air pollution control district
SANTA BARBARA COUNTY

DRAFT

PERMIT to OPERATE No. 8234-R11

and

PART 70 RENEWAL OPERATING PERMIT No. 8234-R11

PLATFORM HOLLY

PARCEL 3242-1
SOUTH ELLWOOD OFFSHORE FIELD
SANTA BARBARA COUNTY, CALIFORNIA
STATE TIDELANDS

OPERATOR

California State Lands Commission/Beacon West Energy Group

OWNERSHIP

California State Lands Commission

Santa Barbara County
Air Pollution Control District

May 2021

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ABBREVIATIONS/ACRONYMS

APCO	Air Pollution Control Officer
AP-42	USEPA *Compilation of Emission Factors* document
API	American Petroleum Institute
AQAP	Air Quality Attainment Plan
ASTM	American Society for Testing and Materials
ATC	Authority to Construct
bbl	barrel (42 gallons per barrel)
BS&W	Basic water and sediment
bhp	brake horsepower
bpd	barrels per day
BSFC	brake-specific fuel consumption
Btu	British thermal unit
CAAA	Clean Air Act Amendments of 1990
CAP	Clean Air Plan
CARB	California Air Resources Board
CEMS	continuous emissions monitoring system
CFR	Code of Federal Regulations
clp	component leak-path
CO	carbon monoxide
CO_2	carbon dioxide
COA	corresponding offshore area
District	Santa Barbara County Air Pollution Control District
EOF	Ellwood Onshore Facility
ERC	emission reduction credit
FHC	fugitive hydrocarbon
FR	Federal Register
gr	grain
g	gram
gal	gallon
HHV	higher heating value
H_2S	hydrogen sulfide
H&SC	California Health and Safety Code
IC	internal combustion
I&M	inspection and maintenance
k	thousand
kV	kilovolt
lb	pound
LHV	lower heating value
MCC	motor control center
MM, mm	million
MSDS	Material Safety Data Sheet
MW	molecular weight
NESHAP	National Emissions Standards for Hazardous Air Pollutants
NGL	natural gas liquids
NO_x	oxides of nitrogen (calculated as NO_2)
NSPS	New Source Performance Standards
PFD	process flow diagram
P&ID	piping and instrumentation diagram
ppmv	parts per million volume (concentration)

psia	pounds per square inch absolute
psig	pounds per square inch gauge
PM	particulate matter
$PM_{2.5}$	particulate matter less than 2.5 mm in size
PM_{10}	particulate matter less than 10 mm in size
PSV	pressure safety valve
PTO	Permit to Operate
PRD	pressure relief device
PVRV	pressure vacuum relief valve
ROC	reactive organic compounds
scf	standard cubic feet
scfd	standard cubic feet per day
scfm	standard cubic feet per minute
SCAQMD	South Coast Air Quality Management District
SCE	Southern California Edison
SO_x	sulfur oxides
TEG	triethylene glycol
TOC	total organic compounds
tpq	tons per quarter
tpy	tons per year
TVP	true vapor pressure
USEPA	United States Environmental Protection Agency or EPA
UPS	uninterrupted power supply
VRS	vapor recovery system
wt %	weight percent

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 that affect any stationary source of air pollution in Santa Barbara County. The federal requirements include regulations listed in the Code of Federal Regulations: 40 CFR Parts 50, 51, 52, 55, 60, 61, 63, 68, 70, and 82. The State regulations may be found in the California Health & Safety Code, Division 26, Section 39000 et seq. The applicable District enforceable regulations can be found in the District's Rules and Regulations. This combined permitting action covers both the Federal Part 70 permit (*Part 70 Operating Permit No. 8234*) as well as the State Operating Permit (*Permit to Operate No. 8234*).

Santa Barbara County is designated as a non-attainment area for the state PM_{10} ambient air quality standard. As of July 1, 2020, the County achieved attainment status for the ozone state ambient air quality standards.

Part 70 Permitting. This is the seventh renewal of Platform Holly's (Holly's) Part 70 operating permit and satisfies the permit issuance requirements of the District's Part 70 operating permit program. The District triennial permit reevaluation has been combined with this Part 70 Permit renewal. Holly is a part of the *South Ellwood Field* stationary source (SSID = 1063), which is a major source for VOC[1], NO_x and CO. Conditions listed in this permit are based on federal, state, or District-enforceable 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. Conditions listed in Section 9.D are "District-only" enforceable.

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

Tailoring Rule. 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". This reevaluation incorporates greenhouse gas emission calculations for the stationary source.

Platform Holly'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.

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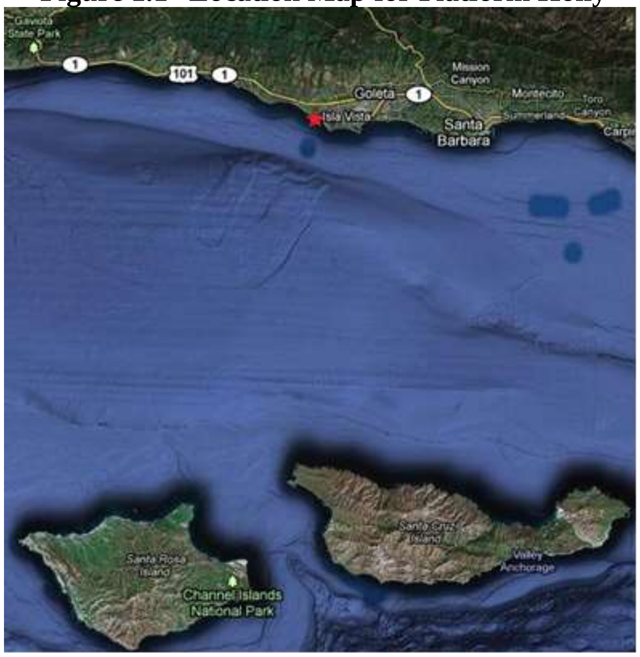
[1] VOC as defined in Regulation XIII has the same meaning as reactive organic compounds as defined in Rule 102. The term ROC shall be used throughout the remainder of this document, but where used in the context of the Part 70 regulation, the reader shall interpret the term as VOC.

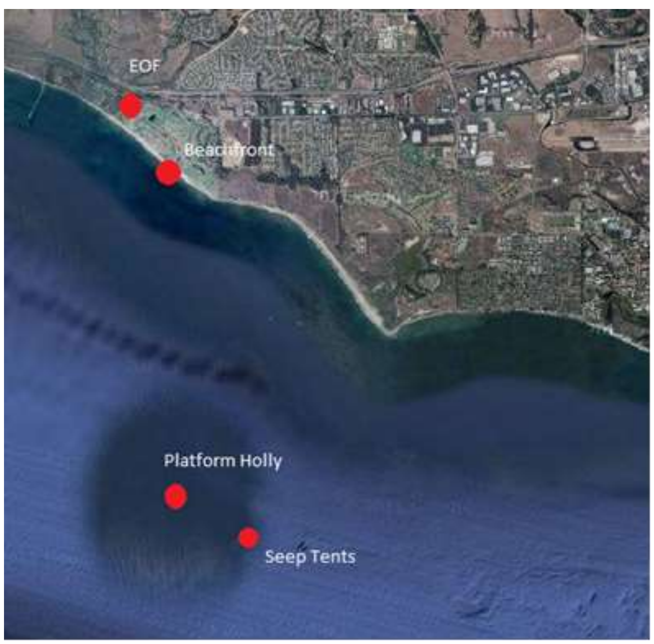
1.2 Facility Overview

1.2.1 General: The California State Lands Commission is the sole owner and operates Platform Holly jointly with Beacon West Energy Group. Platform Holly, located on offshore lease tract 3242-1 (with wells located in PRC 3120 and 3242), approximately two miles southwest from the Coal Oil Point, California. Holly is situated in the Southern Zone[2] of Santa Barbara County. Figure 1.1 shows the relative location of Holly off the Santa Barbara County coast.

[2] District Rule 102, Definition: "Southern Zone"

Figure 1.1 Location Map for Platform Holly





The platform consists of the following systems:

- Production wellhead and subsurface system
- Well cleanup system
- Test separation system
- Oil shipping, metering, and pipeline system
- Deck drain system
- Low-pressure compression system
- Gas compression system
- Gas shipping and metering system
- Electrical system
- Safety systems
- Vapor recovery system
- High-pressure and low-pressure flare systems
- Deck crane
- Drilling operations

1.2.2 Facility Operations Overview: Platform Holly is a twelve (12) leg, thirty (30) well slot platform installed in 211 feet of water in 1966. Drilling operations began in 1966. Oil and gas are produced from the wells on the platform. Produced gas is separated from the oil/water emulsion, compressed, and sent via a 6-inch subsea pipeline to the Ellwood Onshore Facility (EOF) for further processing. Water is separated from the oil and injected into disposal wells located on Platform Holly. Remaining oil/water emulsion is pumped to the EOF via a 6-inch subsea pipeline for additional processing. The platform has a design capacity of 20 million standard cubic feet gas per day and 20,000 barrels per day (bpd) of oil/water emulsion (wet crude oil). A crew boat makes periodic runs between Ellwood Pier and Holly for crew changes, and a supply boat brings supplies from Port Hueneme as needed.

All production equipment on Holly, except the pedestal crane and an emergency electrical generator, is powered by electricity via a Southern California Edison 16.5-kilovolt-subsea cable from shore. The platform operates 24 hours per day and 365 days per year.

The *South Ellwood Field* stationary source consists of the following 4 facilities:

- Platform Holly (FID= 3105)
- Ellwood Onshore Facility (FID= 0028)
- Beachfront Lease (FID= 3035)
- Seep Containment Device (FID= 1065)

1.2.3 New Source Review Permitting. This permit consolidates a number of outstanding NSR permit applications as part of this combined triennial Reevaluation and Part 70 Renewal process.

Holly operates under a combined Federal Part 70 Operating Permit No. 8234 and District Permit to Operate 8234, both issued by the Santa Barbara District. The District issued the initial permit (PTO 5097) for this facility in December 1982, based on a PTO application from the permittee (ARCO). This PTO number was changed to 8234 during the 1989 triennial re-evaluation. There were no NSR permit actions prior to 1998. Since the issuance of the initial Part 70 Operating Permit on September 25, 1998, the following permit actions have occurred:

ATC 10106: Replacement of existing single VRU compressor with two new smaller capacity VRU compressors. Not a routine, equivalent replacement, therefore subject to NSR. This permit was issued on 8/20/99.

ATC/PTO 10106-01. Amends ATC 10106 to include the relocation of a heat exchanger to the Glycol Overhead Cooler. This PTO/Part 70 permit incorporates the provisions of PTO 10106-01.

ATC/PTO 10106-02. Updates the fugitive component counts for the project. The final component count and associated air emissions were lower than originally permitted under ATC 10106. This PTO/Part 70 permit incorporates the provisions of PTO 10106-02.

ATC 10134: Temporary open-pipe flare permit. The flare was only allowed to operate for sixty days after SCDP startup. This permit was issued on 5/20/99. This ATC was modified/superseded by ATC 10128 (see below).

ATC Mod 10134-1: Operating extension for a temporary open-pipe flare permit to September 30, 1999. This permit was issued on 7/19/99. This ATC was modified/superseded by ATC 10128 (see below).

ATC 10128: Installation of a permanent Kaldair-type high-pressure flare. The ATC was issued on 9/1/99.

ATC Mod 10128-1/PTO 10128: Addition of a low-pressure flare tip to the Holly permanent flare system to handle Glycol system releases. The ATC was issued on 1/13/00. A draft District permit to operate was issued on 06/01/2001. Subsequently, the draft PTO was rolled into Part 70/District PTO 8234-R5 on 11/08/2002.

ATC/PTO 10786: Permit an increase of the number of pigging launching operations per quarter and year. It also included emissions controls consisting of purging pig launchers with nitrogen or in-plant fuel gas to the vapor recovery system prior to opening. The application was deemed complete in February 2002 and a draft ATC/PTO was issued in March 2002; subsequently, the draft ATC/PTO was rolled into Part 70/District PTO 8234-R5 on 11/08/2002.

ATC/PTO 11981: Increased the Crew Boat main engine size limit from 1020 hp to 1605 hp. This permit was issued 8/7/2006.

ATC 12804: Authorized the replacement of the existing crane on the platform with a new, larger crane, to comply with the State ATCM for stationary compression engines. ATC 12804 was issued 8/11/2008.

ATC/PTO 13475: Increased the crane's daily fuel limit from 28.5 gallons per day to 120 gallons per day and its annual limit from 10,000 gallons per year to 30,000 gallons per year. This permit was issued on 5/17/2011.

ATC/PTO 13825: Increased the allowable sulfur content during unplanned flaring.

ATC/PTO 13658: Permit fugitive component de minimis emissions to increase the availability of the de minimis exemption. This permit was issued 3/21/2012.

ATC/PTO 13825: Increased the sulfur content of planned flare gas. This permit was issued 5/9/2012.

ATC 13840: Replaced the boom boat servicing Platform Holly. This permit was issue 7/22/2012.

PTO 8235-05: Revisions to the fugitive I&M inventory. A permit was not issued. This permit was incorporated directly into the 8234-R9 permit renewal.

PTO 14181: Install a drain vessel to replace an existing lube oil tank. This permit was incorporated directly into the 8234-R9 permit renewal.

PTO 8235-06: Revise and correct the fugitive hydrocarbon component leakpath totals on the platform. This permit was issue 4/21/2016.

ATC/PTO 14794: Permit fugitive component de minimis emissions to increase the availability of the de minimis exemption. This permit was issue 8/12/2016.

PTO 8235-07: Relocate the Ellwood offsite odor monitoring station to the UCSB West Campus odor monitoring station site and transfer the offsite odor monitoring requirement to this permit from the Ellwood Onshore Facility permit.

ATC 15411: Install a coil tubing unit on Platform Holly for platform decommissioning purposes. This permit was issue 9/5/2019.

PTO 15411: Operate a coil tubing unit on Platform Holly. This permit was issue 2/24/2020.

ATC 15488: Increase auxiliary boat fuel use limit. This permit was issue 6/18/2020.

PTO 15488: Operate auxiliary boat. A PTO was not issued. These changes were incorporated directly in to this permit renewal.

1.3 Emission Sources

Air pollution emissions from Holly are the result of combustion sources, storage tanks, and piping components (e.g., valves and flanges). Section 4 of the permit provides the District's engineering analysis of these emission sources. Section 5 describes the allowable emissions from each permitted emissions unit, and lists the estimated emissions from non-permitted emission units.

Specifically, the emission sources include:

- Diesel-fired IC engines (pedestal crane, emergency electrical generator, engines associated with drilling operations)
- Combustion of produced gases in the high-pressure and low-pressure flare systems
- Fugitive hydrocarbon emissions from valves, flanges, connections, and seals that release fugitive hydrocarbons into the atmosphere
- Supply boats used for transport of equipment, fuel, and supplies to and from the platform

- Crew boats used for transport of personnel and cargo to and from the platform
- Oil and gas pig launchers
- Wastewater tanks
- Solvent and coating usage
- Natural gas-fired generators supporting drilling operations

Two emergency firewater pumps also service Holly. These pumps are driven by electric motors. A list of all permitted equipment is provided in Section 10.5.

1.4 Emission Control Overview

Air quality emission controls are used on Holly for a number of emission units to reduce air pollution emissions. Additionally, the use of onshore utility grid power allows Holly to operate without engine-powered generators or compressors except for the IC engines powering the drilling rig. The emission controls employed on the platform include:

- A Fugitive Hydrocarbon Inspection & Maintenance (I&M) program for detecting and repairing leaks of hydrocarbons from piping components, consistent with the requirements of Rule 331, to reduce ROC emissions by approximately 80 percent.

- Use of a vapor recovery and flare relief system to capture hydrocarbon gases from tanks, vessels and the glycol system. The flare system is comprised of a main high-pressure flare and a smaller low-pressure flare.

- Non-selective catalytic reduction systems on the gas-fired drilling generators.

1.5 Offsets/Emission Reduction Credit Overview

Offsets: Holly does not require emission offsets.

Emission Reduction Credits: Holly does not generate emission reduction credits.

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 these requirements are enforceable by the public under CAAA. See Tables 3.1 and 3.2 for a list of federally enforceable requirements.

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

1.6.3. Federal potential to emit: The federal potential to emit (PTE) of a stationary source does not include fugitive emissions unless the source is: (1) subject to a federal NSPS/NESHAP requirement promulgated prior to August 7, 1980 or (2) included in the 29-category source list specified in 40 CFR1.166 or 52.21. The federal PTE does include all emissions from any insignificant emissions units. See Section 5.4 for the federal PTE for this source.

1.6.4. Permit Shield: The operator of a major source may be granted a permit 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 a detailed review by the District. Permit shields cannot be granted indiscriminately with respect to all federal requirements. The permittee has not made a request for a permit shield.

1.6.5. Alternate Operating Scenarios: A major source may be permitted to operate under different operating scenarios, if appropriate descriptions of such scenarios are included in its Part 70 permit application and if such operations are allowed under federally enforceable rules. The permittee made no request for permitted 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 semi-annually on or before March 1st and September 1st, as specified in the permit. Each certification is signed by a "responsible official" of the owner/operator company whose name and address is listed prominently in the Part 70 permit. See Section 1.6.9 below.

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

1.6.8. MACT/Hazardous Air Pollutants (HAPs): Part 70 permits also regulate emission of HAPs from major sources through the imposition of maximum achievable control technology (MACT), where applicable. The federal PTE for HAP emissions from a source is computed to determine MACT or any other rule applicability. See Sections 3.2.4, 4.9 and 5.5.

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

Jennifer Lucchesi, Executive Officer
State Lands Commission
100 Howe Ave. Suite 100-South
Sacramento, CA 95825-8202

2.0 Process Description

2.1 Process Summary

Platform Holly produces oil and gas from leases PRC 3120 and 3242 located in state waters. The equipment consists of oil and gas wells, oil and gas separators, a gas dehydration unit, gas compressors, deck drain system, water treating equipment, oil shipping pumps, water injection pumps, a well cleaning and test system, and a flare relief system. The crude oil and natural gas produced are sour and have significant concentrations of hydrogen sulfide (H_2S) and mercaptans.

Initial separation of the oil/water/gas emulsion occurs on the platform. The gas is separated from the oil/water emulsion, compressed and sent via a 6-inch subsea pipeline to the Ellwood Onshore Facility (EOF) for further processing. Water is separated from the oil and injected into disposal wells located on Platform Holly. The remaining oil/water emulsion is pumped to the EOF via a 6-inch subsea pipeline for additional processing. The treated deck drain system water is mixed with the crude oil before being pumped to EOF.

2.1.1 Production: Platform Holly has thirty (30) well slots located in one well room. All thirty well slots have been developed starting in 1966, into one or more of three production zones; the Rincon and Sespe zones that produce sweet gas and the Monterey zone that produces sour gas. While all 30 well slots were originally drilled for production, over the life of the platform some of the wells have been converted to other uses. At this time twenty-three (23) wells are setup as producers, two are used for re-injecting gas, three are used for disposing of water, one is used for disposing of drill cuttings, and one well is abandoned. Four production wells are equipped with downhole variable speed drive (VSD) pumps to enhance production. Gas lift is used as needed in the remaining wells. Holly has a design production rate of 20,000 bpd of oil emulsion and 20 MMSCFD of gas.

Production flow lines from each wellhead tie into one of four separate piping manifolds or headers. The four manifolds are:

Lease PRC 3242 production header
Lease PRC 3242 test header
Lease PRC 3120 production header
Lease PRC 3120 test header

Oil Production - Gross well production from the leases is directed through two flow lines to Group Separators V-107 and V-108. The group separators operate at approximately 65-90 psig. Oil and water are separated in V-107 and V-108. The water phase is directed to drain sump tank V-109 and injected into disposal wells. The oil phase is directed to Surge Vessel V-110 and is pumped by shipping pump P-200 to the Ellwood Onshore Facility via a six-inch subsea pipeline. A flow meter at the pipeline inlet measures and totalizes the emulsion shipped from Holly. Test separator V-106 is used to flow test the individual production wells. During well testing, the well is switched from the production header to the test header. Only one well is tested at a time in each test separator. Emulsion from the test separators is commingled with oil emulsion from the group separators after metering.

Gas Production - Gas separated in the production and test separator is compressed by the single stage Ingersoll-Rand (IR) compressor to approximately 220 psig then dehydrated in the Glycol dehydration unit. Part of the dehydrated gas stream is further compressed in the three-stage White Superior (WS) compressor to approximately 1100 psig and injected into the wells for gas lift and/or gas injection. The remainder is piped to the Ellwood Onshore Facility through a six-inch line for further processing. An orifice meter at the gas pipeline inlet records the gas flow rate from Holly.

Well casing gas and natural gas off crude oil surge vessel V-110 is compressed by one of two 50 bhp vapor recovery compressors (C-100A or C-100B) to approximately 70-90 psig. The vapor compressor discharge is commingled with gas from the production and test separators. Both of the compressors are electrically driven.

2.1.2 Gas, Oil, and Water Separation: Fluid from the production wells is a mixture of oil, gas, and water. Separation of the liquid and gas streams is accomplished in gross oil group separators No. 3120 and No. 3242 (V-107 and V-108). These separators are horizontal, three-phase separators 6.5 feet in diameter by 20 feet long. Production from all the wells on Holly is directed to these separators. These separators are usually in simultaneous operation, thereby maximizing the liquid retention time and providing optimum liquid and gas separation.

The gross oil group separators operate at 60-90 psig and 100°F. The gas section (top half) of the separator is designed to sufficiently reduce the velocity of the gas to cause any liquid to drop out. These separators also have a mist extractor to promote removal of liquid droplets from the gas stream. The operating pressure of the separators is automatically controlled by a pressure control valve in the gas outlet line. Gases from these separators flow into a common header leading to the main gas scrubber (V-113) of the Ingersol Rand main gas compressor. Oil emulsion removed in the scrubber flows to the surge vessel. There is no backup compressor for the main gas compressor.

The liquid section (bottom half) of the gross oil group separators is designed with sufficient retention time to allow most of the free water to collect in the inlet section of the vessel. The separator liquid levels are controlled by level control valves. The oil emulsion discharged from these separators flows to the surge vessel. The free water is sent to V-109 and then injected back into the Monterey formation in one of the disposal wells.

2.1.3 Waste Water and Process Waste Tanks: The Drain Sump Tank (T-1) collects storm water wash down from platform drains, as well as runoff from deluge/fire suppression testing. Water is pumped from the drain sump tank to V-109 and injected into one of the disposal wells. In the event of rain volumes in excess of what is being pumped off the bottom of the drain sump tank, it will overflow to the Overflow Sump Tank (T-4). Water that overflows to T-4 is then pumped back to V-109. Tank T-4 is equipped with an overflow pipe open at the bottom to the ocean.

2.1.4 Oil Sump Tank: Oil Sump Tank (T-5) is an open top tank that collected liquids from four sources at a rate of about 3 gallons per day. Tank T-5 contents were sampled in June 2002 and the TVP was found to trigger District Rule 325 controls applicability. To meet compliance with Rule 325, the permittee has taken T-5 out of service. T-5 cannot be returned to service without first obtaining an ATC to install controls.

2.1.5 Well Testing and Maintenance: To measure the oil, gas, and water flow rates from a well, the well is produced into Test Separator V-106 by closing the well flow line valve to the gross oil header and opening the well flow line valve to the test header. The test separator is a horizontal, two-phase separator 4 feet in diameter by 15 feet in length with a capacity of 10,000 bpd dry oil and 10

MMscfd of natural gas. This separator capacity is smaller than the gross oil group separators since only one well is tested at a time. The separator has a mist extractor to promote removal of liquid droplets from the gas stream. The separator has a pressure control valve to maintain the operating pressure at 60-70 psig. Gas separated in the separator is measured by an orifice meter in the outlet line and is commingled with the gas from the gross oil group separators.

The liquid from test separator V-106 is measured by a flow meter. This meter measures the total liquid flow of the combined oil and water stream. The water cut is determined by collection and analysis of samples. The oil and water from test separator V-106 is combined with the gross oil production ahead of the oil group separators.

2.1.6 Emulsion Breaking and Crude Oil Storage: There are no emulsion breaking or crude oil storage facilities on Holly. The produced oil/water emulsion is shipped to the Ellwood Onshore Facility for final processing.

2.1.7 Emulsion Shipping: Oil shipping surge vessel V-110 receives oil from the group separators and waste oil pumps. This surge vessel is a horizontal pressure vessel 6-feet 6-inch in diameter by 20 feet in length operating at 3 to 5 psig. This vessel provides surge capacity to stabilize the flow of oil and prevent upsets in the downstream processing equipment. The system uses a shipping pump to transfer oil from surge vessel V-110. The oil shipping pump discharges into the 6-inch diameter subsea pipeline to the Ellwood Onshore Facility. A flow meter measures oil flow rate to the pipeline.

2.1.8 Gas Compression, Dehydration, and Disposition: Natural gas collected by the vapor recovery system and the annulus trap is compressed and mixed with gas from Test Separator V-106, and group separators before gas dehydration. A portion of the gas is shipped onshore and the rest is further compressed in the White Superior (WS) compressor and injected for gas lift and/or gas injection.

Vapor recovery unit (VRU) gas is commingled with the main gas production to the IR suction scrubber (V-113). The discharged gases from the IR and the WS compressors are cooled by fan coolers. Liquids condensed in these heat exchangers are removed in the gas scrubbers.

From final gas scrubber V-114, wet gas flows to the glycol dehydration unit, which is used to lower the water content of the gas. The dehydration unit consists of a glycol contactor, filters, exchangers, a dehydrator, a surge vessel, and pumps. Contactor V-115 is a trayed tower pressure vessel 5 feet 6 inches in diameter by 20.0 feet high with a capacity of 40 MMscfd. Pressure in the contactor is maintained at 200-225 psig by a pressure control valve in the gas outlet line. Inside the contactor, the wet gas flows in contact with triethylene glycol (TEG), which absorbs water from the natural gas. The rich (wet) TEG from the contactor is regenerated in the dehydrator after passing through two filters to remove impurities picked up from the natural gas. The dehydrator operates at atmospheric pressure and 395°F; it uses twelve, 40 kW (each) electric immersion heaters to heat the TEG and boil off the entrained water and hydrocarbons. The vapor is vented to the vapor recovery system. The lean (regenerated) TEG from the dehydrator is cooled in the glycol exchangers, improving water absorption in the contactor and preheating the rich TEG going to the dehydrator. From the exchangers, the lean TEG flows into 5-foot diameter by 15-foot long storage tank V-122 that provides surge capacity to allow the lean TEG to be pumped back to the contactor. Two glycol pumps (P-106 A/B) move the glycol from storage tank V-122 to absorber V-115.

The dehydrated gas from contactor V-115 passes through after-scrubber V-116. Part of the gas from the after-scrubber is used for gas lift and/or gas injection and the rest flows directly to the six-inch diameter subsea pipeline to the Ellwood Onshore Facility. A flow meter on the pipeline inlet records the gas flow rate from Holly.

2.1.9 Gas Sweetening and Sulfur Recovery: The gas produced from the Monterey Formation is sour. There are no gas sweetening or sulfur recovery devices on Holly.

2.1.10 Vapor Recovery System: Low-pressure gas from crude oil shipping surge vessel V-110 and annulus separator V-101 is compressed by one of two vapor recovery system compressors (C-100A or C-100B). The vapor recovery compressor compresses the gas to approximately 65-90 psig and discharges to the IR main gas scrubber where the gas is commingled with the gas from the gross oil and test separator.

2.1.11 Fuel Gas System: Holly receives EOF's in-plant fuel gas through the 4-inch utility pipeline from the Ellwood Onshore Facility that supplies fuel to the flare systems (H-100 and H-101) and the drill rig generator engines. The pedestal crane and other diesel-fired equipment use Diesel #2 fuel, which contains less than 0.0015 percent sulfur by weight. Holly has one 1500-gallon capacity diesel storage tank (T-111) located in the crane pedestal.

2.1.12 Gas Relief Flare System: The permanent flare on Holly incinerates the sour gases released during process upsets, and other "unplanned" operating conditions (as defined under Rule 359). Such incineration will safely convert the H_2S and ROC content of these gases to SO_2 and other combustion products.

The permittee's Platform Holly utilizes a glycol dehydration skid designed to lower the dew point of produced gas before it is re-injected or shipped to EOF via undersea pipeline. The glycol skid includes four low-pressure vessels (V-122, V-124, V-125, and V-126) that are protected by PSV-131 and 132 set to relieve at glycol pressures at 10 psig. The permittee routes these PSVs to the low-pressure flare tip.

Planned Flaring Scenarios: The permittee claims no planned flaring activities for Holly other than pilot and purge for the flares. All gases generated during planned activities are routed to the EOF.

Unplanned Flaring Scenarios: Unplanned flaring events on the platform most commonly originate from platform safety trips and compressor safety trips that cause equipment shutdowns.

2.2 Support Systems

2.2.1 Piping Assemblies and Pipelines: The piping on Holly is designed, tested, and installed in general accordance with API 14C and 14E.

Four pipelines are associated with the platform: a 6-inch oil line, a 6-inch gas line, a 4-inch utility line, and a 2-inch fresh water line to the Ellwood Onshore Facility.

2.2.2 Power Generation: Southern California Edison provides electrical power for Holly from shore through a 16.5 kV subsea cable. The platform has a 250 kW diesel stand-by generator, which is used in the event of a power outage from Southern California Edison. During such a power failure, the Motor Control Center (MCC) on Holly supplies standby power from the diesel generator to critical equipment. A 24-volt battery backup system is provided for the essential platform controls.

2.2.3 Diesel-Powered Crane: Holly is equipped with a crane powered by a 250 bhp diesel-fired IC engine. The crane is used to transfer supplies from supply boats to Holly.

2.2.4 Crew Boats: The permittee uses one crew boat for crew and light supply transport in support of Holly. The crew boat makes up to 6 round trips per day and 728 round trips per year to the platform from the Ellwood Pier in Goleta. In addition, there is also a small gasoline powered boat for deploying oil spill booms around the platform. This vessel is stored on the platform.

2.2.5 Supply Boats: The permittee uses supply boats for supply and equipment transport and emergency response drills in support of Holly. When the platform is in a production mode (i.e., no drilling or well repair), the supply boat activity is approximately 6-7 trips per year. During well drilling or well repair activity, the supply boat activity increases to about one trip every 2 days or more (up to 192 trips per year).

2.2.6 Helicopter: Although there is a helipad on Holly, helicopters are not used for routine offshore transportation.

2.2.7 Emergency Response Drills: The permittee conducts periodic and unannounced emergency response drills. Several plans have been developed for different types of emergencies that could occur on or around the platform. The plans include the Emergency Evacuation Plan and Oil Spill Contingency Plan. All of the plans have been prepared to comply with applicable rules and regulations and guidelines set forth by the appropriate regulatory agencies. Emissions from emergency response boats are documented and reported along with the supply boats information.

2.3 Oil & Gas Production Activities: Drilling

2.3.1 Drilling Program: There is a resident drilling rig on Holly. There have been several drilling programs conducted on Holly from 1966 through 2006.

2.3.2 Well Work-over Program: The permittee occasionally performs well work-overs on Holly. Three gas-fired IC engines are used to provide electrical power for the drill rig. Portable diesel-fired IC engines are used to power the ancillary equipment used during drilling and well work-overs.

2.4 Maintenance/Degreasing Activities

2.4.1 Paints and Coatings: Intermittent surface coating operations are conducted throughout the platform for occasional structural and equipment maintenance needs, including architectural coating. Normally only touch-up and equipment labeling or tagging is performed. All architectural coatings used must comply with District Rule 323, as verified through the rule-required recordkeeping.

2.4.2 Solvent Usage: Solvents not used for surface coating thinning may be used on the platform for daily operations. Solvent usage includes cold solvent degreasing and wipe cleaning with rags.

2.5 Planned Process Turnarounds

Process turnarounds on the permitted equipment are scheduled to occur when the Ellwood Onshore Facility or Holly are shut down for maintenance. Major pieces of equipment such as the gas compressors have maintenance schedules specified by the manufacturer, that equipment be removed from service, inspected, and repairs are made as necessary. Maintenance of critical components is carried out according to the requirements of Rule 331 (*Fugitive Emissions Inspection and Maintenance*). The permittee has not listed any emissions from planned process turnarounds that should be permitted.

2.6 Other Processes

Pigging: Pigging operations occur between the Platform and the Ellwood Onshore Facility. The pigging system is connected to the Ellwood Onshore Facility's pig receivers. Holly has three pig launchers; one for pigging the pipeline sending produced gas to shore, one for pigging the pipeline bringing utility gas to Holly, and one for pigging the pipeline sending oil to shore.

Unplanned Activities/Emissions: The permittee does not anticipate or foresee any circumstances that would require special equipment use and result in excess emissions.

2.7 Detailed Process Equipment Listing

Refer Attachment 10.5 for a complete listing of all permitted equipment.

3.0 Regulatory Review

3.1 Rule Exemptions Claimed

- District Rule 202 (Exemptions to Rule 201): The permittee has requested a number of exemptions under this rule. An exemption from permit, however, does not necessarily grant relief from any applicable prohibitory rule. The following exemptions were approved by the District:

  - Section D.6 (De Minimis). As of January 1, 2020 the permittee documented the total de minimis emissions increase at Holly to be 10.88 lbs/day for ROC. Therefore, the total de minimis emissions from the stationary source are 9.36 (EOF) + 10.88 = 20.24 lbs/day of ROC. There are no de minimis increases at the Beachfront or Seeps. Detailed records of the de minimis emissions changes can be viewed at the District's office.

  - Section U.2.a for a cold cleaner degreaser unit with an evaporative surface area of less than 1 sq.ft.

  - Section V.2 for one diesel fuel #2 storage tank with a 1500-gallon capacity.

  The two gas-fired generator engines used to power the drill rig were previously District permit exempt. Due to the revisions to Rule 202 on June 19, 2008, these engines lost their exemption status and were permitted under PTO 12912. The diesel-fired IC engines, which powered the associated equipment for the drilling and well work-over program, also lost their exemption. All diesel-fired IC engines used during well drilling and work-over are registered in the Statewide Portable Equipment Registration Program and will be exempt from permit per Section F.2 or they will be replaced with electric motors.

- District Rule 321 (Solvent Cleaning Operation): The following exemption was applied for and approved by the District:

- Section B.2.b for a cold cleaner degreaser unit with an evaporative surface area of less than 1 sq.ft.

☞ District Rule 325 (Crude Oil Production and Separation): The following exemptions were applied for and approved by the District:

- Section B.3 for wastewater tanks T-1 and T-4 (see also Permit Condition 9.C.6 for ongoing monitoring requirements).

☞ District Rule 331 (Fugitive Emissions Inspection and Maintenance): The following exemptions were applied for and approved by the District:

- Section B.2(c) for one-half inch and less stainless steel tubing fittings.
- Section B.3(c) for PRDs vented to a closed system.
- Section B.3(c) for components totally enclosed or contained.
- Section B.2.b for components buried below the ground.
- Sections F.1, F.2 and F.7 for components that are unsafe-to-monitor, as documented and established in a safety manual or policy, and with prior written approval of the Control Officer.

☞ District Rule 333 (Control of Emissions from Reciprocating IC Engines): One diesel-fired IC engine is an emergency standby engine, as defined by 17 CCR, 93115. Therefore, this engine 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 (Non-attainment Area Review and Prevention of Significant Deterioration)}: Holly was constructed and permitted prior to the applicability of these regulations. Compliance with District Regulations VIII (New Source Review) and XIII (Part 70 Operating Permits Program) ensures that any future modifications to the facility will comply with these regulations.

3.2.2 40 CFR Part 60 {New Source Performance Standards}: The diesel-fired crane engine is subject to Subpart IIII, as a stationary CI ICE that commenced construction after July 11, 2005. This 2006 model year engine is an EPA-certified Tier 3 unit that meets the emission standards for pre-2007 non-emergency CI ICE. The engine must be operated and maintained according to the manufacturer's written instructions.

3.2.3 40 CFR Part 63 {MACT}: On June 17, 1999, EPA promulgated Subpart HH, a National Emission Standards for Hazardous Air Pollutants (NESHAPS) for Oil and Natural Gas Production and Natural Gas Transmission and Storage. The permittee submitted information on September 18, 2001 indicating that Holly is exempt from the requirements of MACT based on its "black oil" production per section 63.670(e)(1) of the subpart. Based on the information provided, the District concurred with the black oil exemption for this facility. Thus, only recordkeeping requirements apply to this facility, as specified in condition 9.B.12.

3.2.4 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 crane engine meets the requirements of this NESHAP by meeting the requirements of NSPS IIII, therefore no further requirements apply to the crane engine under the NESHAP.

The emergency standby compression ignition RICE must comply with the applicable emission and operating limits of this subpart. The following operating requirements apply:

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

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

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

The four-stroke rich-burn spark ignited drilling rig engines must comply with the following requirements of this subpart.

(1) change the oil and filter every 2,160 hours of operation or annually, whichever comes first

(2) inspect spark plugs every 2,160 hours of operation or annually, whichever comes first and replace as necessary, and,

(3) inspect all hoses and belts every 2,160 hours of operation or annually, whichever comes first and replace as necessary.

3.2.5 40 CFR Part 64 {Compliance Assurance Monitoring}: This rule became effective on April 22, 1998. This rule affects emission units at the source subject to a federally-enforceable emission limit or standard that use a control device to comply with the emission standard, and either pre-control or post-control emissions exceed the Part 70 source emission thresholds. Compliance with this rule was evaluated and it was determined that no emission units at this facility are currently subject to CAM. See section 4.10.3 for further information on CAM.

3.2.6 40 CFR Part 70 {Operating Permits}: This Subpart is applicable to Holly. Table 3.1 lists the federally enforceable District promulgated rules that are “generic” and apply to Holly. Table 3.2 lists the federally enforceable District promulgated rules that are “unit-specific” that apply to Holly. These tables are based on data available from the District’s administrative files and from the permittee’s Part 70 Operating Permit application No. 9553 filed in May 1996 and subsequent renewal applications. Table 3.4 includes the adoption dates of these rules.

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

3.2.7 CFR 60 Subpart OOOO {*Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution*} this subpart does not apply to operations in the outer continental shelf (OCS). As defined in 60.5365, this regulation applies to owners and operators of “onshore affected facilities". The OCS is specifically excluded from the definition of onshore as found in section 60.5430.

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 and will be enforced by the District. These provisions are District enforceable only.

3.3.2 California Code of Regulations, Title 17, Sub-Chapter 6, Sections 92000 through 92530: These sections specify the standards by which abrasive blasting activities are governed throughout the State. All abrasive blasting activities at Holly are required to conform to these standards. Compliance will be assessed through onsite inspections. These standards are District-enforceable only. However, CAC Title 17 does not preempt enforcement of any SIP-approved rule that may be applicable to abrasive blasting activities.

3.3.3 California Code of Regulations, Title 17, Section 93115: This section specifies the airborne toxic control measure (ATCM) to reduce diesel particulate matter (PM) and criteria pollutant emissions from stationary diesel-fueled compression ignition (CI) engines. Its provisions apply to any stationary CI engine operated in California with a rated horsepower of 50 bhp or greater. Portable, off-road, or marine vessel IC engines are exempt from this ATCM. The emergency standby IC engine powering an electrical generator and the IC engine powering the crane are subject to this ATCM. The original platform crane was replaced with a crane powered by a Tier 3 engine controlled by a diesel particulate filter.

3.3.4 California Code of Regulations, Title 17, Section 93116: This section specifies the airborne toxic control measure (ATCM) to reduce diesel particulate matter (PM) and criteria pollutant emissions from portable diesel-fueled compression ignition (CI) engines. Its provisions apply to any portable CI engine operated in California with a rated horsepower of 50 bhp or greater. The portable diesel-fired IC engines used for the well drilling and work-over program are subject to this ATCM. New engines must meet the most stringent Tier standard.

3.3.5 Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities (CCR Title 17, Section 95665 *et. Seq.*): On October 1, 2017, the California Air Resources Board (CARB) finalized this regulation, which establishes greenhouse gas emission standards for onshore and offshore crude oil and natural gas production facilities. This facility is subject to the provisions of this regulation.

The separators and tanks at this facility satisfy the requirements of the CARB regulation through the use of a vapor collection system.

This facility is exempt from the leak detection and repair (LDAR) requirements of the CARB regulation per Section 95669(b)(1), which exempts components that are subject to District Rule 331 LDAR requirements prior to January 1, 2018.

This facility does not utilize circulation tanks for well stimulation treatments, reciprocating or centrifugal natural gas compressors, natural gas powered pneumatic devices or pumps, natural gas only wells, or well casing vents, and is therefore not subject to the CARB regulation standards and requirements for these equipment and processes.

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 Holly. Table 3.3 lists the non-federally-enforceable District rules that apply to Holly. Table 3.4 lists the adoption date of all rules that apply to Holly.

3.4.2 Rules Requiring Further Discussion:

The following is a rule-by-rule evaluation of compliance for Holly:

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 10.5. 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 Section I.B.2, District permits are reevaluated every three years. The fees for this facility are based on the District Rule 210, Fee Schedule A. Attachment 10.3 presents the fee calculations for the reevaluated permit. The fees for this reevaluation are calculated per Section I.B.2.

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, the permittee is operating in compliance with this rule.

Rule 302 - Visible Emissions: This rule prohibits the discharge from any single source any air contaminants for which a period or periods aggregating more than three minutes in any one hour which is as dark or darker in shade than a reading of 1 on the Ringelmann Chart or of such opacity to obscure an observer's view to a degree equal to or greater than a reading of 1 on the Ringelmann Chart. Sources subject to this rule include: the flare, all diesel-fired piston internal combustion engines on the platform and crew and supply boats. Compliance will be assured by requiring all engines to be maintained according to manufacturer maintenance schedules, and through visible emissions monitoring requirements. Rule 359 addresses the need for the flare to operate in a smokeless fashion.

Rule 303 - Nuisance: This rule prohibits Holly from causing a public nuisance due to the discharge of air contaminants. Compliance with this Rule is achieved based on the *Odor Abatement Agreement* between the District and the permittee (March 1995) and the *Complaint Response Plan* (May 1995), and the requirements of Abatement Order 99-6A. This permit contains federally enforceable conditions (see Permit Condition 9.B.3) to minimize the potential for additional nuisances, such as operation limits and monitoring, to ensure compliance with this rule.

Rule 305 - Particulate Matter, Southern Zone: Holly is considered a Southern Zone source. This rule prohibits the discharge into the atmosphere from any source particulate matter in excess of specified concentrations measured in gr/scf. The maximum allowable concentrations are determined as a function of volumetric discharge, measured in scfm, and are listed in Table 305(a) of the rule. Sources subject to this rule include: the flare, all diesel-fired piston internal combustion engines on the platform and crew and supply boats. Improperly maintained diesel engines have the potential to violate this rule. Compliance will be assured by requiring all engines to be maintained according to manufacturer maintenance schedules according to a District-approved *IC Engine Particulate Matter Operation and Maintenance Plan*. Rule 359 addresses the need for the flare to operate in a smokeless fashion.

Rule 309 - Specific Contaminants: Under Section "A", no source may discharge sulfur compounds and combustion contaminants in excess of 0.2 percent as SO_2 (by volume) and 0.3 gr/scf (at 12% CO_2) respectively. Sulfur emissions due to flaring of sour gas under 20,000 ppmv H_2S should comply with the SO_2 limit. All diesel-powered piston IC engines have the potential to exceed the combustion contaminant limit if not properly maintained (see discussion on Rule 305 above for compliance).

Rule 310 - Odorous Organic Compounds: This rule prohibits the discharge of H_2S and organic sulfides that result in a ground level impact beyond the property boundary in excess of either 0.06 ppmv averaged over 3 minutes and 0.03 ppmv averaged over 1 hour. No measured data exists to confirm compliance with this rule; however, all produced gas from Holly is collected for sales, re-injection or is collected by vapor recovery (i.e., no venting occurs). As a result, it is expected that compliance with this rule will be achieved. Further, the platform is equipped with numerous H_2S monitors (alarms set to 10 ppmv). If the equipment leaks sour gas, the alarm sounds and the operator will take corrective action. These H_2S monitors are connected to the District's DAS.

Rule 311 - Sulfur Content of Fuels: This rule limits the sulfur content of fuels combusted on Holly to 0.5 percent (by weight) for liquids fuels and 15 gr/100 scf (calculated as H_2S, equivalent to 239 ppmvd) for gaseous fuels. All diesel-fired IC engines on Holly and on the crew and supply boats are expected to comply with the liquid fuel limit as determined by fuel analysis documentation. The drill rig generator engines are expected to comply with the gaseous fuel limits.

Rule 317 - Organic Solvents: This rule sets specific prohibitions against the discharge of emissions of both photochemically and non-photochemically reactive organic solvents (40 lb/day and 3,000 lb/day respectively). Solvents may be used on the platform 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. The permittee is required to maintain records to ensure compliance with this rule.

Rule 321 - Solvent Cleaning Operations: This rule sets equipment and operational standards for degreasers using organic solvents. There is a small (i.e., less than 1 sq.ft. evaporative surface) cold solvent degreaser unit on the platform which is permit-exempt and also exempt from the Rule requirements except to keep its surface covered when not in use. Compliance will be determined through District inspections of the platform.

Rule 322 - Metal Surface Coating Thinner and Reducer: This rule prohibits the use of photochemically reactive solvents for use as thinners or reducers in metal surface coatings. The permittee 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 photochemically reactive solvent per day by means that will allow the evaporation of the solvent to the atmosphere. The permittee is required to maintain records to ensure compliance with this rule.

Rule 325 - Crude Oil Production and Separation: This rule applies to equipment used in the production, processing, separation, gathering, and storage of crude oil and gas prior to custody transfer. The primary requirements of this rule are under Sections D and E. Section D requires the use of vapor recovery systems on all tanks and vessels, including wastewater tanks, crude oil/water separators, and sumps. Section E requires that all produced gas be controlled at all times, except for wells undergoing routine maintenance. Production and test vessels and the shipping tanks on Holly are all connected to the gas gathering systems. Compliance with Section E is met by directing all produced gas to sales, injection, gas lift, or to the flare relief system.

The wastewater tanks T-1 and T-4 on the platform were determined to be exempt from Rule 325.D.1 and D.2 after an inspection in 1997 because the ROC content of the liquid entering the wastewater tanks is less than 5 milligrams per liter. Sampling in June 2002 per Rule 325.F.2 showed 7,900 mg/l of ROC, but a subsequent sample in July 2002 showed less than 1.0 mg/l ROC. Further sampling has indicated the tanks meet the Rule 325.B.3 exemption. This permit requires annual sampling by using the testing procedures specified in Section G to justify the exemption.

Rule 326 - Storage of Reactive Organic Compound Liquids: This rule applies to equipment used to store ROC liquids with a vapor pressure greater than 0.5 psia.

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 Venoco – Ellwood stationary source emits to the atmosphere more than 5 lb/hr of non-methane hydrocarbons, oxides of nitrogen, and sulfur oxides and more than 10 lb/hr of particulate matter, thereby triggering the Section C.2 requirement that the need and application of CEMs be evaluated. An evaluation was made by the District and it was determined that CEMS are not required for Holly.

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. It is anticipated that the permittee will not trigger the requirements of this rule. Compliance shall be based on site inspections and permittee records.

Rule 331 - Fugitive Emissions Inspection and Maintenance: This rule applies to components in liquid and gaseous hydrocarbon service at oil and gas production fields. The permittee submitted a Fugitive Inspection and Maintenance Plan and received final District approval of the Plan on July 15, 1994. Ongoing compliance with the provisions of this rule will be assessed via platform inspection of fugitive components by the permittee and District personnel using an organic vapor analyzer and through analysis of operator records. Holly does not perform any routine venting of hydrocarbons to the atmosphere.

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. All diesel-fired IC engines powering well drilling equipment on Platform Holly are registered in the state PERP and are permit-exempt per District Rule 202. Therefore, they are exempt from Rule 333. The emergency standby IC engine is exempt from the requirements of Rule 333. The gas-fired generators used to power drilling equipment and the diesel-fired engine powering the crane are subject to Rule 333. The engines subject to Rule 333 are monitored quarterly to determine compliance with the emission limits of the rule.

Rule 352- Natural Gas-Fired Fan-Type Central Furnaces and Small Water Heaters.
This rule applies to any person who manufactures, supplies, sells, offers for sale, installs, or solicits the installation of any natural gas-fired fan-type central furnaces or water heaters for use within the District. Compliance shall be based on site inspections.

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 and permittee records.

Rule 359 - Flares and Thermal Oxidizers: This rule applies to flares for both planned and unplanned flaring events. Compliance with this rule has been documented. A detailed review of compliance issues is as follows:

§ D.1 - Sulfur Content in Gaseous Fuels: Part (a) limits the total sulfur content of all planned flaring from South County flares to 15 gr/100 cubic feet (239 ppmv) calculated as H_2S at standard conditions. Treated produced gas from the Ellwood onshore facility is used at the flare for purge and pilot gas (a planned flaring category) that is within the limits of this rule. The permittee has claimed that there will be no other planned flaring associated with platform operations, as all such gas will be routed to the Ellwood onshore facility. Unplanned flaring is exempt from the sulfur standards of this rule.

§ D.2 - Technology Based Standard: Requires all flares to be smokeless and sets pilot flame requirements. The flare on Holly complies with this section.

§ D.3 - Flare Minimization Plan: This section requires sources to implement flare minimization procedures to reduce SO_x emissions. The permittee has implemented the District-approved *Flare Minimization Plan*.

Rule 360 - Emissions of Oxides of Nitrogen from Large Water Heaters and Small Boilers. 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 British thermal units per hour up to and including 2,000,000 British thermal units per hour.

Rule 361- Small Boilers, Steam Generators, and Process Heaters: On January 17, 2008, the District Board of Directors adopted Rule 361 that includes requirements for process heaters rated between 2.0 MMBtu/hr 5.0 MMBtu/hr. Units installed prior to January 17, 2008 are designated as existing units per Rule 361.

Rule 505 - Breakdown Conditions: This rule describes the procedures that the permittee must follow when a breakdown condition occurs to any emissions unit associated with Holly. 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 item.

Rule 603 - Emergency Episode Plans: Section A of this rule requires the submittal of a *Stationary Source Curtailment Plan* for all stationary sources that can be expected to emit more than 100 tons per year of hydrocarbons, nitrogen oxides, carbon monoxide, or particulate matter. The permittee submitted this plan in July 1994 and updated it in March 2002. The Plan was approved in August 2002.

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 by reference. 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 file.

3.5.1 Platform Inspections: Routine District inspections are conducted at Platform Holly on a biennial basis. Each inspection report issued since the previous permit renewal was reviewed as a part of this permit renewal process. These inspection reports indicate that no enforcement actions were issued as a result of these inspections. There were no other significant compliance issues resulting from these inspections.

3.5.2 Variances: There has been one variance issued for this facility since the previous permit renewal. *VO 2019-13-E* was issued for the period 7/16/2019 through 7/30/2019 due to a failure of the DAS channels associated with Platform Holly's H2S alarms and High Pressure Flare caused by District DAS due to a PLC card failure.

3.5.3 Violations: There has been one enforcement action issued to this facility since the previous permit renewal. NOV 12083 was issued on 10/28/2019 for exceeding the number of allowable leaks during a self inspection as reported in an associated deviation report. This NOV has been resolved.

3.5.3 Significant Historical Hearing Board Actions: The actions taken by the District and the Hearing Board in 1998 and 1999 resulted in the issuance of Abatement Order No. 99-6(A) to in April of 1999. This Order made findings that air emissions from Holly, EOF, and the Barge Jovalan resulted in several public complaints. Condition 11.b of the Order was modified in 2001 to clarify that the SIMQAP Plan for Holly may only be modified with approval of the Control Officer. The Hearing Board ordered to the following:

1. Perform a safety audit of Holly, the Ellwood Onshore Facility, Lease 421 (aka the Beachfront Lease), the Marine Terminal and Line 96. The permittee was required to comply with the recommendations of these audits.

2. *Safety, Inspection, Maintenance and Quality Assurance Plan* (SIMQAP). The permittee was required to prepare and implement a SIMQAP Plan for all its Ellwood stationary source facilities. The SIMQAP for Holly is reviewed by the District (the District may consult with third party experts, including members of other County Departments) every two years and is updated as needed. The permittee may only revise the SIMQAP for the other Ellwood facilities upon approval of the Systems Safety and Reliably Review Committee.

3. Significant Gas Releases; Shutdown and Restart Protocol. The permittee was required to suspend any production and drilling operations immediately in the event of any defined shutdown trigger events.

4. Install a permanent flare system on Holly.

5. Implement several facility improvements to address odors while loading crude oil at the Barge Jovalan.

6. Implement a number of hydrogen sulfide monitoring procedures.

7. Install an emergency backup generator at EOF.

8. Comply with the County-approved *Emergency Action Plan* for the Project.

Abatement Order measures applicable to Holly have been incorporated in the permit conditions of this permit.

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, as listed in Form 1302-H in Part 70 application 9553	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 or 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 or modification to existing equipment.
RULE 212: Emission Statements	All emission units	Administrative
RULE 301: Circumvention	All emission units	Any pollutant emission
RULE 302 : Visible Emissions	All emission units	Particulate matter emissions
RULE 303: Nuisance	All emission units	Emissions that can injure, damage or offend.
RULE 305: PM Concentration - South Zone	Each PM source	Emission of PM in effluent gas
RULE 309: Specific Contaminants	All emission units	Combustion contaminant emission
RULE 311: Sulfur Content of Fuel	All combustion units	Use of fuel containing sulfur
RULE 317: Organic Solvents	Emission units using solvents	Solvent used in process operations
RULE 321: Solvent Cleaning Operations	Emission units using solvents	Solvent used in process operations

Generic Requirements	**Affected Emission Units**	**Basis for Applicability**
RULE 322: Metal Surface Coating	Emission units using solvents	Solvent used in process operations.
RULE 323.1: Architectural Coatings	Paints used in maintenance and surface coating activities	Application of architectural coatings.
RULE 324: Disposal and Evaporation of Solvents	Emission units using solvents	Solvent used in process operations.
RULE 353: Adhesives and Sealants	Emission units using adhesives and sealants	Adhesives and sealants use.
RULE 505.A, B1, D: 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 permittee – Ellwood is a major source.
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
REGULATION VIII: New Source Review	All emission units	Addition of new equipment or modification to existing equipment.
REGULATION XIII (RULES 1301-1305): Part 70 Operating Permits	All emission units	The South Ellwood Field Source is a major source.

Table 3.2. Unit-Specific Federally-Enforceable District Rules

Unit-Specific Requirements	**Affected Emission Units**	**Basis for Applicability**
RULE 325: Crude Oil Production and Separation	Storage tanks: Emission units capable of venting gases	Venting prohibited under Rule 325.E
RULE 330: Surface Coating of Metal Parts & Products	All surface coating used for any metal coating operations	Metal surfaces
RULE 331: Fugitive Emissions Inspection & Maintenance	Components (valves, flanges etc.) used to handle oil and gas: ID # 009601, 104754-104756	Components emit fugitive ROCs
RULE 333: Control of Emissions from Reciprocating IC Engines	Crane IC Engine, ID # 002336 Generator Engines ID #s 001930, 001931, 001932	Diesel-fired engine >50 hp. Gas-fired engines > 50 hp.
RULE 359: Flares and Thermal Oxidizers	ID # 007982, 009603	Flaring

Table 3.3. Non-Federally-Enforceable District Rules

Requirement	Affected Emission Units	Basis for Applicability
RULE 210: Fees	All emission units	Administrative
RULE 310: Odorous Sulfides	Process Units with emissions	Odorous sulfide emissions
RULE 361:Small Boilers, Steam Generators and Process Heaters	All emission units	Units rated greater than 2.0 MMbtu/hr and less than 5.0 MMbtu/hr.
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 3.4. Adoption Dates of District Rules Applicable at Issuance of Permit

Rule No.	Rule Name	Adoption Date
Rule 101	Compliance by Existing Installations: Conflicts	June 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	June 21, 2012
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 208	Action on Applications - Time Limits	April 17, 1997
Rule 212	Emission Statements	October 20, 1992
Rule 301	Circumvention	October 23, 1978
Rule 302	Visible Emissions	June 1981

Rule No.	**Rule Name**	**Adoption Date**
Rule 303	Nuisance	June 1981
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 323.1	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 328	Continuous Emissions Monitoring	October 23, 1978
Rule 330	Surface Coating of Metal Parts and Products	June 21, 2012
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	Control of Oxides of Nitrogen (NOx) from Boilers, Steam Generators and Process Heaters	April 17, 1997
Rule 343	Petroleum Storage Tank Degassing	December 14, 1993
Rule 344	Petroleum Sumps, Pits and Well Cellars	November 10, 1994
Rule 346	Loading of Organic Liquid Cargo Vessels	January 18, 2001
Rule 352	Natural Gas-Fired Fan-Type Central Furnaces and Small Water Heaters	October 20, 2011
Rule 353	Adhesives and Sealants	June 12, 2012
Rule 359	Flares and Thermal Oxidizers	June 28, 1994
Rule 360	Emissions of Oxides of Nitrogen From Large Water Heaters and Small Boilers	March 15, 2018

Rule No.	Rule Name	Adoption Date
Rule 361	Small Boilers, Steam Generators, and Process Heaters	June 20, 2019
Rule 505	Breakdown Conditions (Section A, B1 and D)	October 23, 1978
Rule 603	Emergency Episode Plans	June 15, 1981
Rule 801	New Source Review	August 25, 2016
Rule 802	Nonattainment Review	August 25, 2016
Rule 803	Prevention of Significant Deterioration	August 25, 2016
Rule 804	Emission Offsets	August 25, 2016
Rule 805	Air Quality Impact and Modeling	August 25, 2016
Rule 806	Emission Reduction Credits	August 25, 2016
Rule 808	New Source Review for Major Sources of Hazardous Air Pollutants	May 20, 1999
Rule 810	Federal Prevention of Significant Deterioration	June 20, 2013
Rule 901	New Source Performance Standards (NSPS)	September 20, 2010
Rule 1301	General Information	August 25, 2016
Rule 1302	Permit Application	November 9, 1993
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 engineering analyses performed for this permit were limited to the review of:

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

Unless noted otherwise, default ROC/THC reactivity profiles from the District's document titled "*VOC/ROC Emission Factors and Reactivities for Common Source Types*" dated 3/12/01 (version. 1.2) was used to determine non-methane, non-ethane fraction of THC.

4.2 Stationary Internal Combustion Engines

4.2.1 General: Stationary internal combustion engines associated with Holly consist of diesel and natural gas-fired piston IC engines.

Holly has two permanent diesel-fired IC engines. These include the 250 bhp pedestal crane engine and the 373 bhp emergency electrical generator engine. The 373-hp IC engine is limited by the ATCM to 20 hours per year of testing and maintenance operations. Emergency uses of the engine are not limited. Fuel usage of the crane engine is limited to 120 gallons per day and 30,000 gallons per year.

The platform also has two natural gas-fired Caterpillar Model G399 SITA generator engines (803 bhp) used for well work-over and drilling operations.

Other diesel-fired IC engines (e.g., electric line unit, hydraulic unit for casing tongs, coil tubing units) are used for well work-over and drilling operations.

4.2.2 Emission Controls: The crane engine is a Tier 3-certified engine, in addition, the engine is controlled by a diesel particulate filter in order to meet the ATCM PM limit of 0.01 g/bhp-hr or, alternatively, 85% reduction across the filter.

The drilling generators are each controlled by two 3-way NSCR catalysts and air-fuel ratio controllers.

Any diesel-fired engines brought to the platform for well drilling and work-over are rented engines. The permittee must ensure that any drilling and work over engines meet the requirements of the ATCM and are either permitted by the district or registered in the statewide PERP.

4.2.3 Emission Factors: Emission factors for the emergency generator are based on Table 3.3-1 of USEPA AP-42 for all criteria pollutants except for SO_x, which is based on mass balance techniques. Emission factors for the crane engine are based on Tier 3 and ATCM standards. The manufacturer's supplied information on NO_x and ROC emissions was used to convert the Tier NO_x+NMOC standard into NO_x and ROC emission factors. Emission factors for the gas-fired generators are based on the controlled emission factors previously approved under Exemption 10406.

4.2.4 Calculations: The following calculation methodology is used for the emergency-standby IC engine, which is subject to limits on the total hours of operation, and for the gas-fired generators:

$$ER = [(EF \times BHP \times BSFC \times CF \times HPP) \div 10^6]$$

where:

ER =	emission rate (lb/period)
EF =	pollutant specific emission factor (lb/MMBtu)
BHP =	engine rated max brake-horsepower (bhp)
BSFC =	engine brake specific fuel consumption (Btu/bhp-hr)
CF =	fuel correction factor, LHV to HHV
HPP =	operating hours per time period (hrs/period)

The emission factor is an energy-based value using the higher heating value (HHV) of the fuel. As such, the energy-based BSFC value must also be based on the HHV. Manufacturer BSFC data are based on lower heating value (LHV) data and require a conversion (CF) to the HHV basis. For diesel fuel oil, the HHV values are typically 6 percent greater than the corresponding LHV data, while for natural gas fuel this correction is typical 10 percent greater. Volume or mass-based BSFC data do not require conversion.

The crane engine is subject to daily and annual fuel use limits. Emissions are calculated based on the maximum rated horsepower, fuel consumption at the maximum rated horsepower, permitted emission factors, and the daily and annual fuel use limits:

E1, lb/day = Rating (bhp) * EF (g/bhp-hr) / Fuel Consumption (gal/hr) * (lb/453.6 g) * (28.5 gal/day)
E2, tpy = Rating (bhp) * EF (g/bhp-hr) / Fuel Consumption (gal/hr) * (lb/453.6 g) * (10,000 gal/year) * (ton/2000 lb)

For each generator, hourly fuel consumption at maximum rated horsepower is provided by the manufacturer. Therefore, emissions are calculated as follows:

E1, lb/day = EF (lb/MMBtu) * Fuel Consumption (scf/hr) * hr/day / (1,050 btu/scf) / (1,000,000)
E2, tpy = EF (lb/MMBtu) * Fuel Consumption (scf/hr) * hr/year / (1,050 btu/scf) / (1,000,000) * (ton/2000 lb)

4.2.5 Monitoring: All IC engines are equipped with non-resettable hour meters. The crane engine and the gas-fired generators are equipped with non-resettable fuel use meters. The hours of operation of all the engines at the platform are monitored. The fuel usage of the engines equipped with fuel use meters are also monitored. In addition, the engines that are subject to Rule 333 are monitored quarterly for NO_x and CO.

4.3 Flare Systems

4.3.1 General: The flare relief system consists of two flares, high-pressure flare H-100, and low-pressure flare H-101. Pilot and purge gas for each flare is in-plant fuel gas from EOF. The in-plant fuel gas is delivered to Holly by a gas pipeline from shore.

The high-pressure flare serves a header that connects to various PSVs on production and test vessels, compressors and pigging vessels. The high-pressure flare is a Kaldair model INDAIR 1-24-H-VS-WB self-assisted flare with a 10-inch diameter inlet; mounted to the existing vent stack boom; design rated to flare gas flow rates of up to 30 MMSCFD. The high-pressure flare pilot system uses one pilot, with a flow rate of up to 100 SCFH total and equipped with automatic igniters. The flare purge gas is manually controlled by a flow-control system (FCV-171) using a pressure gauge and flow orifice for up to 2,100 SCFH (equivalent to 50,400 SCFD). Small leaks from various sources around the plant may combine with the purge gas. This is allowed if the total flow does not exceed 50,400 SCFD and an H_2S concentration of 239 ppmv.

The low-pressure flare serves the glycol system reboiler relief valves PSV-131 and PSV-132, and the IR compressor distance piece relief valve PSV-170. This low-pressure flare is a Kaldair model CAK-4 combined pilot/flare tip; mounted to an existing flare stack boom and permit limited to flare gas flow rates of up to 2000 SCFM. The low-pressure flare pilot system uses one pilot with a flow rate of up to 100 SCFH total and equipped with automatic igniters. Flare purge gas flow-control FCV-173 is a manual system using a pressure gauge and rotameter for up to 300 SCFH (equivalent to 7,200 SCFD). Other sources can also be included in the planned continuous flaring category provided that the total flow does not exceed 7,200 SCFD and an H_2S concentration of 239 ppmv.

4.3.2 Emission Controls: The Kaldair INDAIR flare tip on the high pressure flare has a tulip shaped design that uses the Coanda Effect to reduce particulate emissions (i.e., smokeless design). The low-pressure flare has a Kaldair CAK-4 tip, which is not a smokeless design, but it is still subject to the visible emission limits of Rule 302.

4.3.3 Emission Factors: NO_x, ROC and CO emission factors are from Table 13.5-1 of USEPA's AP-42. The PM/PM_{10} factor is based on Table 3.1.1 of the District's *Flare Study Phase I Report* (7/91). SO_x emissions are based on a mass balance of total flared gas sulfur content per District document titled "*Technical Information and References Gaseous Fuel SOx Emission Factor*" (Version 1.0, 1/31/97). The $PM/PM_{10/2.5}/PM_{10}$ ratio is assumed to equal 1.0.

4.3.4 Calculations: The emissions for flaring events are calculated using the calculation methodology below:

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

where:		
	ER =	emission rate (lb/period)
	EF =	pollutant specific emission factor (lb/MMBtu)
	SCFPP =	gas flow rate per operating period (scf/period)
	HHV =	gas higher heating value (Btu/scf)

4.3.5 Monitoring: The high-pressure flare flow-metering system (FI-170) is capable of metering gas flow rates between 0.050 MMSCFD (i.e., 35 SCFM) to 26 MMSCFD. The low-pressure flare flow-metering system (FI-172) is capable of metering gas flow rates between 5 SCFM to 2000 SCFM. A Houston Atlas H_2S detector located at EOF monitors the H_2S concentration of the purge and pilot gas. The sulfur content of the pilot gas may not exceed 12 ppmv, and the sulfur content of the purge gas may not exceed 239 ppmv.

Both the high-pressure flare and the low-pressure flare are equipped with gas volume metering systems to measure the total gas flared including the continuous purge gas systems. The high-pressure flare flow meter (FI-170) and the low-pressure flare flow meter (FI-172) are also required to continuously transmit their respective outputs to the District Data Acquisition System (DAS). The pilot systems for the flares are limited by their design flow capability based upon a fixed size flow-limiting orifice and monitored fuel gas delivery pressure.

The purge gas sulfur content is monitored for H_2S content and total sulfur at EOF. A correlation ratio between total sulfur and H_2S is established for this system that allows weekly compliance assessments of total sulfur content based on H_2S monitoring alone. The H_2S content of the mixture of purge gas and small leaks is measured at V-127.

4.3.6 Flare Planned Operations (Purge and Pilot Emissions): The permittee specified that the flare pilots consume EOF in-plant fuel gas (12 ppmv total sulfur and 4 ppmv H_2S) at a rate of 200 SCF per hour (for both pilots combined). The purge rate to the flare that is used to prevent air intrusion and facilitate safe operations of the flare system has been specified at up to 2,100 SCF per hour (i.e., 35 SCFM). The purge gas is also EOF in-plant fuel gas, but small leaks from PSVs and other sources at the platform may mix with the purge gas in relief header V-127. This gas mixture will have a total fuel sulfur content of up to 239 ppmv. For emissions calculation purposes, both pilot and purge rates are presumed to occur at the maximum permitted flows 24 hours per day.

4.3.7 Flare Planned-Intermittent Operations: The permittee is prohibited from flaring any gas categorized as planned-intermittent. Emissions from these activities typically occur from depressurizing of vessels and equipment for maintenance. The permittee will not use either of the flares for this type of activity, but will instead depressurize these gases to EOF using its vapor recovery unit (through either the normal 6-inch produced gas, or the 4-inch utility lines). Any of these gas flows into these piping systems can be scrubbed of H_2S to Rule 359 limits prior to flaring onshore or commingling with EOF sales gas production.

4.3.8 Flare Unplanned Operations: The permittee is permitted for the unplanned flaring of produced gas containing up to 35,000 ppmv of H_2S. Unplanned flaring of such gas is authorized under Rule 359, if it is the result of emergencies and other process upsets or equipment failures beyond the normal control. The permittee is also permitted for the unplanned flaring of volumes up to 40,000 SCF total per month. This limit was derived through evaluating past venting records which show that no single event releases more than 20,000 SCF of gas, and that an average of two events occur per month.

4.3.9 Flare Worst-Case Credible Rate Event: The permittee is permitted for worst-case flare-event rate limit equivalent to the design gas flow rate capacity of Holly. This rate equates to 18,055 SCF per min of produced gas containing up to 35,000 ppmv of H_2S. Such an event at this rate is estimated to last no more than 66 seconds. An analysis was performed of the associated NO_x, SO_x and CO impacts from this type of event. The results of the analysis are documented in Section 6 of this permit.

4.4 Fugitive Hydrocarbon Sources

4.4.1 General: Fugitive hydrocarbon emissions occur from leaks in process components such as valves, connections, pumps, compressors and pressure relief devices. Each of these component types may be comprised of several potential "leak paths" at the facility. For example, leak paths associated with a valve include the valve stem, bonnet, and the upstream and downstream flanges. The total number of leak paths at the facility must be determined to perform fugitive emission calculations.

4.4.2 Emission Controls: A fugitive emissions control program is used to minimize potential leaks from the process components. Emission reductions are expected as a result of the implementation of a Fugitive Hydrocarbon Inspection and Maintenance (I&M) program. The I&M program is designed to minimize leaks through a combination of pre-leak and post-leak controls. Pre-leak controls include venting of leaks from compressor seals to the vapor recovery system, venting of pressure relief devices to the flare system, and plugging of open-ended lines (an open-ended line is a valve that has one side of the valve seat in contact with the process fluid, and is open to the atmosphere on the other). Post-leak controls consist of regular inspection of each leak source for leakage and repair of all components found leaking. An emission control efficiency of 80 percent is credited to all accessible and inaccessible components that are safe to monitor (as defined per Rule 331) due to the implementation of a District-approved Inspection and Maintenance program for leak detection and repair consistent with Rule 331 requirements. Unsafe to monitor components are not eligible for I&M control credit. Ongoing compliance is determined in the field by inspection with an organic vapor analyzer and verification of operator records.

4.4.3 Emission Factors: Emissions of reactive organic compounds from piping components such as valves, flanges and connections have been calculated using emission factors pursuant to District P&P 6100.061 (*Determination of Fugitive Hydrocarbon Emissions at Oil and Gas Facilities Through the Use of Facility Component Counts - Modified for Revised ROC Definition*) for components in gas/light liquid and oil/emulsion service. The component leak paths were counted consistent with P&P 6100.061. This leak path count is not the same as the "component" count required by District Rule 331.

4.4.4 Calculations: The current component leakpath count on Platform Holly is listed in Table 5.1-1. The calculation methodology for the fugitive emissions is:

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

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

Note that the same emission factor and ROC/THC ratio is used for all component types on offshore platforms, so it is not necessary to break down the component leak path count by type in order to calculate emissions.

4.4.5 Monitoring: Inspections are performed with an Organic Vapor Analyzer consistent with EPA Method 21. Components are required to be repaired between 1 to 14 days, depending on the severity of the leak. The I&M program is consistent with the requirements of District Rule 331. The I&M program also includes a leak path identification system. Leak paths are physically identified in the field with a tag and given a unique number. An inventory of each tag is then maintained which describes the component type, service, accessibility and all associated leak paths. The leak path inventory serves as a basis for compliance with fugitive hydrocarbon emission limits.

4.5 Crew and Supply Vessels

4.5.1 General: Holly is serviced by both crew and supply boats. Crew boats are used to transport personnel and light supplies between Ellwood Pier and the platform. Supply boats are used to transport equipment and supplies, between Port Hueneme and the platform. Total mileage in the state coastal waters, from Holly to Ventura's Port Hueneme is approximately 41 miles (one way). Total mileage between the Ellwood Pier and Holly is approximately 3.2 miles (one way).

The permittee does not have dedicated crew or supply boats for servicing Holly. Instead, whatever boats are available are used, provided the boats comply with the permit conditions and emission limits of this permit. Crew and supply boats that are permitted for use at Holly are listed in the District-approved Boat Monitoring and Reporting Plan issued to this facility.

4.5.2 Emission Controls: The main and auxiliary engines for crew and supply boats are controlled and meet at minimum EPA Tier 2 marine engine emissions standards.

4.5.3 Emission Factors: The main engines for both crew and supply boats use NOx, ROC, CO and PM EPA Tier 2 marine emission factors for category 1 vessels with a displacement between 2.5 and 4.999 liters per cylinder. The auxiliary engines for supply boats use NOx, ROC, CO and PM EPA Tier 2 marine emission factors for category 1 vessels with displacement between 1.2 and 2.499 liters per cylinder. The auxiliary engines for the crew boat use NOx, ROC, CO and PM EPA Tier 2 off road emission factors for engines between 175 to 300 bhp. Sulfur oxide emissions are based on mass balance calculations assuming 0.0015 weight percent sulfur diesel fuel.

4.5.4 Calculations: The calculation methodology for the crew and supply boat main engine emissions is:

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

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

The calculations for the auxiliary engines are similar, except that a 50 percent engine load factor for the generators is utilized.

4.5.5 Monitoring: Ongoing compliance will be assessed through implementation of a District-approved Boat Monitoring and Reporting Plan. This Plan will be required to follow the District *Data Reporting Protocol for Crew and Supply Boat Activity Monitoring* document (dated June 21, 1991 and subsequent updates). The plan requirements include fuel use and hours of operation.

4.5.6 Emergency Response Boat: A permanently assigned emergency response vessel (i.e., the *Clean Seas II*) is associated with Holly. The engines on these vessels are uncontrolled. The total engine horsepower, including auxiliary engines, is 1,770 bhp. Emissions liability is assigned in a prorated fashion among the sixteen offshore platforms that utilize the vessel off the Santa Barbara coast. Emission factors, calculations, and compliance procedures are the same as for the supply vessels discussed above. If used, other emergency response boat fuel usage (and resulting emissions) shall be assessed against this emissions category.

4.6 Tanks/Vessels/Sumps/Separators

4.6.1 Tanks: Platform Holly has one diesel fuel storage tank and one glycol storage tank. The diesel storage tank servicing the various IC engines on the platform is not controlled. The glycol storage tank is also uncontrolled. Emissions from the diesel fuel and glycol tanks are small and are assumed to be less than 0.10 tpy (200 lb/year).

4.6.2 Pressure Vessels: Platform Holly has several pressure vessels (e.g., production separators, a test separator, a glycol contactor, surge vessels, and scrubbers). Emissions from pressure vessels are due to fugitive hydrocarbon leaks from valves and connections.

4.6.3 Sumps: Oil Sump Tank T-5 collects liquids from the laboratory sink and sample drains. Fluids from this tank are pumped to V-109 or V-110 surge vessels. The platform also has a deck water drainage system that consists of two open top tanks in series (T-1 and T-4). Liquids from these tanks are pumped to V-109 or V-110 surge vessels. Vacuum trucks are periodically transported to the platform on the supply boat to remove solids from the tanks. The emissions from all three of these tanks are based on the CARB/KVB Report (*Emissions Characteristics of Crude Oil Production in California,* January 1983). These vessels are classified as being in tertiary production and light oil service and are all vented to the atmosphere. The calculation method is:

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

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

4.7 Other Emission Sources

4.7.1 Pigging: Pipeline pig launching to the Ellwood Onshore Facility occurs on the platform. Some backpressure remains inside the launcher when it is opened to the atmosphere at the end of pigging. The District has assumed that this remaining pressure should not exceed 20 psig. Negligible ROC emissions occur during the depressurization of the unit after being purged with nitrogen five times (see Section 10.1). The calculation per depressurization event is:

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

where:	ER = emission rate (lb/event)
V_1 =	volume of launcher/receiver vessel (ft^3)
ρ =	density of vapor (99.99 % N_2) at actual conditions (lb/ft^3)
wt % =	weight percent ROC in the nitrogen-ROC mix

4.7.2 General Solvent Cleaning/Degreasing: Solvent usage (not including thinners for surface coating) occurs on Holly as part of normal daily operations and consists of small cold solvent degreasing and wipe cleaning. Mass balance emission calculations are used assuming all the solvent used evaporates to the atmosphere. Emission estimates and compliance are based on monthly usage data. For the purposes of calculations, the daily emissions are assumed equal to the monthly emissions divided by the number of days per month.

4.7.3 Surface Coating: Surface coating operations typically include normal touch up activities. Entire platform painting programs are performed once every few years. Emissions are determined based on mass balance calculations assuming all solvents evaporate into the atmosphere. Emissions of $PM/PM_{10}PM_{2.5}$ from paint over-spray are not calculated due to the lack of established calculation techniques.

4.7.5 Abrasive Blasting: Abrasive blasting with CARB certified sands may be performed as a preparation step prior to surface coating. Particulate matter is emitted during this process. A general emission factor of 0.01 pound PM per pound of abrasive is used (*SCAQMD - Permit Processing Manual*, 1989) to estimate emissions of $PM/PM_{10}PM_{2.5}$ when needed for compliance calculations. A $PM/PM_{10}PM_{2.5}$ ratio of 1.0 is assumed.

4.8 Vapor Recovery/Control Systems

Vapor Recovery Systems: Holly has two electric-powered VRU compressors (C-100A, C-100B) for collecting vapors from various low-pressure systems on the platform for recycle in gas-lift operations, or delivery to the EOF for processing to sales gas. Low-pressure systems include the glycol system, compressor distance pieces, acid surge vessel, and oil surge vessels. A control efficiency of 95 percent is assigned to the vapor recovery system.

4.9 BACT/NSPS/NESHAP/MACT

The crane engine is subject to Best Available Control Technology provisions of the District and federal New Source Performance Standard Subpart IIII.

The existing generator engines and the emergency standby engine are subject to 40 CFR Part 63 Subpart ZZZZ (NESHAPS). Holly is subject to MACT provisions prescribed under Subpart HH but qualifies for the black oil exemption.

4.10 CEMS/Process Monitoring/CAM

4.10.1 CEMS: There are no in-stack continuous emission monitors (CEMS) at Holly.

4.10.2 Process Monitoring: In many instances, ongoing compliance beyond a single (snap shot) source test is assessed by process monitoring systems. Examples of these monitors include: engine hour meters, water injection mass flow meters, fuel usage meters, flare gas flow meters, and hydrogen sulfide analyzers. Once these process monitors are in place, it is important that they be well maintained and calibrated to ensure that the required accuracy and precision of the devices are within specifications. At a minimum, the following process monitors will be required to be calibrated and maintained in good working order:

- Crew boat diesel fuel meters (main and auxiliary engines)
- Supply boat diesel fuel meters (main and auxiliary/bow thruster engines)
- Hour meters (crane, emergency generator, drilling generator engines)
- Flare flow meters (high-pressure and LP flares)
- Fuel flow meters (drilling generator engines)

- Ambient H_2S sensors and LEL sensors required by the SIMQAP

To implement the above calibration and maintenance requirements, the permittee updated the existing *Process Monitor Calibration and Maintenance Plan.* The permittee is required to comply with the Plan and any subsequent District-approved update.

4.10.3 CAM: A review of the equipment associated with Holly indicates that there are no emission units or activities that are subject to the rule. This rule affects emission units at the source subject to a federally enforceable emission limit or standard that uses a control device to comply with the emission standard, and either pre-control or post-control emissions exceed the Part 70 source emission thresholds.

4.11 Source Testing/Sampling

Source Testing/Sampling/Calibration: Source testing and sampling are required in order to ensure compliance with permitted emission limits, prohibitory rules, control measures and the assumptions that form the basis of this operating permit.

Source testing of the two generator engines for NO_x, ROC, and CO is required every two years by Rule 333. Source testing must be conducted using the methods specified by Rule 333. Source testing is not required for the crane engine, unless portable analyzer monitoring exceeds a threshold of 197 ppmvd NO_x @ 15% O_2, and a failure to demonstrate compliance with this threshold by a retest within 15 days of the initial reading.

At a minimum, the process streams below are required to be sampled and analyzed. Duplicate samples are required for TRS/H_2S; and for wastewater when Rule 325 applicability is to be determined:

- ☞ Produced Gas: Sample taken at production separator outlet. Analysis for: HHV, total sulfur, hydrogen sulfide, composition. Samples are to be taken on an annual basis.
- ☞ Produced Oil: Sample taken at outlet from production separator. Analysis for: API gravity; true vapor pressure (per Rule 325 methods). Samples are to be taken on an annual basis.
- ☞ Wastewater: Sample taken of liquid entering the wastewater surge tank (T-1), oil salvage tank (T-5) and surge skimmer tank (T-4). Analysis for: ROC content in units of mg/l (per Rule 325 methods). Samples to be taken upon request of the District, except for Tank T-1, which is to be taken annually.
- ☞ Flare Gas Stream: Sample to be taken at District-approved collection point per Process Stream Sampling Plan. Analysis for total sulfur. Samples to be taken on an annual basis.
- ☞ Flare Gas Stream: Sample to be taken at District-approved collection point at the platform per Process Stream Sampling Plan. Analysis for hydrogen sulfide. Samples to be taken on a daily/weekly/quarterly basis.
- ☞ Flare Pilot and Purge Gas Stream: Flare pilot and purge gas is EOF in-plant fuel gas. Hydrogen sulfide and total sulfur analyses of the in-plant fuel gas are taken at the EOF.
- ☞ IC Engine Diesel Fuel: Sample to be taken at the fuel tank. Analysis for HHV per District-approved ASTM Methods. Sample to be taken annually.

4.12 Part 70 Engineering Review: Hazardous Air Pollutant Emissions

Hazardous air pollutant emissions from the different categories of emission units at Holly are based on emission factors listed in USEPA AP-42. Where no emission factors are available, the HAP fractions from the ARB VOC Speciation Manual – Second Edition (August 1991) are used in conjunction with the ROC emission factor for the equipment item in question. Potential HAP emissions from each emissions unit at Holly are listed in Section 5. The HAP emission factor basis is detailed in Table 10.1-4.

5.0 Emissions

5.1 General

Emissions calculations are divided into "permitted" and "exempt" categories. Permit exempt equipment is determined by District Rule 202. The permitted emissions for each emissions unit are based on the equipment's potential to emit (as defined by Rule 102). Section 5.2 details the permitted emissions for each emissions unit. Section 5.3 details the overall permitted emissions for the facility based on reasonable worst-case scenarios using the potential to emit for each emissions unit. Section 5.4 provides the federal potential to emit calculation using the definition of potential to emit used in Rule 1301. Section 5.5 provides the estimated HAP emissions for the platform. Section 5.6 provides the estimated emissions from permit exempt equipment and also serves as the Part 70 list of insignificant emissions. In order to track the emissions from a facility accurately, the District uses a computer database. Attachment 10.4 contains the District's documentation for the information entered into that database. Consistent with the District and federal rules, all marine vessel emissions associated with the platform are included in the potential-to-emit calculations.

5.2 Permitted Emission Limits - Emission Units

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

⇒ Nitrogen Oxides (NO_x) [3]
⇒ Reactive Organic Compounds (ROC)
⇒ Carbon Monoxide (CO)
⇒ Sulfur Oxides (SO_x) [4]
⇒ Particulate Matter (PM) [5]
⇒ Particulate Matter smaller than 2.5 and 10 microns ($PM_{10/2.5}$)
⇒ Greenhouse Gases (GHGs)

Permitted emissions are calculated for both short term (daily) and long term (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 may be found in Section 4 and Attachment 10.1. Table 5.1-1 provides the basic

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

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

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

operating characteristics. Table 5.1-2 provides the specific emission factors. Table 5.1-3 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". Those emissions limits that are District-only enforceable are indicated by the symbol "A". Emissions data that are shown for informational purposes only are not enforceable (District or federal) and are indicated by the symbol "NE".

5.3 Permitted Emission Limits - Facility Totals

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

Daily Scenario:

- Fugitive components
- Crew and supply boat main engines
- Generator engines on crew and supply boats
- Bow thruster on supply boat
- Oil emulsion, produced gas, and utility gas pig launchers
- Flaring (purge, pilot, planned continuous)
- Salvage tank
- Skimmer tank
- Oil recovery tank
- Solvent/coating usage
- Emergency generator
- Drill rig generator engines
- Crane engine

Annual Scenario:

- Fugitive components
- Crew and supply boat main engines
- Generator engines on crew and supply boats
- Bow thruster on supply boat
- Oil emulsion and produced gas, and utility gas pig launchers
- Flaring (purge, pilot, planned continuous, unplanned other)
- Drain Sump Tank (T-1)
- Overflow Sump Tank (T-4)
- Solvent/coating usage
- Emergency generator
- Drill rig generator engines
- Crane engine

5.4 Part 70: Federal potential to emit for the Facility

Table 5.3 lists the federal Part 70 potential to emit. Fugitive emissions are excluded from the federal definition of potential to emit unless the source belongs to one of the categories listed in 40 CFR 70.2. Petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels are listed in 40 CFR 70.2. This facility has a total petroleum storage capacity less than 300,000 barrels. Stationary sources that were being regulated as of August 7, 1980 under section 111 or 112 are also listed in 40 CFR 70.2. Each NSPS and NESHAP applicable to the equipment subject to this permit was promulgated after August 7, 1980 therefore fugitive emissions are not included in the federal potential to emit.

5.5 Part 70: Hazardous Air Pollutant Emissions for the Facility

Total emissions of hazardous air pollutants (HAP) are computed based on the factors listed in Table 5.5-1 for each emissions unit. Refer to Table 10.1-4 for the basis of the HAP emission factors. HAP emission factors are shown in Table 5.5-1. Facility HAP emissions are shown in Table 5.5-2. Stationary Source HAP emissions are shown in Table 5.5-3. These are based on a combination of the worst-case scenario listed in Section 5.3. HAPs emissions fugitive emissions have been revised based on revised HAPs emission factors.

5.6 Exempt Emission Sources/Part 70 Insignificant Emissions

Equipment/activities exempt from District permits pursuant to Rule 202 include:

- maintenance operations involving surface coating (painting operations)
- portable registered drilling engines
- diesel fuel tank (1500 gallons)

Insignificant emission units are defined under District Rule 1301 as any regulated air pollutant emitted from the unit, excluding HAPs, that are less than 2 tons per year based on the unit's potential to emit and any HAP regulated under section 112(g) of the Clean Air Act that does not exceed 0.5 ton per year based on the unit's potential to emit. Solvent usage and surface coating operations for maintenance are exempt from District permit per Rule 202, but are not Part 70 insignificant emission units, since they exceed the insignificant emissions threshold.

Table 5.4 presents the estimated annual emissions from these exempt equipment items, including those exempt items not considered insignificant. This permit covers the Solvents/Surface coating operations used maintenance operations.

Table 5.1-1
Venoco Platform Holly PTO 8234-R11
Operating Equipment Description

		Device Specifications						Usage Data			Maximum Operating Schedule (in hours/time perio			
		Venoco			% S									
Equipment Category	Description	Equip. No	EQ No.	Fuel	by volume	Size	Units	Capacity	Units	Load	hr	day	year	References
Combustion - Flare	Planned - Pilot (all)	H-100/101	7982/9603	PUC	0.0012	200	scfh	0.220	MMBtu/hr	--	1.0	24	8760	A
	Planned - Purge	H-100	7982	PG	0.0239	2,100	scfh	2.310	MMBtu/hr	--	1.0	24	8760	
	Planned - LP Purge	H-101	9603	PG	0.0239	300	scfh	0.330	MMBtu/hr	--	1.0	24	8760	
	Planned - Intermittent	H-100/101	7982/9603	PG	0.0239	0	scfh	0.000	MMBtu/hr	--	0	0	0	
	Unplanned	H-100/101	7982/9603	SG	3.5000	480,000	scf/yr	528.000	MMBtu/yr	--	n/a	n/a	0.38	
	Worst-Case Flare Event	--	7982/9603	SG	3.5000	18,056	scf/min	19.861	MMBtu/min		0.0183	n/a	n/a	
IC Engine	Crane Engine	--	111506	Diesel	0.0015	250	bhp	14.1	gal/hr	--	1.0	2.0	709.2	
	Emergency Generator		2337	Diesel	0.0015	373	bhp	21.24	gal/hr		1.0	2.0	20.0	
	Generator No. 1		9130	NG	0.008	803	bhp	7.59	MMBtu/hr		1.0	24	8760	
	Generator No. 2		9131	NG	0.008	803	bhp	7.59	MMBtu/hr		1.0	24	8760	
Fugitive Components	Oil - controlled	3105-02	9601	--	--	3,992	comp-lp	--	--	--	1.0	24	8760	B
	Oil - unsafe	3105-03	104754	--	--	14	comp-lp	--	--	--	1.0	24	8760	
					sub-total =	4,006								
	Gas - controlled	3105-04	104755	--	--	14,278	comp-lp	--	--	--	1.0	24	8760	
	Gas - unsafe	3105-05	104756	--	--	964	comp-lp	--	--	--	1.0	24	8760	
					sub-total =	15,242								
Supply Boat	Main Engines	3105-AA	9789	D2	0.0015	4,920	bhp-total	270.1	gal/hr	0.65	1.0	13	2544	C
	Generator Engines	3105-BB	9790	D2	0.0015	530	bhp-total	29.1	gal/hr	0.50	1.0	24	3500	
	Bow Thruster	3105-CC	9791	D2	0.0015	530	bhp-total	29.1	gal/hr	1.00	1.0	3	500	
Crew Boat	Main Engines	3105-DD	9787	D2	0.0015	5,200	bhp-total	285.5	gal/hr	0.85	1.0	7.0	1792	D
	Auxilliary Engines	3105-EE	9788	D2	0.0015	250	bhp-total	13.7	gal/hr	0.50	1.0	7.0	1792	
											(pigging events per period)			
Pigging Equipment	Oil Launcher	3105-06	9792	--	--	1.40	ft3	5	psig	--	5	5	960	E
	Utility Gas Launcher	3105-07	9793	--	--	1.40	ft3	5	psig	--	10	10	120	
	Gas Launcher	3105-08	9794	--	--	1.40	ft3	5	psig	--	10	10	120	
Sumps/Tanks/Separators	Drain Sump Tank (T-1)	3105-09	2345	--	--	44.20	ft2	--	--	--	1.0	24	8760	F
	Overflow sump Tank (T-4)	3105-11	5882	--	--	113.20	ft2	--	--	--	1.0	24	8760	
Solvent/Coatings Usage*	Cleaning/degreasing	3105-15	5884	--	--	1,500	gal/yr	125	gal/month	--	1.0	24	8760	G
Boom Boat	Oil spill boom deployment		114797	gas		225	bhp-total	0.1	gal/hp-hr	0.65	1.0	5.5	24	H

*-- estimated solvent usage

Table 5.1-2
Venoco Platform Holly PTO 8234-R11
Equipment Emission Factors

				Emission Factors							
Equipment Category	Description	Venoco Equip. No	EQ No.	NOx	ROC	CO	SOx	PM	PM2.5/10	Units	References
Combustion - Flare	Planned - Pilot (all)	H-100/101	7982/9603	0.068	0.086	0.370	0.002	0.020	0.020	lb/MMBtu	A
	Planned - Purge	H-100	7982	0.068	0.086	0.370	0.037	0.020	0.020	lb/MMBtu	
	Planned - LP Purge	H-101	9603	0.068	0.086	0.370	0.037	0.020	0.020	lb/MMBtu	
	Planned - Intermittent	H-100/101	7982/9603	0.068	0.086	0.370	0.037	0.020	0.020	lb/MMBtu	
	Unplanned	H-100/101	7982/9603	0.068	0.086	0.370	5.377	0.020	0.020	lb/MMBtu	
	Worst-Case Flare Event	--	7982/9603	0.068	0.086	0.370	5.377	0.020	0.020	lb/MMBtu	
IC Engine	Crane Engine	--	111506	2.69	0.31	2.60	0.006	0.01	0.01	g/hp-hr	
	Emergency Generator		2337	14.061	1.12	3.03	0.93	0.984	0.984	g/hp-hr	
	Generator No. 1		9130	0.166	0.037	0.292	0.013	0.046	0.046	lb/MMBtu	
	Generator No. 2		9131	0.166	0.037	0.292	0.013	0.046	0.046	lb/MMBtu	
Fugitive Components	Oil - controlled	3105-02	9601	--	0.0009	--	--	--	--	lb/day-clp	B
	Oil - unsafe	3105-03	104754	--	0.0044	--	--	--	--	lb/day-clp	
	Gas - controlled	3105-04	104755	--	0.0147	--	--	--	--	lb/day-clp	
	Gas - unsafe	3105-05	104756	--	0.0736	--	--	--	--	lb/day-clp	
Supply Boat	Main Engines	3105-AA	9789	195	21.68	148.58	0.21	6.02	5.78	lb/1000 gal	C
	Generator Engines	3105-BB	9790	195	21.68	148.58	0.21	6.02	5.78	lb/1000 gal	
	Bow Thruster	3105-CC	9791	195	21.68	148.58	0.21	6.02	5.78	lb/1000 gal	
								6.02			
Crew Boat	Main Engines	3105-DD	9787	195	21.68	148.58	0.21	6.02	5.78	lb/1000 gal	D
	Auxilliary Engines	3105-EE	9788	181	16.06	77.86	0.21	6.02	5.78	lb/1000 gal	
Pigging Equipment	Oill Launcher	3105-06	9792	--	0.054	--	--	--	--	lb/evnt	E
	Utility Gas Launcher	3105-07	9793	--	0.001	--	--	--	--	lb/evnt	
	Gas Launcher	3105-08	9794	--	0.001	--	--	--	--	lb/evnt	
Sumps/Tanks/Separators	Drain Sump Tank (T-1)	3105-09	2345	--	0.0058	--	--	--	--	lb/ft2-day	F
	Overflow Sump Tank (T-	3105-11	5882	--	0.0058	--	--	--	--	lb/ft2-day	
Solvent/Coatings Usage	Cleaning/degreasing	3105-15	5884	--	250	--	--	--	--	g/l	G
Boom Boat	Oil spill boom deployment		114797	7.20	4.90	1,357.34	0.27	48.10	48.10	g/hp-hr	H

Table 5.1-3
Venoco Platform Holly PTO 8234-R11
Daily and Annual Emissions

		Venoco		NOx		ROC		CO		SOx		PM		PM2.5/10		Federal
Equipment Category	Description	Equip. No	EQ No.	lb/day	tpy	lb/day	tpy	lb/day	tpy	lb/day	tpy	lb/day	tpy	lb/day	tpy	Enforceability
Combustion - Flare	Planned - Pilot (all)	H-100/101	7982/9603	0.36	0.07	0.46	0.08	1.95	0.36	0.01	0.00	0.11	0.02	0.11	0.02	FE
	Planned - Purge	H-100	7982	3.77	0.69	4.79	0.87	20.51	3.74	2.04	0.37	1.11	0.20	1.11	0.20	FE
	Planned - LP Purge	H-101	9603	0.54	0.10	0.68	0.12	2.93	0.53	0.29	0.05	0.16	0.03	0.16	0.03	FE
	Planned - Intermittent	H-100/101	7982/9603	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	FE
	Unplanned	H-100/101	7982/9603	n/a	0.02	n/a	0.02	n/a	0.10	n/a	1.42	n/a	0.01	n/a	0.01	FE
				lb/min	lb/event	lb/min	lb/event	lb/min	lb/event	lb/min	lb/event	lb/min	lb/event	lb/min	lb/event	
	Worst-Case Flare Event	--	7982/9603	1.35	1.48	1.72	1.88	7.35	8.07	106.80	117.27	0.40	0.44	0.40	0.44	FE
IC Engine	Crane Engine	--	2336	3.00	0.53	0.35	0.06	2.90	0.51	0.01	0.00	0.01	0.00	0.01	0.00	A
	Emergency Generator		2337	23.13	0.12	1.84	0.01	4.98	0.02	1.53	0.01	1.62	0.01	1.62	0.01	A
	Generator No. 1		9130	30.26	5.52	6.74	1.23	53.22	9.71	2.37	0.43	8.38	1.53	8.38	1.53	
	Generator No. 2		9131	30.26	5.52	6.74	1.23	53.22	9.71	2.37	0.43	8.38	1.53	8.38	1.53	
Fugitive Components	Oil - controlled	3105-02	9601	--	--	3.50	0.64	--	--	--	--	--	--	--	--	A
	Oil - unsafe	3105-03	104754	--	--	0.06	0.01	--	--	--	--	--	--	--	--	A
					sub-total =	3.57	0.65									A
	Gas - controlled	3105-04	104755	--	--	210.14	38.35	--	--	--	--	--	--	--	--	A
	Gas - unsafe	3105-05	104756	--	--	70.94	12.95	--	--	--	--	--	--	--	--	A
					sub-total =	281.08	51.30									A
Supply Boat	Main Engines	3105-AA	9789	454.00	43.58	50.43	4.84	345.64	33.18	0.49	0.05	14.00	1.34	13.44	1.29	A
	Generator Engines	3105-BB	9790	68.14	4.97	7.57	0.55	51.88	3.78	0.07	0.01	2.10	0.15	2.02	0.15	A
	Bow Thruster	3105-CC	9791	17.04	1.42	1.89	0.16	12.97	1.08	0.02	0.00	0.53	0.04	0.50	0.04	A
Crew Boat	Main Engines	3105-DD	9787	331.52	42.43	36.83	4.71	252.40	32.31	0.36	0.05	10.23	1.31	9.82	1.26	A
	Auxilliary Engines	3105-EE	9788	8.66	1.11	0.77	0.10	3.73	0.48	0.01	0.00	0.29	0.04	0.28	0.04	A
Pigging Equipment	Oill Launcher	3105-06	9792	--	--	0.27	0.03	--	--	--	--	--	--	--	--	A
	Utility Gas Launcher	3105-07	9793	--	--	0.01	0.00	--	--	--	--	--	--	--	--	A
	Gas Launcher	3105-08	9794	--	--	0.01	0.00	--	--	--	--	--	--	--	--	A
Sumps/Tanks/Separators	Drain Sump Tank (T-1)	3105-09	2345	--	--	0.26	0.05	--	--	--	--	--	--	--	--	A
	Overflow Sump Tank (T-	3105-11	5882	--	--	0.66	0.12	--	--	--	--	--	--	--	--	A
Solvent/Coatings Usage*	*Cleaning/degreasing**	3105-15	5884	--	--	8.56	1.56	--	--	--	--	--	--	--	--	
Boom Boat	Oil spill boom deployment		104765	12.77	0.03	8.69	0.02	2406.99	5.25	0.48	0.00	85.30	0.19	85.30	0.19	A

Notes
FE = federally enforceable
A = APCD-only enforceble
*-- *These estimated emissions do not constitute any emissions limit*

Table 5.2
Venoco Platform Holly PTO 8234-R11
Total Permitted Facility Emissions

A. DAILY (lb/day)

Equipment Category	NOx	ROC	CO	SOx	PM	PM2.5/10
Combustion - Flare	4.67	5.93	25.40	2.34	1.37	1.37
IC Engines	86.64	15.68	114.33	6.28	18.40	18.40
Fugitive Components	--	284.65	--	--	--	--
Supply Boat	539.18	59.90	410.49	0.58	16.63	15.97
Crew Boat	340.19	37.60	256.13	0.37	10.51	10.09
Pigging	--	0.30	--	--	--	--
Sumps/Tanks/Separators	--	0.91	--	--	--	--
*Solvent/Coatings Usage**	--	8.56	--	--	--	--
Boom Boat	12.77	8.69	2,406.99	0.48	85.30	0.19
Facility Total	**983.44**	**422.21**	**3,213.33**	**10.04**	**132.21**	**46.02**

B. ANNUAL (tpy)

Equipment Category	NOx	ROC	CO	SOx	PM	PM2.5/10
Combustion - Flare	0.87	1.10	4.73	1.85	0.26	0.26
IC Engines	11.69	2.53	19.96	0.87	3.07	3.07
Fugitive Components	--	51.95	--	--	--	--
Supply Boat	49.97	5.55	38.05	0.05	1.54	1.48
Crew Boat	43.54	4.81	32.78	0.05	1.35	1.29
Pigging	--	0.03	--	--	--	--
Sumps/Tanks/Separators	--	0.17	--	--	--	--
*Solvent/Coatings Usage**	--	1.56	--	--	--	--
Boom Boat	0.03	0.02	5.25	0.00	0.19	0.19
Facility Total	**106.10**	**67.72**	**100.77**	**2.82**	**6.40**	**6.28**

Table 5.3
Venoco Platform Holly PTO 8234-R11
Federal Potential to Emit

A. DAILY (lb/day)

Equipment Category	NOx	ROC	CO	SOx	PM	PM2.5/10
Combustion - Flare	4.67	5.93	25.40	2.34	1.37	1.37
IC Engines	86.64	11.69	15.68	2.53	114.33	19.96
Fugitive Components	--	--	--	--	--	--
Supply Boat	539.18	59.90	410.49	0.58	16.63	15.97
Crew Boat	340.19	37.60	256.13	0.37	10.51	10.09
Pigging	--	--	--	--	--	--
Sumps/Tanks/Separators	--	--	--	--	--	--
Solvent Usage	--	--	--	--	--	--
Exempt Eqpt.	1,319.30	250.80	250.80	116.10	86.60	86.60
Facility Total	**2,289.97**	**365.91**	**958.49**	**121.92**	**229.45**	**133.99**

B. ANNUAL (tpy)

Equipment Category	NOx	ROC	CO	SOx	PM	PM2.5/10
Combustion - Flare	0.87	1.10	4.73	1.85	0.26	0.26
IC Engines	11.69	15.68	2.53	114.33	19.96	6.28
Fugitive Components	--	--	--	--	--	--
Supply Boat	49.97	5.55	38.05	0.05	1.54	1.48
Crew Boat	43.54	4.81	32.78	0.05	1.35	1.29
Pigging	--	0.03	--	--	--	--
Sumps/Tanks/Separators	--	0.17	--	--	--	--
Solvent Usage	--	1.56	--	--	--	--
Exempt Equipment	8.92	7.32	7.99	0.25	1.63	1.63
Boom Boat	0.03	0.02	5.25	0.00	0.19	0.19
Facility Total	**115.02**	**36.24**	**91.34**	**116.52**	**24.92**	**11.12**

Table 5.4
Venoco Platform Holly PTO 8234-R11
Estimated APCD Permit Exempt Emissions

A. DAILY (lb/day)

Equipment Category	EQ No.	NOx	ROC	CO	SOx	PM	$PM_{10/2.5}$
Surface Coating - Maintenance	10-3	--	27.78	--	--	--	--
Drilling Rig Engines (*)	10-4	1,319.30	119.50	250.80	116.10	86.60	86.60
		1,319.30	147.28	250.80	116.10	86.60	86.60

Equipment Category	EQ #	NOx	ROC	CO	SOx	PM	$PM_{10/2.5}$
Surface Coating - Maintenance	10-3	--	5.00	--	--	--	--
Drilling Rig Engines (*)	10-4	8.92	2.32	7.99	0.25	1.63	1.63
		8.92	7.32	7.99	0.25	1.63	1.63

Please refer Table 10.1-1 for documentation of emission estimates.

(*) Based on Mitigated Negative Declaration for Platform Holly Re-drilling Project for first year, Table 14.3-3, May 15, 2001.

Table 5.5-1
Platform Holly: Part 70/PTO 8234-R11
Hazardous Air Pollutant Emission Factors

Equipment Category	Description	Venoco Equip No.	EQ No.	Hexane	Benzene	Toluene	Xylene	iso-Octane	Formaldehyde	Naphthalene	Acetaldehyde	Acrolein	1,3-Butadiene	Carbon Tetrachloride	Chlorine	Chlorobenzene	Chloroform	Ethylbenzene	Ethylene Dichloride	Hydrogen Chloride	Methanol	Methyl Ethyl Ketone	Methyl tert-butyl ether	Methylene Chloride	Styrene	Vinyl Chloride	1,1,2,2-Tetrachloroethane	1,1,2-Trichloroethane	Arsenic	Beryllium	Cadmium	Total Chromium	Cobalt	Copper	Lead	Manganese	Mercury	Nickel	Selenium	Units	References
				Emission Factors																																					
Combustion - Flare	Planned - Pilot (all)	H-100/101	7982/9603	0.0290	0.1590	0.0580	0.0290	—	1.1690	0.0110	0.0430	0.0100	—	—	—	—	—	1.4440	—	—	—	—	—	—	—	—	—	—	2.0E-04	1.2E-05	1.1E-03	1.4E-03	8.4E-05	—	—	3.8E-04	2.6E-04	2.1E-03	2.4E-05	lb/MMscf	A
	Planned - Purge	H-100	7982	0.0290	0.1590	0.0580	0.0290	—	1.1690	0.0110	0.0430	0.0100	—	—	—	—	—	1.4440	—	—	—	—	—	—	—	—	—	—	2.0E-04	1.2E-05	1.1E-03	1.4E-03	8.4E-05	—	—	3.8E-04	2.6E-04	2.1E-03	2.4E-05	lb/MMscf	A
	Planned - LP Purge	H-101	9603	0.0290	0.1590	0.0580	0.0290	—	1.1690	0.0110	0.0430	0.0100	—	—	—	—	—	1.4440	—	—	—	—	—	—	—	—	—	—	2.0E-04	1.2E-05	1.1E-03	1.4E-03	8.4E-05	—	—	3.8E-04	2.6E-04	2.1E-03	2.4E-05	lb/MMscf	A
	Planned - Intermittent	H-100/101	7982/9603	0.0290	0.1590	0.0580	0.0290	—	1.1690	0.0110	0.0430	0.0100	—	—	—	—	—	1.4440	—	—	—	—	—	—	—	—	—	—	2.0E-04	1.2E-05	1.1E-03	1.4E-03	8.4E-05	—	—	3.8E-04	2.6E-04	2.1E-03	2.4E-05	lb/MMscf	A
	Unplanned	H-100/101	7982/9603	0.0290	0.1590	0.0580	0.0290	—	1.1690	0.0110	0.0430	0.0100	—	—	—	—	—	1.4440	—	—	—	—	—	—	—	—	—	—	2.0E-04	1.2E-05	1.1E-03	1.4E-03	8.4E-05	—	—	3.8E-04	2.6E-04	2.1E-03	2.4E-05	lb/MMscf	A
	Worst-Case Flare Event		7982/9603	0.0290	0.1590	0.0580	0.0290	—	1.1690	0.0110	0.0430	0.0100	—	—	—	—	—	1.4440	—	—	—	—	—	—	—	—	—	—	2.0E-04	1.2E-05	1.1E-03	1.4E-03	8.4E-05	—	—	3.8E-04	2.6E-04	2.1E-03	2.4E-05	lb/MMscf	A
IC Engine	Crane Engine		111509	0.0269	0.1863	0.1054	0.0424	—	1.7261	0.0197	0.7833	0.0339	0.2174	—	—	0.0002	—	0.0109	—	0.1863	—	—	—	—	—	—	—	—	0.0016	—	0.0015	0.0006	—	—	0.0083	0.0031	0.0020	0.0039	0.0022	lb/1000 gal	B
	Emergency Generator		2337	0.0269	0.1863	0.1054	0.0424	—	1.7261	0.0197	0.7833	0.0339	0.2174	—	—	0.0002	—	0.0109	—	0.1863	—	—	—	—	—	—	—	—	0.0016	—	0.0015	0.0006	—	—	0.0083	0.0031	0.0020	0.0039	0.0022	lb/1000 gal	B
	Generator No. 1		9130	1.13	1.38	0.062	0.273	—	58.3	0.099	8.53	7.94	0.836	0.0619	—	—	0.049	0.11	0.2746	—	3.12	—	—	0.15	0.0599	0.0252	0.0878	0.0538	2.0E-04	1.2E-05	1.1E-03	1.4E-03	8.4E-05	—	—	3.8E-04	2.6E-04	2.1E-03	2.4E-05	lb/MMscf	C
	Generator No. 2		9131	1.13	1.38	0.062	0.273	—	58.3	0.099	8.53	7.94	0.836	0.0619	—	—	0.049	0.11	0.2746	—	3.12	—	—	0.15	0.0599	0.0252	0.0878	0.0538	2.0E-04	1.2E-05	1.1E-03	1.4E-03	8.4E-05	—	—	3.8E-04	2.6E-04	2.1E-03	2.4E-05	lb/MMscf	C
Fugitive Components	Oil - controlled	3105-02	9801	0.1758	0.0018	—	—	0.2838	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	lb/lb-ROC	D
	Oil - unsafe	3105-03	104754	0.1758	0.0018	—	—	0.2838	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	lb/lb-ROC	D
	Gas - controlled	3105-04	104755	0.1877	0.0032	—	—	0.1364	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	lb/lb-ROC	E
	Gas - unsafe	3105-05	104756	0.1877	0.0032	—	—	0.1364	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	lb/lb-ROC	E
Supply Boat	Main Engines	3105-AA	9789	1.98E-04	9.33E-04	4.09E-04	2.85E-04	—	1.18E-03	8.48E-05	7.67E-04	9.25E-05	3.91E-05	—	—	1.46E-06	—	7.98E-05	—	1.38E-03	—	—	—	—	—	—	—	—	1.17E-05	—	1.09E-05	4.38E-06	—	—	6.08E-05	2.26E-05	1.48E-05	2.85E-05	1.81E-05	lb/MMBtu	F
	Generator Engines	3105-BB	9790	1.98E-04	9.33E-04	4.09E-04	2.85E-04	—	1.18E-03	8.48E-05	7.67E-04	9.25E-05	3.91E-05	—	—	1.46E-06	—	7.98E-05	—	1.38E-03	—	—	—	—	—	—	—	—	1.17E-05	—	1.09E-05	4.38E-06	—	—	6.08E-05	2.26E-05	1.48E-05	2.85E-05	1.81E-05	lb/MMBtu	F
	Bow Thruster	3105-CC	9791	1.98E-04	9.33E-04	4.09E-04	2.85E-04	—	1.18E-03	8.48E-05	7.67E-04	9.25E-05	3.91E-05	—	—	1.46E-06	—	7.98E-05	—	1.38E-03	—	—	—	—	—	—	—	—	1.17E-05	—	1.09E-05	4.38E-06	—	—	6.08E-05	2.26E-05	1.48E-05	2.85E-05	1.81E-05	lb/MMBtu	F
Crew Boat	Main Engines	3105-DD	9787	1.98E-04	9.33E-04	4.09E-04	2.85E-04	—	1.18E-03	8.48E-05	7.67E-04	9.25E-05	3.91E-05	—	—	1.46E-06	—	7.98E-05	—	1.38E-03	—	—	—	—	—	—	—	—	1.17E-05	—	1.09E-05	4.38E-06	—	—	6.08E-05	2.26E-05	1.48E-05	2.85E-05	1.81E-05	lb/MMBtu	F
	Auxiliary Engines	3105-EE	9788	1.98E-04	9.33E-04	4.09E-04	2.85E-04	—	1.18E-03	8.48E-05	7.67E-04	9.25E-05	3.91E-05	—	—	1.46E-06	—	7.98E-05	—	1.38E-03	—	—	—	—	—	—	—	—	1.17E-05	—	1.09E-05	4.38E-06	—	—	6.08E-05	2.26E-05	1.48E-05	2.85E-05	1.81E-05	lb/MMBtu	F
Pigging Equipment	Oil Launcher	3105-06	9792	0.2000	0.0030	—	—	0.3000	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	lb/lb-ROC	D
	Utility Gas Launcher	3105-07	9793	0.1978	0.0830	—	—	0.1384	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	lb/lb-ROC	E
	Gas Launcher	3105-08	9794	0.1978	0.0830	—	—	0.1384	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	lb/lb-ROC	E
Sumps/Tanks/Separators	Drain Sump Tank (T-1)	3105-09	2344	0.0528	0.0264	0.0165	—	0.0050	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	lb/lb-ROC	G
	Overflow sump Tank (T-4)	3105-11	5662	0.0528	0.0264	0.0165	—	0.0050	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	lb/lb-ROC	G
Solvent/Coatings Usage	Cleaning/degreasing	3105-13	9884	—	0.05	0.05	0.05	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	lb/lb-ROC	H
Boom Boat	Oil spill boom deployment		* 114797	1.4404	2.0961	7.5125	0.6584	—	3.452	0.1438	0.8280	0.1082	0.8183	—	8.455	—	—	1.8598	—	—	3.7740	0.0684	2.0579	—	0.1436	—	—	—	—	—	—	—	—	0.0033	—	0.0033	—	0.0033	—	lb/1000 gal	I

References
A1 - VCAPCD, AB 2588 Combustion Emission Factors (2001) - Natural Gas Fired External Combustion Equipment (flare)
A2 - USEPA, AP-42 Table 1.4-4, Emission Factors for Metals from Natural Gas Combustion
B - VCAPCD, AB 2588 Combustion Emission Factors (2001) - Diesel Combustion Factors (internal combustion)
C1 - SCAQMD, Reporting Procedures for AB2588 Facilities for Reporting their Quadrennial Air Toxics Emissions Inventory (2016) - Table B-1 Default EF for Natural Gas Combustion, Stationary and Portable Internal Combustion Engines
C2 - USEPA, AP-42 Table 1.4-4, Emission Factors for Metals from Natural Gas Combustion
D - The emission factors, originally in units of lb/lb-TOC, were converted to lb/lb-ROC using an ROC/TOC fraction of 0.31 from Table 2 of the District's P&P 6100.061
E - The emission factors, originally in units of lb/lb-TOC, were converted to lb/lb-ROC using an ROC/TOC fraction of 0.88 from Table 2 of the District's P&P 6100.061
F1 - USEPA, AP-42 Table 3.3-2, Speciated Organic Compound Emission Factors for Uncontrolled Diesel Engines
F2 - VCAPCD AB 2588 Combustion Emission Factors (2001) - Diesel Combustion Factors (internal combustion)
F3 - SBCAPCD Piston IC Engine Technical Reference Document (2002) - Table 3 Default Fuel Properties
G - CARB Speciation Manual Second Edition (1991) Profile Number 532 - Oil & Gas Extraction - Well Heads & Cellars/Oil & Water Separators
H - APCD: Solvents assumed to contain 5% benzene, 5% toluene, 5% xylene
I - SCAQMD, Reporting Procedures for AB2588 Facilities for Reporting their Quadrennial Air Toxics Emissions Inventory (2016) - Table B-4 Default EF for Gasoline Combustion, Stationary and Portable Internal Combustion Engines - Non-catalyst (Portable and Stationary)

Table 5.5-2
Platform Holly: Part 70/PTO 8234-R11
Annual Hazardous Air Pollutant Emissions (TPY)

Equipment Category	Description	Venoco Equip No.	EQ No.	HAP emissions (TPY)
Combustion - Flare	Planned - Pilot (all)	H-100/101	79824/9603	[illegible]
	Planned - Purge	H-100	7982	[illegible]
	Planned - LP Purge	H-101	9603	[illegible]
	Planned - Intermittent	H-100/101	79824/9603	[illegible]
	Unplanned	H-100/101	79824/9603	[illegible]
	Worst-Case Flare Event		79824/9603	[illegible]
IC Engine	Crane Engine		111509	[illegible]
	Emergency Generator		2337	[illegible]
	Generator No. 1		8130	[illegible]
	Generator No. 2		8131	[illegible]
Fugitive Components	Oil - controlled	3105-02	8601	[illegible]
	Oil - unsafe	3105-03	104754	[illegible]
	Gas - controlled	3105-04	104755	[illegible]
	Gas - unsafe	3105-05	104756	[illegible]
Supply Boat	Main Engines	3105-AA	8789	[illegible]
	Generator Engines	3105-BB	8790	[illegible]
	Bow Thruster	3105-CC	8791	[illegible]
Crew Boat	Main Engines	3105-DD	8787	[illegible]
	Auxiliary Engines	3105-EE	8788	[illegible]
Pigging Equipment	Oil Launcher	3105-06	8792	[illegible]
	Utility Gas Launcher	3105-07	8793	[illegible]
	Gas Launcher	3105-08	8794	[illegible]
Sumps/Tanks/Separators	Drain Sump Tank (T-1)	3105-09	2365	[illegible]
	Overflow sump Tank (T-4)	3105-11	8862	[illegible]
Solvent/Coatings Usage	Cleaning/degreasing	3105-15	5884	[illegible]
Boom Boat	Oil spill boom deployment		* 114797	[illegible]

Notes:
1. These are estimates only, and are not intended to represent emission limits. [illegible]
2. Based on CAAA, Section 112 (a) [illegible] [illegible]
3. Natural gas emission calculations are based on a standard value of [illegible]
4. Default fuel properties [illegible] from Table [illegible] of the [illegible] IC Engine Technical Reference Document [illegible]

Table 5.5-3
Platform Holly: Part 70/PTO 8234-R11
Stationary Source Hazardous Air Pollutant Emissions (TPY)

Facility	Permit #	Hexane	Benzene	Toluene	Xylene	Iso-Octane	Formaldehyde	Naphthalene	Acetaldehyde	Acrolein	1,3-Butadiene	Carbon Tetrachloride	Chlorine
08028 - Ellwood Onshore Facility	PTO 7904-R10	2.41E+01	4.43E-01	1.46E-01	8.78E-02	2.10E+01	2.48E-01	2.71E-03	9.71E-03	2.47E-03	6.30E-05	--	--
01065 - Seep Containment Device	PTO 4541-R7	--	--	--	--	--	--	--	--	--	--	--	--
03035 - Beachfront Lease	PTO 8103-R10	5.87E-02	1.92E-02	1.18E-02	0.00E+00	2.18E-02	--	--	--	--	--	--	--
03105 - Platform Holly	PTO 8234-R10	8.83E+00	4.66E-01	1.85E-01	1.25E-01	7.33E+00	3.70E+00	1.46E-02	6.18E-01	5.12E-01	5.81E-02	3.02E-03	1.23E-04
Total SS - By Individual HAPs:		3.30E+01	9.28E-01	3.43E-01	2.12E-01	2.84E+01	3.95E+00	1.73E-02	6.28E-01	5.15E-01	5.81E-02	3.02E-03	1.23E-04

Facility	Chlorobenzene	Chloroform	Ethylbenzene	Ethylene Dibromide	Hydrogen Chloride	Methanol	Methyl Ethyl Ketone	Methyl tert butyl ether	Methylene Chloride	Styrene	Vinyl Chloride	1,1,2,2-Tetrachloroethane	1,1,2-Trichloroethane
08028 - Ellwood Onshore Facility	5.80E-08	--	3.04E-01	--	5.40E-05	--	--	--	--	--	--	--	--
01065 - Seep Containment Device	--	--	--	--	--	--	--	--	--	--	--	--	--
03035 - Beachfront Lease	--	--	--	--	--	--	--	--	--	--	--	--	--
03105 - Platform Holly	1.40E-04	3.04E-03	3.16E-02	4.75E-03	1.30E-01	1.88E-01	1.79E-05	5.59E-04	9.59E-03	3.58E-03	1.68E-03	4.28E-03	3.41E-03
Total SS - By Individual HAPs:	1.40E-04	3.04E-03	3.36E-01	4.75E-03	1.30E-01	1.88E-01	1.79E-05	5.59E-04	9.59E-03	3.58E-03	1.68E-03	4.28E-03	3.41E-03

Facility	Arsenic	Beryllium	Cadmium	Total Chromium	Cobalt	Copper	Lead	Manganese	Mercury	Nickel	Selenium	Total - All HAPS
08028 - Ellwood Onshore Facility	6.88E-05	4.10E-06	3.76E-04	4.78E-04	2.87E-05	--	2.41E-06	1.31E-04	8.94E-05	7.18E-04	8.84E-06	4.63E+01
01065 - Seep Containment Device	--	--	--	--	--	--	--	--	--	--	--	0.00E+00
03035 - Beachfront Lease	--	--	--	--	--	--	--	--	--	--	--	1.12E-01
03105 - Platform Holly	1.13E-03	8.98E-07	1.13E-03	5.25E-04	6.29E-06	8.91E-07	5.81E-03	2.20E-03	1.42E-03	2.89E-03	1.54E-03	2.22E+01
Total SS - By Individual HAPs:	1.20E-03	5.00E-06	1.51E-03	1.00E-03	3.50E-05	8.91E-07	5.81E-03	2.33E-03	1.51E-03	3.61E-03	1.55E-03	6.87E+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

6.1 Modeling

Air quality impact analyses were not performed for the issuance of this permit.

Modeling was previously performed under ATC 10128 per District policy No. 6100.004 which requires that an air quality impact analysis for certain planned and unplanned flaring events be performed. Only the reasonable credible worst-case flaring event of sour gas was analyzed. The planned purge and pilot operations were not analyzed because of their low daily and annual emissions rates.

The District used the EPA Screen3 model to assess the ambient air quality impact of the reasonable worst-case credible flaring event defined in Section 4 of this permit. The Screen3 model is an appropriate tool to evaluate air emission impacts from this flare. The analysis results are summarized in Table 6.1-1 below and show that no adverse impact or exceedance of any applicable hourly, 8-hour or 24-hour standard will be caused by the worst-case event usage of the flare (that is 20,000 SCF in 66 seconds). The table below only compares compliance with state standards because they are more stringent than corresponding federal standards.

Table 6.1-1 - Analysis Results of Worst-Case Flaring at Holly

Pollutant		Emssion Rate	AQIA Impacts (micrograms/m3)		Compliance	Applicable State Standards (micrograms/m3)		
Name	Symbol	(lb/min)	1-hour	8 or 24-hour	w/ Standards	1-hour	8-hour	24-hour
Sulfur Dioxide	SO_2	51.87	132.9	53.2	Yes	655	N/A	105
Nitrogen Dioxide	NO_2	1.35	3.5	N/A	Yes	470	N/A	N/A
Carbon Monoxide	CO	7.35	18.8	13.2	Yes	23,000	10,000	N/A

6.2 Increments

An air quality increment analysis has not been required for this stationary source.

6.3 Monitoring

Pursuant to Abatement Order 99-6(A), the permittee installed two ambient air monitoring stations, approved by the District, to monitor meteorological and odorous organic sulfide concentrations in the vicinity of the Ellwood Onshore Facility. As part of a Part 70 Significant Modification (re: PT-70 Mod 7904-06), the Ellwood offsite odor monitoring station was relocated to the UCSB West Campus odor monitoring station site, and the offsite odor monitoring requirement was transferred from the Ellwood Onshore Facility permit to this permit. The District determined that West Campus odor monitoring station, in combination with the existing 14 onsite H_2S monitors and meteorological station, is better suited to serve the public during the next phase of operations of the South Ellwood Field source. The remaining ambient air monitoring station is equipped to continuously monitor and telemeter the data to the District in a manner consistent with the District's Ambient Air Monitoring Protocol. This monitor is identified and described in Table 9.C.13-1 of Permit Condition 9.C.13 of this permit.

6.4 Health Risk Assessment

Platform Holly is subject to the Air Toxics "Hot Spots" Information and Assessment Act of 1987 (AB 2588). The most recent HRA for the facility was prepared by the District on October 28, 1993 under the Air Toxics "Hot Spots" program. The HRA was based on 1991 toxic emissions inventory data submitted to the District by Mobil, the previous owners of Holly.

Cancer risk and chronic and acute non-cancer Hazard Index (HI) risk values were calculated based on the 1991 inventory and compared to *significance thresholds* for cancer and chronic and acute non-cancer risk adopted by the District's Board of Directors. The calculated risk values and applicable thresholds are as follows:

	Holly Max Risks	Significance Threshold
Cancer risk:	8.0 /million	>10/million
Chronic non-cancer risk:	0.04	> 1
Acute non-cancer risk:	6.0	> 1

Based on the 1991 toxic emissions inventory, a cancer risk of 8.0 per million was estimated for the Holly facility. The cancer risk is primarily due to emissions of polycyclic aromatic hydrocarbon (PAH) from internal combustion devices (e.g., cranes, crew boat activities). Approximately 2.0 pounds of PAH were emitted from Holly devices in 1991. This risk was determined to occur approximately 3,400 meters northwest of the platform (over the ocean).

The District has estimated a chronic non-cancer hazard risk of 0.04 and an acute hazard risk of 6.0. The acute hazard risk is over the District's significance threshold of 1. This significant acute hazard index is due to H_2S emissions from fugitive sources. Approximately 21,340 pounds of H_2S were emitted from Holly devices in 1991. The peak acute hazard risk was determined to occur approximately 280 meters northwest of the platform (over the ocean).

7.0 CAP Consistency, Offset Requirements and ERCs

7.1 General:

Santa Barbara County has not attained the state 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 $PM_{2.5}$).

On July 1, 2020, Santa Barbara County achieved attainment for the State ozone standards. This change was initiated by the California Air Resources Board (CARB) at their December 2019 public hearing and it was later approved by the Office of Administrative Law.

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 2010 Clean Air Plan. As Santa Barbara County has only recently attained the state eight-hour ozone standard, the 2019 Clean Air Plan demonstrates how the District plans to maintain that standard. The 2019 Clean Air Plan therefore satisfies all state triennial planning requirements.

7.3 Offset Requirements

The South Ellwood Field stationary source exceeds the emission offset thresholds of Regulation VIII for NO_x, ROC and SO_x. This stationary source did not become subject to the emission offset requirements of Regulation VIII until adoption of revised Rule 802 in August 2016, therefore the permittee is not required to offset exiting facility emissions. Any new project emission increase for these pollutants are required to provide emission reduction credits for the project.

7.4 Emission Reduction Credits

Platform Holly is not a source of emission reduction credits.

8.0 CEQA and Lead Agency Permit Consistency

8.1 CEQA

The District is the lead agency under CEQA for this permit, and has prepared a Notice of Exemption. This project is exempt from CEQA pursuant to the Environmental Review Guidelines for the Santa Barbara County APCD (revised April 30, 2015). Appendix 1.A.i (*APCD Projects Exempt from CEQA* and *Equipment or Operations Exempt from CEQA*) provides an exemption specifically for permits to operate and reevaluations thereof. A copy of the final Notice of Exemption is filed with the Santa Barbara County Clerk of the Board.

8.2 Lead Agency Permit Consistency

The installation of Platform Holly predates the California Environmental Quality Act (CEQA) as the platform was installed in 1966 and the act was adopted in 1970. The State Lands Commission approved the construction of Holly on April 28, 1966. In 1974, an environmental impact report (EIR) was completed for Holly.

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9.0 Permit Conditions

This section lists the applicable permit conditions for Holly. 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 Platform Holly:

A.1 **Condition Acceptance.** Acceptance of this operating permit by the permittee shall be considered as acceptance of all terms, conditions, and limits of this permit. [*Re: ATC/PTO Mod 10106-01/-02*]

A.2 **Grounds for Revocation.** Failure to abide by and faithfully comply with this permit shall constitute grounds for revocation pursuant to California Health & Safety Code Section 42307 *et seq*. [*Re: ATC/PTO 10106-01/-02*]

A.3 **Severability.** In the event that any condition herein is determined to be invalid, all other conditions shall remain in force. *[Re: District Rules 103 and 1303.D.1]*

A.4 **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, implementation of Abatement Order 99-6A, and emergency response, directly and necessarily related to enforcement of the permit shall be reimbursed by the permittee as required by Rule 210. [*Re: ATC/PTO 10106-01/-02, District Rule 210*]

A.5 **Access to Records and Facilities.** As to any condition that requires for its effective enforcement the inspection of records or facilities by the District or its agents, the permittee 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/PTO 10106-01/-02*]

A.6 **Compliance.** Nothing contained within this permit shall be construed to allow the violation of any local, State or Federal rule, regulation, ambient air quality standard or air quality increment. [*Re: ATC/PTO 10106-01/-02*]

A.7 **Consistency with Analysis.** Operation under this permit shall be conducted consistent with all data, specifications and assumptions included with the application, supplements thereof (as documented in the District's project file), and the District's analyses under which this permit is issued. [*Re: ATC/PTO 10106-01/-02*]

A.8 **Consistency with Federal, State and Local Permits.** Nothing in this permit shall relax any air pollution control requirement imposed by the State of California or the California Coastal Commission in any consistency determination for the Project with the California Coastal Act, or by any other governmental agency. [*Re: ATC/PTO 10106-01/-02*]

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 re-issuance, or modification; or for denial of a permit renewal application.

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

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

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

(i) compliance with the permit, or

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

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

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

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

A.11 **Compliance Plan.**

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

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

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

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

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

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

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

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

A.13 **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 submit an application for renewal of the Part 70 permit not later than 6 months before the date of the permit expiration. Upon submittal of a timely and complete renewal application, the Part 70 permit shall remain in effect until the Control Officer issues or denies the renewal application. [*Re: District Rule 1304.D.1*]

A.14 **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.15 **Deviation from Permit Requirements.** The permittee shall submit a written report to the District documenting each and every deviation from the federally enforceable 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.16 **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, 1302.D.3, 1303.2.c*]

A.17 **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.18 **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, 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.19 **Conditions for Permit Reopening.** The permit shall be reopened and revised for cause under any of the following circumstances:

(a) <u>Additional Requirements</u>: 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 causes to reopen exist. 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)*]

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).** The permittee 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 that is:

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

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

For all combustion sources listed in Section 9.C, the permittee shall comply with the requirements of this Rule in accordance with the monitoring and compliance recordkeeping procedures in Condition 9.C.22. [*Re: District Rule 302*]

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

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

B.5 **Specific Contaminants (Rule 309).** The permittee shall not discharge into the atmosphere from any single source sulfur compounds, carbon monoxide and combustion contaminants in excess of the applicable standards listed in Sections A, E and G of Rule 309. [*Re: District Rule 309*].

B.6 **Sulfur Content of Fuels (Rule 311).** The permittee shall not burn fuels with a sulfur content in excess of 0.5% (by weight) for liquid fuels and 239 ppmvd or 15 gr/100 scf (calculated as H_2S) for gaseous fuel. Compliance with this condition shall be based on daily measurements of the fuel gas using (sulfur detection tubes, ASTM, or other District-approved) methods and diesel fuel billing records or other data showing the certified sulfur content for each shipment. [*Re: District Rule 311*]

B.7 **Organic Solvents (Rule 317).** The permittee shall comply with the emission standards listed in Section B of Rule 317. Compliance with this condition shall be based on compliance with the Solvent Usage condition of this permit. [*Re: District Rule 317*]

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

B.9 **Architectural Coatings (Rule 323.I).** The permittee shall comply with the emission standards listed in Section D of Rule 323.I as well as the Administrative requirements listed in Section F of Rule 323. Compliance with this condition shall be based on compliance with the Solvent Usage condition of this permit and facility inspections. [*Re: District Rules 323, 317, 322, 324*]

B.10 **Disposal and Evaporation of Solvents (Rule 324).** The permittee 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 compliance with the Solvent Usage condition of this permit and facility inspections. [*Re: District Rule 324*]

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

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

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

[Re: District Rule 353]

B.12 **Oil and Natural Gas Production MACT.** The permittee shall comply with the requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPS) for Oil and Natural Gas Production and Natural Gas Transmission and Storage (promulgated June 17, 1999). At a minimum, The permittee shall maintain records of 'API Gravity' and 'Initial GOR' for the facility to demonstrate the 'black oil' exemption [*Re:* 40 CFR 63.760 (e)(1) & 63.761]. Such record keeping shall meet the requirements of 40 CFR Part 63, Subpart A, Section 63.10 (b) (1) and (3). [*Re:* 40 CFR 63, Subpart HH]

B.13 **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 Equipment Specific Conditions

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

C.1 **Spark-Ignited Internal Combustion Engines.** The following equipment is included in this emissions unit category:

District ID No.	Equip ID No.	Name
009130	Generator No. 1	Caterpillar 803 hp G399 SITA
009131	Generator No. 2	Caterpillar 803 hp G399 SITA
111856	Catalytic Converter No. 1	Miratech EQ-801 3-Way NSCR
111857	Catalytic Converter No. 2	Miratech EQ-801 3-Way NSCR

(a) Emission Limits: Mass emissions from the IC engines listed above shall not exceed the limits listed in Table 5.1-3.

(i) Emission Concentrations. Exhaust concentrations from each engine, corrected to 15% O_2, shall not exceed any of the following:

Caterpillar G-399	**Source Testing lb/MMBtu**	**Quarterly Monitoring ppmv at 15% Oxygen**
NOx (as NO_2)	0.166	45
CO	0.292	130
ROC	0.037	n/a

Compliance with these requirements shall be based on the source testing and the *ICE Inspection and Maintenance (I&M) Plan* monitoring requirements.

(b) Operational Limits: The following operational limits apply to each engine:

(i) Air/Fuel Ratio Controls: An air/fuel ratio controller shall be operated with each NSCR catalytic converter to ensure that the control equipment maintains the required removal efficiencies at all times. The permittee shall maintain the NSCR catalyst inlet oxygen content between 0.0% - 1.0% at all times when operating the generators. Compliance shall be based on maintaining the oxygen sensor output between 700-950 millivolts. Depending upon source testing results, the District may require that this range be decreased to ensure continuous compliant operations.

(ii) Fuel Sulfur Limit - Natural Gas: The total sulfur content (calculated as H_2S at standard conditions, 60 F and 14.7 psia) of the gaseous fuel burned at the facility shall not exceed 80 ppmvd (as H_2S). The permittee shall measure the sulfur content of the gaseous fuel monthly using colorimetric gas detection tubes, or other District-approved devices.

(iii) Engine Operating Requirements: Each engine is subject to the following operating requirements:

(1) change the oil and filter every 2,160 hours of operation or annually, whichever comes first;

(2) inspect spark plugs every 2,160 hours of operation or annually, whichever comes first and replace as necessary, and

(3) inspect all hoses and belts every 2,160 hours of operation or annually, whichever comes first and replace as necessary.

(c) Monitoring: The following monitoring conditions apply to each engine:

(i) Non-Resettable Hour Meter. The engines subject to this permit shall have installed a non-resettable hour meter with a minimum display capability of 9,999 hours. A log shall be maintained that records the hours of operation and the number of operating days per month for each engine.

(ii) Fuel Usage Metering. The volume of fuel (in scf) burned in the engine shall be measured through the use of a District-approved calibrated non-resettable fuel meter. A log shall be maintained that records the fuel usage of the engine.

(iii) ICE Inspection and Maintenance Plan. The permittee shall implement the District approved ICE Inspection and Maintenance (I&M) Plan as required by Rule 333, Section F.

(iv) Equipment Identification. Identifying tag(s) or name plate(s) shall be displayed on the equipment to show manufacturer, model number, and serial number. The tag(s) or plate(s) shall be issued by the manufacturer and shall be affixed to the equipment in a permanent and conspicuous position.

(d) Recordkeeping: The following recordkeeping conditions apply to each engine:

(i) Operating Hours: A log shall be maintained that details the number of operating hours and days for each month that each engine is operated and the cumulative total annual hours.

(ii) Fuel Use: The total amount of fuel combusted in each engine shall be recorded on a monthly and annual basis in units of scf.

(iii) Engine Inspection and Maintenance Logs: IC engine inspection and maintenance logs shall be maintained, including quarterly inspection results, AFRC fault message outputs, oxygen sensor outputs, and portable analyzer calibration records, consistent with the reporting requirements incorporated in the I&M Plan.

(iv) For each engine the following records shall be kept:

(1) The date of each engine oil and filter change, the number of hours of operation since the last oil and filter change, and the date and results of each oil analysis;

(2) The date of spark plug inspections, the number of hours of operation since the last inspection and dates of all spark plug replacements;

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

(v) A log shall be maintained for any engine subject to 40 CFR 63 Subpart ZZZZ that had a malfunction. The log shall include the date, number, duration, and a brief description for each type of malfunction that occurred and what caused or may have caused any applicable emission limitation to be exceeded. The log must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with 40 CFR 63 Subpart ZZZZ §63.6605(b), including actions taken to correct a malfunction.

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

C.2 **Crane Engine.** The following equipment is included in this emissions unit category:

District ID No.	Equip ID No.	Name
111506	Crane Engine	Caterpillar C7-ACERT, IND-C
111508	Diesel Particulate Filter	DCL Mine-X Sootfilter

(a) Emission Limits: Mass emissions from the crane engine listed above shall not exceed the limits listed in Table 5.1-3. Compliance with the mass emission limits shall be based on the operational, monitoring, source testing, recordkeeping and reporting conditions:

(i) Diesel PM Standard. The stationary prime diesel fueled CI engine subject to this permit shall emit diesel PM at a rate that demonstrates compliance with the 0.01 grams diesel PM per brake-horsepower-hour (g/bhp-hr) emission standard in California Code of Regulations Title 17, Section 93115.7. Compliance with the PM emission limit shall be based on the source testing requirements of this permit.

(ii) Emission concentrations. Exhaust concentrations from the engine, corrected to 15% O_2, shall not exceed any of the following: NO_x (as NO_2) - 197 ppmv, ROC - 65 ppmv, or CO - 313 ppmv. *(Note: these limits are based on the permitted g/bhp-emission factors. Compliance with these limits ensures compliance with the Rule 333 limits of 700 ppmv NO_x, 750 ppmv ROC, and 4,500 ppmv CO, all corrected to 15% O_2.)* Compliance with the emission concentration limits shall be based on the source testing requirements of this permit.

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

(i) Fuel Usage Limits. Daily fuel usage shall not exceed 120 gallons per day and annual fuel usage shall not exceed 30,000 gallons per year.

(ii) Fuel and Fuel Additive Requirements. The permittee may only add fuel and/or fuel additives that comply with the Stationary Diesel Engine ATCM to the engine, or to any fuel tank directly attached to the engine.

(iii) Diesel Fuel Sulfur Limit. The total sulfur content of the diesel fuel used shall not exceed 15 ppmw in accordance with the requirements of the Stationary Diesel Engine ATCM for CARB diesel.

(iv) Diesel Particulate Filter (DPF) Operations: The DPF shall be in place at all times the engine is operational. The DPF backpressure shall not exceed 40 inches water column. The DPF shall be operated according to the District-approved *DPF Operation Plan.*

(v) Visual Leak Check. The permittee shall perform a visual check of the exhaust system every 200 hours of operation checking for signs of exhaust leaks such as evidence of soot. The components to be checked include the piping, fittings, clamps, and gaskets. Corrective action shall be taken within 24 hours when leaks are found.

(vi) Pressure Transmitter Check. The permittee shall check the pressure transmitter every 200 hours of operation. The pressure transmitter shall be removed and pressure applied to the line in order to check the function of the DPF transmitter and the line for leaks.

(vii) Backpressure Monitor Alarm Response Actions. The response actions defined in the approved *DPF Operation Plan* shall be taken in the event of an alarm condition.

(c) Monitoring: The following monitoring conditions apply to the engine:

(i) Non-Resettable Hour Meter. A non-resettable hour meter with a minimum display capability of 9,999 hours shall be installed on the engine. A log shall be maintained that records the hours of operation and the number of operating days per month for the engine.

(ii) Fuel Usage Metering. The volume of diesel fuel (in gallons) burned in the engine shall be measured through the use of a District-approved calibrated non-resettable fuel meter. A log shall be maintained that records the fuel usage of the engine.

(iii) Back Pressure Monitoring. The backpressure from the engine shall be monitored using the Backpressure Monitor installed with the diesel particulate filter.

(iv) Diesel Fuel Sulfur Content. Compliance with the *Diesel Fuel Sulfur Limit* condition shall be based upon vendor analysis or documentation for each fuel shipment that the fuel meets California Code of Regulations, Title 13, Section 2281 standards (i.e., ARB "Clean Diesel"). Alternately, the permittee shall annually sample and perform a fuel total sulfur analysis consistent with appropriate ASTM procedures.

(v) ICE Inspection and Maintenance Plan. The permittee shall implement the District approved *ICE Inspection and Maintenance (I&M) Plan* as required by Rule 333, Section F.

(vi) Visible Emissions Monitoring. A person shall perform a visible emissions evaluation at least once per calendar quarter. The evaluation shall be conducted for at least six consecutive minutes while the engine is operating and start at least 5 minutes after startup of the engine. The hydraulic dummy load may be used to load the engine during monitoring. If any visible emissions reading of 5% opacity or greater is detected by the observer at any time during the 6 minute observation, then the permittee shall conduct a source test for diesel PM emissions from the engine within 60 days of the observation.

(vii) District Inspections. The operator shall make the inside of the downstream section of the DPF housing available for District inspection upon request. If inspection of the DPF indicates that particulate matter is blowing by the gasket around the filter elements, or that the filter elements may not be operating properly, the District may require a source test to verify compliance with permitted emission limits.

(d) Recordkeeping: The following recordkeeping conditions apply to the crane engine:

(i) Operating Hours. A log shall be maintained that details the number of operating hours and days for each month that the engine is operated and the cumulative total annual hours.

(ii) Fuel Use. The total amount of diesel fuel combusted in the engine shall be recorded on a daily and annual basis in units of gallons.

(iii) Diesel Particulate Filter. A log shall be maintained that records all required leak and pressure transmitter checks, maintenance activities, regenerations using the "dummy load" circuit, visible emission evaluations, filter cleaning, and corrective actions for the DPF.

(iv) Diesel Fuel Purchase. The owner or operator shall retain fuel purchase records that account for all fuel used in the engine. The vendor analysis or fuel purchase records for each fuel shipment shall demonstrate that the fuel meets California Code of Regulations, Title 13, Section 2281 standards (i.e., ARB "Clean

Diesel"). Alternately, the permittee shall submit on an annual basis a fuel total sulfur analysis consistent with appropriate ASTM procedures. On an annual basis, the higher heating value of the diesel fuel (Btu/gal) shall be recorded as provided by diesel fuel suppliers.

(v) Engine Inspection and Maintenance Logs. IC engine inspection and maintenance logs shall be maintained, including quarterly inspection results, consistent with the reporting requirements incorporated in the I&M Plan.

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

C.3 **Combustion Equipment - Flare.** The following equipment is included in this emissions unit category:

District ID No.	Equip ID No.	Name
7982	H-100	High-pressure Flare (H-100)
9603	H-101	Low-pressure Flare (H-101)

(a) Emission Limits: Mass emissions from the flare systems listed above shall not exceed the limits listed in Table 5.1-3.

(b) Operational Limits:

(i) *Flaring* - The hourly, daily and annual gas flow to the high-pressure (H-100) and low-pressure (H-101) flares shall not exceed the limits listed in Table 9.1. Mass emissions from the flares shall not exceed the limits listed in Table 5.1-3. These limits are based on the design rating of the pilots, high-pressure and low-pressure flare purge rates, and unplanned flaring activities. Planned intermittent flaring as defined under Rule 359 is not authorized under this permit.

Table 9.1

FLARE CATEGORY	VOLUME LIMIT
Pilot Gas: H-100 and H-101	200 SCFH of PUC gas (for both pilots)
Purge Gas: H-100 *	50,400 SCFD
Purge Gas: H-101*	7,200 SCFD
Intermittent - Unplanned Flaring: H-100 **	18,055 SCFM
Intermittent - Unplanned Flaring: H-101 **	2,000 SCFM
Total Unplanned Flaring: H-100 and H-101combined =	480,000 SCF per year

* The stated SCFD purge flow limits above may be exceeded only when authorized by the District to facilitate flare flow meter testing and calibration.

** FI-170 does not record flows less than 35 scfm. It is assumed that the purge and pilot gas flow constantly at 35 scfm. For H-100, any FI-170 flare flow meter readings at or above 35 scfm as recorded by the DAS using six-minute average data are assumed to be flare events.

FI-172 does not record flows less than 5.0 SCFM. It is assumed that the purge and pilot gas flow constantly at a total flow rate of 5.0 scfm. For H-101, any FI-172 flare flow meter readings at or above 5.0 scfm as recorded by the DAS using six-minute average data are assumed to be flare events.

Total unplanned flaring event limits are based on total flows measured by combined readings of flare flow meters FI-170 and FI-172. Planned purge flows measured during flare meter testing and documented as required by this permit do not accrue toward this limitation.

(ii) *Flare Purge Gas Fuel Sulfur Limit* - Only in-plant fuel gas from EOF shall be used as flare purge gas. The total sulfur content (calculated as H_2S-equivalents at standard conditions, 60° F and 14.7 psia) of the combined purge and flare gas shall not exceed 239 ppmv. Compliance with this condition shall be based on measurements of the combined purge and flare gas H_2S content as described in Section C.3(c)(vi) below.

(iii) *Flare Pilot Gas Fuel Sulfur Limit* - Only in-plant fuel gas from EOF shall be used as flare pilot gas. The total sulfur content (calculated as H_2S-equivalents at standard conditions, 60° F and 14.7 psia) of the pilot gas shall not exceed 12 ppmv. Compliance with this condition shall be based on measurements of the pilot gas H_2S content as described in Section C.3(c)(vii) below.

(iv) *Unplanned Flare Event Sulfur Limit* - The total sulfur content (calculated as H_2S-equivalents at standard conditions, 60° F and 14.7 psia) of any unplanned flare event gas shall not exceed 35,000. Compliance with this condition for each flaring event shall be based on the most recent weekly measurement of the combined produced gas H_2S content as described in Section C.3(c)(viii) below.

(v) *Flare Pilot Operation* - The permittee shall comply with the provisions of Rule 359.D.2 for flare pilots at all times. If at any time the pilot system cannot be confirmed to be operating by the permittee through instrumentation or visual means, the permittee shall:

(1) Not commence gas and oil production; or

(2) If in production, shut down production within 1-hour of failing to confirm the pilot system's operation.

(vi) The pilot *Low Temperature Alarm (TSL-170)* shall be connected to the District DAS.

(vii) The permittee shall comply with their District-approved *Rule 359 - Flare Minimization Plan*. The plan may only be revised upon written approval of the District.

(c) Monitoring: The following monitoring conditions apply to the flare relief system:

(i) *Purge Gas Metering (H-100)* **-** The permittee shall install and operate a dedicated flow rate controller, FCV-171, or other District-approved equivalent, to control the purge gas flow to the high-pressure flare system. The controller shall be operated consistent with the *Process Monitor Calibration and Maintenance Plan*.

(ii) *Purge Gas Metering (H-101)* **-** The permittee shall install and operate a dedicated flow rate controller, FCV-173, or other District-approved equivalent, to control the purge gas flow to the low-pressure flare system. The controller shall be operated consistent with the *Process Monitor Calibration and Maintenance Plan*.

(iii) *Flare Gas Metering* (H-100) - The permittee shall install and operate a dedicated, totalizing, non-resettable type meter, FI-170, or other District-approved equivalent, to meter total flare gas flows, including purge gases. The flare flow meter shall be calibrated to accurately meter flare gas flows when they exceed the purge gas limit of 50,400 SCFD (or 2100 SCFH). The flare flow meter shall be equipped with an un-interruptible power supply (UPS). The UPS shall allow the flare flow meter to accurately meter flows whenever and for as long as utility power is lost to Holly and the flare remains operating.

(iv) *Flare Gas Metering* (H-101) - The permittee shall install and operate a dedicated, totalizing, non-resettable type meter, FI-172, or other District-approved equivalent, to meter total flare gas flows, including purge gases. The flare flow meter shall be calibrated to accurately meter flare gas flows when they exceed 5.0 SCFM and up to 2000 SCFM. The flow meter shall be equipped with a UPS. The UPS shall allow the flare flow meter to accurately meter flows whenever and for as long as utility power is lost to Holly and the flare remains operating.

(v) *Total Sulfur Content* **-** The total sulfur and H_2S content of the pilot gas, purge gas and sour produced gas sent to the EOF shall be measured on an annual basis using District-approved ASTM methods. The purpose of these annual analyses is to determine the non-H_2S fraction of total sulfur compounds present in these gases and to use these values to correct the hydrogen sulfide values measured at the platform. The permittee shall take the results of the testing and add it to the hydrogen sulfide test results for the subsequent year to obtain an estimate of the total sulfur content of these gases. The permittee shall perform additional testing of the sulfur content, using approved test methods, as requested by the District. The permittee shall submit the lab analyses reports to the District.

(vi) *Flare Gas Hydrogen Sulfide Content* - The combined purge and flare gas shall be monitored for hydrogen sulfide on a weekly basis by taking measurements in V-127 using colorimetric gas detection tubes or other District approved methods. The permittee shall add the most recent analysis results for the non-H_2S fraction of total sulfur compounds to derive the total sulfur content.

(vii) *Flare Purge and Pilot Gas Hydrogen Sulfide Content* **-** The flare purge and pilot gas shall be monitored for hydrogen sulfide on a weekly basis by taking measurements of the EOF in-plant fuel gas hydrogen sulfide content as specified in the *Platform Holly Process Stream Sampling Plan*. The permittee shall add the most recent analysis results for the non-H_2S fraction of total sulfur compounds to derive the total sulfur content.

(viii) *Flare Unplanned Event Gas Hydrogen Sulfide Content* - The produced gas sent to the Ellwood Onshore Facility shall be monitored for hydrogen sulfide on a weekly basis using colorimetric gas detection tubes, or other District approved methods. The most recent measurement of the combined produced gas H_2S content shall be used to establish the H_2S content of unplanned flaring events, unless otherwise approved by the District. The permittee shall add the most recent analysis results for the non-H_2S fraction of total sulfur compounds to derive the total sulfur content.

(d) Recordkeeping: The following recordkeeping conditions apply to the flare relief system:

(i) *Flare Event Volumes* - All flaring events shall be recorded in a District-approved log. The log shall include: date; the flare (H-100 or H-101); duration of each flaring event (start and stop time); quantity of gas flared per event in units of standard cubic feet; cumulative total volume flared for all events to date through the year (by category); the H_2S content of the gas flared; reason/cause for the flaring event; whether there were visible emissions; and, the type of event (e.g., planned or unplanned). This log shall include all *unplanned and planned* flaring events.

(ii) *Purge and Pilot Volumes* - The volume (scf) of purge and pilot gases consumed each day and each month shall be recorded in a District-approved log.

(iii) *Total Sulfur Content Analyses* - The results of the annual analyses for the total sulfur and H_2S content of the pilot, purge and produced gas sent onshore along with a calculation of the non-H_2S fraction of the total sulfur compounds that is used to correct the daily/weekly/quarterly H_2S readings to estimate the total sulfur of these gases for the subsequent year.

(iv) *Sulfur Content of the Combined Flare and Purge Gas* - The records of weekly colorimetric gas detection tube sampling of the combined flare and purge gas H_2S content.

(v) *Sulfur Content of Flare Purge and Pilot Gas* - The records of weekly colorimetric gas detection tube sampling of the flare relief system purge and pilot gas H_2S content.

(vi) *Sulfur Content Produced Gas* - The records of weekly sulfur detection tube sampling of the produced gas H_2S content to the EOF.

(vii) *Maintenance Logs* - Maintenance logs for the pilot igniter/alarm system, purge gas flow-controllers, and flare gas flow meters.

(e) Reporting: On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the District. The report must list all data required by the *Semi-Annual Compliance Verification Reports* condition of this permit.
(*Re: District Rules 359 and 1303, ATC 10128, ATC 10128-01, PTO 10128, 40 CFR 70.6*)

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

District ID No.	Equip ID No.	Name
		Oil Service Components
9601	3105-02	Oil - Controlled
104754	3105-03	Oil - Unsafe
		Gas/Light Liquid Service Components
104755	3105-04	Gas Controlled
104756	3105-05	Gas Unsafe

(a) Emission Limits: Mass emissions from the gas/light liquid service and oil service components listed above shall not exceed the limits listed in Table 5.1-3.

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

(i) *I&M Program* - The District-approved I&M Plan for Holly shall be implemented for the life of the project.

(ii) *Leak-Path Count* - Component and leak-path counts shall not exceed the District approved totals by more than five percent. This five percent range is to allow for minor differences due to component counting methods and does not constitute allowable emissions growth due to the addition of new equipment. {*Note: 'de minimis' component-leak-path count is not included in Table 5.1-1.*}.

(iii) *Venting* - All routine venting of hydrocarbons shall be routed to either the VRU compressor, flare header, injection well or other District-approved control device.

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

(c) Monitoring: The equipment listed in this section are subject to all the monitoring requirements listed in District Rule 331.F. The test methods in Rule 331.H shall be used. In addition, the permittee shall track the 'component-leak-path' (clp) counts for all categories of components at Holly that are listed in the table above; and, log any 'clp' count changes, including de minimis changes, in a component-leak-path inventory maintained for the facility.

(d) Recordkeeping: The equipment listed in this section are subject to all the recordkeeping requirements listed in District Rule 331.G. In addition, the permittee shall record in a table at the Holly facility showing clearly all changes in the 'clp' counts, for all categories of components including the 'de minimis' components at the facility.

(e) Reporting: The equipment listed in this section is subject to all the reporting requirements listed in District Rule 331.G. On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the District. The report must list all data required by the Compliance Verification Reports condition of this permit. [*Re: District Rules 331 and 1303, ATC 10128, PTO 10128,* ATC 10106, ATC/PTO 10106-01, ATC/PTO 10106-02, *40 CFR 70.6*]

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

District ID No.	Equip ID No.	Name
9792	SP-132	Oil Launcher (0.67' dia., 4' long)
9793	SP-133	Utility Gas Launcher (0.50' dia., 4' long)
9794	SP-134	Gas Launcher (0.67' dia., 4' long)

(a) Emission Limits: Mass emissions from the gas and oil service components listed above shall not exceed the limits listed in Table 5.1-3.

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

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

(ii) *Purging/Pressure* - Prior to opening the pig launchers, the permittee shall purge the oil launcher with nitrogen or sweet fuel gas (not to exceed 30 ppmv total sulfur content calculated as H_2S at standard conditions), and shall purge the gas launchers with nitrogen. Such purging shall be done in strict accordance with the currently approved *Pig Launching Procedures - 6" Gas Pipeline.* The pig launchers shall be purged/depressurized to the vapor recovery system or flare via the surge tank, to the maximum extent feasible. At no time shall the pig launcher chamber be bled down to atmosphere when the initial pressure inside the chamber is greater than 20 psig. Compliance with this condition shall be based on pressure indicators that monitor the internal pressure of the launcher pig chamber. Pig chamber pressure readings shall be recorded prior to the final 'bleed down' of the pig launcher, before opening the chamber door.

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

(c) Monitoring: The permittee shall monitor the pressure inside the pig launcher chambers with a District-approved pressure test gauge or equivalent District-approved monitor installed to determine the internal pressure of the launcher prior to "bleed down" of the chamber.

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

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

[*Re:* ATC/PTO 10784, *District Rules 325 and 1303, 40 CFR 70.6*]

C.6 **Wastewater/Process Water Tanks.** The following equipment is included in this emissions category:

District ID No.	Equip ID No.	Equipment Name	KVB Service
2345	T-1	Drain Sump (vented to atmosphere)	Deck drain water from storm water and wash down
5882	T-4	Overflow sump tank (vented to atmosphere)	Deck drain water from storm water and wash down

(a) Emission Limits: Mass emissions from the sump and sump tank shall not exceed the limits listed in Table 5.1-3.

(b) Operational Limits: All process operations from the equipment listed in this section are exempt from Sections D.1 and D.2 of Rule 325 as long as they satisfy the requirements of Section B.3; however, they shall meet the requirements of District Rule 325, Sections D.4 and E. Compliance with these limits shall be assessed through compliance with the monitoring, recordkeeping and reporting conditions in this permit. In addition, the following requirements apply:

(i) *ROC Content* - The reactive organic compound content of the liquid entering the wastewater tanks listed herein shall be less than 5 milligrams per liter or the ROC emissions from each tank shall be maintained at less than 0.25 tons per year. Compliance with this limit shall be verified by annual sampling of the liquid.

(ii) *Liquid Tight* - All tanks shall be maintained in a liquid-tight condition.

Other District-enforceable limits for these items are listed in Section 9.D.

(c) Monitoring: The ROC content of the liquid entering tank T-1 shall be determined *annually* using the test methods outlined in District Rule 325.G.3. The District shall be notified at least 3 days in advance of sampling. The tank T-1 data shall be used to determine Rule 325 compliance/applicability of both tanks T-1 and T-4.

(d) Recordkeeping: The equipment listed in this section is subject to all the recordkeeping requirements listed in District Rule 325.F.2 and F.3.

(e) Reporting: The equipment listed in this section are subject to all the reporting requirements listed in District Rule 325.I. On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the District. The report must list all data required by the *Compliance Verification Reports* condition of this permit. [*Re: District Rules 325 and 1303, 40 CFR 70.6*]

C.7 **Solvent/Coating Use.** The following emission units are included in this condition:

District ID No.	Emission Unit Name, Category, etc.
Not provided	Solvents - Cleaning/Degreasing (*as part of regular operations)*
5884	Surface Coating (*that also includes solvents as thinners)*

(a) Emission Limits: Mass emissions from solvent cleaning and surface coating operations shall not exceed the limits listed in Table 5.1-3. The solvent emission limits outlined in District Rule 317.B are federally enforceable for the entire stationary source.

(b) Operational Limits: Use of solvents for cleaning/degreasing and maintenance surface coating shall conform to the requirements of District Rules 317, 321, 322, 323 and 324. Compliance with these rules shall be assessed through compliance with the monitoring, recordkeeping and reporting conditions in this permit and facility inspections.

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

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

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

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

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

(d) Reporting: On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the District. The report must list all data required by the *Semi-Annual Compliance Verification Reports* condition of this permit. [*Re: District Rules 317, 322, 323, 324, 1301 and 1303, 40 CFR 70.6*]

C.8 **Recordkeeping.** All records and logs required by this permit and any applicable District, state or federal rule or regulation shall be maintained for a minimum of five calendar years from the date of information collection and log entry at the platform. These records or logs shall be readily accessible and be made available to the District upon request. [*Re: District Rule 1303, ATC 10128, ATC 10128-01, PTO 10128, ATC 10106, ATC 10106-01, ATC/PTO 10106-02, 40 CFR 70.6*]

C.9 **Semi-Annual Monitoring/Compliance Verification Reports.** Twice a year, the permittee 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) *Internal Combustion Engines.*

(i) All records required by the Internal Combustion Engines recordkeeping conditions.

(ii) Summary results of all compliance emission source testing performed, if applicable.

(iii) All records required by the Crane Engine recordkeeping conditions.

(iv) For the engines listed in permit condition 9.C.1 the following shall be reported:

(1) The date of each engine oil and filter change, the number of hours of operation since the last oil and filter change, and the date and results of each oil analysis;

(2) The date of spark plug inspections, the number of hours of operation since the last inspection and dates of all spark plug replacements;

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

The log for any engine subject to 40 CFR 63 Subpart ZZZZ that had a malfunction. The log shall include the date, number, duration, and a brief description for each type of malfunction that occurred and what caused or may have caused any applicable emission limitation to be exceeded. The log must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with 40 CFR 63 Subpart ZZZZ §63.6605(b), including actions taken to correct a malfunction.

(b) *Flare Relief Systems*.

(i) The volumes of gas combusted and resultant mass emissions for each flare category (i.e., Purge; LP Purge; Pilot (all); Unplanned; Planned Intermittent), shall be presented as a cumulative summary for each day, quarter and year.

(ii) The results of the annual analyses for the total sulfur and H_2S content of the pilot and purge gas sent from onshore and the produced gas sent onshore along with a calculation of the non-H_2S fraction of the total sulfur compounds that is used to correct the daily/weekly H_2S readings to estimate the total sulfur of these gases for the subsequent year, including a copy of all lab analyses.

(iii) The results of all hydrogen sulfide testing for the pilot and purge sent from onshore and the produced gas sent to the onshore facility (showing the H_2S readings and the corrected total sulfur values).

(iv) A copy of Flare Event Log for the reporting period *for all planned/unplanned flaring events*.

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

(i) Inspection summary.

(ii) Record of leaking components.

(iii) Record of leaks from critical components.

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

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

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

(vii) Listing of components installed as BACT under District Rule 331 and/or Regulation VIII as approved by the District.

(viii) A table showing clearly all changes in the 'clp' counts from the count shown in Table 5.1-1 of this permit, for all categories of components including the deminimis components at the facility.

(d) *Pigging*. A copy of the Holly Pigging Log.

(e) *Wastewater Tanks*.

(i) Results of all ROC content analyses (including a copy of the lab analysis sheets), if sampling was requested by District.

(ii) The type of organic liquid in each tank, and

(iii) The results of the inspections required by Rule 325.H (if required).

(f) *Solvent/coatings Usage*.

(i) <u>Solvent Cleaning Degreasing</u>: On a monthly basis: the amount of solvent used; the percentage of ROC by weight (as applied); the solvent density; the amount of solvent reclaimed; whether the solvent is photochemically reactive; and, the resulting emissions of ROC and photochemically reactive solvents to the atmosphere in units of pounds per month.

(ii) <u>Surface Coating - Maintenance</u>: On a monthly basis: the amount of solvent and coatings used; the percentage of ROC by weight (as applied); the solvent density; the amount of solvent reclaimed; whether the solvent is photochemically reactive; and, the resulting emissions of ROC and photochemically reactive solvents to the atmosphere in units of pounds per month.

(iii) Information required by the Solvent Reclamation Plan, if any.

(g) *General Reporting Requirements*.

(i) On a semi-annual and annual basis, the emissions from each permitted emission unit for each criteria pollutant. Also, include a quarterly and annual emissions summary for each criteria pollutant.

(ii) On a semi-annual and annual basis, the emissions from each exempt emission unit for each criteria pollutant. Also, include a quarterly and annual emissions summary for each criteria pollutant.

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

See also Section 9.D.1 for additional District required reporting requirements.
[*Re: Rule 202, Rule 317, Rule 325, Rule 331, Rule 333, ATC 10128, ATC 10128-01, PTO 10128, ATC 10106, ATC 10106-01, ATC/PTO 10106-02*]

C.10 **Permitted Equipment.** Only those equipment items listed in Attachment 10.5 are covered by the requirements of this permit and District Rule 201.B. [*Re: District Rule 1303, ATC 10128*, ATC 10128-1, PTO 10128, ATC 10106, ATC/PTO 10106-01, ATC/PTO 10106-02]

C.11 **Diesel IC Engines - Particulate Matter Emissions.** To ensure compliance with District Rules 205.A, 302, 309 and the California Health and Safety Code Section 41701, the permittee shall implement manufacturer recommended operational and maintenance procedures to ensure that all project diesel-fired engines minimize particulate emissions. The permittee shall implement a District-approved *IC Engine Particulate Matter Operation and Maintenance Plan* for the life of the project. This Plan shall detail the manufacturer recommended maintenance and calibration schedules that the permittee will implement. Where manufacturer guidance is not available, the recommendations of comparable equipment manufacturers and good engineering judgment shall be utilized. All project diesel-fired engines, regardless of exemption status, shall be included in this Plan. [*Re: District Rules 205.A, 302, 305, 309*]

C.12 **Process Monitoring Systems - Operation and Maintenance.** All platform process monitoring devices listed in Section 4.10.2, and any other monitoring devices that in the District's determination are necessary to accurately demonstrate compliance with the conditions of this permit, shall be properly operated, maintained, and calibrated according to manufacturer recommended specifications. The permittee shall implement the District-approved *Process Monitor Calibration and Maintenance Plan*. The permittee shall submit revisions to the plan and obtain District approval of the proposed revisions prior to changing a process monitoring device specified in the plan. Additionally, within 30 days of a District request, the permittee shall provide updates to the plan and shall obtain District approval of the updated plan within 90 days of receipt of the District's request. [*ATC 10128*]

C.13 **Ambient Air Monitoring Station.** The permittee shall install and maintain an ambient air monitoring station, approved by the District, in the area of Coal Oil Point. The monitoring station shall be equipped to continuously monitor and telemeter the data identified in Table 9.C.13-1 below to the District in a manner consistent with the District's Ambient Air Monitoring Protocol. The permittee shall connect all ambient and meteorological parameters to the District central data acquisition system (DAS) as documented in Table 9.C.13-1 below.

Table 9.C.13-1. Ambient Air Monitoring Station Requirements

Ambient Air Monitoring Station	**Required Parameters** (by "bullet" item)
Coal Oil Point Area (location of station approved by the District)	▪ Ambient Air Total Hydrocarbon Concentration ▪ Wind Speed (Scalar Average) ▪ Wind Direction (Scalar Average) ▪ Wind Speed (Resultant) ▪ Wind Direction (Resultant) ▪ Sigma Theta (Wind Variation) ▪ Station Temperature (Inside) ▪ Hydrogen Sulfide ▪ Total Reduced Sulfur ▪ Sulfur Dioxide

The permittee shall reimburse the District's costs for the review and audit of the station's data in accordance with the cost reimbursement provisions of District Rule 210 and Permit condition 9.C.16 and Table 9.C.16-1.

C.14 **Data Acquisition System.** The permittee shall install, connect to the District central data acquisition system (DAS), and maintain the process and alarm systems and ambient air monitoring station parameters approved by the District, and identified in Table 9.C.14-1 below.

Table 9.C.14-1

Facility Location	**Required Parameters**
Platform Holly	▪ Flare Flow Meter (FI-170) ▪ Flare Pilot Low Temp Alarm (TSL-170) ▪ Holly H_2S Detector Alarms ▪ Low-pressure Flare Flow Meter (FI-172)
Coal Oil Point Area	▪ Ambient Air Total Hydrocarbon Concentration ▪ Wind Speed (Scalar Average) ▪ Wind Direction (Scalar Average) ▪ Wind Speed (Resultant) ▪ Wind Direction (Resultant) ▪ Sigma Theta (Wind Variation) ▪ Station Temperature (Inside) ▪ Hydrogen Sulfide ▪ Total Reduced Sulfur ▪ Sulfur Dioxide

C.15 **Data Acquisition System Operation and Maintenance Fee.** The permittee is required to connect certain parameters to the District central data acquisition system (DAS). In addition, the permittee shall reimburse the District for the cost of operating and maintaining the DAS. The permittee shall be assessed an annual fee, based on the District's fiscal year, collected semi-annually.

Pursuant to Rule 210 III.A, the permittee shall pay fees specified in Table 9.C.15-1 below. The District shall use these fees to operate, maintain, and upgrade the DAS in proper running order. Fees shall be due and payable pursuant to governing provisions of Rule 210, including CPI adjustments.

All ongoing costs and anticipated future capital upgrades will be the District's responsibility and will be accomplished within the above stated DAS fee. This fee is intended to cover the annual operating budget and upgrades of the DAS and is intended to gradually phase the District into a share of the DAS costs (as outlined in the March 27, 1998, letter - *Fixed Fee Proposal for Monitoring and DAS Costs*). In the event that the assumptions used to establish this fee substantially increase or decrease, District may revisit and adjust the fee based on documentation of cost of services. Adjusted fees will be implemented by transmitting a revised Table 9.C.15-1, which will become an enforceable part of this permit.

The fees prescribed in this condition shall expire if and when the Board adopts a Data Acquisition System Operation and Maintenance Fee schedule and such fee becomes effective.

Table 9.C.15-1. FEES for DAS OPERATION and MAINTENANCE [(a) (b)]

FEE DESCRIPTION	FEE
Per CEM, ambient or meteorological parameter required by permit to be transmitted real-time to the District Central Data Acquisition System. See Table 9.C.14-1.	$2,037 annually

(a) All fees shall be due and payable pursuant to the governing provisions of Rule 210, including CPI adjustments.
(b) The fees in this table are based on the District's March 27, 1998 letter (*Fixed Fee Proposal for Monitoring and DAS Costs*), adjusted for CPI, and may be updated pursuant to Rule 210 and shall be effective when issued and shall not require a modification to this permit.

[ATC 10128, ATC 10128-1, PTO 10128]

C.16 **Ambient Monitoring Station Data Review and Audit Fee**. The permittee shall submit data from the ambient air monitoring station described in permit condition 9.C.13, to the District for quality assurance review and shall have the station audited quarterly by the District, or its contractor. In addition, the permittee shall reimburse the District for the cost of this service. The permittee shall be assessed an annual fee, based on the District's fiscal year, collected semi-annually.

Pursuant to Rule 210 III.A., the permittee shall pay fees specified in Table 9.C.16-1. The District will use this fee to pay staff costs to review and quality assure the monitoring data collected by The permittee and the contractor or staff costs to audit the monitoring equipment. This fee shall not cover any District time necessary to issue or respond to any Notice of Violation, which will be billed on a reimbursable basis. Fees shall be due and payable pursuant to governing provisions of Rule 210, including CPI adjustments.

In the event that the permittee consistently requires services in excess of those assumed in the March 27, 1998 letter (*Fixed Fee Proposal for Monitoring and DAS Costs*), the Control Officer may move the permittee to a reimbursable method of payment, subject to provisions of Rule 210. In the event that the assumptions used to establish this fee substantially increase or decrease, the District may revisit and adjust the fee based on documentation of cost of services. Adjusted fees will be implemented by transmitting a revised Table 9.C.16-1, which will become an enforceable part of the permit.

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

Table 9.C.16-1 - Fees for Data Review and Audit

FEE DESCRIPTION	FEE
Monitoring Station Data Review and Audit Fee	
Data review and audit activities associated with data submitted from any monitoring station in Table 9.C.13-1.	$36,757 annually

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

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

C.17 **Glycol Reboiler Configuration & Vapor Testing.** The Glycol Reboiler overhead vapors from V-126 shall be directed to the Vapor Recovery Unit compressor at all times. [ATC 10128, ATC 10128-1, PTO 10128]

C.18 **Emergency Episode Plan.** As necessary, the permittee shall implement the Emergency Episode Plan for the Venoco Ellwood Stationary Source and any subsequent District-approved updates.
[*Re: District Rule 603 and 1303*]

C.19 **Documents Incorporated by Reference.** The documents listed below, including any District-approved updates thereof, are incorporated herein, and shall have the full force and effect of a permit condition for this operating permit. These documents shall be implemented for the life of Platform Holly.

(a) *Fugitive Emissions Inspection and Maintenance (I&M) Program for South Ellwood.* (dated 05/28/2002 and approved by the District on 10/11/2002; revised 3/2020).

(b) *IC Engine Particulate Matter Operation and Maintenance Plan* (Dated March 20, 2006).

(c) *Process Monitor Calibration and Maintenance Plan* (dated 05/30/2003 and approved by the District on 06/05/2003) and any subsequent District-approved updates.

(d) *Rule 359 Flare Minimization and Monitoring* (dated 04/04/2003 and approved 06/05/2003) and any subsequent District-approved updates.

(e) *Emergency Episode Plan* (dated 02/10/2002 and approved by the District in 8/02) and any subsequent District-approved updates.

(f) *Platform Holly SIMQAP* (approved by the District on 12/24/2008) and any subsequent District-approved updates *[Re:AO-99-6A, District Rules 317, 331, 333,359, ATC 10128, PTO 10128]*

(g) *Platform Holly Process Stream Sampling Plan* (dated 10/07/2004 and approved on 10/11/2004 and 7/8/05 addendum) and any subsequent District-approved updates.

(h) *Rule 333 Inspection and Maintenance Plan* (dated 03/27/2009 and revised on 07/30/2010) and any subsequent District-approved updates.

C.20 **Safety, Inspection, Maintenance, and Quality Assurance Plan (SIMQAP).** The permittee shall implement the District approved SIMQAP Plan and any subsequent District approved revisions for Platform Holly. This plan shall be reviewed by the permittee every two years (or more frequently if requested by the District), and the adequacy of the Plan shall be assessed and verified by the permittee. The written assessment and verification shall be submitted to District for review. If determined necessary by the District, the permittee shall submit a Plan update for District approval. The permittee shall respond to any District comments on the Plan within 30 days of receipt of comments by District, and shall implement any operational changes within the deadlines so stipulated by the Control Officer. The Control Officer may grant extensions to these deadlines for good cause. In the administration of the SIMQAP, the Control Officer may consult with third party experts, including members of the other County Departments. The permittee shall pay for all reasonable costs related to the District's review of the Platform Holly SIMQAP. [*Re: Rule 303, Abatement Order 99-6(A)*]

C.21 **Source Testing.** The following source testing provisions shall apply:

(a) The permittee shall conduct source testing of NO_x, CO, and ROC emissions from the two natural gas fired generator engines on a biennial (every two years) schedule using the initial source test date as the anniversary date. During testing, the following parameters shall be determined: (a) pollutant concentrations in units of ppmvd corrected to 15 percent excess oxygen, (b) NSCR catalyst efficiencies (mass basis), (c) mass emission concentrations in units of lb/MMBtu and (d) the air/fuel ratio controller oxygen sensor signal operational compliance range. A duplicate fuel gas sample shall be taken and analyzed for HHV, total sulfur, and composition.

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

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

(d) A source test for an item of equipment shall be performed on the scheduled day of testing (the test day mutually agreed to) unless circumstances beyond the control of the operator prevent completion of the test on the scheduled day. Such circumstances include mechanical malfunction of the equipment to be tested, malfunction of the source test equipment, delays in source test contractor arrival and/or set-up, or unsafe conditions on site. Except in cases of an emergency, the operator shall seek and obtain District approval before deferring or discontinuing a scheduled test, or performing maintenance on the equipment item on the scheduled test day. If the test cannot be completed on the scheduled day, then the test shall be rescheduled for another time with prior authorization by the District. Once the sample probe has been inserted into the exhaust stream of the equipment unit to be tested (or extraction of the sample has begun), the test shall proceed in accordance with the approved source test plan. In no case shall a test run be aborted except in the case of an emergency or unless approval is first obtained from the District. Failing to perform the source test of an equipment item on the scheduled test day without a valid reason and without District's authorization shall constitute a violation of this permit. If a test is postponed due to an emergency, written documentation of the emergency event shall be submitted to the District by the close of the business day following the scheduled test day.

The timelines in (a), (b), and (c) may be extended for good cause provided a written request is submitted to the District at least three (3) days in advance of the deadline, and approval for the extension is granted by the District.

C.22 **Visible Emissions.** The permittee shall not discharge any visible emissions into the atmosphere from the emission sources below for a period or periods aggregating more than three minutes in any one hour.

(a) *Diesel-Fueled IC Engine(s)*. Once per calendar quarter, the permittee shall perform a visible emissions observation for a six-minute period on each permitted and exempt engine when operating. If an engine does not operate during a calendar quarter, no monitoring is required. Visible emission observations shall be documented using a District-approved Visible Emissions Recordkeeping Log. If no visible emissions are detected during the six-minute observation period, no further monitoring is required. If visible emissions are detected during the six-minute period, then the visible emission inspection shall continue in accordance with the "Monitoring Procedure" below. This condition shall not apply to boats.

(b) *Monitoring Procedures*: The permittee shall conduct visible emissions observations every 15 seconds (using a stop-watch) and record the observation as either “0” (no visible emissions) or “E” (visible emissions) on a Visible Emissions Recordkeeping Log. Any time visible emissions are observed at the end of a 15-second interval, it shall be assumed that the visible emissions occurred for the entire 15 seconds preceding the reading. The start time and end time of the visible emission observations shall be recorded together with the date of the observation and name of the observer. The permittee shall conduct a visible emissions observation for the length of time necessary to document three continuous minutes of no visible emissions or the presence of visible emissions for more than the aggregation of three minutes during any hour, whichever occurs first.

(c) *Compliance*: The permittee shall be deemed in compliance with this condition if no visible emissions are observed during the initial six-minute period. If any visible emissions are observed during the initial six-minute period, the permittee shall continue with the visible emissions observation. The permittee shall be deemed to be in compliance with this condition if no more than 12 “E” notations occur within any one-hour period. For compliance purposes, “one hour period” shall mean a rolling hour.

C.23 **Abrasive Blasting Equipment.** All abrasive blasting activities performed on Holly shall comply with the requirements of the California Code of Regulations, Title 17, Sub-Chapter 6, Sections 92000 through 92530. [*Re: District Rule 303, CCR Title 17*]

9.D District-Only Conditions

The following section lists permit conditions that are not enforceable by the USEPA or the public. However, these conditions are enforceable by the District and the State of California. These conditions are issued pursuant to District Rule 206 (*Conditional Approval of Authority to Construct or Permit to Operate*), which states that the Control Officer may issue an operating permit subject to specified conditions. Permit conditions have been determined as being necessary for this permit to ensure that operation of Holly complies with all applicable local and state air quality rules, regulations and laws. Failure to comply with any condition specified pursuant to the provisions of Rule 206 shall be a violation of that rule, this permit, as well as any applicable section of the California Health & Safety Code and any applicable requirement.

D.1 **Compliance Verification Reports.** Twice a year, the permittee 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) *Crew and Supply Boats*.

(i) Daily, monthly, and annual fuel use for the crew boat main engines and auxiliary engines while operating within the California coastal waters adjacent to Santa Barbara County.

(ii) Daily, monthly and annual fuel use for the supply boat and seep device maintenance vessel main engines and auxiliary engines (including the bow thruster engine) while operating within the California coastal waters adjacent to Santa Barbara County.

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

(iv) Information regarding any new project boats servicing Holly or the seep device as detailed in crew and supply boat permit condition herein.

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

(vi) Summary results of all compliance emission source testing performed, if applicable.

(b) *General Reporting Requirements*.

(i) Facility throughput of oil emulsion and produced gas production per month, the number of operating days per month and the average monthly oil emulsion and produced gas production per month.

(ii) Breakdowns and variances reported/obtained per Regulation V along with the excess emissions that accompanied each occurrence.

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

(iv) A copy of all completed District-10 forms (*IC Engine Timing Certification Form*).

(v) The produced gas, produced oil, fuel gas, and produced wastewater process stream analyses as required by Section 9.C and Section 9.D of this permit. The process stream analyses per Section 4.11 of this permit.

(vi) Helicopter trips (by type and trip segments with emission calculations)

(c) *Emergency/Standby Diesel IC Engine*.

(i) All records required by the Emergency/Standby IC Engine recordkeeping requirement.

(ii) The following records required by subpart ZZZZ:

(1) The date of each engine oil and filter change, the number of hours of operation since the last oil and filter change, and the date and results of each oil analysis;

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

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

(d) *CARB GHG Regulation Reporting*. The permittee shall report all throughput data and any updates to the information recorded pursuant to the CARB GHG Regulation Recordkeeping Condition above using District Annual Report Form ENF-108.

D.2 **Facility Throughput Limitations.** Holly production shall be limited to a monthly average of 20,000 barrels of oil emulsion and 20 million standard cubic feet of produced gas per day. The permittee shall record in a log the volumes of crude oil, produced water, and gas produced and the actual number of days in production per month. The above limits are based on actual days of operation during the month.

D.3 **Produced Gas.** The permittee shall direct all produced gases to gas lift and/or gas injection, the EOF pipeline, vapor recovery system or other permitted control device when degassing, purging or blowing down any oil and gas well or tank, vessel or container that contains reactive organic compounds or reduced sulfur compounds due to activities that include, but are not limited to, process or equipment turnarounds, process upsets (e.g., well spikes), well below down and governmental ordered safety tests, unless allowed otherwise pursuant to District Rule 325.

D.4 **Emission Factor Revisions.** The District may update the emission factors for any calculation based on USEPA AP-42 or District P&P emission factors at the next permit modification or permit reevaluation to account for USEPA and/or District revisions to the underlying emission factors. Further, the permittee shall modify its permit via an ATC application if compliance data shows that an emission factor used to develop the permit's potential to emit is lower than that documented in the field. The ATC permit shall, at a minimum, adjust the emission factor to that documented by the compliance data consistent with applicable rules, regulations, and requirements.

D.5 **Odor Abatement Agreement and Complaint Response Plan.** The permittee shall abide by the requirements of District-approved *Odor Abatement Agreement* and implement the requirements of the District-approved *Complaint Response Plan* for the life of the project. Upon written request and subsequent approval by the District, this Agreement and Plan may be revised.

D.6 **Crew, Supply, and Boom Boats.** The following equipment is included in this emissions category:

District ID No.	Equipment ID No.	Name
Supply Boat		
9789	3105-AA	Supply Boat Main Engines - Controlled
9790	3105-BB	Supply Boat Auxiliary Engines- Controlled
9791	3105-CC	Supply Boat Bow Thruster - Controlled
Crew Boat		
9787	3105-DD	Crew Boat Main Engines - Controlled
9788	3105-EE	Crew Boat Auxiliary Engines - Controlled
Boom Boat		
114797		Boom boat main engine

(a) Emission Limits: Mass emissions from the crew, supply, and emergency response boats listed above shall not exceed the limits listed in Table 5.1-3. Compliance with this condition shall be based on the operational, monitoring, recordkeeping, and reporting conditions in this permit. Emissions from marine vessels used for seep containment device inspection and maintenance or oil removal activities shall be counted against the supply boat limits. In addition, emission rates from each main engine on each crew and supply boat shall not exceed the "lb/1000 gallons" emission factors listed in Table 5.1-2.

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

(i) *Crew Boat Main and Auxiliary Engine Limits* - The crew boat main and auxiliary engines for Holly shall not use more than: 511 gallons per day nor 130,881 gallons per year of diesel fuel. Notwithstanding the above, Crew boat main and auxiliary engines for Holly on vessels used exclusively for platform decommissioning activities shall not use more than 1,747 gallons per day nor 447,141 gallons per year of diesel fuel.

(ii) *Supply Boat Main Engine Limits* - The supply boat main engines for Holly shall not use more than: 2,326 gallons per day nor 446,651 gallons per year of diesel fuel. This limit shall include fuel used by emergency response boats.

(iii) *Supply Boat Auxiliary Engine Limits* - The supply boat auxiliary engines (including the bow thruster) for Holly shall not use more than: 251 gallons per day nor 48,184 gallons per year of diesel fuel. This limit shall include fuel used by emergency response boats. Notwithstanding the above, supply boat auxiliary engines (including bow thruster) for Holly on vessels used exclusively for platform decommissioning activities shall not use more than 436 gallons per day nor 65,468 gallons per year of diesel fuel.

(iv) *Boom Boat Main engine* - The boom boat main engine for Holly shall not operate more than 5.5 hours per day and 24 hours per year.

(v) *Liquid Fuel Sulfur Limit* - Diesel fuel used by all IC engines shall have sulfur content no greater than 0.0015 weight percent as determined by District-approved ASTM methods.

(vi) The M/V GOL Lightning crew vessel shall only be used in support of Platform decommissioning activities.

(c) Monitoring:

(i) The permittee shall comply with the *Boat Monitoring and Reporting Plan*.

(ii) *Fuel Use Monitoring* - The permittee shall equip all crew and supply boats servicing Holly and all marine vessels used for seep containment device activities with in-line, continuous, cumulative, non-resettable fuel meters. Alternative monitoring methods for short-term boat activities may be used if approved in advance by the District.

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

(i) *Maintenance Logs* - For all main and auxiliary engines on crew and supply boats, maintenance log summaries that include details on injector type and timing, setting adjustments, major engine overhauls, and routine engine maintenance. These log summaries shall be made available to the District upon request.

(ii) *Crew Boat Fuel Usage* - Daily, monthly, and annual fuel use for crew boat main engines and auxiliary engines while operating within 'California Coastal Waters' adjacent to Santa Barbara County.

(iii) *Supply Boat Fuel Usage* - Daily, monthly, and annual fuel use for main engines and auxiliary engines (including fuel use on emergency response boats) for supply boats and vessels used for seep device maintenance while operating within 'California Coastal Waters' adjacent to Santa Barbara County.

(iv) *Boom Boat Use* - A daily use log shall be maintained for the boom boat, recording its hours of use whenever it is used.

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

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

(i) The main engines are of the same or less bhp rating as listed in Table 5.1-1; and

(ii) The combined pounds per day potential to emit (PTE) of all generator and bow thruster engines is the same or less than the sum of the pounds per day PTE for these engines as determined from the corresponding Table 5.1-3 emission line items of this permit; and

(iii) The NO_x, ROC, CO, PM and PM_{10} emission factors are the same or less for the main and auxiliary engines.

In order to verify that a boat meets the requirements specified in (i) – (iii) above, the permittee shall submit the following information to the District for review prior to bringing a new boat into service:

(iv) Boat description, including the type, size, name, engine make, model, year, and rating and emission control equipment.

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

(vi) A quantitative analysis using the operating and emission factor assumptions given in Tables 5.1-1 and 5.1-2 of this permit that demonstrates criteria (b) above is met.

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

(viii) A description of the fuel metering and emissions computation procedures for the new boat.

(ix) The permittee shall obtain a permit before using a new/replacement crew or supply boat that does not meet the above requirements (i) - (iii). The District may require manufacturer guarantees and emission source tests to confirm compliance with (iii).

(x) The permittee shall revise the *Boat Monitoring and Reporting Plan*, obtain District approval of such revisions, and implement the revised Plan prior to bringing any boat into service that has not been previously approved by the District. In special cases, the permittee may utilize a boat prior to revising the *Boat Monitoring and Reporting Plan* if approval to do so is obtained, in writing, from the District prior to use of the boat.

(xi) In order to verify compliance with the mass emission limits of this permit, the permittee shall conduct a source test of any boat in service within 90 days of written request by the District.

D7 **Permitted Equipment.** Only those permitted equipment items listed in Attachment 10.5 are covered by the requirements of this permit and District Rule 201.

D.8 **Documents Incorporated by Reference.** The documents listed below, including any District-approved updates thereof, are incorporated herein and shall have the full force and effect of a permit condition for this operating permit:

(a) Boat Monitoring and Reporting Plan for Holly (approved 1/24/2006 and revised) 1/21/2020).

(b) Complaint Response Plan (approved May 1995) and any subsequent District-approved updates.

D.9 **Emergency/ Standby Diesel IC Engine (E/S-DICE).** The equipment listed below belongs to this emissions unit category.

District ID No.	Equipment ID No.	Name
2337	62B306	Emergency Electrical Generator (373 bhp)

(a) **Emission Limitations.** The mass emissions from the E/S-DICE (ID # 2337) shall not exceed the values listed in Table 5.1-3. Compliance shall be based on the operational, monitoring, recordkeeping, and reporting conditions of this permit.

(b) **Operational Restrictions.** The equipment E/S-DICE (ID #2337) is subject to the following operational restrictions listed below. Emergency use operations, as defined in Section (d)(25) of the ATCM[6], have no operational hours limitations.

(i) Maintenance & Testing Use Limit: The E/S-DICE (ID #2337) shall not be operated for more than 20 hours per year for maintenance and testing[7] purposes.

(ii) Impending Rotating Outage Use: The in-use E/S-DICE (ID #2337) may be operated in response to the notification of an impending rotating outage if all the conditions cited in Section (e)(2)(B)(1) of the ATCM are met.

(iii) Fuel and Fuel Additive Requirements: The permittee may only add fuel and/or fuel additives to the engine or any fuel tank directly attached to the engine that comply with Section (e)(1)(B) of the ATCM.

(iv) The following maintenance requirements shall apply:

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[6] 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

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

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

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

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

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

(i) Non-Resettable Hour Meter: The E/S-DICE (ID #2337) 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 emission testing to show compliance with Section (e)(2)(B)(3) {if specifically allowed for under this permit};

(iv) initial start-up hours {if specifically allowed for under this permit};

(v) hours of operation to comply with the requirements of NFPA 25/100 {if applicable};

(vi) hours of operation for all uses other than those specified in items (i) - (iv) above along with a description of what those hours were for;

(vii) The owner or operator shall document fuel use through the retention of fuel purchase records that demonstrate that the only fuel purchased and added to an emergency standby engine or engines, or to any fuel tank directly attached to an emergency standby engine or engines, meets the requirements of the ATCM.

(viii) Subpart ZZZZ:

(1) The date of each engine oil and filter change, the number of hours of operation since the last oil and filter change, and the date and results of each oil analysis;

(2) The date of the air cleaner inspections, the number of hours of operation since the last inspection and dates of all filter replacements;

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

(e) **Reporting.** On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the District. The report shall include the information required in the Recordkeeping Condition above. This reporting requirement may be satisfied by using District Form ENF-92 (*Diesel-Fired Emergency Standby Engine Recordkeeping Form*).

(f) **Temporary Engine Replacements - DICE ATCM.** The E/S-DICE (ID #9010), subject to the requirements listed in 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 engine.

(g) **Permanent Engine Replacements.** The permittee may install a new engine in place of a permitted Emergency/Standby (E/S) IC engine, fire water pump engine or engine used for an essential public service that breaks down and cannot be repaired, without first obtaining an ATC permit only if the requirements (i - v) listed herein are satisfied.

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

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

(iii) The facility provides “good cause” (in writing) for the immediate need to install a permanent replacement engine prior to the time period before an ATC permit can be obtained for a new engine. The new engine must comply with the requirements of the ATCM for new engines. If a new engine is not immediately available, a temporary engine may be used while the new replacement engine is being procured. During this time period, the temporary replacement engine must meet the same guidelines and procedures as defined in the permit condition above (*Temporary Engine Replacements - DICE ATCM*).

(iv) An Authority to Construct application for the new permanent engine is submitted to the District within 15 days of the existing engine being replaced and the District permit for the new engine is obtained no later than 180 days from the date of engine replacement (these timelines include the use of a temporary engine).

(v) For each permitted engine to be permanently replaced pursuant to the condition, the permittee shall submit a completed *Permanent IC Engine Replacement Notification* form (Form ENF-96) within 14 days of either the permanent or temporary engine being installed. This form shall be sent electronically to: *temp-engine@sbcapcd.org*.

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

(h) **Notification of Non-Compliance.** Owners or operators who have determined that they are operating their stationary diesel-fueled engine(s) in violation of the requirements specified in Sections (e)(2) of the ATCM shall notify the District immediately upon detection of the violation and shall be subject to District enforcement action.

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

(j) **Enrollment in a DRP/ISC - January 1, 2005.** Any stationary diesel IC engine rated over 50 bhp that enrolls for the first time in a Demand Response Program/Interruptible Service Contract (as defined in the ATCM) on or after January 1, 2005, shall first obtain a District Authority to Construct permit to ensure compliance with the emission control requirements and hour limitations governing ISC engines.
[*Re: District PTO 11597, issued September 2005*]

D.10 **Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities.** The equipment permitted herein shall be operated in compliance with the California Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities regulation (CCR Title 17, Section 95665 *et. Seq*.).

D.11 **CARB GHG Regulation Recordkeeping.** The permittee shall maintain at least 5 years of records that document the following:

(a) The number of crude oil or natural gas wells at the facility.

(b) A list identifying all pressure vessels, tanks, separators, sumps, and ponds at the facility, including the size of each tank and separator in units of barrels.

(c) The annual crude oil, natural gas, and produced water throughput of the facility.

(d) A list identifying all reciprocating and centrifugal natural gas compressors at the facility.

D.12 **CARB GHG Regulation Reporting:** On an annual basis, the permittee shall report all throughput data and any updates to the information recorded pursuant to the *CARB GHG Regulation Recordkeeping* Condition above using District Annual Report Form ENF-108. This report shall be submitted by March 1 of each year detailing the previous year's activities.

AIR POLLUTION CONTROL OFFICER

____

____
Date

NOTES:

(a) Permit Reevaluation Due Date: December 2023
(b) This permit supersedes: PTO 8234-R10, PTO 15488, Pt70 ADM 15128

10.0 ATTACHMENTS

10.1 Emission Calculation Documentation
10.2 Pig Launching Procedure
10.3 Fee Calculations
10.4 IDS Database Emission Tables
10.5 Equipment List

10.1 Emission Calculation Documentation

This attachment contains relevant emission calculation documentation used for the emission tables in Section 5. Refer to Section 4 for the general equations. Supporting calculation spreadsheets are attached to this Section as tables, where necessary. The letters A-H refer to Tables 5.1-1 and 5.1-2.

Reference A - Combustion Flare

- The maximum operating schedule for the purge/pilot gas and planned continuous flaring is in units of hours.
- All flaring volumes based on permittee's application
- HHV = 1,100 Btu/scf for all flare and purge and pilot gas (per permittee application)
- SO_x emissions are based on 12 ppm H2S for pilot gas and 239 ppm H2S for purge.
- The permittee claims no "Planned - Other" flaring events.
- Purge flow rates are greater than ½ the flow meter's minimum detection limit (MDL)
- "Unplanned flaring" volumes based on permittee's application. SO_x emissions based on 35,000 ppmv S. The permittee claims no "Planned - Other" flaring events.
- Planned intermittent (other) and unplanned flaring events not calculated for short-term events per District policy
- NOx, ROC and CO emission factors are from Table 13.5-1 of USEPA's AP-42. . The $PM/PM_{2.5/10}$ factor is based on Table 3.1.1 of the District's *Flare Study Phase I Report* (7/91). SO_x emissions are based on a mass balance of total flared gas sulfur content per District document titled "*Technical Information and References Gaseous Fuel SOx Emission Factor*" (Version 1.0, 1/31/97). The $PM/PM_{2.5}$ PM_{10}/PM ratio is assumed to equal 1.0.
- ROC/THC ratio is based on EPA Table 13.5-2 (See Table 10.1-3 for the derivations of ROC/THC ratio).
- Flaring emissions are calculated consistent with the methodology described in Section 4.3.4 of this permit.
- SO_x emissions based on mass balance per District Application Processing and Calculations Procedures, Section "SOx Emission factors for Gaseous Fuels":

Pilot:

SOx lbs/MMBtu =

12 parts S/10^6 x (64lbs SOx/lb-mole)x(lb-mole/379.4scf)x(scf/1100btu) x (10^6btu/MMBtu)

= 0.00184 lbs SOx/MMBtu

Purge:

SOx lbs/MMBtu =

239 parts S/10^6 x (64lbs SOx/lb-mole)x(lb-mole/379.4scf)x(scf/1100btu) x (10^6btu/MMBtu)

= 0.0366 lbs SOx/MMBtu

Unplanned:

SOx lbs/MMBtu =35,000 parts S/10^6 x (64lbs SOx/lb-mole)x(lb-mole/379.4scf)x(scf/1100btu) x (10^6btu/MMBtu)

= 5.37 lbs SOx/MMBtu

- 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. CO_2 equivalent emission factors are calculated for CO_2, CH_4, and N_2O individually, then summed to calculate a total CO_{2e} emission factor. Annual CO_{2e} emission totals are presented in short tons.

  For natural gas combustion the emission factor is:
  (53.02 kg CO_2/MMbtu) (2.2046 lb/kg) = 116.89 lb CO_2/MMBtu
  (0.001 kg CH_4/MMBtu) (2.2046 lb/kg)(21 lb CO_{2e}/lb CH_4) = 0.046 lb CO_{2e}/MMBtu
  (0.0001 kg N_2O/MMBtu) (2.2046 lb/kg)(310 lb CO_{2e}/lb N2O) = 0.068 lb CO_{2e}/MMBtu
  Total CO_{2e}/MMBtu = 116.89 + 0.046 + 0.068 = 117.00 lb CO_{2e}/MMBtu

- Produced gas may be up to 40% CO_2 with a heating value of 636 Btu/scf. Therefore, 1 MMBtu of produced gas is 1,572.3 scf. 628.9 scf of CO_2 and 943.40 scf of combustible gas.

  628.9 scf CO_2 / 379 scf per mol x 44 lb per mol = 73.02 lb CO_2/MMBtu of produced gas

  The adjusted CO_2 emission factor is then:

  117.00 + 73.02 = 190.02 lb CO_2/MMBtu of produced gas

Reference B - Fugitive Components

- The maximum operating schedule is in units of hours

- All safe to monitor components are credited an 80 percent control efficiency. Unsafe to monitor components (as defined in Rule 331) are considered uncontrolled.

- The component leak path definition differs from the Rule 331 definition of a component. A typical leak path count for a valve would be equal to four (one valve stem, a bonnet connection and two flanges).

- Leak path counts are provided by applicant. The clp count is listed in Table 5.1-1 and represents the current clp count as of the issuance date of this permit.

- See Section 4 for the emission factors.

Reference C - Supply Boat

- The maximum operating schedule is in units of hours

- Supply boat engine data based on the specifications of a boat identical to 'American Heritage'.

- Three 1,640 bhp main engines (i.e., 4,920 bhp), two 265 bhp auxiliary engines (i.e., 530 bhp) and two 265 bhp bow thruster engines (i.e., 530 bhp) are used

- Main engine load factor based on District *Crew and Supply Boat* study (6/87)

- Supply boat bow thruster engine only operates during maneuver mode

- Supply boat generator engines provide half of total rated load, either with one engine at full load or both engines at half load

- Based on the boat trip distance from Port Hueneme to Holly, the District has computed the total time a supply boat operates (per trip) within California Coastal Waters (adjacent to Santa Barbara County) limits. This is 13.25 hours. A trip includes time to, from, and at the platform. The time is based on a typical trip consisting of: 10.75 hours cruise, 2 hours maneuver, and 0.5 hour idle. Annual supply boat usage time is 2544 hours based on 192 trips. For operations related to the decommissioning of Platform Holly, usage of the auxiliary engines is calculated at 24 hours per day for the generator engine and 3 hours per day for the bow thruster in order to allow the supply vessel to remain at the Platform for additional time.

- Main engine emission factors are based on EPA Marine Tier 2 emission factors for Category 1 engines with a displacement equal to or greater than 2.5 and less than 5 liters per cylinder

- Auxiliary engine emission factors are based on EPA Marine Tier 2 emission factors for Category 1 engines with a displacement equal to or greater than 1.2 and less than 2.5 liters per cylinder

- Supply boat engines achieve a controlled NO_x + HC emission rate of 5.4 g/bhp-hr with an allocation of 90% to NOx and 10% to HC. This emission factor equates to 195 lb/1000 gallons for NOx and 21.68 lb/1000 gallons for ROC:

$$\rightarrow EF_{NOx} = (5.4 \text{ g/bhp-hr x } 0.9 \text{ ratio}) \div (0.055 \text{ gal/bhp-hr}) \div (453.6 \text{ g/lb}) \times (1000)$$

$$\rightarrow EF_{ROC} = (5.4 \text{ g/bhp-hr x } 0.1 \text{ ratio}) \div (0.055 \text{ gal/bhp-hr}) \div (453.6 \text{ g/lb}) \times (1000)$$

Supply boat engines achieve a controlled CO emission rate of 3.7 g/bhp-hr. This emission factor equates to 148.58 lb/1000 gallons.

$\rightarrow EF_{CO}$ = (3.7 g/bhp-hr) ÷ (0.055 gal/bhp-hr) ÷ (453.6 g/lb) × (1000)

Supply boat engines achieve a controlled PM emission rate of 0.15 g/bhp-hr. This emission factor equates to 6.02 lb/1000 gallons.

$\rightarrow EF_{PM}$ = (6.02 g/bhp-hr) ÷ (0.055 gal/bhp-hr) ÷ (453.6 g/lb) × (1000)

- $PM_{10/2.5}$:PM ratio = 0.96; ROC to TOC ratio = 1.0

- All SO_x emissions based on mass balance

  SO_x (as SO_2) = (0.0015 %S / 100) × (7.05 lb/gal) × (64 lbs/lb-mole SO2 ÷ 32 lbs/lb-mole S) x 1000 = 0.2115 lbs S/ kgal.

- 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. CO_2 equivalent emission factors are calculated for CO_2, CH_4, and N_2O individually, then summed to calculate a total CO_{2e} emission factor. Annual CO_{2e} emission totals are presented in short tons.

  For diesel fuel combustion the emission factor is:
  (73.96 kg CO_2/MMBtu) (2.2046 lb/kg) = 163.05 lb CO_2/MMBtu
  (0.003 kg CH_4/MMBtu) (2.2046 lb/kg)(21 lb CO_{2e}/lb CH_4) = 0.139 lb CO_{2e}/MMBtu
  (0.0006 kg N_2O/MMBtu) (2.2046 lb/kg)(310 lb CO_{2e}/lb N2O) = 0.410 lb CO_{2e}/MMBtu
  Total CO_{2e}/MMBtu = 163.05 + 0.139 + 0.410 = 163.60 lb CO_{2e}/MMBtu

  163.60 lb CO_{2e}/MMBtu x 137,000,000 Btu/1,000 gal = 22,413.2 lb CO_{2e}/1,000 gal

- Brake specific fuel consumption is 0.055 gal/bhp-hr [=1/(18.2 bhp-hr/gal)] for all engines.

- Main and auxiliary engine fuel use limits are determined as follows:

  Gallons/time period = (BSFC) × (bhp) × (hours/time period) × (load factor)

  Main engines:

  Q = (0.055 gal/bhp-hr) (4,920 bhp) (13.25 hours/day) (0.65)
  = 2,326 gallons per day

  Q = (0.055 gal/bhp-hr) (4,920 bhp) (2544 hours/yr) (0.65)
  = 446,651 gallons per year

Auxiliary engines – Generators

  Q = (0.055 gal/bhp-hr) (530 bhp) (24 hours/day) (0.50)
  = 349 gallons per day

  Q = (0.055 gal/bhp-hr) (530 bhp) (3500 hours/yr) (0.50)
  = 50,920 gallons per year

Auxiliary engines - Bow Thruster

Q = (0.055 gal/bhp-hr) (530 bhp) (3 hours/day)
= 87 gallons per day

Q = (0.055 gal/bhp-hr) (530 bhp) (500 hours/yr)
= 14,549 gallons per year.

Reference D - Crew Boat

- The maximum operating schedule is in units of hours.

- Crew boat engine data based on the specifications of a boat identical to the M/V GOL Lightning

- Four 1,300 bhp main engines (i.e., 5,200 bhp) and two 125 bhp auxiliary engine (i.e., 250 bhp)

- Main engine load factor based on District *Crew and Supply Boat* study (6/87)

- Crew boat auxiliary engine provides half of the total rated load

- The total time a crew boat operates (per trip) is 1.0 hour, based on actual distance. Annual crew boat usage time is based on 1792 trips at 1.0 hr/trip for a total of 1,792 hours per year

- Main engine emission factors are based on EPA Marine Tier 2 emission factors for Category 1 engines with a displacement equal to or greater than 2.5 and less than 5 liters per cylinder

- Auxiliary engine emission factor is based on EPA Off-road Tier 2 emission factors for engines rated between 175 to 300 bhp

- Crew boat main engines achieve a controlled NO_x + HC emission rate of 5.4 g/bhp-hr with an allocation of 90% to NO_x and 10% to HC. This emission factor equates to 195 lb/1000 gallons for NOx and 21.68 lb/1000 gallons for ROC:

  $\rightarrow EF_{NOx}$ = (5.4 g/bhp-hr x 0.9 ratio) ÷ (0.055 gal/bhp-hr) ÷ (453.6 g/lb) × (1000)

  $\rightarrow EF_{ROC}$ = (5.4 g/bhp-hr x 0.1 ratio) ÷ (0.055 gal/bhp-hr) ÷ (453.6 g/lb) × (1000)

- Crew boat main engines achieve a controlled CO emission rate of 3.7 g/bhp-hr. This emission factor equates to 148.58 lb/1000 gallons:

  $\rightarrow EF_{CO}$ = (3.7 g/bhp-hr) ÷ (0.055 gal/bhp-hr) ÷ (453.6 g/lb) × (1000)

- Crew boat main engines achieve a controlled PM emission rate of 0.15 g/bhp-hr. This emission factor equates to 6.02 lb/1000 gallons

  $\rightarrow EF_{PM}$ = (6.02 g/bhp-hr) $\div$ (0.055 gal/bhp-hr) $\div$ (453.6 g/lb) $\times$ (1000)

- PM_{10}:PM ratio = 0.96; ROC:TOC ratio = 1.0

- All SO_x emissions based on mass balance

- SO_x (as SO_2) = (0.0015 %S / 100) $\times$ (7.05 lb/gal) $\times$ (64 lbs/lb-mole SO2 $\div$ 32 lbs/lb-mole S) x 1000 = 0.2115 lbs S/ kgal

- Brake specific fuel consumption is 0.055 gal/bhp-hr (18.2 hp-hr/gal) for all engines

- Main and auxiliary engine fuel use limits are determined as follows

(Gallons/time period) = (BSFC) $\times$ (bhp) $\times$ (hours/time period) $\times$ (load factor)

Main engines:

Q = (0.055 gal/bhp-hr) (5,200 bhp) (7 hours/day) (0.85)
= 1,699 gallons per day

Q = (0.055 gal/bhp-hr) (5,200 bhp) (1,792 hours/yr) (0.85)
= 434,843 gallons per year

Auxiliary engines – Generators

Q = (0.055 gal/bhp-hr) (250 bhp) (7 hours/day) (0.50)
= 48 gallons per day

Q = (0.055 gal/bhp-hr) (250 bhp) (1,792 hours/yr) (0.50)
= 12,298 gallons per year

Reference E - Pigging Equipment

- Maximum operating schedule is in units of events

- No pigs are received at the platform.

- The gas & oil launcher volumes, pressures, and temperatures based on file data;

- The oil/emulsion launcher is purged with nitrogen or sweet gas and the gas launchers are purged with nitrogen, then vented to the VRS via a surge tank at 5 psig prior to opening the launchers to the atmosphere. The procedures are listed in the permittee-submitted permit modification application incorporated in Section 10.8 of this permit. The ROC content calculations shown in Section 10.8 are used to compute the emissions for the pig launchers.

- MWoil = 50 lb/lb-mol for oil; MWgas = 23 lb/lb-mol for gas; MW_{N2} = 28 lb/lb-mol for N_2.

- Average TOC weight fraction in the nitrogen/ROC mix in the gas launcher is 0.0001(see calculations in Section 10.8) for gas launcher. This is due to purging with nitrogen as discussed above. In addition, the ROC/TOC ratio is 0.308 [Reference: CARB VOC Speciation Profile 757 for ROC/TOC ratio of 0.308]. Thus, the ROC fraction in the released gases to atmosphere is 0.00003.

- Average ROC weight fraction in sweet gas to purge oil launcher is 0.1924 [Reference: 2001 Annual Report for Holly]. After five purges, the purge gas comprises 99.99% of sweet gas; this is released to the atmosphere.

- Density ρ = (Ppsig * MW) / (R*T), density of vapor remaining in the vessel (lbs VOC/acf)

- Site-specific pigging emission factor EF = (ρ x ROC weight %), (lb ROC/acf-event)

☞ ρ = (19.7 *28) / (10.73*520) = 0.0989 lb/cu.ft, of the nitrogen/ROC mix in the pig chamber = 0.0989 lb/cubic feet of TOC for gas launchers;

EF(gas-mix) = 0.0989 * 0.00003 = 0.00 lb of ROC/acf-event for gas launchers.

☞ The pig launcher initially contains ROC. It is bled down to 20 psig or less, then purged with nitrogen or sweet fuel gas at 125 psig and bled back down to 20 psig or less five times before opening the launcher. It is assumed that the gas in the launcher and the purge gas behave as an ideal gas mixture. The following properties are assumed:

Launcher volume = 1.4 ft^3
R = 10.73 psi ft^3/^oR lb-mol
T = 535 ^oR
MW ROC = 23 lb/lb-mol
$\gamma = c_p/c_v = 1.4$
$M_{initial} = P_1V_1/RT_1$ x MW

For each cycle the initial volume of gas is compressed adiabatically, so the temperature and volume of the initial volume of gas after it is compressed to 125 psig is:

$$T_2 = T_1 \left(\frac{P_2}{P_1}\right)^{\gamma-1/\gamma}$$

$$V_2 = V_1 \left(\frac{P_2}{P_1}\right)^{-1/\gamma}$$

The remaining volume in the chamber is taken by the purge gas. The mass of the purge gas added in each cycle is determined by:

M_{purge} = 28 lb/lb-mol * 139.7 psia * (1.4 ft^3 – V_2) / (10.73 * 535 ^oR)

The final temperature in the chamber before bleeding down is equal to the weighted average of the temperature of the compressed initial volume and the temperature of the purge gas (which is assumed to be 535°R):

$$T_{final} = \frac{T_2 M_{initial} + 535 \quad ^oR M_{purge}}{M_{initial} + M_{purge}}$$

The ROC mass fraction of the ROC and purge gas mixture is equal to:

$M_{initial} / (M_{initial} + M_{purge})$

The compressed gas mixture is then bled down to the vapor recovery system until the remaining ROC and purge gas mixture is back to 20 psig. The temperature in the chamber after bleeding down is calculated based on adiabatic expansion. The mass of ROC in the chamber after bleeding down is equal to the mass of gas in the chamber times the ROC fraction at the end of the last purge cycle. After 5 purge cycles and the final bleed-down the mass of ROC remaining in the chamber is 0.0014 lb.

R =	10.73	psi ft^3 / °R lb-mol	Initial Pressure =	20	psig
gamma =	1.40		Purge Pressure =	125	psig
V1 =	1.40	Ft^3	Initial Temperature =	75	Deg F

	Purge 1	Purge 2	Purge 3	Purge 4	Purge 5	Final Vent 6
MW (lb/lb-mol)	23	26.78	27.59	27.85	27.95	27.98
P1 (psia)	34.7	34.7	34.7	34.7	34.7	34.7
T1 (deg R)	535.00	402.32	373.71	364.49	361.24	360.05
M1 (lb)	0.19	0.30	0.33	0.35	0.35	0.35
P2 (psia)	139.7	139.7	139.7	139.7	139.7	
T2 (deg R)	598.95	556.35	542.63	537.79	536.03	
V2 (ft^3)	0.52	0.52	0.52	0.52	0.52	
V_{purge} (ft^3)	0.88	0.88	0.88	0.88	0.88	
M_{purge} (lb)	0.60	0.60	0.60	0.60	0.60	
Fraction ROC	0.24457293	0.08165757	0.02917908	0.01065858	0.00392379	
Mass ROC		**0.07369853**	**0.02729623**	**0.01009565**	**0.00373333**	**0.00138054** **lb/launch**

The gas and utility launchers may be pigged up to 10 times per day each, so total emissions are equal to 0.01 lb ROC/day.

The oil launcher may be purged with fuel gas. When the launcher is opened, 0.35 lb of gas is released, of which 0.39% is the initial ROC, the remainder is fuel gas. Based on the first half 2009 CVR report, in-plant fuel gas from EOF has C3+ weight percentages of around 15% or less. Therefore, the mass of ROC in the purge gas is:

0.35 lb (1-0.0039) * 0.15 = 0.052 lb ROC

The permit allows up to 5 oil launches per day and 960 per year, so the potential to emit is 0.27 lb ROC/day and 0.03 ton ROC/year. This is a negligible increase from the current permit limit of 0.11 lb ROC/day and 0.01 ton ROC/year.

Reference F - Sumps/Tanks/Separators

- Maximum operating schedule is in units of hours

- There are no oil/water separators on Holly

- Emission calculation methodology based on District P&P 6100.060 (specifically, the CARB/KVB report *Emissions Characteristics of Crude Oil Production Operations in California* (1/83) was used).

- Calculations are based on surface area of emissions unit as supplied by the applicant.

- All non-oil/water separator emission units are classified as tertiary production and light oil service

Reference G - Solvents

- Solvents are used for daily operations such as wipe cleaning or cold solvent degreasing. A low VOC cleaner, D-5, is used. Solvents used to thin surface coatings are not included in this equipment category.

- To compute ROC emissions from paints and thinners under the *worst-case scenario*, the maximum allowable ROC content in such paints/thinners (250 g/l) has been used as the emission factor for the entire group of chemicals.
- Annual emission rates per prior permit. Daily number is annualized.

- Hourly emissions based on daily value divided by an average 24-hour day. Compliance with daily value based on monthly emissions divided by the number of days per month.

Reference H - Boom Boat

-- The boom boat is a 22'3" Boston Whaler driven by a motor, powered by a Honda BF225A 225 bhp 4-stroke gasoline-fired, spark-ignition engine.
-- Usage is limited to 24 hours per year.
-- Uncontrolled NOx, ROC and CO emission factors are obtained from USEPA's Reference Report "Non-Road Engine and Vehicle Emission Study [USEPA 460/3-91-02]." Since the document was published in 1991, it addressed all marine vessel engines manufactured prior to that date, such as the one being permitted. NO_x and ROC emission factors are based on ARB Executive Order U-W-005-0043 certifying the new boat engine level of cleanliness as "ultra low emissions". CO, SO_x and PM emission factors are obtained from USEPA's Reference Report "Non-Road Engine and Vehicle Emission Study [USEPA 460/3-91-02]". A load factor of 65% is recommended. In addition, a correction factor of 0.8 is required to convert the HC emission factor to an ROC emission factor. The adjusted emission factors, not accounting for the load factor, are;

  ROC = 4.90 g/hp-hr; NOx = 7.20 g/hp-hr; CO = 1,357 g/hp-hr; SOx = 0.27 g/hp-hr; and PM = 48.10 g/hp-hr.

-- The respective emission factors are multiplied first by the load factor of 0.65 and then by the hp (85); and finally by either 12 (daily hours) or 24 (number of hours/year) to obtain the permitted daily or annual emissions.

Reference I - Crane Engine

- The emission factor for NO_x and ROC is calculated as follows:

  Tier 3 standard: 3.0 g NMHC+NO_x/bhp-hr
  Manufacturer – supplied NO_x EF (at rated hp) = 1.32 lb/hr
  Manufacturer – supplied ROC EF (at rated hp) = 0.15 lb/hr

  NO_x EF = 3.0 g/bhp-hr x (1.32/(1.32 + 0.15)) = 2.69 g NO_x/bhp-hr
  ROC EF = 3.0 g/bhp-hr x (0.15/(1.32 + 0.15)) = 0.31 g ROC/bhp-hr

- 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. CO_2 equivalent emission factors are calculated for CO_2, CH_4, and N_2O individually then summed to calculate a total CO_{2e} emission factor. Annual CO_{2e} 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 CO_2/MMBtu) (2.2046 lb/kg) = 163.05 lb CO_2/MMBtu
  (0.003 kg CH_4/MMBtu) (2.2046 lb/kg)(21 lb CO_{2e}/lb CH_4) = 0.139 lb CO_{2e}/MMBtu
  (0.0006 kg N_2O/MMBtu) (2.2046 lb/kg)(310 lb CO_{2e}/lb N2O) = 0.410 lb CO_{2e}/MMBtu
  Total CO_{2e}/MMBtu = 163.05 + 0.139 + 0.410 = 163.60 lb CO_{2e}/MMBtu

  Converted to g/hp-hr:
  (163.60 lb CO_{2e}/MMBtu)(453.6 g/lb)(7500 Btu/hp-hr)/1,000,000
  = 556.58 g/hp-hr as CO_{2e}

Table 10.1-3
Platform Holly
Flare ROC/TOC Weight Ratio

Flare ROC/THC Weight Ratio

	Vol % (moles)	MW	lbs	Wt. %
methane	55%	16	8.8	34%
Ethane/ethylene	8%	30.07	2.4056	9%
Acetylene	5%	26.04	1.302	5%
Propane	7%	44.09	3.0863	12%
Propylene	25%	42.08	10.52	40%
	1.00		26.1139	100%

Assume half of ethane/ethylene is ROC

ROC/THC weight ratio = 61.70%

Data per USEPA AP-42, Table 13.5-2

Reference J - Hazardous Air Pollutants

Revised table to be provided in the final permit.

10.2 Pig Launching Procedure

Platform Holly
Pig Launching Procedure – 6" Gas Transfer Pipeline

Safety Requirements:

- Standard Venoco PPE – Nomex, hard hat, safety boots, safety glasses and hearing protection.
- Face shield.
- Chemical gloves.
- SCBA at the scene for emergency use.

THESE PROCEDURES SHALL BE PERFORMED BY QUALIFIED OPERATORS ONLY.

CAUTION: Use of unapproved tools such as snipes, pry bars, etc., on the pig receiver door is strictly prohibited.

Initial Set Up

1. Notify Ellwood to set-up to receive pig. Verify type of pig to be launched.
2. Set-up purge blower (bug fan) for safe ventilation of area.
3. Bypass PSHH 151 and PSLL 151. (Tag, log and monitor)
4. Isolate the Gas Launcher
   A. Close 4" Inlet ball valve
   B. Close 6" Discharge ball valve

Purging and Depressurizing

1. Open 1" bleed valve to the Surge Tank.
2. Equalize launcher pressure with Surge Tank pressure.
3. Close 1" bleed valve to the Surge Tank.
4. Open Nitrogen purge gas and fill launcher to 125 psig.
5. Shut-in Nitrogen purge gas.
6. Repeat steps 1 through 5 four more times, filling the launcher with Nitrogen and blowing it down to the Surge tank.
7. Slowly open bleed nut on launcher door until launcher is completely depressurized.
8. Slowly loosen clamp and open launcher door.

Pig Loading & Launcher Preparation

1. Insert pig nose down.
2. Wipe down and inspect O-ring. (It must be clean to ensure a good seal) Lube if necessary.
3. Close door and align launcher flanges.
4. Tighten clamp bolt until bleed nut assembly is free to drop into place.
5. Tighten bleed nut.

Launching Pig

1. Notify Ellwood again that actual launch is ready.

2. Slowly open 4" Inlet ball valve to pressure up launcher to system pressure.
3. Check for leaks.
4. Slowly open the 6" Discharge ball valve.
5. Slowly close the 6" Normally Open ball valve to force gas path through the launcher. Listen for the pig leaving the launcher.
6. After 2 to 3 minutes, slowly open the 6" Main ball valve.
7. Close the 3" Inlet ball valve.
8. Close the 6" Discharge valve.
9. Open 1" bleed valve to the Surge Tank. Equalize launcher with Surge Tank Pressure.
10. Close 1" bleed valve to the Surge Tank.

<u>Return to Service</u>

1. Verify that all valves are returned to normal operating positions.
2. Remove bypasses PSHH 151 and PSLL 151.
3. Turnoff and store the ventilation fan.
4. Log pig launch in Operations Pig Log Book.
5. After Ellwood receives the pig, note any condition or problems reported by the receiving operators, such as liquids, solids, etc.

10.3 Fee Calculations

All permit fees for the reevaluation of Holly are based on the fee schedules of Rule 210. The District has calculated these fees based on a CPI adjusted Rule 210 fee schedule.

All work performed with respect to implementing the requirements of the Part 70 Operating Permit program are assessed on a cost reimbursement basis pursuant to District Rule 210.

air pollution control district
SANTA BARBARA COUNTY

FEE STATEMENT

PT-70/Reeval No. 08234 - R11

FID: 03105 Platform Holly / SSID: 01063

Device No.	Device Name	Fee Schedule	Qty of Fee Units	Fee per Unit	Fee Units	Max or Min. Fee Apply?	Number of Same Devices	Pro Rate Factor	Device Fee	Penalty Fee?	Fee Credit	Total Fee per Device
002345	Drain Sump Tank	A6	1.000	4.22	Per 1000 gallons	Min	1	1.000	73.07	0.00	0.00	73.07
386623	Lube Oil Drain Tank	A1.b	1.000	458.00	Per equipment	No	1	1.000	458.00	0.00	0.00	458.00
005882	Overflow Sump Tank	A6	1.000	4.22	Per 1000 gallons	Min	1	1.000	73.07	0.00	0.00	73.07
009661	Solvent Storage Tank	A6	10.000	4.22	Per 1000 gallons	Min	1	1.000	73.07	0.00	0.00	73.07
002337	IC Engine: Emergency Generator	A3	3.530	551.72	Per 1 million Btu input	No	1	1.000	1,947.57	0.00	0.00	1,947.57
009130	IC Engine: Drilling Rig Generator #1	A3	7.590	551.72	Per 1 million Btu input	No	1	1.000	4,187.55	0.00	0.00	4,187.55
009131	IC Engine: Drilling Rig Generator #2	A3	7.590	551.72	Per 1 million Btu input	No	1	1.000	4,187.55	0.00	0.00	4,187.55
007982	High-pressure Flare	A3	1312.500	551.72	Per 1 million Btu input	Max	1	1.000	7,382.27	0.00	0.00	7,382.27
009603	Low-Pressure Flare	A3	126.000	551.72	Per 1 million Btu input	Max	1	1.000	7,382.27	0.00	0.00	7,382.27
111506	Crane Engine	A3	1.920	551.72	Per 1 million Btu input	No	1	1.000	1,059.30	0.00	0.00	1,059.30
009598	WS Cylinder 1: 3rd Stage Discharge Bottle, C-102	A1.a	1.000	73.54	Per equipment	No	1	1.000	73.54	0.00	0.00	73.54
009629	Oil Surge Vessel	A6	1.000	4.22	Per 1000 gallons	Min	1	1.000	73.07	0.00	0.00	73.07
009638	Water Surge Vessel	A6	1.000	4.22	Per 1000 gallons	Min	1	1.000	73.07	0.00	0.00	73.07
009628	1st-Stage Discharge Scrubber, W-S, C-102	A1.a	1.000	73.54	Per equipment	No	1	1.000	73.54	0.00	0.00	73.54
009617	3rd-Stage Suction Scrubber, W-S, C-102	A1.a	1.000	73.54	Per equipment	No	1	1.000	73.54	0.00	0.00	73.54
009641	1st-Stage Suction Scrubber, W-S, C-102	A1.a	1.000	73.54	Per equipment	No	1	1.000	73.54	0.00	0.00	73.54

009618	3rd-Stage Discharge Scrubber, W-S, C-102	A1.a	1.000	73.54	Per equipment	No	1	1.000	73.54	0.00	0.00	73.54
009616	2nd-Stage Suction Scrubber, W-S, C-102	A1.a	1.000	73.54	Per equipment	No	1	1.000	73.54	0.00	0.00	73.54
009630	Annulus Separator (V-101), Well Bay Test Separator (V-100)	A1.a	1.000	73.54	Per equipment	No	2	1.000	147.08	0.00	0.00	147.08
009584	WS Cylinder 1: 3rd Stage Suction Bottle, C-102	A1.a	1.000	73.54	Per equipment	No	1	1.000	73.54	0.00	0.00	73.54
009613	WS Cylinder 2 & 4 1st Stage Discharge Bottle, C-102	A1.a	1.000	73.54	Per equipment	No	1	1.000	73.54	0.00	0.00	73.54
009612	WS Cylinder 2 & 4 1st Stage Suction Bottle, C-102	A1.a	1.000	73.54	Per equipment	No	1	1.000	73.54	0.00	0.00	73.54
009614	WS Cylinder 3 : 2nd Stage Suction Bottle, C-102	A1.a	1.000	73.54	Per equipment	No	1	1.000	73.54	0.00	0.00	73.54
009615	WS Cylinder 3: 2nd Stage Discharge Bottle, C-102	A1.a	1.000	73.54	Per equipment	No	1	1.000	73.54	0.00	0.00	73.54
009611	IR Cylinder 2 & 4 Discharge Bottle, C-101	A1.a	1.000	73.54	Per equipment	No	1	1.000	73.54	0.00	0.00	73.54
009608	IR Cylinder 1 & 3 Suction Bottle, CYL-1, CYL-3, C-101	A1.a	1.000	73.54	Per equipment	No	1	1.000	73.54	0.00	0.00	73.54
009609	IR Cylinder 1 & 3, C-101 Discharge Bottle	A1.a	1.000	73.54	Per equipment	No	1	1.000	73.54	0.00	0.00	73.54
009640	I.R. Discharge Scrubber, C-101	A1.a	1.000	73.54	Per equipment	No	1	1.000	73.54	0.00	0.00	73.54
009639	I.R. Suction Scrubber, C-101	A1.a	1.000	73.54	Per equipment	No	1	1.000	73.54	0.00	0.00	73.54
009610	IR Cylinder 2 &4 Suction Bottle, C-101	A1.a	1.000	73.54	Per equipment	No	1	1.000	73.54	0.00	0.00	73.54
009651	Monterey 3120 Group Trap Separator	A1.a	1.000	73.54	Per equipment	No	1	1.000	73.54	0.00	0.00	73.54
009652	Monterey 3242 Group Trap Separator	A1.a	1.000	73.54	Per equipment	No	1	1.000	73.54	0.00	0.00	73.54
009622	Stack Scrubber	A1.a	1.000	73.54	Per equipment	No	1	1.000	73.54	0.00	0.00	73.54
009654	Monterey 3242 Test Trap	A1.a	1.000	73.54	Per equipment	No	1	1.000	73.54	0.00	0.00	73.54
009601	Fugitives: Oil - Controlled	A1.a	1.000	73.54	Per equipment	No	1	1.000	73.54	0.00	0.00	73.54
009794	Pig Launcher - Gas	A1.a	1.000	73.54	Per equipment	No	1	1.000	73.54	0.00	0.00	73.54
009792	Pig Launcher - Oil	A1.a	1.000	73.54	Per equipment	No	1	1.000	73.54	0.00	0.00	73.54
009793	Pig Launcher - Utility	A1.a	1.000	73.54	Per equipment	No	1	1.000	73.54	0.00	0.00	73.54

009595	Oil Pipeline to Shore	A1.a	1.000	73.54	Per equipment	No	1	1.000	73.54	0.00	0.00	73.54
009596	Gas Pipeline to Shore	A1.a	1.000	73.54	Per equipment	No	1	1.000	73.54	0.00	0.00	73.54
009624	Direct Contact Cooler	A1.a	1.000	73.54	Per equipment	No	1	1.000	73.54	0.00	0.00	73.54
009590	Chemical Injection Tank	A6	0.430	4.22	Per 1000 gallons	Min	1	1.000	73.07	0.00	0.00	73.07
009589	Chemical Injection Tank	A6	0.430	4.22	Per 1000 gallons	Min	1	1.000	73.07	0.00	0.00	73.07
009588	Chemical Injection Tank	A6	0.430	4.22	Per 1000 gallons	Min	1	1.000	73.07	0.00	0.00	73.07
009587	Chemical Injection Tank	A6	0.430	4.22	Per 1000 gallons	Min	1	1.000	73.07	0.00	0.00	73.07
009586	Chemical Injection Tank	A6	0.240	4.22	Per 1000 gallons	Min	1	1.000	73.07	0.00	0.00	73.07
009585	Chemical Injection Tank	A6	0.980	4.22	Per 1000 gallons	Min	1	1.000	73.07	0.00	0.00	73.07
107279	Chemical Injection Pumps	A2	1.000	38.13	Per total rated hp	Min	2	1.000	146.14	0.00	0.00	146.14
107274	Pipeline Shipping Pump	A2	250.000	38.13	Per total rated hp	Max	1	1.000	7,382.27	0.00	0.00	7,382.27
009571	Firewater Pumps	A2	60.000	38.13	Per total rated hp	No	2	1.000	4,575.60	0.00	0.00	4,575.60
107278	Stack Scrubber Pump	A2	6.000	38.13	Per total rated hp	No	1	1.000	228.78	0.00	0.00	228.78
107276	Drain Sump Pump, T-1	A2	7.500	38.13	Per total rated hp	No	1	1.000	285.98	0.00	0.00	285.98
386624	Drain Pump	A2	1.000	38.13	Per total rated hp	Min	1	1.000	73.07	0.00	0.00	73.07
107277	Direct Contact Cooler Condensate Pumps	A2	2.000	38.13	Per total rated hp	No	2	1.000	152.52	0.00	0.00	152.52
009594	Omnipure Wastewater Treatment Skid	A1.a	1.000	73.54	Per equipment	No	1	1.000	73.54	0.00	0.00	73.54
009633	Glycol Absorber	A1.a	1.000	73.54	Per equipment	No	1	1.000	73.54	0.00	0.00	73.54
009634	Glycol Afterscrubber	A1.a	1.000	73.54	Per equipment	No	1	1.000	73.54	0.00	0.00	73.54
009635	Glycol Flash Drum	A1.a	1.000	73.54	Per equipment	No	1	1.000	73.54	0.00	0.00	73.54
009580	Glycol Overhead Condenser	A1.a	0.000	73.54	Per equipment	No	1	1.000	0.00	0.00	0.00	0.00
009623	Glycol Reboiler	A3	1.640	551.72	Per 1 million Btu input	No	1	1.000	904.82	0.00	0.00	904.82

009631	Glycol Reflux Column	A1.a	1.000	73.54	Per equipment	No	1	1.000	73.54	0.00	0.00	73.54
009632	Glycol Storage Reboiler	A1.a	1.000	73.54	Per equipment	No	1	1.000	73.54	0.00	0.00	73.54
111856	Catalyst	A1.a	1.000	73.54	Per equipment	No	1	1.000	73.54	0.00	0.00	73.54
111857	Catalyst	A1.a	1.000	73.54	Per equipment	No	1	1.000	73.54	0.00	0.00	73.54
111858	Catalyst	A1.a	1.000	73.54	Per equipment	No	1	1.000	73.54	0.00	0.00	73.54
009636	Cuno Filter	A1.a	1.000	73.54	Per equipment	No	1	1.000	73.54	0.00	0.00	73.54
009605	Oil Filters, VRU, C-100A, C-100B	A1.a	1.000	73.54	Per equipment	No	2	1.000	147.08	0.00	0.00	147.08
009637	Peco Filter	A1.a	1.000	73.54	Per equipment	No	1	1.000	73.54	0.00	0.00	73.54
009666	Motor: Compressor	A2	1500.000	38.13	Per total rated hp	Max	1	1.000	7,382.27	0.00	0.00	7,382.27
009645	Motor: Direct Contact Cooler Condensate Pumps	A2	2.000	38.13	Per total rated hp	No	2	1.000	152.52	0.00	0.00	152.52
009664	Motor: Gas Lift Compressor	A2	1000.000	38.13	Per total rated hp	Max	1	1.000	7,382.27	0.00	0.00	7,382.27
009669	Motor: Drain Sump Pump, T-1	A2	7.500	38.13	Per total rated hp	No	1	1.000	285.98	0.00	0.00	285.98
009642	Motor: Glycol Pumps	A2	3.000	38.13	Per total rated hp	No	2	1.000	228.78	0.00	0.00	228.78
009643	Motor: Pipeline Shipping Pump	A2	250.000	38.13	Per total rated hp	Max	1	1.000	7,382.27	0.00	0.00	7,382.27
009646	Stack Scrubber Pump	A2	1.000	38.13	Per total rated hp	Min	1	1.000	73.07	0.00	0.00	73.07
009644	Motor: VRU Scrubber Dump Pumps, C-100A/C-100B	A2	2.000	38.13	Per total rated hp	No	2	1.000	152.52	0.00	0.00	152.52
009665	Motor: Vapor Recovery Unit (VRU) Compressors	A2	50.000	38.13	Per total rated hp	No	2	1.000	3,813.00	0.00	0.00	3,813.00
009626	Well Heads	A1.a	1.000	73.54	Per equipment	No	30	1.000	2,206.20	0.00	0.00	2,206.20
009621	VRU Coalescer Filters, C-100A/C-100B	A1.a	1.000	73.54	Per equipment	No	2	1.000	147.08	0.00	0.00	147.08
009620	VRU Suction Scrubbers, C-100A, C-100B	A1.a	1.000	73.54	Per equipment	No	2	1.000	147.08	0.00	0.00	147.08
	Device Fee Sub-Totals =								**$73,672.72**	**$0.00**	**$0.00**	
	Device Fee Total =											**$73,672.72**

Permit Fee

Fee Based on Devices	**$73,672.72**

Fee Statement Grand Total = $73,672

Notes:

(1) Fee Schedule Items are listed in District Rule 210, Fee Schedule "A".
(2) The term "Units" refers to the unit of measure defined in the Fee Schedule.

10.4 IDS Database Emissions Tables

PERMIT POTENTIAL TO EMIT

	NO_x	ROC	CO	SO_x	PM	$PM_{2.5/10}$
lb/day	983.44	422.21	3213.33	10.04	132.21	46.02
lb/hr						
TPQ						
TPY	106.10	67.72	100.77	2.82	6.40	6.28

FACILITY POTENTIAL TO EMIT

	NO_x	ROC	CO	SO_x	PM	PM_{10}
lb/day	994.30	427.27	3291.54	10.17	132.45	46.26
lb/hr						
TPQ						
TPY	106.52	65.22	103.82	2.83	6.41	6.29

STATIONARY SOURCE POTENTIAL TO EMIT

	NO_x	ROC	CO	SO_x	PM	PM_{10}
lb/day	1055.64	924.15	3569.25	59.16	149.34	63.15
lb/hr						
TPQ						
TPY	114.96	155.37	148.66	10.16	8.72	8.60

10.5 Permitted Equipment List

Santa Barbara County Air Pollution Control District – Equipment List

PT-70/Reeval 08234 R11 / FID: 03105 Platform Holly / SSID: 01063

A PERMITTED EQUIPMENT

1 Storage Tanks

1.1 Drain Sump Tank

Device ID #	**002345**	***Device Name***	**Drain Sump Tank**
Rated Heat Input		*Physical Size*	44.00 Square Feet Sump Area
Manufacturer		*Operator ID*	T-1
Model		*Serial Number*	
Location Note			
Device Description			

1.2 Lube Oil Drain Tank

Device ID #	**386623**	***Device Name***	**Lube Oil Drain Tank**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	V-147
Model		*Serial Number*	
Location Note			
Device Description	24" O.D. x 6 1/2' ht. 150 gal capacity		

1.3 Overflow Sump Tank

Device ID #	**005882**	*Device Name*	**Overflow Sump Tank**
Rated Heat Input		*Physical Size*	113.00 Square Feet Sump Area
Manufacturer		*Operator ID*	T-4
Model		*Serial Number*	
Location Note			
Device Description			

1.4 Solvent Storage Tank

Device ID #	**009661**	*Device Name*	**Solvent Storage Tank**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note	At drilling deck		
Device Description	At drilling deck, <10,000 gallons capacity		

2 Diesel I.C. Engines

2.1 IC Engine: Emergency Generator

Device ID #	**002337**	*Device Name*	**IC Engine: Emergency Generator**
Rated Heat Input	3.530 MMBtu/Hour	*Physical Size*	373.00 Brake Horsepower
Manufacturer	Caterpillar	*Operator ID*	62B306
Model	D-343	*Serial Number*	62B-306
Location Note			
Device Description	250 kW diesel stand-by generator, which is used in the event of a power outage from Southern California Edison.		

3 Spark Ignited IC Engines

3.1 IC Engine: Drilling Rig Generator #1

Device ID #	**009130**	***Device Name***	**IC Engine: Drilling Rig Generator #1**
Rated Heat Input	7.590 MMBtu/Hour	*Physical Size*	803.00 Horsepower
Manufacturer	Caterpillar	*Operator ID*	Generator #1
Model	G399 SITA	*Serial Number*	
Location Note			
Device Description			

3.2 IC Engine: Drilling Rig Generator #2

Device ID #	**009131**	***Device Name***	**IC Engine: Drilling Rig Generator #2**
Rated Heat Input	7.590 MMBtu/Hour	*Physical Size*	803.00 Horsepower
Manufacturer	Caterpillar	*Operator ID*	Generator #2
Model	G399 SITA	*Serial Number*	
Location Note			
Device Description			

4 Flare Systems

4.1 High-pressure Flare

Device ID #	**007982**	***Device Name***	**High-pressure Flare**
Rated Heat Input		*Physical Size*	1312.50 MMBtu/Hour
Manufacturer	Indair Self-Assisted	*Operator ID*	H-100
Model	1-24-H-VS-WB	*Serial Number*	
Location Note			
Device Description	The pressurized flare has a 10-inch diameter inlet; mounted to the existing vent stack boom; design rated to flare gas flow rates of up to 30 MMSCFD		

4.2 Low-Pressure Flare

Device ID #	**009603**	***Device Name***	**Low-Pressure Flare**
Rated Heat Input		*Physical Size*	126.00 MMBtu/Hour
Manufacturer		*Operator ID*	H101
Model	CAK-4	*Serial Number*	
Location Note			
Device Description	This low pressure flare is a combined pilot/flare tip; mounted to an existing flare stack boom with a permit limited to flare gas flow rates of up to 2000 SCFM		

5 Supply Boat

5.1 Supply Boat - Generator Engines

Device ID #	**009790**	***Device Name***	**Supply Boat - Generator Engines**
Rated Heat Input		*Physical Size*	530.00 Brake Horsepower
Manufacturer		*Operator ID*	3105-BB
Model		*Serial Number*	
Location Note			
Device Description			

5.1.1 Supply Boat - Bow Thruster

Device ID #	**009791**	***Device Name***	**Supply Boat - Bow Thruster**
Rated Heat Input		*Physical Size*	530.00 Brake Horsepower
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description			

5.2 Supply Boat - Main Engines - Controlled

Device ID #	**009789**	***Device Name***	**Supply Boat - Main Engines - Uncontrolled**
Rated Heat Input		*Physical Size*	4920.00 Brake Horsepower
Manufacturer		*Operator ID*	3105-AA
Model		*Serial Number*	
Location Note			
Device Description			

6 Crew Boat

6.1 Crewboat - Main Engines -Controlled

Device ID #	**009787**	***Device Name***	**Crewboat - Main Engines - Uncontrolled**
Rated Heat Input		*Physical Size*	1020.00 Brake Horsepower
Manufacturer		*Operator ID*	3105-DD
Model		*Serial Number*	
Location Note			
Device Description			

6.2 Crewboat - Auxiliary Engines

Device ID #	**009788**	***Device Name***	**Crewboat - Auxiliary Engines**
Rated Heat Input		*Physical Size*	40.00 Brake Horsepower
Manufacturer		*Operator ID*	3105-EE
Model		*Serial Number*	
Location Note			
Device Description			

7 Boom Boat

7.1 Boom Boat

Device ID #	**114797**	***Device Name***	**Boom Boat**
Rated Heat Input		*Physical Size*	2.36 MMBtu/Hour
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description			

7.2 Boom Boat - Main Engines

Device ID #	**104765**	***Device Name***	**Boom Boat - Main Engines**
Rated Heat Input		*Physical Size*	112.00 Brake Horsepower
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description	Fuel use rate 11.2 gal/hr at max rated hp.		

8 Emergency Boat

8.1 Emergency Response Boat - All Engines

Device ID #	**104762**	***Device Name***	**Emergency Response Boat - All Engines**
Rated Heat Input		*Physical Size*	1770.00 Brake Horsepower
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description			

9 Crane Engine

Device ID #	**111506**	***Device Name***	**Crane Engine**
Rated Heat Input	1.920 MMBtu/Hour	*Physical Size*	250.00 Horsepower
Manufacturer	Caterpillar	*Operator ID*	Crane Engine
Model	C7-ACERT, IND-C	*Serial Number*	JTF00836
Location Note			
Device Description	Tier 3 Diesel IC engine		

10 Pressure Vessels

10.1 WS Cylinder 1: 3rd Stage Discharge Bottle, C-102

Device ID #	**009598**	***Device Name***	**WS Cylinder 1: 3rd Stage Discharge Bottle, C-102**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	V-146
Model		*Serial Number*	
Location Note			
Device Description	2’0” diameter by 7’8” high.		

10.2 Oil Surge Vessel

Device ID #	**009629**	***Device Name***	**Oil Surge Vessel**
Rated Heat Input		*Physical Size*	
Manufacturer	Natco	*Operator ID*	Mezz.V-110
Model		*Serial Number*	7050401-02
Location Note			
Device Description	6’ dia. x 20’ long, 100 psi, 100°F.		

10.3 Water Surge Vessel

Device ID #	**009638**	***Device Name***	**Water Surge Vessel**
Rated Heat Input		*Physical Size*	
Manufacturer	Natco	*Operator ID*	Mezz V-109
Model		*Serial Number*	7050401-01
Location Note			
Device Description	6’ dia. x 20’ long, 100 psi, 100°F.		

10.4 1st-Stage Discharge Scrubber, W-S, C-102

Device ID #	**009628**	***Device Name***	**1st-Stage Discharge Scrubber, W-S, C-102**
Rated Heat Input		*Physical Size*	
Manufacturer	National BD	*Operator ID*	V-118
Model	559 V-2	*Serial Number*	
Location Note			
Device Description	2’ dia. x 9.6’ long, 600 psi, 250°F.		

10.5 3rd-Stage Suction Scrubber, W-S, C-102

Device ID #	**009617**	***Device Name***	**3rd-Stage Suction Scrubber, W-S, C-102**
Rated Heat Input		*Physical Size*	
Manufacturer	National BD	*Operator ID*	V-120
Model	559 V-4	*Serial Number*	
Location Note			
Device Description	2’ dia. x 8.75’ long, 960 psi, 250°F.		

10.6 1st-Stage Suction Scrubber, W-S, C-102

Device ID #	**009641**	***Device Name***	**1st-Stage Suction Scrubber, W-S, C-102**
Rated Heat Input		*Physical Size*	
Manufacturer	National BD	*Operator ID*	V-117
Model	559 V-1	*Serial Number*	
Location Note			
Device Description	3' dia. x 9.6' long, 325 psi, 250°F.		

10.7 3rd-Stage Discharge Scrubber, W-S, C-102

Device ID #	**009618**	***Device Name***	**3rd-Stage Discharge Scrubber, W-S, C-102**
Rated Heat Input		*Physical Size*	
Manufacturer	National BD	*Operator ID*	V-121
Model	559 V-5	*Serial Number*	
Location Note			
Device Description	2' dia. x 6.5' long, 2000 psi, 250°F.		

10.8 2nd-Stage Suction Scrubber, W-S, C-102

Device ID #	**009616**	***Device Name***	**2nd-Stage Suction Scrubber, W-S, C-102**
Rated Heat Input		*Physical Size*	
Manufacturer	National BD	*Operator ID*	V-119
Model	559 V-3	*Serial Number*	
Location Note			
Device Description	2' dia. x 9.6' long, 600 psi, 250°F.		

10.9 Annulus Separator (V-101), Well Bay Test Separator (V-100)

Device ID #	**009630**	***Device Name***	**Annulus Separator (V-101), Well Bay Test Separator (V-100)**
Rated Heat Input		*Physical Size*	
Manufacturer	Natco	*Operator ID*	V-100/101
Model	878	*Serial Number*	
Location Note			
Device Description	3’ dia x 10’ long, 350 psi, 100°F. V-100 is currently idle.		

10.10 WS Cylinder 1: 3rd Stage Suction Bottle, C-102

Device ID #	**009584**	***Device Name***	**WS Cylinder 1: 3rd Stage Suction Bottle, C-102**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	V-145
Model		*Serial Number*	
Location Note			
Device Description	1’ diameter by 3’7” high.		

10.11 WS Cylinder 2 & 4 1st Stage Discharge Bottle, C-102

Device ID #	**009613**	***Device Name***	**WS Cylinder 2 & 4 1st Stage Discharge Bottle, C-102**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	V-142
Model		*Serial Number*	
Location Note			
Device Description	1’6” diameter by 7’6” high.		

10.12 WS Cylinder 2 & 4 1st Stage Suction Bottle, C-102

Device ID #	**009612**	***Device Name***	**WS Cylinder 2 & 4 1st Stage Suction Bottle, C-102**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	V-141
Model		*Serial Number*	
Location Note			
Device Description	2’0” diameter by 7’8” high.		

10.13 WS Cylinder 3 : 2nd Stage Suction Bottle, C-102

Device ID #	**009614**	***Device Name***	**WS Cylinder 3 : 2nd Stage Suction Bottle, C-102**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	V-143
Model		*Serial Number*	
Location Note			
Device Description	1’4” diameter by 3’11” high.		

10.14 WS Cylinder 3: 2nd Stage Discharge Bottle, C-102

Device ID #	**009615**	***Device Name***	**WS Cylinder 3: 2nd Stage Discharge Bottle, C-102**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	V-144
Model		*Serial Number*	
Location Note			
Device Description	1’4” diameter by 4’5” high.		

10.15 IR Cylinder 2 & 4 Discharge Bottle, C-101

Device ID #	**009611**	***Device Name***	**IR Cylinder 2 & 4 Discharge Bottle, C-101**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	V-140
Model		*Serial Number*	
Location Note			
Device Description	1'-4" diameter by 6'5" high.		

10.16 IR Cylinder 1 & 3 Suction Bottle, CYL-1, CYL-3, C-101

Device ID #	**009608**	***Device Name***	**IR Cylinder 1 & 3 Suction Bottle, CYL-1, CYL-3, C-101**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	V-137
Model		*Serial Number*	
Location Note			
Device Description	1'-1" diameter by 6'5" high.		

10.17 IR Cylinder 1 & 3, C-101 Discharge Bottle

Device ID #	**009609**	***Device Name***	**IR Cylinder 1 & 3, C-101 Discharge Bottle**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	V-138
Model		*Serial Number*	
Location Note			
Device Description	1'-4" diameter by 6'5" high.		

10.18 I.R. Discharge Scrubber, C-101

Device ID #	**009640**	***Device Name***	**I.R. Discharge Scrubber, C-101**
Rated Heat Input		*Physical Size*	
Manufacturer	National BD	*Operator ID*	V-114
Model	14856	*Serial Number*	
Location Note			
Device Description	3.5’ dia. x 8.2’ long, 300 psi, 350°F.		

10.19 I.R. Suction Scrubber, C-101

Device ID #	**009639**	***Device Name***	**I.R. Suction Scrubber, C-101**
Rated Heat Input		*Physical Size*	
Manufacturer	National BD	*Operator ID*	V-113
Model	14855	*Serial Number*	
Location Note			
Device Description	4’ dia. x 9.4’ long, 150 psi, 300°F.		

10.20 IR Cylinder 2 &4 Suction Bottle, C-101

Device ID #	**009610**	***Device Name***	**IR Cylinder 2 &4 Suction Bottle, C-101**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	V-139
Model		*Serial Number*	
Location Note			
Device Description	1’-6” diameter by 6’5” high.		

10.21 Monterey 3120 Group Trap Separator

Device ID #	**009651**	***Device Name***	**Monterey 3120 Group Trap Separator**
Rated Heat Input		*Physical Size*	
Manufacturer	Natco	*Operator ID*	V-107
Model		*Serial Number*	
Location Note			
Device Description	6.5’ dia. x 20’ long, 250 psi, 100°F.		

10.22 Monterey 3242 Group Trap Separator

Device ID #	**009652**	***Device Name***	**Monterey 3242 Group Trap Separator**
Rated Heat Input		*Physical Size*	
Manufacturer	Natco	*Operator ID*	V-108
Model		*Serial Number*	
Location Note			
Device Description	6.5’ dia. x 20’ long, 250 psi, 100°F.		

10.23 Stack Scrubber

Device ID #	**009622**	***Device Name***	**Stack Scrubber**
Rated Heat Input		*Physical Size*	
Manufacturer	Downey	*Operator ID*	V-127
Model		*Serial Number*	
Location Note			
Device Description	6’ dia. x 6’ long, 90 psi, 80°F.		

10.24 Monterey 3242 Test Trap

Device ID #	**009654**	***Device Name***	**Monterey 3242 Test Trap**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	V-106
Model		*Serial Number*	
Location Note			
Device Description	4' dia. x 15' long, 275 psi, 100°F. Replaced V-105		

11 Fugitive Hydrocarbon Components - CLP

11.1 Fugitives: Gas - Controlled

Device ID #	**104755**	***Device Name***	**Fugitives: Gas - Controlled**
Rated Heat Input		*Physical Size*	14,278.00 Component Leakpath
Manufacturer		*Operator ID*	3105-04
Model		*Serial Number*	
Location Note			
Device Description			

11.2 Fugitives: Gas - Unsafe

Device ID #	**104756**	***Device Name***	**Fugitives: Gas - Unsafe**
Rated Heat Input		*Physical Size*	964 Component Leakpath
Manufacturer		*Operator ID*	3105-05
Model		*Serial Number*	
Location Note			
Device Description			

11.3 Fugitives: Oil - Controlled

Device ID #	**009601**	***Device Name***	**Fugitives: Oil - Controlled**
Rated Heat Input		*Physical Size*	3992.00 Component Leakpath
Manufacturer		*Operator ID*	3105-02
Model		*Serial Number*	
Location Note			
Device Description			

11.4 Fugitives: Oil - Unsafe

Device ID #	**104754**	***Device Name***	**Fugitives: Oil - Unsafe**
Rated Heat Input		*Physical Size*	14.00 Component Leakpath
Manufacturer		*Operator ID*	3105-03
Model		*Serial Number*	
Location Note			
Device Description			

12 Pigging Equipment

12.1 Pig Launcher - Gas

Device ID #	**009794**	***Device Name***	**Pig Launcher - Gas**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	Sp-134
Model		*Serial Number*	
Location Note			
Device Description	One gas pig launcher with 0.67’ diameter by 4’ long.		

12.2 Pig Launcher - Oil

Device ID #	**009792**	***Device Name***	**Pig Launcher - Oil**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	Sp-132
Model		*Serial Number*	
Location Note			
Device Description	One oil pig launcher with 0.67' diameter by 4' long.		

12.3 Pig Launcher - Utility

Device ID #	**009793**	***Device Name***	**Pig Launcher - Utility**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	Sp-133
Model		*Serial Number*	
Location Note			
Device Description	One utility gas pig launcher with 0.50' diameter by 4' long.		

13 Oil Pipeline to Shore

Device ID #	**009595**	***Device Name***	**Oil Pipeline to Shore**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	Line 6-PO-454-HC-D
Model		*Serial Number*	
Location Note			
Device Description			

14 Gas Pipeline to Shore

Device ID #	**009596**	***Device Name***	**Gas Pipeline to Shore**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	Line 6-PO-453-HC-E
Model		*Serial Number*	
Location Note			
Device Description			

15 Direct Contact Cooler

Device ID #	**009624**	***Device Name***	**Direct Contact Cooler**
Rated Heat Input		*Physical Size*	
Manufacturer	NALTE	*Operator ID*	V-126
Model	S1-77096	*Serial Number*	
Location Note			
Device Description	1’ dia. x 12’ long, 15 psi, 300°F.		

16 Chemical Injection System

16.1 Chemical Injection Tank

Device ID #	**009590**	***Device Name***	**Chemical Injection Tank**
Rated Heat Input		*Physical Size*	430.00 Gallons
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description			

16.2 Chemical Injection Tank

Device ID #	**009589**	***Device Name***	**Chemical Injection Tank**
Rated Heat Input		*Physical Size*	430.00 Gallons
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description			

16.3 Chemical Injection Tank

Device ID #	**009588**	***Device Name***	**Chemical Injection Tank**
Rated Heat Input		*Physical Size*	430.00 Gallons
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description			

16.4 Chemical Injection Tank

Device ID #	**009587**	***Device Name***	**Chemical Injection Tank**
Rated Heat Input		*Physical Size*	430.00 Gallons
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description			

16.5 Chemical Injection Tank

Device ID #	**009586**	***Device Name***	**Chemical Injection Tank**
Rated Heat Input		*Physical Size*	240.00 Gallons
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description			

16.6 Chemical Injection Tank

Device ID #	**009585**	***Device Name***	**Chemical Injection Tank**
Rated Heat Input		*Physical Size*	980.00 Gallons
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description			

16.7 Chemical Injection Pumps

Device ID #	**107279**	***Device Name***	**Chemical Injection Pumps**
Rated Heat Input		*Physical Size*	1.00 Horsepower (Electric Motor)
Manufacturer	Texstream	*Operator ID*	P-209/210
Model		*Serial Number*	
Location Note			
Device Description	1 hp each; Pumps put in service last year, replacing earlier pumps		

17 Pumps

17.1 Pipeline Shipping Pump

Device ID #	**107274**	***Device Name***	**Pipeline Shipping Pump**
Rated Heat Input		*Physical Size*	250.00 Horsepower (Electric Motor)
Manufacturer	REDA	*Operator ID*	P-200
Model		*Serial Number*	
Location Note			
Device Description	Oil shipping Pump, 20,000 gpm		

17.2 Firewater Pumps

Device ID #	**009571**	***Device Name***	**Firewater Pumps**
Rated Heat Input		*Physical Size*	60.00 Horsepower (Electric Motor)
Manufacturer		*Operator ID*	P-150A/B
Model		*Serial Number*	
Location Note			
Device Description	Two pumps, electric powered, 60 hp each.		

17.3 Stack Scrubber Pump

Device ID #	**107278**	***Device Name***	**Stack Scrubber Pump**
Rated Heat Input		*Physical Size*	6.00 Horsepower (Electric Motor)
Manufacturer		*Operator ID*	P-108
Model		*Serial Number*	
Location Note			
Device Description	Pumps stack scrubber liquid to surge vessel.		

17.4 Drain Sump Pump, T-1

Device ID #	**107276**	***Device Name***	**Drain Sump Pump, T-1**
Rated Heat Input		*Physical Size*	7.50 Horsepower (Electric Motor)
Manufacturer		*Operator ID*	P-202
Model		*Serial Number*	
Location Note			
Device Description	Pumps all deck drains to surge tank, 7.5 hp motor		

17.5 Drain Pump

Device ID #	**386624**	***Device Name***	**Drain Pump**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	P-147
Model		*Serial Number*	
Location Note			
Device Description			

17.6 Direct Contact Cooler Condensate Pumps

Device ID #	**107277**	***Device Name***	**Direct Contact Cooler Condensate Pumps**
Rated Heat Input		*Physical Size*	2.00 Horsepower (Electric Motor)
Manufacturer		*Operator ID*	P-107 A/B
Model		*Serial Number*	
Location Note			
Device Description	Handles water vapors from glycol skid; 40 gpm rated		

18 Omnipure Wastewater Treatment Skid

Device ID #	**009594**	***Device Name***	**Omnipure Wastewater Treatment Skid**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	X-100
Model		*Serial Number*	
Location Note			
Device Description			

19 Gas Dehydration

19.1 Glycol Absorber

Device ID #	**009633**	***Device Name***	**Glycol Absorber**
Rated Heat Input		*Physical Size*	
Manufacturer	Superior	*Operator ID*	V-115
Model	X-3963	*Serial Number*	
Location Note			
Device Description	5.66’ dia. x 20’ long, 325 psi, 200°F.		

19.2 Glycol Afterscrubber

Device ID #	**009634**	***Device Name***	**Glycol Afterscrubber**
Rated Heat Input		*Physical Size*	
Manufacturer	Superior	*Operator ID*	V-116
Model	X-3980	*Serial Number*	
Location Note			
Device Description	4’dia x 8.3’ long, 325 psi, 650°F.		

19.3 Glycol Flash Drum

Device ID #	**009635**	***Device Name***	**Glycol Flash Drum**
Rated Heat Input		*Physical Size*	
Manufacturer	Superior	*Operator ID*	V-123
Model	X-3965	*Serial Number*	
Location Note			
Device Description	4’ dia. x 7’ long, 125 psi, 600°F.		

19.4 Glycol Overhead Condenser

Device ID #	**009580**	***Device Name***	**Glycol Overhead Condenser**
Rated Heat Input		*Physical Size*	5.00 Horsepower (Electric Motor)
Manufacturer		*Operator ID*	E-101
Model		*Serial Number*	
Location Note			
Device Description	5 hp motor Listed as VaporCooler Exchanger, V-124		

19.5 Glycol Reboiler

Device ID #	**009623**	***Device Name***	**Glycol Reboiler**
Rated Heat Input		*Physical Size*	1.64 MMBtu/Hour
Manufacturer		*Operator ID*	V-125
Model		*Serial Number*	
Location Note			
Device Description	5’ dia, x 15’ long; uses 12 electric heaters, 40 kW each = 1.64 MMBtu/hr heat input.		

19.6 Glycol Reflux Column

Device ID #	**009631**	*Device Name*	**Glycol Reflux Column**
Rated Heat Input		*Physical Size*	
Manufacturer	Trico	*Operator ID*	V-124
Model	V-124	*Serial Number*	
Location Note			
Device Description	1.66’ dia. x 10’ long.		

19.7 Glycol Storage Reboiler

Device ID #	**009632**	*Device Name*	**Glycol Storage Reboiler**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	V-122
Model		*Serial Number*	
Location Note			
Device Description	3.5’ dia. x 15’ long, 2 psi, 600°F.		

20 Catalytic Converters/Filters

20.1 Catalyst

Device ID #	**111856**	*Device Name*	**Catalyst**
Rated Heat Input		*Physical Size*	
Manufacturer	Miratech	*Operator ID*	Catalytic Convertor #1
Model	EQ-801	*Serial Number*	
Location Note			
Device Description			

20.2 Catalyst

Device ID #	**111857**	***Device Name***	**Catalyst**
Rated Heat Input		*Physical Size*	
Manufacturer	Miratech	*Operator ID*	Catalytic Convertor #2
Model	EQ-801	*Serial Number*	
Location Note			
Device Description			

20.3 Catalyst

Device ID #	**111858**	***Device Name***	**Catalyst**
Rated Heat Input		*Physical Size*	
Manufacturer	Miratech	*Operator ID*	Catalytic Convertor #3
Model	EQ-3030	*Serial Number*	
Location Note			
Device Description			

20.4 Cuno Filter

Device ID #	**009636**	***Device Name***	**Cuno Filter**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	F-101
Model		*Serial Number*	
Location Note			
Device Description	1.33’ diameter x 3.5’ long.		

20.5 Oil Filters, VRU, C-100A, C-100B

Device ID #	**009605**	***Device Name***	**Oil Filters, VRU, C-100A, C-100B**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	F-113 A/B
Model		*Serial Number*	
Location Note			
Device Description	5.5' diameter x 1.66' long.		

20.6 Peco Filter

Device ID #	**009637**	***Device Name***	**Peco Filter**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	F-102
Model		*Serial Number*	
Location Note			
Device Description	2' diameter x 4.66' long		

20.7 Diesel Particulate Filter

Device ID #	**111508**	***Device Name***	**Diesel Particulate Filter**
Rated Heat Input		*Physical Size*	
Manufacturer	DCL International	*Operator ID*	
Model	Mine-X Sootfilter	*Serial Number*	136292
Location Note			
Device Description	DPF serving the Holly crane engine		

21 Surface Coating Operations

Device ID #	**005884**	***Device Name***	**Surface Coating Operations**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description	Including paints, primers, coatings solvents used for thinning and associated cleanup operations		

22 Electrical Motors

22.1 Motor: Compressor

Device ID #	**009666**	***Device Name***	**Motor: Compressor**
Rated Heat Input		*Physical Size*	1500.00 Horsepower (Electric Motor)
Manufacturer	Ingersoll-Rand	*Operator ID*	C-101
Model	4RDS-1	*Serial Number*	
Location Note			
Device Description	Capacity = 40 MMscf/day		

22.2 Motor: Direct Contact Cooler Condensate Pumps

Device ID #	**009645**	***Device Name***	**Motor: Direct Contact Cooler Condensate Pumps**
Rated Heat Input		*Physical Size*	
Manufacturer	Worthington	*Operator ID*	P-107 A/B
Model	D-512	*Serial Number*	
Location Note			
Device Description			

22.3 Motor: Gas Lift Compressor

Device ID #	**009664**	***Device Name***	**Motor: Gas Lift Compressor**
Rated Heat Input		*Physical Size*	1000.00 Brake Horsepower
Manufacturer	White Superior	*Operator ID*	C-102
Model	W-64	*Serial Number*	
Location Note			
Device Description	Capacity = 8.0 MMscf/day		

22.4 Motor: Drain Sump Pump, T-1

Device ID #	**009669**	***Device Name***	**Motor: Drain Sump Pump, T-1**
Rated Heat Input		*Physical Size*	7.50 Horsepower (Electric Motor)
Manufacturer	Moyund	*Operator ID*	P-202
Model	2L3SSFCAA	*Serial Number*	
Location Note			
Device Description	Capacity = 250 gal/minute		

22.5 Motor: Glycol Pumps

Device ID #	**009642**	***Device Name***	**Motor: Glycol Pumps**
Rated Heat Input		*Physical Size*	3.00 Horsepower (Electric Motor)
Manufacturer	Union	*Operator ID*	P-106 A/B
Model	Tx-10	*Serial Number*	
Location Note			
Device Description	888 gal/hr capacity each.		

22.6 Motor: Pipeline Shipping Pump

Device ID #	**009643**	***Device Name***	**Motor: Pipeline Shipping Pump**
Rated Heat Input		*Physical Size*	250.00 Horsepower (Electric Motor)
Manufacturer	Reda	*Operator ID*	P-200
Model	66CT/ES	*Serial Number*	
Location Note			
Device Description	Capacity = 583 gal/hour		

22.7 Stack Scrubber Pump

Device ID #	**009646**	***Device Name***	**Stack Scrubber Pump**
Rated Heat Input		*Physical Size*	1.00 Horsepower (Electric Motor)
Manufacturer	Dean	*Operator ID*	P-108
Model	PH-211	*Serial Number*	
Location Note			
Device Description			

22.8 Motor: VRU Scrubber Dump Pumps, C-100A/C-100B

Device ID #	**009644**	***Device Name***	**Motor: VRU Scrubber Dump Pumps, C-100A/C-100B**
Rated Heat Input		*Physical Size*	2.00 Horsepower (Electric Motor)
Manufacturer		*Operator ID*	P-105 A/B
Model		*Serial Number*	
Location Note			
Device Description			

22.9 Motor: Vapor Recovery Unit (VRU) Compressors

Device ID #	**009665**	***Device Name***	**Motor: Vapor Recovery Unit (VRU) Compressors**
Rated Heat Input		*Physical Size*	50.00 Horsepower (Electric Motor)
Manufacturer		*Operator ID*	C-100A, C-100B
Model		*Serial Number*	
Location Note			
Device Description	Electric motors 50 hp each, 0.250 MMscf/day capacity each compressor.		

23 Well Heads

Device ID #	**009626**	***Device Name***	**Well Heads**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description	2 gas-injection wells, 1 plugged/abandoned well.		

24 Vapor Recovery System

24.1 VRU Coalescer Filters, C-100A/C-100B

Device ID #	**009621**	***Device Name***	**VRU Coalescer Filters, C-100A/C-100B**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	F-112A/F-112B
Model		*Serial Number*	
Location Note			
Device Description	1.5’ diameter x 7.25’ long.		

24.2 VRU Suction Scrubbers, C-100A, C-100B

Device ID #	**009620**	***Device Name***	**VRU Suction Scrubbers, C-100A, C-100B**
Rated Heat Input		*Physical Size*	
Manufacturer	B.T. Corp	*Operator ID*	V-111A, V-111B
Model	B-756	*Serial Number*	
Location Note			
Device Description	1.5' dia x 5.8' long, 5 oz. pr., 104°F.		

B EXEMPT EQUIPMENT

1 VRU Aftercooler Exchangers

Device ID #	**009574**		***Device Name***	**VRU Aftercooler Exchangers**
Rated Heat Input			*Physical Size*	2.00 Horsepower (Electric Motor)
Manufacturer			*Operator ID*	E-101A, E-101B
Model			*Serial Number*	
Part 70 Insig?	Yes	*District Rule Exemption:* 202.L.1 Heat Exchangers		
Location Note				
Device Description	2 hp motor each			

2 Crankcase Oil Fill Pumps for C-100A

Device ID #	**009570**		***Device Name***	**Crankcase Oil Fill Pumps for C-100A**
Rated Heat Input			*Physical Size*	0.50 Horsepower (Electric Motor)
Manufacturer			*Operator ID*	P-117A, P-117B
Model			*Serial Number*	
Part 70 Insig?	Yes	*District Rule Exemption:* 202.V.9 Tank/Vessel/Pump Equipment For Storage/Disp		
Location Note				
Device Description	electric, 0.5 hp each.			

3 Diesel Transfer Pump

Device ID #	**009569**	***Device Name***	**Diesel Transfer Pump**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Part 70 Insig?	Yes	*District Rule Exemption:* 202.V.9 Tank/Vessel/Pump Equipment For Storage/Disp	
Location Note			
Device Description	Electric powered pump.		

4 VRU Oil Coolers, E-100A, -101A, -100B, -101B, C-100A, -100B

Device ID #	**009573**	***Device Name***	**VRU Oil Coolers, E-100A, -101A, -100B, -101B, C-100A, -100B**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	E-100A, E-100B
Model		*Serial Number*	
Part 70 Insig?	Yes	*District Rule Exemption:* 202.L.1 Heat Exchangers	
Location Note			
Device Description			

5 Diesel Day tank

Device ID #	**009566**	***Device Name***	**Diesel Day tank**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Part 70 Insig?	Yes	*District Rule Exemption:* 202.V.2 Storage Of Refined Fuel Oil W/Grav <=40 Api	
Location Note			
Device Description	less than 10,000 gallons		

6 Air Dryer Pre-Filters

Device ID #	**107291**	***Device Name***	**Air Dryer Pre-Filters**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	F-136 A/B
Model		*Serial Number*	
Part 70 Insig?	No	*District Rule Exemption:* 202.L.2 Air Cond/Vent Systm W/No Air Contaminant Removal	
Location Note			
Device Description	6 in dia by 24 in tall		

7 Air Dryers

Device ID #	**107287**	***Device Name***	**Air Dryers**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	V-136 A/B
Model		*Serial Number*	
Part 70 Insig?	No	*District Rule Exemption:* 202.L.2 Air Cond/Vent Systm W/No Air Contaminant Removal	
Location Note			
Device Description	1.5 ft dia by 4 ft tall		

8 Diesel Fuel tank

Device ID #	**009565**	***Device Name***	**Diesel Fuel tank**
Rated Heat Input		*Physical Size*	1500.00 Gallons
Manufacturer		*Operator ID*	T-111
Model		*Serial Number*	
Part 70 Insig?	Yes	*District Rule Exemption:* 202.V.2 Storage Of Refined Fuel Oil W/Grav <=40 Api	
Location Note			
Device Description			

9 Breathing Air Compressor

Device ID #	**107289**	***Device Name***	**Breathing Air Compressor**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	C-120
Model		*Serial Number*	
Part 70 Insig?	No	*District Rule Exemption:* 202.L.2 Air Cond/Vent Systm W/No Air Contaminant Removal	
Location Note			
Device Description	10 hp electric motor		

10 Fresh Air Blower - Maintenance Office

Device ID #	**107284**	***Device Name***	**Fresh Air Blower - Maintenance Office**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	BL-103
Model		*Serial Number*	
Part 70 Insig?	No	*District Rule Exemption:* 202.L.2 Air Cond/Vent Systm W/No Air Contaminant Removal	
Location Note			
Device Description	5 hp electric motor		

11 Fresh Air Blower East

Device ID #	**107283**	***Device Name***	**Fresh Air Blower East**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	BL-102
Model		*Serial Number*	
Part 70 Insig?	No	*District Rule Exemption:* 202.L.2 Air Cond/Vent Systm W/No Air Contaminant Removal	
Location Note			
Device Description	5 hp electric motor		

12 Fresh Air Blower West

Device ID #	**107282**	***Device Name***	**Fresh Air Blower West**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	BL-101
Model		*Serial Number*	
Part 70 Insig?	No	*District Rule Exemption:* 202.L.2 Air Cond/Vent Systm W/No Air Contaminant Removal	
Location Note			
Device Description	5 hp electric motor		

13 IR Aftercooler Exchanger, C-101

Device ID #	**009575**	***Device Name***	**IR Aftercooler Exchanger, C-101**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	E-102
Model		*Serial Number*	
Part 70 Insig?	Yes	*District Rule Exemption:* 202.L.1 Heat Exchangers	
Location Note			
Device Description			

14 Fresh Water Supply Pumps

Device ID #	**107288**	***Device Name***	**Fresh Water Supply Pumps**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	P-130 A/B
Model		*Serial Number*	
Part 70 Insig?	No	*District Rule Exemption:* 202.L.13 H2O Well/Filtration Sys/Reverse Osmosis	
Location Note			
Device Description	5 hp each, electric motor		

15 Rich/Lean Glycol Cooler Exchanger

Device ID #	**009579**	***Device Name***	**Rich/Lean Glycol Cooler Exchanger**
Rated Heat Input		*Physical Size*	1.00 Horsepower (Electric Motor)
Manufacturer		*Operator ID*	E-106A
Model		*Serial Number*	
Part 70 Insig?	Yes	*District Rule Exemption:* 202.L.1 Heat Exchangers	
Location Note			
Device Description	1 hp motor		

16 W-S 1st-Stage Aftercooler Exchanger for Gas Lift Comp, C-102

Device ID #	**009576**	***Device Name***	**W-S 1st-Stage Aftercooler Exchanger for Gas Lift Comp, C-102**
Rated Heat Input		*Physical Size*	15.00 Horsepower (Electric Motor)
Manufacturer		*Operator ID*	E-103
Model		*Serial Number*	
Part 70 Insig?	Yes	*District Rule Exemption:* 202.L.1 Heat Exchangers	
Location Note			
Device Description			

17 Platform Air Compressors

Device ID #	**107285**	***Device Name***	**Platform Air Compressors**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	C-110 A/B
Model		*Serial Number*	
Part 70 Insig?	No	*District Rule Exemption:* 202.L.2 Air Cond/Vent Systm W/No Air Contaminant Removal	
Location Note			
Device Description	20 hp electric motor each		

18 W-S 2nd-Stage Aftercooler Exchanger for Gas Lift Comp, C-102

Device ID #	**009577**	***Device Name***	**W-S 2nd-Stage Aftercooler Exchanger for Gas Lift Comp, C-102**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	E-104
Model		*Serial Number*	
Part 70 Insig?	Yes	*District Rule Exemption:* 202.L.1 Heat Exchangers	
Location Note			
Device Description			

19 Rich/Lean Glycol Aftercooler Exchanger

Device ID #	**107270**	***Device Name***	**Rich/Lean Glycol Aftercooler Exchanger**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	E-106
Model		*Serial Number*	
Part 70 Insig?	No	*District Rule Exemption:* 202.L.1 Heat Exchangers	
Location Note			
Device Description	No description		

20 W-S 3rd-Stage Aftercooler Exchanger for Gas Lift Comp, C-102

Device ID #	**009578**	***Device Name***	**W-S 3rd-Stage Aftercooler Exchanger for Gas Lift Comp, C-102**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	E-105
Model		*Serial Number*	
Part 70 Insig?	Yes	*District Rule Exemption:* 202.L.1 Heat Exchangers	
Location Note			
Device Description			

21 Utility Air Compressor

Device ID #	**107286**	***Device Name***	**Utility Air Compressor**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	C-110 C
Model		*Serial Number*	
Part 70 Insig?	No	*District Rule Exemption:* 202.L.2 Air Cond/Vent Systm W/No Air Contaminant Removal	
Location Note			
Device Description	10 hp electric motor		