

Table 7.2 - ROC Project Emissions and Offsets

Table 7.3 - SO_x Project Emissions and Offsets

Table 7.4 - PM Project Emissions and Offsets

Table 7.5 - ESE Project Emissions and Offsets

Table 7.6 - Disposition of Excess NO_x and ROC ESE ERCs

Table 7.7 - Exxon SYU Project Offset Sources for the Entire Source Emissions

Table 7.7 continued

8.0 Lead Agency Permit Consistency

8.1 Prior Lead Agency Action

The Preliminary Development Plan (PDP) for the Exxon SYU Project was approved by the Santa Barbara County Board of Supervisors on September 3, 1986. The Final Development Plan (FDP) was issued by the Santa Barbara County Planning Commission on September 15, 1987. In this FDP approval, the Planning Commission included permit conditions (XII-3, 5, 8, 11, and 17) requiring Exxon to fully mitigate adverse air quality impacts of the project which would affect the County. Exxon is also required to satisfy other lead agency air quality conditions prior to issuance of the land use permit. The following is a summary of the major lead agency air quality conditions and their relationship to the APCD evaluation and decision on this project.

1. FDP Condition XII-2 - Authority to Construct: Requirement for an Authority to Construct (ATC) prior to any construction, including grading begins. The issuance of the APCD ATC Permit (before construction) fulfilled this condition.

2. FDP Condition XII-3.a - Consolidation: Requirement for consolidation of facilities in Las Flores and Corral Canyons. The air quality impact analysis modeling (Section 6.1.8) performed as part of ATC 5651 showed no violations of air quality standards from the SYU project operating in conjunction with consolidated facilities in Las Flores and Corral Canyons, with the exception of exacerbating an existing violation of the 24-hour PM_{10} standard.

3. FDP Condition XII-3.b - Mitigation and Offsets of NO_x and ROC Emissions: Requirement for demonstration that all oxides of nitrogen and hydrocarbon emissions associated with the construction and operation of the SYU project are fully mitigated, permitted emissions onshore and in State waters are offset as applicable according to APCD rules, and total offsets for operation are equal to or greater than entire source emissions, including OCS sources. Section 2.3, Applicant Proposed Project Operating Assumptions of ATC 5651, and Section 6.1, Compliance with Ambient Air Quality Standards of ATC 5651, discussed the proposed mitigation. Section 7.0, Offset Requirements, discusses the offsets used as mitigation.

4. FDP Condition XII-4 - Odor: Requirement for project to be designed, constructed, operated and maintained so as to eliminate odors. Section 6.4, Public Nuisance, Section 4.14, Section 9.C includes enforceable permit condition language to ensure compliance.

5. FDP Condition XII-5 - Construction Mitigation: Requirement for mitigation of construction air quality impacts to the maximum extent feasible. Section 2.3, Applicant Proposed Project Operating Assumptions of ATC 5651, and Section 6.1, Compliance with Ambient Air Quality Standards of ATC 5651, discussed the mitigation and Section 7.1 of ATC 5651 discussed the offset requirements for construction.

6. FDP Condition XII-6 - Ambient Monitoring: Requirement for ambient air quality monitoring stations in numbers and locations specified by the air pollution control officer and for participation in the purchase, installation, operation, and maintenance of a central data acquisition system. Section 4.13, Operational and Regional Monitoring, and Permit Section 9.C.12 includes enforceable permit condition language to ensure compliance.

7. FDP Condition XII-7 - Operating Phase Episode Plan: Requirement for an operations-phase episode plan for sources within the APCD's jurisdiction. An Emergency Episode Plan is approved for the SYU stationary source. Permit Condition 9.C.37 requires that this plan be kept current every three years.

8. FDP Condition XII-8 - Operation Phase Mitigation: Requirement for implementation of mitigation measures contained in the project's EIS/EIR. Section 9.C incorporates the mitigation measures discussed in Section 2.3, Applicant Proposed Project Operating Assumptions of ATC 5651 and Section 6.1, Compliance with Ambient Air Quality Standards of ATC 5651.

9. FDP Condition XII-9 - Vapor Control System: Requirement for a vapor control system (VCS) to reduce marine vessel loading and storage tank emissions by 99.8 percent or more. The marine terminal is no longer part of the project. Section 9.C includes enforceable permit condition language to ensure compliance.

10. FDP Condition XII-11 - Vessel Reports: Requirement for submission of information as to the type and size of tankers and support boats used during the previous six months and estimates of anticipated use during the next six months. Tankers are no longer part of the project. Section 9.C includes enforceable permit condition language to ensure compliance.

11. FDP Condition XII-16 - Continuous Monitoring: Requirement for continuous monitoring and record keeping. Sections 4.11, *Continuous Emission Monitoring*, and 4.12, *Source Testing*, describe the requirements. Attachments 10.1 and 10.2 provide additional details on the CEM and source testing requirements. Section 9.C includes enforceable permit condition language to ensure compliance.

12. FDP Condition XII-17 - OS&T and SALM Dismantlement: Requirement that emissions from operation or dismantling of the OS&T and SALM, together with project and other source emissions, not violate any standards or increments and not interfere with reasonable further progress. Section 6.1, Compliance with Ambient Air Quality Standards of ATC 5651, indicated that no standard will be violated.

13. FDP Condition V-1 - Cogeneration Facility: Permits the cogeneration facility to operate with a minimum of 80 percent NO_x control, if sufficient offsets are provided. Section 4.2, *Cogeneration Power Plant*, discusses the cogeneration facility's NO_x control measures. Section 9.C includes enforceable permit condition language to ensure compliance.

8.2 Lead Agency Actions for PTO 5651

Pursuant CEQA Guidelines Section 15300.4 and Appendix A (*APCD List of Exempt Projects*) of the APCD'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 Las Flores Canyon (LFC) Oil Treating Plant, Stripping Gas Treating Plant, Cogeneration Power Plant, Transportation Terminal facilities and Marine Support Vessels that comprise the Santa Ynez Expansion Project. Section 9 contains the permit's enforceable requirements.

Section 9.A lists the standard administrative conditions. Section 9.B lists 'generic' permit conditions, including emission standards, for all equipment in this permit. Section 9.C lists conditions affecting specific equipment. Section 9.D lists non-federally enforceable (i.e., APCD only) permit conditions. Conditions listed in Sections A, B and C are enforceable by the USEPA, the APCD, the State of California and the public. Conditions listed in Section D are enforceable only by the APCD 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.

Number	Title
A.1	Condition Acceptance
A.2	Grounds for Revocation
A.3	Defense of Permit
A.4	Reimbursement of Costs
A.5	Access to Records and Facilities
A.6	Conflicts Between Conditions
A.7	Compliance
A.8	Consistency with Analysis
A.9	Consistency with State and Local Permits
A.10	Compliance with Permit Conditions
A.11	Emergency Provisions
A.12	Compliance Plans
A.13	Right of Entry
A.14	Severability
A.15	Permit Life
A.16	Payment of Fees
A.17	Prompt Reporting of Deviations
A.18	Reporting Requirements/Compliance Certification
A.19	Federally-enforceable Conditions
A.20	Recordkeeping Requirements
A.21	Conditions for Permit Reopening
A.22	Permit Shield
B.1	Circumvention (Rule 301)
B.2	Visible Emissions (Rule 302)
B.3	Nuisance (Rule 303)
B.4	PM Concentration - South Zone (Rule 305)
B.5	Specific Contaminants (Rule 309)

Number	Title
B.6	Odorous Organic Sulfides (Rule 310)
B.7	Sulfur Content of Fuels (Rule 311)
B.8	Organic Solvents (Rule 317)
B.9	Solvent Cleaning Operations (Rule 321)
B.10	Metal Surface Coating Thinner and Reducer (Rule 322)
B.11	Architectural Coatings (Rule 323)
B.12	Disposal and Evaporation of Solvents (Rule 324)
B.13	Continuous Emission Emissions Monitoring (Rule 328)
B.14	Adhesives and Sealants (Rule 353)
B.15	CARB Registered Portable Equipment
C.1	Cogeneration Power Plant
C.2	Thermal Oxidizer
C.3	Fugitive Hydrocarbon Emissions Components
C.4	Crew and Supply Boats
C.5	Pigging Equipment/Compressor Vents
C.6	Tanks/Sumps/Separators
C.7	Solvent Usage
C.8	Sulfur Recovery Unit/Waste Gas Incinerator.
C.9	Recordkeeping
C.10	Compliance Verification Reports
C.11	BACT
C.12	Ambient Monitoring Requirements
C.13	Operational Increment Fee
C.14	Source Testing
C.15	Process Stream Sampling and Analysis
C.16	Offsets and Consistency with the AQAP
C.17	Continuous Emission Monitoring (CEM)
C.18	Process Monitoring Systems - Operation and Maintenance
C.19	Data Telemetry
C.20	Central Data Acquisition System
C.21	Central Data Acquisition System Operation and Maintenance Fee
C.22	Emissions Reduction Credit Certificate No. 0004-0103
C.23	Emissions Reduction Credits Dedicated to Specific Projects – ATC 9651
C.24	Mass Emission Limitations
C.25	Permitted Equipment
C.26	Facilities Approved for Future Construction
C.27	Facility Throughput Limitations
C.28	Emission Factor Revisions
C.29	Abrasive Blasting Equipment
C.30	Vacuum Truck Use
C.31	Temporary Gas Sweetening Unit (BUGSU)
C.32	Emergency Firewater/Floodwater Pumps
C.33	Diesel Fuel Sulfur Limit
C.34	Transportation Terminal Operational Limits

Number	Title
C.35	Purging/Degassing of Vessels to the Atmosphere
C.36	Diesel IC Engines - Particulate Matter Emissions
C.37	Emergency Episode Plan
C.38	Odor Monitoring Plan
C.39	As-Built Drawings
C.40	Particulate Matter Mitigation
C.41	Flare Study
C.42	Consolidation
C.43	Documents Incorporated by Reference
C.44	Documentation of Outer Continental Shelf (OCS) Activities
C.45	Additional Mitigation Measures
C.47	deleted
C.48	LFC-1 Ambient Monitoring Station/ LFC-Odor Monitoring Station Operation Fee
C.49	Ambient and Odor Monitoring Station Data Review and Audit Fee
C.50	Thermal Oxidizer Variance Order

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9.A Standard Administrative Conditions

A.1 **Condition Acceptance.** Acceptance of this operating permit by Exxon shall be considered as acceptance of all terms, conditions, and limits of this permit. [*Re: ATC 5651, PTO 5651]*

A.2 **Grounds for Revocation.** Failure to abide by and faithfully comply with this permit shall constitute grounds for revocation pursuant to California Health & Safety Code Section 42307 *et seq*. [*Re: ATC 5651, PTO 5651]*

A.3 **Defense of Permit.** Exxon agrees, as a condition of the issuance and use of this permit, to defend at its sole expense any action brought against the APCD because of issuance of this permit. Exxon shall reimburse the APCD for any and all costs including, but not limited to, court costs and attorney's fees which the APCD may be required by a court to pay as a result of such action. The APCD may, at its sole discretion, participate in the defense of any such action, but such participation shall not relieve Exxon of its obligation under this condition. The APCD shall bear its own expenses for its participation in the action. [*Re: ATC 5651, PTO 5651]*

A.4 **Reimbursement of Costs**. All reasonable expenses, as defined in APCD Rule 210, incurred by the APCD, APCD contractors, and legal counsel for all activities 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 Exxon as required by Rule 210. [*Re: ATC 5651, PTO 5651]*

A.5 **Access to Records and Facilities.** As to any condition that requires for its effective enforcement the inspection of records or facilities by the APCD or its agents, Exxon shall make such records available or provide access to such facilities upon notice from the APCD. Access shall mean access consistent with California Health and Safety Code Section 41510 and Clean Air Act Section 114A. [*Re: ATC 5651, PTO 5651]*

A.6 **Conflicts Between Conditions.** 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: ATC 5651, PTO 5651]*

A.7 **Compliance.** Nothing contained within this permit shall be construed to allow the violation of any local, State or Federal rule, regulation, ambient air quality standard or air quality increment. [*Re: ATC 5651, PTO 5651]*

A.8 **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 APCD's project file) and the APCD's analyses under which this permit is issued. [*Re: ATC 5651, PTO 5651]*

A.9 **Consistency with State and Local Permits.** Nothing in this permit shall relax any air pollution control requirement imposed on the Santa Ynez Unit Project by:

(a) the County of Santa Barbara in Final Development Plan Permit 87-DP-32cz and any subsequent modifications; and,

(b) the California Coastal Commission in the consistency determination for the Project with the California Coastal Act.

[*Re: ATC 5651, PTO 5651]*

A.10 **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 re-issuance, 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), APCD Rules 1303.D.1]*

A.11 **Emergency Provisions.** The permittee shall comply with the requirements of the APCD, Rule 505 (Upset/Breakdown rule) and/or APCD 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 APCD, 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), APCD Rule 1303.F*]

A.12 **Compliance Plans.**

(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: APCD Rule 1302.D.2*]

A.13 **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: APCD Rule 1303.D.2*]

A.14 **Severability.** The provisions of this Permit to Operate are severable and if any provision of this Permit to Operate is held invalid, the remainder of this Permit to Operate shall not be affected thereby. [*Re: APCD Rules 103 and 1303.D.1*]

A.15 **Permit Life.** The Part 70 permit shall become invalid five years from the date of issuance unless a timely and complete renewal application is submitted to the APCD. 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 APCD rules.

The permittee shall apply for renewal of the Part 70 permit no earlier than 18 months and not later than 6 months before the date of the permit expiration. 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: APCD Rule 1304.D.1*]

A.16 **Payment of Fees.** The permittee shall reimburse the APCD 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 APCD and the USEPA pursuant to section 502(a) of the Clean Air Act. [*Re: APCD Rules 1303.D.1 and 1304.D.11, 40 CFR 70.6(a)(7)*]

A.17 **Prompt Reporting of Deviations.** The permittee shall submit a written report to the APCD 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 6 months 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 APCD in accordance with Rule 505. Breakdown Conditions, or Rule 1303.F Emergency Provisions. *[APCD Rule 1303.D.1, 40 CFR 70.6(a) (3)]*

A.18 **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 APCD approved 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 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 August 15 and February 15, 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: APCD Rules 1303.D.1, 1302.D.3, 1303.2.c*]

A.19 **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 APCD-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.20 **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 APCD upon request. [*Re: APCD Rule 1303.D.1.f, 40 CFR 70.6(a)(3)*]

A.21 **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 APCD 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 APCD 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 a permit is reopened, the expiration date does not change. Thus, if the permit is reopened, and revised, then it will be reissued with the expiration date applicable to the re-opened permit. [*Re: 40 CFR 70.7(f), 40 CFR 70.6(a)*]

A.22 **Permit Shield.** The rules and regulations listed in Table 1.1 of this permit have been specifically identified as non-applicable to the Las Flores Canyon facility. This shield shall remain in effect until expiration of this permit or re-opening and re-issuance of this permit. [*Re: 40 CFR 70.6(f), APCD Rule 1303.E.4*]

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. These rules apply to the equipment and operations at the Las Flores Canyon facility as they currently exist. Compliance with these requirements is discussed in Section 3.4.2. In the case of a discrepancy between the wording of a condition and the applicable APCD rule, 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 APCD Rule 303. [*Re: APCD Rule 301*]

B.2 **Visible Emissions (Rule 302).** Exxon 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 Ringelmann 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.

Compliance shall be determined by APCD staff certified in visual emission evaluations. [*Re: APCD Rule 302*]

B.3 **Nuisance (Rule 303).** No pollutant emissions from any source at Exxon shall create nuisance conditions. No operations shall endanger health, safety or comfort, nor shall they damage any property or business. [*Re: APCD Rule 303*]

B.4 **PM Concentration - South Zone (Rule 305).** Exxon shall not discharge into the atmosphere, from any source, particulate matter in excess of the concentrations listed in Table 305(a) of Rule 305. [*Re: APCD Rule 305*]

B.5 **Specific Contaminants (Rule 309).** Exxon shall not discharge into the atmosphere from any single source sulfur compounds, hydrogen sulfide, combustion contaminants and carbon monoxide in excess of the standards listed in Sections A, B and G of Rule 309. Exxon shall not discharge into the atmosphere from any fuel burning equipment unit, sulfur compounds, nitrogen oxides or combustion contaminants in excess of the standards listed in Section E and F of Rule 309. [*Re: APCD Rule 309*]

B.6 **Odorous Organic Sulfides (Rule 310).** Exxon shall not discharge into atmosphere H_2S and organic sulfides that result in a ground level impact beyond the Exxon property boundary in excess of either 0.06 ppmv averaged over 3 minutes and 0.03 ppmv averaged over 1 hour. Compliance shall be based on data gathered from the *LFC Odor* monitoring station. For the purposes of compliance with this rule, this odor monitoring station shall be assumed to be located at Exxon's property boundary. [*Re: APCD Rule 310*]

B.7 **Sulfur Content of Fuels (Rule 311).** Exxon shall not burn fuels with a sulfur content in excess of 0.5% (by weight) for liquid fuels and 239 ppmvd or 15 gr/100scf (calculated as H_2S) for gaseous fuels. Compliance with this condition shall be based on continuous monitoring of the fuel gas with H_2S and HHV analyzers, quarterly total sulfur content measurements of the fuel gas using ASTM or other APCD-approved methods and diesel fuel billing records or other data showing the certified sulfur content for each shipment. [*Re: APCD Rule 311*]

B.8 **Organic Solvents (Rule 317).** Exxon shall comply with the emission standards listed in Section B of Rule 317. Compliance with this condition shall be based on Exxon's compliance with Condition C.7 (*Solvent Usage*) of this permit. [*Re: APCD Rule 317*]

B.9 **Solvent Cleaning Operations (Rule 321).** Exxon shall comply with the operating requirement, equipment requirements and emission control requirements for all solvent cleaners subject to this Rule. Compliance shall be based on APCD inspection of the existing cold solvent cleaner and a thorough ATC application review for future solvent cleaners (if any). [*Re: APCD Rule 321*]

B.10 **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 Exxon's compliance with Condition C.7 (*Solvent Usage*) of this permit, and facility inspections. [*Re: APCD Rule 322*]

B.11 **Architectural Coatings (Rule 323).** Exxon shall comply with the emission 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 Exxon's compliance with Condition C.7 (*Solvent Usage*) of this permit and facility inspections. [*Re: APCD Rule 323*]

B.12 **Disposal and Evaporation of Solvents (Rule 324).** Exxon shall not dispose through atmospheric evaporation more than one and a half gallons of any photochemically reactive solvent per day. Compliance with this condition shall be based on Exxon's compliance with Condition C.7 (*Solvent Usage*) of this permit, and facility inspections. [*Re: APCD Rule 324*]

B.13 **Continuous Emissions Monitoring (Rule 328).** Exxon shall comply with the requirements of Section C, F, G, H and I of Rule 328. Compliance shall be based on the monitoring, recordkeeping and reporting requirements of this permit as well as on-site inspections. [*Re: APCD Rule 328*]

B.14 **Adhesives and Sealants (Rule 353).** The permittee 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 the permittee uses such materials from containers larger than 16 fluid ounces and the materials are not exempt by Rule 353, Section 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: APCD Rule 353]

B.15 **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: APCD Rule 202*]

9.C Requirements and Equipment Specific Conditions

C.1 **Cogeneration Power Plant.** The following equipment are included in this emissions unit category:

EQ No.	Name
1-1	Gas Turbine (39.0 MW)
1-2	Heat Recovery Steam Generator (345 MMBtu/hr)
1-3	Selective Catalytic Reduction Unit

(a) Emission Limits: Except as noted below, mass emissions from the Cogeneration Power Plant ("CPP") shall not exceed the limits listed in Tables 5.1-3 and 5.1-4. The *Normal Operation Mode/Heat Recovery Steam Generator* line item in Tables 5.1-3 and 5.1-4 shall not be enforced. Compliance shall be based on sliding one-hour readings of 15-minute averages (or less) through the use of process monitors (e.g., fuel use meters) and CEMS; and the monitoring, recordkeeping and reporting conditions of this permit. For pollutants without CEMS monitors, the permitted emission factors in Table 5.1-2 shall be used for determining compliance with the mass emission rates. In addition, the following specific emission limits apply:

(i) *BACT* – Except during the Startup/Shutdown Mode, the emissions, after control, from the CPP shall not exceed the BACT limits listed in Table 4.2 (*BACT Emission Limits*). Compliance shall be based on annual source testing for all pollutants. For NO_x and CO, compliance shall also be based on the following emission concentrations {parts per million volume dry at 3 percent oxygen, based on 15-minute clock average (or less)} which shall be logged on a continuous basis using CEMS:

Operating Mode	NO_x (as NO_2)	CO
Gas Turbine Only Operations	24.6	29.1
Gas Turbine/HRSG Tandem Operations	22.3	35.0
HRSG Only Operations	24.6	400.0

The above BACT concentration limits apply only during Normal Operations and HRSG Only modes as defined in Section 4.2.2 of this permit. Further, in addition to the concentration limits, CO mass emissions shall not exceed 17.0 lb/hr.

(ii) *Ammonia Slip* – Except during the Startup/Shutdown Mode, the concentration of ammonia from the CPP stack shall not exceed 20 ppmv. Compliance shall be based source tests and during inspections using absorbent tubes or bag samples.

(iii) *NSPS Subpart GG* - Per 40 CFR 60.332(a)(1), Exxon shall comply with the nitrogen oxides standard of 75.0 ppmvd (at 15% O_2), if applicable.

(b) Operational Limits: The following operational limits apply to the CPP:

(i) *Fuel Gas Sulfur Limit* - Exxon shall use pipeline quality natural gas at all times. The natural gas shall contain total sulfur in concentrations not exceeding 24 ppmvd. Compliance with this condition shall be based on monitoring, recordkeeping and reporting requirements of this permit.

(ii) *Operating Mode Limits* - Exxon may only operate the CPP in one of the three modes (Normal Operations Mode, HRSG Mode and Startup/Shutdown Mode) as defined in Section 4.2.2 of this permit. Compliance shall be based on the monitoring, recordkeeping and reporting requirements of this permit.

(iii) *Usage Limits – Normal Operations Mode* - Exxon shall comply with the following usage limits:

- Combined Gas Turbine and HRSG Heat Input: 605.140 MMBtu/hr; 14,523 MMBtu/day; 1,321,626 MMBtu/quarter; 5,290,134 MMBtu/year

- Bypass Stack Flow Rate: The exhaust flow rate from the gas turbine bypass stack shall not exceed 386 dscfm.

Compliance shall be based on the monitoring, recordkeeping and reporting requirements of this permit.

(iv) *Usage Limits – HRSG Only Mode* - Exxon shall comply with the following usage limits:

- Gas Turbine Heat Input: no fuel input is allowed to the gas turbine.

- HRSG Heat Input: 345.000 MMBtu/hr; 8,280 MMBtu/day; 753,480 MMBtu/quarter; 3,015,990 MMBtu/year.

Compliance shall be based on the monitoring, recordkeeping and reporting requirements of this permit.

(v) *Usage Limits – Planned Startup/Shutdown Mode* - Exxon shall comply with the following usage limits:

- Gas Turbine/HRSG Heat Input: 308.821 MMBtu/hr; 618 MMBtu/day; 1,853 MMBtu/quarter; 5,559 MMBtu/year

- Operating Hours: 2 hours/day; 6 hours/quarter; 18 hours/year

Compliance shall be based on the monitoring, recordkeeping and reporting requirements of this permit.

(vi) *Emission Controls – Gas Turbine* - Exxon shall use steam injection and selective catalytic reduction (SCR) emission controls at all times when operating the gas turbine during the Normal Operations Mode and shall achieve a minimum of 90 percent (by mass) overall reduction and a minimum of 80 percent (by mass) NO_x reduction across the SCR. Except during startups/shutdowns, the steam-to-fuel injection ratio to the gas turbine shall be maintained at a minimum ratio of 0.6 lb H_2O/1.0 lb fuel and the ammonia injection ratio to the SCR reactor shall be maintained at a minimum ratio of 1.0 lb-mole NH_3/1.0 lb-mole NO_x (inlet). The steam and ammonia injection ratios shall be based on a 15-minute clock average (or less). Compliance shall be based on the monitoring and recordkeeping requirements of this permit.

(vii) *Emission Controls – HRSG* - Exxon shall use low-NO_x burners and selective catalytic reduction (SCR) emission controls at all times when operating the HRSG during the Normal Operations Mode and HRSG Only Mode and shall achieve a minimum of 80 percent (by mass) NO_x reduction across the SCR. Except during startups/shutdowns, the ammonia injection ratio to the SCR reactor shall be maintained at a minimum ratio of 1.0 lb-mole NH_3/1.0 lb-mole NO_x (inlet). The ammonia injection ratio shall be based on a 15-minute clock average (or less). Compliance shall be based on the monitoring and recordkeeping requirements of this permit.

(viii) *Emission Controls - SCR Unit* - Exxon shall operate and maintain the SCR unit according to the manufacturer's instructions and operations manuals. These instructions and manuals shall be kept onsite. The flue gas entering the SCR unit shall be maintained (during Normal Operations Mode and HRSG Only Mode) between 500 ºF and 750 ºF. Compliance shall be based on the monitoring and recordkeeping requirements of this permit. Exxon shall use grid power during periods when the SCR catalyst is no longer capable of achieving the NO_x BACT standards and during catalyst replacements.

(ix) *Startup/Shutdown Operations* - Exxon shall minimize pollutant emissions during all CPP startup and shutdown operating periods. During gas turbine shutdown, Exxon shall operate the steam injection system until the point of flame instability. During gas turbine startup, Exxon shall initiate steam injection once a stable flame can be maintained and shall inject ammonia at a minimum ratio of 1.0 lb-mole NH_3/1.0 lb-mole NO_x (inlet) to the SCR once a minimum operating temperature of 500 ºF is reached (this requirement does not limit Exxon from introducing ammonia at temperatures lower than 500 ºF). The ammonia injection ratio shall be based on a 15-minute clock average (or less). Compliance shall be based on the monitoring and recordkeeping requirements of this permit and APCD inspections. To eliminate projected 1-hr NO_x ambient air quality standard violation due to Startup/Shutdown Operations, Exxon shall not initiate CPP startup or shutdown operations while the POPCO facility thermal oxidizer is flaring during a gas plant startup. Exxon shall implement APCD-approved procedures to ensure that this restriction is met.

(x) *SCR Replacement* - With prior written notification to the APCD, Exxon may replace the existing catalyst with a new unit consistent with the requirements of this permit and as long as no emission or permit exceedances occur.

(xi) *Bypass Stack* - The damper on the gas turbine bypass stack shall remain in a fully closed position except during the startup and shutdown of the turbine. During start-up, the damper on the bypass stack shall remain open only for the period from when the turbine is down to when it reaches 4 MW. In no case shall the damper on the bypass stack remain open for more than 120 minutes during any startup or shutdown period. If testing or maintenance is performed, the bypass damper may remain open if the load on the turbine does not exceed 4 MW, and the entire startup period, including testing and maintenance time, does not exceed 120 minutes. Leakage exhaust rate from the bypass stack during the Normal Operations Mode shall be assumed to be 1 percent of the exhaust flow rate from the turbine at all times. Exxon shall implement an operations and maintenance program to ensure that the bypass damper is properly functioning at all times. Compliance shall be based on the monitoring, recordkeeping and reporting requirements of this permit.

(xii) *Fuel Restriction* - Exxon may only use natural gas as fuel for CPP.

(c) Monitoring: Exxon shall monitor the emission and process parameters listed in Table 10.1-1 for the life of the project. Exxon shall perform annual source testing of the CPP consistent with the requirements listed in Table 10.2-1 and the source testing condition of this permit. In addition, Exxon shall:

(i) Monitor the time the CPP operates in the Startup/Shutdown mode.

(ii) Continuously monitor the fuel gas using H_2S and HHV analyzers.

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

(d) Recordkeeping: Exxon shall record the emission and process parameters listed in Table 10.1-1. Further, except where noted, Exxon shall maintain hardcopy records of the following:

(i) For each operating mode, the daily, quarterly and annual heat input in units of million Btu for the gas turbine and HRSG. In addition, the five highest hourly heat input rates per month in units of MMBtu/hr.

(ii) Daily, quarterly and annual records identifying the time and duration the CPP is in the *Startup/Shutdown* Mode.

(iii) On a continuous basis, the rate of steam injection to the gas turbine in units of pounds steam per pound fuel, the rate of ammonia injection to the SCR in units of lb-moles ammonia to lb-moles inlet NO_x, and the temperature of the flue gas entering the SCR. These records may be maintained in an electronic format.

(iv) Documentation (log) of actions taken by Exxon to minimize emissions during each CPP startup and shutdown event shall be maintained. This documentation shall include a timeline of each event showing: when the bypass stack is opened/closed (including the duration), the turbine and HRSG heat inputs, the exhaust temperature to the SCR, when steam injection is turned on/off, when ammonia injection is turned on/off, exhaust flow rates from the bypass and main stacks, MW produced by the gas turbine generator, and the concentration and mass emissions of NO_x and CO. The log shall also indicate all times when testing and maintenance operations occur as well as the nature of the testing and maintenance.

(v) On a continuous basis, the higher heating value and the hydrogen sulfide content of the fuel gas used in the CPP (as determined by APCD-approved ASTM methods). These records may be maintained in an electronic format. On a quarterly basis, the total sulfur content of the fuel gas used in the CPP (as determined by APCD-approved ASTM methods).

(e) Reporting: On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the APCD. The report must list all data required by the *Compliance Verification Reports* condition of this permit.

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[*Re: ATC 5651, PTO 5651, ATC/PTO 5651-01, ATC/PTO 10172]*

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

EQ No.	Name
2-1	Thermal Oxidizer (3,193 MMBtu/hr)

(a) Emission Limits: Mass emissions from the flare relief system listed above shall not exceed the limits listed in Tables 5.1-3 and 5.1-4. Notwithstanding the above and consistent with APCD P&P 6100.004, the short-term emission limits for *Planned - Other* and *Unplanned - Other* flaring categories in Table 5.1-3 shall not be considered as enforceable limits. Compliance with this condition shall be based on the monitoring, recordkeeping and reporting conditions in this permit.

Continuous planned flaring emissions are assumed for the Low Pressure and Acid Gas flare headers based on one-half the minimum detection limit for each meter according to manufacturer minimum velocity detection limits (0.25 fps). Other than flare purge and pilot, this is the only continuous flaring allowed under this permit.

For the four calendar quarters that comprise 1999, the mass emission limits for the *Planned Other* and *Unplanned Other* categories in Table 5.1-4 shall be enforced as a combined limit. Prior to the end of 1999, Exxon may submit an ATC/PTO permit application, and receive APCD permit approval, to modify the allowable mass emission limits for the *Planned Other* and *Unplanned Other* categories provided there is no increase in potential mass emissions. If Exxon decides not to modify these mass emission limits, or if a permit is not granted prior to January 1, 2000 for such a permit modification, the limits for the *Planned Other* and *Unplanned Other* categories in Table 5.1-4 shall be enforced as separate line items.

(b) Operational Limits:

(i) *Flaring Volumes* - Flaring volumes from the purge and pilot, planned continuous, planned other and unplanned other events shall not exceed the following volumes:

Flare Category	**Hourly** (10^3 scf)	**Daily** (10^3 scf)	**Quarterly** (10^6 scf)	**Annual** (10^6 scf)
Purge/Pilot	1.948	46.752	4.266	17.064
Continuous – LP	1.414	33.936	3.097	12.387
Continuous – AG	0.245	5.880	0.537	2.146
Planned Other			11.740	24.887
Unplanned Other			2.680	7.539

For the four calendar quarters that comprise 1999, the flaring volume limits for the *Planned Other* and *Unplanned Other* categories shall be enforced as a combined limit. Prior to the end of 1999, Exxon may submit an ATC/PTO permit application, and receive APCD permit approval, to modify the allowable flare volumes for the *Planned Other* and *Unplanned Other* categories provided there is no increase in potential mass emissions. If Exxon decides not to modify these flare volume limits, or if a permit is not granted prior to January 1, 2000 for such a permit modification, the flaring volume limits for the *Planned Other* and *Unplanned Other* categories above shall be enforced as separate line items.

(ii) *Flare Purge/Pilot Fuel Gas Sulfur Limits* - The purge/pilot fuel gas combusted in the thermal oxidizer shall not exceed a total sulfur content of 24 ppmv. Compliance shall be based on the monitoring, recordkeeping and reporting requirements of this permit.

(iii) *Flare Planned Continuous Flaring Sulfur Limits* - The sulfur content of all gas burned as continuous flaring in the low pressure flare header shall not exceed 500 ppmv total sulfur. The sulfur content of all gas burned as continuous flaring in the acid gas flare header shall not exceed 239 ppmv total sulfur. These limits shall be enforced on an average quarterly basis (i.e., the average of all sulfur content measurements during the quarter). Compliance shall be based on the monitoring, recordkeeping and reporting requirements of this permit.

(iv) *Rule 359 Technology Based Standards* - Exxon 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 APCD inspections.

(v) *Ammonia* - Exxon shall only combust ammonia in the thermal oxidizer during ammonia tank loading operations and during approved breakdown conditions. The amount of ammonia sent to the thermal oxidizer is limited to that volume contained in the hose connecting the ammonia tank and the tank truck. For reporting purposes, Exxon shall assume that each loading operation results in 6.1 pounds of NO_x formed during the combustion process. Exxon shall not exceed 6 ammonia tank loading operations per quarter and 24 ammonia tank loading operations per year.

(vi) *Acid Gas Fuel Enrichment Usage* - Exxon shall only combust acid gas fuel enrichment gas in the thermal oxidizer in volumes needed to ensure combustion of the acid gas.

(vii) *Flaring Modes* - Exxon shall operate the thermal oxidizer consistent with APCD P&P 6100.004 (*Planned and Unplanned Flaring Events*). Section 4.5.2 of this permit defines each of the modes and flare categories. If Exxon is unable to comply with the infrequent planned and infrequent unplanned flaring limit of 4 events per year from the same processing unit or equipment type, then an ATC permit application shall be submitted to incorporate those emissions in the short-term (hourly and daily) emissions of Table 5.1-3.

(v) *Rule 359 Planned Flaring Target Volume Limit* - Pursuant to Rule 359, Exxon shall not flare more than 19 million standard cubic feet per month during planned flaring events.

(c) Monitoring: The equipment listed in this section are subject to all the monitoring requirements listed in APCD Rule 331.G. Exxon shall monitor the emission and process parameters listed in Table 10.1-3 for the life of the project. In addition, the following monitoring requirements apply to the flare relief system:

(i) *Flare Volumes* - The volumes of gas flared during each event shall be monitored by use of APCD-approved flare header flow meters. The meters shall be calibrated and operated consistent with Exxon's CEMS Plan (approved 10/22/93 and all subsequent APCD-approved updates). An event is defined as any flow recorded by the flare header flow meters that exceeds the event flow rate thresholds listed below where the duration is 60 seconds or greater. During an event, any subsequent flows recorded by the flare header flow meter within 5 minutes after the flow rate drops below the minimum detection level of the meter shall be considered as part of the event.

FLARE HEADER	EVENT FLOW RATE THRESHOLD (scfh)	METER MINIMUM DETECTION LEVEL (scfh)
Low Pressure	4,596	2,827
High Pressure	1,590	1,590
Acid Gas	491	491

All flaring not classified as an event pursuant to the above definition shall be aggregated as a single quarterly volume and recorded in the *Planned Other* flaring category. Notwithstanding the above definition of an event, continuous flaring is prohibited for the *Planned Other* and *Unplanned Other* flaring categories.

(ii) *Purge/Pilot Gas* - Exxon shall continuously monitor the purge/pilot fuel gas using H_2S and HHV analyzers. Exxon shall also perform quarterly total sulfur content measurements of the fuel gas using ASTM or other APCD-approved methods. Exxon shall utilize APCD-approved sampling and analysis procedures.

(iii) *Flaring Sulfur Content* - The hydrogen sulfide content of produced gas and acid gas combusted during flaring events shall be measured on the schedule pursuant to Appendix D.13 of the APCD-approved CEMS Plan (approved 10/22/93 and all subsequent APCD-approved updates) using APCD-approved ASTM methods. On an annual basis, Exxon shall also measure the non-hydrogen sulfide reduced sulfur compounds and these values shall be added to the hydrogen sulfide measurements to obtain the total sulfur content. Exxon shall perform additional testing of the sulfur content and hydrogen sulfide content, using approved test methods, as requested by the APCD. The definition of an event as stated in Appendix D.13 shall only be applicable for the sole purpose of determining when Exxon is required collect samples through the automatic flare gas sampling system.

On a monthly basis, Exxon shall sample the low pressure and acid gas flare headers to determine the hydrogen sulfide content using sorbent tubes. To obtain the total sulfur content, Exxon shall add the prior year's non-hydrogen sulfide reduced sulfur compounds analysis result to the absorbent tube readings.

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

(d) <u>Recordkeeping</u>: The equipment listed in this section are subject to all the recordkeeping requirements listed in APCD Rule 331.G. Exxon shall record the emission and process parameters listed in Table 10.1-3. In addition, the following recordkeeping conditions apply to the thermal oxidizer:

(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; total sulfur content; hydrogen sulfide content; high heating value; reason for each flaring event, including the processing unit or equipment type involved; the total heat input (MMBtu) per event; and, the type of event (e.g., Planned - Continuous LP, Unplanned - Other). 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. This log shall include any flaring events of ammonia and use of fuel for acid gas enrichment.

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

(iii) *Infrequent Flaring Events* - Exxon shall track and log the number of infrequent flaring events (as defined by APCD P&P 6100.004) from each processing unit or equipment type in a manner approved by the APCD.

(iv) *Ammonia Tank Loading Operations Log* - Exxon shall track and log the date of each ammonia tank loading operation.

(e) Reporting: The equipment listed in this section are subject to all the reporting requirements listed in APCD Rule 331.H. On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the APCD. The report must list all data required by the *Compliance Verification Reports* condition of this permit as well as the information required by and Section H of Rule 359.

[*Re: ATC 5651, PTO 5651, ATC/PTO 10172]*

C.3 **Fugitive Hydrocarbon Emissions Components.** The following equipment are included in this emissions unit category:

EQ No.	Name
	Gas/Light Liquid Service Components
3-1	Valves – Bellows Seal
3-2	Valves - Accessible Monthly
3-3	Valves – Accessible
3-4	Valves – Inaccessible
3-5	Valves – Unsafe
3-6	Valves - LEV Accessible Monthly
3-7	Valves - LEV Accessible
3-8	Valves - LEV Inaccessible
3-9	Valves - LEV Unsafe
3-15	Valves – E500
3-10	Relief Valves
3-11	Compressor Seals – To VRU
3-12	Flanges/Connections
3-13	Flanges/Connections – Unsafe
3-16	Flanges/Connections – E500
3-14	Exempt
	Oil Service Components
4-1	Valves – Bellows
4-2	Valves – Accessible
4-3	Valves – Inaccessible
4-4	Valves – Unsafe
4-5	Valves - LEV Accessible
4-6	Valves - LEV Inaccessible
4-7	Valves - LEV Unsafe
4-12	Valves – E500
4-8	Pump Seals – Tandem
4-14	Pump Seals - Single
4-9	Flanges/Connections
4-10	Flanges/Connections – Unsafe
4-13	Flanges/Connections – E500
4-11	Exempt

(a) Emission Limits: Mass emissions from the gas/light liquid service (sub-total) and oil service (sub-total) components listed above shall not exceed the limits listed in Tables 5.1-3 and 5.1-4. Compliance with this condition shall be based on actual component-leakpath counts as documented through 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 APCD 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 Exxon shall meet the following requirements:

(i) *VRS Use* - The vapor recovery and gas collection (VR & GC) systems at LFC 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 APCD-approved I&M Plan for Exxon LFC {*Fugitive Emissions Inspection and Maintenance Program for Las Flores Canyon Process Facilities* (approved 7/20/93)} shall be implemented for the life of the project. The Plan, and any subsequent APCD approved revisions, is incorporated by reference as an enforceable part of this permit.

(iii) *Leakpath Count* - The total component-leakpath count listed in Exxon's most recent I&M component-leakpath inventory shall not exceed the total component-leakpath count 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, flare header, or other APCD-approved control device.

(v) *BACT* - Exxon shall apply BACT, as defined in Tables 4.1, 4.2 and 4.3, to all component- leakpaths in hydrocarbon service for the life of the project. This requirement applies to components subject to the *de minimis* exemption of Rule 202 as well as projects that do not trigger the BACT threshold of Rule 802 and equivalent routine replacements.

(vi) *Rule 331 BACT* - The component-leakpaths in hydrocarbon service listed in Table 4.2b are subject to BACT requirements pursuant to Rule 331. BACT, as defined in Table 4.2b, shall be implemented for the life of the project.

(vii) *NSPS KKK* - For all permitted and future component-leakpaths in hydrocarbon service, Exxon shall comply with the emission standard requirements of 40 CFR 60.632, as applicable.

(viii) *E500 Requirements* - Component-leakpaths classified as emitters less than 500 ppmv ("E500") shall achieve a mass emission control efficiency of 85 percent. E500s are defined as component-leakpaths associated with closed vent systems (e.g., vapor recovery systems) for which screening values are maintained at or below 500 ppmv as methane, monitored per EPA Reference Method 21. For such E500s, screening values above 500 ppmv shall trigger the Rule 331 repair process per the minor leak schedule.

(c) <u>Monitoring</u>: The equipment listed in this section are subject to all the monitoring requirements listed in APCD Rule 331.F and NSPS Subpart KKK (as applicable). The test methods in Rule 331.H and NSPS Subpart KKK shall be used, when applicable. In addition, Exxon shall:

(i) *ERC Certificate No. 0004-0103* - Perform monthly monitoring on 217 standard (i.e., non-bellows seal and non-low emissions) valves and a minimum of 170 low-emissions packing valves in order to generate the 0.18 tpq of ROC ERCs for ERC Certificate No. 0004-0103. These valves are listed in a separate table in Exxon's I&M Plan. Exxon shall replace any valve on the list with a replacement if the valve is no longer in hydrocarbon service. The APCD shall be notified, in writing, of all such replacements within 90 days after the replacement. The notification shall include complete equipment description information equivalent to the table in Exxon's I&M Plan and the reason for the replacement. Subsequent I&M records and reports shall include the replacement valve(s).

(ii) *ERCs for Platforms Harmony and Heritage Compressor Projects* **-** Exxon shall perform monthly monitoring on a minimum of 400 standard (i.e., non-bellows seal and non-low emissions) valves and a minimum of 265 low-emissions packing valves in order to generate 0.39 tpq of ROC ERCs required for projects permitted by PTO 9634 and PTO 9640. These valves are listed in a separate table in Exxon's I&M Plan. Exxon shall replace any valve on the list with a replacement if the valve is no longer in hydrocarbon service. The APCD shall be notified, in writing, of all such replacements within 90 days after the replacement. The notification shall include complete equipment description information equivalent to the table in Exxon's I&M Plan and the reason for the replacement. Subsequent I&M records and reports shall include the replacement valve(s).

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

(i) *I&M Log* - Exxon 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.

For the purpose of the above paragraph, a leaking component is any component which exceeds the applicable limit (e.g., greater than or equal to 1,000 ppmv for minor leaks under Rule 331; greater than or equal to 100 ppmv for components subject to current BACT standards; greater than 500 ppmv for E500 components).

(ii) *Enhanced I&M* - For the 387 valves monitored monthly as required by ERC Certificate 0004-0103 and the 665 valves monitored monthly as required by PTO 9634 and PTO 9640, maintain a record of information concerning leaks and repairs to include 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. Further, maintain on a monthly basis a record that all the valves were monitored in accordance with Permit Condition 9.C.3(c) above.

(e) Reporting: The equipment listed in this section are subject to all the reporting requirements listed in APCD 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 APCD. The report must list all data required by the *Compliance Verification Reports* condition of this permit.

[*Re: ATC 5651, PTO 5651]*

C.4 **Crew and Supply Boats.** The following equipment are included in this emissions category:

EQ No.	Name
5-1	Crew Boat Main Engines – Controlled
5-2	Crew Boat Main Engines – Uncontrolled
5-3	Crew Boat Auxiliary Engines
5-4	Supply Boat Main Engines – Controlled
5-5	Supply Boat Main Engines – Uncontrolled
5-6	Supply Boat – Bow Thruster
5-7	Supply Boat – Auxiliary Engines

(a) Emission Limits: Mass emissions from the crew and supply boats listed above shall not exceed the limits listed in Tables 5.1-3 and 5.1-4. Compliance with this condition shall be based on the monitoring, recordkeeping and reporting conditions in this permit. In addition:

(i) *NO_x Emissions* - Controlled emissions of NO_x from each diesel fired main engine in each controlled crew and supply boat shall not exceed 337 lb /1000 gallons (8.4 g/bhp-hr). Uncontrolled spot charter crew and supply boats shall not be required to comply with this controlled NO_x emission rate. Compliance shall be based on annual source testing consistent with the requirements listed in the Permits to Operate for Exxon's Platforms Hondo, Harmony and Heritage.

(b) Operational Limits: Operation of the equipment listed in this section shall not exceed the limits listed below. Compliance with these limits shall be assessed through compliance with the monitoring, recordkeeping and reporting conditions in this permit.

(i) *Crew Boat Main Engine Limits* - The crew boat main engines for Platforms Harmony and Heritage combined shall not use more than: 95.4 gallons per hour; 572.2 gallons per day; 16,523 gallons per quarter; 66,091 gallons per year of diesel fuel.

(ii) *Crew Boat Auxiliary Engine Limits* - The crew boat auxiliary engines for Platforms Harmony and Heritage combined shall not use more than: 7.2 gallons per hour; 43.2 gallons per day; 1,248 gallons per quarter; 4,993 gallons per year of diesel fuel.

(iii) *Supply Boat Main Engine Limits* - The supply boat main engines for Platforms Harmony and Heritage combined shall not use more than: 42.9 gallons per hour; 85.8 gallons per day; 6,006 gallons per quarter; 6,006 gallons per year of diesel fuel.

(iv) *Supply Boat Auxiliary Engine Limits* - The supply boat auxiliary engines (including the bow thruster) for Platforms Harmony and Heritage combined shall not use more than: 19.9 gallons per hour; 281.9 gallons per day; 2,021 gallons per quarter; 2,021 gallons per year of diesel fuel.

(v) *Spot-Charter Limits* - The number of allowable annual spot charter crew boat trips shall not exceed ten percent of the actual annual number of trips made by the Dedicated Project Vessel ("DPV") crew boats. The number of allowable annual spot charter supply boat trips shall not exceed ten percent of the actual annual number of trips made by DPV supply boats. Compliance shall be based on a comparison of the main engine fuel use for DPV and spot charter boats (i.e., the total main engine spot charter supply boat fuel use must be less than 10 percent of the total main engine DPV supply boat fuel use and the total main engine spot charter crew boat fuel use must be less than 10 percent of the total main engine DPV crew boat fuel use).

(vi) *Liquid Fuel Sulfur Limit* - Diesel fuel used by all IC engines shall have a sulfur content no greater than 0.20 weight percent as determined by APCD-approved ASTM methods.

(viii) *New/Replacement Boats* - Exxon may utilize any new/replacement project (DPV) boat without the need for a permit revision if that boat meets the following conditions:

(a) The main engines are of the same or less bhp rating; and
(b) The auxiliary engines and bow thruster engine are of the same or less bhp rating for the corresponding engine; and
(c) The NO_x, ROC, CO, PM and PM_{10} emission factors are the same or less for the main and auxiliary engines. For the main engines, NO_x emissions must meet the 337 lb/1000 gallons emission standard. The APCD may require manufacturer guarantees and emission source tests to verify this NO_x emission standard.

The above criteria also apply to spot charter boats, except for the NO_x emission standard noted in (c) above. Any proposed new/replacement crew, supply or spot charter boat that does not meet the above requirements shall first obtain a permit revision prior to operating the boat.

Exxon shall revise the *Boat Monitoring and Reporting Plan*, obtain APCD approval of such revisions and implement the revised Plan prior to bringing any new/replacement boat into service.

Prior to bringing the boat into service for the first time, Exxon shall submit the information listed below to the APCD for any new/replacement crew and supply boat (including spot charters) that meets the requirements set forth in (a) – (c) above. Any boat put into service that does not meet the requirements above, as determined by the APCD at any time, shall immediately cease operations and all prior use of that boat shall be considered a violation of this permit.

(i) Boat description, including the type, size, name, engine descriptions and emission control equipment.

(ii) Details of the fuel monitoring system for main and auxiliary engines.

(iii) Engine manufacturers' data on the emission levels for the various engines and applicable engine specification curves.

(iv) Estimated fuel usage within state territorial waters on a daily basis.

(v) Any other information the APCD deems necessary to ensure the new boat will operate consistent with the analyses that form the basis for this permit.

(c) Monitoring: Exxon shall comply with the requirements of the *APCD's Data Reporting Protocol for Crew and Supply Boat Activity Monitoring* document ("Boat Protocol", dated June 21, 1991 and any subsequent updates) for documenting and reporting boat activity, fuel usage and emissions. Boats reporting emissions based on cruise mode only shall not be required to comply with the Boat Protocol requirements for boat speed, engine rpm, mode or activity code.

Exxon shall equip all crew and supply boats servicing the Santa Ynez Unit platforms in support of drilling and production operations with in-line, continuous fuel meters, engine shaft revolution meters and Loran-C or equivalent location devices. These devices shall be connected to hardcopy records and computer disk outputs that are in a format acceptable to the APCD. These data shall demonstrate that the vessels are being operated consistent with the emission assumptions used in the issuance of this permit. Fuel use, engine rpm data, and Loran-C position must be collected while the boats are within state territorial waters. This data must be submitted in an APCD-approved format to the APCD as part of the *Compliance Verification Reports* condition of this permit

Exxon shall also equip all crew and supply boats used for construction within the APCD, with fuel monitoring and shaft RPM meters to allow for determination of compliance with the 8.4 g/hp-hr standard. The data will be submitted to the APCD as part of the *Compliance Verification Reports* condition of this permit.

Exxon's *Boat Monitoring and Reporting Plan* shall follow the above-referenced Boat Protocol. Exxon shall fully implement their *Boat Monitoring and Reporting Plan* (7/16/99 and all subsequent APCD-approved updates) for the life of the project, and shall obtain APCD approval for any proposed updates or modifications to the Plan.

Exxon may use alternative methods (including location methods) for documenting and reporting boat activity, fuel usage and emissions, provided these methods are approved by the APCD as being equivalent in accuracy and reliability to those of the Boat Protocol.

Spot charter boats shall, at a minimum, track total fuel usage on a per day basis using APCD-approved procedures. These data shall be submitted in an APCD-approved format to the APCD.

(d) Recordkeeping: The following records shall be maintained in legible logs and shall be made available to the APCD upon request:

(i) *Maintenance Logs* - For all main and auxiliary engines on controlled crew and controlled supply boats, maintenance log summaries that include details on injector type and timing, setting adjustments, major engine overhauls, and routine engine maintenance. These log summaries shall be made available to the APCD upon request. For each main and auxiliary engine with timing retard, an APCD Form –10 (*IC Engine Timing Certification Form*) must be completed each time the engine is serviced.

(ii) *Crew Boat Fuel Usage* - Daily, monthly, quarterly and annual fuel use for crew boat main engines and auxiliary engines while operating in state territorial waters, itemized by controlled and uncontrolled boats. In addition, the fuel use must be summarized for all crew boats by main and auxiliary engines.

(iii) *Supply Boat Fuel Usage* - Daily, monthly, quarterly and annual fuel use for supply boat main engines and auxiliary engines while operating in state territorial waters, itemized by controlled and uncontrolled boats. In addition, the fuel use must be summarized for all supply boats by main and auxiliary engines.

(e) Reporting: On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the APCD. The report must list all crew, supply and spot charter boat data required by the *Compliance Verification Reports* condition of this permit.

If, at any time, the APCD determines that logs or reports indicate fuel use greater than the limits of Condition 9.C.4(b) of this permit, Exxon shall restrict its vessel activities to ensure that emissions do not exceed total quarterly emissions allowed in the permit, or shall submit an application for and obtain a permit providing additional offsets. Such offsets shall be in place no later than the start of the next quarter..

[*Re: ATC 5651, PTO 5651, ATC/PTO 10172]*

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

EQ No.	Name
6-1	Oil Emulsion Pig Receiver
14-1	SOV Distance Piece Compressor Vent
14-2	VR Distance Piece Compressor Vent

(a) Emission Limits: Mass emissions from the oil pig receiver and compressor vents listed above shall not exceed the limits listed in Tables 5.1-3 and 5.1-4. 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 APCD Rule 325.E. Compliance with these limits shall be assessed through compliance with the monitoring, recordkeeping and reporting conditions in this permit. In addition Exxon shall meet the following requirement:

(i) Pigging *Events* - The number of oil pig operations (events) shall not exceed the maximum operating schedule listed in Table 5.1-1.

(ii) Pig *Pressure* - Prior to opening the oil pig, the pressure in the pig shall not exceed 1 psig. Compliance shall be based on a test gauge installed to monitor the internal pressure of the receiver. Test gauge readings shall be recorded prior to each opening of the receiver.

(iii) 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. Prior to opening the pig receiver, Exxon shall purge the vessel with sweet fuel gas.

(iv) *VRS Use* - The vapor recovery system connected to the compressor seal/distance piece system shall be in operation when the SOV and VR compressors are in use. The VRS system includes piping, valves, and flanges associated with each VRS system. The VRS system shall be maintained and operated to minimize the release of emissions from all systems, including pressure relief valves.

(v) *Carbon Canister Control Requirements* - The carbon canister units connected to the compressor seal/distance piece system shall be in operation when the SOV and VR compressors are in use. 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.

(c) Monitoring: Exxon shall monitor the pressure inside the pig receiver with an APCD-approved pressure gauge, or alternative APCD-approved method. For the carbon canister control units on each distance piece compressor vent, monitor on a monthly basis the ROC control efficiency across each canister (inlet/outlet) according to APCD-approved methods. Exxon shall submit and obtain APCD approval of a *Carbon Canister Monitoring and Maintenance Plan* within 90 days after the issuance of this permit. Exxon shall implement the approved Plan for the life of the project.

(d) Recordkeeping: Exxon shall record in a log the date of each pigging operation and the pressure inside the receiver prior to each opening. For each carbon canister, Exxon shall record in a log the results of every efficiency verification check (including all test results and lab analyses).

(e) Reporting: On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the APCD. The report must list all data required by the *Compliance Verification Reports* condition of this permit.

[*Re: ATC 5651, PTO 5651]*

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

EQ No.	Name [12]	KVB Service
GROUP A UNITS		
7-1	Oil Storage Tank A (Vapor Recovery)	
7-2	Oil Storage Tank B (Vapor Recovery)	
7-3	Rerun Tank A (Vapor Recovery)	
7-4	Rerun Tank B (Vapor Recovery)	
GROUP B UNITS		
8-1	TT Area Drain Oil/Water Separator (Carbon Canister)	3º heavy oil
8-2	OTP Equalization Tank (Venturi Scrubber/Carbon Canister)	3º heavy oil
8-3	OTP Oily Sludge Thickener (Vapor Recovery)	3º heavy oil
8-4	OTP Backwash Sump (Vapor Recovery)	3º heavy oil
8-9	OTP Backwash Collection Tank (Vapor Recovery)	3º heavy oil
8-5	OTP Open Drain Sump (Carbon Canister)	3º heavy oil
8-6	OTP Area Drain Oil/Water Separator (Carbon Canister)	3º heavy oil
8-7	SGTP Area Drain Oil/Water Separator (Carbon Canister)	3º heavy oil
8-8	SGTP Open Drain Sump (Carbon Canister)	3º heavy oil
GROUP C UNITS		
9-1	TT Area Drain Sump	3º heavy oil
9-2	OTP Area Drain Sump	3º heavy oil
9-3	SGTP Area Drain Sump	3º heavy oil
GROUP D UNITS		
10-1	Demulsifier Tank (Carbon Canister)	
GROUP E UNITS		
13-1	Chemical Storage Tote Tanks	

(a) Emission Limits: Except as noted below, mass emissions from the equipment listed above shall not exceed the limits listed in Tables 5.1-3 and 5.1-4. For Group A tanks only, the hourly mass emission rate limits shall not be enforced. Mass emissions of hydrogen sulfide from the Equalization Tank shall not exceed: 0.10 lb/hr, 2.4 lb/day, 0.11 tpq, 0.44 tpy. Compliance with this condition shall be based on the monitoring, recordkeeping and reporting conditions in this permit.

(b) Operational Limits: All process operations from the Group A and Group B equipment listed in this section shall meet the requirements of APCD Rule 325, Sections D, E, F and G. All process operations from the Group D equipment listed in this section shall meet the requirements of APCD Rule 326, Sections D, I, J and K. All process operations from the

[12] Group A tanks are subject to Rule 325 and NSPS Subpart Kb
Group B tanks are subject to Rule 325
Group C and E tanks are not subject to any Rule requirements
The Group D 300 bbl tank is subject to Rule 326. For the purposes of this permit only, the two 500 gallon demulsifier tanks shall adhere to all requirements for the 300 bbl demulsifier tank.

Group A equipment shall comply with the requirements of NSPS Subpart Kb. All process operations from Groups A, B, C and D shall comply with the BACT requirements listed in Tables 4.1 and 4.2. Compliance with these limits shall be assessed through compliance with the monitoring, recordkeeping and reporting conditions in this permit. In addition, Exxon 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) *Vapor Recovery System Efficiency* - The vapor recovery systems serving the OTP, TT and SGTP shall maintain a minimum efficiency of 95 percent (mass basis) for the short term (hourly and daily) and 99.8 percent (mass basis) for long term (quarterly and annual). Compliance shall be based on the monitoring, recordkeeping and reporting requirements of this permit as well as operating consistent with the requirements of the NSPS Subpart Kb required *Operating Plan*. Further, non-compliance with any of the daily, quarterly or annual mass emission limits in Tables 5.1-3 and 5.1-4 for any of the Group A tanks shall be assumed as non-compliance with this requirement for all vapor recovery systems.

(iii) *NSPS Subpart Kb Operating Plan* - Consistent with NSPS Subpart Kb requirements, Exxon shall operate the vapor recovery systems serving the Group A units in accordance with the APCD-approved *Operating Plan* (and all subsequent APCD-approved updates thereof). A copy of the *Operating Plan* shall be maintained onsite for the life of the SYU project. The *Operating Plan* and its operating parameters are incorporated as an enforceable part of this permit.

(iv) *Carbon Canister Control Requirements* - The carbon canister units shall be in operation when the equipment connected to them at the facility are in use. 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).

(v) *Venturi Scrubber Control Requirements* - The venturi scrubber shall be in operation when the Equalization Tank is in use. The scrubber shall be maintained and operated to minimize the release of emissions of sulfur compounds. The scrubber shall achieve a minimum 99.9 percent (by mass) control efficiency for hydrogen sulfide. Compliance with the scrubber control efficiency may include use of the carbon control system. During monitoring, the hydrogen sulfide concentration in the exhaust to the atmosphere shall not exceed 13 ppmv. The 99.9 percent control efficiency requirement shall not apply during annual source testing if the inlet hydrogen sulfide concentration to the venturi scrubber is less than 3,181 ppmv. In these cases, the venturi scrubber shall meet an emission standard of 3.2 ppmv. The scrubber circulation pump shall be running at all times when the Equalization Tank is in use (including storage).

(vi) *Service Type Restrictions* - The KVB service type, as defined pursuant to APCD P&P 6100.060, for each Group B and Group C unit shall be restricted to the service type listed above or a service of a lesser emitting type (e.g., a secondary heavy oil sump may be used as a tertiary heavy oil sump).

(vii) *Throughput and Vapor Pressure Limits* - The following tank throughput and vapor pressure limits shall not be exceeded:

Tank Name	**Daily** (bbl/day)	**Quarterly** (bbl/qtr)	**Annual** (bbl/yr)	**TVP** (psia)
Oil Storage Tank A/B	140,000	11,406,250	45,625,000	11.0
ReRun Tank A/B	140,000	456,250	1,825,000	
Demulsifier Tank	55	218	869	0.81

The oil storage tank TVP data is an average of all TVP readings for the tank in any given calendar quarter. Compliance with these limits shall be assessed through compliance with the monitoring, recordkeeping and reporting conditions in this permit.

(viii) *Group E Tanks BACT* - All permitted chemical storage tote tanks containing ROC compounds where the fluid vapor pressure is greater than 0.5 psia must be kept closed at all times and must be equipped with a functional PSV valve.

(ix) *Demulsifier Tank(s)* - Exxon may elect use two 500 gallon demulsifier tanks in lieu of the 300 barrel demulsifier tank (Eq No. 10-1). At not time shall both the 300 bbl tank and the 500 gallon tanks operate concurrently or store fluids containing ROCs concurrently. The throughput limits listed in this permit apply to the total demulsifier use at the facility. The vapor pressure limit applies regardless of the tank used. The 500 gallon demulsifier tanks shall be equipped with carbon controls at all times. The 300 bbl demulsifier tank shall be equipped with carbon controls at all times when storing fluids containing ROCs. Notwithstanding the above, Exxon may elect to take the 300 bbl demulsifier tank out of service. To qualify as being taken out of service, the tank must be inerted and blinded off. Prior to placing the tank back in service, Exxon shall submit a written notice to the APCD stating the effective date of startup and verifying that carbon controls will be in place as well as verifying that the 500 gallon tanks will not be operated concurrently.

(c) Monitoring: The equipment listed in this section are subject to all the monitoring requirements of APCD Rule 325.H (for Group A and B units), NSPS Subpart Kb (for Group A units) and Table 10.1-3 for the life of the project. The test methods outlined in

APCD Rule 325.G, NSPS Subpart Kb and APCD Rule 326.K shall be used, as applicable. In addition, Exxon shall:

(i) For Group A units, monitor: the position of each PSV through the use of a proximity switch; the date, time and duration of each PRV opening; the vapor headspace properties during each release (pressure relief set-point, molecular weight, weight percent of ROC in the vapor).

(ii) For the vapor recovery systems, monitor the parameters identified in the APCD-approved NSPS Kb *Operating Plan*.

(iii) 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).. For the carbon canister control units on the Equalization tank, monitor on a weekly basis the ROC emission concentration (as methane) at the outlet of each unit using a calibrated organic vapor analyzer (OVA). Exxon shall follow the requirements of the APCD approved *Carbon Canister Monitoring and Maintenance Plan*. Exxon shall implement the approved Plan for the life of the project.

(iv) For the venturi scrubber, on a weekly basis monitor the concentration of the caustic solution in the scrubber. On a daily basis (or on a different schedule approved by the APCD), monitor the outlet concentration of hydrogen sulfide from the scrubber. On annual basis, Exxon shall source test the venturi scrubber to determine the control efficiency. Source testing shall be performed in accordance with the *Source Testing* condition of this permit.

(v) For each Group B and C unit, monitor (visually and by other means, such as engineering analysis) the source of fluid streams entering the unit to assess any change in service type (as defined by APCD P&P 6100.060).

(vi) On a daily, quarterly and annual basis, monitor the throughput for each of the Group A units using APCD-approved meters. For Group D units, monitor the throughput on a daily, quarterly and annual basis using an APCD-approved level gauge or other APCD-approved alternative method.

(vii) For the Group A Oil Storage tanks, no less than three days per week measure the Reid vapor pressure and storage temperature of the liquid according to APCD-approved methods. For the Group A Rerun tanks, no less than 24 hours after a PSV event measure the Reid vapor pressure and storage temperature of the liquid according to APCD-approved methods. In addition, for the Group A Rerun tanks, measure the Reid vapor pressure and storage temperature of the liquid according to APCD-approved methods at least once per year. For the Group D units, measure the Reid vapor pressure and storage temperature according to APCD-approved methods on an annual basis and for each time a different demulsifier agent product is used.

(viii) *NGL Data* - Through use of its DCS system, Exxon shall monitor the ratio at which the NGLs are injected into the treated crude oil prior to storage in the Oil Tanks as well as the amount of NGL injected for each day.

(d) Recordkeeping: The equipment listed in this section is subject to all the recordkeeping requirements listed in APCD Rule 325.F (for Group A and B units), NSPS Subpart Kb (for Group A units) and Table 10.1-3. Exxon shall maintain hardcopy records for the information listed below:

(i) For each PSV event for Group A units, log: the date, time and duration the PSV was open (include start/stop times); the vapor headspace properties (pressure relief set-point, molecular weight, weight percent of ROC in the vapor); the volume of vapor released (based on manufacturer flow data); the calculated mass emissions for ROC. The mass emissions from each PSV and the cumulative mass emissions for each tank shall be summarized in a log on a daily, quarterly and annual basis.

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

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

(iv) For the venturi scrubber, log the weekly reading of the caustic solution concentration in the scrubber and the daily measured hydrogen sulfide results at the outlet.

(v) For the Group B and C units, log any changes in service type and provide an explanation of the change(s) that occurred.

(vi) For the Group A and D units, log the throughput on a daily, quarterly and annual basis.

(vii) For the Group A and D units, log all Reid vapor pressure and temperature readings of the liquid stored as well the corresponding true vapor pressure values. Log all changes in demulsifier agents used and maintain a copy of the MSDS sheet for the new agent with the log. Vendor RVP and TVP data will be accepted for Group D units.

(viii) For the Oil Storage Tanks, record each day (via the DCS) the minimum and maximum daily ratio at which the NGLs are injected into the treated crude oil prior to storage in these tanks as well as the total amount of NGL injected each day.

(e) Reporting: On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the APCD. The report must list all data required by the *Compliance Verification Reports* condition of this permit.

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[13] Group A tanks are subject to Rule 325 and NSPS Subpart Kb
Group B tanks are subject to Rule 325
Group C and E tanks are not subject to any Rule requirements

[*Re: ATC 5651, PTO 5651, ATC/PTO 5651-01, ATC/PTO 10172]*

C.7 **Solvent Usage.** The following equipment are included in this emissions unit category:

EQ No.	Name
11-1	Cleaning/Degreasing

(a) Emission Limits: Mass emissions from the solvent usage shall not exceed the limits listed in Tables 5.1-3 and 5.1-4. Compliance shall be based on the recordkeeping and reporting requirements of this permit. For short-term emissions, compliance shall be based on monthly averages.

(b) Operational Limits: Use of solvents for cleaning, degreasing, thinning and reducing shall conform to the requirements of APCD Rules 317 and 324. Compliance with these rules shall be assessed through compliance with the monitoring, recordkeeping and reporting conditions in this permit and facility inspections. In addition, Exxon shall comply with the following:

(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 discernable continuous flow of solvent.

(iv) *Reclamation Plan* - Exxon may submit a Plan to the APCD for the disposal of any reclaimed solvent. If the Plan is approved by the ACPD, all solvent disposed of pursuant to the Plan will not be assumed to have evaporated as emissions into the air and, therefore, will not be counted as emissions from the source. Exxon shall obtain APCD approval of the procedures used for such a reclamation Plan. The Plan shall detail all procedures used for collecting, storing and transporting the reclaimed solvent. Further, the ultimate fate of these reclaimed solvents must be stated in the Plan.

(c) Monitoring: none

(d) Recordkeeping: Exxon 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 APCD-approved disposal according to the APCD-approved *Solvent Reclamation Plan*, if such a plan is submitted by Exxon; whether

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Group D tanks are subject to Rule 326

the solvent is photochemically reactive; and, the resulting emissions of ROC to the atmosphere in units of pounds per month and the resulting emissions of photochemically reactive solvents to the atmosphere in units of pounds per month. Product sheets (MSDS or equivalent) detailing the constituents of all solvents shall be maintained in a readily accessible location at LFC.

(e) Reporting: On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the APCD. The report must list all data required by the *Compliance Verification Reports* permit condition below.

[*Re: ATC 5651, PTO 5651]*

C.8 **Sulfur Recovery Unit/Waste Gas Incinerator.** The following equipment are included in this emissions unit category:

EQ No.	Name
12-1	Sulfur Recovery Unit (Claus and Tail Gas Unit)
12-2	Waste Gas Incinerator w/Thermal DeNOx

(a) Emission Limits: Mass emissions from the SRU TGCU Waste Gas Incinerator ("WGI") shall not exceed the limits listed in Tables 5.1-3 and 5.1-4. Compliance shall be based on sliding-one hour readings of 15-minute averages (or less) through the use of process monitors (e.g., fuel use meters) and CEMS; and the monitoring, recordkeeping and reporting condition of this permit. For pollutants without CEMS monitors, the permitted emission factors in Table 5.1-2 shall be used. In addition, the following specific emission limits apply:

(i) *BACT* – Except during the startup, shutdown or maintenance modes (as defined herein), the emissions, after control, from the WGI shall not exceed the BACT limits listed in Table 4.2 (*BACT Emission Limits*). Compliance shall be based on annual source testing for all pollutants. For NO_x and SO_x only, compliance shall also be based on the emission concentrations (based on a 60-minute clock average) listed in Table 4.2 which shall be logged on a continuous basis using CEMS.

(ii) *Ammonia Slip* – Except during the Startup/Shutdown Mode, the concentration of ammonia from the WGI stack shall not exceed 20 ppmv. Compliance shall be based on absorbent tubes, source tests or bag samples.

(iii) *NSPS Subpart LLL* - Per 40 CFR 60.642(b), Exxon shall comply with the SO_2 emission reduction efficiencies as listed in Table 2 of the Subpart. Compliance with this Subpart shall be based on the monitoring, recordkeeping and reporting requirements of this permit and NSPS Subpart LLL.

(iv) *Planned SGTP Startup, Shutdown and Maintenance SO_x Emission Limits* - Emissions of SO_x (as SO_2) from the WGI shall not exceed mass emissions listed in Tables 5.1-3 and 5.1-3 during any SGTP startup, shutdown or maintenance activity as defined herein. Startup is defined as the period of time not to exceed 48-hours following the introduction of sour gas into the SGTP. Shutdown is defined as the 12-hour period following cessation of inlet sour gas streams (measured by FE 10212, FE 40004) to the SGTP. Maintenance is defined as the period of time not to exceed 24-hours required for conducting planned shutdown events that impact WGI emissions (e.g., sulfur catalyst strip). Exxon shall not exceed 84 hours per quarter and 84 hours per year for all planned SGTP startup, shutdown and maintenance activities. Compliance shall be based on the monitoring, recordkeeping and reporting requirements of this permit.

(b) Operational Limits: All process operations from the equipment listed in this section shall meet the requirements of APCD Rule 311.A.2, the BACT requirements listed in Tables 4.1 and 4.2, and the requirements of NSPS Subpart LLL. Compliance with these limits shall be assessed through compliance with the monitoring, recordkeeping and reporting conditions in this permit. In addition, Exxon shall:

(i) *Sulfur Recovery Unit Removal Efficiency* - The recovery of sulfur compounds entering the plant shall meet a minimum overall control efficiency of 99.9 percent (mass basis) at design throughput or a concentration of 100 ppmv H_2S in the feed to the WGI, whichever is more stringent. Exxon shall follow calculation methodology presented in NSPS Subpart LLL.

(ii) *Thermal DeNO$_x$* – The Thermal DeNO$_x$ system shall be used at all times when the WGI is in operation. The Thermal DeNO$_x$ system shall meet a minimum NO_x control efficiency of 50 percent (mass basis). Compliance shall be based on source testing and by maintaining the NO_x outlet set-point for the Thermal DeNO$_x$ system at 9 ppmv. Exxon may request APCD written approval to revise the NO_x outlet set-point value to another value based on source test results.

(iii) *Low-NO$_x$ Burners* - Low-NO$_x$ burners shall be used at all times when the WGI is in operation.

(iv) *Fuel Gas Sulfur Limit* - Exxon shall use pipeline quality natural gas at all times. The natural gas shall contain total sulfur in concentrations not exceeding 24 ppmvd. Compliance with this condition shall be based on monitoring, recordkeeping and reporting requirements of this permit.

(v) *Usage Limits* – Exxon shall comply with the follow usage limits:

- Fuel Gas Heat Input: 11.05 MMBtu/hr; 265 MMBtu/day; 24,200 MMBtu/quarter; 96,798 MMBtu/year

- Inlet WGI Flow Rate from TGCU Amine Contactor: 133.68 kscfh

- Inlet WGI Flow Rate from Merox Vent: 0.37 kscfh

Compliance shall be based on the monitoring, recordkeeping and reporting requirements of this permit.

(vi) *Operating Load Restriction* - Consistent with APCD P&P 6100.039, Exxon shall not operate the WGI above loads observed during compliance source testing. Exxon shall perform a compliance source test within 60 days of the fuel gas heat input to the WGI exceeding 7.00 MMBtu/hr (averaged over rolling 30 days). Should the rolling 30 day average fall below 7.00 MMBtu/hr prior to the scheduled source test, the source test may be delayed at the discretion of the APCD. This process shall be repeated for new operating load restrictions of 8.00 MMBtu/hr, 9.00 MMBtu/hr and then 10.00 MMBtu/hr, until a compliance source test is observed at a fuel gas heat input to the WGI exceeding 10.00 MMBtu/hr. Within two business days of occurring, Exxon shall notify the APCD once the applicable operating load restriction is exceeded.

(c) Monitoring: Exxon shall monitor the emission and process parameters listed in Table 10.1-2 for the life of the project. Exxon shall perform annual source testing of the WGI consistent with the requirements listed in Table 10.2-2 and the source testing permit condition below. In addition, Exxon shall:

(i) Continuously monitor the fuel gas using H_2S and HHV analyzers.

(ii) Perform quarterly total sulfur content measurements of the fuel gas using ASTM or other APCD-approved methods. Exxon shall utilize APCD-approved sampling and analysis procedures.

(d) Recordkeeping: Exxon shall record the emission and process parameters listed in Table 10.1-2. In addition, Exxon shall maintain hardcopy records of the following:

(i) The daily, quarterly and annual heat input in units of million Btu for the fuel gas to the WGI. In addition, the five highest hourly heat input rates per month in units of MMBtu/hr.

(ii) The daily, quarterly and annual Inlet Tail Gas Flow Rate from the TGCU Amine Contactor in units of standard cubic feet to the incinerator. In addition, the five highest hourly flow rates per month in units of standard cubic feet per hour.

(iii) The daily, quarterly and annual Inlet Flow Rate from Merox Vent in units of standard cubic feet to the incinerator. In addition, the five highest hourly flow rates per month in units of standard cubic feet per hour.

(iv) Documentation (Log) of the actions taken by Exxon to minimize emissions during each WGI startup, shutdown and maintenance activity (as defined herein) shall be maintained. This documentation (Log) shall include a timeline of each activity showing: the activity start and stop time (including duration); the type of activity; the fuel gas heat input; the temperature, the hourly concentrations of NO_x and SO_x; and the mass emissions of all criteria pollutants for the entire activity duration.

(v) On a continuous basis, the higher heating value and the hydrogen sulfide content of the fuel gas used in the WGI (as determined by APCD-approved ASTM methods). On a quarterly basis, the total sulfur content of the fuel gas used in the WGI (as determined by APCD-approved ASTM methods).

(e) Reporting: On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the APCD. The report must list all data required by the *Compliance Verification Reports* condition of this

[*Re: ATC 5651, PTO 5651, ATC/PTO 5651-01]*

C.9 **Recordkeeping.** All records and logs required by this permit and any applicable APCD, 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 Las Flores Canyon facility. These records or logs shall be readily accessible and be made available to the APCD 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 APCD at LFC within a reasonable time period after request by the APCD. This requirement applies to data required by this permit and archived by Exxon's DCS, PI and any other data-storage systems including but not limited to charts and manual logs. With the exception of CEMS data, prior to archiving any required data from the data-storage system, Exxon shall prepare written reports and maintain these reports in 3-ring binders at the LFC facility. CEMS data shall be kept consistent with the requirements of Exxon's APCD-approved CEMS Plan. 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: ATC 5651, PTO 5651]*

C.10 **Compliance Verification Reports.** Twice a year, Exxon shall submit a compliance verification report to the APCD. Each report shall document compliance with all permit, rule or other statutory requirements during the prior two calendar quarters. The first report shall cover calendar quarters 1 and 2 (January through June) and the second report shall cover calendar quarters 3 and 4 (July through December). The reports shall be submitted within 45 days of the end of the second and fourth quarters respectively. Each report shall contain information necessary to verify compliance with the emission limits and other requirements of this permit and shall document compliance separately for each calendar quarter. These reports shall be in a format approved by the APCD. Compliance with all limitations shall be documented in the submittals. All logs and other basic source data not included in the report shall be made available to the APCD upon request. The second report shall also include an annual report for the prior four quarters. Pursuant to Rule 212, the annual report shall include a completed *APCD Annual Emissions Inventory* questionnaire. Exxon may use the Compliance Verification Report in lieu of the Emissions Inventory questionnaire if the format of the CVR is acceptable to the APCD's Emissions Inventory Group and if Exxon submits a statement signed by a responsible official stating that the information and calculations of quantifies of emissions of air pollutants presented in the CVR are accurate and complete to best knowledge of the individual certifying the statement. The report shall include the following information:

(a) *Cogeneration Power Plant.*

(1) By operating mode, the daily, quarterly and annual heat input in units of million Btu for the gas turbine and HRSG. In addition, the five highest hourly heat input rates per month in units of million Btu/hr for the gas turbine and HRSG.

(2) The length of time (in hours) that the CPP was operated in the Startup/Shutdown mode by day, quarter and year.

(3) Quarterly analyses of the total sulfur content; and the five highest quarterly recorded values of the hydrogen sulfide content and the five highest quarterly recorded higher heating values of the fuel gas used in the CPP.

(4) A report of the amount of electricity generated, consumed by onshore facility, sold to the grid and the amount bought from the grid summarized by month and by year.

(5) Summary results of all compliance emission source testing performed.

(6) A copy of CPP Startup/Shutdown Documentation log for the reporting period.

(b) *Thermal Oxidizer*.

(1) The volumes of gas combusted and resultant mass emissions for each flare category (i.e., Purge/Pilot; Continuous – LP; Continuous – AG; Planned Other; Unplanned - Other), shall be presented as a cumulative summary for each day, quarter and year.

(2) A listing of all infrequent flaring events that exceed 4 events per year from the same cause from the same processing unit or equipment type.

(3) The highest total sulfur content and hydrogen sulfide content observed each week in the LP header, HP header, Acid Gas header and Fuel Gas header combusted during flaring events triggering automatic sampling.

(4) The estimated amount of ammonia combusted in the thermal oxidizer listed by each occurrence.

(5) A copy of the Ammonia Tank Loading Operations Log for the reporting period.

(6) A copy of Flare Event Log for the reporting period.

(7) A copy of the Infrequent Flaring Events Log for the reporting period.

(c) *Fugitive Hydrocarbons*. Rule 331/Enhanced Monitoring fugitive hydrocarbon I&M program data (on a quarterly basis):

(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 APCD.

(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) *Crew and Supply Boats*.

(1) Daily, quarterly and annual fuel use for the crew boat main engines and auxiliary engines while operating in state territorial waters, itemized by controlled boat usage and uncontrolled boat usage. In addition, the fuel use must be summarized for all crew boats by main and auxiliary engines.

(2) Daily, quarterly and annual fuel use for the supply boat main engines and auxiliary engines (including the bow thruster engine) while operating in state territorial waters, itemized by controlled boat usage and uncontrolled boat usage. In addition, the fuel use must be summarized for all supply boats by main and auxiliary engines.

(3) The sulfur content of each delivery of diesel fuel used by the crew and supply boats.

(4) Information regarding any new project boats servicing Exxon's OCS platforms as detailed in Permit Condition 9.C.4(e) above.

(5) Maintenance log summaries including details on injector type and timing, setting adjustments, major engine overhauls, and routine engine tune-ups. For spot charters this shall be provided as available.

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

(f) *Tanks/Sumps/Separators*.

(1) For each PSV event for Group A units, the date, time and duration each PSV was open (include start/stop times); the vapor headspace properties (pressure relief set-point, molecular weight, weight percent of ROC in the vapor); the volume of vapor released (based on manufacturer flow data); the calculated mass emissions for ROC. The mass emissions from each PSV and the cumulative for each tank summarized on a daily, quarterly and annual basis.

(2) For the Group A and D units, the throughput on a daily, quarterly and annual basis.

(3) For the Group B and C units, list any changes in service type and provide an explanation of the change(s) that occurred.

(4) Summary results of all compliance emission source testing performed.

(5) A copy of all LFC Carbon Canister Monitoring and Maintenance Logs.

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

(h) *Sulfur Recovery Unit/Waste Gas Incinerator*.

(1) The daily, quarterly and annual heat input in units of million Btu for the fuel gas to the incinerator. In addition, the five highest hourly heat input rate per month in units of million Btu/hr.

(2) The daily, quarterly and annual Inlet Tail Gas Flow Rate from the TGCU Amine Contactor to the WGI in units of standard cubic feet. In addition, the five highest hourly flow rates per month in units of standard cubic feet per hour.

(3) The daily, quarterly and annual Inlet Flow Rate from Merox Vent to the WGI in units of standard cubic feet. In addition, the five highest hourly flow rates per month in units of standard cubic feet per hour.

(4) Quarterly analyses of the total sulfur content; and the five highest quarterly recorded values of the hydrogen sulfide content and the five highest quarterly recorded higher heating values of the fuel gas used in the WGI.

(5) Summary results of all compliance emission source testing performed.

(6) Summary of all SGTP startup, shutdown and maintenance activities including the date, duration and emissions for each activity and the cumulative for all activities.

(7) A copy of WGI Documentation Log for WGI Startup/Shutdown/Maintenance Activity.

(i) *Ambient Monitoring*. Reports as required by Exxon's AQMM R&O Plan.

(j) *Facility Throughput Data*.

(1) The amount of wet oil (oil/water emulsion) treated and dry oil produced from the Oil Treating Plant per day in units of barrels.

(2) The amount of platform sour gas treated in the stripping gas treating plant per day in units of million standard cubic feet.

(3) The amount sour stripping gas and platform sour gas (combined) treated in the stripping gas treating plant per day in units of million standard cubic feet.

(4) The amount of sweet gas produced in the stripping gas treating plant per day in units of million standard cubic feet.

(5) The amount of oil exported from the Transportation Terminal for each calendar quarter.

(k) *Backup Gas Sweetening Unit (BUGSU)*. A summary of each use of the BUGSU including the date of use and the reason for its use. In addition, a copy of the Daily BUGSU Log for the reporting period.

(n) *Documentation of Outer Continental Shelf (OCS) Activities*. For all OCS activities associated with the SYU project, submit the information required by condition 9.C.44 of this permit.

(p) *General Reporting Requirements*.

(1) On quarterly basis, the emissions from each permitted emission unit for each criteria pollutant.

(2) On quarterly basis, the emissions from each exempt emission unit for each criteria pollutant.

(3) On quarterly basis, Exxon shall submit data for CEM downtime and CEM detected excess emissions in a format approved by the APCD. This report shall be submitted each quarter in accordance with the requirements of Rule 328.

(4) Exxon shall submit with each required semi-annual report two quarterly CEMS Reports. The CEMS Reports shall follow the format and provide the information detailed in Section 7 of the APCD-approved CEMS Plan.

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

(6) The amount, in units of gallons, and source (by monthly reports summarized quarterly) of LNG, NGL, liquid hydrocarbons or combinations thereof, shipped from the Las Flores Canyon facility and the number and size of trucks used.

(7) The amount, in units of long tons, and source (by monthly reports summarized quarterly) of sulfur shipped from the Las Flores Canyon 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) The produced gas, produced oil, fuel gas, and produced wastewater process stream analyses as required by condition 9.C.15 of this permit.

(10) A copy of all completed APCD–10 forms (*IC Engine Timing Certification Form*).

(11) A summary of each use of CARB Certified equipment used at the facility. List the type of equipment used, CARB Registration Number, first date of use and duration of use and an estimate of the emissions generated.

(12) A copy of the Rule 202 De Minimis Log for the stationary source.

[*Re: ATC 5651, PTO 5651, ATC/PTO 10172]*

C.11 **BACT.** Exxon shall apply emission control and plant design measures which represent Best Available Control Technology (BACT) to the operation of the Las Flores Canyon facilities as described in Section 4.10 and Tables 4.1, 4.2 (a and b) and 4.3 of this permit. BACT measures shall be in place and in operation at all times for the life of the project. [*Re: ATC 5651, PTO 5651]*

C.12 **Ambient Monitoring Requirements.** Exxon shall implement the requirements of Section 4.13 (*Operational and Regional Monitoring*) and Table 4.4 (*Requirements For Operational and Regional Monitoring*) for the life of the Santa Ynez Project. These monitoring stations shall be fully operational at all times. Exxon shall implement the APCD-approved AQMRO Monitoring Plan (approved 6/22/93 and all updates thereof). All monitoring plans and quality assurance manuals shall be in accordance with the APCD Monitoring Protocol (October 1990 and all updates). Data from the monitoring stations shall be transmitted in real-time to the APCD's office. [*Re: ATC 5651, PTO 5651]*

C.13 **Operational Increment Fee.** Exxon shall submit increment fees on the following schedule:

May/1999	$90,373
May/2000	$67,780
May/2001	$45,186
May/2002	$22,593

[*Re: ATC 5651, PTO 5651]*

C.14 **Source Testing.** The following source testing provisions shall apply:

(i) Exxon shall conduct source testing of air emissions and process parameters listed in Section 4.12 and Tables 10.2-1, 10.2-2 and 10.2-3 of this permit. More frequent source testing may be required if the equipment does not comply with permitted limitations or if other compliance problems, as determined by the APCD, occur. Source testing shall be performed on an annual schedule (except as specifically noted) using December/January as the anniversary date for the CPP and March/April as the anniversary date for the SGTP and the Equalization Tank.

(ii) Exxon shall submit a written source test plan to the APCD for approval at least thirty (30) days prior to initiation of each source test. The source test plan shall be prepared consistent with the APCD's Source Test Procedures Manual (revised May 1990 and any subsequent revisions). Exxon shall obtain written APCD approval of the source test plan prior to commencement of source testing. The APCD 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 APCD personnel may observe the test.

(iii) Source test results shall be submitted to the APCD within forty-five (45) calendar days following the date of source test completion and shall be consistent with the requirements approved within the source test plan. Source test results shall document Exxon's compliance status with BACT requirements, mass emission rates in Section 5 and applicable permit conditions, rules and NSPS (if applicable). All APCD costs associated with the review and approval of all plans and reports and the witnessing of tests shall be paid by Exxon as provided for by APCD Rule 210.

(iv) 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 APCD approval before deferring or discontinuing a scheduled test, or performing maintenance on the equipment item on the scheduled test day. If the test can not be completed on the scheduled day, then the test shall be rescheduled for another time with prior authorization by the APCD. Failing to perform the source test of an equipment item on the scheduled test day without a valid reason and without APCD's authorization shall constitute a violation of this permit.

[*Re: ATC 5651, PTO 5651]*

C.15 **Process Stream Sampling and Analysis.** Exxon shall sample and analyze the process streams listed in this Section 9.0 according to the specified methods and frequency detailed therein. All process stream samples shall be taken according to APCD-approved ASTM methods and must follow traceable chain of custody procedures.

In addition, the following process streams are required to be sampled and analyzed. Duplicate samples are required:

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

- 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 a annual basis.

- Fuel Gas: For both SGTP processed and/or public utility provided gas, samples are taken at the Fuel Gas Scrubber (MBF-2102). Analysis for: HHV, total sulfur, H_2S, composition. For process gas, samples to be taken on a continuous basis for HHV and H_2S and on a quarterly basis for total sulfur and composition. For utility supplied gas, samples for HHV, H_2S, total sulfur and composition to be taken on a monthly basis.

- Produced Wastewater: Streams are analyzed for ROC content necessary to maintain compliance with Rule 325.B. Samples to be taken on an annual basis.

All sampling and analyses are required to be performed according to APCD-approved procedures and methodologies. All sampling and analysis must be traceable by chain of custody procedures. [*Re: ATC 5651, PTO 5651]*

C.16 **Offsets and Consistency with the AQAP.** Exxon shall comply with all the procedures and requirements specified in Section 7 of this document including all requirements for offsets, source testing and reporting. Exxon shall provide the following offsets:

(i) Exxon shall offset the net emission increase (NEI) resulting from operation of the Las Flores Canyon facility as detailed in Chapter 7 and Tables 7.1, 7.2, 7.3 and 7.4.

(ii) In order to mitigate potential ozone impacts from the Santa Ynez Unit Expansion Project and for consistency with reasonable further progress for attainment of the federal ozone standard and FDP Condition XII-3.b, Exxon shall mitigate all operation phase emissions, which are shown in Table 7.5, and as specified in Section 7.0 of this permit. Through the implementation of the procedures specified above, the APCD is able to make the finding that the project will result in a net air quality benefit and is consistent with the AQAP, as necessary for the issuance of this permit.

(iii) Notwithstanding any force majeure, termination, or transfer provision contained in the agreements referenced above, Exxon will offset all SYU project emissions at the ratios specified in Chapter 7. If offsets are not in place as required by this permit, Exxon shall provide replacement offsets and shall obtain variance relief.

[*Re: ATC 5651, PTO 5651]*

C.17 **Continuous Emission Monitoring (CEM).** Exxon shall implement a CEM program for emissions and process parameters as specified in Section 4.11 and Attachment 10.1 of this permit. Exxon shall implement the APCD-approved CEM Plan (approved 10/22/93 and all subsequent APCD-approved updates). The CEM monitors shall be in place and functional for the life of the project. The APCD shall use the CEM data alone or in combination with other data, to verify and enforce project conditions. Excess emissions indicated by the CEM systems shall be considered a violation of the applicable emission limits. [*Re: ATC 5651, PTO 5651]*

C.18 **Process Monitoring Systems - Operation and Maintenance.** All LFC facility process monitoring devices listed in Section 4.11 of this permit shall be properly operated and maintained according to manufacturer recommended specifications. Exxon shall implement their *Continuous Emissions Monitoring Plan* (approved 10/22/93 and all subsequent APCD-approved updates) for the life of the project. This Plan details the manufacturer recommended maintenance and calibration schedules. Where manufacturer guidance is not available, the recommendations of comparable equipment manufacturers and good engineering judgement is utilized. [*Re: ATC 5651, PTO 5651]*

C.19 **Data Telemetry.** Exxon shall telemeter monitoring data to the APCD as specified by Conditions C.12 (*Ambient Monitoring Requirements*), C.17 (*Continuous Emission Monitoring*) and C.38 (*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 APCD's Central Data Acquisition System. [*Re: ATC 5651, PTO 5651]*

C.20 **Central Data Acquisition System.** This system shall receive and analyze continuous emissions data from Exxon CEMs (as specified in Condition C.19), ambient air monitoring and meteorological data (as specified in Conditions C.12), odor monitoring (as specified in Condition C.38) and any other data necessary to evaluate observed and potential air quality impacts either site-specific or regional.

Exxon shall provide a pro rata share of the costs for the operation and maintenance of the Central Data Acquisition System referred to in this condition. In addition, Exxon shall pay its pro rata share (26.58 percent as of January 21, 1998) of the one-time only final acceptance cost for the design, purchase and installation of the DAS. These funds shall be provided to the APCD or a designated agent within thirty (30) days after receipt of a request.

The central data acquisition system referred to in this permit condition is a unique and separate system from the system referred to in MOA II, Section 7, Page 8. [*Re: ATC 5651, PTO 5651]*

C.21 **Central Data Acquisition System Operation and Maintenance Fee.** By permit condition C.17, Exxon shall connect certain Continuous Emission Monitors (CEM) and all ambient, meteorological, and odor parameters to the APCD central data acquisition system (DAS). In addition, Exxon shall reimburse the APCD for the cost of operating and maintaining the DAS. Exxon shall be assessed an annual fee, based on the APCD's fiscal year, collected semi-annually.

Pursuant to Rule 210 III.A., Exxon shall pay fees specified in Table 9.1. The APCD 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 APCD'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 APCD into a share of the DAS costs {as outlined in the APCD's March 27, 1998 letter (*Fixed Fee Proposal for Monitoring and DAS Costs*)}. In the event that the assumptions used to establish this fee change substantially, the APCD may revisit and adjust the fee based on documentation of the cost of services. Adjusted fees will be implemented by transmitting a revised Table 9.1.

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 5651, PTO 5651]*

C.22 **Emissions Reduction Credit Certificate No. 0004-0103.** The 0.18 tpq of ROC ERCs created by ATC/PTO 9826 (Enhanced I&M by monthly monitoring of the 387 valves in gas service identified in Attachment 10.9) and incorporated into this permit are dedicated to ERC Certificate No. 0004-0103 only. [*Re: ATC 5651, PTO 5651]*

C.23 **Emissions Reduction Credits Dedicated to Specific Projects – ATC 9651.** The ERCs created under ATC and PTO 9651 are for use as offsets by Exxon at Platforms Heritage and Harmony to satisfy the offsets requirements for emissions created by the compressor skid emission units permitted under PTO 9634 (Heritage) and PTO 9640 (Harmony) only. Exxon shall meet the requirements of those permits in applying these ERCs. Emission reduction measures implemented to create the required emission reduction credits, monthly monitoring of the valves specified in ATC 5651-17/PTO 5651 (1/27/99), shall be in place and maintained for the life of each project. This permit does not authorize the dedication of these emission reductions to any other project. [*Re: ATC 5651, PTO 5651]*

C.24 **Mass Emission Limitations**. Except as noted in Conditions 9.C.1, 9.C.2 and 9.C.6, mass emissions for each equipment item (i.e., emissions unit) associated with Exxon's Las Flores Canyon facilities shall not exceed the values listed in Tables 5.1-3 and 5.1-4. Emissions for the entire facility shall not exceed the total limits listed in Table 5.2. [*Re: ATC 5651, PTO 5651]*

C.25 **Permitted Equipment.** Only those equipment items listed in Section 2.3 are covered by the requirements of this permit and APCD Rule 201.B. Exxon may petition the APCD to include any item not listed in Section 2.3 that Exxon claims to have been constructed at the Las Flores Canyon facility under ATC 5651 (11/17/87) upon the submittal of creditable evidence. With the exception of the third Oil Train and the third phase of the Water Treatment Plant, any equipment item listed in Section 2.3 that is not constructed as of December 1, 1998 shall not be covered by this permit and an ATC permit shall be required for such construction. [*Re: ATC 5651, PTO 5651]*

C.26 **Facilities Approved for Future Construction.** This permit authorizes the future construction of a third Oil Train and the third phase of the Water Treatment Plant consistent with the design drawings and material balance documentation submitted by Exxon and approved by the APCD under ATC 5651 (11/17/87). The specific component-leakpath inventory for the approved future construction is detailed in Attachment 10.9. At least 60 days prior to constructing either of these two facilities, Exxon shall provide the APCD the following:

(a) An updated project and process description including: process flow diagrams; piping and instrument diagrams; and, material balances.

(b) An update to the LFC Fugitive Hydrocarbon Inspection and Maintenance Program.

(c) A detailed listing of all fugitive component leak-paths, the associated service and resulting mass emission calculations.

(d) A BACT analysis for the new emission units taking into account the most current BACT technology and performance standards. At a minimum, BACT shall meet the technology and performance standards listed in Appendix 5.1 of the APCD's Rule 331 BACT Guidelines document (see Appendix 10.9). The APCD's approval shall be deemed as approval via ATC 5651-17.

(e) An offsets analysis. Exxon shall show that the emissions increase from the new facilities has sufficient offsets.

(f) A detailed estimate of the NO_x and ROC construction emissions associated with building of each phase as well as a detailed listing of the equipment used..

Exxon shall obtain written APCD approval prior to commencement of construction. An ATC permit may be required if the proposed construction is inconsistent with the originally approved design. Upon APCD approval, Exxon may temporarily operate the facility(ies) under a SCDP for a period no longer than 90 days. During this SCDP (defined as the introduction of hydrocarbon containing fluids), Exxon shall request an APCD inspection no later than 30 days after initiation of the SCDP. Upon submittal of a complete Permit to Operate application, Exxon may continue to operate the facility(ies) for up to an additional 90 days under this permit. No further SCDP extensions shall be authorized. [*Re: ATC 5651, PTO 5651]*

C.27 **Facility Throughput Limitations.** Exxon shall process no more than 140,000 barrels per day of dry oil. The stripping gas treating plant shall not process more than 15 million standard cubic feet of platform gas, nor more than 21 million standard cubic feet of sour stripping gas and platform gas, combined. The oil and gas processed under this permit shall be produced only from the Hondo, Harmony, Heritage and Heather platforms within the boundaries of the SYU area described in the project EIS/R and supplemental EIRs. The transportation terminal shall be used only for the export of a maximum of 125 thousand barrels of oil per day (averaged over a calendar quarter). Oil storage facilities shall be limited to a maximum working capacity of 509 thousand barrels of oil. If Exxon wishes to process oil from platforms other than those listed above, Exxon must modify as appropriate, this permit.

On a daily basis, Exxon 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, Exxon shall log the volume of oil exported from the transportation terminal each day, summarized on a calendar quarter basis. [*Re: ATC 5651, PTO 5651]*

C.28 **Emission Factor Revisions.** The APCD may update the emission factors for any calculation based on USEPA AP-42 or APCD P&P emission factors at the next permit modification or permit reevaluation to account for USEPA and/or APCD revisions to the underlying emission factors. Further, Exxon shall modify its permit via an ATC application if compliance data shows that an emission factor used to develop the permit's potential to emit is lower than that documented in the field. The ATC permit shall, at a minimum, adjust the emission factor to that documented by the compliance data consistent with applicable rules, regulations and requirements. [*Re: ATC 5651, PTO 5651]*

C.29 **Abrasive Blasting Equipment.** All abrasive blasting activities performed at the Las Flores Canyon facilities shall comply with the requirements of the California Administrative Code Title 17, Sub-Chapter 6, Sections 92000 through 92530. [*Re: ATC 5651, PTO 5651]*

C.30 **Vacuum Truck Use.** During vacuum truck use, Exxon shall use an APCD-approved control device (i.e., carbon adsorption system or equivalent) to reduce emissions of reactive organic compounds (ROC) and odorous compounds from the vacuum truck vent. Exxon shall maintain a log of all vacuum truck operations. The log shall include for each use, the date, the location and equipment ID where vacuum truck operations occur, volume and description of material, reason for use, duration of the operation and any emission control maintenance activities. Exxon shall implement the APCD-approved Vacuum Truck Operation & Maintenance Procedures document (approved June 14, 1993 and subsequent APCD-approved updates). [*Re: ATC 5651, PTO 5651]*

C.31 **Backup Gas Sweetening Unit (BUGSU)**:

a. Emission Limitations: SO_2 emissions from the Thermal Oxidizer due to combustion of BUGSU sweetened gas shall not exceed: 0.1 lb/hr, 2.4 lb/day, 0.10 tpq, 0.10 tpy. Compliance with this limit shall be based upon the BUGSU outlet H_2S concentration and the BUGSU exhaust flow rate.

b. Operational Limitations: The BUGSU shall only be used under one of the following conditions: (i) during commissioning of the water treatment plant; (ii) during planned plant turnarounds or extended periods of down time where the gas processing equipment is shut down; (iii) other APCD-approved usages such that SO_2/H_2S emissions can be effectively reduced; or, (iv) control of excess emissions related to equipment breakdowns. Exxon shall notify the APCD by noon of the next business day after each usage of the BUGSU and shall operate the system consistent with the information contained in the permit application and/or APCD Breakdown rules.

c. Monitoring, Recordkeeping and Reporting: For each use, Exxon shall measure, on a daily basis, the H_2S concentration of the treated off-gas using absorbent tube analysis. For concentrations below 40 ppmvd, the exhaust flow rate shall be assumed to be 14.58 kcfh (350 kcfd). If the treated off-gas H_2S concentrations exceed 40 ppmvd, then Exxon shall also measure the exhaust flow rate from the BUGSU and calculate hourly and daily SO_2 emissions. The flow rate measurements must commence within 24-hours of the H_2S concentration exceeding 40 ppmvd. The above information shall be recorded daily in a log. The flow measurement device shall be APCD approved.

[*Re: ATC 5651, PTO 5651, ATC/PTO 5651-01]*

C.32 **Emergency Firewater/Floodwater Pumps.** The onshore diesel-fired firewater pumps shall not be operated for more than 30 minutes at any one time. Each firewater and floodwater pump engine shall not operate more than a total of 390 minutes each per calendar quarter, except during emergencies that require their use for longer periods for not exceeding 200 hours per year. Each pump engine shall be equipped with a non-resettable hour meter. Exxon shall maintain an operating log detailing for each use: the start and stop times, the duration of use, the reason for use, the aggregate number of minutes each pump is operated quarterly and annually. This log shall be available for APCD review. [*Re: ATC 5651, PTO 5651, ATC/PTO 5651-01]*

C.33 **Diesel Fuel Sulfur Limit.** Diesel fuel used by all diesel-fired equipment including vessels (i.e., crew and supply boats) shall have a sulfur content no greater than 0.20 weight percent. Exxon shall maintain fuel-use records and fuel specifications for each piece of equipment onsite and shall make such information available to the APCD upon request. [*Re: ATC 5651, PTO 5651]*

C.34 **Transportation Terminal Operational Limits.** Exxon shall operate the onshore transportation terminal consistent with the information and data used for the analysis that determined the requirements of this permit. Oil transportation via the Las Flores Canyon Marine Terminal is not authorized by this permit. [*Re: ATC 5651, PTO 5651]*

C.35 **Purging/Degassing of Vessels to the Atmosphere.** Exxon shall use the vapor recovery system or flare system when degassing or purging or blowing down any tank, vessel or container that contains reactive organic compounds or reduced sulfur compounds. Exxon shall submit and obtain APCD approval of a *Purging/Degassing Plan* within 90 days after the issuance of this permit. This plan shall detail Exxon's procedures for degassing/purging tanks, vessels and containers prior to operations which require they be opened to the atmosphere. Exxon shall implement this Plan for the life of the project. [*Re: ATC 5651, PTO 5651]*

C.36 **Diesel IC Engines - Particulate Matter Emissions.** To ensure compliance with APCD Rules 205.A, 302, 305, 309 and the California Health and Safety Code Section 41701, Exxon shall implement manufacturer recommended operational and maintenance procedures to ensure that all project diesel-fired engines minimize particulate emissions. Exxon shall submit and obtain APCD approval of an *IC Engine Particulate Matter Operation and Maintenance Plan* within 90 days after the issuance of this permit. Exxon shall implement this Plan for the life of the project. This Plan details the manufacturer recommended maintenance and calibration schedules that Exxon will implement. Where manufacturer guidance is not available, the recommendations of comparable equipment manufacturers and good engineering judgement shall be utilized. [*Re: ATC 5651, PTO 5651]*

C.37 **Emergency Episode Plan**. Six months prior to the scheduled triennial operating permit reevaluation date, Exxon shall review and update the *Emergency Episode Plan* for LFC and submit it for APCD approval. [*Re: ATC 5651, PTO 5651]*

C.38 **Odor Monitoring Plan.** Exxon shall implement the requirements of Section 4.14 (*Odor Monitoring*) and Table 4.5 (*Requirements For Odor Monitoring*) for the life of the Santa Ynez Project. These monitoring stations shall be fully operational at all times. Exxon shall implement the APCD-approved *Odor Monitoring Plan* (approved 6/22/93 and all updates thereof). All monitoring plans and quality assurance manuals shall be in accordance with the APCD Monitoring Protocol (October 1990 and all updates). Data from the monitoring stations shall be transmitted in real-time to the APCD's office. [*Re: ATC 5651, PTO 5651]*

C.39 **As-Built Drawings.** On a quarterly basis, Exxon shall provide the APCD with all updates to the final "as-built" drawings (P&IDs and PFDs) for the Las Flores Canyon facilities. In no case shall Exxon provide the APCD drawings of a lesser quality than those drawings possessed by Exxon. [*Re: ATC 5651, PTO 5651]*

C.40 **Particulate Matter Mitigation.** Exxon shall implement the PM_{10} mitigation requirements as specified by the up-coming APCD *PM_{10} Attainment Plan*. The APCD will use, in part, the *Particulate Matter Emission Reduction Study*, dated June 1991, as a basis for development of control measures in the PM_{10} Attainment Plan. Within one year of notification by the APCD, Exxon shall implement PM_{10} control measures identified in the future *PM_{10} Attainment Plan* on appropriate equipment regulated by APCD permits. [*Re: ATC 5651, PTO 5651]*

C.41 **Flare Study.** In order to eliminate or reduce AQIA projected air quality standard or increment violations associated with flaring events, Exxon shall implement the recommendations of the *Phase II Flare Study* within 24 months of the completion of the study. Exxon shall obtain the necessary permits from affected agencies, including the APCD, as required prior to making the modifications. [*Re: ATC 5651, PTO 5651]*

C.42 **Consolidation.** Consistent with the consolidation modeling results conducted as part of ATC 5651(11/17/87), Exxon shall cooperate with ARCO and other Las Flores Canyon users to develop the necessary plans to insure that the testing of Exxon's emergency firewater/floodwater pumps do not occur at the same time as that of the back-up and emergency equipment of the other Las Flores Canyon Facilities which cause air emissions. [*Re: ATC 5651, PTO 5651]*

C.43 **Documents Incorporated by Reference.** The documents listed below, including any APCD-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 SYU Project and shall be made available to APCD inspection staff upon request.

(i) *Fugitive Emissions Inspection and Maintenance Program for Las Flores Canyon Process Facilities* (approved 7/20/93).

(ii) *Vacuum Truck Plan* (approved 6/14/93)

(iii) *CEM (CGA) Plan* (approved 7/22/93 and 10/22/93)

(iv) *Emergency Episode Plan* (approved 5/20/93)

(v) *AQMRO Monitoring Plan* (approved 6/22/93)

(vi) *Odor Monitoring Plan* (approved 6/22/93)

(vii) *Petroleum Storage Tank Degassing Plan* (approved 5/20/99)

(viii) *Rule 359 Flare Minimization Plan* (approved 12/22/94)

(ix) *Purging/Degassing Plan* (approved 5/20/99)

(x) *IC Engine Particulate Matter Operation and Maintenance Plan* (approved 5/20/99)

(xi) *NSPS Subpart Kb Operating Plan* (approved 1/15/99))

(xii) *Carbon Canister Monitoring and Maintenance Plan* (approved 5/20/99)

(xiii) *Boat Monitoring and Reporting Plan* (approved 7/20/99)

(xiv) *Solvent Reclamation Plan* (upon approval)

[*Re: ATC 5651, PTO 5651]*

C.44 **Documentation of Outer Continental Shelf (OCS) Activities.** Exxon shall provide sufficient information to the MMS and the APCD on project activities on the OCS to verify air emission calculations used for this permit. Such information shall consist of the following: a) Fugitive hydrocarbon information; b) flaring information; c) for all fuel burning equipment 50 bhp or greater Exxon will provide the total hours of operation for each piece of equipment and amount of fuel used by equipment type. To avoid duplication, Exxon may reference information already provided in Compliance Verification Reports required by Exxon's OCS operating permits for Platforms Hondo, Harmony and Heritage. Exxon shall also provide monthly summaries of the composition of fuel used at each platform. Upon written request by the APCD, Exxon shall make all logs available for review.

Information on construction of OCS project components shall consist of the following:

1) Description of all fuel consuming equipment and vessels 500 hp or greater.

2) Engine description including make, model, size, and output ratings.

3) Monthly fuel use.

Exxon shall provide monthly summaries of all the above data within 45 days after the end of 2nd and 4th quarters. [*Re: ATC 5651, PTO 5651]*

C.45 **Additional Mitigation Measures.** If, at any time, the APCD determines that the mitigation measures, imposed by these Permit Conditions, are inadequate to effectively mitigate significant environmental impacts caused by the project, then additional reasonable and feasible conditions shall be imposed to further mitigate these impacts. Exxon agrees that it will comply with such reasonable and feasible conditions, subject to review thereof under all applicable provisions of law. The APCD may conduct a comprehensive review of the project conditions three years after permit issuance and at appropriate intervals thereafter. Upon appeal by Exxon to the Hearing Board, the Hearing Board shall determine whether any new conditions imposed by the APCD are reasonable and feasible, considering the economic burdens imposed and environmental benefits to be derived. In no event shall this condition be construed so as to preclude Exxon from vesting rights under this permit as provided under California law.

For purposes of this Condition, "mitigation" and "feasible" shall have the same meanings as defined in CEQA Guidelines, and "significant environmental impact" as applied to air quality means the project's emissions cause a violation of any applicable air quality standards or result in a nuisance as defined by the California Health and Safety Code Section 41700. [*Re: ATC 5651, PTO 5651]*

C.47 *deleted*

C.48 **LFC-1 Ambient Monitoring Station/ LFC-Odor Monitoring Station Operation Fee.** By permit conditions C.12 and C.38, Exxon shall operate and provide APCD the data from LFC-1 and LFC-Odor monitoring stations for the life of Exxon’s Santa Ynez Project. Exxon has requested that the APCD operate Exxon’s LFC-1 and LFC-Odor monitoring sites and assess an annual fee for this service.

Pursuant to Rule 210 III.A, Exxon shall pay fees specified in Table 9.2. The APCD shall use these fees to operate the stations, purchase consumables, spare parts and fixed assets, and pay for utilities (except power as noted below), communications, maintenance of equipment, and vehicle operation per assumptions in the APCD’s March 27, 1998 letter (*Fixed Fee Proposal for Monitoring and DAS Costs*), and as modified by APCD’s March 30, 1999 memorandum (*APCD costs for Operating Exxon’s LFC1 and Odor Monitoring Stations*). Fees shall be due and payable pursuant to governing provisions of Rule 210, including CPI adjustments. Exxon shall be assessed an annual fee, based on the APCD’s fiscal year, collected semi-annually. The APCD will operate the stations according to standard APCD, CARB and EPA protocols. In the event that the operation of the station shows that the assumptions used to establish the fee were inaccurate or incomplete, or if costs associated with the fee substantially increase or decrease, the APCD may revisit and adjust the fee based on documentation of the actual cost of services. Adjusted fees will be implemented by transmitting a revised Table 9.2, which will become an enforceable part of the permit in the subsequent fiscal year.

The fee will cover costs for station operation, maintenance of equipment, equipment audits, data collection, review and submittal of data to EPA, and all future upgrades to equipment (including to the fencing or the enclosure). Exxon will continue to have the permit requirement to operate the monitoring site for the life of the Santa Ynez Project, however, Exxon will not be held responsible for the quality or quantity of the data collected at monitoring stations operated by the APCD.

Exxon has entered into a Lease Agreement with the APCD which provides for , but is not limited to, access, utilities, (power, telephone and rubbish collection), terms for termination, indemnity and ownership of improvements. This Lease Agreement (dated May 20, 1999) is incorporated herein as an enforceable part of this permit.

If the APCD ceases to operate Exxon’s LFC-1 and LFC-Odor monitoring sites for any reason, then Exxon shall be responsible for operating these two sites. [*Re: ATC/PTO 5651-01]*

C.49 **Ambient and Odor Monitoring Station Data Review and Audit Fee.** By permit condition C.12 and C.38, Exxon shall operate ambient and odor monitoring stations and submit data to the APCD for quality assurance review and shall have the stations audited quarterly by the APCD, or its contractor. In addition, Exxon shall reimburse the APCD for the cost of this service. Effective July 1, 1999, Exxon shall be assessed an annual fee, based on the APCD's fiscal year, collected semi-annually.

Pursuant to Rule 210 III.A., Exxon shall pay fees specified in Table 9.3. The APCD will use this fee to pay staff costs to review and quality assure the monitoring data collected by Exxon and the contractor or staff costs to audit the monitoring equipment. This fee shall not cover any APCD 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 Exxon consistently requires services in excess of those assumed in the APCD's March 27, 1998 letter (*Fixed Fee Proposal for Monitoring and DAS Costs*), the Control Officer may move Exxon to a reimbursable method of payment, subject to provisions of Rule 210. The APCD will operate the stations according to standard APCD, CARB and EPA protocols. In the event that the actual data review and audit process shows that the assumptions used to establish the fee were inaccurate or incomplete, or if costs associated with the fee substantially increase or decrease, the APCD may revisit and adjust the fee based on documentation of the actual cost of services. Adjusted fees will be implemented by transmitting a revised Table 9.3, which will become an enforceable part of the permit.

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

Notwithstanding the above, the data review and audit fee shall not apply as long as the APCD operates the two monitoring stations consistent with the requirements of Permit Condition C.48. *[Re: ATC/PTO 5651-01]*

C.50 **Thermal Oxidizer Variance Order.** Pursuant to the APCD Hearing Board Regular Variance Order *H.B. Case No. 17-99R* issued on October 6, 1999, Exxon was granted a variance from certain provisions of Rule 359 (*Flares and Thermal Oxidizers*). Specifically, Exxon is in violation of District Rule 359 D.2.b.3 due to the recurrent failures of pilots serving the facility's Thermal Oxidizer unit (equipment ID number EAW-1601). Rule 359 D.2.b.3 requires the flame (in the pilot) to be operating at all times when combustible gases are vented through the Thermal Oxidizer. The requirements of Rule 359.D are incorporated into this permit in Permit Condition 9.C.2.(b)(iv). This permit condition (9.C.50) temporarily relieves Exxon of the requirement to comply with Rule 359 D.2.b.3 and Permit Condition 9.C.2.(b)(iv) until June 30, 2000. Exxon shall meet the following requirements by no later than June 30, 2000:

a. Exxon shall not conduct any planned flaring activities in the Thermal Oxidizer located at the Las Flores Canyon Oil Treatment Plant during the period that this Permit Condition is in effect unless all pilots are functioning properly.

b. By not later than October 10, 1999, Exxon shall complete the initial inspection, cleaning, repair and replacement of all pilots as necessary. Exxon shall repeat this requirement every six months (180 days) thereafter during the period this Permit Condition is in effect. Exxon shall inspect any pilot which experiences two (2) or more failures since the most recent cleaning (to be completed by October 10, 1999) with the inspection to occur by not later than January 15, 2000 to determine if more frequent cleaning, repair or replacement is warranted.

c. Exxon shall inspect, clean, repair and replace as necessary any pilot assembly within 24 hours of any pilot failure during the period this Permit Condition is in effect.

d. Exxon shall report all pilot failures to the APCD using the Breakdown Reporting format of Rule 505, including 1) an estimate of emissions of unburned hydrocarbons and hydrogen sulfide, and 2) whether flaring was occurring at the time of the pilot failure. Exxon shall include an update to the table appearing as Attachment 4 of Exxon's Interim Variance 16-99I application for each reported pilot failure.

e. Exxon shall track and record the thermal oxidizer header location number and identification number of each pilot that experiences a failure during the period of this Permit Condition.

f. During the period this Permit Condition is in effect, Exxon shall submit a revised timeline for increments of progress to be achieved by the Exxon to identify and implement long term solutions to correct the failures of the Thermal oxidizer pilots. The revised timelines shall be submitted to the APCD within 15 days of the close of each calendar month.

g. During the period this Permit Condition is in effect, Exxon shall also submit a monthly report detailing the actions taken by Exxon during the previous month to identify and implement short and long-term corrective actions to the identified cause(s) of the Thermal Oxidizer pilot failures. The reports shall be submitted to the APCD within 15 days of the close of each calendar month.

Failure of Exxon to meet all dates specified above in (a) – (g) shall constitute a violation of this Permit Condition. Exxon shall be subject to all civil and criminal penalties, fines, sanctions and remedies provided by law. Exxon shall retain the obligation to comply with all other local, state and federal regulations not specifically referenced in this order. This Permit Condition expires on July 1, 2000.

9.D APCD-Only Conditions

The following section lists permit conditions that are not enforceable by the USEPA or the public. However, these conditions are enforceable by the APCD and the State of California. These conditions are issued pursuant to APCD Rule 206 (*Conditional Approval of Authority to Construct or Permit to Operate*), which states that the Control Officer may issue an operating permit subject to specified conditions. Permit conditions have been determined as being necessary for this permit to ensure that operation of the facility complies with all applicable local and state air quality rules, regulations and laws. Failure to comply with any condition specified pursuant to the provisions of Rule 206 shall be a violation of that rule, this permit, as well as any applicable section of the California Health & Safety Code.

= There are no permit conditions that are APCD-only enforceable for this permit =

AIR POLLUTION CONTROL OFFICER

____

____

Date

<u>NOTES</u>:

(a) This permit supersedes all previous APCD permits issued for the Las Flores Canyon facility.

(b) Permit Reevaluation Due Date: December 2002

(c) Part 70 Operating Permit Expiration Date: December 2004

Table 9.1

FEES for DAS OPERATION and MAINTENANCE [(a) (b)]

FEE DESCRIPTION	FEE
DATA ACQUISITION SYSTEM OPERATION AND MAINTENANCE FEE	
Per CEM, ambient or meteorological parameter required by permit to be transmitted real-time to the APCD Central Data Acquisition System	$1,307 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 APCD'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.

Table 9.2

FEES for MONITORING STATION OPERATION [(a) (b)]

FEE DESCRIPTION	Annual Fee
LFC-1 Operation	$67,981
LFC-Odor Operation	$54,988
Total	$122,969

(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 APCD's March 27, 1998 letter (*Fixed Fee Proposal for Monitoring and DAS Costs*), and APCD's March 30, 1999 memorandum (*APCD costs for Operating Exxon's LFC1 and Odor Monitoring Stations*) and may be updated pursuant to the requirements of this permit.

Table 9.3

FEES for MONITORING 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 4.4	$23.569 annually
data review and audit activities associated with data submitted from any odor or meteorological station in Table 4.4 or Table 4.5	$11,784 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 APCD’s March 27, 1998 letter (*Fixed Fee Proposal for Monitoring and DAS Costs*) and may be updated pursuant to the requirements of this permit.

10.0 Attachments

10.1 CEMS Requirements

10.2 Source Testing Requirements

10.3 Emission Calculation Documentation

10.4 Tanks, Sumps and Separators List

10.5 List of Insignificant Emission Units

10.6 NSPS Compliance Report

10.7 IDS Database Emission Tables

10.8 Source Test Results Summary

10.9 Phase III Oil/Water Equipment List/Appendix 5.1 – BACT Table

10.10 Equipment List (Tables Q and P)

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10.1 CEMS REQUIREMENTS

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Table 10.1-1

EMISSION AND PROCESS PARAMETER MONITORING AND REPORTING REQUIREMENTS FOR THE COGENERATION FACILITY [1, 7, 8]

Location Number	Test Location	Parameter Monitored	Monitoring Method
1	Exhaust Stack	NO_x	NO_x Analyzer [2, 3, 5, 6]
		O_2	O_2 Analyzer [2, 3, 6]
		CO	CO Analyzer [2, 3, 5, 6]
		Temperature	Thermocouple [2, 3, 5]
		Flow Rate	Annubar [2, 3, 5, 6] (or equivalent)
2	SCR Inlet	NO_x	NO_x Analyzer [2, 3, 6]
		Temperature	Thermocouple [2, 3, 5]
3	Bypass Stack	Flow Rate (while operating)	Calculated [2, 3, 5]
		Damper Position	Monitor Position [2, 3]
4	Turbine Fuel Feed	Flow Rate	Process Flow Meter [2, 3, 6]
5	Turbine Steam Injection	Flow Rate	Process Flow Meter [2, 3, 6]
6	HRSG Fuel Feed	Flow Rate	Process Flow Meter [2, 3, 6]
7	Cogeneration Plant Turbines	Electrical Output [4]	Plant Meters [2, 3]
8	Waste Heat Recovery Unit	Steam Production	Process Flow Meter [2, 3, 6]
9	Ammonia Injection Point	NH_3 Feed Rate	Process Flow Meter [2, 3, 6]
10	Cogeneration Plant	Mode	Process Monitors [2, 3, 5]

1 Parameters in addition to those listed must be monitored continuously if deemed necessary by the APCD.

2 Parameter raw data must be permanently recorded using: (a) strip chart or circular chart and/or (b) computer or data/logger.

3 Parameters must be monitored continuously and reported to the APCD on a semi-annual basis.

4 Monitor and record the amount of electricity generated, the amount consumed by the onshore facility, the amount sold to the grid and the amount purchased from the grid. Reported by month and year.

5 Parameter monitoring must be telemetered to the APCD

6 Each emissions monitoring instrument must be performance certified annually (or more often if this is deemed necessary by the APCD) in accordance with 40 CFR 60 Appendix B and 40 CFR 50 Appendix E, or equivalent method approved by the APCD. Flow meter shall be calibrated per the CEMs Plan.

7 Monitoring and reporting frequency per APCD CEMS Protocol and Exxon’s APCD-approved CEMS Plan.

8 Telemetry may be required in the future.

Table 10.1-2

EMISSION AND PROCESS PARAMETER MONITORING AND REPORTING REQUIREMENTS FOR THE STRIPPING GAS TREATING PLANT [1, 7, 8]

Location Number	Test Location	Parameter Monitored	Monitoring Method
1	Incinerator Exhaust	NO_x	NO_x Analyzer [2, 3, 5, 6]
		SO_2	SO_x Analyzer [2, 3, 5, 6]
		O_2	O_2 Analyzer [2, 3, 6]
		Temperature	Thermocouple [2, 3, 5]
		Flow Rate	Annubar [2, 3, 5, 6] (or equivalent)
2	Inlet Gas - Platform gas	Flow Rate	Process Flow Meter [2, 3, 6]
	- Stripping Gas	Flow Rate	Process Flow Meter [2, 3, 6]
3	Assist Gas to Incinerator	Flow Rate	Process Flow Meter [2, 3,, 6]
4	Sweet Gas from Amine Unit	H_2S	H_2S Analyzer [2, 3, 6]
5	Sulfur Production	Production Rate	Tank Gauging
6	Tail Gas Feed	Flow Rate	Process Flow Meter [2, 3, 6]
		H_2S	H_2S Analyzer [2, 3, 6]
7	Acid Gas Feed	Flow Rate	Process Flow Meter [2, 3, 6]
8	Incinerator Inlet	Flow Rate from TGCU	Process Flow Meter [2, 3, 6]
		Flow Rate from Merox	Process Flow Meter [2, 3, 6]
		H_2S from TGCU	Absorbent tube [4]
		H_2S from Merox	Absorbent tube [4]

1 Parameters in addition to those listed must be monitored continuously if deemed necessary by the APCD.

2 Parameter raw data must be permanently recorded using: (a) strip chart or circular chart and/or (b) computer or data/logger.

3 Parameters must be monitored continuously and reported to the APCD on a semi-annual basis.

4 Reading a minimum of once every week at evenly spaced intervals.

5 Parameter monitoring must be telemetered to the APCD

6 Each emissions monitoring instrument must be performance certified annually (or more often if this is deemed necessary by the APCD) in accordance with 40 CFR 60 Appendix B and 40 CFR 50 Appendix E, or equivalent method approved by the APCD. Flow meter shall be calibrated per the CEMs Plan.

7 Monitoring and reporting frequency per APCD CEMS Protocol and Exxon's APCD-approved CEMS Plan.

8 Telemetry may be required in the future.

Table 10.1-3

EMISSION AND PROCESS PARAMETER MONITORING AND REPORTING REQUIREMENTS FOR THE OIL TREATING PLANT, THERMAL OXIDIZER and TRANSPORTATION TERMINAL [1, 6]

Location Number	Test Location	Parameter Monitored	Monitoring Method
1	Dry Oil Produced	Volume	Process Flow Meter [2, 3, 5]
2	Waste Gas to Thermal Oxidizer	Flow Rate	Process Flow Meter [2, 3, 5]
		Composition	Sample [4]
3	Pilot, Purge and Acid Gas Enrichment Fuel Gas to Thermal Oxidizer	Flow Rate	Process Flow Meter [3, 5]
4	Thermal Oxidizer	Combustion Temperature	Thermocouple or Optical Pyrometer [2, 3]
-	Oil Storage Tanks and Rerun Tanks	Tank Pressure Safety Valve Actuations	Pressure Transmitter [2, 3] PSV Seat Position Transmitter [2, 3]

1 Parameters in addition to those listed must be monitored continuously if deemed necessary by the APCD.

2 Parameter raw data must be permanently recorded using: (a) strip chart or circular chart and/or (b) computer or data/logger.

3 Parameters must be monitored continuously and reported to the APCD on a semi-annual basis.

4 Initial sample taken at 3 minutes, 27 minutes and 53 minutes into flaring event with additional samples taken at successive continuous one hour intervals. Composition analysis will include determination of the following: heating value, ultimate analysis, and sulfur content.

5 Each emissions monitoring instrument must be performance certified annually (or more often if this is deemed necessary by the APCD) in accordance with 40 CFR 60 Appendix B and 40 CFR 50 Appendix E, or equivalent method approved by the APCD. Flow meter shall be calibrated per the CEMs Plan.

6 Telemetry may be required in the future.

Table 10.1-4

SPECIFIC CEMs PARAMETERS TO BE
TELEMETERED TO THE DATA ACQUISISTION SYSTEM (DAS)

Plant	Location	Parameter Monitored	Items Telemetered
CPP	Exhaust Stack	NO_x [1]	lb/hr; ppmvd at 3% oxygen
	Exhaust Stack	CO	lb/hr; ppmvd at 3% oxygen
	Exhaust Stack	Temperature	°F
	Exhaust Stack	Flow Rate	million scfh
	SCR Inlet	Temperature	°F
	n/a	Mode	Operating Mode (GT Only, HRSG Only, Tandem, Startup/Shutdown)
SGTP	WGI Exhaust Stack	NO_x [1]	lb/hr; ppmvd at 2% oxygen
	WGI Exhaust Stack	SO_x [2]	lb/hr; ppmvd at 2% oxygen
	WGI Exhaust Stack	Temperature	°F
	WGI Exhaust Stack	Flow Rate	thousand scfh

Notes

1 NO_x as NO_2
2 SO_x as SO_2

10.2 SOURCE TESTING REQUIREMENTS

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Table 10.2-1

SOURCE TESTING REQUIREMENTS FOR THE COGENERATION FACILITY [3, 4]

Location Number	Test Location	Parameter Monitored	Test Method [1]
1	Exhaust Stack [3]	NO_x; O_2	CARB Method 100
		CO; CO_2	CARB Method 100; EPA Method 3
		NH_3	BAAQMD St-1B [2]
		ROC; THC	EPA Method 18
		PM; PM_{10} [5]	EPA Methods 1, 2, 5
		Flow Rate	EPA Method 2
		Moisture	EPA Method 4
2	SCR Inlet	NO_x; O_2	CARB 100
		Temperature	EPA Method 2
3	Bypass Stack [6]	NO_x; O_2	CARB 100
		Temperature	EPA Method 2
		Flow Rate, Moisture, CO	EPA Method 2
4	Turbine Fuel Feed	Flow Rate	Process Flow Meter
5	Turbine Steam Injection	Flow Rate	Process Flow Meter
6	HRSG Fuel Feed	Flow Rate	Process Flow Meter
7	Cogeneration Plant Turbines	Electrical Output	Plant Meters
8	Waste Heat Recovery Unit	Steam Production Rate	Process Flow Meter
9	Ammonia Injection Point	NH_3 Feed Rate	Process Flow Meter
--	Facility	Ambient Temperature	n/a
		Barometric Pressure	n/a
		Relative Humidity	n/a

1 Equivalent source test methods may be used if approved by the APCD.

2 EPA or CARB methods are not available. The method used is subject to APCD approval.

3 Source testing shall be performed annually, except for particulate matter (PM and PM_{10}), for which testing is required on a triennial basis.

4 Source testing shall be performed at or near maximum load conditions unless otherwise directed by the APCD.

5 For compliance purposes, Exxon may choose to assume that all PM is equal to PM_{10}.

6 Bypass stack testing to be performed when requested by the APCD.

Table 10.2-2

SOURCE TESTING REQUIREMENTS FOR THE
STRIPPING GAS TREATING PLANT [3, 4]

Location Number	Test Location	Parameter Monitored	Test Method [1]
1	Incinerator Exhaust [5]	NO_x; O_2	CARB Method 100
		SO_2	EPA Method 6 or CARB 100
		CO; CO_2	CARB Method 100; EPA Method 3
		NH_3	BAAQMD St-1B [2]
		H_2S; TRS	EPA Method 16 or 16A
		ROC; THC	EPA Method 18 or 25A
		PM; PM_{10} [6]	EPA Methods 1, 2, 5
		Temperature	EPA Method 2
		Flow Rate	EPA Method 2
		% Moisture	EPA Method 4
2	Inlet Gas - Platform Gas	Flow Rate	Process Flow Meter
	- Stripping Gas	Flow Rate	Process Flow Meter
3	Assist Gas Fee to Incinerator	Flow Rate	Process Flow Meter
4	Sweet Gas from Amine Unit	H_2S	EPA Method 11
5	Sulfur Production	Rate	Tank Gauging
6	Tail Gas Feed to Incinerator	H_2S	APCD-approved methods [2]
7	Acid Gas to Sulfur Recovery	H_2S	APCD-approved methods [2]

1 Equivalent source test methods may be used if approved by the APCD.

2 EPA or CARB methods are not available. The method used is subject to APCD approval.

3 Source testing shall be performed annually, except for particulate matter (PM and PM_{10}), for which testing is required on a triennial basis.

4 Source testing shall be performed at or near maximum load conditions unless otherwise directed by the APCD.

5 Exxon shall also test for thermal De-NOx efficiency

6 For compliance purposes, Exxon may choose to assume that all PM is equal to PM_{10}.

Table 10.2-3

SOURCE TESTING REQUIREMENTS FOR THE
EQUALIZATION TANK [2, 3]

Location Number	Test Location	Parameter Monitored	Test Method [1]
1	Inlet to Venturi Caustic Scrubber	H_2S; TRS	EPA Method 16 or 16A
		ROC; THC	EPA Method 18 or 25A
		Temperature	EPA Method 2
		Flow Rate	EPA Method 2
		% Moisture	EPA Method 4
2	Outlet from Venturi Scrubber	H2S; TRS	EPA Method 16 or 16A
		ROC; THC	EPA Method 18 or 25A
		Temperature	EPA Method 2
		Flow Rate	EPA Method 2
3	Outlet from Carbon Canister	ROC; THC	EPA Method 18 or 25A
		Temperature	EPA Method 2
		Flow Rate	EPA Method 2
4	Venturi Scrubber	Caustic Circulation Rate	Process Meter
		Caustic pH	ASTM-approved

1 Equivalent source test methods may be used if approved by the APCD.

2 Source testing shall be performed annually.

3 Source testing shall be performed at or near maximum load conditions unless otherwise directed by the APCD.

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10.3 EMISSION CALCULATION DOCUMENTATION

LAS FLORES CANYON

This attachment contains emission calculation spreadsheets and other supporting calculations used for the emission tables in Section 5 and permit conditions in Section 9. Refer to Section 4 for the general equations, assumptions and emission factor basis used.

10.4 TANKS, SUMPS AND SEPARATORS LIST

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10.5 List of Insignificant Emission Units

1. Diesel-fired internal combustion engine (216 bhp)driving an emergency firewater pump.
2. Diesel-fired internal combustion engine (221 bhp)driving an emergency firewater pump.
3. Diesel-fired internal combustion engine (230 bhp)driving an emergency floodwater pump.
4. Portable Abrasive blasting equipment (does not include associated IC engine).
5. Diesel fuel storage tanks and containers.
6. Lube oil storage tanks and containers.
7. Single pieces of degreasing equipment that have a liquid surface area of less than one square foot and where the total aggregate liquid surface area of all such units at the stationary source is less than 10 square feet.

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10.6 NSPS COMPLIANCE REPORT

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10.7 IDS DATABASE EMISSION TABLES

Table 10.7-1
Permitted Potential to Emit (PPTE)

	NO_X	ROC	CO	SO_X	TSP	PM_{10}
PTO 5651 – Las Flores Canyon						
lb/hour	170.67	67.03	196.75	12.77	15.31	13.02
lb/day	919.87	871.29	532.17	224.73	283.85	232.12
tons/qtr	26.57	17.40	22.33	11.68	12.09	9.78
tons/year	99.13	68.87	87.12	40.70	47.82	38.56

Table 10.7-2
Facility Potential to Emit (FPTE)

	NO_X	ROC	CO	SO_X	TSP	PM_{10}
PTO 5651 – Las Flores Canyon						
lb/hour	170.67	67.03	196.75	12.77	15.31	13.02
lb/day	919.87	871.29	532.17	224.73	283.85	232.12
tons/qtr	26.57	17.40	22.33	11.68	12.09	9.78
tons/year	99.13	68.87	87.12	40.70	47.82	38.56

Table 10.7-3
Facility Net Emission Increase Since 1990 (FNEI-90)

	NO_X	ROC	CO	SO_X	TSP	PM_{10}
PTO 5651 – Las Flores Canyon						
lb/hour	170.67	67.03	196.75	12.77	15.31	13.02
lb/day	919.87	871.29	532.17	224.73	283.85	232.12
tons/qtr	26.57	17.40	22.33	11.68	12.09	9.78
tons/year	99.13	68.87	87.12	40.70	47.82	38.56

Table 10.7-4
Facility Exempt Emissions (FXMT)

	NO_X	ROC	CO	SO_X	TSP	PM_{10}
PTO 5651 – Las Flores Canyon						
tons/year	9.40	6.64	2.03	0.68	1.58	0.80

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10.8 SOURCE TESTS RESULTS SUMMARY

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10.9 PHASE III OIL/WATER EQUIPMENT LIST/APPENDIX 5.1 – BACT TABLE

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10.10 EQUIPMENT LIST (Tables Q and P)

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