air pollution control district
SANTA BARBARA COUNTY

PERMIT to OPERATE No. 15455 - R1

and

PART 70 OPERATING PERMIT No. 15455

GAVIOTA OIL HEATING FACILITY

POINT ARGUELLO PROJECT STATIONARY SOURCE

GAVIOTA OIL HEATING FACILITY
17100 CALLE MARIPOSA REINA, GAVIOTA, CA

<u>EQUIPMENT OPERATOR</u>

Freeport-McMoRan Oil and Gas, LLC (FM O&G)

<u>OWNERSHIP</u>

Harvest Energy, Inc., Whiting Oil and Gas Corporation, Arguello Inc., Anadarko US Offshore Corporation, Koch Exploration Company, LLC, Devon Energy Production Company, LP

Santa Barbara County
Air Pollution Control District

February 2024

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ABBREVIATIONS/ACRONYMS

AP-42	USEPA's *Compilation of Emission Factors*
District	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
dscf	dry standard cubic foot
E100	emitters less than 100 ppmv
E500	emitters less than 500 ppmv
EQ	equipment
ESE	entire source emissions
EU	emission unit
°F	degree Fahrenheit
FID	facility identification
gal	gallon
gr	grain
HAP	hazardous air pollutant (as defined by CAAA, Section 112(b))
H_2S	hydrogen sulfide
I&M	Inspection & Maintenance
ISO	International Standards Organization
k	kilo (thousand)
l	liter
lb	pound
lbs/day	pounds per day
lbs/hr	pounds per hour
LACT	Lease Automatic Custody Transfer
LPG	liquid petroleum gas
GOHF	Gaviota Oil Heating Facility
M	mega (million)
MACT	Maximum Achievable Control Technology
MM	million
MW	molecular weight
NAR	Nonattainment Review
NGL	natural gas liquids
NG	natural gas
NH_3	ammonia
NSPS	New Source Performance Standards
NESHAP	National Emissions Standards for Hazardous Air Pollutants
O_2	oxygen
OCS	outer continental shelf
PM	particulate matter
PM_{10}	particulate matter less than 10 microns
$PM_{2.5}$	particulate matter less than 2.5 microns

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)
SIP	State Implementation Plan
SSID	stationary source identification
STP	standard temperature (60°F) and pressure (29.92 inches of mercury)
THC, TOC	total hydrocarbons, total organic compounds
tpq, TPQ	tons per quarter
tpy, TPY	tons per year
TVP	true vapor pressure
USEPA	United States Environmental Protection Agency
VE	visible emissions
VRS	vapor recovery system
w.c.	water column

1.0 Introduction

1.1 Purpose

General. The Santa Barbara County Air Pollution Control District ("District) is responsible for implementing all applicable federal, state and local air pollution requirements which affect any stationary source of air pollution in Santa Barbara County. The federal requirements include regulations listed in the Code of Federal Regulations: 40 CFR Parts 50, 51, 52, 55, 60, 61, 63, 68, 70 and 82. The State regulations can be found in the California Health & Safety Code, Division 26, Section 39000 et seq. The applicable local regulations can be found in the District's Rules and Regulations.

Santa Barbara County is designated as a non-attainment area for the state PM_{10} ambient air quality standard. On July 1, 2020, the County achieved attainment status for the ozone state ambient air quality standards, however in February 2021, the California Air Resources Board took action at a public hearing to change Santa Barbara County's designation from attainment to nonattainment for the State ozone standard. This change was based on data measured at multiple locations in the County for the 3-year period from 2017 to 2019. The California Office of Administrative Law (OAL) finalized the designation change on September 27, 2021.

Part 70 Permitting. This is a combined permitting action that covers both the Federal Part 70 permit (*Part 70 Operating Permit No. 15455*) as well as the State Operating Permit (*Permit to Operate No. 15455*). The previous PT-70 operating permit, PT-70 PTO 5704-R5, was cancelled in June 2020 after permanent decommissioning of the GOHF facility. After cancellation of the permit, it was determined that a single fire-water pump remained on-site and would remain in operation, as a result this engine was issued a District permit under PTO 15455. It was later determined that the GOHF facility remains as a major source because it remained as part of the Point Arguello Stationary Source, which exceeds the major source threshold based. As a result, this permit for the fire-water pump constitutes the first re-issuance of the PT-70 permit for the GOHF facility. This permit also incorporates any Part 70 minor modifications since the last renewal and is being issued as a combined Part 70 and District reevaluation permit.

The GOHF is a part of the *Point Arguello Project* stationary source (SSID = 1325), which is a major source for VOC[1], NO_x, CO and Greenhouse gasses. Conditions listed in this permit are based on federal, state or local rules and requirements. Sections 9.A, 9.B and 9.C of this permit are enforceable by the District, the USEPA and the public since these sections are federally enforceable under Part 70. Where any reference contained in Sections 9.A, 9.B or 9.C refers to any other part of this permit, that part of the permit referred to is federally enforceable.

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

[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.

the permittee, the regulatory agencies and the public to assess compliance.

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

The facility's potential to emit has been estimated; however, the greenhouse gas PTE is not an emission limit. The facility will not become subject to emission limits for GHGs unless a project triggers federal Prevention of Significant Deterioration requirements under Rule 810.

1.2 Facility/Project/Stationary Source Overview

Note: The equipment and processes provided in Section 1.2 below is a description of the original GOHF facility processes and equipment. With the exception of the emergency firewater pump, all equipment been decommissioned and depermitted as of the issuance of this permit renewal.

1.2.1 Facility: The GOHF was originally designed and operated as an oil and gas processing facility for crude and natural gas produced from OCS platforms Hermosa, Hidalgo and Harvest. Due to contractual requirements to reduce emissions and declining field production, several significant modifications were made to the GOHF in 2002 to extend the economic life of the project. These modifications consisted of the de-permitting of all gas processing equipment and the 'removal from service[2]' of much of the oil processing equipment. With the exception of a small volume of natural gas delivered to the GOHF through existing pipelines for use as fuel gas, platform natural gas production that was formerly processed at the GOHF was subsequently reinjected at the platforms or utilized as platform fuel. The only treatment occurring at the GOHF following the above modifications was the heating of the crude to pipeline quality specifications prior to delivery to the All American Pipeline Pump Station (AAPL) located adjacent to the GOHF.

Project: The GOHF is part of the Point Arguello Project that produces oil and gas from the Point Arguello Field located in the Santa Maria Offshore Basin. The District originally issued ATC 5704 on February 6, 1986 with oil and gas production commencing in 1989 from offshore platforms Hermosa, Hidalgo and Harvest. Each of these platforms produced crude oil that was shipped by pipeline to the GOHF through a 24-inch crude oil transmission line. Facility operations were subsequently suspended in May 2015 due to the failure of AAPL's pipeline that transports crude oil from the Gaviota Oil Heating Facility to oil refining facilities.

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[2] Equipment 'removed from service' is equipment that has been taken out of service but not de-permitted. Permit condition 9.C.31 provides details regarding the restrictions involved in operating this equipment.

Stationary Source: GOHF is part of the *Point Arguello Project* stationary source (SSID = 1325). The *Point Arguello Project* stationary source consists of the following four facilities:

- GOHF (FID= 1325)
- Platform Harvest (FID= 8013)
- Platform Hermosa (FID= 8014)
- Platform Hidalgo (FID= 8015)

The GOHF is the primary facility addressed in this permit. Each platform is subject to individual permits pursuant to OCS regulation 40 CFR Part 55. The platforms are addressed in this permit only with respect to lead agency (Santa Barbara County Planning and Development) requirements as outlined in the various agreements and contracts entered into between FM O&G, the county and the District. Individual Part 70 permits have been issued for each platform.

1.2.2 Facility New Source Review Overview: Since the issuance of the initial Part 70 operating permit for thew GOHF on April 19, 2001, the following permitting actions occurred.

PERMIT TYPE	ISSUE DATE	DESCRIPTION
ATC/PTO 10332	08/23/01	Installation of H_2S Sensors at the GOHF.
ATC/PTO 10332-01	12/12/01	Modification to ATC/PTO 10332 (revision to monitoring requirements).
ATC/PTO 10332-02	06/27/02	Modification to ATC/PTO 10332-01 (Changes to the number and manufacturer of the H_2S sensors).
ATC 10394	03/23/01	Installation of fuel gas H_2S scavenging equipment.
ATC 10439	05/25/01	Reallocation of ERCs.
ATC 11034	09/15/03	Installation of a Temporary Flare.
ATC/PTO 11203	05/20/04	Modification to Turbine Starter Engines allowable run times.
ATC/PTO 11816	10/31/05	Increase H_2S concentration of GOHF fuel gas.
ATC 11211-01	01/27/06	Modification to ATC 11211.
PTO 5704-06	12/04/01	Modification to VEE Condition 9.B.2.
PTO 5704-07	07/10/03	Revision to MERC ERCs.
PTO 5704-08	10/16/03	Modification to Turbine Starter Engine Use.
PTO 5704-09	02/23/04	Removal of permit condition restricting use of Tank T-1 for emergency use only.
PTO 5704-10	02/03/05	Remove Sigma VWS from the Carpinteria Ambient Monitoring Station.
Trn O/O 5704-05	10/06/05	Project Change of Ownership.
PTO 11513	12/19/05	Installation of one emergency firewater pump due to the loss of the Rule 202.F.1.d exemption.
PTO 5704-12	06/28/07	Replacement of MERC emission reduction credits with credits generated by the installation of emission controls on gas operated turbines on Platform Harvest.
PTO 5704-13	03/13/07	Remove 100-day use restriction from tank T-2.

PERMIT TYPE	ISSUE DATE	DESCRIPTION
Trn O/O 5704-06	06/27/07	Change of Project Operator.
ATC 12948	11/19/08	Flare Replacement.
ATC 14128	10/07/2013	Replace Ammonia Control System.
PTO 5704-14	01/07/2014	Correct fugitive component counts.
PTO 15455	6/11/2020	One Emergency Firewater Pump.

1.3 Emission Sources

The primary sources of project emissions are an internal combustion engine and solvents.

Internal Combustion Engines. Internal combustion engines include one (1) diesel ICE-driven emergency firewater pump.

Solvents. Solvents are used periodically for maintenance activities.

Section 4 of this permit provides the District's engineering analysis of these emission sources. Section 5 of this permit describes the allowable emissions from each permitted emissions unit and lists the potential emissions from non-permitted emission units.

1.4 Emission Control Overview

There are no emission controls in use at the GOHF.

1.5 Offsets/Emission Reduction Credit Overview

Emissions from the Point Arguello Project must be offset pursuant to the District's New Source Review regulation. Specifically, during the original permitting of this project, offsets were required for ROC and NO_x for the GOHF emissions as well as the platform emissions. The agreement entitled "*Contract for Implementation of Conditions E-4, E-7 and E-9 of the Chevron Point Arguello Project Preliminary Development Plan No. 83-DP-32-CZ*", (signed August 19, 1985, and amended on September 8, 1992), hereinafter referred to as the "Arguello/District Contract" details the emission offsets that were originally required for the project. A copy of this contract is located in the project file.

1.6 Part 70 Operating Permit Overview

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

1.6.2 Insignificant Emissions Units: The criteria for treating a unit as insignificant are that regulated air pollutants emitted from the unit, excluding HAPs, are less than 2 tons per year potential to emit and that any HAP regulated under section 112(g) of the Clean Air Act does not exceed 0.5 ton per year potential to emit. Insignificant activities must be listed in the Part 70 application with supporting calculations. Applicable requirements may apply to insignificant units.

1.6.3 Federal Potential to Emit: The federal potential to emit ("PTE") of a stationary source does not include fugitive emissions of any pollutant, unless the source is: (1) subject to a federal NSPS/NESHAP requirement as of August 7, 1980, or (2) included in the 29-category source list specified in 40 CFR 51.166 or 52.21. The federal PTE does include all emissions from any insignificant emissions units. (*See Section 5.0 for the federal PTE for this source).*

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

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. FM O&G has not made any requests for alternative operating scenarios.

1.6.6 Compliance Certification: Part 70 permit holders must certify compliance with all applicable federally enforceable requirements including permit conditions. Such certification must accompany each Part 70 permit application and be re-submitted annually on or before March 1st or on a more frequent schedule specified in the permit. Each certification is signed by the "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 may be re-opened in the future to address new monitoring rules, if the permit is revised significantly prior to its first expiration date.

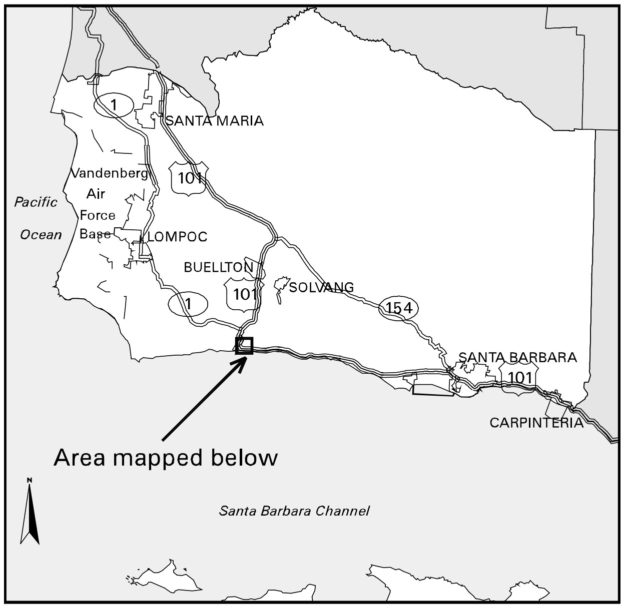
1.6.8 Hazardous Air Pollutants ("HAPs"): The requirements of Part 70 permits also regulate HAPs emissions from major sources through the imposition of maximum achievable control technology ("MACT"), where applicable. The federal PTE for HAP emissions from a source is computed to determine MACT or any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

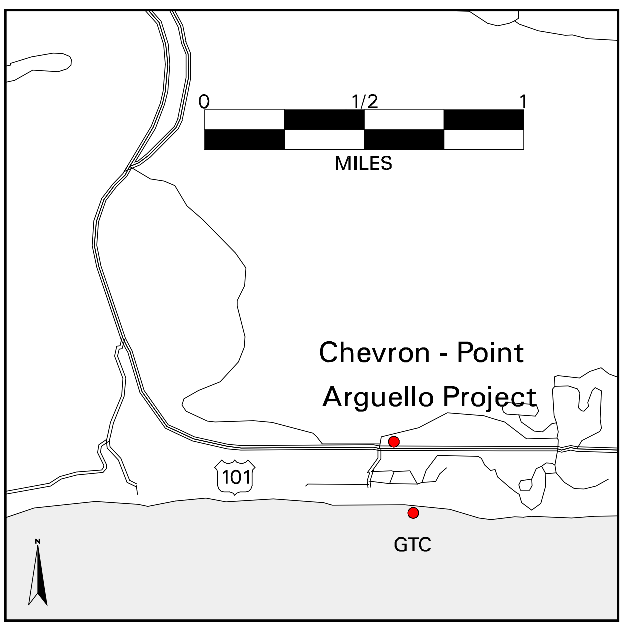
1.6.9 Responsible Official: The designated responsible official and his mailing address is:

Todd Cantrall, Vice President of Operations
Freeport-McMoRan Oil & Gas, LLC
21 Waterway Ave. Suite 250
The Woodlands, Texas 77380-3121

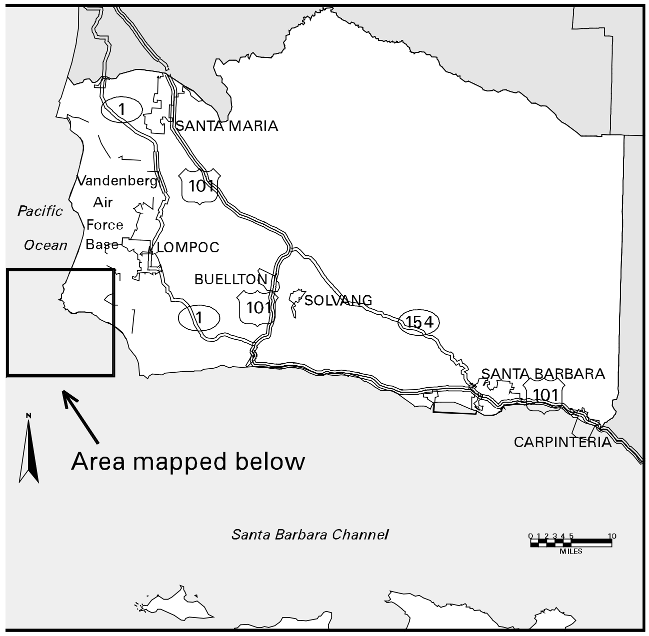
Figure 1.1 - Location Map

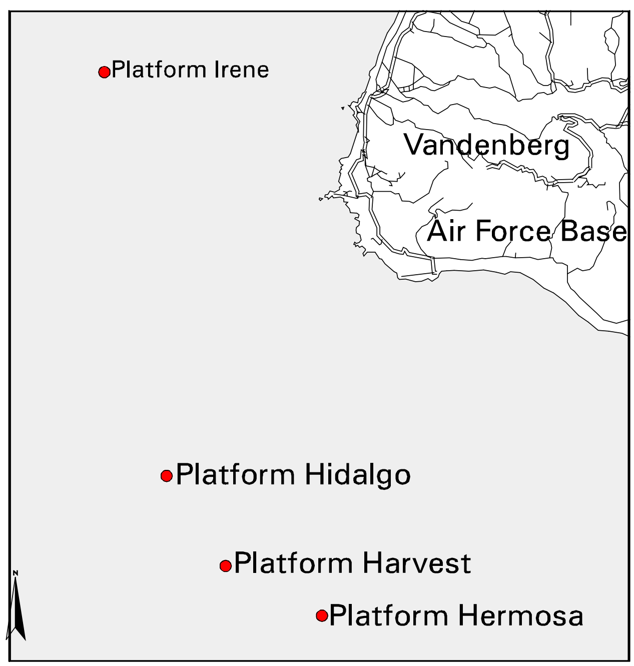
Point Arguello Project - Onshore





Point Arguello Project - Offshore





2.0 Description of Proposed Project and Process Description

2.1 Project and Process Description

2.1.1 Project Ownership

The Point Arguello Companies partnership is the owner and FM O&G is the operator of the GOHF. Arguello, Inc., wholly owned by FM O&G, is a member of the Point Arguello Companies partnership.

2.1.2 Geographic Location

The GOHF is located approximately 28 miles west of the City of Santa Barbara at 17100 Calle Mariposa Reina. The facility sits on a 56.9-acre parcel of land on the north side of U.S. highway 101. See Figure 1.1 (Location Map) for additional detail.

2.1.3 Operations History

Permit to Operate 5704 was issued for the GOHF on March 26, 1996. That permit authorized the processing of up to 125,000 barrels per day of wet oil; 60 million standard cubic feet per day (MMSCFD) of gas; 531,286 SCFD (based on 20 long tons) of H_2S in the amine units; and, sour gas containing up to 20,000 ppmv H_2S. The onsite cogeneration plant was permitted to generate 14.0 megawatts of electricity. As discussed below, significant reductions in these permitted throughput capacities commenced in 1998.

The first significant modification was authorized under ATC/PTO 9933 (July 14, 1998) to satisfy the requirements of the Third Amendment to the Ozone Mitigation Agreement ("OMA") dated May 20, 1997. The OMA required the reduction in NO_x potential to emit ("PTE") and associated ROC emissions from fuel burning equipment by 30 tons per year ("tpy") at the GOHF. The OMA also required a reduction of in-service fugitive emission components at GOHF to achieve an actual emission reduction of 20 tpy of non-ethane ROC emissions.

To achieve the required NO_x PTE and ROC fugitive emission reductions, specific equipment items were removed from service. Two oil trains, one amine plant, one V-1001 and one F-1000 unit were removed from service but remained on permit and were allowed to be returned to service provided similar equipment is simultaneously shutdown or the permit is modified to increase emission limits. One cogeneration plant turbine and two fuel gas systems were also removed from service.

Additional equipment removed from service under ATC/PTO 9933 was V-1B, 5 V-21s, P-36, the butane line, butane loading rack, PCV-T30, Plant 17, 3 FE-V2-5s, T-5B, V-1500, P-1500A&B, and two V-20s). Removal from service of the above-mentioned equipment effectively de-rated the facility so that operations were limited to one oil train, one amine plant, one V-1001 unit and one F-1000 unit. The facility throughput limit was reduced to 62,500 barrels per day of wet oil; 30 million standard cubic feet per day (MMSCFD) of gas; and, 265,643 SCFD (based on 10 long tons) of H_2S in one amine unit. The cogeneration plant electrical power generation was reduced to 10.5 megawatts.

On October 7, 1998, Authority to Construct/Permit to Operate 9940 was issued and authorized the GOHF modifications referred to as "Reconfiguration I". The GOHF was reconfigured to the extent that, with the exception of a small volume of natural gas delivered to the GOHF for plant fuel use, gas was no longer shipped to the GOHF for processing and was reinjected at the platform or used as fuel. Primary processing of the crude oil was performed on Platforms Harvest and Hermosa. The only processing operations occurring after these modifications at the GOHF was the heating of the crude to pipeline specifications and chemical treatment of vapors to reduce sulfur emissions.

ATC/PTO 9940 also included the routing of the vapor recovery unit emissions to the flare since the gas processing facilities could no longer accept this gas. The H_2S content of these vapors required the injection of H_2S reducing chemical to meet District rule and SO_x emission limits.

The gas processing facilities were formally de-permitted, thereby prohibiting the processing of natural gas at the plant, under Authority to Construct/Permit to Operate 10199 (April 12, 2000).

On June 27, 2007, the operator of the facility changed from Arguello, Inc. to FM O&G. All lead agency requirements and contracts that applied to Arguello, Inc. continue to apply to FM O&G.

2.1.4 Operations/Processing Facilities

Note: This section provides the details regarding the equipment and operations at this facility permitted under ATC 5704 for the original project. Oil and gas operations at this facility have ceased. The only equipment in service is the emergency firewater pump. All other equipment formerly at this facility has been decommissioned and depermitted.

Crude Oil Heating. Crude oil from the offshore platforms transported via the DOT regulated PAPCO pipeline enters the GOHF at about 59-70°F and 70 psig. The oil is metered at one of the three oil LACT units for pipeline leak detection purposes. Oil leaving the oil LACT unit enters the free water knockout, V-1A, which provides back pressure control and surge capacity. The free water knockout operates at about 100 psig and relieves to the flare at 160 psig. The pressure in V-1A is maintained by fuel gas makeup. The level in the vessel is automatically controlled to minimize the need for fuel gas makeup and to prevent unnecessary flare emissions. Typical operations bypass V-1A completely.

Oil leaving V-1A and the vessel bypass is heated in oil heat exchanger, E-3B; from about 59 to 70°F up to approximately 90°F. Steam generated at the onsite cogeneration plant provides the heating medium at E-3B. Hot crude oil leaving E-3B is sent directly to the shipping tank T-1. Oil may also be diverted to the 40,000-barrel capacity reject oil tank, T-2, through a bypass line downstream of E-3B. Oil is then moved from tank T-1 using pumps 601-A/B/C/D through heat exchanger E-3C and then routed at the pipeline specified temperature of 120-130°F to the All American Pipeline. The oil goes through one of two oil LACT units for metering.

Tank T-2 normally serves as a reject oil tank. The level in tank T-2 is normally kept at a minimum. The tank has a minimum 4 foot depth of water at all times. The tank primarily receives the following streams: full flow relief-valves upstream of the wet LACT are set at 250 psig to protect equipment from overpressure when there is a sudden valve closure or blockage downstream. The full flow relief valves allow oil from the pipeline to divert to tank T-2. The following may also be diverted to tank T-2: water accumulated at the bottom of V-1A; heated oil diverted manually downstream of E-3B; oil skimmed from tank T-25; and dry oil not meeting pipeline specification at the dry oil LACT unit and fluids from V-50 (oil plant flare header knockouts) using P-25 A and B and pigging fluids.

From tank T-2, recycle oil pumps P-5A and P-5B are used to rerun skimmed or reject oil to the inlet of V-1A. Water may also be pumped to V-1A and blended with the inlet oil to the extent the oil meets pipeline specifications.

Tank T-25 is a 1,300-barrel capacity tank that collects primarily skimmed oil and process drainage. In the tank, water is separated from oil for disposal while oil is returned to the process. Main feed streams to T-25 are the oily water sewer system, oil skimmed from run-off impoundment pond, oil skimmed from water tanks, impound water that does not meet discharge specifications, and boiler blowdown when the raw water treating unit is not in service. Tank T-25 is skimmed regularly. Skimmed oil is pumped to T-2 using pumps P-50A/B and then to the inlet of V-1A for reprocessing. Water in T-25 is also pumped by P-50A/B to tank T-8 for further removal of oil. It is then pumped through polishing filters and is pumped by pump P-61 into an injection well for disposal.

The T-4 wastewater tank is currently out of service but remains on permit.

C*rude Tank Blanketing and Vapor Recovery*. Sweet natural gas is supplied to GOHF primarily from Platform Hermosa through the PANGL pipeline. Gas from the pipeline enters the plant through vessel V-1000 to drop out any residual moisture that accumulates in the pipeline. Gas is also supplied on a backup basis by the Southern California Gas Company pipeline. This natural gas is used as fuel for the cogeneration plant and a blanket gas for the plant tank battery.

The VRU collects vapors from the oil and wastewater tanks T-1, T-2, T-8 and T-25. VRU compressors, K-3 and K-3A, and fuel gas makeup maintain the VRU header pressure at about 1.2-inches water column. Tank vapors are routed through knockout vessel V-51, compressed by the VRU compressors and then discharged into the fuel gas recovery vessels V-1001A and B.

Fuel Gas Recovery System. Vessels V-1001A and B are used to store vapors recovered by the VRU system. V-1001A is the primary storage vessel with operating pressure of 60 psig. Gases in this vessel are routed to the suction of compressors K-1230A and B. The compressors raise this gas stream to 275 psig that is then blended into the fuel gas stream for the cogeneration plant. The secondary vessel, V-1001B, can also be connected to the PANGL pipeline and used up to an operating pressure of 275 psig when gas pigging operations are occurring. Gases from V-1001B are also routed to the suction side of K-1230A and B.

Flare Relief System. The flare system collects and combusts vapors from oil and produced water tanks T-1, T-2, T-8 and T-25 that are served by the VRU system that are not reused for fuel gas, vapors released by pressure safety valves tied into the flare system, and vapors routed to the flare header from plant equipment degassing and inerting activities.

The flare is steam assisted and is equipped with an igniter system and pilot flame, which is always lit. The steam cools the flare tip and induces oxygen within the combustion zone to ensure complete combustion to reduce the formation of smoke and the release of volatile organic compounds. Purge gas (fuel gas or nitrogen) provides a continuous gas flow through the flare stack to prevent ambient air ingress into the flare system. Vapors routed to the flare go through knockout vessels, V-7120 A&B, and as needed, are treated with H_2S scavenging chemicals to reduce the sulfur content in the flared gas.

The base of the flare is equipped with two water seals to provide two levels of backpressure. In this configuration, the water in at least one of the seals must be removed for a flaring event to occur. The water seal located on the 6-inch diameter bypass line provides 21 inches of water column back-pressure. The second water seal is located on the 42-inch diameter main flare line in the flare base and provides 30 inches of water column backpressure.

The volume of gas flared is metered. The gas composition is measured by a gas chromatograph. The H_2S content is also measured by an H_2S analyzer, gas chromatograph or by color indicating tubes, as appropriate.

Cogeneration Plant. Cogeneration Plant, comprised of five 3.5 MW gas turbine driven generators manufactured by Allison (Model number 501-KB), provides electrical power and steam to meet facility needs. The turbine exhaust gas is routed through its respective heat recovery steam generator (HRSG) to recover heat and generate steam for the plant. The HRSGs are also equipped with gas burners to provide supplemental steam capacity for the plant. Exhaust gases from each HRSG are routed to a common duct, which is also equipped with an in-line duct burner and a non-fired waste heat recovery boiler.

Each turbine is equipped with water injection to reduce NO_x emissions in the combustion chamber. Flue gas from the turbines and the HRSG is combined and routed through a selective catalytic reduction (SCR) unit. Ammonia (NH_3) is injected to convert nitrogen oxides to nitrogen, thus reducing stack emissions. The catalyst is maintained at the optimum operating temperatures by heat from the turbines or the SCR burner. Currently, any three turbines, any two HRSGs and the SCR burner are permitted to operate simultaneously.

The fuel gas requirements for the GOHF are met by the shipment of natural gas from platform Hermosa and the injection of vapor recovery vapors into the fuel gas system. The fuel can be treated with H_2S scavenging chemical to ensure that it meets the BACT limit of 4 ppmv as H_2S.

The GOHF power output exceeds the facility electrical power needs. Surplus power is sold to a utility company and steam produced by the plant's HRSG is used to heat oil at E-3B.

Desalination Plant. Fresh water for GOHF is produced by seawater desalination. Seawater is pumped to the plant, filtered and processed through two of three reverse osmosis trains. About 200 gallons per minute of freshwater is produced. This water is chlorinated for use as drinking water or softened for use as steam generator feed water. Part of the water is further purified to produce process water. The remaining portion is deionized and used for injection into the gas turbines for NO_x emission control.

3.0 Regulatory Review

3.1 *Rule Exemptions*

⇒ District Rule 202 (*Exemptions to Rule 201*): FM O&G has requested 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 were either approved by the District or may apply to individual equipment units meeting the exemption criteria:

- Section D.8 for routine repair or maintenance activities that meet the specified criteria in this provision.

- Section D.14 for application of architectural coatings in the repair and maintenance of a stationary source.

- Section 202.U.2 for solvent application equipment and operations if the degreasing equipment contains unheated solvent and has a liquid surface area of less than 1 square foot and that the cumulative surface area of all the degreasers is less than 10 square feet.

- Section 202.U.3 for wipe cleaning using solvents as long as the solvents meet other applicable requirements and the use does not exceed 55 gallons per year.

⇒ District Rule 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. The firewater pump engine is a compression ignition emergency standby engine, therefore it is exempt from Rule 333 per Section B.1.d.

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 GOHF was originally permitted in February 6, 1986 under District Rule 205.C. That rule was superseded by District Regulation VIII (*New Source Review*) in April 1997. Regulation VIII was revised in August 2016. Compliance with PTO 5704 requirements and Regulation VIII ensures that this facility will comply with federal NSR requirements.

3.2.2 40 CFR Part 63 Subpart ZZZZ {NESHAP}: Subpart ZZZZ applies to owners and operators of stationary reciprocating IC engines (RICE). For area sources of HAP emissions, stationary RICE are “existing” if construction or reconstruction commenced before June 12, 2006. Engines that are not categorized as existing are considered “new”.

The emergency diesel-fired IC engine at the GOHF was installed prior to June 12, 2006 and is therefore considered existing for the purpose of this subpart.

Operating requirements for the emergency firewater pump are:

(1) change the oil and filter every 500 hours of operation or annually, whichever comes first;
(2) inspect the air cleaner every 1,000 hours of operation or annually, whichever comes first; and;
(3) inspect all hoses and belts every 500 hours of operation or annually, whichever comes first.

In lieu of changing the oil, FM O&G may instead conduct an oil analysis. The analysis measures the Total Base Number, the oil viscosity, and the percent water content. The oil and filter will be changed if any of the following limits are exceeded:

(1) The tested Total Base Number is less than 30 percent of the Total Base Number of the oil when new;
(2) The tested oil viscosity has changed by more than 20 percent from the oil viscosity when new;
(3) The tested percent water content (by volume) is greater than 0.5 percent.

The Total Base Number is the amount acid necessary to neutralize the base reserve in one gram of oil. It is expressed in the equivalent number of milligrams of potassium hydroxide and is a measure of the ability of the oil to neutralize acids created during combustion. If FM O&G chooses to change the oil at the specified frequencies, no analysis is required.

Per Section 63.6625(e) the engine must be operated and maintained according to the manufacturer's written instructions, or FM O&G must develop their own maintenance plan to minimize emissions.

Per Section 63.6645, existing stationary RICE that are not subject to numerical emission standards do not have to submit an initial notification. No reporting requirements are identified in Section 63.6650 for this unit. Per Section 63.6655, FM O&G must keep records of maintenance on the engine.

Per Section 63.6640(f), the engine is considered an emergency engine and is subject to a maximum 100 hours per year for maintenance checks and readiness testing.

Per Section 63.6604(b), beginning January 1, 2015 the engine is required to only use diesel fuel that meets the requirements of 40 CFR 1090.305 for nonroad diesel fuel. 40 CFR 1090.305 sets standards for Ultra Low Sulfur Diesel (ULSD) fuel. Compliance with the ATCM diesel fuel requirements ensures compliance with this NESHAP Subpart ZZZZ requirement.

3.2.3 40 CFR Part 70 {*Operating Permits*}: This Subpart is applicable to the GOHF. Table 3.1 lists the federally enforceable District promulgated rules that are "generic" and apply to the facility. Table 3.2 lists the federally enforceable District promulgated rules that are "unit-specific". These tables are based on data available from the District's administrative files and from FM O&G's Part 70 Operating Permit application. Table 3.4 includes the adoption dates of these rules.

In its Part 70 permit renewal application (Form I) FM O&G certified compliance with all existing District rules and permit conditions. This certification is also required of FM O&G semi-annually. Issuance of this permit and compliance with all its terms and conditions will ensure that FM O&G 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 GOHF are required to conform to these standards. Compliance is typically assessed through onsite inspections. However, CAC Title 17 does not preempt enforcement of any SIP-approved rule that may be applicable to abrasive blasting activities.

3.3.3 Airborne Toxic Control Measure (ATCM) for Stationary Compression Ignition (CI) Engines (CCR Section 93115, Title 17): This ATCM applies for all stationary diesel-fueled engines rated above 50 brake horsepower (bhp) at this facility. On March 17, 2005, District Rule 202 was revised to remove the compression-ignited engine (e.g. diesel) permit exemption for units rated over 50 bhp to allow the District to implement the State's ATCM for Stationary Compression Ignition Engines. The diesel firewater pump is subject to the ATCM. Compliance shall be assessed through onsite inspections and reporting.

3.3.4 Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities (CCR Title 17, Section 95665 *et. Seq.*): This regulation establishes greenhouse gas emission standards for crude oil, condensate, and produced water separation and storage facilities. Based on the definitions of the regulation, the GOHF is subject to the requirements of this regulation. This facility complies with the requirements of the regulation.

3.4 Compliance with Applicable Local Rules and Regulations

3.4.1 Applicability Tables: Tables 3.1 and 3.2 list the federally enforceable District rules that apply to the facility. Table 3.3 lists the non-federally-enforceable District rules that apply to the facility. Table 3.4 lists the adoption date of all rules that apply to the facility.

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 the plant:

Rule 201 - Permits Required: This rule applies to any person who builds, erects, alters, replaces, operates or uses any article, machine, equipment, or other contrivance that may cause the issuance of air contaminants. The equipment included in this permit is listed in Attachment 10.4. An

Authority to Construct is required to return any de-permitted equipment to service and may be subject to New Source Review.

Rule 210 - Fees: Pursuant to Rule 201.G: District permits are reevaluated every three years. This includes the re-issuance of the underlying permit to operate. Fees for this facility are recovered under the cost reimbursement provisions of this rule.

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 District rules and regulations. To the best of the District's knowledge, FM O&G 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. The internal combustion engine driving the firewater pump is subject to this rule. Improperly maintained diesel engines have the potential to violate this rule. Compliance will be assured by onsite inspections and proper operation and maintenance of the internal combustion engine.

Rule 303 - Nuisance: This rule prohibits FM O&G from causing a public nuisance due to the discharge of air contaminants. All nuisance complaints are investigated by the District and follow the guidelines outlined in District RCD Policy & Procedure I.G.2 (*Compliance Investigations*). This rule is included in the SIP.

Rule 305 - Particulate Matter, Northern Zone: The GOHF is considered a Southern Zone source. This rule prohibits the discharge into the atmosphere from any source particulate matter in excess of the specified concentrations measured in grains per standard cubic feet ("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 diesel-fired IC engines. Compliance will be assured by requiring all engines and the flare system to be maintained according to manufacturer maintenance schedules.

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 planned flaring events will comply with the SO_2 limit. The diesel powered piston IC engine driving the emergency firewater pump has the potential to exceed the combustion contaminant limit if not properly maintained, however continued compliance will be assured by requiring this engine to be maintained according to manufacturer's specifications.

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.

Rule 311 - Sulfur Content of Fuels: This rule limits the sulfur content of fuels combusted to 0.5 percent (by wt.) for liquids fuels and 50 gr/100 scf (calculated as H_2S) {or 239 ppmvd) for gaseous fuels. The firewater pump engine complies with the liquid fuel limit as determined by fuel analysis documentation.

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 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. FM O&G is required to maintain records to ensure compliance with this rule.

Rule 321- Solvent Cleaning Machines and Solvent Cleaning. Rule 321 was revised on September 20, 2010 to fulfill the commitment in the 2001 and 2004 Clean Air Plans to implement requirements for solvent cleaning machines and solvent cleaning. The revised rule contains solvent reactive organic compounds (ROCs) content limits, revised requirements for solvent cleaning machines, and sanctioned solvent cleaning devices and methods. These proposed provisions apply to solvent cleaning machines and wipe cleaning.

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

Rule 323.1 (Architectural Coatings): This rule sets the standards for any architectural coating that is supplied, sold, offered for sale, or manufactured for use within the District.

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. FM O&G 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 wastewater tanks, oil/water separators and sumps. Section E requires that all produced gas be controlled at all times, except for wells undergoing routine maintenance. This rule also requires that all produced gas be controlled at all times, either by directing produced gases to a gas system for handling gas for fuel sale or underground storage, a flare or a device with a minimum ROC destruction efficiency of 90%.

Rule 328 - Continuous Emissions Monitoring: This rule details the applicability and standards for the use of continuous emission monitoring systems ("CEMS"). Per Section B.2, the District may require stationary sources that emit more than 5 lb/hr of non-methane hydrocarbons, oxides of nitrogen and sulfur oxides and more than 10 lb/hr of particulate matter.

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. FM O&G is required to maintain records to verify compliance with this rule.

Rule 331 - Fugitive Emissions Inspection and Maintenance: This rule applies to components in liquid and gaseous hydrocarbon service at oil and gas processing plants. Ongoing compliance with the provisions of this rule are assessed through facility inspection by District personnel (using an organic vapor analyzer) and through review of operator records.

Rule 333 - Control of Emissions from Reciprocating Internal Combustion Engines: This rule applies to all engines with a rated brake horsepower of 50 or greater that are fueled by liquid or gaseous fuels. The firewater pump engine is a compression ignition emergency standby engine, therefore it is exempt from Rule 333 per Section B.1.d.

Rule 342 - Control of Oxides of Nitrogen from Boilers, Steam Generators and Process Heaters: This rule limits NO_x emissions from external combustion units with a rated heat input greater than 5.0 MMBtu/hr to less than 30 ppmv (corrected to 3% O_2) when operated on gaseous fuel. In addition, carbon monoxide is limited to 400 ppmv (corrected to 3% O_2).

Rule 343 - Petroleum Storage Tank Degassing: This rule applies to the degassing of any aboveground 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.

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.

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. 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 239 ppmv calculated as H_2S at standard conditions. Sampling of flare gas is required.

§ D.2 - Technology Based Standard: Requires all flares and thermal oxidizers to be smokeless and sets pilot flame requirements.

§ D.3 - Flare Minimization Plan: This section requires sources to implement flare minimization procedures to reduce SO_x emissions.

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

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

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

c. Is not the result of improper maintenance;

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

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

Rule 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. FM O&G submitted an Emergency Episode Plan in June February 15, 2001 which was subsequently updated February 5, 2005.

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

3.5 Compliance History

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

3.5.1 Facility Inspections. The District inspects the GOHF each calendar quarter. Since the previous permit renewal, each quarterly inspection report indicates that this facility was found to be operating in compliance with the District rules, regulations and the permit conditions of this permit.

3.5.2 Violations: There have been no enforcement actions issued to this facility since issuance of the previous permit.

3.5.3 Variances: There have been no significant variances issued for the GOHF since the last permit renewal.

Table 3.1 - Generic Federally-Enforceable District Rules

Generic Requirements	Affected Emission Units	Basis for Applicability
RULE 101: Compliance by Existing Installations	All emission units	Emission of pollutants
RULE 102: Definitions	All emission units	Emission of pollutants
RULE 103: Severability	All emission units	Emission of pollutants
RULE 201: Permits Required	All emission units	Emission of pollutants
RULE 202: Exemptions to Rule 201	Applicable emission units	Insignificant activities/emissions, per size/rating/function
RULE 203: Transfer	All emission units	Change of ownership
RULE 204: Applications	All emission units	Addition of new equipment of modification to existing equipment.
RULE 205: Standards for Granting Permits	All emission units	Emission of pollutants
RULE 206: Conditional Approval of Authority to Construct or Permit to Operate	All emission units	Applicability of relevant Rules
RULE 207: DENIAL OF APPLICATIONS	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 304: PM Concentration – North Zone	Each PM source	Emission of PM in effluent gas
RULE 309: Specific Contaminants	All emission units	Combustion contaminants
RULE 311: Sulfur Content of Fuel	All combustion units	Use of fuel containing sulfur
RULE 317: Organic Solvents	Emission units using solvents	Solvent used in process Ops.

Table 3.1 Continued - Generic Federally-Enforceable District Rules

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 323:I Architectural Coatings	Paints used in maintenance and surface coating activities for paints made on or after 01/01/2015.	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	The Point FM O&G 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.
RULE 810: Federal Prevention of Significant Deterioration	All emission units	Sources subject to any requirement under 40 Code of Federal Regulations, Part 52, Section 52.21
RULE 901: New Source Performance Standards (NSPS)	All emission units	Applicability standards are specified in each NSPS.
RULE 1001: National Emission Standards for Hazardous Air Pollutants (NESHAPS)	All emission units	Applicability standards are specified in each NESHAP.
REGULATION XIII (RULES 1301-1305): Part 70 Operating Permits	All emission units	The Point FM O&G Project is a major source.

Table 3.2 - Non-Federally-Enforceable District Rules

Requirement	Affected Emission Units	Basis for Applicability
RULE 210: Fees	All emission units	Administrative
RULE 310: Odorous Org. Sulfides	All emission units	Emission of organic sulfides
RULE 352: Natural Gas-Fired Fan-Type Central Furnaces and Small Water Heaters	All emission units	Upon Installation
RULES 501-504: Variance Rules	All emission units	Administrative
RULE 505.B2, B3, C, E, F, G: BREAKDOWN CONDITIONS	All emission units	Breakdowns where permit limits are exceeded or rule requirements are not complied with.
RULES 506-519: Variance Rules	All emission units	Administrative

Table 3.3 - Adoption Dates of District Rules Applicable at Issuance of Permit

Rule No.	Rule Name	Adoption Date
Rule 101	Compliance by Existing Installations: Conflicts	June 21, 2012
Rule 102	Definitions	August 25, 2016
Rule 103	Severability	October 23, 1978
Rule 201	Permits Required	June 21, 2012
Rule 202	Exemptions to Rule 201	August 25, 2016
Rule 203	Transfer	April 17, 1997
Rule 204	Applications	August 25, 2016
Rule 205	Standards for Granting Permits	April 17, 1997
Rule 206	Conditional Approval of Authority to Construct or Permit to Operate	October 15, 1991
Rule 207	Denial of Applications	October 23, 1978
Rule 208	Action on Applications - Time Limits	April 17, 1997
Rule 212	Emission Statements	October 20, 1992
Rule 301	Circumvention	October 23, 1978

Rule No.	Rule Name	Adoption Date
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	June 21 , 2012
Rule 322	Metal Surface Coating Thinner and Reducer	October 23, 1978
Rule 323.I	Architectural Coatings	January 1, 2015
Rule 324	Disposal and Evaporation of Solvents	October 23, 1978
Rule 325	Crude Oil Production and Separation	July 19, 2001
Rule 326	Storage of Reactive Organic Compound Liquids	January 18, 2001
Rule 331	Fugitive Emissions Inspection and Maintenance	December 10, 1991
Rule 333	Control of Emissions from Reciprocating Internal Combustion Engines	June 19, 2008
Rule 342	Boilers, Steam Generators, and Process Heaters (5 MMBtu/hr and greater)	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 used in process operations	June 21, 2012
Rule 359	Flares and Thermal Oxidizers	June 28, 1994
Rule 360	Boilers, Water Heaters, and Process Heaters (0.075 – 2 MMBtu/hr)	March 15, 2018
Rule 361	Boilers, Steam Generators, and Process Heaters (Between 2 – 5 MMBtu/hr)	June 20, 2019
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	August 25, 2016
Rule 802	Nonattainment Review	August 25, 2016
Rule 804	Emission Offsets	August 25, 2016
Rule 805	Air Quality Impact and Modeling, Monitoring, and Air Quality Increment Consumption	August 25, 2016
Rule 806	Emission Reduction Credits	August 25, 2016
Rule 810	Federal Prevention of Significant Deterioration (PSD)	June 20, 2013
Rule 901	New Source Performance Standards (NSPS)	September 20, 2010
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	August 25, 2016
Rule 1302	Permit Application	January 18, 2001
Rule 1303	Permits	January 18, 2001
Rule 1304	Issuance, Renewal, Modification and Reopening	January 18, 2001
Rule 1305	Enforcement	November 9, 1993

4.0 Engineering Analysis

4.1 General

The District has confirmed that all emission sources are included in the emissions listings. In addition, process flow diagrams "PFDs" and piping and instrumentation drawings "P&IDs" were reviewed to ensure that all emission sources and appropriate instrumentation controls are included in the project's emissions and equipment inventory. This section assesses the need for, and discusses as necessary, project emission controls and calculations, process monitoring, sampling, and meter calibration.

The District conducted a limited review of the project design for upset potential which could lead to excess emissions. An EIS/EIR analysis of the potential for upsets and the release of air pollutants was done. A number of major systems safety features and operations were included in FM O&G's project design. The project contains several key features to minimize the potential for excess emissions resulting from process upsets.

4.2 Piston Internal Combustion Engines

The GOHF has one emergency firewater pump driven by a diesel fired engine manufactured by Caterpillar Model 3306 and is rated at 267 bhp. The calculation methodology for the diesel-fired engines is as follows:

E1, lb/day = Engine Rating (bhp) * EF (g/bhp-hr) * Daily Hours (hr/day) * (lb/453.6 g)
E2, tpy = Engine Rating (bhp) * EF (g/bhp-hr) * Annual Hours (hr/yr) * (lb/453.6 g) * (ton/2000 lb)

The emission factors (EF) were chosen based on the engine's rating and age. Unless engine specific data was provided, default emission factors are used as documented on the District's webpage at http://www.ourair.org/dice/emission-factors/. The engine subject to this permit is limited to 2 hours per day and 100 hours per year for maintenance and testing.

The engine is equipped with an elapsed hour meter. The firewater pump is restricted to operating less than 100 hours per year. The emission factors for each pollutant are listed in Table 5.2-2.

4.3 Other Emission Sources

General Solvent Cleaning/Degreasing: Solvent usage (not used as thinners for surface coating) occurring as part of normal daily operations and includes cold solvent degreasing and wipe cleaning. Emissions are determined based on mass balance assuming that all the solvent used evaporates to the atmosphere.

Surface Coating: Surface coating operations typically include normal touch up activities. Emissions are determined based on mass balance calculations assuming all solvents evaporate into the atmosphere. Emission of PM/PM_{10} from paint overspray are not calculated due to the lack of established calculation techniques.

Abrasive Blasting: Abrasive blasting with CARB certified sands may be performed as a preparation step prior to surface coating. The engines used to power the compressor are not subject to this permit (FM O&G or the engine operator is responsible for engine compliance prior to the time of use). Particulate matter is emitted during this process. A general emission factor of 0.01 pound PM per pound of abrasive is used (SCAQMD - Permit Processing Manual, 1989) to estimate emissions of PM, PM_{10} and $PM_{2.5}$. A $PM/PM_{10}/PM_{2.5}$ ratio of 1.0 is assumed.

4.4 BACT/NSPS/NESHAP/MACT

NESHAP: The emergency diesel-fired engine is subject to NESHAPS.

4.5 Source Testing/Sampling/Monitoring/Meter Calibration

Monitoring and meter calibration are required in order to ensure compliance with permitted emission limits, prohibitory rules, NSPS, control measures and the assumptions that form the basis of this operating permit.

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 and fuel usage meters. 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 will be required to be calibrated and maintained in good working order:

→ hour meter (firewater pump)

To ensure compliance with this permit and applicable rule and regulations, the District may require FM O&G, by written notice, to install additional process monitors. Further, the District may require FM O&G, by written notice, to expand the list of existing plant process monitors detailed in the list above.

Meter Calibration. FM O&G is required to maintain meters at the GOHF in accordance with the Process Monitor Calibration and Maintenance Plan. This Plan takes into consideration manufacturer recommended maintenance and calibration schedules and may include other accuracy checks. Where manufacturer guidance is not available, the recommendations of comparable equipment manufacturers and good engineering judgment are to be utilized.

5.0 Emissions

5.1 General

All emission sources are included in the potential-to-emit calculations. Total emission limits for the entire Project are summarized in Table 5.1. The permitted emissions for each emissions unit is based on the equipment's potential-to-emit. 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 addresses greenhouse gases, Section 5.5 provides the federal potential to emit calculation using the definition of potential to emit used in Rule 1301, Section 5.6 quantifies greenhouse gas emissions, and Section 5.7 quantifies Hazardous Air Pollutant (HAP) emissions.

5.2 Permitted Emission Limits - Emission Units

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

⇒ Nitrogen Oxides (NO_x) [3]
⇒ Reactive Organic Compounds (ROC)
⇒ Carbon Monoxide (CO)

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

⇒ Sulfur Oxides (SO_x) [4]
⇒ Particulate Matter (PM) [5]
⇒ Particulate Matter smaller than 10 microns (PM_{10})
⇒ Particulate Matter smaller than 2.5 microns ($PM_{2.5}$)[6]
⇒ Greenhouse Gases (as CO_2)

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

5.3 Permitted Emission Limits - Facility Totals

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

Hourly/Daily Scenario

Peak hourly and daily emissions were based on the following equipment operating assumptions:

→ 1 emergency firewater pump
→ Solvent use for wipe cleaning and cold solvent degreasing (monthly average based on eight-hour day)

Quarterly and Annual Scenario:

→ 1 emergency firewater pump
→ Solvent use for wipe cleaning and cold solvent degreasing (monthly average based on eight hour day)

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

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

[6] Since the previous permit renewal, $PM_{2.5}$ has been added as a regulated pollutant, therefore $PM_{2.5}$ emissions have been quantified.

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, which are not subject to any applicable NSPS or NESHAP requirement, are included in the federal definition of potential to emit.

5.5 Exempt Emission Sources/Part 70 Insignificant Emissions

Equipment/activities exempt pursuant to Rule 202 include maintenance operations involving surface coating. Exempt units such as maintenance operations using paints and coatings, contribute to the facility emissions.

5.6 Greenhouse Gases

GHG emissions from combustion sources are calculated using emission factors found in Tables C-1 and C-2 of 40 CFR Part 98 and global warming potentials found in Table A-1 of 40 CFR Part 98. The following emission factor applies. The derivation of these emission factors is provided in Attachment 10.1.

Internal Combustion Engines: 556.60 g/bhp-hr

The facility's GHG potential to emit has been estimated, however the greenhouse gas PTE is not an emission limit. The facility will not become subject to emission limits for GHGs unless a project triggers federal Prevention of Significant Deterioration requirements under Rule 810.

5.7 Hazardous Air Pollutants (HAPs)

Total emissions of hazardous air pollutants (HAP) are computed based on the factors listed in Table 5.4-1 for each emissions unit. Potential Facility HAP emissions are shown in Table 5.4-2. Stationary Source HAP emissions are shown in Table 5.4-3. These are based on a combination of the worst-case scenario listed in Section 5.3.

Table 5.1-1
Operating Equipment Description
Pt70 Permit to Operate 15455-R1

		Device Specifications				Usage Data			Maximum Load Schedule			
Equipment Category	**Emissions Unit**	**Fuel**	**% S**	**Size**	**Units**	**Capacity**	**Units**	**Load**	**hr**	**day**	**qtr**	**year**
Combustion - Engines	Emergency F/W Pump	D2	0.0015	267	bhp	--	--	--	1.000	2.000	200.000	200.000

Table 5.1-2
Equipment Emission Factors
Pt70 Permit to Operate 15455-R1

		Emission Factors							
Equipment Category	**Emissions Unit**	**NOx**	**ROC**	**CO**	**SOx**	**PM**	**$PM_{2.5/10}$**	**GHG**	**Units**
Combustion - Engines	Emergency F/W Pump	14.060	1.120	3.030	0.002	0.310	0.310	556.60	g/bhp-hr

Table 5.1-3
Hourly and Daily Emissions
Pt70 Permit to Operate 15455-R1

		NOx		ROC		CO		SOx		PM		$PM_{2.5/10}$		GHG		Federally
Equipment Category	**Emissions Unit**	**lbs/hr**	**lbs/day**	**lbs/hr**	**lbs/day**	**lbs/hr**	**lbs/day**	**lbs/hr**	**lbs/day**	**lbs/hr**	**lbs/day**	**lbs/hr**	**lbs/day**	**lbs/hr**	**lbs/day**	**Enforceable**
Combustion - Engines	Emergency F/W Pump	8.27	16.54	0.66	1.32	1.78	3.56	0.00	0.00	0.18	0.36	0.18	0.36	327.63	655.25	--

Table 5.1-4
Quarterly and Annual Emissions
Pt70 Permit to Operate 15455-R1

		NOx		ROC		CO		SOx		PM		$PM_{2.5/10}$		GHG		Federally
Equipment Category	**Emissions Unit**	**TPQ**	**TPY**	**TPQ**	**TPY**	**TPQ**	**TPY**	**TPQ**	**TPY**	**TPQ**	**TPY**	**TPQ**	**TPY**	**TPQ**	**TPY**	**Enforceable**
Combustion - Engines	Emergency F/W Pump	0.41	0.41	0.03	0.03	0.09	0.09	0.00	0.00	0.01	0.01	0.01	0.01	16.381	16.381	--

Table 5.2
Total Permitted Facility Emissions
Pt70 Permit to Operate 15455-R1

A. Peak Hourly (lb/hr)

Equipment Category	NOx	ROC	CO	SOx	PM	$PM_{2.5/10}$	GHG
Combustion - Engines	8.27	0.66	1.78	0.00	0.18	0.18	327.63
TOTALS (lb/hr)	**8.27**	**0.66**	**1.78**	**0.00**	**0.18**	**0.18**	**327.63**

B. Peak Daily (lb/day)

Equipment Category	NOx	ROC	CO	SOx	PM	$PM_{2.5/10}$	GHG
Combustion - Engines	16.54	1.32	3.56	0.00	0.36	0.36	655.27
TOTALS (lb/day)	**16.54**	**1.32**	**3.56**	**0.00**	**0.36**	**0.36**	**655.27**

C. Peak Quarterly (Tons/Qtr)

Equipment Category	NOx	ROC	CO	SOx	PM	$PM_{2.5/10}$	GHG
Combustion - Engines	0.41	0.03	0.09	0.00	0.01	0.01	16.38
TOTALS (ton/qtr)	**0.41**	**0.03**	**0.09**	**0.00**	**0.01**	**0.01**	**16.38**

D. Peak Annual (Ton/yr)

Equipment Category	NOx	ROC	CO	SOx	PM	$PM_{2.5/10}$	GHG
Combustion - Engines	0.41	0.03	0.09	0.00	0.01	0.01	16.38
TOTALS (ton/yr)	**0.41**	**0.03**	**0.09**	**0.00**	**0.01**	**0.01**	**16.38**

Table 5.3
Federal Potential to Emit
Pt70 Permit to Operate 15455-R1

A. Peak Hourly (lb/hr)

Equipment Category	NOx	ROC	CO	SOx	PM	$PM_{2.5/10}$
Combustion - Engines	8.27	0.66	1.78	0.00	0.18	0.18
Exempt	--		--	--	--	--
TOTALS (lb/hr)	**8.27**	**0.66**	**1.78**	**0.00**	**0.18**	**0.18**

B. Peak Daily (lb/day)

Equipment Category	NOx	ROC	CO	SOx	PM	$PM_{2.5/10}$
Combustion - Engines	16.54	1.32	3.56	0.00	0.36	0.36
Exempt	--	--	--	--	--	--
TOTALS (lb/day)	**16.54**	**1.32**	**3.56**	**0.00**	**0.36**	**0.36**

C. Peak Quarterly (Tons/Qtr)

Equipment Category	NOx	ROC	CO	SOx	PM	$PM_{2.5/10}$
Combustion - Engines	0.41	0.03	0.09	0.00	0.01	0.01
Exempt	3.72	0.41	2.20	0.18	0.26	0.25
TOTALS (ton/qtr)	**4.13**	**0.44**	**2.29**	**0.18**	**0.27**	**0.26**

D. Peak Annual (Ton/yr)

Equipment Category	NOx	ROC	CO	SOx	PM	$PM_{2.5/10}$
Combustion - Engines	0.41	0.03	0.09	0.00	0.01	0.01
Exempt	14.88	1.63	8.78	0.71	1.05	1.00
TOTALS (ton/yr)	**15.29**	**1.66**	**8.87**	**0.71**	**1.06**	**1.01**

Table 5.4-1
Point Arguello Gaviota Oil Heating Facility: Pt70 Permit to Operate 15455-R1
Equipment Hazardous Air Pollutant Factors

Emission Factors

Equipment Category	Description	Hexane	Benzene	Toluene	Xylene	Iso-Octane [1]	Formaldehyde	PAHs (not incl. napthalene)	Naphthalene	Acetaldehyde	Acrolein	1,3-Butadiene	Chlorobenzene	Ethylbenzene	Hydrogen Chloride	Arsenic	Beryllium	Cadmium	Total Chromium	Cobalt	Lead	Manganese	Mercury	Nickel	Selenium	Units
Combustion - Engines	Emergency F/W Pump	2.69E-02	1.86E-01	1.05E-01	4.24E-02	--	1.73E+00	3.62E-02	1.97E-02	7.83E-01	3.39E-02	2.17E-01	2.00E-04	1.09E-02	#######	1.60E-03	--	1.50E-03	6.00E-04	--	8.30E-03	3.10E-03	2.00E-03	3.90E-03	2.20E-03	lb/1000 gal

Notes:
- VCAPCD AB 2588 Combustion Emission Factors (2001) - Diesel Combustion Factors (internal combustion)
- USEPA, AP-42 Table 3.3-2. Speciated Organic Compound Emission Factors for Uncontrolled Diesel Engines
- VCAPCD AB 2588 Combustion Emissions Factors (2001) - Diesel Combustion Factors (internal combustion) - Used to supplement USEPA's AP-42 Table 3.3-2. VCAPCD's factors were used for HAPs not included in AP-42

Table 5.4-2
Point Arguello Gaviota Oil Heating Facility: Pt70 Permit to Operate 15455-R1
Annual Hazardous Air Pollution Emissions (TPY)

Equipment Category	Description	Hexane	Benzene	Toluene	Xylene	Iso-Octane	Formaldehyde	PAHs (not incl. napthalene)	Naphthalene	Acetaldehyde	Acrolein	1,3-Butadiene	Chlorobenzene	Ethylbenzene	Hydrogen Chloride	Arsenic	Beryllium	Cadmium	Total Chromium	Cobalt	Lead	Manganese	Mercury	Nickel	Selenium
Combustion - Engines	Emergency F/W Pump	7.66E-10	5.30E-09	3.00E-09	1.21E-09	--	4.91E-08	1.03E-09	5.61E-10	2.23E-08	9.65E-10	6.19E-09	5.69E-12	3.10E-10	5.30E-09	4.55E-11	--	4.27E-11	1.71E-11	--	2.36E-10	8.82E-11	5.69E-11	1.11E-10	6.26E-11
	Total Facility HAPs (TPY):	**7.66E-10**	**5.30E-09**	**3.00E-09**	**1.21E-09**	**0.00E+00**	**4.91E-08**	**1.03E-09**	**5.61E-10**	**2.23E-08**	**9.65E-10**	**6.19E-09**	**5.69E-12**	**3.10E-10**	**5.30E-09**	**4.55E-11**	**0.00E+00**	**4.27E-11**	**1.71E-11**	**0.00E+00**	**2.36E-10**	**8.82E-11**	**5.69E-11**	**1.11E-10**	**6.26E-11**

Notes:
1. These are estimates only, and are not intended to represent emission limits.
2. Based on CAAA, Section 112 (n) (4) stipulations, the HAP emissions listed above can not be aggregated at the source for any purpose, including determination of HAP major source status for MACT applicability.
3. Default fuel properties for diesel come from the SBCAPCD's Piston IC Engine Technical Reference Document (2002) - Table 5 Default Fuel Properties & Table 6 Default Engine Specifications.

Table 5.4-3
Point Arguello Project: Permit to Operate 5704-R5
Stationary Source Hazardous Air Pollutant Emissions (TPY)

Facility	Permit #	Hexane	Benzene	Toluene	Xylene	Iso-Octane	Formaldehyde	PAHs (not incl. napthalene)	Naphthalene	Acetaldehyde	Acrolein	1,3-Butadiene	Chlorobenzene	Ethylbenzene	Hydrogen Chloride
01325 - Gaviota Oil Heating Facility	**PTO 5704-R5**	7.66E-10	5.30E-09	3.00E-09	1.21E-09	0.00E+00	4.91E-08	1.03E-09	5.61E-10	2.23E-08	9.65E-10	6.19E-09	5.69E-12	3.10E-10	5.30E-09
08013 - Platform Harvest	**PTO 9103-R5**	1.29E+01	6.20E-01	3.05E-01	1.64E-01	1.11E+01	2.81E-01	6.63E-03	1.13E-02	9.47E-02	9.72E-03	2.26E-02	5.95E-05	5.32E-02	5.54E-02
08014 - Platform Hermosa	**PTO 9104-R5**	7.12E+00	1.10E+00	8.46E-01	6.50E-01	5.83E+00	2.21E-01	5.68E-03	7.31E-03	8.35E-02	6.95E-03	1.86E-02	5.80E-05	4.29E-02	5.40E-02
08015 - Platform Hidalgo	**PTO 9105-R5**	5.41E+00	9.91E-01	8.02E-01	6.54E-01	4.43E+00	2.39E-01	6.23E-03	8.47E-03	9.28E-02	7.73E-03	2.16E-02	6.03E-05	2.85E-02	5.62E-02
Total Stationary Source - By Pollutant		**2.54E+01**	**2.71E+00**	**1.95E+00**	**1.47E+00**	**2.13E+01**	**7.41E-01**	**1.85E-02**	**2.70E-02**	**2.71E-01**	**2.44E-02**	**6.29E-02**	**1.78E-04**	**1.25E-01**	**1.66E-01**

Facility	Permit #	Arsenic	Beryllium	Cadmium	Total Chromium	Cobalt	Lead	Manganese	Mercury	Nickel	Selenium	**Total - All H**
01325 - Gaviota Oil Heating Facility	**PTO 5704-R5**	4.55E-11	0.00E+00	4.27E-11	1.71E-11	0.00E+00	2.36E-10	8.82E-11	5.69E-11	1.11E-10	6.26E-11	9.67E-08
08013 - Platform Harvest	**PTO 9103-R5**	2.75E-03	7.23E-05	2.73E-03	3.99E-03	1.23E-04	5.04E-03	1.47E-01	1.15E-03	4.69E-03	5.28E-03	2.58E+01
08014 - Platform Hermosa	**PTO 9104-R5**	1.48E-03	3.19E-05	1.38E-03	1.79E-03	4.73E-05	3.58E-03	6.72E-02	8.09E-04	2.55E-03	2.74E-03	1.61E+01
08015 - Platform Hidalgo	**PTO 9105-R5**	1.85E-03	4.25E-05	1.70E-03	2.32E-03	6.18E-05	4.07E-03	8.98E-02	9.05E-04	3.05E-03	3.48E-03	1.29E+01
Total Stationary Source - By Pollutant		**6.08E-03**	**1.47E-04**	**5.81E-03**	**8.09E-03**	**2.32E-04**	**1.27E-02**	**3.04E-01**	**2.86E-03**	**1.03E-02**	**1.15E-02**	**5.47E+01**

Notes:
1. These are estimates only, and are not intended to represent emission limits.
2. Based on CAAA, Section 112 (n) (4) stipulations, the HAP emissions listed above can not be aggregated at the source for any purpose, including determination of HAP major source status for MACT applicability.

6.0 Air Quality Impact Analyses[7]

Note: The information provided in this section is for historical purposes only as oil and gas operations at this facility have ceased. The only equipment in service is the emergency firewater pump. All other equipment formerly at this facility has been decommissioned and depermitted.

6.1 Compliance with Ambient Air Quality Standards

Impacts from operation of the GOHF, as originally proposed by Chevron, and the associated pipelines were modeled for NO_2, SO_2, CO and PM using the Complex II Model following the procedures specified in the District's *Authority to Construct Permit Processing Manual*. The ISC Model was used to predict ROC pollutant impacts. Based on the maximum-hour scenario, an ISC model was used to simulate the maximum ambient. ISC was found by the District to produce comparable results to those generated by Complex II with significantly lower computer time requirements.

The following pollutants were analyzed for both phases:

- Nitrogen Oxides (NO_x)[8]
- Reactive Organic Compounds (ROC)
- Carbon Monoxide (CO)
- Sulfur Oxides (SO_x)[9]
- Particulate Matter (PM)[10]

Pre-construction monitoring data principally from the Gaviota station were used to provide the meteorological and background pollutant value input to the models.

A review was conducted to determine if any permitted emission sources, not accounted for in the pre-construction monitoring data, would be present during the installation or operation of the proposed project. The installation and operation of Exxon's Harmony, Heritage and Heather platforms, offshore of the Gaviota area were identified as having the potential to impact the same locations as the proposed project and were therefore included in the analysis.

In order to determine compliance with ambient air quality standards during the installation and operation of offshore platforms, the modeling results contained within the

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[7] This section provides an historical analysis that does not necessarily reflect current operations.
[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

project EIR/EIS were used. For project modifications, the analysis of ATC 5704 was reviewed to determine if the modifications would jeopardize ambient air quality standards.

The data and information provided in this section is based on the Point Arguello project as it was originally designed, installed and operated.

6.1.1 Production Impact from Onshore Facilities

Production emissions were modeled as 12 point sources and 35 ROC area sources occurring inside the facility boundary. Emission rates and stack parameters for each of these sources are given in Table 10.1-2 of ATC 5704 (issued 2/6/86). An array of 99 receptors was used for modeling of all pollutants except ROC, which had an array of 115 receptors.

The modeling results for the project are shown in Table 6.1. The project contribution of PM_{10} will be added to the existing background levels that exceeded the standards. This resulted in implementation of PM_{10} mitigation procedures outlined in the PM_{10} Emissions Reduction Study. No other violations of the ambient air quality standards were projected for normal operations of the Phase I oil and gas facilities.

Compliance with the SO_2 and NO_2 hourly standards was achieved only after Chevron relocated one of the Phase I tail gas scrubber stacks and agreed to remove the Phase II gas plant from the permit process.

The District investigated the potential for improving the permitability of Phase II gas plant by using grid power rather than power from cogeneration plant, however, since the cogeneration plant did not contribute to peak SO_2 impacts, replacement of the cogeneration plant with grid power did not improve the permitability of the Phase II gas plant. As previously noted, the entire gas plant has since been de-permitted.

6.1.2 Drilling and Production Impacts from Platforms

Table 6.2 contains air quality impact results (obtained from the Project EIR/EIS) for normal operation of the three platforms and the five area study platforms. The total values include background values measured during the pre-construction monitoring period at Gaviota.

No violations of standards were predicted during normal operation, except in the case of PM_{10} which has a background value higher than the 24-hour standard.

Failure of the onshore 30 MMSCFD amine unit was projected to exceed the state 1-hour standard. Failure of the 60 MMSCFD amine unit proposed as a part of the Phase II gas plant is projected to cause exceedances of the state 1-hour SO_2 standard. A sulfur plant failure was predicted to cause an exceedance of the 1-hour, 3-hour, and 24-hour SO_2 standards.

6.1.3 Flaring Impacts from Onshore Facilities

Table 6.3 contains the flaring event impacts expected from the onshore facilities. The expected frequency and duration of each of the flaring events and stack parameters for modeling are shown in Table 10.1-3 of ATC 5704 (issued 2/6/86). Continuous purge and pilot is a daily activity and is included in the analysis of normal production impacts from the onshore facilities.

Controlled oil plant and gas plant shutdown flaring was not projected to exceed any standards. The use of an emergency caustic scrubber, designed for the gas processing facility, resulted in the compliance with the SO_2 standard.

Failure of the onshore 30 MMSCFD amine unit was projected to exceed the state 1-hour standard. Failure of the 60 MMSCFD amine unit proposed as a part of the Phase II gas plant is projected to cause exceedances of the state 1-hour SO_2 standard. A sulfur plant failure was predicted to cause an exceedance of the 1-hour, 3-hour, and 24-hour SO_2 standards. As previously noted, the entire gas plant has since been de-permitted.

6.1.4 Flaring Impacts from Platforms

Flaring impacts from the platforms were analyzed in the project EIR/EIS. Descriptive information on flaring events were shown in Table 10.1-3 of ATC 5704 (issued 2/6/86).

The modeling results, shown in Table 6.3, projected a peak 1-hour SO_2 concentration of 627, which approaches but did not exceed the state standard of 655 $\mu g/m^3$. The 1-hour NO_2 and 3-hour SO_2 standards were not predicted to be violated. The California 24-hour SO_2 standard is 131 $\mu g/m^3$, when simultaneous TSP and/or O_3 concentrations exceed 100 $\mu g/m^3$ and 10 pphm, respectively. The 24-hour TSP concentration did not predict an exceedance of 100 $\mu g/m^3$ and simultaneous occurrence of high ozone (above 10 pphm) and the flaring event is not likely; therefore, the state SO_2/TSP/O_3 standard is not anticipated to be exceeded during offshore flaring.

6.1.5 Project Contribution to Ozone Formation

The potential for the project to contribute to the formation of ozone was examined in the project EIR/EIS. A photochemical pollutant analysis was conducted using the Trace Model for a wide range of initial pollutant concentrations and trajectory paths. A detailed description of the analysis is contained in the EIR/EIS.

Table 6.4 summarizes the results of the ozone analysis. Significant increases in ozone levels were predicted from the project. Ozone levels in excess of the state standard (10.0 pphm) were predicted for facility operation and impacts above the federal standard (12.0 pphm) were predicted for upset conditions on the platforms and for facility operations under reduced wind speed conditions.

Mitigation of potential ozone standard violations are discussed in Section 7.0 (Offsets and Clean Air Plan Consistency.

6.2 Air Quality Increment Analysis

An increment consumption analysis was performed for the pollutants NO_2, TSP, PM_{10}, CO, SO_2 and ROC. An examination was first conducted to identify any existing sources which would consume increment within the general vicinity of the project site. Increment consuming sources include major stationary sources (per 40 CFR 52.21) constructed since January 6, 1975, and all sources constructed, modified or otherwise permitted to increase emissions after either August 8, 1978 (for TSP and SO_2) or January 1, 1984 (for PM_{10}, NO_2, CO and ROC). The only increment consumers identified in the project area, in addition to the proposed project, were Exxon's Platforms Harmony, Heritage and Heather, which were approved for installation by the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE), formerly the US Minerals Management Service).

The same modeling methodology was used for increment analysis as was employed for the standards compliance analyses (see Section 6.1). For the computation of NO_2 by the ozone limiting method, the highest ozone value observed during pre-construction monitoring, a value of 14 pphm, was used. This value was measured at 1200 on April 14, 1984, at the County's El Capitan monitor. Neither FM O&G's Gaviota monitor or Shell's Molino monitor were operating during this peak ozone event for the pre-construction monitoring period.

The results of the increment analysis are shown in Table 6.5. During facility operation maximum increment consumption from the onshore oil and gas facility was anticipated to exceed the allowable maximum for only ROC (3-hour).

Increment consumption from platform operation was determined to be less than that shown for the oil and gas processing facility. Simultaneous emissions from Exxon's platforms were not projected to contribute to the maximum-modeled increments.

During the first year of operation increment fees ($333.00 per year per microgram above lower increment level) required were $244.00 per day for NO_2, $3.00 per day for PM_{10} and $1874.00 per day for ROC. The required fee is reduced by 10% per year, as per District rules. The final increment fee payment was made in November 1998.

6.3 Vegetation and Soils Analysis

The land in the general area of the proposed project is used for grazing. At sufficient concentration and duration, ambient air pollutants, specifically ozone, sulfur dioxide, nitrogen dioxide, and various combinations of the three, can injure vegetation.

An ozone concentration of 0.25 ppm over a six-hour period has been shown to injure plants. Additional studies have also demonstrated slight injury to sensitive plants at ozone exposure levels of 0.02-0.03 ppm for an 8-hour duration and 0.08-0.15 ppm for 2 hours. Evidence of minimal foliar injury to trees and shrubs at ozone concentrations of 0.2-0.5 ppm for 1 hour and to agricultural crops at 0.2-0.41 ppm for one-half hour has also been substantiated.

The maximum hourly ozone concentration expected during construction and production of the proposed project was projected to be 0.12 ppm (0.13 ppm in rare occasions). Based on past studies this concentration may cause slight damage to sensitive plants.

Recent studies of sulfur dioxide exposure show injury thresholds at 0.3 ppm for 8 hours (for middle-aged plants), at 0.14 ppm for 15-20 hours (for oat seedlings), and at an 0.007-0.010 ppm average for the growing season. The maximum hourly ambient concentration of sulfur dioxide expected during operation of the facility is approximately 0.25 ppm, (assuming implementation of the mitigation measures in section 6.1) which is below the thresholds cited by these studies. Therefore, no plant injury is expected from sulfur dioxide.

Nitrogen dioxide sensitivity has been cited in the literature at concentrations of 2.5 ppm for a 4-hour duration for tomato seedlings and other plants with middle-aged leaves. Leaf symptoms have been observed at 1.6-2.6 ppm for 2-day exposures and 20 ppm for 1-hour exposures. The maximum hourly ambient concentration of nitrogen dioxide predicted during the production phase would be 0.23 ppm, which is well below the injury threshold cited. Therefore, no plant injury is expected from nitrogen dioxide emissions.

During the production phase, total emissions from the facility were predicted to be 245 pounds per day of sulfur dioxide and 950 pounds per day of nitrogen oxides. Annual deposition of sulfates and nitrates onto the surrounding soils will be minimal, based on the large project area over which the pollutants are dispersed. In addition, the pronounced alkalinity of the soils will ameliorate the effects of the minor decrease in pH expected from nitrate or sulfate deposition. No long-term buildup of deposition products is expected because of utilization of these compounds by existing vegetation. In addition, the facility was not anticipated to emit heavy metals or other toxic substances which could damage soils used for crop or forage production. Therefore, no impact on soils was predicted to occur from project emissions.

6.4 Potential to Impact Visibility and Opacity

During facility operations the potential exists for opacity violations due to flaring activities and due to operation of the diesel-fired internal combustion engines. The potential for these violations are minimized through the use of a smokeless flare and through proper operation and maintenance of the IC engines.

6.5 Health Risk Assessment

The GOHF is not of significant risk status (significant risk is >10 in one million for cancer risk and HI=1.0 for acute and chronic non-cancer risk). As a result, an Update Summary Form is required to be submitted by this facility each four years.

6.6 Public Nuisance

Historically, oil and gas processing facilities handling high sulfur content petroleum 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 particularly important to evaluate the potential for public nuisance from the proposed facilities. Emissions from the operation phases of the project were reviewed to determine compliance with District 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.

As initially designed and operated, there was a comparatively greater potential for public nuisance due to emissions of reduced sulfur compounds which could occur during facility operation than there is under the current permit for this facility. In the original design and operation of the GOHF both the high sulfur content of the petroleum feedstock and the ethyl mercaptan addition unit used to odorize the natural gas, propane and butane were potential sources of reduced sulfur compounds. Additional sources of reduced sulfur emissions included the amine unit, the sulfur unit, the tail gas unit, the sour gas pipeline and fugitive emissions from gas and oil handling facilities.

As such, it was determined that piping for the sour gas facility would contain process streams with H_2S content above the 825 ppm level specified in Ordinance No. 2832 as the trigger point for classifying the operations to be in "Potentially Hazardous Emission Area". Petroleum operations in Potentially Hazardous Emission Areas are required to submit a plan for detecting and monitoring emissions and must conduct operations so that ambient H_2S concentrations do not exceed the values set forth in Ordinance No. 2832 for the protection of public health. However, substantially lower reduced sulfur concentrations than those specified in the Ordinance have the potential to cause a public nuisance. 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 FM O&G facilities include highway travelers immediately to the south and beach users to the southwest and southeast.

Since the human odor threshold for H_2S is 0.00047 ppm (Ref. SCAQMD EIR Handbook, App. M), it was determined that odors will, at times, likely be detectable outside the property line. Thus, due to the potential for odorous emissions from the facilities, an odor monitoring program was required. This program required several odor monitoring stations, including the Gaviota East and Gaviota West Odor stations. Odor monitoring was also required by the County Final Development Plan (condition E-4). The GOHF no longer receives sour gas from the platforms. The Gaviota East and West odor stations were subsequently decommissioned following the installation of three H_2S monitoring sensors under ATC 10332.

6.7 Ambient Air Quality Monitoring

In order to comply with the pre-construction monitoring requirements of District Rule 205.C.3.b.5, FM O&G installed an ambient air quality monitor in July, 1984 at their Gaviota site. The monitoring station was capable of measuring NO, NO_x, SO_2, ROC, THC, TSP, PM_{10}, ozone and meteorological parameters. This pre-construction monitoring data was used in the Air Quality Impact Analysis discussed in ATC 5704 (issued 2/6/86) and summarized in that permit. Locations outside the facility boundary were identified for the citing of ambient air quality monitors during and after construction activities. As required under the County Preliminary Development Plan Condition E-4, FM O&G installed monitoring stations at Jalama Beach, Point Conception, Gaviota and Carpinteria to provide data on the impacts from platform and facility construction and operation and regional ozone levels. The Jalama Beach and Point Conception monitoring stations were decommissioned by the District on December 1, 1995 and April 06, 1998, respectively, after a review of the data determined that these stations had addressed their objectives and satisfied the operational monitoring criteria.

Two monitor locations were identified in the vicinity of the GOHF. One location is north of the facility (UTM 3818.48 N and 756.66 E) and 390 feet elevation. The second site is north-west of the facility (UTM 3818.49 N and 756.16 E) at 400 feet elevation. These stations were decommissioned on April 11, 1998 after a review of the data determined that these stations had addressed their objectives and satisfied the operational monitoring criteria.

Table 6.6 summarizes the remaining operational station site and parameters to be monitored. If deemed necessary by the District, additional monitoring stations shall be installed by FM O&G to monitor operational impacts or upset/breakdown impacts.

6.8 Emergency Episode Plans and Curtailment Plans for the Protection of Ambient Air Quality Standards

Pursuant to District Rule 603.A.1, FM O&G is required to maintain an Emergency Episode Plan, approved by the District, for this facility. The contents of the Emergency Episode Plan must comply with the provisions specified in Rule 603.A.2. The Episode Plan was approved on April 20, 1988 and most recently updated on February 5, 2005. The update adequately addressed the staff contact changes. In addition, the County Development Plan Condition E-3 and E-5 originally required FM O&G to submit for District approval of an "Air Pollution Curtailment Plan" to provide for the protection of ambient air quality standards during construction and operation of the facility. However, during a Condition Effectiveness Study (dated November 22, 1991) of the Final Development Plan, the requirement for curtailment of operation activities was deleted, since curtailment of plant operations would result in increased flaring activities, thus having a greater adverse impact than continued operations.

Table 6.1
FM O&G GOHF- PTO 5704-R5
Air Quality Impacts
Onshore Facilities - Production Phase [11]

POLLUTANT	AVERAGING TIME (μg/m³)	PROJECT CONTRIBUTION (μg/m³)	BACKGROUND (μg/m³)	TOTAL (μg/m³)	STANDARD (μg/m³)
NO_2	1-Hour	348	75	423	470
	Annual	9	19	28	100
TSP [12]	24-Hour	16	124	140	260
	Annual	2	23	25	75
PM_{10}	24-Hour	15 [13]	58	73 [14]	50
	Annual	2	15		30
CO	1-Hour	964	8,000	8,964	23,000
	8-Hour	205	2,663	2,868	10,000
SO_2	1-Hour	590	47	637	655
	3-Hour	199	35	234	1,300
	24-Hour	31	10	41	131
	Annual	3	0	3	80
ROC	3-Hour	2,095	318	2,413	160 [15]

9. This was Table 6-2 in ATC 5704 (2/6/86).
10. TSP standard no longer applicable. TSP increment is still applicable for both 24-hour Class II increment (37μg/m³) and the annual Class II increment (19 (μg/m3).
13. PM10 emissions are assumed to be 96 percent of TSP emission rate.
14. Project contribution of PM10 adds to existing standard violations.
15. ROC standard is retained by the District for ROC increment tracking as a precursor to ozone formation.

Table 6.2
FM O&G GOHF- PTO 5704
Air Quality Impacts
Platforms - Production Phase [16]

POLLUTANT	AVERAGING TIME ($\mu g/m^3$)	PROJECT CONTRIBUTION ($\mu g/m^3$)	BACKGROUND ($\mu g/m^3$)	TOTAL ($\mu g/m^3$)	STANDARD ($\mu g/m^3$)
NO_2	1-Hour	259	75	334	470
	Annual	26	19	45	100
TSP	24-Hour	15	124	139	n/a
	Annual	1.5	23	25	n/a
PM_{10}	24-Hour	15	58	73 [17]	50
	Annual	1.5	15	16.5	30
CO	1-Hour	91	8,000	8,091	23,000
	8-Hour	64	2,663	2,727	10,000
SO_2	1-Hour	19	47	66	655
	3-Hour	17	35	52	1,300
	24-Hour	8	10	18	131
	Annual	1.9	0	1.93	80

15. This was Table 6-4 in ATC 5704-06 (1/30/92) and ATC 5704 (2/6/86).
17. Project contribution of PM10 adds to existing standard violations.

Table 6.3
FM O&G GOHF - PTO 5704
Flaring Impacts- Production Phase [18]

FLARING EVENT [19]	1-HOUR NO_2 IMPACT ($\mu g/m^3$)	1-HOUR SO_2 IMPACT ($\mu g/m^3$)	3-HOUR SO_2 IMPACT ($\mu g/m^3$)	24-HOUR SO_2 IMPACT ($\mu g/m^3$)
ONSHORE				
- Continuous purge and pilot [20]	--	--	--	--
- Intermittent Pigging [c]	--	--	--	--
- Controlled oil plant shutdown	328	--	--	--
- Controlled gas plant shutdown [21]	357 [23]	304	185	29
- Amine Failure				
(30 MMSCFD)	186 [f]	1,576	545	74
(60 MMSCFD) [22]	216 [f]	1,997	685	91
- Sulfur plant failure [d]	352 [f]	8,644	2,901	368
OFFSHORE				
- Platforms	271	627	460	248
STANDARDS	470 (State)	655 (State)	1,300 (Federal Secondary)	131 (State) 365 (Federal Primary)

17. This was Table 6-5 in ATC 5704 (2/6/86).
19. Values are totals including facility contribution and background values from Table 10.1-3 of ATC 5704 (2/6/86).
20. Contributions are included in normal operation of onshore facility.
21. These emission scenarios are based on of 90 percent SO_2 reduction by use of the emergency amine scrubber.
22. 60 MMSCFD amine unit failure would be associated with Phase II gas plant.
23. NO_2 value scaled from SO_2 value.

Table 6.4
FM O&G GOHF - PTO 5704-R5
Onshore Ozone Impacts of Project Facilities [24]

Project Facilities	Peak Onshore Ozone Concentration (pphm)	Increase Over Baseline Concentration (pphm)
Trajectory 1 - Offshore Carpinteria to Project platforms to Santa Ynez Valley		
3 Platforms	11.2 (12.6) [25]	1.1 (2.5) [b]
8 Platforms	11.5	1.4
Trajectory 2 - Project platforms to offshore Gaviota to Goleta		
3 Platforms	10.8 (13.0) [26]	0.1 (2.3) [c]
8 Platforms	11.0	0.3
Trajectory 3 - Gaviota to offshore Gaviota to Goleta		
Onshore Processing Plant	10.3	0.0
Trajectory 4 - Project platforms to offshore Gaviota to Ojai		
3 Platforms	11.7 (15.1) [b]	0.6 (4.0) [b]
8 Platforms	11.3	0.2

24 This was Table 6-6 in ATC 5704 (2/6/86).
25 Facility upset conditions.
26 Reduced wind speed over platforms.

Table 6.5
FM O&G GOHF - PTO 5704-R5
Maximum Project Increment Consumed [27, 28]

POLLUTANT	AVERAGING TIME	INCREMENT CONSUMPTION [29] ($\mu g/m^3$)	ALLOWABLE INCREMENT ($\mu g/m^3$)
NO_2	1-Hour	367	100-470 [30]
	Annual	9	25
TSP	24-Hour	16	37
	Annual	2	19
PM_{10}	24-Hour	15	12-50
CO	1-Hour	964	10,000
	8-Hour	205	2,500
SO_2	3-Hour	199	512
	24-Hour	31	91
	Annual	3	20
ROC	3-Hour	2,095 [31]	40-160 [d]

27 This was Table 6-6 in ATC 5704 (2/6/86).
28 The results are for equipment allowed under the permit. Preliminary modeling of the proposed project with both Phase I and Phase II gas plants predicted exceedances of the State 1-hour standards for NO2 and SO2.
29 Maximum increment consumed is due to operation of the oil and gas plant.
30 Increment fee is imposed for impact above lower limit.
31 ROC increment revised per District 6/2/89 letter.

Table 6.6
FM O&G Gaviota - PTO 5704-R5
Monitoring Station Requirements

Monitoring Station	O_3	NO	NO_x	NO_2	SO_2	THC	H_2S	PM_{10}	ROC	TRS	Ave WS	Ave WD	VWS	ATM	SIGMA W	SIGMA V	SIGMA T	Int Stn Temp	Res WS	Res WD
Carpinteria	x	x	x	X							x	x		x			x	x	x	x

7.0 CAP Consistency, Offset Requirements and ERCs

7.1 General

Santa Barbara County has not attained the state Ozone and PM_{10} air quality standards. Therefore, emissions from all emission units at the stationary source and its constituent facilities must be consistent with the provisions of the USEPA and State approved Clean Air Plans (CAP) and must not interfere with progress toward attainment of federal and state ambient air quality standards. Under District regulations, any modifications at the source that result in an emission increase of any nonattainment pollutant exceeding 25 lbs/day must apply BACT (NAR). Increases above offset thresholds will trigger offsets at the source or elsewhere so that there is a net air quality benefit for Santa Barbara County. These offset threshold levels are 240 lbs/day for all attainment pollutants and precursors (except carbon monoxide and $PM_{2.5}$) and 25 tons/year for all non-attainment pollutants and precursors (except carbon monoxide and $PM_{2.5}$).

7.2 Clean Air Plan

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

In December 2019, the District Board adopted the 2019 Ozone Plan. The 2019 Plan provides a three-year update to the 2016 Ozone Plan, (which was later revised in August 2017), and is the ninth triennial update to the initial State Air Quality Attainment Plan. As Santa Barbara County was designated nonattainment-transitional for the state eight-hour ozone standard at the time of the 2019 Ozone Plan publication, the county reached attainment status on July 1, 2020. The 2019 Ozone Plan demonstrates how the District plans to attain and keep that standard. The 2019 Ozone Plan therefore satisfies all state triennial planning requirements.

7.3 Offset Requirements and Emission Reduction Credits (ERCs)

Note: This section provides the details regarding the project's offset requirements during permitting of the original project under ATC 5704. Oil and gas operations at this facility have ceased. The only equipment in service is the emergency firewater pump. Section 7.6 provides the only recent ERC actions issued for this facility.

District rules and regulations require that emissions from the entire project, when considered in conjunction with emission reductions proposed by the applicant for existing sources, result in a Net Air Quality Benefit. Additionally, operational emissions must be consistent with the Clean Air Plan ("CAP") and must not interfere with reasonable further progress toward attainment and maintenance of ozone standards.

The agreement entitled "*Contract for Implementation of Conditions E-4, E-7 and E-9 of the Chevron Point Arguello Project Preliminary Development Plan No. 83-DP-32-CZ*", (signed August 19, 1985, and amended on September 8, 1992) and the "*OCS Ozone Mitigation Agreement*" (signed September 8, 1992 and subsequently amended on September 5, 1995; October 22, 1996 and May 20, 1997) provides specific procedures FM O&G must implement to ensure that project emissions, including operation emissions onshore, nearshore and on the OCS, are consistent with the CAP and result in a Net Air Quality Benefit and reasonable further progress provisions of the CAP. *OCS Ozone Mitigation Agreement* (approved September 8, 1992).

District rules require existing source emission reductions to be in place prior to the initiation of and for the duration of the project's emissions. The emission reductions must be quantifiable, surplus, permanent and enforceable. When permitted in 1986, FM O&G obtained emission reductions/offsets through the following mechanisms: a written agreement between the District and FM O&G, a modification of existing FM O&G permits and a written agreement between the owner of emission reduction sources and FM O&G with the District as third party beneficiary.

Offset credit is based on actual demonstrated emissions reductions for each offset source, adjusted for the distance factor between the offset and the project (the OCS emission offset ratio is specified in the *OCS Ozone Mitigation Agreement*). Source testing and further quantification of emissions, using procedures approved by the District, is necessary to ensure the actual emissions reductions from each source used as offsets occurs throughout the life of the Project.

7.4 Onshore Offset Requirements

Details of the original offset requirements for the onshore facility can be found in PTO 5704-R5 which was the last permit to operate issued for the GOHF prior to the decommissioning of the equipment and processes at this facility.

7.5 Offshore Offset Requirements

Details of the original offset requirements for the offshore facility can be found in PTO 5704-R5 which was the last permit to operate issued for the GOHF prior to the decommissioning of the equipment and processes at this facility. PTO 5704-R5 contains the offset requirements, formerly required for the entire stationary source, including the platforms.

7.6 ERC Source Verification

With the exception of facilities that have shut down permanently, the District regularly inspects each of the emission offset sources for compliance with emission reduction requirements. For combustion sources, this may include an annual emissions source test to ensure that the control efficiencies are maintained.

Decision of Issuance 113 was issued final March 20, 2019 for ERCs generated by the shutdown of the oil and gas equipment at the GOHF. ERCs are not required for emissions associated with the operation of the firewater pump.

8.0 Lead Agency Permit Consistency

Note: This section provides the details regarding the lead agency's permitting requirements and summary of findings as part of the original project issued under ATC 5704. Oil and gas operations at this facility have since ceased. The only equipment in service is the emergency firewater pump. All other equipment formerly at this facility has been decommissioned and depermitted.

8.1 CEQA Requirements for PTO 5704

Pursuant to the *Environmental Review Guidelines for the Santa Barbara County Air Pollution Control District* (October 1995), the issuance of this Permit to Operate is exempt from CEQA review. The PTO relies on and is consistent with ATC 5704 (including all updates). No discretion or judgment is required in the granting of this permit.

8.2 Summary of CEQA Findings for ATC 5704 (Original Project)

The California Environmental Quality Act ("CEQA") requires that both "lead" and "responsible" agencies make certain findings in approving projects. The Santa Barbara County Resource Management Department, the CEQA lead agency for the original approval of this project, has made the necessary findings for project approval. These findings include consideration of environmental documents, Class I and II impacts, project alternatives, benefits of the project and statements of overriding consideration. On December 21, 1984, the Santa Barbara County Planning Commission approved the project and the CEQA findings.

The complete CEQA analysis is presented in the project EIR and ATC 5704 and subsequent permit modifications. A summary of these findings is as follows:

<u>CEQA Finding # 1</u>: *Significant impacts that cannot be substantially lessened or avoided.*

> Particulate emissions from operation of GOHF will add to existing violations of the State PM_{10} standard. FM O&G is required to provide mitigation for PM_{10} emissions as specified in the PM_{10} Emission Reduction Study. Implementation of these requirements was delayed by the District. The residual impact, after implementation of the permit conditions, is considered acceptable due to the local nature of the impact and the high background PM_{10} levels typical of coastal environments.

<u>CEQA Finding #2</u>: Significant impacts have been eliminated or substantially lessened, where feasible, by implementation of all BACT requirements and air pollution controls proposed by the applicant.

> Emissions of NO_x and ROCs from project components will lead to significant increases in ambient ozone concentrations, as NO_x and ROC are precursors to ozone formation. Ozone levels in excess of both the state and federal standards are anticipated to occur. However, by providing offsets for project NO_x and ROC emissions, these impacts are effectively mitigated.
>
> Emissions of SO_x from the flare were anticipated to cause exceedances of state 1 and 24-hour and federal 3-hour SO_2 ambient air quality standards during periods of amine and sulfur plant failures. However, FM O&G implemented a number of control devices as specified in the Phase II Flare Study which effectively mitigated these impacts.

<u>CEQA Finding #3:</u> The unavoidable significant impacts of the project are found to be acceptable due to overriding considerations.

Particulate emissions from GOHF result in an unavoidable significant adverse impact to air quality. However, offsets provided to mitigate NO_x and ROC emissions result in a net air quality benefit for these pollutants and are sufficient to outweigh the unavoidable environmental impact resulting from particulate emissions.

8.3 Lead Agency Permit Requirements

A Final Development Plan ("FDP") for the FM O&G Gaviota Development Project was approved by the Santa Barbara County Board of Supervisors. The approved Plan contains a number of provisions that relate to the air quality aspects of the proposed project. The following is a summary of major conditions and their relationship to the District's evaluation and final decision on the project.

<u>FDP Condition E-2:</u> Requirement for ATC prior to construction.

> The issuance of the ATC permit fulfilled this requirement for the construction activities.

<u>FDP Condition E-3/E-5:</u> Requirement for preparation and implementation of Curtailment Plans for the protection of ambient air quality standards.

> This requirement is no longer applicable.

<u>FDP Condition E-4</u>: Requirement for ambient air quality monitoring stations to examine onshore effects of construction and operation emissions.

Section 6.6, Ambient Monitoring identify the requirement for FM O&G to operate ambient air quality monitors during the project life.

<u>FDP Condition E-6</u>: Requirement for use of natural gas containing less than 4 ppm H_2S in gas turbines.

The GOHF is limited to 4 ppmv total sulfur in the fuel gas.

<u>FDP Conditions E-7 and E-9</u>: Requirement that all NO_x and HC emissions that contribute to ozone standard violations be completely mitigated. Requires that Arguello submit a plan based upon the letter agreements reached during the SCDP for project components on the OCS.

Compliance with emission mitigation requirements are discussed in Section 7. Arguello has implemented the *Contract for Implementation of Conditions E-4, E-7 and E-9 of the Chevron Point Arguello Preliminary Development Plan No. 83-DP-32-CZ* (amended September 8, 1992) and the *OCS Ozone Mitigation Agreement* (dated September 8, 1992) in fulfillment of this requirement. Consolidation of OCS letters was achieved through the APCD approved *"OCS Control Measures, Recordkeeping, and Reporting Plan*", dated (April 1993, updated February 1995). The elements of the plan have been incorporated directly into the platform Part-70 permits.

<u>FDP Condition E-8</u>: Cogeneration units can be used (up to the proposed 17.5 MW) provided that exceedances of local, state or federal ambient air quality standards do not occur, as determined by District-approved modeling of cumulative impacts. Arguello shall equip the cogeneration unit stack with Continuous Emissions Monitoring and telemeter the data to the District offices.

The AQIA results (Section 6.1) show that the capacity of cogeneration facilities can be up to 17.5 MW without violating standards, providing that SCR is used. Permit conditions limit the cogeneration capacity and emissions and identify the requirement for Continuous Emissions Monitoring.

<u>FDP Condition E-11</u>: Requirement for data submission on helicopters, crew and supply boats.

Platform permits require submission of this data.

<u>FDP Condition K-7</u>: Prohibits visible smoke emissions during normal operations.

Compliance with District Rules 302 and 359 fulfills this condition.

<u>FDP Condition P-12</u>: Requires modification of construction schedule to prevent $N0_2$ standard violations during construction.

No longer applicable.

<u>FDP Condition A-21:</u> Requires mitigation of onshore air quality impacts from offshore operations, as projected through the AQAP update.

As described in Section 7.3, FM O&G shall implement measures required by the *Contract for Implementation of Conditions E-4, E-7 and E-9 of the Chevron Point Arguello Preliminary Development Plan No. 83-DP-32-CZ* (amended September 8, 1992) and the *OCS Ozone Mitigation Agreement* (dated September 8, 1992).

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9.C REQUIREMENTS AND EQUIPMENT SPECIFIC CONDITIONS

9.D DISTRICT-ONLY CONDITIONS

9.0 Permit Conditions

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

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

9.A Standard Administrative Conditions

The following federally enforceable administrative permit conditions apply to the GOHF. In the case of a discrepancy between the wording of a condition and the applicable District rule, the wording of the rule shall control.

A.1 **Condition Acceptance.** Acceptance of this operating permit by FM O&G shall be considered as acceptance of all terms, conditions, and limits of this permit. *[Re: ATC 5704]*

A.2 **Grounds for Revocation.** Failure to abide by and faithfully comply with this permit shall constitute grounds for the APCO to petition for permit revocation pursuant to California Health & Safety Code Section 42307 *et seq.* *[Re: ATC 5704]*

A.3 **Reimbursement of Costs.** All reasonable expenses, as defined in District Rule 210, incurred by the District, District contractors, and legal counsel for all activities related to the implementation of Regulation XIII (*Part 70 Operating Permits*) that follow the issuance of this PTO 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 FM O&G as required by Rule 210. *[Re: ATC 5704; Rule 210]*

A.4 **Access to Records and Facilities.** As to any condition that requires for its effective enforcement the inspection of records or facilities by the District or its agents, FM O&G shall make such records available or provide access to such facilities upon notice from the District. Access shall mean access consistent with California Health and Safety Code Section 41510 and Clean Air Act Section 114A. *[Re: ATC 5704]*

A.5 **Compliance.** Nothing contained within this permit shall be construed to allow the violation of any local, State or Federal rules, regulations, ambient air quality standards or air quality increments. *[Re: ATC 5704]*

A.6 **Injunctive Relief.** In addition to any administrative remedies or enforcement provided hereunder, the District may seek and obtain temporary, preliminary, or permanent injunctive relief to prohibit violation of the conditions set forth herein or to mandate the conditions set forth herein or to mandate compliance with the conditions herein. All remedies and enforcement procedures set forth herein shall be in addition to any other legal or equitable remedies provided by law. *[Re: ATC 5704]*

A.7 **Consistency with Analysis.** Operation under this permit shall be conducted consistent with all written data, specifications and assumptions included with the application and supplements thereof (as documented in the District's project file), and with the District's analyses under which this permit is issued as documented in the permit analyses prepared for and issued with this permit. *[Re: ATC 5704]*

A.8 **Consistency with State and Local Permits.** Nothing in this permit shall relax any air pollution control requirement imposed on this facility by the State of California or the California Coastal Commission in any consistency determination for the Project with the California Coastal Act. *[Re: ATC 5704]*

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

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

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

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

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

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

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

(i) compliance with the permit, or

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

(g) In the event that any condition herein is determined to be in conflict with any other condition contained herein, then, if principles of law do not provide to the contrary, the condition most protective of air quality and public health and safety shall prevail to the extent feasible. *[Re: 40 CFR Part 70.6.(a)(6), District Rule 1303.D.1]*

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

A.11 **Compliance Plan.**

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

(b) For all applicable equipment, the permittee shall implement and comply with any specific compliance plan required under any federally enforceable rules or standards. *[Re: District Rule 1302.D.2]*

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

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

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

(c) To sample substances or monitor emissions from the source or assess other parameters to assure compliance with the permit or applicable requirements, at reasonable times. Monitoring of emissions can include source testing. *[Re: District Rule 1303.D.2]*

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

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

503(d) and of the District rules.

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

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

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

A.17 **Reporting Requirements/Compliance Certification.** The permittee shall submit compliance certification reports to the USEPA and the Control Officer every six months. A paper copy, as well as, a complete PDF electronic copy of these reports, shall be in a format approved by the District. These reports shall be submitted on District forms and shall identify each applicable requirement/condition of the permit, the compliance status with each requirement/condition, the monitoring methods used to determine compliance, whether the compliance was continuous or intermittent, and include detailed information on the occurrence and correction of any deviations (excluding emergency upsets) from permit requirement. The reporting periods shall be each half of the calendar year, e.g., January through June for the first half of the year. These reports shall be submitted by September 1 and March 1, respectively, each year. Supporting monitoring data shall be submitted in accordance with the "Semi-Annual Compliance Verification Report" condition in section 9.C. The permittee shall include a written statement from the responsible official, which certifies the truth, accuracy, and completeness of the reports.
Re: District Rules 1303.D.1, 2.c; 1302.D.3]

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

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

(a) The date, place as defined in the permit, and time of sampling or measurements;
(b) The date(s) analyses were performed;
(c) The company or entity that performed the analyses;
(d) The analytical techniques or methods used;
(e) The results of such analyses; and
(f) The operating conditions as existing at the time of sampling or measurement;

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

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

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

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

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

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

A.21 **Risk Management Plan – Section 112r.** FM O&G shall comply with the requirements of 40 CFR 68 on chemical accident prevention provisions. The annual compliance

certification, if required, must include a statement regarding compliance with this part, including the registration and submission of the risk management plan (RMP).
[Re: 40 CFR 68]

9.B Generic Conditions

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

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

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

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

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

For the emergency firewater pump, FM O&G shall determine compliance with this Condition/Rule, as specified below:

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

FM O&G shall obtain District approval of the Visible Emissions Log required by this condition. All VEE sheets and records shall be maintained consistent with the recordkeeping condition of this permit.

For the purposes of this condition, "certified in VEE" shall mean that each individual assigned to perform a VEE has completed Smoke School Training and obtained certification in accordance with Method 9, section 3. Continued certification every six months is required. *[Re: District Rule 302]*

B.3 **Nuisance (Rule 303).** No pollutant emissions from any source at this facility shall create nuisance conditions. Operations shall not endanger health, safety or comfort, nor shall they damage any property or business. *[Re: District Rule 303]*

B.4 **PM Concentration – Southern Zone (Rule 305).** FM O&G shall not discharge into the atmosphere, from any source, particulate matter in excess of the concentrations listed in the PM concentrations listed in the table included in this rule. *[Re: District Rule 305]*

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

B.6 **Sulfur Content of Fuels (Rule 311).** FM O&G shall not burn fuels with a sulfur content in excess of 0.5% (by weight) for liquid fuels and 238 ppmvd (50 gr/100 scf calculated as H_2S) for gaseous fuel. *[Re: District Rule 311]*

B.7 **Organic Solvents (Rule 317).** FM O&G shall comply with the emission standards listed in Rule 317.B. Compliance with this condition shall be based on FM O&G compliance with Condition 9.C.1 of this permit and facility inspections. *[Re: District Rule 317]*

B.8 **Metal Surface Coating Thinner and Reducer (Rule 322).** The use of photochemically reactive solvents as thinners or reducers in metal surface coatings is prohibited. Compliance with this condition shall be based on FM O&G compliance with Condition 9.C1 of this permit and facility inspections. *[Re: District Rule 322]*

B.9 **Architectural Coatings (Rule 323.1).** FM O&G shall comply with the rule requirements for any architectural coating that is supplied, sold, offered for sale, or manufactured for use within the District.
[Re: District Rules 323, 317, 322, 324]

B.10 **Disposal and Evaporation of Solvents (Rule 324).** FM O&G shall not dispose through atmospheric evaporation of more than one and a half gallons of any photochemically reactive solvent per day. Compliance with this condition shall be based on FM O&G compliance with Condition 9.C.1 of this permit and facility inspections. *[Re: District Rule 324]*

B.11 **Adhesives and Sealants (Rule 353).** FM O&G 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 FM O&G uses such materials from containers larger than 16 fluid ounces and the materials are not exempt by Rule 353.B.1, the total reactive organic compound emissions from the use of such material shall not exceed 200 pounds per year unless the substances used and the operational methods comply with Sections D, E, F, G, and H of Rule 353. Compliance shall be demonstrated by recordkeeping in accordance with Section B.2 and/or Section O of Rule 353. *[Re: District Rule 353]*

B.12 **Emissions Of Oxides Of Nitrogen From Large Water Heaters and Small Boilers (Rule 360)**: This rule applies to any person who supplies, sells, offers for sale, installs, or solicits the installation of any new water heater, boiler, steam generator or process heater for use within the District with a rated heat input capacity greater than or equal to 75,000 Btu/hour up to and including 2,000,000 Btu/hour. There are no new units at this facility that are subject to this rule.

B.13 **Small Boilers, Steam Generators, and Process Heaters (Rule 361)**: The permittee shall comply with the requirements of District Rule 361: *Small Boilers, Steam Generators, and Process Heaters* whenever a new boiler, process heater or other external combustion device is added or an existing unit is replaced.

B.14 **Emergency Episode Plan.** During emergency episodes, FM O&G shall implement the District-approved (February 2005) Emergency Episode Plan.

B.15 **Oil and Gas MACT.** FM O&G shall maintain records in accordance with 40 CFR Part 63, Subpart A--General Provisions, Sec. 63.10 (b)(3), to demonstrate the black oil exemption applies per 40 CFR 63.760(e)(1). *[Re: 40 CFR 63, Subpart HH]*

B.16 **CARB Registered Portable Equipment.** State registered portable equipment shall comply with State registration requirements. A copy of the State registration shall be readily available whenever the equipment is at the facility. *[Re: District Rule 202]*

9.C Requirements and Equipment Specific Conditions

C.1 **Standby/Emergency Diesel IC Engines.** The following equipment are included in this emissions unit category:

Device ID #	Device Name
107063	IC Engine: Emergency Standby Firewater Pump (267 bhp)

(a) Emission Limits. Emissions from this engine shall not exceed the emission limit standards (emission factors) listed in Table 5.1-2 or the mass limits listed in Tables 5.1-3 and 5.1-4. Compliance shall be based on the operational, monitoring, recordkeeping and reporting conditions of this permit. These limits are based on the maintenance and testing operational limits listed in permit condition 9.D.2(b)(i) below.

(b) Operational Limits. The equipment permitted herein is subject to the following operational restrictions listed below. Emergency use operations, as defined in Section (d)(25) of the ATCM[32], have no operational hours limitations.

(i) *Maintenance & Testing Use Limit:* The stationary emergency standby diesel-fueled CI engine subject to this permit, shall limit maintenance and testing[33] operations to no more than 2 hours per day and 100 hours per year.

(ii) *Fuel and Fuel Additive Requirements:* The permittee may only add CARB Diesel, or an alternative diesel fuel that meets the requirements of the ATCM Verification Procedure, or CARB Diesel fuel used with additives that meet the requirements of the ATCM Verification Procedure, or any combination of the above to the engine or any fuel tank directly attached to the engine.

(iii) *Maintenance Requirements:* Each engine shall comply with the following engine maintenance requirements:

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

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

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

[32] As used in the permit, "ATCM" means Section 93115, Title 17, California Code of Regulations. Airborne Toxic Control Measure for Stationary Compression Ignition (CI) Engines

[33] "maintenance and testing" is defined in Section (d)(41) of the ATCM

whichever comes first.

In lieu of changing the oil and filter, the permittee may analyze the oil of each engine every 500 hours of operation or annually, whichever occurs first. The analysis shall measure the Total Base Number, the oil viscosity, and the percent water content. The oil and filter shall be changed if any of the following limits are exceeded:

- The tested Total Base Number is less than 30 percent of the Total Base Number of the oil when new.
- The tested oil viscosity has changed by more than 20 percent from the oil viscosity when new.
- The tested percent water content (by volume) is greater than 0.5 percent.

(c) Monitoring. The equipment permitted herein is subject to the following monitoring requirements:

(i) The diesel-fueled CI engine subject to this permit shall have installed a non-resettable hour meter with a minimum display capability of 9,999 hours, unless the District has determined (in writing) that a non-resettable hour meter with a different minimum display capability is appropriate in consideration of the historical use of the engine and the owner or operator's compliance history.

(d) Recordkeeping. The permittee shall record and maintain the information listed below. Log entries shall be retained for a minimum of 36 months from the date of entry. Log entries made within 24 months of the most recent entry shall be retained on-site, either at a central location or at the engine's location, and made immediately available to the District staff upon request. Log entries made from 25 to 36 months from most recent entry shall be made available to District staff within 5 working days from request. District Form ENF-92 (*Diesel-Fired Emergency Standby Engine Recordkeeping Form*) can be used for this requirement:

(i) emergency use hours of operation.

(ii) maintenance and testing hours of operation.

(iii) hours of operation for all uses other than for emergency use and maintenance and testing, along with a description of what those hours were for.

(iv) Fuel purchase records or a written statement on the fuel supplier's letterhead signed by an authorized representative of the company confirming that the fuel purchased is either CARB Diesel, or an alternative diesel fuel that meets the requirements of the Verification Procedure, or an alternative fuel, or CARB Diesel fuel used with additives that meet the requirements of the Verification Procedure, or any combination of the above *(Reference Stationary Diesel ATCM and Title 13, CCR, Sections 2281 and 2282)*.

(v) The sulfur content of each fuel shipment as documented by fuel supplier records (e.g. billing vouchers or bills of laden). On an annual basis, the heating value of the diesel fuel (Btu/gal) shall be recorded based on measurement by FM O&G or certified by the fuel supplier.

(vi) The following maintenance records:

(1) The date of each oil and filter change, the number of hours of operation since the last oil change. If an oil analysis is performed, the records must include the date and results of each oil analysis and the Total Base Number and oil viscosity of the oil when new;

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

(3) The date of each hose and belt inspection and the number of hours of operation since the last hose and belt inspection. Indicate if any hose or belt was replaced because of the inspection.

C.1 **Complaint Response.** FM O&G shall provide the District with the name, title, current address, and 24-hour telephone number of contact person(s) who shall be available to respond to complaints from the public concerning nuisance or odors. These contact person(s) shall aid the District staff, as requested by the District, in the investigation of any complaints received. FM O&G shall take actions necessary to correct the facility activity that is reasonably believed by FM O&G to have caused the complaint. FM O&G shall keep the District fully appraised of their assessment and resolution of the problem. *[Re: ATC 5704]*

C.2 **Diesel IC Engines - Particulate Matter Emissions.** To ensure compliance with District Rules 205.A, 302, 304, 309 and the California Health and Safety Code Section 41701, FM O&G shall comply with the most recently District-approved *Diesel IC Engine Particulate Matter Operation and Maintenance Plan*. This Plan details the manufacturer recommended maintenance and calibration schedules that FM O&G will implement. Where manufacturer guidance is not available, the recommendations of comparable equipment manufacturers and good engineering judgment shall be utilized. All diesel-fired engines, regardless of exemption status, shall be included in this Plan. *[Re: 40 CFR 70.6]*

C.3 **Mass Emission Limitations.** Mass emissions for each emissions unit associated with the GOHF shall not exceed the limits listed in Tables 5.1 and 5.2. *[Re: ATC 5704]*

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

(a) *Emergency Standby Firewater Pump*

(i) emergency use hours of operation.

(ii) maintenance and testing hours of operation.

(iii) hours of operation for all uses other than for emergency use and maintenance and testing, along with a description of what those hours were for.

(iv) Fuel purchase records or a written statement on the fuel supplier's letterhead signed by an authorized representative of the company confirming that the fuel purchased is either CARB Diesel, or an alternative diesel fuel that meets the requirements of the Verification Procedure, or an alternative fuel, or CARB Diesel fuel used with additives that meet the requirements of the Verification Procedure, or any combination of the above *(Reference Stationary Diesel ATCM and Title 13, CCR, Sections 2281 and 2282).*

(v) The sulfur content of each fuel shipment as documented by fuel supplier records (e.g. billing vouchers or bills of laden). On an annual basis, the heating value of the diesel fuel (Btu/gal) shall be recorded based on measurement by FM O&G or certified by the fuel supplier.

(vi) The following maintenance records:

(1) The date of each oil and filter change, the number of hours of operation since the last oil change. If an oil analysis is performed, the records must

include the date and results of each oil analysis and the Total Base Number and oil viscosity of the oil when new;

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

(3) The date of each hose and belt inspection and the number of hours of operation since the last hose and belt inspection. Indicate if any hose or belt was replaced because of the inspection.

(b) *Emissions Reporting*.

(i) On an annual basis, NO_x and ROC emissions from all exempt activities.

(ii) Tons per quarter of all pollutants (by emissions unit) including supporting data.

(c) *General Reporting Requirements*.

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

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

C.5. **Documents Incorporated by Reference.** FM O&G shall implement, and operate in accordance with, each of the plans listed below. The documents listed below, including any District-approved updates thereof, are incorporated herein and shall the full force and effect of a permit condition of this operating permit:

a) *Diesel IC Engine Particulate Matter Operation and Maintenance Plan (revised and approved March 21, 2001)*

b) *Process Monitor Calibration and Maintenance Plan (revised and approved March 21, 2001)*

c) *Emergency Episode Plan (revised February 2005).*

9.D District-Only Conditions

D.1 **Standby/Emergency Diesel IC Engines.** The following equipment are included in this emissions unit category:

Device ID #	Device Name
107063	IC Engine: Emergency Standby Firewater Pump (267 bhp)

(a) **Temporary Engine Replacements - DICE ATCM.** Any reciprocating internal combustion engine subject to this permit and the stationary diesel ATCM may be replaced temporarily only if the requirements (i) - (viii) listed herein are satisfied:

(i) The permitted engine that is being temporarily replaced is in need of routine repair or maintenance.

(ii) The permitted engine does not have a cracked block, unless the block will be replaced under manufacturer's warranty.

(iii) Replacement parts are available for the permitted engine.

(iv) The permitted engine is returned to its original service within 180 days of installation of the temporary engine.

(v) The temporary replacement engine has the same or lower manufacturer rated horsepower and same or lower potential to emit of each pollutant as the permitted engine. At the written request of the permittee, the District may approve a replacement engine with a larger rated horsepower if the proposed temporary engine has manufacturer guaranteed emissions (for a brand new engine) or source test data (for a previously used engine) less than or equal to the permitted engine.

(vi) The temporary replacement engine shall comply with all rules and permit requirements that apply to the permitted engine.

(vii) For each permitted engine to be temporarily replaced, the permittee shall submit a completed *Temporary IC Engine Replacement Notification* form (Form ENF-94) within 14 days of the temporary engine being installed. This form may be sent hardcopy, or can be e-mailed (e-mail: engr@sbcapcd.org) to the District (Attn: Engineering Supervisor).

(viii) Within 14 days of returning the original permitted engine to service, the permittee shall submit a completed *Temporary IC Engine Replacement Report* form (Form ENF-95). This form may be sent hardcopy, or can be e-mailed (e-mail: engr@sbcapcd.org) to the District (Attn: Engineering Supervisor).

Any engine in temporary replacement service shall be immediately shut down if the District determines that the requirements of this condition have not been met. If the requirements of this condition are not met, the permittee must obtain an ATC before installing or operating a temporary replacement.

(b) **Permanent Engine Replacements.** Any E/S engine, firewater pump engine or engine used for an essential public service that breaks down and cannot be repaired may install a new replacement engine without first obtaining an ATC permit only if the requirements (i) - (vi) listed herein are satisfied.

(i) The permitted stationary diesel IC engine is an E/S engine, a firewater pump engine or an engine used for an essential public service (as defined by the District).

(ii) The permitted engine breaks down, cannot be repaired and needs to be replaced by a new permitted engine.

(iii) The facility provides "good cause" (in writing) for the need to install a new permanent engine before an ATC can be obtained for a new engine.

(iv) The new permanent engine must comply with the requirements of the ATCM for new engines. A temporary replacement engine may be used while the new permanent engine is being procured only if it meets the requirements of the *Temporary Engine Replacements - DICE ATCM* permit condition.

(v) An ATC application for the new permanent engine must be submitted to the District within 15 days of the existing engine being replaced and the ATC must be obtained no later than 180 days from the date of engine replacement (these timelines include the use of a temporary engine).

(vi) For each new permanent engine installed pursuant to this condition, the permittee shall submit a completed *Permanent IC Engine Replacement Notification* form (Form ENF-96) within 14 days of the new engine being installed. This form may be sent hardcopy, or can be e-mailed (e-mail: engr@sbcapcd.org) to the District (Attn: Engineering Supervisor).

Any engine installed pursuant to this permit condition shall be immediately shut down if the District determines that the requirements of this condition have not been met.

(c) **Notification of Non-Compliance.** Owners or operators who have determined that they are operating their stationary diesel-fueled engine(s) in violation of the requirements specified in Sections (e)(1) of the ATCM shall notify the District immediately upon detection of the violation and shall be subject to District enforcement action.

(d) **Notification of Loss of Exemption.** Owners or operators of in-use stationary diesel-fueled CI engines, who are subject to an exemption specified in Section (c) from all or part of the requirements of Section (e)(2), shall notify the District immediately after they become aware that the exemption no longer applies and pursuant to Section (e)(4)(F)(1) of the ATCM shall demonstrate compliance within 180 days after notifying the District.

D.3 **Particulate Matter Mitigation.** FM O&G shall implement PM_{10} mitigation requirements specified by any future District PM_{10} Attainment Plan. The District 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 District, FM O&G shall implement PM_{10} control measures identified in the future PM_{10} Attainment Plan on appropriate equipment regulated by District permits.

D.4 **Odorous Organic Sulfides (Rule 310).** FM O&G shall not discharge into the atmosphere H_2S or organic sulfides that result in a ground level impact beyond the FM O&G property boundary in excess of either 0.06 ppmv averaged over 3 minutes and 0.03 ppmv averaged over 1 hour. Monitoring specified in condition 9.C.13 shall be used to assess compliance. [*Re: District Rule 310]*

AIR POLLUTION CONTROL OFFICER

____

____
Date

<u>NOTES</u>:

(a) Permit Reevaluation Due Date: July 2026
(b) This permit supersedes Part 70 Minor Mod/PTO 15455 and Part 70 ADM 15585.

Attachments

10.1 Emission Calculation Documentation

10.2 IDS Tables

10.3 Equipment List

ATTACHMENT 10.1
Emission Calculation Documentation

GAVIOTA OIL PLANT

This attachment contains all relevant emission calculation documentation used for the emission tables in Section 5. Refer to Section 4 for the general emission equations.

Reference A - Internal Combustion Engines

Emission factors (EF) for the emergency firewater ICE were chosen based on the engine's rating and age. Unless engine specific data was provided, default emission factors are used as documented on the District's webpage at http://www.ourair.org/dice/emission-factors/. The engine subject to this permit is limited to 2 hours per day and 100 hours per year for maintenance and testing.

Reference B - Solvents

-All solvents not used to thin surface coatings are included in this equipment category

-Daily, quarterly and annual emission rates per FM O&G's July 20, 1995 application

- Hourly emissions based on the daily solvent value divided by an average 8-hour day. Compliance with hourly data to be based on the calculated daily usage (actual monthly solvent usage divided by the number of days that solvents are used per month) divided by 8 hrs/day.

Reference C - Greenhouse Gases

GHG emissions from combustion sources are calculated using emission factors found in Tables C-1 and C-2 of 40 CFR Part 98 and global warming potentials found in Table A-1 of 40 CFR Part 98. CO2 equivalent emission factors are calculated for CO2, CH4, and N2O individually then summed to calculate a total CO2e emission factor. Annual CO2e emission totals are presented in short tons.

For IC engines, the emission factor in lb/MMBtu heat input is converted to g/bhp-hr output based on a standard brake-specific fuel consumption.

For diesel fuel combustion the emission factor is:
(73.96 kg CO2/MMbtu) (2.2046 lb/kg) = 163.05 lb CO2/MMBtu
(0.003 kg CH4/MMBtu) (2.2046 lb/kg)(25 lb CO2e/lb CH4) = 0.165 lb CO2e/MMBtu
(0.0006 kg N2O/MMBtu) (2.2046 lb/kg)(298 lb CO2e/lb N2O) = 0.394 lb CO2e/MMBtu
Total CO2e/MMBtu = 163.05 + 0.139 + 0.410 = 163.61 lb CO2e/MMBtu

Converted to g/bhp-hr:
(163.60 lb/MMBtu)(453.6 g/lb)(7500 Btu/bhp-hr)/1,000,000 = 556.60 g/bhp-hr as CO2

ATTACHMENT 10.2
IDS Database Emission Tables

Table 10.2-1
Permitted Potential to Emit (PPTE)

	NO_X	ROC	CO	SO_X	PM	$PM_{2.5/10}$
PTO 15455-R1 - Pt-70 Permit to Operate						
lb/day	16.54	1.32	3.65	0.00	0.36	0.36
tons/year	0.41	0.03	0.09	0.00	0.01	0.01

Table 10.2-2
Facility Potential to Emit (FPTE)

	NO_X	ROC	CO	SO_X	PM	$PM_{2.5/10}$
PTO 15455-R1 - Pt-70 Permit to Operate						
lb/day	16.54	1.32	3.65	0.00	0.36	0.36
tons/year	0.41	0.03	0.09	0.00	0.01	0.01

Table 10.2-3
Stationary Source Potential to Emit (SSPTE)

	NO_X	ROC	CO	SO_X	PM	$PM_{2.5/10}$
Pt. Arguello Project Stationary Source						
lb/day	5,099.48	479.74	1,09438	2.16	382.75	367.60
tons/year	314.53	51.29	109.08	0.18	30.64	29.45

ATTACHMENT 10.3
Equipment List

Santa Barbara County Air Pollution Control District – Equipment List

PT-70/Reeval 15455-R1/ FID: 01325 Gaviota Oil Heating Facility / SSID: 01325

A PERMITTED EQUIPMENT

1 Stationary Internal Combustion Engines (Table A)

1.1 Emergency Firewater Pump

Device ID #	000992	*Maximum Rated BHP*	267.00
Device Name	Emergency Firewater Pump	*Serial Number*	64Z03820
Engine Use	Fire Water Pump	*EPA Engine Family Name*	
Manufacturer	Caterpillar	*Operator ID*	A-006
Model Year	1984	*Fuel Type*	CARB Diesel - ULSD
Model	3306D1		
DRP/ISC?	No	*Healthcare Facility?*	No
Daily Hours	24.00	*Annual Hours*	100
Location Note			
Device Description	Engine Use: Fire Water Pump Rating @ 2100 rpm Fuel: Diesel w/ HHV 19,620 Btu/lb; 0.05% wt. S Engine Type: Lean/Non-Cyclic Device Grouping No: unknown Device SCC No: 2-02-001-02 Max Operating Hrs:24/day; 100/qtr; 100/yr.		