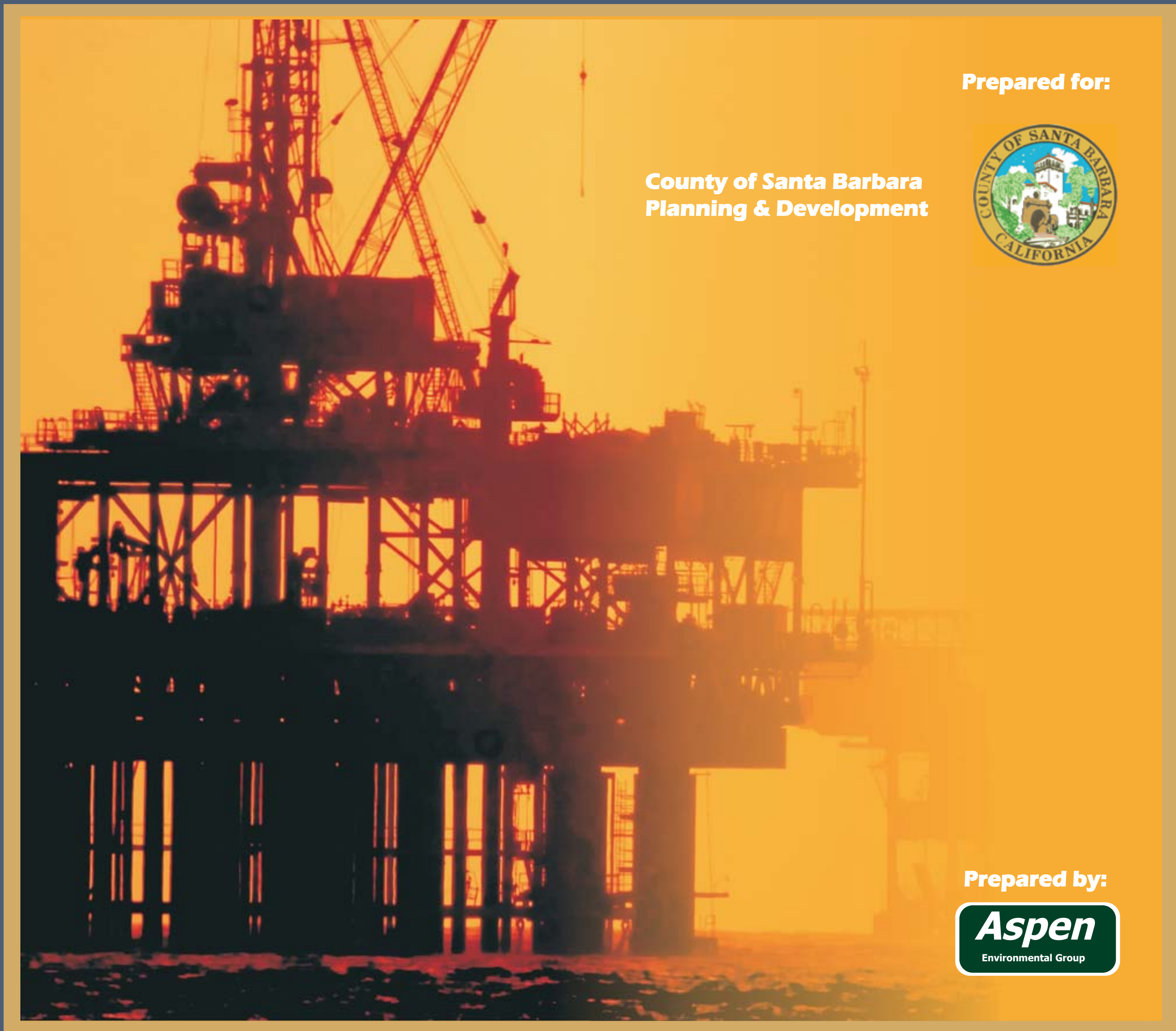
Environmental Impact Report



Prepared for:

County of Santa Barbara
Planning & Development

Prepared by:

Aspen Environmental Group

County of Santa Barbara
PLANNING AND DEVELOPMENT

FINAL ENVIRONMENTAL IMPACT REPORT FOR THE PROPOSED TRANQUILLON RIDGE PROJECT

(SCH #2006021055; County EIR #06EIR-00000-00005)

PROJECT DESCRIPTION: Plains Exploration and Production Company (PXP) is requesting a permit modification (County Case #06RVP-00000-00001) to allow introduction of Tranquillon Ridge oil and gas production from State waters into the existing Point Pedernales Project. The existing Platform Irene, its associated offshore and onshore oil and gas pipelines, the Surf electrical substation, and the Lompoc Oil and Gas Plant (LOGP) would be used to produce, process and transport the Tranquillon Ridge production which would be commingled with current Federal production. These existing facilities have been in operation since 1987. The proposal analyzed in the EIR would require minor modifications to existing equipment, increase production levels above existing levels, and extend the operating life of the original Point Pedernales Project by about 30 years. The project location is offshore Vandenberg Air Force Base and onshore from Wall/Surf Beach to the LOGP, north of Lompoc and west of Santa Maria, in northern Santa Barbara County (Third and Fourth Supervisorial districts).

ENVIRONMENTAL REVIEW: As Lead Agency, the Santa Barbara County Planning and Development Department (P&D) prepared a Draft Environmental Impact Report pursuant to requirements of the State Guidelines for Implementation of the California Environmental Quality Act (CEQA) and the County of Santa Barbara Guidelines for Implementation of CEQA. The Draft EIR was circulated for public review and comment from November 1, 2006 through January 16, 2007. Santa Barbara County P&D held a workshop on the Draft EIR on November 15, 2006 and a public comment hearing on December 11, 2006. Written comments, comments made at the December 2006 hearing, and responses to the comments are included in Section 9.0 of the Final EIR. In addition, revisions to the EIR text were made in several places. These revisions are noted by ~~strikethrough~~ and underline text in the Final EIR. (Minor edits, such as corrections of typographical or spelling errors, are not shown.)

The EIR identifies and discusses potential impacts, mitigation measures, residual impacts and monitoring requirements for identified subject areas. Significant effects on the environment are anticipated in the following areas: marine and terrestrial biology, marine and onshore water resources, fishing, recreation, cultural, agricultural, visual, and geological resources, and public safety.

If you challenge this environmental document in court, you may be limited to raising only those issues raised by you or others in written correspondence or in hearings on the proposed project.

PUBLIC HEARING: The Final EIR will be considered by the County Planning Commission in its deliberations on the proposed project at a public hearing. This hearing is currently scheduled for Monday, April 21, 2008 at the Betteravia Government Center in Santa Maria, beginning at 9:00 a.m. You are invited to comment on the merits of the proposed project prior to or at this hearing. Separate notice of the hearing will be sent by April 11, 2008 and posted on the Energy Division's website: www.countyofsb.org/energy/projects/PlainsPedernales.asp. If you received this notice in the mail, you will also receive a mailed notice of the Planning Commission hearing.

DOCUMENT AVAILABILITY: The Final Environmental Impact Report may be reviewed at the P&D offices located at 123 E. Anapamu Street, Santa Barbara and at the Energy Division website. The Final EIR is also available for review at these public libraries: Lompoc (501 E. North Ave.), Vandenberg Village (3755 Constellation Rd.), Santa Maria (420 S. Broadway), and Santa Barbara (40 E. Anapamu St.).

STAFF CONTACT: Kevin Drude, Energy Specialist, (805) 568-2519, Kevin@co.santa-barbara.ca.us.

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List of Abbreviations and Acronyms

ADT	Average Daily Traffic
AADT	Annual Average Daily Trips
AADT	Annual Average Daily Traffic
AAPL	All American Pipeline
AFY	acre-feet/year
ANSI	American National Standards Institute
APCD	Air Pollution Control District
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
ATC	Authority to Construct
AQAP	Air Quality Attainment Plan
Bbls	barrels
BMP	best management practices
Bod	biological oxygen demand
bpd	barrels per day
BTEX	benzene, toluene, ethylbenzene and xylenes
CAAQS	California Air Quality Standards
CalCOFI	California Cooperative Oceanic Fisheries Investigations
CaMP	California Monitoring Program
CAMP	California Offshore Monitoring Program
CAP	Clean Air Plan
CARB	California Air Resources Board
CCAA	California Clean Air Act
CCC	California Coastal Commission
CCCCS	Central California Coastal Circulation Study
CCIC	Central Coastal Information Center
CCMP	California Coastal Management Program
CCPS	Center for Chemical Process Safety
CDFG	California Department of Fish and Game
CDMG	California Division of Mines and Geology
CDOGGR	California Division of Oil, Gas, and Geothermal Resources
CEQ	Council on Environmental Quality
CEQA	California Environmental Quality Act
CESA	California Endangered Species Act
CFR	Code of Federal Regulations
cfs	cubic feet per second
CH_4	Methane
CHL	California State Historic Landmark
CINMS	Channel Islands National Marine Sanctuary
CNDDB	California Natural Diversity Database
CNEL	Community Noise Equivalent Level

CNPS	California Native Plant Society
CO	carbon monoxide
CO_2	carbon dioxide
COOGER	California Offshore Oil and Gas Energy Resources
CPFV	commercial passenger fishing vessel
CSFM	California State Fire Marshal
CSLC	California State Lands Commission
CSC	California Species of Concern
CV	check valve
CWA	Clean Water Act
CZARAA	Coastal Zone Act Reauthorization Amendments
CZM	Coastal Zone Management
CZMA	Coastal Zone Management Act
dB	decibel
dBA	decibel A-weighted
DFG	Department of Fish and Game
DOCD	Development Operations Coordination Documents
DOGGR	Division of Oil, Gas, and Geothermal Resources
DOT	Department of Transportation
DPP	Development and Production Plan
EDL	elevated data levels
EFH	Essential Fish Habitat
EIR	Environmental Impact Report
EIS	Environmental Impact Study
ERD	extended-reach drilling
ERL	effects range-low
ERM	effects range-medium
ERP	Emergency Response Plan
ERPG	Emergency Response Planning Guidelines
ERW	electric resistance weld
ESA	Endangered Species Act
ESD	emergency shutdown
ESE	Entire Source Emissions
<u>ESU</u>	<u>Evolutionarily Significant Unit</u>
FAA	Federal Aviation Administration
FBE	Fusion bonded epoxy
FDP	Final Development Plan
FHWA	Federal Highway Administration
FMC	Fishery Management Council
FMP	Fishery Management Plan
FSC	Federal Species of Concern
FT	flow transmitter
FWKO	Free Water Knock-Out
FWPCA	Federal Water Pollution Control Act
GHG	greenhouse gases

Gpd	Gallons per day
H_2S	hydrogen sulfide
HAP	Hazardous Air Pollutants
Hg	Mercury
hp	horse power
HS&P	Heating, Separation and Pumping [Facility]
HVL	Highly Volatile Liquids
IC	Incident Commander
IRI	Industrial Risk Insurers
JRP	Joint Review Panel
kV	kilovolt
LCP	Local Coastal Program
LOGP	Lompoc Oil and Gas Plant
LOS	Level of Service
LPG	Liquefied petroleum gas
LTS	low temperature separation
m	meters
M	million
MAOP	maximum allowable operating pressure
mbd	thousand barrels per day
MCE	Maximum Credible Earthquakes
MGD	million gallons per day
mg/kg	milligrams per kilogram
MLLW	mean lower low water
mm	millimeters
MMPA	Marine Mammals Protection Act
MMS	Minerals Management Service
mmscfd	million standard cubic feet per day
MMTCE	million metric tons of carbon equivalent
MOV	motor actuated valve
mph	miles per hour
MSFCMA	Magnuson-Stevens Fishery Conservation and Management Act
N_2O	nitrous oxide
NAAQS	National Air Quality Standards
NACE	National Association of Corrosion Engineers
NAROC	Non-Alkaline Reactive Organic Compounds
NDBC	NOAA Data Buoy Center
NEC	National Electric Code
NEPA	National Environmental Policy Act
NFPA	National Fire Protection Association
NGL	natural gas liquids
NHL	National Historic Landmark
NHPA	National Historic Preservation Act
NMFS	National Marine Fisheries Service
NO	nitric oxide

NO_2	nitrogen dioxide
NOAA	National Oceanic and Atmospheric Administration
NOP	Notice of preparation
NO_x	oxides of nitrogen
NPDES	National Pollutant Discharge Elimination System
NRHP	National Register of Historic Places
NS&T	National Status and Trends
O_3	ozone
OCS	Outer Continental Shelf
OCSLA	Outer Continental Shelf Lands Act
OD	outer diameter
OPA	Oil Pollution Act
OPS	Office of Pipeline Safety
OPUS	Organization of Persistent Upwelling Structures
OSCP	Oil Spill Contingency Plan
OSMB	Offshore Santa Maria Basin
OSPR	Oil Spill Prevention and Response
OSRA	Oil Spill Risk Analysis
OSRP	Oil Spill Response Plan
PAH	poly-aromatic hydrocarbons
PANGL	Point Arguello Natural Gas Pipeline
PAPCO	Point Arguello Pipeline Company
pCi/L	picoCurries/liter
PEL	probable effects level
PLC	Programmable Logic Controller
PM	particulate matter
POPCO	Pacific Offshore Pipeline Company
ppb	parts per billion
ppm	parts per million
psig	pounds per square inch
PT	pressure transmitter
PTO	Permit to Operate
PXP	Plains Exploration and Production Company
ROC	reactive organic compounds
ROG	reactive organic gases (see ROC)
ROP	Rate of Progress Plan
ROW	right of way
RTU	Remote Terminal Unit
RVP	Reid vapor pressure
RWQCB	Regional Water Quality Control Board
SBCAPCD	Santa Barbara County Air Pollution Control District
SBC	Santa Barbara County
SBCh	Santa Barbara Channel
SBCFD	Santa Barbara County Fire Department
SBCP&D	Santa Barbara County Planning & Development Department

SCADA	supervisory control and data acquisition system
SCCAB	South Central Coast Air Basin
SCCPA	South Coast Consolidation Planning Area
SCGC	Southern California Gas Company (aka The Gas Company)
SDV	shutdown valve
SEIR	Supplemental Environmental Impact Report
SFA	Sustainable Fisheries Act
SFSCC	Santa Fe Springs Control Center
SIMQAP	Safety Inspection, Maintenance and Quality Assurance Program
SLC	(California) State Lands Commission
SLOB	San Luis Obispo Bay
SMB	Santa Maria Basin
SMW	State Mussel Watch
SO_2	sulfur dioxide
SOO	Suspension of Operation
SOP	Suspension of Production
SO_x	oxides of sulfur
SPCC	Spill Prevention Control and Countermeasures
SPCP	Spill Prevention and Cleanup Plan
SSLO	South San Luis Obispo
SSRRC	System Safety and Reliability Review Committee
SWPPP	Storm Water Pollution Prevention Plan
SWRCB	State Water Resource Control Board
TAC	Toxic Air Contaminants
TDS	total dissolved solids
TEL	threshold effects level
TOC	total oxygen content
TMDL	Total Maximum Daily Load
TMP	Traffic Management Plan
UCSB	University of California – Santa Barbara
UFC	Uniform Fire Code
UNOCAP	Unocal California Pipeline Company
USDOI	U.S. Department of Interior
USEPA	U. S. Environmental Protection Agency
USFWS	U.S. Fish and Wildlife Service
USMR	Unocal Santa Maria Refinery
VAFB	Vandenberg Air Force Base
VCE	vapor cloud explosion
WDP	Waste Discharge Permit
WIS	Wave Information Study
YOY	young of the year

Final

Environmental Impact Report

Tranquillon Ridge Oil and Gas Development Project

County EIR #: 06-EIR-000000-00005
State Clearinghouse No. 2006021055

Volume 1 – Main Document

Prepared for:

County of Santa Barbara Planning & Development

April 2008

Prepared by:

Aspen Environmental Group

EXECUTIVE SUMMARY

This Environmental Impact Report (EIR) assesses the environmental impacts associated with the Tranquillon Ridge Oil and Gas Development Project ("Tranquillon Ridge Project"). Plains Exploration and Production Company (PXP) is the Applicant. The location of the proposed project is shown in Figure ES-1.

This EIR is an informational document that is being used by the general public and governmental agencies to review and evaluate the proposed project. The reader should not rely exclusively on the Executive Summary as the sole basis for judgment of the proposed project and alternatives. The complete EIR should be consulted for specific information about the environmental effects and associated mitigation measures. The Executive Summary consists of the following sections:

- ~~The drilling of 22 to 30 new wells for oil and gas production and utility use such as water injection and redrills.~~
- An introduction, which discusses the various governmental agencies that participated in preparation of this EIR.
- A brief description of the proposed project.
- A brief description of the alternatives evaluated throughout this EIR.
- A discussion of how the environmental setting (i.e., baseline) was established for the proposed project.
- A summary of key impacts for the proposed project and the alternatives.
- A discussion of the environmentally superior alternative.

A set of Impact Summary Tables is provided at the end of the Executive Summary. These tables summarize the impacts and mitigation measures for the proposed project, alternatives, and cumulative projects. In addition, tables are provided that present a comparison of the various alternatives to the proposed project. The impacts and mitigation measures are discussed in detail in Chapter 5 of the EIR.

ES.1 Introduction

The purpose of the Executive Summary and Impact Summary Tables is to provide the reader with a brief overview of the proposed project, the anticipated environmental effects, and the potential mitigation measures that could reduce the severity of the impacts associated with the project. The reader is encouraged to review the complete EIR for further detail.

Santa Barbara County (SBC), as lead agency under the California Environmental Quality Act (CEQA), prepared a Scoping Document for the proposed project and determined that an EIR would be required as part of the permitting process for the proposed project. In compliance with CEQA Guidelines, SBC solicited public and agency comments through distribution of a Notice of Preparation (NOP). A public workshop was held on March 29, 2006, in Lompoc to provide an opportunity for the public to comment on the scope of the EIR. The Scoping Document and comments received in response to the NOP are included as Appendix K, and were used to help direct the scope of the analysis and the technical studies in this EIR.

A number of State, Federal, and local governmental agencies require an environmental analysis of the proposed project consistent with the requirements of CEQA in order to act on the project. These agencies include SBC, the California State Lands Commission (CSLC), and the California Coastal Commission (CCC). These governmental agencies have formed a Joint Review Panel (JRP) to oversee the environmental review process. Each of these agencies will use the document as part of its decision-making process. In addition, the Minerals Management Service (MMS), the Santa Barbara County Air Pollution Control District (SBCAPCD), and Vandenberg Air Force Base (VAFB) are serving on the JRP in an advisory role.

ES.2 Proposed Project

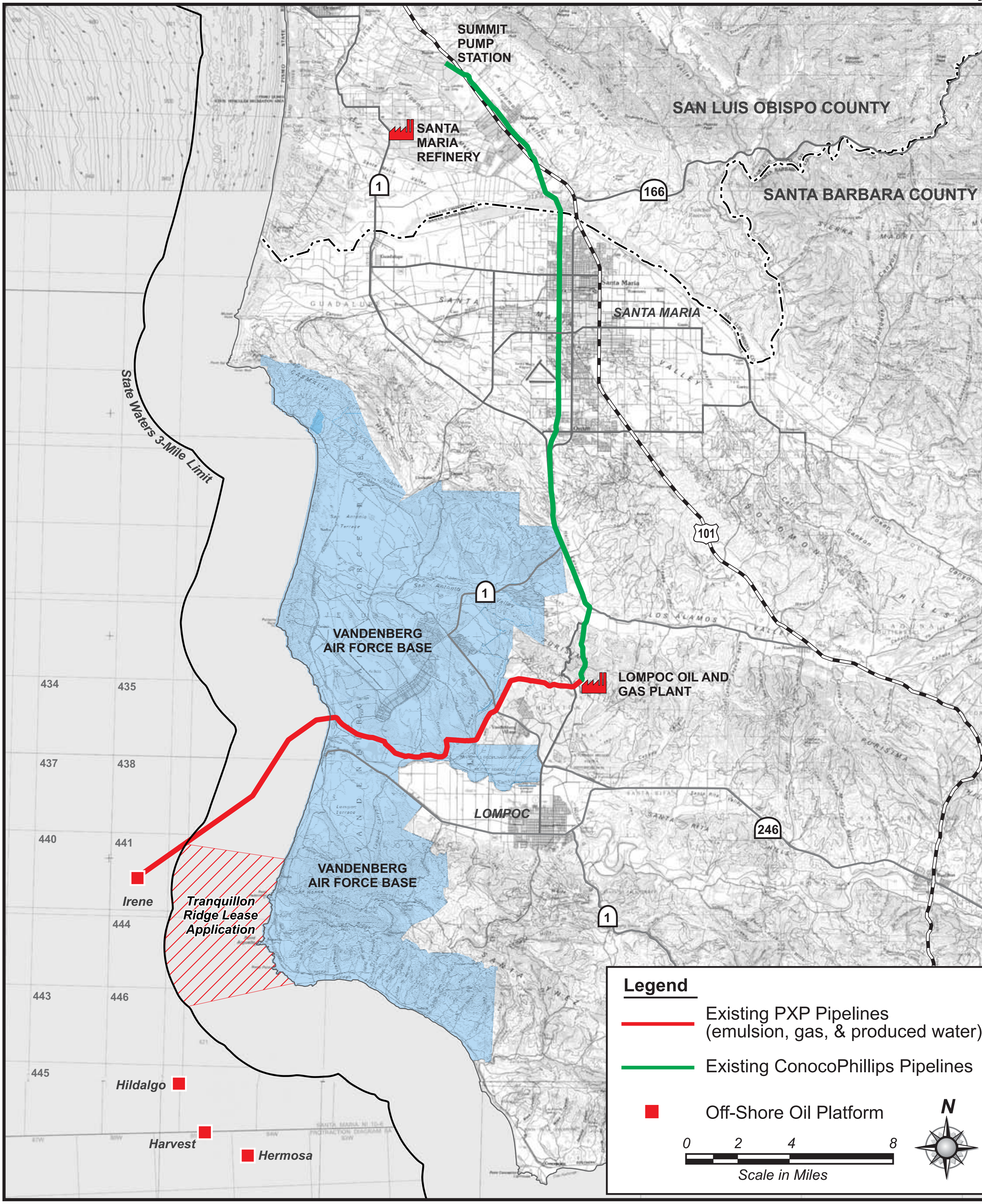
The proposed Tranquillon Ridge Project would involve the development of oil and gas wells from Platform Irene into the Tranquillon Ridge Field, the majority of which is located in State waters (see Figure ES-1). Platform Irene is located in Federal waters and is currently used to develop and produce the Point Pedernales Field also located in Federal waters. At Platform Irene, the produced oil and gas from the Tranquillon Ridge Field would be commingled with the Point Pedernales oil and gas, and sent ashore via existing pipelines from Platform Irene to the Lompoc Oil and Gas Plant (LOGP), located just north of Lompoc. Based on the applicant's data, the proposed project will have an expected total life of approximately 30 years once the first well is drilled.

The main objective of the proposed Tranquillon Ridge Project is to efficiently and effectively develop oil and gas reserves from the Tranquillon Ridge Field and to sell the oil and gas production to help meet the energy demands of the State of California. If implemented, this project will provide an additional supply of crude oil and natural gas to California. It is also the applicant's objective to develop the State portion of the Tranquillon Ridge Field from an existing platform in Federal waters using extended reach drilling and to transfer and process the produced oil and gas using existing pipelines and LOGP, respectively, which serves to minimize environmental impacts.

In order to implement this project, PXP, owner of the Point Pedernales Project, is requesting modifications to the SBC Point Pedernales Project Final Development Plan (FDP) to include development (drilling and production operations) of a proposed California State Lease (Tranquillon Ridge Field). The current FDP (see Appendix M) only allows for the processing of oil and gas from the four Point Pedernales Federal leases. PXP has also applied to the CSLC for the issuance of a lease of State Tidelands for the purposes of oil and gas development. A lease from the CSLC is required to drill into the portions of the Tranquillon Ridge Field that lie within the State Tidelands.

Development and production of the Tranquillon Ridge Field would result in the following.

- The drilling of 22 to 30 oil and gas production wells from Platform Irene into the Tranquillon Ridge Field.
- An increase in oil and gas throughput in the existing Point Pedernales facilities over what is occurring today, but within the limits allowed under the FDP. (The FDP allows up to 36,000 barrels (bbls) of oil and 15 million standard cubic feet per day [mmscfd] of gas from the four Point Pedernales Federal leases and onshore Lompoc Field [gas only].) The average 2005 production from Platform Irene was 7,000 barrels per day (bpd) of oil and 2.6 mmscfd of gas. Peak production from Platform Irene with the Tranquillon Ridge Project is estimated to be about 30,000 bpd of oil and 6 mmscfd of gas.



PREPARED BY Aspen Environmental Group

Figure ES-1
Proposed Project Location

- The possible installation of new oil booster pumps on the oil emulsion pipeline from Platform Irene to the LOGP at Valve Site #2. Installation of a new electrical power line to Valve Site #2 to provide power to the new booster pumps, if they are installed.
- A possible 15 year extension in the estimated life of the LOGP and 30 year extension of estimated life of Platform Irene from what was assumed in the 1985 Point Pedernales EIR/EIS and the 1993 Point Pedernales Subsequent EIR (SEIR).

Total recoverable reserves from the Tranquillon Ridge Project have been estimated to be 170 to 200 million bbls of oil and 40 to 50 billion standard cubic feet of gas.

ES.3 Description of Project Alternatives

Alternatives to the proposed project have been developed per CEQA Guidelines Section 15126.6. This EIR has used an alternative screening analysis to limit the number of alternatives evaluated in detail throughout the EIR. The use of an alternative screening analysis provides the detailed explanation of why some of the alternatives were rejected for further analysis, and assures that only potentially environmentally preferred alternatives are evaluated and compared in the EIR. The following are alternatives selected as part of the screening analysis. Section 3.0 of the EIR provides a complete description of all alternatives considered in the screening analysis.

No Project Alternative

Under the No Project Alternative, production of the Point Pedernales Field would continue through the economic life of the project, estimated to be year 2017. In addition, the existing PXP pipelines and the Lompoc Oil and Gas Plant (LOGP) would continue to be used to transport and process the produced emulsion and gas, respectively. Produced water would continue to be treated at the LOGP and sent back to Platform Irene for disposal, although for the next few years it is assumed that a portion of the produced water would be injected into the onshore Lompoc Field. Under the No Project Alternative there would be no extension of life of the Point Pedernales facilities.

Under the No Project Alternative, the portion of the Tranquillon Ridge Field located in Federal waters would continue to be developed from Platform Irene using Well A-28. PXP has stated that no additional wells would be drilled from Platform Irene to develop the Federal portion of the field unless reservoir geology and future economics warrant otherwise. However, there is the possibility that the Tranquillon Ridge Field could be developed from an onshore site, as currently proposed by Sunset/ExxonMobil, in the event the proposed project is not implemented. Throughout this EIR, ~~an~~ a conceptual onshore drilling alternative is addressed as the Vandenberg Air Force Base (VAFB) Onshore Alternative. This alternative should not be confused with the Sunset/ExxonMobil proposal.

By year 2017, it is assumed that the production volumes from the Point Pedernales field would no longer be economically viable. At that time, Platform Irene; the emulsion, gas, and produced water pipelines; and LOGP would be decommissioned and removed. This abandonment effort would undergo separate Santa Barbara County (SBC) environmental review and permitting and is not considered part of the No Project Alternative.

It should be noted that there is a possibility the Tranquillon Ridge Field could be developed by others from an onshore location, should the proposed project not be implemented. The discussions of the potential effects of the No Project Alternative do not address this situation. Potential environmental impacts that could result from such development are considered under the VAFB Onshore Alternative, but only at a conceptual level. The conceptual VAFB Onshore Alternative evaluated in this EIR was developed based on certain assumptions regarding potential project components, as described in Section 3.0, and may not reflect all details of an actual proposal. In addition, some impacts ascribed to the VAFB Onshore Alternative herein may or may not be expected to occur for a differently configured onshore drilling and production proposal. Detailed analysis of a specific proposed onshore drilling and production project would occur through a separate environmental review process for that project.

VAFB Onshore Alternative

The VAFB Onshore Alternative would involve the development of a new oil and gas drilling and production facility on southern VAFB near the coastline, approximately seven miles south of the Santa Ynez River. In addition, 10 miles of emulsion and gas pipelines would be constructed in a common corridor from the new drilling/production site to the existing PXP pipelines just north of the Santa Ynez River and west of 13th Street. To provide power to the drilling/production facility, a six mile transmission line would be constructed from a new substation adjacent to the existing Surf substation, located near the coastline just south of Ocean Park, to the drilling/production site. A tie-in station would also be constructed just west of 13th Street to connect the VAFB Onshore Alternative to~~would~~ ~~use~~ the existing PXP pipelines~~from the tie-in point, just west of 13th Street, to the LOGP~~. An approximate one-mile power line and substation would also be needed to provide power to the tie-in station. ~~In addition,~~The LOGP would be utilized to process the oil emulsion and gas production, the same as the proposed project. Produced water would either be treated and re-injected at the VAFB drilling/production site or sent to Platform Irene for re-injection or ocean discharge. Over the short-term, a portion of the produced water may be re-injected into the onshore Lompoc Field. Maintenance of the existing PXP pipelines would be conducted in accordance with the Safety, Inspection, Maintenance and Quality Assurance Program as discussed in Section ES-4.

Casmalia Processing Site Alternative

The SBC North County Siting Study identified several onshore processing locations that could serve as possible consolidated oil and gas processing facilities in the North County (North County Siting Study, October 2000). Specifically, potential sites in the Casmalia oil field and Casmalia Canyon are more rural and would potentially result in lower impacts than the LOGP facility. Oil and gas processing at the Casmalia East site would require the construction of completely new processing facilities and additional pipelines. Approximately 10 to 15 miles of new wet oil and sour gas pipelines would need to be constructed from the LOGP to the Casmalia site. In addition, a new gas compressor station and wet oil/produced water pump station would need to be built at the LOGP site to move the wet oil and sour gas to the Casmalia site and the produced water back to Platform Irene for disposal. The primary objective of this alternative would be to eliminate the majority of the LOGP.

New Emulsion Pipeline from Platform Irene to the LOGP Alternative

Under this alternative, the emulsion pipeline between Platform Irene and the LOGP would be replaced with a new pipeline of the same diameter and within the existing pipeline right-of-way. The primary objective of this alternative would be to address potential impacts associated with the integrity of the existing pipeline as a result of the increased throughput and extended project life associated with the proposed project. This newer pipeline would allow for the operation of the pipeline at higher pressures and therefore may eliminate the need for the Valve Site #2 pumps and associated power lines.

Alternative Power Line Routes to Valve Site #2

The proposed Tranquillon Ridge Project may require the construction of new power lines to Valve Site #2 to power three 1,250 horse-power (hp) electrical booster pumps that are proposed to be installed on the 20-inch oil pipeline between Platform Irene and the LOGP. These pumps and associated power line would ~~only~~ be needed if the oil pipeline's working pressure has to be derated below 1,000 pounds per square inch gauge (psig) sometime in the future. The proposed power line route would deliver power from an existing power line located on Ocean Avenue, using new power poles that would run from Ocean Avenue to Valve Site #2. Three different alternative power line routes have been evaluated in this EIR. Two of the alternative routes involve alternate locations/methods of crossing the Santa Ynez River. One of the alternatives involves undergrounding the power lines along a portion of the route to Valve Site #2.

Alternative Muds and Cuttings Disposal Options

The applicant has proposed to discharge the drill muds and cuttings to the ocean in accordance with the existing National Pollutant Discharge Elimination System (NPDES) permit. One of the alternatives would involve collecting and injecting the muds and cuttings into an appropriate underground reservoir for disposal. Equipment required to inject the drill muds and cuttings would include a holding tank, pulverizing pump, injection pump, and piping connections to an injection well head on a dedicated disposal well.

Injecting all drilling muds and cuttings into underground formations can be difficult to achieve in some offshore oil fields. Even after extensive pretreatment of the muds and cuttings, including grinding and dilution, the solids content can quickly plug most permeable formations after initial pumping. Consequently, injection is unusual on the Pacific Outer Continental Shelf. However, it is currently being practiced on the Exxon Santa Ynez Unit platforms in the Santa Barbara Channel. The efficacy of this approach is dependent on the availability of suitable underground formations.

The other alternative would be to move the muds and cuttings via boat to shore for disposal at an approved site. During drilling, drill muds and cuttings would be emptied into Coast Guard-approved closed top tanks and sent to shore via supply boat instead of discharged to the ocean as in the proposed Tranquillon Ridge Project. Once ashore, trucks would transport the used drill muds and cuttings to an approved disposal site or, if feasible, to a facility for recycling. The muds and cuttings would be transported ashore on the return trip of the regularly scheduled supply boat trips. No special boats would be needed.

ES.4 Environmental Setting (i.e., Baseline) Determination

The proposed project is unique in that it represents changes to existing facilities and operations, rather than construction and operation of entirely new facilities. These existing facilities are considered part of the environmental setting (i.e., baseline), for evaluating the environmental effects of the proposed project. The baseline should normally be the physical environmental conditions in the vicinity of the project, as they exist at the time the NOP is published (CEQA Guideline Section 15125). Where a proposed project will modify an existing project, it is important that the baseline also consider historic operations of the existing project based upon "normal fluctuations" as determined by need, capacity and other relevant factors.

The Point Pedernales facilities are currently and will be maintained according to the Point Pedernales Safety, Inspection, Maintenance, Quality Assurance Program (SIMQAP). Current pipeline operations include performing ongoing routine internal and external pipeline surveys. Pipeline surveys include, but are not limited to, smart pigging[1], corrosion checks, pressure tests, air and ground patrols, visual surveys using a video camera, and cathodic protection surveys. These periodic internal and external pipeline inspections are performed on a schedule specified by Minerals Management Service (MMS), SBC, and Santa Barbara County Air Pollution Control District (SBCAPCD) permits, and PXP policy. These inspections also satisfy the requirements of the Department of Transportation (DOT) and the California State Fire Marshal (CFSM) for portions of the pipelines. In addition, the County Systems Safety Reliability Review Committee (SSRRC) conducts an annual SIMQAP audit and approves all facility/operation plans and future modifications.

All of the existing facilities have permits that specify maximum operating levels. However, a number of these facilities are not currently operating or could not be expected to feasibly operate, at the maximum levels allowed by the permits. Since permitted operating levels differ from actual operating levels, the baseline that was used in the EIR analysis reflects current operations.

The existing Point Pedernales facilities are currently used to handle the oil and gas production from the Point Pedernales Field. The baseline for the Tranquillon Ridge Project in this EIR reflects the existing Point Pedernales facilities operating at the oil and gas production levels experienced at the time of issuance of the NOP (December 2005) and not the permitted levels, which were never achieved with the Point Pedernales Project. This baseline was used for the following reasons:

- Oil and gas reserves in this field are diminishing (average 2005 production was 7,000 bpd of dry oil and 2.6 mmscfd of gas);
- The 1985 Point Pedernales EIR/EIS did not consider the environmental impacts of processing future projects at the LOGP to a permit level of detail; and
- The FDP permit conditions limit throughput at the LOGP to oil and gas from only the four Federal leases that make up the Point Pedernales Unit and gas from the onshore Lompoc Field production.

The baseline for the expected life of the Point Pedernales facilities is the same as assumed in the 1985 Point Pedernales EIR/EIS and the 1993 Point Pedernales SEIR. As discussed in Section 2.2.6, the original Point Pedernales Field EIR/EIS projected a 20 year life for Platform Irene and

[1] A smart pig is an internal device that is run through the pipeline on a periodic basis to check for pipeline anomalies, including reduction in pipeline wall thickness. PXP utilizes a high-resolution smart pig that detects metal losses and pipe thickness along the pipeline.

30 to 35 year life for the original Lompoc Heating, Separation and Pumping Facility (HS&P). The 1993 Point Pedernales SEIR projected a 10 to 25 year life for the gas plant at the Lompoc site. Based on the applicant's projection of an approximate 30-year life for the Tranquillon Ridge Project, the Point Pedernales facilities life expectancy would be extended by 15 years for the LOGP and 30 years for Platform Irene beyond what was assumed in the previous environmental documents.

Tables ES.1 and ES.2 summarize the changes that the Tranquillon Ridge Project would have on existing Point Pedernales facility operations as compared to the operating levels at the time of issuance of the NOP and various permitted levels.

Table ES.1 Summary of Point Pedernales Facility Changes due to Tranquillon Ridge Project

Project Component	Permitted Operating Level	Operating Level at Time of Issuance of NOP	Proposed Operating Level for Tranquillon Ridge	Net Increase (Current to Proposed)
Dry Oil (bpd)	36,000[a]	7,000[b]	30,000	23,000
Gas (mmscfd)	15[c]	2.6[b]	6	3.4
H_2S Concentration of Gas (ppm)	8,000[d]	Varies	Up to 8,000	None
LPG/NGL Truck Trips (per week)	16.1	2.7	4.7	2.0

a. This is the limit specified in the SBC FDP. The SBCAPCD Permit to Operate has a limit of 25,000 bpd for Platform Irene and 36,000 bpd for the LOGP. The CCC consistency determination staff report states a level of 20,000 bpd for Platform Irene.
b. Average production for the year 2005.
c. This is the limit specified in the SBC FDP. The SBCAPCD PTO has a limit of 12 mmscfd.
d. The Applicant has received discretionary approval from Santa Barbara County to increase the H_2S content of the gas to 8,000 ppm. This increase is not the result of the Tranquillon Ridge Project.

Table ES.2 Summary of Extension of Life Estimates from Environmental Documents

Existing Point Pedernales Facilities			
Project Component	**Original Estimated Life (Years)**	**Estimated Time Frame[a]**	**Source of Estimate**
Platform Irene	20	1987-2007	1985 Point~~.~~ Pedernales EIR/EIS
LOGP (HS&P) Gas Plant	30-35[b] 10-25	1987-2022 1997-2022	1985 Point Pedernales EIR/EIS 1993 Supplemental EIR
Tranquillon Ridge	30	2007-2037	Project Application
Estimated Increase in Life with Tranquillon Ridge			
Project Component	**Estimated Total Life (Years)**	**Estimated Total Time Frame**	**Net Increase in Life (Years)**
Platform Irene	50	1987-2037	30[c]
LOGP (HS&P)	50	1987-2037	15[d]

a. Current production forecasts (MMS 2000 and CSLC 2001) show a current estimated Point Pedernales project life extending to between 2010 to 2022. Thus, the original project life for Platform Irene may have been underestimated by approximately 3 to 15 years.
b. This estimate goes beyond permitted development levels, and was predicated on the development of up to six offshore platforms located in the Central Santa Maria Basin.
c. Assuming the estimated life of Platform Irene was through 2007, the Tranquillon Ridge Project would extend the life of the platform by 30 years.
d. Assuming the estimated life of the LOGP was through 2022, the Tranquillon Ridge Project would extend the life of the LOGP by 15 years.

Implementation of the Tranquillon Ridge Project would also result in an increased throughput of crude oil through the ConocoPhillips Line 300 pipeline system, which moves dry oil from the

LOGP, ~~to the ConocoPhillips Santa Maria Refinery or connects to additional pipelines for transport to Bay Area refineries. Point Pedernales projection has historically been processed at the Santa Maria Refinery.~~ as well as Santa Ynez Unit, Point Arguello, Lompoc Field, and Orcutt Field production, to the ConocoPhillips Santa Maria Refinery in San Luis Obispo County. From the Santa Maria Refinery, partially refined products are transported to Bay Area refineries via existing pipelines. The Line 300 pipeline system is a regulated common carrier and is operated by ConocoPhillips under a separate SBC permit. The portion of the system that moves dry oil from LOGP to the Santa Maria Refinery has a permitted capacity of 36,000 barrels per day (bpd). The average Point Pedernales production throughput through the subject portion of the pipeline in 2005 was 7,000 bpd. Since this pipeline primarily ships oil ~~only~~ from LOGP (with some production from the Lompoc and Orcutt Fields), the throughput in the pipeline segment from LOGP to Suey Junction has been diminishing along with the production from the Point Pedernales Field. At Suey Junction, Santa Ynez Unit and Point Arguello production make up the required throughput rate (limited by the Santa Maria Refinery capacity) via the Sisquoc portion of the Line 300 pipeline system. As such, the baseline for this pipeline segment from LOGP to Suey Junction was assumed to be the throughput at the time the NOP was issued (7,000 bpd).

ES.5 Impacts of the Proposed Project and Alternatives

In the Impact Summary Tables at the end of this Executive Summary and throughout this EIR, impacts of the proposed project, alternatives, and the cumulative effects have been classified using the categories Class I, II, III, and IV as described below.

- ***Class I - Significant adverse impacts that are unavoidable:*** Significant impacts that cannot be effectively mitigated. No measures could be taken to avoid or reduce these adverse effects to insignificant or negligible levels. Even after application of feasible mitigation measures, the residual impact would be significant.
- ***Class II - Significant but mitigable adverse impacts:*** These impacts are potentially similar in significance to those of Class I, but can be reduced or avoided by the implementation of mitigation measures. After application of feasible mitigation measures, the residual impact would not be significant.
- ***Class III - Adverse but not significant impacts:*** While not required under CEQA to reduce an impact to a level of insignificant, mitigation measure(s) are often applied to an identified adverse but not significant impact to mitigate the impact to the maximum extent feasible in accordance with Santa Barbara County policy.
- ***Class IV – Beneficial impacts:*** Effects that are beneficial to the environment.

The term “significance” is used in these tables and throughout this EIR to characterize the magnitude of the projected impact. For the purposes of this EIR, a significant impact is a substantial or potentially substantial change to resources in the local project area or the area adjacent to the project in comparison to the thresholds of significance established for the resource or issue area. These thresholds of significance are discussed by issue area in Section 5 of the EIR.

For each impact, the applicable project phase has been identified as shown below. These levels of characterization are shown, along with mitigation measures for each impact, in the Impact Summary Tables, which are located right after this Executive Summary.

- ***Construction***: Impacts associated with construction activities.

- ***Drilling***: Impacts associated with the drilling of wells on Platform Irene.
- ***New Operations***: Impacts due to the operation of new facilities.
- ***Increased Throughput***: Impacts associated with the increase in oil and gas throughput through the project pipelines, processing facility, and platform over baseline conditions. This increase in production has the potential to increase the magnitude and/or severity of the existing impact.
- ***Extension of Life***: Impacts due to an increase in the expected life of the Point Pedernales Project over what was assumed in the 1985 Point Pedernales EIR/EIS and the 1993 Point Pedernales SEIR, as modified via permit approvals. Impacts associated with extension of life do not represent new impacts but impacts that exist for the current Point Pedernales operations. The proposed Tranquillon Ridge Project would extend the duration of time over which the existing impact(s) would occur.

The remainder of this section provides a brief discussion of the Class I impacts identified for the proposed project as well as the alternatives. A detailed listing of the impacts can be found in the Impact Summary Tables.

ES.5.1 Significant Impacts Associated with the Proposed Project

A number of significant (Class I) impacts were identified for the Tranquillon Ridge Project (see Table ES.3a), and are summarized below. Tables ES.3b and ES.3c present the significant but mitigable (Class II) and adverse but not significant (Class III) impacts of the proposed project, respectively. Table ES.3d provides a summary of the cumulative impacts associated with the proposed project.

Significant (Class I) impacts are associated, in general, with two aspects of the Tranquillon Ridge Project: the increased transportation and processing of oil and gas *(increased throughput*) over what is occurring today, and the extension of the Point Pedernales facility operations for an additional 15 years for the LOGP and 30 years for Platform Irene *(extension of life)* beyond what was evaluated in the previous environmental documents. All of the Class I impacts were identified in the previous environmental documents covering the Point Pedernales Field project. However, these documents assumed a life expectancy of the facilities that was shorter than what would occur with the Tranquillon Ridge Project. Tranquillon Ridge Project would extend the duration of these impacts to about 2037, beyond what is currently projected for the Point Pedernales Field operations which is cessation of operations ~~by~~around 2017.

Increased Throughput

Significant (Class I) impacts associated with the proposed Tranquillon Ridge Project are in part due to the increased oil spill volumes over what could occur today. The higher spill volumes are associated with the higher pumping rates and the higher levels of oil in the oil/water emulsion pipeline. While the estimated maximum spill volume with the Tranquillon Ridge Project would increase over the maximum spill volume that exists today, it would be less than the spill volume analyzed in previous environmental documents. The 1985 Point Pedernales EIR/EIS assumed a worst-case oil spill of 8,500 barrels (bbls). The worst-case oil spills analyzed in this EIR for the Tranquillon Ridge Project for the estimated 30 year life of the project were 7,929 bbls for the offshore pipeline and 4,500 bbls for Platform Irene, whereas spill volumes for current operations are 2,913 bbls for the offshore pipeline and 426 bbls for Platform Irene (Table 5.1-29). Class I impacts due to oil spills associated with the increase in throughput were identified in the following issue areas:

- Terrestrial and Freshwater Biology,
- Onshore Water Resources,
- Marine Biology,
- Marine Water Quality,
- Commercial and Recreational Fishing,
- Recreation, and
- Cultural Resources.

Increased spill volumes over current operations could potentially impact larger areas and, as the County criteria for significance are based on spill volumes, this would increase the severity of the existing significant impacts associated with an oil spill from the current Point Pedernales operations.

A significant risk of upset impact was associated with the increase in the transportation of natural gas liquids/liquid petroleum gas (NGL/LPGs) from LOGP to various destinations. The impact was also identified as significant in the 1985 Point Pedernales EIR/EIS. Increasing the amount of NGL/LPG truck trips, due to the increased throughput, would increase the severity of this previously identified impact.

Extension of Life

The proposed project could extend the life of the Point Pedernales facilities beyond what was projected in the 1985 Point Pedernales EIR/EIS. Significant impacts associated with the extension of life issue are applicable to all of the issue areas discussed above due to the increased throughput as they would involve extending an already significant impact for a longer period of time. In addition, two extended Class I significant impacts were identified due to the presence of Platform Irene, Surf substation, and the LOGP facility beyond what is currently projected for Point Pedernales ~~Field~~.

ES.5.2 Significant Impacts Associated with Alternatives

This section provides a summary of the significant and unavoidable (Class I) impacts associated with the alternatives to the Tranquillon Ridge Project and compares them to those that were identified for the proposed project.

No Project Alternative

Under the No Project Alternative, existing significant (Class I) impacts associated with the Point Pedernales Project would continue through approximately 2017; however, all of the proposed Tranquillon Ridge Project ~~significant~~ Class I impacts associated with increased throughput would be eliminated. ~~since the production from the Federal portion of the Tranquillon Ridge Field using Well A-28 would be the same as current production.~~ Production from Platform Irene would be close to the average production in 2005 (i.e., 7,000 bpd of dry oil and 2.6 mmscfd of gas) and production volumes would taper off with time through 2017, when decommissioning of the Point Pedernales facilities is anticipated. All of the significant (Class I) impacts associated with extension of life of the Point Pedernales facilities would also be eliminated since ~~fewer wells would be drilled and~~ production would occur within the currently projected life of the Point Pedernales Field (i.e., through 2017).

VAFB Onshore Alternative

The VAFB Onshore Alternative would eliminate the extension of life of Platform Irene, the offshore pipeline, and onshore pipeline from landfall at Wall/Surf Beach to 13th Street (approximately 4.5 miles of pipeline) after 2017. By eliminating the extension of life for these offshore facilities, the alternative oil spill risk and associated impacts would be greatly reduced for marine biology, marine water quality, commercial/recreational fisheries, and coastal terrestrial and recreational resources. However, because of the installation of approximately 10 miles of new onshore pipeline, the alternative oil spill risk and associated impacts would be greater than the proposed project for terrestrial biology, cultural resources, and onshore water resources. In addition, construction of the VAFB Onshore Alternative drilling/production site, pipelines, ~~and~~ ~~transmission~~ power lines, tie-in station, and substations would create new significant impacts for the issue areas of terrestrial biology and cultural resources. Operation of the drilling/production site and gas pipeline could present possible significant risk impacts to VAFB operations and personnel. Finally, the presence of the drilling/production facility and new substation within the coastal zone would present possible significant visual impacts. Table ES.4a provides a summary of these Class I impacts, whereas Tables ES.4b and ES.4c provide a summary of the Class II and Class III impacts associated with the VAFB Onshore Alternative, respectively.

Casmalia Processing Site Alternative

Significant impacts associated with the Casmalia Alternative were principally due to increased air emissions, potential impacts to biological resources due to construction, and visual impacts due to nighttime glare (new Class I impacts). In addition, there would be an increase in severity of the Class I impacts over the proposed project for terrestrial biology, onshore water quality, recreation/land use and cultural resources due to the increased pipeline transportation of the crude oil and water emulsion from the LOGP to the Casmalia site. The severity of the Class I visual impacts associated with the extension of life of LOGP for the proposed project would be reduced but not eliminated due to the continued need for facilities (pumps and compressors) at the LOGP. All of the other significant (Class I) impacts associated with extension of life of the Point Pedernales facilities would remain the same as for the proposed project. Table ES.5a provides a summary of these Class I impacts, whereas Tables ES.5b and ES.5c provide a summary of the Class II and Class III impacts associated with the Casmalia Processing Site Alternative, respectively.

New Emulsion Pipeline from Platform Irene to the LOGP Alternative

All of the proposed Tranquillon Ridge Project significant (Class I) impacts associated with increased throughput and extension of life would remain the same as for the proposed project. While the new pipeline ~~w~~could have a lower spill frequency than the existing pipeline, the reduction in spill frequency was determined to be approximately 10% (a reduction in spill frequency from 11.2 to 10.1 percent for the onshore portion of the emulsion line and 9.7 to 8.7 percent for the offshore portion), and the spill volumes would be the same as for the proposed project. All of the impacts associated with the installation of the new pipeline were determined to be Class II or III because construction would occur in an existing disturbed corridor. The installation of the new oil emulsion pipeline would not result in any new significant (Class I) impacts above and beyond the proposed project. Tables ES.6a and ES.6b provide a summary of the Class II and Class III impacts associated with the New Emulsion Pipeline Alternative, respectively.

Alternative Power Line Routes to Valve Site #2

The installation of the alternative power line routes does not affect the severity of any Class I impact associated with the proposed project with one exception (boring of Santa Ynez River). All impacts associated with the power lines were determined to be Class II or III. These impacts would be slightly greater in severity for some of the power line alternatives, such as impacts to cultural resources and air quality for the trenching or boring alternative. A Class I impact to biological resources was identified for the boring alternative due to possible releases of drill muds into the Santa Ynez River. The trenching alternative was not found to substantially reduce the severity of the visual impacts of the proposed project (power line on poles) since even with the trenching alternative, there would be some above ground poles used. Table ES.7a provides a summary of this Class I impact, whereas Tables ES.7b and ES.7c provide a summary of the Class II and Class III impacts associated with the alternative power line routes, respectively.

Alternative Muds and Cuttings Disposal Options

The muds and cuttings disposal alternatives would not change nor affect the severity of any Class I impact associated with the proposed project. Impacts associated with muds and cuttings discharge to the ocean in the proposed project were determined to be Class III. A reduction in severity, or elimination, of this impact would be seen with muds and cutting injection or transportation to shore for disposal. The potential for a contaminated muds and cuttings spill during transportation, or for the seepage of mud-contaminated waters into the marine environment would ~~still~~ be considered ~~a~~ Class III ~~impact~~, but lower in severity than the ocean discharge of the muds and cutting since the potential volume and frequency of a spill to the ocean would be less with transportation to shore or injection. Table ES.8 provides a summary of the Class III impacts associated with the alternative muds and cuttings disposal options.

ES.5.3 Mitigation Measures

Mitigation measures have been developed for a number of the impacts identified for the proposed project and alternatives. All of the mitigation measures are listed in the Impact Summary Tables (Tables ES.3a through ES.8). The proposed project would involve changes to operations that are currently covered under the existing FDP from Santa Barbara County (see Appendix M). As such, the majority of the FDP conditions would continue to apply to the proposed project. Where the EIR has identified new impacts and existing impacts that have increased in severity or extension of life related impacts, modifications to the existing FDP conditions may be required to implement any identified mitigation measures. The relationship between the recommended mitigation measures and the existing Point Pedernales FDP conditions can be grouped into the following categories.

1. The mitigation measure is already addressed by an existing FDP condition, so no changes to the condition are needed to implement the mitigation measure.

2. The mitigation measure is partially implemented by an existing FDP condition, so modifications are needed to the condition to fully implement the mitigation measure.

3. The mitigation measure is not covered by an existing FDP condition, so a new condition needs to be added to implement the mitigation measure.

The remaining existing FDP conditions would continue to be applicable to the Point Pedernales facilities, which would cover the Tranquillon Ridge Project.

ES.6 Environmentally Superior Alternative

The alternatives analysis compares the impacts of the examined alternatives to the impacts identified for the proposed project. The remainder of this section summarizes the comparison of the proposed project to the No Project Alternative, VAFB Onshore Alternative, and the other three major component alternatives evaluated in the EIR, and discusses the environmental preferability of these alternatives relative to the proposed project.

No Project Alternative

The No Project Alternative was found to be the environmentally superior alternative since this alternative would eliminate all of the Class I impacts associated with increased throughput and extension of life of the Point Pedernales facilities. However, the No Project Alternative would not meet the applicant's objectives of the project, which is the full development of the Tranquillon Ridge Field. The No Project Alternative would result in only partial development of the recoverable reserves since the portion of the Field within State waters would not be produced and only existing Well A-28 would be used to produce the Federal portion of the Field, as is currently being done.[2] CEQA Guidelines Section 15126.6(e)(2) states "If the environmentally superior alternative is the no project alternative, the EIR shall also identify an environmentally superior alternative among the other alternatives."

Proposed Project

The proposed project would use existing facilities, including Platform Irene, Surf substation, the offshore and onshore pipelines, and LOGP. The increased throughput associated with the proposed project would increase the oil spill risk and volumes above baseline conditions. For the existing Point Pedernales Project, PXP has implemented a comprehensive corrosion monitoring and control program for the oil, gas and produced water pipelines that does reduce the potential risks for releases into the marine and terrestrial environments. However, even with these and other operational safeguards, the extension of life resulting from the proposed project would continue significant oil spill risks and associated impacts to marine biology, marine water quality, commercial/recreational fisheries, terrestrial biology, cultural resources, onshore water resources, and recreational resources beyond the lifetime of the original Point Pedernales Project. In addition, long-term visual impacts regarding the continued presence of Platform Irene and Surf substation within the coastal zone, and LOGP nighttime glare would continue through 2037, instead of 2017 as estimated for current operations. Construction activities associated with the proposed project, however, are nominal, requiring only an estimated 0.43 acres of vegetation removal.

[2] As previously discussed, if the proposed project is not implemented, development of the Tranquillon Ridge field could occur from an onshore location, as currently proposed by Sunset Exploration, Inc. and Exxon Mobil Corporation. ~~This~~ An onshore drilling option has been considered in the EIR as the VAFB Onshore Alternative.

VAFB Onshore Alternative

The VAFB Onshore Alternative would eliminate the extension of life of Platform Irene, the offshore pipeline, and onshore pipeline from landfall at Wall/Surf Beach to 13th Street (approximately 4.5 miles of pipeline) after 2017. By eliminating the extension of life for these offshore facilities, the alternative oil spill risk and associated impacts would be greatly reduced for marine and coastal biology, marine water quality, commercial/recreational fisheries, and coastal recreational resources. Installation and operation of approximately 10 miles of new onshore pipeline could result in significant oil spill risk and associated impacts to terrestrial biology, cultural resources, onshore water resources, and potential estuarine resources. In addition, construction and operation of the VAFB Onshore Alternative drilling/production site, pipelines, ~~and~~ tie-in station, power lines, and substations could create new significant impacts to terrestrial biology, and cultural resources. Operation of the drilling/production site and gas pipeline could present possible significant risk impacts to VAFB operations and personnel. Finally, the presence of the drilling/production facility and new substation within the coastal zone would present possible significant visual impacts.

Conclusion: Since the VAFB Onshore Alternative is the only feasible project-level alternative to the proposed project, it could be considered a de facto environmentally superior alternative. However, this classification does not speak to how the VAFB Onshore Alternative compares to the proposed project. To determine whether a proposed project or an alternative would be environmentally preferred, the process normally is to compare the significant Class I impacts of the proposed project to those of the alternative(s), and to identify the option with the fewest significant impacts that meets the primary project objectives. Guidance for this comparison is also sought from the relevant regulatory policies for each issue area, as necessary. However, such policies do not always provide explicit direction on relative importance when weighing one issue area over another (e.g., biological resources versus cultural resources). As a result, this analysis relies on a comparison of the nature, extent, permanence and probability of each Class I impact in order to identify the environmentally preferred option.

Table ~~6.1a~~ES.9 compares each of the proposed project's impacts to those that could be expected to result from the VAFB Onshore Alternative. Implementation of the onshore alternative would substantially reduce the likelihood of an offshore oil spill and its related impacts after 2017, when Platform Irene, the offshore pipeline, and the existing onshore pipeline to the 13th Street tie-in would be decommissioned. During these ten years, the offshore pipeline would carry a diminishing amount of crude oil which would lead to diminishing risk from an oil spill from the Point Pedernales project. Offshore impacts due to an onshore oil spill could still occur, though the likelihood and severity of such impacts would be expected to be less~~small~~.

Implementation of the onshore alternative also would result in substantially more significant impacts to onshore biological and cultural resources than the proposed project. Several threatened and/or endangered species, both plant and animal, occur at the drillsite and along the likely pipeline corridor and would be affected by facility construction of the alternative and by operational impacts, such as an onshore oil spill. Operation of the drilling/production site and gas pipeline could present possible significant risk impacts to VAFB operations and personnel. Presence of the drilling/production facility and substation within the coastal zone could result in a possible significant visual impact. There is a potential that many of these impacts could be mitigated, but there is no assurance they could be mitigated to insignificance.

It can be seen from the comparison in Table ~~6.1a~~ES.9 that both the proposed project and VAFB Onshore Alternative would result in permanent and significant impacts, with varying probabilities, and in varying issue areas. As such, and because of their uniquely different locations (offshore versus onshore) and resulting disparate impact issue areas, and partly because the proposed and alternative onshore projects are described and analyzed to different levels of detail, it is extremely difficult to determine that one is environmentally preferable over the other.

Casmalia Processing Site Alternative

The Casmalia Alternative would not eliminate any of the Class I impacts associated with the proposed project regarding extension of life for oil spill risks and volumes, and continued presence of Platform Irene, Surf substation, and LOGP. In addition, because of the installation of approximately 10 to 15~~3~~ miles of new onshore pipeline, the alternative oil spill risk and associated impacts would be greater than the proposed project for terrestrial biology, cultural resources, and onshore water resources. In addition, construction of the Casmalia Alternative processing facility and pipelines would create new significant impacts for the issue areas of terrestrial biology and cultural resources.

Conclusion: A comparison of the Casmalia Alternative to the proposed project is provided in Table ES.9. Since the Casmalia Alternative offers no environmental benefit to the proposed project, the proposed project component of processing at LOGP is considered to be environmentally preferable to this alternative.

New Emulsion Pipeline from Platform Irene to the LOGP Alternative

The Emulsion Pipeline Replacement Alternative would be similar to the proposed project with regards to extension of life and associated oil spill risks and impacts to marine biology, marine water quality, commercial/recreational fisheries, terrestrial biology, cultural resources, onshore water resources, and recreational resources. The oil spill risk for the new emulsion pipeline would be approximately 10 percent less than for the existing pipeline to be used by the proposed project. However, regardless of spill risk, the volumes of spill would be the same. In addition, construction of the new emulsion pipeline within the previously disturbed right-of-way would create intensified Class II impacts for the issue areas of terrestrial biology and cultural resources.

Conclusion: A comparison of the Emulsion Pipeline Alternative to the proposed project is provided in Table ES.9. Because a 10 percent reduction in spill risk is considered nominal (reduced from 11.2 percent for the proposed project to 10.1 percent for the onshore portion of the emulsion line and 9.7 to 8.7 percent for the offshore portion), and would not lead to reduced spill volumes and associated impacts, and construction efforts would intensify several Class II impacts in comparison to the proposed project, the proposed project's use of the existing pipelines is considered to be environmentally preferable to the Emulsion Pipeline Replacement Alternative.

Alternative Power Line Routes to Valve Site #2

For the most part, all of the power line alternatives have similar impacts (see Table ES.10). The proposed project, with mitigation, was found to be the environmentally preferred alternative. The proposed project, with mitigation, would eliminate the need to install poles or bore under the Santa Ynez River since the power line would be placed on existing VAFB poles, and the portion from the intersection of Terra Road and Pipeline Dirt Road would be placed underground. If and when this power line is built, the applicant and the County would need to work with VAFB to gain permission to use their existing poles. By using existing poles, a number of Class III impacts would be avoided.

Amongst the alternative power line routes analyzed, burying the power line along Terra Road was identified as slightly environmentally superior since this alternative would reduce, but not entirely eliminate the significant visual impacts associated with the installation of new power lines, because some above ground poles (transition poles) would be required. Impacts to biological resources associated with trenching could be effectively mitigated if this alternative is implemented.

Burying of the power line along Terra Road would also result in Class II cultural impacts since avoidance of all cultural sites along this route would not be possible. With the overhead option, there is greater flexibility with respect to pole placement and cultural resource sites.

Alternative Muds and Cuttings Disposal Options

Table ES.11 provides a summary of the relative impacts associated with the alternative muds and cutting disposal options. With regard to the handling of muds and cuttings, injection at the platform was selected as the environmentally superior alternative. This would eliminate the ocean discharge of the muds and cuttings (Class II for marine biology and marine water quality), and would eliminate the traffic and air emissions associated with onshore disposal (Class III). However, in order for this alternative to be implemented, a suitable underground formation would need to be found that could handle all of the muds and cuttings and would require MMS approval. In addition, the CSLC currently prohibits the release of ocean disposal of drill muds and cuttings to the ocean in State waters (where well completions would be located). However, disposal would take place in Federal waters at Platform Irene (where the muds and cuttings are collected), a currently approved practice. If a suitable formation cannot be found, or MMS does not approve the injection of muds and cuttings, then the onshore disposal of muds and cuttings would be considered the second environmentally superior option.

Table ES.3a
CLASS I Impacts of the Proposed Project
Impacts that may not be Fully Mitigated to Less than Significant Levels

(Impacts that must be addressed in a "statement of overriding consideration" if the project is approved in accordance with Sections 15091 and 15093 of the State CEQA Guidelines.)

Table ES.3a: Class I Impacts of the Proposed Project

Impact #	Project Phase	Description of Impact	Mitigation Measures	Residual Impact
HAZARDOUS MATERIALS/RISK OF UPSET (Section 5.1)				
Risk.3	*Increased Throughput Extension of Life*	The proposed project could generate risks to public safety by exposing the public to transportation hazards.	Risk-~~2~~3 The applicant shall implement all of the measures identified in the SBC's policies regarding the transportation of gas liquids that were developed as part of the LPG/NGL Transportation Risk Assessment, including the blending of gas liquids into the crude oil to the maximum extent feasible. (The policies are included in the Point Pedernales Final Development Plan permit conditions P-2 and P-23). The applicant shall submit a plan to SBC for review and approval indicating maximum blending levels that are achievable with the proposed operations prior to land use clearance.	Significant
TERRESTRIAL AND FRESHWATER BIOLOGY (Section 5.2)				
TB.6	*Increased Throughput Extension of Life*	A pipeline leak or rupture could result in an oil spill and subsequent degradation of upland, riparian and freshwater aquatic habitats and injury to plants and terrestrial and aquatic wildlife through direct toxicity, smothering, and entrapment as well as through resultant cleanup efforts. An offshore spill may affect the terrestrial environment if oil is transported to the shoreline. Oil could be transported up creeks and rivers that are open to tidal influence. The modeled trajectory for a worst-case offshore oil spill (Appendix G) indicates that shorelines, lagoons, estuaries, and river mouths may be directly affected. Surrounding terrestrial areas may be affected by cleanup efforts.	In addition to clean-up measures identified in the Core Oil Spill Response Plan (OSRP), measures identified in Section 5.4, Onshore Water Resources, have the potential to reduce impacts on biological resources. Where a spill or clean up results in the loss of native vegetation, implementation of Mitigation Measures TB-6 and TB-7 would reduce impacts to native vegetation. Mitigation measures described above would also apply to a produced water spill. The following measures are recommended to further reduce impacts to terrestrial and aquatic biota. Note that these mitigation measures apply to the proposed project pipeline sections only. TB–11 The November 2004 Core Oil Spill Response Plan and July 2005 Supplement shall be revised and updated to address increased potential spill volumes and updated procedures for oil and produced water spill clean up beneath ground surface and in sensitive habitats including rivers and streams. This plan shall include updated, site-specific measures for spill containment along watercourses and at other sensitive habitats. It shall specify that sensitive habitats shall be avoided to the maximum extent feasible during oil spill clean up activities. It shall include specific measures to avoid impacts on listed endangered and threatened species during response and repair operations and minimize impacts on riparian and other native habitats. The plan shall include identification of specific access points at locations where containment and clean up efforts can be initiated under different scenarios. ~~The~~Access points shall be reviewed and, if necessary, additional access points shall be ~~need to be~~identified immediately adjacent to pipeline river crossings and points where spilled oil could enter the Santa Ynez River, San Antonio Creek, Santa Maria River, Nipomo Creek, and Los Berros Creek. These updates~~This plan~~ shall be reviewed and approved by SBC ~~the P&D Department~~ prior to land use permit approval.~~construction.~~	Significant

Table ES.3a: Class I Impacts of the Proposed Project				
Impact #	**Project Phase**	**Description of Impact**	**Mitigation Measures**	**Residual Impact**
			TB-12 The Core Oil Spill Response Plan and its Supplement include species- and site-specific procedures for collection, transportation, and treatment of all potentially affected native wildlife, including sensitive species, for topsoil salvage and replacement, and procedures to minimize the loss of native seedbanks and prevent the spread of non-native weeds. Where disturbance to any habitats ~~disturbance~~ cannot be avoided as determined by a P&D-approved biologist, ~~the November 2004 Core Oil Spill Response Plan and July 2005 Supplement shall be updated to provide stipulations for development and implementation of site-specific habitat restoration plans and other site-specific and species-specific measures appropriate for mitigating impacts on local populations of sensitive wildlife species and to restore native plant and animal communities to pre-spill conditions~~these stipulations for development and implementation of these site-specific habitat restoration plans and other site- and species-specific measures for mitigating impacts on local populations of all sensitive wildlife species and to restore native plant and animal communities to prespill conditions shall be implemented. Access and egress points, staging areas, and material stockpile areas that avoid sensitive habitats shall be identified, prior to ground disturbance.~~The Core Oil Spill Response Plan and its Supplement shall include species- and site-specific procedures for collection, transportation, and treatment of oiled wildlife, particularly sensitive species. The plan shall be reviewed by the federal, state, and local agencies identified in Measure TB-11 prior to approval by the lead agencies.~~ TB-13 Prior to construction or any ground disturbance activity, the applicant shall ~~develop~~ identify low impact clean up procedures ~~for inclusion in~~from the Core Oil Spill Response Plan, and/or updated measures to be implemented. Where feasible, low-impact site-specific clean up techniques such as hand cutting contaminated vegetation and using low-pressure water flushing from boats shall be specified ~~in the Oil Spill Response Plan~~to remove spilled material from particularly sensitive wildlife habitats (e.g., coastal estuaries), because procedures such as shoveling, bulldozing, raking, and draglining can cause more damage to a sensitive habitat than the oil spill itself. As described in the Oil Spill Response Plan, ~~shall evaluate~~the non-clean up option for ecologically vulnerable habitats such as coastal estuaries shall be considered. Prior to approval of the Land Use Permit, the applicant shall revise the OSRP to update the low-impact clean up procedures consistent with current technology. These strategies shall be reviewed and revised during the required future Plan updates to include best available practices. TB-14 The applicant shall ~~develop and implement~~ update the OSRP to ensure that~~pill response training program. S~~ spill response personnel ~~shall be~~are adequately trained for response in terrestrial environments and spill containment and recovery equipment shall be inspected at least annually and maintained at full readiness. Drills shall be conducted at least annually and the results evaluated so that spill response personnel are familiar with the equipment and with the project area, including sensitive terrestrial biological resources. Rehabilitation centers, within the project area, for birds and other wildlife species affected by spilled material shall be involved in the drills. If a rehabilitation center is not available in	

Table ES.3a: Class I Impacts of the Proposed Project

Impact #	Project Phase	Description of Impact	Mitigation Measures	Residual Impact
			the project area, the applicant shall contribute a pro-rata share of funds necessary to cover the costs of establishing and operating a bird and wildlife rehabilitation center.	
TB.7	*Increased Throughput Extension of Life*	A spill and/or subsequent cleanup efforts may directly or indirectly cause the loss of habitat and individuals or colonies of state-or federally-listed plant species including seaside bird's beak, Surf thistle, beach spectacle pod, La Graciosa thistle, Gaviota tarplant, and possibly Pismo clarkia or degrade designated critical habitat for the Lompoc yerba santa and La Graciosa thistle. An offshore spill may affect listed plant species in coastal dunes and foredune habitat due to resultant containment or cleanup efforts.	Impacts to listed species would be reduced through implementation of Mitigation Measures TB-11 through TB-14, which include, but are not limited to, minimization of habitat disturbance during clean up, the use of low-impact clean up techniques, and restoration of the site to pre-spill conditions. Mitigation Measure TB-5 would reduce the effects of sedimentation in the event clean up activities disturb soil and increase erosion. Implementation of Mitigation Measures TB-6 and TB-7, which address, in part, the restoration of native plant species would also reduce impacts in areas where spills or cleanup results in the loss of native vegetation. These measures described above would also apply to a produced water spill.	Significant
TB.8	*Increased Throughput Extension of Life*	An oil spill and/or subsequent cleanup effort may directly or indirectly cause the loss of individual state or federally-listed wildlife species or cause the loss or degradation of sensitive species habitat. An oil spill and/or subsequent cleanup effort may impact designated critical habitat for steelhead, western snowy plover, California tiger salamander, and California red-legged frog. ~~An offshore spill may affect listed fish and wildlife that inhabit shorelines, beaches, lagoons, estuaries, and river mouths.~~	Impacts to listed wildlife species would be reduced through implementation of Mitigation Measures TB-11 through TB-14, which include, but are not limited to, updating the OSRP, minimizing habitat disturbance during clean up, using low-impact clean up techniques, and restoring of the site to prespill conditions. Implementation of Mitigation Measures TB-6 and TB-7, which address, in part, the restoration of native plant species would also reduce loss of foraging and breeding habitat in areas where spills or cleanup results in the loss of native vegetation. Mitigation Measure TB-5 would reduce the effects of sedimentation in the event clean up activities disturb soil and increase erosion. Mitigation measures identified in Sections 5.4 (Onshore Water Resources) and 5.6 (Marine Water Quality) would also reduce the impacts of oil spill on state and federally listed species in the project area. These mitigation measures would also apply to a produced water spill.	Significant
		ONSHORE WATER RESOURCES (Section 5.4)		
OWR.2	*Increased Throughput Extension of Life*	A rupture or leak from the emulsion, produced water or dry oil pipelines could substantially degrade surface and groundwater quality.	In addition to Mitigation Measure Risk-1, the following mitigation measures are proposed. OWR-2 The applicant shall construct a berm around Valve Site #2 with sufficient capacity to retain 150 percent of the maximum spill volume associated with this portion of the onshore pipeline (see Section 5.1, Risk of Upset). The applicant shall submit specific plans for the catchment basin at Valve Site #2 to SBC/CCC for review and approval prior to land use clearance. The berm shall be installed prior to operations. OWR-3 Update the Oil Spill Contingency Plan and the November 2004 Oil Spill Response Plan and July 2005 Supplement to address the SCADA system and GR.1-related	Significant

Table ES.3a: Class I Impacts of the Proposed Project

Impact #	Project Phase	Description of Impact	Mitigation Measures	Residual Impact
			requirements for the proposed project. Conduct annual readiness exercises and audits to ensure that containment and cleanup equipment is readily available close to areas with greatest vulnerability to spills (e.g., along the lower sections of the Santa Ynez River). OWR-4 PXP shall ensure that catchment basins located along the Santa Ynez River section of the pipeline are cleaned and surveyed periodically to ensure that they are capable of holding at least 110 percent of the associated release volume from nearby pipeline segments. Prior to land use clearance, PXP shall provide volume calculations to SBC for each of the catchment basins for the following leak scenarios: (1) 11 minutes of pumping time for a worst case leak in accordance with the MMS Oil Spill Response Plan, Volume 2, worst case scenario, and (2) 20 minutes of pumping time for a small leak as detected by the PXP leak detection system. The total pipeline emulsion fluids, including produced water, shall be included in the calculations. If it is determined that the volume of any of the catchment basins is insufficient to fully contain the leak scenarios analyzed, the catchment basin(s) shall be expanded. Plans for catchment basin(s) expansion shall be submitted to SBC for review and approval prior to land use clearance. OWR-5 Ensure that any pipeline replacement within stream beds is engineered such that the replacement pipeline and any pipeline support structures are protected from scour and erosion effects of a 100-year flood discharge. Plans demonstrating these requirements shall be submitted to SBC/CCC for review and approval prior to land use clearance.	
MARINE BIOLOGICAL RESOURCES (Section 5.5)				
MB.1	*Increase Throughput Extension of Life*	Oil spills from the project may impact benthic and intertidal organisms, fish, marine mammals, marine birds, and marine turtles.	MB-1a The November 2004 Core OSRP and July 2005 Supplement shall be updated to incorporate changes in platform activities that result from the proposed project. For example, the plan shall incorporate detailed response procedures for marine oil spills resulting from a blowout if wells producing the Tranquillon-Ridge field are expected to be free flowing. Worst-case discharge scenarios shall be updated accordingly. In addition, lessons learned from the cleanup of the 1997 oil spill shall be incorporated into the Response Plan. The efficacy of various containment and cleanup techniques applied during the 1997 spill shall be evaluated with regard to potential future spills. Hindcasts of the observed oil-spill trajectory shall be used to improve site-specific trajectory models. Potential ecological damage resulting from cleanup techniques applied in 1997 shall be discussed. The updated OSRP shall specifically detail methods to reduce impacts to sea otters and pinniped colonies should a spill occur. This discussion should include methods for preventing oil from reaching places where otters congregate and pinniped colonies. It should detail protocols for handling and rehabilitation of oiled otters and pinnipeds, and should specify methods to avoid disturbing pinniped colonies during cleanup activities. Finally, the updated OSRP shall re-evaluate the toxicity of Corexit 9527 and its inclusion as a potential dispersant for the Tranquillon Ridge project based on current information. The personnel and training sections of the OSRP shall be updated to identify training requirements for all personnel who would respond to oil spills. At a minimum, new	Significant

Table ES.3a: Class I Impacts of the Proposed Project				
Impact #	**Project Phase**	**Description of Impact**	**Mitigation Measures**	**Residual Impact**
			personnel shall be trained immediately in the overall operational aspects of oil spill response, including the proper use of all equipment that would be utilized in spill response. Annual training for all personnel shall also be included in the OSRP. The annual training shall include training in the operation of new equipment that may be utilized in oil spill response, retraining in the operation of existing equipment, and review of the oil spill response requirements that are identified in the OSRP. MB-1b In order to provide a baseline for shoreline clean-up efforts in the event of a spill, the applicant shall contribute to the funding of a program to document the amount, variability, and chemical fingerprint of the tar normally present in the intertidal zone within the potential oil spill zone. The program shall include both visual observations and chemical sampling of tar along five segments (less than or equal to one-mile each) of shoreline located within the area of the coast located between Point Sal and Point Conception. The program shall continue for as long as Tranquillon Ridge Field development is occurring or until analysis of the collected data indicates that extension of sampling will not significantly increase understanding of the pattern of tar deposition and improve documentation of the baseline. The amount of tar shall be estimated and its chemical fingerprint determined, based on the shoreline tar sampling protocol used by the U.S. Geological Survey (USGS) in its MMS-funded study "Submarine Oil and Gas Seeps of the Southern Offshore Santa Maria Basin, California" (2001-2004). The program shall document visual observations and chemical sampling. The samples shall be analyzed for chemical fingerprint in the USGS laboratory. If analysis by the USGS is not available, another comparable fingerprinting method may be substituted. Annual cost of the applicant's contribution to this program shall not exceed $100,000. The program shall be developed in cooperation with Santa Barbara County's Department of Planning and Development, and shall be coordinated by the Energy Division. The Energy Division shall evaluate the program on an annual basis in coordination with staffs of the California State Lands Commission, California Coastal Commission, Department of Fish and Game Office of Spill Prevention and Response, and Minerals Management Service. If new information indicates that changes to the methodology or protocol would improve the efficiency or accuracy of determining baseline oiling conditions, the County shall revise the program. Any revisions to the program shall not cause the annual cost to the applicant to exceed the $100,000 limitation. MB-1c PXP shall make a yearly contribution of $90,000 toward establishing a marine mammal and sea bird impact mitigation fund. The funding shall be used for either facilities construction or operating costs associated with the rescue and rehabilitation of injured marine mammals and sea birds. This yearly contribution shall be in lieu of the applicant's annual three (3) point Coastal Resource Enhancement Fund (CREF) assessment for biological resource impacts, as currently required by Condition N-1 of PXP's Final Development Plan for the Point Pedernales Project.	

Table ES.3a: Class I Impacts of the Proposed Project

Impact #	Project Phase	Description of Impact	Mitigation Measures	Residual Impact
			Mitigation Measure TB-14 would also apply to this impact to address impacts to marine birds from an oil spill. Mitigation Measure OWR-2, which covers the leak detection system, would also serve to reduce the likelihood of a spill to the marine environment.	
OCEANOGRAPHY AND MARINE WATER QUALITY (Section 5.6)				
MWQ.1	*Increased Throughput Extension of Life*	Accidental discharge of petroleum hydrocarbons into marine waters would adversely affect marine water quality.	MWQ-1 Offshore inspections of the wet-oil pipeline shall continue to be conducted on a regular basis as determined by the County and/or other regulatory agency throughout the life of the project. Inspections shall use the best available technology to identify unsupported spans and deteriorating or inadequate welds. When structural anomalies or unsupported spans are identified that compromise the integrity of the pipeline as determined by the County and/or other regulatory agency, flow through the pipeline flow shall cease until repairs can be effected, spans can be supported, or problematic pipeline components can be replaced. If the leak detection system causes an unexplained shutdown of flow through the offshore pipeline, flow shall remain shutdown until the entire length of pipe is inspected. The applicant shall submit annual inspection reports the parities responsible for verification. These requirements shall be referenced in the project's Safety, Inspection, Maintenance, and Quality Assurance Program (SIMQAP).	Significant
COMMERCIAL AND RECREATIONAL FISHING/KELP HARVESTING (Section 5.7)				
CRF/ KH.2	*Increased Throughput Extension of Life*	Oil spills may potentially impact commercial and recreational fishing in the proposed project area.	See Mitigation Measures MB-1a and MB-1b in Section 5.5, Marine Biology.	Significant
TRAFFIC (Section 5.9)				
T.4	*Increased Throughput Extension of Life*	An oil spill from the proposed Tranquillon Ridge project could result in the disruption of commercial shipping, fishing, and recreational marine traffic and onshore transportation infrastructure.	Refer to Sections 5.5, Marine Biology, and 5.6 Oceanography and Marine Water Quality of this EIR for specific spill-related mitigation measures. Mitigation measures directly applicable include MB-2 (contingency planning), MWQ-1 (updated Oil Spill Response Plan), and MWQ-3 (increased inspection frequency).	Significant
CULTURAL RESOURCES (Section 5.12)				
CR.3	*Increased Throughput Extension of Life*	Containment and cleanup activities associated with an accidental oil spill would result in ground disturbance and potential impacts on cultural resources.	CR-5 The OSRP shall be revised to include procedures for minimizing impacts on cultural resources during oil spill containment and cleanup activities. These procedures shall include contacting a County-qualified archaeologist and Native American monitor in the event of a spill. To the extent possible, heavy earth moving equipment or manual excavation shall be minimized at archaeological sites. If unanticipated cultural resources are discovered during containment and cleanup activities, then a county-qualified archaeologist shall document the discovery at the earliest time it is deemed safe to do so. It is possible that post-cleanup archaeological excavations (with Native American monitoring, if applicable) shall be necessary to help mitigate impacts from the containment/cleanup ground disturbances. The revised OSRP shall be submitted to P&D prior to issuance of coastal development permit or land use clearance for grading.	Significant

Table ES.3a: Class I Impacts of the Proposed Project				
Impact #	**Project Phase**	**Description of Impact**	**Mitigation Measures**	**Residual Impact**
		AESTHETICS/VISUAL RESOURCES (Section 5.13)		
Visual.1	*Extension of Life*	Visual impacts due to long-term continued presence of the project facilities visible from Coastal Zone (Platform Irene and Surf Substation).	Visual-1 The applicant shall prepare and implement a visual mitigation plan for the Surf Substation that provides for better screening of the facility. The plan shall address measures to reduce the visual impact of the facility including, but not limited to, painting of substation substructures and re-landscaping. The plan shall be submitted to SBC P&D for approval prior to land use clearance.	Significant
Visual.4	*Extension of Life*	Visual impacts due to long-term continued presence of the LOGP.	Visual-4 The applicant shall implement a lighting plan that would minimize nighttime glare. The applicant shall submit the plan to SBC P&D for review and approval prior to land use clearance. The plan shall include the facility lighting placement and design.	Significant
		RECREATION/LAND USE (Section 5.14)		
Rec.1	*Increased Throughput Extension of Life*	The proposed project would increase the likelihood and volume of an oil spill, which could result in public access restrictions to coastal and inland recreational resources.	See Marine Biology Mitigation Measure MB-2, and Marine Water Quality Mitigation Measures MWQ-1, MWQ-2, MWQ-3. ~~and Commercial and Recreational Fishing Mitigation Measures CRF/KH-1.~~	Significant

Table ES.3b
CLASS II Impacts of the Proposed Project
Impacts that can be Mitigated to Less than Significant Levels

(Impacts that must be addressed in Findings that the mitigation measures would reduce the level of impact to insignificant in accordance with Section 15091 State CEQA Guidelines.)

Table ES.3b: Class II Impacts of the Proposed Project

Impact #	Project Phase	Description of Impact	Mitigation Measures	Residual Impact
Construction and Operations				
TERRESTRIAL AND FRESHWATER BIOLOGY (Section 5.2)				
TB.1	*Construction* *New Operations*	Modification of Valve Site #2 and installation of power poles and transformer station would result in disturbance or loss of less than one acre of native vegetation and wildlife habitat, as well as disturbance and possible injury to wildlife.	TB-1 Prior to construction, a survey of the power line corridor shall be conducted to verify the locations of sensitive plants, including Gaviota tarplant, La Purisima manzanita, sand mesa manzanita, and dune vegetation that includes coast buckwheat (Eriogonum parvifolium), and thus may support El Segundo blue butterfly. Power poles shall be sited to avoid impacting these resources. TB-2 Prior to constructing the power line to Valve Site #2, the ~~applicant~~operator shall enter into discussions with VAFB to determine the feasibility of placing the power line on the 13th Street bridge or using the existing VAFB power poles for crossing the Santa Ynez River. If placing the power line on the bridge or the existing poles is determined to be not feasible, the applicant shall site the power poles outside the limits of the Santa Ynez River riparian vegetation, use "raptor-safe" pole designs with the conductors spaced as far apart as possible to minimize the potential for bird wings to span them, install poles and lines outside the breeding season of birds (March 1 through August 15), cover the augered holes if the poles are not installed immediately, elevate the power line above the level of the tree canopy, taking into consideration future growth of the canopy, and fit wires with some type of device to make them more visible, such as bright-colored plastic balls. Pole designs will either discourage raptor nesting or be made suitable for nesting by ~~If the pole lines are of a type that raptors might nest on, investigate the feasibility of~~ fitting the poles with 3 ft. by 3 ft. nesting platforms a minimum of 4 feet above the tops of the poles as recommended by the California Department of Fish and Game (CDFG). CDFG and the U.S. Fish and Wildlife Service (USFWS) will be contacted for review and approval of pole design at the time the power line to Valve #2 is deemed necessary. TB-3 ~~Prior to construction~~ Immediately (within 48 hours) prior to each critical pole placement activity, including excavation, foundation installation, pole placement, and stringing, applicant-funded surveys within the disturbance area shall be conducted by a SBC- and VAFB-approved wildlife biologist to document and remove individuals of wildlife species encountered, including reptiles, amphibians, and badgers and other burrowing animals, as appropriate to suitable habitat outside the area of impact. The construction area shall ~~should~~ be regularly monitored to ensure that wildlife species do not enter areas where they would be exposed to hazards.	Insignificant

Table ES.3b: Class II Impacts of the Proposed Project				
Impact #	**Project Phase**	**Description of Impact**	**Mitigation Measures**	**Residual Impact**
TB.2	*Construction*	Modification of Valve Site #2, modifications at LOGP, and installation of power poles and the transformer station have the potential to increase erosion and sedimentation in aquatic habitats.	TB-4 All ground disturbance activities shall occur, if feasible, during the dry season (generally April 1 through November 1). Work can continue during the rainy season if a County and CCC (if required) approved erosion and sediment control plan is in place. The applicant shall submit construction plans and schedules to SBC and CCC (if required) for review and approval prior to land use clearance. TB-5 Site-specific measures consistent with the Restoration, Erosion Control, and Revegetation Plan (RECRP) approved under Point Pedernales FDP Condition H-1 shall be updated and implemented as applicable to new areas of ground disturbance along the existing ROW. Erosion and sediment control measures (e.g., water bars, silt fencing, dust control, and/or other appropriate measures) shall be implemented at any drainages; along portions of the affected project area that intersect slopes greater than a 2-to-1 incline; and within 200 feet of downslope water bodies. Appropriate erosion and sediment control measures shall be installed prior to ground disturbance and maintained until after the rainy season or until vegetation has become re-established in the disturbed areas. The applicant shall submit erosion and sediment control plans and specifications to SBC for approval prior to land use clearance.	Insignificant
GEOLOGIC RESOURCES (Section 5.3)				
GR.2	*Construction*	Ground-disturbing construction activities could result in geologic disturbances such as slope failure, gullying, erosion, and sedimentation.	GR-1 Best Management Practices (BMPs), such as temporary berms and sedimentation traps, such as silt fencing, straw bales, and sand bags, shall be installed to minimize erosion of soils and sedimentation in nearby drainages. The BMPs shall be included in the Oil Spill Response Plan (OSRP). The BMPs shall include maintenance and inspection of the berms and sedimentation traps during rainy and non-rainy periods, as well as revegetation of impacted areas. Revegetation shall address plant type as well as monitoring to ensure appropriate coverage of exposed areas and shall be consistent with existing project revegetation plans.	Insignificant
GR.3	*Construction*	Upgrades and modifications of facilities at LOGP could result in new, continued or accelerated ground settlement.	GR-2 The 2007 grouting program shall be completed prior to any equipment additions/modifications at the LOGP. If deemed necessary by the County System Safety and Reliability Review Committee (SSRRC), based on equipment weights and foundation requirements, an elevation surveys shall be conducted before and during the equipment additions~~recommissioning~~/modification period followed by routine post-construction monitoring as deemed appropriate by the SSRRC. The elevation survey should use existing benchmarks to continue the subsidence monitoring currently being conducted at LOGP~~and a pre- and post-recommissioning monitoring plan shall be developed. The plan shall require a baseline survey 30 days prior to construction and once per month during LOGP equipment recommissioning/ modifications. Post-commissioning survey frequency shall be based on the settlement results measured during recommissioning. The plan shall include contingencies for soil grouting or other ground stabilization measures to prevent damage to the facility.~~	Insignificant

Table ES.3b: Class II Impacts of the Proposed Project

Impact #	Project Phase	Description of Impact	Mitigation Measures	Residual Impact
GR.5	*Extension of Life*	Scouring along drainage areas could cause impacts to the pipeline and increase pipeline failure probabilities.	GR-3 The applicant shall implement a creek and drainage maintenance program to monitor and repair potential scour areas that could affect the pipeline integrity. The plan shall include annual surveys of the pipeline route and any adjacent drainages within 500 feet that are up slope of the pipeline right-of-way. Any areas that exhibit scouring or erosion shall be documented. Areas that exhibit increased scour should be addressed through stabilization or other appropriate permanent erosion control measures.	Insignificant
ONSHORE WATER RESOURCES (Section 5.4)				
OWR.1	*Construction*	Project-related construction could cause erosion or siltation resulting in substantial degradation of surface water quality.	Mitigation Measures OWR-1, GR-1, AG-6, AG-7, TB-18 and TB-22 would reduce the magnitude of potential impacts to onshore water quality associated with disturbances to soils and vegetation during construction. OWR-1 Prepare a Stormwater Pollution Prevention Plan (SWPPP) that describes Best Management Practices (BMPs) to be implemented for the purpose of minimizing soil loss and other construction-related sources of water pollution for any new construction associated with the project. The SWPPP will be prepared in accordance with RWQCB guidelines and will designate BMPs that will be followed during construction activities. Erosion-minimizing efforts may include measures such as avoiding excessive disturbance of steep slopes; using drainage control structures (e.g., coir rolls or silt fences) to direct surface runoff away from disturbed areas; strictly controlling soil stockpiling and vehicular traffic; implementing a dust-control program during construction; restricting access to sensitive areas; using vehicle mats in wet areas; and revegetating disturbed areas following construction. Erosion-control measures will be installed before extensive clearing and grading begins, and before the onset of winter rains. The SWPPP BMPs shall specify that the staging of construction materials, equipment, and excavation spoils, and refueling of equipment will be performed at least 100 feet outside of drainage channels and intermittent streams, where these receive overland runoff. Mulching, seeding, or other suitable stabilization measures will be used to protect exposed areas during and after construction activities. If required, concrete washout stations will be established to avoid direct release to surface water or to areas where groundwater could become contaminated. The SWPPP shall be submitted to SBC/CCC for review and approval prior to construction..	Insignificant
MARINE BIOLOGICAL RESOURCES (Section 5.5)				
MB.5	*Drilling* *Extension of Life*	Increased vessel traffic resulting from the proposed project drilling, production, and oil clean up response may impact marine mammals and marine turtles.	In addition to Mitigation Measure MB-1c, the following mitigation measure is required: MB-4 A marine mammal observer shall be employed on each vessel servicing Platform Irene as described herein. The observer shall be provided training which focuses on the identification of marine mammal species, the specific behavior of species common to the project area, and awareness of seasonal concentrations of marine mammals. The marine mammal observer shall be placed on all support vessels during the spring and fall gray whale migration periods and during periods/seasons having high concentrations of marine mammals in the project area, such as the early summer blue whale migration. The observer shall have no other responsibilities during periods when the vessels are in transit.	Insignificant

Table ES.3b: Class II Impacts of the Proposed Project				
Impact #	**Project Phase**	**Description of Impact**	**Mitigation Measures**	**Residual Impact**
			The observer shall have unobstructed views onboard each vessel and serve as lookout so that collisions with marine mammals can be avoided. Additionally, vessel operators or the applicant shall develop, submit for approval, and implement a contingency plan that focuses on avoidance procedures when marine mammals are encountered at sea. Minimum components of the plan include: a) Vessel operators will make every effort to maintain a distance of 1,000 feet from sighted whales and other threatened or endangered marine mammals or marine turtles. b) Vessel operators shall avoid travelling through blue whale feeding grounds and shall adjust transit routes to avoid large-scale krill populations during the annual blue whale migration period in the Santa Barbara Channel. ~~Support vessels will not cross directly in front of migrating whales or any other threatened or endangered marine mammals or marine turtles.~~ c) When paralleling whales, support vessels will operate at a constant speed that is not faster than the whales. d) Female whales will not be separated from their calves. e) Vessel operators will not herd or drive whales. f) If a whale engages in evasive or defensive action, support vessels will drop back until the animal moves out of the area. g) Any collisions with marine wildlife will be reported promptly to the Federal and State agencies listed below pursuant to each agency's reporting procedures. Stranding Coordinator, Southeast Region National Marine Fisheries Service Long Beach, CA 90802-4213 (310) 980-4017 Enforcement Dispatch Desk California Department of Fish and Game Long Beach, CA 90802 (562) 590-5132 or (562) 590-5133 California State Lands Commission Environmental Planning and Management Division Sacramento, CA 95825-8202 (916) 574-1890 ~~MB-5 PXP shall make a yearly contribution of $90,000 toward establishing a marine mammal and sea bird impact mitigation fund. The funding shall be used for either facilities construction or operating costs associated with the rescue and rehabilitation of injured marine mammals and sea birds. This yearly contribution shall be in lieu of the applicant's annual three (3) point Coastal Resource Enhancement Fund (CREF) assessment for biological resource impacts, as currently required by Condition N-1 of PXP's Final Development Plan for the Point Pedernales Project.~~	

Table ES.3b: Class II Impacts of the Proposed Project				
Impact #	**Project Phase**	**Description of Impact**	**Mitigation Measures**	**Residual Impact**
			AIR QUALITY (Section 5.8)	
Air.2	*Drilling Increased Throughput Extension of Life*	Increased oil processing and drilling of the new Tranquillon Ridge Unit wells at Platform Irene would result in an increase in operational air emissions.	Air-2 PXP shall ensure that emission reductions are provided to fully mitigate increases in operational criteria pollutant emissions associated with the proposed project consistent with SBCAPCD Rules and Regulations. The documentation supporting the available emission mitigations for operations shall be submitted to the SBCAPCD prior to land use clearance. No operations shall occur until the applicable project Permits to Operate are modified.	Insignificant
			CULTURAL RESOURCES (Section 5.12)	
CR.2	*Construction*	Modifications to Valve Site #2 and installation of power poles would result in ground disturbance and potential impacts on cultural resources.	CR-2 PXP shall revise grading plans to include note for protocols to follow during unexpected discovery of archaeological resources. The grading plans shall be submitted to P&D prior to issuance of coastal development permit or land use clearance for grading. Prior to construction all crew members shall receive training on unanticipated cultural resource discovery protocols. In the event of an unanticipated cultural resource discovery during construction, all ground disturbances within 200 feet of the discovery shall be halted or re-directed to other areas until the discovery has been documented by a county-qualified archaeologist, and its potential significance evaluated consistent with Santa Barbara County Cultural Resource Guidelines. Resources considered significant shall be avoided by project redesign. If avoidance is not feasible, the cultural resource shall be subject to a Phase 3 data recovery mitigation program (with Native American monitoring, if applicable), consistent with Santa Barbara County Cultural Resource Guidelines. CR-4 A Phase I archaeological surface survey shall be conducted at unsurveyed areas of ground disturbance associated with installation of the power pole line across the Santa Ynez River and proposed trenching areas prior to land use clearance to identify any cultural resources that may be affected during construction. If a cultural resource is encountered during the survey, it shall be shall be avoided by power pole and/or trench relocation. If archaeological site avoidance is technologically infeasible due to topographic or engineering constraints, the site's potential significance shall be evaluated pursuant to Santa Barbara County Cultural Resource Guidelines and CEQA Guidelines Section 15064.5 criteria. Resources considered significant and unavoidable shall be subject to a Phase 3 data recovery program (with Native American monitoring, if prehistoric), consistent with Santa Barbara County Cultural Resource Guidelines, and if located on VAFB, shall incorporate the investigation methodology reviewed and approved by VAFB environmental management staff. To comply with VAFB requirements, any trenching or excavation in a floodplain on VAFB shall require archaeological monitoring.	Insignificant
			AESTHETICS/VISUAL RESOURCES (Section 5.13)	
Visual.3	*Operations*	Visual impacts due to the new transformer station and power lines to Valve Site #2.	Visual-3 Prior to constructing the power line to Valve Site #2, the applicant shall enter into discussions with VAFB to determine the feasibility of placing the power line on the 13th Street bridge or using the existing VAFB power poles for crossing the Santa Ynez River. The applicant shall also use existing poles to the maximum extent feasible for approaching the existing pipeline corridor's dirt road. The applicant shall utilize one of	Insignificant

Table ES.3b: Class II Impacts of the Proposed Project				
Impact #	**Project Phase**	**Description of Impact**	**Mitigation Measures**	**Residual Impact**
			these options if they are allowed by VAFB. The applicant shall submit documentation to the SBC P&D from VAFB detailing their position on using the 13th Street bridge or the existing power poles for crossing the Santa Ynez River by the power line to Valve Site #2. This documentation shall be submitted to SBC P&D prior to land use clearance for construction of the power line to Valve Site #2.	
Accidental Releases (e.g. Oil Spills and Gas Releases)				
GEOLOGIC RESOURCES (Section 5.3)				
GR.1	*Increased throughput Extension of Life*	Remediation activities associated with a pipeline spill could increase slope failures, erosion, sedimentation, and gullying.	See Mitigation Measure GR-1 above.	Insignificant
ONSHORE WATER RESOURCES (Section 5.4)				
OWR.4	*Increased throughput Extension of Life*	Remediation activities associated with a pipeline spill could increase erosion and siltation and substantially degrade surface water quality.	Implementation of Mitigation Measures OWR-1, GR-1 and OWR-6 would reduce the potential for causing significant erosion or siltation associated with spill remediation activities along the pipeline right-of-way.	Insignificant
AGRICULTURAL RESOURCES (Section 5.15)				
AG.3	*Increased Throughput Extension of Life*	Potential degradation and reduced productivity of agricultural land from a pipeline leak or rupture resulting in an oil or produced water spill.	AG-1 PXP shall revise the Point Pedernales Oil Spill Response Plan (OSRP) and submit to SBC for review and approval. The Plan to include specific cleanup techniques for agricultural lands, focusing on minimizing removal of top soil. ~~The OSRP shall include a compensation plan for the purchase of agricultural crops lost/damaged and for replacement of removed top soil with equivalent imported soils.~~	Insignificant
Maintenance and Repairs				
TERRESTRIAL AND FRESHWATER BIOLOGY (Section 5.2)				
TB.3	*Extension of life*	Pipeline maintenance and repair, if needed, would result in potential <u>disturbance and</u> removal of native vegetation and wildlife habitat and erosion and sedimentation as a result of ground disturbance.	TB-6 Applicant shall prepare and submit ~~a Standard Maintenance and Repair Plan that will include~~ <u>as an update to the RECRP (FDP Condition H-1 and applicable CDP conditions),</u> plans for restricting work areas, delineating construction zones, biological surveys of disturbance areas, and impact minimization efforts, including scheduling. Where ground disturbances are required, the Plan would specifically include: • Restrict construction activities, equipment and personnel to existing disturbed areas (such as roads, pads, or otherwise disturbed areas) to the maximum extent feasible. • Clearly mark and delineate in the field the limits of the construction zone. Personnel or equipment in native habitats outside the construction limits shall be prohibited. • Biologically sensitive resources, such as occurrences of sensitive plant species including sand mesa manzanita, La Purisima manzanita,Gaviota tarplant, coast buckwheat (which may support El Segundo blue butterfly) and black-flowered figwort as well as individual oak trees, shall be identified through surveys conducted by a qualified biologist acceptable to the resource agencies prior to ground disturbance and shall be clearly marked on work or construction plans so they may be avoided. • Where avoidance of biologically sensitive features is infeasible, the plan shall specify	Insignificant

Table ES.3b: Class II Impacts of the Proposed Project				
Impact #	Project Phase	Description of Impact	Mitigation Measures	Residual Impact
			means by which impacts on the features would be minimized and their survival and recovery facilitated (such as preserving the root system and root crown of resprouting species such as sand mesa manzanita). TB-7 Site-specific measures listed in the approved RECRP (FDP Condition H-1 and applicable CDP conditions) shall be updated and implemented as applicable for new areas of ground disturbance along the existing pipeline right-of-way. Prior to the issuance of a Land Use Permit, an updated RECRP ~~Habitat Revegetation, Restoration, and Monitoring Plan (HRRMP)~~shall be submitted to Planning and Development for approval. Once approved, the plan shall be implemented by PXP and monitored by Planning and Development through advanced written updates of construction status and plans. Success of the restoration and revegetation plans should be monitored by a qualified independent biologist. The plan shall contain, but not be limited to, the following: • Procedures for stockpiling and replacing topsoil, replacing and stabilizing backfill, such as at stream crossings, steep or highly erodible slopes, and in dune areas. Additionally, provisions ~~should~~ shall be made for recontouring to approximate the original topography. Excess fill shall be disposed of offsite unless suitable arrangements are made with the property owner. Excess fill shall not be deposited in any drainage, or on any unstable slope. Topsoil shall be salvaged, protected, and replaced. This shall include at a minimum the upper 6-12 inches of topsoil in all areas of open land, other than road shoulders. Final construction plans shall designate areas of topsoil storage and protection, and procedures for handling excess trench spoils. Within wetland areas, topsoil salvage shall be as described above except that wetland topsoil shall be stored separately from all other spoil piles. It shall be labeled with signs as "wetland topsoil." The plan shall contain specific provisions for protection of topsoil stockpiles (such as covering them or using a tackifier or temporary hydromulch) if the soil is to be left for an extended period of time to prevent loss of topsoil due to erosion. Stockpiles shall not be placed in biologically sensitive areas. • Specific plans for control of erosion, gully formation, and sedimentation, including, but not limited to, sediment traps, check dams, diversion dikes, culverts, and slope drains. Plans would also include, where applicable, dikes and catch basins proposed along the pipeline route, to ensure protection and maintenance of the height of berms and containment capacity of the basins, for the life of project. A soil conservation program, to be applied in areas of 20 percent (or greater) slopes along the pipeline corridor, detailing site specific techniques, such as use of jute or excelsior netting, to stabilize soil and sand and encourage revegetation of steeper slopes. Plans shall identify areas with high erosion potential and the specific control measures for these sites. • Procedures for containing sediment and allowing continued downstream flow at stream or biologically significant drainage crossings (identified in the EIS/EIR [84-EIR-7]), including scheduling construction activities during periods of historical low-flow and having erosion control structures or sediment retention devices in place prior	

Table ES.3b: Class II Impacts of the Proposed Project				
Impact #	**Project Phase**	**Description of Impact**	**Mitigation Measures**	**Residual Impact**
			to start of construction. Existing water levels in all streams shall be maintained at all times during construction. • Procedures for timely re-establishment of vegetation that replicates indigenous and naturalized communities disturbed. These should include: measures preventing invasion and/or spread of undesired plant species; restoration of wildlife habitat; restoration of native communities and native plant species propagated from locally-acquired existing plant species, including any sensitive species (such as sand mesa manzanita, La Purisima manzanita, and black-flowered figwort); and replacement of trees at the appropriate rate. RECRP performance criteria for weed invasion shall be updated to require action to control any and all invasive noxious weeds (listed as of 2007 by the California Invasive Plant Council that could interfere with revegetation efforts. Examples include, but are not limited to, Cape ivy (*Delairea odorate*) and onion weed (*Asphodelus fistulosus*). • Procedures for minimizing tree removal, tree root and branch damage, and removal of or damage to other significant plant species including confining disturbance to the approved right-of-way; providing for onsite monitoring of construction by a qualified independent local biologist; and flagging significant species and areas that should be avoided. • Procedures for restoration of riparian corridor stream banks and streambed substrates and elevation, emphasizing natural and existing materials, shall be included as well as methods for minimizing exposure of riparian habitats to disturbance during construction. • Monitoring procedures and minimum performance criteria to be satisfied for revegetation and erosion control are specified in Table 5 of the existing RECRP. These criteria shall be updated as necessary for each vegetation type, including percent coverage that must be achieved, monitoring methods and frequencies, and quantitative thresholds for success, reevaluation, or remedial action. Updates to the existing RECRP~~The performance criteria should~~ shall consider the current level of disturbance and the condition of adjacent habitats. Consistent with the RECRP, monitoring ~~should~~ shall continue for 3-5 years, depending on habitat, or until performance criteria are met. Appropriate remedial measures, such as replanting, erosion control or weed (including invasive exotic species) control, shall be identified, using the existing RECRP as a guideline, and implemented if it is determined that performance criteria are not being met.	
TB.4	*Extension of Life*	Pipeline repair may injure or eliminate individuals or colonies and habitat of state or federally listed plant species including seaside bird's beak, Surf thistle, beach spectacle pod, La Graciosa thistle, Gaviota tarplant, and possibly Pismo clarkia.	TB–8 Prior to ground disturbance or other activities, a qualified botanist shall survey all proposed construction, staging and access areas for presence of state or federally-listed plant species and for coast buckwheat, which may support El Segundo blue butterfly. Colonies shall be mapped and clearly marked and numbers of individuals in each colony and their condition determined and recorded. To the maximum extent feasible, construction areas and access roads shall avoid loss of individual plant and or damage to habitats supporting federal or state-listed plants.	Insignificant

Table ES.3b: Class II Impacts of the Proposed Project

Impact #	Project Phase	Description of Impact	Mitigation Measures	Residual Impact
			TB-9 Where impacts to these species are unavoidable, the applicant shall develop and implement a site- and species-specific salvage, propagation, replanting, and monitoring ~~program~~ plan consistent with the requirements of the RECRP that would utilize both seed and salvaged (excavated) plants constituting an ample and representative sample of each colony of the species that would be impacted. The ~~program~~ plan shall include measures to perpetuate to the maximum extent feasible the genetic lines represented on the impacted sites by obtaining an adequate sample prior to construction, propagating them and using them in the restoration of that site. The ~~program~~ plan shall be approved by the County, CCC, ~~U.S. Fish and Wildlife Service (~~USFWS~~)~~ and CDFG prior to its implementation. Activities involving handling of federal and/or state-listed plant species may require permits including a memorandum of understanding from USFWS and/or CDFG. The plan shall incorporate provisions for recreating suitable habitat and measures for re-establishing self-sustaining colonies of seaside bird's beak, beach spectacle-pod and Surf thistle should they be impacted on the site. The plan shall include provisions for monitoring and performance assessment including standards that would allow annual assessment of progress, and provisions for remedial action, should the species fail to re-establish successfully.	
TB.5	*Extension of Life*	Pipeline repair or maintenance may cause disturbance, injury or mortality to individuals and affect habitat of common and federally and state-listed fish and other sensitive wildlife species including western snowy plover, California least tern, California red-legged frog, California tiger salamander, southwestern pond turtle, tidewater goby, and steelhead.	Implementation of Mitigation Measures OWR-1, GR-1, and TB-4, scheduling the work during the dry season; TB-5, controlling erosion; TB-6, minimizing disturbance to native habitats; and TB-7, preparing and implementing of an approved Habitat, Revegetation, Restoration and Monitoring Plan would reduce impacts to native wildlife, including sensitive wildlife species. Pre-project surveys by a qualified biologist to determine presence/absence of sensitive species, and monitoring to ensure that sensitive species do not enter the construction area are additional appropriate species protection measures. These and other applicable measures are described more fully under the pipeline replacement alternative (see Mitigation Measures under Impacts TB.12 through TB.16). Scheduled maintenance and repair activities would normally be conducted after specific environmental review conducted as part of issuance of a grading permit or other permit by the Counties of Santa Barbara or San Luis Obispo, as applicable. Emergency repairs are subject to a different set of guidelines. Implementation of the following measure would further reduce impacts to wildlife species: TB-10 All routine pipeline repair and maintenance activities occurring within the beach and foredune habitats at landfall (Wall/Surf Beach) need to be scheduled to avoid the breeding season (March 1 to September 30) of the western snowy plover and California least tern. A contingency plan for emergency repairs in this area during the nesting season needs to be developed in coordination with 30 CES/CEVPN at VAFB and with the USFWS. This may require Section 7 consultation. Schedule and timing restrictions for this shall be included in the updated RECRP ~~Standard Maintenance and Repair Plan~~ (Mitigation Measure TB-6) to be submitted for SBC review	Insignificant

Table ES.3b: Class II Impacts of the Proposed Project				
Impact #	**Project Phase**	**Description of Impact**	**Mitigation Measures**	**Residual Impact**
			and approval prior to land use clearance. The plan shall include impact avoidance measures to be implemented in the event that emergency repairs cannot be scheduled to avoid the breeding season.	
GEOLOGIC RESOURCES (Section 5.3)				
GR.4	*Extension of Life*	Ground-disturbing maintenance activities could result in geologic disturbances such as slope failure, gullying, erosion, and sedimentation.	See Mitigation Measure GR-1 above.	Insignificant
ONSHORE WATER RESOURCES (Section 5.4)				
OWR.3	*Extension of Life*	Continued monitoring and pipeline maintenance and replacement activities associated with the onshore pipeline system could cause disturbances to soils that could cause erosion and subsequent siltation resulting in degradation of surface water quality.	Implementation of Mitigation Measure OWR-1 and GR-1 would reduce potentials for causing significant erosion or siltation associated with excavation along the pipeline right-of-way, along with the following measure: OWR-6 If soil excavation is needed to expose buried pipeline or cleanup a spill within a stream bed, the area shall be restored to the maximum extent feasible to pre-spill conditions after excavation is completed.	Insignificant
OCEANOGRAPHY AND MARINE WATER QUALITY (Section 5.6)				
MWQ.2	*Drilling*	Reduced marine water and sediment quality would result from increased oceanic discharge of drilling fluids.	No additional mitigation is required beyond the requirements imposed by the NPDES discharge permit.	Insignificant
MWQ.3	*New Operations*	Reduced marine water quality would result from the oceanic discharge of produced water.	In addition to implementation of NPDES permit requirements, Mitigation Measure MB-3 would also apply to this impact.	Insignificant
MWQ.4	*Drilling* *~~Extension of Life~~New Operations*	Reduced marine water quality would result from additional discharges of sanitary wastes, desalinization brine, and other materials from Platform Irene.	No mitigation measures beyond the NPDES permit restrictions currently imposed on the offshore facility are required.	Insignificant
CULTURAL RESOURCES (Section 5.12)				
CR.1	*Extension of Life*	Pipeline maintenance and repair would result in ground disturbance and potential impacts on cultural resources.	CR-1 PXP shall prepare and submit grading plans showing all ground disturbances within 200 feet of a recorded archaeological site. The grading plans shall be submitted to P&D prior to issuance of coastal development permit or land use clearance for grading. All ground disturbance within 200 feet of a recorded archaeological site shall be monitored by a County-qualified archaeologist and, if prehistoric, by a Native American observer, unless the resource has been previously determined to have no potential for significance because it is re-deposited, an isolated occurrence, modern, or otherwise lacks data potential.	Insignificant

Table ES.3b: Class II Impacts of the Proposed Project

Impact #	Project Phase	Description of Impact	Mitigation Measures	Residual Impact
			CR-2 PXP shall revise grading plans to include note for protocols to follow during unexpected discovery of archaeological resources. The grading plans shall be submitted to P&D prior to issuance of coastal development permit or land use clearance for grading. Prior to construction all crew members shall receive training on unanticipated cultural resource discovery protocols. In the event of an unanticipated cultural resource discovery during construction, all ground disturbances within 200 feet of the discovery shall be halted or re-directed to other areas until the discovery has been documented by a county-qualified archaeologist, and its potential significance evaluated consistent with Santa Barbara County Cultural Resource Guidelines. Resources considered significant shall be avoided by project redesign. If avoidance is not feasible, the cultural resource shall be subject to a Phase 3 data recovery mitigation program (with Native American monitoring, if applicable), consistent with Santa Barbara County Cultural Resource Guidelines. CR-3 If pipeline maintenance and repair are planned on a segment of the unsurveyed pipeline route, then a Phase I archaeological surface survey shall be conducted prior to land use clearance for grading to identify any cultural resources that may be affected. If a cultural resource is encountered during the survey, it shall be documented by a County-qualified archaeologist and its potential significance evaluated in terms of applicable criteria prior to maintenance and repair work. Resources considered significant shall be avoided or subject to a Phase 3 data recovery program (with Native American monitoring, if applicable), consistent with Santa Barbara County Cultural Resource Guidelines.	
CR.4	*Extension of Life*	Pipeline repair associated with an accidental produced water spill from the pipeline would result in ground disturbance and potential impacts on cultural resources.	Mitigation Measures CR-1 and CR-2 would be applicable.	Insignificant
AGRICULTURAL RESOURCES (Section 5.15)				
AG.4	*Extension of Life*	Potential loss of agricultural productivity during pipeline repair and maintenance.	~~AG-2 Monetary Payment for Lost Agricultural Productivity. Landowners shall receive compensation for the loss of any crops directly resulting from pipeline replacement activities. Compensation will take into account the duration of lost agricultural productivity~~ AG-2~~3~~ Soil Replacement and Replanting. All soils within agricultural lands disturbed by pipeline replacement activities shall be replaced and if necessary enriched to support their former crops (or cattle grazing areas). All disturbed areas shall be restored in accordance with land owner agreements ~~replanted at a 1:1 ratio. Applicant shall prepare and submit for SBC review and approval, a soil preservation plan that describes activities, including soil replacement, soil enrichment, and replanting (at a 1:1 ratio) to take place after pipeline replacement activities~~.	Insignificant

Table ES.3c
CLASS III Impacts of the Proposed Project
Impacts that are Adverse but Insignificant

(In accordance with State and local policy, impacts are to be mitigated to the maximum extent feasible.)

Table ES.3c: Class III Impacts of the Proposed Project

Impact #	Project Phase	Description of Impact	Mitigation Measures	Residual Impact
Construction and Operations				
GEOLOGICAL RESOURCES (Section 5.3)				
GR.6	*Operation*	Earthquake-induced tsunami could cause scour and endanger worker safety.	GR-4 The applicant shall conduct a study to determine the probable maximum tsunami and evaluate potential flooding and scour in the Santa Ynez River valley and at project facilities, as appropriate. The scour analysis shall determine a minimum burial depth to protect the pipe. In addition, the Applicant shall include in the Project Safety Plan a discussion of tsunami hazards, training and ensure that work crews receive tsunami-warning notifications from the Pacific Tsunami Warning Center (operated by NOAA) in accordance with the safety plan. If no such Project Safety Plan is prepared, a tsunami safety plan is herein required and shall include a protocol for workers to follow in the event of a tsunami. The tsunami plan shall be submitted to SBC P&D for review and approval prior to land use clearance.	Insignificant
ONSHORE WATER RESOURCES (Section 5.4)				
OWR.5	*Extension of Life*	Increased water injection rates could potentially infiltrate fresh water aquifers.	No mitigation measures are proposed because of existing regulatory oversight of injection wells.	Insignificant
OWR.6	*Extension of Life*	~~Continued use of groundwater by LOGP~~The project could contribute or lead to groundwater basin~~an~~ overdraft~~condition~~.	No mitigation measures are ~~been~~ proposed because of the nominal contribution of the LOGP.	Insignificant
MARINE BIOLOGICAL RESOURCES (Section 5.5)				
MB.1	*Increase Throughput Extension of Life*	Oil spills from the project may impact plankton.	No mitigation measures have been identified.	Insignificant
MB.2	*Drilling*	The discharge of drilling muds and cuttings from Platform Irene may potentially impact marine organisms in the project area.	MB-2 The shunt depth (150 feet below the sea surface) for the discharge of drilling muds and cuttings shall be continued for the proposed project. The shunt depth shall be stated in the development plan that is submitted to MMS prior to drilling.	Insignificant
MB.3	*Operations*	Discharge of produced water from Platform Irene may potentially impact marine organisms in the project area.	MB-3 The shunt depth (180 feet [55 m] below the sea surface) for the discharge of produced water shall be continued for the proposed project. The shunt depth shall be stated in the development plan that is submitted to MMS prior to drilling.	Insignificant
MB.4	*Drilling*	Noise caused by drilling activities may potentially disturb marine mammals and marine birds in the project area.	No mitigation measures have been identified.	Insignificant

Table ES.3c: Class III Impacts of the Proposed Project				
Impact #	**Project Phase**	**Description of Impact**	**Mitigation Measures**	**Residual Impact**
MB.6	*Operations*	The uptake of sea water may result in impingement and entrainment of marine organisms.	No mitigation measures have been identified.	Insignificant
MB.7	*Operations*	Lighting on Platform Irene may have adverse effects on fishes and zooplankton.	No mitigation measures have been identified	Insignificant
COMMERCIAL AND RECREATIONAL FISHING/KELP HARVESTING (Section 5.7)				
CRF/ KH.3	*Drilling*	The discharge of drilling muds and drill cuttings from Platform Irene may potentially impact kelp communities in the project area.	No mitigation measures have been identified.	Insignificant
CRF/ KH.4	*Drilling* *Extension of Life*	Marine Vessel traffic to and from Platform Irene could cause loss or damage to commercial fishing gear in the project area.	CRF/KH-1 Disputes over damage to commercial fishing gear resulting from support vessel traffic to and from Platform Irene shall be submitted to the Joint Oil/Fisheries Committee for resolution.	Insignificant
CRF/ KH.5	*Drilling* *Extension of Life*	The deposition of shells, or shell mounds, could prevent commercial trawling activities beneath Platform Irene.	CRF/KH-2 At the time of platform abandonment, the Applicant shall ensure that the environmental review of the abandonment activities pursuant to the National Environmental Policy Act (NEPA) and California Environmental Quality Act (CEQA), as appropriate, includes an analysis as to whether or not the shell mounds should be removed or modified so they do not interfere with commercial trawling activities. This subsequent NEPA/CEQA review shall evaluate the best available technologies for removal or modification of the shell mounds. The best available technology shall be determined by the Applicant and the permitting agencies, in consultation with the Joint Oil/Fisheries Liaison Office and shall be implemented.	Insignificant
AIR QUALITY (Section 5.8)				
Air.1	*Construction*	Construction activities would generate air emissions.	Air-1 PXP shall prepare and submit Dust Control and Reduction Plan to SBCAPCD prior to land use clearance. PXP shall implement dust reduction measures during construction. The following APCD Standard Dust Mitigation Measures shall be implemented: 1. Dust generated by the development activities shall be retained onsite and kept to a minimum by following the dust control measures listed below. Reclaimed water shall be used whenever possible. a. During clearing, grading, earth moving or excavation, water trucks or sprinkler systems are to be used in sufficient quantities to prevent dust from leaving the site and to create a crust, after each day's activities cease. b. After clearing, grading, earth moving or excavation is completed, the disturbed area must be treated by watering, or revegetating; or by spreading soil binders until the area is paved or otherwise developed so that dust generation would not occur. c. During construction, water trucks or sprinkler systems shall be used to keep all areas of vehicle movement damp enough to prevent dust from leaving the site. At a minimum, this would include wetting down such areas in the late morning and after work is completed for the day. Increased watering frequency will be required whenever the wind speed exceeds 15 mph.	Insignificant

Table ES.3c: Class III Impacts of the Proposed Project

Impact #	Project Phase	Description of Impact	Mitigation Measures	Residual Impact
			2. Importation, exportation and stockpiling of fill material: a. Soil stockpiled for more than two days shall be covered, kept moist, or treated with soil binders to prevent dust generation. b. Trucks transporting fill material to and from the site shall be tarped from the point of origin. c. If the construction site is greater than five acres, gravel pads must be installed at all access points to minimize tracking of mud onto public roads. 3. Activation of increased dust control measures: a. The contractor or builder shall designate a person or persons to monitor the dust control program and to order increased watering, as necessary, to prevent transport of dust offsite. Their duties shall include holiday and weekend periods when work may not be in progress. The name and telephone number of such persons shall be provided to the APCD.	
Air.3	*Increased Throughput Extension of Life*	Increased health risks from the increased air emissions due to the expected increase in equipment operation and oil volumes processed.	No mitigation measures have been identified.	Insignificant
TRAFFIC (Section 5.9)				
T.1	*Construction*	Onshore construction associated with the project would temporarily add to local road traffic.	T-1 PXP shall include a restriction on delivery of equipment and supplies to non-rush hour periods (rush hour periods are considered to be 7a.m. to 9a.m. and 4p.m. to 6p.m.) in the project construction plans that are sent out in the contractor bid packages. The construction plans shall be submitted to SBC Planning and Development for approval prior to land use clearance.	Insignificant
T.2	*Increased Throughput Extension of Life*	Increased production at LOGP would increase facility truck traffic on local roads.	T-2 PXP shall include a restriction on LPG/NGL and sulfur truck traffic at the LOGP to non-rush hour periods (rush hour period are considered to be 7a.m. to 9a.m. and 4p.m. to 6p.m.) in their contracts with vendors. The applicant shall also document arrival and departure times for these trucks. This requirement shall be include in the Traffic Management Plan (TMP). The revised TMP shall be submitted to SBC Planning and Development for approval prior to land use clearance.	Insignificant
T.3	*Drilling*	Increased offshore drilling activity would increase offshore traffic.	T-3 Require supply boats from Port Hueneme to use the Coast Guard's recommended marine traffic corridors to the maximum extent feasible.	Insignificant
NOISE (Section 5.10)				
N.1	*Drilling*	Drilling associated with the proposed project would increase ambient noise levels due to drilling rig operation and additional helicopter and supply boat trips.	N-1 PXP shall adhere to ~~establish~~ overland flight height minimums of 1,000 feet when feasible with the approval of the FAA, and shall not fly over Oso Flaco Lake.	Insignificant
N.2	*Construction*	Construction noise would temporarily increase ambient daytime noise levels.	N-2 Construction activities shall be limited to 7:00 a.m. and 4:00 p.m., Monday through Friday. Construction equipment maintenance shall be limited to the same hours. Non-noise generating construction activities such as interior painting are not subject to these restrictions. Signs shall note appropriate contact information for a	Insignificant

Table ES.3c: Class III Impacts of the Proposed Project				
Impact #	**Project Phase**	**Description of Impact**	**Mitigation Measures**	**Residual Impact**
			complaint to be filed. Signs stating these restrictions shall be provided by the applicant and posted on site. Signs shall be in place prior to issuance of Land Use Permit and throughout grading and construction activities. All complaints received shall be forwarded to SBC within 24 hours of receipt by PXP.	
N.3	*Extension of Life*	Operations noise from pumps would increase long-term ambient noise levels.	No mitigation measures have been identified.	Insignificant
AESTHETICS/VISUAL RESOURCES (Section 5.13)				
Visual.2	*Operations*	Visual impacts due to installation of new equipment at Valve Site #2 and the LOGP.	Visual-2 To minimize visual effects, all new equipment shall be painted in colors that are compatible with the surroundings. The applicant shall submit the painting plans for the new facilities to SBC P&D before land use clearance. In addition, future painting plans for any existing portions of the LOGP shall be submitted to SBC for review and approval prior to commencing with painting.	Insignificant
AGRICULTURAL RESOURCES (Section 5.15)				
AG.1	*Construction*	Addition of power poles and substation to Valve Site #2 could disturb farm operations.	No mitigation measures have been identified.	Insignificant
AG.2	*Construction* *Increased Throughput* *Extension of Life*	Increased truck trips during construction and operation. Increased traffic unlikely to interfere with farm operations.	No mitigation measures have been identified.	Insignificant
ENERGY AND MINERAL RESOURCES (Section 5.16)				
Energy.1	*Construction*	Impacts to energy resources due to electricity and fuel consumption during construction phase.	No mitigation measures have been identified.	Insignificant
Energy.2	*New Operations* *Increased Throughput* *Extension of Life*	Impacts due to increased electricity and natural gas consumption by additional or upgraded equipment and due to increased operation of the existing equipment.	Energy-1 PXP ~~The applicant~~ shall prepare an-energy efficiency Study ~~to~~ be reviewed and approved by SBC and then-implemented by PXP. The Study-shall address future energy consumption by function (i.e., heater treaters, etc.) and assess available options to optimize energy efficiency utilizing existing equipment and operations. The Study-shall also include a cost-benefit analysis for cogeneration. The Study shall be submitted to SBC for review and approval prior to land use clearance for the Tranquillon Ridge Project modifications at the LOGP facility. Energy efficiency measures deemed feasible by the County shall be incorporated into the LOGP modifications.	Insignificant

Table ES.3c: Class III Impacts of the Proposed Project

Impact #	Project Phase	Description of Impact	Mitigation Measures	Residual Impact
Accidental Releases (e.g. Oil Spills and Gas Releases)				
HAZARDOUS MATERIALS/RISK OF UPSET (Section 5.1)				
Risk.1	*Increased Throughput Extension of Life*	The proposed project could generate risks to public safety by exposing the public to crude oil spills and subsequent fires.	Risk-1 ~~The applicant shall install an upgraded SCADA system on the existing emulsion line and a new system on the produced sour gas line. The new system shall have improved sensitivity to detect leaks, similar to the upgrade installed on PXP's Point Arguello facility. The new SCADA system should be able to detect 0.08 percent of flow leaks in less than 48 minutes and be able to detect leaks as small as 1/16 inch in diameter in less than two minutes.~~ The applicant shall install an upgraded state-of-the-art leak detection system on the existing emulsion pipeline and on the sour gas pipeline. The upgraded system shall use the Best Available Technology (BAT) for detection of small leaks (less than 0.5 inches in diameter) in the emulsion pipeline. The applicant shall provide the County with a comparative analysis of available technologies that have been used in applications similar to this project and the demonstrated effectiveness and reliability of those systems. The County shall review and approve the leak detection technology prior to its installation. Review and approval of the comparative analysis and installation of the approved leak detection system shall occur prior to land use permit approval.	Insignificant
Risk.2	*Extension of Life*	The proposed project could generate risks to public safety by exposing the public to produced gas releases from the sour gas pipeline from Platform Irene to the LOGP.	Risk-2 The ~~applicant~~ operator shall ensure that pipeline operation does not exceed 600 pounds per square inch (psig) and 8,000 parts per million (ppm) hydrogen sulfide. If any increase in pipeline operating pressure and/or hydrogen sulfide concentration is proposed, the operator shall conduct a risk assessment to demonstrate to the County's satisfaction that such increase would not expand the existing hazard footprint associated with the sour gas pipeline. If such demonstration cannot be made, the proposed increase in pressure/concentration shall not be approved or implemented. Mitigation Measure Risk-1 would also apply.	Insignificant
COMMERCIAL AND RECREATIONAL FISHING/KELP HARVESTING (Section 5.7)				
CRF/ KH.1	*Increased Throughput Extension of Life*	Oil spills may potentially impact commercial and recreational kelp harvests in the proposed project area.	Mitigation Measures MB-1a and MB-1b in Section 5.5, Marine Biology, would mitigate Impact CRF/KH.1 to the maximum extent feasible in accordance with County policies.	Insignificant
FIRE PROTECTION/ EMERGENCY RESPONSE (Section 5.11)				
Fire.1	*New Operations*	Due to equipment modifications at the Valve Site #2 the increased potential for upset conditions at the site could create impacts to fire protection and emergency response resources.	Fire-1 PXP shall review and revise the Fire Protection Plan, Emergency Response Plan, and Oil Spill Response Plan that apply to all the facilities which will have equipment or operations modifications due to the proposed project. The plans shall be submitted to the SBC Fire Department and P&D for review and approval prior to land use clearance.	Insignificant
Fire.2	*Operations*	Operation of the new power line to Valve Site #2 could result in impacts to fire protection and emergency response	Fire-2 The applicant shall update the LOGP Fire Protection Plan (FDP Condition P-10) to include the power line, in particular, the Flammable Vegetation Management Plan and Fire Prevention and Inspection Program parts of the plan, to	Insignificant

Table ES.3c: Class III Impacts of the Proposed Project				
Impact #	**Project Phase**	**Description of Impact**	**Mitigation Measures**	**Residual Impact**
		resources due to addition of an ignition source into a high fire hazard area.	minimize possibility of a brush fire. The applicant shall submit the updated Fire Protection Plan to SBC Fire Department for review and approval prior to land use clearance.	
Fire.3	*Increased Throughput* *Extension of Life*	Increased risk of upset due to increased oil flow rates through the project pipelines and pipeline facilities could create impacts to fire protection and emergency response resources.	No mitigation measures have been identified.	Insignificant
Fire.4	*Operations* *Increased Throughput* *Extension of Life*	Increased likelihood of upset conditions due to equipment modifications at the LOGP and potential increase of wet oil and sour gas quantities processed at the facility could create impacts to fire protection and emergency response.	No mitigation measures have been identified.	Insignificant

Table ES.3d
Cumulative Impacts of the Proposed Project

HAZARDOUS MATERIALS/RISK OF UPSET
Offshore development of the potential federal Outer Continental Shelf (OCS) oil and gas projects would be expected to result in cumulative public safety impacts related to: oil spills and related fires; natural gas releases, including sour gas releases due to pipeline ruptures and leaks; and exposure to hazardous materials, including Natural Gas Liquids (NGLs) and Liquid ~~Natural~~ Petroleum Gases (~~LNG~~LPGs) due to truck transportation risks. Although the degree of significance associated with these cumulative impacts cannot be reasonably predicted within the context of this document due to a lack of information regarding these potential federal OCS projects, based upon the proposed project's risk of upset impacts it is expected that the proposed project's incremental contribution to cumulative risk of upset impacts would not be considered significant for oil spills or gas releases, but significant for LNG truck transport. In addition, the offshore development projects are expected to generate a cumulative impact as a result of NGL/~~LNG~~LPG transport. The potential offshore oil and gas development projects located within State waters are located a substantial distance away from the proposed project, thus, no overlap in cumulative impacts to public safety would be anticipated to occur, and the proposed project's incremental contribution to theses impacts would not be expected to be cumulatively significant. Potential onshore development projects would contribute to an already significant cumulative impact by increasing the traffic on roadways that are used by the trucks that transport NGL/~~LNG~~LPGs from the Lompoc Oil and Gas Plant (LOGP) facility. The route principally affected would be Harris Grade Road and the areas within Lompoc where NGL/~~LNG~~LPGs are transported. With additional vehicles on the roadways used for NGL/~~LNG~~LPG transportation, the consequences of a NGL/LNG truck accident would increase in severity for this already significant impact. Santa Barbara County Safety Element Supplement Policies 2A, 3A, and 3B, and Planned Development Policy 3(c) would preclude the siting and construction of future residential developments within the hazard footprints of the proposed project's existing onshore pipelines; therefore, with full implementation of this policy, the number of additional ~~would consequentially put more~~ people placed at risk due to ~~in harms way in the event of~~ a pipeline ~~accident~~failure (rupture or leak) would be minimized. ~~However~~Given the nominal frequency value for emulsion or gas pipeline failure, and with implementation of the policies listed above and the mitigation measures identified in this Environmental Impact Report to reduce potential risk of upset impacts, the proposed project's incremental contribution to cumulative impacts associated with pipeline failure hazards would not be expected to be significant.
TERRESTRIAL AND FRESHWATER BIOLOGY
Incrementally, the proposed project would not significantly contribute to cumulative impacts related to terrestrial and freshwater biology; impacts associated with the proposed project could be mitigated to a level of less than significant. However, the combined impacts from the other potential off- and onshore development projects would be significant due to: an increased oil spill potential; the removal of vegetation due to construction; the introduction of non-native vegetation; and, increased disturbances to wildlife from additional lights, traffic, and noise.
ONSHORE WATER RESOURCES
Impacts to onshore water resources from the potential onshore development projects would not be expected to be cumulatively significant. However, the potential offshore oil and gas development projects could result in significant cumulative impacts to onshore water resources due to an increased potential for oil spills into surface water bodies. The proposed project's incremental contribution to these oil spill-related cumulative impacts into surface water bodies would also be expected to be significant.
MARINE BIOLOGICAL RESOURCES
Potential onshore development projects would not cumulatively impact marine biological resources. Potential offshore oil and gas development projects would not be expected to result in cumulatively significant impacts related to: marine traffic collisions with marine mammals and fish; noise; drilling muds discharges; or, produced water discharges. Similarly, the proposed project would not be expected to significantly contribute to these types of cumulative impacts. However, cumulative impacts associated with the effects of an offshore or coastal oil spill(s) on marine biological resources, including the proposed project's incremental contribution to them, would be expected to be significant.

Table ES.3d
Cumulative Impacts of the Proposed Project

OCEANOGRAPHY AND MARINE WATER QUALITY
Although there would be no impacts to marine water quality from the potential onshore development projects, the potential offshore oil and gas development projects, and their associated underwater pipelines, could result in cumulatively significant impacts to marine water quality and sediments due to an increased potential for oil spills. The proposed project's incremental contribution to oil spill-related cumulative impacts on oceanography and marine water quality could also be significant.
COMMERCIAL AND RECREATIONAL FISHING/KELP HARVESTING
There would be no cumulatively significant impacts to commercial and recreational fishing and kelp harvesting due to the potential onshore development projects. The potential offshore projects would not be expected to result in cumulatively significant impacts related to kelp beds and harvesting, drilling muds discharges, marine vessel traffic damage to fishing gear, or shell mounds, nor would the proposed project's incremental contribution to these types of cumulative impacts be expected to be significant. However, due to an increased potential for oil spills, cumulative impacts on commercial and recreational fishing and kelp harvesting due to the potential offshore oil and gas development projects, including the proposed project's incremental contribution to these impacts, could be significant.
TRAFFIC
The marine traffic associated with construction and operation of the potential offshore oil and gas development projects would not be expected to be cumulatively significant. Construction-related impacts from the potential onshore development projects, if they occur at the same time as the proposed project, could be cumulatively significant due to use of the same local roadways, such as Harris Grade Road. However, with full implementation of recommended mitigation measures, the proposed project's incremental contribution to these cumulative impacts would not be expected to be significant.
CULTURAL RESOURCES
Overall, cumulative impacts to cultural resources due to construction and routine operation of the potential on- and offshore development projects could be significant but fully mitigable, and the proposed project's incremental contribution to these impacts, with implementation of applicable mitigation measures that have been recommended, would not be expected to be significant. However, potential impacts from oil spill cleanup activities could be adverse and significant. The likelihood of oil spills and their subsequent cleanup activities would be increased if the potential offshore oil and gas development projects were developed. Cumulative oil spill cleanup impacts on cultural resources, including the proposed project's incremental contribution to them, could be significant.
AESTHETICS/VISUAL RESOURCES
If implemented, the potential offshore oil and gas development projects, including the proposed project, would be expected to result in cumulatively significant visual impacts due to either: (1) the construction and operation of new offshore facilities (platforms); or, (2) the extended lifetime of existing facilities. These facilities would be visible from the Coastal Zone. The potential onshore development projects within the proposed project area would result in an irreversible loss of open space and additionally change the visual character of affected local areas from semi-rural to urban. Therefore, their cumulative impacts to existing visual resources would be expected to be significant and the proposed project's incremental contribution to these impacts would also be significant due to the prolonged lifetime of the LOGP.
RECREATION/LAND USE
The potential onshore development projects would not be expected to result in significant cumulative impacts to recreation and land use, and the proposed project would not be expected to significantly contribute to these types of cumulative impacts. However, the potential offshore oil and gas development projects, and their associated underwater pipelines, could result in cumulatively significant impacts to coastal recreational areas due to an increased potential for oil spills, and the proposed project's incremental contribution to these cumulative recreational impacts would be considered cumulatively significant as well.

Table ES.3d
Cumulative Impacts of the Proposed Project

AGRICULTURAL RESOURCES
The onshore development projects located in the Santa Maria-Orcutt area could result in a cumulatively significant impact to agricultural resources due to the permanent loss of agriculturally productive lands. If all of the potential offshore oil and gas development projects were to occur, it is likely that a new onshore processing facility and associated connecting pipelines would be needed in northern Santa Barbara County (the Casmalia area). Introducing new onshore facilities, and extending the lifespan of existing onshore facilities, would increase the potential for disturbing agricultural production during both construction and operation; cumulative impacts could be significant. However, the proposed project's contribution to these impacts, while adverse, would not be considered significant with implementation of recommended mitigation measures.
GEOLOGICAL RESOURCES
Cumulative impacts to geological resources from the potential on- and offshore development projects would be localized and not expected to be significant. The combined impacts associated with erosion and sedimentation due to construction and operation of new onshore facilities related to the potential offshore oil and gas development projects could be mitigated to a level of less than significant. Therefore, cumulative geologic impacts, and the proposed project's incremental contribution to them, would not be expected to be significant.
AIR QUALITY
Air quality impacts from construction of the potential offshore oil and gas development projects could be adverse. However, these impacts could be mitigated to a level of less than significant by the provisions for emission reduction offsets as required by the Santa Barbara County Air Pollution Control District's (SBCAPCD's) regulations. Operational impacts associated with the potential offshore oil and gas development projects could also be mitigated to a level of less than significant with application of the emission reduction offsets required by the SBCAPCD's regulations. Therefore, cumulative construction and operational emissions, including the proposed project's incremental contribution to them, would not be considered significant. The potential onshore development projects are likely to result in significant air quality impacts. However these potential projects were conceptually accounted for in the 2004 Clean Air Plan; therefore, their associated air quality emissions would be expected to be consistent with the air quality planning document that is currently used to bring the region into attainment with ambient air quality standards. Cumulative impacts, including the proposed project's incremental contribution to them, would not be expected to be significant. Both onshore and offshore development projects would contribute to greenhouse gas emissions at varying levels. Significance of these impacts is not assigned.
NOISE
Cumulative noise impacts from the potential offshore oil and gas development projects would not be significant since their construction and operation would not occur within areas that are in close proximity to sensitive receptors, other than an increase in helicopter fly overs. However, if FAA flight paths and heights are utilized, no significant cumulative impact, including the proposed project's incremental contribution, is expected. Construction of some of the onshore development projects may be close to sensitive receptors and, therefore, could have cumulatively significant impacts. However, with implementation of recommended mitigation measures for noise, the proposed project's incremental contribution to cumulative noise impacts would not be expected to be significant.
FIRE PROTECTION AND EMERGENCY RESPONSE
The potential offshore oil and gas development projects would be required to develop, regularly update, and implement (as needed) emergency response and fire protection plans. These plans would be reviewed and approved by local fire departments. Additionally, existing facilities associated with offshore oil and gas development contribute funds to local fire protection and emergency response services, and any new facilities would be required to do so as well. Therefore, cumulative impacts, including the proposed project's incremental contribution to them, would be not significant. The residential and other onshore cumulative projects located in the Lompoc and Santa Maria-Orcutt areas would be adequately protected due to existing fire and emergency response services in the region, and the planned expansion of Fire Station No. 51; therefore, their cumulative fire protection and emergency response services impacts, and the proposed project's incremental contribution to them, would not be expected to be significant.

Table ES.3d
Cumulative Impacts of the Proposed Project

ENERGY RESOURCES
Potential offshore oil and gas development projects would be expected to utilize efficient technologies for drilling and production, and some of them may use existing facilities. Use of existing facilities would substantially reduce the overall energy consumption per barrel of oil produced by avoiding construction-related energy use and taking advantage of underutilized transportation and processing capacity. Therefore, the cumulative impact on energy resources, including the incremental contribution of the proposed project, would not be considered significant. With the exception of the Lompoc Wind Energy Project, which would generate up to 80 to 120 megawatts of commercially available power, the potential onshore development projects would be expected to require more energy. However, this potential development is not expected to affect available power supply or distribution in the area. Therefore, the cumulative energy resources impacts associated with these onshore development projects, including the proposed project's incremental contribution to them, would not be considered significant.

Alternatives Impact Summary Tables

This portion of the impact summary tables provides a list of the new impacts or impacts for which the level of significance has changed compared to the proposed project for each of the alternatives evaluated throughout the EIR. The majority of the alternatives represent changes to various components of the project. This is because the proposed project involves modifications to existing facilities. As such, many of the impacts identified for the proposed project would also apply to the alternatives. ~~The following table provides a list of all of the proposed project's impacts and identifies which ones would also apply to the various alternatives.~~Impacts that are common to the proposed project and an alternative are not listed in the alternative impact tables unless the impact class has changed. The reader is referred to the impact summary tables for the proposed project for these common impacts. Tables ES.4a through ES.8 list the potential Class I, II, and III impacts of the alternatives. The reader should note that:

- ~~Beginning on page ES-44, the potential Class I, II, and II impacts of the alternatives are listed. The reader should note that:~~
- There is no listing of any impacts for the No Project Alternative since there are no new impacts that are not already identified for the proposed project.
- There are no ~~descriptions of~~ Class I or Class II impacts for the Oil Emulsion Pipeline Replacement Alternative since there are no new Class I impacts that are not already identified for the proposed project.
- There are no ~~descriptions of~~ Class I or Class II impacts for the Drill Muds and Cuttings Alternatives since there are no new Class I or Class II impacts that are not already identified for the proposed project.
- There is no listing of Class IV impacts for any of the alternatives since there are no Class IV impacts identified for the proposed project or any of the alternatives.
- A complete discussion of the proposed project and alternative impacts is provided in Section 5.0 of the EIR and a comprehensive summary is provided in Section 6.0.

Following Table ES.8, tables are provided that directly compare the alternative impacts to the proposed project. Table ES.9 summarizes the Class I impacts for the proposed project, VAFB Onshore Alternative, Casmalia Alternative, and Emulsion Pipeline Replacement Alternative. Table ES.10 provides a comparison of the proposed project power line impacts with each of the power line route alternatives and Table ES.11 provides a comparison of the proposed project drill muds and cuttings impacts with the two drilling muds/cuttings disposal alternatives analyzed.

Table ES.4a
CLASS I Impacts of the VAFB Onshore Alternative
Impacts that may not be Fully Mitigated to Less than Significant Levels

(Impacts that must be addressed in a "statement of overriding consideration" if the project is approved in accordance with Sections 15091 and 15093 of the State CEQA Guidelines.)

Table ES.4a: Class I Impacts of the VAFB Onshore Alternative

Impact #	Project Phase	Description of Impact	Mitigation Measure	Residual Impact
		RISK OF UPSET/HAZARDOUS MATERIALS (Section 5.1)		
Risk.4	Operation	The alternative project could generate additional risks to public safety by exposing the public to produced gas releases from the new drilling/production/processing facilities, additional length of sour gas pipeline and new metering/pigging facilities at the PXP pipeline tie-in station that could leak gas.	See Mitigation Measures Risk-1 and Risk-2. Risk-4 The applicant shall conduct a facility siting study using an accepted industry standard (e.g., API Recommended Practice 752: Management of Hazards Associated With Location of Process Plant Buildings) to select the best location of gas treating equipment so as to minimize the impact of sour gas releases at Space Launch Complex 5. Risk-5 The applicant shall coordinate with the Air Force in the development of an emergency protocol that is satisfactory to SBC, and addresses how access for safety will be allowed during launch periods for critical events such as explosions, fires, and vapor cloud incidents at the production facility Risk-6 The applicant shall install hydrogen sulfide and flammable gas sensors in-plant and at the fence line to detect the presents of gas leaks. Before unsafe levels are reached, an emergency plan shall be activated to close Coast Road, Delphy Road and Surf Road to all vehicle and pedestrian traffic and to stop any rail traffic. Risk-7 Excess flow valves shall be installed on the gas pipeline at the VAFB production site location and automatic shutoff valves and/or check valves shall be installed on the emulsion pipeline at intermittent locations to minimize the amount of gas or crude oil/emulsion that could be released in the event of a pipeline leak or rupture.	Significant (If Class II, insignificant)
		TERRESTRIAL AND FRESHWATER BIOLOGY (Section 5.2)		
TB.9	*Construction*	Drilling noise, construction, and accidental release of boring materials ("frac-outs") during construction activities related to boring could impact one or more sensitive wildlife species.	Mitigation Measure TB-4, scheduling the work during the dry season, would reduce run off and potentially enhance the early detection of a "frac-out" in the Santa Ynez River. Implementation of Mitigation Measures TB-3, TB-5, TB-6 and TB-7 would reduce impacts to vegetation and wildlife habitat, and should be implemented along with the following measures: TB-15 If construction activities are scheduled to occur during the breeding season for the sensitive bird species (March 1 through September 30), pre-construction surveys shall be carried out by a qualified biologist to determine if nests of any of these species are present within 100 meters from the construction locations. If nests are found, construction activities shall be postponed until after the end of the breeding seasons of these bird species, on October 1. Results of surveys and recommended actions shall be submitted to SBC for review and approval prior to construction.	Significant

Table ES.4a: Class I Impacts of the VAFB Onshore Alternative				
Impact #	**Project Phase**	**Description of Impact**	**Mitigation Measure**	**Residual Impact**
			TB-16 Prior to commencement of boring, a detailed site-specific Frac-Out Contingency Plan shall be developed that would include, but is not limited to the following, site analysis to determine optimum depth to prevent "frac-outs", use of fluorescent dye in drilling fluids, seasonal restrictions on work to be conducted, mapped locations of sensitive resources, measures to reduce the project footprint. The plan shall also contain methods to identify, report, and respond to "frac-outs," including notification procedures, response equipment staging, and site-specific clean-up procedures. TB-17 All boring activities shall be monitored to ensure all precautionary measures are taken to prevent release of drilling fluids into aquatic and terrestrial habitats. Prior to construction, bore crews and monitors shall receive specific training in operational methods to reduce the incidence of frac-outs, and in frac-out response and reporting procedures. Documentation that training has been completed shall be submitted to SBC and CCC for review and approval prior to construction.	
TB.10	*Construction*	~~Replacement of the existing pipeline from landfall to the LOGP has the potential to remove or damage up to 88.6~~Construction of the drilling site and installation of the pipelines, tie-in station, substations, and power lines have the potential to remove or damage up to 76.65 acres of native vegetation and wildlife habitat including sensitive plant species.	Mitigation Measures TB-1 and TB-3 (avoiding sensitive plant species and wildlife) would be less feasible due to the large area required for onshore drilling and production operations, and the linear nature of the pipeline corridor. These measures should be implemented when feasible. Mitigation Measure TB-2 would also apply. Revegetating the area impacted during pipeline installation (Mitigation Measures TB-6 and TB-7) with native species, including any sensitive plant species would reduce impacts. The amount of required restoration would be greater and the revegetated species assemblages would be adjusted to more accurately represent the disturbed habitat along Surf and Coast Roads.	Significant
TRAFFIC (Section 5.9)				
T.4~~3~~	~~*Drilling*~~ *Operations*	~~Increased offshore drilling activity would increase offshore traffic.~~An oil spill could result in the disruption of onshore transportation infrastructure.	T-4 Consultation with VAFB shall be conducted to develop a Construction Traffic Management Plan that minimizes conflicts to Base operations during alternative construction and operation. In addition, the Plan shall address traffic related to potential oil spill clean-up operations. The VAFB-approved plan shall be provided to SBC prior to land use clearance for review and approval.	Significant

Table ES.4a: Class I Impacts of the VAFB Onshore Alternative

Impact #	Project Phase	Description of Impact	Mitigation Measure	Residual Impact
CULTURAL RESOURCES (Section 5.12)				
CR.5	*Construction*	Disturbance or destruction of cultural sites that may contain significant or potentially significant cultural materials due to the construction of new drilling/production/ processing facilities, pipelines, power lines, tie-in station, and electrical substations..	CR-6 Prior to the approval of a Final Development Plan for the onshore drilling alternative, a comprehensive cultural resources mitigation plan shall be submitted to the County of Santa Barbara and the Vandenberg Air Force Base Cultural Resources Program Manager for review and approval. The plan shall include at minimum the following elements: 1. A complete inventory of previously known sites, their characteristics, and potential significance that may exist within 200 feet of potential ground disturbance. 2. Results of a Phase I archaeological survey covering all previously unsurveyed areas within 200 feet of identified construction footprints and corridors. 3. Procedures for monitoring during construction, the evaluation of newly discovered cultural or paleontological materials, and mitigation through avoidance, in situ preservation, research, or data recovery, as warranted before construction is allowed to continue. These procedures shall incorporate Native American representation.	Significant (If Class II, insignificant)
AESTHETICS/VISUAL RESOURCES (Section 5.13)				
Visual.5 ~~nighttime~~	Operations	New oil and gas facilities due to their tall structures and glare from lighting could impact visual resources in the area.	Mitigation Measures Visual-2 and Visual-4 would apply.	Significant (If Class II, insignificant)

Table ES.4b
CLASS II Impacts of the VAFB Onshore Alternative
Impacts that can be Mitigated to less than Significant Levels

(Impacts that must be addressed in a "statement of overriding consideration" if the project is approved in accordance with Sections 15091 and 15093 of the State CEQA Guidelines.)

Table ES.4b: Class II Impacts of the VAFB Onshore Alternative

Impact #	Project Phase	Description of Impact	Mitigation Measure	Residual Impact
		~~RISK OF UPSET/HAZARDOUS MATERIALS (Section 5.1)~~		
~~Risk.4~~	*~~Operations~~*	~~The alternative project could generate additional risks to public safety by exposing the public to produced gas releases from the new drilling/production/processing facilities and additional length of sour gas pipeline that could leak gas.~~	~~See Mitigation Measures Risk-1 and Risk-2.~~ ~~Risk-4 The applicant shall conduct a facility siting study using an accepted industry standard (e.g., API Recommended Practice 752: Management of Hazards Associated With Location of Process Plant Buildings) to select the best location of gas treating equipment so as to minimize the impact of sour gas releases at Space Launch Complex 5.~~ ~~Risk-5 The applicant shall coordinate with the Air Force in the development of an emergency protocol that is satisfactory to SBC, and addresses how access for safety will be allowed during launch periods for critical events such as explosions, fires, and vapor cloud incidents at the production facility~~ ~~Risk-6 The applicant shall install hydrogen sulfide and flammable gas sensors in-plant and at the fence line to detect the presents of gas leaks. Before unsafe levels are reached, an emergency plan shall be activated to close Coast Road, Delphy Road and Surf Road to all vehicle and pedestrian traffic.~~ ~~Risk-7 Excess flow valves shall be installed on the gas pipeline at the VAFB production site location and automatic shutoff valves and/or check valves shall be installed on the emulsion pipeline at intermittent locations to minimize the amount of gas or crude oil/emulsion that could be released in the event of a pipeline leak or rupture.~~	~~Insignificant~~
		TERRESTRIAL AND FRESHWATER BIOLOGICAL RESOURCES (Section 5.2)		
TB.12	*Construction*	Pipeline <u>and power line</u> construction has the potential to result in disturbance to and loss of wetland and aquatic biota.	Measures identified in Section 5.3, Geologic Resources, and Section 5.4, Onshore Water Resources, would reduce impacts on aquatic biological resources. These measures include OWR-1, and GR-1. Mitigation Measures TB-6, minimize disturbance to native habitats, and TB-7, preparation and implementation of an approved HRRMP shall be also implemented. TB-18 Erosion and sediment control measures, which shall include the use of silt fencing, dust control, and other appropriate measures, shall be implemented at drainages; along portions of the right-of-way that intersect slopes greater than a 2-to-1 incline; and within 200 feet of downslope water bodies. Appropriate erosion and sediment control measures shall be installed and maintained until revegetation of the disturbed area is considered successful. (The use of straw bales and silt fences as erosion control protection shall not be considered to be appropriate in areas grazed by cattle unless the cattle are excluded from the area.). Applicant shall submit erosion and sediment control plans and	Insignificant

Table ES.4b: Class II Impacts of the VAFB Onshore Alternative				
Impact #	**Project Phase**	**Description of Impact**	**Mitigation Measure**	**Residual Impact**
			specifications to SBC for approval prior to land use clearance. TB-19 Drainages shall be restored to original contours after construction activities in order to preserve downstream biological resources and minimize sedimentation. Plans for drainage recontouring shall be included in the restoration and revegetation plan ~~HRRMP~~ (TB-7) and submitted to SBC/CCC for review and approval prior to land use clearance. TB-20 All ground disturbance activities shall occur, if feasible, during the dry season (generally April 1 through November 1). TB-21 Applicant-funded SBC/CCC-qualified biological monitors shall be on-site during construc-tion activities to ensure avoidance of individual animals and minimization of habitat destruction. TB-22 A construction spill response plan shall be prepared prior to the onset of construction to ensure a prompt and effective response to any accidental spills or leaks of diesel, gasoline, oil or other contaminating materials. Examples of measures would include the following: All equipment will be inspected for fuel, lubricant, and hydraulic fluid leaks prior to and during the work. Any leaks will be repaired immediately. Drip pans will be used to capture leaked fluids until the repair is completed. Fueling of stationary equipment will be by fuel truck and no equipment shall be fueled or maintained within 100 feet of drainages. Fueling or maintenance will occur over a drip pan or in a lined fueling area. Plan to be submitted to SBC for review and approval prior to land use clearance.	
TB.13	*Construction*	~~Replacement of the pipeline~~Installation of the drilling site, pipelines, tie-in station, substations, and power lines ~~has~~ have the potential to remove or damage federally or state-listed plant species, including Gaviota tarplant.	Where impacts are unavoidable, the following mitigation measures shall be implemented: Mitigation Measures TB-8, to map locations of sensitive plant species, TB-9, to develop a program to salvage, propagate, and re-establish plant species that could not be avoided during project activities, and to re-establish and monitor state and federally listed plant species. Implementation of Mitigation Measures TB-6 and TB-7 would minimize disturbed areas to the maximum extent feasible.	Insignificant
TB.14	*Construction*	~~Pipeline replacement in the riparian woodland, wetlands, and upland habitats in Oak Canyon and Santa Lucia Canyon~~Pipeline and power line construction in the riparian woodland, wetlands, and upland habitats near the Santa Ynez River, Bear Creek, and several smaller drainages could adversely impact California red-legged frogs as well as several California species of concern (southwestern pond turtles, Cooper's hawk, yellow warbler, yellow-breasted chat).	TB-23 Preconstruction surveys shall be conducted by SBC/CCC-approved biologists with suitable experience to determine the presence of California red-legged frogs and other sensitive species no more than 30-days prior to construction. If surveys indicate that California red-legged frogs would likely be present in the work areas in or near stream crossings or riparian vegetation, construction activities shall be postponed and federal and state agencies shall be contacted to coordinate suitable protection measures (such as relocations, through authorization for incidental take, or avoidance) for implemen-tation by the applicant. If southwestern pond turtles, two-striped garter snakes or other sensitive species are encountered in work areas they shall be relocated or otherwise protected from harm by means acceptable to CDFG. Preconstruction survey documentation shall be submitted to SBC/CCC for review and approval prior to the commencement of construction. TB-24 Before any construction activities begin on the project, the biological monitor(s)	Insignificant

Table ES.4b: Class II Impacts of the VAFB Onshore Alternative				
Impact #	Project Phase	Description of Impact	Mitigation Measure	Residual Impact
			shall conduct an employee training session for all construction crews and others present during construction. At a minimum, the training shall include a discussion of the biology, identification, and habitat needs of California red-legged frogs and the importance of their habitat, their status under the California Endangered Species and Federal Endangered Species Acts, and measures taken for the protection of these species and their habitat as part of the project. Upon completion of the orientation, employees shall sign a form stating that they attended the program and understand and will implement all protection measures for the species. Documentation of training shall be submitted to SBC/CCC for approval prior to construction. TB-25 Construction shall be scheduled to avoid the rainy season (after first soaking rains through April) when California red-legged frogs would be most likely to be moving between different bodies of water. Construction shall be completed between April 1 and November 1. If necessary, the project proponent shall seek approval from the Corps and the USFWS to work outside of this time period. TB-26 An applicant-funded, qualified SBC/CCC-approved California red-legged frog biologist shall be present throughout the construction phase to monitor for the species and to implement additional mitigation for the species. The approved biologist shall have the authority to halt any action that might result in impacts that exceed the levels anticipated during review of the action by the Corps and the USFWS. Documentation shall be included as part of SBC's Environmental Quality Assurance Program (EQAP). TB-27 The pipeline trench shall be provided with escape ramps constructed of earth fill to prevent entrapment of sensitive species or other animals during the construction phase of the project. The ramps shall be located at no greater than 1,000-foot intervals and be constructed at less than 45 degrees inclination. Include plans and specifications as part of TB-6 plan submitted by applicant to SBC/CCC for review and approval prior to land use clearance. TB-28 All trenches, open pipes and culverts, or similar structures at the construction site open for one or more overnight periods shall be thoroughly inspected for trapped animals by an SBC/CCC-qualified, applicant-funded biologist before the pipe is subsequently buried, capped, or otherwise used or moved in any way. Pipes in, or adjacent to, trenches left overnight shall be capped by the applicant and/or their contractors. If an animal is discovered inside a pipe during construction, that section of pipe shall not be moved, or if necessary, moved only once, to remove it from the path of construction until the animal has voluntarily escaped. Include plans and specifications as part of TB-6 plan submitted by applicant to SBC/CCC for review and approval prior to land use clearance. TB-29 Applicant shall ensure that all trash that may attract predators shall be properly contained, removed from the work site, and disposed of regularly. Following construction, all trash and construction debris shall be removed from work areas. Include plans and specifications as part of TB-6 plan submitted by applicant to SBC/CCC for review and approval prior to land use clearance.	

Table ES.4b: Class II Impacts of the VAFB Onshore Alternative

Impact #	Project Phase	Description of Impact	Mitigation Measure	Residual Impact
			TB-30 If dewatering is necessary, intakes shall be completely screened with wire mesh (not larger than five millimeters mesh size) to prevent California red-legged frogs from entering the pump system. Water shall be released or pumped downstream at an appropriate rate to maintain downstream flows during construction. No water containing any sediment shall be allowed to flow back into any flowing water. Upon completion of construction, any barriers to flow shall be removed in a manner that would allow flow to resume with the least disturbance to the substrate. Include plans and specifications as part of TB-6 plan submitted by applicant to SBC/CCC for review and approval prior to land use clearance. TB-31 A SBC-approved biologist shall permanently remove from within suitable habitat in the disturbance corridor any individuals of exotic species, such as bullfrogs, crayfish, and non-native fishes, to the maximum extent possible. Include plans and specifications as part of TB-6 plan submitted by applicant to SBC/CCC for review and approval prior to land use clearance. TB-32 Surveys in suitable habitat shall be conducted on a regular basis (twice a week at night) during the construction phase to ensure that California red-legged frogs are not present in the work areas. Include plans and specifications as part of TB-6 plan submitted by applicant to SBC/CCC for review and approval prior to land use clearance. TB-33 If construction work is scheduled to occur during the period April 1 to August 1, a qualified avian biologist shall survey riparian habitat within 100 feet of the right-of-way. If surveys reveal Cooper's hawks, yellow warblers, or yellow-breasted chats are nesting within 100 feet of the right-of-way, construction activities in those areas shall be postponed until after the conclusion of the nesting period, April 1 to August 1. Include plans and specifications as part of TB-6 plan submitted by applicant to SBC/CCC for review and approval prior to land use clearance. TB-34 Drainage and wetland crossings shall be revegetated with an appropriate assemblage of native riparian and wetland species suitable for the area. A species list and restoration and monitoring plan shall be included with the project proposal for approval by SBC/CCC. This plan must include, but not be limited to, location of restoration, species to be used, restoration techniques, timing of restoration, identifiable success criteria for completion, and remedial actions if the success criteria are not achieved. Include plans and specifications as part of TB-6 plan submitted by applicant to SBC/CCC for review and approval prior to land use clearance.	

Table ES.4b: Class II Impacts of the VAFB Onshore Alternative				
Impact #	**Project Phase**	**Description of Impact**	**Mitigation Measure**	**Residual Impact**
TB.15	*Construction*	~~Replacement of the pipeline in the drainages in Oak Canyon and Santa Lucia Canyon~~Pipeline and power line construction in riparian areas and drainages could cause downstream impacts to listed aquatic species (California red-legged frog) and species of concern (southwestern pond turtle). ~~could cause downstream impacts to tidewater gobies and southern steelhead~~	Implementation of Mitigation Measures identified previously, including TB-4, scheduling the work during the dry season; TB-5, controlling erosion; TB-6, minimize disturbance to native habitats; TB-7, preparation and implementation of an approved HRRMP; and, TB-22, equipment spill control measures, would reduce downstream impacts to aquatic species.	Insignificant
GEOLOGICAL RESOURCES (Section 5.3)				
GR.7	*Operation*	Liquefaction could jeopardize the integrity of the VAFB Onshore Alternative pipelines at the Santa Ynez River valley and Bear Creek crossings.	GR-5 Reduce Liquefaction Hazard. Final geotechnical investigations shall be conducted in the areas underlain by alluvium and dune sand at the Santa Ynez River and Bear Creek crossings. The results and recommendations of the geotechnical investigations shall be incorporated into the final pipeline design. If moderate to high liquefaction potential is confirmed by the geotechnical analyses, then design measures shall be implemented at the corresponding locations. Appropriate design is dependent on site-specific conditions and could include deep burial of the pipeline below liquefiable layers, densification of the ground above the pipeline to mitigate uplift, and selection of thick-walled, ductile steel pipe. The applicant shall submit the final geotechnical studies and design recommendations to SBC for review and approval prior to land use clearance.	Insignificant
ONSHORE WATER RESOURCES (Section 5.4)				
OWR.1	*Construction*	Project- related construction could cause erosion or siltation resulting in substantial degradation of surface water quality (Class II).	Mitigation Measure OWR-1 would apply. OWR-7 The applicant shall schedule construction activities during the dry season, unless otherwise approved by SBC, CCC, CDFG, and USFWS. Construction time restrictions shall be included in the contractor bid solicitation packages and depicted on construction plans which will be provided to SBC prior to construction.	Insignificant
OWR.2	*Increased Throughput Extension of Life*	A rupture or leak from the emulsion, produced water or dry oil pipelines could substantially degrade surface and groundwater quality.	Mitigation Measures OWR-3 and OWR-5, as well as the following mitigation measures would apply. OWR-8 Install catchment basins to prevent spills from entering the Santa Ynez River. Basin volumes shall be designed in accordance with Mitigation Measure OWR-5. Catchment basin design and construction plans shall be submitted to SBC for review and approval prior to land use clearance. OWR-9 Implement an oil-spill response and containment plan, including catchment basins as necessary, for the drilling and production facility. The plan shall be submitted to SBC/CCC for review and approval prior to land use clearance.	Insignificant

Table ES.4b: Class II Impacts of the VAFB Onshore Alternative

Impact #	Project Phase	Description of Impact	Mitigation Measure	Residual Impact
OWR.7	*Construction*	Potential "frac-out" of boring muds could cause siltation and degrade surface water quality.	Mitigation Measures TB-16 and TB-17 would minimize impacts associated with a frac-out. OWR-10 The applicant shall monitor boring operations, immediately cleaning spilled drilling muds, restricting construction activities to avoid potential conflicts with special status species, and use of best management practices to prevent or minimize soil erosion and effects of siltation on surface waters.	Insignificant
OWR.8~~9~~	*Operations*	Scour from large flood events could uncover, expose, and place the pipeline at risk for rupture at Santa Ynez River and Bear Creek crossings.	OWR-11 The pipelines shall be placed below the 100-year depth of scour at all river crossings. The river cross section topography shall not be altered in a manner that would result in increased levels of scour or erosion. Pipeline construction plans for the Santa Ynez River and Bear Creek crossings shall be submitted to SBC for review and approval prior to land use clearance.	Insignificant
OWR.9~~10~~	*Construction*	Disturbance of sites contaminated with hazardous substances could result in contamination of surface water and groundwater.	OWR-12 The applicant shall work with the U.S. Air Force, the RWQCB Central Region, and the Department of Toxic Substances Control to identify Federal Installation Restoration Program (IRP) sites, Areas of Concern and Areas of Interest within the construction area, and characterize the nature and extent of hazardous substances that may be present at each. In conjunction with the USAF, the RWQCB Central Region, and the Department of Toxic Substances Control, the applicant shall develop a plan of action to avoid and/or minimize any contamination of groundwater or surface water that may result from construction in these areas. Permits/approvals from these respective agencies shall be provided to SBC prior to construction.	Insignificant
			TRAFFIC (Section 5.9)	
T.1	*Construction*	Onshore construction associated with the project would temporarily add to local road traffic.	Mitigation Measure T-1 would apply. T-4 Consultation with VAFB shall be conducted to develop a Construction Traffic Management Plan that minimizes conflicts to Base operations during alternative construction and operation. In addition, the Plan shall address traffic related to potential oil spill clean-up operations. The VAFB-approved plan shall be provided to SBC prior to land use clearance for review and approval.	Insignificant

Table ES.4b: Class II Impacts of the VAFB Onshore Alternative				
Impact #	**Project Phase**	**Description of Impact**	**Mitigation Measure**	**Residual Impact**
FIRE PROTECTION AND EMERGENCY RESPONSE (Section 5.11)				
Fire.5	*Construction*	~~Pipeline~~ Pipeline and production/processing facilities construction could create short-term impacts to fire protection and emergency response.	Fire-3 All construction equipment shall be equipped with the appropriate spark arrestors and functioning mufflers. ~~PXP~~The applicant shall submit the pipeline construction procedures to the SBC Fire Department for review and approval prior to land use clearance. Fire-4 A fire watch with appropriate fire fighting equipment (i.e., hydrants, water truck, etc.) shall be available at the project site at all times when welding or grinding activities are taking place. Further, welding or grinding shall not occur when sustained winds exceed 15-20 mph, as determined by SBC Fire Department, unless an SBC Fire Department approved wind shield is on site. ~~PXP~~The applicant shall submit the pipeline construction procedures to the SBC Fire Department for review and approval prior to land use clearance. Fire-5 All rubber-tired construction vehicles shall be equipped with appropriate fire fighting equipment, such as shovels and axes or pulaskis, to aid in the prevention or containment of fires. ~~PXP~~The applicant shall submit the pipeline construction procedures to the SBC Fire Department for review and approval prior to land use clearance.	Insignificant
AESTHETICS/VISUAL RESOURCES (Section 5.13)				
Visual.6	*Construction*	Visual impacts due to new pipeline installation construction activities.	Visual-5 Revegetation Plan shall describe revegetation efforts, including a schedule for achieving revegetation milestones. The plan shall be submitted to SBC for review and approval prior to land use clearance. A bond equivalent to the cost of installation and maintenance shall be provided. Initial pipeline right-of-way revegetation shall be completed within 90 days of the commencement of pipeline operations.	Insignificant
AGRICULTURAL RESOURCES (Section 5.15)				
AG.5	*Construction*	Directional drilling locations could reduce farmland areas.	Mitigation Measures AG-2 through AG-3 would apply. AG-4 The applicant shall prepare and submit for review and approval, a grazing land preservation plan that describes activities, including soil replacement, soil enrichment, and replanting to take place after pipeline replacement activities. The plan shall be submitted to SBC for review and approval prior to land use clearance.	Insignificant
AG.6	*Construction*	Potential loss of agricultural productivity during pipeline and facility construction.	Mitigation Measures AG-2 through AG-4 would apply.	Insignificant

Table ES.4c
CLASS III Impacts of the VAFB Onshore Alternative
Impacts that are Adverse but Insignificant
(In accordance with State and local policy, impacts are to be mitigated to the maximum extent feasible.)

Table ES.4c: Class III Impacts of the VAFB Onshore Alternative

Impact #	Project Phase	Description of Impact	Mitigation Measure	Residual Impact
TERRESTRIAL AND FRESHWATER BIOLOGICAL RESOURCES (Section 5.2)				
TB.11	*Construction*	~~Replacement of the existing pipeline from landfall to the LOGP has~~Construction of the drilling site and installation of the pipelines, tie-in station, substations, and power lines have the potential to cause temporary habitat loss for mobile wildlife species and to cause mortality to individual animals.	Mitigation Measures TB-3, remove sensitive species out of the harms way, TB-6, minimize disturbance to native habitats, and TB-7, preparation and implementation of an approved Habitat Revegetation, Restoration, and Monitoring Plan.	Insignificant
ONSHORE WATER RESOURCES (Section 5.4)				
OWR.6~~8~~	*Operations*	The VAFB Onshore Alternative would contribute or lead to ~~the possible~~ groundwater basin overdraft~~of the Lompoc groundwater basin~~.	No mitigation measures have been identified.	Insignificant
COMMERCIAL AND RECREATIONAL FISHING/KELP HARVESTING (Section 5.6)				
CRF/KH.1	*Increased Throughput Extension of Life*	Oil spills may potentially impact commercial and recreational kelp harvests~~in the proposed project area~~.	Mitigation Measure MB-1 would apply. CRF/KH-3 An Oil Spill Response Plan shall detail methods to keep oil spilled into creeks and drainages from reaching the ocean and ways to protect kelp beds and important nearshore fishing areas along the southern VAFB coast should spilled oil enter the ocean. The Plan shall be submitted to SBC for review and approval prior to land use clearance.	Insignificant
AIR QUALITY (Section 5.8)				
Air.1	*Construction*	Construction activities would generate air emissions.	Mitigation Measure Air-1 would apply. Air-3 PXP shall implement the following SBC NOx reduction emissions measures: - Engines and emission systems shall be maintained, - High pressure fuel injectors shall be installed, and - Reformulated diesel fuel shall be used. The documentation supporting the implementation of the NOx reduction measures shall be submitted to the SBC P&D and the SBCAPCD prior to land use clearance. No operations shall occur until the applicable project Permits to Operate are modified. Air-4 PXP shall provide emission mitigations for the construction activities consistent with SBCAPCD Rules and Regulations. The documentation supporting the available emission mitigations for construction shall be submitted to the SBCAPCD and SBC P&D prior to	Insignificant

Table ES.4c: Class III Impacts of the VAFB Onshore Alternative				
Impact #	**Project Phase**	**Description of Impact**	**Mitigation Measure**	**Residual Impact**
			land use clearance. No operations shall occur until the applicable project Permits to Operate are modified.	
TRAFFIC (Section 5.9)				
T.2	*Increased Throughput Extension of Life*	Increased production at LOGP would increase facility truck traffic on local roads.	Mitigation Measures T-2 and T-4 would apply.	Insignificant
CULTURAL RESOURCES (Section 5.12)				
CR.6	*Construction and Operation*	Aesthetic impacts on VAFB cultural sites and landscapes.	No mitigation measures have been identified for this impact.	Insignificant
AESTHETICS/VISUAL RESOURCES (Section 5.13)				
Visual.2	*Operations*	Visual impacts due to installation of new equipment at LOGP.		
~~Visual.5 nighttime~~	~~*Operations*~~	~~New oil and gas facilities due to their tall structures and glare from lighting could impact visual resources in the area.~~	~~Mitigation Measures Visual-2 and Visual-4 would apply.~~	~~Insignificant~~
RECREATION/LAND USE (Section 5.14)				
Rec.2	*Construction*	Pipeline and power line construction could interfere with or restrict recreational activities along the pipeline/power line route(s).	No mitigation measures have been identified.	Insignificant

Table ES.5a
CLASS I Impacts of the Casmalia East Processing Location
Impacts that may not be Fully Mitigated to Less than Significant Levels

(Impacts that must be addressed in a "statement of overriding consideration" if the project is approved in accordance with Sections 15091 and 15093 of the State CEQA Guidelines.)

Table ES.5a: Class I Impacts of the Casmalia Alternative

Impact #	Project Phase	Description of Impact	Mitigation Measure	Residual Impact
TERRESTRIAL AND FRESHWATER BIOLOGICAL RESOURCES (Section 5.2)				
TB.10	*Construction*	~~Replacement of the existing pipeline from landfall to the LOGP~~ Construction of the processing facility and installation of the pipelines has the potential to remove or damage up to ~~88.6~~142 acres of native vegetation and wildlife habitat including sensitive plant species.	Mitigation Measures TB-4 through TB-7 would be required.	Significant
AESTHETICS/VISUAL RESOURCES (Section 5.9)				
Visual.5 nighttime	*Operations*	New oil and gas facilities due to their tall structures and glare from lighting could impact visual resources in the area.	Mitigation Measures Visual-2 and Visual-4 would apply.	Significant

Table ES.5b

CLASS II Impacts of the Casmalia East Processing Location

Impacts that can be Mitigated to Less than Significant Levels

(Impacts that must be addressed in Findings that the mitigation measures would reduce the level of impact to insignificant in accordance with Section 15091 State CEQA Guidelines.)

Table ES.5b: Class II Impacts of the Casmalia Alternative

Impact #	Project Phase	Description of Impact	Mitigation Measure	Residual Impact
HAZARDOUS MATERIAL/RISK OF UPSET (Section 5.1)				
Risk.4	*Operations*	The alternative project could generate additional risks to public safety by exposing the public to produced gas releases from the new ~~drilling/production/~~processing facility and additional length of sour gas pipeline that could leak gas.	Mitigation Measures Risk-1 and Risk-2 would apply. Risk-8 The applicant shall route the LOGP-Casmalia pipeline such that they are ~~it is~~ not closer than 2,500 feet from the southern Orcutt. The route shall turn westward from Highway 1/135 near the Harris Canyon Creek area in order to avoid impacts to the southern Orcutt. The pipeline route shall be located on plans submitted to SBC P&D for review and approval prior to land use clearance. Timing shall be as part of land use permit conditions. Risk-9 Excess flow valves shall be installed on the gas pipeline at the LOGP location and automatic shutoff valves and/or check valves shall be installed on the emulsion pipeline at appropriate locations to minimize the amount of gas or crude oil/emulsion that could be released in the event of a pipeline leak or rupture. Plans shall include proposed valve locations and be submitted to SBC for review and approval prior to land use clearance.	Insignificant
TERRESTRIAL AND FRESHWATER BIOLOGY (Section 5.2)				
TB.12	*Construction*	Pipeline and power line construction has the potential to result in disturbance to and loss of wetland and aquatic biota.	Mitigation Measures OWR-1, GR-1, TB-18 through TB-22 would serve to reduce impacts to aquatic biota and reduce sedimentation issues.	Insignificant
TB.13	*Construction*	~~Replacement of the pipeline has~~ Installation of the drilling site, pipelines, tie-in station, substations, and power lines have the potential to remove or damage federally or state-listed plant species, including Gaviota tarplant.	Mitigation Measures TB-8 and TB-9 would reduce impacts.	Insignificant
TB.14	*Construction*	Pipeline construction ~~replacement~~ in ~~the~~ riparian woodland, wetlands, and upland habitats ~~in Oak Canyon and Santa Lucia Canyon~~could adversely impact California red-legged frogs as well as several California species of concern (southwestern pond turtles, Cooper's hawk, yellow	Implementation of Mitigation Measures TB-23 through TB-34 would reduce impacts.	Insignificant

Table ES.5b: Class II Impacts of the Casmalia Alternative				
Impact #	**Project Phase**	**Description of Impact**	**Mitigation Measure**	**Residual Impact**
		warbler, yellow-breasted chat).		
GEOLOGICAL RESOURCES (Section 5.3)				
GR.2	*Construction*	Ground-disturbing construction activities could result in geologic disturbances such as slope failure, gullying, erosion, and sedimentation.	Mitigation Measure GR-1 would apply. GR-6 Ensure that all pipeline and facility construction areas have adequate review by geotechnical engineers and geologists for expansive/collapsible soils and for potential areas of slope instability prior to construction. The geotechnical report shall be submitted to SBC for review and approval prior to land use clearance.	Insignificant
FIRE PROTECTION (Section 5.11)				
Fire.5	*Construction*	Pipeline construction could create short-term impacts to fire protection and emergency response.	Fire-3 All construction equipment shall be equipped with the appropriate spark arrestors and functioning mufflers. ~~PXP~~ The applicant shall submit the pipeline construction procedures to the SBC Fire Department for review and approval prior to land use clearance. Fire-4 A fire watch with appropriate fire fighting equipment (i.e., hydrants, water truck, etc.) shall be available at the project site at all times when welding or grinding activities are taking place. Further, welding or grinding shall not occur when sustained winds exceed 15-20 mph, as determined by SBC Fire Department, unless an SBC Fire Department approved wind shield is on site. ~~PXP~~The applicant shall submit the pipeline construction procedures to the SBC Fire Department for review and approval prior to land use clearance. Fire-5 All rubber-tired construction vehicles shall be equipped with appropriate fire fighting equipment, such as shovels and axes or pulaskis, to aid in the prevention or containment of fires. ~~PXP~~ The applicant shall submit the pipeline construction procedures to the SBC Fire Department for review and approval prior to land use clearance.	Insignificant
Fire.7	*Operations Extension of Life*	Operation of the new oil and gas facility at Casmalia East site could create long-term impacts to fire protection and emergency response.	Mitigation Measure Fire-6 would apply. Fire-7 The new facility shall be designed in accordance with all applicable fire protection and emergency response standards. The new facility should be designed with all early fire detection and prevention of fire spread as the basis of the fire safety design. The facility should have adequate supply of water and oil fire fighting foam as per the National Fire Protection ~~Agency~~ Association (NFPA) requirements (i.e., Standards 11, 15, 22, 24, 25). The facility layout should provide sufficient access for emergency response vehicles and provide adequate equipment spacing as per the American Petroleum Institute (API) and Industrial Risk Insurers (IRI) guidelines (IRI IM 2.5.2). The new facility should have fire detection monitors positioned in the locations most likely to be affected by fire. All appropriate equipment such as crude oil storage tanks should have sufficient secondary containment. Grading under liquefied petroleum gas (LPG) storage vessels should be sloped to allow any spilled flammable liquids to flow outward from the vessel and into an impoundment area. The applicant shall submit all appropriate documentation for the new facility to the	Insignificant

Table ES.5b: Class II Impacts of the Casmalia Alternative				
Impact #	**Project Phase**	**Description of Impact**	**Mitigation Measure**	**Residual Impact**
			SSRRC for review and approval prior to land use clearance Fire-8 Fire protection, oil spill, and emergency response plans of the new facility shall be developed or adjusted using the similar LOGP plans and coordinated with the SBC Fire Department. These plans shall address the fire prevention measures at the facility, the fire suppression systems, the specific hazards at the facility, and fire and emergency response training and planning. The Fire Protection, Oil Spill Response, and Emergency Response Plans shall be submitted to the SBC Fire Department for review and approval prior to land use clearance. Fire-9 The facility operators/owners shall provide funding to the SBC Fire Department to provide adequate staffing and equipment for the Santa Maria Fire Station to address the emergency response requirements of the Casmalia oil and gas processing facility. The facility operators/owners shall enter into an agreement with the SBC to provide the reasonable share of funds for fire protection and emergency response. The operators/owners shall provide documentation of the monetary deposits into the appropriate funds prior to land use clearance.	
Fire.8	*Operations*	Operation of the sour gas pipeline to the new plant at Casmalia East site could create long-term impacts to fire protection and emergency response.	Mitigation Measure Fire-9 would apply. Fire-10 The sour gas pipeline shall be equipped with a leak detection system that is capable of detecting leaks as small as ¼ inch. The pipeline shall be equipped with remotely operated block valves to limit the volume of material release in the event of a leak or rupture. The applicant shall submit documentation for the pipeline controls design to the SBC SSRRC for review and approval prior to land use clearance. Fire-11 The pipeline shall be constructed following all applicable standards for sour gas pipeline service. The applicant shall submit all pipeline documentation (e.g. route, materials of construction, operation procedures) to the SBC SSRRC for review and approval prior to land use clearance. Mitigation Measure Risk-3 requires that the route of the LOGP-Casmalia pipeline to be not closer than 2,500 feet from southern Orcutt.	Insignificant

Table ES.5b: Class II Impacts of the Casmalia Alternative

Impact #	Project Phase	Description of Impact	Mitigation Measure	Residual Impact
CULTURAL RESOURCES (Section 5.12)				
CR.5	*Construction*	Disturbance or destruction of cultural sites that may contain significant or potentially significant cultural materials due to the construction of new drilling/production/ processing and pipeline facilities.	Mitigation Measure CR-6 would apply. CR-7 A Phase I archaeological surface survey shall be conducted along the new pipeline right-of-way and at the location of the new processing site prior to land use clearance to identify any cultural resources that may be affected during construction. If a cultural resource is encountered during the survey, it shall be documented by a County-qualified archaeologist and its potential significance evaluated in terms of applicable criteria prior to any construction activities. Resources considered significant shall be avoided or subject to a Phase 3 data recovery program (with Native American monitoring, if applicable), consistent with Santa Barbara County Cultural Resource Guidelines.	Insignificant
AGRICULTURAL RESOURCES (Section 5.15)				
AG.6	*Construction*	Potential loss of agricultural productivity during pipeline and facility construction.	Mitigation Measures AG-2 through AG-3 would apply. AG-4 PXP shall prepare and submit for review and approval, a grazing land preservation plan that describes activities, including soil replacement, soil enrichment, and replanting to take place after pipeline replacement activities. The plan shall be submitted to SBC for review and approval prior to land use clearance.	Insignificant
AESTHETICS/VISUAL RESOURCES (Section 5.13)				
Visual.6	*Construction*	Visual impacts due to new pipeline installation construction activities.	Visual-5 Revegetation Plans shall be prepared (or existing PXP Revegetation Plans updated) to include new revegetation efforts, including a schedule for achieving revegetation milestones. The updated plans shall be submitted to SBC for review and approval prior to land use clearance. A bond equivalent to the cost of installation and maintenance shall be provided. Initial pipeline right-of-way revegetation shall be completed within 90 days of the commencement of pipeline operations.	Insignificant

Table ES.5c
CLASS III Impacts of the Casmalia East Processing Location
Impacts that are Adverse but Insignificant

(In accordance with State and local policy, impacts are to be mitigated to the maximum extent feasible.)

Table ES.5c: Class III Impacts of the Casmalia Alternative

Impact #	Project Phase	Description of Impact	Mitigation Measure	Residual Impact
TERRESTRIAL AND FRESHWATER BIOLOGICAL RESOURCES (Section 5.2)				
TB.11	*Construction*	~~Replacement of the existing pipeline from landfall to the LOGP~~Pipeline construction has the potential to cause temporary habitat loss for mobile wildlife species and to cause mortality to individual animals.	Mitigation Measures TB-3 through TB-7 would be applied to mitigate the impact to the maximum extent feasible.	Insignificant
MARINE BIOLOGY (Section 5.5)				
MB.8	*Construction*	The burial of the pipeline would disturb soft-bottom habitats	No mitigation measure has been identified.	Insignificant
AIR QUALITY (Section 5.8)				
Air.1	*Construction*	Construction activities would generate air emissions.	Mitigation Measure Air-1 would apply. Air-3 PXP shall implement the following SBC NOx reduction emissions measures: - Engines and emission systems shall be maintained, - High pressure fuel injectors shall be installed, and - Reformulated diesel fuel shall be used. The documentation supporting the implementation of the NOx reduction measures shall be submitted to the SBC P&D and the SBCAPCD prior to land use clearance. No operations shall occur until the applicable project Permits to Operate are modified. Air-4 PXP shall provide emission mitigations for the construction activities consistent with SBCAPCD Rules and Regulations. The documentation supporting the available emission mitigations for construction shall be submitted to the SBCAPCD and SBC P&D prior to land use clearance. No operations shall occur until the applicable project Permits to Operate are modified.	Insignificant
FIRE PROTECTION (Section 5.11)				
Fire.6	*Construction*	Construction of Casmalia site facilities and dismantling of the LOGP could create short-term impacts to fire protection and emergency response.	Fire-6 For the new facilities, PXP shall follow all appropriate fire protection and safety measures outlined in the Point Pedernales Project Final Development Plan (FDP), Systems Safety and Reliability, Part P. PXP shall submit the construction procedures to the SBC Systems Safety Reliability Review Committee (SSRRC) for review and approval prior to land use clearance.	Insignificant

~~CLASS I Impacts of the Alternative Power Line Routes to Valve Site #2~~

~~Impacts that may not be Fully Mitigated to Less than Significant Levels~~

~~(Impacts that must be addressed in a "statement of overriding consideration" if the project is approved in accordance with Sections 15091 and 15093 of the State CEQA Guidelines.)~~

~~Class I Impacts of the Alternative Power Line Routes~~				
~~Impact #~~	~~Project Phase~~	~~Description of Impact~~	~~Mitigation Measure~~	~~Residual Impact~~
~~TERRESTRIAL AND FRESHWATER BIOLOGY (Section 5.2)~~				
~~TB.9 Option 2b~~	~~*Construction*~~	~~Drilling noise, construction, and accidental release of boring materials ("frac-outs") during construction activities related to boring could impact one or more sensitive wildlife species.~~	~~Mitigation Measures TB-1, TB-2, TB-5, TB-6, TB-7, and TB-15 through TB-17 would apply to minimize disturbance in the riparian area and to avoid construction during the breeding seasons of sensitive avian species. Additionally, the bore would be drilled below the scour depth of the river. The mitigation measures would reduce the impacts to listed wildlife in the power line corridor. The mitigation measures would reduce the possibility of frac-outs, although the possibility of impact to listed species downstream of the site cannot be eliminated.~~	~~Significant~~

~~CLASS II Impacts of the Alternative Power Line Routes to Valve Site #2~~

~~Impacts that can be Mitigated to Less than Significant Levels~~

~~(Impacts that must be addressed in Findings that the mitigation measures would reduce the level of impact to insignificant in accordance with Section 15091 State CEQA Guidelines.)~~

~~Class II Impacts of the Alternative Power Line Routes~~				
~~Impact #~~	~~Project Phase~~	~~Description of Impact~~	~~Mitigation Measure~~	~~Residual Impact~~
~~ONSHORE WATER RESOURCES (Section 5.4)~~				
~~OWR.7 Option 2b~~	~~*Construction*~~	~~Potential "frac-out" of boring muds could cause siltation and degrade surface water quality.~~	~~Mitigation Measure OWR-9 would apply.~~	~~Insignificant~~
~~CULTURAL RESOURCES (Section 5.12)~~				
~~CR.8 Under-ground Along Terra Road~~	~~*Construction*~~	~~Trenching along Terra Road would result in ground disturbance and potential impacts on cultural resources.~~	~~Mitigation Measures CR-1, CR-2, CR-3, CR-4 and CR-5 would apply.~~ ~~CR-8 Avoid impacts on known cultural resources by rerouting the trench so that no ground disturbance occurs within 200 feet from established site boundaries of CA-SBA-913, -1917, -689, and -2126. PXP shall submit plans that demonstrate avoidance of known cultural sites prior to issuance of coastal development permit or land use clearance for grading.~~	~~Insignificant~~
~~AGRICULTURAL RESOURCES (Section 5.15)~~				
~~AG.5~~	~~*Construction*~~	~~Directional drilling locations could reduce farmland areas.~~	~~Mitigation Measures AG-2 through AG-3 would apply.~~ ~~AG-4 PXP shall prepare and submit for review and approval, a grazing land preservation plan that describes activities, including soil replacement, soil enrichment, and replanting to take place after pipeline replacement activities. The plan shall be submitted to SBC for review and approval prior to land use clearance.~~	~~Insignificant~~

Table ES.6a
CLASS II Impacts of the Replacement of Oil Emulsion Pipeline from Platform Irene to LOGP
Impacts that can be Mitigated to Less than Significant Levels

(Impacts that must be addressed in Findings that the mitigation measures would reduce the level of impact to insignificant in accordance with Section 15091 State CEQA Guidelines.)

Table ES.6a: Class II Impacts of the Emulsion Pipeline Replacement Alternative

Impact #	Project Phase	Description of Impact	Mitigation Measure	Residual Impact
TERRESTRIAL AND FRESHWATER BIOLOGY (Section 5.2)				
TB.10	*Construction*	Replacement of the existing pipeline from landfall to the LOGP has the potential to remove or damage up to 88.6 acres of native vegetation and wildlife habitat including sensitive plant species.	The following mitigation measures shall be implemented: Mitigation Measures TB-4, scheduling the work during the dry season, TB-5, controlling erosion, TB-6 and TB-7, which address, in part, the restoration of native plant species would also reduce loss of native vegetation and wildlife habitat in affected project area.	Insignificant
TB.12	*Construction*	Replacement of the existing pipeline has the potential to result in disturbance to and loss of wetland and aquatic biota during pipeline replacement.	Mitigation Measures OWR-1, GR-1, TB-18 through TB-22 would serve to reduce impacts to aquatic biota and reduce sedimentation issues	Insignificant
TB.13	*Construction*	Replacement of the pipeline has the potential to remove or damage federally or state-listed plant species, including Gaviota tarplant.	Revegetating the area impacted during pipeline installation (Mitigation Measures TB-6 and TB-7) with native species, including any sensitive plant species and coast buckwheat would reduce impacts. Additionally, Mitigation Measures TB-8 and TB-9 would reduce impacts.	Insignificant
TB.14	*Construction*	Pipeline replacement in the riparian woodland, wetlands, and upland habitats in Oak Canyon and Santa Lucia Canyon could adversely impact California red-legged frogs as well as several California species of concern (southwestern pond turtles, Cooper's hawk, yellow warbler, yellow-breasted chat).	Implementation of Mitigation Measures TB-23 through TB-34 would reduce impacts.	Insignificant
TB.15	*Construction*	Replacement of the pipeline in the drainages in Oak Canyon and Santa Lucia Canyon could cause downstream impacts to tidewater gobies and southern steelhead.	Implementation of Mitigation Measures identified previously including TB-4, scheduling the work during the dry season; TB-5, controlling erosion; TB-6, minimize disturbance to native habitats; TB-7, preparation and implementation of an approved Habitat, Revegetation, Restoration and Monitoring Plan; and TB-22, equipment spill control measures; would reduce downstream impacts to listed aquatic species.	Insignificant
TB.16	*Construction*	Replacement of the pipeline in the coastal beach and foredune habitat, where the pipeline array makes landfall, would result in potential impacts to nesting western snowy plovers and California least terns.	Mitigation Measure TB-10, to schedule construction activities within the beach and foredune habitat at Wall Beach to avoid the nesting season for snowy plovers and California least terns.	Insignificant

Table ES.6a: Class II Impacts of the Emulsion Pipeline Replacement Alternative				
Impact #	**Project Phase**	**Description of Impact**	**Mitigation Measure**	**Residual Impact**
TB.17	*Construction*	Replacement of the pipeline in the Eucalyptus tree habitat, between catchment basins 8 and 9, could result in potential impacts to a monarch butterfly autumnal aggregation site.	TB-35 Avoid scheduling construction activities between Catchment Basins #8 and #9 when aggregations of monarch butterflies are present, typically during the fall and winter months. Do not remove or trim trees within or surrounding the aggregation site if it would significantly alter temperature or humidity within the aggregation site, due to altered air flow patterns. Include schedule for this area in construction plan (TB-6) and submit to SBC for review and approval prior to land use clearance.	Insignificant
GEOLOGICAL RESOURCES (Section 5.3)				
GR.2	*Construction*	Ground-disturbing construction activities could result in geologic disturbances such as slope failure, gullying, erosion, and sedimentation.	Mitigation Measure GR-1 would apply. GR-7 Geotechnical analyses shall be completed in existing erosion-prone areas to determine proper pipeline burial depth.	Insignificant
GR.5~~8~~	*Construction*	Pipeline installation offshore could result in increased resuspension of bottom sediment material, increased bottom sediment drift, and decreased stability of sediments within the offshore pipeline right-of-way.	GR-8 Pipeline surveys shall be conducted to confirm the absence of unsupported spans after installation of the offshore pipeline and at periodic intervals during the life of the facility. Initial surveys shall be conducted annually, but may be reduced in frequency at the discretion of the MMS, CSLC, and SBC.	Insignificant
FIRE PROTECTION AND EMERGENCY REPONSE (Section 5.11)				
Fire.5	*Construction*	Pipeline ~~construction~~ replacement could create short-term impacts to fire protection and emergency response.	Fire-3 All construction equipment shall be equipped with the appropriate spark arrestors and functioning mufflers. PXP shall submit the pipeline construction procedures to the SBC Fire Department for review and approval prior to land use clearance. Fire-4 A fire watch with appropriate fire fighting equipment (i.e., hydrants, water truck, etc.) shall be available at the project site at all times when welding or grinding activities are taking place. Further, welding or grinding shall not occur when sustained winds exceed 15-20 mph, as determined by SBC Fire Department, unless an SBC Fire Department approved wind shield is on site. PXP shall submit the pipeline construction procedures to the SBC Fire Department for review and approval prior to land use clearance. Fire-5 All rubber-tired construction vehicles shall be equipped with appropriate fire fighting equipment, such as shovels and axes or pulaskis, to aid in the prevention or containment of fires. PXP shall submit the pipeline construction procedures to the SBC Fire Department for review and approval prior to land use clearance.	Insignificant
CULTURAL RESOURCES (Section 5.12)				
CR.5	*Construction*	Disturbance or destruction of cultural sites that may contain significant or potentially significant cultural materials due to pipeline replacement~~the construction of new drilling/production/ processing facilities.~~	Mitigation Measure CR-6 would apply	Insignificant

Table ES.6a: Class II Impacts of the Emulsion Pipeline Replacement Alternative				
Impact #	**Project Phase**	**Description of Impact**	**Mitigation Measure**	**Residual Impact**
CR.8	*Construction*	Offshore oil emulsion pipeline replacement would result in seafloor disturbance and potential impacts on cultural resources.	CR-9 The original offshore construction corridor shall be mapped and labeled on appropriate offshore Project maps. All seafloor disturbances from construction activities associated with the new pipeline shall be confined within the original pipeline construction corridor to avoid impacts on potentially significant cultural resources. Applicant shall submit plans that demonstrate avoidance of known cultural sites prior to issuance of coastal development permit or land use clearance for grading.	Insignificant
CR.9	*Construction*	Onshore oil emulsion pipeline removal and replacement would result in ground disturbance and potential impacts on cultural resources.	Mitigation Measures CR-1 and CR-2 would apply. CR-10 The normal 100-foot wide right-of-way shall be reduced to a 40-foot wide right-of-way when within 200 feet of a recorded archaeological site unless the resource has been previously determined to have no potential for significance because it is re-deposited, an isolated occurrence, modern, or otherwise lacks data potential. PXP shall submit plans that demonstrate avoidance of known cultural sites prior to issuance of coastal development permit or land use clearance for grading. CR-11 Develop a Cultural Resources Monitoring Plan to prepare for archaeological and Native American monitoring activities during construction. This plan shall be submitted to P&D prior to issuance of coastal development permit or land use clearance for grading. PXP shall arrange for archaeological monitoring as per the construction monitoring plans.	Insignificant
AESTHETICS/VISUAL RESOURCES (Section 5.13)				
Visual.6	*Construction*	Visual impacts due to ~~new~~ pipeline ~~installation~~ <u>replacement</u> construction activities.	Visual-5 Revegetation Plans shall be prepared (or existing PXP Revegetation Plans updated) to include new revegetation efforts, including a schedule for achieving revegetation milestones. The updated plans shall be submitted to SBC and VAFB for review and approval prior to land use clearance. A bond equivalent to the cost of installation and maintenance shall be provided. Initial pipeline right-of-way revegetation shall be completed within 90 days of the commencement of pipeline operations.	Insignificant
AGRICULTURAL RESOURCES (Section 5.15)				
AG.6	*Construction*	Potential loss of agricultural productivity during pipeline <u>replacement</u> ~~and facility construction~~.	Mitigation Measures AG-2 through AG-4 and GR-1 would apply. AG-5 Pipeline sedimentation basins and traps shall be inspected, cleaned, and if necessary replaced. Silt fences shall be inspected monthly during dry periods and immediately after each rainfall. Sediment must be removed when more than 1/3 filled, until vegetation is reestablished in the area of the disturbed soil. Straw bales shall be inspected weekly and after each rain. Sediment shall be removed when it reaches a depth of 6 inches, until vegetation is reestablished.	Insignificant

Table ES.6b
CLASS III Impacts of the Replacement of Oil Emulsion Pipeline from Platform Irene to LOGP
Impacts that are Adverse but Insignificant
(In accordance with State and local policy, impacts are to be mitigated to the maximum extent feasible.)

Table ES.6b: Class III Impacts of the Emulsion Pipeline Replacement Alternative

Impact #	Project Phase	Description of Impact	Mitigation Measure	Residual Impact
TERRESTRIAL AND FRESHWATER BIOLOGICAL RESOURCES (Section 5.2)				
TB.11	*Construction*	Replacement of the existing pipeline from landfall to the LOGP has the potential to cause temporary habitat loss for mobile wildlife species and to cause mortality to individual animals.	Mitigation Measures TB-3 through TB-7 would mitigate Impact TB.11 to the maximum extent feasible.	Insignificant
MARINE BIOLOGICAL RESOURCES (Section 5.5)				
MB.7	*Construction*	The burial of the pipeline would disturb soft-bottom habitats.	No mitigation measure has been identified.	Insignificant
OCEANOGRAPHY AND MARINE WATER QUALITY (Section 5.6)				
MWQ.5	*Construction*	Marine water-quality impacts would result from seafloor sediments resuspended during the installation of a new offshore pipeline.	Mitigation Measures MWQ-1 and MB-1 would apply.	Insignificant
AIR QUALITY (Section 5.8)				
Air-1	*Construction*	Construction activities would generate air emissions.	See Mitigation Measure Air-1. Air-3 PXP shall implement the following SBC NOx reduction emissions measures: - Engines and emission systems shall be maintained, - High pressure fuel injectors shall be installed, and - Reformulated diesel fuel shall be used. The documentation supporting the implementation of the NOx reduction measures shall be submitted to the SBC P&D and the SBCAPCD prior to land use clearance. No operations shall occur until the applicable project Permits to Operate are modified. Air-4 PXP shall provide emission mitigations for the construction activities consistent with SBCAPCD Rules and Regulations. The documentation supporting the available emission mitigations for construction shall be submitted to the SBCAPCD and SBC P&D prior to land use clearance. No operations shall occur until the applicable project Permits to Operate are modified.	Insignificant

Table ES.6b: Class III Impacts of the Emulsion Pipeline Replacement Alternative				
Impact #	**Project Phase**	**Description of Impact**	**Mitigation Measure**	**Residual Impact**
NOISE (Section 5.10)				
N.4	*Construction*	~~Construction~~ Pipeline replacement activities along the pipeline route would temporarily increase ambient noise levels near Surf Beach and Ocean Beach Park, at residences along the north edge of Vandenberg Village and at Cabrillo High School, and at the residential complex at the Lompoc Federal Penitentiary.	Mitigation Measure N-2, limiting operating hours of construction, would apply.	Insignificant
RECREATION/LAND USE (Section 5.14)				
Rec.2	*Construction*	Pipeline ~~construction~~ replacement could interfere with or restrict recreational activities along the pipeline route.	No mitigation measures have been identified.	Insignificant

Table ES.7a

CLASS I Impacts of the Alternative Power Line Routes to Valve Site #2

Impacts that may not be Fully Mitigated to Less than Significant Levels

(Impacts that must be addressed in a "statement of overriding consideration" if the project is approved in accordance with Sections 15091 and 15093 of the State CEQA Guidelines.)

Table ES.7a: Class I Impacts of the Alternative Power Line Routes

Impact #	Project Phase	Description of Impact	Mitigation Measure	Residual Impact
TERRESTRIAL AND FRESHWATER BIOLOGY (Section 5.2)				
TB.9 Option 2b	*Construction*	Drilling noise, construction, and accidental release of boring materials ("frac-outs") during construction activities related to boring could impact one or more sensitive wildlife species.	Mitigation Measures TB-1, TB-2, TB-5, TB-6, TB-7, and TB-15 through TB-17 would apply to minimize disturbance in the riparian area and to avoid construction during the breeding seasons of sensitive avian species. Additionally, the bore would be drilled below the scour depth of the river. The mitigation measures would reduce the impacts to listed wildlife in the power line corridor. The mitigation measures would reduce the possibility of frac-outs, although the possibility of impact to listed species downstream of the site cannot be eliminated.	Significant

Table ES.7b
CLASS II Impacts of the Alternative Power Line Routes to Valve Site #2
Impacts that can be Mitigated to Less than Significant Levels
(Impacts that must be addressed in Findings that the mitigation measures would reduce the level of impact to insignificant in accordance with Section 15091 State CEQA Guidelines.)

Table ES.7b: Class II Impacts of the Alternative Power Line Routes				
Impact #	**Project Phase**	**Description of Impact**	**Mitigation Measure**	**Residual Impact**
ONSHORE WATER RESOURCES (Section 5.4)				
OWR.7 Option 2b	*Construction*	Potential “frac-out” of boring muds could cause siltation and degrade surface water quality.	Mitigation Measure OWR-9 would apply.	Insignificant
CULTURAL RESOURCES (Section 5.12)				
CR.8 Under-ground Along Terra Road	*Construction*	Trenching along Terra Road would result in ground disturbance and potential impacts on cultural resources.	Mitigation Measures CR-1, CR-2, CR-3, CR-4 and CR-5 would apply. CR-8 Avoid impacts on known cultural resources by rerouting the trench so that no ground disturbance occurs within 200 feet from established site boundaries of CA-SBA-913, -1917, -689, and -2126. PXP shall submit plans that demonstrate avoidance of known cultural sites prior to issuance of coastal development permit or land use clearance for grading.	Insignificant
AGRICULTURAL RESOURCES (Section 5.15)				
AG.5	*Construction*	Directional drilling locations could reduce farmland areas.	Mitigation Measures AG-2 through AG-3 would apply. AG-4 PXP shall prepare and submit for review and approval, a grazing land preservation plan that describes activities, including soil replacement, soil enrichment, and replanting to take place after pipeline replacement activities. The plan shall be submitted to SBC for review and approval prior to land use clearance.	Insignificant

Table ES.7c
CLASS III Impacts of the Alternative Power Line Routes to Valve Site #2
Impacts that are Adverse but Insignificant

(In accordance with State and local policy, impacts are to be mitigated to the maximum extent feasible.)

Table ES.7c: Class III Impacts of the Alternative Power Line Routes

Impact #	Project Phase	Description of Impact	Mitigation Measure	Residual Impact
TERRESTRIAL AND FRESHWATER BIOLOGICAL RESOURCES (Section 5.2)				
TB.1	*Construction*	Installation of power poles would result in disturbance or loss of less than one acre of native vegetation and wildlife habitat and possible injury to wildlife. Impact TB.1 would change under this alternative depending on the proposed alternative route (see Table ES.10).	Mitigation Measures TB-1 through TB-3 would apply, depending on the proposed alternative route.	Insignificant
TB.2	*Construction*	Installation of power poles have the potential to increase erosion and sedimentation in aquatic habitats. Impact TB.2 would change under this alternative depending on the proposed alternative route (see Table ES.10).	Mitigation Measures TB-1 through TB-3 would apply, depending on the proposed alternative route.	Insignificant
ONSHORE WATER RESOURCES (Section 5.4)				
OWR.7	*Construction*	Potential "frac-out" of boring muds could cause siltation and degrade surface water quality. Option 2b only.	Mitigation Measure OWR.9 would apply.	Insignificant
Air.1	*Construction*	Construction activities would generate air emissions.	Mitigation Measure Air-1 would apply.	Insignificant
TRAFFIC (Section 5.9)				
T.1	*Construction*	Onshore construction associated with the project would temporarily add to local road traffic.	Mitigation Measure T-1 would apply.	Insignificant
NOISE (Section 5.10)				
N.2	*Construction*	Construction noise would temporarily increase ambient daytime noise levels.	Mitigation Measure N-2 would apply.	Insignificant
FIRE PROTECTION AND EMERGENCY SERVICES (Section 5.11)				
Fire.2	*Operations*	Operation of the new power line to Valve Site #2 could result in impacts to fire protection and emergency response resources due to addition of an ignition source into a high fire hazard area.	Mitigation Measure Fire-2 would apply.	Insignificant
AGRICULTURAL RESOURCES (Section 5.15)				
AG.1	*Construction*	Addition of power poles and substation to Valve Site #2 could disturb farm operations.	No mitigation measures have been identified.	Insignificant

Table ES.8
CLASS III Impacts for the Alternative Drill Muds and Cuttings Disposal
Impacts that are Adverse but Insignificant
(In accordance with County policy, impacts are mitigated to the maximum extent feasible.)

Table ES.8: Class III Impacts for Alternative Muds and Cuttings Disposal

Impact #	Project Phase	Description of Impact	Mitigation Measures	Residual Impact
MARINE BIOLOGICAL RESOURCES (Section 5.5)				
MB.9~~8~~	*Drilling*	Marine organisms would be impacted by accidental discharge of drilling muds and cuttings during transit to shore.	Mitigation Measures MWQ-3 and MWQ-4 would apply.	Insignificant
OCEANOGRAPHY AND MARINE WATER QUALITY (Section 5.6)				
MWQ.6 Inject	*Drilling*	Marine water-quality impacts could result from the marine release of interstitial waters contaminated by drill-muds injection into a near surface formation.	No mitigation is required beyond those specified in current underground injection control regulations.	Insignificant
MWQ.7 Onshore Disposal	*Drilling*	Marine water quality would be impacted by accidental discharge of drill muds and cuttings during transit to shore.	MWQ-2 The applicant shall regularly inspect all Baker tanks, bins, and hoses used to transfer muds and cuttings to the transport vessels and immediately repair of damaged components or require these inspection and repair tests within their contractual agreements with the vessel operators. Inspection records shall be submitted to MMS on a regular basis. MWQ-3 The applicant shall collect and dispose onshore, all wastewater generated by cleaning the boats, transport containers, and mud-transfer equipment or require these inspection and repair tests within their contractual agreements with the vessel operators. The applicant shall keep all disposal records to be available for inspection.	Insignificant
RECREATION/LAND USE (Section 5.14)				
Rec.3	*Drilling*	Muds and cuttings spilled near the shore could disrupt recreational activities such as SCUBA diving.	Mitigation Measure MWQ-6 would apply. REC-1 During project construction and operation, the applicant shall require project vessels to travel in recommended marine traffic corridors.	Insignificant

TABLE ES.9
Comparison of Class I Impacts for the Proposed Project and Major Alternatives

Class I Impacts	Proposed Project	VAFB Onshore Alternative	Casmalia Alternative	Emulsion Pipeline Replacement Alternative
Risk.3: Increased risk to public due to NGL/LPG transport.[1]	Extension of life of LOGP would continue risk. *No Preference*	Same as proposed project. *No Preference*	*No Preference*, but from Casmalia site instead of LOGP.	Same as proposed project. *No Preference*
Risk.4: Increased risk to VAFB operations and personnel.	Impact would not occur under proposed project. **Preferred.**	Additional hazards within VAFB due to drilling/production facilities and pipelines.[4]	Same as proposed project.	Same as proposed project.
TB.6: Oil spill impact to upland, riparian, and aquatic habitats, and wildlife.[1]	Increased throughput increases oil spill risk and volumes above baseline conditions.	Higher risk than proposed project because of new pipeline through sensitive resources.	Higher risk than proposed project because of new pipeline through sensitive resources.	Throughput same as proposed project. **Slightly preferred** due to 10% decrease in spill probability, compared to proposed project.
TB.7: Oil spill impact to state-or federally-listed plant species.[1]	Increased throughput increases oil spill risk and volumes above baseline conditions.	Higher risk than proposed project because of new pipeline through sensitive resources.	Higher risk than proposed project because of new pipeline through sensitive resources.	Throughput same as proposed project. **Slightly preferred** due to 10% decrease in spill probability.
TB.8: Oil spill impact to state-or federally-listed wildlife species.[1]	Increased throughput increases oil spill risk and volumes above baseline conditions.	Higher risk than proposed project because of new pipeline through sensitive resources.	Higher risk than proposed project because of new pipeline through sensitive resources.	Throughput same as proposed project. **Slightly preferred** due to 10% decrease in spill probability.
TB.9: Directionally drilling impacts to Santa Ynez River.[2]	Impact would not occur under proposed project. [3] **Preferred**	Frac-out could cause Class I impacts to aquatic resources and water quality.	Same as proposed project.	Same as proposed project.
TB.10: New pipeline construction impacts.[2]	Construction would result in 0.43 acres of vegetation removal (Class II). **Preferred**	Construction would result in 61 acres of vegetation removal.	Construction would result in 152 acres of vegetation removal.	Construction would result in 88.6 acres of vegetation removal, but within previously disturbed right-of-way (Class II).
OWR.2: Oil spill impacts to surface and ground waters.[1]	Increased throughput increases oil spill risk and volumes above baseline conditions.	Higher risk than proposed project because of additional pipeline length.	Higher risk than proposed project because of additional pipeline length.	Throughput same as proposed project. **Slightly preferred** due to 10% decrease in spill probability.
MB.1: Oil spill impacts to marine organisms.[1]	Extension of life of platform and offshore pipeline would continue oil spill risk to marine organisms an additional 20 years.	No extension of life. Risk to marine organisms reduced since alternative facilities are inland. **Preferred**.	Same as proposed project.	Throughput same as proposed project; however 10% decrease in spill probability.
MWQ.1: Oil spill impacts to marine water quality.[1]	Extension of life of platform and offshore pipeline would continue oil spill risk to marine water quality an additional 20 years.	No extension of life. Risk to marine water quality reduced since alternative facilities are inland.	Same as proposed project.	Throughput same as proposed project; however 10% decrease in spill probability.

Class I Impacts	Proposed Project	VAFB Onshore Alternative	Casmalia Alternative	Emulsion Pipeline Replacement Alternative
		Preferred.		
CRF/KH.2: Oil spill impacts to fisheries.[1]	Extension of life of platform and offshore pipeline would continue oil spill risk to fisheries an additional 20 years.	No extension of life. Risk to fisheries reduced since alternative facilities are inland. **Preferred**.	Same as proposed project.	Throughput same as proposed project; however 10% decrease in spill probability.
T.4: Oil spill impacts to marine transportation corridors.[1]	Spill could temporarily close Coast Guard recommended marine traffic corridors. *No preference.*	Spill could close mission critical VAFB transportation corridors. *No preference.*	Same as proposed project. *No preference.*	Throughput same as proposed project; however 10% decrease in spill probability. *No preference.*
CR.3: Oil spill clean up impacts to cultural resources.[1]	Increased throughput increases oil spill risk and volumes above baseline conditions.	Higher risk than proposed project because of additional pipeline length and proximity to NRHP sites.	Higher risk than proposed project because of additional pipeline length through sensitive resources.	Throughput same as proposed project. **Slightly preferred** due to 10% decrease in spill risk compared to proposed project.
CR.5: New pipeline construction impacts to cultural resources.[2]	Impact would not occur under proposed project. **Preferred.**	44 significant or potentially significant cultural sites could be destroyed as part of construction.[4]	4 recorded sites located within 200 ft of pipeline corridor; 7 miles of corridor have not been surveyed.	29 recorded sites within ½ mile of previously disturbed pipeline corridor.
Visual.1: Long term presence of Platform Irene & Surf substation.[1]	Extension of life would continue platform and substation presence an additional 20 years.	No extension of life; platform removed in 10 years. Substation to remain an additional 20 years. **Preferred.**	Same as proposed project.	Same as proposed project.
Visual 4: Long term presence of LOGP nighttime glare.[1]	Extension of life would continue LOGP nighttime glare an additional 20 years. *No preference.*	Same as proposed project. *No preference.*	More severe than proposed project because of new Casmalia facility.	Same as proposed project. *No preference.*
Visual 5: Presence of tall structures (180-200 foot drilling rig and 50 foot tall tank).	Impact would not occur under proposed project. **Preferred.**	Addition of tall structures within VAFB due to drilling/production facilities.[4]	Same as proposed project.	Same as proposed project.
Rec.1: Oil spill impacts to recreational resources.[1]	Extension of life would continue oil spill risk to coastal recreational resources an additional 20 years.	No extension of life. Risk to coastal recreational resources reduced since alternative facilities are inland. **Preferred**.	Same as proposed project.	Throughput same as proposed project; however 10% decrease in spill probability.

1. Operational impact.
2. Construction impact.
3. Proposed project preferred even if Option 2b is implemented for providing power to Valve Site #2.
4. Potential Class I, significant and unavoidable, or Class II, significant but mitigable, impact.

TABLE ES.10 COMPARISON OF IMPACTS FOR THE PROPOSED PROJECT WITH THE POWER LINE ROUTES TO VALVE SITE #2 ALTERNATIVES[1]

Impact #	Description of Impact	Option 2a	Option 2b	Underground along Terra Road	Comments
TB.9	Accidental release of boring materials (“frac-outs”) during construction activities related to boring could impact one or more sensitive wildlife species **(Class I)**.	NA	+	NA	This impact would only occur as a result of boring the Santa Ynez River. This impact would not occur with the proposed project.
CR.2 and CR.6	Installation of power poles would result in ground disturbance and potential impacts on cultural resources **(Class II).**	Same	Same	+	The severity of the impact would be greater for undergrounding along Terra Road as a result of the increase in ground disturbance due to trenching.
Visual.2	Visual impacts due to the power lines to Valve Site #2 **(Class II).**	Same	Same	-	The severity of the impact would be less with the Terra Road undergrounding alternative since a portion of the route would not have power poles. However, the impact would still be Class II since some power poles would still be needed.
TB.1	Installation of power poles would result in disturbance or loss of less than one acre of native vegetation and wildlife habitat and possible injury to wildlife **(Class III).**	Same	Same	+	The severity of the impact would be greater for undergrounding along Terra Road as a result of the increase in ground disturbance due to trenching.
TB.2	Installation of power poles have the potential to increase erosion and sedimentation in aquatic habitats **(Class III).**	Same	Same	+	The severity of the impact would be greater for undergrounding along Terra Road as a result of the increase in ground disturbance due to trenching.
Air.1	Construction activities would generate air emissions **(Class III).**	Same	+	+	The severity of the impact would be greater for undergrounding along Terra Road as a result of the increase in ground disturbance due to trenching. The severity would be greater for Option 2b due to the increased equipment needed to bore the Santa Ynez River.
T.1	Onshore construction associated with the project would temporarily add to local road traffic **(Class III)**.	Same	+	Same	The severity would be greater for Option 2b due to the increase equipment needed to bore the Santa Ynez River.

[1] NA = Impact does not apply to this alternative.
+ = Severity of the impact is greater than the proposed project.
- = Severity of the impact is less than the proposed project.

TABLE ES.10 COMPARISON OF IMPACTS FOR THE PROPOSED PROJECT WITH THE POWER LINE ROUTES TO VALVE SITE #2 ALTERNATIVES[1]

Impact #	Description of Impact	Option 2a	Option 2b	Underground along Terra Road	Comments
N.2	Construction noise would temporarily increase ambient daytime noise levels **(Class III)**.	Same	+	Same	The severity would be greater for Option 2b due to the increase equipment need to bore the Santa Ynez River, and the fact that the boring machine has a higher noise level.
AG.1	Addition of power poles to Valve Site #2 could disturb farm operations **(Class III).**	Same	+	Same	The work areas needed for boring the Santa Ynez River would both be located on agricultural lands. This would preclude the use of the land during the boring operations.
OWR.7	Potential “frac-out” of boring muds could cause siltation and degrade surface water quality **(Class III)**.	NA	+	NA	This impact would only occur as a result of boring the Santa Ynez River. This impact would not occur with the proposed project.
Fire.2	Operation of the new power line to Valve Site #2 could result in impacts to fire protection and emergency response resources due to addition of an ignition source into a high fire hazard area **(Class III)**.	Same	Same	-	The severity of the impact would be less for the Terra Road undergrounding alternative since less of the powerline would be aboveground. However, it would still be considered a Class III impact since portions of the power line would still be aboveground.

TABLE ES.11 COMPARISON OF IMPACTS FOR THE PROPOSED TRANQUILLON RIDGE PROJECT WITH THE MUDS AND CUTTINGS DISPOSAL ALTERNATIVES[2]

Impact #	Description of Impact	Injection	Transportation to Shore	Comments
MB.2	The discharge of drilling muds and cuttings from Platform Irene may potentially impact marine organisms in the project area **(Class III).**	NA	-	The injection alternative would eliminate this impact. The transportation to shore alternative would reduce the severity of the impact as compared to the proposed project. However, it would not be eliminated since there is still the possibility of accidentally spilling the muds and cutting into the ocean during transport to shore.
MWQ.2 and MWQ.7	Reduced marine water and sediment quality would result from increased oceanic discharge of drilling fluids **(Class III).**	NA	-	The injection alternative would eliminate this impact. The transportation to shore alternative would reduce the severity of the impact as compared to the proposed project. However, it would not be eliminated since there is still the possibility of accidentally spilling the muds and cutting into the ocean during transport to shore.
CRF/ KH.3	The discharge of drilling muds and drill cuttings from Platform Irene may potentially impact kelp communities in the project area **(Class III).**	NA	-	The injection alternative would eliminate this impact. The transportation to shore alternative would reduce the severity of the impact as compared to the proposed project. However, it would not be eliminated since there is still the possibility of accidentally spilling the muds and cutting into the ocean during transport to shore.
CRF/ KH.5	The deposition of shells, or shell mounds, could prevent commercial trawling activities beneath Platform Irene **(Class III).**	-	-	The severity of the impact would be reduced, but not eliminated since shells would still deposit on the sea floor from the platform. The contribution of the cuttings to the shell mounds would be eliminated for both alternatives.
Rec.3	Muds and cuttings spilled near the shore could disrupt recreational activities such as SCUBA diving **(Class III).**	NA	+	This impact only applies to the transportation to shore alternative. This impact could occur in the unlikely event that muds and cuttings are spilled into the ocean during transport to shore. This impact would not occur for the proposed project.
T.2	Transportation of drilling muds and cuttings would increase truck traffic on local roads **(Class III).**	NA	+	This impact only applies to the transportation to shore alternative. This impact would not occur for the proposed project.

[2] NA = Impact does not apply to this alternative.
+ = Severity of the impact is greater than the proposed project.
- = Severity of the impact is less than the proposed project.

1.0 INTRODUCTION

This Draft Environmental Impact Report (EIR) assesses the environmental impacts associated with the Tranquillon Ridge Oil and Gas Development Project (proposed project). Plains Exploration and Production Company (PXP) is the Applicant. The location of the proposed project is shown in Figure 1-1.

Santa Barbara County (SBC), as lead agency under the California Environmental Quality Act (CEQA), prepared a Scoping Document for the proposed project and determined that an EIR would be required as part of the permitting process for the proposed project. In compliance with CEQA Guidelines, SBC solicited public and agency comments through distribution of a Notice of Preparation (NOP). A public workshop was held on March 29, 2006 in Lompoc to provide an opportunity for the public to comment on the scope of the EIR. The Scoping Document and comments received in response to the NOP are included as Appendix K, and were used to help direct the scope of the analysis and the technical studies in this EIR.

This section is organized as follows:

1.1 Overview of the Proposed Project

In January 2000, Torch Operating Company, as Operator of the Point Pedernales Project, submitted an application to the County of Santa Barbara (and other permitting agencies) for development of the Tranquillon Ridge Field. In June 2002, a proposed Final EIR was released for that proposal. In August 2002, the project (then owned by Nuevo Energy Company) was denied by the County Board of Supervisors. While the Torch/Nuevo project was the same in most aspects to the proposal evaluated in the EIR, the Board of Supervisors' denial was based on the inability to find that the project impacts would be mitigated to the maximum extent feasible due to Nuevo's then-pending appeal as to whether County permit conditions that relate to the operation of the platform and the oil pipeline were preempted by federal law. PXP has not carried forward this challenge to the County permit conditions that were the subject of the Nuevo appeal.

The proposed Tranquillon Ridge Project would involve the development of oil and gas wells in a proposed State Tidelands lease from Platform Irene. This platform is currently used to develop and produce the Point Pedernales Field, existing within Federal waters. Under the proposed project, the produced oil and gas from the Tranquillon Ridge Field would be commingled with the Point Pedernales oil and gas and sent ashore via pipelines from Platform Irene to PXP's onshore processing facility, the Lompoc Oil and Gas Plant (LOGP), located just north of Lompoc. Based on PXP's data, the proposed project will have an expected total life of approximately 30 years once the first well is drilled.

The Point Pedernales Final Development Plan (FDP) permits the production and processing of up to 36,000 barrels per day (bpd) of dry oil and 15 million standard cubic feet per day (mmscfd) of gas from four lease blocks on the Outer Continental Shelf (OCS) and onshore Lompoc Oil Field (gas only). PXP has estimated that the combined oil and gas production from the Tranquillon Ridge and the Point Pedernales Fields would peak at around 30,000 bpd of dry oil and 6 mmscfd of gas, and is below the limits specified in the FDP. However, the proposed project would introduce oil and gas from a new source (State Tidelands lease) which is not currently permitted under the FDP, nor was it evaluated in the 1985 Point Pedernales Field EIR/EIS. Therefore, an FDP modification is required for the development of the Tranquillon Ridge Field.

The development of the Tranquillon Ridge Field would result in a number of changes to the existing Point Pedernales Project, which include the following:

- The drilling of 22 to 30 new wells for oil and gas production and utility use such as water injection and redrills.
- An increase in the total oil and gas throughput at the existing Point Pedernales facilities over what is occurring today. As discussed in Section 3.0, Project Description, the proposed project would increase dry oil production from an average of 7,000 barrels per day (bpd) in 2005 to a peak level of 30,000 bpd, and gas production would increase from a current average of 2.6 mmscfd to 6.0 mmscfd. PXP has estimated the ultimate recovery of the Tranquillon Ridge Field to be approximately 170 to 200 million barrels of dry oil and 40 to 50 billion standard cubic feet of gas.
- An increase in oil throughput in portions of the existing ConocoPhillips pipeline system from the Lompoc Oil and Gas Plant (LOGP) to the Summit Pump Station where the oil is ~~can be either~~ transported to the Santa Maria Refinery for initial processing. Semi-refined products are then transported ~~or continue~~ north to refineries in the Bay Area for further processing. The PXP Point Pedernales FDP allows 36,000 bpd of dry oil to be processed at the LOGP. From the LOGP, the oil is placed in the ConocoPhillips pipeline system for transport to the Summit Pump Station for transport to the eventual refinery destination. The ConocoPhillips pipeline system is a permitted common carrier and transports not only Point Pedernales production, but also transports Lompoc, Orcutt Hill, and Cat Canyon productions, as well as oil brought into the system via the Sisquoc Pipeline.
- A possible 15 to 30 year extension in the life of the Point Pedernales facilities from what was assumed in the 1985 Point Pedernales Field EIR/EIS.

As discussed in Section 5.0, Analysis of Environmental Issues, the Point Pedernales facilities are evaluated as part of the environmental setting (i.e., the baseline). The impacts associated with these facilities and their operation at current production levels ~~is~~ are also considered part of the environmental setting. Numerous mitigation measures/permit conditions of approval are in place to address the impacts associated with the current operations.

This EIR focuses on the new construction and new operational impacts that would occur with the development of the Tranquillon Ridge Field. In addition, the EIR addresses the effect the proposed project would have on the existing Point Pedernales Project impacts due to the projected increase in the oil and gas production levels and the extension of life of the Point Pedernales facilities. All of the impacts associated with increased oil and gas production are impacts that exist for the current Point Pedernales Project, but the severity is increased over what exists for the current operations. The impacts identified due to the extension of life of the Point

Pedernales facilities are existing impacts that would continue for longer periods of time than what was assumed during the permitting of the Point Pedernales Project.

The majority of the FDP conditions would continue to apply to the proposed project. Where the EIR has identified new impacts, existing impacts that have increased in severity, or extension of life related impacts, modifications to the existing FDP conditions may be required to incorporate any identified mitigation measures. The relationship between the recommended mitigation measures and the existing Point Pedernales FDP conditions can be grouped into the following categories.

1. The mitigation measure is already addressed by an existing FDP condition, so no changes to the condition are needed to implement the mitigation measure.
2. The mitigation measure is partially implemented by an existing FDP condition, so modifications are needed to the condition to fully implement the mitigation measure.
3. The mitigation measure is not covered by an existing FDP condition, so a new condition needs to be added to implement the mitigation measure.

The remaining existing FDP conditions would continue to be applicable to the Point Pedernales facilities, which would serve both the Point Pedernales and Tranquillon Ridge projects.

1.2 Objectives of the Project

Section 15124(b) of the CEQA Guidelines requires that the EIR discuss the objectives sought by the proposed project. The applicant's main objective of the proposed Tranquillon Ridge Project is to efficiently and effectively develop oil and gas reserves from the Tranquillon Ridge Field, and to sell the oil and gas production to help meet the energy demands of the State of California. If implemented, the proposed project would provide an additional supply of crude oil and natural gas to California. It is also PXP's objective to develop the State portion of the Tranquillon Ridge Field from an existing platform in Federal waters using extended reach drilling to maximize the development of the field, since PXP has expressed concern that the current method of developing the Tranquillon Ridge Field (utilizing bottomhole locations on Federal lands to drain reserves from the State Tidelands) could result in a loss of the reserves and State resources. Further, PXP has stated that it would be in the best interests of the State to grant the lease, allowing for the proper development of the reservoir. PXP has also stated that one of the objectives of the project is to provide increased royalty and tax revenue to the State and local community, and to provide a reasonable rate of return to investors. It should be noted that California has no stated objective or policy that State royalties and revenues should be increased and energy demand met specifically by leasing new areas of the submerged and tidal lands offshore California. That determination in the context of the Tranquillon Ridge project would be considered by the State Lands Commission at the end of the permitting process.

1.3 Agency Use of the EIR

A number of State and local governmental agencies require an environmental analysis of the proposed project consistent with the requirements of CEQA in order to act on the project. These agencies include ~~the~~ SBC, the California State Lands Commission (CSLC), and the California Coastal Commission (CCC). These governmental agencies formed a Joint Review Panel (JRP) to oversee the environmental review process. The Minerals Management Service (MMS), Vandenberg Air Force Base (VAFB), and the Santa Barbara County Air Pollution Control District (SBCAPCD) are advisory members of the JRP. Each agency will use the document as part of its respective decision-making process. The permitting requirements for each of these agencies are summarized below. Table 1.1 provides a list of permits and other approvals that will be needed for the proposed project.

Table 1.1. Permits or Other Actions Required for Implementation of the Proposed Project

Agency	Jurisdiction	Permit/Action
JRP Members		
Santa Barbara County	CEQA Lead Agency	• Certification of EIR • Revisions to the PXP Point Pedernales FDP • Compliance review and construction permits • Operations compliance
State Lands Commission	State lands and waters[a]	• Lease and Drilling Permits • Changes to existing right-of-way leases PRC 6923 or 6911[b]
California Coastal Commission	California coastal zone	• Possible Consistency Determination • Coastal Development Permit for activities proposed in State waters (e.g. wells)
Advisory JRP Members[c]		
Minerals Management Service	Manage development of mineral, oil, and gas resources in Federal waters.	• Possible revisions to the Point Pedernales Development and Production Plan (DPP) or a Right of Use and Easement[c]
Santa Barbara County Air Pollution Control District	Santa Barbara County	• Authority to Construct • Permit to Operate
Vandenberg Air Force Base	Within VAFB	• Oversight of private facilities located within the Base. • Review and authorization of PXP pipeline repair and maintenance activities • Discretionary regulatory authority for VAFB Onshore Alternative.
Other Possible Permitting Agencies		
U.S. Fish and Wildlife Service	Federal Listed, Threatened, and Endangered Species	• Consultation for Section 7 of the Endangered Species Act (if required)
U.S. Army Corps of Engineers	Construction or operation of facilities which may result in any discharge into U.S. navigable waters	• Section 401/404 Permit – streambed alteration/crossing (if required)
California Department of Fish and Game	Manage fish, wildlife, plant resources and habitats	• Streambed Alteration 1602 Permit (if required)
State Historic Preservation Office	Any archaeological or paleontological resource recovery work	• Cultural Resources Use Permit, Field Use Authorization, or an ARPA Permit (if required) • Consultation for Section 106 of the National Historic Preservation Act
Regional Water Quality Control Board, Central Coast	Clean Water Act, Section 401	• 401 Certification (if required) • Storm Water Construction General Permit • National Pollutant Discharge and Elimination System (NPDES) Permit • Waste Discharge Requirements (WDRs)

Table 1.1. Permits or Other Actions Required for Implementation of the Proposed Project

Agency	Jurisdiction	Permit/Action
California Division of Oil, Gas, and Geothermal Resources (California Department of Conservation)	Manage development of oil, gas, and geothermal resources with the State	• Oil and Gas Production Well Permits • Onshore Injection Well Permits • Offshore Injection Well Permits (if bottomhole located in State water)[d]

a. State waters include ocean waters from the mean high tide line to three miles out.
b. Changes to the existing right-of-way leases would only be needed if there are changes to the offshore pipelines or power cables.
~~c. While VAFB is an advisory agency to the JRP, VAFB only has regulatory authority over the VAFB Onshore Alternative. VAFB has oversight of private facilities located within the Base.~~
c~~d~~. The MMS will require the DPP to be revised if the State, MMS and the operator enter into a joint Right of Use and Easement grant from the MMS. The MMS will not take any action on the project until after the State lease is issued and the proposed Tranquillon Ridge Project has been approved by Santa Barbara County and the CSLC.
d~~e~~. Offshore injection well permits would cover both produced water, and muds and cuttings.

Santa Barbara County (SBC)

In order to implement this project, PXP, owner of the Point Pedernales Project, is requesting modifications to the SBC Point Pedernales Project FDP to include development (drilling and production operations) of a proposed California State lease (Tranquillon Ridge Field). SBC, as the CEQA Lead Agency, will need to certify the EIR in order to approve ~~consider~~ PXP's request for revisions to its ~~the various~~FDP~~s~~. The County, as the CEQA Lead Agency, will act first on the project before any of the responsible agencies take action on the project. SBC will use the document for decision-making regarding the proposed project. If the proposed project is approved by all required permitting agencies, SBC would be responsible for reviewing and approving all pre-construction compliance plans, and ensuring that the proposed project modifications and operations are conducted in accordance with the modified FDP, mitigation measures, and other permit conditions.

California State Lands Commission (CSLC)

PXP has applied to the CSLC for the issuance of a lease of State Tidelands for the purposes of oil and gas development. A lease from the CSLC is required to drill into the portions of the Tranquillon Ridge Field that lie within the State Tidelands. The results of the EIR, if certified by SBC, and following action by SBC on the revised FDP, will be used by the CSLC in determining whether or not to issue a lease and to approve the project. The CSLC may also need to use the EIR to address any proposed changes to the existing State right-of-way leases for the offshore pipelines and/or power cable (PRC 6923 and 6911).

Minerals Management Service (MMS)

In May ~~March~~ of 2005~~0~~, PXP submitted to the MMS ~~a Revised~~revisions to the Development and Production Plan (DPP) for the Point Pedernales Field to include the Tranquillon Ridge Development. The MMS determined that revisions to the DPP were not ripe for consideration because the State lease for the proposed development did not exist, and the development would be in State Waters with no development or production activities in the submerged lands of the Federal OCS. ~~The MMS has decided to wait until the final State lease and the project have been approved before making a determination if a revised DPP or other Federal action is needed. The MMS will take action if the revised FDP is approved by SBC and the State lease is granted by~~

~~CSLC. The MMS will require that the Point Pedernales Unit DPP be revised if the Tranquillon Ridge becomes a joint Federal/State unit as development of the joint unit proposes an activity that was not previously identified and evaluated. Without the joint Federal/State unit, it would be a State project, and the MMS would only need to grant a Right-of-Use and Easement.~~ PXP, the CSLC, and the MMS are considering the formation of a joint Federal/State unit as a means of ensuring the efficient and prudent development of the Federal and State reserves of the Tranquillon Ridge Field. In joint Federal/State units, the State leases are considered to be extensions of the OCS leases. In the case of the Tranquillon Ridge Project, development of these "extended OCS leases" proposes an activity that was not previously identified and evaluated, and will therefore result in a revision to the Point Pedernales DPP. Without the joint Federal/State unit, it would be considered strictly a State project, and the MMS would only need to grant a Right-of-Use and Easement.

California Coastal Commission (CCC)

For activities proposed in State waters (e.g., wells), PXP must apply to the CCC for a Coastal Development Permit. In addition, if the MMS requires a revised DPP for the Tranquillon Ridge Project, and determines that the revisions will likely result in a significant change in the impacts previously identified and evaluated, then the CCC must determine if the amendment (or project change) will cause an effect on any coastal use or resource substantially different than those originally approved by the CCC when it concurred with the consistency certification for the original DPP. In the event of a consistency determination by the CCC, they will rely in part on information in the EIR to assess the impacts to land or water uses or natural resources of the coastal zone. If the MMS grants a Right-of-Use and Easement (instead of a revised DPP), the CCC would need to seek authorization from the National Oceanic and Atmospheric Administration (NOAA) to do a Federal Consistency Review.

Santa Barbara County Air Pollution Control District (SBCAPCD)

The SBCAPCD will need to issue an Authority to Construct (ATC) and Permit to Operate (PTO) for a number of the proposed project changes. To fulfill its obligations as a Responsible Agency, the SBCAPCD will rely on information contained in this EIR.

California Division of Oil, Gas and Geothermal Resources (DOGGR)

The DOGGR will need to issue permits for the oil and gas development wells that have bottom-hole locations within the State Tidelands. They would also have to issue well permits for any injection wells that have bottom-hole locations within State lands. This would include injection wells for produced water and/or drill muds and cuttings.

1.4 EIR Contents

This EIR was prepared in accordance with State and SBC administrative guidelines established to comply with the CEQA. Section 15151 of the State CEQA Guidelines provides the following standards for EIR adequacy:

> *"An EIR should be prepared with a sufficient degree of analysis to provide decision makers with information which enables them to make a decision which intelligently takes account of environmental consequences. An evaluation of the*

environmental effects of a proposed project need not be exhaustive, but the sufficiency of an EIR is to be reviewed in light of what is reasonably feasible. Disagreement among experts does not make an EIR inadequate, but the EIR should summarize the main points of disagreement among the experts. The courts have looked not for perfection; but for adequacy, completeness, and a good faith effort at full disclosure."

The EIR is divided into the following major sections: Referenced figures in each section are provided at the end of the respective section.

Executive Summary. Provides an overview of the project, and a summary of the significant impacts identified in the analysis and associated mitigation measures. A summary of the alternatives and environmentally superior alternative is also provided.

Impact Summary Tables. Provides a summary of the identified impacts by significance class for the proposed project and each alternative. The tables also provide a summary of proposed and/or recommended mitigation measures for the impacts.

1. **Introduction.** Provides an overview on the proposed project evaluated in the EIR and a summary of the objectives for the project. The section also discusses agency use of the document, and provides a summary of the contents of the EIR.

2. **Background and Project Description.** Provides a detailed description of the proposed project, as well as the detailed project background, including current operations.

3. **Alternatives.** Provides descriptions of the alternatives that were evaluated in this document. The section also presents an alternatives screening analysis that was used to identify alternatives that could reduce significant impacts associated with the proposed project. The alternatives that made it through the screening analysis were evaluated in detail throughout the document.

4. **Cumulative Projects Descriptions.** This Section provides a description of the projects that have been included in the cumulative analysis. The cumulative analysis contained in this document covers the cumulative impacts of reasonably foreseeable projects located in the vicinity of the proposed project that have either been proposed or are in various stages of permitting.

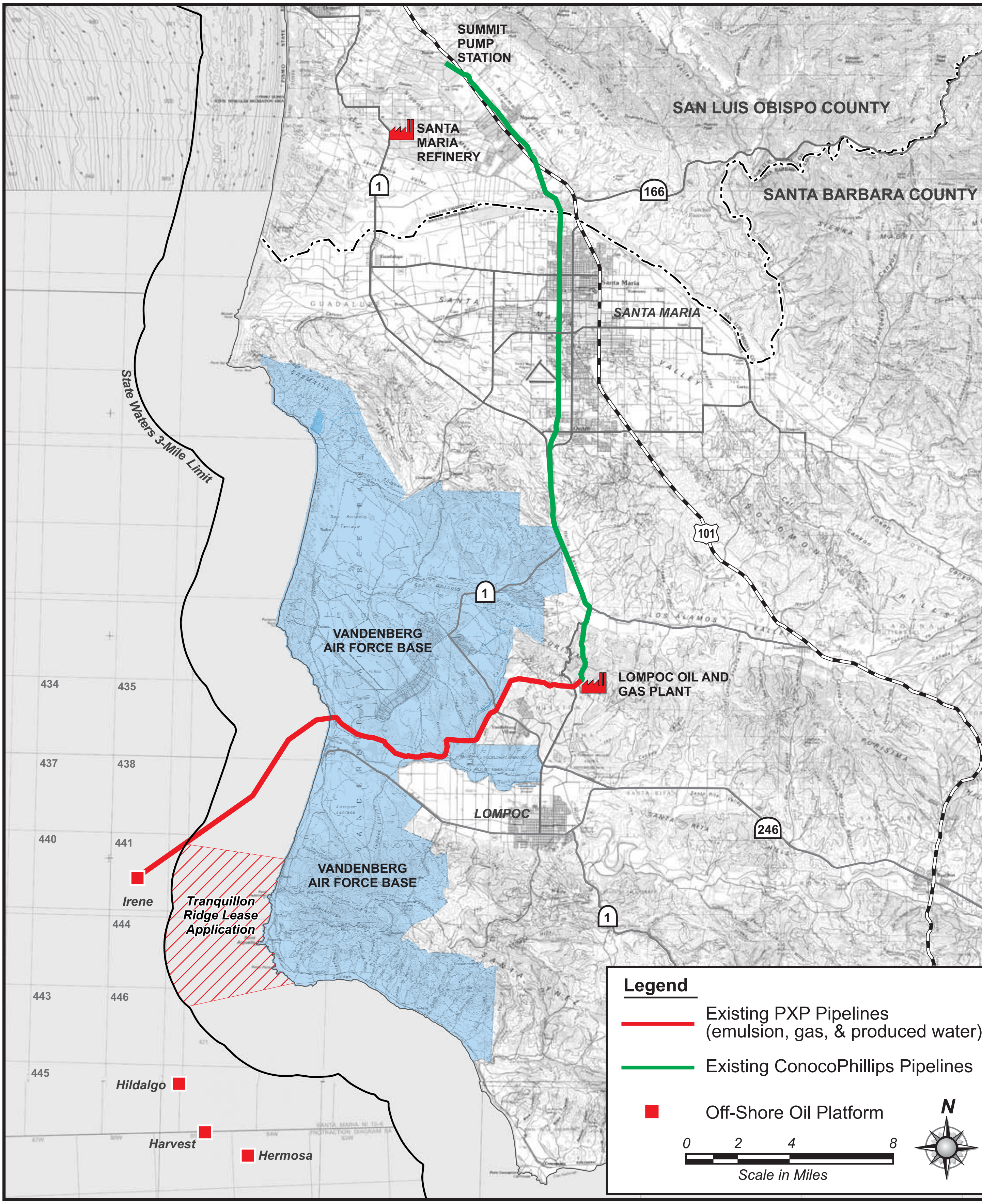
5. **Analysis of Environmental Issues.** Describes the existing conditions found on the project site and vicinity, and assesses the potential environmental impacts that may be generated by implementation of the proposed project. These potential project impacts are compared to various "Thresholds of Significance" in order to determine the severity of the impacts. Mitigation measures intended to reduce significant impacts are proposed where feasible. This Section also assesses the potential environmental impacts associated with the alternatives that passed the screening analysis presented in Section 3.0. In addition, cumulative impacts are assessed for the proposed project together with the other "reasonably foreseeable projects" listed in Chapter 4.0. This Section also presents the Mitigation Monitoring Plan.

6. **Environmentally Superior Alternative.** Compares the environmental advantages and disadvantages associated with the proposed project and the alternatives. Based on this discussion, the environmental preferability of the alternatives relative to the proposed project is discussed.

7. **Growth Inducing Impacts.** Identifies the spatial, economic, and/or population growth impacts that may result from development of the proposed project.

8. **Significant Irreversible Environmental Changes.** Describes any changes to the existing environment which are irreversible in nature, such as use of nonrenewable resources or commitment of future generations to similar land uses.

The EIR also contains a number of appendices that support the environmental analysis. These appendices are included in Volume II of the EIR, which has been bound separately from this Volume I.



PREPARED BY Aspen Environmental Group

Figure 1-1
Proposed Project Location

2.0 PROJECT DESCRIPTION

The proposed Tranquillon Ridge Project (proposed project) involves the development of the Tranquillon Ridge Field located primarily in State waters. As proposed by Plains Exploration and Production Company (PXP), the applicant, the Tranquillon Ridge Field would be accessed using extended reach drilling from Platform Irene. Platform Irene is an existing platform located in Federal waters which is currently producing the Point Pedernales Field. Oil emulsion (a mixture of produced oil and water) and gas are transported to the Lompoc Oil and Gas Plant (LOGP) via existing pipelines for processing. PXP proposes to utilize these existing pipelines and LOGP for the transport and processing, respectively, of the Tranquillon Ridge Field production. Platform Irene, the existing pipelines, and LOGP are collectively referred to as the Point Pedernales Project, approved by the Santa Barbara County (SBC) Board of Supervisors in 1986. Because the proposed project would utilize the existing Point Pedernales Project facilities, Section 2 has been organized as follows:

- **Section 2.1 - General Background**, including an overview of the existing Point Pedernales Project facilities and current production volumes. In addition, an overview of Tranquillon Ridge Field exploration is provided.
- **Section 2.2 – Proposed Project Description**: This section describes the proposed Tranquillon Ridge Project, including well development using extended reach drilling technology, utilization and modifications to the existing Point Pedernales Project facilities, and anticipated production volumes and duration.
- **Section 2.3 – Current Point Pedernales Project Operation**: This section describes in detail the current operation of Platform Irene; emulsion, gas, and produced water pipelines; and LOGP, including leak detection and corrosion monitoring systems, and production.

2.1 General Background

2.1.1 Existing Point Pedernales Project

~~As noted,~~ The original Point Pedernales Project (85-DP-071~~94-DP-027~~) was approved by the SBC Board of Supervisors in 1986. The Minerals Management Service (MMS) approved the federal portion of the project and the California Coastal Commission (CCC) concurred in a consistency certification in 1985/~~1986~~. The facility has operated since 1987. Gas treatment facilities were installed in 1997 that allowed for the production of sales quality natural gas at the LOGP. The Point Pedernales Project facilities are summarized below and are illustrated in Figure 2-1 (all figures are at the end of this section):

- Platform Irene, an oil and gas drilling and production platform, located on Lease OCS-P 0441, approximately 6 miles from shore.
- The LOGP, an oil dehydration and gas processing facility (formerly known as the Heating, Separation, and Pumping [HS&P] facility), is located approximately three miles northeast of Lompoc, in northern SBC. The site address is 3602 Harris Grade Road, Assessor Parcel number 097-360-010. The plant occupies a 22.5-acre portion of a 2,283-acre parcel within the Lompoc Oil Field.
- Three pipelines (a 20-inch emulsion line, an 8-inch gas line, and an 8-inch produced water return line for discharge at the platform), located in one common right-of-way, connecting Platform Irene to LOGP, with all the valves, valve sites and other pipeline appurtenances along the pipeline route. The

offshore portion of the pipelines traverses 10.1 miles and are partially buried on the ocean floor. The pipelines reach landfall just north of the Santa Ynez River at Wall/Surf Beach and cross Vandenberg Air Force Base (VAFB) and PXP property. The onshore portions of the pipelines are buried and traverse 12.1 miles between Wall/Surf Beach and the LOGP.

- A power supply system consisting of an electrical substation located on Union Pacific Railroad property at Surf Beach (Surf substation), a subsea power cable from the substation to Platform Irene, and an upgraded transmission line from the Pacific Gas and Electric (PG&E) power line north of Lompoc to the Surf substation.
- Dry oil from the LOGP is sent to the Santa Maria Refinery in San Luis Obispo County via the existing ConocoPhillips pipeline system.
- A 12-inch sales gas pipeline from LOGP to the Righetti valve site and a 6-inch sales gas pipeline from the Righetti valve site to The Gas Company gas transmission line #1010.
- Three onshore produced water disposal lines, one 10-inch, one 12-inch line, and one 8-inch line, used to transport treated produced water from the LOGP to the Lompoc Oil Field for injection.

Currently, the Point Pedernales Project is permitted to operate under the following Final Development Plan (FDP 94-DP-027) production/processing capacities:

- 36,000 barrels per day (bpd) of dry oil;
- 15 million standard cubic feet per day (mmscfd) of natural gas with a maximum hydrogen sulfide (H_2S) concentration level of 8,000 parts per million (ppm);
- 9.205 mmscfd of onshore gas reinjection (only during upset conditions); and
- Monthly average of 2.3 liquid petroleum gas/natural gas liquids (LPG/NGL) truck trips per day.

The Point Pedernales Project was initially developed and operated by Unocal Oil Company. In the 1990's the facility was acquired by Nuevo Energy Company ("Nuevo") and Bellwether Exploration Company ("Bellwether"), and operated by Torch Operating Company. The Point Pedernales Project is currently owned and operated by the applicant, PXP.

2.1.2 Tranquillon Ridge Field Exploration

Pursuant to a Lease Line Well Agreement between the MMS and the California State Lands Commission (CSLC) dated February 13, 1997, Torch, as Operator for Nuevo and Bellwether, drilled Well A-28 on Federal OCS Lease OCS-P 0441 from Platform Irene to a bottomhole location approximately 50 feet from the seaward boundary of the State of California. Production from this well resulted in the discovery of a hydrocarbon-bearing structure, which has been named the Tranquillon Ridge Field. Recent 3-D seismic data and existing historic 2-D seismic data, along with a geologic interpretation developed by using the Point Pedernales Field as an analog, indicated that the majority of the Tranquillon Ridge Field is in State Tidelands. On March 25, 1997, the Lease Line Well Royalty Sharing Agreement between the MMS and the CSLC was ratified by the Secretary of the Department of the Interior and the Executive Officer of the CSLC. This agreement provided for royalty sharing related to production from Well A-28. Well A-28 production is combined at Platform Irene with production from other Federal leases and transported to the LOGP.

The State of California is concerned that Well A-28 is draining oil and gas from lands owned by the State of California. Several additional wells can be drilled on Federal Lease OCS-P 0441 from Platform Irene to bottomhole locations near the seaward boundary of the State of California. In addition, wells could also be drilled into Federal Lease OCS-P 0444. However, these wells may also drain significant quantities of oil and gas from lands owned by the State of California. As a prerequisite to leasing, the CSLC must make a finding that drainage of state resources is occurring. The CSLC had an independent study prepared to aid the Commission in making its determination.

The applicant has expressed an interest in developing the Well A-28 related areas under State waters through the use of extended-reach drilling technology. Well bottom locations would be located under State waters. Drilling would occur at Platform Irene in Federal waters. Some project changes would be required at Platform Irene, possibly along the pipeline route, and at the LOGP to accommodate the increased production from these additional wells. The applicant has stated that they will ensure that any of the parameters that~~, which~~ are limited under all applicable permits (e.g., pipeline pressures, air pollutant emissions) will ~~, do~~ not exceed the permitted levels due to ~~by~~ the increased production.

2.2 Proposed Project Description

Section 2.2 presents the description of the proposed Tranquillon Ridge Project (proposed project). This section has been organized as follows:

2.2.1 Well Development and Production
2.2.2 Platform Irene Modifications
2.2.3 Lompoc Oil and Gas Plant (LOGP) Modifications
2.2.4 Existing Pipeline Modifications
2.2.5 Project Schedule, Personnel, and Equipment Requirements
2.2.6 Extension of Life of Point Pedernales Facilities

2.2.1 Well Development and Production

Plains Exploration and Production Company (PXP) plans for development of the Tranquillon Ridge Field include directionally drilling a maximum of 30 wells, including 22 new production wells and potentially eight utility and re-drilled wells from Platform Irene into California State Lands, utilizing extended reach drilling technology. One well would be drilled at a time. Access to State Lands would be accomplished solely through extended reach drilling, several thousand feet below the ocean floor. The horizontal distances of the extended-reach wells are within the capability of existing drilling technology. Drilling plans were developed by using Point Pedernales Field drilling experience as an analog. Actual drilling results may indicate that fewer than 30 wells would be needed to develop the proposed State lease.

PXP has preliminarily determined the bottomhole locations of the 22 new production wells to be drilled (see Figure 2-2). Bottomhole locations for additional wells, if needed, would be determined as additional information is obtained from drilling. The specific bottomhole locations currently identified will likely be revised as additional geotechnical information is obtained. Specific drilling programs and bottomhole locations for each well would be submitted for approval to the California State Lands Commission (CSLC), California Division of Oil, Gas and Geothermal Resources (CDOGGR), and Minerals Management Service (MMS) prior to drilling.

Recompletion in a well, if needed, would likely commence eight to ten years after the initial completion date of a well. Recompletion involves the re-work/drilling of a well to ensure full production levels are achievable. Wells currently proposed to be drilled are shown in Table 2-1. (The well numbers correspond to the bottomhole locations shown in Figure 2-2.)

TABLE 2.1 PROPOSED WELL LOCATIONS AND DISTANCES

Well Number	Approximate Measured Length, feet	Estimated Drilling Days	Horizontal Distance from Irene, feet
B-1	15,000	60	13,250
B-2	15,000	60	13,250
B-3	17,300	90	15,600
B-4	13,090	60	11,250
B-5	14,060	60	12,250
B-6	12,850	60	10,975
B-7	16,200	90	14,600
B-8	18,100	90	16,600
B-9	16,860	90	15,300
B-10	15,000	60	13,250
B-11	17,370	90	15,800
B-12	21,540	120	20,000
B-13	19,800	120	18,400
B-14	24,700	120	23,300
B-15	23,390	120	22,050
B-16	22,225	120	20,750
B-17	23,750	120	22,300
B-18	19,900	120	18,500
B-19	18,650	90	16,900
B-20	24,070	120	22,750
B-21	24,900	120	23,400
B-22	25,150	120	23,800

Note: the wells may not be drilled in numerical order.

Total well drilling and completion times are anticipated to range between 60 and 120 days per well. These times are consistent with drilling and completion times of similar-length development wells drilled from Platform Irene in the Point Pedernales Field. However, actual drilling times for wells of similar length may vary due to dynamic dependencies on equipment, total well length, angle, completion techniques, and weather. The 30-well development plan proposed for the Tranquillon Ridge Field is designed to provide 80-acre well spacing (each well would be approximately centered on an 80-acre area) in all of the four commercial Monterey zones.

PXP has developed a detailed well development program only for 22 of the possible 30 Tranquillon Ridge Field wells. Each well would be directionally drilled using extended reach technology from unused well-slot locations currently available on Platform Irene. Total measured well lengths would exceed in some instances 25,000 feet, with overall vertical depths below the ocean surface averaging between 3,000 and 5,000 feet. These well lengths and depths can be accomplished utilizing existing extended-reach drilling development technology. To fit within the existing framework of the facility infrastructure at Platform Irene and the LOGP, and the existing permits, the proposed 22 production well development program would be drilled over a 15-year time period.

Due to the geotechnical constraints associated with developing a coastal California Monterey oil-bearing structure, production estimates can only be made from studying similar reservoirs. Fortunately, the Tranquillon Ridge Field is similar in structure and chemical makeup to and is adjacent to the Point Pedernales Field, so analogies between the two fields can be made. PXP has used analogies with Point Pedernales production data to provide a statistical background for developing the proposed Tranquillon Ridge Field well drilling schedules and production forecasts. Figure 2-3 provides an estimate of the oil production for the proposed Tranquillon Ridge Project. The figure also shows total estimated production from Platform Irene, which includes both the Tranquillon Ridge and Point Pedernales Fields.

Production from the Tranquillon Ridge Field is estimated to peak at around 27,000 bbls/day of dry oil and 5 mmscfd of gas. With the proposed Tranquillon Ridge Project, production from Platform Irene would be at around 30,000 bbls/day of dry oil and 6 mmscfd of gas. Based upon PXP's estimates, the ultimate recovery at the economic limit for the Tranquillon Ridge Field is estimated to be approximately 170 to 200 million barrels of oil (or approximately 18,000 bpd averaged over ~~the~~ an approximate 30-year project life) and 40 to 50 billion standard cubic feet of gas. Oil produced from the Tranquillon Ridge Field is expected to be heavy, 16-18 degrees API gravity, similar to that of the Point Pedernales Field oil.

The oil production estimates for the Tranquillon Ridge and Point Pedernales Fields are based on limited data, and may not represent the actual production achieved once the wells are drilled. The actual production will depend on the number of wells that are drilled, the rate at which the wells are drilled, and the performance of each development well. The reader should not assume that the estimated production curve is what will actually occur with the development of the Tranquillon Ridge Field. It can only be used to provide information on the expected trends that would be associated with development of the Tranquillon Ridge Field.

Gas H_2S concentrations are estimated to remain between 4,000 and 8,000 ppm with addition of Tranquillon Ridge gas production to the Point Pedernales produced gas. If Tranquillon Ridge production is similar to Point Pedernales production, then the H_2S concentration in the gas stream is expected to decrease during the initial period of production.

2.2.2 Platform Irene Modifications

The following discussion details the upgrades and minor modifications that are required on Platform Irene in order to integrate the proposed Tranquillon Ridge Project with the current operation of the Point Pedernales Project.

The proposed Tranquillon Ridge Project would require installing new pumps on Platform Irene. PXP proposes to replace three 600-horsepower electrical shipping pumps with three 1,250-horsepower electrical shipping pumps. In addition, approximately 15 of the new Tranquillon Ridge wells would utilize new 500-horsepower electrical submersible pumps. The other production wells would utilize gas-lift technology. PXP would continue ongoing maintenance and upgrades of the electrical transformers and switchgear on the platform for these additional pump loads.

During the Tranquillon Ridge drilling operations on Platform Irene, PXP proposes to batch discharge the muds and cuttings into the ocean in accordance with the National Pollutant Discharge Elimination System (NPDES) General Permit No. CA280000. The temperature of the discharged muds depends on the true vertical depth of the hole being drilled. In general, temperature of subsurface strata increases with depth. Based on data gathered in exploratory drilling on OCS P-0441, the maximum mud temperature at the mud shaker will be 117°F, assuming a depth of 5,000 feet total vertical distance. From the shaker area, the mud for discharge is continuously sent to a cuttings washing system, where it is diluted with seawater. Assuming a mud discharge rate of 3.5 gallons per minute diluted with wash water (seawater) at 100 gallons per minute rate, the resulting effluent temperature will be 63.3°F. As proposed, this effluent would be discharged at a point approximately 150 feet below mean lower low water (MLLW) into an ocean environment with the ambient temperature of 60 to 61°F. Any cuttings or muds that do not meet the NPDES permit requirements would be stored in bins and hauled to a permitted disposal site onshore or injected, if feasible. For example, if oil-based mud is used, the cuttings and excess muds would be stored in bins and transported to a permitted disposal site onshore, or injected offshore at the platform.

Drilling activities and equipment would be similar to those of ongoing drilling programs, but with different frequency and duration. The existing drilling rig that is currently on Platform Irene would be used to drill the Tranquillon Ridge wells. The only additional equipment for drilling will be ~~a~~ two new 1,600-horsepower electric pumps for mud handling that would replace two existing 1300-horsepower electric pumps. PXP has stated that they have no plans to use diesel-powered pumps for mud handling.

The existing 8-inch produced water return pipeline is currently used to return part of the Point Pedernales produced water from the LOGP to Platform Irene for offshore water injection (a part is injected onshore into the Lompoc Oil Field). For the proposed Tranquillon Ridge Project, the produced water would ~~continue to~~be transported offshore to Platform Irene for disposal; however, over the short-term a portion might be re-injected into the Lompoc Oil Field. This water would either be discharged to the ocean under the NPDES permit or re-injected offshore in accordance with the MMS authorization. ~~When combined, approximately~~Given the capacity of the 8-inch produced water line, a maximum 40,000 barrels per day (bpd) of ~~water~~produced water ~~from the Point Pedernales and Tranquillon Ridge Fields~~would be shipped from the LOGP to

Platform Irene for discharge. The applicant is authorized to discharge to the ocean from the platform up to 55,845,000 barrels of water per year (153,000 bpd) in accordance with the General NPDES Permit.

PXP projections for the Point Pedernales field production indicate that the water content of these federal wells will continue to increase in the future[1] at the same time that Tranquillon Ridge production is brought on-line. In addition, re-injection of produced water into the Lompoc Oil Field is only available over the short-term. In response to the projected produced water disposal needs, PXP is in the process of designing upgrades to the Platform Irene Point Pedernales water handling system to effectively treat produced water to the standards required for NPDES discharge, given the capacity of the 8-inch produced water pipeline (40,000 bpd). PXP plans to route select Point Pedernales wells with high water cuts through the new water separation and polishing equipment, and then commingle the produced water from this flow with the produced water being sent back from LOGP for a blended discharge. All blended discharges would be conducted in accordance with the current General NPDES Permit.

A part of the produced water that would be treated at or shipped to Platform Irene may still be re-injected into Point Pedernales reservoir wells, as is currently the operation, to enhance current Point Pedernales production. Offshore water re-injection would be conducted as authorized by the MMS.

The Platform Irene operations changes with the proposed project are summarized in Table 2.2.

TABLE 2.2 SUMMARY OF CHANGES TO PLATFORM IRENE OPERATIONS WITH PROPOSED PROJECT

Parameter (Permitted Level[a])	Platform Irene with Addition of Tranquillon Ridge Project	
	During Normal Operations	During Drilling of New Wells
Total Employees	No additional personnel [b] (Currently there are 14-15 personnel).	No additional personnel. (Currently during drilling there are up to 70 personnel = = 15 [normal operations] + 55 [drilling]).
Total Boat Trips (1 one-way trip every 3 days)	No increase (Currently [c] – 1 one-way trip every 3 to 4 days annual average or 107 trips per year).	Increase to a total of 1 one-way trip every 3 days or 120 trips per year (at the permitted limit).[d]
Total Helicopter Trips (3 round trips per day)	Increase of 1 one-way trip per week or 26 round trips per year (Currently [c] – 13 round trips per week annual average, or 654 in 2005)	Increase to a total of 3 round trips per day annual average.
Equipment Additions, Upgrades or Replacements	1) Replacement of three 600 hp pumps with three 1,250 hp pumps. 2) Installation of 500 hp submersible pumps on 15 new wells. 3) Ongoing transformer and switchgear upgrades.	Installation and operation of two ~~one~~ 1,600 hp electric pumps to replace two existing 1,300 hp electric pumps.
Additional Maintenance and Service of Wells	With addition of new wells could be up to 50% increase in maintenance and service.	None
Additional	104%[e]	116.9%[e]

1 There are currently five Point Pedernales wells producing with an excess of 90% water cuts. The water cut for Point Pedernales wells can be as high as 99%.

TABLE 2.2 SUMMARY OF CHANGES TO PLATFORM IRENE OPERATIONS WITH PROPOSED PROJECT

	Platform Irene with Addition of Tranquillon Ridge Project	
Electrical Power Requirement		
Muds and Cuttings Disposal	N/A	Disposal into ocean outfall as per the NPDES permit or offshore injection if feasible.[f]
Produced Water Disposal (2005 annual average)	Addition of 20,000 bpd for discharge offshore with a total of 40,000 bpd for injection or discharge to ocean. (Currently up to 20,000 bpd is injected offshore.)	N/A

N/A – not applicable; hp – horsepower.

a. The permitted level is listed only where it is applicable.

b. Normal current operations include periodic well workover drilling, which takes 8 weeks per year and requires up to 55 personnel to operate the drilling rig and perform other work during the well workovers.

c. Maximum permitted helicopter trips and boat trips are occasionally used (e.g. during the platform shift change).

d. Assuming that drilling muds will be discharged into the ocean or re-injected (e.g., no onshore disposal).

e. Data provided by PXP.

f. Through 2008 to 2010, PXP estimates that their average annual muds and cuttings disposal will be approximately 48,700 bbls and 5,700 bbls, respectively. The current general NPDES permit limits muds and cuttings discharge to 105,000 bbls/yr and 30,000 bbls/yr, respectively.

2.2.3 Lompoc Oil and Gas Plant (LOGP) Modifications

The following minor modifications at the LOGP would be required in order to handle production from the proposed Tranquillon Ridge Project.

PXP proposes to return to service two existing plate and frame heat exchangers, and install piping for the heat medium with the existing heater treater water outlets, to allow additional oil emulsion processing capacity. It would be necessary to heat the water and oil emulsion to aid in separation. In addition, PXP would install a new duplex feed strainer ~~on the 20-inch pipeline inlet~~ between the first and second plate and frame heat exchangers within the LOGP. One of the reasons the existing plate and frame heat exchangers are currently out of service is fouling from solid material in the emulsion stream. The installation of a feed strainer would facilitate the removal of solids, extend the time between cleaning, and maintain the efficiency of the exchangers. The duplex design would allow cleaning of one strainer while the other is online.

Other modifications include upgrades to the existing free-water knockout vessel, including installation of baffles and insulation of its exterior. In addition, upgrades and installation of baffles would be required for the three existing heater treaters. Installing baffles in the existing free water knockout and heater treaters would expand their emulsion breaking capacity. They would also aid in the water clarification process. Insulating the free water knockout would aid in heat retention and reduce the fuel consumption in the heater treaters.

Due to the increased use of the heater treaters for heating of the crude oil natural gas, fuel consumption could increase by 100 percent. Electricity consumption at the LOGP could increase by approximately 30 percent due to the increased operations of the existing equipment. Increases in maintenance and service of the new equipment would not require additional new employees.

Currently there are 2.7 liquid petroleum gas/natural gas liquid (LPG/NGL) truck trips per week (year 2005 annual average). It is expected that the Tranquillon Ridge Project would generate up to two additional trips per week[2].

All LOGP upgrades and modifications would occur within the existing boundaries of the facility. No new grading or lighting would be required at the LOGP.

Table 2.3 summarizes all the changes to the LOGP facility that will occur with the introduction of the Tranquillon Ridge Project.

TABLE 2.3 SUMMARY OF CHANGES TO THE LOGP WITH TRANQUILLON RIDGE PROJECT

Changes with Project	During Normal Operations
Additional Employees	None
Additional LPG/NGL Truck Trips	Approximately 2 per week (to a total of 5 per week[a])
Additional Sulfur Truck Trips	Approximately 1 per week (an increase from 12/yr to 48/yr. No increase in amine and vacuum truck trips.[b]
Additional Equipment Or Equipment Modifications	1) Return to service of two heat exchangers. 2) Addition of duplex feed strainer. 3) Addition of internal coalescing assemblies inside the existing free-water knockout vessel and insulation of its exterior. 4) Addition of internal coalescing assemblies and four (4) externally adjustable baffles on the three existing heater treaters.
Additional Maintenance	To be handled by the current employees.
Additional Electrical Power Requirement	30%[c]
Additional Natural Gas Requirement	100%[d]
Water Disposal Onshore	No increase

hp – horse power.
a. Based on the ratio of NGL/LPG that could be generated to currently being produced.
b. Data provided by PXP.
c. Data provided by PXP. The increase is due to increased operations due to production from Tranquillon Ridge.
d. To run additional heater treaters.

2.2.4 Existing Pipeline Modifications

This section addresses the modifications to the existing Point Pedernales Project onshore pipelines and ConocoPhillips dry oil pipeline system. The ConocoPhillips pipeline system is an existing common carrier dry oil pipeline system. The Point Pedernales Project was approved in 1986, at which time the ConocoPhillips pipeline system was owned and operated by Unocal Oil Company. As a result, the subject dry oil pipelines were included in the original permitting for the Point Pedernales Project. The subject dry oil pipelines have been under different ownership for many years; including Tosco and now ConocoPhillips. PXP does not have any ownership interests in ConocoPhillips and has not included any modifications to the ConocoPhillips system in the PXP application for the proposed project. If modifications are required, ConocoPhillips would need to address these changes under their existing permits with the County. Information about the ConocoPhillips pipeline system is provided herein for context and reference only.

2 Additional truck trips for Tranquillon Ridge have been estimated based on the ratio of current gas production (3.4 mmscfd Platform Irene and 0.8 mmscfd Lompoc Field) to future gas production with Tranquillon Ridge (6 mmscfd Platform Irene and 0.8 mmscfd Lompoc Field).

2.2.4.1 Point Pedernales Project Onshore Pipelines

PXP is proposing the option to install crude oil booster pumps at Valve Site #2. No other modifications are proposed for the Platform Irene to LOGP pipelines. Monitoring of the pipelines would continue, and sections of old pipe would be replaced with new pipe, as required, to maintain a sufficient operating pressure in order to continue operation of the Point Pedernales Project with the Tranquillon Ridge Project.

The expected volume of oil/water emulsion produced by Point Pedernales and Tranquillon Ridge combined is 90,000 bpd. Currently, the pressure rating on the 20-inch emulsion pipeline from Platform Irene to the LOGP is sufficient for the expected operation. However, during the course of the Tranquillon Ridge project, if the Maximum Allowable Operating Pressure (MAOP) of the 20-inch pipeline needs to be lowered (i.e., the pipeline derated to less than 1,000 psig), then operation at the pressures needed to transport 90,000 bpd of emulsion would not be possible. For this case, PXP proposes to install three new 1,250-horsepower, electric booster pumps at Valve Site #2 in order to minimize the operating pressure of the offshore pipeline segment of the 20-inch oil pipeline. Two pumps would be operated simultaneously with the third pump on standby. Apart from the power lines, all equipment modifications would be accommodated within the existing footprint of Valve Site #2 and would be integrated into the existing safety systems at the LOGP. Approximately one person-month per year would be required for pump station maintenance (see Table 2.4).

2.2.4.2 Electrical Systems Upgrade

The existing electrical system would be upgraded at Valve Site #2 by installing a new power line (see Appendix A). Power is proposed to be supplied from one of two possible sources. The first choice is to supply power from the 115 kilovolt (kV) line that exists along Renwick Avenue in Lompoc. In this case, a substation would need to be constructed to step power down from 115 kV to 34.5 kV. The substation would be placed in the farm field on the northwest corner of Renwick and Ocean Avenues. The new power line poles would be installed along Renwick Avenue. The second choice is to supply power from the existing 12 kV power line, in which case, there would be no need for the substation and the power line could be placed on the existing poles along Renwick Avenue. The selection of the power grid tie-in point will be contingent upon property availability and cost evaluation for power line installation and operation.

At the northern end of Renwick Avenue the line would need to cross the Santa Ynez River. PXP proposes that the new power line would cross the Santa Ynez River on a new set of poles that would be installed on both sides of the river. After crossing the river and crossing under the VAFB power line via trenching, the new power line would run along the east side of 13th Street to its intersection with Terra Road. Once at Terra Road, the new power line would be run under 13th Street and under another VAFB power pole line that follows 13th Street in this location. This crossing will be done via trenching. After the power line emerges on the west side of 13th Street, it would follow Terra Road and the right-of-way of the Platform Irene to LOGP pipeline route to Valve Site #2. For the portion of the route along Terra Road, the power line would be placed on new poles. It is assumed that approximately 45 poles would be required. The average height of power poles would be 60 feet and the average span between the poles would be 350 to 400 feet depending on the terrain. Installation of the power poles would require minimal grading and clearing around each installed pole as required by the Fire Department.

Table 2.4 summarizes the changes to the Point Pedernales project onshore pipelines and associated facilities.

TABLE 2.4 SUMMARY OF CHANGES TO VALVE SITE #2 WITH PROPOSED PROJECT[a]

Changes with Tranquillon Project	During Normal Operations
Additional Equipment	1) Three 1,250 hp electrical booster pumps on 20-inch oil pipeline with an additional transformer and required switchgear. 2) New power lines with power poles[b], and possibly a new substation.
Additional Maintenance	One person-month per year for maintenance to pump station equipment.

a. These changes would only be necessary if the 20-inch emulsion pipeline MAOP is derated.

b. The alternative to this is underground installation of a portion of the power line. For other alternative routes see Section 3.0.

2.2.4.3 ConocoPhillips Pipeline System

The ConocoPhillips Orcutt Pump Station modifications would be limited to placing a second electrically driven shipping pump, driven by 175 to 350-horsepower variable speed electric motor, back into service, or replacing it with a new pump. This would allow the system at the Orcutt Pump Station to be able to pump at the flow rate of up to 36,000 bpd. The pump is already permitted under the UNOCAP Point Pedernales Project permit No.94-DP-028 and SBCAPCD PTO 7511; however, the PTO would require an amendment. Replacement of the permitted pump on as-needed basis is a part of normal operations at the pump station and does not represent new equipment installation.

The pipelines connecting the LOGP to the Summit Pump Station include the 12-inch pipeline from LOGP to Orcutt Pump Station, the 8-inch pipeline from Orcutt Pump Station to Summit through Suey Junction; and the 10/12-inch pipeline from Suey Junction to the Summit Station (see Figure 2-4). Only the 12-inch pipeline between the LOGP and Orcutt Pump Station and the 8-inch pipeline between Orcutt Pump Station and Suey Junction are expected to have increased oil throughput once Tranquillon Ridge production begins, since more oil would be shipped from the LOGP to the ConocoPhillips Santa Maria Refinery. Nonetheless, no modifications to the pipelines are expected. Some adjustments to the leak control and the overall pipeline operation control parameters could be necessary. Adjustment of these parameters is a usual operation matter that is handled by control operators on a regular basis. The proposed Tranquillon Ridge Project is not expected to result in a net increase in crude oil throughput for the other portions of the ConocoPhillips pipeline system. This is because the additional oil from Tranquillon Ridge is anticipated to displace crude oil delivered into the ConocoPhillips pipelines system from other sources, primarily outer continental shelf crude entering the system at Sisquoc (see Figure 2-4).

2.2.5 Project Schedule, Personnel, Equipment Requirements

Schedule: The addition of shipping pumps at Platform Irene and modifications at the LOGP are estimated to take approximately 9 weeks.~~months.~~ The addition of booster pumps and associated equipment including the power line installation to Valve Site #2 is estimated to take 14 weeks.

Installing the transformer/substation is estimated to take 4 weeks. Electrical upgrades at Platform Irene would be conducted as needed throughout development of Tranquillon Ridge.

Based on PXP's data, the Tranquillon Ridge Project would have a total life of approximately 30 years from the time the first well is drilled. Drilling of all new wells is expected to take 15 years to complete. Figure 2-5 shows the proposed schedule for drilling of the Tranquillon Ridge wells.

Personnel and Equipment: Table 2.5 provides an estimate of personnel and equipment which would be used to complete the onshore facilities upgrades and modifications at the LOGP and Valve Site #2.

TABLE 2.5 EQUIPMENT AND PERSONNEL REQUIREMENTS FOR MODIFICATIONS AT LOGP AND VALVE SITE #2 (INCLUDING TRANSFORMER AND POWER LINES)

Position	Number of Personnel
Project Supervisor	2
Contract Crew Foreman	2
Electricians	6
Welders	6
Roustabouts	10
Equipment Operators	14
Total	**40**
Equipment	**Number of Equipment**
Medium Duty Crane	2
Backhoe	2
Welding Machines/Track Mounted	4
Concrete Trucks	2
A-Frame Trucks	3
Delivery Trucks	2
Total	**15**

2.2.6 Extension of Life of Point Pedernales Facilities

Due to the geotechnical constraints associated with developing a coastal California Monterey oil-bearing structure, estimating project life as well as ultimate recoveries is difficult without extensive production data from a number of wells. This type of data is typically not available during the permitting phase of a project. As such, the production and project life estimates made during the permitting phase are rough estimates and typically change over the course of the project's development. Other factors that affect total recoverable reserves and project life are changes in technology (e.g., enhanced oil recovery techniques), new well development technologies (e.g., directional and horizontal drilling), and the price of crude oil.

PXP has estimated that the Tranquillon Ridge Project would have a total life of approximately 30 years from the time the first well is drilled, assuming that development of the Tranquillon Ridge Field is successful. It is possible that the initial wells drilled into the Tranquillon Ridge Field may not be commercially viable. Under this scenario, the full development of the Tranquillon Ridge Field would not occur. However, for the purposes of this EIR, it has been assumed that full development of the Tranquillon Ridge Field does occur.

Based on the applicant's assumption of a 30-year life for the Tranquillon Ridge Project, the Point Pedernales facilities (Platform Irene, the associated pipelines, and the LOGP) would have a total projected life of approximately 50 years (based on startup of Point Pedernales Field operations in 1987). This assumes that the first well for Tranquillon Ridge is drilled in 2007.

The 1985 Point Pedernales EIR/EIS assumed a 20-year life expectancy for Platform Irene and a 30- to 35-year life expectancy for the pipelines and the Lompoc Oil and Gas Plant (formerly the HS&P). This 35-year timeframe referenced in the EIR/EIS was predicated on the use of the Point Pedernales onshore facilities to process reserves from five additional offshore platforms located in the Central Santa Maria Basin, which were part of the document's Area Study. Two of these platforms were in the Point Pedernales Unit, one was in the Santa Maria Unit, one was in the Purisima Point Unit, and one was in the Bonito Unit. Based on improvements in drilling technology, the two additional platforms in the Point Pedernales Unit would not be needed. Full development of this unit is occurring from Platform Irene. To date, no development has occurred at the other three units. Although Exploration Plans for these three units were approved in the early 1980s, the units are under directed suspensions due to litigation and there are no plans to develop the units.

The 20-year life expectancy of Platform Irene, assumed in the 1985 Point Pedernales EIR/EIS was based on an estimated production curve submitted by the applicant as part of its DPP submitted to the MMS in 1984. With startup in 1987 and an estimated life of 20 years, the estimate was that production would continue until 2007. Current production forecasts for the Point Pedernales Field now project that the production would continue until 2012 to 2022, which would represent a 25- to 35-year life. MMS has projected that operations for Point Pedernales Field could end sometime between 2010 and 2015 (MMS, 2004). These estimates are based on a number of assumptions that could change over time. CSLC (2001) has estimated that operations for the Point Pedernales Field would end around 2018-2022. This represents a life expectancy that is 9 to 15 years greater than what was assumed in the 1985 Point Pedernales EIR/EIS. For this analysis, Platform Irene was assumed to have a remaining life until 2017 and would produce 2000 bpd of oil over that period, with 2017 representing the mid-point of the Point Pedernales Field production forecasts by PXP (2012 to 2022) and approximate mid-point of the combined MMS and CSLC operation projections (2010 to 2022).

The 1993 Point Pedernales Supplemental EIR (SEIR), which evaluated the relocation of gas processing facilities from the Battles Gas Plant in Santa Maria to the Lompoc Oil and Gas Plant site, assumed a life expectancy of 10 to 25 years for the new gas plant. Original estimates of Point Pedernales Project life as well as the estimated life of the Point Pedernales facilities with Tranquillon Ridge field development are summarized in Table 2.6.

TABLE 2.6 SUMMARY OF EXTENSION OF LIFE ESTIMATES FROM ENVIRONMENTAL DOCUMENTS

Existing Point Pedernales Facilities			
Project Component	**Original Estimated Life (Years)**	**Estimated Time Frame[a]**	**Source of Estimate**
Platform Irene	20	1987-2007	1985 Point Pedernales EIR/EIS
LOGP (HS&P) Gas Plant	30-35[b] 10-25	1987-2022 1997-2022	1985 Point Pedernales EIR/EIS 1993 Supplemental EIR
Tranquillon Ridge	30	2007-2037	Project Application

Estimated Increase in Life with Tranquillon Ridge			
Project Component	**Estimated Total Life (Years)**	**Estimated Total Time Frame**	**Net Increase in Life (Years)**
Platform Irene	50	1987-2037	30[c]
LOGP (HS&P)	50	1987-2037	15[d]

a. Current production forecasts (MMS 2000 and CSLC 2001) show a current estimated Point Pedernales project life extending to between 2010 to 2022. Thus, the original project life for Platform Irene may have been underestimated by approximately 3 to 15 years.
b. This estimate goes beyond permitted development levels, and was predicated on the development of up to six offshore platforms located in the Central Santa Maria Basin.
c. Assuming the estimated life of Platform Irene was through 2007, the Tranquillon Ridge Project would extend the life of the platform by 30 years.
d. Assuming the estimated life of the LOGP was through 2022, the Tranquillon Ridge Project would extend the life of the LOGP by 15 years.

If development of the Tranquillon Ridge Project is successful, the expected life of the Point Pedernales Facilities will be extended beyond what was projected for the current Point Pedernales Field operations. However, it is uncertain how long the proposed Tranquillon Ridge Project would extend the life of these facilities. Based on the applicant's current projections for the Tranquillon Ridge Project (~30-year life), the life expectancy of the Point Pedernales Project facilities would be extended approximately 10 to 20 years beyond what the MMS and CSLC have projected for the Point Pedernales Field. However, it is possible that due to changes in technology and oil prices that production from the Tranquillon Ridge Field could extend beyond the 30-year estimate provided by the applicant, similar to what is now projected to occur for the Point Pedernales Field.

If the life expectancy assumed in the Point Pedernales 1985 EIR/EIS and 1993 SEIR and the applicant's project life expectancy of the Tranquillon Ridge Project are used as the basis for estimating extension of life, then the Tranquillon Ridge project would be expected to extend the life of Platform Irene by approximately 30 years, and the LOGP by 15 years.

As such, it is reasonable to assume for the purposes of this EIR, that the proposed Tranquillon Ridge Project could extend the life of the Point Pedernales Facilities by 15 to 30 years, beyond what is currently projected for the Point Pedernales Field.

2.3 Current Point Pedernales Project Operations

This section covers current operations of the facilities affected by the proposed project. These facilities include the PXP Point Pedernales Project facilities and ConocoPhillips dry oil pipeline system.

2.3.1 PXP Point Pedernales Project Facilities

The major components of the current operations of the Point Pedernales Project facilities include the following (see Figure 2-1 for a location map):

- Drilling and production at Platform Irene;
- Transportation of production via pipelines from offshore to onshore;
- Oil dehydration and gas processing at the Lompoc Oil and Gas Plant (LOGP);
- Produced water injection onshore and/or return to Platform Irene and injection offshore; and

- Shipment of oil and gas products for further processing or sale by pipeline or by liquid petroleum gas/natural gas liquids (LPG/NGL) trucks.

Historical production levels from the Point Pedernales Project peaked at close to 25,000 barrels per day (bpd) of dry oil in 1987 and 1989, and close to 9 million standard cubic feet per day (mmscfd) of gas production in 1995. Production levels in 2005 averaged approximately 7,000 bpd of dry oil, 50,000 bpd of water and a total of 2.6 mmscfd of gas production. The peak monthly production in 2005 was approximately 8,600 bpd of dry oil and 3.3 mmscfd of gas. Figure 2-6[3] shows the fluids produced from the project from April 1987 through June 2006.

Gas produced from Point Pedernales currently has an average hydrogen sulfide (H_2S) concentration of 3,400 parts per million (ppm). The crude oil has a Reid vapor pressure (RVP) of 4.1 pounds per square inch absolute (psia). Crude oil is transported from the LOGP to the ConocoPhillips Santa Maria Refinery via an existing ConocoPhillips pipeline network.

Currently, the Point Pedernales Project is permitted to operate under the following Santa Barbara County (SBC) Final Development Plan (FDP) production/processing capacities:

- 36,000 bpd of dry oil;[4]
- 15 mmscfd of natural gas[5] with a maximum H_2S concentration level of 8,000 ppm;
- 9.205 mmscfd of onshore gas reinjection (only during upset conditions); and
- Monthly average of 2.3 LPG/NGL truck trips per day.

2.3.1.1 Platform Irene

Platform Irene sits in 242 feet of water on Lease OCS-P 0441. Platform Irene was set in April 1986, and development drilling started in April 1987. The platform has a total of 72 well slots. Oil and gas are produced from the Point Pedernales Field. Twenty-eight wells have been drilled to date with a maximum of 14 wells producing in a given month. As of July 2006, there were 12 producing wells in service. The platform is equipped with an electric top-drive drilling rig used for well workovers and maintenance which operates on average~~s~~ 10 weeks per year. Power is supplied to the platform via a subsea power cable from an electrical substation located in Union Pacific Railroad property at Surf Beach. The platform safety systems are monitored using the August System Programmable Logic Controller (PLC) leak detection system. In 2005 the rig worked 29 weeks and, ~~to date in~~ as of the third quarter of 2006, the rig had worked 30 weeks.

The produced liquid from Platform Irene is a combination of crude oil, gas and water. The gas exists as free gas or is in solution in the oil, and the water exists both as free water and emulsion in the oil. The liquid stream is transferred to the LOGP through the 20-inch emulsion pipeline, which has a capacity of approximately 108,000 bpd of emulsion. Current design limit of Platform Irene is approximately 100,000 barrels of total fluids per day (as stated in the 1985

3 This figure was generated using the separate Point Pedernales wells' production data available from the MMS. The separate wells' monthly production numbers were added to yield the total monthly Point Pedernales production.

4 The Santa Barbara County Air Pollution Control District (SBCAPCD), Permit to Operate (PTO) 6708, Section C22, reduces the dry oil throughput to 25,000 bpd. ~~Further~~The California Coastal Commission Consistency Determination identified maximum production at Platform Irene of ~~set the dry oil throughput at~~20,000 bpd oil and 13.25 mmscfd gas.

5 SBCAPCD PTO 9106, Section C.8, reduces the maximum flow rate to 12 mmscfd.

Point Pedernales Facilities EIR/EIS), with a processing capacity at LOGP of 36,000 bbls per day of dry oil per the SBC FDP.

Produced gas from Platform Irene which is not in solution in the liquid stream is separated from the liquid at Platform Irene and dehydrated offshore using a glycol system. The dehydrated gas is then transported via an 8-inch pipeline to the inlet of the LOGP, where the gas is sweetened (removal of carbon dioxide [CO_2] and H_2S) and processed to produce sales quality natural gas.

Produced water is separated from the crude oil at the LOGP. A portion of the produced water is sent back to Platform Irene (the 2005 annual average was 20,000 bpd out of approximately 50,000 bpd of water) through an 8-inch pipeline and is currently injected into the Point Pedernales Field through wells A-10 and A-11 with MMS authorization (injection in other wells would be subject to MMS authorization). The pressure from the pumps onshore (at the LOGP) provides the injection pressure needed to re-inject water into these wells. Currently there is no ocean outfall disposal of produced water. However, PXP is permitted for such disposal pursuant to the NPDES permit.[6] The remainder of the produced water is injected onshore into wells at the Lompoc oil field.

Platform Irene is owned and operated by PXP. Employees (including contract employees) are housed on the platform and transported by helicopter. During normal operations, the platform has a workforce of approximately 12 employees per each 12-hour day shift, and two to three employees per each 12-hour night shift: a total of approximately 14 to 15 employees per crew. Each crew works a rotation of 7 days on and 7 days off. During drilling there can be as many as 70 personnel at the platform. Equipment and other supplies are brought to the platform by supply boat. An average of six helicopter one-way trips per day and two supply boat one-way trips per 3 days is permitted. In 2005, there was an annual average of 13 one-way helicopter flights per week with a maximum of six one-way trips every Thursday (shift change). In 2005, supply boat trips averaged one one-way trip every 3 to 4 days. Manpower requirements and boat schedules can vary depending on the workload. Helicopter flights originate from the Santa Maria or Lompoc airports, and supply boat trips originate from Port Hueneme.

2.3.1.2 Lompoc Oil and Gas Plant (LOGP)

Platform Irene ships all of its produced product to the LOGP. Throughput, pressure, and temperature at the LOGP are monitored using the August System Process Logic Controller (PLC). The control system is operated from the control room, which is manned 24 hours per day. The operator monitors operating pressures, levels, temperatures, flows, and other operating conditions. The LOGP is equipped with emergency alarms and equipment including hydrocarbon gas and hydrogen sulfide detectors, ultraviolet/infrared (UV/IR) fire detectors, fire hydrants, fire water line, fire monitors, foam capabilities, and other safety equipment. PXP maintains offshore and onshore spill response plans (the Core Oil Spill Response Plan for Operations in the Point Arguello and Point Pedernales Fields, Onshore Facilities and Associated Pipelines, Vol. 1, OSPR Supplement to the Core Oil Spill Response Plan (Vol. 2), DOT Supplement to the Core Oil Spill Response Plan (Vol. 2), MMS Supplement to the Core Oil Spill Response Plan (Vol. 2) and the Santa Barbara County Supplement to the Core Oil Spill Response Plan for Operation of the Point Pedernales Onshore 20-Inch Wet Oil Pipeline (Vol. 2), as well as the Emergency Response Plan

[6] General Permit CAG 280000 was issued by EPA and became effective on December 1, 2004.

for Operations on Point Pedernales Onshore Facilities). The oil dehydration facility has operated since 1987, and the gas plant began operation in September 1997. The LOGP currently employs 22 PXP workers and various contractors.

The LOGP receives oil/water emulsion and sour gas from Platform Irene, and sour gas from the onshore Lompoc Oil Field. Process operations at the LOGP include oil dehydration, produced water treatment, produced water injection offshore and onshore into the Lompoc Oil Field, oil reclamation, oil storage, oil shipment, gas compression, gas reinjection, gas sweetening, gas dehydration, LPG/NGL stabilization and storage, LPG/NGL truck loading, and NGL/crude oil blending. Figure 2-7 shows a simplified process flow diagram of the LOGP.

The oil dehydration system dehydrates 57,000 bpd of oil/water emulsion (2005 annual average). The produced oil is characterized as heavy oil (16 degree American Petroleum Institute (API) gravity). At the LOGP, water removed from the oil/water emulsion is treated with emulsion breaking chemicals to separate the trace oil contained in the water. This oil is skimmed off the water in the water treatment tanks and sent back through the process. The existing oil processing and storage equipment at the LOGP includes heat exchangers, separators, free water knockout vessel, three heater treaters, flare system, flare sulfur dioxide (SO_2) minimization scrubber, pressurized shipping vessel, wash tank, reject tanks, reclaimed oil storage tank, surge tank, vapor recovery system, gas compressors, and other miscellaneous pumps and equipment. Once dehydrated, the oil is sold to ConocoPhillips and shipped by pipeline from the LOGP to the Orcutt Pump Station, and then to the Santa Maria Refinery in San Luis Obispo County.

The majority of the produced gas is separated from oil/water emulsion at Platform Irene and is shipped to LOGP via an 8-inch pipeline. The LOGP also receives produced gas from the onshore Lompoc Field; this gas is shipped from the field via a separate 4- to 6-inch gas pipeline. At the LOGP, gas that remained dissolved in the oil/water emulsion is further separated from the emulsion. The vapor recovery system collects vapors from all the tanks, including the heater treaters and other miscellaneous vessels. Gas collected by the vapor recovery system, and the solution gas separated from the emulsion are combined and compressed to the inlet of the gas sweetening and processing equipment along with the gas delivered by the two gas pipelines.

The existing gas sweetening and processing equipment at the LOGP consists of an amine gas sweetening skid with an associated acid gas handling (Sulferox) system, gas dehydration, a low temperature separation (LTS) skid, LPG/NGL stabilization skid and storage, LPG/NGL truck loading, and NGL/crude oil blending.

The H_2S removed from the combined inlet gas streams is reduced to elemental sulfur in the associated Sulferox unit. The tail gas from the Sulferox unit is sent to the thermal oxidizer for oxidation of residual hydrocarbon vapors to carbon dioxide and water. The sweetened gas then flows into the LTS skid where it is dehydrated. The raw NGL formed during this process then flows to the LPG/NGL stabilization skid. LPG gas (called “bute-mix”) comes off the top of the stabilizer column and is condensed and stored for sale and transported via trucks to other facilities for further fractionation. Currently, the monthly average is 2.7 LPG/NGL truck round-trips per week (139 in the year 2005) based on the year 2005 annual average. Total LPG/NGL transported in the year 2005 was a monthly average of 105,000 gallons, with approximately 9,000 gallons per truck load. The stabilized NGL liquids flow to the NGL surge tank for blending into the dry crude oil to the maximum extent feasible. The processed sweet natural gas is sold and shipped by pipeline and/or used as fuel at the LOGP.

There are also truck trips due to sulfur removal (annual average of 12 trucks in 2005), amine makeup (annual average of 1 truck in 2005), and miscellaneous vacuum trucks (estimated at two trucks per week).

The existing water treatment equipment at the LOGP consists of the Wemco flotation cell (currently out of service), wash tank, clean water tanks, and injection pumps. After the water is treated to recover the hydrocarbon liquids, the treated water is either shipped via onshore produced water disposal lines (one 10-inch, one 12-inch and one 8-inch lines) to the Lompoc Oil Field for onshore injection or shipped via the 8-inch produced water return line to Platform Irene for offshore injection.

A typical composition of the current produced water is presented below.

Compound	Concentration, mg/l	Practical Quantification Limit, mg/l
Ammonia	120*	20
Cyanide (total)	0.03*	0.03
Chromium VI	0.005*	0.03
Oil & Grease	280**	1
Phenols (total)	2*	0.2
Sulfide	79*	2

*Source: *Capco Analytical Services, Inc., LOGP Produced Water Wet Chemistry Analysis, November 11, 2004.*
***Capco Analytical Services, Inc., LOGP Produced Water Wet Chemistry Analysis, April 25, 2000.*

2.3.1.3 Other Point Pedernales Facilities

The Point Pedernales Project currently includes three subsea and buried pipelines between Platform Irene and the LOGP. The total pipeline route is 22.2 miles long with approximately 12.1 miles located onshore. The pipelines include one 20-inch diameter wet crude oil line, one 8-inch produced water return line, and one 8-inch produced gas line. There are ten valve sites located on the oil pipeline, and four valve sites located on the water return and gas pipelines. Valves are used to close off segments of the pipelines in the event of leak, rupture, or repair and maintenance. Nine of the valve sites are located in underground vaults. Valve Site #2 is an aboveground facility located on Vandenberg Air Force Base (VAFB) and is approximately 100 feet by 100 feet and fenced. Valve Site #2 has two block valves on each of the three pipelines. For a detailed route map including the pipeline routes and the valve site locations see Appendix A. The pipeline elevation profile is given in Figure 2-8.

Current pipeline operations include performing ongoing routine internal and external pipeline surveys. Pipeline surveys include, but are not limited to, smart pigging[7], corrosion checks, pressure tests, air and ground patrols, visual surveys using a video camera, and cathodic protection surveys. These periodic internal and external pipeline inspections are performed on a schedule specified by Minerals Management Service (MMS), SBC, and Santa Barbara County

[7] A smart pig is an internal device that is run through the pipeline on a periodic basis to check for pipeline anomalies, including reduction in pipeline wall thickness. PXP ~~utilizes~~ uses a high-resolution smart pig that detects metal losses and pipe thickness along the pipeline.

Air Pollution Control District (SBCAPCD) permits, and PXP policy. These inspections also satisfy the requirements of the Department of Transportation (DOT) and the California State Fire Marshal (CFSM) for ~~the onshore portions of~~ the pipelines. ~~The~~ A summary of the permitted and current operating~~on~~ parameters of the three pipelines is given in Table 2.7. These inspection programs for the pipelines allow pipeline defects to be identified and corrosion measures adjusted to avoid failure. Section 5.1.1.4.2 provides more detailed information about the smart pigging inspections.

TABLE 2.7 SUMMARY OF THE CURRENT AND PERMITTED PIPELINES OPERATING PARAMETERS

Parameter/Pipeline	Emulsion	Gas	Return Water
Diameter	20 inches	8 inches	8 inches
Original wall thickness, inches	0.625 (onshore); 0.688 (offshore)	0.312 (onshore), 0.438 (offshore)	0.312 (onshore), 0.438 (offshore)
Pipe steel grade	API 5L-X52 ERW onshore, API 5L-X46 ERW offshore	API 5L-X42 ERW (onshore), API 5L-Grade B ERW (offshore)	API 5L-X42 ERW (onshore), API 5L-Grade B ERW (offshore)
Pipe corrosion coating	PRITEC 70/15	PRITEC 70/15	PRITEC 70/15
Age	20 years (average)	20 years (average)	20 years (average)
Current Average Pressure/Maximum Allowable~~d o~~Operating Pressure	400-500 psig/1,194 psig	425-570psig/1,516 psig	350 psig at Platform Irene, 500 psig at LOGP/ 1,311 psig
Original Design Pressure	2,160 psig	2,160 psig	2,160 psig
Current Temperature	175 °F, 135°at LOGP	90 °F	130 °F
Current Average Flowrate (2005)	57,000 bpd (yr 2,005 average: 7,000 bpd of oil + 50,000 bpd of water)	2.6 mmscfd (yr 2005 average),	10,000-20,000 bpd
Maximum permitted flowrate (from FDP, APCD PTOs, and CCC Consistency Certification)	150,000 bpd of emulsion on a monthly average (PTO 9106 Section C.8) 36,000 bpd dry oil (both from APCD PTO 9106 Section C.8 and FDP Condition A-12) 25,000 bpd dry oil (from APCD PTO 6708 Section C22) 20,000 bpd ~~dry~~ oil (CCC consistency certification)~~ staff report)~~	12 mmscfd (PTO 9106 Section C.8) 15 mmscfd (FDP Condition A-12)	NA
Current/Maximum H_2S		3,400 ppm H_2S/ 8,000 ppm	
Leak detection system	SCADA-based	Pressure differential based system	None
Pigging schedule	Approximately once every week	Monthly	weekly
Smart pigging schedule	Annually	Annually	Annually
Corrosion Coupons	Pulled every 6 months. Continuous corrosion potential monitoring	Pulled every 6 months	Pulled every 6 months
Other anti-corrosion measures	Corrosion inhibitor continuously, Beta foils[a] and batch-pigged every week.	Corrosion inhibitor injected continuously and batched pigged	Corrosion inhibitor injected continuously, and batch pigged

a. A beta foil (also known as a hydrogen patch) is a non-intrusive device used primarily to monitor internal corrosion in pipelines. A stainless steel foil patch is secured around its edges to the exterior of the pipe with epoxy, creating a sealed void between the pipe and the foil. This is attached via capillary tubing to a vacuum gauge and a vacuum is created in the void. If internal corrosion occurs, atomic hydrogen flux is generated which permeates the wall of the pipe and affects the vacuum. This allows corrosion engineers to continuously monitor for the presence of corrosion.

Oil Emulsion Pipeline

The oil emulsion pipeline, or the wet crude pipeline, between Platform Irene and the LOGP has a 20-inch outer diameter (OD) with a Maximum Allowable Operating Pressure (MAOP) of 1,194 pounds per square inch gauge (psig). However, as noted in Table 2.7, the pipeline current average operating pressure is 400 to 500 psig. MAOP is a function of pipeline design and integrity. Operating pressure is a factor monitored during leak detection (e.g., loss of pressure could indicate a pipeline leak or rupture). Another factor monitored as part of leak detection is throughput at the Platform Irene entry location versus the LOGP exit location. Again, a change in throughput (entry versus exit) could be an indication of pipeline leak or rupture.

The design wall ~~Wall~~ thickness of the pipeline is 0.625 inches onshore, 0.688 inches offshore. The steel grade is API 5L-X52 electric resistance welded (ERW) onshore and API 5L-X46 ERW offshore. The entire length of the pipeline is coated with PRITEC 70/15 (70 millimeters polyethylene, 15 millimeters butyl adhesive). The average age of the pipeline is approximately 20 years, which includes sections replaced due to corrosion. The pipeline currently operates at a temperature of 175°F starting at Platform Irene and decreasing to 135°F at LOGP.

Approximately once every week, the 20-inch oil pipeline is batch-pigged with approximately 400 gallons of corrosion inhibitor and approximately 400 gallons of diesel in order to clean the line and control corrosion. Corrosion inhibitor chemical is also injected continuously. Fluid samples are frequently analyzed for metal deposits and chemical residuals. Corrosion coupons[8] are pulled every six months at the LOGP and Platform Irene. There is a flush mounted coupon probe at Valve Site #2 for continuous corrosion monitoring of the oil pipeline, and Beta foil, which indicates corrosion potential on the pipeline. Section 5.1 provides a detailed description of the current PXP corrosion monitoring program.

In 1997, a failure of the offshore pipeline occurred at a flange weld approximately midway between Platform Irene and the shoreline. A crack developed in the weld connecting a flange to the pipe. The metal in this area was determined to be brittle due to the weld construction techniques where the metals were not properly pre-heated, thereby increasing the metal brittleness, and due to the high carbon content. The shutdown system on Platform Irene operated correctly, quickly detecting the low pressure and initiating a low pressure alarm and shutdown of the pumps and valves. At this point, the operator attempted to restart the system, bypassing the low pressure alarm and the pump shutdowns. The valve was re-opened and remained open for almost 80 minutes until the operator determined that there was an imbalance between Platform Irene shipping and the LOGP receiving. The pumps operated approximately 25 minutes during this 80-minute period. Approximately 163 to 1,242 bbls of crude oil[9] were released into the marine environment, causing oil to soil beach areas along Surf Beach and south of the Santa Ynez River.

The 20-inch crude pipeline is equipped with alarms and controls that allow operation of the equipment and protection during upset conditions. The pipeline is equipped with a shutdown valve at both the inlet and outlet. The inlet shutdown valve (SDV), SDV-171, is located at the outlet of the shipping tank prior to the pig launcher on Platform Irene. SDV-171 is actuated by the platform emergency shutdown switch, as well as interlocks on the pressure transmitter (PT), PT-171, located directly downstream of the SDV-171.

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[8] Corrosion coupons are samples of a test material (typically metal) that are placed in a pipeline to accurately measure the corrosion rate. These samples are removed from the pipeline after a specific time period of exposure and then analyzed to determine the extent of corrosion.

[9] The CDFG official spill volume from the Torch Point Pedernales pipeline was 163 barrels. The 1,242-barrel estimate is from Santa Barbara County and is based on additional factors that were not taken into account with the CDFG official number. These include drainage from the landward side of the pipeline, oil between pigs 1 and 2, and oil behind pig 2.

Inlet shutdown valve, SDV-40, provides automatic protection and isolation at the pipeline inlet to the LOGP facility upstream of the gas-oil separation vessel. SDV-40 is actuated manually by the “Oil Process Stop” button, and automatically by the LOGP facility emergency shutdown switch as well as by a number of pressure and level transmitters. The onshore portions of the pipelines are protected from external corrosion by a rectifier and deep-well anode bed that is installed adjacent to Valve Site #8. Test stations are installed at one-mile intervals to monitor the performance of the system.

The pipeline is equipped with a leak detection system used to detect leaks when the pipeline is in operation. The major component of the leak detection system is the August System PLC, which is used to monitor various operating parameters of the pipeline such as flowrates and pressures. The August System PLC collects and processes the data, and activates the system alarms and shutdowns when specific thresholds are reached.

The oil/water emulsion is metered at Platform Irene prior to shipment via the 20-inch pipeline and again when the emulsion reaches the LOGP facility. Flow meters are located adjacent to the shutdown valves. The signal from the LOGP flow meter is transmitted to the control room where it is compared with the flow meter reading from the platform. Should the total fluid production fall outside the following limits, an alarm will sound at Platform Irene indicating a potential pipeline leak:

- 6 percent – more than 12 minutes or 50 ~~63~~ barrels (based on 100,000 bpd)
- 15 percent – more than 20 minutes or 208 barrels (based on 100,000 bpd)

For example, if the flow meter detects a discrepancy in flow of 50 ~~63~~ barrels (or 6% of volume based on 100,000 bpd) at a 12 minute interval, an alarm would sound. In the event of a large release from the oil pipeline, motor operated valves (MOVs) would close along the pipeline within two minutes after the operator initiates the appropriate shutdown command. For a large release, the Oil Spill Response Plan assumes that the operator has nine minutes to confirm the release and two minutes for MOV shutdown. The locations of MOVs are addressed in the following sections. Smaller leaks would also be detected but detection would take a longer time depending on the size of the leak. To aid prompt leak detection, PXP conducts one pipeline overflight and one right-of-way inspection per week.

Past internal surveys of the oil pipeline identified a number of anomalies. As part of the overall pipeline maintenance and monitoring plan, some sections of the old pipe with significant anomalies were removed and replaced with new pipe (more information on the pipeline replacements can be found in Section 5.1). The oil line ~~will~~ would continue to be monitored, ~~and~~ inspected, and repaired as needed if the proposed project is implemented. ~~sections replaced as appropriate.~~

In August and September of 1999, Nuevo (operator at that time) conducted inspections of the flanges on the offshore oil pipeline. The inspections found defects at a flange on the bottom spool on the riser located on the offshore pipeline. As a result of this defect, the bottom spool was removed and replaced with a Big Inch flange spool, similar to the 1997 repair. During repairs, the Point Pedernales facilities were shutdown, and the pipeline was flushed with water. In September 2001, during flange inspections, Nuevo found cracks on a number of offshore flanges. As a result, Nuevo undertook a program to remove and replace all existing flanges on the offshore pipeline with the exception of the first flange (Flange #1-1). These flanges have been removed and replaced. Nuevo applied for, and received, permits from SBC, CCC, MMS, and CSLC for the repair work. In 2005, PXP completely encapsulated Flange #1-1.

Produced Water Pipeline

The MAOP of the water return pipeline is 1,311 psig. The produced water pipeline inlet pressure at the LOGP is approximately 500 psig and the outlet pressure at Platform Irene is approximately 350 ~~500~~ psig. Repairs on the 8-inch produced water pipeline were conducted in the Fall of 2001 to address corrosion discovered during annual surveys. The water pipeline is designed to automatically close valves at Valve Sites #1, 2, 8, and 10 when the pressure is low.

The produced water pipeline ~~is~~ design specifications include an 8.625-inch OD with a wall thickness of 0.312 inch onshore and 0.438 inch offshore. The pipe is made of steel grade API 5L-X42 ERW onshore and API 5L-Grade B ERW offshore. The entire length of the water pipeline is also coated with PRITEC 70/15 (70 millimeters [mm] polyethylene, 15 mm butyl adhesive). The age of the pipe is approximately 20 years. The water pipeline operates at 130°F.

The corrosion program for the 8-inch water pipeline includes the following activities:

- Continuous injection of corrosion inhibitor;
- Pigging once per week;
- Taking residual readings frequently for detection of chemical and metal deposits;
- Pulling corrosion coupons every 6 months; and
- Smart pigging annually.

There are no anticipated changes to the corrosion control program, however, the frequency of the maintenance pigging may increase or decrease based on pipeline parameters. If, for example, the pipeline smart pigging demonstrates increased corrosion rates, then pigging (both maintenance and smart pigging) would occur more frequently. The 2000 Smart Pig Survey showed evidence of corrosion. As a result, a section of pipe was repaired and a confirmation dig was conducted along another section of pipeline.

The 8-inch produced water pipeline has four MOVs at Valve Sites #1, 2, 8, and 10, which can be operated locally or remotely from the LOGP. Position indication of the valves is transmitted to the control room operator at the LOGP facility.

The 8-inch produced water pipeline is equipped with a shutdown valve (SDV) at both the inlet and outlet. Inlet shutdown valve SDV-400 is located at the outlet of the clean water tank at the LOGP facility before the shipping pumps. SDV-400 responds solely to level controls on the clean water tank and the LOGP facility emergency shutdown switch. The valve position is displayed in the control room at the LOGP facility.

~~Inlet~~Outlet shutdown valve SDV-242 provides automatic protection and isolation on the pipeline on Platform Irene. SDV-242 is actuated by the Platform Irene emergency shutdown switch. MOV-612 also provides automatic protection, actuated from the high/low pressure (PSHL) switch, PSHL-612, located downstream of the SDV. The pressure, SDV position and shutdown signals are displayed in the control room on the platform.

Sour Gas Pipeline

The gas separated from emulsion and dehydrated at Platform Irene is shipped to LOGP via an 8-inch pipeline. The internal corrosion survey conducted in 2005 using a high resolution pig showed that the majority (greater than 99 percent) of anomalies were between 10 and 29 percent of wall thickness. Only three anomalies were between 30 to 49 percent of wall thickness.

The gas pipeline is an 8.625-inch OD pipe with a wall thickness of 0.312 inch onshore and 0.438 inch offshore. The pipe is made of steel grade API 5L-X42 ERW onshore and API 5L-Grade B ERW offshore. The entire length of the gas pipeline is also coated with PRITEC 70/15 (70 mm polyethylene, 15mm butyl adhesive). The age is approximately 20 years. The gas pipeline operates at 90°F and with a MAOP of 1,516 psig.

Four valve sites are located along the onshore portion. MOVs are located at Valve Sites #1, 2, 8, and 10 (see Appendix A). These valves can be operated manually or remotely from the LOGP. The gas pipeline is equipped with an SDV at the inlet (Platform Irene, SDV-401) and outlet (LOGP, SDV-100). The inlet SDV is actuated by the Platform Irene emergency shutdown switch, as well as interlocks on PT-401, located on the platform downstream of SDV-401. The pipeline pressure, valve positions, and shutdown signals are displayed in the control room on the platform. The pipeline is also equipped with a dew point analyzer.

SDV-100 provides isolation at the LOGP. SDV-100 is actuated manually by the "Gas Stop" button as well as by the LOGP ESD procedure. The LOGP isolation valve (SDV-100) will automatically close based on signals from a number of pressure transmitters located throughout the plant.

Co-located H_2S sensors have been installed along the gas pipeline in the following locations: (a) at the pipeline's crossing of Highway 1, (b) upwind of Cabrillo High School, and (c) upwind of the north/northeast boundaries of Vandenberg Village. When any pair of the co-located sensors detects 40 ppm of H_2S, the pipeline would be shutdown at the inlet (Platform Irene) and the situation investigated.

Valve Sites

The onshore portion of the pipelines incorporates ten valve sites between the shoreline and the LOGP. These valve sites consist of valves, either check or block[10], and Remote Terminal Unit (RTU) electronic equipment. The valves are contained in below-grade prefabricated vaults, with the exception of Valve Site #2, which is above grade.

The valve vaults and the area around the valves at Valve Site #2 are classified as Class 1, Division 1, Group D areas, as per the National Electrical Code[11], which determines types of electrical equipment and installations considered safe in locations with hazardous classifications. The vaults are locked and designed such that a special tool is required to open them prior to entering. These areas must be checked for the oxygen concentration and presence of combustible and/or hazardous gases (H_2S) using hand-held gas detectors prior to entering these locations.

[10] A block valve is used to isolate a section of pipeline and prevents flow of fluid in either direction. A check valve allows flow of fluid in one direction, but prevents flow in the reverse direction.
[11] NFPA 70.

The RTU electronic equipment provided at each valve site is contained in either below-grade prefabricated vaults or in an above-grade prefabricated metal building. Valve Site #10 is not provided with RTU equipment. Valve Site #10 communicates directly with the LOGP August Systems' PLC.

As summarized in Table 2.8, Valve Sites #1, 2, 8 and 10 on all three pipelines are provided with an isolation valve that can be actuated locally at the station or remotely from the Pipeline Control Station at the LOGP. At Valve Sites #4 and 7 only the oil/water emulsion pipeline is provided with an isolation valve that can be actuated locally at the station or remotely from LOGP. Valve Sites #3, 5, 6 and 9 each contain a check valve in the crude oil pipeline only. Valve Site #2 is an aboveground installation with two isolation valves in each pipeline and a 60-foot dropout spool between the valves for installation of future launchers, receivers, and pumps.

TABLE 2.8 VALVE SITES SPECIFICS

Valve Site	Type	Oil Pipeline	Gas Pipeline	Water Pipeline
1	Vault	MOV	MOV	MOV
2	Above Ground	MOV x 2	MOV x 2	MOV x 2
3	Vault	CV	-	-
4	Vault	MOV	-	-
5	Vault	CV	-	-
6	Vault	CV	-	-
7	Vault	MOV	-	-
8	Vault	MOV	MOV	MOV
9	Vault	CV	-	-
10	Vault	MOV	MOV	MOV

CV =Check Valve, MOV=Motor Operated (remotely) Valve.

The communication link between the valve site and the LOGP is accomplished by the RTU system. The RTU system and associated equipment are contained in a below-grade, prefabricated vault installed adjacent to the valve vault. The exception is Valve Site #2, in which the RTU equipment is installed above-grade in a prefabricated metal control building. The RTU vaults are covered with a weather-tight lid. The lid includes two spring-loaded doors that serve as an entrance into the vault. A ladder is also provided to facilitate entrance into the RTU vaults.

The RTU system receives all the status signals from the valve site and transmits these signals to the controller at the LOGP. The RTU system also receives remote valve open/close commands from the controller and sends these commands to the respective valves. Valve Site #10 communicates directly with the LOGP August Systems' PLC for exchange of this information.

Pipeline Catchment Basins

The pipeline route is constructed with 12 secondary containment catchment basins located at strategic locations along the route (see Appendix A). These basins are designed to catch oil if a pipeline leak or rupture were to occur. They were originally designed with a 10 percent excess capacity of a 100,000 bpd total fluids transportation rate to account for loss of volume due to erosion (Point Pedernales Facilities EIR, 1985). Current conditions and spill volumes are estimated in Section 5.1, Risk of Upset. The basins contain concrete weirs that allow for water to flow out from the basin while retaining oil. The basins primarily protect the areas near the Santa Ynez River.

Surf Substation

Surf substation is located on Union Pacific Railroad property at Surf Beach. It supplies power to Platform Irene via a subsea power cable. The substation is connected to the PG&E power line north of Lompoc, approximately 700 feet north of the Surf railroad station on the ocean side of Ocean Avenue. The substation is approximately 60 by 70 feet and is enclosed inside a chain link fence. The substation contains meters, transformers and protective devices. Operation of the station does not require full time employees; however it is checked on a regular basis. The station does not generate any emissions, or any solid or liquid waste.

PXP Sales Gas Pipeline

Sales gas is shipped from the LOGP through a 12-inch sales gas pipeline to the Righetti valve site. The length of this line is approximately 6.5 miles with operating pressure ranges from 700 to 1,000 psig. The 12-inch sales gas line is API 5L-Grade B ERW pipe with 0.375-inch wall thickness. From the Righetti valve site, sales gas is then shipped through a 6-inch sales gas pipeline, The Gas Company gas transmission line # 1010. The Righetti valve site is located ~~in the Lompoc~~ near the Orcutt Hill Oil Field approximately 1.3 miles northeast of the intersection of Highway 1 and Highway 135.

2.3.2 ConocoPhillips Pipeline System

Point Pedernales treated oil is shipped from the LOGP to the Santa Maria Refinery in San Luis Obispo County by a system of pipelines known as Line 300 (previously known as the UNOCAP network), which is owned by ConocoPhillips. This pipeline system is made up of the following major facilities with interconnecting pipelines:

- LOGP Pump Station;
- Orcutt Pump Station;
- Suey Junction;
- Santa Maria Pump Station;
- Summit Pump Station; and
- Sisquoc Pump Station.

The pipelines and facilities described below are parts of Line 300 and most of them are discussed in detail in the Tosco Sisquoc SEIR (County of Santa Barbara, 2001) including the pipeline system controls and leak detection.

All parts of Line 300 are remotely controlled and monitored via ConocoPhillips Supervisory Control and Data Acquisition (SCADA) system located in Ponca City Control Center (PCCC), Oklahoma. The SCADA system allows a Pipeline Controller to remotely monitor the pipeline system and initiate appropriate action in the event of an abnormal condition. In relation to this project, the SCADA system monitors pressure, temperature, and flowrate at the LOGP and the Santa Maria, Orcutt, and Summit Pump Stations. The SCADA system computers poll values of pressure, temperature and flowrate every 15 seconds and barrels per hour numbers are generated by correcting the flowrate values for temperature and pressure. If responses are not received at the PCCC, an alarm is sounded and maintenance personnel are dispatched to investigate. Response personnel and response equipment ~~would be~~are stationed at the Santa Maria Pump Station.

The SCADA system provides the Pipeline Controller with volume balance alarms as an indicator of a potential leak. The shortest-term alarm is currently set for a 35-barrel imbalance in a 10-minute period and the longest-term alarm is currently set for a 200-barrel imbalance in a 24-hour period. The PCCC operator then has the option to remotely shutdown the pumps and close the remotely operated valves on the pipelines. Shutdown of the pumps and closing of the valves is initiated by the PCCC operator.

Figure 2-4 shows a system schematic including flows and line sizes for the ConocoPhillips pipeline system. See Appendix B for a detailed pipeline route map.

LOGP to Orcutt Pump Station Pipeline Segment

The branch of Line 300 that transports crude oil from the LOGP to the Orcutt Pump Station is 12 inches in diameter and runs in a generally northerly direction for approximately 10.3 miles. The pipeline currently ships at a flow rate of approximately 5,000 to 10,000 bpd with a discharge pressure of 250 psig, but is able to ship up to 43,200 bpd with the existing pumps. LOGP discharge pressure varies based upon flowrate and ambient temperature conditions, and is usually between 250 and 680 psig. This pipeline segment is capable of handling up to 96,000 bpd at 800 psig.

A pressure control valve for the LOGP to Orcutt Station pipeline is located at LOGP. The valve at LOGP is set to close when pipeline pressure exceeds the pre-determined safe operating level for the pipeline facilities.

Orcutt Pump Station

Orcutt Pump Station receives oil from two sources: (1) the LOGP ~~and the Lompoc Oil Field~~(12-inch pipeline) and (2) Gathering Line 353 (6-inch pipeline) which collects oil from the Orcutt Hill oil field. The oil at the station is blended and pumped to Suey Junction and further to the Summit Pump Station (see Figure 2-4).

The current maximum throughput at the Orcutt Pump Station is approximately 24,000 bpd of crude oil. The station is permitted to pump up to 9,125,000 barrels (bbls)/year (25,000 bbls daily average; however, there is no daily limitation on the throughput). Oil at the pump station can be heated. There are two low-pressure steam boilers rated at 10.5 million British Thermal Units per hour (mmbtu/hour) heat input and fired with natural gas permitted to operate 24 hours/day only one boiler at a time. Oil storage at the pump station is limited to one unheated floating roof tank with the capacity of 23,000 bbls. This tank has a throughput permitted level of 7,450 bpd. Flow rates of oil at Orcutt Pump Station vary between 10,000 to 24,000 bpd with a discharge pressure of 450 to 780 psig depending on the amount of crude oil added to the system from Orcutt area fields. The pump station is a non-staffed facility; however, it is checked daily ~~during the week~~ and when periodic maintenance is required.

Orcutt Pump Station to Summit Pump Station Pipeline Segment

Orcutt Pump Station ships the oil through a segment of Line 300 in a generally northerly direction for approximately 4.5 miles to a point in the city of Santa Maria called Suey Junction. The crude oil can then be shipped to the Summit Pump Station through the 8-inch Orcutt line or commingled with oil that comes from the Santa Maria Pump Station and sent through the 10/12-inch (some segments are 10 inches, some are 12 inches) Santa Maria Line. The Line 300 pipeline between Orcutt Pump Station and Summit Pump Station is 8 inches in diameter and is not in service north of Suey Junction. The current final destination of the crude oil is the ConocoPhillips Santa Maria Refinery in San Luis Obispo County.

Crude oil from Sisquoc Pump Station can be shipped to the Santa Maria Refinery only through the 10/12-inch line. The 8-inch line was constructed to ship oil from Orcutt Pump Station to the Santa Maria Refinery. These two pipelines were constructed at different times, and as such have slightly different routes (see Appendix B for detailed route maps). Although oil from Orcutt is normally sent through the 10/12-inch pipeline, the 8-inch line, which currently is idle from Suey Junction to Summit Pump Station, could be kept operational for contingency purposes (e.g., when the other line is shutdown for maintenance, oil from Orcutt could still reach the refinery through the 8-inch line).

The Santa Maria Pump Station currently collects crude oil from trucks originating in the Santa Maria area and combines the oil with oil from Cat Canyon and from the Sisquoc Pump Station. This oil is shipped to Suey Junction, and then northward to the Summit Pump Station via a 10/12-inch pipeline. At Suey Junction, this oil is commingled with oil from LOGP and the Orcutt area which is transported to Summit Station via a 10/12-inch pipeline. The oil that comes to Suey Junction from the LOGP and Orcutt could also be shipped to the Summit Pump Station via an 8-inch pipeline. Oil that comes from the Sisquoc Pump Station is not allowed into this 8-inch pipeline connecting Suey Junction and the Summit Station. Appendix B provides detailed route maps for these pipelines.

Movements from the Summit Pump Station to ConocoPhillips Santa Maria Refinery currently occur at 32,000 to 45,000 bpd and at a discharge pressure of 250 to 780 psig, but can handle up to 84,000 bpd with a combination of station bypass flow and pumped flow. Crude oil from Orcutt and Santa Maria Pump Stations currently bypasses Summit Pump Station. Santa Maria Refinery capacity is limited to 48,000 bpd as permitted by the County of San Luis Obispo Air Pollution Control District.

Sisquoc Pipeline

The branch of Line 300 that receives crude oil from the Plains All American Pipeline (AAPL) system starts at the Sisquoc Pump Station and moves in a generally westerly direction for approximately 10.5 miles to the Santa Maria Pump Station. This branch of Line 300 is 12 inches in diameter.

Movements from Sisquoc Pump Station to Santa Maria Pump Station currently occur at approximately 30,000 to 40,000 bpd and at a pressure of 250 to 1,000 psig. The MAOP of this pipeline segment is 1,440 psig. The pipeline from the Sisquoc Pump Station to Santa Maria Pump Station is currently permitted by SBC to operate at a maximum throughput of 40,000 bpd, therefore, the line is operating at or close to its permitted capacity.

As mentioned above, crude oil from the Santa Maria Pump Station normally commingles with crude oil from the Orcutt Pump Station at Suey Junction for movement to Summit Pump Station in San Luis Obispo County through the 10/12-inch pipeline. The segment of the Line 300 system from the Santa Maria Pump Station to Summit Pump Station is currently permitted by the County to operate at a maximum throughput of 84,000 bpd.

Normally, crude oil passes through the Santa Maria Pump Station without being pumped as sufficient pressure is produced at the Sisquoc Pump Station to allow the oil to travel all the way to the Summit Pump Station. Currently, the oil passes through the heat exchangers at the Santa Maria Pump Station. At certain times of the year, the oil is heated at the Santa Maria Pump Station depending on ground temperature and the need for increasing the temperature of the oil. The oil could also be pumped at the Santa Maria Pump Station or stored there in the station tankage.

Table 2.9 summarizes the current operating parameters and capacities of different segments of the ConocoPhillips Line 300 Pipeline system.

TABLE 2.9 CONOCOPHILLIPS LINE 300 PIPELINE SYSTEM DESIGN CAPACITY[a] AND CURRENT OPERATING PARAMETERS

Segment	Current Operating Throughput, bpd, 2005 Average	Current Operating Pressure, psig	Design Pipe Capacity, bpd	MAOP, Psig
LOGP to Orcutt Pump Station, 12-inch	7,500	250-680	96,000	800
Orcutt Pump Station to Suey Junction, 8-inch	8,500 to 9,000	450-780	50,000	800
Sisquoc Pump Station to Santa Maria Pump Station, 12-inch	32,000	250-1,000	50,000	1,440
Santa Maria Pump Station to Suey Junction, 12-inch	34,500	600-780	84,000	800
Suey Junction to Summit Pump Station, 8-inch	0 (idle)	0	50,000	800
Suey Junction to Summit Pump Station and Santa Maria Refinery 12/10-inch	42,000 to 43,500	250-780	84,000	800

[a]: Design capacity does not necessarily reflect permitted capacity, which may be much lower.

2.4 References

MMS (Minerals Management Service). 2004. Offshore Facility Decommissioning Costs, Pacific OCS Region, September 17.

Plains Exploration and Production Company. 2004. Revised Application for the Tranquillon Ridge Development Project. November.

____. 2006. Responses to Project Description Information Requests.

County of Santa Barbara. May 31, 2001. Tosco Sisquoc Pipeline Project Request for Increased Throughput and Change in Tankage. 00-EIR-09.

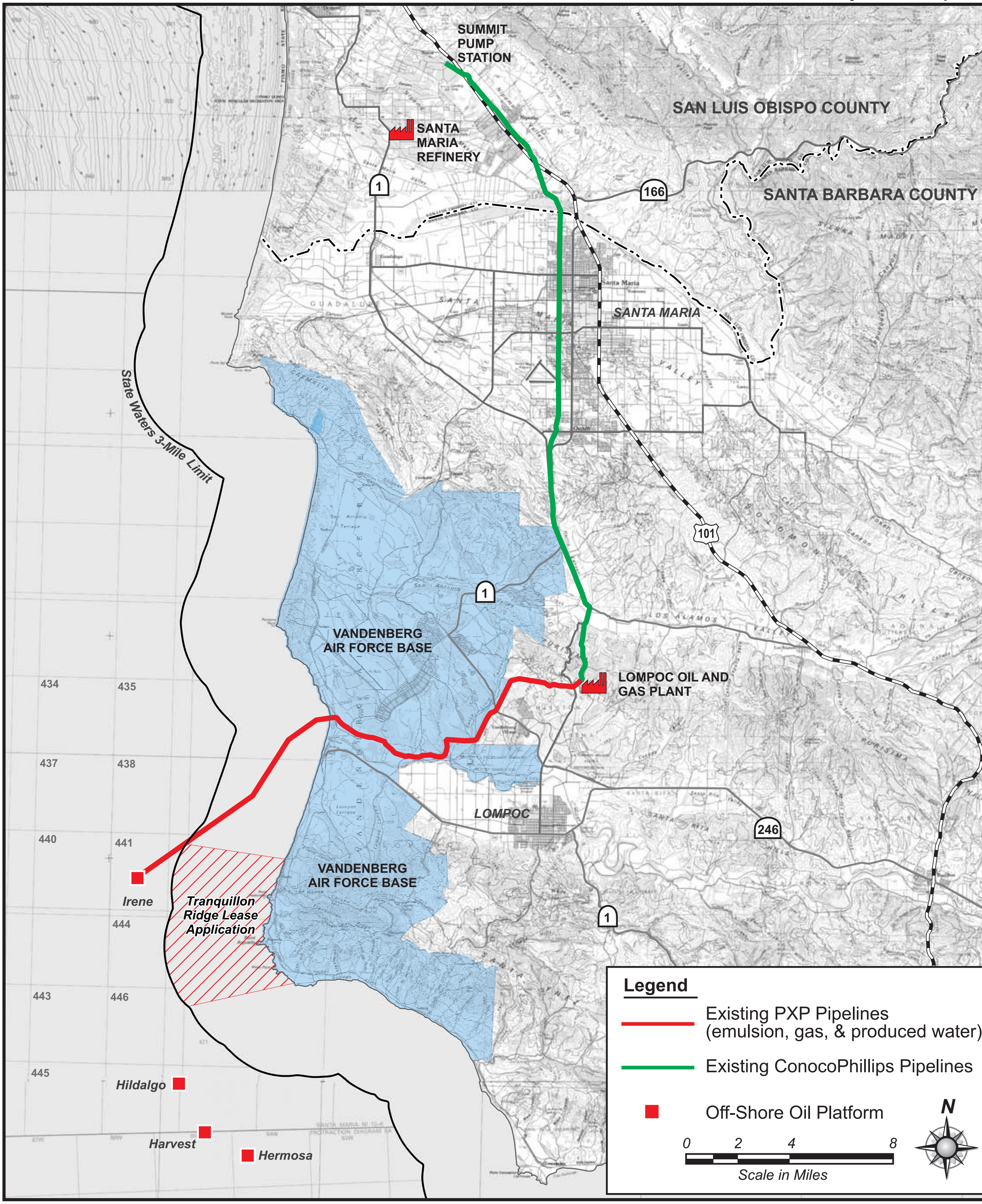

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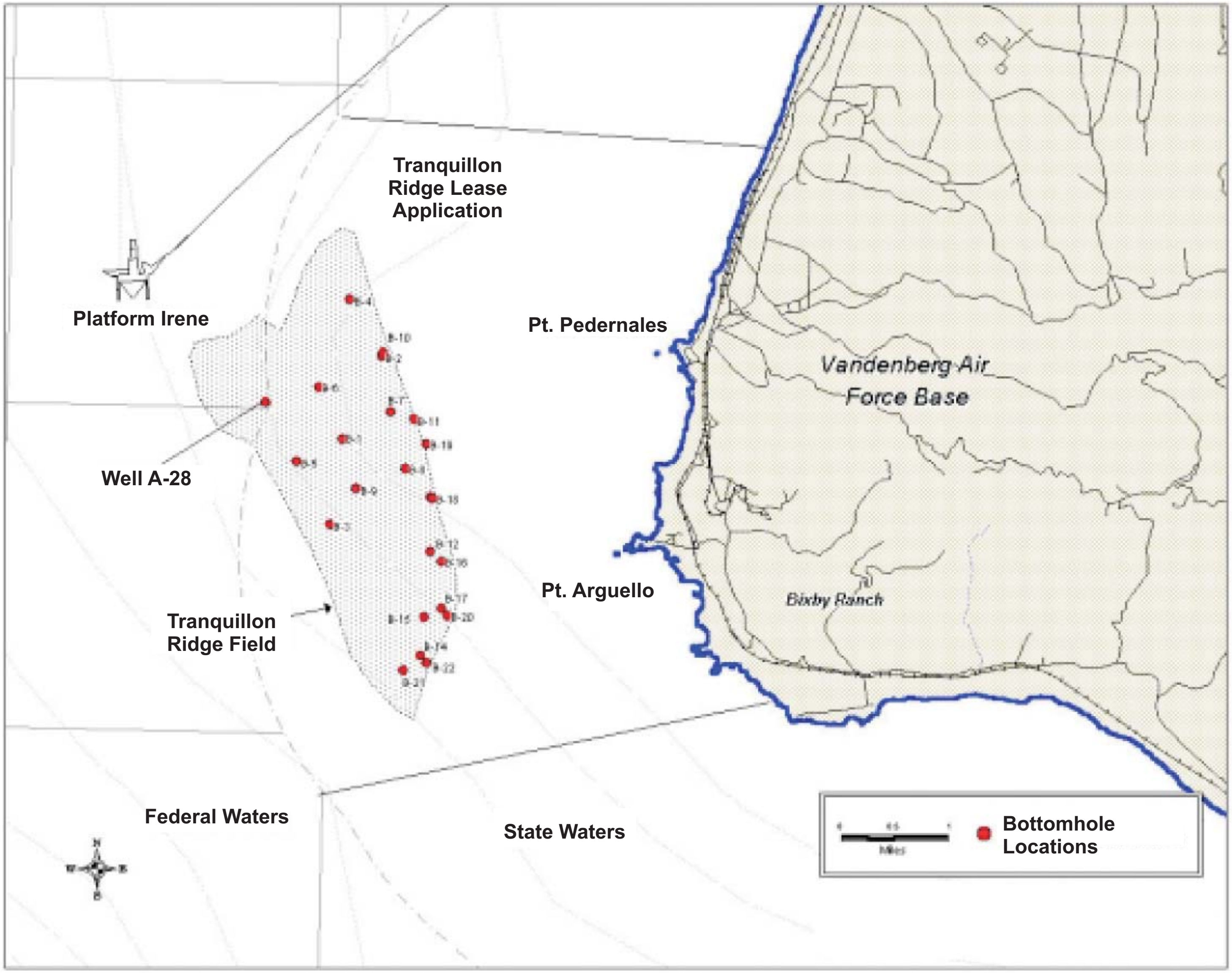
Figure 2-1
Proposed Project Location



Source: MRS, 2002.

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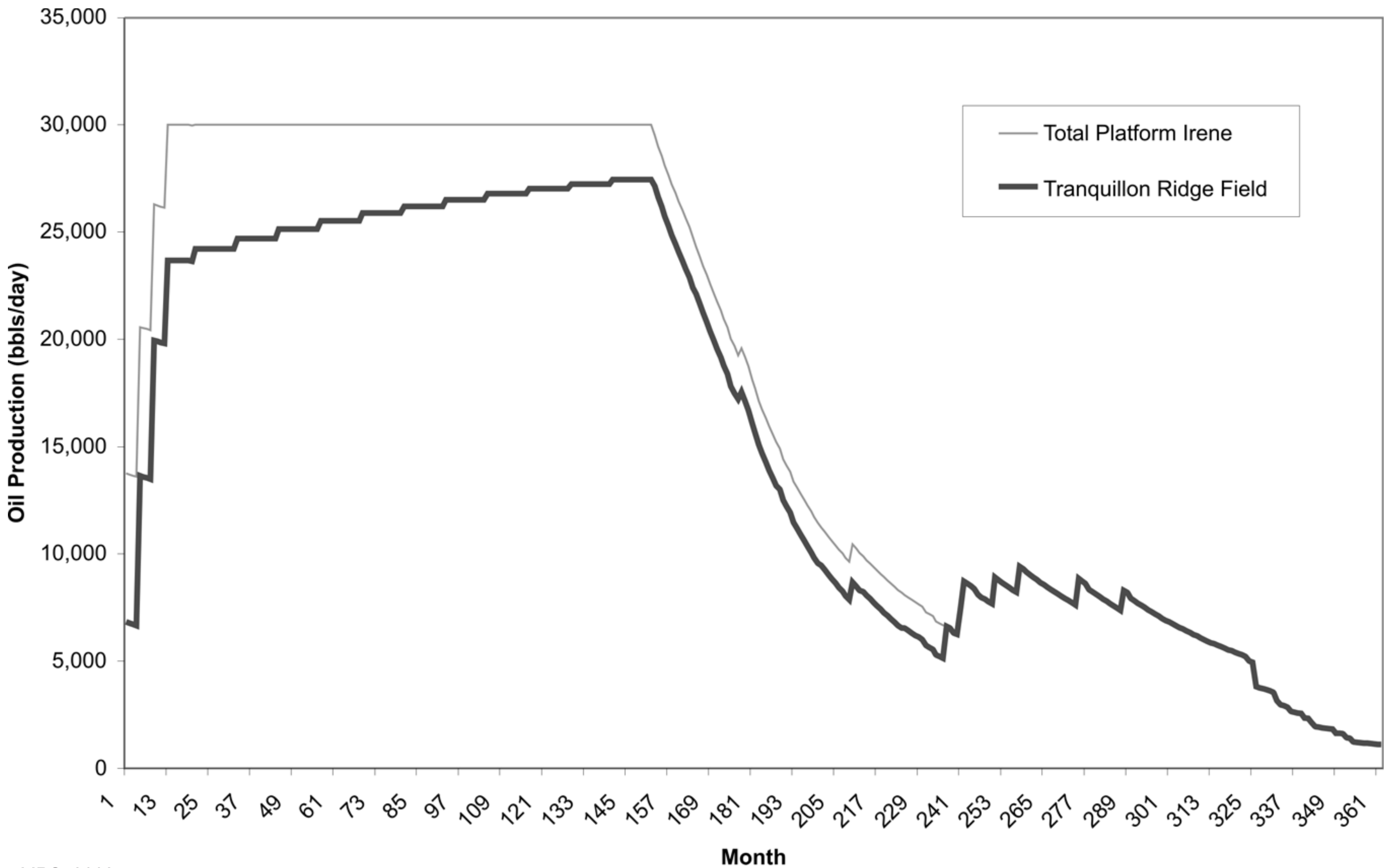
Figure 2-2
Proposed Tranquillon Ridge Drilling Map



Source: MRS, 2002.

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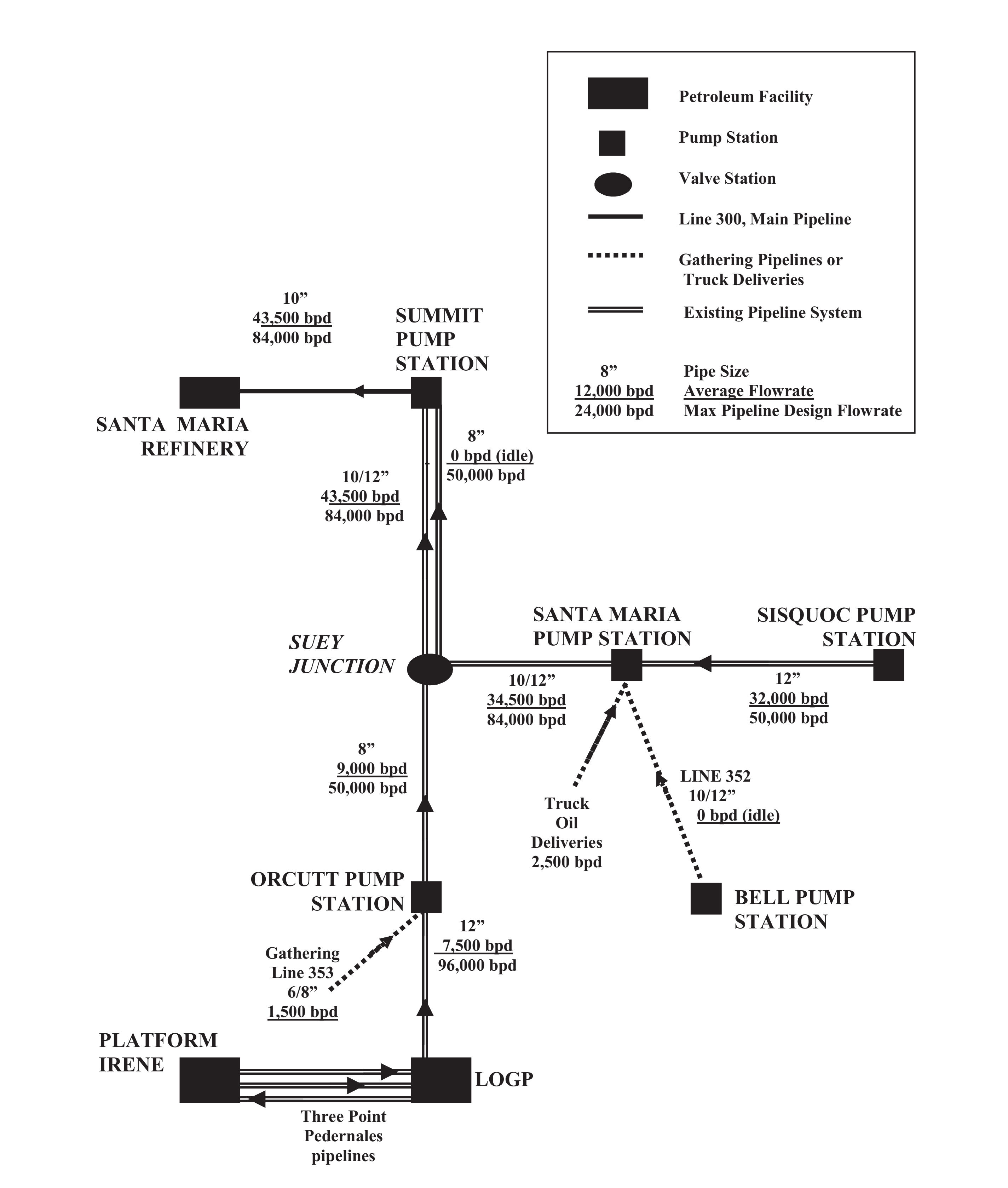
Figure 2-3

Estimated Oil Production for the Tranquillon Ridge Field



Source: PXP, 2006.

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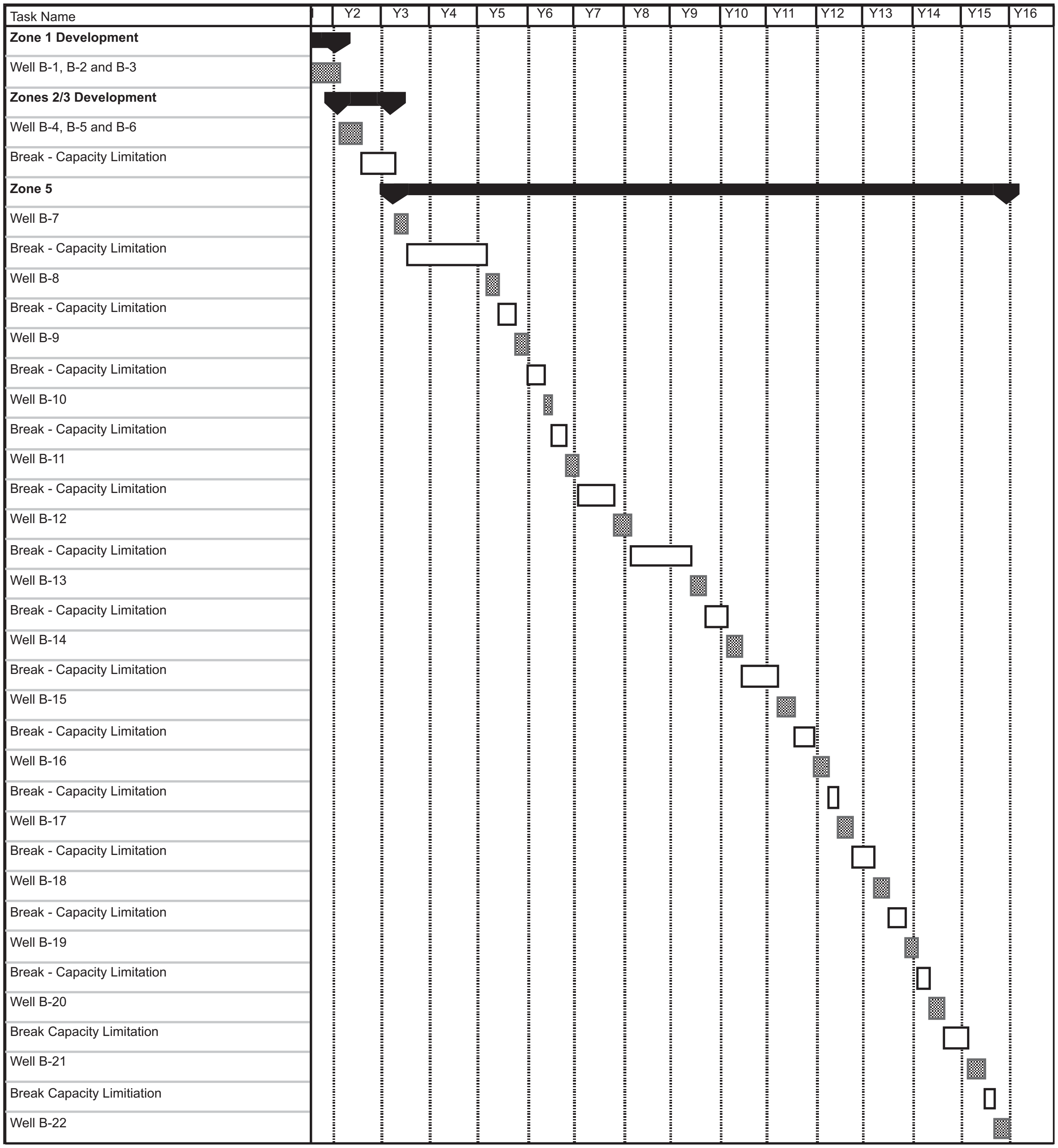
Figure 2-4
ConocoPhillips Pipeline System



Source: MRS, 2002.

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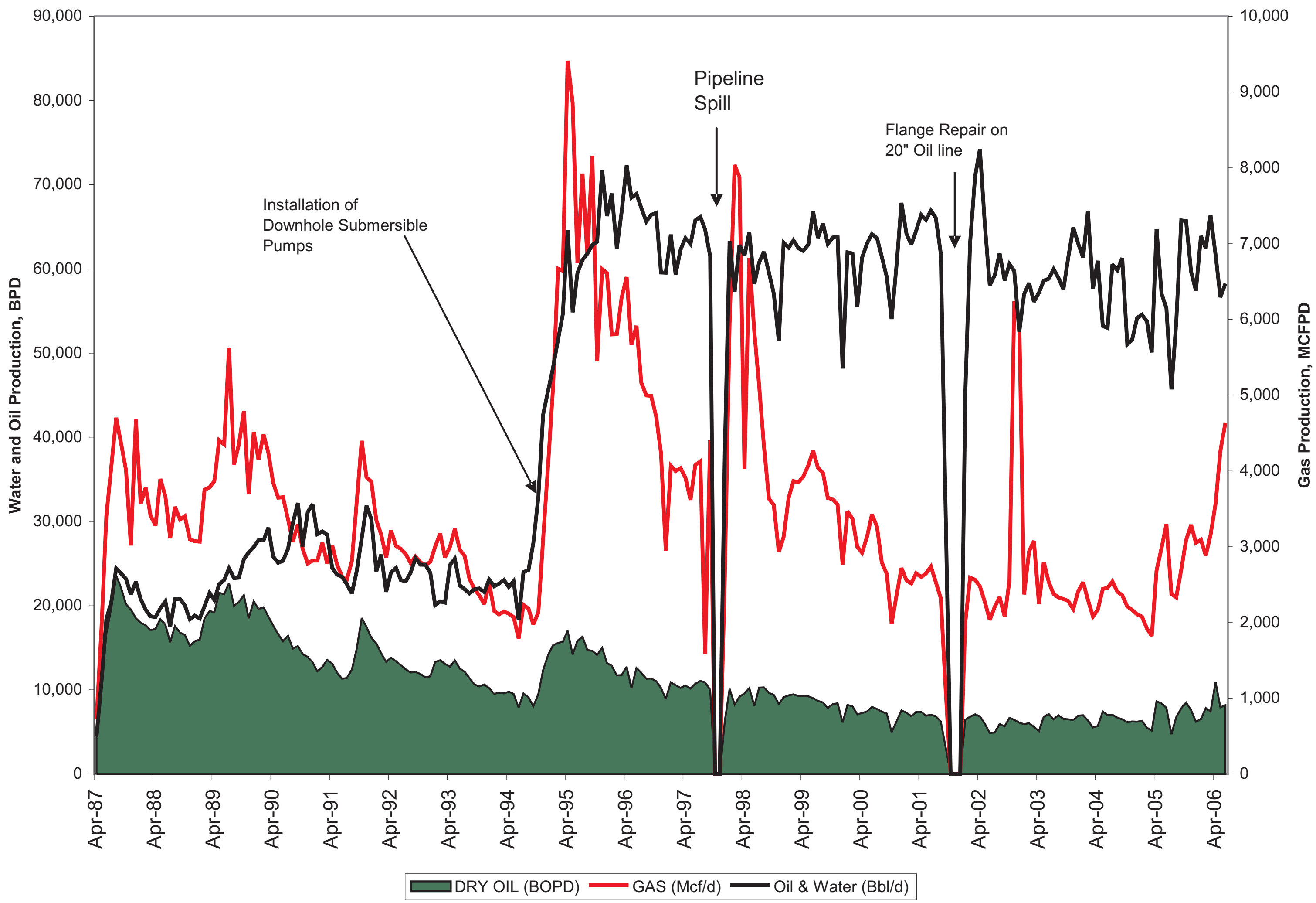
Figure 2-5

Proposed Tranquillon Ridge Field Drilling Schedule



Note: Average daily production data is derived from monthly production data by dividing it by the number of days of production.

Source: PXP, 2006.

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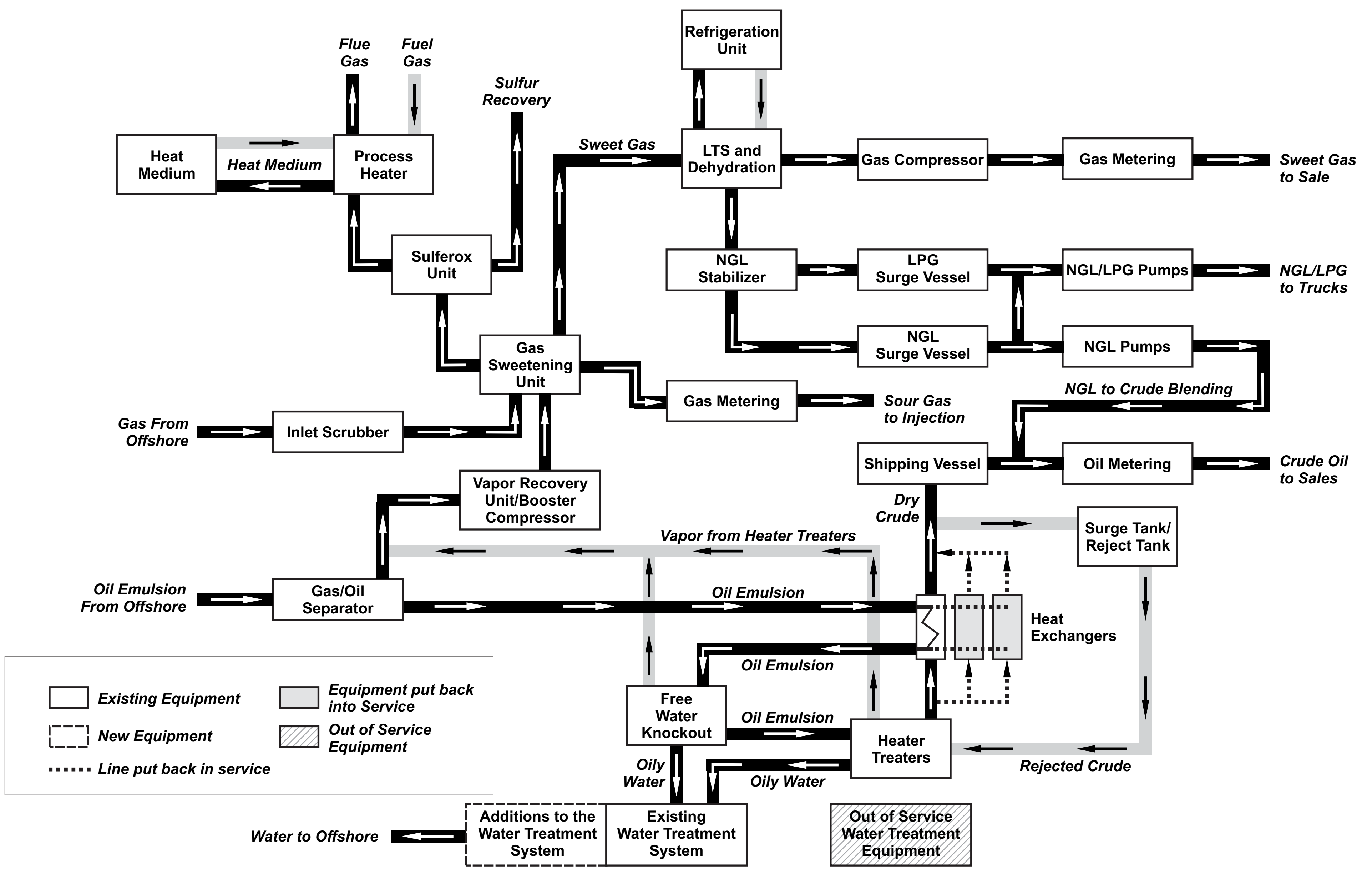
Figure 2-6

Point Pedernales Total Produced Fluids (1987-2006)



Source: PXP, 2006.

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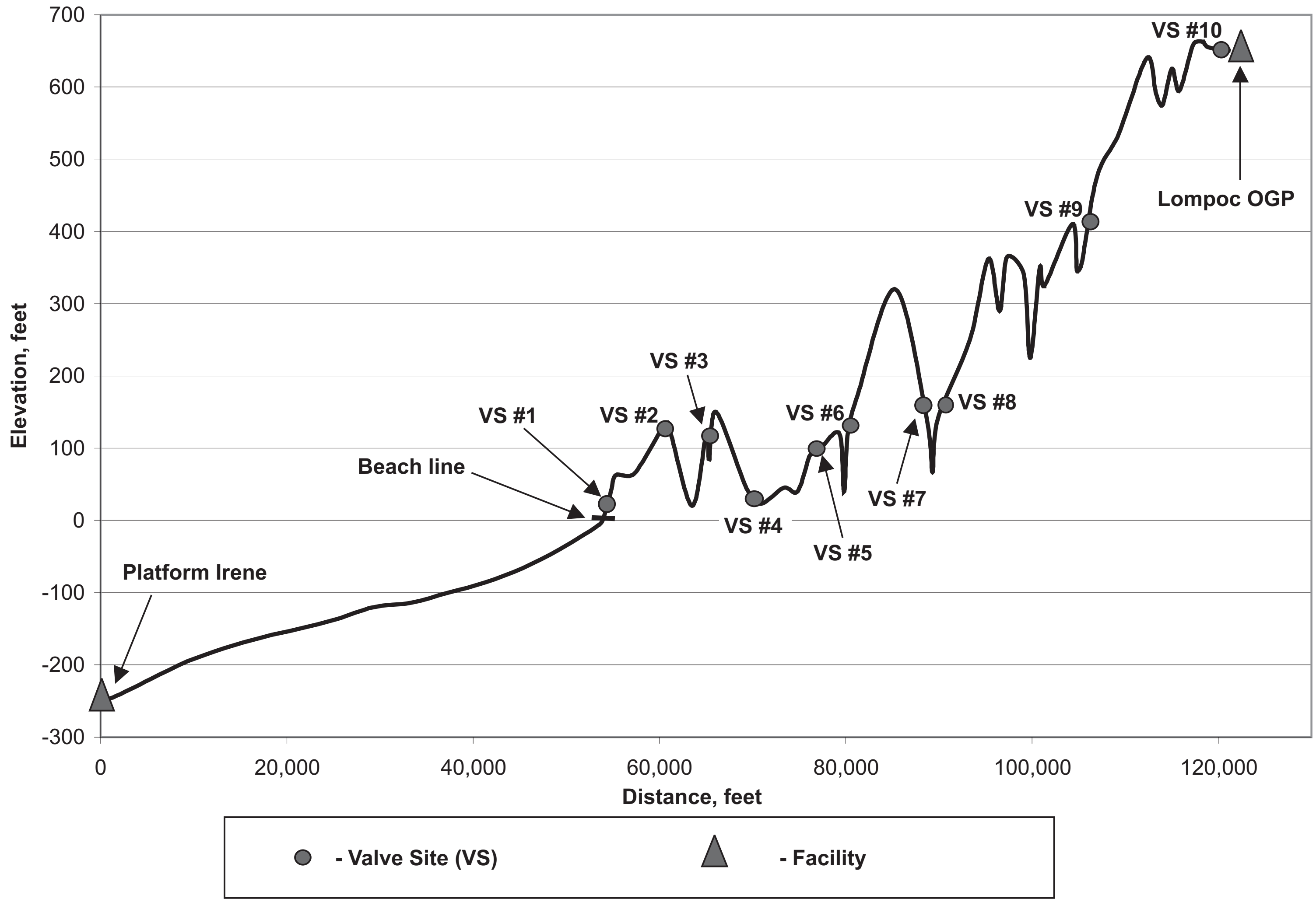
Figure 2-7
LOGP Block Flow Diagram



Source: MRS, 2002.

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Figure 2-8
Platform Irene to LOGP 20-inch Oil Emulsion Pipeline Elevation Profile

3.0 ALTERNATIVES

Section 3.0 presents the various alternatives considered in this Environmental Impact Report (EIR) in accordance with the California Environmental Quality Act (CEQA). This section is organized as follows:

3.1 CEQA Alternative Analysis Overview

CEQA Guidelines Section 15126.6 provides direction for the discussion of alternatives to the proposed project. This section requires:

- A description of "...a range of reasonable alternatives to the project, or to the location of a project, which would feasibly attain most of the basic objectives of the project but would avoid or substantially lessen any of the significant effects of the project, and evaluate the comparative merits of the alternatives." [15126.6(a)]
- A setting forth of alternatives that "...shall be limited to ones that would avoid or substantially lessen any of the significant effects of the project. Of those alternatives, the EIR need examine in detail only the ones that the lead agency determines could feasibly attain most of the basic objectives of the project." [15126.6(f)]
- A discussion of the "No Project" alternative, and "...If the environmentally superior alternative is the "no project" alternative, the EIR shall also identify an environmentally superior alternative among the other alternatives." [15126.6(e)(2)]
- A discussion and analysis of alternative locations "…that would substantially lessen any of the significant effects of the project need to be considered for inclusion in the EIR." [15126.6(f)(2)(~~B~~A)]

This document uses an alternative screening analysis to limit the number of alternatives evaluated in detail throughout the Environmental Impact Report (EIR). The use of an alternative screening analysis provides the detailed explanation of why some of the alternatives were rejected from further analysis, and assures that only the alternatives that could lessen any of the significant effects of the proposed project are evaluated and compared in the EIR.

This screening methodology uses the *"rule of reason"* approach to alternatives as discussed in CEQA (CEQA Guidelines Section 15126.6(f)). The rule of reason approach has been defined to require that EIRs address a range of feasible alternatives that have the potential to diminish or avoid adverse environmental impacts. The CEQA guidelines state:

> *"The alternatives shall be limited to ones that would avoid or substantially lessen any of the significant effects of the project. Of those alternatives, the EIR need examine in detail only the ones that the lead agency determines could feasibly attain most of the basic objectives of the project."* (CEQA Guidelines Section 15126.6(f))

In defining feasibility of alternatives, the CEQA Guidelines state:

> *"Among the factors that may be taken into account when addressing the feasibility of alternatives are site suitability, economic viability, availability of infrastructure, general plan consistency, other plans or regulatory limitations, jurisdictional boundaries (projects with a regionally significant impact should consider the regional context), and whether the proponent can reasonably acquire, control or otherwise have access to the alternative site."* (CEQA Guidelines Section 15126.6(f)(1))

If an alternative was found to be technically infeasible, then it was dropped from further consideration. This was the only feasibility factor that was used to eliminate an alternative without further screening analysis.

In addition, CEQA states that alternatives should "…*attain most of the basic objectives of the project* ..." (15126.6[a]). If an alternative is found to not obtain the basic objective (to efficiently and effectively develop oil and gas reserves from the Tranquillon Ridge Field to help meet California's energy demand), then it was also eliminated.

The use of a screening analysis for the alternatives assures that the full spectrum of environmental concerns is adequately represented, and that a reasonable range of alternatives is selected for further evaluation throughout the EIR. Alternatives screening analyses are used in EIRs as a tool for focusing the environmental review process and limiting the amount of detailed analysis (i.e., eliminating potential alternatives that are technically infeasible or do not satisfy the basic objectives of the proposed project).

A wide variety of alternatives for the Tranquillon Ridge Project was considered in the screening analysis to address potential alternatives to the proposed project, as well as individual project components. Alternatives were considered for the following components of the proposed project, including the No Project Alternative:

- Section 3.2 – No Project Alternative
- Section 3.3 - Alternative Drilling/Production Location
- Section 3.4 - Alternative Processing Locations
- Section 3.5 - Alternative Oil Emulsion Transportation
- Section 3.6 - Alternative Power Line Routes to Valve Site #2
- Section 3.7 - Alternative Drill Muds and Cuttings Disposal

Given the CEQA mandates listed above, the remainder of this section covers: (1) a description of a range of reasonable alternatives to the projects, including the No Project Alternative; (2) a screening analysis that summarizes and compares the significant environmental effects of the project and each alternative; and (3) the selection of alternatives chosen for further evaluation throughout the EIR. In addition, a brief discussion of alternative energy sources is provided below for informational purposes.

Alternatives to Oil and Gas Development

The State of California is pursuing a comprehensive strategy addressing energy supply and demand, in part through development of regulatory schemes that are intended to result in increased energy efficiencies, increased conservation, development of alternative fuels, and increased use of alternative transportation. The California Energy Commission's Energy Action Plan II[1] recognizes that "cost-effective energy efficiency is the resource of first choice for meeting California's energy needs" and promotes continued and expanding use of, and improvements in, energy-saving technologies, such as building standards, appliance standards, and energy supplier efficiency programs. (The State has already adopted energy efficiency building and appliance standards.)[2] The Energy Action Plan also recognizes the need for "aggressively developing renewable energy resources to meet the Renewables Portfolio Standard (RPS) requirements" and for achieving "significant reductions in gasoline and diesel use and increase the use of alternative fuels…"

The State also has recognized that use of fossil fuels will continue, at least in the short-term, while its energy strategy is further developed and alternatives to oil and gas become generally available on an increasingly larger scale. The Energy Action Plan II identifies nine "Specific Action Areas" and several "Key Actions" within each of these Areas for achieving the State's goals and objectives regarding energy supply and demand. Key Action #2 for *Specific Action Area 7: Transportation Fuels Supply, Demand, and Infrastructure*, which states: "Increase coordination of petroleum infrastructure permitting among state, local, and regional agencies, including developing guiding principles for approval of new petroleum facilities." However, although there is no indication the State is considering a complete ban on the development of petroleum resources, California law (Public Resources Code §§6240-6244 and 6872.5) does prohibit new leasing of any State tidelands for oil and gas development, except under limited circumstances: (1) legislative determination that the President of the United Sates has found that a severe interruption in the supply of energy exists and development of reserves within the State's tidelands will significantly alleviate the interruption; or, (2) the CSLC determines that oil and gas deposits in State tidelands are being drained by adjacent federal wells and leasing of the tidelands is in the best interests of the State; or, (3) for a lease boundary adjustment of an existing lease, subject to certain conditions.

California has recognized the need to significantly reduce its use of fossil fuels and, especially in recent years, has stepped up its efforts to attain these objectives, which include developing regulations to require greater energy efficiencies and use of renewable energy resources. As with the development of any new major policy direction, the process of promulgating new standards

[1] The Energy Action Plan II (dated September 21, 2005) was prepared by the California Energy Commission and California Public Utilities Commission and "describes a coordinated implementation plan for state policies that have been articulated through the Governor's Executive Orders, instructions to agencies, public positions, and appointees' statements; the CEC's Integrated Energy Policy Report (IEPR); CPUC and CEC processes; the agencies' policy forums; and legislative directive." The EAP II is available at http://www.energy.ca.gov/energy_action_plan/index.html.

[2] CEC. See http://www.energy.ca.gov/efficiency/index.html

involves considerable research and discussion among the State's various economic sectors, the public, and the decision-makers. While California is advancing toward its goals for reducing fossil fuel consumption and has made progress in reducing per capita electricity demand[3], until efforts to develop and increase use of alternative fuels yield more substantive results, oil and natural gas resources will remain a major component of California's mix of energy sources. It is not yet known whether Federal, State or local policies currently being developed will eventually discourage or prohibit development of petroleum resources in the future. Replacement of fossil fuels with alternative fuels may occur as these alternatives are further developed and become more economical when compared to oil and gas production. However, at this time, California remains dependant on fossil fuels for a large portion of its energy supply, particularly over the short-term. It is beyond the scope of a project-specific EIR to address energy policy development in detail and premature to identify and apply new standards that are in preparation at the State and Federal levels. Thus, potential alternatives to oil and gas production to meet the State's energy demand, such as solar and wind power, bio-fuels, and energy conservation programs, are not considered feasible alternatives to the proposed project and are not evaluated further in this EIR.

3.2 No Project Alternative

CEQA requires that the "No Project" Alternative be evaluated along with its impacts as part of the EIR (CEQA Guidelines Section 15126.6(e)). As such, the No Project Alternative was not subject to the screening analysis and has been evaluated as an alternative for the project throughout the EIR. The descriptions and evaluations of the No Project Alternative in this EIR assume that the portion of fuel demand that would be filled by the Tranquillon Ridge project would be met using other sources if the Tranquillon Ridge project is not approved and implemented.

CEQA requires that the likely impacts of the No Project alternative be analyzed by examining what would reasonably be expected to occur, given existing land use plans and consistent with available infrastructure and community services. In this case, for most issue areas, project-related impacts would not occur if the proposed project is not approved and implemented because the project-related impacts result directly from the increased production from, and extended operational life of, the Point Pedernales facilities. One of three basic scenarios potentially could occur if the Tranquillon Ridge project is not approved; these are: (1) full development of the Tranquillon Ridge reserves from an onshore location; (2) development of only the federal portion of the Tranquillon Ridge field from Platform Irene; or, (3) continued production of the Point Pedernales field for the remaining economic life of that project, estimated to be until about 2017, with no further development of the Tranquillon Ridge Field. Each of these scenarios is described below.

(1) Onshore Tranquillon Ridge Development: Under Section 15126.6(e)(3)(B) of the CEQA Guidelines, "[if] disapproval of the project under consideration would result in predictable actions by others, such as the proposal of some other project, this 'no project' consequence should be discussed." As presented in Section 3.3.3, Sunset Exploration, Inc. and ExxonMobil Corporation have submitted applications to SBC, CSLC, and Vandenberg Air Force Base

[3] See Energy Action Plan II, Section II.1, September 21, 2005.

(VAFB) for the development of the Tranquillon Ridge Field from an onshore location within southern VAFB. Therefore, it is feasible that the Tranquillon Ridge resources could be developed by others if the proposed project is not approved and implemented (the No Project Alternative). A conceptual onshore project was developed to identify the range of potential environmental impacts of developing the Tranquillon Ridge Field from an onshore location for comparison to the proposed project. This conceptual alternative is described in more detail in Section 3.3 of this EIR and its likely impacts are discussed qualitatively throughout this EIR under the VAFB Onshore Alternative; therefore, in the impact analysis presented in Section 5, Scenario 1 is addressed under the VAFB Onshore Alternative and Scenarios 2 and 3 are addressed under the No Project Alternative. It should be noted the conceptual onshore alternative discussed herein is not the Sunset/ExxonMobil proposal.

(2) Federal Tranquillon Ridge Development: The second No Project Alternative scenario is continued, and possibly increased, development of the portion of the Tranquillon Ridge Field in Federal waters, from Platform Irene. Under this scenario, there would be no need to obtain a lease from the State Lands Commission; however, other County, and federal authorizations may need to be granted[4]. One well (A-28) has a drainage radius that reaches into the Federal portion of the Tranquillon Ridge Field. This well had a maximum production of 932 barrels per day (bpd) of oil (recorded in April 1997, MMS production data) only during the first month of operation and declined to 430–540 bpd in the following 4 months. PXP is not currently proposing to drill and develop additional wells into the Federal portion of the Tranquillon Ridge Field since it is not considered to be the best oil-bearing portion of the field. For example, as shown in Figure 2-2, approximately 11 percent of the Tranquillon Ridge Field lies in Federal waters. As stated by PXP, no further development of the Federal portion of the Tranquillon Ridge Field has been conducted or is planned at this time, since well A-28 may be sufficient to develop the Federal portion of the Tranquillon Ridge Field (PXP, 2006); however, PXP has also stated that additional wells could be drilled, based upon its ongoing review of the reservoir geology and economics. It is assumed that with any further development of the Tranquillon Ridge federal portion, no extension of life of Point Pedernales facilities (Platform Irene, pipelines, LOGP) would occur.

(3) Point Pedernales Continuation: Production of the Point Pedernales Field from Platform Irene through the economic life of the project, estimated to be year 2017, is expected to occur under any circumstance, including if the Tranquillon Ridge Field is developed by others (Scenario 1), the federal portion of the Tranquillon Ridge Field is developed from Platform Irene (Scenario 2), or no further development of the Tranquillon Ridge Field occurs. This discussion assumes that no further development of the federal portion of the Tranquillon Ridge Field would occur from Platform Irene within the expected lifetime of the Point Pedernales project.

There would be no extension of life of the Point Pedernales facilities under this scenario. Due to the geologic and technical factors involved with developing a coastal California Monterey oil-bearing structure, project life and ultimate recovery volumes are extremely difficult to estimate without extensive production data from a number of wells. This EIR uses assumptions for the No Project Alternative that are based on currently available PXP, MMS, and CSLC data. These data

[4] Condition A-12 of the Point Pedernales Final Development Plan only allows Point Pedernales and Lompoc Oil Field production to be processed at LOGP.

represent rough estimates of production and project life. Actual production depends on many variables, and could be substantially different from the estimates provided.

The existing PXP pipelines and the Lompoc Oil and Gas Plant (LOGP) would continue to transport and process the produced emulsion and gas, respectively. Produced water would continue to be treated at the LOGP and sent back to Platform Irene for disposal, although for the next few years it is assumed that a portion of the produced water would be injected into the onshore Lompoc Oil Field.

By about year 2017, it is assumed that the production volumes from the Point Pedernales Field would no longer be economically viable. At that time, Platform Irene, the emulsion, gas, and produced water pipelines, and the LOGP would be decommissioned and removed.[5] This decommissioning effort would undergo separate Santa Barbara County (SBC) permitting and environmental review and is not discussed further in this EIR.

Options for Meeting California Fuel Demand

If the Tranquillon Ridge project is approved, the crude oil and gas produced from it would meet a portion of expected fuel needs in California. If the Tranquillon Ridge project is not approved, it is assumed that this demand for fuel would be met by other means. Other energy sources that potentially could meet or reduce some or all of this demand are briefly described below.

(3a) Conventional Oil and Gas Sources: The amount of gasoline produced and used in California is not dependant on refineries being supplied with Tranquillon Ridge crude oil. California refineries are currently operating at or near capacity and are expected to continue to do so for the foreseeable future. Other existing sources of crude oil and natural gas that could be used in place of the Tranquillon Ridge reserves to supply transportation fuels include onshore California crude oil and gas production and increased importation of crude oil from out-of-state locations via marine tanker. Note that if Tranquillon Ridge production were to be replaced with other domestic offshore production, impacts would be essentially the same as for the proposed project. In addition, increased importation of gasoline by truck or pipeline, and liquefied natural gas (LNG) via marine tanker and/or pipeline could augment current refined fuel supplies. Environmental impacts associated with the development and use of these conventional sources of oil and gas could be either more or less severe than those for the proposed project, depending on how and where the oil and gas are developed and delivered and which environmental resources would be affected by their production and use.

(3b) Alternatives to Oil and Gas: Future State policy-level decisions may discourage development of oil and gas resources while encouraging development of alternative energy sources, including increased conservation and improved energy efficiency technologies to meet demand for stationary energy uses and transportation fuels (see box next page). Market incentives, such as steadily increasing gasoline and diesel fuel prices, could accelerate conservation and implementation of more energy-efficient practices. Demand reduction measures and development of energy sources other than oil and gas could be developed to replace the amount of energy that would be provided by the Tranquillon Ridge project, as discussed below.

[5] Portions of the pipelines may be abandoned in place.

Demand Reduction: Transportation fuel demand reduction includes increasing fuel efficiencies and conserving fuel supplies by using less. Gasoline conservation can be achieved through switching to alternatives such as increased use of ethanol and biodiesel, increased use of transportation modes such as mass transit, bicycling, walking, carpooling, telecommuting, and electric and gasoline-electric hybrid vehicles. For individuals, the feasibility of making these changes varies. Walking, cycling, and ridesharing are readily available for many people, but not all. Telecommuting depends on employer participation, but also is readily available for many jobs. Mass transit use depends on availability of infrastructure and service; electric and gasoline-electric hybrid vehicles and ethanol and biodiesel fuels must be manufactured and made available.

Increased fuel efficiencies also can be implemented through regulatory measures, such as increased Corporate Average Fuel Economy (CAFÉ) standards, as well as market-based incentives. The purpose of the CAFÉ standards is to reduce energy consumption by increasing the fuel economy of cars and light trucks. Increased fuel economies would reduce per-vehicle fuel use. Increasing total numbers of vehicles would offset this fuel savings by some amount.

For stationary uses, increased efficiencies for space and water heating, cooking, air conditioning, lighting, and ventilation could reduce the state's per capita consumption of natural gas. Some technologies are proven and available. Population growth tends to increase total natural gas consumption and corresponding emissions in the state.

To meet future demand, electricity for commercial and residential uses, including

CALIFORNIA ENERGY STRATEGIES

The State of California is pursuing a comprehensive strategy addressing energy demand and supply, in part through development of various regulations and incentives that are intended to result in increased energy efficiencies, increased conservation, development of alternative fuels, and increased use of alternative transportation. The California Energy Commission's Energy Action Plan II (http://www.energy.ca.gov/energy_action_plan/index.html) recognizes that "cost-effective energy efficiency is the resource of first choice for meeting California's energy needs" and promotes continued and expanding use of, and improvements in, energy-saving technologies, such as building standards, appliance standards, and energy-supplier efficiency programs. The Energy Action Plan also recognizes the need for "aggressively developing renewable energy resources to meet the Renewables Portfolio Standard (RPS) requirements" and for achieving "significant reductions in gasoline and diesel use and increase the use of alternative fuels…"

The Energy Action Plan II identifies nine "Specific Action Areas" and several "Key Actions" within each of these Areas for achieving the State's goals and objectives regarding energy supply and demand. An example of the State's recognition of the need for oil and gas development while alternative energy sources are further developed is found in Key Action #2 for Specific Action Area 7: Transportation Fuels Supply, Demand, and Infrastructure, which states: "Increase coordination of petroleum infrastructure permitting among state, local, and regional agencies, including developing guiding principles for approval of new petroleum facilities." Although there is no indication the State is considering a ban on the development of petroleum resources, California law (Public Resources Code §§6240-6244 and 6872.5) does prohibit new leasing of any State tidelands for oil and gas development, except under limited circumstances: (1) legislative determination that the President of the United States has found that a severe interruption in the supply of energy exists and development of reserves within the State's tidelands will significantly alleviate the interruption; or, (2) the CSLC determines that oil and gas deposits in State tidelands are being drained by adjacent federal wells and leasing of the tidelands is in the best interests of the State; or, (3) for a lease boundary adjustment of an existing lease, subject to certain conditions.

In 2006, the State of California enacted the Global Warming Solutions Act, also known as AB 32. AB 32 requires reductions in the emissions of greenhouse gases such that 1990 levels are achieved by 2020 and 80% of 1990 levels are achieved by 2050. These reductions are to be achieved through a combination of regulatory measures currently being developed, market-based incentives, and a continuation of current state energy policies. For more detailed discussion of AB 32, see Section 5.8 of this EIR and http://arbis.arb.ca.gov/cc/factsheets/ab32factsheet.pdf.

for recharging electric vehicles, could be generated from sources other than Tranquillon Ridge oil and gas. Liquefied natural gas imported via marine vessels or by pipeline could be used in existing power plants. Coal can be burned to produce electricity and used instead of, or in addition to, natural gas in power plants. Hydroelectric and nuclear power plants also produce electricity which could be used to augment or replace oil and natural gas consumption for that purpose. Impacts associated with generating electricity from these other sources would vary, depending on several factors, including the degree to which infrastructure exists to produce, deliver, and use these potential sources.

Alternative Transportation Fuels: Ethanol and biodiesel are currently being used in California and other states as a gasoline additive. Several ethanol plants have been built or are under construction and several more are in the permitting process in central and southern California, including one proposal near Santa Maria in Santa Barbara County. These plants, both existing and proposed, ferment primarily corn delivered by rail to the plant site. Increased production and use of ethanol could extend gasoline supplies.

Hydrogen fuel cell technology is also in development. A fuel cell uses hydrogen and oxygen to create electricity. If pure hydrogen is used as the fuel, only heat and water are emitted. Key challenges are developing hydrogen production capabilities and storage and delivery infrastructure so as to be available at a cost that is competitive with other fuels and power sources (see http://www.www1.eere.energy.gov/hydrogenandfuelcells).

Other Energy Resources: Other energy resources (solar, wind, wave) could also offset consumption of natural gas for generating electricity. These sources require varying types and degrees of infrastructure development. For example, wind projects require turbines (see http://www.gosolarcalifornia.ca.gov/solar101/what_is.html) and a distribution system (usually power lines and poles); solar power requires installation of collectors and a power distribution system; and wave energy requires installation of wave energy extraction equipment and a collection and distribution system. Solar and wind power technologies are further along than wave power, which is in relatively early stages of development in the United States (see http://energy.ca.gov/development/oceanenergy/). Several wind and solar facilities have been built or are in the permitting process in central and southern California, including one proposal south of Lompoc in Santa Barbara County.

~~Under the No Project Alternative, production of the Point Pedernales field would continue through the economic life of the project, estimated to be year 2017. In addition, the existing PXP pipelines and the Lompoc Oil and Gas Plant (LOGP) would continue to be used to transport and process the produced emulsion and gas, respectively. Produced water would continue to be treated at the LOGP and sent back to Platform Irene for disposal, although for the next few years it is assumed that a portion of the produced water would be injected into the onshore Lompoc field.~~

~~By year 2017, it is assumed that the production volumes from the Point Pedernales field would no longer be economically viable. At that time, Platform Irene; the emulsion, gas, and produced water pipelines; and LOGP would be decommissioned and removed. This decommissioning effort would undergo separate Santa Barbara County (SBC) permitting and is not considered part of the No Project Alternative.~~

~~Under the No Project alternative, the portion of the Tranquillon Ridge Field in Federal waters could be developed. Development of the Federal portion of the Tranquillon Ridge Field could occur without SBC or Minerals Management Service (MMS) permit modifications because this portion of the field lies within Leases OCS-P 0441 and OCS-P 0444 which are encompassed under the existing Point Pedernales permits. Under this alternative, there would be no need to obtain a California State Lands Commission (CSLC) lease. As part of the Tranquillon Ridge Project, PXP is not proposing to drill and develop wells into the Federal portion of the field since it is not considered to be the best oil-bearing portion of the Tranquillon Ridge Field. This well has a maximum production of 932 barrels per day (BPD) of oil (recorded in April 1997, MMS production data) only during the first month of operation which declined down to 430-540 bpd in the following 4 months. As stated by PXP, no further development of the federal portion of the Tranquillon Ridge Field has been conducted or is planned, since well A-28 is sufficient to develop the Federal portion of the Tranquillon Ridge Field (PXP, 2006).~~

~~Under the No Project Alternative there would be no extension of life of the Point Pedernales facilities. Due to the geologic and technical factors involved with developing a coastal California Monterey oil-bearing structure, project life and ultimate recovery volumes are extremely difficult to estimate without extensive production data from a number of wells. This EIR uses assumptions for the No Project Alternative that are based on currently available PXP, MMS and CSLC data. These data represent very rough estimates of production and project life. Actual production depends on many variables, and could be substantially different from the estimates provided.~~

~~Under Section 15126.6(e)(3)(B) of the CEQA Guidelines, "If disapproval of the project under consideration would result in predictable actions by others, such as the proposal of some other project, this 'no project' consequence should be discussed. As presented in Section 3.2.3, Sunset Exploration, Inc. and Exxon Mobile Corporation have submitted applications to SBC, CSLC, and Vandenberg Air Force Base (VAFB) for the development of the Tranquillon Ridge Field from an onshore location within southern VAFB. The Sunset/ExxonMobile Project is addressed in this EIR as the VAFB Onshore Alternative.~~

3.3 Alternative Drilling/Production Locations

Several drilling/production scenarios for development of the Tranquillon Ridge Field were considered to evaluate potential alternatives to the proposed project and avoid potentially significant environmental impacts, including:

- New Offshore Platform,
- Subsea Completion with Connection to Platform Irene, and
- Using Extended Reach Drilling Technology from VAFB

The screening analysis for drilling/production alternatives is presented in Table 3.1. The results of the screening analysis for each of the alternative drilling and production locations are also presented.

Table 3.1 Screening of Drilling/Production Alternatives

Area of Impact	Would Alternative Substantially Lessen or Avoid Impacts (-), Result in Increased Impacts (+) or Remain About the Same (0) when compared to the Proposed Project?			
	Sub Sea Completion	New Platform	Drilling From Shore	Notes
Aesthetic/Visual Resources	0	+	0	A subsea completion could require the continued operation of Platform Irene. New platforms would increase visual impacts. Drilling from shore might allow Platform Irene and offshore pipelines to be decommissioned as assumed in the 1985 EIR/EIS, reducing visual impacts of platform. Given its location, the onshore drilling/production site would not be readily viewable by the public. However, new oil and gas facilities would impact visual resources due to their tall structures and glare from lighting. Overall, visual impacts from drilling from shore would be comparable to the proposed project.
Agricultural Resources	0	0	+	Onshore production facility would require new pipelines, potentially crossing agricultural areas.
Air Quality	+	+	+	Construction emissions would increase for all alternatives. Operation emissions would be comparable to the proposed project.
Biological Resources	+	+	+	Increased offshore oil spill probability for a new platform or sub sea completion. Increased onshore spill probability for onshore drilling. The onshore alternative would result in the loss of habitat due to facility and pipeline construction. The pipeline would also require crossing a number of waterways, including the Santa Ynez River.
Cultural Resources	0	0	+	New facilities and pipelines associated with onshore production could potentially affect areas of cultural significance.
Energy	+	+	+	Increased energy consumption for construction and operation of all alternatives.
Fire Protection	+	+	+	Increased risk of fire with new platform and onshore facilities.
Geologic Processes	+	+	+	New facilities associated with each alternative could be adversely affected by geologic processes.
Hazardous Materials/Risk of Upset	+	+	+	Increased risk of oil spill for all alternatives. Onshore drilling site would be in immediate proximity of VAFB launch facilities.
Land Use	0	0	0	Onshore production facilities at VAFB would result in land use changes. However, if such facilities would interfere with Base uses, the Air Force would not allow them to be located within VAFB.
Noise	0	0	+	Construction and operation of onshore production facility would increase local noise levels.
Public Facilities	0	0	+	Onshore production facilities would increase demand for fire protection and emergency response services.

Table 3.1 Screening of Drilling/Production Alternatives

Area of Impact	Would Alternative Substantially Lessen or Avoid Impacts (-), Result in Increased Impacts (+) or Remain About the Same (0) when compared to the Proposed Project?			
	Sub Sea Completion	New Platform	Drilling From Shore	Notes
Recreation	+	+	-	Increased risk of oil spill from new platform and subsea completion could adversely affect coastal recreation. Onshore drilling site might allow Platform Irene and the offshore pipelines to be decommissioned as assumed in the 1985 EIR/EIS, thereby eliminating the potential adverse impacts to recreation from an offshore spill.
Transportation/Circulation	+	+	+	New offshore facilities could affect marine traffic during construction. A new platform would impact marine transportation and safety. The onshore drill site would require increased traffic through VAFB.
Hydrology, Water Resources/Quality	+	+	+	Increased risk of oil spill associated with new facilities could impact onshore water quality.
Marine Biology	+	+	-	New offshore structures would increase risk of oil spill into the marine environment. Drilling from shore might allow Platform Irene and the offshore pipelines to be decommissioned ~~as assumed in the 1985 EIR/EIS~~ at the end of their economic life (assumed to be 2017), thereby eliminating oil spill impacts to marine biota. The VAFB Onshore Alternative would reduce, but not eliminate the potential spill risk into the marine environment.
Oceanographic and Marine Water Quality	+	+	-	New offshore structures would increase risk of oil spill into the marine environment. Drilling from shore might allow Platform Irene and the offshore pipelines to be decommissioned at the end of their economic life (assumed to be 2017),~~as assumed in the 1985 EIR/EIS,~~ thereby eliminating the potential adverse impacts to marine water quality from an offshore spill risk. The VAFB Onshore Alternative would reduce, but not eliminate the potential spill risk into the marine environment.
Commercial/Recreational Fishing	+	+	-	New offshore structures would conflict with commercial fishing. Increased risk of oil spill could adversely affect fishing. The onshore drill site might allow Platform Irene and the offshore pipelines to be decommissioned at the end of their economic life (assumed to be 2017),~~as assumed in the 1985 EIR/EIS~~ thereby eliminating the potential adverse impacts to commercial fishing from an offshore oil spill, and the existing subsea pipelines. The VAFB Onshore Alternative would reduce, but not eliminate the potential spill risk into the marine environment.

3.3.1 Tranquillon Ridge Field Development from a New Offshore Platform

Under this alternative, a new platform would be constructed in State Tideland Waters to develop the Tranquillon Ridge Field. Production from the new platform could be shipped to shore using a new pipeline, or the platform could connect to Platform Irene and use the existing PXP pipelines. The design of the platform would be similar to that for Platform Irene. The platform facilities would include a drilling rig and support equipment, well heads and well head test separators, three phase separators, a flare system, a control room, crew quarters, and various tanks, pumps, and compressors. It has been assumed that 22 to 30 wells would be drilled and that the production and lifetime would be the same as for the proposed project. The oil and gas production would be processed at the LOGP as described for the proposed project (see Section 2.0). The estimated location of the new facilities needed for this alternative is shown in Figure 3-1.

This alternative would not eliminate any of the significant impacts associated with the proposed project. In fact, it would increase the likelihood of an oil spill to the marine environment by adding a new offshore oil platform. It would result in an increase in severity over the proposed project's significant impacts to marine resources by increasing the total volume of offshore vessels and piping that could lead to a marine spill. In particular, the new emulsion pipeline from the new platform to Platform Irene would represent a significant increase in potential oil spill volumes. It is also likely that this alternative would lead to significant air quality impacts during the offshore construction activities. This alternative would also result in substantial, significant visual impacts due to the presence of the new platform.

This alternative would not reduce the expected life extension of the Point Pedernales Facilities that may result with the development of the Tranquillon Ridge Field if Platform Irene is used as a transfer point. Therefore, the oil spill impacts would remain for 30 years. Regardless, Platform Irene would be in production through 2017, and its associated potential for oil spill impacts would also remain.

Clearly, the development of oil and gas reservoirs from existing platforms using extended reach drilling is environmentally preferred when compared to a new platform. This type of development strategy utilizes the existing infrastructure to the maximum extent feasible. For the reasons stated above, this alternative has been dropped from further consideration.

3.3.2 Tranquillon Ridge Field Development from Subsea Completion with Connection to Platform Irene

This alternative would involve developing the oil and gas wells from a drill ship using subsea completions that would be connected to Platform Irene or the shore using subsea flow lines. This alternative would basically be the same as installing a new platform, except the visual impact would only occur during development drilling, reworking, redrilling, and/or abandonment activities, in aggregate.

The environmental impacts associated with this alternative would be significant because new flow lines would have to be laid along the sea floor from each subsea location to Platform Irene or from each subsea location to shore. Also, given the nature of the Tranquillon Ridge reservoir, this alternative is not feasible because down-hole submersible pumps and gas lift are to be used as a means of recovery to enhance oil and gas production. This type of recovery is critical to the full development of these types of reservoirs. In addition, servicing of the wells (e.g., pump changes) would have to be done using drill ships, which would have to be available throughout the life of the project. These drill ships would result in significantly higher air emissions than the proposed project. Given the technical difficulties associated with the subsea completions into Monterey type formations, the lack of ability to adequately maintain the wells, and the inability to use secondary recovery techniques, this alternative has been dropped from further consideration as technically infeasible.

3.3.3 Tranquillon Ridge Field Development Using Extended Reach Drilling Technology from VAFB (VAFB Onshore Alternative)

Background

The VAFB Onshore Alternative was considered in the 2002 Torch EIR, but eliminated from further consideration ~~because VAFB considered such a commercial project~~ as infeasible at the time because it might interfere with Base operations. However, in March 2006, Sunset Exploration, Inc. and Exxon Mobil Corporation submitted applications to Santa Barbara County, CSLC, and VAFB for development of the Tranquillon Ridge Field from an onshore site within VAFB. The County has deemed the application incomplete and VAFB has agreed to review the project in accordance with its Base Unit Beddown Program ~~Site Survey Process~~ to determine if the project would conflict with current and future Base operations. Because applications have been filed for a project that would develop the Tranquillon Ridge resources from VAFB, such development should be considered, under CEQA, a potentially feasible alternative to the proposed project. As such, this EIR evaluates an onshore development alternative to the proposed project. The ~~current~~VAFB Onshore Alternative examined herein is a conceptual alternative whose features were developed with the intent of avoiding or reducing environmental impacts of the proposed project.~~based to some extent on the Sunset/ExxonMobil application, although an independent analysis of alternative features was conducted (such as pipeline and transmission line alignments, and produced water disposal).~~

Alternative Description

The VAFB Onshore Alternative considers the construction and operation of an onshore drilling and production facility located on southern VAFB near Point Pedernales, about 10 miles southwest of Lompoc. The Tranquillon Ridge Field offshore reserves would be produced using directional drilling technology. Given the constraints of existing directional drilling technology (i.e., distance and depth), it is assumed that the drilling site would be located approximately seven miles south of the Santa Ynez River within a 75-acre area bound by Coast Road to the west and south, Surf Road to the east, and Delphy Road to the north (see Figure 3-2). Approximately 25 acres of the 75-acre area would be required for the drilling and production facilities.

The Union Pacific Railroad (UPRR) is located west of Coast Road and the VAFB Space Launch Complex 5 (SLC-5) is located east of Surf Road. Moving the onshore drilling and production facility to the west of Coast Road would be constrained by the UPRR tracks and available acreage and could result in additional potential impacts to marine resources, given the closer proximity to the coast. Moving the onshore drilling and production facility to the east of Surf Road would be prohibited by SLC-5, and moving the onshore facility to the northeast of Surf Road would be constrained by higher elevation. Given that the northeast location is also further from the Tranquillon Ridge Field, the combination of increased distance and elevation could compromise the full development of the field. Honda Canyon and its associated creek and biological resources are located to the south. South of Honda Canyon is SLC-6, a major launch site, and its supporting facilities. Therefore, no further consideration of these alternative onshore drilling locations was given.

The VAFB Onshore Alternative considers the construction of up to 30 well slots, production well heads, piping and well test facilities, an oil dehydration facility including a Wet Lease Automatic Custody Transfer (LACT), and a gas compression and dew point control plant, within the alternative site. It is assumed that the drilling rig would be approximately 180 to 200 feet high. As noted, approximately 25 acres would be required for the onshore drilling and production facilities, of which approximately 5 acres would be reserved for a water cleaning and injection plant. This water treatment/injection facility would be necessary if offshore disposal of produced water at Platform Irene is prohibited by federal regulations or if re-injection of produced water is prohibited at the ~~LOGP~~ Lompoc Oil Field because of limited capacity. The LOGP water treatment facility currently processes approximately 10,000 to 20,000 bpd and is permitted to expand to 80,000 bpd. The analysis of the VAFB Onshore Alternative considers the following scenarios with respect to disposal of produced water. All of these scenarios have been carried forward in Section 5.0 for analysis.

- Produced Water Scenario 1: Re-injection or ocean discharge of produced water from Platform Irene. The projected life of Platform Irene without development of Tranquillon Ridge is assumed to be approximately 10 years. Under this scenario, water and oil produced from the onshore drilling and production site would travel to the LOGP via the alternative emulsion pipeline and existing PXP emulsion pipeline (see Figure 3-2). Once the oil is separated from the emulsion at the LOGP, the remaining produced water would be treated at the LOGP and sent to Platform Irene in the existing PXP produced water pipeline.
- Produced Water Scenario 2: Construction of a water cleaning and injection plant within the alternative drilling and production site, requiring approximately 5 acres, to be used over the life of the facility. Treated water would be re-injected from the onshore drilling and production site. The dry oil would be sent to the LOGP via the alternate emulsion pipeline and existing PXP emulsion pipeline for further processing.
- Produced Water Scenario 3: Initial re-injection of produced water ~~at~~ in the Lompoc Oil Field ~~LOGP~~, but when capacity constraints warrant (assumed to be 6 years), construction of a water cleaning and injection plant within the alternative drilling and production site. During initial re-injection of the produced water ~~at~~ in the Lompoc Oil Field ~~LOGP~~, the water and oil produced from the onshore drilling and production site would travel to the LOGP via the alternative emulsion pipeline and existing PXP emulsion pipeline (see Figure 3-2). Once the oil is separated from the emulsion at the LOGP, the remaining produced water would be re-injected ~~at~~ in the Lompoc Oil Field ~~LOGP~~. When capacity constraints warrant, all produced water would then be handled at the onshore drilling and production site water cleaning and injection plant. The dry oil would be sent to the LOGP via the alternate emulsion pipeline and existing PXP emulsion pipeline for further processing.

Production from the VAFB Onshore Alternative is assumed to peak at around 27,000 bbl/day of oil and 5 mmscfd of gas, the same as for the proposed project.

Twenty ~~20~~-inch oil emulsion and 8-inch gas pipelines would be required to connect the VAFB onshore drilling and production facility to the existing PXP pipelines, allowing final transport of produced emulsion and gas from the onshore drilling site to LOGP for processing. It is assumed that the pipelines would be placed in a common right-of-way, and that the pipeline construction corridor would vary from 25 to 75 feet depending on the presence of sensitive environmental resources, utilities, and other existing physical obstacles. Maintaining a 25-foot wide corridor is very difficult because it would eliminate passage of equipment through the area under construction. This is especially problematic when refueling is necessary and/or when large equipment needs to turn around. Therefore, an average 50-foot construction corridor is assumed. In addition, the adjacent roadways would be utilized for equipment passage. It is further assumed that all waterway, rail, and roadway crossings would be accomplished either by bore or horizontal directional drilling. In addition, it is assumed that the directional drill depth underneath the Santa Ynez River would be a minimum of 40 to 50 feet to prevent pipeline exposure due to scouring. Finally, access routes to the construction corridor and material/ equipment staging areas would be required for construction. Approximately 10 weeks would be required for the installation of the VAFB Onshore Alternative pipelines. Manpower requirements are estimated to be about 60 persons with construction ongoing 6 days per week, 12 hours per day. It is assumed that all access routes and staging areas will be located within previously disturbed areas which are devoid of resources. The analysis of the VAFB Onshore Alternative considered the following potential pipeline alignments.

- Pipeline Scenario 1: The pipelines would follow Surf Road to Bear Creek Road at which point they would turn west to Coast Road. The pipelines would then follow Coast Road in a northerly direction until Coast Road turns into Highway 246, at which point the pipelines would follow Highway 246 in an easterly direction to 13th Street (see Figure 3-3). At 13th Street, the pipelines would travel north until they reach the existing PXP pipelines just west of 13th Street (near Milepost 4.5 of the PXP pipeline system). It is assumed that approximately ten miles of pipeline construction would be required. Pipeline Scenario 1 is being carried forward for analysis in Section 5.0 of this EIR.
- Pipeline Scenario 2: Pipeline Scenario 2 is the same as Pipeline Scenario 1 except that the pipelines would leave the drilling and production site and follow Coast Road, instead of traveling along Surf Road (see Figure 3-4). Based on VAFB consultation, Coast Road south of Bear Creek Road is a main thoroughfare for launch operations and therefore is not considered a viable option by VAFB. Based on the greater potential for conflict with VAFB operations and mission, no further consideration of Pipeline Scenario 2 is being given.
- Pipeline Scenario 3: Pipeline Scenario 3 is the same as Pipeline Scenario 1~~2~~ except that the pipelines would take a cross country route north of Bear Creek Road to connect to either Highway 246 or 13th Street (see Figure 3-5). The area bound by Bear Creek Road to the south, Coast Road to the west, Highway 246 to the north, and Arguello Road to the east contains critical infrastructure for launch, range, and defense operations based on VAFB consultations. Further, some of the oldest cultural sites on VAFB are located within this area. Finally, since much of the area has been undeveloped, the likelihood of encountering threatened and endangered species is greater than within lands along the roadways and potential biological impacts would likely be greater with this scenario than others. Therefore, no further consideration of Pipeline Scenario 3 is being given.
- Pipeline Scenario 4: Under Pipeline Scenario 4, the pipelines would travel along Surf Road to Bear Creek Road, where they would travel east until Arguello Road. At Arguello Road the pipelines would turn north until their connection to the existing PXP pipelines just west of 13th Street (see Figure 3-6). Based on consultations with VAFB, the lands along Bear Creek and Arguello Roads are located

within an Unexploded Ordnance area. As a result, VAFB does not consider Pipeline Scenario 4 a viable option and no further consideration of this option is being given.

- Pipeline Scenario 5: Under Pipeline Scenario 5, the pipelines would travel north within the Union Pacific Railroad (UPRR) right-of-way to Highway 246, then east to 13th Street where they would turn north and continue to their connection point with the existing PXP pipelines (see Figure 3-7). The UPRR right-of-way is severely constrained in areas where extensive fill was used to elevate the tracks above Bear Creek and numerous drainages. Further, the UPRR right-of-way is directly adjacent to the coast, presenting a greater risk of marine impacts as a result of construction and during a pipeline leak. Therefore, no further consideration of this alternative is given.
- Pipeline Scenario 6: Pipeline Scenario 6 is the same as Pipeline Scenario 5 except that the pipelines would travel within the UPRR right-of-way to just north of the Santa Ynez River, where the pipelines could tie into PXP Valve #1 (see Figure 3-8). Because of the extensive biological resources associated with the estuary at the river mouth and for the reasons noted under Pipeline Scenario 5, no further consideration of this potential alternative was given.

As presented under Pipeline Scenario 1, the pipelines would tie into the existing PXP pipelines just west of 13th Street. A tie-in station would be required for the tie-ins into the PXP pipelines.~~could be at such a radius that would allow continuous travel of pipeline pigs and therefore the tie-ins could be placed underground. The tie-in connection would have the appropriate valve connections to block pipeline flow from the VAFB Onshore Alternative while the pipeline between Platform Irene is internally inspected or maintained~~. Two pipelines, a 20-inch oil emulsion pipeline and an 8-inch sour gas pipeline from the VAFB Onshore Facility would tie in to PXP's existing 20-inch oil emulsion and 8-inch sour gas pipelines from Platform Irene. The equipment necessary at the tie-in station would consist of:

- **Block valves:** Isolation block valves would be installed on each pipeline for operational flexibility as well as maintenance.
- **Metering Skids**: Four separate gross fluids metering skids would be required to measure the individual production for each pipeline.
- **Pig Receiving Facilities**: Four separate pig receiving facilities to receive maintenance pigs and smart pigs for each pipeline. Each facility would comprise a pig receiver and pigging fluid handling vessel.
- **Pig Launching Facilities**: The 20-inch and 8-inch emulsion and gas pipelines would be equipped with pig launchers to pig the pipelines from the tie-in station to the LOGP.
- **Overpressure Protection**: Pressure safety valves (PSVs) installed on each receiver, pigging fluid handling vessel and launcher would protect each system from overpressure. The PSVs on the gas pipeline systems would relieve to safe atmospheric locations. The PSVs on the liquids handling systems would relieve to a drain system designed to handle these releases.
- **Disposition of the collected fluids**: The pigging fluids collected in the vessels could be oil emulsion, liquid sludge, hydrocarbon condensate (gas-liquids) or solids. These fluids would either be pumped back into their respective pipelines or trucked to LOGP for processing or to a disposal site, depending on the nature of the fluid. Vacuum truck access would be provided on each vessel.
- **Purging and Depressuring**: Each pig receiving and launching facility would be purged or depressured to atmosphere by routing through a carbon canister system to remove hydrocarbons and acid gases (H_2S, Mercaptans, etc.).
- **Emulsion Pipeline Pumps**: If additional pumping capacity is required for the existing PXP emulsion pipeline to accommodate the potential dry oil volumes associated with the VAFB Onshore Alternative (see Produced Water Scenarios 2 and 3), it is assumed that three pumps would be installed

at the tie-in station and that the pumps would be similar in size as those potentially required for the proposed project, Valve Site #2. Further, power requirements would be comparable to that required for Valve Site #2 pump installation and power would be extended to the tie-in station using one of the potential substation sites and power line alignments illustrated on Figure 3-10.

The approximate size of the tie-in station facility would be 150 feet x 150 feet. The station would provide access for the pig receiving, launching, and vacuum truck equipment. With the installation of this tie-in station, each pipeline could be operated, monitored and maintained separately by each operator (PXP and VAFB Onshore Facility), and the common pipelines operated and maintained jointly.

To provide electricity to the VAFB Onshore Alternative site, construction of a six-mile 69 kV transmission line tying into a new 115 kV/69 kV substation, ~~at or near~~ adjacent to and to the south of the existing substation at Surf Beach, is assumed. The substation would receive power from the existing PG&E 115 kV power system that currently feeds the existing Surf substation. The substation site would be approximately one acre in size and substation components would vary in height up to 35 feet maximum. The analysis of the VAFB Onshore Alternative considered the following two power line alternatives.

- Power Line Scenario 1: The 69 kV power would be routed from the new Surf Substation to the VAFB Onshore Alternative Site via a new overhead power line that would be constructed for approximately 6 miles along Coast Road, to Bear Creek Road, to Surf Road (see Figure 3-9). Power Line Scenario 1 is being carried forward for analysis in Section 5.0 of this EIR.
- Power Line Scenario 2: Power Line Scenario 2 is the same as Power Line Scenario 1 except that the power line would be placed underground within the new oil and gas pipeline right-of-way. Transmission lines do generate electro-magnetic frequencies (EMF), and by placing the 69 kV transmission line underground within the pipeline right-of-way, the EMF could interfere with the oil and gas pipeline cathodic protection and pigging magnetic systems, as well as VAFB communication systems. In addition, there are numerous overhead distribution lines throughout the onshore alternative study area and as a result, Power Line Scenario 2 offers little benefit in the reduction of visual impacts in the area. Therefore, no further consideration of Power Line Scenario 2 is being given.

In addition, the analysis of the VAFB Onshore Alternative considered the provision of power from sources supplying existing Base infrastructure, such as SLC-5. However, based on discussions with VAFB, they would not allow PXP to use power that is generated by the Base for their power line to Valve Site #2 due to operational and security concerns. Cogeneration was also considered. While cogeneration could be incorporated into the drilling/production facility design, it is unclear if it would be economically feasible. For purposes of analysis of this alternative, it is assumed that cogeneration would be incorporated into the 25-acre facility footprint.

It is assumed that natural gas will be conveyed to the alternative site via a connection to the existing VAFB gas utility pipeline located in Coast Road, adjacent to the site. Natural gas would be used for some of the drilling/production facilities. Finally, it is assumed that potable water will be provided to the alternative site by VAFB.

Oil and gas production from the VAFB Onshore Alternative is assumed to match the available permitted processing capacity at the LOGP, making use of the existing LOGP equipment, some of which is currently out of service but could be recommissioned. All modifications required at the LOGP as part of the proposed project would still be required with this alternative. Further, shipment of processed crude oil from LOGP to the Santa Maria Refinery in San Luis Obispo County and shipment of sales-quality natural gas to the Gas Company via the existing sales gas metering station at LOGP is assumed, consistent with present operations at LOGP. The life of the onshore drilling and production facility is assumed to be 30 years.

Construction of an onshore drilling and production facility on VAFB would require Air Force approval per the Air Force Base Unit Beddown Program. The Beddown process is necessary to determine the full extent of impacts to base operations and personnel and to manage these impacts properly. Safety, environmental, and operational impacts are analyzed in depth. The final decision on whether or not to "Bed Down" a commercial operation rests with the Secretary of the Air Force. ~~As part of their review, VAFB would conduct a formal Site Survey. The purpose of the Site Survey is to determine the potential impacts of the project on the present and future Air Force operations at VAFB. For example, design considerations related to the facilities' location within over-flight areas of SLC-3, SLC-4, and SLC-5 would be considered. The Site Survey process also would involve having the various departments at VAFB (i.e., operations, safety, transportation, environmental, etc.) review the subject facility. The Site Survey process would involve iterative steps to identify and incorporate measures to reduce potentialoperations, safety, and environmental conflicts to the maximum extent feasible. After the Site Survey, the proponent would submit a "Beddown Request" to the Secertary of the Air Force. The Air Force would then determine if an onshore drilling and production facility is compatible with VAFB operations and mission and either accept or deny the request.~~

3.4 Alternative Processing Locations

Alternatives to oil and gas processing at the LOGP were also evaluated. These alternatives include:

- Gaviota Oil Heating Facility (GOHF),
- Las Flores Canyon, and
- Casmalia Canyon/Oil Field.

Each of these alternatives are summarized below. The screening analysis for the alternative processing locations is presented in Table 3.2. The results of the screening analysis for each of the alternative production locations are also presented below.

3.4.1 Gaviota Oil and Gas Plant

Oil is heated, metered, and transferred to the Plains All-American Pipeline (Plains AAPL) at Gaviota. No oil or gas processing occurs at GOHF. Oil and gas processing at PXP's Point Arguello Project facilities at Gaviota would require the construction of subsea emulsion and sour gas (contains hydrogen sulfide, which is corrosive) pipelines between Platform Irene and Platform Hidalgo. Figure 3-1 shows the locations of the new project components that would be required for this alternative. Since Point Arguello Field crude oil is dehydrated on Platforms Harvest and Hermosa prior to shipment to shore in the Point Arguello oil pipeline, additional oil

Table 3.2 Screening of Processing Location Alternatives

Area of Impact	Would Alternative Substantially Lessen or Avoid Impacts (-), Result in Increased Impacts (+) or Remain About the Same (0) when compared to the Proposed Project?			
	Processing at Gaviota Facility	**Processing at Las Flores Canyon Facility**	**Processing at new Casmalia Facility**	**Notes**
Aesthetic/Visual Resources	-	-	+	Both alternatives might allow the LOPG to be decommissioned ~~as assumed in the 1985 EIR/EIS~~ at the end of its economic life (assumed to be 2017), thereby eliminating or reducing the potential adverse impacts to visual resources due to nighttime glare. With the Casmalia site there would be a new source of nighttime glare, and there would still be nighttime glare at the LOGP due to the remaining equipment.
Agricultural Resources	+	+	+	New onshore pipelines would likely traverse agricultural areas to reach new onshore processing facility.
Air Quality	+	+	+	A new Casmalia facility would result in increased construction and operational emissions. The Las Flores Canyon and Gaviota sites would result in substantial offshore and onshore pipeline construction emissions. Operational emissions in Las Flores Canyon and at Gaviota might have to increase. There would be increased air emissions on Platforms Irene and Hermosa due to the need to process the oil and gas offshore for the Gaviota alternative.
Biological Resources	+	+	+	Offshore and onshore pipelines to Las Flores Canyon and Casmalia would increase oil spill risk. Onshore construction of new facilities and pipelines would likely affect sensitive species and/or habitats.
Cultural Resources	+	+	+	New facilities and pipelines could potentially affect areas of onshore and offshore cultural significance.
Energy	+	+	+	Increased energy requirements to transport oil/gas to LFC or Gaviota. Increased construction and operation energy use for new onshore processing facilities.
Fire Protection	+	+	+~~0~~	The risk of fire associated with new Casmalia onshore processing facility would~~be the same as for the LOGP~~ increase given that a portion of the LOGP would remain operational in addition to the new Casmalia processing facility and associated pipelines. For the Gaviota and Las Flores site the addition of new oil and gas pipelines would increase the potential for fires and the need for emergency response.
Geologic Processes	+	+	+	New onshore facilities and pipelines could adversely affect geologic processes. All of these alternatives would involve the construction of new onshore pipelines.

Table 3.2 Screening of Processing Location Alternatives

Area of Impact	Would Alternative Substantially Lessen or Avoid Impacts (-), Result in Increased Impacts (+) or Remain About the Same (0) when compared to the Proposed Project?			
	Processing at Gaviota Facility	Processing at Las Flores Canyon Facility	Processing at new Casmalia Facility	Notes
Hazardous Materials/Risk of Upset	+	+	+	Increased risk of oil spill for all alternatives due to increase in the length of oil pipelines. Increased public safety risk due to potential sour gas release from new pipelines from LOGP to Casmalia site and sour gas compressor and oil shipping stations that would remain in operation at the LOGP. Casmalia site would be expected to have the same risk of upset impacts as the existing LOGP. Use of new pipelines would offset some of the increased risks.
Historic Resources	0	0	0	No impact on historic resources expected.
Land Use	0	0	0	Land use would be consistent with all County land use policies.
Noise	0	0	+~~0~~	The noise levels at the Casmalia site would be expected to be the same as for the LOGP. The pump and compressor station at the LOGP would still generate some level of noise.
Public Facilities	0	0	+	New onshore processing facilities at Casmalia would increase demand for fire protection services. This demand would be partially offset by the decommissioning of a major portion of the LOGP.
Recreation	+	+	0	Increased risk of oil spill from offshore pipelines could adversely affect coastal recreation.
Transportation/Circulation	0	0	0	Potential impacts not substantially different except during construction, which is viewed as temporary.
Hydrology, Water Resources/Quality	+	+	+	Increased risk of oil spill associated with new offshore and onshore pipelines could impact water quality.
Commercial/Recreational Fishing	+	+	0	New offshore pipelines would conflict with commercial fishing. Increased risk of oil spill could adversely affect fishing.

dehydration equipment would be required on Platform Irene and/or Platforms Harvest and Hermosa. Additional pipelines would also be needed between Platforms Hidalgo and Hermosa to accommodate the oil and gas.

In addition, the Point Arguello gas pipeline from Platform Hermosa to the Gaviota Facility is currently moving sweet gas (contains little hydrogen sulfide, non-corrosive). In order to handle the gas from Platform Irene, gas-sweetening equipment would need to be installed on Platform Irene, or the gas would have to be injected. The gas and oil from Platform Irene would be commingled with the Point Arguello production at Platform Hermosa and then shipped via pipeline to the Gaviota Facilities. At Gaviota, the oil would be heated, temporarily stored, and then transferred to the Plains All-American Pipeline (Plains AAPL) for transport to various refining locations. The gas would be burned at the Gaviota cogeneration facility or sold to The Gas Company.

The GOHF alternative would require additional pipelines between Platforms Hidalgo and Hermosa to accommodate increased crude oil transport. In addition, the gas pipeline from Platform Hermosa to the Gaviota Facility is currently moving only sweet gas. In order to handle the gas from Platform Irene, gas-sweetening equipment would need to be installed on Platform Irene, as well as acid gas injection equipment to dispose of the acid gas generated in the gas sweetening process. Also the oil pipeline to Gaviota moves dry oil and its use for Tranquillon Ridge oil would require the installation of oil dehydration equipment on Platform Irene. Given the limited space available on Platform Irene, it would not be possible to add oil dehydration and gas sweetening equipment. Therefore, this alternative processing site is considered technically infeasible and has been dropped from further consideration.

3.4.2 Las Flores Canyon

This alternative would involve processing the Tranquillon Ridge oil and gas at ExxonMobil's Las Flores Canyon facilities. This would require the construction of new oil emulsion and gas pipelines from Platform Irene to the Las Flores Canyon site. It would not be possible to use the existing Point Arguello oil and gas pipelines since they are in dry oil and sweet gas service, respectively. It is assumed that the gas pipeline would be run entirely offshore, and the oil pipeline would landfall at Point Conception and follow the Arguello oil pipeline route across Bixby and Hollister Ranches to the Gaviota site. A new wet oil pump station would need to be built at the Gaviota site. The wet oil would then travel via a new pipeline from Gaviota to Las Flores Canyon following the existing Plains AAPL right-of-way. The wet oil and the sour gas would be processed in the existing Las Flores Canyon facilities. Figure 3-1 shows the locations of the new project components that would be required for this alternative. Currently, the gas plant is operating at its permitted capacity (75 million standard cubic feet per day [mmscfd]). There would not be sufficient capacity to handle the Tranquillon Ridge gas production without backing out Santa Ynez Unit (SYU) production.

This alternative would require about 30 miles of new emulsion and sour gas pipelines. In the proposed project, it is assumed that with the Tranquillon Ridge development the peak produced water volume from Platform Irene could reach 60,000 bpd. Given the current produced water treatment capacity at Las Flores Canyon (60,000 bpd), it is unlikely that the produced water from Tranquillon Ridge could be handled without an increase in produced water treatment capacity or backing out SYU production. It is also unlikely that the volumes of produced water from Tranquillon Ridge could be ocean discharged as is currently occurring at the Las Flores Canyon facility without exceeding National Pollutant Discharge Elimination System (NPDES) permit limits.

The Las Flores Canyon alternative would eliminate all of the significant onshore impacts associated with the extension of life of the Point Pedernales facilities that could result from the Tranquillon Ridge Project. At the end of the productive life of the Point Pedernales field, the LOGP and the pipeline from Irene to the LOGP could be decommissioned. However, Platform Irene would continue to produce from the Tranquillon Ridge Field and offshore impacts associated with extending the life of the Platform would occur.

This alternative would greatly increase the severity of the significant impacts to marine resources and recreation over the proposed project due to the substantial increase in length of offshore wet oil pipelines and potential for significant oil-spill related impacts to occur. This alternative could also have significant construction impacts in the areas of air quality, onshore biology, cultural resources, and onshore water resources.

This alternative has been dropped from further consideration because it would result in significant impacts that would be much more severe than the proposed project, even though it might allow for an earlier decommissioning of the LOGP and associated pipelines than with the proposed project.

3.4.3 Casmalia Canyon/Oil Field

The Santa Barbara County North County Siting Study identified several onshore processing locations that could serve as possible consolidated oil and gas processing facilities in the North County (North County Siting Study, October 2000). Specifically, potential sites in the Casmalia oil field and Casmalia Canyon are more rural and would potentially result in lower impacts than the LOGP facility. Two potential Casmalia sites for oil and gas processing were identified in the North County Siting Study. For the purpose of this analysis, the Casmalia East site was chosen since it could minimize the length of new pipeline that would need to be built.

Oil and gas processing at this site would require the construction of completely new processing facilities and additional pipelines. Ten to fifteen miles of new emulsion and sour gas pipelines would need to be constructed from the LOGP to the Casmalia site. From LOGP the pipelines would initially follow the existing ConocoPhillips pipeline right-of-way to Orcutt. The pipelines would then run west to the Casmalia site. A new dry oil pipeline would have to be built from the Casmalia site to the ConocoPhillips Orcutt Pump Station. The pipeline routes are detailed in Appendix B.

In addition, a new gas compressor station and wet oil pump station would need to be built at the LOGP site to move the wet oil and sour gas to the Casmalia site. Pumps would also be needed to move the produced water back to Platform Irene for injection. Figure 3-1 shows the locations of the new project components that would be required for this alternative.

Approximately 20 acres of land would be needed to build the new oil and gas processing facility. It has been assumed that a facility identical to the LOGP would be built at the site in order to handle the peak production of 100,000 bpd of total liquids as assumed in the proposed project. (See ~~Chapter~~ Section 2.0 for a description of the LOGP facilities.)

Use of the Casmalia site would allow for the early abandonment of most of the equipment at the LOGP. Decommissioning of most of the LOGP would reduce the severity of the significant visual impact due to nighttime glare that would occur if the expected lifetime of the LOGP was extended due to the Tranquillon Ridge Project. However, the nighttime glare impact would most likely remain significant with this alternative since a pump and compressor station would still be needed at the LOGP, and there would be nighttime glare associated with the new Casmalia site.

With this alternative, the sour gas, emulsion, and produced water pipelines from Irene to the LOGP would remain in service. New sour gas, emulsion, and produced water pipelines would have to be built from the LOGP to the Casmalia site. These new pipelines would result in new significant onshore biology, onshore water resource, and public safety impacts.

Even with these new significant environmental impacts, this alternative has been selected for evaluation throughout the EIR. The main driver for selecting this alternative processing site is the potential early decommissioning of the LOGP. In addition, this was one of the preferred oil and gas processing sites identified in the North County Siting Study (October 2000) for future offshore development projects. The Casmalia East site was found to be the most environmentally preferable site for an oil and gas processing facility that would support new offshore oil and gas development projects for the northern leases within the Santa Maria Basin.

3.5 Alternative Oil Emulsion Transportation

The only alternative identified for alternative oil emulsion transportation to the existing PXP emulsion line from Platform Irene to LOGP was the replacement of the existing line with a new pipeline. This alternative is described below and ~~will be~~ carried forward for analysis in Section 5.0.

3.5.1 New Oil Emulsion Pipeline Alternative

This alternative involves transporting oil produced from the Tranquillon Ridge Field by way of a new pipeline, which would replace the existing oil emulsion pipeline from Platform Irene to the LOGP. The primary objective of this alternative would be to address potential impacts associated with the integrity (cracking and corrosion) of the existing pipeline as a result of the extended project life associated with the proposed project. The new oil emulsion pipeline would have the same diameter (20 inches) as the existing pipeline. To minimize new construction impacts, the existing onshore section of the oil emulsion pipeline would be removed and the new pipeline would be installed in the same location as the existing pipeline. The existing offshore oil emulsion pipeline would be decommissioned in place and the new pipeline would be installed parallel and immediately adjacent to the existing pipeline corridor. The ultimate fate of the decommissioned pipeline (i.e., abandonment in place versus removal) would be determined in a future environmental review when the other pipelines in the corridor are abandoned. All other components of this alternative would be the same as for the proposed project.

The new oil emulsion pipeline would be capable of moving 100,000 bbls of fluid (i.e., oil and water) at a higher design maximum allowed operating pressure (MAOP) than the existing pipeline which has been de-rated (~~or~~ required to operate at reduced pressure) as per Department of Transportation (DOT) requirements, due to corrosion concerns. This alternative would eliminate the need for installing pumps at Valve Site #2 and the associated ~~transmission~~ power lines to provide electrical service to these pumps. The new oil emulsion pipeline could also be installed with a greater wall thickness, which would protect the pipeline's capacity from de-rating due to corrosion.

Installing the new pipeline would occur in two phases: installing the offshore portion (Phase 1) of the pipeline, and installing the onshore portion (Phase 2) of the pipeline. These two phases would be conducted simultaneously. Work on this alternative would involve shutting down the Point Pedernales operations for 2 to 3 months to allow for removal of the existing onshore pipeline, installing the new pipeline onshore and offshore, and tie-in and testing. The offshore and onshore phases are discussed below. Information related to installing the pipeline is based primarily on the 1985 Point Pedernales EIR.

The pipeline replacements would be designed and built to meet or exceed all codes, specifications, and requirements set forth by but not limited to ANSI, ASME, ASTM, DOT, API, NACE, and MMS. The pipeline would be manufactured from welded steel in accordance with API requirements. The pipe would be ultrasonically mill inspected for defects prior to being shipped. All pipe would have an external fusion bonded epoxy protective coating to help prevent and control corrosion. All valves and fittings would be manufactured from steel and meet or exceed all design requirements.

As the pipeline would be exposed to a hydrogen sulfide (H_2S) environment, the pipe mill specification and welding criteria would meet the best standards for H_2S service to ensure that the pipe can withstand stress corrosion. The National Association of Corrosion Engineers publishes standards for this type of service (MR-0175) applicable to sour crude oil above 50~~265~~ psig.

3.5.1.1 Offshore Pipeline Installation

The offshore portion of the Irene to LOGP oil emulsion pipeline is approximately 10.1 miles long, of which 2.0 miles is in Federal Waters. The pipeline route leaves the platform on a northeasterly course heading for the coast on the most direct route to the existing onshore alignment. The existing offshore alignment is virtually "line-of-sight" and avoids crossing any other adjacent Federal tracts.

Shallow hazard studies by McClelland Engineers before installation of the original offshore pipelines showed that the platform site and the entire pipeline route (as well as the surf zone area), have a sandy firm bottom with only minor rock outcroppings. No existing lines or cables are crossed.

The pipeline has a landfall approximately ½ mile north of the Santa Ynez River, north of the sand dunes and south of the cliffs. At this point, the new offshore pipeline segment would be tied into the new onshore pipeline segment.

While the exact method used for installing a new offshore pipeline is not known, it could be done using a pull barge method or with a dynamic positioning pipe laying vessel. With the pull barge method, the pipeline is constructed offshore on a stationary (i.e., anchored) lay barge and then pulled off the barge by tug boats to the installation site. With the dynamic positioning vessel, no anchors or tugs are needed since the vessel uses its own set of engines to keep the vessel positioned over the pipeline corridor. Most offshore pipelines are now installed using dynamic positioning vessels. The original offshore Point Pedernales pipelines were ~~installed using the lay barge method~~.welded on the beach and then pulled into position using a barge and tugs. For the purpose of this analysis, it has been assumed that the offshore pipelines would be installed using the ~~dynamic positioning~~pull barge method given the sandy ocean bottom along the length of the existing PXP offshore pipelines.

The new oil emulsion pipeline would be the same size as the existing pipeline but may have a thicker wall to provide additional allowances for corrosion and potentially allow for increased operating pressures.

The pipe would be delivered from the Los Angeles area to Port Hueneme by rail car or truck, and then loaded onto special barges for delivery to the installation site. The flotation buoys used for buoyancy would be trucked to Port Hueneme from either the Los Angeles or Oxnard area, and loaded on another special barge and transported to the construction site.

The pipe laying vessel would be outfitted at Port Hueneme with all necessary equipment and support gear for welding and installing the pipe. This equipment would include welding machines, coating materials for joints, lifting equipment, navigation and X-ray equipment. At the completion of outfitting, the vessel would move offshore to the project site. Approximately half the manpower would move to the site onboard the vessel with the remainder being flown from the Santa Maria area by helicopter.

The new pipeline would be installed immediately adjacent to the existing pipeline corridor consisting of three pipelines (oil emulsion, gas, and produced water). The pipelines would be laid or buried in the designated right-of-way (200 feet wide) using navigation equipment. Pursuant to agency requirements, the existing emulsion pipeline would be pigged, evacuated, flushed, capped, filled with a scavenger solution and abandoned in place prior to installing the new emulsion pipeline.

The vessel would start laying the pipe just outside of the surf zone and move toward the platform. Each weld would be X-rayed for integrity and compliance with API-1104. If a defect were found, it would be repaired and then X-rayed again to insure compliance. Upon acceptance of the weld, joint material would be applied to insure a homogenous coating.

When the pipeline has been laid from the surf zone to the platform, then the remainder of the pipeline would be laid between the vessel and the onshore tie-in location. This would require concrete coated pipeline to be laid through the surf zone to be tied into the onshore pipeline system.

A "hard tie" (welded connection) is desired between the surf zone and offshore pipelines. This would be done by lifting the ends of the lines onto the vessel, making and X-raying the weld, and then laying the line back on the ocean floor. This procedure can be used in relatively shallow water; however, in deeper water, spools must be fabricated between pipeline sections.

The pipeline would be buried to a depth of 5 feet to –15 feet below the mean low water level through the surf zone (from shore up to 4,000 feet offshore) by divers using hand held “air jets.”

These jets pump seawater under the pipeline to displace the sand. This action would bury the line to a depth of 3 to 6 feet.

The pipeline would terminate approximately 30 to 50 feet from the existing pipeline risers on the platform. Water depth at this point is 242 feet from the mean low water line. Divers using a "template" and diving off the pipeline barge would set spools to connect the pipelines to the risers as well as replace the “J” tube risers, which would have been previously removed from the existing pipeline. A "template" is an adjustable telescoping device that is bolted to the flanges on the lead end of pipelines and the flanges at the bottom of the platform risers. From the template, a pipeline spool or connection can be made to fit between the two flanges. Divers using hydraulic impact wrenches would connect the flange connections.

After the offshore pipe-laying operations are completed, a sidescan sonar scan survey and a post construction biological/hard bottom survey would be conducted to verify that the pipeline was not damaged, that it was positioned properly on the ocean floor, that no unsupported “spans” exist which could cause excessive stresses, and that the ocean floor was not adversely altered by the operation. Corrective measures would be carried out if necessary.

Schedule and Equipment

About 7.5 weeks would be required to construct the offshore portion of the pipeline using a maximum work force of 60 persons and assuming construction would occur 12 hours per day, 7 days per week. The offshore construction would require one supply boat trip from Port Hueneme every five days and one helicopter trip from the Santa Maria Airport every day to the construction site. Equipment and duration are shown in Table 3.3.

Table 3.3 Offshore Pipeline Installation Equipment and Duration

Equipment Item	Number	HP Rating	Duration, Days
Tug Boat	1	3000	53
Lay Vessel	1	3000	53
Supply Barge	1	800	53
Supply Boat	1	2200	11
Helicopter	1	1400	53
Crane	1	120	53
Welding Machine	7	40	53
Air Compressor	2	30	53
Test Pump	1	75	2

Source: Adapted from the 1985 Point Pedernales EIR/EIS Air Quality Appendix B Volume 1. Equipment numbers reduced for single pipe installation, duration reduce to 7 weeks due to fewer tie-ins.

Truck trips to transport the pipe and materials to Point Hueneme, if this option were elected, would total about 550 round trips, assuming each truck can carry about 100 feet of pipe.

Cathodic Protection

Cathodic protection of the offshore emulsion pipeline would be provided by sacrificial anodes physically cast onto specific joints of pipe. The anodes, which are contoured to prevent snagging by fishing equipment, are installed at the pipe-coating facility in Los Angeles. Anode material would be either aluminum or zinc, depending on location. The anodes would be designed to provide protection for the life of the pipeline.

Valves

There are no subsea valves planned for the new offshore emulsion pipeline. However, there would be at least two valves, as is currently the case, at the +17 foot mean low water level on the platform. The nearest onshore valve site would be located easterly from the beach at Valve Site #1 on VAFB property, which is identical to the current oil emulsion pipeline.

3.5.1.2 Onshore Pipeline Installation

The onshore portion of the oil emulsion pipeline is approximately 12.1 miles long. The proposed alignment for this alternative is identical to the existing pipeline alignment shown in Appendix A.

The existing pipeline route has a landfall approximately ½ mile north of the Santa Ynez River and crosses VAFB property, running eastward parallel to the Santa Ynez River. The pipeline then turns northeast and follows the northern boundary of the Lompoc Federal Penitentiary. Just east of the Federal Penitentiary, the pipeline turns north and follows the VAFB property line for about 2.75 miles. The line then makes a gentle turn to the east into the LOGP.

The design for the new onshore oil emulsion pipeline would be the same as the existing oil emulsion pipeline except that the wall thickness may be greater to provide greater protection against corrosion. This, in combination with the newer pipeline, would enable the pipeline to operate at higher pressures than the current pipeline which has been de-rated due to corrosion.

The pipe would be delivered by railcar from the Los Angeles area. The railcars would serve as the primary storage area for the pipe, and as needed, trucks would be used to carry the pipe from the railcars to the construction site. The pipeline would be installed using conventional land pipe-laying methods and equipment, and would be buried with a minimum cover of 3 feet, except at stream crossings where the line would be buried below scour depth.

Most of the onshore pipeline construction would occur in units known as “spreads.” Each spread is organized and equipped so that it is capable of moving forward, clearing the way, installing the pipeline, testing it, and restoring the land. The spread is divided into several distinct functions:

1. Right-of-way clearing and grading
2. Trenching/Excavation
3. Cutting and removal of existing pipeline
4. Stringing the new pipe
5. Welding the new pipe
6. Radiographic inspection of each weld
7. Coating the joints
8. Lowering the pipe into the ditch
9. Backfill/cleanup
10. Pressure testing
11. Revegetation

A single spread consists of the equipment and manpower to perform the total operations from trenching to backfilling. The first part of the spread would involve trenching and removing the existing pipeline. The existing pipeline would be pigged, evacuated and capped, then excavated and cut out as the first part of the spread. This pipe would be transported for appropriate disposal before the new pipeline is laid in its place. For road and railroad crossings, existing holes and casing would be used to the greatest extent possible. The remaining portions of the spread would involve welding and installing the new pipeline and backfilling.

Normally, a 100-foot wide right-of-way would be required during construction to accommodate clearing, trenching, hauling, and stringing, welding, and traffic. However, a narrower right-of-way would be used for short distances to negotiate difficult areas or to avoid impact to localized environmental concerns such as an archaeological site or a cluster of trees. The right-of-way can be reduced to 40 feet for distances up to 200 feet by staging and assembling the pipeline on the normal right-of-way then walking it into place with side booms. The same right-of-way that was used for the initial pipeline installation would be used for this alternative.

Only a 50-foot strip (portion) of the 100-foot construction right-of-way would be cleared for use. This strip would provide room for trenching, hauling, and stringing. Where additional work area is necessary, the remaining 50 feet of the construction corridor would be "matted" by either "walking" or “rolling" over the existing brush and vegetation with tractors. This matting would provide a "hard surface" for vehicular traffic to travel on especially in areas of soft soil.

A 50-foot permanent maintenance right-of-way would be retained in a manner identical to current operations.

Schedule and Equipment

Approximately 10 weeks would be required for the installation of the onshore portion of the pipeline. Manpower requirements are estimated to be about 60 persons with construction ongoing 6 days per week, 12 hours per day. Table 3.4 details the equipment requirements.

Table 3.4 Onshore Pipeline Installation Equipment And Duration

Equipment Item	Number	HP Rating	Duration, Days
Welder	4	40	48
Crane	1	120	24
Backhoe, sm	1	80	24
Backhoe, lg	1	250	24
Compressor	1	30	12
Bulldozer	1	80	48
Sideboom	2	70	48
Bonder	1	125	16
Test pump	1	75	6
Grader	1	135	9

Source: Adapted from the 1985 Point Pedernales EIR/EIS Air Quality Appendix B Volume 1. Equipment numbers and duration reduced for single pipe installation.

Truck trips to transport the pipe from the rail line to the construction site would total about 650 round trips.

Cathodic Protection

The new emulsion pipeline would utilize the current cathodic protection system with rectifier and 300-foot deep anodes on the emulsion pipeline. This system protects the lines from external corrosion in case of coating damage.

Valves and Catchment Basins

This alternative would retain the existing valve sites and catchment basins currently in place on the oil emulsion pipeline.

3.5.1.3 New Emulsion Pipeline Cleaning, Hydrotesting and Operations

At the completion of pipeline installation, the oil emulsion pipeline (both the onshore and offshore portions) would be hydrotested with water to a specified pressure, as per MMS, DOT, and California State Fire Marshal requirements. This pressure would be held for a specified time period (minimum of 8 hours) to test the integrity of the pipeline. The hydrotest would meet or exceed all applicable codes or regulations governing the project. Prior to hydrotesting the pipeline, a cleaning "pig" (a polyurethane flexible, bullet-shaped foam cylinder) would be pumped through the pipeline to clear it of welding slag, dirt, debris, and other items that may have accumulated during construction.

Both the onshore and offshore portions of the new emulsion pipeline would be hydrotested at the same time as one complete pipeline. At the completion of the hydrotesting, the water would remain in the pipeline until displaced by production. The water would then be treated through the LOGP and disposed of as per the proposed project.

After pipeline installation, tie-in and testing, operation would commence in the same manner as the current operations. However, the new emulsion pipeline would be capable of operating at higher pressures than the current pipeline. Therefore, there would be no need for additional pumping at Valve Site #2, as may be necessary for the proposed project.

3.6 Alternative Power Line Routes to Valve Site #2

The proposed project would require the construction of new electrical power lines to Valve Site #2 to power three 1,250 hp electrical booster pumps that are proposed for installation on the 20-inch oil pipeline from Platform Irene to the LOGP. These booster pumps would only be required if the maximum allowable operating pressure of the oil pipeline from Platform Irene is reduced to 1,000 psig or less due to continued corrosion in the onshore portion of the pipeline. A number of alternative power line routes to Valve Site #2 have been developed, and are described below. Figure 3-10 shows the proposed and alternative power line routes. The results of the screening analysis for each of the alternative power line routes are also presented below.

3.6.1 Alternative Power Line Route – Option 1

The Option 1 route is identical to the proposed route except the power line would be placed in a conduit along the side of the 13th Street Bridge instead of using power poles to cross the Santa Ynez River. The 13th Street Bridge is owned by VAFB, and at this time they have stated that the power line can not be placed on the bridge for security reasons. Other than the river crossing, the rest of the route and methods of construction would be the same as for the proposed project.

The advantage this alternative has is that it would avoid the need to span the Santa Ynez River on power poles. This would avoid the need to set power poles in the riparian habitat on either side of the river. In addition, this alternative would eliminate the visual impacts associated with a new power line over the river. This alternative would offer no other advantages over the proposed route. Based upon discussions with VAFB, as noted above, this option is considered infeasible and has been dropped from further consideration in the EIR.

3.6.2 Alternative Power Line Route – Option 2a

With Option 2a the power line would be placed on new poles for the entire length of the route. The route would start on Ocean Avenue on the west side of 13th Street and move in a northerly direction toward the Santa Ynez River. The route would cross the Santa Ynez River close to an existing VAFB power line, then move in a north-easterly direction, parallel to 13th Street, until the intersection of 13th Street and Terra Road. From Terra Road to Valve Site #2, the route would be the same as the proposed project. Figure 3-10 shows the Option 2a route.

With this alternative, electricity would be supplied from either the 115 kV or 12 kV lines located near Ocean Avenue. Power supply from the 115 kV line would require a small substation (40'x 40') to be built on the north side of Ocean Avenue close to 13th Street (see Figure 3-3). The substation would step the power down to 34.5 kV. From the tie-in point, a new pole line would need to be run through an existing agricultural field to the Santa Ynez River. If the power is drawn from the 12 kV line, construction of a substation would not be necessary, and the new power line could be placed on the existing power poles through the agricultural field. Selection of the power grid tie-in point will be contingent on property availability and cost evaluation of power line installation and operation.

The power line would cross the river on poles in close proximity to an existing VAFB power line. After crossing the river, a pole line would need to be constructed parallel to the existing VAFB power line, on its west side and follow the VAFB line north towards Terra Road. Once the power line reaches Terra Road, the route would be the same as the proposed project.

This alternative would take the same amount of time to construct as the proposed project, and utilize the same equipment.

Construction of the power line pursuant to this alternative would not utilize trenching. This could be a potential advantage over the proposed project because there will not be air quality impacts due to trenching. Other impacts from this alternative are expected to be the similar to the proposed project. This alternative has been carried forward for analysis in Section 5.0.

3.6.3 Alternative Power Line Route – Option 2b

Option 2b is the same as Option 2a except the Santa Ynez River would be crossed using an underground directional drill instead of above ground on power poles. Small work areas would be needed on both sides of the river to accommodate the equipment needed for the directional drilling. The power line would surface on the north bank of the river in the existing agricultural field. The rest of the line route and method of construction would be the same as in Option 2a. The locations of the underground directional drill site and the work areas are shown in Figure 3-10.

It is expected that construction of this alternative would require two weeks more than the proposed project as a result of the directional drilling of the Santa Ynez River. A drill rig with a mud pump would be added to the equipment required for this alternative.

The underground directional drill of the Santa Ynez River could increase air emissions. In addition, during the drilling operations there is the possibility that drilling muds could be released into the river resulting in impacts to biological resources and onshore water quality. This alternative would reduce the visual impacts associated with the above ground power line crossing the Santa Ynez River. Other impacts from this alternative are expected to be similar to the proposed project. This alternative has been carried forward for analysis in Section 5.0.

3.6.4 Alternative Power Line Route – Option 3

Option 3 would involve the construction of an above ground power line from the intersection of 13th Street and Terra Road to Valve Site #2 following the same route as the proposed project. Power would be obtained from the existing VAFB power line at 13th Street and Terra Road. With this option, electrical power would be obtained from VAFB instead of PG&E. Construction of this option would be about two weeks less than the proposed project since no new power line would need to be built from Ocean Avenue to Terra Road. The equipment used to construct this option would be the same as for the proposed project. Figure 3-10 shows the location of this alternative route.

This option would eliminate all of the proposed power poles south of Terra Road, and would avoid the need to cross the Santa Ynez River. Elimination of this portion of the power line would reduce construction time and therefore air emissions. In addition, impacts to biological, cultural and agricultural resources would be reduced compared to the proposed project. VAFB has a number of onsite cogeneration facilities that are used to provide some of the power on the Base. However, based on discussions with VAFB, they would not allow PXP to use power that is generated by the Base due to operational and security concerns. Therefore, this option is considered infeasible and has been dropped from further consideration in the EIR.

3.6.5 Underground Power Line along Terra Road

This alternative involves burying the portion of the power line that runs along Terra Road to Valve Site #2. This alternative would require the construction of a trench from the intersection of Terra Road and 13th Street to Valve Site #2. The trench would follow the existing roadway. It is estimated that approximately two months would be needed to install this underground cable using a backhoe and other small construction equipment.

Undergrounding of the power line along Terra Road would eliminate the need to install new 60-foot power poles along a corridor that is some what visible from public areas. This alternative would result in less visual impacts than the proposed project. In addition, the buried power line would follow an existing road, thereby minimizing the potential impacts to cultural and biological resources. This alternative would lead to greater air emissions due the construction of a trench. Other impacts from this alternative are expected to be the similar to the proposed project. This alternative has been carried forward for analysis in Section 5.0

3.7 Alternative Drill Muds and Cuttings Disposal

Under the proposed project, drill muds and cuttings that meet Environmental Protection Agency discharge requirements would be released into the ocean during well drilling activities. The California State Lands Commission (CSLC) currently prohibits the release of drill muds and cuttings to the ocean within State Waters. While drilling for the proposed project would occur in Federal Waters, where releases of drill muds and cuttings are acceptable under certain conditions, well completions would occur within State Waters. Therefore, the following alternatives to drill muds and cuttings disposal have been evaluated.

Both drill muds disposal alternatives have the potential to avoid adverse project-related impacts to marine water quality and marine biology. New impacts associated with air quality and transportation/circulation are not considered to be significant. In addition, it is possible that the EPA could not approve ocean disposal of muds and cuttings for wells that are drilled into State Waters. For these reasons, both drill muds alternatives have been evaluated throughout the EIR.

3.7.1 Inject Drill Muds and Cuttings into Reservoir

During drilling, drill muds and cuttings can be collected and injected into the reservoir for disposal. The exact location for the muds and cuttings injection is not established at this time. However, muds and cuttings disposal during the initial drilling phase would need to utilize Point Pedernales Field disposal wells. If injection is proposed to occur into a Federal lease reservoir (e.g., Point Pedernales wells), the MMS would have to review the proposal and determine whether negative impacts to production or the reservoir would occur, the significance of any impacts, and the advisability of the injection program. MMS could require that injection occur in a zone other than the producing formation if drill muds and cuttings injection is found to adversely affect reservoir dynamics. Therefore, it was assumed that no adverse impacts to the producing reservoirs would occur as a result of muds and cuttings injection.

Minimal equipment would be required to inject the drill muds, mainly a holding tank, pulverizing pump, injection pump and piping connections to an injection well head on a dedicated disposal well. One of the key elements for this alternative is the availability of a suitable formation for injection of the muds and cuttings.

Injecting all drilling muds and cuttings into underground formations can be difficult to achieve in some offshore oil fields (MMS, 2001). Even after extensive pretreatment of the muds, including grinding and dilution, the solids content can quickly plug most permeable formations after initial pumping (Amstutz, 1980). Consequently, injection is unusual on the Pacific outer continental shelf. However, it is currently being practiced on the Santa Ynez Unit (SYU) platforms in the Santa Barbara Channel, where oil based muds and cuttings are being re-injected into underground formations.[6] The efficacy of this approach is dependent on the availability of underground formations with numerous large cavities, which can hold the required volume of muds and cuttings.

With this alternative, the cuttings would be ground to a fine particle size and mixed with seawater in various ratios to obtain desired density and viscosity. In addition to slurried cuttings,

[6] Non-oil based muds are routinely discharged at the Santa Ynez Unit platforms consistent with NPDES permit requirements.

all wash water, contaminated rain water, muds and displacement interface fluids collected will be injected. For a typical Tranquillon Ridge well, about 20,000 bbls of material would be injected.

The typical process for handling the cuttings for injection is as follows. The cuttings would be transported from the shale shakers, using a vacuum transfer system, into a slurry tank. The cuttings would be mixed thoroughly with water and would be circulated through a centrifugal shredding pump. Any particle larger than 20 mesh equivalent would be screened out over a 20 mesh shaker screen and returned to the slurry tank for further particle size attrition. Once the desired slurry properties are achieved, the fluid would be transported into a holding tank. A triplex injection pump would then be used to inject the slurry down the casing annulus. If needed, a drill rig cement unit pump could be used as a backup for the triplex injection pump.

For each Tranquillon Ridge well, the injection of the muds and cuttings would occur over a period of approximately 60 to 70 days. Based upon an analysis conducted by the previous applicant (Torch/Nuevo), injection of drill muds and cuttings should not affect reservoir dynamics.

3.7.2 Transport Drill Muds and Cuttings to Shore for Disposal

The drill cuttings would be loaded into sealed and lined roll off bins. Each bin would be capable of holding approximately 20 tons of cuttings. These bins would be taken ashore to Port Hueneme via supply boat. The roll off bins would be loaded onto roll off trucks and taken to an approved disposal site in Kern County. Possible disposal sites would include Terrain Technology in McKittrick, California, Safety-Kleen in Buttonwillow, California, and Chemical Waste Management in Kern County, California.

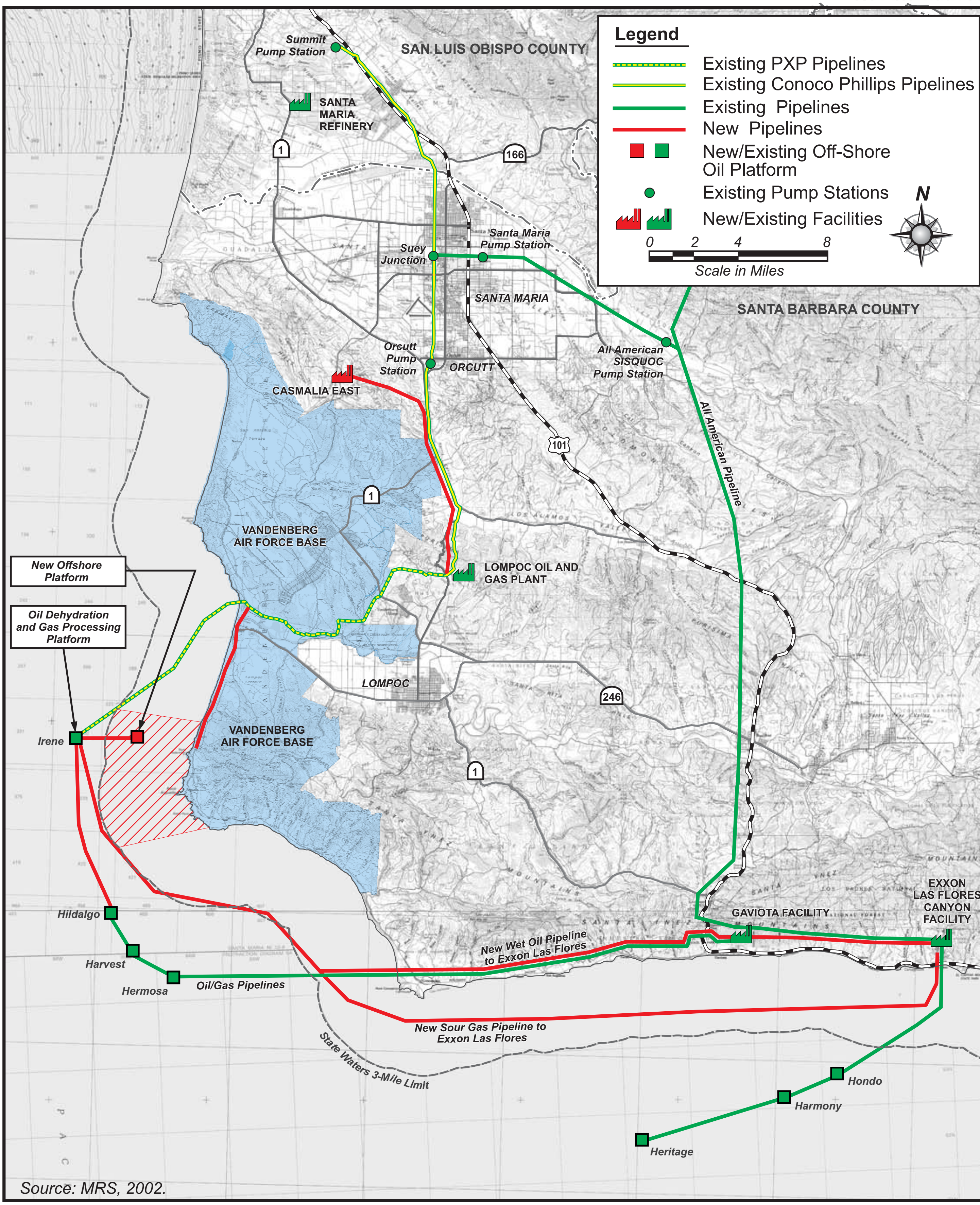
The drilling fluid (i.e., muds) would be emptied into Coast Guard-approved closed top tanks and sent to shore via supply boat. Once ashore, vacuum trucks ~~will~~ would transport the used drilling fluids to an approved disposal site or, if feasible, to a facility for recycling.

3.8 Summary of Alternatives Selected for Further Analysis

Based upon the results of the alternative screening analysis presented in Sections 3.2 through 3.7, a number of alternatives were selected for analysis throughout the EIR. Each of the alternatives selected for analysis is listed in Table 3.5 and is evaluated by issue area in Section 5.0 of the EIR. However, the level of analysis of the selected alternatives is not to a project-level of detail as allowed under CEQA (CEQA Guidelines, Section 15126[d]).

Table 3.5 List of Alternatives Selected for Analysis Throughout the EIR

Alternative	Brief Description
No Project Alternative	Under the No Project Alternative Scenario 2, only the Federal portion of the Tranquillon Ridge Field would be developed. Development of the Federal portion of the field would be allowable under the existing County of Santa Barbara and MMS permits. The new pumps and associated power line at Valve Site 2 would not be installed. Under the No Project Alternative Scenario 3, the Point Pedernales project would continue to operate until approximately 2017 pursuant to existing permit requirements. Other conventional and alternative energy sources could be developed. The Tranquillon Ridge reserves could be developed by others under No Project Alternative Scenario 1 (see VAFB Onshore Alternative, below). Development of alternative energy sources is also possible.
VAFB Onshore Alternative	Development of the Tranquillon Ridge Field would occur from onshore at southern VAFB. A new drilling/production facility, 10 miles of emulsion and gas pipelines, and six miles of power lines would be required. The alternative pipelines would tie into the existing PXP pipelines just west of 13th Street. The LOGP would be utilized for emulsion and gas processing. Extension of life of the PXP pipelines (from the tie-in location east) and LOGP would be the same as for the proposed project.
Casmalia East Site	A new oil, gas and produced water treatment facility would be constructed at Casmalia East Site. Most of the LOGP would be dismantled, but a compressor and pump station would remain at the LOGP site in order to move the oil and gas from the LOGP to the Casmalia site. The LOGP site would also have pumps for moving produced water from the LOGP back to Platform Irene. New wet oil, produced water and sour gas pipelines would be constructed to connect the current LOGP site to the new facility site at Casmalia.
New Emulsion Oil Pipeline	This alternative would involve replacing the existing oil emulsion pipeline from Platform Irene to the LOGP. The new line would be able to handle higher pressures so the need for the pumps and associated power line at Valve Site #2 would be eliminated.
Power Line to Valve Site #2 – Options 2a, 2b and undergrounding along Terra Road	Options 2a and 2b have been evaluated throughout the EIR at the request of the Applicant. Undergrounding of the power line along Terra Road has been evaluated throughout the EIR since it has the potential to eliminate the visual impacts associated with the 60-foot power poles. Since all the routes are on VAFB, the ultimate choice of route ~~will~~ would need to be approved by VAFB. However, SBC ~~will~~ would need to approve a route as part of the FDP revision. By evaluating all of these options throughout the EIR, the Applicant, VAFB, and SBC have flexibility in selecting the final power line route.
Muds/Cuttings Injection into Reservoir	Muds and cuttings would be injected into an offshore reservoir.
Transportation of Drill Muds and Cuttings to Shore for Disposal	Drill muds and cuttings ~~will~~ would be transported by supply boat and then by trucks to an authorized disposal facility.



PREPARED BY Aspen Environmental Group

Figure 3-1
Alternatives Locations

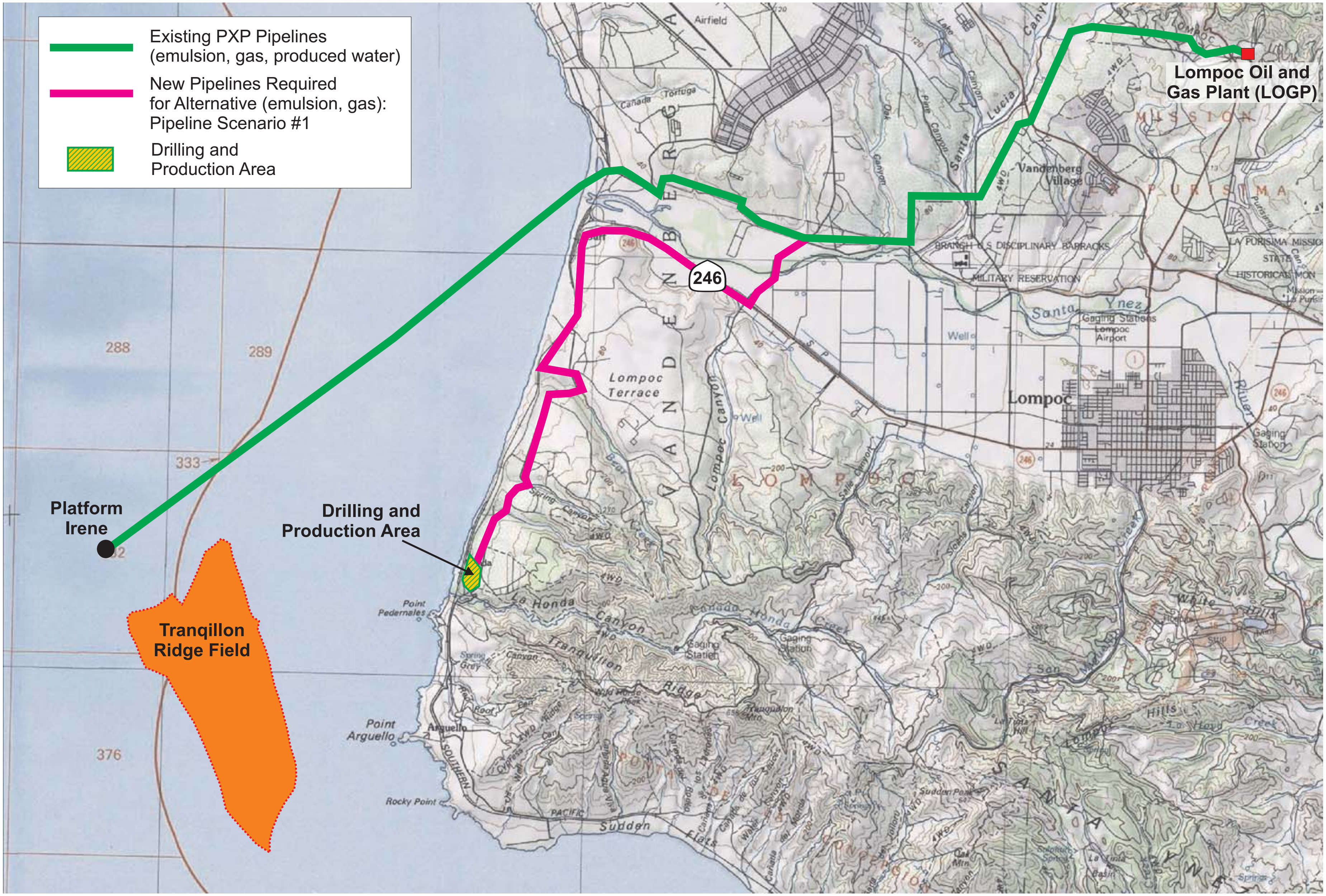


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Figure 3-2
VAFB Onshore Alternative

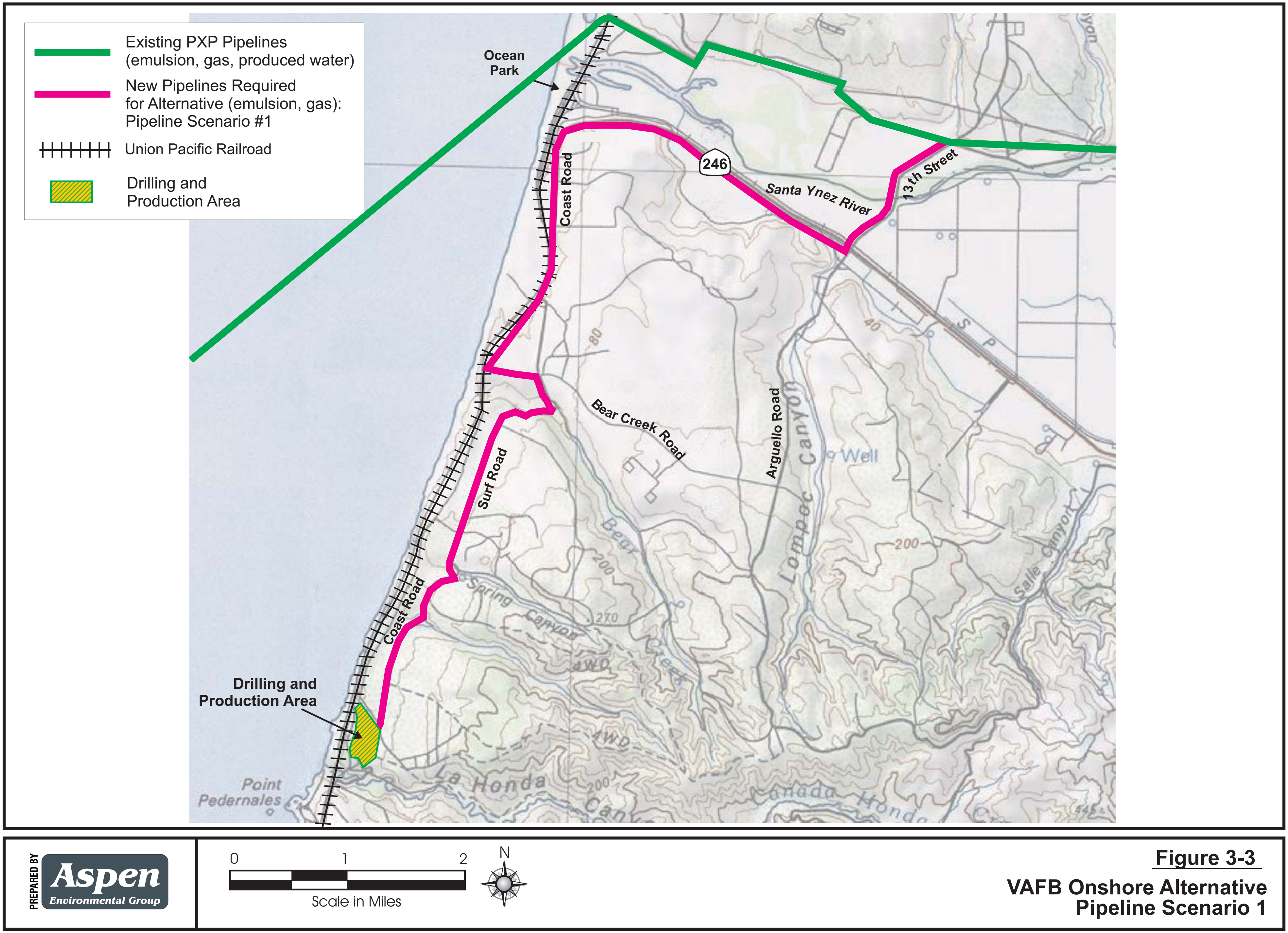

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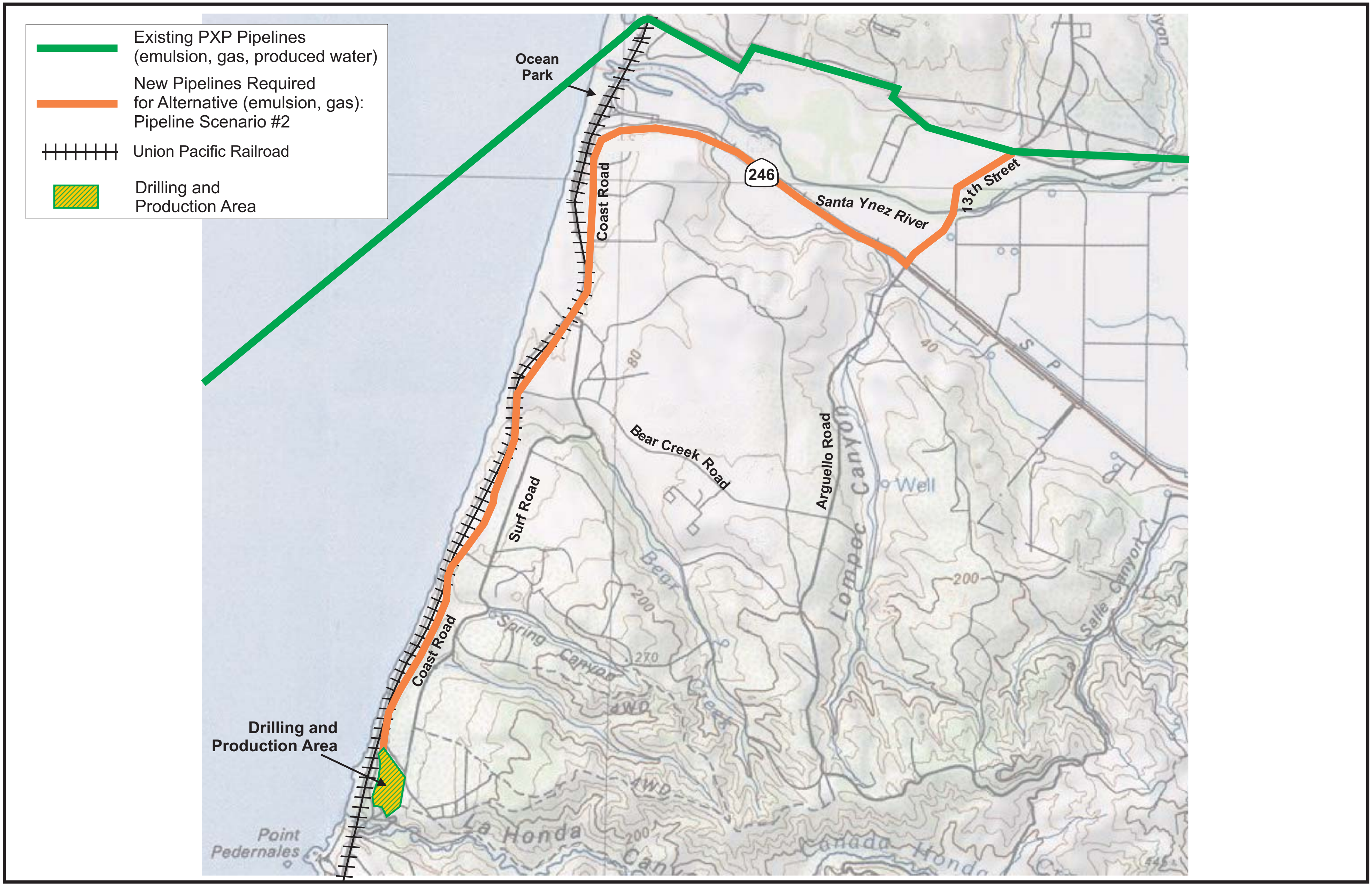
Figure 3-3

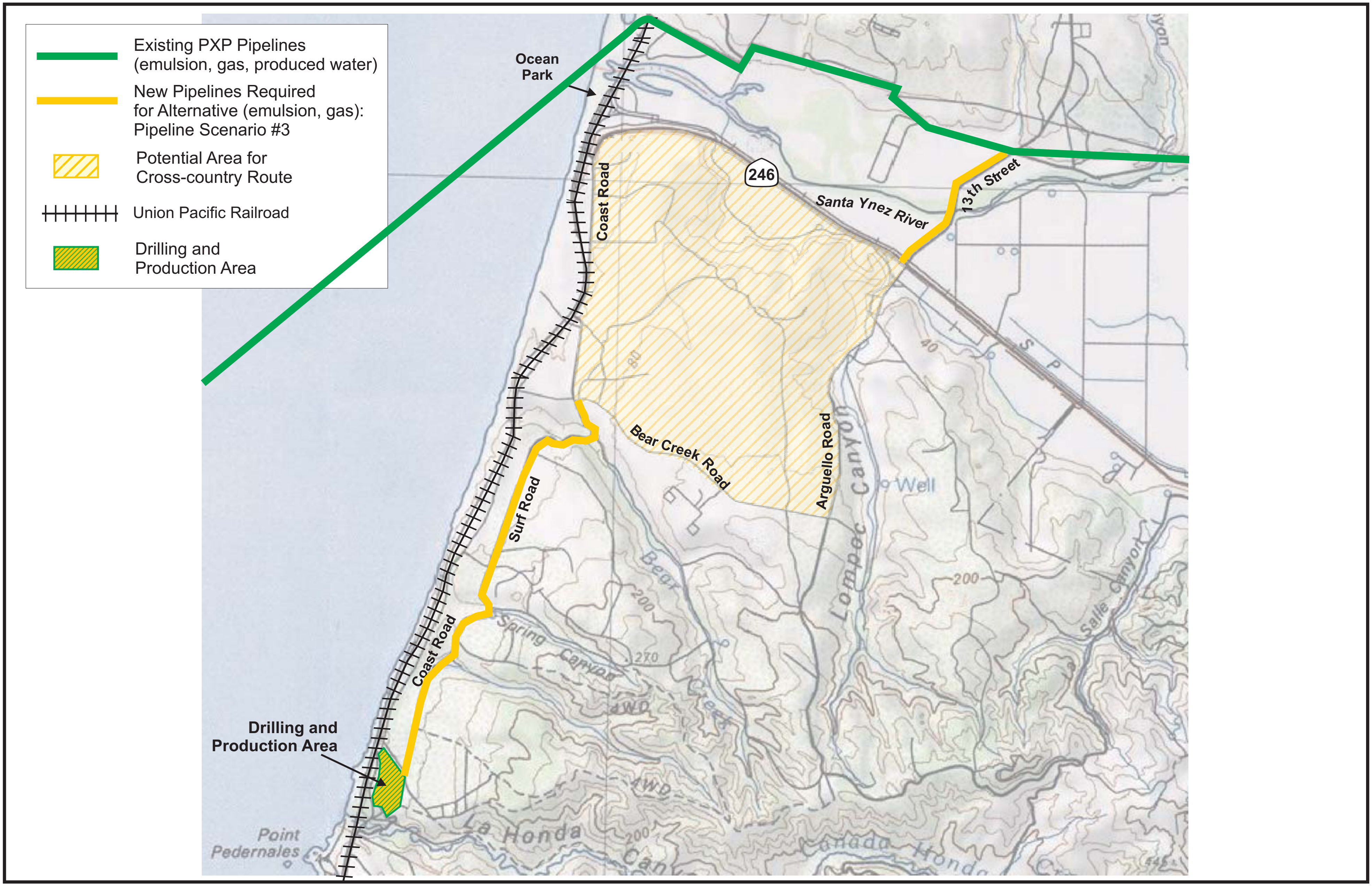
VAFB Onshore Alternative
Pipeline Scenario 1



0 1 2
Scale in Miles
N

PREPARED BY Aspen Environmental Group

Figure 3-4
VAFB Onshore Alternative
Pipeline Scenario 2



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Scale in Miles
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Figure 3-5
VAFB Onshore Alternative Pipeline Scenario 3

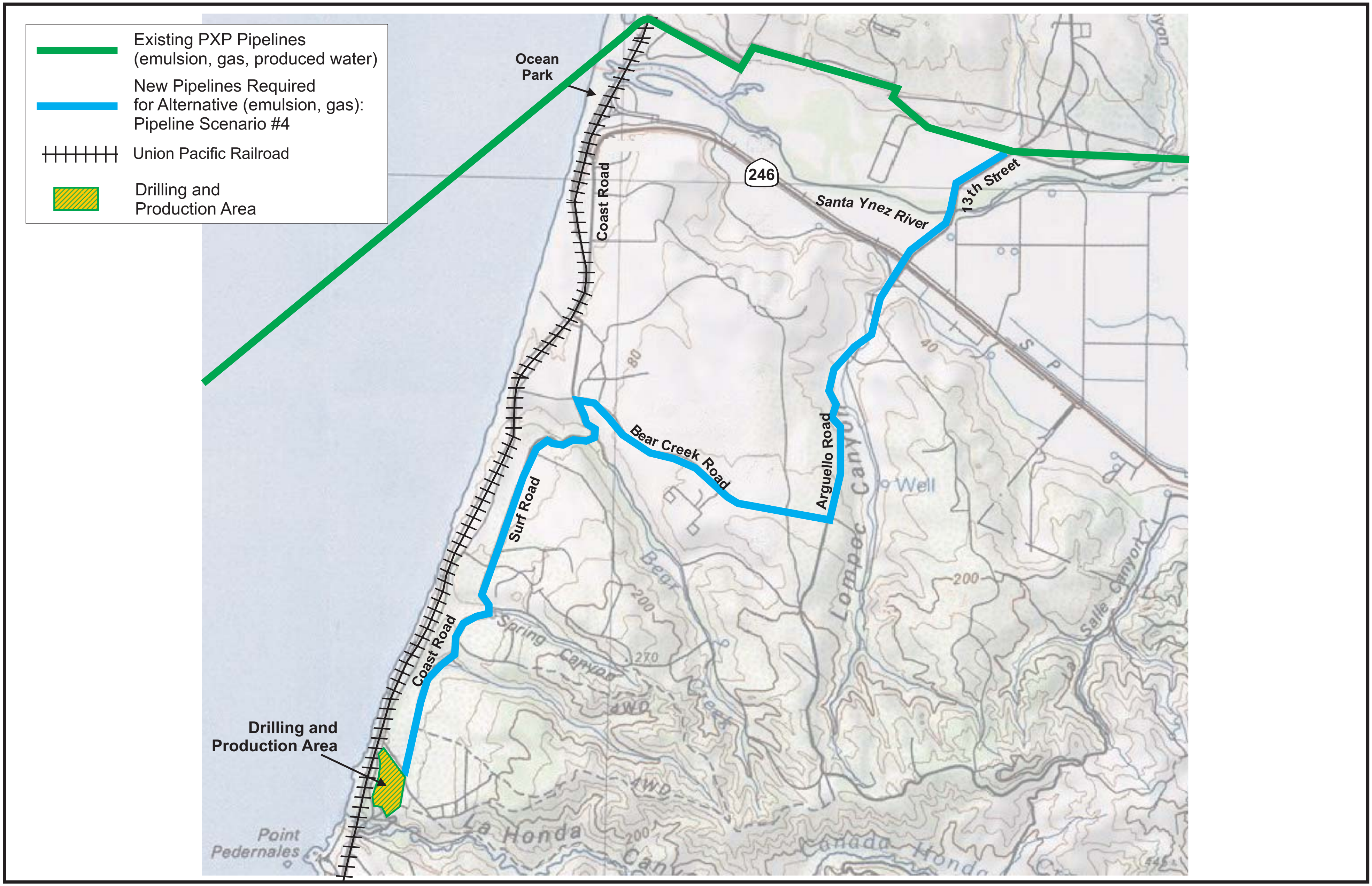

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Figure 3-6
VAFB Onshore Alternative Pipeline Scenario 4

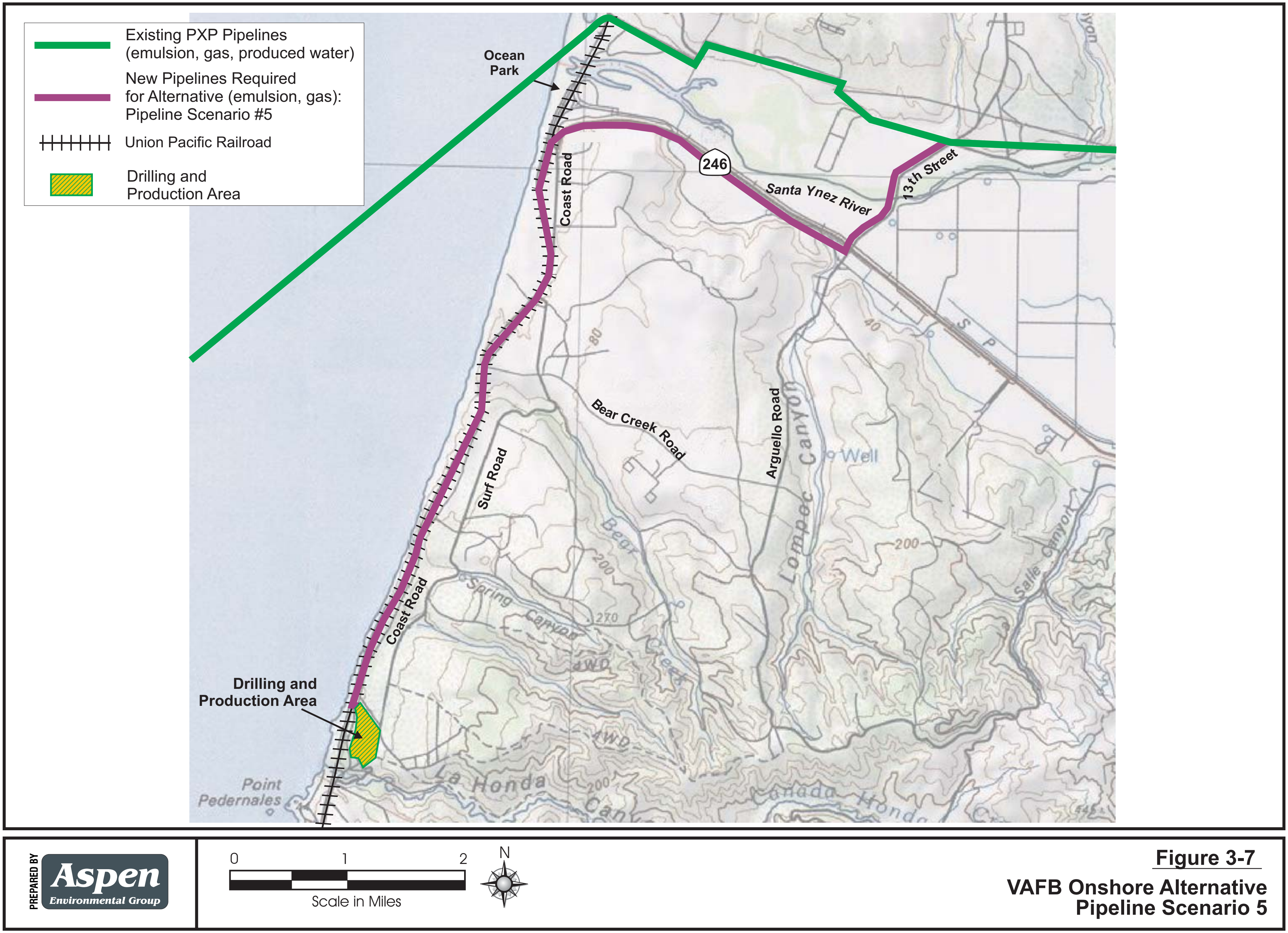

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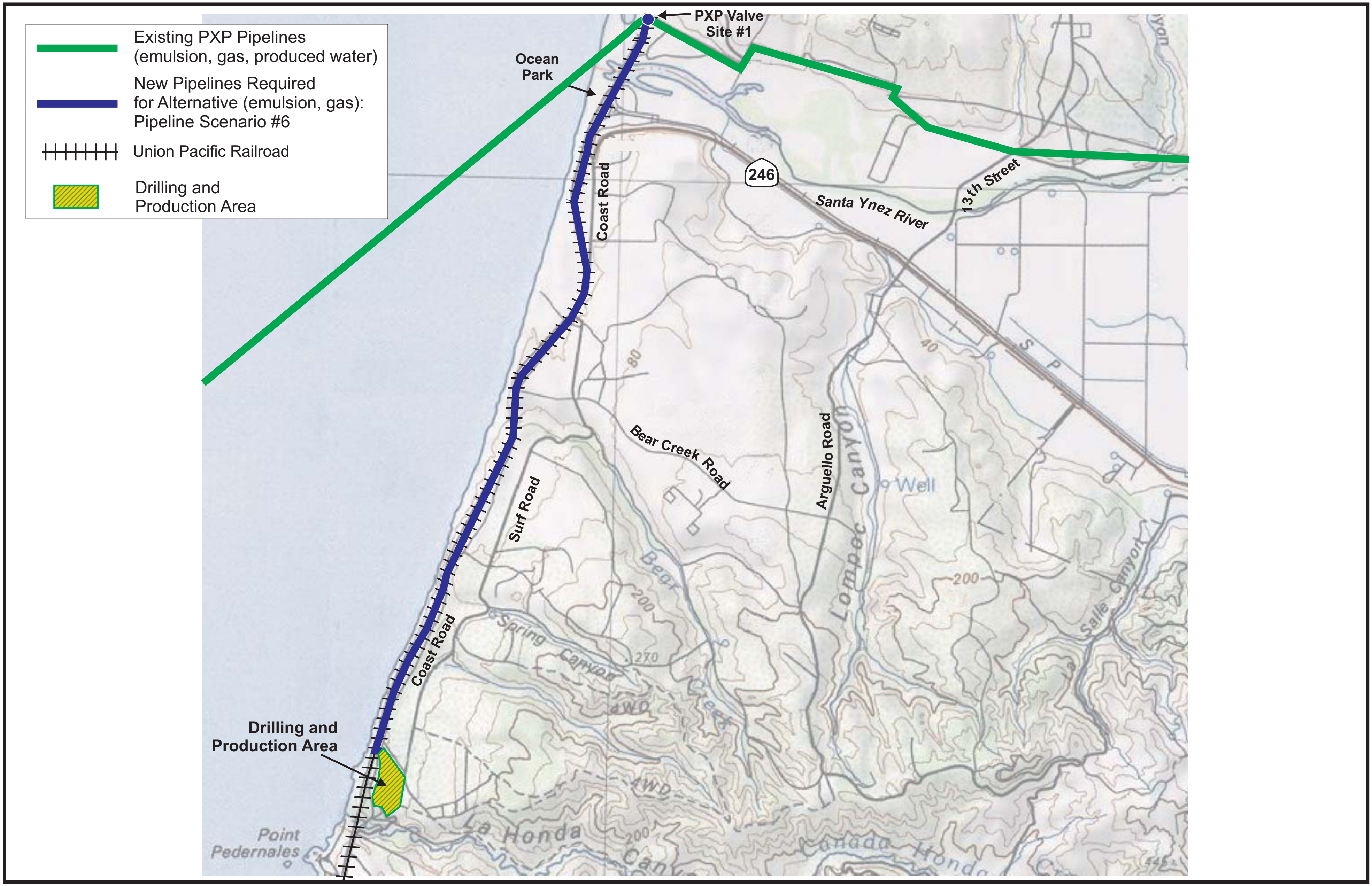
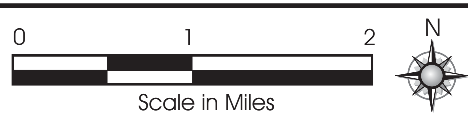
Figure 3-7
VAFB Onshore Alternative Pipeline Scenario 5

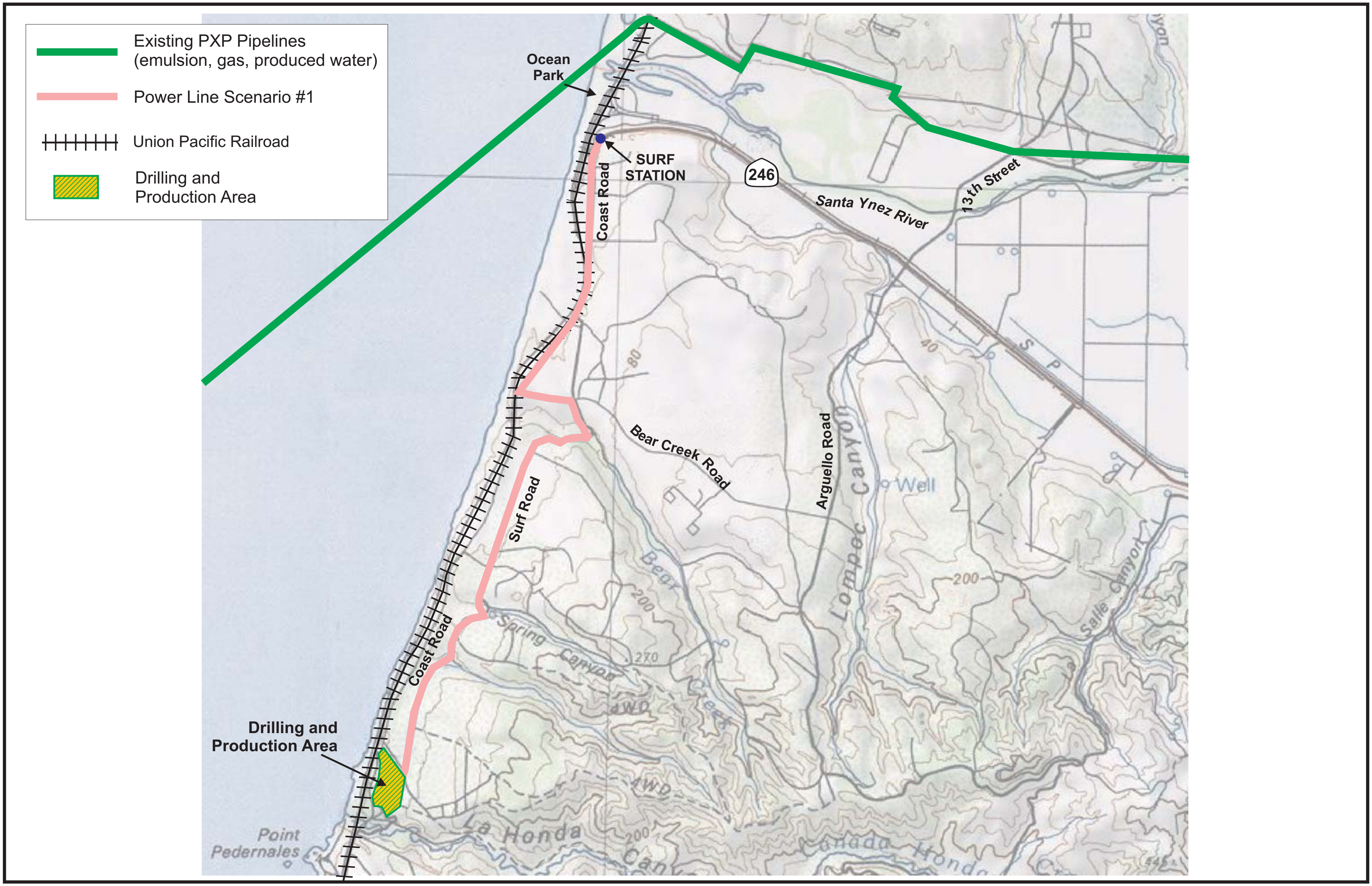




PREPARED BY Aspen Environmental Group

Figure 3-8

VAFB Onshore Alternative Pipeline Scenario 6



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0 1 2
Scale in Miles
N

Figure 3-9
VAFB Onshore Alternative Power Line Scenario 1

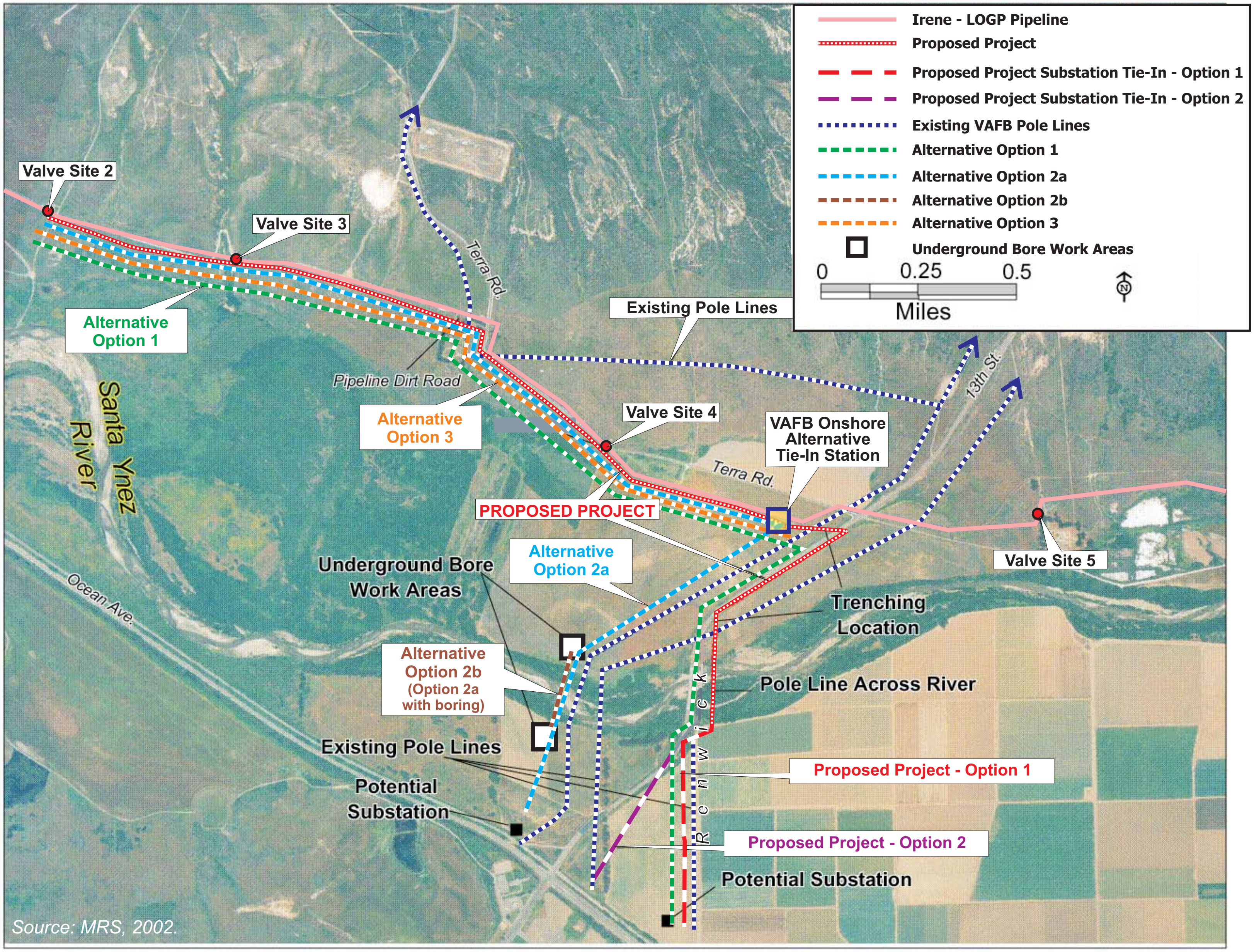

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Figure 3-10
Alternative Power Line Routes

4.0 CUMULATIVE PROJECTS DESCRIPTION

Section 4.0 presents the various cumulative projects considered in this Environmental Impact Report (EIR) in accordance with the California Environmental Quality Act (CEQA). This section is organized as follows:

4.1 CEQA Cumulative Analysis Overview

Section 15355 of the CEQA Guidelines defines "cumulative impacts" as two or more individual effects that, when considered together, are either considerable or compound other environmental impacts.

A typical "project specific" cumulative analysis looks at the changes in the environment that result from the incremental impact of development of a proposed project and other reasonably foreseeable projects that have not been included in the environmental setting. For example, the traffic impacts of two projects in close proximity may prove to be insignificant when analyzed separately, but could be significant when the impacts of the projects are analyzed together. While these projects may be unrelated, their combined (i.e., cumulative) impacts are significant.

The cumulative analysis identifies those projects that could have spatial and/or temporal overlaps with the proposed project, and that could have a potential to cause significant cumulative environmental impacts. Temporal overlaps include those projects that are planned to occur during the same timeframe as the proposed project. Spatial projects are those that would have impacts in the same area or on the same resources as those of the proposed project.

A list of all approved or potential oil and gas, residential, commercial and other development projects located in the study area of the proposed project was assembled using information from the Santa Barbara County (SBC) Planning and Development, Minerals Management Service (MMS), and California State Lands Commission (CSLC). The projects in the assembled list were analyzed using the above mentioned criteria. Although some uncertainty exists as far as the start time of the mentioned projects, the best available information was used to determine the temporal overlaps. Section 4.2 provides a description of the federal offshore oil and gas development projects that are significant in size, may overlap with the proposed projects in time, and are geographically close to the proposed project. Section 4.3 presents potential State offshore development projects related to oil and gas development that are considered germane to the proposed project, either by close geographic proximity or by potential oil spill effects. Section 4.4 provides a summary of the cumulative residential, commercial and other development projects located within the study area (northern Santa Barbara County). Cumulative impacts are analyzed in the respective issue area sections of Section 5.0, Analysis of Environmental Issues.

4.2 Federal Offshore Energy Projects – Reasonably Foreseeable Projects

Currently, 36 of the 79 federal Outer Continental Shelf (OCS) leases offshore California are undeveloped. Plans to develop these leases are outlined below. However, the future of the undeveloped leases is in question as a result of litigation and continuing objections from the State of California. The disposition of the undeveloped leases may now be established as a result of a decision in the Amber Resources et al. v. United States case, (currently in the U.S. Court of Federal Claims), which held that the United States breached its contract with the owners of the leases and must repay original bonus bid amounts, roughly $1.1 billion. The judge in Amber deferred final judgment pending resolution of all claims; therefore, the case remains in litigation.

For the purposes of the cumulative analysis it has been assumed that the development of these OCS leases would occur as projected by the lease operators and summarized by the MMS in 2005 and 2006 (MMS, 2005; MMS, 2006). This is viewed as a reasonable worst case scenario, because it would result in the greatest overlap with the proposed development of the Tranquillon Ridge Field. Further delays in the development of these cumulative offshore oil and gas development projects would only serve to reduce or eliminate the overlap with the proposed project.

Future activities on existing Federal outer continental shelf (OCS) leases include the following and are described below:

- Drilling of New Wells within Existing Leases from Existing Platforms,
- Exploration Well Abandonment,
- Decommissioning,
- Development of Some Undeveloped Offshore Leases from Existing Platforms or Mobile Offshore Drilling Units (MODUs), and
- Development of Other Undeveloped Offshore Leases from New Platforms.

4.2.1 Drilling of New Wells within Existing Leases from Existing Platforms

Drilling operations are currently underway at Platforms Heritage, Irene, and Gail. In the future, drilling may occur on Platforms Irene (the proposed project), Harvest, Hermosa, Harmony, Heritage, Hogan, Houchin, Gail, Grace, Ellen, and Eureka. There are no oil and gas lease sales scheduled or anticipated in Federal or State waters.

4.2.2 Exploration Well Abandonment

Well OCS-P 0320 #2 was drilled and temporarily abandoned in 1985. Samedan Oil Company proposes to permanently abandon well OCS-P 0320 #2 using a Mobile Offshore Drilling Unit (MODU). The sequence of activities would be as follows: (1) the MODU would anchor over the well; (2) the well would be entered and temporary plugs removed; (3) permanent cement plugs would be placed; (4) the wellhead and casing would be removed; and, (5) anchors removed and the MODU moved offsite. Samedan Oil Company estimates that 11 days would be needed to conduct abandonment activities.

Well OCS-P 0241 #2 was drilled and temporarily abandoned in 1968. The operator proposes to permanently abandon the well using a MODU. The sequence of activities for well abandonment would be the same as described above.

4.2.3 Decommissioning

Over the next several decades, all existing oil and gas platforms in Federal and State waters are expected to be removed. Some decommissioning has already occurred. The Offshore Storage and Treatment Vessel and Single Anchor Leg Mooring were removed from the Santa Ynez Unit in Federal waters in 1994, and Platforms Hazel, Heidi, Hilda, and Hope were removed from State waters in 1996. Platform decommissioning projects are likely to be phased and may occur in the following chronological sequence: (1) South Coast; (2) Eastern Santa Barbara Channel; (3) Western Santa Barbara Channel and Southern Santa Maria Basin; (4) Western Santa Barbara Channel; (5) Southern Santa Maria Basin; and, (6) Northern/Southern Santa Maria Basin and Gato Canyon. However, no proposals are anticipated for decommissioning of platforms during the next several years.

4.2.4 Development of Some Undeveloped Offshore Leases from Existing Platforms or Mobile Offshore Drilling Units

The potential federal lease development projects that are in close proximity to Tranquillon Ridge are listed in Table 4.1.

Table 4.1 Relevant Cumulative Energy Projects Located in Federal OCS Waters

Project Name/Applicant	Description/Size/Status
Energy Projects (Figure 4-1)	
Rocky Point Unit Development (PXP)	Development of offshore leases
Bonito Unit Development (PXP)	Development of offshore leases
Sword Unit Development (Samedan)	Development of offshore leases
Santa Maria Unit Development (Aera Energy)	Development of offshore leases
Lion Rock Unit Development (Aera Energy)	Development of offshore leases
Point Sal Unit Development (Aera Energy)	Development of offshore leases
Purisima Point Unit Development (Aera Energy)	Development of offshore leases
Gato Canyon Unit Development (Samedan)	Development of offshore leases
Cavern Point (Venoco)	Development of offshore leases
Non-unitized Lease OCS-P 0409 Development (Aera Energy)	Development of offshore leases

Sources: Minerals Management Service, 2005 and 2006.

The majority of the lease development projects would be located in the Santa Maria Basin and would use existing platforms, pipelines, and processing facilities to the maximum extent feasible. The location of each of the Federal offshore Units (and one non-Unitized lease) where existing development occurs, or potential exploration and development may occur, is shown in Figure 4-1. The potential development scenarios for each of the undeveloped Federal Units and Lease OCS-P 0409, as outlined by the MMS in 2005 and 2006, are briefly described below. It should be noted that there is limited data available on most of these projects at this early stage. In most cases, delineation test wells would be necessary to determine if and where development could occur.

4.2.4.1 Aera Energy Company (Aera) – Santa Maria, Lion Rock, Point Sal, and Purisima Point Units

Delineation drilling of three wells may be proposed on the Point Sal, Purisima Point and Gato Canyon Units subject to the results of litigation in the Amber case (see above). If delineation drilling were to occur, a Mobile Offshore Drilling Unit (MODU) would be used. If delineation drilling results indicated that development of these Units would be economically viable, their development would likely require the placement and operation of up to three new platforms, as described in Section 4.2.5.2, below.

4.2.4.2~~1~~ Plains Exploration & Production (PXP) Company – Rocky Point

PXP is the operator of the Rocky Point Unit. The Rocky Point Unit includes Leases OCS-P 0452 and 0453 in the southern offshore Santa Maria Basin. Twenty development wells, 14 oil wells and 6 service wells, would be drilled from Platforms Harvest, Hermosa, and Hidalgo to develop the entire Rocky Point Field (these 20 wells include those already encompassed in the Development and Production Plan [DPP] revisions for the eastern half of OCS-P 0451, four of which have been drilled). Seven wells would be drilled from both Platforms Harvest and Hermosa and six from Platform Hidalgo. The wells would be extended reach wells with horizontal displacement of 4.6 to 6.4 kilometers (km) (2.5 to 3.5 miles). Drilling of each well would require 3 to 4 months.

Oil would be dehydrated and stabilized on the platforms, then sent to the Gaviota facility via the existing subsea dry oil pipeline (see Figure 4-1). At Gaviota, the oil would be metered, heated, stored temporarily, and then transported via the Plains All-American Pipeline (Plains AAPL) to various refining destinations.

Rocky Point gas would be sweetened on the platforms and (1) sent via pipeline for sales onshore, (2) used to generate electricity and heat for platform operations, (3) sent to shore to fuel the Gaviota co-generation units, and/or (4) injected into the Point Arguello Field, the Rocky Point Field, or both.

~~*4.1.4.2 Aera Energy Company (Aera) – Santa Maria, Lion Rock, Point Sal, and Purisima Point Units*~~

~~Delineation drilling of three wells is proposed on the Point Sal, Purisima Point and Gato Canyon Units subject to the results of litigation in the Amber case (see above). If delineation drilling were to occur, a Mobile Offshore Drilling Unit (MODU) would be used. If delineation drilling results indicated that development of these Units would be economically viable, their development would likely require the placement and operation of up to three new platforms, as described in Section 4.1.5.2, below.~~

4.2.4.3 PXP – Bonito Unit

PXP is the operator of the Bonito Unit. The Unit includes Leases OCS-P 0499, 0500, 0443, 0445, 0446, 0449, and a portion of 0450. The Unit is located approximately six to fifteen miles west of Point Arguello in the Santa Maria Basin offshore Santa Barbara County.

Development wells would be drilled from Platform Hidalgo located on Lease OCS-P 0450. The wells would be extended reach wells with horizontal displacements of approximately 4.8 km (3 miles) or greater. Drilling of each well would require 3 to 4 months.

Oil would be dehydrated and stabilized on the platforms, then sent to the Gaviota facility via the existing subsea dry oil pipeline (see Figure 4-1). At Gaviota, the oil would be metered, heated, stored temporarily, and then transported via the Plains AAPL to various refining destinations.

Bonito gas would be sweetened on the platforms and (1) sent via pipeline for sales onshore, (2) used to generate electricity and heat for platform operations, (3) sent to shore to fuel the Gaviota co-generation units, and/or (4) injected into the Point Arguello Field.

4.2.4.4 Samedan Oil Company (Samedan) – Sword Unit

Samedan is the current operator of the Sword Unit. The Sword Unit includes Leases OCS-P 0319, 0320, 0322, and 0323A. A portion of Lease OCS-P 0323 was relinquished and the remaining lease was redesignated 0323A to reflect the change. Eleven development wells, 10 oil wells and 1 service well would be drilled from Platform Hermosa, located on Lease OCS-P 0316. The wells would be extended reach wells with horizontal displacements of 6.4 to 8.3 km (3.5 to 4.5 miles). Drilling each well would require 3 to 4 months.

Oil would be dehydrated and stabilized on the platforms, then sent to the Gaviota facility via the existing subsea dry oil pipeline. At Gaviota, the oil would be metered, heated, stored temporarily, and then transported via the Plains AAPL to various refining destinations.

Sword gas would be sweetened on Platform Hermosa and (1) sent via pipeline for sales onshore, (2) used to generate electricity and heat for platform operations, (3) sent to shore to fuel the Gaviota co-generation units, and/or (4) injected into the Point Arguello Field.

4.2.4.5 Venoco, Inc. (Venoco) – Cavern Point Unit

Venoco is the current operator of the Cavern Point Unit. The Unit includes Leases OCS-P 0210 and 0527, located off the coast of Ventura County (see Figure 4-1). Potential development of the Cavern Point Unit would occur from existing Platform Gail. Development could include extended reach drilling of eleven wells from Platform Gail, including ten oil wells and one service well (MMS, 2005). Produced oil and gas would be transported via Platform Gail's existing off- to onshore pipelines to Venoco's existing Carpinteria Oil and Gas Processing Facility, located in the City of Carpinteria.

4.2.5 Development of Other Undeveloped Offshore Leases from New Platforms

4.2.5.1 Samedan – Gato Canyon Unit

Samedan is the current operator of the Gato Canyon Unit. The Gato Canyon Unit includes Leases OCS-P 0460 and 0464. The Gato Canyon Unit would be developed from a new platform in Lease OCS-P 0460, offshore the El Capitan area of the Gaviota Coast. In total, the new platform could potentially include 28 well slots, 20 production wells and four service wells. A new 14-inch wet oil pipeline, 8-inch gas pipeline, 8-inch produced water pipeline, and two power cables would connect the platform to the existing ExxonMobil Las Flores Canyon facility (MMS, 2005). The pipelines and cable would run from the platform, traversing State Lease PRC

2991.1 to landfall, and then through the existing Santa Ynez Unit pipeline corridor to the Las Flores Canyon facility. Gas would be processed at the Las Flores Canyon Gas Plant and sold to The Gas Company (MMS, 2005). Oil would be processed at the Las Flores Canyon facility using existing capacity, and then transported to other locations outside of Santa Barbara County via the Plains AAPL. Produced water would be treated at the existing Las Flores Canyon Water Treatment Plant, transported offshore by pipeline, and disposed of at the new platform.

4.2.5.2 Aera – Santa Maria, Lion Rock, Point Sal, and Purisima Point Units and Lease OCS-P 0409

If delineation drilling of Lease OCS-P 0409 and the Santa Maria, Lion Rock, Point Sal and Purisima Point Units proved successful (see Section 4.2.4.~~2~~1, above), their full development could include the installation of up to three new platforms in the northern offshore Santa Maria Basin. The new platforms would potentially be located in Leases OCS-P 0409 (a non-Unitized lease), 0422 (located within the Point Sal Unit), and 0431 (located in the Santa Maria Unit) (MMS, 2005). The platforms located in Leases OCS-P 0409 and 0431 would both be connected to the platform located in Lease OCS-P 0422 by three pipelines each (a 10-inch water pipeline, 8-inch gas pipeline, and 16-inch wet oil emulsion pipeline). From the platform located in Lease OCS-P 0422, produced water, oil and gas would then be transported to shore via three pipelines including a: 12 inch produced water pipeline; 24-inch wet oil emulsion pipeline; and, 10-inch gas pipeline (MMS, 2005). The off- to onshore pipeline corridor would make landfall approximately three to four miles south of Point Sal, hypothetically connecting to a new onshore oil and gas processing facility located in Casmalia (MMS, 2005).

4.3 State Offshore Energy Projects – Reasonably Foreseeable Projects

In addition to the potential Federal OCS energy projects summarized above, several offshore energy projects located in State waters have also been proposed. These potential projects are summarized below and their respective locations are shown in Figure 4-2.

As presented in Section 3.2, applications have been filed by Sunset Exploration, Inc. and Exxon Mobil Corporation for the development of the Tranquillon Ridge Field from an onshore location within southern Vandenberg Air Force Base (VAFB). The ultimate development of this project would only occur if the proposed project is denied; therefore, the Sunset/ExxonMobil Project is not considered in the cumulative analysis. However, the Sunset/ExxonMobil Project is conceptually considered as the VAFB Onshore Alternative in this EIR.

4.3.1 Carone Petroleum Corporation (Carone) – Redevelopment of Carpinteria Field

Carone has proposed redevelopment of the offshore Carpinteria Field (existing State Leases PRC-4000, PRC-7911, and PRC-3133). The proposed project includes the drilling of up to 25 new production or injection wells from existing Platform Hogan (located in Federal waters in Lease OCS-P 0166). Oil and gas production from the leases would be commingled on Platform Hogan with existing production and sent via existing pipelines to the La Conchita Facility (CSLC, 2006). After processing, gas and oil would be sold to The Gas Company and other third parties at the La Conchita sales meters, and shipped via existing pipelines (CSLC, 2006). Total production would increase from approximately 1,300 to 1,500 barrels of oil per day (bpd) to approximately 6,000 bpd through January 2020, at which time total production would decline. The proposed project is currently under review.

4.3.2 Venoco, Inc. (Venoco) - Ellwood Full Field Development

In 2006, Venoco applied to the CSLC and City of Goleta to fully develop the offshore Ellwood Field. The proposed project includes an adjustment to the State Lease PRC-3242.1 boundary eastward to allow development of the South Ellwood Field from Platform Holly, the drilling of up to 40 new wells, construction of a new 10-mile onshore pipeline from Venoco's Ellwood Onshore Facility to the Plains AAPL pipeline system at Las Flores Canyon, decommissioning and abandonment of the Ellwood Marine Terminal and offshore loading facility, and safety and environmental upgrades of the Ellwood Onshore Facility and a new power generating plant. If approved, the proposed project is anticipated to have a peak oil production rate of 12,600 bpd, and peak gas production rate of 20 million standard cubic feet per day (mmscfd) after five years (SBC, 2006a). The proposed project is currently under review.

4.3.3 Venoco - Resumption of State Lease PRC-421 Development

In May 2004, Venoco proposed to bring two idle Coastal Zone oil production wells within State Lease PRC-421 back into production. The wells are located in the City of Goleta on two adjacent piers. Pier 421-1 supports an idled water and gas injection well, and Pier 421-2 supports an idled oil production well. Venoco proposes to install new production equipment and reactivate the oil well on Pier 421-2, and reactivate the former injection well on Pier 421-1 for disposal of wastewater and natural gas (SBC, 2006b). Based on current projections, the estimated life of the proposed project would be twelve years of oil production; production would be expected to be no more than an average of 700 BPD in the first year, tapering off to approximately 100 BPD by year 12 (CSLC, 2005). The proposed project is currently under review.

4.3.4 Venoco – Paredon Project

In February 2005, Venoco applied to the CSLC and to the City of Carpinteria to develop existing State Lease PRC-3150.1 by conducting extended reach drilling from an onshore site located within Venoco's existing Carpinteria Oil and Gas Processing Facility, located in the City of Carpinteria (CSLC, 2006). Venoco estimates that the proposed project could produce up to 10,000 bpd of crude oil, and 10 mmscfd of gas; after processing, oil would enter an existing 16-inch diameter pipeline to the existing Rincon Onshore Separation Facility for connection with the existing pipeline system extending to Los Angeles refineries (CSLC, 2006). Processed gas would be delivered via an existing 6-inch diameter pipeline connection to The Gas Company's existing regional 12-inch diameter pipeline that passes near Venoco's Carpinteria Oil and Gas Processing Facility (CSLC, 2006). The proposed project is currently under review.

4.3.5 Venoco - Ellwood Marine Terminal Lease Renewal

Venoco is currently seeking approval from the CSLC for a new State Lease (PRC-3904.1) through February 28, 2013. This would allow Venoco to continue operating the existing Ellwood Marine Terminal located offshore the City of Goleta and lands under the ownership of the University of California, Santa Barbara (CSLC, 2006). The proposed project does not include construction of any new facilities or modifications to any existing facilities; however, it does include the potential for increasing crude oil throughput and transportation from current levels to permitted levels (CSLC, 2006). The proposed project is currently under review.

4.4 Onshore Development Projects

In addition to the offshore oil and gas development projects presented in Sections 4.2 and 4.3, there are several onshore development projects that could have cumulative impacts in areas that are close to proposed project locations. Table 4.2 lists the potential development projects in the Lompoc area and the Orcutt-Santa Maria area, and Figures 4-3, 4-4, and 4-5 present their locations. ~~respectively.~~

4.4.1 Development Projects in Lompoc Area

The City of Lompoc population may increase by 21,000 by the year 2030 (Arthur D. Little et al, 2002). Over 7,000 new homes would be needed to house new residents. Currently, there are several residential developments under construction, approved and awaiting construction, or under review and pending approval in the vicinity of Lompoc~~area~~, within both the jurisdictional boundaries of the City and its surrounding unincorporated areas.~~, within Santa Barbara County immediately adjacent to the City of Lompoc.~~ The projects that are expected to affect resources similar to the proposed project are listed in Table 4.2 and illustrated in Figure 4-3 (the northern [unincorporated] Lompoc area), and Figure 4-4 (the incorporated area of the City of Lompoc).

Table 4.2 Relevant Cumulative Projects

Project Name/Applicant	Description/Size/Status
Development Projects – Northern (Unincorporated) Lompoc Area (Figure 4-3)	
Providence Landing/Capital Pacific Homes, Inc. (Figure 4-3 Key Site #1)	284 SFD and 72 low income units, 141 acres, under construction
Bluffs at Mesa Oaks/Martin Farrell Homes (Figure 4-3 Key Site #2)	72 SFD and 2 duplexes (4 units), 35 acres, under construction
Clubhouse Estates/Urban Planning Concepts, Inc. (Figure 4-3 Key Site #3)	53 lots, 1 open space lot, 162.31 acres, approved
Burton Ranch Specific Plan/Martin Farrell Homes, Inc. and the Towbes Group, Inc. (Figure 4-3 Key Site #4)	149 acres, annexation, under review
Fire Station 51/County of Santa Barbara (Figure 4-3 Key Site #5)	15.35 acres, 1 fire station and 1 sheriff sub-station, under review
Oak Hills/Permit Planners, Inc. (Figure 4-3 Key Site #6)	21 homes, 5.5 acres, under review
Story Tentative Parcel Map/Fletcher Cross and Associates (Figure 4-3 Key Site #7)	4.55 acres, two way split into 1 parcel with 1 acre, and another parcel with 3.55 acres, under review
Duckett Caretaker/Watchman Dwelling/Mike Duckett (owner) (Figure 4-3 Key Site #8)	Single family home, 34, 108 s.f. lot, under review
Hunter General Plan Amendment (Figure 4-3 Key Site #9)	Redesignate rural/recreation/AG II-100 to inner rural area, rural residential, 1723 acres.
Gaffaney General Plan Amendment (Figure 4-3 Key Site #10)	Redesignate existing rural neighborhood (EDRN); RR-10 and RR-20 (rural residential) to EDRN; RR-5, 150 acres.
Stoker General Plan Amendment (Figure 4-3 Key Site #11)	September 19, 2006, Planning Commission initiated a redesignation from recreation to residential for the 2.82-acre parcel.

Table 4.2 Relevant Cumulative Projects

Project Name/Applicant	Description/Size/Status
PXP Residential Development Annexation to the City of Lompoc (Figure 4-3 Key Site #12)	1,30~~0~~8 residential units (339 acres), streets (51 acres), open space (294 acres) and parks/trails (119 acres), ~~homes, 800 acres~~preliminary planning currently under way, no formal application has been filed.
Courtney Recorded Map Modification/Fletcher Cross and Associates (Figure 4-3, Key Site #13)	Request to relocate designated building envelope of a 3.06-acre parcel, under review.
Mission Oaks/Burton Mesa Partners, LLC (Figure 4-3, Key Site #14)	Subdivision of 3.65-aces site into 15 lots for development of 27 residential units, under review.
Lompoc Wind Energy Project/Pacific Renewable Energy Generation LLC (Located southwest of Lompoc and east of VAFB)	Wind generation of 80 to 120 megawatts of electricity and associated 9-mile, 115-kilovolt power line, under review.
Development Projects – City of Lompoc (Incorporated Area) (Figure 4-4)	
Lompoc Historical Museum (Carnegie Library) Rehabilitation/City of Lompoc (Figure 4-4 Key Site #1)	Interior and exterior building renovations, approved.
14-Unit Residential Development/The Olson Company (Figure 4-4, Key Site #2)	14 detached single family residential units, 1.36 acres, approved.
60-Unit Residential Development/The Olson Company (Figure 4-4, Key Site #3).	60 detached single family residential units, 5.13 acres, approved.
Chestnut Crossing Mixed-Use Infill Project/ Martin Farrell Homes, Inc. (Figure 4-4, Key Site #4)	New development and redevelopment for residential units and commercial space, 5.5 acres (80,595 square feet), approved.
Coastal Meadows Residential Infill Project/Coastal Vision, Inc. (Figure 4-4, Key Site #5)	42 units, 3.09 acres, approved.
Lompoc Regional Wastewater Reclamation Plant Master Plan and Plant Upgrade/City of Lompoc (Figure 4-4, Key Site #6)	Master Plan Revision and Plant Upgrade for the Lompoc Regional Wastewater Reclamation Plant to meet discharge requirements of the Regional Water Quality Control Board, no additional acreage outside existing property boundaries, approved.
Transitions Extended Stay Facility/ Santa Barbara Housing Assistance Corporation (Figure 4-4, Key Site #7)	Community counseling and advocacy office and 39 unit independent living facility, approved.
Lompoc Hospital Relocation/Lompoc Hospital District (Figure 4-4, Key Site #8)	60-bed hospital facility, 111,000 square feet on 8 acres, under construction.
Crown Laurel Mixed Use Project/ JM Development, Inc. (Figure 4-4, Key Site #9)	73 residential units on 9.53 acres and planned manufacturing space (1.36 acres), approved.
Riverbend Park and Trail Master Plan/City of Lompoc (Figure 4-4, Key Site #10)	Recreation and educational facilities, multi-use trails, public parking, habitat enhancement, 95 acres, in review/development.
River Terrace Residential Development/Coastal Vision, Inc. (Figure 4-4, Key Site #11)	308 residential units, 17,666 square feet of commercial floor area, 9,110 square-foot community recreation center, private park and recreational amenities, 26.22 acres, approved.
Dixon Industrial Building/Applicant unknown (Figure 4-4, Key Site #12)	1,150 square-foot industrial building, under construction.
Fast Pass Car Wash/Applicant unknown (Figure 4-4, Key Site #13)	2,800 square-foot commercial facility (car wash), under construction.
4 Unit Residential Development/Lompoc Housing Community Development Corp. (Figure 4-4, Key Site #14)	10,500 square-foot, 4-unit residential development and childcare facility, under construction.
Warehouse/Barto Heating and Air (Figure 4-4, Key Site #15)	12,580 square-foot office and warehouse building, under construction.
Commercial Development/Yanez Electric (Figure 4-4, Key Site #16)	3 commercial buildings, 6,600 square feet, under construction.

Table 4.2 Relevant Cumulative Projects

Project Name/Applicant	Description/Size/Status
Industrial Development/Hotwire Foam Factory (Figure 4-4, Key Site #17)	3,318 square-foot industrial building, under construction.
Optometry Center/Shepard Eye Clinic (Figure 4-4, Key Site #18)	18,600 square-foot medical (optometry) building, under construction.
Commercial/Community Bank of Lompoc (Figure 4-4, Key Site #19)	4,875 square-foot commercial bank, under construction.
The Gardens at Briar Creek/Centex Homes (Figure 4-4, Key Site #20)	150 single-family residential units, under construction.
Mixed Use Residential and Office Development/Coastal Vision, Inc. (Figure 4-4, Key Site #21)	10,500 square-foot office and residential development, approved, grading permit issued.
8-Unit Residential Development/Wolfberg (Figure 4-4, Key Site #22)	7,712 square-foot , 8-unit residential development, approved,
The Courtyards at Briar Creek/Centex Homes (Figure 4-4, Key Site #23)	145 single-family residential units and community park, 37.8 acres, approved.
5-Unit Apartment Complex/Applicant unknown (Figure 4-4, Key Site #24)	4,770 square-foot, 5-unit residential development, approved.
5-Unit Residential Development/Applicant unknown (Figure 4-4, Key Site #25)	5-unit residential development, 0.24 acres, approved.
35-Unit Affordable Housing Residential Development/Lompoc Housing Community Development Corp. (Figure 4-4, Key Site #26)	35-unit residential development and daycare facility, 2.2 acres, approved.
Lompoc Indoor Market/Applicant unknown (Figure 4-4, Key Site #27)	20-vendor indoor market renovations and addition, 21,000 square feet, approved.
Industrial Development/Wilco Distributors (Figure 4-4, Key Site #28)	18,000 square-foot industrial building, approved.
Lompoc Hospital Training Center/ Lompoc Hospital District (Figure 4-4, Key Site #29)	2,000 square-foot training center, approved.
Lompoc Valley Vet Clinic/Applicant unknown (Figure 4-4, Key Site #30)	6,800 square-foot office building, approved.
Good Samaritan Shelter/Applicant unknown (Figure 4-4, Key Site #31)	Drug and alcohol recovery shelter and thrift store, 0.64 acres, approved.
George Ann Estates/Applicant unknown (Figure 4-4, Key Site #32)	8-unit residential development, 3.31 acres, approved.
Wine Processing Facility/Loring/Pali Winery (Figure 4-4, Key Site #33)	30,000 square-foot wine processing facility, approved.
5-Unit Residential Complex/Lompoc Housing Community Development Corp. (Figure 4-4, Key Site #34)	5,941 square-foot, 5-unit condominium complex, approved.
Commercial Development/Applicant unknown (Figure 4-4, Key Site #35)	Commercial building renovation (6,250 square feet) and addition (3,736 square feet), approved.
Mixed-Use Development Project/Lompoc Housing Development Corp., (Figure 4-4, Key Site #36)	34,332 square-foot retail, commercial, office and public plaza development, approved.
City Park in OTC/Applicant unknown (Figure 4-4, Key Site #37)	0.16 acre park, approved.
Commercial Development/Moore Mill & Lumber (Figure 4-4, Site #38)	2,363 square-foot renovation and addition to existing hardware store, approved.
Development Projects –Orcutt-Santa Maria Area (Figure 4-54)	
Jensen's Crossing-Cobblestone Creek/Cal-Cobblestone Creek, LLC (Figure 4-5~~4~~ Key Site #5)	112 units, 48.63 acres, recently constructed or under construction
Mesa Verde/Larwin Company (Figure 4-5~~4~~ Key Site #6)	64 units, 45.21 acres, recently constructed or under construction
Orcutt Apartments/Meyer Asset Management (Figure 4-5~~4~~ Key Site #24)	117 units, 5.88 acres, recently constructed or under construction

Table 4.2 Relevant Cumulative Projects

Project Name/Applicant	Description/Size/Status
Shared Senior Housing/Home Suites, LLC (Figure 4-5 ~~4~~ Key Site #29)	7 units, 5.37 acres, recently constructed or under construction
Vintage Ranch/Martin Farrell Homes, Inc. (Figure 4-5 ~~4~~ Key Site #7)	52 units, 31.52 acres, approved
Harp Springs/Urban Planning Concepts (Figure 4-5 ~~4~~ Key Site #8)	44 units, 20.43 acres, approved
Orcutt Creek/EDA Design Professionals (Figure 4-5 ~~4~~ Key Site #10)	16 residential lots, 9.28 acres, approved
Rice Ranch/Rice Ranch Ventures, LLC (Figure 4-5 ~~4~~ Key Site #12)	725 units, 626 acres, approved
Stonegate/Urban Planning Concepts (Figure 4-5 ~~4~~ Key Site #17)	44 units, 7.91 acres, approved
Old Mill Run/HMW Group, LTD (Figure 4-5 ~~4~~ Key Site #20)	60 units, 19.2 acres, approved
Orcutt Plaza/Hawkeye Investments (Figure 4-5 ~~4~~ Key Site #25)	220,779 s.f., 22.23 acres, approved
Orcutt Marketplace/Penfield and Smith (Figure 4-5 ~~4~~ Key Site #1)	306,100 s.f. proposed, 23.9 acres, under review
Orcutt Gateway/SRI One (Figure 4-5 ~~4~~ Key Site #2)	Residential/Commercial (201 unit triplex or 147 unit "bungalow" project), 18.8 acres, under review
Gjerdrum Lot Split/Dr. Thor Gjerdrum (Figure 4-5 ~~4~~ Key Site #13)	2 residential lots, 4.28 acres, under review
Lebard Retail Center/Mr. Steve LeBard (Figure 4-5 ~~4~~ Key Site #18)	13,364 s.f. retail, 4.28 acres, under review
Rancho Maria/Urban Planning Concepts (Figure 4-5 ~~4~~ Key Site #21)	203 units, 189.2 acres, under review
North Hills/Jackson Washburn on behalf of Orcutt Fee LLC (Located within the hills south of Orcutt between Highways 101 and 135)	Mixed use community of up to 7,500 residential units, including affordable and workforce housing, and up to 2,000,000 square feet of commercial/retail space on approximately 3,000 acres of a 4,125 acre site. Comprehensive Plan Amendment would be required for this project. Application currently withdrawn by applicant for reconsideration.
Onshore Oil Development/Breitburn (Located in the Orcutt Hill area)	Onshore oil and gas development within the Orcutt Hill area. Two Phases of development: Phase I for the drilling of 16 steam injection wells approved in 2006; Phase 2 for an additional 80 wells under review.
Onshore Oil Development/Santa Maria Pacific (Located in the Casmalia area)	46 Oil development wells approved in 2005. Project in construction as of September 2006.
Ethanol Production Facility/American Ethanol Inc. (Located within Santa Barbara County on Betteravia Road west of the City of Santa Maria.	The facility would process corn through a distillation process and produce 110 million gallons per year of ethanol for the California automotive fuels market. Application under review.

Sources: Santa Barbara County 2030 Land and Population, Nov. 2000;
Alice McCurdy, Supervising Planner, SB North County P&D, August and October 2006 (County of Santa Barbara, 2006d)
Larry Appel, Supervising Planner, SB North County P&D, August and September 2006. (County of Santa Barbara, 2006e)
County of Santa Barbara, Planning and Development Department, (County of Santa Barbara, 2007)
City of Lompoc, Community Development Department (City of Lompoc, 2007a and 2007b)

Table 4.2 shows that there are over 2,700~~432~~ residential units that are either currently under construction, about to begin construction, or are currently in the review and decision making process within the incorporated and unincorporated areas of Lompoc ~~area~~. There are also multiple commercial, industrial, office, mixed-use and redevelopment projects that are either in construction, or currently in the review and decision making process. ~~There have also been 53 residential lots approved.~~Additional potential development projects include parks and recreational facilities, ~~Currently under review is a 149-acre annexation to Lompoc, as well as the~~construction of a fire station and a sheriff sub-station, relocation of the Lompoc Hospital, and upgrades to the Lompoc Regional Wastewater Reclamation Plant. Also under review ~~are an additional 22 units/homes, two lots,~~are three General Plan Amendments for residential redesignation, and a proposed annexation/Sphere of Influence extension for a proposed 804~~0~~-acre residential development west of Harris Grade Road and two miles north of the City of Lompoc for ~~that would include the~~construction of approximately 1,308~~0~~ residential units. The proposed project area for this housing development is located south, west, and northwest of the LOGP and includes a segment of the Point Pedernales pipeline corridor (see Figure 4-3). Cook-Hill Properties filed a "Pre-Annexation Inquiry" with the City of Lompoc regarding this proposal for the 804 acres owned by PXP. This Inquiry requires that the City Council determine whether the city is willing to consider processing permit applications for a project currently outside the City's boundaries before permit applications are filed. The proposed 804~~3~~-acre residential project is currently undergoing a City of Lompoc General Plan consistency review for the City of Lompoc's Planning Commission and City Council to consider (Breese, 2006) and no formal applications for the development itself have been filed. The City Council is expected to review the City Planning Commission's recommendation that additional information be collected before the Commission makes a recommendation to the Council on the Pre-Annexation Inquiry. This potential project is independent of the proposed project (Plains Exploration and Production Company, 2007).

In addition to the above, the Lompoc Wind Energy Project, an 80 to 120 megawatt commercial wind farm, is proposed to be located south of Lompoc and adjacent to the boundaries of VAFB. Key features of the proposed project include the placement of 60 to 80 wind turbines over a 2,950-acre area, new and improved access roads, and a new approximately nine-mile 115 kV power line from the proposed wind farm site to Lompoc (SBC, 2006c). The proposed project is currently under review; if approved, construction is anticipated to begin in 2007.

4.4.2 Development Projects in Orcutt-Santa Maria Area

The cumulative projects located in close proximity to the ConocoPhillips crude oil pipelines that traverse the Orcutt-Santa Maria area are listed in Table 4.2 and illustrated on Figure 4-5 ~~4~~. Currently there are several residential and commercial developments under construction, approved and awaiting construction, or under review and pending approval.

Table 4.2 shows that there are 300 residential units recently constructed or currently under construction in the Orcutt-Santa Maria area. There have been 925 residential units, 16 residential lots, and a 220,779 square foot commercial site approved. Under review are a 203 unit residential development, one (1) residential/commercial site (up to 201 units), a 306,100 square foot commercial site, and a 13,364 square foot retail site, and 2 residential lots. As presented in Table 4-2, the proposed North Hills project would include up to 7,500 homes and 2,000,000 square feet of commercial/retail space; however, the request for a Comprehensive Plan Amendment for this project has been withdrawn by the applicant for consideration at this time.

In addition to the residential and commercial developments outlined above, two onshore oil development projects have been approved either in full, or in part. These projects include onshore oil development within the vicinities of Orcutt Hill and Casmalia, as summarized in Table 4.2. In addition, an application for a proposed ethanol plant west of the Santa Maria area is currently undergoing application completeness review (see Table 4-2).

Within San Luis Obispo County, the Guadalupe Oil Field Remediation Project remains an on-going effort, generating up to 30 round-trip truck trips per day. In June 2005, a Final Supplemental Environmental Impact Report (FSEIR) for the project was completed that addressed a proposed amendment to the project which includes the transport of up to 850,000 cubic yards of Non-Hazardous Hydrocarbon Impact Soil (NHIS), via truck, from the Guadalupe Oil Field (Field) to the City of Santa Maria Landfill, and to allow the use of clean sand for backfill from the project site (County of San Luis Obispo, 2006). This amendment was approved, and as of September 2006, approximately nine to ten trucks were hauling material to the Santa Maria Landfill from the remediation site, with each truck making three round-trips each per day (Science Application International Corporation, 2006). The first trucks do not leave the remediation site until after 7:30 a.m. and the last trucks leave the site by no later than 2:30 p.m. (SAIC, 2006). As of September 2006, approximately 770 truck loads comprising 18,000 tons of material had been hauled to the Santa Maria Landfill and there were no immediate plans to increase the number of daily round-trips per truck to four; however, a request to change the total number of round-trip truck trips per day may be made following the end of daylight savings time in October 2006 (Science Application International Corporation, 2006).

4.4.3 Additional Projects That May Affect Resources Associated with the Santa Ynez River

In addition to the approved or potential development projects outlined in Sections 4.4.1 and 4.4.2, above, there are three projects associated with the Santa Ynez River that may affect that portion of the river which is adjacent to the proposed project's off- to onshore pipeline corridor. A summary of these projects is provided below.

- Bee Rock Quarry Expansion. The Bee Rock Quarry is located approximately 1.5 miles south of State Route 154, opposite the Bradbury Dam observation site at Lake Cachuma. The proposed expansion includes limestone mining within an additional nine acres of land, thereby expanding the existing quarry's footprint from 22.5 acres to 31.5 acres. The total amount of material mined would be approximately 11.7 million tons, and mining operations would continue through the year 2043. Three watercourses are within the vicinity of the proposed expansion area, including Hilton and Sweetwater creeks, and an unnamed tributary of Hilton Creek locally known as "Bee Rock Creek." These watercourses drain to Lake Cachuma. The Final Environmental Impact Report (EIR) for the proposed mine expansion was published in July 2006, and no significant unavoidable impacts related to the downstream reaches of the Santa Ynez River (below Bradbury Dam) were identified (County of Santa Barbara, 2006f). The proposed mine expansion was approved and the Final EIR certified in January 2007 (Minick, 2007).
- Modifications to the U.S. Bureau of Reclamation's Water Right Permits 11308 and 11310 (Applications 11331 and 11332) to Protect Public Trust Values and Downstream Water Rights on the Santa Ynez River Below Bradbury Dam (Cachuma Reservoir). This project involves water release modifications from Bradbury Dam to protect downstream water rights and public trust resources along the Santa Ynez River. A Draft EIR was published by the State Water Resources Control Board in August 2003, and is currently being revised to incorporate two new alternatives and eliminate two previously addressed alternatives (Riddle, 2007). The 2003 Draft EIR did not identify any significant unavoidable impacts related to biological resources downstream of Bradbury Dam, although several

impacts that can be mitigated to a level of less than significant were identified within that portion of the river located adjacent to Lompoc (State Water Resources Control Board, 2003). A preferred (or proposed) alternative for this project has not been identified; release of the revised Draft EIR is tentatively planned for March or April 2007 (Riddle, 2007).

- Lower Santa Ynez River Fish Management Plan for Southern Steelhead Trout. The Lower Santa Ynez River Fish Management Plan for Southern Steelhead Trout includes various flow and no-flow release measures to be implemented by the Bureau of Reclamation and Cachuma Project Member Units to protect and enhance habitat for the southern steelhead trout along the Santa Ynez River downstream of Bradbury Dam (U.S. Bureau of Reclamation, 2004). A Final Environmental Impact Statement/Environmental Impact Report (Final EIS/EIR) for the Management Plan and its related Biological Opinion was published in 2004. Downstream of Bradbury Dam, potential adverse impacts identified in the 2004 Final EIS/EIR include temporary construction related disturbances to riparian and aquatic habitat during fish habitat restoration work in the river and its tributaries (U.S. Bureau of Reclamation, 2004). Implementation of the Management Plan has not occurred due to on-going litigation issues (Riddle, 2007).

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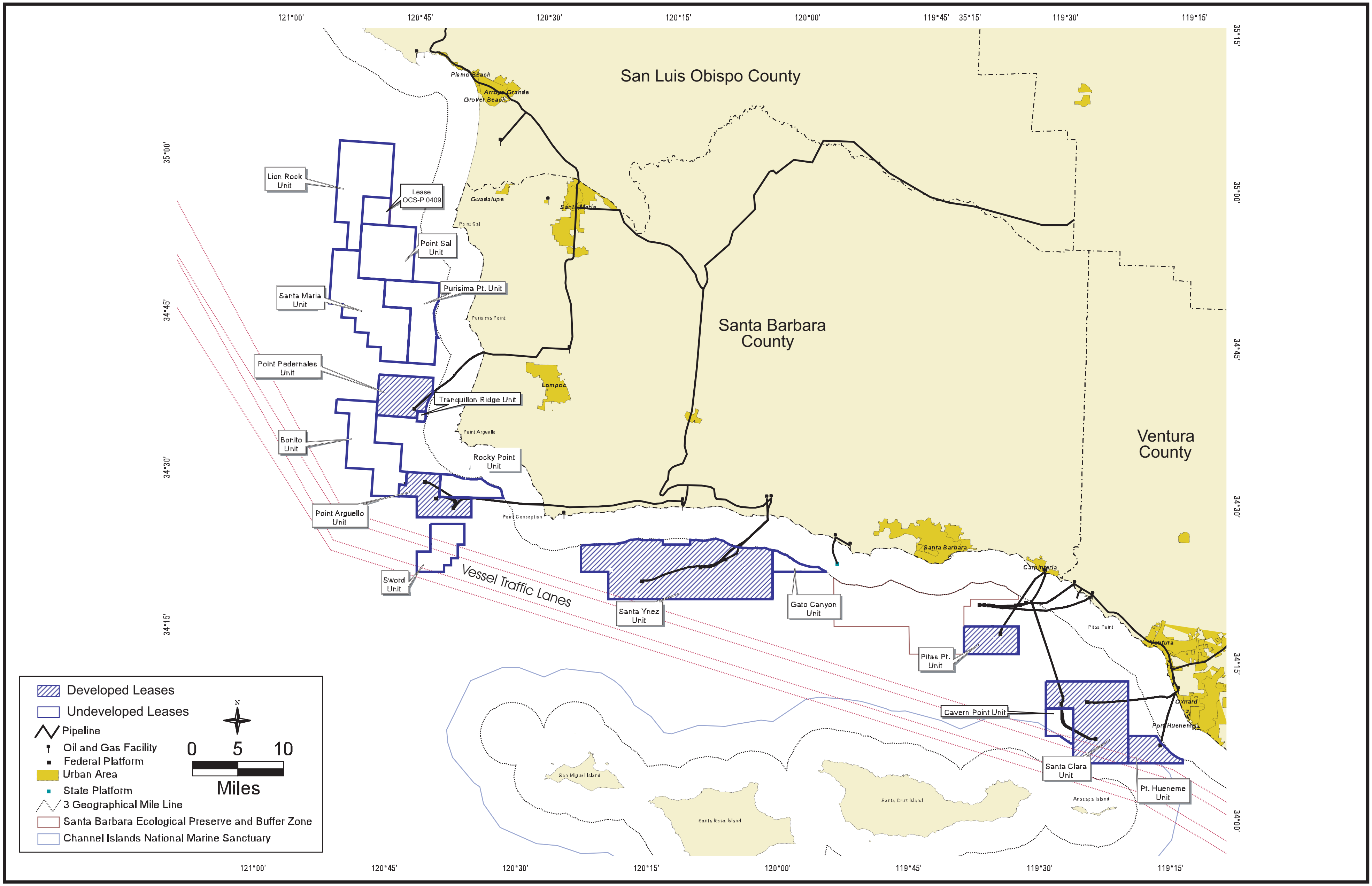
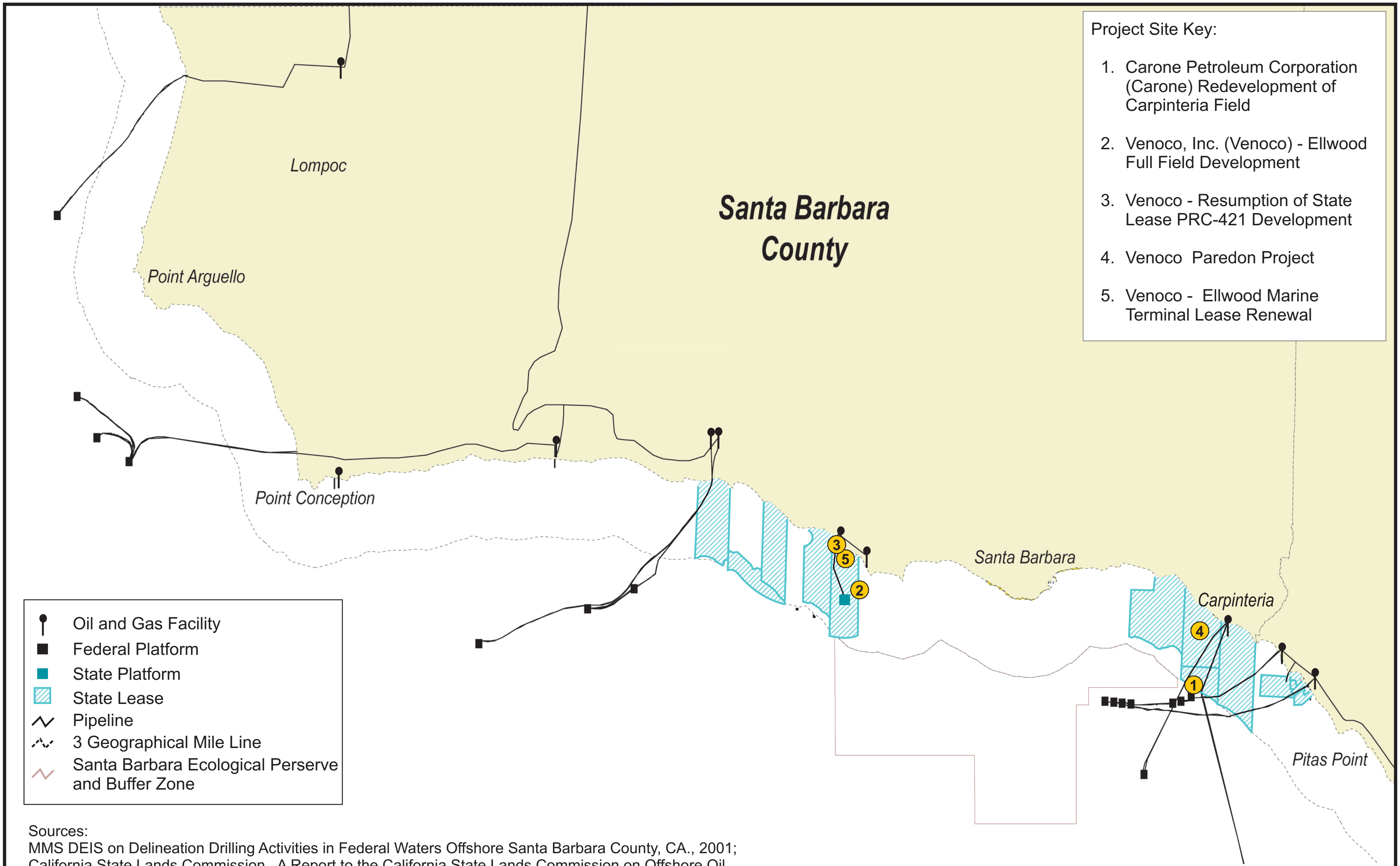


PREPARED BY Aspen Environmental Group

Figure 4-1
Location of Cumulative Federal OCS Oil and Gas Development Projects



Sources:
MMS DEIS on Delineation Drilling Activities in Federal Waters Offshore Santa Barbara County, CA., 2001;
California State Lands Commission. A Report to the California State Lands Commission on Offshore Oil and Gas Leases: Area Maps. 2005. (http://www.slc.ca.gov/Reports/Offshore_Oil_and_Gas.htm).

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Figure 4-2

Potential State Offshore Oil and Gas Development Projects

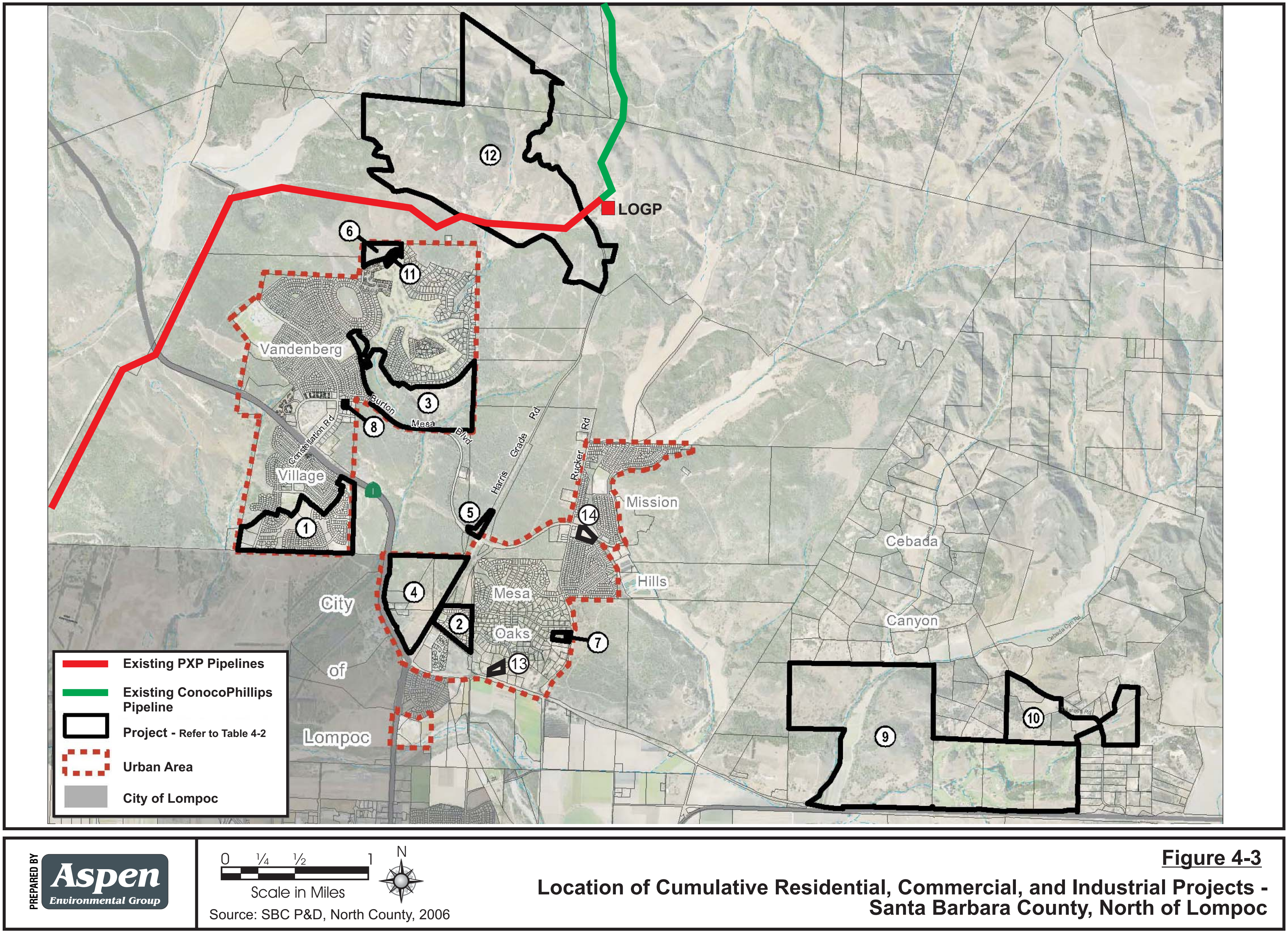

Figure 4-3
Location of Cumulative Residential, Commercial, and Industrial Projects - Santa Barbara County, North of Lompoc

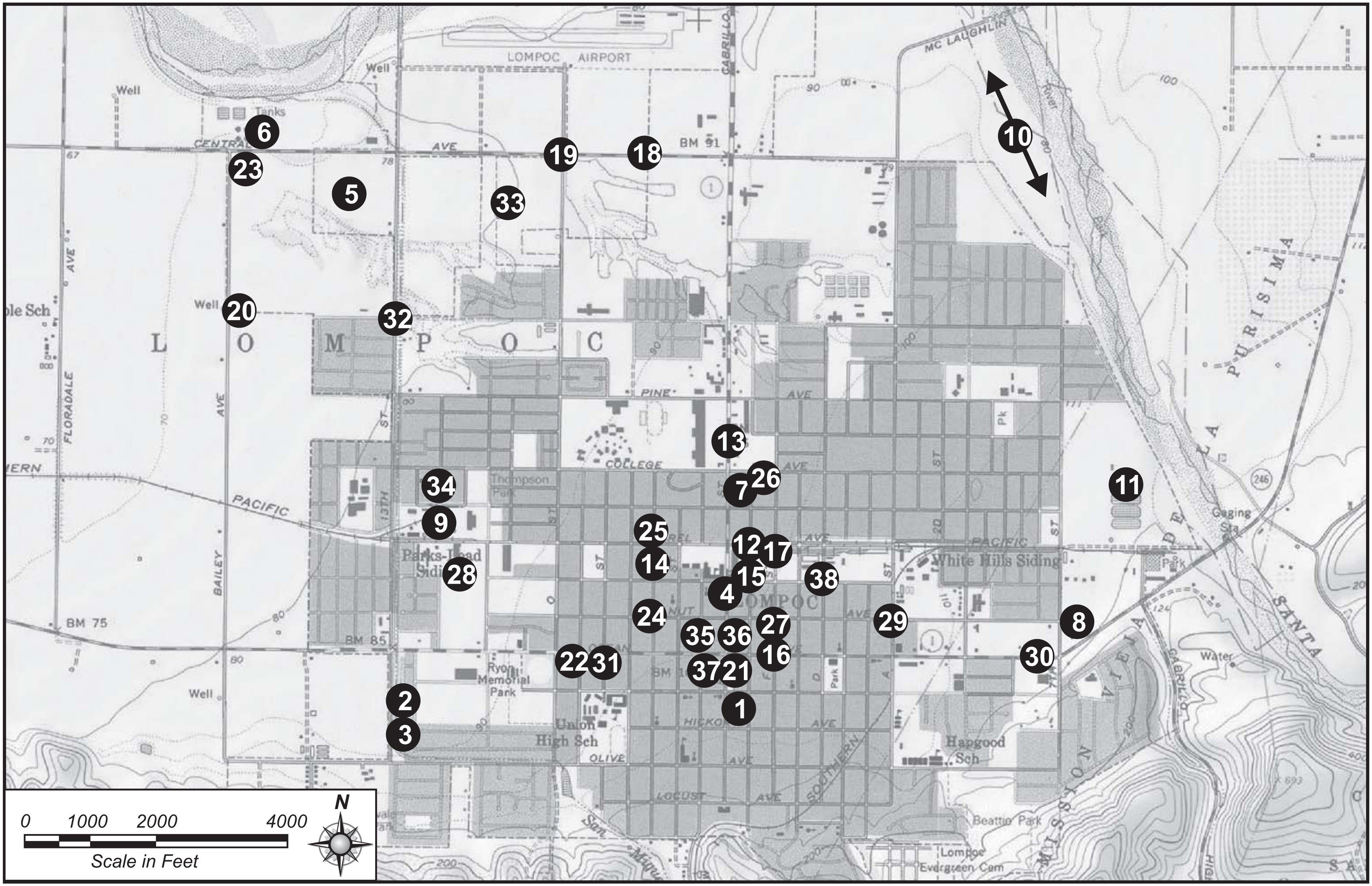

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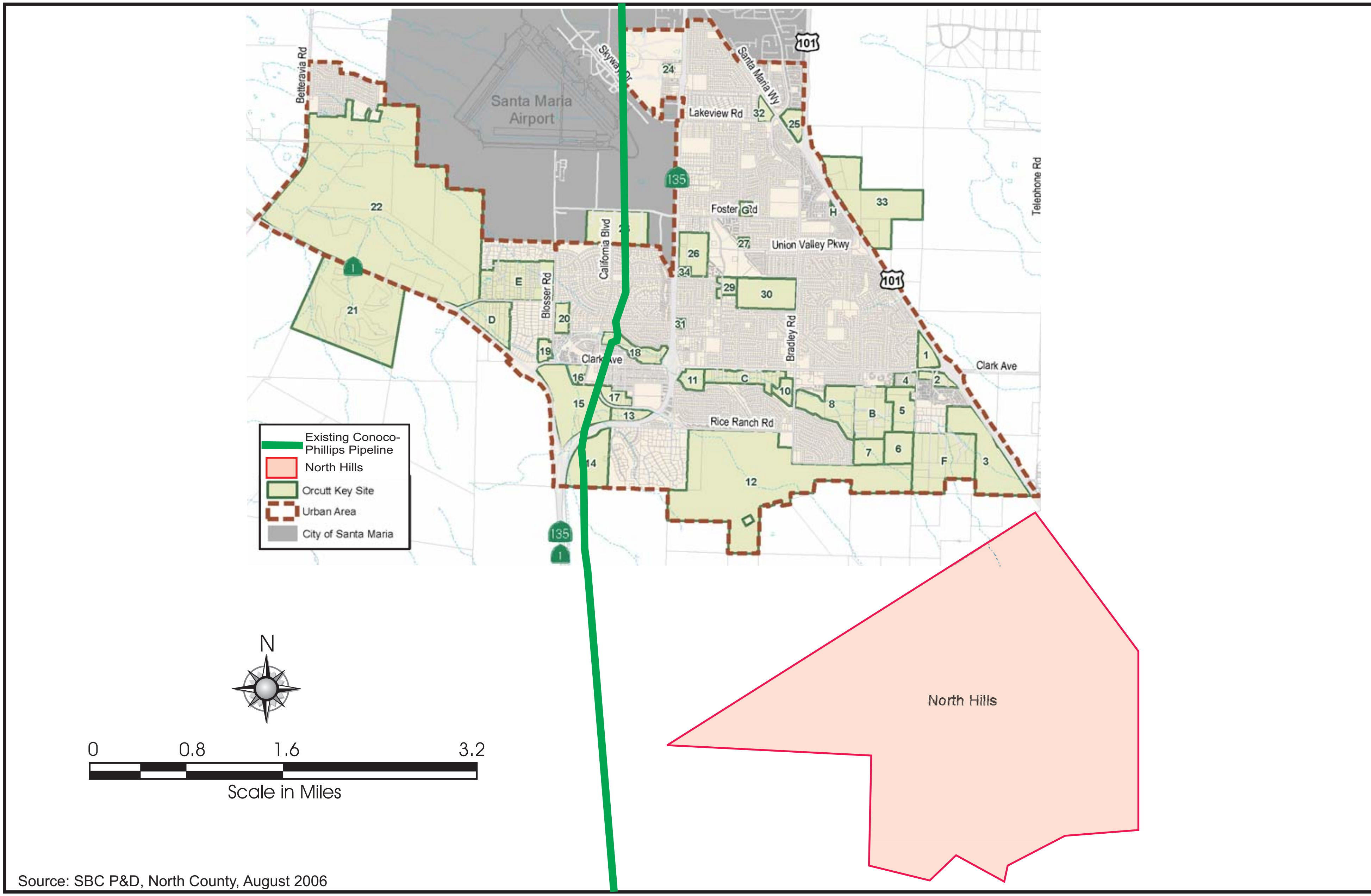
Figure 4-4

Location of Cumulative, Residential, Commercial, and Industrial Projects - Incorporated City of Lompoc



Source: SBC P&D, North County, August 2006

PREPARED BY Aspen Environmental Group

Figure 4-5

Location of Cumulative Residential, Commercial, and Industrial Projects - Orcutt/Santa Maria Area

5.0 ANALYSIS OF ENVIRONMENTAL ISSUES

Chapter 5 presents an analysis of the environmental impacts associated with the Tranquillon Ridge Project (proposed project). This project is unique in that it represents changes to existing facilities and operations, rather than construction and operation of entirely new facilities. These existing facilities are considered part of the environmental setting (i.e., baseline), for evaluating the environmental effects of the proposed project.

The baseline should normally be the physical environmental conditions in the vicinity of the project, as they exist at the time the Notice of Preparation is published (California Environmental Quality Act [CEQA] Guideline Section 15125). Where a proposed project will modify an existing project, it is important that the baseline also consider historic operations of the existing project based upon "normal fluctuations" as determined by need, capacity, and other relevant factors. ~~Table 2.1 in Section 2.0, Project Description, presents the permitted maximum operating levels of the existing facilities and their current production volumes.~~

Development of the Tranquillon Ridge Field, as proposed, would increase the production volumes above current rates (but within permitted capacity) and require some facility modifications as presented in Section 2.3. These operational and structural changes to the existing PXP facilities are analyzed by issue area in this section.

The 2006 scoping document for the proposed project identified 16 issue/resource areas where significant impacts could occur. For each issue area, the impact evaluations are presented in the following format:

- Environmental Setting
- Regulatory Setting
- Significance Criteria
- Impact Analysis of the Proposed Project
- Impact Analysis for the Alternatives
- Cumulative Impacts
- Mitigation Monitoring Plan
- References

Within each issue area, the defined study area (environmental setting) is presented for purposes of the impact analysis. In most cases, the study area is the region in the vicinity of the proposed project. Exceptions include, but are not limited to, regional air quality data and transportation networks. The study area or environmental setting also includes a comprehensive list of regulations that apply to each issue area within the context of the study area (Regulatory Setting).

Santa Barbara County significance criteria are then presented by issue area. These criteria define the threshold or limit against which a potential environmental impact is considered. The term "significance" is used throughout the EIR to characterize the magnitude of the projected impact. For the purposes of this EIR, a significant impact is a substantial or potentially substantial change to resources in the local project area or the area adjacent to the project in comparison to the thresholds of significance established for the resource or issue area. Within each issue area an analysis of potential impacts compared to the appropriate significance criteria is presented.

The impact analysis sections also include detailed mitigation measures that have been developed to reduce the severity of the identified impacts. Mitigation measures have been developed for both the proposed project and the project alternatives. Based on the application of available mitigation measure(s) to an identified impact, the residual impact is then described. All impacts identified in this EIR have been classified according to the following criteria:

- ***Class I - Significant adverse impacts that are unavoidable:*** Significant impacts that cannot be effectively mitigated. No measures could be taken to avoid or reduce these adverse effects to insignificant or negligible levels. Even after application of feasible mitigation measures, the residual impact would be significant.
- ***Class II - Significant but mitigable adverse impacts:*** These impacts are potentially similar in significance to those of Class I, but can be reduced or avoided by the implementation of mitigation measures. After application of feasible mitigation measures, the residual impact would not be significant.
- ***Class III - Adverse but not significant impacts:*** While not required under CEQA to reduce an impact to a level of insignificant, mitigation measure(s) are often applied to an identified adverse but not significant impact to mitigate the impact to the maximum extent feasible in accordance with Santa Barbara County policy.
- ***Class IV – Beneficial impacts:*** Effects that are beneficial to the environment.

Identified impacts for the proposed project and alternatives are systematically presented in impact tables throughout each issue area. Each of these impact tables identifies the following:

- Impact #,
- Impact Description,
- Phase in which the impact would occur, and
- Residual Impact (includes impact classification)

The defined phases for which an impact could occur include the following:

- ***Construction***: Impacts associated with construction activities.
- ***Drilling***: Impacts associated with the drilling of wells on Platform Irene.
- ***New Operations***: Impacts due to the operation of new facilities.
- ***Increased Throughput***: Impacts associated with the increase in oil and gas throughput through the project pipelines, processing facility, and platform over baseline conditions. This increase in production has the potential to increase the magnitude and/or severity of the existing impact.
- ***Extension of Life***: Impacts due to an increase in the expected life of the Point Pedernales Project over what was assumed in the 1985 Point Pedernales EIR/EIS and the 1993 Point Pedernales SEIR, as modified via permit approvals. Impacts associated with extension of life do not represent new impacts but impacts that exist for the current Point Pedernales operations. The proposed Tranquillon Ridge Project would extend the duration of time over which the existing impact(s) would occur.

Each impact table is then followed by available mitigation measure(s) to reduce the severity of the identified impact. Finally, the residual impact as presented in each impact table is described and the impact classification identified.

Impacts and mitigation measures, for the proposed project and project alternatives, are also systematically presented in tabular form in the impact summary tables, which immediately follow the Executive Summary.

5.1 Risk of Upset/Hazardous Materials

This section discusses potential risk of upset impacts associated with the proposed Tranquillon Ridge Project. Risk of upset issues include those scenarios that could adversely affect public health as well as those scenarios that could discharge hazardous materials into the environment. Information presented below outlines environmental setting, regulatory setting, significance criteria, potential upset scenarios, the levels of risk associated with these scenarios, and the significance of the upset scenarios. This section also presents discussions on impacts associated with alternatives to the proposed project as well as projects identified in the cumulative project analysis.

5.1.1 Environmental Setting

For the proposed project, environmental setting or baseline conditions would reflect the baseline risks of upset associated with the existing Platform Irene, pipeline system and processing facilities. Once these baseline risks are quantified, the significance criteria can be used to determine if there is an increased level of risk associated with the proposed project or alternatives, and if the proposed changes in the system introduces a significant increase in the risk of upset or an increase in the severity of an already significant impact.

5.1.1.1 Regional Overview

Santa Barbara and San Luis Obispo Counties have a number of oil and gas fields located onshore and offshore. Development and exploitation of these natural resources have occurred in these counties for approximately a century. As a result, there are many different oil and gas facilities of different ages and functions scattered throughout the region and connected by various pipelines.

Oil and gas pipelines and processing facilities in the region are engineered to current safety standards at the time of construction and undergo rigorous safety studies and environmental reviews during approvals and prior to construction. However, due to the nature of the materials handled by these pipelines and facilities, they still pose risks to people and the environment in the vicinity. Upsets in normal operations of the oil and gas pipelines and facilities in the area pose a risk of exposing the population to accidental releases of materials, which can subsequently lead to biological or hydrological damage, exposure to toxic materials, fires and explosions.

5.1.1.2 Study Area and Scope

For the risk of upset analysis, the study area includes the existing facilities and pipelines associated with the proposed project, its alternatives, and the areas in the immediate vicinity of the proposed project that could be affected by an upset at the facilities. The facilities where the risk of upset is potentially changed due to the proposed project include:

- Platform Irene
- Offshore pipeline route
- Onshore pipeline route from landfall to the Lompoc Oil and Gas Plant (LOGP)
- LOGP Facility
- LOGP to Summit pipeline segments

- PXP Sales Gas Pipeline

An upset condition at the listed facilities could have an adverse impact on the public or environmental resources in the study area. Impacts to water and biological resources are discussed in the appropriate sections of this EIR. The study area that would be affected in terms of public safety by an upset condition is the population near the City of Lompoc and the land and any population along the pipeline route between landfall and the LOGP and north of the LOGP to Summit Pump Station. Impacts to water, biological or marine resources near Platform Irene and the Irene/LOGP pipeline due to a release from these facilities are also examined by assessing the potential spill sizes and marine trajectories. Public safety-related impacts to boats and populations in the vicinity of Platform Irene are assumed to be minimal and are therefore not quantified (as per the original Point Pedernales EIR, 1985 and previous studies including the Venoco Ellwood Quantitative Risk Assessment, 2000).

Oil spill volumes that could be released in the event of a pipeline spill are identified, with the assumption that the leak detection system, also known as the SCADA (Supervisory Control and Data Acquisition) system, responds appropriately and activates appropriate isolation valves. Motor Operated Valves (MOVs) along the line must be closed by the operator. Closing of the isolation valves within the appropriate response time would considerably reduce spill volumes from the pipeline segment. Evaluation of spill volumes for the worst-case scenario when the SCADA system malfunctions, or is overridden by an operator, is also addressed.

5.1.1.3 Characteristics of Crude Oil and Produced Gas

This section discusses the properties of crude oil and produced gas as they relate to safety impacts, such as oil spills, toxic exposure, and fires.

A crude oil spill from the pipeline could damage the environment if oil spilled on land, or in rivers, creeks, or the ocean, and could produce public safety concerns from fires that may arise if the oil burns. Flammable vapors (propane, butane, and pentane) may also emanate from the crude oil, and there may be safety hazards arising from toxic vapors in the crude oil (primarily benzene and hydrogen sulfide).

As crude oil emerges from the wellhead, is a heterogeneous mixture of solids, liquids and gases. This mixture includes sediments, water, salts, and acid gases, including hydrogen sulfide and carbon dioxide. The major hydrocarbon constituents include:

- Alkanes (paraffins) – straight-chain normal alkanes and branched iso-alkanes with the general formula CnH2n+2, where C stands for carbon and H stands for hydrogen. The major paraffinic components of most crude oils are in the C1 to C35 range.
- Cycloalkanes (naphthenes) – saturated hydrocarbons containing structures with carbon atoms linked in a ring. The cycloalkane composition in crude oil worldwide typically varies from 30 to 60 percent.
- Aromatic Hydrocarbons – most commonly benzene, benzene derivatives, and fused benzene ring compounds. The concentration of benzene in crude oil ranges between 0.01 percent and 1 percent.

Crude Oil

Sulfur occurs in many natural compounds and as hydrogen sulfide (H_2S) in the crude oil. Total sulfur ranges from approximately 1 to 5 percent or higher by weight in crude oils, and hydrogen sulfide concentrations can reach 100 parts per million (ppm) in “sour” crudes. Other constituents of crude oil include nitrogen and oxygen compounds, ~~and~~ water, and metal-containing compounds such as vanadium and nickel.

Physical properties of crude oil are needed to assess the effects of a potential spill from the pipeline. Properties have been obtained for the types of crude oil most likely to be transported in ConocoPhillips's Line 300 pipeline system, including crude oil from Point Arguello, the Exxon Santa Ynez Unit, the LOGP, Bell Pump Station, and Orcutt Fields. These data are summarized in Table 5.1.1. Only the LOGP crude oil would affect the risks associated with the Platform Irene pipeline system.

Table 5.1.1 Crude Oil Properties

	Arguello Inc. Point Arguello	Exxon Las Flores	LOGP	Orcutt Fields	Bell (Cat) Station
API Gravity	21-22	21-22	16-18	14-36	13-15
Viscosity (centistokes at 100ºF)	130	446	213 (122)[a]	60	90-110
Sulfur Content (% wt)[b]	2	5	2	NA	4

Source: California Division of Oil and Gas.
a. Parentheses indicate temperature different than 100ºF.
b. Not the same as hydrogen sulfide.

However, as the emulsion mixture between Platform Irene and the LOGP does and would continue to have a large percentage of water (currently close to 88 percent water, with the Tranquillon Ridge Project decreasing this to close to 60 percent water), impacts would be limited to marine, biological, and hydrological, as opposed to safety impacts to populations. The large volume of produced water that is transported from Platform Irene to the LOGP inhibits the release of flammable vapor in the event of an oil spill, thus minimizing potential fire and explosion hazards. Therefore, the safety analysis is primarily focused on gas transportation and processing, and crude transportation north of the LOGP (at which point the crude would be dehydrated). Crude oil spills and frequencies are presented in order to understand the impacts to marine resources, biology, and hydrology.

Produced Gas

Produced gas transported from Platform Irene to the LOGP presents hazards in the form of toxicity, due to the presence of H_2S gas; flammability in the form of vapor cloud fires and explosions; and thermal radiation impacts due to flame jet fires emanating from a gas pipeline leak or rupture. Historic concentrations of H_2S in the gas have ranged from 800 parts per million (ppm) in 1993, when the Supplemental EIR (SEIR) was completed, to 5,000 ppm in 2006. Current pipeline operating pressures range up to 570 pounds per square inch (psig). The Point Pedernales Project gas pipeline is currently permitted to transport gas with a maximum hydrogen sulfide concentration of 8000 ppm.

Hydrogen sulfide is a toxic gas often present in the fluids extracted from wells. In the gas phase, it produces odors at levels down to 0.007 ppm (SBC Fire Department, 2000a) and can produce injuries at levels equal to 30 ppm (ERPG [Emergency Response Planning Guidelines] -2) and fatalities as low as 100 ppm (ERPG-3) if exposed to for long enough periods (>60 minutes). It has a characteristic "rotten egg" smell. A complicating factor that increases its hazards is that it also produces olfactory paralysis (loss of ability to smell) at levels as low as 50 ppm, or below those at which it could produce injuries or fatalities.

5.1.1.4 Existing Facility Risks

The potential impacts for the currently operating Platform Irene to LOGP pipeline system and the LOGP facility were addressed in the Point Pedernales EIR in 1985, the Unocal Point Pedernales Project SEIR in 1993, the Torch Gas Plant Project Addendum in 1996, and the Torch Tranquillon Ridge Final EIR (FEIR) in 2002.

These risks include:

- Potential spills both offshore and onshore to the LOGP of oil/water emulsion and produced water returned to Platform Irene
- Potential spills of crude oil from the LOGP to Summit pipeline
- Potential releases between Platform Irene and the LOGP of produced gas containing up to 5,000 ppm of hydrogen sulfide
- Potential releases of oil or natural gas from the processing equipment at the LOGP
- Potential releases of sales gas from the LOGP to The Gas Company
- Potential releases of liquefied petroleum gas due to truck shipments from the LOGP to local customers.

The Point Pedernales EIR did not classify risk into the Santa Barbara County (SBC) California Environmental Quality Act (CEQA) significance criteria (e.g., Class I, II, and III). However, risks to the public health were calculated and FN (frequency versus number of fatalities/injuries) curves were developed and can be assessed based on the current SBC criteria. These criteria would indicate that a significant risk to public safety would exist primarily for gas liquids transportation, where it was calculated that a severe consequence (one or more fatalities) could occur over the project lifetime. However, subsequent to the Point Pedernales 1985 EIR, the 1993 SEIR and 1996 Addendum developed additional release scenarios. Due to increased gas processing, previous release scenarios were reassessed and transportation of gas liquids has subsequently changed.

The existing PXP facilities are being maintained according to the Point Pedernales Safety, Inspection, Maintenance, and Quality Assurance Program (SIMQAP). Current pipeline operations include performing ongoing routine internal and external pipeline surveys. Pipeline surveys include, but are not limited to, smart pigging[1], corrosion checks, pressure tests, air and ground patrols, visual surveys using a video camera, and cathodic protection surveys. These periodic internal and external pipeline inspections are performed on a schedule specified by the Minerals Management Service (MMS), SBC, and Santa Barbara County Air Pollution Control District (SBCAPCD) permits, and PXP policy. These inspections also satisfy the requirements of the Department of Transportation (DOT) and the California State Fire Marshal (CFSM) for the pipelines. In addition, the County Systems Safety Reliability Review Committee (SSRRC) conducts an annual SIMQAP audit and approves pipeline and LOGP operations plans, repair and maintenance execution plans, and future facility modifications. The summary of the permitted

[1] A smart pig is an internal device that is run through the pipeline on a periodic basis to check for pipeline anomalies, including reduction in pipeline wall thickness. PXP utilizes a high-resolution smart pig that detects metal losses and pipe thickness along the pipeline.

and current operation parameters of the three pipelines is given in Table 2.7. Table 5.1.2c, Section 5.1.1.4.2, provides a summary of the PXP pipeline corrosion control and monitoring program, and Sections 5.1.1.4.2 and 5.11.4.3 provide further detail on the program. Table 5.1.2a provides a summary of the history of repairs made to the Platform Irene to LOGP pipelines:

Table 5.1.2a History of PXP Pipeline Repairs

Year	Summary of Repair
20" Emulsion Pipeline, Platform Irene to LOGP[1]	
1986	Line installed and tested.
1987	Line placed into service.
1995	Bolts loose/missing on riser clamp bracket. Replaced bolts and reattached clamp.
1997	Replaced the 60' spool at valve site #2. It was used as a test spool to check for corrosion.
1997	Replaced spool and flanges at subsea-tie-in spool #2. A failure occurred in the heat affected zone of a welded flange. This was caused by improper pre-heating during the welding of the flange to the pipe during construction.
1997	Installed a 2' welded split sleeve on the riser in the splash zone. Riser corrosion was detected in splash zone with visual inspections.
1998	Installed 5' welded split sleeve at wheel count 88,527.10' (onshore). The smart pig identified an anomaly which was verified with a UT inspection.
1999	The spool at the base of the riser was replaced. It was suspected that the flange was not hardened properly during its installation during construction.
2001	The flanges and spools were replaced at tie-in #1 and #3. It was suspected that the flanges were not hardened properly during their installation during construction.
2003	A clock spring was installed near valve box #6. Internal corrosion was detected by smart pig.
2005	The flange set at bottom of riser was completely encapsulated. Carbon content data was marginal. With this 2005 repair all sub-sea flanges have been either replaced or encapsulated.
2005	Replaced pipeline spool at valve box #2. No data or required material certifications could be located for the flanges and part of the piping that was replaced in 1997.
2006	Removed loose coating shield from the riser. The shield was not allowing cathodic protection (CP) current to the riser under the shield. CP is now protecting this area. No further corrosion activity has been noted.
8" Produced Water Pipeline, LOGP to Platform Irene[2]	
2000	Subsea spans in excess of allowable length were detected during diver and ROV inspection; span supports were designed, fabricated and installed by divers.
2004	An anomaly was inspected by divers at 92,445' from the platform. The anomaly was originally detected by the smart pig. The diver inspection determined that an external groove was created during construction. This groove is posing no operational concerns with the pipeline and is being monitored closely with continued smart pigs.
2005	The insulating fitting was replaced at valve site #1. A smart pig detected corrosion in the fitting. The fitting was removed and replaced with a section of pipe.
8" Sour Gas Pipeline, Platform Irene to LOGP[3]	
2000	Sub-sea spans in excess of allowable length were detected during diver and ROV inspection; span supports were designed, fabricated and installed by divers.

1. Emulsion line installed in 1986 and placed into service in 1987.
2. Produced water line installed and placed into service in 1987.
3. Sour gas pipeline installed in 1986 and placed into service in 1987.

5.1.1.4.1 Risk Assessment Methodology

This risk assessment evaluates baseline failure rates, spill volumes, impacts, and associated risks, as per the SBC safety criteria, that exist at the facilities as currently configured. Previous documents covering the Point Pedernales Field Development (1985 EIR, 1993 SEIR, 1996 Addendum, and 2002 EIR) were used to formulate the scenarios, the failure frequencies, and the hazard zones for current operations. Additionally, recent studies from the Minerals Management Service (MMS) and failure frequency databases were used to update the information. Modeling was conducted to address the ~~recent~~ increase in permitted hydrogen sulfide concentrations in the produced gas from 4,000 ppm to 8,000 ppm. Current population information was used to estimate the population that could be affected by an accidental spill or release. The frequencies and consequences were then used to prepare an FN curve, as per the SBC safety criteria. At the time of the SEIR and Addendum, the SBC criteria utilized a risk matrix as opposed to the current risk profile (FN) method. Therefore, the additional issues developed in the SEIR and the Addendum are folded into the 1985 EIR analysis to produce new risk profiles in this report.

Discharges to the environment, primarily crude oil spills from Platform Irene and the associated pipelines, are also addressed. Calculations related to these discharge volumes, frequencies and probabilities are based on the 1985 Point Pedernales EIR, the PXP Core Oil Spill Response Plan (November, 2004) and Supplement (July, 2005), and various failure rate and spill rate sources such as the MMS and the Office of Pipeline Safety. A number of different frequency sources and calculations have been included in order to give a range of frequency numbers and thereby address the potential uncertainties associated with estimating future events.

For oil spills into the marine or onshore environment, estimated frequencies (events per year) are used to develop the probability (in percent) of an oil spill over the project lifetime utilizing the MMS probability approach. Spill volumes are also estimated. Spill volumes are generally divided into leaks or small spills, and ruptures or large spills with small spills being less than 100 barrels (bbls) and larger spills being more than 100 bbls. As the criteria for risk impacts only addresses public safety, spill volumes and probabilities are used to compare the baseline with the proposed project and as a guide for the biology, water and marine resources sections.

A range of scenarios was developed and analyzed in the original EIR, SEIR and Addendum, and the 2002 EIR. Each of these scenarios is discussed below.

Crude or Emulsion Pipeline Scenarios

The oil emulsion pipeline, or the wet crude pipeline, between Platform Irene and the LOGP has a 20-inch outer diameter (OD) with a Maximum Allowable Operating Pressure (MAOP) of 1,194 psig.

Historical production levels from the Point Pedernales Project peaked at close to 25,000 barrels per day (bpd) of dry oil in 1987 and 1989. Production levels in 2005 averaged approximately 7,000 bpd of dry oil and 50,000 bpd of water. The peak monthly production in 2005 was approximately 8,600 bpd of dry oil.

The following scenarios involve a rupture (spill greater than 100 bbls) or a leak (spills less than 100 bbls) of the crude or emulsion pipeline. In the event of a pipeline rupture, the leak detection system should be capable of detecting and isolating (shutting off flow to the leak point) the pipeline within five minutes. Once the pipeline is shutdown, the oil would continue to spill until the oil was drained from the affected segments of the pipeline. The maximum spill volumes from the pipeline are a function of the location of the pipeline rupture in relationship to the isolation valves, check valves, and the pipeline elevation profile, and the duration of the pumping that occurs before the leak or rupture is detected. If the leak detection (SCADA) system is not operational or is overridden by an operator, it is assumed that the pumping would continue for 30 minutes before the rupture would be detected and response initiated.

How an operator responds to SCADA system alarms and automatic shutdowns has an impact on the size of the oil spill in the event of a leak. The 1997 release from the wet oil pipeline was exacerbated by an operator restarting the shipping pumps after they had automatically shut down in response to an abrupt loss of pressure in the pipeline, thereby increasing the release volume over what would have been released had the pumps been left off and the pipeline isolated sooner. Following the 1997 incident, Nuevo Energy (the operator at the time) developed a new training document: *Response Procedures for Unintended Shutdown of Platform Irene and the 20" Oil Emulsion Pipeline from Platform Irene to the LOGP*. This document outlines the specific steps that must be taken to verify the reason for pump shutdown before the pumps can be restarted. If the cause is a leak, the Oil Spill Response Plan would be implemented. PXP continues to implement these procedures. Effectiveness of oil spill response techniques is discussed in Section 5.5, Marine Biology.

The frequency of a release (leak or rupture) is primarily a function of the construction of the pipeline, the maintenance and operational practices, as well as third-party damage. The volume of the subsequent release is a function of the training of the operators as well as the design, construction and maintenance of the leak detection system.

Crude or emulsion pipeline leaks are similar to ruptures described above, except that they address smaller sized releases from the pipeline. This distinction has been made between leaks and ruptures to account for the different failure frequencies that exist between ruptures and leaks. Pipeline leaks are most commonly a result of corrosion, erosion, or third-party damage to the pipeline. The project's pipeline leak detection system uses a volume-based monitoring system to assist in the detection of small leaks. Typically, a small corrosion-induced leak would have a leak rate of 1 to 2 barrels per hour, which might require approximately 10 to 12 hours to detect.

With any spill of crude oil, there is the potential for a fire associated with a spill at either the LOGP or along any of the pipelines. If the crude oil spill were to catch fire, there could be a subsequent threat to public safety through thermal radiation effects. Given the properties of the crude oil, the likelihood of an explosion is virtually non-existent, and therefore explosions have not been addressed further in this document. In addition, due to the high water content in the crude oil transported to the LOGP from Platform Irene, a fire and subsequent safety impacts are assumed to be non-existent for the Platform Irene to LOGP emulsion pipeline (as per the 1985 Point Pedernales EIR). However, impacts to other resources (e.g., biology, water quality, agriculture) for that pipeline segment would remain.

It is assumed that a crude oil spill along the LOGP to Summit Pump Station route (where water content is minimal) could have the potential for public safety impacts. This is due to statistics that indicate possible public safety impacts related to crude oil transportation. The Department of Transportation Office of Pipeline Safety (DOT OPS) database indicates there have been no fatalities, and only nine out of 841 crude oil pipeline incidents led to injuries over a 14-year period in the United States. All but two of these incidents have been associated with Class 1 (flammable) liquids. For the period pre-1985 (1968 to 1985), there were eight crude oil pipeline incidents that produced fatalities and 12 incidents that produced injuries. The DOT OPS database is unclear if these incidents occurred at or near other processing equipment. The California State

Fire Marshal's Hazardous Liquid Pipeline Risk Assessment report (CSFM, 1993) indicates that over a 10-year period (1981-1990) there were no injuries or fatalities associated with crude oil pipeline spills in California.

Offshore marine impacts would be associated with spills of the oil/water emulsion into the marine environment, which could cause impacts to marine resources. The frequencies and spill volumes are examined utilizing MMS and other standard approaches.

Gas Pipeline Scenarios

Gas pipeline leaks and ruptures have also been included here, consistent with previous analyses in the Point Pedernales 1985 EIR, 1993 SEIR, 1996 Addendum, and 2002 EIR. Impacts due to high pressure gas releases are complex as the gas transported from Platform Irene is not processed and therefore contains some gas liquids in vapor form and contains some hydrogen sulfide. Consequences are based on H_2S exposure or flammable vapor cloud/explosion exposure to nearby populations. The previous environmental documents addressed a range of pipeline operating conditions. These included throughput ranges up to 6 million standard cubic feet per day (mmscfd) and 600 psig operating pressures. The Point Pedernales 2005 year average production was 2.6 mmscfd, with operating pressures in the 425 to 570 psig range. Peak annual average (running 12 month average) levels have ranged from 2.2 mmscfd in 1994 up to almost 9 mmscfd in 1995 with operating pressures in the 400 to 500 psig range. As the operating pressure of the pipeline is the dominant factor in determining the size of impact zones, the SEIR 600 psig case has been used as the worst-case operating scenario in this analysis.

A gas pipeline release could cause impacts to biological resources along the onshore pipeline route. These might include fatalities of animals or wildlife, or impacts to sensitive species due to fires.

Gas pipeline releases offshore are assumed to present insignificant risks to the public due to the remote location and low density of public receptors.

LOGP Scenarios

Failures at the LOGP could range from process vessel ruptures to pipe ruptures or leaks. Potential failures could also occur during gas liquids vessel storage and handling operations. Consequences could include an oil spill with subsequent fire, a gas release with subsequent toxic hydrogen sulfide exposure, flammable gas vapor cloud explosions, or thermal radiation effects.

Platform Irene Scenarios

Scenarios are developed for potential emulsion fluid releases from Platform Irene into the marine environment. These releases take into account the platform drain system, which is currently designed to capture leaks and redirect them back into the process stream. Scenarios related to gas releases or impacts to the public were not considered due to the remote location of the facility.

Transportation Scenarios

Transportation risks were limited to examining the risks associated with the onshore transportation of gas liquids. Risks due to gas liquids transportation include a spill with a subsequent fire or explosion affecting persons along the transportation corridor. Transportation impacts were assessed in the 1985 Point Pedernales EIR. This assessment is scaled to reflect the current operating conditions.

Biology and Hydrology

These areas are addressed in Section 5.2, Terrestrial and Freshwater Biology, Section 5.3, Onshore Water Resources, Section 5.5, Marine Biology, and Section 5.6, Oceanography and Marine Water Quality of this EIR. The spill volumes and frequencies used in those sections are documented in this Risk of Upset section. The spill volumes and spill frequencies and probabilities over the proposed project lifetime are developed as part of this analysis.

5.1.1.4.2 Existing Onshore Facilities

Onshore facilities include the onshore portion of the Platform Irene to LOGP pipelines (gas, emulsion and produced water return), the LOGP Facility, the PXP Sales Gas pipeline, and the crude oil pipeline from the LOGP to the Summit Pump Station.

Existing Onshore Emulsion Pipeline Spill Frequencies and Probabilities

While pipelines have historically had one of the lowest spill rates of any mode of transportation, there still is some level of risk that a pipeline could leak or rupture. In order to estimate the frequency of such an event and the probability of the event occurring over the project lifetime, historic data for other operating liquid pipelines has been used to estimate the probability of a leak or rupture for the existing pipeline.

Historically, spills from pipelines have been attributed to a number of different causes, including corrosion, defects in material or welding, damage from third-party interference, natural hazards such as earthquakes or landslides, and operational errors.

Information on the number and causes of pipeline spills in the United States greater than 50 barrels in size is available from the DOT OPS. These data were obtained for spills from 1968 to 2000 (information from pre-1985 is less reliable in the DOT OPS data). Information is available from the OPS for crude-oil pipelines, as well as for all liquid pipelines (DOT OPS, 1990). In the years since 1985, crude oil has comprised 42 to 51 percent of the liquid spilled from pipelines, and petroleum products have made up 47 to 55 percent of the total volume spilled. Spills due to corrosion rank as the most frequent cause with an estimated 39 percent of all failures (since 1985). The number of spills due to corrosion has remained in the same range since 1985, ranging from a high of 36 and 35 spills in 1987 and 1996, respectively, down to eight spills in 2000.~~ There has been no trend of decreasing numbers of spills due to corrosion since 1985.~~ The number of spills due to third-party impact ranks next with 30 percent of the spills. The overall spill rate of crude oil pipelines was estimated by the DOT OPS database to be $8.9x10^{-4}$ spills (with spill volumes greater than 50 barrels) per mile year.

The California State Fire Marshal (CSFM) publication, Hazardous Liquid Pipeline Risk Assessment (CSFM, 1993), analyzes leak information for the 7,800 miles of liquid pipelines within California for the years 1981 through 1990. This study enables pipeline spill rates to be adjusted based on variables such as pipeline age, diameter, operating temperature, etc., as well as spill cause. The study found that external corrosion was the major cause of pipeline leaks, causing approximately 59 percent of spills, followed by third party damage at 20 percent. Older pipelines and those that operate at higher temperatures had significantly higher spill rates. The

CSFM base rate for pipeline crude oil spills was calculated to be 9.89×10^{-3} incidents (of any size) per mile year. Note that this is for crude oil only. Crude oil had the highest spill rate primarily due to the transportation of crude oil at elevated temperatures thereby increasing the rate of external corrosion. This is because faster corrosion rates occur at elevated temperatures when metal comes in contact with soil moisture.

Spill frequencies were estimated using the latest information on crude oil pipeline spill rates available from the CSFM report. This approach was considered to be the most conservative. As discussed above, the DOT OPS predicted spill rates lower than the CSFM report. The CFSM study involved surveying of pipeline operators. Reporting requirements had changed during the 10-year study period thereby possibly affecting the accuracy of the data. However, the report indicated that most operators kept records on all leaks, regardless of reporting requirements. Some discrepancies in the data were due to leaks reported on pipeline segments that were subsequently replaced or leaks on pipeline segments that had been shut down. Both of these issues, however, would add conservatism to the estimated leak rates. The CSFM leak rates are therefore considered to be quite conservative and to overestimate the existing risks.

The CSFM report presented a set of hazardous liquid pipeline incident rates for all pipelines and uses. A review of the CSFM report shows that the following pipeline design and operation parameters can have a significant effect on pipeline spill rates:

- Pipeline age
- Pipeline diameter
- Pipe specification
- Pipe type
- Normal operating temperature
- SCADA (leak detection) system
- Cathodic protection system
- Coating type
- Internal inspection

Better coatings have been developed over time, so newer pipelines tend to have better coatings than older pipelines. The type of coating can have a significant effect on lowering external corrosion rates. The Point Pedernales emulsion, produced gas, and produced water lines have a PRITEC 70/15 coating, which is a polyethylene topcoat with a butyl rubber adhesive. The CSFM database showed a mean year of pipe construction beginning to use this coating was 1973. Therefore, for lines with this coating, the credit for pipeline age was considered redundant and not applied.

Based on the CSFM data, pipeline-specific spill rates can be estimated for a pipeline based on the above-listed parameters. Using the CSFM data, the following pipeline design and operational parameters for the emulsion pipeline (Platform Irene to LOGP) were used for baseline operating conditions. The correction factor is a multiplier by which the CSFM base rate (9.89×10^{-3} for crude oil pipelines) would be multiplied to develop the parameter specific failure rate. The correction factor is calculated by taking the incident rate for the pipelines that contain the specific parameter of interest and dividing it by the average incident rate. For example, the pipeline diameter incident rate for 16 to 20 inch pipelines is divided by the average incident rate for pipelines of all diameters. Another example includes the pipeline incident rate for 180°F operating temperature is divided by the average incident rate for all pipeline operating temperatures. The CSFM Study provides the incident rates for the various pipeline connection factors.

Correction factors greater than one indicate~~s~~ worse than average performance for that parameter while correction factors of less than one indicate~~s~~ better than average performance.

- Pipeline diameter of 20 inches (0.49 correction factor)
- Pipeline specification is average (1.0 correction factor)
- Pipeline type is API 5L X46 grade, electric resistance welded (0.71 correction factor)
- Operating temperature of 180°F (2.14 correction factor)
- SCADA system is present (0.9 correction factor)
- Cathodic protection system is present (0.98 correction factor)
- Pipeline coating is polyethylene butyl adhesive (0.09 correction factor)
- Pipeline is internally inspected (0.63 correction factor)

Based on the above pipeline specifications, a pipeline specific spill rate was calculated from the CSFM base data with the correction factors, which is lower than the DOT OPS spill rate due to the relative design of the pipeline versus those that comprise the DOT OPS database. The CSFM report also estimated that larger spills (greater than 100 barrels) comprise approximately 18 percent of the total number of spills. These larger spills are assumed to equate to a rupture of the pipeline, whereas spills less than 100 barrels would equate to a leak.

Frequencies and probabilities of pipeline spills for ruptures and leaks are shown in Table 5.1.2b below.

Table 5.1.2b Current Operations Onshore Emulsion Pipeline Spill Frequencies and Probabilities, CSFM

Scenario	Spill Frequency per year	Lifetime Spill Probability, %
Onshore Emulsion Pipeline ruptures	8.59×10^{-4}	0.9
Onshore Emulsion Pipeline leaks	3.68×10^{-3}	3.6

Existing project lifetime until 2017 (ten-year remaining life)
Spill rate based on the base rate of 9.89×10^{-3} incidents/mile-year with the correction factors, which total 3.68×10^{-4} incidents/mile-year, multiplying by the pipeline distance of 12.2 miles and adding in the seismic frequency for ruptures of 5.1×10^{-5}/year for this pipeline.

Emulsion Pipeline Spill Frequencies for Seismic Activity

Based on the information in the CSFM report, three of the 507 pipeline spills reported during the 1981 to 1990 study period were related to seismic activity. Based on the total length of pipelines in the state (72,303 mile-years), and the number of spills observed during this ten-year period (3), one could assume that the base rate for seismically-induced spills could be 4.15×10^{-6} spills per mile-year, or a probability of 4.15 in a million of having a leak in any one-mile pipeline segment per year. This number has been included in the rupture rates in the above table.

PXP Emulsion Pipeline and LOGP ~~Summit Pipeline~~ SCADA System Failure Rates

The Point Pedernales facilities have a computerized leak detection system (SCADA) that is used to monitor and detect leaks in the Platform Irene emulsion pipeline between the platform and the LOGP. The computer-based system is a triply redundant August System Process Logic Controller (PLC) that monitors the pipeline's flow rates and pressure. Crude oil is metered at Platform Irene and the LOGP. The signal from the LOGP meter is transmitted to the LOGP control room August System PLC where it is compared with the flow meter from Platform Irene. Should the totalized fluid productions differ by more than the following limits, an alarm is sounded indicating a potential pipeline leak:

- 6 percent deviation over 12 minutes, or a
- 15 percent deviation over 20 minutes

Pressures are monitored at Platform Irene and the LOGP. If pressure crosses high or low shutdown set points as specified in the operating manual, then Shut Down Valves (SDVs) at the Platform and the LOGP will activate automatically. The August System PLC is monitored by the operator at the LOGP. If a low pressure pipeline shutdown occurs at the LOGP, the Operator is required by procedure to close the entire pipeline MOVs; thereby, initiating isolation of each segment of the line.

The time it would take the pipeline monitoring system to detect a release is a function of the size of the release. A large leak or rupture would most likely be detected in 30 seconds or less. Smaller leaks could take longer to detect. Once a leak has been detected, the valves can then be closed remotely and production shut down on Platform Irene using the Emergency Shutdown Switch (ESD). Automatic ESD-initiated valves can shut-in the oil pipeline in less than two minutes. Closure of the MOVs would be initiated by the operator and would take from 30 seconds to two minutes depending on the MOV.

Failure of the SCADA system to detect a leak or rupture of the pipeline would prolong the time that the pumps continue to operate and would delay emergency response actions. Failure of the SCADA system could be caused by faulty sensors, failure of the actuated valves to close or the pumps to shutdown, a communications failure, or operator error. In the event of a communication failure in parts of the SCADA system, alternative methods for detecting leaks are available as described in Appendix I of the PXP Core Oil Spill Response Plan. For example, the SCADA system is based on redundant microwave transmitters and receivers at the platforms and pipeline landfall and a hard-wired system along the onshore pipeline right-of-way. The platform and landfall systems are separate from the right-of-way system, so it is unlikely both would fail simultaneously. If the onshore right-of-way system failed (e.g., by being severed or washed out), the platform, landfall, and plant receiving systems would continue to function permitting the operator to monitor flow rates and detect a potential leak.

Flow rates are continuously monitored at the platform and onshore. If one or more of the redundant SCADA communications systems fail, pipeline flow rates would be manually monitored closely to detect potential leaks. In the event of complete SCADA system failure, the pipeline is shut down.

Emulsion and LOGP Pipeline Historical Activities and Releases

Historical incidents along the pipeline include a rupture of the sub-sea portion of the pipeline in September 1997. According to reports from the SBC, the MMS, the CSFM, and various consultants and other groups, the release and contributing events occurred between approximately 10 and 11 p.m. on September, 28, 1997 in 120 feet of water. Approximately 163 to 1,242 bbls of crude oil were released into the marine environment (SBCPD, 1/11/2001), causing oil to soil beach areas along Surf Beach and south of the Santa Ynez River. Approximately 635 to 815 birds were reported to be impacted by the spill (OSPR, 1998).

The 1997 failure of the pipe occurred at a flange weld approximately midway between Platform Irene and the shoreline. A crack developed in the weld connecting a flange to the pipe. The metal in this area was determined to be brittle due to the weld construction techniques where the metals were not properly pre-heated, thereby increasing the metal brittleness, and due to the high carbon content.

The shutdown system on Platform Irene operated correctly, quickly detecting the low pressure and initiating a low pressure alarm and shutdown from pressure transmitter, PT-171. This pressure transmitter is the emulsion line pressure transmitter located at Platform Irene just before the pipeline leaves the platform. This alarm initiated a shutdown of Platform Irene. This level 2 shutdown involved shutting the MOV-224 located downstream of PT-171, which isolated the pipeline from Platform Irene. This shutdown occurred within ten seconds of the PT-171 low pressure alarm. At this point, the operator attempted to restart the system, bypassing PT-171 and the pump shutdowns. The MOV-224 was re-opened within eight minutes of the initial PT-171 alarm. MOV-224 remained open for almost 80 minutes until the operator determined that there was an imbalance between Platform Irene shipping and the LOGP receiving. The pumps operated approximately 25 minutes during this 80-minute period.

On August 8, 2001, a release occurred at the Bradley Valve box on Tosco's (now owned by ConocoPhillips) Line 300 system (approximately 2 miles south of Suey Junction between Orcutt and Suey). The release filled the valve box and spilled into the neighboring parking lot. Approximately 182 bbls of crude oil were released. The cause was determined to be a valve failure related to corrosion. The valve had been installed in approximately 1976 and was manufactured in the 1950s. The SCADA system performed as expected, indicating an imbalance. However, the SCADA system operator reviewing available data (volume balance alarms and pressure data), incorrectly determined that a release had not occurred and allowed the system to continue to operate. Visual observations by a third-party initiated the shut down.

Emulsion Pipeline Smart Pigging Results

Smart pig internal pipeline inspections are conducted on the emulsion pipeline on an annual basis. PXP utilizes a high-resolution smart pig that detects metal losses and pipe thickness along the pipeline. A smart pig survey conducted in 1995 and 1996 (with a lower-resolution smart pig than is currently being used) indicated significant corrosion on segments of the pipeline, mostly on the bottom. A more aggressive corrosion prevention program was initiated which has reduced the rate of corrosion since that time. This program included increased continuous corrosion inhibitor injection, the weekly running of brushing pigs along with batch corrosion inhibitor addition with every pig run, and a survey of the adequacy of the cathodic protection. The cathodic protection survey indicated that the cathodic protection is provided per the National

Association of Corrosion Engineers (NACE) standards, except that rapid depletion of the anodes near the platform was anticipated because the galvanic potential is influenced by the platform.

~~The extent~~A summary of the PXP corrosion and monitoring program is presented in Table 5.1.2c~~a~~.

Table 5.1.2a~~c~~ PXP Pipeline Corrosion Control and Monitoring Program

Program Element	20" Emulsion	8" Gas	8" Water	Purpose
Line Cleaning	Weekly brush pigging	Monthly cup pigging	Weekly brush pigging	Remove solids (deposits) from pipe walls to eliminate corrosion
Corrosion Surveys	Instrumented pig (annual)	Instrumented pig (annual)	Instrumented pig (annual)	Identification of internal and external wall thickness anomalies
Corrosion Inhibitor Injection	Continuous and batch with pig run	Batch with pig run	Continuous and batch with pig run	Reduction of internal corrosion rates
Corrosion Monitoring	Coupons, Continuous electrochemical probes, Beta Foil, Microbiological cultures, Ultrasound, Chemical analysis (Fe/Mn), Visual inspection	Coupons, Microbiological cultures, Ultrasound, Chemical analysis (Mn/Fe), Visual inspection	Coupons, Continuous electrochemical probes, Beta Foil, Microbiological cultures, Ultrasound, Chemical analysis (Fe/Mn), Visual, inspection	To trend corrosion activity for optimization of internal corrosion control program
Cathodic Protection Monitoring	CP potential survey	CP potential survey	CP potential survey	To ensure field potentials do not drop below minimums

Source: PXP Pipeline Integrity Review Update presentation, August 2006.

More recent smart pig data using high resolution tools (October, 2005) found that 27,995 wall anomalies (most of these minor and not a safety issue) exist in the emulsion pipeline with the deepest being 50 percent of the wall thickness (PXP EIR Update Meeting Presentation, August 1, 2006). Most of these are on the bottom of the pipe and are internal to the pipe, characteristic of internal corrosion. All of the most significant anomalies (ranging in depth from 40 to 59 percent) are located in the onshore portion of the pipeline with the deepest anomaly being located immediately before Valve Site #6. Most (16) of the more serious anomalies are located between Valve Sites #6 and 7. The pipeline maximum allowable operating pressure has been reduced (de-rated) due to the presence of anomalies detected in 1995, 1996 and 1997. No de-ratings have occurred since 1997.

A report generated in July 1996 correlated corrosion levels with pipeline location in an attempt to identify areas that could, in the future, experience corrosion-related failures or require replacement type maintenance. Segments that indicated high levels of corrosion were between Valve Sites #1 and 2, between Valve Sites #3 and 4, and between Valve Sites #7 and 8.

As a result of the increased corrosion observed in the 1995 smart pig results, additional analysis and precautions have been implemented, including increasing the corrosion inhibitor injection rates to achieve 200 ppm residual, conducting additional laboratory testing of fluid corrosivity, and installation of additional corrosion monitoring devices. Corrosive rates have slowed since the program has been undertaken, and smart pig results from the last five years have indicated reduced rates of corrosion in the pipeline, that are in line with the pipeline's design parameters.

The emulsion pipeline has had a history of internal corrosion in the onshore section. In addition, as a result of the 1997 offshore failure, the emulsion pipeline would have been considered a "high-risk" pipeline by the CSFM. Since the 1997 release, smart-pig survey results have indicated that the internal corrosion program has been effective at substantially reducing the rate of corrosion in the onshore portion of the pipeline. In addition, smart-pig survey results indicate that external corrosion, the primary cause of the difference between "high risk" and "non-high risk" pipelines in the CSFM report, is non-existent for the emulsion pipeline.

Although internal corrosion has been experienced on the existing emulsion pipeline, adhering to DOT de-rating requirements reduces the failure rates associated with internal corrosion to levels similar to pipelines that do not exhibit internal corrosion problems. This is due primarily to the failure modes of corrosion failures. Corrosion-related failures are generally experienced when the corrosion on the pipeline reaches the point where the reduction in metal increases the stresses in the metal pipe wall, due to the operating pressure, and these stresses exceed the metal capabilities. Metals generally do not fail as long as the stresses are below a given threshold level, or minimum yield strength. However, if the stresses exceed this threshold, failure occurs quite rapidly. This is why de-ratings are conducted; to ensure that the stresses in the pipe walls are below the minimum yield strength of the pipe material. If the stresses are below the minimum yield strength of the pipe, then the pipe effectively operates like a new pipe would. This is supported by the fact that the CSFM report indicates that there is not a statistical correlation between failure rates and operating pressure, or pipe stresses.

It is important to note that the primary difference in rates between pipelines built since 1950 and those built before 1950 is due to external corrosion. External corrosion is not an issue with the current pipeline system.

<u>The Point Pedernales Safety Inspection, Maintenance, and Quality Assurance Program (SIMQAP) defines when repair and maintenance of the pipelines is required.</u> Smart pig runs are done on an annual basis as required by <u>the SIMQAP.</u> ~~the Point Pedernales Safety Inspection, Maintenance, and Quality Assurance Program (SIMQAP). Further~~ <u>As part of the SIMQAP, Santa Barbara County staff review the annual inspection results and require repairs where necessary, in coordination with the appropriate State and Federal agencies.</u> Tests also indicate that the cathodic protection system is effective in protecting the external surface of the pipelines. By removing the external corrosion influence, a high risk pipeline would be expected to have a similar spill frequency as a "non-high risk" pipeline, as per the CSFM report. Therefore, the onshore portion of the emulsion pipeline would be expected to have a spill frequency comparable with other "non-high risk" pipelines.

In August and September of 1999, then-operator Nuevo conducted inspections of the flanges on the offshore oil pipeline. The inspections found defects at the sweep spool or "J Tube" flange located at the bottom of the offshore pipeline riser. As a result of this defect, the "J Tube" spool was removed and replaced with a Big Inch flange spool similar to the 1997 repair. During repairs, the Point Pedernales facilities were shutdown and the pipeline was flushed with water. In September 2001, during flange inspections, Nuevo found cracks on a number of offshore flanges.

As a result, Nuevo undertook a program to remove and replace all existing flanges on the offshore oil pipeline, with the exception of the riser flange (Flange #1-1). These flanges have been removed and replaced. Nuevo applied for and received permits from SBC, California Coastal Commission (CCC), MMS, and California State Lands Commission (CSLC) for the repair work. Additional information on this project can be found in the Nuevo Energy Company Irene to Shore Oil Pipeline Repair Project Execution Plan (October 19, 2001). In 2005, PXP took steps to upgrade the integrity of the riser flange #1-1, which had not been replaced by Nuevo. Due to the location of the flange at the bottom of a long (greater than 250 foot) vertical leg of pipe, the flange was totally encapsulated using a specially designed clamping fixture instead of removing the flange and inserting a spool. All offshore flanges that were susceptible to failure due to micro cracks in the heat-affected zone have been replaced or encapsulated.

Existing Onshore Emulsion Pipeline Spill Volumes

The Platform Irene to LOGP pipeline volume is close to 1.9 million gallons (or 46,000 bbls). However, much of this volume would not be released in the event of a rupture or leak of the pipeline. This is due primarily to the onshore terrain of the pipeline which would trap some oil in the pipeline “low points”, or valleys. The presence of check valves would also prevent the oil from draining backwards down the pipe towards a break. The presence of MOVs would also allow the isolation of sections, thereby reducing a spill volume further. In addition, as oil is released, air must enter the pipeline to occupy the displaced volume. This can slow draining and prevent the maximum pipeline release volume from occurring. The CSFM report indicates that only 6 percent of incidents generated release volumes close to the theoretical maximum (greater than 50 percent of the pipeline volume between block valves). Much of this was due to terrain. For the purposes of this report, the maximum theoretical spill volume for each segment of the pipeline, including a terrain adjustment, was used (see Table 5.1.3).

Pipeline spill volumes for the onshore Platform Irene to LOGP pipeline are presented in Table 5.1.3. Spill volumes are shown for two scenarios: SCADA operational and SCADA not operational. If the SCADA system were to fail, thereby not closing the automatic valves, spill volumes would be increased on segments of the pipeline where spill volumes are controlled by the valves, not by terrain. Spill volumes are a function of both the line drainage and the pumping rate. If a leak or rupture occurs in the pipeline, crude oil will flow out of the pipeline due to gravity draining the pipeline and due to crude oil being forced through the pipeline from the shipping pumps. The length of pipeline that would drain is a function of the terrain and elevation profile of the pipeline and the characteristics of the crude oil. Higher viscosity crude oil would drain slower. In addition, relatively level terrain would contribute to slower draining. Also, remotely operated valves that are closed via the SCADA system or the presence of check valves would limit the length of pipeline that would drain.

How an operator responds to SCADA system alarms and automatic shutdowns has an impact on the size of the oil spill in the event of a leak. The 1997 release from the wet oil pipeline was exacerbated by an operator restarting the shipping pumps, thereby increasing the release volume. Following the release, the operator (Nuevo) developed a response procedure for unintended shutdown of the emulsion pipeline. The MMS Supplement to the Core Oil Spill Response Plan (Volume 2) states the shutdown time for the shipping pumps in the event of a release is estimated to be 11 minutes; 9 minutes to discover and confirm the leak and 2 minutes to close the

Table 5.1.3 Current Operations Onshore Emulsion Pipeline Spill Volumes (barrels)

Location Description	Normal Operation: SCADA Operational		Worst-case: SCADA Not Operational		Notes
	Drain-down Spill Volume	Total, with Pumping Loss	Drain-down Spill Volume	Total, with Pumping Loss	
On Beach	386	584	2738	3,926	Loss of contents between beach and VS1 (1,000'). Worst-case loss of contents between beach and high point before VS2 (7,000'). Check valve at VS3 prevents backflow.
At Valve Site #2	179	376	179	1,366	Loss of contents from pipeline uphill from VS2 (500'). Worst-case same as VS3 check valve prevents backflow.
Canyon and Terra Road Crossing	952	1,150	952	2,140	Loss of contents between VS2 and VS3 (2,500'). Worst-case same as VS3 check valve prevents backflow
Valve Site #3	714	912	714	1,902	Break just downstream of VS3 (after CV). Loss of contents between VS3 and high point after VS3 (1,800'). Worst-case the same as check valve at VS5 prevents backflow.
Valve Site #4	952	1,150	952	2,140	Loss of contents between hill before VS4 and VS4 (2,500'). Worst-case the same as VS5 check valve would prevent backflow.
After Valve Site #4	1,500	1,698	2,452	3,640	Break located after VS4 and Terra Road Crossing in small drainage. Loss of contents between VS4 and VS5 (3,900'). Worst-case loss of contents between hill after VS3 and VS5 (6,300').
Valve Site #5	571	769	571	1,759	Loss of contents from pipeline located upstream and downstream of VS5 not including valleys (1,500'). Worst-case would be the same as the check valve at VS6 would prevent backflow.
Drainage Area Before Valve Site #6	417	615	417	1,604	Limited by elevation profile and VS6 check valve (1,100'). Worst-case would be the same as the VS6 check valve would prevent backflow.
Valve Site #6	1,405	1,603	2,571	3,759	Loss of contents located above VS6 including valleys between VS6 and VS7 (3,600'). Worst-case would include all areas above VS6 between VS6 and the VS9 check valve excluding valleys (6,600').
Valve Site #7	1,143	1,341	3,083	4,271	Loss of contents between hill upstream of VS7 and VS7 (2,900'). Worst-case due to all segments of pipeline downstream of VS7 before the VS9 check valve excluding valleys (7,900').
Between Valve Site #7 and Valve Site #8	786	984	5,131	6,318	Loss of contents between VS7 and VS8 (2,000'). Worst-case release due to pipeline above drainage bottom before the VS9 check valve excluding valleys (13,200').
Valve Site #8	2,619	2,817	4,048	5,235	Loss of contents from areas downstream of VS8 between VS8 and VS9 excluding valleys (6,700'). Worst-case would include upstream volume between hill before VS7 and VS8 which is above VS8 (10,400').
Drainage Area Before Valve Site #9	2,943	3,141	2,943	4,130	Loss of contents from pipeline located above drainage area between highway S-20 and VS9 (7,600'). Worst-case would be the same because of the check valve at VS9.

Table 5.1.3 Current Operations Onshore Emulsion Pipeline Spill Volumes (barrels)

Location Description	Normal Operation: SCADA Operational		Worst-case: SCADA Not Operational		Notes
	Drain-down Spill Volume	Total, with Pumping Loss	Drain-down Spill Volume	Total, with Pumping Loss	
Valve Site #9	2,755	2,953	2,755	3,942	Loss of contents from pipeline located downstream of VS9 excluding valleys (7,100’). Worst-case would be the same.
Valve Site #10	167	365	167	1,354	Release from last section of pipeline above VS10 (400’).
Largest Spill Volume		**3,141**		**6,318**	**Largest Spill Volumes from all segments.**

Pumping rate calculated at 57,000 bpd.

shutdown valves. The frequency of a release (leak or rupture) is primarily a function of the construction of the pipeline, the maintenance and operational practices, as well as third party damage. The volume of the subsequent release is a function of the training of the operators as well as the design, construction, and maintenance of the leak detection system.

The spill volumes are for total pipeline fluids. Spill volumes of just oil would be 12 percent of the above listed numbers (current operation is with 88 percent produced water, 12 percent oil). Produced water also may contain potentially hazardous materials and may not comply with National Pollutant Discharge Elimination System (NPDES) discharge requirements. Worst-case scenarios would assume that the SCADA system is not operational and that pumping continues for 30 minutes. Normal operations assume pumps continue to run for 5 minutes.

Along selected portions, the pipeline route is equipped with catchment basins that are designed to catch spilled oil resulting from a pipeline leak or rupture. The 1985 Point Pedernales EIR detailed these catchment basins and their associated potential storage volumes. The locations of the catchment basins are shown in Appendix A. Also, see Section 5.4, Onshore Water Resources, for a discussion of the catchment basins and associated mitigation measures.

Existing Onshore Sour Gas Pipelines: Frequencies, Probabilities and Release Impacts

Operation of the gas pipeline from Platform Irene to LOGP presents a hazard to the public in the form of toxic and flammable vapor exposure. Scenarios for releases and subsequent consequence events were developed as part of the Point Pedernales 1985 EIR, 1993 SEIR and 1996 Addendum. All scenarios were included as any release from the pipeline has the potential to harm populations. The PXP corrosion control monitoring program for the 8-inch gas pipeline is summarized in Table 5.1.2c~~a~~. There have not been any pipe failures to date on this pipeline.

Both pipeline ruptures and pipeline leaks were included. Each of these has the potential to produce toxic effects, flammable vapor cloud effects, thermal effects due to flame jets and flammable vapor explosions and vapor cloud fires/explosions (VCE) due to the ignition of flammable vapors.

The operating pressures were assumed to be the worst-case addressed in the 1993 Point Pedernales SEIR as historic operations have been up to this level. Operation of the gas pipeline at 600 psig was assumed. Impact distances assumed are those developed as part of the 1993 SEIR and are listed in Table 5.1.4 along with levels of concern criteria for fatality and injury. See Appendix H for more details on release scenarios presented in Table 5.1.4. Toxic impacts distances were modeled in the 1993 SEIR at 4,000 ppm hydrogen sulfide. ~~Recently~~ Since then, the permitted level of hydrogen sulfide was raised to 8,000 ppm. Therefore, the 1993 SEIR toxic impact numbers have been updated to reflect the higher hydrogen sulfide concentrations. Impact distances due to this change have increased by a factor of close to 2.5 times for the stable wind condition scenarios.

Table 5.1.4 Current Operations Gas Pipeline Release Scenario Impacts

Type	Stability Class/Wind Speed	Fatality Distance, ft	Injury Distance, ft	Criteria
Leak – Explosion	-	49	289	Fatality-3 psi, Injury-0.5 psi
Leak – Thermal	-	75	92	Fatality–10 kw/m2, Injury–5 kw/m2
Leak – Toxic*	F-2 m/s	172	461	Fatality–ERPG-3, Injury–ERPG-2
Leak – Toxic*	D-4 m/s	112	246	Fatality–ERPG-3, Injury–ERPG-2
Leak – VCE	F-2 m/s	400	1,060	Fatality – LFL, Injury – ½ LFL
Leak – VCE	D-4 m/s	89	135	Fatality – LFL, Injury – ½ LFL
Rupture – Explosion	-	125	751	Fatality-3 psi, Injury-0.5 psi
Rupture – Thermal	-	217	259	Fatality–10 kw/m2, Injury–5 kw/m2
Rupture – Toxic*	F-2 m/s	780	2,033	Fatality–ERPG-3, Injury–ERPG-2
Rupture – Toxic*	D-4 m/s	448	974	Fatality–ERPG-3, Injury–ERPG-2
Rupture – VCE	F-2 m/s	1,066	2,477	Fatality – LFL, Injury – ½ LFL
Rupture – VCE	D-4 m/s	262	407	Fatality – LFL, Injury – ½ LFL

**Toxic impact distances have been updated to 8,000 ppm.*

For toxic exposure, levels of concern conservatively utilized the Emergency Response Planning Guidelines (ERPG) for hydrogen sulfide as established by the American Industrial Hygiene Association. ERPG-3 (100 ppm for 60 minutes), defined as the dose at which persons could be exposed for up to one hour without developing life threatening effects, was chosen as the level at which 10 percent of persons exposed would experience fatalities. ERPG-2 (30 ppm for 60 minutes), defined as the dose at which persons could be exposed for up to one hour without developing serious injury effects, was chosen as the level at which 10 percent of persons exposed would experience injuries. These compare to the 100 ppm for 30 minutes IDLH value (Immediately Dangerous to Life and Health) which is defined as the level at which no life threatening health effects would occur.

Effects of acute exposures to hydrogen sulfide include eye irritation, respiratory tract irritation, headache, dizziness, excitement, staggering gait, and gastro enteric disorders. Exposure to concentrations of 1,000 to 2,000 ppm causes respiratory paralysis after a breath or two, due to inhibition of the respiratory center of the brain. Olfactory paralysis is estimated to occur between 50 and 200 ppm (SBC Fire, 2000a). The ERPG-2 and ERPG-3 values for injuries and fatalities, respectively, are based on past workshops and studies (SBC Fire, 2000b) as well as a level of conservativeness related to impacts on elderly and child populations. For explosions, the fatality level was estimated to be 3 psi above normal atmospheric pressure and the injury level was estimated to be 0.5 psi. These are based on impacts to buildings where, according to the Center for Chemical Process Safety (CCPS), occupants would most likely suffer fatalities or injuries at these levels due to collapsing walls or shattered windows.

For thermal exposure to fires or flames, the fatality exposure level was estimated to be 10 kilowatts per square meter (kw/m^2) and the injury level to be 5 kw/m^2. These levels are based on the time it takes to develop second degree burns. For vapor cloud explosions, the fatality level was estimated to be within the lower flammability limit (LFL) and the injury level as estimated to be within the ½ LFL.

Gas pipeline failure frequencies utilized the DOT failure rates for gas pipelines (based on the 1993 Point Pedernales SEIR for the LOGP). These rates are to 4.34×10^{-4} and 2.13×10^{-4} per mile-year for leaks and ruptures, respectively. The pipeline specific failure frequencies and probabilities shown in Table 5.1.5~~, on the following page~~ are for ruptures and leaks and were developed as part of the 1993 SEIR.

Table 5.1.5 Current Operations Onshore Produced Gas Pipeline Failure Frequencies and Probabilities

Scenario	Failure Frequency, per year	Lifetime Release Probability, %
Leak rate	5.29×10^{-3}	5.2
Rupture rate	2.60×10^{-3}	2.6

For a project lifetime of ten years until 2017.
Pipeline length of 12.2 miles.
Frequencies based on the 1993 Point Pedernales SEIR.

Existing Onshore Water Return Pipeline: Frequencies, Probabilities and Spill Volumes

Although the water return line does not currently transport crude oil or gas, and therefore would present minimal, if any, public safety hazard, the water carried does not meet the California Ocean Plan or the Federal requirements (NPDES) for discharge of the water into the environment. Therefore, a failure of the pipeline could produce a spill that could degrade the existing environment.

The methodology for determining spill frequencies for the onshore water return pipeline is the same as described for the oil emulsion pipeline. Based on the CSFM data, pipeline-specific spill rates can be estimated for a pipeline based on its specific criteria. Using the CSFM data, the following pipeline design and operational parameters for the water return pipeline were used for baseline and operating conditions:

- Pipeline diameter of 8 inches (1.04 correction factor)
- Pipeline specification is average (1.0 correction factor).
- Pipeline type is API 5L X46 grade, electric resistance welded (0.71 correction factor).
- Operating temperature of 125°F (1.59 correction factor).
- SCADA system is not present (1.57 correction factor).
- Cathodic protection system is present (0.98 correction factor).
- Pipeline is internally inspected (0.63 correction factor).
- Pipeline coating is polyethylene butyl adhesive (0.09 correction factor).

Based on the above pipeline specifications, a pipeline spill rate was calculated. This spill rate is slightly higher than that for the crude oil pipeline, mainly due to the smaller pipeline diameter and absence of a SCADA system. The CSFM report also estimated that larger spills (greater than 100 barrels) comprise approximately 18 percent of the total number of spills. These larger spills are assumed to equate to a rupture of the pipeline, whereas spills less than 100 bbls would equate to a leak. Pipeline-specific spill frequencies and probabilities for leaks and ruptures are shown in Table 5.1.6 below.

Table 5.1.6 Current Operations Onshore Water Return Pipeline Spill Frequencies and Probabilities

Scenario	Spill Frequency per year	Lifetime Spill Probability, %
Onshore Water Pipeline ruptures	1.65×10^{-3}	1.6
Onshore Water Pipeline leaks	727×10^{-3}	7.0

For a project lifetime of ten years until 2017.
Spill rate based on the base rate of 7.1×10^{-3} incidents/mile-year (for all pipelines) with the correction factors and multiplying by the pipeline distance of 12.2 miles and adding in the seismic frequency for ruptures of 5.1×10^{-5}/year for this pipeline.

The corrosion control and monitoring program for the 8-inch produced water pipeline is summarized in Table 5.1.2c~~a~~. The produced water pipeline has not experienced any leaks or failures to date.

There are no anticipated changes to the corrosion control program; however, the frequency of the maintenance pigging may increase or decrease based on pipeline parameters. If for example, the pipeline smart pigging demonstrates increased corrosion rates, then pigging would occur more frequently. A recent Smart Pig Survey (2005) showed evidence of corrosion and a section of pipe was repaired. As a result of a confirmation dig for the identified anomalies, a monolithic isolation flange and pipe spool were replaced at Valve Site #1. The internal corrosion survey conducted in 2005 using a high resolution pig showed that the majority (greater than 99 percent) of anomalies were between 10 and 29 percent of wall thickness. There were 23 anomalies between 30 to 79 percent.

The total produced water return line volume is calculated to be approximately 307,000 gallons. However, as with the crude oil pipeline, terrain greatly affects the release volumes. As the produced water return pipeline follows the same route as the crude oil/emulsion pipeline, the elevation profile would be identical. However, the produced water return line has fewer automatic valves and no check valves. Therefore, greater lengths of the pipeline would drain and affect the release volumes; hence the release volumes would be greater than for the crude oil/emulsion pipeline.

Pipeline spill volumes for the onshore produced water pipeline between Platform Irene and the LOGP are presented in Table 5.1.7. Because the produced water return line is not equipped with a SCADA system, time to respond to a rupture or leak would be longer than for the emulsion line. Time to respond is estimated to be 30 minutes. Detection most likely would be through loss of flow rate and an associated pressure drop in the water pipeline, both of which are monitored as follows. MOV-612 located at Platform Irene would close on detection of high or low pressure on Pressure Switch High-Low (PSHL) #612 which is located downstream of the platform SDV. The leak would also be noticed at the Platform Irene flow transmitter (FT) and located immediately downstream of the water pipeline pig catchers (FT-612). The water pipeline is designed to close at Valve Sites #1, 2, 8 and 10 when the pressure is low.

Table 5.1.7 Current Operations Onshore Water Return Line Estimated Spill Volumes (bbls)

Location Description	Normal Operation: Automatic Valves Operational		Worst-case: Automatic Valves Not Operational		Notes
	Drain-down Spill Volume	Total, With Pumping Loss	Drain-down Spill Volume	Total, With Pumping Loss	
On Beach	62	478	1,146	1,563	Loss of contents to Valve Site #2 (1,000'). Worst-case: downstream pipeline minus the valleys (18,400').
At Valve Site #2	255	672	708	1,124	Loss of contents to Valve Site #8 (4,100'). Worst-case: downstream pipeline minus the valleys (11,400').
Canyon and Terra Road Crossing	533	950	986	1,403	Loss of contents upstream to Valve Site #2 and downstream to Valve Site #8 excluding the valleys (8,600'). Worst-case: upstream and downstream pipeline minus the valleys (15,900').
After Valve Site #4	659	1,076	1,112	1,528	Loss of contents towards Valve Site #4 and downstream to Valve Site #8 excluding valleys (10,600'), Worst-case towards VS4 and downstream to LOGP minus valleys (17,900').
Drainage area before Valve Site #6	343	760	795	1,212	Drainage primarily from downstream pipeline to Valve Site #8 (5,500'). Worst-case past Valve Site #8 (12,800').
Between Valve Site #7 and Valve Site #8	312	729	986	1,403	Drainage primarily from upstream portion (5,000'). Worst-case from downstream (towards LOGP) as well (15,900').
Drainage area before Valve Site #9	437	854	437	854	Drainage primarily from downstream portion minus valleys (7,000'). Worst-case the same.
Valve Site #10	27	443	27	443	Release due to last section of pipeline above Valve Site #10 (400'). Worst-case the same.
Largest Spill Volume		1,076		1,563	**Largest Spill Volumes from all segments**

Pumping rate calculated at 20,000 bpd

Existing LOGP to Summit Pipeline Frequencies, Probabilities and Spill Volumes

The LOGP to Summit 8/10/12-inch pipeline transports crude oil, which is produced by the Point Pedernales Field, to the ~~Orcutt~~Summit Pump Station. The line is 12-inch from the LOGP to the Orcutt pump station. At Orcutt, it is mingled with oil produced from the Lompoc Oil and Gas Field and pumped to Suey Junction through an 8-inch line. At Suey Junction, the oil moves through the 10/12-inch pipeline to Summit Pump Station where it is transported by pipeline to the Santa Maria Refinery. From Suey Junction to Summit Pump Station, there is also an 8-inch pipeline that is manifolded to the 10/12-inch pipeline at Suey Junction. Between Suey Junction and Summit, the 8-inch and 10/12-inch pipelines run roughly parallel to one another. The 10/12-inch pipeline currently carries crude oil from the Santa Maria Pump Station, the Plains AAPL Sisquoc Station, and LOGP~~PG~~ (see Figure 2-4). The 8-inch line is currently idle and in need of inspections and possible repairs. Once any necessary repairs are completed, this line could be put back into crude service. It would then be kept in stand-by mode for use when the 10/12-inch pipeline is down for maintenance. For purposes of estimating worst-case current oil spill frequencies, probabilities, and volumes, it is assumed it would be full of oil at any time. For the baseline analysis, it was assumed that the 12-inch line from Suey Junction to Summit Pump Station is used for transport of oil from Orcutt Pump Station and that the oil flow rate in the line from LOGP to ~~Summit~~ Suey Junction is 9,000 bpd.

The 8" and 10/12" pipeline is approximately 28 miles long, is below-ground the entire segment, is cathodically protected and coated, and is smart-pigged or hydrostatically tested every five years as per CSFM requirements. The pipeline runs through Orcutt and the City of Santa Maria. Details of the pipeline route are shown in Appendix B.

The pipeline is divided into a number of segments to assess the spill volumes and frequencies. Pipeline spill frequencies are determined from the CSFM database as previously described for the oil emulsion pipeline. The assumptions include the following:

- Pipeline average age of 50 years. The LOGP to Orcutt Pump station lines are about 20 years old and the lines from the Orcutt Pump station to Summit are about 50 years old. We have assumed the entire line is 50 years old. (0.59 correction factor).
- Pipeline diameter of 8-12 inches (1.18 correction factor).
- Pipeline specification is average (1.0 correction factor).
- Pipeline type is average (1.0 correction factor).
- Operating temperature of 165°F (2.14 correction factor).
- SCADA system is present (0.9 correction factor).
- Cathodic protection system is present (0.98 correction factor).
- Pipeline is internally inspected (0.63 correction factor).
- Pipeline coating is average (1.0 correction factor).

Table 5.1.8 Current Operations LOGP-Summit Pipeline Spill Frequencies and Probabilities

Scenario	Spill Frequency per year	Lifetime Spill Probability, %*
LOGP-Summit Pipeline ruptures	0.041	70.7
LOGP-Summit Pipeline leaks	0.19	99.6

**Assuming a remaining life of 30 years.*
Spill rate based on the base rate of $9.89x10^{-3}$ incidents-mile/year (for all pipelines) with the correction factors and the pipeline distance.

Contrary to the emulsion and produced water lines, this oil line does not have an advanced type of external coating, thus the pipeline age factor was applied. Based on the above pipeline specifications, a pipeline spill rate was calculated. These equate to the following pipeline specific spill frequencies and probabilities:

Spill volumes associated with the LOGP to Summit pipeline are a function of the terrain and the associated pipeline profile (see Table 5.1.9). These pipelines are now operated by ConocoPhillips and are controlled via a leak detection system which is remotely monitored in the ConocoPhillips Ponca City Control Center (PCCC) in Oklahoma. The shortest term alarm is currently set for a 35-barrel imbalance in a ten-minute period. Shutdown of the pumps and closing of the valves is initiated by the PCCC operator and is not automatically shutdown by the flow imbalance alarms and indicators. The spill volumes in Table 5.1.9 assume under Normal Operation it would take five minutes to shutdown the line since the rupture would be quickly detected by the pressure and flow transmitters. Under a worst-case scenario it would take 30 minutes. The 30-minute spill volumes are used in the risk analysis.

Table 5.1.9 Current Operations LOGP-Summit Pipeline Spill Volumes (barrels)

Location Description (All line segments are assumed at 12-inch except for Orcutt PS to Suey which is 8-inch)	Normal Operation: Automatic Valves Operational		Worst-case: Automatic Valves Not Operational	
	Draindown Spill Volume	Total, With Pumping Loss	Draindown Spill Volume	Total, With Pumping Loss
LOGP-Harris Grade	886	912	886	1042
Harris Grade - Mid Grade	443	469	443	599
Mid Grade-Highway 135/Highway 1	5094	5120	5094	5250
Highway 135/Highway 1 - Before OPS	1698	1724	1698	1854
Before OPS – Orcutt PS	1772	1798	1772	1928
Orcutt Pump Station - Suey	5012	5043	5012	5200
Suey to RR Avenue Valve Box	5824	5975	5824	6730
RR Avenue to South of SM River	5824	5975	5824	6730
South of SM River to Highway 101	8260	8411	8260	9167
Highway 101 to Price Street Valve	10771	10922	10771	11677
Price Street Valve to Highway 101	6275	6426	6275	7182
Highway 101 to Summit Pump Station	3987	4138	3987	4893
Largest Spill Volume		10922		11677

Segment losses include drainage from adjacent segments as a function of terrain.

Existing LOGP Facility and Sales Gas Pipeline: Scenarios and Failure Rates

Operation of the LOGP has the potential to cause impacts to the public through releases of flammable and toxic materials. Modeling conducted as part of the Point Pedernales 1985 EIR, 1993 SEIR, 1996 Addendum and 2002 EIR was utilized in this study. Only scenarios which produced a fatality or injury impact distance equal to or greater than the LOGP facility boundary (700 feet) were selected for analysis. All other scenarios, even though they could produce secondary effects such as fires or traffic hazards, were not addressed. Secondary effects were assumed to be effectively mitigated through existing emergency response actions and community preparedness and are considered to be outside the scope of this analysis. The scenarios included in this study are listed below in Table 5.1.10. See Appendix H for more details on release scenarios presented in Table 5.1.10.

Only flammable releases from the LOGP facility were determined to produce impacts offsite. Toxic releases were contained within the facility boundaries.

The sales gas pipeline connects the LOGP to The Gas Company transmission line located approximately 6.5 miles to the north of the LOGP. Failure rates for gas transmission and gathering pipelines are estimated by the DOT to be approximately 2.25x10^{-4} incidents (a leak or a rupture) per mile-year. This number is lower than the produced gas pipelines due to the presence of hydrogen sulfide, which is highly corrosive when wet, in the produced gas. The sales gas pipeline hazards would be limited to flammable hazards (VCE or thermal) due to the lack of hydrogen sulfide in the sales gas stream. Impact distances are somewhat greater than those for the LOGP scenarios due to the larger pipeline size and higher operating pressures.

Table 5.1.10 Current Operations LOGP Release Scenarios Impacting Offsite and Base Frequencies

Scenario	Type	Stability Class/ Wind Speed	Fatality Distance, ft	Injury Distance, ft	Base Frequency/yr	Source
Crude tank fire	Thermal		650	885	4.00x10^{-05}	1985 EIR
Gas/oil separator vessel rupture	VCE	D-5 m/s	318	740	2.00x10^{-05}	1985 EIR
Gas/oil separator vessel rupture	VCE	F-2 m/s	705	1,640	2.00x10^{-05}	1985 EIR
LPG/NGL vessel BLEVE	Thermal		1635	2,240	8.00x10^{-07}	1993 and 1996 SEIR and Addendum
LPG/NGL vessel Explosion	Explo-sion		470	1,880	8.00x10^{-07}	1993 and 1996 SEIR and Addendum
LPG/NGL tank rupture/release	VCE	D-5 m/s	1,032	2,400	2 00x10^{-05}	1985 EIR
LPG/NGL tank rupture/release	VCE	F-2 m/s	1,075	2,500	2.00x10^{-05}	1985 EIR
LPG/NGL tank truck rupture	Explo-sion		460	1,800	4.04x10^{-07}	1985 EIR
LPG/NGL tank truck rupture	VCE	D-5 m/s	593	1,380	4.04x10^{-07}	1985 EIR
LPG/NGL tank truck rupture	VCE	F-2 m/s	538	1,250	4.04x10^{-07}	1985 EIR
~~LPG/NGL tank truck rupture~~	~~VCE~~	~~F-2 m/s~~	~~538~~	~~1,250~~	~~4.04x10^{-07}~~	~~1985 EIR~~
Sales Gas Pipeline leak	Thermal		126	138	1.51x10^{-04}	PANGL, 1999*
Sales Gas Pipeline leak	VCE	~~D-5 m/s~~F-2 m/s	335	600	1.51x10^{-04}	PANGL, 1999*
Sales Gas Pipeline leak	VCE	~~F-2 m/s~~D-5 m/s	167	259	1.51x10^{-04}	PANGL, 1999*
Sales Gas Pipeline rupture	Thermal		771	791	7.43x10^{-05}	PANGL, 1999*
Sales Gas Pipeline rupture	VCE	F-2 m/s ~~D-5 m/s~~	1,761	3,050	7.43x10^{-05}	PANGL, 1999*
Sales Gas Pipeline rupture	VCE	D-5 m/s ~~F-2 m/s~~	928	1,450	7.43x10^{-05}	PANGL, 1999*

Stability Class D represents neutral atmospheric stability, or moderate turbulence. Stability Class F represents "stable" or less turbulent (the wind is weak) atmospheric conditions.
*Lifetime Probabilities would be less than 0.1% for all scenarios. Cumulative total lifetime probability is 0.15%. VCE = Vapor Cloud Fire/Explosion. * Corrected to the appropriate line size and pressure.*

The following is a history of incidents that have occurred from the LOGP and associated pipelines:

In 2006, there were six reportable incidents at LOGP. Four of the six incidents involved tank hatch activation which released vapors that exceeded APCD emission control standards. These releases were the result of safety equipment functioning properly, did not result in any offsite impacts, and were remedied immediately. One of the six incidents involved a vacuum truck operator overfilling his truck resulting in less than a barrel of oil spilling onto the ground within the LOGP fence line (this was immediately cleaned up). The last of the six incidents involved no release but was reported in accordance with current County standards. It involved a measurement of 4.09 ppm of hydrogen sulfide inside the sales gas line, exceeding the limit specification of 4.0 ppm. If/when this occurs, it is corrected operationally with the gas being returned to LOGP rather than entering the Gas Company system.

The four vapor releases required a deviation report to be filed with the APCD. The oil spill on to the ground within the LOGP fence line required a Hazardous Materials Minor Spill and Release Incident Report Form, a.k.a. Community Awareness & Emergency Response (CAER) form to be faxed to the County Fire Department. The 4.09 ppm of H_2S in the sales gas line required a call to 911. No emergencies or danger to the public were associated with any of these incidents.

In 2005, there were seven reportable releases and in 2004, there were five reportable releases. These incidents involved primarily releases of oil or other combustible liquid within LOGP, one release of vapors that exceeded APCD emission control standards, one heat-related incident with no ignition, one unintentional fire detector activation, and two non-LOGP related incidents (one vehicle accident and one outside fire).

There were no pipeline incidents in 2006 but there was one in 2005. A vacuum truck was being used to depressure the 20-inch oil line for maintenance when a gas bubble entered the truck and caused approximately 5 gallons of crude oil to spray out of the truck's vent scrubber onto the ground. The area affected by the release was approximately 15' x 6' and was cleaned up immediately.

Existing Transportation: Scenarios and Failure Rates

Transportation of flammable gas liquids (propane and butane) to markets both locally and regionally presents a risk to populations along the transportation corridors. Transportation impacts were examined as part of the 1985 Point Pedernales EIR. Risks to populations were generated by utilizing historical accident rates for trucks along with spill probabilities for small, medium and large spills and subsequent ignition. Population densities (urban or rural) were assigned to designated routes and the release impact distances were utilized to generate the number of persons that could be affected.

Scenarios associated with gas liquids transport include a truck accident with a subsequent spill of the truck vessel contents. The material would vaporize rapidly and produce a flammable cloud that, upon ignition, could impact public safety.

Table 5.1.11 shows inputs to the transportation risk model developed as part of the 1985 Point Pedernales EIR.

Table 5.1.11 Current Operations Transportation Risk Inputs, 1985 Point Pedernales EIR

Input	Number
Base accident frequency, per vehicle-mile	1.5×10^{-6}
Spill probability given an accident occurs	0.5
Fraction of spills that are less than 100 gallons (minor spills)	0.5
Fraction of spills that are less than 900 gallons (major spills)	0.30
Fraction of spills that are catastrophic	0.20

Table 5.1.11 Current Operations Transportation Risk Inputs, 1985 Point Pedernales EIR

Input	Number
Major spills ignition probability	0.25
Catastrophic spills ignition probability	0.75
Percent of trucks traveling to Los Angeles	40
Percent of trucks traveling to Bakersfield	10
Percent of trucks traveling to local destinations	50

The SBC Board of Supervisors' Resolution 93-480 (adopted in 1993, amended resolution 85-334) requires the implementation of safety measures to minimize the hazards associated with the transportation of natural gas liquids on roads within the County and region. These measures include the blending of gas liquids with crude oil for pipeline shipment to the maximum extent feasible; the use of DOT LPG rated trucks (MC-331); the development of a risk management program that includes carrier audits, vehicle speed monitoring and operating procedures; and the use of only "lower-risk" routes. In the PXP Point Pedernales SBC permit, this resolution is incorporated into Conditions P-2 and P-23. Since December, 2001, SBC has determined that Torch (now PXP) has demonstrated that the existing operation is in compliance with resolution 93-480.

5.1.1.4.3 Existing Offshore Facilities

Offshore facilities include Platform Irene and the offshore portions of the emulsion, gas and water return pipelines.

Existing Offshore Facilities Spill Frequencies, Probabilities and Spill Volumes

Offshore oil spill probabilities have been generated from a number of different sources and approaches. The MMS has developed an approach for estimating the oil spill occurrence, normalized as a function of total oil handled (Anderson, et al., 1994). The 1985 Point Pedernales EIR addressed oil spill probabilities based on past studies and an equipment-specific analysis of the then-proposed project.

Offshore MMS Spill Probabilities

The MMS approach is presented in order to provide a comparison to more equipment specific and operations-derived calculations of spill frequency. The MMS has developed this approach in order to calculate spill probabilities of future development scenarios. This analysis is based on the actual spills that have occurred for offshore platforms and pipelines for the period 1964 to 1992. Table 5.1.12 provides the Outer Continental Shelf (OCS) platform and pipeline spill rates for this period. For the Pacific region, spills range in size from 1 to 163 bbls (recorded in 1997). This excludes the 80,900 bbl spill that occurred in 1969. Since 1969 there have been only six other spills above 50 bbls (of sizes 900, 100, 50, 50, 150 and 163 bbls). According to MMS "a number of preventative measures have been initiated since that time. These measures make reoccurrence a highly unlikely event" (MMS, 2001). Therefore, in order to avoid skewing the results, the 1969 spill was excluded.

Table 5.1.12 MMS OCS Platform and Pipeline Spill Rates

US OCS Spills	Number of Spills	Median Spill Size (bbls)	Spill Rate (spills per 10^9 bbls produced)
Spills less than 50 bbls (Small or Leaks)			
Platforms	154	25	11.1
Pipelines	457	25	33.2
Spills greater than 50 bbls (Large or Ruptures)			
Platforms	27	159	1.9
Pipelines	80	159	5.8

Source: Comparative Occurrence Rate for Offshore Oil Spills, Anderson and La Belle, MMS. Also, MMS, 2001. Values for breakdown of spills between platforms and pipelines have been estimated based on ratios associated with larger spills (for which better data is available). Please see Appendix H for more details.

Using the data provided above, estimated oil spill probabilities were generated for Platform Irene and the associated pipeline. These spill probability estimates are shown in Table 5.1.13 below and are based upon the remaining life of Platform Irene as determined from the CSLC production estimates (to approximately the year 2017). The Point Pedernales Field is expected to continue in production until this time.

Table 5.1.13 Current Operations MMS Oil Spill Probability Estimates for the Point Pedernales Field (2007-2017)

Location	Total Oil Production (10^9 bbls)	Duration of Total Oil Production (years)	Estimated Number of Spills During the Duration	Probability of Zero Spills Occurring (P)	Probability of One or More Spills Occurring
Spills between 1 and 50 bbls (Small or Leaks)					
Platform Irene	0.0073	10	0.0808	92.2%	7.8%
Irene Pipeline	0.0073	10	0.2425	78.5%	21.5%
Total			0.3233	72.4%	27.6%
Spills > 50 bbls (Large or Ruptures)					
Platform Irene	0.0073	10	0.0141	98.6%	1.4%
Irene Pipeline	0.0073	10	0.0424	95.8%	4.2%
Total			0.0566	94.5%	5.5%

Estimated average rate of oil production over remaining life is 2,000 bpd.
Duration of production is from the beginning of 2007 through the end of 2017.
Estimated number of spills during the duration= (spill rate) x (total oil production).
Probability (P) =e^ (-number of spills during duration).
The probability of one or more spills=1-P. Please see Appendix H for more details.

The maintenance practices currently in place will help ensure that spills from the existing facilities will be minimized and most likely will be lower than historical values. Current pipeline operations include performing ongoing routine internal and external pipeline surveys. Pipeline surveys include, but are not limited to, smart pigging, corrosion checks, pressure tests, air and ground patrols, visual surveys using a video camera, and cathodic protection surveys. These periodic internal and external pipeline inspections are performed on a schedule specified by Minerals Management Service (MMS), SBC, and Santa Barbara County Air Pollution Control District (SBCAPCD) permits, and PXP policy. These inspections also satisfy the requirements of the Department of Transportation (DOT) and the California State Fire Marshal (CFSM) for the pipelines. A summary of the permitted and current operating parameters of the three pipelines is given in Table 2.7.

Existing Offshore Equipment-Specific Failure Frequencies and Probabilities

The MMS oil spill probability estimates are based on historic data of oil spills from OCS facilities and the total production from these facilities. These data are combined to generate a spill rate as a function of total oil production. This method of estimating spill rates is useful in evaluating the likelihood of an oil spill, in general, from OCS facilities. However, when looking at a specific project, spill probabilities are typically generated based upon equipment failure rate, which allows one to account for variations in project-specific designs. For example, projects that have a large number of oil handling vessels on a platform would have a higher probability of an oil spill since there is more equipment that could fail. Also, platforms that have a closed drain system would have fewer spills to the ocean than a platform without a closed drain system.

The 1985 Point Pedernales EIR developed project-specific estimates of the frequency of an oil spill release from Platform Irene. The areas examined included the following:

- *Wellhead drilling and production*: Currently, all wells on Platform Irene are using submerged pumps or gas lift. The risk of a blowout is therefore minimized due to the relatively low pressures of these systems and the ability of the platform systems to control the pressure. However, the wells could produce releases as addressed under Wellhead Systems. Well workovers could produce blowouts. The Hydrocarbon Leak and Ignition Database (1992) estimates well workovers are performed every seven years. In addition, some of the blowouts occur subsea, below the platform deck areas. These blowouts would not be trapped by the platform drain system and would therefore release directly to the ocean. Blowouts that occur at the wellhead or the drilling deck could be captured by the platform deck system, if small enough. However, larger blowouts could directly affect the ocean.
- *Wellhead Systems:* Wellhead failures would be due to a failure in the piping or fittings with a subsequent failure to close the safety valves. For medium to small leaks, a failure of the platform drainage system would also have to occur for a release to affect the ocean.
- *Oil and Gas Separation*: Releases from separation vessels on the platform could occur due to piping or connection failures or vessel leaks and ruptures. For medium to small leaks, a failure of the platform drainage system would also have to occur for a release to impact the ocean. Larger spills could exceed the capacity of the drain system and cause a release to the ocean (1985 Point Pedernales EIR).
- *Crude Oil Pumping/Shipping:* Releases from these areas would be due to pump failures, piping valve, or fitting failures or the pump surge vessel failure. Shipping failures could be due to pig-launching equipment or operator errors during the pig-launching activity. All small and medium leaks would be captured by the platform drain system and a failure of the drain system would be required for the spill to reach the ocean. Only the catastrophic rupture of the surge vessel could produce a spill large enough to directly affect the ocean.
- *Gas Dehydration:* Although releases from the gas equipment could affect personnel at the platform, impacts to the public or to the ocean are considered remote.
- *Utilities:* Impacts from utilities are primarily due to diesel fuel loading to operate the two cranes and the emergency power generators. Loading failures that could cause a small to medium sized release to the ocean would include a hose failure with subsequent failure of the check valve.
- *Platform Drain System:* Platform Irene, as most offshore platforms, has a drain system which captures all liquids (e.g., leaks, rainwater, washdowns) released to the platform decks and directs

these to a system which pumps the liquids into the oil emulsion pipeline and takes the liquids to the onshore LOGP. This system is limited both by the deck capacity to hold liquids (each deck is enclosed by a 6-inch welded "lip"), the drain capacity and the ability of the deck drain system to move liquids away from the decks, and the system pumps which pump the liquids into the emulsion pipeline (pump capacity is 40 gallons per minute (gpm) for sump pumps which drain sumps and 200 gpm for transfer pumps which drain the decks). Spill histories offshore have indicated that spills can occur if it is windy or if a release has sufficient velocity to "ride over" the deck lip. Also, if a failure of any of the drain system were to occur, such as drain pluggage, pump failures, valve failures, etc., the spill could be released to the ocean.

Gas lift and reinjection would not involve releases of crude oil, and pipelines are discussed in other sections.

Table 5.1.14 lists the failure rates for the above-listed equipment categories. The failure frequencies are derived from the 1985 Point Pedernales EIR and from other sources. The CCPS details uncertainties associated with equipment specific failure rates. As per the CCPS analysis, confidence intervals span approximately two orders of magnitude with the mean value used in this analysis.

Table 5.1.14 Current Operations Platform Irene Spills to Ocean (Frequency and Probabilities)

Scenario	Frequency, per year	Lifetime Probability of Spill, %[1]
Small Spills or Leaks		
Irene - Wellhead Area Spill to Ocean – small	$1.47x10^{-08}$	0.0
Irene - Separator Failure Spill to Ocean – small	$3.74x10^{-06}$	0.0
Irene - Pumping and Shipping Spill to Ocean – small	$2.38x10^{-04}$	0.2
Irene - Diesel Fuel Loading – Small spill to Ocean	$2.90x10^{-04}$	0.3
Cumulative Small Spills	$5.33x10^{-04}$	0.5
Large Spills or Ruptures		
Irene – Blowouts	NA	NA
Irene - Wellhead Area Spill to Ocean – large	$1.25x10^{-08}$	0.0
Irene - Separator Failure Spill to Ocean – large	$9.60x10^{-05}$	0.1
Irene - Pumping and Shipping Spill to Ocean – large	$2.80x10^{-05}$	0.0
Irene - External Impact	$1.00x10^{-05}$	0.0
Cumulative Large Spills	$1.34x10^{-04}$	0.1
Cumulative All Spills	***$6.67x10^{-04}$***	***0.7***
MMS Throughput method, 1 – 50 bbls spills, small spills	$8.1x10^{-3}$	7.8
MMS Throughput method, > 50 bbls spills, large spills	$1.4x10^{-3}$	1.4

1 Zero indicates less than 0.1%. Lifetime assumes until the year 2017.

For Platform Irene, the MMS method estimates the probability of a spill to be higher in relation to the equipment-specific method.

Pipeline failures would be caused primarily by corrosion of the pipeline or outside force damage. The OPS compiles data on spills from pipelines, both onshore and offshore, that release greater than 50 bbls of material. For crude oil pipelines only, between the years 1985 and 2000, the majority of releases from offshore pipelines were due to outside force damage followed by corrosion. This is different than the onshore pipelines, which were due primarily to corrosion (38 percent) followed by outside force damage (29 percent). This is because offshore pipelines are more susceptible to outside impacts because they are not buried.

Pipeline spill rates are shown in Table 5.1.15 from a number of sources, giving a range of the frequency of pipeline spills. These rates are for the emulsion pipeline only. The water return pipeline is discussed below. The gas pipeline rates are examined for the onshore portion only.

Table 5.1.15 Summary of Current Operations Emulsion Pipeline Spills to Ocean (Frequency and Probabilities)

Source	Frequency, per year	Lifetime Probability of Spill, %[1]
Leaks		
1985 Point Pedernales EIR Table 2-2, leaks	4.41×10^{-3}	4.3
CSFM for this pipeline, leak	3.11×10^{-3}	3.1
MMS pipeline throughput method, 1 – 50 bbls spill	2.42×10^{-2}	21.5
Rupture/Larger Spills		
1985 EIR Table 2-2, ruptures	4.90×10^{-4}	0.5
CSFM for this pipeline, rupture	6.82×10^{-4}	0.7
OPS all crude lines, spills > 50 bbl	9.17×10^{-3}	8.8
MMS pipeline throughput method, > 50 bbl spill	4.24×10^{-3}	4.2

[1] *For a project life until year 2017.*

The CSFM pipeline database shows the lowest frequency for spills. The MMS gives estimates in the middle to high end of the range, with larger spills being more frequent than the 1985 Point Pedernales EIR or the CSFM estimates and small spills being significantly more frequent.

Total spill frequencies for the offshore emulsion pipeline and Platform Irene are shown in Table 5.1.16. These numbers utilize the 1985 Point Pedernales EIR pipeline leak rate for leaks and for pipeline ruptures.

Table 5.1.16 Offshore Current Operations Combined Platform Irene and Emulsion Pipeline Spills to Ocean (Frequency and Probabilities)

Scenario	Frequency, per year	Lifetime Probability of Spill, %
Leaks and Small Spills	4.94E-03	4.8
Ruptures and Large Spills	6.24E-04	0.6
Any Spill Size	5.57E-03	5.4

Numbers may not add due to rounding.
Utilizing 1985 Point Pedernales EIR numbers.

Spills from the pipeline dominate the spill frequency. This is primarily due to the drain system on the platform, which prevents most small and medium sized leaks from entering the ocean.

As previously discussed, the offshore portion of the emulsion pipeline experienced a mechanical failure and subsequent spill in 1997. The spill was caused by a failure in the heat-affected zone of a welded and flanged connection. As a result of the 1997 offshore failure, the emulsion pipeline would have been considered a "high-risk" pipeline by the CSFM. After the 1997 spill, the SBC required inspections of the remaining welded and flanged connections every six months. As a result of these inspections, a number of cracks were found in other welded and flanged connections. In 2001, the applicant chose to replace all but one of the remaining welded and flanged connections on the offshore portion of the emulsion pipeline. The flanges were removed and replaced with Flexiforge® flanges (BIMS, 1999), which do not require welding to make a joint connection. The welded and flanged connection (Flange #1-1) at the Platform was subsequently encapsulated in the fall of 2005 (DIVECON, 2005). Therefore, flanges that were susceptible to failure due to microcracks in the heat-affected zone have been eliminated or encapsulated.

The offshore pipeline is smart-pigged every year as required by the SIMQAP. The 2005 smart-pig survey results indicate that both internal and external corrosion is negligible for the offshore portion of the emulsion pipeline. External corrosion is the primary cause of the difference between "high risk" and "non-high risk" pipelines in the CSFM report.

With the replacement or encapsulation of all offshore welded and flanged connections, the annual smart-pig inspection, and the lack of internal and external corrosion, a "high risk" pipeline would be expected to have a similar spill frequency as a "non-high risk" pipeline, as per the CSFM report. Therefore, the offshore portion of the emulsion pipeline would be expected to have a spill frequency comparable to other "non-high risk" offshore pipelines.

Existing Offshore Water Return Pipeline Spills to Ocean Frequency and Probabilities

The produced water return pipeline carries water for injection into the Point Pedernales formation. As this water does not currently meet NPDES standards for discharge to the marine environment, a leak or rupture of the water return pipeline could have impacts to the marine environment. Release frequencies are shown in Table 5.1.17 for the 8-inch water return pipeline.

Table 5.1.17 Current Operations Water Return Pipeline Spills to Ocean (Frequency and Probabilities)

Source	Frequency, per year	Lifetime Probability of Spill, %
Leaks		
1985 Point Pedernales EIR, Table 2-2, leaks	3.60E-03	3.5
CSFM for this pipeline, leak	6.14E-03	6.0
Rupture/Larger Spills		
1985 EIR, Table 2-2, ruptures	4.00E-04	0.4
CSFM for this pipeline, rupture	1.35E-03	1.3
OPS all crude lines, spills > 50 bbl	9.17E-03	8.8

For a project life of 10 years, CSFM assumes rate for all product types, 1985 EIR assumes rate from 10-inch Platform Irene pipeline.

Smart-pig results using a high resolution tool conducted by PXP on September 26, 2005 show moderate corrosion. There were a total of 162,025 metal loss anomalies, the majority of them (161,599) of internal corrosion. Out of 162,025 anomalies, 160,309 anomalies are less than 20 percent (<20 percent), 1,711 anomalies are between 20 percent and less than 40 percent (20 percent to <40 percent). There are total of five ~~4~~ anomalies greater than 40 percent metal loss (>40 percent), one of which is equal to 79 percent metal loss at 60,224.8 feet from Platform Irene (onshore downstream of Valve site #1). Upon further inspection, this anomaly was found to be a corroded monolithic fitting. The fitting was replaced and relocated to a better monitoring location. Currently, this produced water pipeline is on an annual smart pig schedule.

Existing Offshore Oil Spill Volumes

Existing offshore spill volumes are based on the 1985 Point Pedernales EIR and the October 2000 Torch Oil Spill Response Plan (OSRP); adjustments to each of these based on a worst-case analysis. The 1985 EIR estimated spill volumes are shown in Table 5.1.18. Spill volumes are listed for total pipeline and platform fluids. Current production levels have been approximately 88 percent water, 12 percent crude oil (2005 average).

Table 5.1.18 Offshore Spill Volume Estimates: 1985 Point Pedernales EIR

Scenario	Area	Total Fluids Spill Volume(bbls)	Crude Oil Spill Volume(bbls)*
Irene-Blowouts	Well area or sub sea	NA	NA
Irene-Wellhead Area	5 minute spill	20	2
Irene-Separator Failure	Separators	120	14
Irene-Pumping and Shipping	Surge Tanks/Pig Launchers	200/70	24/8
Irene-Diesel Fuel Loading	Diesel transfers	10	10
Irene-External Impact	Complete Platform Loss	2,500	300
Emulsion Pipeline Rupture	Near-shore	18,000	2,160
Emulsion Pipeline Rupture	Near Irene	650	78
Emulsion Pipeline Leak	Near-shore	1- 2,000	1 - 240
Emulsion Pipeline Leak	Near Irene	1 - 650	1 - 78

**Current operation is with 88% water, 12% crude oil in the pipeline (as of year 2005).*
Source: 1985 Point Pedernales Facilities EIS/EIR, 84-EIR-17.

As part of the Federal 30 CFR 254 requirements, then-operator Torch compiled its October 2000 OSRP for the Point Pedernales facilities. Section 30 CFR 254.47 details requirements for determining the worst-case spill volume from the platform and from the pipeline. As per this procedure, for an oil production platform facility, 30 CFR 254.47 specifies that the size of the worst-case discharge scenario is the sum of the following:

1. The maximum capacity of all oil storage tanks and flow lines on the facility;
2. The volume of oil calculated to leak from a break in any pipelines connected to the facility considering shutdown time, the effect of hydrostatic pressure, gravity, frictional wall forces and other factors; and
3. The daily production volume from an uncontrolled blowout of the highest capacity well associated with the facility.

In addition, for exploratory or development drilling operations, the size of the worst-case discharge scenario is the daily volume possible from an uncontrolled blowout.

For a pipeline facility, the size of the worst-case discharge scenario is the volume possible from a pipeline break. This is calculated as specified in 30 CFR 254.47:

1. Add the pipeline system leak detection time to the shutdown response time.
2. Multiply the time calculated above by the highest measured oil flow rate over the preceding 12-month period. These are the pumping losses.
3. Estimate the total volume of oil that would leak from the pipeline after it is shut in. These are the line losses. Line losses are the sum of the losses due to decreased oil density and pipeline diameter due to the reduced pressure and the effects of hydrostatic pressure and buoyancy on the oil remaining on the pipeline.
4. Add together the pumping losses and the line losses to equal the total line losses.

Torch estimated in its OSRP the following capacities and release volumes. These estimates are for oil, as the water percentage has already been removed from these numbers.

Table 5.1.19 Offshore Spill Volumes: Torch OSRP

Area	Oil Only Release Volume, bbls
Platform Irene oil tanks and piping, total of all volumes	188
Diesel Storage	238
Pipeline – pumping losses	382
Pipeline – line losses	2,531
Pipeline – total release volume	2,913
Worst-Case Discharge (total)	3,339

The largest single tank was the T-530/540 wastewater tank at 84 bbls of oil.
The Torch OSRP assumed 20% oil cut as opposed to current operations of close to 12%. These numbers reflect the current operations at 12%.
The Torch OSRP assumed only 5% of emulsion pipeline volume released. These numbers represent the same calculations but with 100% of oil volume being released.

In addition, the wells currently producing operate with submersible pumps, meaning that the wells are not free-flowing and there is very low probability of a well blowout.

The volume of oil which will leave the offshore emulsion pipeline in the event of a pipeline leak or rupture is due to density differences between the oil and sea water, which will vary dramatically depending on location of the leak relative to water depth, shape of the exit hole, and position of exit hole on the pipeline. The rate at which this oil will be displaced is not difficult to calculate due to the fact the oil exits the line intermittently rather than with a steady flow. A hole at the bottom of the platform riser will release no oil, as the oil is lighter than the seawater and will therefore stay in the pipeline. A hole at the surf line would, in theory, be able to completely empty the pipeline if the pipe were uniformly straight (i.e., no hills and valleys in the lay of the line), assuming no intervention to stop the leak and an unlimited time allowed for the displacement. The 2000 Torch OSRP estimated that, for offshore pipeline releases, only a small portion (5 percent) of the oil would actually be released due to hydrostatic pressure and buoyancy effects. However, as a worst-case analysis, the Torch OSRP analysis was recalculated here assuming that 100 percent of the emulsion pipeline volume was released to the marine environment. This analysis increased the estimated pipeline total release volume (for details of the analysis, see the Torch OSRP, October, 2000).

The worst-case oil spill volumes used in this analysis are shown in Table 5.1.20.

Table 5.1.20 Offshore Spill Volumes Used in This Analysis

Area	Oil Only Release Volume, bbls
Platform Irene – Total Platform Loss	426
Offshore Emulsion Pipeline – Pipeline Midpoint Failure	1,754
Offshore Emulsion Pipeline – Shoreline Failure	2,913

Existing Offshore Produced Water Return Pipeline Spill Volumes

A release from the offshore portion of the water return pipeline would release water in equal amounts to the hydrostatic head above the ocean level on the land-side of the pipeline route plus the pumping rate of 13.9 barrels per minute, or 417 barrels over 30 minutes. It is estimated it would take 30 minutes to shutdown the produced water return pipeline. For line losses, produced water in the offshore section of the pipeline would only be minimally released due to decompression and pipe diameter reductions (estimated to release approximately 150 gallons, or 4 bbls) as it is the same density as the surrounding ocean water. Releases to the ocean due to hydrostatic head would include the entire onshore portion of the pipeline not trapped by terrain “valleys” and it is assumed that this volume would drain in the time that it would take to isolate the pipeline (i.e., close the automatic valves). The hydrostatic head is estimated to be close to 50,000 gallons, or approximately 1,100 barrels of produced water.

Oil Spill Trajectories

The fate of oil spilled into the marine environment is a function of a number of different variables; primarily wind speed and direction, ocean currents, ocean conditions, and oil characteristics. Models to estimate the fate of oil spills have been developed by a number of different sources, including the MMS and National Oceanic and Atmospheric Administration (NOAA). Modeling was conducted as part of this project using two different models: the MMS Oil Spill Risk Analysis model (OSRA) and the NOAA model GNOME. Modeling results for the OSRA analysis are shown in Figure 5.1-1 and presented in detail in Appendix G, Oil Spill Trajectory Modeling. In summary, spills from Platform Irene or the offshore pipeline could impact the coast and beaches, depending on conditions, as far north as Piedras Blancas, north of Morro Bay, to as far south as Catalina Island. The highest probabilities of impact are Point Arguello and Point Conception as well as Surf Beach and the San Miguel and Santa Rosa Islands. It is noted that the chances of a spill hitting the more distant portions of coastline are dependent upon the volume of oil spilled; a small one barrel spill is not likely to reach the more distant locations.

5.1.1.4.4 Existing Facilities Risk Analysis

Conducting the risk analysis involves combining the scenario frequencies and impact distances with the conditional probabilities of events, meteorological conditions and the respective populations that could be exposed to each event. Each of these is discussed below.

Conditional Probabilities

Event trees are used to determine the fate of a released material after the release has occurred. An event tree is a logic model that graphically displays the combinations of events and the circumstances in an accident sequence. A release of a flammable material, for example, could experience instantaneous ignition leading to a flame jet. It could also disperse downwind and encounter an ignition source and burn or explode, or it could disperse safely. The probability of each of these events occurring is shown in Table 5.1.21 for major and minor events. These numbers are based on CCPS' Chemical Process Quantitative Risk Analysis, as well as other literature.

Table 5.1.21 Event Tree Probabilities

Event	Probability
Immediate Ignition	0.25
Vapor Cloud with Explosion	0.25
Vapor Cloud with Flash Fire	0.50
Toxic Dispersion	0.75*

** If the release is not immediately ignited, it can produce a toxic cloud (assuming H_2S is present in the gas at dangerous levels) until it is ignited or disperses without ignition. After ignition, it is assumed that the plume rises and any residual H_2S or combustion byproducts (SO_x) would rise due to thermal effects and not present a hazard.*

Sensitive Populations

Populations that could be exposed to the resulting material releases include Vandenberg Village, the northern areas of the Lompoc Federal Penitentiary, and sparsely populated rural and farmland areas. See Appendix A for maps of the pipeline route and the sensitive receptors. Distances from the facilities to locations along the route are listed in Table 5.1.22.

Table 5.1.22 Sensitive Population Areas and Distances from Facilities

Location	Distance, feet
From LOGP to:	
Vandenberg Village	4,600
Mission Village	8,000
From Pipeline Right-of-Way to:	
Vandenberg Village	1,800
Penitentiary	2,600
Ocean Beach Park	4,300

Population concentrations at Vandenberg Village are based on the 2000 Census (Block groups 1-5, group 28.08) and are estimated to be 7,000 persons per square mile. Rural populations, including the Burton Mesa Natural Reserve, farmland and unpopulated areas are assigned a population density of one person per square mile. This rural population number equates to an average of three persons being located in the hills around the LOGP for a distance equal to the distance between the LOGP and Vandenberg Village for 24 hours per day, 365 days a year. Automobile and other vehicle traffic along area roadways were addressed through the use of traffic counts available from the SBC. Harris Grade Road average daily traffic produces a vehicle density of 1.76 cars per mile. Assuming two persons per car, this equates to less than four persons per mile. Releases from the LOGP towards Harris Grade Road were assigned a different population density factor due to the presence of these vehicles.

Toxic and vapor clouds generally produce an impact in the form of an elliptical shaped cloud that travels downwind until dispersion reduces the concentration of material to below the toxic injury levels or below the flammability levels or, for a flammable cloud, ignition occurs. A release at the pipeline or the LOGP could create an elliptically shaped cloud that covers rural, low density areas and urban, higher density areas near the end of the ellipse if the release reaches urban areas (see Figures 5.1-2a and 5.1-2b). Geometric calculations were used to estimate the percent of the cloud over rural and urban areas, and that percent of the cloud that is located within the LOGP facility and therefore would not affect the public. For releases that produce impact distances less than the distances to sensitive receptors, all of the cloud would be located over rural areas or within the facility. For the sales gas pipeline hazard zones there are no populated areas north of the LOGP.

Meteorological conditions affect characteristics of releases that generate cloud effects such as toxic and vapor cloud events. Overpressure, and to a lesser extent, thermal effects, are wind-independent. Therefore, for wind-dependant events, the frequency of experiencing a release at a given receptor is dependent on the wind blowing in the direction of that receptor from the release location. Wind rose data were utilized from the 1993 Point Pedernales SEIR to estimate the fraction of time that wind blows towards Vandenberg Village from the LOGP or from the pipeline right-of-way. These estimates are shown in Table 5.1.23 for the LOGP and the pipeline segments.

Table 5.1.23 Wind Directions Towards Sensitive Population Areas

Direction	D Stability Percent of Time, %	F Stability Percent of Time, %
From LOGP towards Vandenberg Village	1.8	4.7
Platform Irene to LOGP Pipeline Segment: Between Valve Site #9 and LOGP toward Vandenberg Village	7.2	11.2
Platform Irene to LOGP Pipeline Segment: Between Valve Site #8 and Valve Site #9 toward Vandenberg Village	32.9	5.0
Platform Irene to LOGP Pipeline Segment: Near Valve Site #7 and Valve Site #8 toward Penitentiary	7.2	11.2

Meteorologists have defined six atmospheric stability classes, each representing a different degree of turbulence in the atmosphere. When moderate to strong incoming solar radiation heats air near the ground, causing it to rise and generating large eddies, the atmosphere is considered “unstable,” or relatively turbulent. Unstable conditions are associated with atmospheric stability classes A and B. When solar radiation is relatively weak, air near the surface has less of a tendency to rise and less turbulence develops. In this case, the atmosphere is considered “stable,” or less turbulent, the wind is weak, and the stability class would be E or F. Stability classes D and C represent conditions of more neutral stability, or moderate turbulence. Neutral conditions are associated with relatively strong wind speeds and moderate solar radiation.

FN Curves

FN curves depict the frequency (F) of events that could produce a given number (N) of fatalities or injuries. Each scenario identified in the previous sections has a number of potential consequences based on what happens to the released material, i.e., the material could encounter an ignition source and ignite; explode; be toxic or disperse without effects (for non-toxic releases that do not encounter an ignition source). The direction and area that the releases affect are also a function of the wind direction and conditions. This situation produces a large number of possible release outcomes, a different number of persons affected for each one. A plot of each of these results cumulatively adding the frequency of affecting a given number of persons produces the FN curves. FN curves show "societal risk," which is the likelihood that any person or persons would be injured or suffer a fatality.

SBC has established Public Safety Thresholds for CEQA documents that establish the areas on an FN curve that are considered acceptable (or not significant) and those areas which are unacceptable (or significant). See the significance criteria discussion below (also see Section 5.1.3).

For fatalities, FN curves are shown in Figure 5.1-3. The baseline risk for fatalities is considered significant, or in the "red" or "significant" region as labeled by the guidelines, for the transportation of gas liquids. These FN curves are taken from the 1985 Point Pedernales EIR and are scaled to the actual number of annual gas liquid truck trips (2.7 per week or 139 per year in 2005 annual average) that have been recorded by PXP and reported to SBC.

The fatality FN curve for the combined LOGP and Platform Irene to LOGP produced sour gas pipeline shows insignificant risk and is within the acceptable "green" region. The PXP sales gas pipeline and the dry oil pipeline from the LOGP to Summit also show insignificant risk.

For injuries, FN curves are shown in Figure 5.1-4. The PXP sales gas pipeline and the dry oil pipeline from the LOGP to Summit show insignificant risk. However, the baseline risk of injuries is considered significant, or in the red region, for the transportation of gas liquids. These FN curves are taken from the 1985 Point Pedernales EIR and are scaled to the actual number of annual gas liquid truck trips that have been recorded. The injury FN curve for the combined LOGP and Platform Irene to LOGP produced sour gas pipeline approaches the significant risk level, which is characterized by the "amber" region, but does not cross over into this region. This is due primarily to the scenario of a pipeline rupture between Valve Site #9 and the LOGP with potential impacts to Vandenberg Village. A portion of the vapor cloud could be located within Vandenberg Village under certain meteorological conditions, thereby having the potential to produce injuries. Note that the levels which could produce fatalities from this same scenario do not reach Vandenberg Village. The reason why the risk level, as represented by the FN curve, is in the acceptable "green" zone is that in order for residents in Vandenberg Village to be potentially impacted, a number of events would have to occur simultaneously. The Irene to LOGP produced sour gas pipeline would have to rupture somewhere between Valve Station 9 and the LOGP, the wind would have to be blowing toward Vandenberg Village and the atmospheric stability class would have to be F. As shown in Table 5.1.23, these atmospheric conditions only occur on average 11.2 ~~4.7~~% of the time. Also, the cloud would have to disperse to its maximum flammable extent (1/2 LFL) before it could ignite. Therefore, when all of these factors are combined with the number of individuals that could potentially be impacted, the probability is low enough to be considered acceptable.

The injury hazard zone from the produced gas pipeline extends over a portion of the Cabrillo High school athletic field. However, as discussed above the overall risk of injury falls within the "green" risk zone. This risk is part of the baseline risk and would not change due to the proposed project. In conducting the dispersion modeling, the produced gas pipeline pressure was assumed to be 600 psig. The pipeline actually operates closer to 425 psig. If the modeling were done using a lower pressure, the hazard zone would not impact the school property.

Due to past studies conducted by Arthur D. Little (SBC Fire Department, 2000) and public workshops conducted as part of these studies, combined with the definitions associated with the ERPG levels and the uncertainty of injury levels particularly related to injury impacts on elderly and young populations, a level of concern for injuries of ERPG-2 (with 10 percent of the population experiencing injuries) was selected for this study. This lower level of concern produced larger injury impact zones which caused the injury impacts to reach Vandenberg Village (again, fatality zones do not reach Vandenberg Village).

In addition, modeling conducted as part of this analysis was conservative, thereby producing larger impact zones. This modeling assumed a degree of cratering associated with a pipeline rupture. As the pipeline is buried approximately six feet deep, it is assumed that a rupture would release into an earthen crater or hole, thereby reducing the jet effects of the release due to impingement on the walls of the crater. This loss in exit velocity substantially reduces mixing due to the jet effects and the level of near-field dilution by air of the released material. The dispersion then approaches a Gaussian dispersion as opposed to being dominated by a jet release, as might be experienced with a release from exposed piping. This effect allows the released material to travel farther with less dilution by air and to therefore produce larger impact zones.

In summary, buried pipelines, or pipelines that could release into an enclosed area, would most likely have impact zones that are larger than those of pipelines that release directly into the atmosphere.

5.1.2 Regulatory Setting

Many regulations and standards exist to assure the safe operation of pipelines carrying hazardous liquids such as crude oil and facilities associated with these pipelines. This section gives an overview of the federal and state regulations.

5.1.2.1 Federal Laws and Regulations

Hazardous liquid pipelines are under the jurisdiction of the DOT and must follow the regulations in 49 CFR Part 195, Transportation of Hazardous Liquids by Pipeline, as authorized by the Hazardous Liquid Pipeline Safety Act of 1979 (49 U.S.C. 2004). Other important federal requirements are contained in 40 CFR Parts 109, 110, 112, 113, and 114, which pertain to the need for Oil Spill Prevention, Control, and Countermeasures (SPCC) Plans and 40 CFR Parts 109-114 promulgated in response to the Oil Pollution Act of 1990, as well as the Outer Continental Shelf Lands Act.

Overview of the 49 CFR 195 Requirements

Part 195.30 incorporates many of the applicable national safety standards of the:

- American Petroleum Institute (API)
- American Society of Mechanical Engineers (ASME)
- American National Standards Institute (ANSI)
- American Society for Testing and Materials (ASTM)

Part 195.49 Annual Report. Beginning no later than June 15, 2005, each operator must annually complete and submit DOT form RSPA F 7000–1.1 for each type of hazardous liquid pipeline facility operated at the end of the previous year. A separate report is required for crude oil, HVL (including anhydrous ammonia), petroleum products, and carbon dioxide pipelines. Operators are encouraged, but not required, to file an annual report by June 15, 2004, for calendar year 2003.

Part 195.50 (amended 1/8/2002) requires reporting of accidents by telephone and in writing for:

- Explosion or fire
- Spills of greater than 5 gallons of a hazardous liquid, or 5 barrels if associated with a maintenance activity
- Death or serious injury of a person.
- Damage to property of operator or others, greater than $50,000.

The Part 195.100 series includes design requirements for the temperature environment, variations in pressure, internal design pressure for pipe specifications, external pressure and external loads, new and used pipe, valves, fittings, and flanges.

The Part 195.200 series provides construction requirements for standards such as compliance, inspections, welding, siting and routing, bending, welding and welders, inspection and nondestructive testing of welds, external corrosion protection and cathodic protection, installing in ditch and covering, clearances and crossings, valves, pumping, breakout tanks, and construction records.

The Part 195.300 series prescribes minimum requirements for hydrostatic testing, compliance dates, test pressures and duration, test medium, and records.

The Part 195.400 series specifies minimum requirements for operating and maintaining steel pipeline systems, including:

- Correction of unsafe conditions within a reasonable time
- Procedural manual for operations, maintenance, and emergencies
- Training
- Maps
- Maximum operating pressure
- Communication system
- Cathodic protection system
- External and internal corrosion control
- Valve maintenance
- Pipeline repairs
- Overpressure safety devices
- Firefighting equipment
- Public education program for hazardous liquid pipeline emergencies and reporting

On December 1, 2000, DOT OPS issued their final rule on Pipeline Integrity Management in High Consequence Areas for large liquid operators under Part 195.452. On February 15, 2002, DOT extended these regulations to operators with less than 500 miles of regulated pipelines. Through this required program, hazardous liquid operators will comprehensively evaluate the entire range of threats to each pipeline segment's integrity by analyzing all available information about the pipeline segment and consequences of a failure on a high consequence area. This includes analyzing information on the potential for damage due to excavation; data gathered through the required integrity assessment; results of other inspections, tests, surveillance and patrols required by the pipeline safety regulations, including corrosion control monitoring and cathodic protection surveys; and information about how a failure could affect the high consequence area.

The final rule requires an operator to take prompt action to address the integrity issues raised by the assessment and analysis. This means an operator must evaluate all defects and repair those that could reduce a pipeline's integrity. An operator must develop a schedule that prioritizes the defects for evaluation and repair, including time frames for promptly reviewing and analyzing the integrity assessment results and completing the repairs. An operator must also provide additional protection for these pipeline segments through other remedial actions, and preventive and mitigative measures.

The Part 195.500 series covers qualification of pipeline personnel and corrosion control.

The DOT OPS has issued a Direct Final Rule concerning new Operator Qualification program requirements for personnel training, notice of program changes, government review and verification of programs, and use of on-the-job performance as a qualification method. The affected rule sections are given below and are identical for both the gas and liquid pipeline regulations.

§192.805 Qualification Program. *(§195.505 in liquid rules)*

Each operator shall have and follow a written qualification program. The program shall include provisions to:

a. Identify covered tasks;

b. Ensure through evaluation that individuals performing covered tasks are qualified;

c. Allow individuals that are not qualified pursuant to this subpart to perform a covered task if directed and observed by an individual that is qualified;

d. Evaluate an individual if the operator has reason to believe that the individual's performance of a covered task contributed to an incident as defined in Part 191;

e. Evaluate an individual if the operator has reason to believe that the individual is no longer qualified to perform a covered task;

f. Communicate changes that affect covered tasks to individuals performing those covered tasks;

g. Identify those covered tasks and the intervals at which evaluation of the individual's qualifications is needed,

h. After December 16, 2004, provide training, as appropriate, to ensure that individuals performing covered tasks have the necessary knowledge and skills to perform the tasks in a manner that ensures the safe operation of pipeline facilities; and

i. After December 16, 2004 notify the Administrator or a state agency participating under 49 U.S.C. Chapter 601 if the operator significantly modifies the program after the Administrator or state agency has verified that it complies with this section.

§192.809 General. (§195.509 in the liquid rules)

1. Operators must have a written qualification program by April 27, 2001. The program must be available for review by the Administrator or by a state agency participating under 49 U.S.C. Chapter 601 if the program is under the authority of that state agency.

2. Operators must complete the qualification of individuals performing covered tasks by October 28, 2002.

3. Work performance history review may be used as a sole evaluation method for individuals who were performing a covered task prior to October 26, 1999.

4. After October 28, 2002, work performance history may not be used as a sole evaluation method.

5. After December 16, 2004, observation of on-the-job performance may not be used as the sole method of evaluation.

Overview of 40 CFR Parts 109, 110, 112, 113, and 114

The Spill Prevention, Control, and Countermeasure Plan (SPCC) covered in these regulatory programs applies to oil storage and transportation facilities and terminals, tank farms, bulk plants, oil refineries, and production facilities, as well as bulk oil consumers such as apartment houses, office buildings, schools, hospitals, farms, and State and Federal facilities.

Part 109 establishes the minimum criteria for developing oil removal contingency plans for certain inland navigable waters by State, local, and regional agencies in consultation with the regulated community (oil facilities).

Part 110 prohibits discharge of oil such that applicable water quality standards would be violated, or that would cause a film or sheen upon or in the water. These regulations were updated in 1987 to adequately reflect the intent of Congress in Section 311(b) (3) and (4) of the Clean Water Act (CWA).

Part 112 deals with oil spill prevention and preparation of SPCC Plans. These regulations establish procedures, methods, and equipment requirements to prevent the discharge of oil from onshore and offshore facilities into or upon the navigable waters of the United States. Current wording applies these regulations to facilities that are non-transportation-related. These rules should be used by pipeline operators as additional guidelines for the development of oil spill prevention, control and emergency response plans.

Part 113 establishes financial liability limits; however these limits were preempted by the Oil Pollution Act (OPA) of 1990.

Part 114 provides civil penalties for violations of the oil spill regulations.

Following a major release of diesel oil at an Ashland Oil Terminal in Floreffe, Pennsylvania on January 3, 1988, the SPCC Program Task Force convened to study the need for enhanced SPCC regulations. More stringent rules were proposed and the Task Force study provided recommendations that are useful for all oil-related facilities in preventing spills. The Ashland oil spill was very similar to many oil pipeline ruptures and spills, so the recommendations are appropriate for the pipeline industry.

Oil Pollution Act of 1990 OPA. Public Law 101-380 (H.R.): August 18, 1990

The Oil Pollution Act of 1990, together with the Oil Pollution Liability and Compensation Act of 1989, builds upon Section 311 of the CWA to create a single Federal law providing cleanup authority, penalties, and liability for oil pollution. The bill creates a single fund to pay for removal of and damages from oil pollution. This new fund replaces those created under the Trans-Alaska Pipeline Act, Deep Water Port Act of 1974, and Outer Continental Shelf Lands Act, and supersedes the contingency fund established under Section 311 of CWA.

The Oil Spill Compensation Fund will be available, up to a limit of $1 billion per incident, for removal costs and compensatory damages. The act provides for liability and availability of the fund to pay removal costs and compensation in case of discharges of oil. It adopts the standard of liability under Section 311 for liability of dischargers for cleanup costs - strict, several and joint liability. The law establishes financial liability for all oil facility operators including pipelines.

The OPA affirms the rights of states to protect their own air, water, and land resources by permitting them to establish State standards which are more restrictive than Federal standards. More stringent State laws are specifically preserved. Section 106 explicitly preserves authority of any state to impose its own requirements or standards with respect to discharges of oil within each state.

5.1.2.2 California Laws and Regulations

California Pipeline Safety Act of 1981

This act gives regulatory jurisdiction to the State Fire Marshal for the safety of all intrastate hazardous liquid pipelines and all interstate pipelines used for the transportation of hazardous or highly volatile liquid substances. The law establishes the governing rules for interstate pipelines to be the Federal Hazardous Liquid Pipeline Safety Act and Federal pipeline safety regulations.

Overview of California Pipeline Safety Regulations

State of California regulations Part 51010 through 51018 of the Government Code provide specific safety requirements that are more stringent than the Federal rules. These include:

- Periodic hydrostatic testing of pipelines, with specific accuracy requirements on leak rate determination.
- Hydrostatic testing by state-certified independent pipeline testing firms.
- Pipeline leak detection.
- Reporting of all leaks required.

Recent amendments require pipelines to include means of leak prevention and cathodic protection, with acceptability to be determined by the State Fire Marshal. All new pipelines must also be designed to accommodate passage of instrumented inspection devices (smart pigs) through the pipeline.

1995 Oil Pipeline Environmental Responsibility Act (AB 1868)

This bill requires each pipeline corporation qualifying as a public utility that transports crude oil in a public utility oil pipeline system, to be strictly liable for any damages incurred by "any injured party which arise out of, or caused by, the discharge or leaking of crude oil or any fraction thereof..." The law only applies to public utility pipelines for which construction would be completed after January 1, 1996, or that part of an existing utility pipeline that is being relocated after the above date and is more than three miles in length. The major features of the law include:

- Each pipeline corporation that qualifies as a public utility that transports any crude oil in a public utility oil pipeline system shall be absolutely liable without regard to fault for any damages incurred by any injured party that arise out of, or are caused by, the discharge or leaking of crude oil.
- Damages for which a pipeline corporation is liable under this law are:
  - All costs of response, containment, cleanup, removal, and treatment including monitoring and administration cost.
  - Injury or economic losses resulting from destruction of or injury to, real or personal property.
  - Injury to, destruction of, or loss of, natural resources, including but not limited to, the reasonable cost of rehabilitating wildlife habitat, and other resources and the reasonable cost of assessing that injury, destruction, or loss, in any action brought by the state, county, city, or district.
  - Loss of taxes, royalties, rents, use, or profit shares caused by the injury, destruction, loss, or impairment of use of real property, personal property, or natural resources.
  - Loss of use and enjoyment of natural resources and other public resources or facilities in any action brought by the state, county, city, or district.
- A pipeline corporation shall immediately cleanup all crude oil that leaks or is discharged from a pipeline.
- No pipeline system subject to this law shall be permitted to operate unless the State Fire Marshal certifies that the pipeline corporation demonstrates sufficient financial responsibility to respond to the liability imposed by this section. The minimum financial responsibility required by the State Fire Marshal shall be seven hundred fifty dollars ($750) times the maximum capacity of the pipeline in the number of barrels per day up to a maximum of one hundred million dollars ($100,000,000) per pipeline system, or a maximum of two hundred million dollars ($200,000,000) per multiple pipeline systems. For the Pacific Pipeline, the Bill specifically requires ($100,000,000 for the financial responsibility (Section l.h.(l)).
- Financial responsibility shall be demonstrated by evidence that is substantially equivalent to that required by regulations issued under Section 8670.37.54 of the Government Code, including insurance, surety bond, letter of credit, guaranty, qualification as a self-insurer, or combination thereof or any other evidence of financial responsibility. The State Fire Marshal shall require the documentation evidencing financial responsibility to be placed on file with that office.
- The State Fire Marshal shall require evidence of financial responsibility to fund post closure cleanup spots. The evidence of financial responsibility shall be 15 percent of the amount of financial responsibility stated above.

Lempert-Keene-Seastrand Oil Spill Prevention and Response Act, (OSPRA, 8670 Gov. Code Chapter 7.4)

This act requires a State oil spill contingency plan to protect marine waters and empowers a deputy director of the Department of Fish and Game to take steps to prevent, remove, abate, respond, contain and clean up oil spills. Notification of all oil spills in the marine environment, regardless of size, is required to the Office of Emergency Services, who in turn notifies the response agencies. Oil Spill Contingency Plans must be prepared and implemented. The Act created the Oil Spill Prevention and Administration Fund and the Oil Spill Response Trust Fund. Pipeline operators will pay fees into the first of these funds for pipelines transporting oil into the state across, under, or through marine waters. The Lempert-Keene Act also directs some authority to the California Coastal Commission.

California Coastal Commission

The California Coastal Act of 1976 (Public Resources Code, Division 20) created the California Coastal Commission which is charged with the responsibility of granting development permits for coastal projects and for determining consistency between Federal and State coastal management programs. Section 30232 of the Coastal Act addresses hazardous materials spills and states that "Protection against the spillage of crude oil, gas, petroleum products, or hazardous substances shall be provided in relation to any development or transportation of such materials. Effective containment and cleanup facilities and procedures shall be provided for accidental spills that do occur".

Sections 30260, 30262 and 30265 require that adverse environmental effects to be mitigated to the maximum extent feasible, that new and expanded oil and gas facilities be consolidated and that platforms not be sited where a substantial hazard to vessel traffic might result from the facility or related operations. Section 30265 finds that pipeline transport of oil is generally both economically feasible and environmentally preferable to other forms of crude oil transport.

Also in 1976, the state legislature created the California State Coastal Conservancy to take steps to preserve, enhance, and restore coastal resources and to address issues that regulation alone cannot resolve.

California State Lands Commission (CCR Title 2, Division 3, Chapter 1)

The CSLC was established in 1938 with authority detailed in Division 6 of the California Public Resources Code. Title 2, Division 3, Chapter 1 (Articles 1 through 14) address the requirements related to leasing and permits, oil and gas operations, mineral resource regulations, and marine terminal regulations. Article 3.4 specifically addresses pollution control, disposal of drilling muds and cuttings and the oil spill contingency plan. Article 3.4 specifically requires the development of an operating manual. Article 3 specifically addresses the operating requirements, such as tankage, laboratory testing, drilling operations and offshore operations. Article 3.2 and 3.3 address specifics related to drilling and production activities.

5.1.2.3 Santa Barbara County (SBC) Regulations

Oil Transportation Plan

The Oil Transportation Plan has determined that pipelines are preferable to marine tankering in terms of air quality, socioeconomics and risk of an oil spill.

Safety Thresholds and Safety Element

The SBC adopted Public Safety Thresholds in August, 1999. The thresholds provide three zones – green, amber, and red – for guiding the determination of significance or insignificance based on the estimated probability and consequence of an accident. In addition, a Safety Element Supplement was adopted in February 2000 (Board of Supervisors Resolution 00-56) covering hazardous materials. The objective of the Safety Element is to define unacceptable risk in a manner that guides consistent and sound land-use decisions involving hazardous facilities. As part of this objective, the SBC has defined unacceptable risk as involving new development as well as modifications to existing development if those modifications increase risk.

Other Recognized National Codes and Standards

Safety and Corrosion Prevention Requirements - ASME, NACE, ANSI

- ASME & ANSI B16.1 Cast Iron Pipe Flanges and Flanged Fittings.
- ASME & ANSI B16.9, Factory-Made Wrought Steel Butt Welding Fittings.
- ASME & ANSI B31.1, Power Piping.
- ASME & ANSI B31.4, "Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids".
- ASME & ANSI B31.8, "Gas Transmission and Distribution Piping Systems".
- NACE Standard RP-01-90,~~95, Item No. 530.71~~ Standard Recommended Practice External Protective Coatings for Joints, Fittings, and Valves on Metallic Underground or Submerged Pipelines and Piping Systems.
- NACE Standard RP-01-69~~96, Item No. 53002~~. Standard Recommended Practice Control of External Corrosion on Underground or Submerged Metallic Piping Systems.

Fire and Explosion Prevention and Control, NFPA Standards

- NFPA 30 Flammable and Combustible Liquids Code and Handbook
- NFPA 11 Foam Extinguishing Systems
- NFPA 12 A&B Halogenated Extinguishing Agent Systems
- NFPA 15 Water Spray Fixed Systems
- NFPA 20 Centrifugal Fire Pumps
- NFPA 70 National Electrical Code

5.1.3 Significance Criteria

As defined in CEQA Appendix G (v) (the Environmental Checklist Form), a significant safety effect is one in which the project "create[s] a potential health hazard or involve[s] the use, production or disposal of materials which pose a hazard to people, animal or plant populations in the area affected."

The SBC Safety Thresholds are used to determine the significance of safety-related impacts. The thresholds utilize frequency versus number of fatalities/injuries (FN) curves to define the significance level of a proposed project or modification. The guidelines indicate that significant impacts would be avoided if the frequency of a single fatality is shown to be less than 1 in

1,000,000 years (the individual specific risk). If the risk of a single fatality is greater than 1 in 1,000,000 years, then a detailed quantitative risk analysis must be completed to indicate that the risks are below those defined by the FN curves. The project related FN curves would need to be in the green region to be defined as not significant.

5.1.4 Impact Analysis for the Proposed Project

This section has been broken down into two major parts. The first part provides a discussion of the risk of upset issues that affect each of the major project components. The second part presents the project-specific impacts.

5.1.4.1 Proposed Project Risk of Upset Issues

The proposed project would involve increased oil transportation from Platform Irene to LOGP and subsequently between LOGP and the Summit Pump Station and extension of life of Platform Irene, the Platform Irene to LOGP pipeline, the LOGP and the LOGP to Orcutt pipeline. In addition, increased drilling would occur on Platform Irene. Increased truck trips of gas liquids would occur from the LOGP due to increased crude oil production. Increased sales gas transport from LOGP to The Gas Company transmission line would also occur.

<u>The estimate of the proposed project's life of 30 years is based on the economics of the project and does not reflect the useful life of the equipment. There is a possibility that the project life could be longer or shorter than 30 years. Any change in the project life would not impact the FN curves generated as they reflect annual risks. The only change would be to the lifetime spill probabilities, which would change proportionately to the change in project life.</u>

Onshore Emulsion Pipeline

The onshore emulsion pipeline would have spill frequency rates similar to those of the current operations as none of the operating parameters that affect spill frequency rates (e.g., temperature) would change (but throughput would increase). As the proposed project would extend the life of the pipeline, this would increase the frequency of spills (ruptures and leaks) due to the increased average age of the pipeline. The CSFM report concluded that spill rates are a function of pipeline age. However, only pipelines built before about 1950 exhibited significantly higher spill rates. Most failures of older pipelines were due to external corrosion effects due to failed external coatings and the use of older (prior to 1950) technologies. As pipelines built in 1955 and those built in 1975 exhibited almost identical failure rates, an increase in the average age of a pipeline built since 1950 would have minimal effect on the pipeline spill rates. Spill rates for pipelines built in the 1950s averaged 4.17×10^{-3} spills per mile-year versus a rate of 3.72×10^{-3} spills per mile-year for pipelines built in the 1970s, a difference of 10 percent. Although this rate difference is true for past pipelines, it is difficult to extrapolate this data to future average spill rates due to the differences in pipeline construction techniques. Prior to the 1950s, pipelines were not built to the same standards as they are today with advanced pipeline coatings, cathodic protection and smart pigging. These better standards will most likely decrease spill rates for pipelines built since 1980 when they are 20 to 50 years old over the pre-1950 pipeline rates. A pipeline built today would most likely not exhibit the same high failure rates as pre-1950 pipelines in 40 years.

The addition of pumps to the emulsion pipeline at Valve Site #2 would increase the frequency of a spill at that location. The new pumps would only be required if the emulsion pipeline MAOP is derated below 1,000 psig. Current MAOP of the emulsion line is 1,194 psig. Spills at pump stations are more common than along the pipeline due to the potential failure of the pumps. The OPS data indicates that there have been 205 spills (>50 bbls) at pump stations since 1985 producing a single fatality and four injuries. Spills from pumps are estimated by a number of different sources ranging from 0.31 spills per year (HLID 1992, reciprocating) to 0.07 spills per year (HLID 1992, centrifugal). Spill frequencies for the pipeline and the pump station are shown below. Due to the high leak rate of the pumps at the pump station, the spill probability would increase substantially over the current operations (0.9 lifetime spill probability currently for ruptures and 3.6 currently for leaks, see Table 5.1.2). This is addressed as a significant impact in the Onshore Water <u>Resources</u> Section (OWR.2) and Terrestrial Biology (TB.6 and TB.7).

Table 5.1.24 summarizes the spill frequencies and probabilities for the proposed project. The pipeline ruptures and leaks are based on the current operations (see Table 5.1.2<u>b</u>).

Table 5.1.24 Proposed Tranquillon Ridge Project Onshore Emulsion Pipeline Spill Frequencies and Probabilities, with Pump Station

Scenario	Spill Frequency per year	Proposed Project Lifetime Spill Probability, %	Current Operations Lifetime Spill Probability, %
Onshore Emulsion Pipeline ruptures	8.59E-04	2.5	0.9
Onshore Emulsion Pipeline leaks	3.68E-03	10.5	3.6
Valve Site #2 ruptures	$3.10x10^{-3}$	<u>8</u>~~0~~.9	-
Valve Site #2 leaks	0.31	100.0	-
Emulsion Pipeline with Valve Site, ruptures	3.<u>9</u>6E-03	11.2	0.9
Emulsion Pipeline with Valve Site, leaks	3.14E-01	100.0	3.6

Failure rates for Valve Site #2 pumps: Hydrocarbon Leak and Ignition Database, 1992
Assumes 30-year project life.

The estimated onshore emulsion pipeline spill volumes for the proposed project are provided in Table 5.1.25. Onshore emulsion spill volumes associated with the proposed project would increase, as the total fluids transported would be increased over current operations. In addition, the fraction of oil in the pipeline would increase. The oil fraction for the proposed project is estimated by PXP to be 40 percent oil and 60 percent water.

Table 5.1.25 Proposed Project Onshore Emulsion Pipeline Spill Volumes (barrels)

Location Description	Normal Operation: SCADA Operational		Worst-case: SCADA Not Operational		Notes
	Drain-down Spill Volume	Total, With Pumping Loss	Drain-down Spill Volume	Total, With Pumping Loss	
On Beach	386	698	2,738	4,613	Loss of contents between beach and VS1 (1,000’). Worst-case loss of contents between beach and high point before VS2 (7,000’). Check valve at VS3 prevents backflow.
At Valve Site #2	179	491	179	2,054	Loss of contents from pipeline uphill from VS2 (500’). Worst-case same as VS3 check valve prevents backflow.
Canyon and Terra Road Crossing	952	1,265	952	2,827	Loss of contents between VS2 and VS3 (2,500’). Worst-case same as VS3 check valve prevents backflow.

Table 5.1.25 Proposed Project Onshore Emulsion Pipeline Spill Volumes (barrels)

Location Description	Normal Operation: SCADA Operational		Worst-case: SCADA Not Operational		Notes
	Drain-down Spill Volume	Total, With Pumping Loss	Drain-down Spill Volume	Total, With Pumping Loss	
Valve Site #3	714	1,027	714	2,589	Break just downstream of VS3 (after CV). Loss of contents between VS3 and high point after VS3 (1,800'). Worst-case the same as check valve at VS5 prevents backflow.
Valve Site #4	952	1,265	952	2,827	Loss of contents between hill before VS4 and VS4 (2,500). Worst-case the same as VS5 check valve would prevent backflow.
After Valve Site #4	1,500	1,813	2,452	4,327	Break located after VS4 and Terra Road Crossing in small drainage. Loss of contents between VS4 and VS5 (3,900'). Worst-case loss of contents between hill after VS3 and VS5 (6,300').
Valve Site #5	571	884	571	2,446	Loss of contents from pipeline located upstream and downstream of VS5 not including valleys (1,500'). Worst-case would be the same as the check valve at VS6 would prevent backflow.
Drainage area before Valve Site #6	417	729	417	2,292	Limited by elevation profile and VS6 check valve (1,100'). Worst-case would be the same as the VS6 check valve would prevent backflow.
Valve Site #6	1,405	1,717	2,571	4,446	Loss of contents located above VS not including valleys between VS6 and VS7 (3,600'). Worst-case would include all areas above VS6 between VS6 and the VS9 check valve excluding valleys (6,600').
Valve Site #7	1,143	1,455	3,083	4,958	Loss of contents between hill upstream of VS7 and VS7 (2,900'). Worst-case due to all segments of pipeline downstream of VS7 before the VS9 check valve excluding valleys (7,900').
Between Valve Site #7 and Valve Site #8	786	1,098	5,131	7,006	Loss of contents between VS7 and VS8 (2,000'). Worst-case release due to pipeline above drainage bottom before the VS9 check valve excluding valleys (13,200').
Valve Site #8	2,619	2,932	4,048	5,923	Loss of contents from areas downstream of VS8 between VS8 and VS9 excluding valleys (6,700'). Worst-case would include upstream volume between hill before VS7 and VS8 which is above VS8 (10,400').
Drainage area before Valve Site #9	2,943	3,255	2,943	4,818	Loss of contents from pipeline located above drainage area between highway S-20 and VS9 (7,600'). Worst-case would be the same because of the check valve at VS9.
Valve Site #9	2,755	3,067	2,755	4,630	Loss of contents from pipeline located downstream of VS9 excluding valleys (7,100'). Worst-case would be the same.
Valve Site #10	167	479	167	2,042	Release from last section of pipeline above VS10 (400').
Proposed Operations Largest Spill Volume		**3,255**		**7,006**	**Largest Spill Volumes from all segments: Proposed Project**
Current Operations Largest Spill Volume		**3,141**		**6,318**	**Largest Spill Volumes from all segments: Current Operations**
Spill Volume Increase		**114**		**688**	**Spill Volume Increase due to proposed project**

Pumping rate calculated at 90,000 bpd emulsion.
Assumes 30-year project life.

Onshore Gas Pipeline

Because the gas pipeline operating pressure for the proposed project would be the same as current operations, there are no additional impacts associated with the proposed project gas pipeline. Impact distances would be the same as the baseline. However, the probability of having a release over the lifetime of the project would increase as the project life would be extended.

Onshore Produced Water Return Pipeline

The onshore produced water return pipeline would have a similar spill rate as the current operation because the parameters that affect spill rates would not change except for the average age of the pipeline. The CSFM indicates that there would be minimal increases in spill rates for an average age difference of 10 to 25 years. However, as the pipeline has shown no increase in corrosion in the most recent testing, proper maintenance and rating as well as frequent surveys of the pipeline integrity would be required in order to maintain an acceptable risk level to the environment. Mitigation has been proposed for this in Section 5.6, Oceanography and Marine Water Quality.

A proposed increase in produced water transported would increase the spill volumes due to an increase in the pumping rate. However, the water would be treated to a level required under the NPDES permit if ocean discharge were to occur. Increased spill volumes for the water return pipeline are shown in Table 5.1.26.

Table 5.1.26 Proposed Project Onshore Produced Water Return Line Estimated Spill Volumes, barrels

Location Description	Normal Operation: Automatic Valves Operational		Worst-case: Automatic Valves Not Operational		Notes
	Drain-down Spill Volume	Total, With Pumping Loss	Drain-down Spill Volume	Total, With Pumping Loss	
On Beach	62	895	1,146	1,979	Loss of contents to Valve Site #2 (1,000’). Worst-case: downstream pipeline minus the valleys (18,400’).
At Valve Site #2	255	1,089	708	1,541	Loss of contents to Valve Site #8 (4,100‘). Worst-case: downstream pipeline minus the valleys (11,400’).
Canyon and Terra Road Crossing	533	1,367	986	1,819	Loss of contents upstream to Valve Site #2 and downstream to Valve Site #8 excluding the valleys (8,600’). Worst-case: upstream and downstream pipeline minus the valleys (15,900’).
After Valve Site #4	659	1,492	1,112	1,945	Loss of contents towards Valve Site #4 and downstream to Valve Site #8 excluding valleys (10,600’), Worst-case towards VS4 and downstream to LOGP minus valleys (17,900’).
Drainage area before Valve Site #6	343	1,176	795	1,629	Drainage primarily from downstream pipeline to Valve Site #8 (5,500’). Worst-case past Valve Site #8 (12,800’).
Between Valve Site #7 and Valve Site #8	312	1,146	986	1,819	Drainage primarily from upstream portion (5,000’). Worst-case from downstream (towards LOGP) as well (15,900’).
Drainage area before Valve Site #9	437	1,271	437	1,271	Drainage primarily from downstream portion minus valleys (7000). Worst-case the same.
Valve Site #10	27	860	27	860	Release due to last section of pipeline above Valve Site #10 (400’). Worst-case the same.

Table 5.1.26 Proposed Project Onshore Produced Water Return Line Estimated Spill Volumes, barrels

Location Description	Normal Operation: Automatic Valves Operational		Worst-case: Automatic Valves Not Operational		Notes
	Drain-down Spill Volume	Total, With Pumping Loss	Drain-down Spill Volume	Total, With Pumping Loss	
Proposed Project Largest Spill Volume		1,492		1,979	Largest Spill Volumes from all segments: Proposed Project
Current Operations Largest Spill Volume		1076		1563	Largest Spill Volumes from all segments: Current operations
Spill Volume Increase		416		416	Spill Volume Increase due to proposed project.

Pumping rate calculated at 40,000 bpd.

LOGP Facility

Under the proposed project changes, the LOGP facility would operate similarly to the current operations scenario except that the number of gas liquids truck trips would increase to an average of five per week (260 per year) from 2.7 per week (139 per year, 2005 actual). This would move the FN curve for transportation further into the red region, as per the SBC Safety Element, the red region is classified as a significant impact) and exacerbate an already significant impact. Operation of additional trucks would also increase the risks associated with the LOGP facility as there would be trucks at the facility more often. Increased truck loading operations at the LOGP facility would very slightly increase the risk levels above the current operations. The operation of the sales gas pipeline connection would remain the same as current operations because operating pressure would not increase. The FN curves attributable to the LOGP operations (without gas liquids transportation) would remain unchanged because most of the risks to the public are associated with the produced gas pipeline and the associated potential impacts to Vandenberg Village.

Figures 5.1-5 and 5.1-6 show the FN curves for fatalities and injuries. For the pipeline and LOGP operations, the FN curves are essentially identical to those for the existing operations. For transportation, the FN curves have shifted upwards due to the increase of gas liquids transportation from 2.7 to 5 truck trips per week.

Offshore Facilities

Increased activities offshore as a result of the proposed project would increase the frequency of spills. Also, an increase in the oil percentages in the pipeline would increase the amount of oil that could be spilled into the marine environment if a spill were to occur. In addition, the longer life associated with Platform Irene and the Platform Irene to LOGP pipeline would increase the probabilities of a spill over the facility lifetime. Spill frequencies and lifetime probabilities are shown in the Table 5.1.27.

Table 5.1.27 Proposed Project Platform Irene and Offshore Emulsion Pipeline Spills to Ocean Frequency and Probabilities

Scenario	Frequency, per year	Lifetime Probability of Spill, %*
PLATFORM IRENE		
Small Spills		
Irene – Wellhead Area Spill to Ocean – small	$1.47x10^{-8}$	0.0
Irene – Separator Failure Spill to Ocean – small	$3.74x10^{-6}$	0.0
Irene – Pumping and Shipping Spill to Ocean – small	$2.38x10^{-4}$	0.7
Irene - Diesel Fuel Loading - Small Spill to Ocean	$2.90x10^{-4}$	0.9
Cumulative Small Spills	$5.33x10^{-4}$	1.6
Large Spills		
Irene – Blowouts	$2.78x10^{-3}$	8.0
Irene – Wellhead Area Spill to Ocean – large	$1.25x10^{-8}$	0.0
Irene – Separator Failure Spill to Ocean – large	$9.60x10^{-5}$	0.3
Irene – Pumping and Shipping Spill to Ocean – large	$2.80x10^{-5}$	0.1
Irene – External Impact	$1.00x10^{-5}$	0.0
Cumulative Large Spills	$2.91x10^{-3}$	8.4
Cumulative All Spills	**$3.4 x10^{-3}$**	**9.8**
MMS Throughput Approach, < 50 bbls, small spill	7.68E-02	90.0
MMS Throughput Approach, > 50 bbls, large spill	1.34E-02	33.2
EMULSION PIPELINE		
Leaks		
1985 Point Pedernales EIR Table 2-2, leaks	$4.41x10^{-3}$	12.4
CSFM for this Pipeline, leak	$3.11x10^{-3}$	8.9
MMS Throughput method, between 1 and 50 bbls, leak	0.230	99.9
Ruptures		
1985 EIR Table 2-2, ruptures	$4.90x10^{-4}$	1.5
CSFM for this Pipeline, rupture	$6.82x10^{-4}$	2.0
OPS all Crude Lines, spills > 50 bbl	$9.17x10^{-3}$	24.0
MMS Pipeline Throughput Method, > 50 bbls, rupture	4.03E-02	70.2

**Zero indicates less than 0.1%. Lifetime assumes 30 years.*

An increase in the average age of the emulsion pipeline due to the increased project life would not appreciably increase the rate of spills from the pipeline, whereas increased oil and gas throughput would. Other parameters that affect spill rates, such as temperature, would remain the same for the proposed project as the current operations. Spill rates for Platform Irene and Platform Irene to LOGP pipeline combined, as shown below, utilize the equipment specific approach and the 1985 Point Pedernales EIR failure rates for pipelines.

Spill volumes of emulsion associated with the offshore Platform Irene to LOGP emulsion pipeline would be similar to those for the current operation with some increase due to the increased pumping rate (increase approximately 100 bbls). However, as the oil percentage would increase, the amount of oil discharged would also increase. In addition, the wells currently producing operate with submersible pumps, meaning that the wells are not free-flowing and there is very low probability of a well blowout. However, as new wells would be drilled with the Tranquillon Ridge project, these new wells could exhibit higher reservoir pressures that may increase the potential for a well blowout. Frequencies of well blowouts are based on the

Hydrocarbon Leak and Ignition Database (1992) based on actual blowout experiences. See Appendix H for more details.

Table 5.1.28 Proposed Project Combined Platform Irene and Offshore Emulsion Pipeline Spills to Ocean Frequency and Probabilities

Scenario	Frequency, per year[1]	Proposed Project Lifetime Probability of Spill, %[2]	Current Operations Lifetime Probability of Spill, %[3]
Leaks and Small Spills	$4.94x10^{-3}$	13.8	4.8
Ruptures and Large Spills	$3.40x10^{-3}$	9.7	0.6
Any Spill Size	$8.34x10^{-3}$	22.1	5.4

1. Utilizing numbers from the 1985 Point Pedernales Facilities EIR/EIS.
2. Lifetime assumes 30 years, numbers may not add due to rounding
3. Remaining life of 10 years

The following table summarizes the proposed project offshore release volumes and includes the release volumes associated with the current operations and with well blowouts.

Table 5.1.29 Proposed Project Offshore Spill Volumes

Area	Current Operations Oil Only Release Volume, bbls	Proposed Project Oil Only Release Volume, bbls	Increase in Spill Volumes due to the proposed Project, Bbls
Platform Irene – Total Platform Loss	426 0 blowout	551 4,500 blowout	+125 +4,500
Offshore Emulsion Pipeline – Pipeline Midpoint Failure	1,754	4,244	+2,490
Offshore Emulsion Pipeline – Shoreline Failure	2,913	7,929	+5,016

Proposed operation is with 60% water, 40% crude oil in the pipeline. Current operations are with submersible pumps, which do not have a blowout potential. Tranquillon Ridge is expected to have free-flowing wells for about 5 years, thereby introducing the potential for well blowouts. See Appendix H.

Spills of crude oil only (just the crude portion of the pipeline stream) would increase by a substantial margin primarily due to the increase in oil composition of the emulsion. Increased pumping rates would account for less than two percent of the spill size increase.

The offshore portion of the produced water return pipeline would have a similar spill frequency rate as the current operation since the increase in average age has a minimal impact on spill frequency rates. Spill volumes would increase as the amount of produced water transported is proposed to increase. Spills due to pumping would total 27.8 barrels per minute, or 833 barrels over the 30 minutes it is estimated it would take to shutdown the water return pipeline. Spills due to hydrostatic head would be the same as for the current operations.

5.1.4.2 Impact Analysis for the Proposed Project

Impact #	Impact Description	Phase	Residual Impact
Risk.1	The proposed project could generate risks to public safety by exposing the public to crude oil spills and subsequent fires.	*Increased Throughput* *Extension of Life*	*Class III*

Increased throughput of crude oil between Platform Irene and the LOGP is not expected to generate increased public risks due to the relatively high level of water located within the process stream (about 60 percent). Therefore, the proposed project is considered to have adverse but not significant public safety impacts due to crude oil spills associated with upset conditions along the crude oil pipelines.

Mitigation Measures

Since the proposed project would have an adverse impact due to potential for crude oil emulsion spills, an upgrade to the SCADA system would improve safety by allowing smaller leaks to be detected. Therefore the following mitigation is recommended to ensure the upgraded SCADA system is implemented and maintained throughout the life of the project.

Risk-1 The applicant shall install an upgraded state-of-the-art leak detection system on the existing emulsion line and on the sour gas line. The upgraded system shall use the Best Available Technology (BAT) for detection of small leaks in the emulsion pipeline. The applicant shall provide the County with a comparative analysis of available technologies that have been used in applications similar to this project and the demonstrated effectiveness and reliability of those systems. The County shall review and approve of the leak detection technology prior to its installation. Review and approval of the comparative analysis and installation of the approved leak detection system shall occur prior to land use permit approval. ~~The applicant shall install an upgraded SCADA system on the existing emulsion line and a new system on the produced sour gas line. The new system shall have improved sensitivity to detect leaks, similar to the upgrade installed on PXP's Point Arguello facility. The new SCADA system should be able to detect 0.08 percent of flow leaks in less than 48 minutes and be able to detect leaks as small as 1/16 inch in diameter in less than two minutes.~~

Residual Impact

This impact is considered to be *adverse but not significant (Class III)* for public safety impacts due to crude oil spills; however, to mitigate this impact to the maximum extent feasible Mitigation Measure Risk-1 is proposed. (See Section 5.2, Terrestrial Biology, for spill-related biological impacts.)

Impact #	Impact Description	Phase	Residual Impact
Risk.2	The proposed project could generate risks to public safety by exposing the public to produced gas releases from the sour gas pipeline from Platform Irene to the LOGP.	*Extension of Life*	*Class III*

The proposed project does not propose to increase the operating pressure of the produced sour gas pipeline between Platform Irene and LOGP nor the maximum hydrogen sulfide levels (maximum levels were examined in this analysis). Because impact zones, and therefore risks to the public, are a function of the operating pressure and the hydrogen sulfide content, not the throughput, the risks to the public are considered to be the same as the current operations. According to the significance criteria defined in the SBC Safety Element, these risks were found to be not significant. This conclusion assumes that the pipeline would not operate above 600 psig operating pressure or above 8,000 ppm hydrogen sulfide concentration. See Section 5.1.1.4.4 for a more detailed discussion of the public safety risks associated with the sour gas pipeline.

The sales gas pipeline connection between the LOGP and The Gas Company transmission pipeline also has the potential for failure. However, as it is located along a more sparsely populated area and farther away from large populations like the produced gas pipeline (Irene to LOGP) it has risk levels in the green (not significant) region of the FN curve.

Mitigation Measures

Impact Risk.2 remains in the green region of the FN curve only when operation of the pipeline is below 600 psig. Therefore, the following mitigation measure is recommended to ensure the proposed operating parameter is applicable throughout the life of the project. In addition, Mitigation Measure Risk-1 would apply to mitigate this impact to the maximum extent feasible. ~~Since the proposed project would have an adverse impact due to potential for produced sour gas releases, an upgrade to the SCADA system would imprsove safety by allowing smaller leaks to be detected. Therefore, t~~The following mitigation is recommended to ensure that the pipeline pressure and hydrogen sulfide concentration are not increased.~~the upgraded SCADA system is implemented and maintained throughout the life of the project.~~

Risk-2 The ~~applicant~~ operator shall ensure that sour gas pipeline operation does not exceed 600 pounds per square inch (psig) and 8,000 parts per million (ppm) hydrogen sulfide throughout the life of the project. If any increase in pipeline operating pressure and/or hydrogen sulfide concentration is proposed, the operator shall conduct a risk assessment to demonstrate to the County’s satisfaction that such increase would not expand the existing hazard footprint associated with the sour gas pipeline. If such demonstration cannot be made, the proposed increase in pressure/ concentration shall not be approved or implemented.

Residual Impact

Impact Risk.2 is considered to be *adverse but not significant (Class III).*

Impact #	Impact Description	Phase	Residual Impact
Risk.3	The proposed project could generate risks to public safety by exposing the public to transportation hazards.	*Increased Throughput* *Extension of Life*	*Class I*

The proposed project would increase the transportation of gas liquids along roadways over current operations. Gas liquids truck transportation was identified as a significant impact in the 1985 Point Pedernales EIR and in this document with the current number of truck trips. By increasing the number of trips, and therefore the risks to the public, this existing significant impact is exacerbated (more truck trips and a longer period over which truck trips would occur). Therefore, impacts are considered to be significant for public risks due to gas liquids transportation.

Mitigation Measures

Risk-3 The applicant shall implement all of the measures identified in the SBC's policies regarding the transportation of gas liquids that were developed as part of the LPG/NGL Transportation Risk Assessment, including the blending of gas liquids into the crude oil to the maximum extent feasible. (The policies are included in the Point Pedernales Final Development Plan~~[FDP]~~ permit conditions P-2 and P-23). The applicant shall submit a plan to SBC for review and approval indicating maximum blending levels that are achievable with the proposed operations prior to land use clearance.

Residual Impact

With the application of Mitigation Measure Risk-3, risks due to increased gas liquid transportation would still be considered *significant (Class I).*

5.1.4.3 Biology and Water Resources Impacts

Because the calculations in the risk section are used in other parts of this EIR, this section briefly discusses the pertinent issues. Implementation of the proposed project would increase the probability of a pipeline oil spill over the life of the project, both onshore and offshore, due to the extended life of the Point Pedernales project over the current operations. Lifetime spill probabilities for the onshore oil pipeline are listed in Table 5.1.24. In addition, the increased amount of crude oil transported in the pipeline would increase the size of the oil spill, particularly into the marine environment. This is due to an increase in fluids transported and an increase in the oil percent over the current operations (see Table 5.1.29).

Increased drilling operations on Platform Irene would contribute to an increase in the frequency of an oil spill. This, combined with the extended life of Platform Irene due to the proposed project, would increase the probability of an oil spill from the platform over the life of the project by a significant margin. Oil spill volumes from Platform Irene would also ~~are not expected to~~ increase.

Spill volumes for the produced water return pipeline are expected to increase due to the increase in the amount of water transported. In addition, the probability of a produced water spill over the lifetime of the project would increase over the current operations due to the extended life. However, if the produced water was treated to the NPDES permit requirements, the level of impact would be significant, but mitigable. Under current practices, the produced water is not treated to NPDES requirements because it is re-injected offshore instead of being discharged directly to the ocean. This issue is discussed more fully in Sections ~~5.2, Terrestrial Biology~~ 5.5, Marine Biology, and 5.6, Oceanography and Marine Water Quality.

5.1.5 Impact Analysis for the Alternatives

Detailed descriptions of the various alternatives have been provided in Chapter 3.0, Alternatives. This section provides a discussion of the risk of upset impacts of the various alternatives.

5.1.5.1 No Project Alternative

Scenarios 2 and 3. As discussed in Section 3.2, under the No Project Alternative Scenarios 2 and 3, production of the federal portion of the Tranquillon Ridge field would and would not occur, respectively. However, no extension of life of Point Pedernales facilities (Platform Irene, pipelines, and LOGP) is assumed under either scenario. If the proposed project is not implemented, some drainage of the Tranquillon Ridge Field from Platform Irene could continue under Scenario 2. However, the development of the Federal portion of the Tranquillon Ridge reservoir only would result in a very low level of recovered reserves. The probability of an oil spill or an accident occurring over the life of the Point Pedernales project would remain at current levels. Oil throughput rates through the emulsion pipeline and the potential spill volumes would be to the same as for the current operations. Under the No Project Alternative Scenarios 2 and 3, Impacts Risk.1, Risk.2 and Risk.3 would not occur, since the production levels would be the same as the baseline conditions.

Options for Meeting California Fuel Demand. The relative risk of upset impacts associated with the various options for meeting California fuel demand are summarized in Table 5.1.30.

Table 5.1.30 No Project Alternative Comparison to Options for Meeting California Fuel Demand, Risk of Upset/Hazardous Materials

Source of Energy		Impacts
Other Conventional Oil & Gas		
	Domestic onshore crude oil and gas	Likely to displace, rather than eliminate, onshore spill and transportation risks.
	Increased marine tanker imports of crude oil	Spill potential and volumes would increase.
	Increased gasoline imports[1]	Displaced production and refinement impacts, and increased transportation hazards.
	Increased natural gas imports (LNG)	Displaced production and refinement impacts, and increased LNG transportation hazards.
Alternatives to Oil and Gas		
	Fuel Demand Reduction: increased fuel efficiencies, conservation, electrification[2]	
	Alternative transportation modes	Proposed project impacts would be eliminated.
	Implementation of regulatory measures	Proposed project impacts would be eliminated.

Table 5.1.30 No Project Alternative Comparison to Options for Meeting California Fuel Demand, Risk of Upset/Hazardous Materials

	Source of Energy	Impacts
	Coal, Nuclear, Hydroelectric	Proposed project impacts would be eliminated; however, coal and nuclear could introduce new risks due to operations, transportation, and disposal.
	Alternative Transportation Fuels	
	Ethanol/Biodiesel[3]	Impacts could be less than proposed project.
	Hydrogen[2]	Impacts would be less than proposed project.
	Other Energy Resources[2]	
	Solar[2,4]	Impacts would be less than proposed project.
	Wind[2,4]	Impacts would be less than proposed project.
	Wave[2,4]	Impacts would be less than proposed project.

Footnotes:
1. Pipeline and tanker truck import from out-of-State assumed.
2. Assumes that Tranquillon Ridge production would not be replaced with other petroleum-based energy supply.
3. Assumes ethanol and biodiesel used as blends only and therefore would reduce, but not eliminate Tranquillon Ridge or equivalent production.
4. Assumes, large centralized facilities.

5.1.5.2 VAFB Onshore Alternative

The major differences between the VAFB alternative and the proposed project are as follows:

- The VAFB alternative would require a new onshore drilling/production treatment site.
- The VAFB alternative would require about 10 miles of new emulsion and sour gas pipelines from the drilling site to the tie-in to the existing PXP pipelines
- The VAFB alternative would require a tie-in station at the PXP pipelines that would include four metering skids, four pig receivers, two pig launchers, vessels and piping for collected fluids including emulsion and condensate. Any collected fluids would need to be transported to the LOGP by reinjecting into the pipelines or by use of trucks.
- If produced water is removed at the production site, the dry oil from the VAFB alternative would be sent to the PXP emulsion line and may require booster pumps on the emulsion line from the tie-in to the LOGP.

The area around the Vandenberg Air Force Base (VAFB) onshore drilling/production treatment site location is sparsely populated, similar to the LOGP vicinity, but it is within 2,000 feet of Space Launch Complex 5 (SLC-5) located to the south east. SLC-6 is also located further southeast of the site. Exposed population may also exist on Coast Road (turns into Route 246), Surf Road, and Delphy~~i~~ Road, which bound the site. Also, the Union Pacific Railroad (UPRR) tracks are located immediately west of Coast Road, approximately 600 feet west of the onshore drill site.

The addition of approximately ten miles of oil emulsion and sour gas pipelines would add to the existing risks associated with the PXP pipelines currently in place. Impacts would be increased for primarily the sour gas pipeline as the emulsion pipeline presents minimal public health risks. The sour gas pipeline length would be increased, thereby increasing the failure frequency and the potential consequences by exposing additional persons along the pipeline route onshore. However, since there is no permanent population along the VAFB Alternative route, the sour gas pipeline impacts are expected to contribute minimally to the existing risk level associated with the Platform Irene to LOGP gas pipeline segments.

The nearness of the production treatment facility to SLC-5 is of some concern. The hazard zones for produced gas could be the result of a release from the drilling and production facility or the produced gas pipeline. Pipeline releases were used to model the impacts from both the drilling and production facility and pipeline. Gas pipeline hazard zone estimates for the proposed project give worst-case downwind distances of approximately 2,000 feet and 2,500 feet to injury (800 and 1,100 feet to fatality) endpoints for toxic and flammable vapor cloud impacts, respectively. The assumed scenario is a pipeline rupture with stable weather (Stability Class F) conditions. Using these distances as an indication of the impact zone for a process vessel or gas shipping pipeline rupture shows that SLC-5 is well within the flammable vapor cloud injury zone (1/2 LEL) and just at the outer limit or inside of the H_2S toxic vapor injury (ERPG-2) zone depending on which map is used. SLC-5 is currently inactive; however, there could be launches in the future. The Base does not have an estimate of when that might occur. In addition, the fatality hazard footprint from a sour gas release at the production site would encompass the nearby Coast and Surf roads and the Union Pacific Railroad, requiring road and rail closures for a period of time. These cars and trains could also be potential ignition sources. This would temporarily isolate approximately 140 personnel at South Vandenberg facilities and could interfere with launch operations at SLC-6. Also, individuals on VAFB traveling in cars and on the railroad could be exposed to toxic or flammable vapors.

These hazard footprints might be considered somewhat conservative in that the production treating facility would have flammable gas and hydrogen sulfide gas sensors to provide early detection and isolation of leaks. However, in the case of a rupture, rapid depressurization of the contained volume occurs before the flow is isolated. Therefore, for the rupture case, the operating pressure and equipment volume are the defining parameters. The current operating pressure range of the PXP Point Pedernales gas line is 425 to 570 psig, which is consistent with an assumed pressure of 600 psig for release calculations. The inlet pressure of the gas shipping line from the VAFB site would have to be in the same range or higher to flow gas into the existing PXP pipeline.

It may be possible to mitigate the impact of a gas release on the launch complex by advantageous placement of the gas compression and water removal equipment, and inlet to the gas pipeline as part of the drilling/production facility design.

The new facilities at the PXP pipeline tie-in station would create the potential for additional sour gas releases. These releases would not create hazard zones larger than those for the existing or new sour gas lines.

The oil emulsion pipeline presents a potential fire hazard in case of a spill. The proposed project would introduce new production into the existing PXP emulsion pipeline, raising the oil content from about 10 percent to about 34 percent. Section 5.1 does not consider flammability hazards associated with the proposed project emulsion given that the PXP emulsion pipeline would contain 66 percent water at minimum. For the VAFB Onshore Alternative, the initial oil cut in the emulsion line is assumed to be close to 88 percent and thus would more clearly pose a flammability hazard. Spill volumes of the emulsion pipeline are tabulated in Table 5.1.31~~0~~ based on the terrain and a pipeline diameter of 20 inches. If a spill were to occur, possible ignition sources along the pipeline include passing vehicles and passengers. The drilling/production facility equipment could also present possible ignition sources.

Table 5.1.31~~0~~ Potential Spill Volumes from VAFB Onshore Production Site to PXP Emulsion Pipeline

Pipeline Segment	Miles	Potential Emulsion Spill Volume[1], bbls
Honda Ridge – Bear Creek	3.2	6,086
Bear Creek – Santa Ynez River	5.5	10,235
Santa Ynez River – PXP Emulsion Line	1.3	1,756

1: Includes pumping losses at 90,000 bpd.
Segment losses include drainage from adjacent segments as a function of terrain. Assumes installation of automatic isolation valves at Bear Creek and Santa Ynez River crossings.

Oil spill frequencies due to the increased pipeline lengths associated with this alternative would be increased in comparison to the proposed project. During the first two to three years of production the oil cut would be in the 88 to 90 percent range. Therefore, the public health impact posed by the thermal hazard from a pool fire is a possibility. The hazard zones for thermal radiation from a spill of emulsion would be much ~~are typically~~smaller than the toxic or flammable vapor clouds from a release of produced gas, therefore the hazard zones for the produced gas were used to determine the potential worst-case hazard zones. Therefore, the impact on SLC-5 would be minimal. The thermal radiation hazard zone could impact Surf Road and the UPRR tracks; however, the shielding provided by the vehicle or rail car would prevent serious injury to individuals.

The additional facilities at the PXP pipeline tie-in station would create the potential for additional spills of emulsion or dry crude. The installation of booster pumps would increase oil spills at the station similar to what was estimated for the proposed project at Valve Site #2. However, the majority of these spills would be leaks of 100 bbls or less and would be expected to be contained within the spill containment of the tie-in station. The collected fluids from pigging operations would need to be stored and then reinjected into the pipelines or transported to LOGP by truck. In addition, a small quantity of sludge or solids would require offsite disposal.

The environmental impacts associated with oil spills from the onshore alternative emulsion pipeline are discussed in the biology and water resources sections. The alternative emulsion line has been divided into three segments as shown in Table 5.1.31~~0~~. This would be considered a minimum number of block valves in order to protect major waterways such as the Bear Creek and Santa Ynez river crossings. Potential oil spill volumes for the VAFB Onshore Alternative emulsion pipeline have been calculated at peak emulsion production where total fluids are 90,000 bpd with an oil cut of 33 percent which occurs in year twelve of production. Initially, the total additional fluids produced would be about 33,000 bpd (90,000 bpd minus 57,000 bpd current production from Irene) with an oil cut of 88 percent. Since the majority of the spill volume is due to gravity drainage, the oil spillage would be approximately 2.6 times (0.88/0.33) higher during initial production than at peak emulsion production because of the higher oil content in the alternative emulsion line.

~~Pipeline design details showing the elevation profile and proposed valve locations are not currently available.~~The spill volumes presented in Table 5.1.31~~0~~ would be lower with the installation of additional block and check valves beyond those assumed. The CSFM report concluded that there was little benefit relative to the associated costs for adding any significant number of block valves to the existing California regulated hazardous liquid pipeline network and that there may be some line segments over about 10 miles long which may benefit from intermediate block valves. The report also states that the average valve spacing for intrastate pipelines is 6.58 miles.

Another potential public safety issue is associated with the Air Force's security requirements during fueling and final stage launching of rockets. During launches and possibly during fueling operations, all personnel would have to evacuate the drilling/production site. During production, operations could possibly continue unmanned. This could affect the County's ability to adequately regulate operations and respond to emergencies at the processing facility within the Base (SBC P&D, 2000). An example of the County's limited access to VAFB property occurred following the Torch Point Pedernales offshore oil spill in 1997. During the response effort following the spill, the Air Force imposed a 15-hour suspension of clean-up and wildlife recovery efforts until launch activities were completed. Given the low annual frequency of launches, the coincidence of a launch occurring during an emergency at the production facility is probabilistically low, but history shows that it is possible and cannot be ignored.

Impact Risk.1 – Impacts to Public Health from Crude Oil Spills: Impacts associated with crude oil spills would be similar to the proposed project, less than significant, with an increase in severity as the length of onshore pipeline that could spill crude oil would be increased, additional facilities would need to be installed for metering and pigging operations at the PXP pipeline tie-in station and the addition of the thermal radiation hazard due to potential fires. Booster pumps may also be required at the tie-in station if the production facility removes the produced water from the emulsion and pumps dry oil through the emulsion pipeline to the PXP pipeline. Mitigation Measure Risk-1 would apply. (See the biology and water resource sections for ~~a~~ discussions of impacts related to crude oil spills to the environment.)

Impact Risk.2 – Sour Gas Pipeline Risks: This impact would not increase for this alternative in comparison to the proposed project since the gas throughput and H_2S content would be the same from the point of tie-in to the existing PXP pipelines to the LOGP facility and the major population areas are east of the tie-in point. This impact is for the Platform Irene to LOGP segment of the pipeline only and operations would be considered to be less than significant. Mitigation Measures Risk-1 and Risk-2 would apply. See Impact Risk.4 for a discussion of impacts for the sour gas pipeline from the alternative drilling/ production facility to the tie-in point.

Impact Risk.3 – Transportation Hazards: This alternative would have the same significant impacts as the proposed project, as gas liquids transportation at LOGP would increase for the operational life of the project. Mitigation Measure Risk-2 would be applicable.

Impact #	Impact Description	Phase	Residual Impact
Risk.4	The alternative project could generate additional risks to public safety by exposing the public to produced gas releases from the new drilling/production/processing facilities, ~~and~~ additional length of sour gas pipeline and new metering/pigging facilities at the PXP pipeline tie-in station that could leak gas.	*Operation*	*Class I or II*

As discussed above, hazards associated with the VAFB Onshore Alternative could affect the Base operations of SLC-5 and/or Coast Road and Surf Road, in addition to exposing the public and Base personnel to produced gas releases.

Mitigation Measures

In addition to measures that would likely be required by the Air Force to mitigate safety-related impacts of an onshore drilling and production project, the following mitigation measures are also recommended for the VAFB Onshore Alternative.

Risk-4 The applicant shall conduct a facility siting study using an accepted industry standard (e.g., API Recommended Practice 752: Management of Hazards Associated With Location of Process Plant Buildings) to select the best location of gas treating equipment so as to minimize the impact of sour gas releases at Space Launch Complex 5.

Risk-5 The applicant shall coordinate with the Air Force in the development of an emergency protocol that is satisfactory to SBC, and addresses how access for safety will be allowed during launch periods for critical events such as explosions, fires, and vapor cloud incidents at the production facility

Risk-6 The applicant shall install hydrogen sulfide and flammable gas sensors in-plant and at the fence line to detect the presence of gas leaks. Before unsafe levels are reached, an emergency plan shall be activated to close Coast Road, Delphy Road and Surf Road to all vehicle and pedestrian traffic and to stop any rail traffic.

Risk-7 Excess flow valves shall be installed on the gas pipeline at the VAFB production site location and automatic shutoff valves and/or check valves shall be installed on the emulsion pipeline at intermittent locations to minimize the amount of gas or crude oil/emulsion that could be released in the event of a pipeline leak or rupture.

Residual Impact

Given the uncertainty in VAFB mitigation requirements and lack of a detailed drilling/production facility and pipeline design, Impact Risk.4 is considered potentially *significant and unavoidable (Class I) or potentially significant and mitigable (Class II)* for the VAFB Onshore Alternative.~~With the application of the above mitigation measures, in addition to Mitigation Measure Risk-2 (pressure-H_2S operating curve), risks to public health due to a sour gas release from the VAFB production site, of emulsion and gas pipelines can be reduced to~~ ~~*significant but mitigable (Class II)*.~~

5.1.5.3 Casmalia East Oil Field Processing Location

The area around the Casmalia East location is sparsely populated, similar to the LOGP vicinity, but it still has populations located to the West: Casmalia at approximately 9,500 feet and railroad tracks and Black Road at approximately 5,500 feet, and to the north: Rancho Maria Golf Club at 7,500 feet. It is expected that the facility location would present lower risk to public health than the LOGP location as it is more removed from sensitive residential populations areas (such as Vandenberg Village and Mission Hills). However, the sensitive population areas near the LOGP are far enough removed from the LOGP facility (not from the produced gas pipeline) that public health risks are in the acceptable region of the SBC criteria.

The addition of approximately 10 to 15 miles of oil emulsion and sour gas pipelines with possibly a produced water return pipeline would add to the existing risks associated with the pipelines currently in place. Impacts would be increased for primarily the sour gas pipeline as the emulsion pipeline and the produced water return pipelines present minimal public health risks. The sour gas pipeline length would be increased, thereby increasing the failure frequency, and the potential consequences would be increased by exposing additional persons along the pipeline route on Highway 135 or located in sparsely populated areas along the route. How close the pipeline comes to the south end of Orcutt would determine whether the sour gas pipeline impacts contribute significantly or minimally to the existing risk level associated with the Platform Irene to LOGP gas pipeline segments.

Spill volumes of the emulsion pipeline are tabulated below based on the terrain and a pipeline diameter of 20 inches.

Oil spill frequencies due to the increased pipeline lengths associated with this alternative would be increased over the proposed project. The impacts associated with oil spills from the new oil and produced water pipelines are discussed in Section 5.2, Terrestrial and Freshwater Biology and Section 5.4, Onshore Water Resources.

Table 5.1.32~~1~~ Potential Spill Volumes from LOGP – Casmalia East Alternative Processing Location

Pipeline Segment	Miles	Potential Emulsion Spill Volume, bbls
LOGP - Harris Grade	1.2	2774
Harris Grade – Mid Grade	0.6	1543
Mid Grade – Highway 135/Highway 1	4.0	8519
Highway 135/Highway 1 - Before Orcutt PS	2.3	6575
Casmalia Segment 1	2.2	4826
Casmalia Segment 2	0.5	1338
Casmalia Segment 3	0.5	1338

Includes pumping losses at 90,000 bpd.
Segment losses include drainage from adjacent segments as a function of terrain.

Impact Risk.1 – Impacts to Public Health from Crude Oil Spills: Impacts associated with crude oil spills would be similar to the proposed project (*Class III*) with a slight increase in severity because the length of pipeline that could spill crude oil would be increased. Mitigation Measure Risk-1 would apply. (See Section 5.2, Terrestrial and Freshwater Biology, and Section 5.5, Marine Biology, for impacts related to crude oil spills to the environment).

Impacts Risk.2 – Sour Gas Pipeline Risks: This impact would be the same for this alternative as for the proposed project. This impact is for the Platform Irene to LOGP segment of the pipeline only and operations would be *adverse but not significant (Class III)*. Mitigation Measures Risk-1 and Risk-2 would apply.

Impact Risk.3 – Transportation Hazards: This alternative would have the same impacts as the proposed project (*Class I)*, as gas liquids transportation would increase for the operational life of this alternative in the same way as for the proposed project. Mitigation Measure Risk-3 would be applicable.

Impact Risk.4 – Public Exposure to Sour Gas Releases: The Casmalia Processing Alternative ~~project~~ could generate risks to public safety by exposing the public to produced gas releases from the additional sour gas pipeline between LOGP and Casmalia, and the new processing facility. If routing of the sour gas pipeline comes too close to the community of Orcutt, impacts due to an accidental release of sour gas could be realized on populations in that area. These impacts would range from toxic exposure to flammable vapor cloud hazards up to 2,500 feet from the pipeline. This would be considered an additional significant impact over the proposed project.

Impacts from the routing of the emulsion pipeline would be principally limited to odor impacts from a release, as the amount of H_2S and flammable materials that would be released is limited due to the amount of water in the emulsion and the characteristics of the crude oil (see Section 5.1.1.3).

Mitigation Measures

Risk-8 The applicant shall route the LOGP-Casmalia pipelines such that ~~it is~~ they are not closer than 2,500 feet from southern Orcutt. The route shall turn westward from Highway 1/135 near the Harris Canyon Creek area in order to avoid impacts to southern Orcutt. The pipeline route shall be located on plans submitted to SBC P&D for review and approval prior to land use clearance.

Risk-9 Excess flow valves shall be installed on the gas pipeline at the LOGP location and automatic shutoff valves and/or check valves shall be installed on the emulsion pipeline at appropriate locations to minimize the amount of gas or crude oil/emulsion that could be released in the event of a pipeline leak or rupture. Plans shall include proposed valve locations and be submitted to SBC for review and approval prior to land use clearance.

Residual Impact

With the implementation of the above mitigation measures, in addition to Risk-2~~1 (pressure H_2S operating curve~~, risks to public health due to a sour gas release from the Casmalia pipeline segment would be reduced to *less than significant levels (Class II)*.

5.1.5.4 Alternative Power Line Routes to Valve Site #2

The installation of the power lines below ground as opposed to above ground, or the alternative power line configurations as specified in Section 3.0 (Options 2a and 2b) would not change the risk analysis developed above for the proposed project. Therefore, the impacts for this alternative would be identical to those for the proposed project, Impacts Risk.1 through Risk.3 and the Mitigation Measures Risk-1 and Risk-2 would apply.

5.1.5.5 Replacement of Oil Emulsion Pipeline from Platform Irene to LOGP

The replacement of the emulsion pipeline would reduce the spill frequency of the pipeline due to the newer pipe. Spill volumes would remain the same due to the replacement of the current pipeline with a pipeline of the same diameter (and therefore volume). Statistics compiled by the CSFM indicate that pipelines ten years old have a spill rate of approximately ten percent less than a pipeline 20 to 30 years old. Pipelines older than 40 to 50 years show a substantial increase in spill rates. This is in part due to the less sophisticated technologies, related to coatings and cathodic protection, in place at the time the older pipelines were constructed. Pipelines built since 1950, or up to 50 years old, do not show an appreciable spill rate difference. At the time of the construction of the existing emulsion pipeline, durable coatings, such as polyethylene butyl, combined with cathodic protection and increased inspection and operating requirements (as promulgated by the DOT, CSFM) have reduced the failure rates of more recently installed pipelines substantially by reducing external corrosion (among other factors). Therefore, the application of current data to future spill frequency rates is somewhat skewed by the installation requirements 30 to 40 years ago. Therefore, it is assumed that current pipelines would operate with the lower spill frequency numbers (of a 20 year old pipeline) even if their age approaches 40 to 50 years old.

Although internal corrosion has been experienced on the existing emulsion pipeline, adhering to DOT de-rating requirements reduces the failure rates associated with internal corrosion to levels similar to pipelines that do not exhibit internal corrosion problems. This is due primarily to the failure modes of corrosion failures. Corrosion-related failures are generally experienced when the corrosion on the pipeline reaches the point where the reduction in metal increases the stresses in the metal pipe wall, due to the operating pressure, and these stresses exceed the metal capabilities. Metals generally do not fail as long as the stresses are below a given threshold level, or minimum yield strength. However, if the stresses exceed this threshold, failure occurs quite rapidly. This is why de-ratings are conducted; to ensure that the stresses in the pipe walls are below the minimum yield strength of the pipe material. If the stresses are below the minimum yield strength of the pipe, then the pipe effectively operates like a new pipe would. This is supported by the fact that the CSFM report indicates that there is not a statistical correlation between failure rates and operating pressure, or pipe stresses.

It is important to note that the primary difference in rates between pipelines built since 1950 and those built before 1950 is due to external corrosion. External corrosion is not an issue with the current pipeline system.

The main advantage of a new pipeline would be that the maximum allowable operating pressure could be higher due to the thicker walls of the pipe and the un-corroded pipe walls (and thereby higher allowable pressure rating). This greater pressure would allow the discharge pressure at Platform Irene to be higher and would eliminate the need for booster pumps at Valve Site #2. Pumps at Valve Site #2 would introduce the potential for leaks and ruptures at the pumps, which have a higher spill rate than those for a pipeline. The installation of a new pipeline would reduce the potential for a spill at Valve Site #2 over the proposed project.

Spill volumes associated with this alternative would remain the same as the proposed project. There would be a decrease in spill frequencies at Valve Site #2 location and a slight decrease in spill frequencies associated with the emulsion pipeline (approximately a 10 percent reduction in spill frequencies). Impact Risk.4, public exposure to sour gas releases, would not occur under the Emulsion Pipeline Replacement Alternative since no additional length of pipeline or processing/ production facilities would be constructed.

Impact Risk.1 – Impacts to Public Health from Crude Oil Spills: Impacts associated with crude oil spills would be the similar to the proposed project (*Class III*) with a slight decrease in severity as the frequency of pipeline spills would be reduced. Mitigation Measure Risk-1 would apply.

Impacts Risk.2 – Sour Gas Pipeline Risks: This impact would be the same for this alternative as for the proposed project, *adverse but not significant* (*Class III)*, as the sour gas pipeline would not be replaced. Mitigation Measure Risk-2 would apply.

Impact Risk.3 – Transportation Hazards: This alternative would have the same impacts as the proposed project (*Class I*) as gas liquids transportation would increase for the operational life of the project. Mitigation Measure Risk-2 would be applicable.

5.1.5.6 Alternative Drill Muds and Cuttings Disposal

Under this alternative, Impacts Risk.1, Risk.2 and Risk.3 would be the same as for the proposed project, Mitigation Measures Risk-1 and Risk-2 would apply.

Inject Drill Muds and Cuttings into Reservoir

Injection of muds and cuttings into the reservoir would most likely require the installation of additional equipment on Platform Irene, such as injection pumps. However, as none of this equipment would be handling crude oil or oily waters, the added equipment would not affect the spill rates calculated above for the proposed project. However, if the muds or cuttings contained contaminants, spills to the ocean would increase in frequency equal to the failure rates of the equipment (pumps, piping and drain system) or an injection-well blowout potential. These scenarios are considered to be relatively low frequency so the spill frequencies for this alternative are considered to be similar to those for the proposed project.

Transport Drill Muds and Cuttings to Shore for Disposal

The risk analysis would be the same for this alternative as for the proposed project as project components would remain essentially identical. However, there is the possibility, as discussed in Section 5.5, Marine Biology, that a boat accident could result in a spill of muds and/or cuttings closer to the shoreline and could affect the shoreline area to a greater extent than discharging. This impact is not present under the current operating scenario or under the proposed project. This would be an increase in impacts over the proposed project and is discussed in Section 5.4, Onshore Water Resources.

5.1.6 Cumulative Impacts

Cumulative projects that could impact the current analysis include both offshore oil and gas projects and onshore development projects. The cumulative impacts of these potential off- and onshore future development projects are discussed separately below.

5.1.6.1 Offshore Oil and Gas Projects

Potential energy related projects associated with federal outer continental shelf (OCS) leases are summarized in Section 4.2~~1~~. These potential projects include the drilling of new wells within existing leases from existing platforms, exploration well abandonment, decommissioning, and development of some undeveloped offshore leases from existing and new platforms. As addressed in Section 4.2~~1~~, the timing and specific implementation plans for these potential projects is currently considered highly speculative due to on-going litigation concerning the federal OCS leases and continuing objections from the State of California regarding their future development. Potential energy related projects associated with State leases that are considered germane to the proposed project are summarized in Section 4.~~2~~3; they include five projects.

As addressed in Section 5.1.4, potential risk of upset impacts to public safety that are associated with the proposed project include: oil spills and related fires; natural gas releases, including sour gas releases due to pipeline ruptures and leaks; and exposure to hazardous materials, including NGL/LP~~N~~Gs, due to truck transportation risks.

In 2005, the MMS (MMS, 2005) evaluated potential environmentally-oriented impacts associated with oil spills as related to development of the federal OCS undeveloped leases; however, that document did not evaluate potential impacts associated with public safety (risk of upset). Consequently, the cumulative public safety impacts associated with development of the federal undeveloped OCS leases is currently not known and considered speculative. Pursuant to Section 15145 of the CEQA Guidelines, a Lead Agency is discouraged from evaluating impacts that are considered too speculative to resolve. Due to the lack of either qualitative or quantitative information regarding the potential risk of upset impacts in federal OCS waters that may occur due to future development, comprehensively assessing the cumulative impacts associated with the proposed project cannot be reasonably ascertained at this time. However, based upon the proposed project's specific risk of upset impacts, as discussed in Section 5.1.4.2, it is generally assumed that its incremental contribution to cumulative risk of upset impacts would not be considered significant for oil spills and gas releases, and significant for NGL/LPG truck transport. Further, cumulative NGL/LPG truck transport impacts due to the potential energy related projects are considered significant.

The potential oil and gas development projects within State waters are located at, or south of the City of Goleta; due to their distance from the proposed project, no overlap in impacts to public safety would be anticipated to occur. Therefore, the proposed project's incremental contribution to the cumulative risk of upset associated with these projects would not be cumulatively significant.

5.1.6.2 Onshore Projects

Cumulative onshore developments as presented in Section 4.3 would contribute to an already significant impact by increasing the traffic on roadways that are used by the trucks that transport NGL/LPGs from the LOGP facility. The route principally affected would be Harris Grade Road and the areas within Lompoc where NGL/LPGs are transported. As continued growth is expected in the region, increased traffic would also be expected on most roadways. With additional vehicles on the roadways used for liquid gas transportation, the consequences of a liquid gas truck accident would increase in severity for this already significant impact.

For projects within Santa Barbara County, ~~The construction of residential developments within the hazard footprints of the existing PXP pipelines would consequentially put more people in harms way in the event of a pipeline accident. However, given the~~ implementation of SBC Safety Element Supplement Policies 2A, 3A, 3B, and Planned Development Policy 3(c) would preclude the siting and construction of future residential developments within the hazard footprints of the existing PXP pipelines; therefore, the number of additional people that may be put in harm's way in the event of a pipeline accident would be minimized. With implementation of the policies noted above and the mitigation measures for the proposed project, in conjunction with the nominal frequency value for emulsion or gas pipeline failure, the proposed project's incremental contribution to cumulative impacts associated with pipeline failure hazards would not be expected to be significant. Significant risk of upset impacts could occur for other projects, such as the PXP residential project, that are proposed to be located outside of the County's jurisdiction but in close proximity to the PXP facilities. In such cases, a detailed quantitative risk assessment should be conducted and mitigation measures developed during the environmental and permit review processes for those projects.

5.1.7 Mitigation Monitoring Plan

Mitigation Measure	Mitigation Requirements and Timing	Method of Verification	Timing of Verification	Party Responsible For Verification
Risk-1	The applicant shall install an upgraded state-of-the-art leak detection system on the existing emulsion line and on the sour gas line. The upgraded system shall use the Best Available Technology (BAT) for detection of small leaks in the emulsion pipeline. The applicant shall provide the County with a comparative analysis of available technologies that have been used in applications similar to this project and the demonstrated effectiveness and reliability of those systems. The County shall review and approve of the leak detection technology prior to its installation. Review and approval of the comparative analysis and installation of the approved leak detection system shall occur prior to land use permit approval. ~~The applicant shall install an upgraded SCADA system on the existing emulsion line and a new system on the produced sour gas line. The new system shall have improved sensitivity to detect leaks, similar to the upgrade installed on PXP's Point Arguello facility. The new SCADA system should be able to detect 0.08 percent of flow leaks in less than 48 minutes and be able to detect leaks as small as 1/16 inch in diameter in less than two minutes.~~	SCADA system review.	~~Before operation of the Tranquillon Ridge project.~~ Prior to land use permit approval.	SBC P&D, SSRRC
Risk-2	The ~~applicant~~ operator shall ensure that sour gas pipeline operation does not exceed 600 pounds per square inch (psig) and 8,000 parts per million (ppm) hydrogen sulfide throughout the life of the project. If any increase in pipeline operating pressure and/or hydrogen sulfide concentration is proposed, the operator shall conduct a risk assessment to demonstrate to the County's satisfaction that such increase would not expand the existing hazard footprint associated with the sour gas pipeline. If such demonstration cannot be made, the proposed increase in pressure/concentration shall not be approved or implemented.	Monthly reports to the SBCP&D to include operating pressure of the gas pipeline.	Before operation of the Tranquillon Ridge project.	SBC P&D, SSRRC

Mitigation Measure	Mitigation Requirements and Timing	Method of Verification	Timing of Verification	Party Responsible For Verification
Risk-3	The applicant shall implement all of the measures identified in SBC policies regarding the transportation of gas liquids that were developed as part of the LPG/NGL Transportation Risk Assessment, including the blending of gas liquids into the crude oil to the maximum extent feasible. (The policies are included in the Point Pedernales Final Development Plan (FDP) permit conditions P-2 and P-23). The applicant shall submit a plan to SBC for review and approval indicating maximum blending levels that are achievable with the proposed operations prior to land use clearance	The plan shall be approved prior to land use clearance and implemented prior to operation of the facilities with Tranquillon Ridge Wells.	Monthly P&D reports. Blending levels shall be documented in the monthly production reports.	SBC P&D, SSRRC
Risk-4 (VAFB Onshore Alternative only)	The applicant shall conduct a facility siting study using an accepted industry standard (e.g., API Recommended Practice 752: Management of Hazards Associated With Location of Process Plant Buildings) to select the best location of gas treating equipment so as to minimize the impact of sour gas releases at Space Launch Complex 5 (SLC-5).	Plans shall be submitted for review and approval.	Prior to land use clearance.	SBC VAFB
Risk-5 (VAFB Onshore Alternative only)	The applicant shall coordinate with the Air Force in the development of an emergency protocol that is satisfactory to SBC, and addresses how access for safety will be allowed during launch periods for critical events such as explosions, fires, and vapor cloud incidents at the production facility	Protocol review and approval	Prior to operations.	VAFB
Risk-6 (VAFB Onshore Alternative only)	The applicant shall install hydrogen sulfide and flammable gas sensors in-plant and at the fence line to detect the presence of gas leaks. Before unsafe levels are reached, an Emergency Plan shall be activated to close Coast Road, Delphy Road and Surf Road to all vehicle and pedestrian traffic.	Design drawing and Emergency Plan review and approval.	Prior to land use clearance.	SBC VAFB
Risk-7 (VAFB Onshore Alternative only)	Excess flow valves shall be installed on the gas pipeline at the VAFB production site location and automatic shutoff valves and/or check valves shall be installed on the emulsion pipeline at intermittent locations to minimize the amount of gas or crude oil/emulsion that could be released in the event of a pipeline leak or rupture.	Design drawing review and approval.	Prior to land use clearance.	SBC VAFB
Risk-8 (Casmalia Alternative only)	The applicant shall route the LOGP-Casmalia pipelines such that it is not closer than 2,500 feet from southern Orcutt. The route shall turn westward from Highway 1/135 near the Harris Canyon Creek area in order to avoid impacts to southern Orcutt. The pipeline route shall be located on plan submitted to SBC P&D for review and approval prior to land use clearance.	Plans shall be submitted for review and approval prior to land use clearance.	B&S inspections, Permit Conditions	B&S, SBC P&D

Mitigation Measure	Mitigation Requirements and Timing	Method of Verification	Timing of Verification	Party Responsible For Verification
Risk-9 (Casmalia Alternative only)	Excess flow valves shall be installed on the gas pipeline at the LOGP location and automatic shutoff valves and/or check valves shall be installed on the emulsion pipeline at intermittent locations to minimize the amount of gas or crude oil/emulsion that could be released in the event of a pipeline leak or rupture. Plans shall be submitted to SBC for review and approval prior to land use clearance.	Plans shall be submitted for review and approval prior to land use clearance. The valves shall be installed prior to operation of the Casmalia facility.	B&S inspections, Permit Conditions	B&S, County Planning and Development, SSRRC

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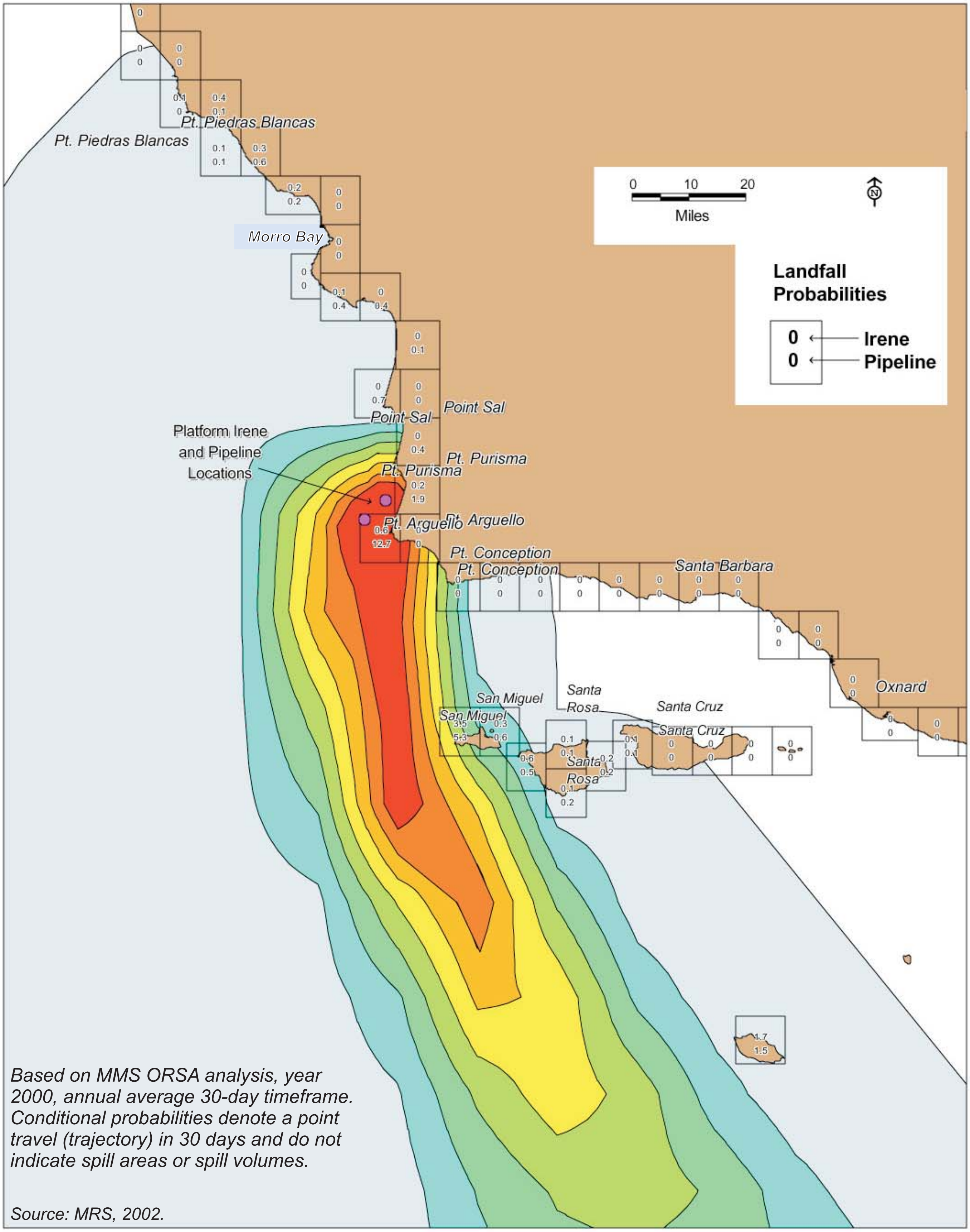

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Figure 5.1-1
MMS OSRA Probabilities (5) of Oil Spill Impact for Platform Irene and Pipeline

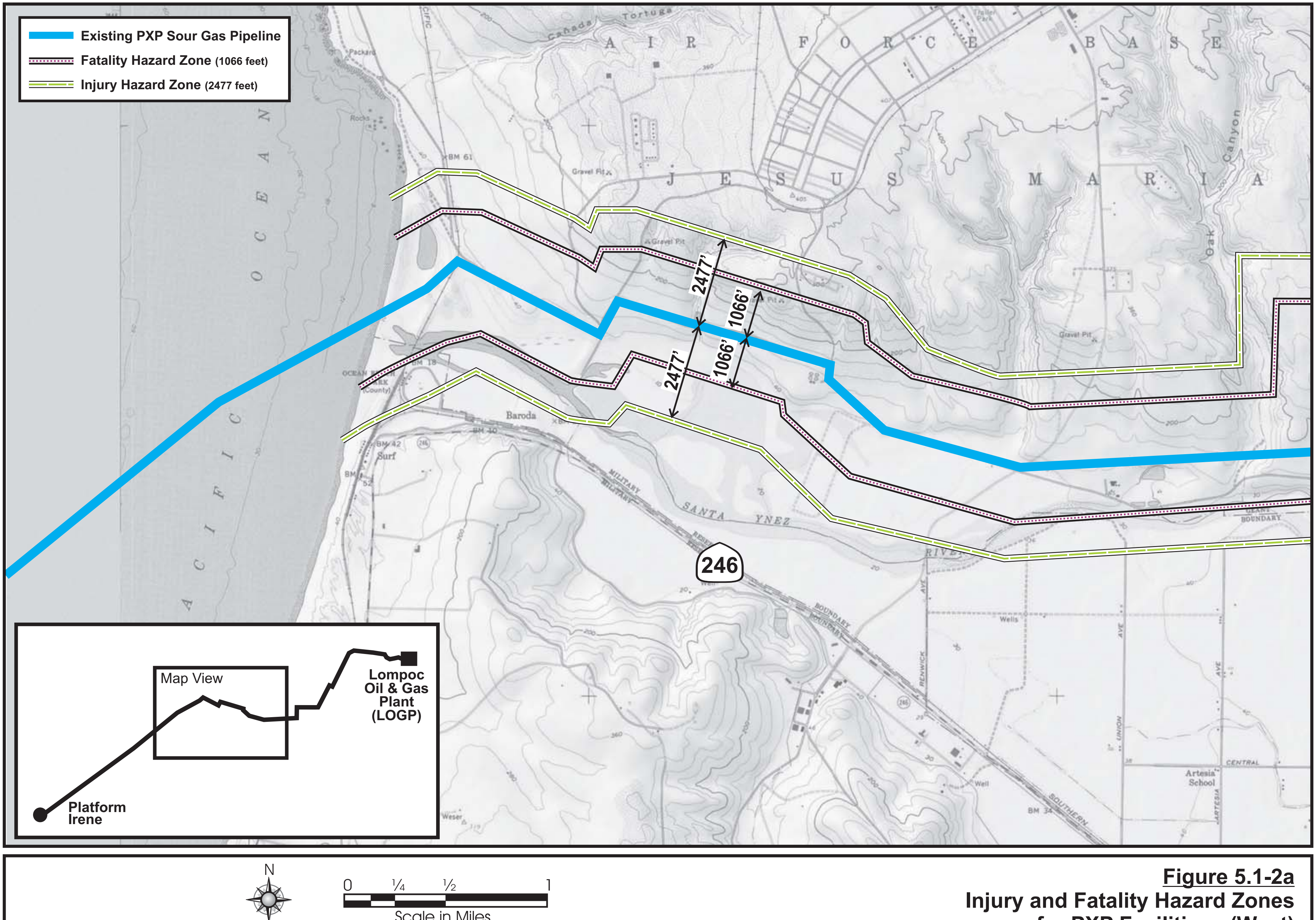


Figure 5.1-2a
Injury and Fatality Hazard Zones for PXP Facilities - (West)

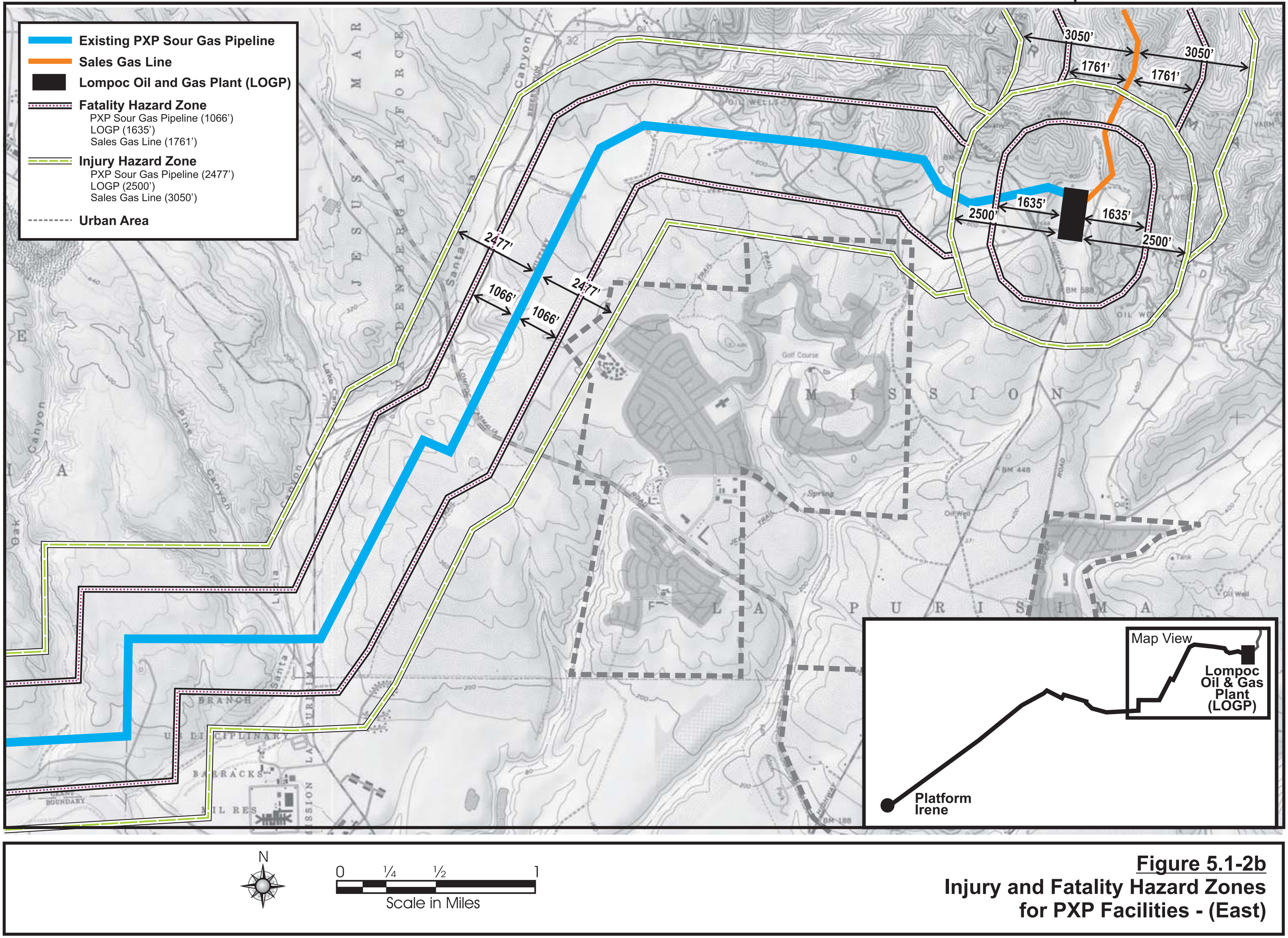
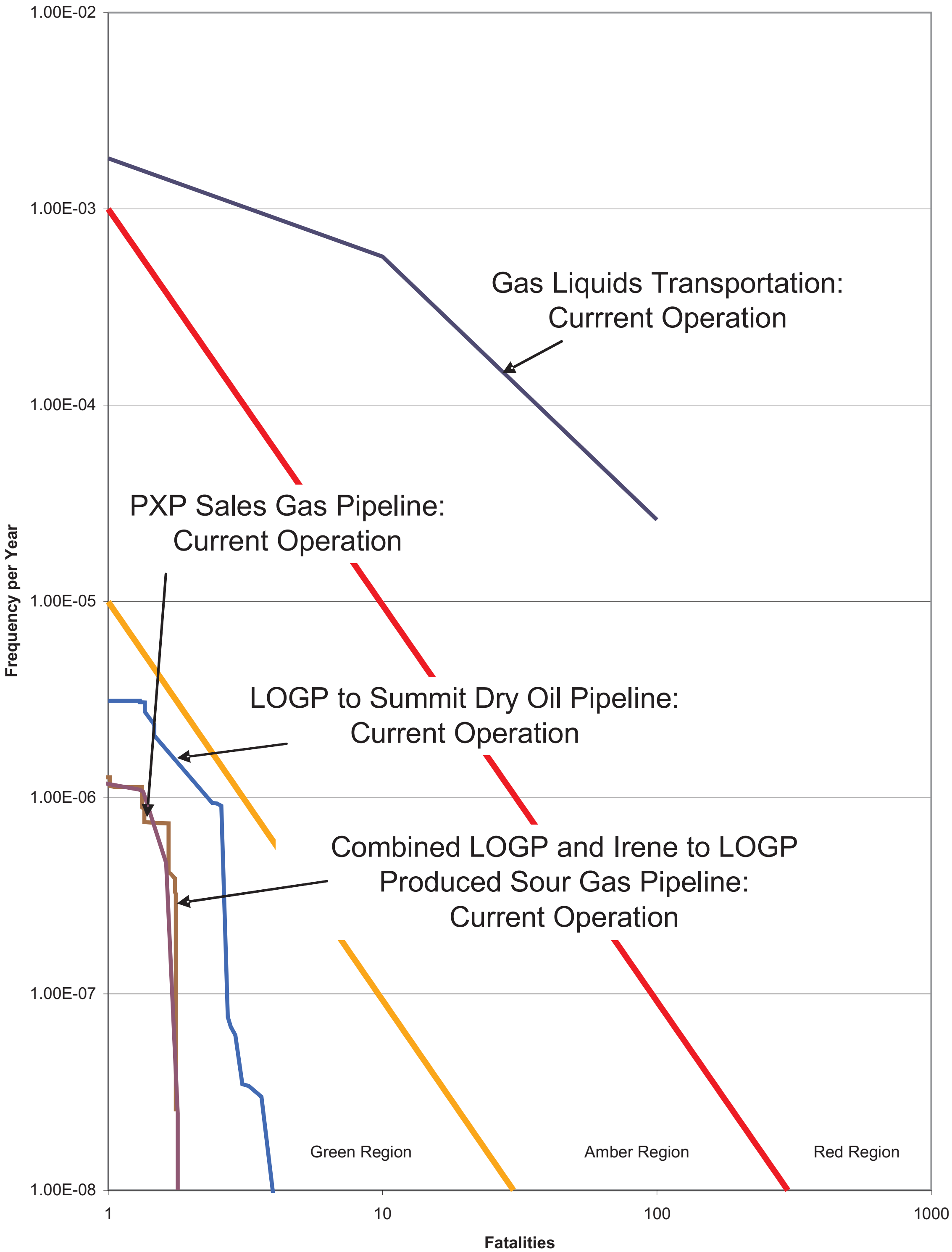


Figure 5.1-2b
Injury and Fatality Hazard Zones for PXP Facilities - (East)



Transportation FN curves are taken from the 1985 Point Pedernales EIR and are scaled to the annual average number of gas liquid truck trips that have been recorded.

Source: ioMosaic, 2006.

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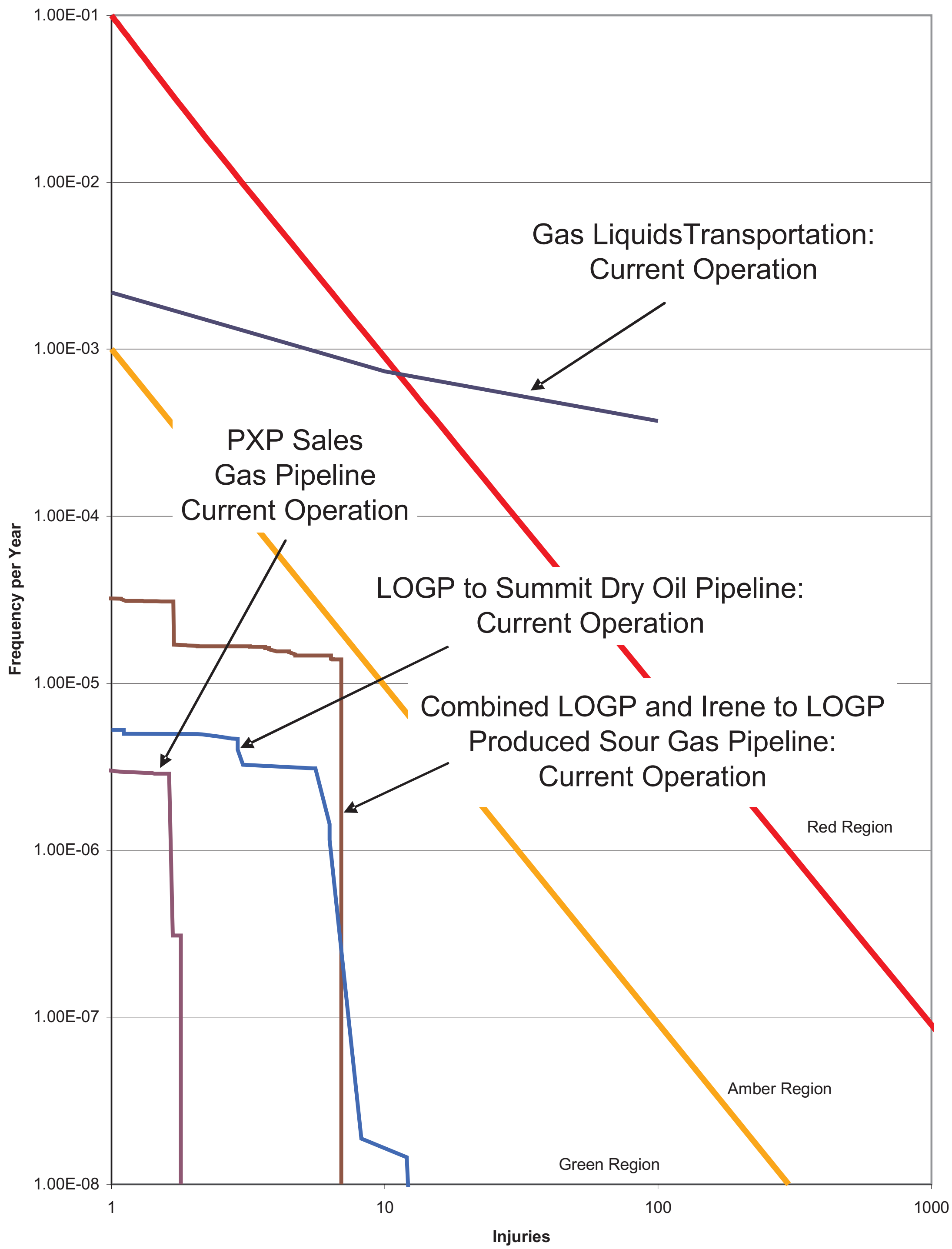
Figure 5.1-3

Fatality FN Curves: Current Conditions



Transportation FN curves are taken from the 1985 Point Pedernales EIR and are scaled to the annual average number of gas liquid truck trips that have been recorded.

Source: ioMosaic, 2006.

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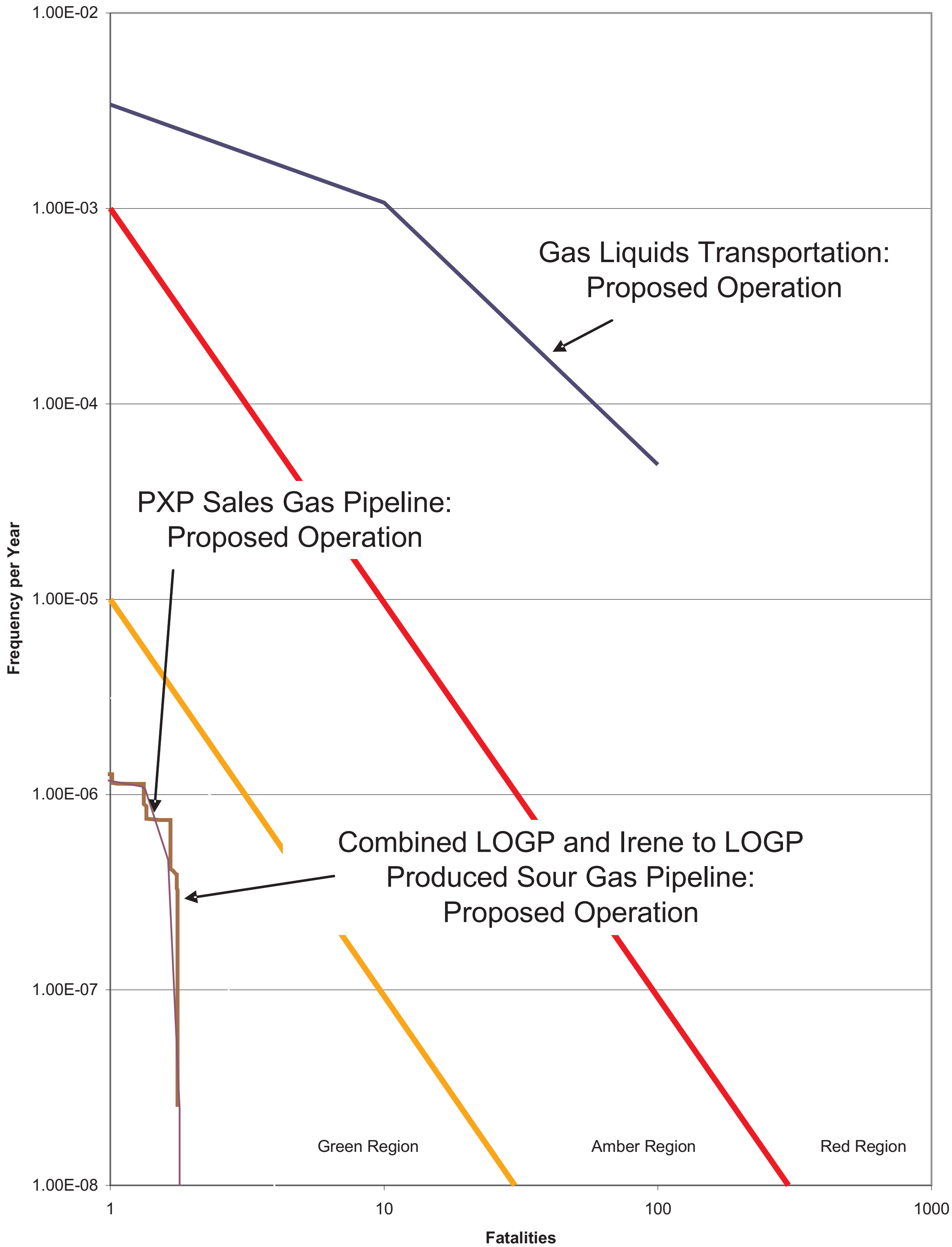
Figure 5.1-4

Injury FN Curves: Current Conditions



Source: ioMosaic, 2006.

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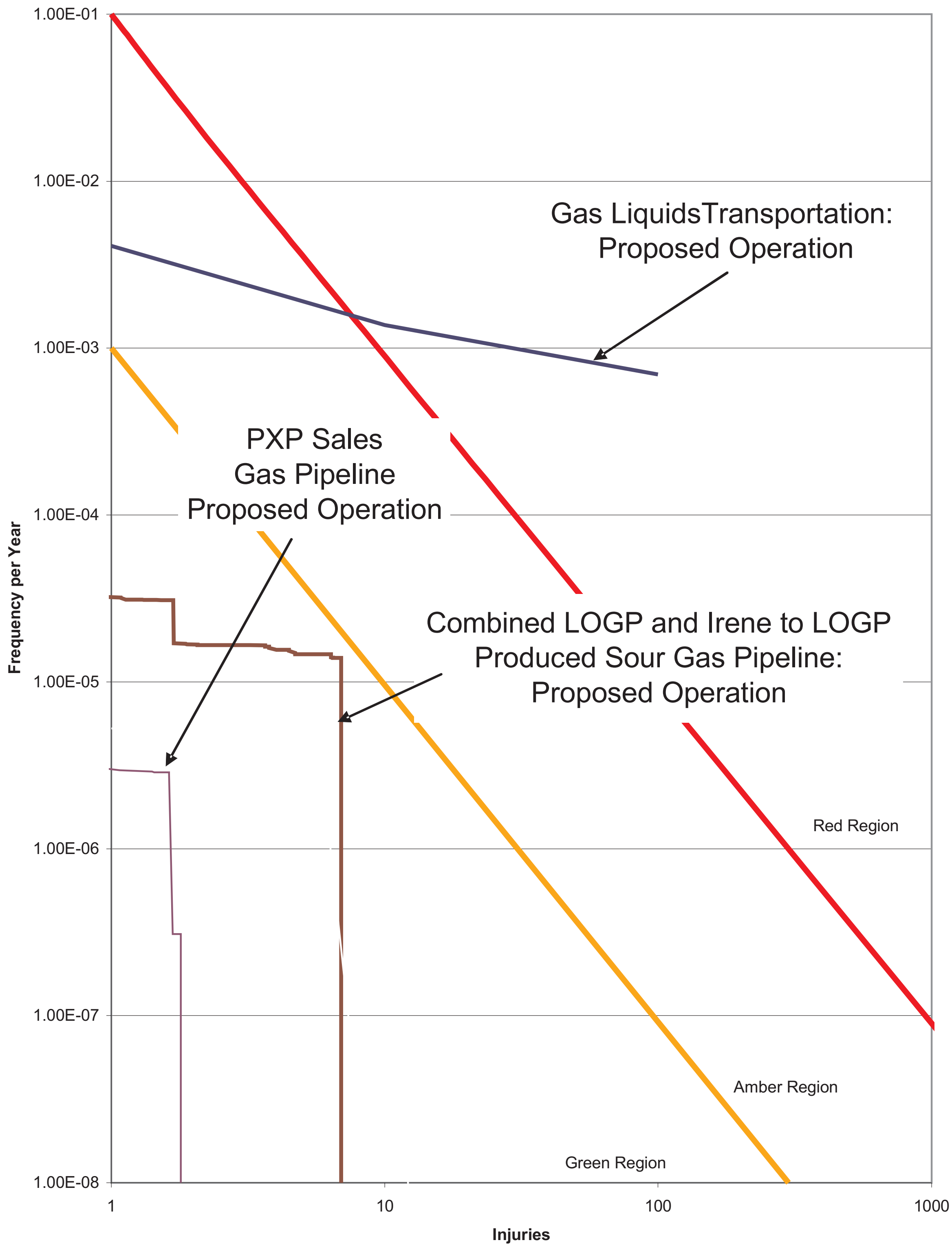
Figure 5.1-5

Fatality FN Curves: Proposed Conditions



Source: ioMosaic, 2006.

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Figure 5.1-6

Injury FN Curves: Proposed Conditions

5.2 Terrestrial and Freshwater Biology

The area that would be affected by the proposed project (see maps in Appendix A) includes western Santa Barbara County (SBC) in the vicinity of the Santa Ynez River, the central region of VAFB, unincorporated areas north of the City of Lompoc, Orcutt, Santa Maria, the Santa Maria and Sisquoc Rivers, and unincorporated areas of San Luis Obispo County. A major oil spill occurring at Platform Irene or along the offshore pipeline could affect shoreline habitats along Santa Barbara and San Luis Obispo Counties, and may be transported as far south as the western Channel Islands. The modeled trajectories for offshore oil spills (Appendix G) indicate that a large offshore spill would be most likely to reach shore between Point Arguello and Point Sal or along the north-facing coastline of San Miguel Island; therefore terrestrial biological resources in these areas are included in the impact analysis. Primary focus is devoted to the terrestrial and freshwater resources along the onshore pipeline corridor that would be directly or indirectly affected by the proposed project.

Some of the last large undeveloped open areas in coastal Southern California are found at VAFB and on the Burton Mesa ~~pr~~Reserve (see CDFG 2005b). Within this region of the state, a pronounced shift in orientation of the coastline, from north-to-south (north of Point Conception), to west-to-east (south of Point Conception) occurs. Climatic conditions along the unprotected coast north of Point Conception are significantly cooler, moister, and windier than to the south. Thus the area encompasses a major climatic transition zone. The region is also topographically diverse, with coastal dune-wetland complexes, two major river systems, terraces and bluffs and interior valleys comprising the lowlands. Uplands include coastal and interior hills and mountains. The resulting habitat diversity, species diversity and high number of species found only in this area (endemic species) make this region biologically unique within the state (Smith, 1998; Santa Barbara County Conservation Element 1979, as amended 1994). Important biological resources, recognized as Environmentally Sensitive Habitat Areas under the County's Local Coastal Plan, include dunes and wetlands, stream and riverine habitats, riparian (streamside) woodlands, relictual (remnant) evergreen forests, interior wetlands and vernal pools, Burton Mesa chaparral, oak woodlands and remnant patches of native grassland.

Biological resources within the project area were studied extensively during preparation of the 1985 Point Pedernales EIR/EIS (Arthur D. Little, 1985) that evaluated the impact of installing the pipelines, valves and processing facilities discussed below. This information was updated in the 2002 EIR (ADL and MRS, 2002), which is the primary information source for this document. Site visitation and subsequent research were conducted in support of the proposed project in 2006. Additional updates are provided due to a change in the status of several listed species and their habitats.

5.2.1 Environmental Setting

5.2.1.1 Terrestrial Habitats and Biota

The native vegetation of the project area is composed mainly of shrub, oak woodland, modified grassland communities, agricultural lands, and Burton Mesa chaparral, distributed in a mosaic pattern over coastal terraces, dunes and bluffs, and through interior hills. Coastal and interior wetlands and riparian woodlands are limited in extent in the project area, and are associated with the Santa Ynez River, tributary streams and coastal dunes. Evergreen forest communities are restricted to moister and cooler mountain environments, such as crests, ravines, and north-facing slopes. This habitat type is not common in the project area except for remnant eucalyptus stands that are classified as evergreen forests for the purposes of this analysis. Evergreen forests, dune, oak and riparian woodland, native grassland and wetland communities have decreased in area within the project area over time due to several factors including:

- A trend toward a warmer, more arid climate over geologic time;
- Changes in the frequency and distribution of wildfires since colonization of the area by Native Americans and European descendants;
- Grazing by non-native ungulates[1]; and
- Agricultural and other development trends, including land clearing and grading.

Of the native vegetation species commonly found in the project area, many plant species are restricted in distribution (endemic) to the project area and/or reach their southern or northern mainland distributional limits in this area. Many of the plant species endemic to the project area have been listed by the U.S. Fish and Wildlife Service (USFWS), the California Department of Fish and Game (CDFG), or the California Native Plant Society (CNPS) as being rare, threatened or endangered. SBC P&D Department has also identified some plant species as being of local concern. The term “rare plant” as used in this report refers to plants listed by one or more of these groups.

Wildlife species distributions are determined largely by the distributions of their preferred habitats. Many species are restricted to one or a small number of plant communities, and often require additional special environmental features (e.g., rocky cliffs as nesting sites for certain birds) in order to complete their life cycles. The project area is characterized by a moderate degree of topographic complexity and a variety of plant community types that provide considerable wildlife habitat diversity. The combination of habitat diversity, and geographic location in a climatic transition zone and relatively undisturbed condition, are factors that contribute to the diverse assemblage of amphibians, reptiles, mammals, and birds found in the project area.

Within the geographic limits of the onshore project area, Burton Mesa, the Santa Ynez River, San Antonio Creek, Santa Maria/Sisquoc Rivers and Nipomo Creek support mainly natural communities, although some areas are used for agricultural activities including grazing and cultivated crops. In particular along the Santa Ynez River and at the base of the Purisima Hills, near the pipeline crossing of San Antonio Creek, there are extensive agricultural lands.

Important biological features within the geographic limits of the onshore project area include:

- Coastal beach and dune habitats between the Santa Ynez River mouth and Wall Beach, approximately a mile north of it, support rare plants (see Section 5.2.1.3 for the definition of “rare plant” as used in this report), and are used seasonally by federal and state-listed, threatened and endangered wildlife species including the California least tern (roosting, nesting, and foraging), California brown pelican (roosting), and western snowy plover (nesting and wintering) at Wall Beach, as well as beach/dune areas south of Wall Beach. The coastal beach and dune area has

[1] Large grazing or browsing mammals such as deer, cattle, and sheep.

been designated by the U.S. Fish and Wildlife Service (USFWS) as critical habitat for the western snowy plover (USFWS, 1999c).

- Coastal wetlands and riparian woodlands near the Santa Ynez River mouth include a nesting site and feeding area for the endangered California least tern and the endangered southwestern willow flycatcher. These habitats are also known to support several species of rare plants, amphibians, birds, and fish. Coastal beach, dune, estuarine and freshwater wetland, and riparian woodland habitats are all protected by the Santa Barbara County Coastal Plan policies (1982).

The Santa Ynez River, a perennial stream listed in the Santa Barbara County Conservation Element (1979, as amended 1994) and Coastal Plan (1982), and the Santa Maria River, an intermittent river, provide habitat for the federally listed endangered Southern California steelhead trout (*Oncorhynchus mykiss irideus*). The rivers have also been designated by National ~~Oceanic and Atmospheric Administration (NOAA) Fisheries (formerly the National~~Marine Fisheries Service (NMFS) as critical habitat for the steelhead (NMFS, 2005~~0~~).

Freshwater portions and tributaries to the Santa Ynez and Santa Maria Rivers, including adjacent freshwater wetlands, as well as San Antonio Creek, may also support the federally listed (threatened) California red-legged frog (*Rana aurora draytonii*). Critical habitat for this species was initially designated in 2001 (USFWS, 2001a). Subsequent litigation resulted in revised designation of critical habitat in 2006 (USFWS, 2006a). Critical habitat is not designated on VAFB or in other areas affected by the project.

The tidewater goby (*Eucyclogobius newberryi*) is an estuarine species known to inhabit the Santa Ynez River and Santa Maria River estuaries, San Antonio Creek, and the brackish water lagoons at the mouths of many smaller streams in coastal Santa Barbara County (USFWS, 2005). It is currently afforded full protection under the Federal Endangered Species Act. Critical habitat is not designated north of Orange County, California.

There are also several intermittent blue-line streams, as indicated on 7.5 minute U.S. Geological Survey (USGS) quadrangles, within the project area that the existing pipeline crosses or is parallel to. SBC creeks include San Antonio Creek, and several unnamed tributaries in Graciosa Canyon adjacent to Highway1/135, Pine Canyon Creek, Orcutt Creek and an unnamed tributary to the Betteravia Lakes near the Santa Maria Airport, and Nipomo Creek in San Luis Obispo County.

Vernal pools (seasonal wetlands), protected by the SBC's Coastal Plan policies, occur in the vicinity of the pipeline corridor. Vernal pools, and their surrounding oak savanna habitats in central and northern SBC, particularly in the Purisima Hills and Santa Rita Hills are known to support populations of the California tiger salamander (*Ambystoma californense*), a distinct vertebrate population segment that is listed as endangered by the USFWS (2000a, b). A vernal pool complex located on the grounds of the Lompoc Federal Penitentiary (south of the pipeline corridor) is also known to support populations of tiger salamanders; however the individuals found there are an introduced species (*Ambystoma tigrinum*), rather than the native, listed species (*Ambystoma californiense)* (Shaffer, 2000).

Coast live oak woodland, Bishop pine forest, and Burton Mesa chaparral plant communities are also considered protected habitats under the Santa Barbara County Conservation Element (1979, as amended 1994). The latter two habitats mentioned above comprise relatively large numbers of regionally endemic and rare plant species, especially in the vicinity of Vandenberg Village, through the Purisima Hills and along Harris Grade to San Antonio Creek.

Meade (1999) indicates that several eucalyptus and Monterey pine habitats in the project area support transitory basking, autumnal, or overwintering aggregation sites for Monarch butterflies (*Danaus plexippus*), a species of local concern. Specifically, trees around the abandoned water treatment plant east of 13th Street on VAFB, Waller County Park, several eucalyptus windrows (the Airport Complex) around Foster Road, California Boulevard, Pioneer Park, and Preisker Park in SBC support substantial aggregations of Monarch butterflies. The Airport Complex was also identified as an important autumnal aggregation site by Calvert (1991) and is considered a sensitive habitat area due to its use by Monarch butterflies and raptors.

San Antonio Creek, a perennial stream listed in the Santa Barbara County Conservation Element (1979, as amended 1994) and Coastal Plan (1982), provides habitat for the federally listed endangered unarmored threespine stickleback, Southern California steelhead, and tidewater goby. The creek has also been designated by NMFS as critical habitat for the steelhead (NMFS, 2000) based on its ocean connection. However, steelhead surveys conducted from 1999 to 2000 did not report any steelhead; historical occurrence has not been documented for San Antonio Creek, and the habitat has been characterized as poor to marginal in a steelhead habitat evaluation study by Swift in 2000 (N. Read Francine, VAFB, 2002). The creek and adjacent uplands and dune swale wetlands of San Antonio Terrace downstream of Harris Grade Road also support the federally listed (threatened) California red-legged frog. The final rule on critical habitat excludes the portion of San Antonio Creek on VAFB because of the protective measures included in VAFB's Integrated Natural Resources Management Plan (INRMP). Therefore, there is no designated critical habitat for California Red-legged frog on VAFB (N. Read Francine, VAFB, 2002). The tidewater goby is known to occur in estuaries and brackish lagoons, including San Antonio Creek, and was documented historically several times upstream in San Antonio Creek (USFWS, 2005). Southwestern pond turtles also inhabit this creek.

The Santa Maria River lagoon and estuary provides habitat for the federally listed endangered tidewater goby, Southern California steelhead (migratory passage of adults and juveniles), and La Graciosa thistle. Areas with perennial water sources along the river support the federally listed threatened California red-legged frog. Nipomo Creek, a tributary to the river, also supports the California red-legged frog.

Los Berros Creek, a tributary to Arroyo Grande Creek, provides habitat for the California red-legged frog, South-Central Coast steelhead, and southwestern pond turtles.

For non-avian wildlife, species and subspecies names follow those provided in the California Natural Diversity Database (CNDDB, 2001), and plant species names are as listed in Hickman (1993). Common names of plants follow Smith (1998). Avian species are identified by common name only following current nomenclature given in the American Ornithologist's Union Checklist of Birds, Seventh Edition (AOU, 1998).

Table 5.2.1 is a list of sensitive plant and wildlife species and their status and includes a brief description of their habitat and potential occurrence within the project area. Table 5.2-6 of the 1985 Point Pedernales EIR/EIS, Technical Appendix F (Terrestrial and Aquatic Biological

Resources) lists all of the sensitive species potentially present in the proposed project area and includes a complete list of the avian California species of concern not listed below.

Table 5.2.1 Sensitive Species Potentially Occurring in the Proposed Project Area

Species	Status Fed/State/ CNPS	Habitat and Occurrence in Project Area
Federally-listed, State-listed, or CNPS-listed Plant Species		
Cirsium loncholepis La Graciosa thistle	E/T/1B	Wet soils surrounding dune lakes or dune ponds, and moist dune swales. An historical record for this species is present along the pipeline corridor in La Graciosa Canyon (CNDDB, 2001), but it has not been observed at this site in recent years. Suitable habitat and known occurrences of this species occur in downstream habitats, especially at the mouth of the Santa Maria River, which currently supports the largest known population of La Graciosa thistle. Also known from the marsh on the north side of the Santa Ynez River near Surf (Smith, 1998).
Cirsium rhothophilum Surf thistle	-/T/1B	Limited to crests and valleys of stabilized, sometimes active foredunes. Suitable habitat is within project area. This species has been recorded in the foredunes crossed by the pipeline (CNDDB, 2001; Smith, 1998).
Clarkia speciosa ssp. *immaculata* Pismo clarkia	E/R/1B	Occurs in sandy soils in openings within chaparral and oak woodland habitat. Appropriate habitat for this species is present and it has been recorded near Summit Pump Station (CNDDB, 2001).
Cordylanthus rigidus ssp. *littoralis* Seaside bird's-beak	-/E/1B	Sandy soil in coastal dune and coastal habitats. Suitable habitat for this species is present in the project area and has been recorded at several locations on the Lompoc Oil Field close to the pipeline (CNDDB, 2001).
Deinandra increscents ssp. *villosa* Gaviota Tarplant	E/E/1B	Fine sandy soils in coastal terrace habitats. Two populations are present near Point Arguello and Point Sal (VAFB, 2006); individual occurrences have been noted along coastal terrace south of Santa Ynez River (Lum, pers. comm.).
Dithyrea maritima Beach spectaclepod	-/T/1B	Occurs in widely scattered locations on coastal dunes. Suitable habitat is present within project area. This species has been recorded in the foredunes crossed by the pipeline (CNDDB, 2001).
Eriodictyon capitatum Lompoc yerba santa	E/R/1B	Maritime chaparral communities. Suitable habitat is within project area.
Layia carnosa Beach layia	E/E/1B	Historically located within the Santa Ynez River dune system. Has not been seen in this location since 1929 (USFWS, 1992a). However, it was relocated on South VAFB by D. Keil during the 1990s (personal communication Gillespie, 1999). May occur in dune and foredune habitat between existing pipeline landfall and Valve Site #1 (PXP, 2005).
Rorippa gambelii Gambel's watercress	E/T/1B	Freshwater or brackish marsh habitats at the edge of lakes or along slow flowing streams. Known to occur in very few sites. Is known to occur at isolated locations on VAFB but is not likely to occur within project area.

Table 5.2.1 Sensitive Species Potentially Occurring in the Proposed Project Area

Species	Status Fed/State/ CNPS	Habitat and Occurrence in Project Area
Federally-listed or State-listed Wildlife Species		
Branchinecta lynchi Vernal pool fairy shrimp	T/--	Vernal pools on VAFB, not along pipeline corridor but one location near W. Ocean Avenue/Ocean Park Rd (Lum, 2006).
Oncorhynchus mykiss irideus Southern steelhead	E/CSC (Southern ESU) T/CSC (South-Central ESU)	Steelhead (sometimes called steelhead trout) are known to occur in the Santa Ynez River where they are the focus of ongoing restoration and management activities. Most of the historic spawning grounds are not available due to the presence of the Bradbury Dam. Steelhead also ~~may use~~occur in ~~San Antonio Creek~~, the Santa Maria River and Los Berros Creek.
Eucyclogobius newberryi Tidewater goby	E/CSC	Isolated populations inhabit California coastal lagoons, including the mouth of the Santa Ynez River, San Antonio Creek, and the Santa Maria River.
Gasterosteus aculeatus williamsoni Unarmored threespine stickleback	E/E	Present in San Antonio Creek, primarily downstream of Barka Slough. Transplanted population established in Honda Creek.
Rana aurora draytonii California red-legged frog	T/CSC	Occurs in freshwater marshes and streams, usually associated with pools of water exceeding 0.5 m in depth. Observations of this species have been made by Bland and Meredith (2000) on the Santa Ynez River mainstem as well in ponds on the Lompoc Federal Penitentiary grounds. It has been observed in Santa Lucia Canyon near the Pine Canyon gate. This species also occurs in San Antonio Creek, along the Santa Maria River, in Nipomo Creek, and in Los Berros Creek.
Ambystoma californiense California tiger salamander	E/CSC	Breeds in vernal pools in Los Alamos, and Santa Rita valleys, Purisima and Santa Rita hills, and east and west of Orcutt in the Santa Maria Valley, but spends a majority of its life cycle in upland burrows within oak savanna or stabilized dune scrub habitats. This species occurs along portions of the existing ConocoPhillips pipeline but is not otherwise believed to be present in the area that could be affected by the proposed project.
Pelecanus occidentalis californicus California brown pelican	E/E	Common along the California coast. Observed year-round near the Santa Ynez River mouth. Largest flocks (several hundred individuals) occur in summer. Forages in estuary and offshore waters.
Falco peregrinus anatum American peregrine falcon	--/E	Frequents open country such as grasslands, agricultural areas, ponds, sloughs, river mouths and seacoasts for foraging activities. Regular observations of this species have been reported at the Santa Ynez River mouth. Historically nested on south VAFB, and unconfirmed report of nesting in 1993 near Point Arguello on VAFB (Lehman, 1994). Nesting confirmed by tagging studies of the California Commercial Spaceport in the mid-1990s.
Charadrius alexandrinus nivosus Western snowy plover	T/CSC	Winters and breeds along beaches of the eastern Pacific to British Columbia. Locally, this species is known to winter and breed north and south of the Santa Ynez River, and is known to breed at Wall Beach around the area where the pipeline array makes landfall.

Table 5.2.1 Sensitive Species Potentially Occurring in the Proposed Project Area

Species	Status Fed/State/ CNPS	Habitat and Occurrence in Project Area
Empidonax traillii extimus Southwestern willow flycatcher	E/E	This species is known to breed from the Santa Ynez River southward. Nesting along the Santa Ynez River typically occurs in willow riparian habitats. Two populations along the Santa Ynez River were discovered between 1986 and 1991. One extends from just west of Buellton to several miles downstream, and the second extends from the Floradale Avenue bridge in Lompoc to the last stand of willows before the river. Additional populations may exist on private lands between these two areas, which have not been surveyed. Known to winter in Mexico, Central America, and possibly northern South America.
Sterna antillarum browni California least tern	E/E	Nests at isolated beaches near bays and lagoons, San Francisco Bay to Baja California. Present in project area from May to September. Historically nested in foredunes near the Santa Ynez River mouth, forages in estuary and nearshore waters. The Santa Ynez River estuary is a regional post-breeding staging area where numerous individuals gather and forage during late summer prior to their southward migration.
Passerculus sandwichensis beldingi Belding's savannah sparrow	-/E	Common but local permanent residents associated with pickleweed habitat, restricted to coastal salt marshes from the vicinity of Goleta and Devereux sloughs (southern Santa Barbara County) southward to San Diego County (Garrett and Dunn, 1981). The subspecific status of savannah sparrows found in salt marshes at the Santa Ynez River mouth is probably either the *alaudinus* subspecies, which is known from Morro Bay (Garrett and Dunn, 1981; Lehman, 1994) or intergrades between *alaudinus* and *beldingi* (Lehman, 1994).
Euphilotes battoides allyni El Segundo Blue Butterfly	E/SA	Coastal dune habitat, dependant upon host plant species, coast buckwheat. Observed on VAFB near SLC 3. Additional surveys are ongoing.
Other Sensitive Plant Species		
CNPS List 1B Plant Species (Rare, Threatened or Endangered in California and Elsewhere)		
Acrtostaphylos purissima La Purisima manzanita	-/-/1B	Known to occur within the Burton Mesa chaparral, along the project pipeline corridor.
Arctostaphylos rudis Sand mesa manzanita	-/-/1B	Known to occur within the Burton Mesa chaparral, along the project pipeline corridor.
Arctostaphylos tomentosa ssp. *Eastwoodiana* Eastwood's manzanita	-/-/1B	Sandy soils on mesas in chaparral community. This species has been recorded in suitable habitat north of the LOGP in the Purisima Hills and on Burton Mesa (CNDDB, 2001).
Arctostaphylos wellsii Wells' manzanita	-/-/1B	Occurs on sandstone in chaparral habitat. Present in the project area, south of Los Berros Creek, but not likely to occur within the pipeline corridor.
Chorizanthe rectispina Straight-awned spineflower	-/-/1B	Occurs in the pipeline corridor from landfall to Valve Site #1 (PXP, 2005).
Delphinium parryi ssp. *~~B~~blochmaniae* Dune larkspur	-/-/1B	Occurs on sandy soils in chaparral and coastal scrub communities. Suitable habitat is present but none have been recorded within the project area.

Table 5.2.1 Sensitive Species Potentially Occurring in the Proposed Project Area

Species	Status Fed/State/ CNPS	Habitat and Occurrence in Project Area
Erigeron blochmaniae Blochman's leafy daisy	-/-/1B	Scattered about active and stabilized dunes. This species is present in the coastal dunes within project area, and has been recorded in the foredunes crossed by the pipeline (CNDDB, 2001).
Lasthenia glabrata ssp. *coulteri* Coulter's goldfields	-/-/1B	Occurs in salt marsh communities. Suitable habitat is present at the mouth of the Santa Ynez River, but none have been recorded.
Monardella crispa Crisp monardella	-/-/1B	Scattered mostly on unstable, active coastal dunes. Suitable habitat for this species is present in the foredunes and transition habitats and it has been recorded in the project area (CNDDB, 2001). However, its distribution south of Point Sal is questionable and may be confused with *M. frutescens* (Smith, 1998).
Monardella frutescens San Luis Obispo monardella	-/-/1B	Mostly located on stabilized dunes, coastal scrub. Suitable habitat for this species is present and it may occur within project area.
Scrophularia atrata Black-flowered figwort	-/-/1B	Scattered in coastal scrub and Burton Mesa chaparral habitats. Suitable habitat for this species is present and it has been recorded within pipeline corridor west and north of the LOGP (CNDDB, 2001).
Agrostis hooveri Hoover's bent grass	-/-/1B	Occurs on dry sandy soils in open chaparral and oak woodland communities. Suitable habitat is present and this species may occur within project area along the pipeline routes.
CNPS List 4 Plant Species (A Watch List)		
Abronia maritima Red sand verbena	-/-/4	Commonly scattered on upper beaches and primary dunes along ocean. Suitable habitat is present and this species was observed in the foredunes crossed by the pipeline.
Malacothrix incana Dunedelion	-/-/4	Frequent on dunes. Suitable habitat is present and this species was observed in the foredunes crossed by the pipeline.
Wildlife Species of Concern in the Project Area		
Danaus plexippus Monarch butterfly	-/SA	Occurs in eucalyptus near the abandoned water treatment plant on VAFB east of 13th street, between Basins 8 and 9, Waller County Park, several eucalyptus windrows (known as the Airport Complex) around Foster Road, California Boulevard, Pioneer Park, and Preisker Park in SBC (Meade, 1999).
Gila orcutti Arroyo Chub	-/CSC	Santa Ynez River and San Antonio Creek.
Scaphiopus hammondi Western spadefoot toad	-/CSC	Breeds in temporary pools in dune scrub habitats in the Orcutt and Santa Maria valleys (CNDDB, 2001).
Phrynosoma coronatum frontale California horned lizard	-/CSC	Occurs in dune scrub habitats in the vicinity of Lompoc and in the Burton Mesa Chaparral (CNDDB, 2001).
Thamnophis hammondii Two-striped garter snake	-/CSC	Habitat includes freshwater streams and rivers bordered by riparian woodlands from South Coastal and Transverse ranges to the coast. Suitable habitat for this species occurs within Oak, Santa Lucia, and Pine Canyons, and San Antonio Creek and Los Berros Creek.

Table 5.2.1 Sensitive Species Potentially Occurring in the Proposed Project Area

Species	Status Fed/State/ CNPS	Habitat and Occurrence in Project Area
Clemmys marmorata pallida Southwestern pond turtle	-/CSC	Occurs in freshwater ponds and slow moving streams. Suitable habitat for this species occurs in Oak Canyon, Santa Lucia Canyon and Pine Canyon, as well as in off-channel areas of the mainstem of the Santa Ynez River. Known to occur in Pine Canyon on VAFB (CNDDB, 2001), San Antonio Creek, and Los Berros Creek.
Agelaius tricolor Tri-colored blackbird	-/CSC	Occurs sparsely in coastal habitats. Observed in coastal dune wetlands near Santa Ynez River (PXP, 2005).
Dendroica petechia Yellow warbler	-/CSC	Occurs in dense willow riparian habitat. Likely breeder in project area. Known breeder along the Santa Ynez River (SAIC unpublished field notes).
Icteria virens Yellow-breasted chat	-/CSC	Inhabits dense willow riparian habitat. Likely breeder in project area. Known breeder along the Santa Ynez River (SAIC unpublished field notes).
Accipiter cooperi Cooper's hawk	-/CSC	Inhabits open woodlands and riparian corridors. Nests in woodland. Likely breeder in project area. CSC designation applies to nesting birds.
Athene cunicularia hypugea Western burrowing owl	-/CSC	Inhabits open, dry grassland. Potential breeder (April – June) and/or winter migrant (VAFB, 2006). Potentially occurs in coastal dune scrub between Valve Sites 1 and 2 (PXP, 2005).
Lanius ludovicianus Loggerhead shrike	-/CSC	Semi-open areas with scattered trees, shrubs, posts, and wires. Common throughout VAFB (VAFB, 2006).
Antrozous pallidus Pallid bat	-/CSC	Inhabits much of western United States, widespread in California. Feeds largely on flightless insects and invertebrates such as Jerusalem crickets, scorpions, and June beetles which it captures on the ground (Jameson and Peeters, 1988). Known to roost under the 13th Street Bridge (N. Read Francine, VAFB, 2002).
Myotis yumanensis Yuma myotis	-/SA	Occurs throughout California, especially common along wooded canyon bottoms (Jameson and Peeters, 1988). Forages on flying insects, such as small moths, beetles, and midges.). Known to roost under the 13th Street Bridge (N. Read Francine, VAFB, 2002).

Sources:
<u>Lum, 2006. Vandenberg Air Force Base.</u>
CDFG, 2006. California Department of Fish and Game.
CNDDB, 2001. California Natural Diversity Database.
CNPS, 2006. California Native Plant Society Inventory.
Lehman, 1994. Birds of Santa Barbara County.
Smith, 1998. A Flora of the Santa Barbara Region, California.
Species Status is determined by the USFWS, NMFS, or CDFG.
E *Endangered: In danger of extinction throughout all or a significant portion of its range.*
R *Rare.*
T *Threatened: Likely to become an endangered species within the foreseeable future throughout all or a significant portion of its range.*
CSC *California Species of Concern.*
SA *Special Animals List. Additional taxa that are tracked by CNDDB, regardless of legal or protection status.*
ESU *Evolutionarily Significant Unit.*
1B *Plants considered by CNPS as rare, threatened, or endangered in California and elsewhere.*
4 *Plants of limited distribution, a watch list.*
-- *No special status.*

Vegetation and Wildlife Communities

The basic vegetation and wildlife community types of the project area are described below by habitat type. Appendix A shows important habitat areas and areas that support regionally rare botanical resources.

Sandy Beach and Foredunes

Foredunes are an especially well represented community along the north coast of SBC from Point Conception to Pismo Beach (in San Luis Obispo County). Some of the best-developed examples of this community in Southern California are found at VAFB. Dunes are poorly represented in other parts of SBC and Southern California in general. The sandy beaches along the coast of California typically consist of a narrow band of unvegetated beach just above the high water mark, followed by a sparsely vegetated area called pioneer dunes that eventually grades into well-developed foredunes and dune scrub transition away from the shore. The pioneer dunes typically consist of scattered, low hummocks with low growing, succulent herbs, that form spreading mats such as sea rocket (*Cakile maritima*), beachbur (*Ambrosia chamissonis)*, yellow sand verbena (*Abronia latifolia*) and red sand verbena (*Abronia maritima*), a CNPS List 4 species (see Table 5.2.1 for species status and descriptions).

Inland, the hummocks become larger, higher and more vegetated creating the undulating topography characteristic of well developed coastal sand dunes. The vegetation becomes more diverse and, in addition to the typical pioneer dunes species, other common species include dune morning glory (*Calystegia soldanella*), beach evening primrose (*Camissonia cheiranthifolia),* dune saltbush (*Atriplex leucophylla*) and dunedelion *(Malacothrix incana)*, a CNPS List 4 species. In addition to the rare species already mentioned, other sensitive plant species restricted to the foredune habitats include the state-listed threatened surf thistle (*Cirsium rhothophilum*) and beach spectaclepod (*Dithyrea maritima*). Dune habitats are very fragile and easily disturbed by human activities. Disturbance of these communities has resulted in the displacement of native species by exotics such as ice plant (*Carpobrotus* sp.) and European beach grass (*Ammophila arenaria)*, historically planted as a method to control sand erosion. Low-growing forms of shrub species that commonly occur in dune scrub habitat, including mock heather (*Ericameria ericoides*), coast goldenbush (*Isocoma menziesii*) and loco weed (*Astragalus* sp.), are often found scattered in the more stabilized foredunes. Several rare plant species more commonly occur in dune scrub habitats but are sometimes found in foredune/dune scrub transition habitat areas, especially disturbed areas, include crisp monardella (*Monardella crispa)*, San Luis Obispo monardella (*Monardella frutescens*), and Blochman's leafy daisy (*Erigeron blochmaniae)*.

The pipeline landfall is at Wall Beach located just north of the mouth of the Santa Ynez River. The foredune habitat crossed by the pipeline supports large stands of iceplant as well as patches of European beach grass with smaller patches of native dune plants mixed in. Human activities, roads and facilities associated with VAFB operations, have likely contributed to the degradation of the foredunes habitat at this location. Sensitive plant species, including dunedelion and red sand verbena, were observed in the project area and several rare plant species have been reported from the project area (see discussion on rare plant species in Section 5.2.1.3). The Union Pacific Railroad track parallels the beach and crosses the pipeline corridor approximately 1,000 feet inland of the shoreline and corresponds to the transition of foredunes into coastal dune scrub habitat.

Sandy beach areas are important habitats for large numbers of shorebirds, gulls and feeding land birds, although only a few birds nest in these habitats. Some of SBC's most protected beaches are at VAFB. Due to historically low levels of use on VAFB, its beaches are relatively undisturbed and support the principal breeding localities remaining in SBC for the federally-listed endangered California least tern and threatened western snowy plover. VAFB supports a significant proportion of the listed population of the western snowy plover (N. Read Francine, VAFB, 2002). The endangered California brown pelican is also commonly observed on beaches and foraging in nearshore ocean waters and coastal bays; however, it does not breed on the California mainland. It is important to note that foredunes with coastal strand vegetation typically attract few birds; however, these habitats occasionally support a small subset of reptiles, amphibians and mammals characteristic of coastal scrub communities.

Coastal Scrub

Distinct forms of coastal scrub are present in the project area including coastal dune scrub and coastal sage scrub. Coastal bluff scrub is also a distinct scrub habitat that is well-represented in rocky areas of the north coast of SBC. However, this habitat is not present near the pipeline corridor and is not included in this discussion. Coastal dune scrub and coastal sage scrub have a few dominant species in common, but differ in site characteristics and associated species.

Coastal dune scrub is the dominant vegetation of the stabilized backdunes. This plant community is well represented north of Point Conception and absent from the south coast of SBC. Shrubs, sub-shrubs and herbs comprise this community including mock heather, seacliff buckwheat (*Eriogonum parvifolium*), deerweed (*Lotus scoparius*), dune lupine (*Lupinus chammissonis*), California aster (*Lessingia californica*), and croton (*Croton californica*). Rare species found in the dune scrub habitats include crisp monardella, Blochman's leafy daisy, and short-lobed broom-rape (*Orobanche parishii brachyloba*), all included on CNPS List 1B (see Table 5.2.1).

Coastal sage scrub is dominated by shrubs such as coyote brush (*Baccharis pilularis*), coastal sagebrush (*Artemisia californica*), and black, white and purple sages (*Salvia mellifera, S. apiana*, and *S. leucophylla*). Associated species include giant wildrye (*Leymus condensatus*), sticky monkey-flower (*Mimulus aurantiacus*), and California coffeeberry (*Rhamnus californica*). This plant community occurs on terraces, on canyon sides, and in foothills. It extends in some places well inland from the coast.

Coastal dune scrub is the primary habitat type along the pipeline corridor on sandy soils for approximately a half-mile inland of the foredunes transition. From here the vegetation is a mosaic of coastal dune scrub and coastal sage scrub with patches of other plant communities, such as grasslands. The coastal scrub habitats in this area have been invaded by iceplant and veldt grass (*Ehrharta calycina*), an aggressive, non-native perennial grass known to displace native species (Smith, 1998). The pipeline corridor is adjacent to a road and much of the vegetation, both within and adjacent to the pipeline corridor, is disturbed and dominated by non-native species including veldt grass and iceplant and annual grasses. Coast goldenbush, a native shrub that often first colonizes disturbed areas, was often observed in the more disturbed areas. However, there are some areas adjacent to the pipeline that support high quality coastal scrub habitats with a diverse mix of native shrubs and low cover of non-native species. A large patch of alkali rye (*Leymus triticoides*), a native perennial grass, was observed adjacent to the pipeline corridor at Valve Site #2. Approximately one mile east of the landfall, the pipeline is exposed and suspended over a steep canyon. The vegetation in the canyon is riparian woodland (discussed below) with the coastal sage scrub, dominated by black sage, on upper slopes.

The vegetation along the corridor grades into a mosaic of coastal scrub and chaparral communities interspersed with non-native grasslands and other habitat types (discussed below) for most of the length of the pipeline. The pipeline right-of-way crosses large expanses of coastal sage scrub between 13th Street and Oak Canyon on VAFB and the western portion of the Lompoc Oil Field. The pipeline corridor within the oil field lease is largely vegetated and distinguished by man-made, above ground indicators. The pipeline corridor is still apparent in the vegetation as well as a corridor associated with a natural gas pipeline that runs directly adjacent to the Point Pedernales pipeline ROW. However, the area appears to be slowly recovering and cover of non-native species is very low. Protective plant cages and an abandoned irrigation system were observed associated with the pipeline corridor.

Coastal dune scrub, found along the north coast of SBC and in southwestern San Luis Obispo County, is characterized by relatively few breeding birds (e.g., Bewick's wren, California thrasher, white-crowned sparrow). Coastal sage scrub is more extensive and is known to support breeding activities of California quail, Anna's hummingbird, song sparrow, California towhee, greater roadrunner, Costa's hummingbird, rufous-crowned sparrow and white-crowned sparrow. Amphibians are scarce in coastal scrub habitats, but reptiles are often abundant. Larger mammals such as rabbits, coyote, raccoon, gray fox, skunk and bobcat are common in northern SBC and in the project area. The ringtail (*Basssariscus astutus*), an uncommonly encountered state-protected mammal, may occupy sites in this habitat near water and rocky outcroppings.

Grasslands

Grasslands are widespread on coastal plains and terraces, covering lower foothill slopes, and are common in valleys. Perennial native bunch grasses (such as *Nassella* spp.), which dominated these grasslands before the advent of grazing by non-native ungulates, are now restricted to remnant patches. Native grasslands are protected habitats pursuant to the SBC Coastal Plan (1982). Most grasslands of the study area are now dominated by non-native annual grasses, with non-native weedy species as well as native wildflowers as associates. The more common non-native annual grasses include wild oats (*Avena* spp.), bromes (*Bromus* spp.) and fescues (*Festuca* spp.). Grasslands of the project area have few endemic or rare species. Large areas of grassland can be found in the pipeline corridor east of Oak Canyon and near the LOGP. In addition, much of the pipeline corridor appears to be used for human access and non-native grasses and forbs are dominant within a large portion of ROW.

Bird species commonly observed in native and naturalized grassland communities include house finch, savannah sparrow, and western meadowlark. Grasslands in the vicinity of Point Sal Ridge (north of VAFB) are one of the last remaining breeding locations on the north coast of SBC of the grasshopper sparrow. A variety of raptors, including the white-tailed kite (a CDFG Fully-Protected species) forage in grasslands because they generally support large rodent populations. These rodent populations also serve as a food source for carnivores such as coyote, gray fox and bobcat. Mule deer, a native ungulate, are commonly observed grazing in grassland communities. Except in natural or artificial ponds, few amphibians occur in grassland communities; however, reptiles (primarily snakes) are more common inhabitants.

Chaparral

Chaparral is distributed widely within the study area. It covers large expanses of VAFB and the Burton Mesa terrace on sandy and shale soils. It is found interspersed with Bishop pine forest and coastal scrub on the upper slopes and crests of the Purisima Hills. Nipomo Mesa, north of the Santa Maria River, once supported large expanses of chaparral although due to development and intrusion by non-native species (planted and escaped), only remnant patches remain. The dominant plants are fire-adapted woody shrubs, many with limited distribution. Lompoc Yerba Santa (*Eriodictyon capitatum*), a federally-listed endangered species is associated with chaparral plant communities and occurs upstream of the pipeline corridor in Pine Canyon. Burton Mesa chaparral, a distinct form of chaparral characteristic of the sandy soils of Burton Mesa terrace and the nearby Purisima Hills, is noteworthy for the high rate of endemism in its flora. More than 20 plant species found in this community have restricted geographic distributions, including rare plants such as La Purisima manzanita (*Arctostapylos purissima*), sand mesa manzanita, (*Arctostaphylos rudis*), Eastwood's manzanita (*Arctostaphylos tomentosa* ssp. *eastwoodiana*), seaside bird's beak (*Cordylanthus rigidus littoralis*), Santa Barbara ceanothus (*Ceanothus impressus*) and black flowered figwort (*Scrophularia atrata*). Other associated species include chamise (*Adenostoma fasciculatum*), toyon (*Heteromeles arbutifolia*), coast ceanothus (*Ceanothus cuneatus var cuneatus*), and coffee berry. Coast live oaks (*Quercus agrifolia*) are common among the Burton Mesa chaparral that surrounds the pipeline corridor; however these trees exhibit a distinctive, multi-trunk form, unlike live oaks in other areas of SBC. Pismo clarkia (*Clarkia speciosa* ssp. *immaculata*), federally-listed endangered and state-listed rare, and Wells' manzanita (*Arctostaphylos wellsii*), CNPS List 1b, are found in chaparral habitats near the project area, north of the Santa Maria River.

Burton Mesa chaparral is most commonly observed in the pipeline corridor east of Oak Canyon as the pipeline crosses the Burton Mesa R~~P~~eserve north of the Lompoc Federal Penitentiary in a northeasterly direction, and north of the LOGP over Harris Grade. The Burton Mesa R~~P~~eserve is an area approximately 6,000 acres in size that surrounds Vandenberg Village and extends generally from the eastern property line of VAFB and eastward to Mission Hills and bounded on the north and south by the LOGP and Highway 1, respectively (CDFG 2005b). This plant community is the dominant feature between the VAFB eastern property line and the LOGP, and north of the LOGP over Harris Grade.

Characteristic lower elevation birds in chaparral habitats include the greater roadrunner, Anna's hummingbird, Bewick's wren, wrentit, California thrasher, California towhee, and lesser goldfinch. Bell's sage sparrow is closely associated with successional-stage Burton Mesa chaparral and may occur in proximity to some of the inland portions of the pipeline. This habitat is too arid for most amphibians, but supports a large diversity of reptiles including several species of lizards and snakes. Many species of small mammals (rabbit, striped skunk), and hence a number of larger, wide-ranging carnivores (gray fox, coyote, bobcat, ringtail, mountain lion) are also found in chaparral communities.

Oak Savanna and Woodland

Oak woodlands dominated by coast live oak cover many lower coastal slopes and canyons, as well as the moist interior hills. The trees in some places form a continuous canopy (woodland), while in other areas, trees are more scattered (savanna) and found in association with grassland and coastal sage scrub and chaparral species. Oak reproduction and regeneration over large areas of SBC, particularly valleys and foothills, is limited by current land use practices and conversion of lands previously used for grazing to vineyards. SBC Conservation Plan policies require that the removal of or damage to mature oaks be minimized, and, if unavoidable, mitigated by replanting in accordance with the County's Standard Conditions and Mitigation Measures. The removal of oak trees on private lands outside of the coastal zone and urban boundary lines is also subject to the requirements of the SBC Grading Ordinance Section 14-8 (Appendix A), and the County Deciduous Oak Tree Protection and Regeneration Ordinance (Article IX, Chapter 35 of SBC Code). These requirements, however, apply primarily to valley and blue oaks (*Quercus lobata* and *Q. douglasii*, respectively). A sudden oak death syndrome that affects apparently healthy adult oaks has been spreading southward from the San Francisco Bay Area and is a concern with regard to the long term future of oaks in coastal central California, including the project area. Along the pipeline corridor, there are a few areas in which the oak resources would be classified as oak savanna or oak woodland. Oak savanna typically consists of scattered oak trees with a grassland or herbaceous understory. Oak woodlands and forests usually exhibit a closed, or nearly closed canopy and are associated with an assemblage of understory species that differs from oak savanna habitats. Oak woodlands are more commonly observed on north facing (moister) slopes in SBC, an example of this habitat exists adjacent to and west of the pipeline corridor in Oak Canyon, north of the Santa Ynez River. The understory typically consists of shade-tolerant plants such as blackberry (*Rubus* spp.), gooseberry (*Ribes* spp.), snowberry (*Symphoricarpos mollis*) and a variety of ferns. Oak savanna habitat and small patches of oak woodland occur on the oil field west of the LOGP, and north and east of the Burton Mesa R~~P~~eserve. Planted oak trees with protective tree cages were observed along the pipeline corridor near Oak Canyon and within the oil field.

Many species of wildlife utilize coast live oak woodland habitats. Representative bird species of oak woodlands include the acorn and Nuttall's woodpeckers, pacific-slope flycatcher, western scrub jay, oak titmouse, bushtit, Hutton's vireo, band-tailed pigeon, and several species of warblers. Oak savanna, with widely spaced trees among grassland or scrub-shrub communities support turkey vultures, red-tailed hawk, yellow-billed magpie, western bluebird, and other bird species. Moist shaded environments beneath the oaks harbor comparatively diverse populations of amphibians (salamanders and frogs), as well as reptiles (snakes and lizards). Many small mammals such as mice, Botta's pocket gopher, broad-footed mole, and dusky-footed woodrat, and larger species such as coyote, gray fox, raccoon, skunk, bobcat, feral pig, mule deer and mountain lion also frequent oak woodlands and savannas.

Oak savanna habitats in the Lompoc and Los Alamos valleys, the Purisima and Santa Rita Hills are also known to support populations of California tiger salamander. This species may also occur in the vicinity of Orcutt, near the Orcutt Pump Station, and is known to range up to one mile or more from breeding ponds (Trenham et al., 2001), but during non-breeding periods California tiger salamander live in burrows of rodent species such as ground squirrels and gophers. Due to conversion of these habitats from grazing to cultivated agriculture (vineyards), the amount of suitable upland oak savanna habitat has declined in recent years.

Evergreen Forests

Evergreen forest, specifically Bishop pine forest, is present along a segment of the pipeline that crosses the Purisima Hills north of the LOGP. The habitat is dominated by monotypic stands of Bishop pine interspersed with chaparral and coastal scrub on the slopes and other riparian woodlands in the lower canyons. Other species are present in openings in the pine stand including a number of endemic or rare plant species. Wildlife found in this habitat are species typical of oak woodland and chaparral communities similar to those species described above for the oak savanna and woodland community. Dense stands of eucalyptus and other planted trees may also be categorized as evergreen forest. However, since these habitats are not naturally occurring, they are included in the discussion below for Agricultural Lands and other Modified Habitats.

Coastal Wetlands

In addition to tidal marine habitats discussed in the Marine Biology chapter, coastal wetlands include transitional (estuarine) and freshwater habitats typically associated with creek and river mouths. Estuaries are characterized by low growing, often succulent species that exhibit zonation according to salinity and soil moisture gradients. Coastal wetlands are sensitive and susceptible to sedimentation, water pollution, terrestrial and marine oil spills, trampling and human activities that alter the natural influx of fresh or salt water. These habitats have declined significantly in area locally and statewide over many decades (Smith, 1998; Jensen, 1983). These habitats are protected by SBC's Coastal Plan (1982), the California Coastal Act (1976), and in many cases the federal Clean Water Act (1972), because of their ecological importance, occurrence in jurisdictional wetlands, sensitivity and limited areal extent.

The estuary at the mouth of the Santa Ynez River supports an extensive pickleweed (*Salicornia virginica*) marsh that transitions into coastal dunes (to the west), riverine (to the south and east) and coastal sage scrub communities (to the north). Freshwater marsh habitats support a diverse array of perennial herbs, including many tall reed-like plants such as cattails (*Typha* spp.) and bulrushes (*Scirpus* spp.). Coastal wetland habitats at the mouth of the Santa Ynez River are used by several federally-listed endangered species including the California brown pelican (bathing, preening, and loafing), California least tern (breeding and feeding), western snowy plover (breeding and feeding), and American peregrine falcon (feeding). This habitat also supports large concentrations of migrant and wintering herons, waterfowl, shorebirds, gulls and tern species. Coastal salt marsh is also the preferred habitat of the endangered light-footed clapper rail and the state-listed endangered Belding's savannah sparrow. However, the clapper rail is now restricted in SBC to Carpinteria Marsh, which now marks its northernmost extent. It was formerly found in Goleta and Devereux Sloughs, and may have occurred in the Santa Ynez River mouth estuary during pre-historic times (Lehman, 1994). Belding's savannah sparrow (*Passerculus sandwichensis beldingi*), a state-listed endangered species, is common in Goleta Slough, and occasionally in Devereux Slough and is not known from the north coast of Santa Barbara County or northward. The subspecific status of savannah sparrows found in the Santa Ynez River mouth salt marshes is probably either the *alaudinus* subspecies (Garrett and Dunn, 1981; Lehman, 1994) or intergrades between *alaudinus* and *beldingi* (Lehman, 1994).

Coastal wetlands within the area potentially reached by an offshore oil spill (Apendix G) may occur at the mouths of Pismo Creek, San Luis Obispo Creek, Arroyo Grande Creek, the Santa Maria River, Shuman Creek, San Antonio Creek, Santa Ynez River, La Honda Creek, and Jalama Creek. The Santa Maria River mouth supports a large wetland area while the remaining creeks have small lagoons and tidal inlets that form limited areas of wetlands or estuaries. The northwest coastlines of San Miguel and Santa Rosa Islands within potential oil spill trajectories consist predominantly of wave-exposed beaches and rocky headlands. Areas of transitional wetland habitat are possible at the mouths of several ephemeral streams on both islands.

Riparian Woodland

These streamside woodland habitats are dominated by dense growths of tall deciduous trees and shrubs including willows (*Salix* spp.), western sycamore (*Platanus racemosa*), cottonwood (*Populus* sp.), and white alder (*Alnus rhombifolia*). A large portion of the riparian woodlands in the project area are dominated by the deciduous arroyo willow (*Salix lasiolepis*). In some areas, the riparian woodland may be better classified as riparian scrub with lower growing willows, including shrubby forms of arroyo willow, and riparian shrub species, such as mulefat (*Baccharis salicifolia*) and coyote bush, are dominant. Riparian woodlands vary from narrow bands along streams in canyons to extensive floodplain groves. Although all perennial and some intermittent streams in the study area support riparian woodland or scrub habitats, the community is limited in area, and has been substantially reduced throughout Southern California by human activities such as development of urban and suburban areas, flood control practices, and agriculture. Riparian habitats are protected by SBC Comprehensive Plan policies (1982) because of their value as essential wildlife habitat and importance as buffers against flooding and erosion. The pipeline array parallels the Santa Ynez River for much of its length, turning north away from the river after crossing Oak Canyon. Riparian woodlands, occur along the Santa Ynez River, with substantial stands of trees east of 13th Street on VAFB. The two tributaries to the Santa Ynez River, Oak Canyon and Santa Lucia Canyon (also crossed by the pipeline array), also support riparian woodland and scrub communities, with similar species composition as observed in the Santa Ynez River. Remnant stands of riparian woodlands also occur along San Antonio Creek and in portions of the unnamed tributaries in Graciosa Canyon, Orcutt Creek and Pine Canyon Creek near the Orcutt Pump Station. Dominant woody riparian species in these creeks include arroyo willow, mulefat and coyote bush.

Along the Santa Maria River, which is crossed by the pipeline ROW, mature riparian vegetation is lacking but stands of willows and freshwater marshes are found in scattered locations, primarily associated with agricultural drains or other freshwater sources. Well-developed riparian woodland and scrub habitats, as well as freshwater marshes, are present along Nipomo Creek and Los Berros Creek in San Luis Obispo County. In addition to willows, cottonwoods and sycamore, big-leaf maple (*Acer macrophyllum*) and box elder (*Acer negundo*) contribute to the riparian woodland canopy. The pipeline corridor parallels most of the length of Nipomo Creek and crosses the creek at two locations. Los Berros Creek flows near Summit Pump Station, the northern terminus of the proposed project.

Riparian woodlands have been much reduced in SBC and San Luis Obispo County during the 20th century. Extensive areas remain along the Santa Ynez River in the vicinity of the project area, but these areas are threatened by ongoing agricultural activities and expansion of agricultural operations, and flood control activities. Riparian woodlands in the northern part of SBC support a large and diverse complement of migrant and resident breeding birds, including several species whose local populations have declined substantially in recent years (Cooper's hawk, Swainson's thrush, warbling vireo, yellow warbler, yellow-breasted chat), or have been extirpated as breeders along the south coast of SBC (tree swallow, Wilson's warbler). Many other birds are abundant, including species normally associated with foothill and montane woodlands. In contrast to other project area habitats, riparian woodlands support a diverse assemblage of amphibians (frogs, toads, salamanders). Wetlands adjacent to the Santa Ynez River support the threatened California red-legged frog, and may potentially support California tiger salamander; however, this species is most commonly associated with interior vernal pools and their associated oak savanna/grassland habitats. Wetlands and riparian woodlands along San Antonio Creek, the Santa Maria River, and Nipomo Creek support California red-legged frogs as well. Although there are no listed threatened or endangered reptiles expected in the project area, declining species that may occur in riparian woodlands include the southwestern pond turtle. Diversity of mammals in this habitat is relatively high. Common small mammals include shrews, mice, woodrats, gophers, rabbits, skunk, and ground squirrels. Riparian woodlands also provide excellent habitat for larger mammals including Virginia opossum, weasels, raccoon, bobcat, mule deer, and feral pigs (on VAFB).

Interior Wetlands

These include freshwater marshes and sloughs upstream from estuaries, inland vernal pools, seeps, and marshy places. Important plants include emergent aquatic and transitional wetland species. Along the pipeline corridor, several interior wetlands are traversed by the pipe array. These habitats occur on VAFB northwest of the pipe crossing at Highway 1, west of Vandenberg Village, and immediately west of Valve Site #9 adjacent to an agricultural field. Marshy areas are also present at scattered locations along the pipeline corridor adjacent to Highway 135, south of Orcutt. The interior wetland located at the intersection of Highway 1 and Santa Lucia Canyon Road is designated on the USGS Lompoc 7.5-minute quadrangle as an area where natural springs or seeps are present. The dominant plant species there include cattails, bulrush, willows, and ruderal vegetation. Other interior wetlands occur downslope of the pipeline corridor along Highway 135 and Graciosa Road. These wetlands support emergent aquatic species such as rushes and wet grassland communities. Vernal pools are also present in the project area south of the pipeline corridor on the Lompoc Federal Penitentiary grounds, approximately ½ mile south of the pipe array. All interior wetlands are important as wildlife habitat, and as traps or filters for sediment and pollutants. Interior wetlands and vernal pools receive protection by the federal Clean Water Act if they are not considered isolated waters and from recommended actions in SBC's Conservation Element.

The extent and quality of these habitats has diminished substantially over the 20th century, resulting in extirpation or significant reduction in local breeding populations of waterfowl and passerine bird species. Remnant marshy habitats support concentrations of migrant and wintering herons, waterfowl, shorebirds, gulls and terns. Marshes and vernal pools provide breeding habitat for native and non-native toads and frogs. Reptiles include the regionally declining southwestern pond turtle and two-striped garter snake. The federally-listed (threatened) California red-legged frog and California tiger salamander (endangered) are known from marshy habitats in the project area, and declining populations of the western spadefoot toad are also commonly associated with these habitats.

Ruderal Vegetation

Areas dominated by ruderal (i.e., weedy) species are generally highly disturbed habitats, such as roadsides, vacant lots, or lands subject to repeated ground disturbances. These species persist by being adapted to colonizing recently disturbed areas, and preventing establishment of native vegetation. Ruderal vegetation is present along the pipeline corridor, but is limited to areas where the pipeline crosses roads that already support this vegetation type.

Agricultural Lands and Other Modified Habitats

Agricultural lands in the study area are used primarily for livestock grazing, cultivated truck crops or wine grapes. Fields that produce truck crops are extensive within the Santa Ynez River floodplain, south of San Antonio Road along Highway 135, around the Santa Maria Airport, along the pipeline corridor adjacent to the Suey Junction, and adjacent to Nipomo Creek. Vineyards (the White Hills vineyard) cover most of the eastern plateau of Graciosa Canyon along Highway 135, and vineyards are becoming more common in interior valleys, terraces and lower foothill areas with well-drained soils. Productive cultivated agricultural fields are also located adjacent to the pipeline corridor east of Valve Site #4 to the eastern side of Oak Canyon, and west of Valve Site #9 in the Santa Ynez River valley. These floodplain areas were reported to be the world's largest center for flower seed production (Shipman, 1972). However, the flower seed industry has declined in importance in subsequent decades. Associated with agricultural fields or other development, large stands of planted eucalyptus (windrow) trees are also found in the study area, the most substantial being the eucalyptus stand surrounding the abandoned water treatment plant, around the Santa Maria Airport, Waller Park and Preisker Park in Santa Maria, and smaller stands of planted (landscape) trees are scattered throughout the area. Some native habitats near the study area support livestock grazing; however, many of these grasslands, or coastal sage scrub habitats are being converted into vineyards.

Agricultural lands are utilized by a variety of introduced and native species. Commonly observed bird species include rock dove, yellow-billed magpie, European starling, Brewer's blackbird, house finch, and the like. Other common wildlife species are also observed on these lands, especially those that have adapted to human presence (coyote, skunk, opossum, squirrels, mice, voles). Extensive areas of planted trees (evergreen forests) including exotic species such as eucalyptus, tamarisk, and bottlebrush, as well as species native to California (Monterey Pine, Monterey cypress) have provided an important new winter food source for a number of bird species including several raptor species, and the Monarch butterfly (*Danaus plexippus*).

Monarch butterflies have been observed at several locations in the project area. These include the abandoned water treatment plant on VAFB east of 13^{th} street, Waller County Park, several eucalyptus windrows (known as the Airport Complex) around Foster Road, California Boulevard, Pioneer Park, and Preisker Park in SBC (Meade, 1999). Autumnal aggregations are typically occupied beginning in October but lack substantial numbers of butterflies by January. Overwintering aggregations often support thousands of individuals and are generally located in coastal drainages. The aggregations described above have been characterized as autumnal aggregations since very low numbers of Monarchs are observed at these sites after December (Meade, 1999). This pattern suggests that Monarchs leave autumnal sites and move to overwintering aggregation sites for breeding activities that take place during the months of January, February and March.

Agricultural lands and their associated [planted] evergreen forests in the project area do not support any locally rare or unique bird populations or herpetofauna. These habitats however support a variety of land mammals, including small mammals (shrews, rats, mice, rabbits) and larger species (coyote, gray fox, raccoon, skunk, bobcat, mule deer). The regionally rare and declining western gray squirrel occurs in naturally occurring evergreen forests on VAFB and in the Purisima Hills in the vicinity of the project area.

In addition, modified habitats such as sewage treatment ponds, settling ponds, livestock ponds, and reservoirs associated with agricultural lands are frequented by waterfowl and shorebirds and have hosted a number of regional rare bird species over the years (such as semi-palmated, curlew and stilt sandpipers; Brewer's, red-winged and tri-colored blackbirds; and Franklin's gull). These man-made or modified habitats are also known to support federally-listed (threatened) California red-legged frogs which are known to range widely from water sources, and may potentially support the endangered California tiger salamander whose habitat includes portions of the project area (e.g., the Lompoc and Los Alamos valleys, and Purisima and Santa Rita hills). Populations of tiger salamander have also been reported from the Orcutt Valley and from vernal pools located east of Highway 101.

5.2.1.2 Aquatic Habitats and Biota

Aquatic habitats in the project area include the Santa Ynez River and its lagoon/estuary, tributaries to the Santa Ynez River (primarily intermittent and ephemeral), San Antonio Creek and its tributary in Harris Canyon, Orcutt Creek, the Santa Maria/Sisquoc Rivers, Nipomo Creek and its tributaries, Los Berros Creek, and a variety of ponds and springs. These habitats have been altered by human activities such as urban development, channelization and flood control, agricultural land use practices, water diversions and groundwater pumping, and runoff of pollutants from human activities in the watershed. The main tributaries to the Santa Ynez River in the project area are Oak Canyon, Santa Lucia Canyon, and Davis Creek.

Perennial and intermittent waters support aquatic invertebrate communities adapted to the water regime. These include aquatic insects, crustaceans, mollusks (primarily snails), and worms. The abundance and species composition of the invertebrates varies by season and habitat type. Algae and submerged and emergent plants range from scarce to abundant by season and habitat.

Both native and non-native fish are present in the Santa Ynez River (SYRTAC, 2000b). Native freshwater species include threespine stickleback (*Gasterosteus aculeatus*), arroyo chub (*Gila orcutti*), and prickly sculpin (*Cottus asper*). Native estuarine and migratory species include tidewater goby (*Eucyclogobius newberryi*), Pacific lamprey (*Lampetra tridentata*), steelhead (*Oncorhynchus mykiss*), staghorn sculpin (*Leptocottus armatus*), starry flounder (*Platichthys stellatus*), topsmelt (*Atherinops affinis*), Pacific herring (*Clupea harengus*), and shiner perch (*Cymatogaster aggregata*). Except for the lamprey and steelhead, the estuarine and migratory species are found in the lagoon at the mouth of the river. Tidewater gobies and steelhead are discussed in more detail in Section 5.2.1.3. A number of non-native fish are present, primarily from stocking of Lake Cachuma. These include largemouth bass (*Micropterus salmoides*), smallmouth bass (*M. dolomieui*), bluegill (*Lepomis macrochirus*), green sunfish (*L. cyanellus*), redear sunfish (*L. microlophus*), black crappie (*Pomoxis nigromaculatus*), channel catfish (*Ictalurus punctatus*), black bullhead (*Ameiurus melas*), goldfish (*Carassius auratus*), carp (*Cyprinus carpio*), mosquitofish (*Gambusia affinis*), and fathead minnow (*Pimephales promelas*).

Native and non-native fish can occur in the streams tributary to the Santa Ynez River where flow is perennial or during intermittent flow through migration. Ponds may also have non-native species that have been introduced by landowners for mosquito control or recreational fishing.

San Antonio Creek is inhabited by both native and non-native fish species. The native species include prickly sculpin, arroyo chub, tidewater goby, unarmored threespine stickleback (*Gasterosteus aculeatus willimasoni*), and steelhead (Irwin and Soltz, 1984 and 1982; NMFS, 2000). Staghorn sculpin and juvenile starry flounder have also been collected in the lagoon at the mouth of the creek (Irwin and Soltz, 1984). Non-native species include carp and mosquitofish (Irwin and Soltz, 1982). Steelhead, tidewater goby, and unarmored threespine stickleback are discussed in more detail below in Section 5.2.1.3.

The Santa Maria River in the project area has intermittent flow, primarily during the rainy season and when releases are made from Twitchell Reservoir for groundwater recharge. The lagoon at the mouth of the river, however, is perennial and supports tidewater goby, threespine stickleback, mosquitofish, starry flounder, and staghorn sculpin (URS, 1986).

The southwestern pond turtle (*Clemmys marmorata pallida*) is a California species of Special Concern. It inhabits fresh to brackish waters that are permanent to intermittent and feeds primarily on small aquatic invertebrates (Federal Register 57 No. 193 1992). Pond turtles prefer quiet waters of deep pools lined with aquatic vegetation. Nesting occurs in uplands adjacent to aquatic habitats. The nest site needs to be dry and warm enough for the eggs to hatch. Soil high in clay or silt on an unshaded slope is typically used. The females can lay eggs up to 0.25 mile away from a water source, but most eggs are laid within approximately 600 feet (Jennings and Hayes, 1994). Pond turtles are found in the Santa Ynez River, San Antonio Creek, drainages into Betteravia Lakes, and Los Berros Creek.

5.2.1.3 Rare, Threatened and Endangered Species

Rare, threatened and endangered species are protected by one or more of the following: the California Endangered Species Act (1984), the Federal Endangered Species Act (1973, as amended), the California Native Plant Protection Act (1977), and the Migratory Bird Treaty Act (1918). The California Environmental Quality Act (1970) provides additional protection for unlisted species that meet the "rare," <u>"threatened"</u> or "endangered" criteria defined in Section 15380. Table 5.2-1 provides a list of the state and federally-listed threatened and endangered plants and wildlife, and species of concern likely to be found in the project area.

Other rare species, obtained from sources listed below, that may occur in the project area could be protected under CEQA Section 15380, although there is some overlap with formal state and federal lists.

- Inventory of Rare and Endangered Vascular Plants of California (California Native Plant Society, seventh edition, August 2006).
- California Natural Diversity Database Special Plant List (CDFG, 2006a).
- Bird Species of Special Concern in California (Remsen, 1978, published by the CDFG).
- The National Audubon Society's "Blue List" (Tate and Tate, 1982).
- The California Fish and Game Code (contains prohibitions against taking or possession of certain species).

<u>Information on species that are not listed as rare, threatened, or endangered under the state and federal Endangered Species Act(s), but which may nevertheless be considered rare, threatened,</u>

or endangered under CEQA, including CNPS List 1B plant species and California wildlife Species of Concern, is provided in Table 5.2.1 and, as applicable, in the foregoing descriptions of Habitats and Biota. Impacts on these species have generally been considered significant in that context. Because of the additional statutory protections afforded to listed species under the state and federal Endangered Species Act(s), and the responsibilities of the California Department of Fish and Game and U.S. Fish and Wildlife Service for these species, additional description is provided below for state- and federally-listed threatened and endangered species.

The following species accounts provide the current listing status under the California state and federal Endangered Species Act(s), ~~and by the CNPS,~~a brief description of proposed or designated critical habitats, the preferred habitat, species associations, current distribution, and factors threatening full recovery of the species.

Plants

Pismo Clarkia (*Clarkia speciosa* ssp. *immaculata*)

The Pismo clarkia was federally-listed as endangered on December 15, 1994 and was state-listed as rare in November 1978. The following description is taken from the Federal Register (USFWS, 1994b).

The Pismo clarkia is an erect or decumbent annual herb. It produces flowers with petals that are white or cream-colored at the base, streaking into pinkish or reddish-lavender in the upper part. It grows in pockets of dry sandy soils, possibly ancient sand dunes, within grassy openings in chaparral and oak woodlands. The historical range for this species includes the area between the town of Edna and the Nipomo Mesa area. Five out of nine original populations remain today in varying condition. Current threats include development and road maintenance.

The species is not known to occur within the immediate vicinity of the project. However, appropriate habitat for this species exists within or adjacent to the pipeline corridor near Summit Pump Station.

Lompoc Yerba Santa (*Eriodictyon capitatum*)

Lompoc yerba santa was listed by the USFWS (2000c) as endangered. Prior to the federal listing, the CDFG listed this species as rare in 1979. This species is a shrub, ranging in sizes. The leaf margins are rolled under with lavender, densely hairy flowers that bloom from May to August (Smith 1998). Lompoc yerba santa occurs in maritime chaparral communities and is often found in association with bush poppy (*Dendromecon rigida*), scrub oaks (*Quercus berberidifolia*, *Q. parvula*), buck brush (*Ceanothus cuneatus*), and in higher elevation areas where bishop pine forests intergraded with chaparral manzanita (*Arctostaphylos* spp.) and black sage (*Salvia mellifera*).

There are four known locations of this species in SBC, including two populations on VAFB. Suitable habitat for Lompoc yerba santa is present within the project area and a population of the species is known from Pine Canyon on VAFB, approximately a half mile upstream of the pipeline corridor. At this location *Eriodictyon capitatum* was noted in 1982 growing on a steep hillside of diatomaceous shale between *Arctostaphylos* sp. and *Pinus muricata*, and this population is presumed extant (CNDDB, 2001). Threats to this species include fire management practices (particularly in areas where prescribed burns are used to control vegetation), and low seed productivity. However, the known population on VAFB receives special management considerations for preservation.

Critical habitat for the Lompoc yerba santa was proposed in 2001 (USFWS, 2001b). Two critical habitat units were proposed on VAFB. The proposed critical habitat rule was finalized in 2002, with the removal of the habitat units on VAFB. Through special management and arrangement with the USFWS, the habitat units were not designated critical habitat, but were listed as Sensitive Resources Protection Areas (SRPA) by VAFB. The INRMP stipulates long-term management strategies for Lompoc yerba santa and SRPAs. The boundaries of SPRAs may be changed based on subsequent surveys, while the total area of SRPAs must be maintained at 3,100 acres or greater (USFWS, 2002; VAFB, 2006). The SRPAs on VAFB are north and upslope of the pipeline corridor between Platform Irene and LOGP. The Vandenberg East Unit of critical habitat includes the population in Pine Canyon. At this location the pipeline corridor is adjacent to the southernmost boundary of the proposed critical habitat, but is within a maintained fire break that follows the northern boundary of the Federal Penitentiary.

Another endemic yerba santa (*Eriodictyon traskiae*) occurs in the Purisima Hills near the ConocoPhillips Pipeline segment (LOGP to Santa Maria Pump Station), but this species has no special status.

Seaside Bird's-beak (*Cordylanthus rigidus* ssp. *littoralis*)

Seaside bird's-beak is listed as a federal Species of Concern and was listed in 1982 by the CDFG as endangered. This species is an annual root-parasite with in-rolled foliage, yellow-green flowers and blooms from June to October. This species is found in sandy soil in coastal dune and coastal habitats about Lompoc, Burton Mesa, Mission La Purisima area, to Buellton (Smith, 1998). Seaside bird's-beak has been recorded at several locations within the project area. In 1989, thousands of plants were recorded on Lompoc Oil Field at the base of Purisima Hills in disturbed areas of coastal scrub vegetation in sandy soil (CNDDB, 2001). Associated species included black sage *(Salvia mellifera),* mock heather *(Ericameria ericoides),* horkelia *(Horkelia cuneata)* and curly-leaved monardella (*Monardella undulata)* (CNDDB, 2001). This record of occurrence is within or directly adjacent to the pipeline corridor and the population is presumed extant.

La Graciosa Thistle (*Cirsium loncholepis*)

La Graciosa thistle was federally-listed as endangered on March 20, 2000, and state-listed as threatened in February, 1990. It is a short-lived (1 or 2 years) member of the sunflower family. The plant produces one to many stems, 4 to 40 inches tall, from a rosette base. The rosette leaves are up to 12 inches long, dark green, deeply lobed with wavy, spine-tipped margins. Flower heads are in tight clusters at the tip of the stems and produce whitish flowers with dark purple anthers. La Graciosa thistle is found in wet soils surrounding dune lakes, moist dune swales, and on the floodplain near the Santa Maria River estuary. Its historical distribution included the backdunes and coastal wetlands from the Pismo Dunes of southern San Luis Obispo County to the Santa Ynez River in northern SBC. Historically, this species occurred in wetland habitats in the Orcutt region that have since been converted to agriculture or otherwise developed. Its current distribution is restricted to several colonies in the Guadalupe-Nipomo Dunes Complex, including the Santa Maria River Estuary, which supports the largest known occurrence of this species. It is threatened by ground water pumping and oil field development (USFWS, 2000c).

An historical record for this species is present along the pipeline corridor in La Graciosa Canyon (CNDDB, 2001), but it has not been observed at this site in recent years.

The USFWS recently designated critical habitat for La Graciosa thistle (USFWS, 2004a). Only a small portion of the critical habitat overlaps the project area. The pipeline corridor crosses through a section of critical habitat south of Orcutt and just north of the intersection of Highway 1 and Highway 135.

Surf Thistle (*Cirsium rhothophilum*)

Surf thistle is listed as a federal Species of Concern and was listed in 1990 by the CDFG as threatened. Although state and federal resource protection agencies, as well as the CNPS, recognize the sensitivity of this species, critical habitat has neither been proposed nor designated. Surf thistle is a short lived perennial, with white felt like foliage and whitish flowers, flowering from May to September. Surf thistle is sparsely scattered on crests and in valleys of stabilized, and sometimes active foredunes along the ocean at Point Conception, Point Arguello, Surf Beach, Casmalia Beach, at the mouth of the Santa Maria River, the Guadalupe Dunes, Nipomo Mesa and Pismo Beach (Smith, 1998). Associated species include beach spectacle pod (*Dithyrea maritima*), sand verbena (*Abronia* spp.), sea rocket (*Cakile maritima*), and beachbur (*Ambrosia chamissonis*). Suitable habitat for surf thistle is present in the project area, and it has been recorded where the pipeline crosses the foredunes (CNDDB, 2001). Populations are threatened by off-road vehicles, human and animal foot traffic, and competition from non-native plants including iceplant, which is prevalent in the foredunes within the project area (CNPS, 2006).

Beach Spectacle Pod (*Dithyrea maritima*)

Beach spectacle pod is listed as a federal Species of Concern and was listed in 1990 by the CDFG as threatened. This species is a perennial with fruit that looks like spectacles. The leaves are fleshy with white to cream colored (sometimes purple) flowers, and flowers from April to July (Smith, 1998). Although state and federal resource protection agencies, as well as the CNPS recognize the sensitivity of this species, critical habitat has neither been proposed nor designated. Beach spectacle pod is found on coastal dunes at Surf beach, Purisima Point to west of Casmalia, Guadalupe Dunes, Point Sal, Oso Flaco Lake and Morro Bay (Smith, 1998), and often in association with surf thistle. Other species associated with beach spectacle pod include sea rocket (*Cakile maritima*), beachbur (*Ambrosia chamissonis*), crisp monardella (*Monardella crispa*), and sand verbena (*Abronia* spp.). Suitable habitat for beach spectacle pod is present in the project area and it has been recorded where the pipeline crosses the foredunes (CNDDB, 2001). In various portions of its range populations are threatened by off-road vehicles, human and animal foot traffic, and competition from non-native plants including iceplant, which is prevalent in the foredunes and sandy soils in the project area (CNPS, 2006).

Gaviota Tarplant (*Deinandra increscents* ssp. *villosa*)

Gaviota tarplant is federally and state listed as endangered. This annual species is narrowly distributed, being limited to fine sandy soils on coastal terraces from the Gaviota area, across VAFB, and north to Point Sal. It has branching stems, gray-green, hairy foliage, and yellow ray flowers that bloom from late spring to early fall (approximately June through September). Gaviota tarplant occurs in association with *Nassella, Aveena,* and *Bromus* spp. in western SBC, often in areas with shallow clay subsoil (USFWS, 2002). This species may occur in open or disturbed areas among grassland and coastal sage scrub communities. Annual variation in distribution and abundance of Gaviota tarplant is common due to seed dispersal and climate conditions (USFWS, 2002). Two locations on VAFB, one near Point Arguello and one near Point Sal, contain known populations of Gaviota tarplant. Occurrence of the species has also been observed along the coastal terrace from Point Pedernales to the Santa Ynez River and in the semi-disturbed coastal bluff terrace habitat between the pipeline landfall and Valve Site #2 (Lum, pers. comm.).

Critical habitat for the Gaviota tarplant was proposed in 2001 (USFWS, 2001b). Three critical habitat units were proposed on VAFB, one unit at Point Sal, a second unit in the upland area of Sudden Peak, and a third unit near the coastline at Point Pedernales. The habitat unit at Point Pedernales extends south to Rocky Point and east to the 500-ft contour line. The critical habitat proposed rule was finalized in 2002, with the removal of the habitat units on VAFB. Through special management and arrangement with the USFWS, the habitat units were not designated critical habitat, but were listed as Sensitive Resources Protection Areas (SRPA) by VAFB. The INRMP stipulates long-term management strategies for Gaviota tarplant and SRPAs. The boundaries of SPRAs may be changed based on subsequent surveys, while the total area of SRPAs must be maintained at 3,100 acres or greater (USFWS, 2002; VAFB, 2006).

Wildlife

Tidewater Goby (*Eucyclogobius newberryi*)

The tidewater goby was federally-listed as endangered on February 4, 1994 (USFWS, 1994a) and is a state-designated Species of Special Concern. A proposed rule to delist the species, except in Orange and San Diego counties, was published on June 24, 1999 (USFWS, 1999a). The proposed rule was withdrawn in 2002, and the tidewater goby remains on the endangered species list throughout its range (USFWS, 2005). Critical habitat has not been proposed or designated north of Orange County, California.

Tidewater gobies are small (usually less than 2 inches long) with large pectoral fins and fused pelvic fins that form a sucker-like disk. This is the only goby species along the coast of California that is restricted to low salinity (less than 10 parts per thousand [ppt]) waters. All life stages are completed in these waters (i.e., no marine life history phase occurs), although the fish can live in waters with a salinity of over 40 ppt (Swift et al., 1989). This limits the frequency of genetic exchange between populations and lowers the potential for recolonization of a habitat once a population has been lost. Recolonization, however, has been documented to occur at distances up to 20 km from a source population (Lafferty et al., 1996). Tidewater gobies are benthic (living on the bottom substrate) and inhabit shallow waters (less than 3 feet deep) that are slow moving to still but not stagnant (Irwin and Soltz, 1984). The coastal lagoons where these fish reside are typically closed off from the ocean by sand bars during summer. The substrate is generally sand and mud with abundant emergent and submerged vegetation (Moyle, 1976). In addition to living in coastal lagoons, these fish can also move upstream at least 5 miles as has been documented in San Antonio Creek, SBC (Irwin and Soltz, 1984).

Spawning in southern California takes place primarily from late April to July, when males dig a vertical burrow approximately 10 to 20 cm into clean coarse sand for nesting. The eggs are attached to the walls of the burrow by the female and are guarded by the male until they hatch in 9 to 10 days. Larval gobies are pelagic and found around vegetation for a short time and then become benthic (Swift et al., 1989). The life span of a tidewater goby is generally only one year, although individuals in the northern part of their range may live to 3 years (Lee et al., 1980).

This species formerly inhabited lower stream reaches and coastal lagoons from the Smith River in Del Norte County, California to Agua Hedionda Lagoon in San Diego County (Lee et al., 1980). Its present distribution extends southward only to the mouth of San Onofre Creek in San Diego County. A reassessment of tidewater goby populations (USFWS, 1999a) indicates that 85 of approximately 110 historical populations remain. The remaining tidewater gobies in Orange and San Diego counties are located on the U.S. Marine Corps Base, Camp Pendleton.

In the project area, tidewater gobies inhabit the lagoon at the mouth of the Santa Ynez River and use the river for an unknown distance upstream from the lagoon. Surveys in 1998 (Swift, 1999) indicated that the population in the lagoon was large. This species is not expected to occur in any of the tributary streams crossed by the pipeline. Tidewater gobies also inhabit the lagoon at the mouth of San Antonio Creek and have been found as far upstream as the Lompoc-Casmalia Road crossing, approximately 5 miles upstream from the lagoon (Irwin and Soltz, 1982 and 1984). The pipeline from the LOGP to Suey Junction crosses San Antonio Creek approximately 9 miles upstream of the Lompoc-Casmalia Road crossing. Tidewater gobies inhabit the lagoon at the mouth of the Santa Maria River as well (Swift et al., 1989).

Steelhead (*Oncorhynchus mykiss irideus*)

Steelhead populations in the Southern California Coast Evolutionarily Significant Unit (ESU), south of the Santa Maria River (inclusive) were federally-listed as endangered on August 18, 1997 (NMFS, 1997). This ESU is recognized as a distinct population segment (DPS), which is also listed as endangered (NMFS, 2006). Populations north of the Santa Maria River to ~~from~~ the Pajaro River ~~on the north to the Santa Maria River on the south were~~are federally-listed as threatened. Critical habitat was designated on September 2, 2005~~February 15, 2000~~ (NMFS, 2005~~0~~). The species is a state-designated Species of Special Concern.

Steelhead are steel-blue to brown above and pale below with small, irregular black spots on the back and most fins and radiating rows of black spots on the caudal fin. Steelhead are the anadromous form of rainbow trout, migrating from the ocean up rivers and streams to spawning grounds. Adult steelhead enter creeks in the winter, usually after the first substantial rainfall (Moore, 1980), and move upstream to suitable spawning areas. Spawning can occur in winter to spring, generally in riffle areas or the tails of pools that contain clean, coarse gravel. Suitable spawning gravels generally are 0.5 to 3 inches in diameter, 8 inches in depth or more, and not heavily compacted and have low amounts of sand or silt in them; however, steelhead can successfully spawn in gravels not meeting these characteristics (WESCO, 1987). Females dig a nest in the gravel and deposit their eggs, the males fertilize the eggs, and the female covers the nest with gravel. After the eggs hatch (3.5 to 5 weeks), fry emerge from the gravel in 2 to 6 weeks and disperse throughout the creek, typically occupying shallow areas along stream margins. Juvenile steelhead often move to deeper pools as they grow and will remain in freshwater for an average of 2 years before migrating to the ocean (NMFS, 1997; Titus et al., 1994). Downstream movement of adults after spawning and juveniles migrating to the ocean usually occurs from March through July. Photoperiod, stream flow, and temperature appear to influence emigration timing (Shapovalov and Taft, 1954; Bjornn and Reiser, 1991; Holubetz and Leth, 1997). Juvenile steelhead may spend several weeks in the coastal lagoon or estuary of a stream before entering the ocean. They reside in the ocean for 2 to 3 years before returning to their natal stream to spawn (NMFS, 1997), although in wet years, steelhead may return to spawn after only one year in the ocean (Moyle et at., 1995). The adults can spawn more than once, although most do not spawn more than twice (NMFS, 1997).

Optimal habitat for steelhead throughout its range on the Pacific Coast can generally be characterized by clear, cool water with abundant instream cover, well-vegetated stream banks, relatively stable water flow, and a 50:50 pool-to-riffle ratio (Raleigh et al., 1984). Pool-to-riffle ratios between 40:60 and 60:40 are generally thought to provide the most productive habitat for steelhead (WESCO, 1987). Although optimal water temperatures for steelhead are considered to range from 12 to 20ºC, various sources document southern steelhead as persisting in streams with water temperatures ranging from 14.4 to 25.5ºC during the summer and early fall months of drought years (WESCO, 1987; Titus et al., 1994). The Critical Thermal Maximum is reported to be up to 29.4ºC (Lee and Rinne, 1980).

The presence of a well-developed riparian corridor along the stream course is considered an essential component in southern steelhead streams. This plant community inhibits substantial erosion of stream banks during high flows, maintains lower stream temperatures, and provides organic input to the stream (Faber et al., 1989). Good rearing habitat contains low current velocities (such as behind boulders or other velocity barriers) and good cover (e.g., undercut banks, logs or brush, surface turbulence). Cobble embeddedness (amount of sediment surrounding rocky substrate) can be used as a measure of shelter availability for aquatic insects (food for fish) and young fish. At an embeddedness of above 35 percent, rearing habitat quality decreases substantially (WESCO, 1987). Embeddedness can also be used to indirectly evaluate habitat suitability for incubation of fish eggs and for salmonid overwintering.

Stream flow within the southern extent of southern steelhead range varies seasonally and annually. In central and southern California coastal drainages, droughts of one or more years can cause streams to have intermittent flow in late summer and fall with reductions in pool depths, thereby reducing the quality and quantity of available habitat. Although southern steelhead are capable of withstanding substantial seasonal and annual fluctuations in stream flow and other physical conditions, prolonged drought periods can periodically result in mortality to juvenile fish inhabiting a stream (Moore, 1980).

Steelhead primarily use the lower Santa Ynez River for migration passage to and from the Pacific Ocean (SYRTAC, 2000a and 2000b). The lagoon at the mouth of the Santa Ynez River may be used briefly by steelhead preparing to enter the sea (SYRTAC, 2000b). Adult steelhead generally spawn from January to April depending on streamflows (SYRTAC, 2000a and 2000b). The smolting and migration of juveniles out to the ocean generally occurs between February and May depending on stream flows (SYRTAC, 2000a and 2000b). Historically, steelhead have spawned in many of the perennial tributaries and on the upper main stem of the Santa Ynez River. Before the construction of Bradbury Dam steelhead were believed to spawn on the main stem of the Santa Ynez River from Solvang to Gibraltar Reservoir during wet years (SYRTAC, 2000b). Currently it is believed that under average conditions small numbers of steelhead migrate into the Santa Ynez River to spawn mainly in the lower tributaries such as Salsipuedes and El Jaro Creeks (SYRTAC, 2000a and 2000b). The low flows and stream characteristics often found along the Santa Ynez River below Buellton offer poor physical habitat conditions for steelhead. However, during wetter years steelhead have also been observed to spawn in the mainstem of the Santa Ynez River above Buellton and in upper tributaries, such as Quiota and Hilton creeks.

Two key areas on the main stem of the Santa Ynez River were identified by SYRTAC (2000b) as important rearing and spawning habitats for steelhead. These key reaches are as follows: the Santa Ynez River below Bradbury Dam to the highway 154 bridge and the reach between Refugio Road and Alisal Road. In the Santa Ynez River basin most of the steelhead occur in tributaries that originate from the south side of the basin. Southern basin tributaries originate from cooler and more vegetated north facing slopes, which have a greater tendency for perennial flow and more favorable steelhead habitat characteristics than do the dryer south facing slopes of the north side of the basin. The project pipelines are located on the north side of the Santa Ynez River and do not cross any tributaries noted by SYRTAC to support important steelhead populations or habitat.

Salsipuedes, El Jaro, and San Miguelito Creeks are three tributaries that originate from the southern side of the lower Santa Ynez River basin that are located nearest to the project area and recognized by SYRTAC (2000b) as streams of interest for steelhead habitat. El Jaro is a tributary to Salsipuedes Creek. Salsipuedes and San Miguelito both enter the Santa Ynez River upstream from where project pipelines parallel the Santa Ynez River. San Miguelito is closest to project pipelines, but enters the Santa Ynez River approximately 4 to 5 miles upstream from where the project pipelines bend away from the river toward the LOGP.

~~Steelhead also may use San Antonio Creek when conditions are favorable, and this creek is included as the critical habitat for this species (NMFS, 2000). No information is available to describe based on its ocean connection. However, s~~Steelhead surveys conducted from 1999 to 2000 did not find any steelhead in San Antonio Creek. Historical occurrence has not been documented for San Antonio Creek, and the habitat has been characterized as poor to marginal in a steelhead habitat evaluation study by Swift in 2000 (N. Read Francine, VAFB, 2002). Steelhead use the Santa Maria River for passage to habitats upstream in the Sisquoc River and are known to use Los Berros Creek as well.

Within the project area, critical habitat has been designated for steelhead and includes the Santa Ynez~~ San Antonio~~ and Santa Maria Rivers, excluding areas above Bradbury (Santa Ynez River) and Vaqueros (Santa Maria River) dams or above longstanding, naturally impassable barriers (i.e., natural waterfalls in existence for at least several hundred years). Critical habitat has also been designated in Los Berros Creek (NMFS 2005).

Unarmored Threespine Stickleback (*Gasterosteus aculeatus williamsoni*)

The unarmored threespine stickleback was federally-listed as endangered on October 13, 1970 (35 FR 16047) and was state-listed as endangered on June 27, 1971. Critical habitat has been proposed but not finalized and is not in the project area. The following description was taken from a biological opinion for this species (Reference No. 9322 in USFWS 1993) and other sources as noted.

The unarmored threespine stickleback is a small (less than 6 cm standard length), scaleless freshwater fish with three dorsal spines and a bony keel on the sides of the caudal peduncle. The back is dark, often with vertical bars, and the undersides are silvery. This species requires slow flow with aquatic vegetation for cover and nest material. The fish are sight feeders, and are intolerant of high turbidity. Most unarmored threespine sticklebacks complete their life cycle in one year, although a few individuals in a population apparently live two or three years. Spawning can occur throughout the year, but peak activity occurs between May and September. The males establish breeding territories, construct a nest of vegetation and sand, and brood the eggs until they hatch (Irwin and Soltz, 1982).

The species was once widely distributed in southern California with records from the Santa Clara, Los Angeles, San Gabriel, and Santa Ana rivers as well as from the Santa Maria River drainage and San Antonio Creek in SBC. By the 1940s this fish had been extirpated from the Los Angeles basin and from the Santa Maria River drainage. Factors leading to these population losses include large scale impoundments, stream channelization, increased water turbidity, introduction of non-native competitors and predators, water pollution, and hybridization with other subspecies of threespine stickleback (USFWS, 1980b). The present distribution of the species includes the headwaters of the Santa Clara River, its tributary San Francisquito Creek, and San Antonio Creek. Fish from the San Antonio Creek population have been introduced into Honda Creek on South VAFB (VAFB, 2006), and ones from San Francisquito Creek have been transplanted to San Felipe Creek in Imperial County.

Unarmored threespine sticklebacks appear to be relatively abundant where found but continue to be threatened by stream degradation. The species is currently being managed by a recovery team, and the recovery plan was revised in 1985. The agencies cooperating in the recovery effort have undertaken several actions to conserve the species, including (1) surveys to discover additional populations, (2) transplants to establish it in other waters, (3) surveys to discover exotic organisms, (4) eradication programs to remove or control exotic species, (5) a contingency plan to establish response procedures in case of oil or toxic chemical spills, and (6) genetic studies to ascertain taxonomic relationships. As a result of these efforts, a remnant population was discovered in Shay Creek (San Bernardino County), additional unarmored threespine stickleback populations have been established, and a potential change in the taxonomic status of one or more of the recognized extant populations was found. USFWS policy is to wait until the taxonomic revisions have been published in a reputable scientific journal before initiating changes in the management of a listed species.

This species is known to inhabit San Antonio Creek primarily downstream of Barka Slough on VAFB (Irwin and Soltz, 1982), and unidentified threespine sticklebacks have been observed as far upstream as Los Alamos in the 1980s (R. Thompson field notes).

California Tiger Salamander (*Ambystoma californiense*)

The California tiger salamander in SBC was emergency listed as endangered on January 19, 2000 (USFWS, 2000a) and was formally listed on September 21, 2000 (USFWS, 2000b). It is a state Species of Special Concern. This distinct vertebrate population segment is largely isolated and thought to be genetically distinct. Critical habitat in SBC was designated in 2004 (USFWS, 2004b). The range of the California tiger salamander overlaps the project area along the route of the ConocoPhillips pipeline, from the north slope of the Purisima Hills to Orcutt and Santa Maria, south of the Santa Maria River (CDFG, 2005a; Williams and Nisbet, 2006).

Critical habitat includes known or potential breeding ponds and surrounding upland areas that provide burrow sites ("refugia") and dispersal habitat. Generally, upland refugia are presumed to exist within a radius of 2,200 feet from breeding ponds, and dispersal habitat is considered to extend up to 0.7 mile from breeding locations. These distances, however, are subject to adjustment based on site-specific factors, such as development that prevents dispersal, or conditions that facilitate dispersal across a greater distance, in one case up to 1.2 miles (USFWS, 2004b). No critical habitat is designated on VAFB property.~~ or within the project area.~~ The existing ConocoPhillips pipeline ~~runs through the vicinity of~~ crosses critical habitat Unit 1, designated south of Santa Maria between Highway 1 and State Highway 135 (USFWS, 2004b ~~2000b~~).

The following description was taken from Jennings and Hayes (1994).

California tiger salamanders are black with pale yellow spots. This species is a lowland inhabitant restricted to grasslands and low foothill regions of central and northern California. It breeds in long-lasting rain pools (e.g., vernal pools) that are often turbid, and sometimes in permanent ponds with no fish predators. During the dry season, the salamanders use rodent burrows, such as ground squirrel or Botta's pocket gopher, as well as man-made structures (e.g., pipes, septic tank drains, and wet basements) on occasion, at distances of up to 1 mile from the breeding pool. Adults migrate to the pools to breed during relatively warm late winter or spring rains. The eggs hatch into larvae that require a minimum of 10 weeks to reach metamorphosis. Juveniles emigrate in mass at night from the drying pool to refuge sites (rodent burrows).

The species occurs in the Central Valley from near Petaluma in Sonoma County to northwestern Tulare County and in the Coast Range south to near Buellton in SBC. Fragmentation and loss of breeding habitat, introduction of exotic and transplanted predatory fish, loss of refuge habitat adjacent to breeding pools due to changes in land use (e.g., agriculture, urbanization, and converting dry land pasture to irrigated pasture), and barriers to migration (roads, berms, and road dividers) have all contributed to the decline of this species.

The California tiger salamander breeds in vernal pools in the Los Alamos and Santa Rita valleys, Purisima and Santa Rita hills, and east and west of Orcutt in the Santa Maria Valley, but spends a majority of its life cycle in upland burrows within oak savanna or stabilized dune scrub habitats. This species is not believed to be present in the affected project area. However, the pipeline corridor from the ridge north of the LOGP to Orcutt falls within the mapped range of the California tiger salamander (USFWS, 2000a, b). California tiger salamanders are known to occur in the area between Orcutt and Santa Maria, which includes designated critical habitat, in the vicinity of the existing pipeline.

California Red-legged Frog (*Rana aurora draytonii*)

The California red-legged frog was proposed for listing as endangered on February 2, 1994 (59 FR 4888). The species was listed as threatened on May 23, 1996, and the final rule became effective on June 24, 1996 (USFWS, 1996b). Critical habitat was proposed for the California red-legged frog on September 11, 2000 (65 FR 54893). The final rule designating critical habitat was published on April 13, 2006 (USFWS, 2006a). No critical habitat is designated within the project area. Lands considered essential to the conservation of the species are identified on San Antonio Terrace on north VAFB, but are not designated as critical habitat.

The following description was taken from the Biological Opinion (1-8-96-F-16) for the Coastal Aqueduct (USFWS, 1993 and 1996a), the final rule for listing the species as threatened (USFWS, 1996b), and the proposed rule for critical habitat (USFWS, 2000d).

The California red-legged frog is one of two subspecies of the red-legged frog (*Rana aurora*) found on the Pacific coast. It is a fairly large frog with adults reaching 5 inches (snout to vent length). The skin of the back is brown, gray, olive, red, or orange with dark flecks or spots. A prominent dorsolateral fold of skin extends from the eye to the hip. The underside is white, often with patches of bright red or orange on the abdomen and hind legs. The final rule states that the species occupies a fairly distinct habitat, combining both specific aquatic and riparian components. Adults prefer dense, shrubby or emergent riparian vegetation closely associated with deep (more than 2.3 feet in depth), still or slowly moving water. However, recent observations indicate that California red-legged frogs will occur in a variety of habitat types, including aquatic, riparian, and upland habitats with permanent water nearby. Well-vegetated terrestrial areas within the riparian corridor may provide important sheltering habitat during winter, foraging areas, and dispersal corridors. California red-legged frogs breed from November to March, with the earlier breeding records occurring in southern localities. Eggs hatch in 8 to 14 days while larvae take 3.5 months or longer to metamorphose. California red-legged frogs may live 8 to 10 years. The frogs disperse upstream and downstream of breeding habitat to forage and seek resting habitat. They take cover in small mammal burrows and moist leaf litter (up to 100 feet from water) in dense riparian vegetation with drying of creeks in summer, but will use other cover sites when traveling overland. Adults can be found within streams over 1.8 miles from breeding habitat and within dense riparian vegetation more than 328 feet from water. After winter rains begin, red-legged frogs may move away from aquatic habitats, primarily at night, and can travel one mile from those habitats (USFWS, 1997a). Juveniles may also disperse locally shortly after metamorphosis in July-September and away from their natal habitats during warm rain events.

The historical range of the California red-legged frog extended from northwestern Baja California, Mexico to a northern boundary extending from the vicinity of Point Reyes National Seashore, Marin County, California on the coast inland to the vicinity of Redding, Shasta County, California. The species has sustained a 70 percent reduction in its geographic range in California as a result of several factors acting singly or in combination. Habitat loss and alteration, combined with over-exploitation and introduction of exotic predators, were significant factors in its decline in the early to mid 1900s. California red-legged frogs were probably extirpated from the Central Valley in the 1960s. Remaining aggregations of California red-legged frogs in the Sierra Nevada foothills became fragmented and were later eliminated by reservoir construction, increased exotic predator populations, grazing, and drought. The pattern of disappearance of California red-legged frogs in southern California is similar to that seen in the Central Valley, except that urbanization and its associated roadways, large reservoirs, exotic predators, and stream channelization projects were the primary factors causing population declines.

As of 1996, California red-legged frogs were known to occur in 243 streams or drainages from 22 counties in central and southern California. Monterey, San Luis Obispo, and Santa Barbara counties support the greatest amount of currently occupied habitat. California red-legged frogs are known to use wetlands and riparian habitats along the lower Santa Ynez River, the unnamed creek draining the LOGP area (approximately 3 km downstream from that site), San Antonio Creek, drainages into Betteravia Lakes, drains into the Santa Maria River, Nipomo Creek, and Los Berros Creek. The potential exists for California red-legged frogs to be present in the project area wherever open water is accessible, including stock ponds, cattle troughs, and other manmade structures that hold water.

Southwestern Willow Flycatcher (*Empidonax traillii extimus*)

The willow flycatcher was state-listed as endangered on December 3, 1990; federal listing of the southwestern willow flycatcher as endangered occurred on February 27, 1995 (USFWS, 1995), and critical habitat was designated on July 22, 1997 (USFWS, 1997b). Revisions to the critical habitat designation were proposed in 2004 (USFWS, 2004d). No designated or proposed critical habitat is present in the project area. The following description was taken primarily from "A Southwestern Willow Flycatcher Natural History Summary and Survey Protocol" (Sogge et al., 1997).

The southwestern willow flycatcher is one of four subspecies recognized in North America (Unitt, 1987). All four subspecies breed in North America but winter to the south in Mexico, Central America, and possibly northern South America. The southwestern willow flycatcher is a brownish-green bird (5.25 to 6.5 inches) with an orange lower mandible and no eye ring. It breeds in California from the Santa Ynez River southward. This subspecies historically nested along the Salinas and Carmel rivers in Monterey County until the early 1970s. Dense riparian habitats 13 to 23 feet tall near surface water or saturated soil are used for nesting. Openings and areas of shorter or sparser vegetation are often present in the riparian habitats used. Southwestern willow flycatchers arrive in May to June for breeding and leave for wintering areas in August to September.

The willow flycatcher was once a common summer resident in California (CESA No. 9317 in USFWS, 1993) and included two subspecies. Breeding has been almost eliminated in the state, primarily due to the extensive loss, fragmentation, and modification of riparian habitats. Habitat losses continue as a result of urbanization, recreation, agricultural development, water diversion and impoundment, stream channelization, livestock grazing, and replacement of native plant species with non-natives. Brood parasitism by the brown-headed cowbird is another threat to the southwestern willow flycatcher.

The southwestern willow flycatcher is known to breed in willow riparian habitats along the Santa Ynez River. Two population centers were discovered in the period between 1986 and 1991. One extends from just west of Buellton to several miles downstream, and the second extends from the Floradale Avenue bridge near Lompoc to the last stand of willows before the river mouth. Due to the inability of biologists to survey on private lands between these two areas, it is not known if there are more territories in between them. A total of "at least 28 territories" were estimated to exist along the Santa Ynez River between Buellton and the coast during the 1995 breeding season (information packet from Willow Flycatcher Workshop, 1995). Surveys in 2000 found 2 territories between the Floradale bridge and the coast, but neither was successful in completing nesting (Mark Holmgren, personal communication, 2001). Between 1995 and 1999, nesting southwestern flycatchers or territorial individuals were present about 50 meters west of the 13th Street Bridge on VAFB. This particular nest site was destroyed in winter storms after that time and nesting was not confirmed in that area during 2000–2001. However, suitable habitat is still present and recolonization of the area is possible (N. Read Francine, VAFB, 2002). Away from the Santa Ynez River within the affected project area, a low potential exists for southwestern willow flycatchers to be present, but may use some of the larger tributaries of the Santa Ynez River on a transitional basis, such as in Santa Lucia Canyon.

Western Snowy Plover (*Charadrius alexandrinus nivosus*)

The Pacific Coast population of western snowy plover (e.g., within 80 km [50 miles] of the Pacific Coast in California, Oregon, Washington, and Mexico) is a federally-listed threatened species. Critical habitat for the western snowy plover was designated on December 7, 1999 (USFWS, 1999c). Critical habitat was designated surrounding the Santa Ynez River mouth, north along the coastline for approximately 1.5 miles and southward along the coastline for approximately 10 miles. The 1999 designation was remanded for reconsideration in 2003. Revised critical habitat was proposed in 2004 (USFWS, 2004c). The 2004 proposal includes the critical habitat unit at the Santa Ynez River mouth.

The western snowy plover is one of two subspecies of snowy plover recognized in North America. The Pacific Coast population breeds on the Pacific Coast from southern Washington to southern Baja California, Mexico.

Western snowy plovers are found on beaches, open mudflats, salt pans and alkaline flats, and sandy margins of rivers, lakes, and ponds. Snowy plovers nest in depressions in the sand above the drift zone. This species was formerly found on quiet beaches the length of the state, but it has declined in abundance and become discontinuous in its distribution. Disturbance to its nest sites, by humans, dogs, and wild predators is a primary reason for its decline (Garrett and Dunn, 1981). This species is a fairly common winter visitor to the mouth of the Santa Ynez River, with a few pairs breeding there (Lehman, 1994). Surveys between 1977 and 1980 by Point Reyes Bird Observatory found up to 150 wintering birds (Page et al., 1981), with approximately 5 pairs nesting in 1978 (Lehman, 1994). From 1990 to 1999, populations on beaches and nesting sites at VAFB ranged from 130 to 258 adult individuals (USFWS, 2001c). Snowy plovers nested and produced young at Wall Beach in 2000 (David Hubbard, personal communication) around the area where the pipeline array makes landfall.

California Least Tern (*Sterna antillarum browni*)

California least terns were federally-listed as endangered on October 10, 1970, and listed as endangered by the state on June 27, 1971. These birds generally arrive in this area in early May and depart by August (Lehman, 1994). They are the smallest member of the tern subfamily, nine inches in length with a wingspan of 20 inches. Nesting occurs in open expanses of light-colored sand, dirt, or dried mud, in close proximity to a lagoon or estuary that offers a readily available food supply (USFWS, 1980).

California least terns have historically nested along the coast of California as far north as San Francisco (USFWS, 1980). However, the distribution of sites has always been discontinuous, and extralimital breeding, as far north as Oregon, has on occasion occurred (USFWS, 1980). Locally, this species now nests only at the mouths of the Santa Maria and Santa Ynez rivers, and several locations on VAFB (at the mouth of San Antonio Creek and at Purisima Point) (Lehman, 1994). During the last two decades the number of nesting birds near the Santa Ynez River mouth has been low, averaging 1-3 pairs per year (Lehman, 1994). Within the project area, the potential exists for breeding or foraging California least terns to occur around the area where the pipeline array makes landfall. In 1999 a total of 27 pairs of terns fledged 15 young from Purisima Point.

California Brown Pelican (*Pelecanus occidentalis californicus*)

The California brown pelican was federally-listed as endangered on October 13, 1970. It was listed by the state of California as endangered on June 27, 1971.

Brown pelicans occur in marine habitats along the Pacific, Atlantic, and Gulf Coasts in North America and range southward through the Gulf and Caribbean areas to Central and South America. The California subspecies nests on Channel Islands off the coast of southern California, mainly on Anacapa (Garrett and Dunn, 1981). The major portion of the population nests south along the coast of Baja California and the Gulf of California, to Guerrero, Mexico. After the breeding season, California brown pelicans wander as far north as British Columbia, Canada and as far south as South America.

Brown pelicans are found primarily in warm estuarine, marine subtidal, and marine pelagic waters They occur mostly over shallow waters along the immediate coast, especially near beaches and on salt bays. Brown pelicans roost on water, rocks, rocky cliffs, jetties, piers, sandy beaches, and mudflats, and forage in open water. When foraging, the brown pelican dives headfirst into the water from as high as 18 m (60 ft) in the air. It completely or partially submerges itself in an attempt to capture fish, which is almost the exclusive prey of this carnivorous species.

Brown pelican populations declined greatly in the mid-twentieth century due to human persecution, disturbance of nesting colonies, and reproductive failure caused by eggshell thinning and the adverse behavioral effects of pesticides. Most North American populations of this species were extirpated by 1970. Since the banning of DDT and other organochlorines in the early 1970s, brown pelicans have made a strong recovery and are now fairly common and perhaps still increasing on the southeast and west coasts. The endangered southern California Bight population of the brown pelican grew to 7,200 breeding pairs by 1987, but has experienced considerable population fluctuations in recent years. In 1992, there were an estimated 6,000 pairs in southern California and approximately 45,000 pairs on Mexico's west coast. The USFWS is presently involved in a status review of the brown pelican to determine if delisting is warranted (USFWS, 2006b).

Locally, brown pelicans forage in spring and summer along the mainland coast, including birds nesting on Anacapa Island, and non-breeding birds. Numbers peak in July, as post-breeding birds arrive from the nesting grounds. Numbers decline through winter and early spring, although there are always some brown pelicans in the area (Lehman, 1994). Although the Santa Ynez River mouth and estuary are not considered major aggregation sites for brown pelicans (Lehman, 1994), they are frequent visitors to the area and occasionally form flocks of 100 or more birds. The potential exists for California brown pelicans to be present in the project area around the area where the pipeline array makes landfall. Recent observations indicate that pelicans still use this area regularly.

American Peregrine Falcon (*Falco peregrinus*)

The American peregrine falcon was listed as an endangered species on June 2, 1970. Populations of this species have recovered substantially since this federal listing, which has prompted the removal of the American peregrine falcon from the federal endangered species list (USFWS, 1999b); however, it remains a California state-listed endangered species. The American peregrine falcon was de-listed as an endangered species on August 25, 1999. This species is currently undergoing a five-year monitoring program to ensure that the falcon populations continue to improve and that delisting of the species was an appropriate action.

Peregrine falcons are medium size raptors with a wingspan of approximately 112 cm and weight of approximately 1 kg (USFWS, 1999b). The crown and back of adult peregrine falcons is dark gray in color, while the abdomen is pale with dark bars or streaks. The diet of the peregrine falcon is almost entirely composed of other birds that are caught in mid air (USFWS, 1999b).

American peregrine falcons have an extensive range as the species can be found from the subarctic boreal forests of Alaska and Canada, south to Mexico (USFWS, 1999b). Nesting of this species occurs from central Alaska, central Yukon Territory, and northern Alberta and Saskatchewan, east to the Maritimes and south (excluding coastal areas north of the Columbia River in Washington and British Columbia) throughout western Canada and the United States to Baja California, Sonora, and the highlands of central Mexico. Populations that nest in subarctic areas often winter in South America. Populations that nest in lower latitudes tend to display variable migratory patterns while some are nonmigratory.

The American peregrine falcon populations significantly declined after World War II (USFWS, 1999b). It was found that population declines were due largely to direct mortality or reproductive complications as a result of environmental contamination by organochlorine pesticides like DDT. Populations declined to extremely low levels by the 1960's, prompting the species listing as an endangered species. Banning of the use of pesticides like DDT and efforts from recovery programs have helped the species recover to more stable levels and have resulted in successful reintroduction of populations in many areas were they had been extirpated in earlier years.

The American peregrine falcon is known to frequent open country such as grasslands, agricultural areas, ponds, sloughs, river mouths and seacoasts for foraging activities. Regular observations of this species have been reported at the Santa Ynez River mouth. Historically, this species nested on south VAFB, and there was an unconfirmed report of nesting in 1993 near Point Arguello on VAFB (Lehman, 1994); however nesting was confirmed on south VAFB by tagging studies conducted in the mid-1990's on behalf of the California Commercial Spaceport. Within the project area, the potential exists that peregrine falcons may be present in the vicinity of where the pipeline array makes landfall. Peregrine falcons are still regularly seen foraging in this part of the project area, especially in winter.

El Segundo Blue Butterfly (*Euphilotes battoides allyni*)

El Segundo blue butterfly was federally listed as endangered in 1976. Critical habitat has not been designated. The species is not legally protected by the State of California, but is included in the CDFG Special Animals list (CDFG, 2006).

El Segundo blue butterfly is one of five subspecies of blue butterflies. This subspecies is relatively small, with a wingspan ranging from 0.75 to 1.25 inches. Males are bright blue in color, with an orange border on the rear hindwings. Females are dull brown in color with an orange wing border. El Segundo blue butterflies occur in coastal dune habitat. Individuals are typically sedentary and do not exhibit migratory tendencies or long-range dispersal. Occurrence of the butterfly is linked to its primary plant food source, coast buckwheat (*Eriogonum parvifolium*). The species also appears to favor areas with high sand content (USFWS, 1998). At the time of listing, the species was known only in the El Segundo region of Los Angeles County (USFWS, 1998).

El Segundo blue butterfly was noted on VAFB near SLC 3. Additional surveys and habitat evaluation for this species are ongoing (Sandburg, pers. comm.). For the current analysis, populations of coast buckwheat are considered a sensitive habitat type due to the potential to support El Segundo blue butterflies.

5.2.2 Regulatory Setting

Table 1.1 in Section 1.0, Introduction, provides a summary of resource agency permitting requirements for the proposed project. The regulatory backing for these permitting requirements is summarized below.

5.2.2.1 Federal Regulations

Endangered Species Act of 1973. Protects species designated as threatened or endangered by prohibiting actions that jeopardize the continued existence of such species. Section 7 of the Act requires consultation with the USFWS and NMFS be conducted for the protection of such species prior to project implementation.

Executive Order 11988, Floodplain Management, and 11990, Protection of Wetlands. Requires that governmental agencies, in carrying out their responsibilities, provide leadership and take action to restore and preserve the natural and beneficial values served by floodplains and wetlands.

Clean Water Act of 1977, Section 404. Regulates restoration and maintenance of the chemical, physical, and biological integrity of the nation's waters. These waters include the navigable waters and "all other waters such as…rivers…wetlands, sloughs…." (U.S. Army Corps of Engineers (Corps)1986, Authorities to Issue Permits, Sec. 320.2). However, isolated waters such as vernal pools with no hydrological connection to a floodplain no longer fall under the jurisdiction of the Corps.

Coastal Zone Management Act of 1972. Requires that projects located entirely or partially within the coastal zone, and for which a federal permit is required, furnish a certification that the proposed activity will comply with the state's coastal zone management program.

Executive Order 13112 – Invasive Species. Establishes an Invasive Species Council whose members include the Secretaries of State, Treasury, Defense, Interior, Agriculture, Commerce, Transportation, and the Administrator of the Environmental Protection Agency and orders establishment of an advisory committee to the Council and orders preparation of a national Invasive Species Management Plan to be updated biennially. The Council is ordered to provide national leadership concerning invasive species and to see that Federal agency activities concerning invasive species are coordinated, complementary, cost-efficient, and effective.

5.2.2.2 State Regulations

California Endangered Species Act. Provides for the protection of rare, threatened and endangered plants and animals, as recognized by CDFG, and prohibits the taking of such species without its authorization. With regard to plants, the California Endangered Species Act greatly expanded upon protection afforded to rare, threatened and endangered plants under the earlier California Native Plant Protection Act 1977.

California Environmental Quality Act (CEQA) of 1970, (Public Resources Code Section 21000-21177). Established requirements and procedures for state and local agency review of the environmental effects of projects proposed within their jurisdictions. CEQA requires that a plant or animal that is not listed but can be shown to meet the criteria for listing under the California Endangered Species Act shall be given the same consideration as a listed species.

California Native Plant Protection Act. Includes provisions that prohibit the taking of listed rare or endangered plants from the wild and a salvage requirement for landowners. It provides the Department of Fish and Game the power to designate native plants as endangered or rare.

California Fish and Game Code, Section 1601 and 1603. Regulates activities that will "substantially divert or obstruct the natural flow of, or substantially change the bed, channel, or bank of, or use material from the streambed of a natural watercourse." Prior to such activities, notification of CDFG is required. If fish or wildlife would be substantially adversely affected, an agreement to implement mitigation measures identified by CDFG would be required.

California Coastal Act (1976). The California Coastal Act provides for the protection of coastal zone resources. Within the coastal zone, some locally issued permits may be appealed to the CCC for review and approval. Activities conducted by federal agencies on federal lands (e.g., VAFB) are generally exempt from state law such as the Coastal Act although projects carried out or approved by a federal agency may require a consistency concurrence from the CCC, pursuant to the Coastal Zone Management Act (CZMA). The California Coastal Act contains legislative policy for public access and recreation (Sections 30210 and 30220); marine environment (Section 30230); land resources (Section 30240); and residential, commercial, and industrial development (Section 30250 and 30260). Sections 30240 and 30260 may be especially relevant to the proposed project and alternatives. Section 30240 addresses environmentally sensitive habitat areas on land, which must be protected against disruption and degradation. Section 30260 includes policies for coastal oil and gas development projects. It has not been determined whether this project will trigger CZMA requirements. However, the local coastal development permit may be appealed to the CCC for project components within or otherwise affecting the coastal zone. The pipeline landfall at the Santa Ynez River, construction at Valve Site #2, and the VAFB onshore alternative may affect the coastal zone and could be appealed for review by the CCC. Similarly, offshore drilling may affect the coastal zone due to the possibility of an oil spill.

5.2.3 Significance Criteria

Significance criteria for biotic resources are described in the SBC Environmental Thresholds and Guidelines Manual (as updated through October 2006). Disturbance to habitats or species may be significant, based on substantial evidence in the record, if they substantially affect biotic resources in the following ways:

- Reduce or eliminate species diversity or abundance.
- Reduce or eliminate quantity or quality of nesting areas.

- Limit reproductive capacity through losses of individuals or habitat.
- Fragment, eliminate, or otherwise disrupt foraging areas and/or access to food sources.
- Limit or fragment range and movement (geographic distribution or animals and/or seed dispersal routes).
- Interfere with natural processes, such as fire or flooding, upon which the habitat depends.

The significance of project impacts is evaluated against these criteria considering the type of impact (e.g., direct, indirect, habitat fragmentation), timing (seasonal impacts and periodic impacts), the size of the impact area, and the remaining plant and wildlife populations off site. Habitat-specific assessment guidelines are promulgated for wetlands, riparian areas, oak woodlands/forests, native grasslands, salt marshes, and vernal pools.

5.2.4 Impact Analysis for the Proposed Project

The PXP Point Pedernales Project Final Development Plan (FDP) Conditions of Approval (see Appendix M) would remain in effect and would continue to be implemented for the proposed project, if it is approved, except as specifically modified as a result of the review and approval process for the Tranquillon Ridge project. Several of the mitigation measures described below are already included in existing PXP compliance plans, such as the Revegetation, Erosion Control and Restoration Plan (RECRP) required by FDP Condition H-1 and the basic RECRP revegetation performance criteria are presented in Table 5.2.2. Prior to any approvals of the proposed project, these plans would need to be reviewed for any necessary updates to specifically incorporate new or updated mitigation measures identified herein.

Table 5.2.2 PXP Point Pedernales Project RECRP Summary List of Revegetation Performance Criteria

Feature	Criteria	Method	Frequency	Findings	Action
Erosion Control	No landslides or gullying; Structures maintained; Soils stabilized	Observation and documentation	After 1st major storm	Structure failure; landslides; gullies; vandalism	Repair
Weed invasion	No interference with revegetation	Observation and documentation	Middle and end of 1st growing season	Erharta; Gasoul; Carpobrotus; Cytisus; Cortaderia; Spartium; Ammophila; Herraea	Manual or mechanical clearing
Vegetation Types					
Coastal Dunes	25% cover. Netting maintained	Observation and documentation; Sample if necessary.	End of 1st growing season	> 25% cover	Continue monitoring
				< 25% cover	Assess failure, redo
			End of 2nd growing season	> 25% cover	Acceptable*
Coastal Sage Scrub	70% cover	Observation and documentation	2nd growing season	> 70% cover	Continue monitoring
			3rd growing season	> 70% cover	Acceptable*
				< 40% cover	Assess failure, redo
Grassland	70% cover	Observation and documentation	End of 1st growing season	> 70% cover	Acceptable*
				> 40% cover	Reevaluate at 2nd season
				< 40% cover	Assess failure, redo
Chaparral	70% cover	Observation and documentation; Sample if necessary	3rd growing season	> 70% cover	Continue monitoring
			5th growing season	> 70% cover	Acceptable*
				< 40% cover	Reseed

Table 5.2.2 PXP Point Pedernales Project RECRP
Summary List of Revegetation Performance Criteria

Feature	Criteria	Method	Frequency	Findings	Action
Oak Woodland Trees	1 – 5 seedlings per exclosure	Observation; tally	Every 6 months	Collapsed exclosures	Repair
			2^{nd} growing season	1 seedling	Acceptable*
				0 seedling	Replant
			5^{th} growing season	1 (48") tree	Acceptable*
				0 trees	Replant
Understory	70% cover; no bare areas; no obvious erosion	Observation and documentation	2^{nd} growing season	> 70% cover	Continue monitoring
			5^{th} growing season	> 40% cover	Continue monitoring
				< 40% cover	Reseed
Bishop Pine Forest Pines	3^{rd} season, 1 individual per exclosure; 5^{th} season, 1 individual per exclosure	Observation; tally; sample if necessary	Every 6 month	Collapsed exclosures	Repair
			2^{nd} growing season	1 seedling	Acceptable*
				0 seedling	Replant
			5^{th} growing season	1 (48") tree	Acceptable*
				0 trees	Replant
Floodplain Scrub	70% cover	Observation and documentation	2^{nd} growing season	> 70% cover	Continue monitoring
			3^{rd} growing season	> 70% cover	Acceptable*
				< 40% cover	Reseed
Agricultural	N/A	N/A	N/A	N/A	N/A
Landscaped Areas	70% healthy individuals	Observation and documentation	Every 6 months	> 70% healthy	Continue monitoring
				< 70% healthy	Replace

* Indicates partial release from Revegetation Bond.

For the proposed Tranquillon Ridge project, only installing the power line to Valve Site #2 and constructing the new transformer station would include ground disturbances outside of an existing pad or disturbed area. Installing the power lines would involve minimal ground disturbance, as poles would be augured into place.

Monitoring of the pipelines associated with the Point Pedernales Project would continue. Sections of existing pipe would be replaced with new pipe, as required, to maintain a sufficient Maximum Allowable Operating Pressure (MAOP) in order to continue operation of the Point Pedernales Project with the proposed Tranquillon Ridge production. These activities and future maintenance work are normal components of petroleum pipeline operations and may be subject to a locally issued grading permit. They may also require a CDFG and/or U.S. Army Corps of Engineers Section 404 permit for maintenance activities across streams or in other jurisdictional water bodies.

Impacts of the proposed project are associated with construction at Valve Site #2 and accidental oil spills. Increased throughput in existing oil and water pipelines would result in an increase in the potential spill volume, both for normal operation and worst-case (these increases are evaluated in Section 5.1, Risk of Upset/Hazardous Materials). The water would be treated to meet the National Pollutant Discharge Elimination System (NPDES) permit requirements, which is not currently the case.

5.2.4.1 Construction Impacts

Impact TB.1: Valve Site #2 and Power Line Construction Impacts to Vegetation, Wildlife, and Listed Species

Impact #	Impact Description	Phase	Residual Impact
TB.1	Modification of Valve Site #2 and installation of power poles and transformer station would result in disturbance or loss of less than one acre of native vegetation and wildlife habitat, as well as disturbance and possible injury to wildlife.	*Construction New Operations*	*Class II*

According to the project description, modifying Valve Site #2 would be accommodated on the existing footprint of the site, therefore there would be no disturbance to vegetation.

Installing up to three miles of power line would include minimal grading and clearing around each installed pole. The average span of the power poles is 350 to 400 feet, corresponding with approximately 13 to 15 poles per mile. Installing the poles would result in approximately 315 square feet of temporary ground disturbance and removal of vegetation due to pole setting and equipment maneuvering per pole. Assuming 45 poles total, the disturbance would be approximately 0.33 acre of vegetation and wildlife habitat, including habitat of the Santa Ynez River.

The proposed transformer station, which would be constructed near the intersection of Renwick Road and Ocean Avenue in the farm field, would be 10 feet by 5 feet in size and require 60 feet by 70 feet of area for installation. This would result in temporary impacts to 4,200 square feet and permanent loss of 150 square feet of vegetation or wildlife habitat (depending on location), for a total of less than 0.1 acre of impact.

Additional areas of terrestrial vegetation and wildlife habitat would be impacted if cultural resources sites are discovered during the proposed project. Ground disturbance and excavation for data recovery could extend outside the disturbed construction right-of-way and beyond the project boundaries identified above.

The vegetation and wildlife habitat potentially affected by the above activities varies in type and quality. Construction noise and activity may temporarily disturb wildlife in the immediate vicinity, but this component of the impact would not be significant because of its localized, temporary nature. The habitat in the immediate vicinity of Valve Site #2 is primarily degraded dune scrub with substantial cover of non-native annual grasses and forbs, including veldt grass (*Ehrharta calycina*), an invasive exotic species. From Valve Site #2 to the intersection of Terra Road and 13th Street, the habitat quality improves with greater cover of native perennial vegetation except for narrow strips of land immediately adjacent to the road. Gaviota tarplant may be present in this habitat. The pipeline right-of-way ~~ROW~~ that parallels the road in the proposed location of the power poles is vegetated with good quality native scrub habitat. Near Valve Site # 3, chaparral is present near the unnamed arroyo spanned by the pipeline array. Both La Purisima manzanita and sand mesa manzanita are present in the chaparral at this location (both are CNPS List 1B species, see Table 5.2.1). It is likely that the locations of the poles on either side of the arroyo can be sited to avoid removal of sensitive plant species. The pipeline corridor in the vicinity of 13th Street is vegetated with primarily non-native grasses and forbs. Temporary loss of less than 0.2 acre and potential permanent loss of approximately 500 square feet (0.01 acre) of vegetation and wildlife habitat would be considered adverse but not significant. Installation of the power line outside of the riparian corridor incrementally increases the risk of avian collisions with the power line (Terres, 1980), but collisions are expected to be infrequent and would not significantly affect any species population.

During installation of the power line span across the river or in adjacent willow riparian habitat, wildlife species, including sensitive species, could be subject to temporary disturbances and loss of habitat from human activity, and possible injury or mortality from trampling or by alerting predators to their location (flushing nesting birds). Southwestern pond turtles and adults and egg masses of California red-legged frogs could possibly be in harm's way and crushed. Roosting bats, including pallid bat, big brown bat, California myotis, Yuma myotis, and Mexican free-tailed bat, which have been found to roost under the 13th Street bridge, could be temporarily disturbed by construction activities on or under the bridge. Several sensitive bird species, including southwestern willow flycatcher, yellow warbler and yellow-breasted chat, could nest in the vicinity of the 13th Street bridge, near which the new power pole line would be installed. Southwestern willow flycatcher has nested both upstream and downstream from this location, and may potentially nest here. Between 1995 and 1999, nesting southwestern flycatchers or territorial individuals were present about 50 meters west of the 13th Street Bridge on VAFB. This particular nest site was destroyed in winter storms after that time and nesting was not confirmed in that area during 2000–2001. However, suitable habitat is still present and recolonization of the area is possible (N. Read Francine, VAFB, 2002).

Other than during migration, steelhead are not likely to spawn or be present in the project area. Impacts to migrating steelhead would be relatively short-term, and could be mitigated to insignificance by implementing a number of measures to limit erosion and sedimentation, and to protect water quality.

The presence of the power line wires that span the river may cause several impacts to bird species. Improperly designed powerlines can cause electrocution and mortality of large birds, especially raptors, an impact avoidable by use of raptor-safe pole designs. Many birds transit along the river at heights below the tops of the trees. This affords them some protection from predators. However, the presence of wires across the river at approximately the same height at which the birds typically fly would likely cause increased rates of injury and mortality to such birds. This would be especially true for peregrine falcons (State-listed endangered [SE]), since they chase their prey in the air, flying at speeds approaching 200 miles per hours (mph). During such high-speed pursuits peregrines are known to collide with power lines (USFWS, 1982). Other aerial predators, such as sharp-shinned hawk (California Species of Concern [CSC]) and Cooper's hawk (CSC), may also be at risk for collisions. The situation is exacerbated by the frequent presence of fog in this location. In addition to collision risk, power lines and power poles would also provide perch sites for raptors and other birds. This would not be expected to significantly alter the distribution or abundance of any species.

Another potential impact of poles and elevated wires in riparian habitat is that the poles and wires could be used as perches by brown-headed cowbirds, thereby facilitating brood parasitism by them on southwestern willow flycatcher, yellow warbler, and yellow-breasted chat. Brood parasitism is known to be one of the main factors in the decline of southwestern willow flycatchers, and is known to occur along other portions of the Santa Ynez River (Holmgren, pers. comm. 2000). Existing power lines now spanning the river are elevated above the level of the willow canopy. There is no evidence that perches for cowbirds are currently a limiting factor in their ability to parasitize nests, however, highly elevated wires may place cowbirds too far from the nesting trees to use such perches effectively. Therefore, potential impacts to listed species from the power wires across the river are considered to be significant but mitigable.

Wood preservative on the poles may also adversely affect plants and animals in the vicinity of the poles. PXP plans on using wood poles treated in accordance with utility company (PG&E) requirements. The majority of the wood poles used by PG&E are treated with pentachlorophenal. Less frequently used treatments include a copper naphthenate wrap at the base of the pole only and creosote. The poles are treated by the manufacturer prior to installation. Pentachlorophenol is a restricted use pesticide and is used industrially as a wood preservative. It is toxic to plants and animals, and its human health effects are of concern (http://www.atsdr.cdc.gov/tfacts51.html; ATSDR 2001). Pentachlorophenol can be inhaled, ingested, or absorbed. Evidence suggests that wood preservatives migrate from treated poles into surrounding media, but that concentrations diminish rapidly within inches to a few feet from the source due to biodegradation and adsorption to soil particles (EPRI 1995, 1997; ATSDR 2001). Pentachlorophenol has a limited potential for bioaccumulation as it is rapidly metabolized (ATSDR 2001; http://extoxnet.orst.edu/pips/pentachl.htm). Estimates of the half-life of pentachlorophenol in soil range from 2-4 weeks to 45 days, whereas its half-life in water is shorter, ranging from hours to a few days (ATSDR 2001; available at http://extoxnet.orst.edu/pips/pentachl.htm). Although soil and groundwater contamination with preservatives has occurred at industrial facilities where poles have been treated and stored (ATSDR 2001), smaller scale ecological effects on plant or animal abundances that might be attributed to wood preservative leaching from individual poles have not been documented. Based on the foregoing, potential toxic effects of wood preservative would be expected to be limited to physiological effects on plant and/or wildlife individuals living in close proximity (within a few feet) of each pole, within the "footprint" already impacted by pole installation.

Mitigation Measures

TB-1 Prior to construction, a survey of the power line corridor shall be conducted to verify the locations of sensitive plants, including Gaviota tarplant, La Purisima manzanita, sand mesa manzanita, and dune vegetation that includes coast buckwheat (*Eriogonum parvifolium*), and thus may support El Segundo blue butterfly. Power poles shall be sited to avoid impacting these resources.

TB-2 Prior to constructing the power line to Valve Site #2, the ~~applicant~~ operator shall enter into discussions with VAFB to determine the feasibility of placing the power line on the 13th Street bridge or using the existing VAFB power poles for crossing the Santa Ynez River. If placing the power line on the bridge or the existing poles is determined to be not feasible, the applicant shall site the power poles outside the limits of the Santa Ynez River riparian vegetation, use "raptor-safe" pole designs with the conductors spaced as far apart as possible to minimize the potential for bird wings to span them, install poles and lines outside the breeding season of birds (March 1 through August 15), cover the augered holes if the poles are not installed immediately, elevate the power line above the level of the tree canopy, taking into consideration future growth of the canopy, and fit wires with some type of device to make them more visible, such as bright-colored plastic balls. ~~If the pole lines are of a type that raptors might nest on, investigate the feasibility of~~ Pole designs will either discourage raptor nesting or be made suitable for nesting by fitting the poles with 3 ft. by 3 ft. nesting platforms a minimum of 4 feet above the tops of the poles as recommended by the California Department of Fish and Game (CDFG). CDFG and the U.S. Fish and Wildlife Service (USFWS) will be contacted for review and approval of pole design at the time the power line to Valve #2 is deemed necessary.

TB-3 Immediately (within 48 hours) prior to each critical pole placement activity, including excavation, foundation installation, pole placement, and stringing, ~~construction~~ applicant-funded surveys within the disturbance area shall be conducted by a SBC- and VAFB-approved wildlife biologist to document and remove individuals of wildlife species encountered, including reptiles, amphibians, and badgers and other burrowing animals, as appropriate to suitable habitat outside the area of impact. The construction area ~~should~~ shall be regularly monitored to ensure that wildlife species do not enter areas where they would be exposed to hazards.

Residual Impact

Implementation of the above mitigation measures would reduce residual impacts to *significant but mitigable (Class II).*

Impact TB.2: Valve Site #2, LOGP, and Power Line Construction Impacts to Freshwater Aquatic Habitats

Impact #	Impact Description	Phase	Residual Impact
TB.2	Modification of Valve Site #2, modifications at LOGP, and installation of power poles and the transformer station have the potential to increase erosion and sedimentation in aquatic habitats.	*Construction*	*Class II*

Ground disturbing activities at Valve Site #2 during winter rains could result in runoff of sediments into local drainage swales that lead to the Santa Ynez River. Due to distance (approximately 0.5 km), the small area that would be disturbed, and the temporary nature (14 weeks) of the work activity, impacts are not expected to be significant.

Other than during migration, steelhead are not likely to spawn or be present in the lower reaches of the Santa Ynez River in the project area. Upstream migration typically occurs from January through April, and downstream migration from January through June (SYRTAC, 2000). Impacts to migrating steelhead would be relatively short-term, and could be mitigated to insignificance by implementing a number of measures to limit erosion and sedimentation, and to protect water quality.

Modifications at the LOGP would be within the existing site and are expected to result in minimal runoff of sediments and construction materials. Site runoff primarily enters a catch basin before overflowing into the intermittent creek adjacent to the site. Impacts are expected to be less than significant for aquatic habitats and biota. Installation of a new power line from 13th

Street to Valve Site #2 would have no impacts on aquatic resources because no aquatic habitats would be affected. Erosion of and runoff from disturbed areas would be reduced or eliminated by conducting the work during the dry season or implementation of erosion control measures included in the geologic resources section.

Mitigation Measures

TB-4 All ground disturbance activities shall occur, if feasible, during the dry season (generally April 1 through November 1). Work can continue during the rainy season if a County and CCC (if required)-approved erosion and sediment control plan is in place. The applicant shall submit construction plans and schedules to SBC and CCC (if required) for review and approval prior to land use clearance.

TB-5 Site-specific measures consistent with the Restoration, Erosion Control, and Revegetation Plan (RECRP) approved under Point Pedernales FDP Condition H-1 shall be updated and implemented as applicable to new areas of ground disturbance along the existing ROW. Erosion and sediment control measures (e.g., water bars, silt fencing, dust control, and/or other appropriate measures) shall be implemented at any drainages; along portions of the affected project area that intersect slopes greater than a 2-to-1 incline; and within 200 feet of downslope water bodies. Appropriate erosion and sediment control measures shall be installed prior to ground disturbance and maintained until after the rainy season or until vegetation has become re-established in the disturbed areas. The applicant shall submit erosion and sediment control plans and specifications to SBC for approval prior to land use clearance.

Residual Impact

Implementation of the above measures to conduct work in the dry season and to control erosion and sedimentation from disturbed areas would further reduce the potential for impacts to aquatic habitats to *be significant but mitigable (Class II).*

5.2.4.2 Operations Impacts and Impacts from Pipeline Maintenance and Repair

The primary concern from continuing operations, other than oil spills, stems from the likelihood of additional disturbances to vegetation and wildlife because of the need for maintenance and repairs as discussed in the impacts below. Continuing operational noise from established facilities is not expected to affect wildlife in surrounding areas due to the familiarity of such sounds and their attenuation to relatively low levels by distance, intervening structures and vegetation.

Impact TB.3: Pipeline Maintenance Impacts to Vegetation and Wildlife Habitat

Impact #	Impact Description	Phase	Residual Impact
TB.3	Pipeline maintenance and repair, if needed, would result in disturbance and potential removal of native vegetation and wildlife habitat and erosion and sedimentation as a result of ground disturbance.	*Extension of Life*	*Class II*

Pipeline maintenance and repair would involve excavating and replacing old sections of pipeline on an as-needed basis. This is not a new impact because such activities already occur along the pipeline. However, this impact would continue for a longer period of time and may occur more frequently if the proposed project is implemented. Due to the proposed project, the lifetime (and age) of the facilities would be extended beyond the lifetime of the approved Point Pedernales Project. The level of impact would depend on several factors including location, type and condition of existing vegetation, presence of sensitive plant species, and disturbance area. All pipeline repair and maintenance activities are expected to result in temporary loss of and disturbance to existing vegetation and wildlife habitats. Noise or visual disturbance to wildlife adjacent to work areas may also occur but is not considered significant due to its localized, temporary occurrence. In most cases, the pipeline corridor is surrounded by similar habitat type, and the corridor represents a small portion of the adjacent habitat. Although the pipeline corridor was revegetated with native species after construction, long segments of the pipeline corridor have become colonized with non-native species or remain unvegetated as fuelbreaks (access corridors or roads). In some cases, where relatively high quality native habitat is adjacent to both sides of the pipeline ROW, revegetation with native plants has been successful. It is likely that pipeline repair and maintenance activities can be confined to existing disturbed areas or, at a minimum, can be restricted in native habitats thus minimizing loss of native vegetation, including sensitive plant species. If sensitive plant species, other than state or federally listed species discussed below, are present in the pipeline corridor, it is likely that they would represent a small portion of the number of individuals present in the adjacent habitat. Indirect impacts to vegetation may occur if ground disturbance or removal of vegetation results in increased soil erosion or if non-native plants become established and expand into existing native habitats. This impact is considered to be significant.

Under the existing PXP FDP and CDP, prior to approving maintenance and repair activities, the County, and other agencies, as appropriate, review baseline information and, if the occurrence of sensitive resources in affected areas needs to be verified, requires new surveys so that protection and restoration measures that comply with the FDP and CDP conditions can be applied. Monitoring of the pipelines would continue, and sections of existing pipe would be replaced with new pipe, as required, to maintain a sufficient MAOP in order to continue operation of the Point Pedernales Project with the Tranquillon Ridge Project.

Some of these activities, as well as other unexpected maintenance and repairs, may be exempt from grading and land use permits but would be subject to applicable CCC and County permit conditions. A CDFG Streambed Alteration Agreement and/or Corps Section 404 permit may be required for maintenance activities across streams or in other jurisdictional water bodies. A Coastal Development Permit may be required for maintenance and repair activities that occur within the coastal zone. These permits and agreements would normally include conditions of approval addressing avoidance or minimization of impacts, erosion control measures, and provisions for revegetation and habitat restoration following maintenance and repair, such as those described below.

The following measures shall be implemented for pipeline repair and maintenance projects that disturb areas with a predominance of native vegetation on the pipeline right-of-way or in adjacent habitat. For relatively small segments of pipeline to be replaced, a scaled-down version of the following measures may be appropriate.

Mitigation Measures

TB-6 Applicant shall prepare and submit as an update to the RECRP (FDP Condition H-1 and applicable CDP conditions, ~~approved under PXP), a Standard Maintenance and Repair Plan that will include~~ plans for restricting work areas, delineating construction zones, biological surveys of disturbance areas, and impact minimization efforts, including scheduling. Where ground disturbances are required, the Plan would specifically include:

- Restrict construction activities, equipment and personnel to existing disturbed areas (such as roads, pads, or otherwise disturbed areas) to the maximum extent feasible.
- Clearly mark and delineate in the field the limits of the construction zone. Personnel or equipment in native habitats outside the construction limits shall be prohibited.
- Biologically sensitive resources, such as occurrences of sensitive plant species including sand mesa manzanita, La Purisima manzanita, Gaviota tarplant, coast buckwheat (which may support El Segundo blue butterfly) and black-flowered figwort as well as individual oak trees, shall be identified through surveys conducted by a qualified biologist acceptable to the resource agencies prior to ground disturbance and shall be clearly marked on work or construction plans so they may be avoided.
- Where avoidance of biologically sensitive features is infeasible, the plan shall specify means by which impacts on the features would be minimized and their survival and recovery facilitated (such as preserving the root system and root crown of resprouting species such as sand mesa manzanita).

TB-7 Site-specific measures listed in the approved RECRP (FDP Condition H-1 and applicable CDP conditions) shall be updated and implemented as applicable for new areas of ground disturbance along the existing pipeline right-of-way. Prior to the issuance of a Land Use Permit, an updated RECRP ~~a Habitat Revegetation, Restoration, and Monitoring Plan (HRRMP)~~shall be submitted to SBC Planning and Development for approval. SBC Planning and Development shall consult with responsible resource agencies (including, but not limited to: CDFG, CCC, U.S. Army Corps of Engineers) to obtain their concurrence or identify any necessary modifications to the proposed plan. Once approved, the plan shall be implemented by PXP and monitored by SBC Planning and Development through advanced written updates of construction status and plans. Success of the restoration and revegetation plans should be monitored by a qualified independent biologist. The plan shall contain, but not be limited to, the following:

- Procedures for stockpiling and replacing topsoil, replacing and stabilizing backfill, such as at stream crossings, steep or highly erodible slopes, and in dune areas. Additionally, provisions ~~should~~ shall be made for recontouring to approximate the original topography. Excess fill shall be disposed of offsite unless suitable arrangements are made with the property owner. Excess fill shall not be deposited in any drainage, or on any unstable slope. Topsoil shall be salvaged, protected, and replaced. This shall include at a minimum the upper 6-12 inches of topsoil in all areas of open land, other than road shoulders. Final construction plans shall designate areas of topsoil storage and protection, and procedures for handling excess trench spoils. Within wetland areas, topsoil salvage shall be as described above except that wetland topsoil shall be stored separately from all other spoil piles. It shall be labeled with signs as "wetland topsoil." The plan shall contain specific provisions for protection of topsoil stockpiles (such as covering them or using a tackifier or temporary hydromulch) if the soil is to be left for an extended period of time to prevent loss of topsoil due to erosion. Stockpiles shall not be placed in biologically sensitive areas.

- Specific plans for control of erosion, gully formation, and sedimentation, including, but not limited to, sediment traps, check dams, diversion dikes, culverts, and slope drains. Plans would also include, where applicable, dikes and catch basins proposed along the pipeline route, to ensure protection and maintenance of the height of berms and containment capacity of the basins, for the life of project. A soil conservation program, to be applied in areas of 20 percent (or greater) slopes along the pipeline corridor, detailing site specific techniques, such as use of jute or excelsior netting, to stabilize soil and sand and encourage revegetation of steeper slopes. Plans shall identify areas with high erosion potential and the specific control measures for these sites.
- Procedures for containing sediment and allowing continued downstream flow at stream or biologically significant drainage crossings (identified in the EIS/EIR [84-EIR-7]), including scheduling construction activities during periods of historical low-flow and having erosion control structures or sediment retention devices in place prior to start of construction. Existing water levels in all streams shall be maintained at all times during construction.
- Procedures for timely re-establishment of vegetation that replicates indigenous and naturalized communities disturbed. These should include: measures preventing invasion and/or spread of undesired plant species; restoration of wildlife habitat; restoration of native communities and native plant species propagated from locally-acquired existing plant species, including any sensitive species (such as sand mesa manzanita, La Purisima manzanita, and black-flowered figwort); and replacement of trees at the appropriate rate. RECRP performance criteria for weed invasion shall be updated to require action to control any and all invasive noxious weeds (listed as of 2007 by the California Invasive Plant Council that could interfere with revegetation efforts. Examples include, but are not limited to, Cape ivy (*Delairea odorate*) and onion weed (*Asphodelus fistulosus*).
- Procedures for minimizing tree removal, tree root and branch damage, and removal of or damage to other significant plant species including confining disturbance to the approved right-of-way; providing for onsite monitoring of construction by a qualified independent local biologist; and flagging significant species and areas that should be avoided.
- Procedures for restoration of riparian corridor stream banks and streambed substrates and elevation, emphasizing natural and existing materials, shall be included as well as methods for minimizing exposure of riparian habitats to disturbance during construction.
- Monitoring procedures and minimum performance criteria to be satisfied for revegetation and erosion control are specified in Table 5 of the existing RECRP. These criteria shall be updated as necessary ~~the performance criteria~~ for each vegetation type, including percent coverage that must be achieved, monitoring methods and frequencies, and quantitative thresholds for success, reevaluation, or remedial action. Updates to the existing RECRP shall ~~should~~ consider the current level of disturbance and the condition of adjacent habitats. Consistent with the RECRP, monitoring shall ~~should~~ continue for 3-5 years, depending on habitat, or until performance criteria are met. Appropriate remedial measures, such as replanting, erosion control or weed (including invasive exotic species) control, shall be identified, using the existing RECRP as a guideline, and implemented if it is determined that performance criteria are not being met.

Residual Impact

Based on previous experience with maintenance and repair activities along pipeline route, with proper planning, as required by these measures, impacts would be successfully mitigated. Reestablishment of affected vegetation may take as little as one growing season (grasses and some other herbaceous species) to several years (e.g., sycamores and oaks). Implementation of the above mitigation measures is expected to reduce impacts to native vegetation and wildlife habitats to *significant but mitigable (Class II).*

Impact TB.4: Pipeline Maintenance Impacts to Listed Plants

Impact #	Impact Description	Phase	Residual Impact
TB.4	Pipeline repair may injure or eliminate individuals or colonies and habitat of state or federally listed plant species including seaside bird's beak, Surf thistle, beach spectacle pod, La Graciosa thistle, Gaviota tarplant, and possibly Pismo clarkia.	*Extension of Life*	*Class II*

The federally listed endangered Lompoc yerba santa is known at few locations within the area affected by the Tranquillon Ridge Project (i.e., landfall to LOGP), all of which are upslope from the pipeline, and is not likely to be affected by pipeline repair or maintenance activities. Pismo clarkia, federally-listed endangered and state-listed rare, is also unlikely to be affected by project activities since suitable habitat for this species is upslope of the pipeline in the vicinity of ConocoPhillips Summit Pump Station. Surf thistle and beach spectacle pod, both state-listed as threatened, have been recorded in the foredunes crossed by the pipeline corridor and, if present at the time of pipeline repair, could be removed or damaged by project-related activities. Seaside bird's-beak, state-listed endangered, is known to occur within or directly adjacent to the pipeline corridor north of the Federal Penitentiary and west of the LOGP and individuals may be removed or damaged by activities associated with pipeline repair. At least two populations of Gaviota tarplant have been identified on VAFB, and individuals of the plant have been sighted in coastal terrace habitat in the general vicinity of the pipeline and Valve Site #2. The loss of individuals or colonies of federally or state-listed rare, threatened or endangered plant species would be considered a significant impact.

Mitigation Measures

TB–8 Prior to ground disturbance or other activities, a qualified botanist shall survey all proposed construction, staging and access areas for presence of state or federally-listed plant species and for coast buckwheat, which may support El Segundo blue butterfly. Colonies shall be mapped and clearly marked and numbers of individuals in each colony and their condition determined and recorded. To the maximum extent feasible, construction areas and access roads shall avoid loss of individual plant and or damage to habitats supporting federal or state-listed plants.

TB-9 Where impacts to these species are unavoidable, the applicant shall develop and implement a site- and species-specific salvage, propagation, replanting, and monitoring ~~program~~ plan consistent with the requirements of the RECRP that would utilize both seed and salvaged (excavated) plants constituting an ample and representative sample of each colony of the species that would be impacted. The ~~program~~ plan shall include measures to perpetuate to the maximum extent feasible the genetic lines represented on the impacted sites by obtaining an adequate sample prior to construction, propagating them and using them in the restoration of that site. The ~~program~~ plan shall be approved by the County, CCC, ~~U.S. Fish and Wildlife Service~~ USFWS and CDFG prior to its implementation. Activities involving handling of federal and/or state-listed plant species may require permits including a memorandum of understanding from USFWS and/or CDFG.

The plan shall incorporate provisions for recreating suitable habitat and measures for re-establishing self-sustaining colonies of seaside bird's beak, beach spectacle-pod and Surf thistle should they be impacted on the site. The plan shall include provisions for monitoring and performance assessment including standards that would allow annual assessment of progress, and provisions for remedial action, should the species fail to re-establish successfully.

Residual Impact

It is likely that pipeline repair or other project activities that require a planning period prior to implementation would be able to avoid most, if not all, impacts to individuals or colonies, of federally or state-listed plant species. Moreover, maintenance and repair activities would generally be confined to the previously disturbed pipeline corridor. Where impacts to listed species are unavoidable, such as needing to excavate a section of pipeline over which listed species have established, or indirect impacts occur due to soil erosion or invasion by exotic species, then implementation of Mitigation Measure TB-9, above, in addition to TB-6 and TB-7, to protect vegetation and wildlife habitats, would reduce impacts to listed plant species. Project activities are expected to be temporary, and site restoration activities can be implemented immediately following completion of pipeline repair. Implementation of Mitigation Measures TB-6, 7, 8, and 9 would reduce impacts to listed plant species to *less than significant (Class II).*

Impact TB.5: Pipeline Maintenance Impacts to Listed Wildlife

Impact #	Impact Description	Phase	Residual Impact
TB.5	Pipeline repair or maintenance may cause disturbance, injury or mortality to individuals and affect habitat of common and federally and state-listed fish and other sensitive wildlife species including western snowy plover, California least tern, California red-legged frog, California tiger salamander, southwestern pond turtle, tidewater goby, and steelhead.	*Extension of Life*	*Class II*

Pipeline repair or maintenance activities could adversely affect listed wildlife species at various locations along the route depending on the location, type and extent of repair activity and timing of repair activity. Sensitive locations are landfall (snowy plover, California least tern), tributaries to the Santa Ynez River such as Oak Canyon and Santa Lucia Canyon, where activities could affect California red-legged frogs and southwestern pond turtles or cause sedimentation or pollution to enter the Santa Ynez River in habitats used by tidewater goby and southern steelhead. Activities along the ConocoPhillips pipeline have the potential to affect upland refugia or dispersal habitats of the California tiger salamander and, near the Santa Maria River and Nipomo Creek, have the potential to affect California red-legged frogs and ~~possibly California tiger salamander and~~ steelhead; however, these areas would not be directly impacted by the proposed project given their geographic distance from the PXP pipelines and LOGP.

Repair or maintenance activities would temporarily expose disturbed soils to wind and water erosion, and thereby increase the potential for transport of sediment into the drainages and downstream areas. In all but Santa Lucia Canyon, water is unlikely to be present in the project area during construction, and no aquatic organisms would be directly affected by the construction activities in these drainages. If water were present in the drainages, impacts to aquatic species would be adverse in the immediate downstream areas but not significant due to their short duration and time of year (fall to winter when rain runoff normally introduces turbidity into the streams). Once flows begin in the drainages during the following rainy season, some turbidity and natural reshaping of the drainages would occur. Impacts of sediments on aquatic organisms are expected to be less than significant due to the small area affected within each drainage and the short duration of the work.

Santa Lucia Canyon contains the only perennial stream crossed by the pipeline. This drainage supports a variety of aquatic invertebrates and is used by several common amphibians, such as Pacific chorus frogs and western toads. Red-legged frogs have been observed in Santa Lucia Canyon near the Pine Canyon gate on VAFB, approximately 0.75 mile upstream of the pipeline crossing. Impacts of construction activities on these species would be adverse but not significant. The small area affected would be recolonized within a few months. Sediment runoff in erosion-prone areas, such as portions of Oak Canyon and Santa Lucia Canyon, could be potentially significant but mitigable.

At the western end of the pipeline route, repair and maintenance activities could disturb western snowy plovers, which nest and winter in the landfall area. Disturbances within the nesting area can result in loss of productivity, either due to the incubating birds being flushed off the nest and the eggs cooling, or from exposure of the eggs to predators. Snowy plovers are known to nest at Wall Beach. Therefore, if construction activities occurred during the nesting season of the snowy plover (March 1 to September 30), plovers could be adversely affected.

California least terns have historically nested near the mouth of the Santa Ynez River, and could also be affected by repair and maintenance activities that occurred during their nesting season (April through July), depending on the proximity of the nesting site to the construction activity. Impacts on nesting snowy plovers or California least terns would be considered significant. Other sensitive avian species, such as brown pelican, do not nest here. Pelicans and wintering snowy plovers would likely just move a short distance up or down the beach to avoid human activity. Impacts on brown pelicans and wintering snowy plovers would be considered adverse but not significant.

Mitigation Measures

Implementation of Mitigation Measures OWR-1, GR-1, and TB-4, scheduling the work during the dry season; TB-5, controlling erosion; TB-6, minimizing disturbance to native habitats; and TB-7, implementation of the RECRP requirements ~~preparing and implementing of an approved Habitat, Revegetation, Restoration and Monitoring Plan~~ would reduce impacts to native wildlife, including sensitive wildlife species. Pre-project surveys by a qualified biologist to determine presence/absence of sensitive species, and monitoring to ensure that sensitive species do not enter the construction area are ~~additional~~ appropriate species protection measures. These and other applicable measures are described more fully under the pipeline replacement alternative (see Mitigation Measures under Impacts TB.12 through TB.16). Scheduled maintenance and repair activities would normally be conducted after specific environmental review conducted as part of issuance of a grading permit or other permit by the ~~Counties of~~ Santa Barbara County and VAFB, ~~or San Luis Obispo,~~ as applicable. In addition, maintenance and repair activities within the coastal zone could require a Coastal Development Permit from the CCC. Emergency repairs are subject to a different set of guidelines.

Implementation of the following measure would further reduce impacts to wildlife species:

TB-10 All routine pipeline repair and maintenance activities occurring within the beach and foredune habitats at landfall (Wall/Surf Beach) need to be scheduled to avoid the breeding season (March 1 to September 30) of the western snowy plover and California least tern. A contingency plan for emergency repairs in this area during the nesting season needs to be developed in coordination with 30 CES/CEVPN at VAFB and with the USFWS. This may require Section 7 consultation.

Schedule and timing restrictions for this shall be included in the ~~Standard Maintenance and Repair Plan~~ updated RECRP (Mitigation Measure TB-6) to be submitted to SBC and all relevant state and local agencies for review and approval prior to land use clearance. The plan shall include impact avoidance measures to be implemented in the event that emergency repairs cannot be scheduled to avoid the breeding season.

Residual Impact

Depending on the species, impacts are preventable or can be minimized through implementation of the general mitigation measures outlined above. The potential for impacts associated with siltation and disturbance to wildlife are considered short-term and are expected to persist until completion of ground disturbing activities and re-establishment of vegetation in disturbed areas along the pipeline route. Residual impact would be *significant but mitigable (Class II).*

5.2.4.3 Impacts of Spills

Impact TB.6: Spill Impacts to Vegetation and Wildlife

Impact #	Impact Description	Phase	Residual Impact
TB.6	A pipeline leak or rupture could result in an oil/ produced water spill and subsequent degradation of upland, riparian and aquatic habitats and injury to plants and terrestrial and aquatic wildlife through direct toxicity, smothering, and entrapment as well as through resultant cleanup efforts.	*Increased Throughput* *Extension of Life*	*Class I*

Emulsion Pipeline

Because the life of the project facilities would be extended with implementation of the proposed project, the period of time over which spills could occur would also increase. Based on the risk analysis (evaluated in Section 5.1, Risk of Upset), the probabilities of pipeline rupture over the lifetime of the proposed project (30 years) would increase from 0.9 percent for current operations through 2017 to 2.5 percent for the onshore pipeline. The probability of ~~pipeline rupture for the offshore pipeline~~oil leaks, ruptures, blowouts, and spills from Platform Irene and the offshore portion of the emulsion pipeline would increase from ~~1.2~~5.4 to ~~9.7~~22.1 percent. Because the amount of oil relative to emulsion water would be higher in the emulsion pipeline from Platform Irene to LOGP under the proposed project, and the volumes transported would be higher, the amount of oil in a spill would be proportionately larger. The maximum spill volumes of emulsion (oil and water combined) for the major tributaries that may be affected by an oil spill are provided in Table 5.1.25 of Section 5.1, Risk of Upset/Hazardous Materials.

The effects of spilled oil on biological resources depend on the location of the spill relative to the shoreline, physical and chemical properties of the oil, specific environmental conditions at the time of the spill, and the species present. Crude oil is a complex mixture containing thousands of compounds, most of which are hydrocarbons. Organic compounds and numerous metals or metal-like elements are also present. The hydrocarbons are of three types: aliphatic, alicyclic, and aromatic. Their solubility in water generally decreases with increasing molecular weight, and the lighter weight ones are more volatile. Several of the petroleum hydrocarbons are also produced by plants and animals, and a variety of organisms ranging from bacteria to fish have developed metabolic pathways for oxidizing these compounds.

Certain types of communities are more severely affected by an oil spill than others. Salt or freshwater marshes are the most sensitive because the biological activity of these communities is concentrated near the soil or water surface, where oil would be stranded. Oil could also be widely dispersed through these types of communities by stream or tidal flow. Several sensitive upland habitat areas are crossed by the pipeline corridor or lie close to and down slope of the corridor. These include foredunes, coastal dune scrub, coastal sage scrub, Burton Mesa chaparral, Bishop pine forest, and coast buckwheat populations which may support El Segundo blue butterfly. Riparian woodland communities may be somewhat less sensitive in one respect because leaves in the canopy would not be susceptible to oiling. Spills or subsequent clean up activities in upland areas that do not reach one of the drainages in the project region would result in degradation and loss of habitat from ground disturbance associated with removal of contaminated soils and vegetation. These impacts are expected to be temporary until the habitat recovers. These impacts would be significant adverse impacts on terrestrial biological resources if the spills or subsequent clean-up efforts result in the removal of native vegetation.

Aquatic Biota

Emphasis is placed on aquatic and wetland habitats because of their sensitivity, proximity to the pipeline, and the potential for spilled oil to flow in a downslope direction and to collect in low spots. Flow can occur overland or through voids in trench backfill. The seasonal or year around presence of water is also taken into account because water, especially flowing water, facilitates the spread of oil.

Environmental conditions such as temperature, slope, soil type, vegetation, and stream flow would influence the transport of oil away from a spill within or adjacent to a drainage channel and affect the weathering process. Spilled oil can alter aquatic habitats by filling crevices, changing substrate characteristics, and coating hard substrates. Volatile components would rapidly evaporate, although some soluble ones would dissolve in the water (where present). Other weathering processes include photochemical oxidation, emulsion, adsorption onto particulates with sedimentation, and compaction into tar balls. Loss of the lower molecular weight components over time reduces the acute toxicity of the oil to aquatic organisms.

An onshore oil spill could enter aquatic habitats through direct entry, runoff from upland areas within the watershed (especially during storm runoff), and contamination of groundwater feeding streams. Direct entry of oil into dry stream channels would have no immediate direct impact on aquatic organisms. However, oil entering flowing streams would be carried downstream and affect aquatic organisms present. Toxic effects would decrease with distance downstream as weathering takes place. Oil remaining in the habitat would lose its toxicity through weathering but could affect organisms colonizing these areas during the wet season through physical and chemical alteration of the habitat.

Impacts to aquatic biota would be similar as previously addressed in the EIRs for the project related pipelines (Point Pedernales 1985 EIR/EIS; and Tosco Sisquoc Pipeline 2001 EIR). While the risk of an oil spill and/or pipeline rupture is a risk already associated with the existing oil pipeline, the proposed increase in throughput and oil percentages would increase the potential volume of oil spilled, thereby exacerbating an already existing significant impact, with the primary concern for spilled oil or produced water affecting aquatic resources. Oil could also enter drainages through overland flow; however, under dry conditions, overland flow of oil would be relatively slow due to the viscous nature of the crude oil. The rate of spread would slow as the oil cools and becomes more viscous. As the water fraction of the oil-water emulsion increases over the life of the project, the emulsion would have different behaviors when spilled. In areas where the pipeline crosses or is very close to creeks or streams, the likelihood is greater that oil from a rupture or leak would enter these waterways and transport to larger streams, such as the Santa Ynez River and the Santa Maria River. If the oil reaches the active channel of a river during a period of stream flow, it could spread downstream and affect plants and wildlife in and near the lagoons at the river mouths and potentially reach the ocean. For example, a spill of approximately 10 barrels of crude oil in the Lompoc Oil Field in early 1998 during high flow conditions oiled the Santa Lucia drain, flowed to the Santa Ynez River and reached the Pacific Ocean at the river mouth.

Aquatic reptiles, amphibians, fish, and waterbirds would be vulnerable to an onshore spill and clean up efforts. Impacts would include toxicity, degradation of habitat and breeding areas, and sediment excavation during containment or cleanup. Species that occur in brackish-estuarine habitats at the mouths of tidal inlets would be similarly affected if oil were dispersed upstream into these areas. Shore- and waterbirds in such areas would experience toxicity due to oil ingestion, and difficulties foraging, swimming, flying, and body temperature regulation due to oiled feathers.

It is possible ~~but very unlikely~~ that an offshore oil spill would directly affect freshwater (or brackish/estuarine) aquatic environments; ~~as~~ this would ~~only~~ occur if oil were driven ashore above the high tide line by wind and high tides, and similarly driven upstream at an open tidal inlet during flood tide and low-outflow conditions. The oil would be highly dispersed by the time it reached the shore, leading to the deposition of relatively small amounts of oil at a given location, but over potentially large areas, as occurred during the 1997 spill from the offshore pipeline (Torch/Platform Irene Trustee Council 2006). Terrestrial or freshwater habitats could be indirectly affected by containment and cleanup efforts in response to an offshore oil spill that approaches the shore.

The modeled trajectories for offshore oil spills (Appendix G) indicate that a large oil spill from Platform Irene or the pipeline would be most likely to reach shore between Point Arguello and Point Sal, or on the north-facing coastline of San Miguel Island. Oil could be dispersed as far north as Piedras Blancas or southward to other shores of the Channel Islands. River mouths, sloughs, lagoons, and estuaries within this area of the shoreline include Pismo Creek, San Luis Obispo Creek, Arroyo Grande Creek, the Santa Maria River, Shuman Creek, San Antonio Creek, Santa Ynez River, La Honda Creek, and Jalama Creek, although the probability of a spill reaching any particular site is small. The vulnerability of these aquatic habitats to oil spills is borne out by the fact that damage from the 1997 spill extended into the estuaries of the Santa Ynez River, San Antonio Creek, and Honda Creek (Torch/Platform Irene Trustee Council 2006). The modeling results (Appendix G) include many different event scenarios and shoreline sites within the trajectory would not be affected to the same extent or degree by an actual spill. The probability is low that an offshore oil spill would impact freshwater aquatic biota; however, if such an impact were to occur, the effects would be significant due to direct impacts and cleanup/containment activities that may disturb aquatic habitats.

Vegetation

An onshore oil spill would affect vegetation both directly and indirectly. Direct effects include reductions in the availability of soil water, nutrients, and oxygen to plant root systems; the physical "smothering" of oiled plants; and toxic effects of oil on foliage and root systems. All of these would lead to reduced growth and reproduction, and possible mortality in plants exposed to oil. Vegetation recovery may be slow in areas of oiled soil because of lingering toxicity and altered soil characteristics. Indirect effects would result from attempts to contain and clean up an oil spill. Impacts of clean up add cumulatively to oil spill impacts, and in some habitats may be more substantial than the effect of the spilled oil. Clearing or grading could be required to provide access at some locations, and oiled vegetation and soil would probably require removal. In such cases, native seedbanks may also be removed, and the subsequent spread of non-native weeds into disturbed areas may occur.

An offshore spill would not be likely to directly affect upland vegetation. Since riparian habitats do not extend downstream into tidal inlets, no impacts due to offshore oil spills would occur. Terrestrial areas that could be directly affected by an offshore spill under certain conditions (Appendix G) include sandy beaches and fringing coastal strand vegetation, as well as rocky shores, just above the high tide line. Oil could be widely dispersed, but in relatively small amounts at any particular location. Containment and cleanup activities could also affect upland habitats if off-road access is necessary to reach the affected shoreline; these impacts would be temporary. Areas with the greatest possibility of impact are the beaches and rocky shorelines from Point Arguello to Point Sal, and on the north side of San Miguel Island.

Wildlife

Oil spills from pipeline leaks and ruptures are also expected to directly affect wildlife species such as Pacific chorus frogs, western toads, a wide range of invertebrates and sensitive species such as western pond turtles and two-striped garter snakes. Depending on the size and areal extent of the spill, an unknown number of birds, reptiles and land mammals could be killed if they come in direct contact with the oil. Aquatic reptiles, amphibians and birds would be the most vulnerable to oil spills. Organisms can be affected physically through smothering, interference with movements (especially benthic organisms), coating of external surfaces with black coloration (leading to increased solar heat gain), and fouling of insulating body coverings (birds and mammals). Toxicity can occur via absorption through the body surface (skin, gills, etc.) or via ingestion. Biological oxidation (through metabolism) can produce products more toxic than the original compounds. Acute toxicity would be lowered for fish, especially after some weathering. Sublethal effects include reduced reproductive success, narcosis, interference with movement, and disruption of chemosensory function (e.g., similar to human smell or taste).

Direct impacts to wildlife from oil spills also include physical contact with oil, ingestion of oil, and loss of food and critical nesting and foraging habitat. Mammals could be expected to die from exposure since oiled fur will lose its water shedding and insulation properties. Waterbirds become waterlogged and will be unable to fly if their feathers are oiled (Nelson-Smith, 1972). Mortality can result from a combination of starvation and exposure brought on by a loss of appetite and sickness as a result of ingesting oil while preening their feathers (Hartung, 1967). Turtles, frogs, and aquatic larval stages of salamanders could be directly impacted and die as a result of exposure to oil. The eggs, larvae and young of these animals have a low tolerance for oil toxicity and have limited dispersal abilities. Aquatic habitats used for breeding by turtles, frogs, and salamanders can become fouled as a result of an oil spill that in turn could prevent successful future reproductive success at affected locales by aquatic dependent wildlife. While the effects of an oil spill on terrestrial habitats adjacent to a stream channel may be only minor and short-term, changes in the food chain or in the habitat of any sensitive aquatic wildlife could result in significant impacts.

Cleanup activities alter the habitat where excavation is used to remove contaminated sediments. For spills that affect large areas (such as several miles of channel), impacts would be significant, especially if bed and bank alteration resulting from contamination or cleanup activities results in greater erosion and sedimentation which would affect habitat quality for species such as California red-legged frogs, steelhead trout or results in barriers to steelhead migration. Access to the creek for spill response is limited in many areas by steep banks, dense trees lining the creeks, and limited road access. These factors would need to be considered in spill response planning. Impacts of habitat alteration during cleanup could be mitigated by restoration of native vegetation after cleanup is completed or by leaving the spilled oil in the habitat, if appropriate.

Impacts on resident biota would be short- to long-term depending on the amount of oil spilled, specific environmental conditions at the time, and containment and cleanup measures taken. An offshore spill would not be expected to have substantial direct effects terrestrial wildlife, but containment or cleanup activities may have a minor effect on terrestrial species if off-road access is necessary to reach the affected shoreline.

In conclusion, oil spill impacts to aquatic biota, vegetation, and wildlife would be considered *significant and unavoidable* (*Class I*).

Produced Water Pipeline

Spills of produced water would be limited to the Platform Irene-to-LOGP pipeline corridor, since produced water does not travel through the pipeline system north of the LOGP. There would be an increase in throughput in the water return pipeline, which would result in an increase in the potential spill volume, but the water would be cleaned to a level acceptable to the NPDES permit requirements, which is not currently the case. A rupture of the produced water return pipeline could result in localized erosion where the produced water, under pressure, leaves the pipeline and may have localized short- to moderate-term effects on vegetation and wildlife due to temporary elevation of salinity and trace element levels. Impacts due to a produced water pipeline spill would be considered significant because of the potential for erosion of native soil and vegetation, particularly on steep slopes.

Mitigation Measures

PXP has prepared a Core Oil Spill Response Plan (OSRP) and related supplement for offshore facilities and onshore pipelines for the Point Arguello and Point Pedernales projects (PXP, 2004 and 2005). This plan is in addition to the OSRP for the LOGP and an Emergency Response Plan for operations including Platform Irene, the LOGP and the pipeline from Platform Irene to the LOGP (Torch Operating Company, 2000a and 2000b, respectively). Sensitive terrestrial resources are identified in the OSRP that would be affected by an oil spill from the LOGP and include oak woodland and Burton Mesa chaparral habitat downslope of the LOGP; the Santa Ynez River and its estuary; dune scrub and coastal strand adjacent to the river; the coastline in the vicinity of the Santa Ynez River; and the marine environment. The OSRP focuses on the actions that would be initiated in the event of an oil spill at the LOGP that would contain the spill as soon as possible in order to prevent damage to these environments. Similar plans have been prepared for the pipeline segments from the LOGP to Summit Pump Station. The OSRP also focuses on the actions required in the event of a spill, training of spill response personnel, and identifies sensitive terrestrial resources that may be potentially affected by a spill from the onshore pipeline. Restoration and revegetation guidelines are presented as well. The following mitigation measures require these plans to be updated to include identification of sensitive terrestrial biological resources, response methods to protect or otherwise minimize damage to these resources from an oil spill as well as subsequent actions to be implemented for clean up if a spill did occur.

The OSRP is one of a number of plans that address emergency response issues related to the Point Pedernales facilities. It addresses requirements common to the Minerals Management Service (MMS), U.S. Department of Transportation (DOT), U.S. Environmental Protection Agency (EPA), the California Office of Spill Prevention and Response in the Department of Fish and Game. The Oil Spill Response Plan contains preventive measures and contingency response plans. <u>Appendix N provides an excerpt from the OSRP Santa Barbara County Supplement for reference.</u>

In addition to clean-up measures identified in the OSRP, measures identified in Section 5.4, Onshore Water Resources, have the potential to reduce impacts on biological resources. Where a spill or clean up results in the loss of native vegetation, implementation of Mitigation Measures TB-6 and TB-7 would reduce impacts to native vegetation. Mitigation measures described above would also apply to a produced water spill. The following measures are recommended to further reduce impacts to terrestrial and aquatic biota. ~~Note that these mitigation measures apply to the proposed project pipeline sections only.~~

TB–11 The November 2004 Core Oil Spill Response Plan and July 2005 Supplement shall be revised and updated to address increased potential spill volumes and updated procedures for oil and produced water spill clean up beneath ground surface and in sensitive habitats including rivers and streams. This plan shall include updated, site-specific measures for spill containment along watercourses and at other sensitive habitats. It shall specify that sensitive habitats shall be avoided to the maximum extent feasible during oil spill clean up activities. It shall include specific measures to avoid impacts on listed endangered and threatened species during response and repair operations and minimize impacts on riparian and other native habitats. The plan shall include identification of specific access points at locations where containment and clean up efforts can be initiated under different scenarios. ~~The~~Access points shall be reviewed and, if necessary, additional access points shall be ~~need to be~~identified immediately adjacent to pipeline river crossings and points where spilled oil could enter the Santa Ynez River, San Antonio Creek, Santa Maria River, Nipomo Creek, and Los Berros Creek. These updates~~This plan~~ shall be reviewed and approved by SBC ~~the P&D Department~~ prior to land use permit approval.~~construction.~~

TB-12 The Core Oil Spill Response Plan and its Supplement include species- and site-specific procedures for collection, transportation, and treatment of all potentially affected native wildlife, including sensitive species, for topsoil salvage and replacement, and procedures to minimize the loss of native seedbanks and prevent the spread of non-native weeds. Where disturbance to any habitats~~disturbance~~ cannot be avoided as determined by a P&D-approved biologist, these stipulations for development and implementation of these site-specific habitat restoration plans and other site- and species-specific measures for mitigating impacts on local populations of all sensitive wildlife species and to restore native plant and animal communities to prespill conditions shall be implemented. ~~November 2004 Core Oil Spill Response Plan and July 2005 Supplement shall be updated to provide stipulations for development and implementation of site-specific habitat restoration plans and other site-specific and species-specific measures appropriate for mitigating impacts on local populations of sensitive wildlife species and to restore native plant and animal communities to prespill conditions.~~ Access and egress points, staging areas, and material stockpile areas that avoid sensitive habitats shall be identified prior to ground disturbance. ~~The Core Oil Spill Response Plan and its Supplement shall include species- and site-specific procedures for collection, transportation, and treatment of all potentially affected native wildlife, including sensitive species, and for topsoil salvage and replacement. The plan shall be reviewed by the federal, state, and local agencies identified in Measure TB-11 prior to approval by the lead agencies.~~

TB-13 Prior to construction or any ground disturbance activity, the applicant shall ~~develop~~ identify low impact clean up procedures from the ~~for inclusion in the~~ Core Oil Spill Response Plan, and/or updated measures, to be implemented. Where feasible, low-impact site-specific clean up techniques such as hand cutting contaminated vegetation and using low-pressure water flushing from boats shall be specified ~~in the Oil Spill Response Plan~~ to remove spilled material from particularly sensitive wildlife habitats (e.g., coastal estuaries) because procedures such as shoveling, bulldozing, raking, and draglining can cause more damage to a sensitive habitat than the oil spill itself. As described in the Oil Spill Response Plan, the ~~shall evaluate~~ non-clean up option for all native and/or ecologically vulnerable habitats, such as coastal estuaries, shall be considered. Prior to approval of the Land Use Permit, the applicant shall revise the OSRP to update the low-impact clean up procedures consistent with current technology. These strategies shall be reviewed and revised during the required future Plan updates to include best available practices.

TB-14 The applicant shall ~~develop and implement a spill response training program~~update the OSRP to ensure that spill response personnel ~~shall be~~are adequately trained for response in terrestrial environments and spill containment and recovery equipment shall be inspected at least annually and maintained at full readiness. Drills shall be conducted at least annually and the results evaluated so that spill response personnel are familiar with the equipment and with the project area, including sensitive terrestrial biological resources. Rehabilitation centers, within the project area, for birds and other wildlife species affected by spilled material shall be involved in the drills. If a rehabilitation center is not available in the project area, the applicant shall contribute a pro-rata share of funds necessary to cover the costs of establishing and operating a bird and wildlife rehabilitation center.

Residual Impact

The mitigation measures identified above coupled with those identified in Section 5.4, Onshore Water Resources, can reduce but cannot eliminate ~~the risk of~~oil spill and related clean-up impacts on biological resources. Large spills entering riparian, wetland, and aquatic habitats, or sensitive native upland grassland, dune scrub, oak woodland, and Burton Mesa chaparral habitats, could have *significant impacts (Class I).* Revegetating with native species in areas where vegetation is removed or otherwise impacted by a spill or clean up activities should reduce significant impacts. However, impacts to riparian, wetland, and aquatic habitats and biota would remain *significant (Class I).*

Impact TB.7: Spill Impacts to Listed Plants

Impact #	Impact Description	Phase	Residual Impact
TB.7	A spill and/or subsequent cleanup efforts may directly or indirectly cause the loss of habitat and individuals or colonies of state-or federally-listed plant species including seaside bird's beak, Surf thistle, beach spectacle pod, La Graciosa thistle, Gaviota tarplant, and possibly Pismo clarkia or degrade designated critical habitat for the Lompoc yerba santa and La Graciosa thistle.	*Increased Throughput Extension of Life*	*Class I*

Several listed endangered or threatened species that could be affected by spills associated with this project were not listed at the time of the 1985 EIR/EIS (Arthur D. Little, 1985). Plant species in the project area listed since 1985 include Lompoc yerba santa, Pismo clarkia, Gaviota tarplant, and La Graciosa thistle. In addition, critical habitat has been designated for Lompoc yerba santa and La Graciosa thistle in close proximity to the existing pipeline. Special Resource Protection Areas on VAFB have also been designated for federally listed plant species. Because of the currently recognized status of these species and the protection afforded them by the Endangered Species Act, these species must be specifically addressed in contingency planning to minimize the potential for harm from spilled oil, and from cleanup activities. The potential for impacts on rare, threatened, and endangered species are discussed below.

Lompoc yerba santa, federally-listed as endangered, is known from few locations in the project area, all of which are upslope from the oil pipeline which is a part of the Tranquillon Ridge Project area, and is not likely to be affected by impacts associated with an oil spill or cleanup activities. Pismo clarkia, federally-listed endangered and state-listed rare, is also unlikely to be affected by spills or clean up since suitable habitat for this species is upslope of the pipeline in the vicinity of Summit Pump Station. Neither of these species would be affected by an offshore spill.

La Graciosa thistle and Gaviota tarplant have the potential to be impacted by an onshore oil spill or cleanup activities if a spill reaches their habitats. Coastal habitats that contain La Graciosa thistle are within the trajectory range for an offshore spill (Appendix G), although the probability of a spill reaching any particular site is small. Oil from an offshore spill could be widely dispersed, but in relatively small amounts at any particular location. An offshore spill would not migrate onshore to areas inhabited by Gaviota tarplant. Containment and cleanup activities could affect upland habitats if off-road access is necessary to reach the affected area.

Surf thistle and beach spectacle pod, both state-listed as threatened, have been recorded in the foredunes crossed by the pipeline corridor and, if present at the time of an oil spill, could be removed or damaged by project related activities. Containment or cleanup activities for an offshore spill may impact occupied coastal dune habitat near Oso Creek, Pismo Beach, and Oceano dunes. These sites are within the trajectory range described in Appendix G, although the probability of a spill reaching any particular site is small.

Seaside bird’s-beak, state-listed endangered, is known to occur within or directly adjacent to the pipeline corridor north of the Federal Penitentiary and west of the LOGP and individuals may be removed or damaged by activities associated with an onshore oil spill and cleanup. An offshore spill and any associated containment or cleanup would not be likely to impact habitats occupied by this Seaside bird’s beak. The loss of individuals or colonies of federal or state-listed rare, threatened or endangered plant species would be considered a significant impact. The level of impact would depend on the numbers of individuals lost and whether that loss represents a significant portion of the colony at a particular location or otherwise affects the ability of that colony to sustain itself. Impacts would be *significant*.

Mitigation Measures

Impacts to listed species would be reduced through implementation of Mitigation Measures TB-11 through TB-14, which include, but are not limited to, minimization of habitat disturbance during clean up, the use of low-impact clean up techniques, and restoration of the site to pre-spill conditions. Mitigation Measure TB-5 would reduce the effects of sedimentation in the event clean up activities disturb soil and increase erosion. Implementation of Mitigation Measures TB-6 and TB-7, which address, in part, the restoration of native plant species would also reduce impacts in areas where spills or cleanup results in the loss of native vegetation. These measures described above would also apply to a produced water spill.

Residual Impact

The most credible worst case spill scenarios would result in impacts to relatively small numbers of plants in localized areas with substantial portions of the local populations left intact. Repair and maintenance activities would be temporary and soil stabilization and re-vegetation measures can be initiated immediately following completion of pipeline repair and cleanup after a spill. Successful reestablishment of native habitats including individuals or colonies of state-listed plant species could reduce potential impacts, but not to a level of less than significant. Therefore, impacts would remain *significant and unavoidable (Class I).*

Impact TB.8: Spill Impacts to Listed Wildlife

Impact #	Impact Description	Phase	Residual Impact
TB.8	An oil spill and/or subsequent cleanup effort may directly or indirectly cause the loss of individual state or federally-listed wildlife species or cause the loss or degradation of sensitive species habitat. An oil spill and/or subsequent cleanup effort may impact designated critical habitat for steelhead, western snowy plover, <u>California tiger salamander</u>, and California red-legged frog.	*Increased Throughput* *Extension of Life*	*Class I*

Wildlife species listed since the 1985 impact analysis conducted for this pipeline segment include steelhead, California red-legged frog, <u>California tiger salamander,</u> tidewater goby, and western snowy plover. In addition, critical habitat has been designated for the western snowy plover, steelhead and the California red-legged frog, and encompasses various portions of the proposed project area and land in close proximity to the existing pipeline. <u>Designated critical habitat for the California tiger salamander, including both aquatic (breeding and upland (refugia and dispersal) habitat, is crossed by the ConocoPhillips pipeline between Orcutt and the Santa Maria Airport; however, this habitat would not be directly impacted by the proposed project given its geographic distance from the PXP pipelines and LOGP.</u> Because of the currently recognized status of these species and the protection afforded them by the Endangered Species Act, these species must be specifically addressed in contingency planning to minimize the potential for harm from spilled oil, and from cleanup activities. The potential for impacts on rare, threatened, and endangered species are discussed below.

Spills from the emulsion pipeline could affect sensitive wildlife species on or near the pipeline right-of-way. Spills of produced water would be limited to the proposed project, since produced water does not travel through pipes north of the LOGP. The impacts to wildlife discussed above would also apply to listed wildlife. El Segundo blue butterfly may be adversely affected if oil spill or subsequent clean up activities result in destruction of its host plant, coast buckwheat. The impacts described below could also occur under a produced water spill scenario.

Spills from the pipeline between the shoreline and LOGP could enter the Santa Ynez River. Spills from the pipeline between LOGP to Summit Pump Station could enter ~~San Antonio Creek,~~ the Santa Maria River or Los Berros Creek, which are ~~all~~ designated critical habitat for steelhead. An offshore spill would reach potentially inhabited streams, including San Luis Obispo Creek, Pismo Creek, Arroyo Grande Creek, Santa Maria River, Shuman Creek, Santa Ynez River, and Jalama Creek. These sites are within the worst-case spill trajectory area (Appendix G) although the probability of a spill reaching any particular site is small. Effects on steelhead would depend on the time of year and size of the spill. Impacts would be greatest if the spill occurred during adult or juvenile migration to or from spawning and rearing areas upstream of the project (January to June). Steelhead exposed to the spill could sustain lethal to sub-lethal toxic effects. Cleanup efforts could also adversely affect steelhead present through direct mortality or stress from harassment or capture and relocation. Impacts to water quality, sediment distribution, and aquatic habitats could also adversely affect steelhead. Impacts could range from not significant when no steelhead are present during and shortly after a spill to significant if individual steelhead are affected.

Oil or produced water spills that enter the Santa Ynez River, however, have a greater potential to affect tidewater gobies than steelhead because the gobies reside in the lower river and lagoon all year. The onshore oil pipeline crosses San Antonio Creek and the Santa Maria River upstream of any known habitat for this species. Large spills that reach occupied habitat downstream would have an impact on tidewater gobies and their habitat in either of these streams. Cleanup activities could also impact tidewater gobies present and their habitat. An offshore spill could affect potential tidewater goby habitat in San Luis Obispo Creek, Pismo Creek, Santa Maria River, Shuman Creek, San Antonio Creek, Santa Ynez River, and Jalama Creek. These sites are within the trajectory range described in Appendix G, although the probability of a spill reaching any particular site is small. The level of impact would depend on the location, time of year, and size of the spill. A large spill during the breeding season (spring to summer) would affect the greatest number of individuals and would be a significant impact. For small spills that do not result in mortality of tidewater gobies or alteration of their habitat, impacts would not be significant.

Oil spills that affect the Santa Ynez River estuary have the potential to adversely affect the American peregrine falcon, primarily through ingestion of contaminated prey. However, due to the scarcity of peregrines in the area (one or two at most), and the fact that peregrines usually only prey on birds caught in flight, the likelihood of a peregrine eating significantly oiled prey is low. Impacts to American peregrine falcons would be significant if directly affected by an oil spill.

The western snowy plover would be adversely affected by an oil spill that occurred on the beach where plovers nest or forage. The 1997 oil spill was estimated to have adversely affected at least 13 individuals of this species. Spills from the onshore pipeline could enter the Santa Ynez River or San Antonio Creek channels and flow downstream to the shoreline. An offshore spill that reaches the shoreline would also affect this species. Critical habitat designated from Point Sal to Point Conception could also be affected.

Estuaries and river mouths are an important resource to western snowy plovers. Western snowy plovers breed, nest, and forage near the tide line and within the kelp wrack. Oiling of beach sediments and kelp litter would adversely affect this species feeding and nesting success. Cleanup efforts could also significantly impact breeding success of this species if such efforts were to occur in the foredunes and beach habitat near the Santa Ynez River or San Antonio Creek river mouths. Several other beaches along the shoreline on San Luis Obispo and Santa Barbara County, and beaches at San Miguel and Santa Rosa Islands are used by western snowy plovers and may be impacted by a large offshore spill (Appendix G). These sites are within the trajectory range described in Appendix G, although the probability of a spill reaching any particular site is small. The greatest potential for impacts would occur during this species' breeding season from March 1 through September 30. Impacts to western snowy plovers would range from not significant during the non-breeding season to significant if individual snowy plovers or critical habitat were affected.

Oil and/or produced water spills have the potential to adversely affect the California least tern. Spills from the onshore pipeline could enter river channels and flow downstream to the foredune habitat near rivermouths where this species has been known to nest. Oil and/or produced water could also affect the smaller species of fish inhabiting the estuaries and rivermouth which are preyed upon by least terns. California least terns forage in estuaries and would be affected be an offshore spill that reaches the coastline near river mouths or lagoons. Coastal areas inhabited by California least tern include the Santa Maria River mouth and Santa Ynez River mouth. These sites are within the trajectory range described in Appendix G, although the probability of a spill reaching any particular site is small. Clean up efforts could also result in disturbances to breeding habitat if such efforts were to occur near the rivermouths in foredunes and beach habitats. Impacts to California least terns would range from not significant during the non-breeding season to significant if individual least terns were affected.

Oil and/or produced water spills have the potential to adversely affect the California brown pelican if spills enter river channels and flow downstream to the estuary and beach habitats, or if an offshore spill is transported to waters near the shoreline. California brown pelicans use the rivermouth and beach habitats near the Santa Ynez River during the summer and winter as a temporary roost site and for foraging habitat. Individual birds could be oiled and food resources could be affected by spills. Impacts to this species would be significant if individual brown pelicans were affected.

Oil or produced water spills reaching the Santa Ynez River, San Antonio Creek, Green Canyon, tributaries to the Santa Maria River, Nipomo Creek, or Los Berros Creek could potentially affect California red-legged frogs. Egg and larval (tadpole) life stages would be the most sensitive to toxic effects of such spills, although juvenile and adult frogs could also be affected through contact with their skin. An offshore spill would not be likely to migrate upstream to occupied California red-legged frog habitat within the river channel. Impacts would be not significant for small onshore spills that do not result in mortality of individuals or alteration of their habitat. For large spills that result in mortality of eggs, larvae, juvenile, or adult California red-legged frogs, impacts would be significant if many individuals or their habitat were affected.

Mitigation Measures

Impacts to listed wildlife species would be reduced through implementation of Mitigation Measures TB-11 through TB-14, which include, but are not limited to, updating the OSCP, minimizing habitat disturbance during clean up, using low-impact clean up techniques, and restoring of the site to prespill conditions. Implementation of Mitigation Measures TB-6 and TB-7, which address, in part, the restoration of native plant species would also reduce loss of foraging and breeding habitat in areas where spills or cleanup results in the loss of native vegetation. Mitigation Measure TB-5 would reduce the effects of sedimentation in the event clean up activities disturb soil and increase erosion. Mitigation measures identified in Sections 5.4 (Onshore Water Resources) and 5.6 (Marine Water Quality) would also reduce the impacts of oil spill on state and federally listed species in the project area. These mitigation measures would also apply to a produced water spill.

Residual Impact

Impacts to State or Federally listed species cannot be mitigated to insignificance. The measures proposed to mitigate impacts to habitat and common wildlife species would reduce impacts to federal and state listed and other locally sensitive wildlife species and their habitats. However, impacts would still be considered *significant and unavoidable (Class I).*

5.2.5 Impact Analysis for the Alternatives

5.2.5.1 No Project Alternative

Scenarios 2 and 3. As discussed in Section 3.2, under the No Project Alternative Scenarios 2 and 3, production of the federal portion of the Tranquillon Ridge field would and would not occur, respectively. However, no extension of life of Point Pedernales facilities (Platform Irene, pipelines, and LOGP) is assumed under either scenario. Spill-related impacts associated with the No Project Alternative Scenarios 2 and 3 would be the same as for the current operations because the volume of oil or produced water spills associated with this alternative would remain at current levels and decline over time. Since ~~this alternative~~ neither Scenario 2 or 3 would not extend the life of the Point Pedernales facilities, there would not be any extension of life impacts.

Impacts TB.1 through TB.5 would not occur because there would be no new facilities constructed, and there would be no extension of life issues. Impacts TB.6 through TB.8 would not occur since there would be no increase in oil spill volumes over the current operations and there would be no extension of life of the Point Pedernales facilities.

Options for Meeting California Fuel Demand. The relative impacts to terrestrial and freshwater biology associated with the various options for meeting California fuel demand are summarized in Table 5.2.3.

Table 5.2.3 No Project Alternative Comparison to Options for Meeting California Fuel Demand, Terrestrial and Freshwater Biology

Source of Energy		Impacts
Other Conventional Oil & Gas		
	Domestic onshore crude oil and gas	Likely to displace, rather than eliminate, spill related impacts. Development of new production could have increased construction impacts depending on resources present on-site.
	Increased marine tanker imports of crude oil	Likely to displace, rather than eliminate, spill related impacts.
	Increased gasoline imports[1]	Likely to displace, rather than eliminate, spill related impacts.

Table 5.2.3 No Project Alternative Comparison to Options for Meeting California Fuel Demand, Terrestrial and Freshwater Biology

Source of Energy		Impacts
	Increased natural gas imports (LNG)	Likely to displace, rather than eliminate, spill related impacts.
Alternatives to Oil and Gas		
	Fuel Demand Reduction: increased fuel efficiencies, conservation, electrification[2]	
	Alternative transportation modes	Proposed project impacts would be eliminated.
	Implementation of regulatory measures	Proposed project impacts would be eliminated.
	Coal, Nuclear, Hydroelectric	Proposed project impacts would be eliminated; however, coal, nuclear, and hydroelectric infrastructure development could introduce construction and operation impacts.
	Alternative Transportation Fuels	
	Ethanol/Biodiesel[3]	Proposed project oil spill impacts would be reduced. Potential ethanol/biodiesel spill impacts could occur. Potential increased construction impacts because of new plant construction.
	Hydrogen[2]	Oil spill impacts would be eliminated. Potential construction related impacts due to hydrogen delivery infrastructure development.
	Other Energy Resources[2]	
	Solar[2,4]	Would greatly reduce oil spill impacts to terrestrial and freshwater biology. Potential increased construction impacts because of solar facility infrastructure construction.
	Wind[2,4]	Would greatly reduce oil spill impacts to terrestrial and freshwater biology. Potential increased construction impacts because of wind facility infrastructure construction. Would result in increased avian species impacts.
	Wave[2,4]	Would greatly reduce oil spill impacts to terrestrial and freshwater biology. Potential increased construction impacts because of wave facility infrastructure construction.

Footnotes:
1. Pipeline and tanker truck import from out-of-State assumed.
2. Assumes that Tranquillon Ridge production would not be replaced with other petroleum-based energy supply.
3. Assumes ethanol and biodiesel used as blends only and therefore would reduce, but not eliminate Tranquillon Ridge or equivalent production.
4. Assumes, large centralized facilities.

5.2.5.2 VAFB Onshore Alternative

VAFB is located in a transitional ecological region that lies at the northern and southern distributional limits of many species, and contains diverse biological resources of considerable importance. The Base provides habitat for 15 federally listed threatened, endangered, and special concern plant and animal species. In the location of the alternative on-shore drilling site, Gaviota tarplant (*Deinandra [Hemizonia] increscens* ssp. *Villosa*) is present. Known threatened and endangered species present along the proposed onshore pipeline route include Gaviota tarplant, beach layia (*Layia carnosa*), and vernal pool fairy shrimp (*Branchinecta lynchi*). The north end of the pipeline would extend beneath the Santa Ynez River via directional bore. Threatened and endangered species associated with the Santa Ynez River ecological zone include little willow flycatcher (*Empidonax traillii brewsteri*), southern steelhead (*Oncorhynchus mykiss*), and tidewater goby (*Eucyclogobius newberryi*). Habitat for the recently discovered El Segundo blue butterfly (*Euphilotes battoides allyn*) may also be present at various locations throughout the pipeline route. The impacts of the VAFB Onshore Alternative as they relate to these noted species are presented below.

Impacts TB.1 and TB.2 would not occur under the VAFB Onshore Alternative as this alternative would eliminate the need for modifications to Valve Site #2. However, construction of the VAFB Onshore Alternative would have additional impacts as described below. Once drilling and production facilities were constructed and operational, continuing noise would not be expected to have a significant adverse effect on wildlife in surrounding areas due to the continuous nature of such sounds and their attenuation to relatively low levels by distance, intervening structures, and vegetation.

Impact TB.3 - Pipeline Maintenance Impacts to Vegetation and Wildlife Habitat would be similar to the proposed project, although the geographic area that may be impacted is larger. The new pipeline that would be installed from the onshore drilling and production site to the existing pipeline would require periodic maintenance during its lifetime. Vegetation and wildlife habitat in the vicinity of the pipeline corridor along Surf Road, Coast Road, and Highway 246 may be subject to temporary disturbance. Mitigation Measures TB-3a and TB-3b would apply. Impacts would be *significant but mitigable (Class II).*

Impacts TB.4 and TB.5 - Pipeline Maintenance Impacts to Listed Plants and Listed Wildlife would be similar to the proposed project. The frequency of maintenance or repair could be expected to increase because of the additional length of pipeline connecting to the onshore drilling and production location. Due to the coastal location of the additional pipeline segment, the species assemblage would be different from the existing pipeline route described for the proposed action. The beach layia is an additional listed species that may occur along this pipeline and may be impacted by pipeline maintenance.

These impacts would be *significant but mitigable (Class II).* Mitigation Measures TB-1a, TB-2a, TB-2b, TB-3a, TB-3b, TB-4a, TB-4b, and TB-4c, as well as OWR-1, GR-1 would still apply. Additional revegetation and restoration (Mitigation Measure TB-3a) would be required due to the additional area of ground disturbance and the higher potential for impact to sensitive plants and wildlife.

Impacts TB.6, TB.7, TB.8 - Spill Impacts to Vegetation, Wildlife, and Listed Species would be similar to the proposed project, although onshore spill frequency would be slightly increased due to the additional length (approximately 10 miles) of the additional pipeline segment running from the onshore drilling and production site to the tie-in ~~location~~ station west of 13th Street. The spill impacts associated with the onshore alternative may affect a wider variety of habitat types than the proposed project due to the pipeline segment along the coastal terrace north of the drilling/production location. Vegetation, wildlife, and sensitive plant species such as La Purisima manzanita, sand mesa manzanita, Gaviota tarplant, beach layia, and coast buckwheat (which may support El Segundo blue butterfly) may be adversely affected by an oil release from the pipeline.

Spill impacts to aquatic biota would be greater than for the proposed project due to the location of the pipeline leading north from the onshore drilling/production location. The pipeline would be installed along Surf Road, Bear Creek Road, and Coast Road, all of which are in close proximity to the shoreline. Several drainages and Bear Creek could be impacted by emulsion released from the pipeline. A spill of sufficient volume could fill the drainages and flow westward into the coastal zone if the drainages and Bear Creek are culverted under the UPRR tracks. Aquatic biota in the drainages would be affected due to contamination, smothering, sedimentation, and loss of habitat. Cleanup and containment activity may also affect sensitive dune habitats, riparian areas, and aquatic habitats along the coastal terrace. Clean-up activities may require access through the dunes to contain the spill before reaching the ocean. This may result in disturbance to coast buckwheat and the dune community as a whole.

The pipeline segment along Highway 246 is directly adjacent to the Santa Ynez River. In the event of a spill or rupture, impacts on aquatic habitats would be more severe under the VAFB Onshore Alternative compared to the proposed project. The Santa Ynez River and adjacent riparian areas support sensitive aquatic species such as the tidewater goby, red-legged frog, and steelhead. A spill into the Santa Ynez River could result in oil flow to the river mouth and beach, which is proposed critical habitat for the western snowy plover.

Spill impacts in the pipeline segment east of the tie-to the PXP pipelines would be the same as the proposed project due to the increased throughput levels. Impacts would be *significant (Class I)*. Mitigation Measures TB-6a through TB-6d and the Core Oil Spill Response Plan would still apply. The onshore alternative would require that mitigation measures and response plans be updated and expanded in scope to address the additional 10 miles of pipeline and the additional habitat types included in the onshore pipeline route. Mitigation measures identified in Sections 5.4 (Onshore Water Resources) and 5.6 (Marine Water Quality) would also reduce the impacts of oil spill on state and federally listed species in the project area. These mitigation measures would also apply to a produced water spill.

The VAFB Onshore Alternative would not involve a change in offshore operations through 2017, at which time Platform Irene and offshore pipeline operations would cease. The impacts associated with an offshore spill would be equivalent to the No Action Alternative since oil production levels and resultant spill probabilities, volumes, and clean up activities would be similar to current operations (i.e., the baseline).

Impact TB.9: Santa Ynez River Drilling Impacts

Impact #	Impact Description	Phase	Residual Impact
TB.9	Drilling noise, construction, and accidental release of boring materials ("frac-outs") during construction activities related to boring could impact one or more sensitive wildlife species.	*Construction*	*Class I*

Directional drilling under the Santa Ynez River would be utilized to install pipelines from the onshore drilling/production site. <u>In addition, if Alternative Power Line Route Option 2b were</u>

implemented to route the power line to the tie-in station, directional drilling under the Santa Ynez River would be required. Boring has the potential to indirectly impact sensitive biological resources in the Santa Ynez River given the potential for frac-out (inadvertent release of bentonite slurry through natural subsurface fractures). This impact would be greater than for Alternative Power Line Route, Option 2b, due to the larger diameter bore that would be required to install the pipeline (see Section 5.2.5.4). Bentonite slurry released into the Santa Ynez River would increase turbidity and sedimentation, potentially affecting the California red-legged frog, tidewater goby, and steelhead by covering egg masses and breeding habitat. Some mortality of invertebrates and possibly amphibians and fish would be expected.

Other than during migration, steelhead are not likely to spawn or be present in the lower reaches of the Santa Ynez River in the project area. Upstream migration typically occurs from January through April, and downstream migration from January through June (SYRTAC 2000). Impacts to migrating steelhead would be more severe during the migration period. Critical habitat for steelhead in the Santa Ynez River could be adversely modified by sediment plumes due to frac-out. Impacts could be reduced by implementing measures to limit erosion and sedimentation and to protect water quality.

To reduce the incidence of "frac-outs", a geological investigation should be conducted prior to work activities to determine sufficient depth for boring. To avoid disruption to aquatic habitats from erosion and released drilling fluids, work should occur during the dry season but outside the breeding season for aquatic species, such as in the fall. The detection of "frac-outs" would be enhanced by adding fluorescent dye to the drilling fluid and by closely monitoring the return flow in the drilling pit. Cessation of return flows indicates loss of drilling fluid, likely to a "frac-out." The size of the "frac-out" would be reduced by immediately halting boring activities until the "frac-out" is located and responded to appropriately. Sensitive species would be moved out of harm's way, if possible. These measures would be part of a monitoring plan, developed from experience gained from similar projects in the region, to reduce the incidence and the size of "frac-outs." The level of impact would depend on the size of the spill, toxicity of spilled material, and species that were present in the affected area. Based on previous projects in the region, despite such precautionary measures, the potential still exists that one or more "frac-out" could occur. Therefore, the implementation of the mitigation measures would reduce, but not eliminate impacts to biological resources, should a "frac-out" occur.

Short-term disturbance associated with boring equipment noise and other project-related activities near the river could be significant if they occurred during the breeding season of sensitive bird species, and if that species was nesting within 100 meters of the boring equipment or other activity. The southwestern willow flycatcher is known to be affected by sounds associated with boring (study conducted by SAIC during Central Coast Water Authority water pipeline installation under the Santa Ynez River). Several sensitive bird species, including southwestern willow flycatcher, yellow warbler and yellow-breasted chat, could nest near the 13th Street bridge, or downstream where bore sites could be located. Southwestern willow flycatcher has nested both upstream and downstream from this location, and between 1995 and 1999 nesting southwestern flycatchers or territorial individuals were present about 50 meters west of the 13th Street Bridge on VAFB. Suitable habitat is still present and recolonization of the area is possible (N. Read Francine, VAFB, 2002). Impacts to bird species can be mitigated to insignificance by avoiding the breeding seasons of the sensitive bird species. Because of the distance from the bridge, implementation of this alternative is unlikely to have any effect on bats roosting under the bridge. The potential impacts of noise and vibration on California red-legged frogs and southwestern pond turtles are not known, but are not expected to be significant because of the absorption of noise and vibration by the deep, unconsolidated river deposits that the bore would pass through.

Because of the potential effects on sensitive species and their habitat associated with potential accidental releases of drilling slurry into the Santa Ynez River, impacts would be considered significant.

Mitigation Measures

Mitigation Measure TB-4, scheduling the work during the dry season, would reduce run off and potentially enhance the early detection of a "frac-out" in the Santa Ynez River. Implementation of Mitigation Measures TB-3, TB-5, TB-6 and TB-7 would reduce impacts to vegetation and wildlife habitat, and should be implemented along with the following measures:

TB-15 If construction activities are scheduled to occur during the breeding season for the sensitive bird species (March 1 through September 30), pre-construction surveys shall be carried out by a qualified biologist to determine if nests of any of these species are present within 100 meters from the construction locations. If nests are found, construction activities shall be postponed until after the end of the breeding seasons of these bird species, on October 1. Results of surveys and recommended actions shall be submitted to SBC for review and approval prior to construction.

TB-16 Prior to commencement of boring, a detailed site-specific Frac-Out Contingency Plan shall be developed that would include, but is not limited to the following, site analysis to determine optimum depth to prevent "frac-outs", use of fluorescent dye in drilling fluids, seasonal restrictions on work to be conducted, mapped locations of sensitive resources, measures to reduce the project footprint. The plan shall also contain methods to identify, report, and respond to "frac-outs," including notification procedures, response equipment staging, and site-specific clean-up procedures.

TB-17 All boring activities shall be monitored to ensure all precautionary measures are taken to prevent release of drilling fluids into aquatic and terrestrial habitats. Prior to construction, bore crews and monitors shall receive specific training in operational methods to reduce the incidence of frac-outs, and in frac-out response and reporting procedures. Documentation that training has been completed shall be submitted to SBC and CCC for review and approval prior to construction.

Residual Impact

With the implementation of the above mitigation measures, impacts are expected to be reduced, but the possibility of "frac-outs" impacting endangered or threatened species at the site or downstream cannot be eliminated. Therefore, the residual impact would be considered *significant (Class I).*

Impact TB.10: Construction Impacts to Vegetation

Impact #	Impact Description	Phase	Residual Impact
TB.10	Construction of the drilling site and installation of the pipelines, tie-in station, substations, and power lines ~~has~~ have the potential to remove or damage up to 76.65 acres of native vegetation and wildlife habitat including sensitive plant species.	*Construction*	*Class I*

This alternative would require the development of an onshore drilling site and installation of approximately 10 miles of new underground pipelines to connect with the existing PXP pipelines. Approximately 25 acres of vegetation and wildlife habitat would be developed for the onshore drilling and production facilities. The 25 acres of disturbance would be contained within a 75-acre plot between Surf Road and Coast Road north of Honda Creek.

Pipelines would run north from the drilling site and connect with the existing pipelines north of the Santa Ynez River at the tie-in station, just west of 13th Street. It is assumed that approximately 10 miles of pipeline would be installed and that the width of ground disturbance would be approximately 50 feet on average. Based on these estimates, the onshore pipeline installation would impact an additional 61 acres of vegetation and wildlife habitat adjacent to existing roadways.

A power line~~s~~ and a new substation would also be installed to connect the onshore drilling site with the existing electricity grid. This project alternative involves approximately 6 miles of new power line~~s~~ routed from a new substation at or near the existing substation at Surf Beach~~Substation.~~ The new substation is assumed to require roughly one acre. Installing up to six miles of power line would include minimal grading and clearing around each installed pole. The average span of the power poles is 350 to 400 feet, corresponding with approximately 13 to 15 poles per mile. Installing the poles would result in approximately 315 square feet of temporary ground disturbance and removal of vegetation due to pole setting and equipment maneuvering per pole. Assuming 90 poles total, the disturbance would be approximately 0.65 acre of vegetation and wildlife habitat along portions of Coast Road, Bear Creek Road, and Surf Road. In addition, a new power line and substation would be required for the tie-in station. The substation for the tie-in station would occupy approximately 1,600 square feet of agricultural land (approximately 0.04 acre). In addition, approximately one mile of power line would be required. Assuming 15 poles total, the disturbance would be approximately 0.11 acre of agricultural lands or primarily non-native grasses and forbs along 13th Street depending upon the final power line alignment chosen (see Section 5.2.5.4).

Additional areas of terrestrial vegetation and wildlife habitat would be impacted if cultural resources sites are discovered during the proposed project. Ground disturbance and excavation for data recovery could extend outside the disturbed construction right-of-way and beyond the project boundaries identified above.

Vegetation at the onshore drilling and production site is semi-disturbed coastal scrub and grassland. Non-native iceplant, veldt grass, and European beach grass are interspersed with native scrub and dune species. Northward along Surf Road and Bear Creek Road, the vegetation along the shoulder varies in habitat quality. Many patches of invasive weedy species exist, while areas of high quality chaparral, coastal scrub, and grassland are also present in the pipeline corridor and power line route.

Loss of individuals of sensitive plant species, such as La Purisima manzanita, sand mesa manzanita, and Gaviota tarplant, would be substantially larger under the onshore alternative due to the additional area of terrestrial ground disturbance. If the pipeline were to be installed along the west side of Surf Road, it may impact a population of beach layia (a federally listed species) due to ground disturbance. Isolated occurrences of coast buckwheat may be present in the dune vegetation to the west of Coast Road. Installation of pipelines and power lines may trample or remove patches of coast buckwheat, and therefore negatively affect El Segundo blue butterfly.

Loss of individuals of wildlife species would be greater under the onshore alternative compared to the proposed action. Vernal pool fairy shrimp could be present along the alternative pipeline route. Further, protected species in or near the willow riparian habitats along Highway 246 could be impacted by pipeline installation. A large drainage swale running parallel to and south of the Highway 246 road shoulder contains wetland plants, riparian birds, and aquatic wildlife. The wetland and riparian habitats are likely to support sensitive and/or protected species. Pipeline installation in this area could result in disturbance or mortality to southwestern pond turtles, California red-legged frogs, and adverse effects on eggs and breeding habitat. Unlike the southern border of Highway 246, the corridor north of the road shoulder does not support an extensive wetland. However, wildlife that inhabits the coastal scrub and coastal terrace would be disturbed and displaced during installation of the pipeline. Wildlife near the Santa Ynez River crossing could be impacted by pipeline installation. Roosting bats and sensitive birds in the vicinity of the 13th Street bridge, would be impacted in the same manner as under the installation of the power line for the proposed project.

Mitigation Measures

Mitigation Measures TB-1 and TB-3 (avoiding sensitive plant species and wildlife) would be less feasible due to the large area required for onshore drilling and production operations, and the linear nature of the pipeline corridor. These measures should be implemented when feasible. Mitigation Measure TB-2 would also apply. Revegetating the area impacted during pipeline installation (Mitigation Measures TB-6 and TB-7) with native species, including any sensitive plant species would reduce impacts. The amount of required restoration would be greater and the revegetated species assemblages would be adjusted to more accurately represent the disturbed habitat along Surf and Coast Roads.

Residual Impact

Although the implementation of mitigation measures would reduce the degree of impact, the large construction corridor in previously undisturbed habitat containing sensitive coastal plant communities would result in a *significant* impact *(Class I).*

Impact TB.11: Construction Impacts to Wildlife

Impact #	Impact Description	Phase	Residual Impact
TB.11	Construction of the drilling site and installation of the pipelines, tie-in station, substations, and power lines have~~has~~ the potential to cause temporary habitat loss for mobile wildlife species and to cause mortality to individual animals.	*Construction*	*Class III*

Impact TB.11 would involve the loss of individuals of wildlife species occurring in the onshore drilling site and within the pipeline and power line corridors. Wildlife that inhabits the coastal scrub and coastal terrace would be disturbed by construction noise and activity and displaced during installation of the pipeline. Wildlife near the Santa Ynez River crossing could be impacted by construction activity. Roosting bats and sensitive birds in the vicinity of the 13th Street bridge, would be impacted in the same manner as under the proposed action. Because these individuals would represent a small portion of the number of individuals present in the adjacent habitat such losses are expected to be not significant.

Mitigation Measures

While not required under CEQA to reduce the impact to a level of insignificance, the following measures are proposed to mitigate the impact to the maximum extent feasible, including: Mitigation Measures TB-3, relocated sensitive species out of the impact area into suitable adjacent habitat; TB-6, minimize disturbance to native habitats; and TB-7, preparation and implementation of an approved ~~HRRMP~~restoration and revegetation plan.

Residual Impact

There would be some unavoidable mortality to individuals of sedentary wildlife species within the right-of-way. However, because of the narrow corridor, history of previous disturbance, and relocation to suitable habitat of any wildlife found in the project area prior to disturbance, this effect is not expected to be measurable on wildlife populations and is considered to be *adverse but not significant (Class III).*

Impact TB.12: Construction Impacts to Freshwater Aquatic Habitats and Biota

Impact #	Impact Description	Phase	Residual Impact
TB.12	Pipeline and power line construction has the potential to result in disturbance to and loss of wetland and aquatic biota.	*Construction*	*Class II*

Most of the expected impacts to aquatic resources from pipeline and power line construction activities would occur as a result of direct disturbance to and temporal loss of aquatic and associated wetland habitats, direct injury or mortality to aquatic organisms, and indirect impacts from erosion and sedimentation.

Construction activities would temporarily expose disturbed soils to wind and water erosion, and thereby increase the potential for transport of sediment into the drainages and downstream areas. Water is likely to be present in the Santa Ynez River and Bear Creek during construction;

therefore, aquatic organisms would be directly affected by the construction activities in these waterways. Direct impacts could result from injury or mortality of individuals entering the work area while indirect effects could result from sediment runoff into downstream habitats used by the species. Sediment may decrease the availability of aquatic food organisms and, if work is conducted during the breeding season, sediment may asphyxiate egg and larval stages of California red-legged frogs. Vegetation removal could adversely alter habitat for this species until re-establishment of vegetation is complete.

If water were present in the drainages, impacts to aquatic species would be adverse in the immediate downstream areas but not significant due to their short duration and time of year (fall to winter when rain runoff normally introduces turbidity into the streams). Once flows begin in the drainages during the following rainy season, some turbidity and natural reshaping of the drainages would occur. Impacts of sediments on aquatic organisms are expected to be not significant due to the small area affected within each drainage and the short duration of the work.

Pollution of the wetland and aquatic habitats due to equipment leaks or spills could severely impact these habitats depending on the quantity released, proximity to the wetland, the presence of flowing water, and effectiveness of spill response. Impacts to aquatic biota from spills have been described under the proposed action for vegetation and wildlife and are considered *significant*.

Mitigation Measures

Measures identified in Section 5.3, Geologic Resources, and Section 5.4, Onshore Water Resources, would reduce impacts on aquatic biological resources. These measures include OWR-1, and GR-1. Mitigation Measures TB-6, minimize disturbance to native habitats, and TB-7, preparation and implementation of an approved ~~HRRMP~~restoration and revegetation plan shall be also implemented.

The following measures are recommended to further reduce impacts of pipeline construction on aquatic biota and habitats.

TB-18 Erosion and sediment control measures, which shall include the use of silt fencing, dust control, and other appropriate measures, shall be implemented at drainages; along portions of the right-of-way that intersect slopes greater than a 2-to-1 incline; and within 200 feet of downslope water bodies. Appropriate erosion and sediment control measures shall be installed and maintained until revegetation of the disturbed area is considered successful. (The use of straw bales and silt fences as erosion control protection shall not be considered to be appropriate in areas grazed by cattle unless the cattle are excluded from the area.). Applicant shall submit erosion and sediment control plans and specifications to SBC for approval prior to land use clearance.

TB-19 Drainages shall be restored to original contours after construction activities in order to preserve downstream biological resources and minimize sedimentation. Plans for drainage recontouring shall be included in the ~~HRRMP~~restoration and revegetation plan (TB-7) and submitted to SBC/CCC for review and approval prior to land use clearance.

TB-20 All ground disturbance activities shall occur, if feasible, during the dry season (generally April 1 through November 1).

TB-21 Applicant-funded SBC/CCC-qualified biological monitors shall be on-site during construction activities to ensure avoidance of individual animals and minimization of habitat destruction.

TB-22 A construction spill response plan shall be prepared prior to the onset of construction to ensure a prompt and effective response to any accidental spills or leaks of diesel, gasoline, oil or other contaminating materials. Examples of measures would include the following: All equipment will be inspected for fuel, lubricant, and hydraulic fluid leaks prior to and during the work. Any leaks will be repaired immediately. Drip pans will be used to capture leaked fluids until the repair is completed. Fueling of stationary equipment will be by fuel truck and no equipment shall be fueled or maintained within 100 feet of drainages. Fueling or maintenance will occur over a drip pan or in a lined fueling area. Plan to be submitted to SBC for review and approval prior to land use clearance.

Residual Impact

Implementing the above mitigation measures to control sediment and pollution is expected to reduce impacts to wetland and aquatic biota to *significant but mitigable (Class II).* The potential for impacts associated with erosion and siltation are considered short-term and are expected to persist until vegetation has re-established in disturbed areas along the pipeline route.

Impact TB.13: Construction Impacts to Listed Plants

Impact #	Impact Description	Phase	Residual Impact
TB.13	Installation of the drilling site,~~and~~ pipelines, tie-in station, substations, and power lines have~~has~~ the potential to remove or damage federally or state-listed plant species, including Gaviota tarplant.	*Construction*	*Class II*

The loss of individuals of sensitive plant species, such as La Purisima manzanita, sand mesa manzanita, and Gaviota tarplant, would be substantially larger under the VAFB Onshore Alternative than the proposed project due to the additional area of terrestrial ground disturbance. The pipeline that would be installed along the west side of Surf Road may impact a population of beach layia (a federally listed species) due to ground disturbance. Gaviota tarplant is also likely to be present along the pipeline corridor. Isolated occurrences of coast buckwheat may be present in the dune vegetation to the west of Coast Road. Installation of pipelines and power lines may trample or remove patches of coast buckwheat, and therefore negatively affect El Segundo blue butterfly. The level of impact would depend on the numbers of individuals lost or damaged and whether that loss represents a significant portion of the colony at a particular location or otherwise affects the ability of that colony ~~or~~to sustain itself.

Mitigation Measures

Where impacts are unavoidable, the following mitigation measures shall be implemented: Mitigation Measures TB-8, to map locations of sensitive plant species, TB-9, to develop a program to salvage, propagate, and re-establish plant species that could not be avoided during project activities, and to re-establish and monitor state and federally listed plant species. Implementation of Mitigation Measures TB-6 and TB-7 would minimize disturbed areas to the maximum extent feasible.

Residual Impact

For habitats where listed plant species are found, it is likely that the disturbance corridor would include a small portion of the potential listed plant species habitat in the project vicinity. In addition, the construction corridor can be narrowed at certain locations to avoid impacts to sensitive biological resources. Avoiding individuals or colonies of listed plant species and implementation of suitable mitigation measures where impacts are unavoidable are expected to reduce potential impacts to listed plant species to *significant but mitigable (Class II).*

Impact TB.14: Construction Impacts to Riparian Species

Impact #	Impact Description	Phase	Residual Impact
TB.14	Pipeline and power line construction in the riparian woodland, wetlands, and upland habitats near the Santa Ynez River, Bear Creek, and several smaller drainages could adversely impact California red-legged frogs as well as several California species of concern (southwestern pond turtles, Cooper's hawk, yellow warbler, yellow-breasted chat).	*Construction*	*Class II*

The onshore drilling alternative would involve pipeline and power line crossings at the Santa Ynez River and at several smaller drainages with small riparian zones along Surf Road. The drainage swale south of the Highway 246 road provides habitat for riparian birds. Several sensitive species of birds, including Cooper's hawk, yellow warbler, and yellow-breasted chat, nest in riparian habitats in northern SBC and could potentially nest in appropriate habitat in the pipeline corridor. Direct impacts to riparian species could result from injury or mortality of individuals entering the work area while indirect effects could result from sediment runoff into downstream habitats used by the species.

Mitigation Measures

TB-23 Preconstruction surveys shall be conducted by SBC/CCC-approved biologists with suitable experience to determine the presence of California red-legged frogs and other sensitive species no more than 30-days prior to construction. If surveys indicate that California red-legged frogs would likely be present in the work areas in or near stream crossings or riparian vegetation, construction activities shall be postponed and federal and state agencies shall be contacted to coordinate suitable protection measures (such as relocations, through authorization for incidental take, or avoidance) for implementation by the applicant. If southwestern pond turtles, two-striped garter snakes or other sensitive species are encountered in work areas they shall be relocated or otherwise protected from harm by means acceptable to CDFG. Preconstruction survey documentation shall be submitted to SBC/CCC for review and approval prior to the commencement of construction.

TB-24 Before any construction activities begin on the project, the biological monitor(s) shall conduct an employee training session for all construction crews and others present during construction. At a minimum, the training shall include a discussion of the biology, identification, and habitat needs of California red-legged frogs and the importance of their habitat, their status under the California Endangered Species and Federal Endangered Species Acts, and measures taken for the protection of these species and their habitat as part of the project. Upon completion of the orientation, employees shall sign a form stating that they attended the program and understand and will implement all protection measures for the species. Documentation of training shall be submitted to SBC/CCC for approval prior to construction.

TB-25 Construction shall be scheduled to avoid the rainy season (after first soaking rains through April) when California red-legged frogs would be most likely to be moving between different bodies of water. Construction shall be completed between April 1 and November 1. If necessary, the project proponent shall seek approval from the Corps and the USFWS to work outside of this time period.

TB-26 An applicant-funded, qualified SBC/CCC-approved California red-legged frog biologist shall be present throughout the construction phase to monitor for the species and to implement additional mitigation for the species. The approved biologist shall have the authority to halt any action that might result in impacts that exceed the levels anticipated during review of the action by the Corps and the USFWS. Documentation shall be included as part of SBC's Environmental Quality Assurance Program (EQAP).

TB-27 The pipeline trench shall be provided with escape ramps constructed of earth fill to prevent entrapment of sensitive species or other animals during the construction phase of the project. The ramps shall be located at no greater than 1,000-foot intervals and be constructed at less than 45 degrees inclination. Include plans and specifications as part of TB-6 plan submitted by applicant to SBC/CCC for review and approval prior to land use clearance.

TB-28 All trenches, open pipes and culverts, or similar structures at the construction site open for one or more overnight periods shall be thoroughly inspected for trapped animals by an SBC/CCC-qualified, applicant-funded biologist before the pipe is subsequently buried, capped, or otherwise used or moved in any way. Pipes in, or adjacent to, trenches left overnight shall be capped by the applicant and/or their contractors. If an animal is discovered inside a pipe during construction, that section of pipe shall not be moved, or if necessary, moved only once, to remove it from the path of construction until the animal has voluntarily escaped. Include plans and specifications as part of TB-6 plan submitted by applicant to SBC/CCC for review and approval prior to land use clearance.

TB-29 Applicant shall ensure that all trash that may attract predators shall be properly contained, removed from the work site, and disposed of regularly. Following construction, all trash and construction debris shall be removed from work areas. Include plans and specifications as part of TB-6 plan submitted by applicant to SBC/CCC for review and approval prior to land use clearance.

TB-30 If dewatering is necessary, intakes shall be completely screened with wire mesh (not larger than five millimeters mesh size) to prevent California red-legged frogs from entering the pump system. Water shall be released or pumped downstream at an appropriate rate to maintain downstream flows during construction. No water containing any sediment shall be allowed to flow back into any flowing water. Upon completion of construction, any barriers to flow shall be removed in a manner that would allow flow to resume with the least disturbance to the substrate. Include plans and specifications as part of TB-6 plan submitted by applicant to SBC/CCC for review and approval prior to land use clearance.

TB-31 A SBC-approved biologist shall permanently remove from within suitable habitat in the disturbance corridor any individuals of exotic species, such as bullfrogs, crayfish, and non-native fishes, to the maximum extent possible. Include plans and specifications as part of TB-6 plan submitted by applicant to SBC/CCC for review and approval prior to land use clearance.

TB-32 Surveys in suitable habitat shall be conducted on a regular basis (twice a week at night) during the construction phase to ensure that California red-legged frogs are not present in the work areas. Include plans and specifications as part of TB-6 plan submitted by applicant to SBC/CCC for review and approval prior to land use clearance.

TB-33 If construction work is scheduled to occur during the period April 1 to August 1, a qualified avian biologist shall survey riparian habitat within 100 feet of the right-of-way. If surveys reveal Cooper’s hawks, yellow warblers, or yellow-breasted chats are nesting within 100 feet of the right-of-way, construction activities in those areas shall be postponed until after the conclusion of the nesting period, April 1 to August 1. Include plans and specifications as part of TB-6 plan submitted by applicant to SBC/CCC for review and approval prior to land use clearance.

TB-34 Drainage and wetland crossings shall be revegetated with an appropriate assemblage of native riparian and wetland species suitable for the area. A species list and restoration and monitoring plan shall be included with the project proposal for approval by SBC/CCC. This plan must include, but not be limited to, location of restoration, species to be used, restoration techniques, timing of restoration, identifiable success criteria for completion, and remedial actions if the success criteria are not achieved. Include plans and specifications as part of TB-6 plan submitted by applicant to SBC/CCC for review and approval prior to land use clearance.

Residual Impact

Implementation of the mitigation measures listed above would reduce impacts to riparian species to *significant but mitigable (Class II).*

Impact TB.15: Construction Impacts to Listed Aquatic Species

Impact #	Impact Description	Phase	Residual Impact
TB.15	Pipeline <u>and power line</u> construction <u>in</u> riparian areas and drainages could cause downstream impacts to listed aquatic species (California red-legged frog) and species of concern (southwestern pond turtle).	*Construction*	*Class II*

The willow riparian habitats along Highway 246 and several small drainages along Surf Road would be impacted by pipeline installation. The wetland and riparian habitats are likely to support sensitive and/or protected species. Pipeline installation in this area could result in disturbance or mortality to southwestern pond turtles, California red-legged frogs, and adverse affect on eggs and breeding habitat. The Santa Ynez River supports listed aquatic species such as the tidewater goby and steelhead. Construction-related impacts along Highway 246 could indirectly affect these species if sediment is transported downstream.

Mitigation Measures

Implementation of Mitigation Measures identified previously, including TB-4, scheduling the work during the dry season; TB-5, controlling erosion; TB-6, minimize disturbance to native habitats; TB-7, preparation and implementation of an approved ~~HRRMP~~restoration and revegetation plan; and, TB-22, equipment spill control measures, would reduce downstream impacts to aquatic species.

Residual Impact

Implementation of the mitigation measures identified above would reduce impacts to aquatic species to *significant but mitigable (Class II).*

5.2.5.3 Casmalia Canyon/Oil Field Processing Location

This alternative would require construction of a new oil and gas processing facility in Casmalia and installation of new pipelines. The new pipelines would follow the existing right-of-way from LOGP to a point just south of Orcutt. They would proceed in a new right-of-way from there to the new Casmalia processing facility. It is likely that new construction would result in significant impacts to terrestrial biological resources along the pipeline route and at the new facility location. Impacts would be similar in nature to the impacts identified for the VAFB Onshore Alternative discussed above, except that the Santa Ynez River would not be crossed. The applicable impacts are listed and discussed below.

Impacts TB.1 and TB.2 would be the same as for the proposed project and Mitigation Measures TB-1 through TB-5 would apply. Impact TB.9, directional drilling of the Santa Ynez River, does not apply to this alternative.

Impacts TB.3, TB.4, TB.5 - Pipeline Maintenance Impacts to Vegetation, Wildlife, and Listed Species would be greater than the proposed project as described below. Maintenance-related impacts would be of greater extent because there would be more miles of pipeline to maintain (Platform Irene to LOGP plus LOGP to Casmalia). All of the impacts would still be *Class II* with implementation of Mitigation Measures TB-6 through TB-9.

Impacts TB.6, TB.7, TB.8 - Spill Impacts to Vegetation, Wildlife, and Listed Species would be greater than for the proposed project due to the increased throughput levels both in the Platform Irene to LOGP pipeline segment (as in the proposed project) and the LOGP to Casmalia segment (this alternative), a portion of which currently lacks any oil or gas pipelines. All of the impacts would still be *Class I*. Mitigation Measures TB-11 through TB-14 would still apply.

Impacts similar to the Platform Irene to the LOGP Pipeline Replacement Alternative would also apply to this alternative. They are discussed below.

Impact TB.10 - Construction Impacts to Vegetation: The construction activities associated with this alternative would result in approximately 55 acres of disturbance, in primarily natural habitats, from installation of a pipeline corridor from Orcutt to the Casmalia East facility. In addition, installing new pipelines along the existing pipeline corridor from the LOGP to the Orcutt Pump Station has the potential to disturb 97 acres, including agricultural fields and previously disturbed natural areas (especially in the Purisima Hills), many of which have recovered from installation of the existing pipeline array. The new facility would be placed in the existing Casmalia Oil Field, which, although disturbed by oil well pads and roads, provides habitat for plants and wildlife. Impacts from installing the pipeline would be temporary, while installation of the new facility would result in the permanent loss of vegetation and wildlife habitat. Impacts would be *significant (Class I)* due to the large extent of habitat affected, permanent loss of habitat in some areas, and the time required for habitat recovery in other areas. Mitigation Measures TB-4 through TB-7 would be required.

Impact TB.11 - Construction Impacts to Wildlife would involve the loss of individuals of wildlife species occurring in the affected area, other than federally or state-listed species discussed below. Because these individuals would represent a small portion of the number of individuals present in the adjacent habitat and because of the previously disturbed nature of the areas, such losses are expected to be *adverse but not significant (Class III).* Mitigation Measures TB-3 through TB-7 would be applied to mitigate the impact to the maximum extent feasible.

Impact TB.12 - Construction Impacts to Freshwater Aquatic Habitats and Biota: Most of the expected impacts to aquatic resources from construction activities would occur as a result of direct disturbance to aquatic and associated wetland habitats, direct injury or mortality to aquatic organisms, and indirect impacts from erosion and sedimentation. Mitigation Measures OWR-1, GR-1, TB-18 through TB-22 would serve to reduce impacts to aquatic biota and reduce sedimentation issues to *significant but mitigable (Class II).*

Impact TB.13 - Construction Impacts to Listed Plants: Construction of the pipeline and the Casmalia facility has the potential to remove or damage individuals or colonies of state-listed plant species. The loss of individuals or colonies of state-listed threatened or endangered plant species would be considered a significant impact. The level of impact would depend on the numbers of individuals lost or damaged and whether that loss represents a significant portion of the colony at a particular location or otherwise affects the ability of that colony to sustain itself. Mitigation Measures TB-8 and TB-9 would reduce impacts to *significant but mitigable (Class II).*

Impact TB.14 - Construction Impacts to Riparian Species: Individual wildlife, including listed species, could be impacted by construction activities in riparian areas. Direct impacts could result from injury or mortality of individuals entering the work area while indirect effects could result from sediment runoff into downstream habitats used by the species. Implementation of Mitigation Measures TB-23 through TB-34 would reduce impacts to *significant but mitigable (Class II).*

5.2.5.4 Alternative Power Line Routes to Valve Site #2

Impacts TB.1 and TB.2 would change under this alternative depending on the proposed alternative route as discussed below. Impacts TB.3 through TB.8 would be similar to the proposed project for all power line alternative routes.

Alternative Power Line Route – Option 2a

Impact TB.1, Construction Impacts to Vegetation and Wildlife, and Impact TB.2, Construction Impacts to Freshwater Aquatic Habitats, would be similar to the proposed project*;* however, the location of the impacts due to the transmission line crossing the Santa Ynez River would be moved west approximately 1,000 feet. Mitigation Measures TB-1 through TB-3 would apply.

Alternative Power Line Route – Option 2b

Option 2b is the same as 2a except that at the Santa Ynez River the power line would cross the river by directional boring. The locations where the boring would occur, both on the north and south side of the river, are within the agricultural fields. After boring, the power line would continue along the same route proposed for Option 2a.

Impacts TB.1 and TB.2 (Construction Impacts to Vegetation, Wildlife, Listed Species, and Freshwater Aquatic Habitats) would be similar to the proposed project; however, there would be no impacts due to the pole installation across the Santa Ynez River, therefore Mitigation Measure TB-2 is not required. Other impacts would be moved west approximately 1,000 feet compared with the proposed project. Mitigation Measures TB-1 and TB-3 would apply.

Option 2b would result in disturbance to and temporary loss of agricultural habitat used by widespread and abundant species, an adverse but not significant impact. With this option, a smaller amount of ground disturbance would result (45,000 square feet compared to 52,500 square feet in Option 2a) due to the fewer number of power poles required and smaller work areas. Directional boring would have no direct impact on native vegetation since all work would be conducted in existing agricultural row crop and hay production fields. As long as work remains outside of the riparian canopy, no direct impacts to biological resources would be associated with this option.

Impact TB.9 – Santa Ynez River Drilling Impacts: Boring has the potential to indirectly impact sensitive biological resources in the Santa Ynez River from accidents such as a release of slurry or other material used for boring ("frac-outs"). Based upon experience with other directional boring projects in the project region, releases are relatively likely to occur. The major ingredient in the slurry is bentonite, a naturally occurring clay. Bentonite stays in suspension in water for a long period of time causing a milky turbidity and creating a filmy deposit on the stream bottom, covering plant material, egg masses, and invertebrates, and inhibiting gas exchange and metabolic activity. Slurry released into a live stream would increase turbidity and deposition of fine sediment downstream of construction activities. Sediment deposition could impact both common and sensitive species of vegetation and wildlife (including California red-legged frog, tidewater goby, and steelhead) by covering egg masses and breeding habitat. Some mortality of invertebrates and possibly fish (including sensitive species such as tidewater goby and steelhead) would be expected from increased turbidity and sediment deposition until dilution or clean up reduces the concentration to normal levels. Sediment deposition would alter aquatic habitat until flushing flows (which may not occur until the following winter) removed the accumulated material for redistribution downstream. The further downstream the less river vegetation and wildlife would be affected by turbidity or spills from the project.

Mitigation Measures TB-1, TB-2, TB-5, TB-6, TB-7, and TB-15 through TB-17 would apply to minimize disturbance in the riparian area and to avoid construction during the breeding seasons of sensitive avian species. Additionally, the bore would be drilled below the scour depth of the river. The mitigation measures would reduce the impacts to listed wildlife in the power line corridor. The mitigation measures would reduce the possibility of frac-outs, although the possibility of impact to listed species downstream of the site cannot be eliminated. Residual impact would be considered *significant and unavoidable (Class I).*

Underground Power Line along Terra Road

Impact TB.1 – Valve Site #2 and Power Line Construction Impacts to Vegetation, Wildlife, and Listed Species would be substantially greater than the proposed project because the trench (approximately 1 to 2.2 miles in length) would require more ground disturbance. One exception would be impacts to peregrine falcons and possibly other raptors, since the risk of collisions with power lines would be eliminated if the wires are underground. Assuming a 50-foot wide disturbance corridor, the impacted habitat would range from approximately six acres for one mile underground to approximately 18 acres for three miles underground. This compares to less than 0.5 acres total disturbance for the above-ground alternative. Loss of individuals of sensitive plant species, such as La Purisima manzanita and sand mesa manzanita, would be more likely than for the above ground alternatives since it would not likely be feasible to locate the trench in a manner that avoids plants. Loss of individuals of common wildlife species, such as small rodents and lizards, would be greater than installing power poles since trenching would result in greater ground disturbance. However, loss of vegetation would be temporary and the number of individuals of sensitive plants and common wildlife species potentially impacted during trenching would likely represent a small percentage of the number of individuals present in the area. Impacts to sensitive wildlife species would also be greater than with the proposed project.

Avoiding sensitive plant species (Mitigation Measures TB-1 and TB-3) and revegetating the area impacted during power line underground installation (Mitigation Measures TB-6 and TB-7) with native species, including any sensitive plant species would reduce impacts to *significant but mitigable* (*Class II*).

Impact TB.2 – Valve Site #2, LOGP, and Power Line Construction Impacts to Freshwater Aquatic Habitats would be similar to the proposed project, *adverse but not significant (Class II)* with mitigation.

5.2.5.5 Replacement of Oil Emulsion Pipeline from Platform Irene to LOGP

Impacts TB.1 and TB.2 would not occur under this alternative as this alternative would eliminate the need for modifications to Valve Site #2 and construction of the transformer station and the new power line. However, construction of the replacement pipeline would have additional impacts as described below.

Impact TB.3 - Pipeline Maintenance Impacts to Vegetation and Wildlife Habitat would be the same as the proposed project. Some reduction in maintenance or repair could be anticipated because the pipeline would be new. Impacts would be *significant but mitigable (Class II).* Mitigation Measures TB-6 and TB-7 would apply.

Impact TB.4 - Pipeline Maintenance Impacts to Listed Plants would be similar to the proposed project. Some reduction in maintenance or repair could be anticipated because the pipeline would be new. Impacts would be *significant but mitigable (Class II).* Mitigation Measures TB-1, TB-8, and TB-9 would still apply.

Impact TB.5 - Pipeline Maintenance Impacts to Listed Wildlife would be similar to the proposed project. Some reduction in maintenance or repair could be anticipated because of the new pipe. Impacts would be *significant but mitigable (Class II).* Mitigation Measures OWR-1, GR-1, and TB-4, scheduling the work during the dry season, TB-5, controlling erosion, TB-6, minimize disturbance to native habitats, and TB-7, preparation and implementation of an approved ~~HRMMP~~restoration and revegetation plan, would still apply.

Impacts TB.6, TB.7, TB.8 - Spill Impacts to Vegetation, Wildlife, and Listed Species would be the same as the proposed project due to the increased throughput levels, although spill frequency would be slightly reduced due to the new pipe, as described in Section 5.1.5.4 (see Section 5.1, Risk of Upset) and there would be a reduced likelihood of a spill at Valve Site #2. Impacts would be *significant (Class I).* Mitigation Measures TB-11 through TB-14 and the Oil Spill Response Plan would still apply.

Impact TB.10 – Construction Impacts to Vegetation: The existing pipeline corridor, from landfall to the LOGP, is estimated to be 12.1 miles long and crosses 16 drainages that are tributaries to the Santa Ynez River. Drainages range in size from 18 to 9,100 acres. Except for Oak Canyon and Santa Lucia Canyon, all of these drain fewer than 250 acres. Oak Canyon drains 1,800 acres and is classified as ephemeral and Santa Lucia Canyon drains 9,100 acres and is classified as intermittent/perennial. As described in Section 5.2.1, the pipeline corridor crosses several native habitats, many of which are considered sensitive habitats and support rare and endangered plant and wildlife species, including federally and state-listed species (discussed below). The current pipeline corridor includes a right-of-way easement approximately 50 feet wide that is maintained to allow vehicle passage. The existing 50-foot wide corridor includes paved or graded dirt roads (regularly used by other vehicles as well as pipeline maintenance), a maintained firebreak, and two-track dirt roads, as well as short segments which lack vehicle access because of steep canyon slopes. In some portions of the maintained right-of-way, the adjacent habitat is in degraded condition or the right-of-way is wider than 50 feet. For example, the coastal foredunes habitat in the project vicinity supports large patches of iceplant and European beachgrass, both invasive exotic species. However, in other areas, such as portions of the Lompoc Oil Field, the~~ROW~~ right-of-way is predominantly covered with native vegetation as a result of past revegetation efforts coupled with natural regrowth.

The project description for the pipeline replacement alternative states that normally a 100-foot wide disturbance corridor would be required during construction. A 50-foot strip would be cleared for construction while the remaining 50 feet of the corridor would be "matted" and used for equipment and personnel access, as needed. Soil disturbance and vegetation removal would not be required in the portion of the corridor that was "matted," however the vegetation would be crushed and left in place. The pipeline replacement project would use the existing 50-foot easement corridor for construction and would remain within this easement as much as feasible.

Following are estimated amounts of disturbed area assuming a 100-foot wide construction corridor and not accounting for existing disturbance within the corridor (except for the 4.6 miles of~~ROW~~ right-of-way which is contained within an existing bladed fuelbreak that extends around the Lompoc Federal Penitentiary and along the eastern VAFB boundary). Given the presence of disturbed areas within the~~ROW~~ right-of-way and the ability to narrow the disturbance corridor through sensitive areas, it is expected that the actual habitat disturbance would be less than described below.

Habitat type	Length	Estimated Disturbed Area*
Within Bladed Fuelbreak	4.5 miles	54.5 acres
Mixed Coastal Scrub and Chaparral	2.3 miles	27.9 acres
Coastal Scrub	2.3 miles	27.9 acres
Burton Mesa Chaparral	1.2 miles	14.5 acres
Oak Woodland	0.6 miles	7.3 acres
Non-native Grassland	0.6 miles	7.3 acres
Agriculture	0.3 miles	3.6 acres
Beach and Foredunes	0.2 miles	2.4 acres
Riparian	0.1 miles	1.2 acres
TOTAL	**12.1 miles**	**146.7 acres**
* Assumes a 100-ft wide disturbance corridor, and does not account for disturbed areas such as roads.		

The temporary disturbance of agricultural land and fuelbreak would not be considered a significant impact. However, the potential temporary loss of the remaining native vegetation and wildlife habitats listed above would be considered significant. Revegetation would take from one year to 5 years or more depending upon the habitat type and the degree of regrowth present since installation of the original pipeline array and subsequent major fire. In addition, loss of individuals of sensitive plant species that may be present in the disturbance corridor, including sand mesa manzanita, La Purisima manzanita, and black-flowered figwort, as well as oak trees and coast buckwheat, would add to this significant impact. Impacts on federally or state-listed plant species are discussed below. Additional indirect impacts to adjacent vegetation and wildlife habitat may occur if ground disturbance or removal of vegetation results in increased soil erosion or if non-native plants become established and expand into existing native habitats. Removal of up to 88.6 acres of native vegetation and wildlife habitat would be temporary and local. Impacts could potentially be significant.

The following mitigation measures shall be implemented: Mitigation Measures TB-4, scheduling the work during the dry season, TB-5, controlling erosion, TB-6 and TB-7, which address, in part, the restoration of native plant species would also reduce loss of native vegetation and wildlife habitat in affected project area.

The project description for the replaced pipeline alternative states that the disturbance corridor may be reduced to 40 feet in width for a distance of up to 200 feet to avoid sensitive resources such as archeological sites or clusters of trees. In this case, construction activities could be restricted to the existing 50-foot disturbed right-of-way and would avoid any new disturbance to existing vegetation. It is assumed that this approach may also be used to avoid or minimize impacts on other sensitive biological resources such as colonies of sensitive plant species, vernal pools or other wetland habitats, as well as native trees. In addition to avoidance or minimization of impacts by narrowing the right-of-way and other means identified above, incorporating any sensitive plant species removed or damaged during project activities into the revegetation plan would further mitigate impacts on these species. The residual impact on sensitive plant species is expected to be not significant with mitigation because of the previously disturbed nature of the corridor, the small portion of the number of individuals present in the adjacent habitat that would be impacted, and the likely success of methods facilitating the recovery of these species on the right-of-way. Implementation of Mitigation Measures TB-6 and TB-7 will reduce overall residual impact on vegetation and wildlife habitat to *significant but mitigable (Class II).*

Impact TB.11 – Construction Impact to Wildlife: Loss of individuals of wildlife species present in the disturbance corridor, other than federally or state-listed species discussed below, is expected to be insignificant because these individuals would represent a small portion of the number of individuals present in the adjacent habitat and because of the previously disturbed nature of the corridor. Temporal loss of habitat resulting from wildlife species avoiding human activities on the corridor is expected to occur throughout the construction period. However this impact would be short-term and local, and would be considered to be *adverse but not significant (Class III)*. Mitigation Measures TB-3 through TB-7 would mitigate Impact TB.11 to the maximum extent feasible.

Impact TB.12 - Construction Impacts to Freshwater Aquatic Habitats and Biota: Most of the expected impacts to aquatic resources from construction activities would occur as a result of direct disturbance to aquatic and associated wetland habitats, direct injury or mortality to aquatic organisms, and indirect impacts from erosion and sedimentation. Mitigation Measures OWR-1, GR-1, TB-18 through TB-22 would serve to reduce impacts to aquatic biota and reduce sedimentation issues to *significant but mitigable (Class II).*

Impact TB.13 – Construction Impacts to Listed Species: Implementation of the pipeline replacement alternative has the potential to remove or damage individuals or colonies of state-listed plant species. Surf thistle and beach spectacle pod, both state-listed threatened plant species, have been recorded in the foredunes habitat crossed by the proposed project. As previously stated, the foredunes habitat in the project vicinity is in degraded condition due to the presence of invasive exotic species such as iceplant and European beachgrass. However, suitable habitat for these species still exists in the project vicinity and there is potential for individuals or colonies to be present within the 100-foot disturbance corridor. Seaside bird's beak, state-listed endangered, is known to occur within or directly adjacent to the pipeline right-of-way north of the Lompoc Federal Penitentiary and west of the LOGP and potentially may be present within the 100-foot disturbance corridor. Gaviota tarplant occurs in several locations along or adjacent to the pipeline right-of-way in coastal sage scrub and grassland habitat. The level of impact would depend on the numbers of individuals lost or damaged and whether that loss represents a significant portion of the colony at a particular location or otherwise affects the ability of that colony to sustain itself. The loss of individuals or colonies of state-listed threatened or endangered plant species would be considered a significant impact.

These measures should be implemented when feasible. Revegetating the area impacted during pipeline installation (Mitigation Measures TB-6 and TB-7) with native species, including any sensitive plant species and coast buckwheat would reduce impacts. Additionally, Mitigation Measures TB-8 and TB-9 would reduce impacts to *significant but mitigable (Class II).*

Impact TB.14 – Construction Impacts to Riparian Species: California red-legged frogs are known to occur in ponds at the Lompoc Federal Penitentiary (adjacent to the pipeline route), and could occur in appropriate habitat in nearby Oak and Santa Lucia canyons. They have also been observed in Santa Lucia Canyon near Pine Canyon gate, upstream of the pipeline crossing (N. Read Francine, VAFB, 2002). During the rainy season, red-legged frogs could be present in upland habitats during movements between aquatic habitats. The new pipeline would cross the riparian habitat in these two canyons, and therefore could have direct or indirect impacts on red-legged frogs. Direct impacts could result from injury or mortality of individuals entering the work area while indirect effects could result from sediment runoff into downstream habitats used by the species. Sediment may decrease the availability of aquatic food organisms and, if work is conducted during the breeding season, sediment may asphyxiate egg and larval stages of California red-legged frogs. Vegetation removal could adversely alter habitat for this species until re-establishment of vegetation is complete.

Southwestern pond turtles occur in the Santa Ynez River system, including tributary drainages with permanent or intermittent water, such as Oak and Santa Lucia canyons. Eggs are laid in riparian and upland habitat adjacent to aquatic habitat. During movements between habitats, pond turtles could be present in the pipeline right-of-way where it passes through riparian and upland habitats. The new pipeline would cross the riparian habitat in these two canyons, and therefore could have direct or indirect impacts on southwestern pond turtles. Direct impacts could result from injury or mortality of individuals entering the work area while indirect effects could result from sediment runoff into aquatic habitats used by the species.

Pipeline replacement is not expected to impact the California tiger salamander because project activities would occur outside the known range of this species.

Impacts to any of these species would be considered a significant impact. Implementation of Mitigation Measures TB-23 through TB-34 would reduce impacts to *significant but mitigable (Class II).*

Impact TB.15 – Construction Impacts to Listed Aquatic Species: No steelhead spawning is known to occur in Santa Lucia Canyon, and during the dry season, steelhead are not likely to be found near the confluence with the Santa Ynez River even if water is present in Santa Lucia Creek. During summer and early fall, this section of the river would likely be shallow, warm, and choked with algae. These conditions provide poor habitat for juvenile steelhead rearing, and both juvenile and adult migration are not expected to occur until sufficient flow is present in the river during the rainy season.

Tidewater gobies occur downstream in the Santa Ynez River estuary all year and upstream in the project vicinity during the winter. A small potential exists for sediment from the project sites to impact tidewater gobies by smothering their nesting burrows and possibly their food items. The turbidity would persist for a short time (a few days or less) and be dispersed by the flowing water. The level of turbidity is expected to be low because of the distance of the pipeline project areas from the Santa Ynez River (approximately 0.5 km) and the relatively small area of impact in each of the drainages.

If construction occurs during the rainy season, the potential exists for storm flows to erode the disturbed banks and erode the excavated channel and transport sediment downstream to the Santa Ynez River. Sediment may decrease the availability of aquatic food organisms and, if work is conducted during the breeding season, sediment may asphyxiate eggs of steelhead and tidewater gobies. Vegetation removal could accelerate erosion and increase downstream sedimentation until re-establishment of vegetation is complete.

Effects to steelhead and tidewater gobies from siltation during the winter are expected to be minor given the large volume of turbid water that flows in the Santa Ynez River during the rainy season. However, impacts would still be considered *significant* because of the potential for suspended sediment to disrupt burrowing (goby only), feeding, juvenile rearing, or seasonal migration.

Implementation of Mitigation Measures identified previously including TB-4, scheduling the work during the dry season; TB-5, controlling erosion; TB-6, minimize disturbance to native habitats; TB-7 and TB-9, preparation and implementation of an approved ~~Habitat, Revegetation, Restoration and Monitoring Plan~~ restoration and revegetation plan; and TB-22, equipment spill control measures; would reduce downstream impacts to listed aquatic species. Implementation of Mitigation Measures identified above would reduce the residual impact to *significant but mitigable (Class II).*

Impact TB.16: Construction Impacts to Coastal Wildlife

Impact #	Impact Description	Phase	Residual Impact
TB.16	Replacement of the pipeline in the coastal beach and foredune habitat, where the pipeline array makes landfall, would result in potential impacts to nesting western snowy plovers and California least terns.	*Construction*	*Class II*

At the western end of the pipeline route, construction activities could disturb western snowy plovers, which nest and winter in the landfall area. Disturbances within the nesting area can result in loss of productivity, either due to the incubating birds being flushed off the nest and the eggs cooling, or from exposure of the eggs to predators. Snowy plovers are known to nest at Wall Beach. Therefore, if construction activities occurred during the nesting season of the snowy plover (March 1 to September 30), plovers could be adversely affected.

California least terns have historically nested near the mouth of the Santa Ynez River, and could also be affected by construction activities if they occurred during their nesting season (April – July), depending on the proximity of the nesting site to the construction activity. Impacts on breeding plovers, if near the construction site, would be considered significant. Other sensitive avian species, such as brown pelican, do not nest here. Pelicans and wintering snowy plovers would likely just move a short distance up or down the beach to avoid human activity. Impacts on pelicans and wintering snowy plovers would be considered adverse but not significant.

Mitigation Measures

The following mitigation measure shall be implemented: Mitigation Measure TB-10, to schedule construction activities within the beach and foredune habitat at Wall Beach to avoid the nesting season for snowy plovers and California least terns.

Residual Impact

Scheduling construction activities at Wall/Surf Beach to avoid the breeding season of the snowy plover and California least tern would reduce impacts to *significant but mitigable (Class II)*.

Impact TB.17: Construction Impacts to Monarch Butterflies

Impact #	Impact Description	Phase	Residual Impact
TB.17	Replacement of the pipeline in the Eucalyptus tree habitat, between Catchment Basins 8 and 9, could result in potential impacts to a monarch butterfly autumnal aggregation site.	*Construction*	*Class II*

An autumnal aggregation site for monarch butterflies exists in the eucalyptus trees between basins 8 and 9. Because this area has been previously disturbed, and no new trees would be removed, it is expected that construction activities would not have a significant impact on monarch butterflies. However, operation of heavy equipment near the aggregation trees when butterflies are present would create noise, dust, exhaust fumes, and other disturbance caused by passing traffic, including mortality to individuals hit or run over by project related vehicles and would be an adverse and significant impact. Therefore, impacts are considered *significant*.

Mitigation Measures

TB-35 Avoid scheduling construction activities between Catchment Basins #8 and #9 when aggregations of monarch butterflies are present, typically during the fall and winter months. Do not remove or trim trees within or surrounding the aggregation site if it would significantly alter temperature or humidity within the aggregation site, due to altered air flow patterns. Include schedule for this area in construction plan (TB-6) and submit to SBC for review and approval prior to land use clearance.

Residual Impact

Implementation of the above mitigation would reduce the impacts to monarch butterflies to *significant but mitigable (Class II).*

5.2.5.6 Alternative Drill Muds and Cuttings Disposal

Inject Drill Muds and Cuttings into Reservoir

There are no additional or changed terrestrial biological resource impacts associated with this alternative.

Transport Drill Muds and Cuttings to Shore for Disposal

There are no additional or changed terrestrial biological resource impacts associated with this alternative.

5.2.6 Cumulative Impacts and Mitigation Measures

5.2.6.1 Offshore Oil and Gas Projects

The proposed project is one of several proposed energy projects in the tri-county area (San Luis Obispo, Santa Barbara and Ventura counties), all of which would contribute incrementally to the cumulative impact scenario. Because of the limited amount and localized impacts of new construction associated with the proposed project, cumulative construction-related impacts are not expected to be significant. However, development of the Tranquillon Ridge Field would extend the life of the Point Pedernales Project, and thus would extend the risk of an oil or produced water spill throughout the life of the project.

Future development on undeveloped federal outer continental shelf (OCS) leases is in question as a result of litigation and continuing objections from the State of California (see Section 4.2). Additionally, several offshore energy projects have been proposed in State waters (Section 4.3). While the exact timing of these developments is unknown, it is possible that they could occur during the drilling and operational phases of the proposed project. Thus, some overlap between the projects may occur, especially with regard to the potential for oil spills from offshore platforms and pipelines.

The original environmental documentation for constructing, installing, and operating the Point Pedernales Project's facilities at permitted levels concluded that impacts from an oil or produced water spill, or release of toxic gas on sensitive plant and wildlife species and their habitats, would be cumulatively significant, depending on the location and season of a spill (County of Santa Barbara 1985 Point Pedernales EIS/EIR). The cumulative impact of greatest concern would be the potential for coastal habitats and species to be affected by an off- or onshore oil spill. Affected resources include the Santa Ynez River and nearby coastal waters, estuaries, and beaches and the species that use these habitats including steelhead, tidewater goby, California least tern, western snowy plover, and California brown pelican.

The mitigation measures recommended in the 1985 Point Pedernales EIS/EIR to address cumulative impacts remain applicable. These include:

- Protection of representative terrestrial and freshwater habitats;
- Design and implementation of a habitat restoration plan for native habitats and sensitive species;
- Long term monitoring of selected biological resources or resource areas;
- Establish a fee system to fund research on long term effects of operations;

- Establish a native plant propagation center to provide locally obtained native plant materials and compatible plant material for revegetation in disturbed areas;
- Habitat rehabilitation, such as to facilitate steelhead migration; and
- Establish guidelines for habitat specific or area specific restoration using native biota and addressing the conflicting objectives of aesthetics, fire hazards, erosion control, etc.

However, oil spill impacts on biological resources that are associated with the cumulative offshore energy projects outlined in Sections 4.2 and 4.3 would still be considered significant.

5.2.6.2 Onshore Projects

As summarized in Section 4.4, within the study area there are numerous new onshore development projects that are either under review or in construction. These include new residential, commercial, industrial and office/business development projects, redevelopment projects, two onshore oil development projects, a wind energy development project, and three projects that may affect resources associated with the Santa Ynez River ~~residential and commercial developments, as well as two onshore oil development projects, that are either under construction or under review~~. Several of these projects would share the existing road that services the LOGP, and have the potential to remove Burton Mesa chaparral habitat, which could be affected by an oil spill from the proposed project. New residential, commercial, industrial and office/business developments (and redevelopment projects), and the wind energy project and two onshore oil development projects could also cause an increase in wildlife mortality from collision with vehicles (and avian mortality from wind turbine collisions associated with the propose wind energy development project), ~~residences in all of these areas could cause an increase in wildlife mortality from collision with vehicles,~~ reductions and fragmentation of habitat, degradation of habitat from introductions of nonnative vegetation into adjacent undeveloped areas, and greater disturbances to wildlife from night lighting, unrestrained pets, and recreational uses (authorized or otherwise) of the surrounding landscape.

The three projects associated with the Santa Ynez River would affect terrestrial and freshwater biological resources. One project is dedicated to habitat enhancement for the Southern steelhead trout, which would be anticipated to result in long-term beneficial impacts to terrestrial and freshwater biological resources, if approved. However, temporary impacts to aquatic and riparian habitats due to fish habitat restoration efforts in the river and its tributaries could occur (U.S. Bureau of Reclamation, 2004). The Bee Rock Quarry Expansion is not anticipated to affect that reach of the Santa Ynez River associated with the proposed project area; its impacts on biological resources are anticipated to occur upstream of Bradbury Dam (County of Santa Barbara, 2006). The third project involves water release modifications from Bradbury Dam, which may negatively impact terrestrial and freshwater biological resources in the lower reaches of the Santa Ynez River. Depending on the final alternative chosen for implementation of this project, if approved, downstream impacts to the Santa Ynez River in the area of Lompoc could include temporary disturbances to wildlife and vegetation during construction of pipelines and related project facilities, possible decreases in riparian growth in the river due to reduced recharge, and possible disturbances to upland habitat (State Water Resources Control Board, 2003).

Mitigation measures related to construction or implementation activities for current and future onshore development projects would serve to reduce some of the adverse impacts associated with biological resources to less than significant levels. Measures to reduce such impacts could include set backs from drainages, wetlands, and other significant natural features, and permanent protection of intact habitats that are adjacent to other protected lands, and project-specific phasing requirements to minimize impacts during time-sensitive periods of the year (such as restricting construction activities during active breeding seasons or during periods when high volumes of water are anticipated to flow through the Santa Ynez River and its tributaries).

Alternatives to the proposed project (VAFB Onshore, Casmalia East Processing Site, and Emulsion Pipeline Replacement) would have significant construction-related impacts on vegetation and wildlife habitat that would be considered cumulatively significant in combination with the other proposed development projects located within in the Lompoc area.

Due to the cumulative impacts on biological resources from other future probable projects in combination with the proposed project, there is a potential for cumulatively significant impacts to occur; however, this would be driven primarily by the other potential development projects because of the magnitude of their construction effects compared to the small and localized construction effects of the proposed project. The proposed project's incremental contribution to these cumulative impacts would be less than significant.

5.2.7 Mitigation Monitoring Plan

Mitigation Measure	Mitigation Requirements and Timing	Method of Verification	Timing of Verification	Party Responsible for Verification
TB-1	Prior to construction, a survey of the power line corridor shall be conducted to verify the locations of sensitive plants, including Gaviota tarplant, La Purisima manzanita, sand mesa manzanita, and dune vegetation that includes coast buckwheat (*Eriogonum parvifolium*), and thus may support El Segundo blue butterfly. Power poles shall be sited to avoid impacting these resources.	Site inspection prior to construction.	Prior to construction or ground disturbing activities.	SBC/CCC-qualified biologist working as part of EQAP or under direction of SBC Permit Compliance (hereafter: SBC EQAP Biologist)
TB-2	Prior to constructing the power line to Valve Site #2, the ~~applicant~~operator shall enter into discussions with VAFB to determine the feasibility of placing the power line on the 13th Street bridge or using the existing VAFB power poles for crossing the Santa Ynez River. If placing the power line on the bridge or the existing poles is determined to be not feasible, the applicant shall site the power poles outside the limits of the Santa Ynez River riparian vegetation, use "raptor-safe" pole designs with the conductors spaced as far apart as possible to minimize the potential for bird wings to span them, install poles and lines outside the breeding season of birds (March 1 through August 15), cover the augered holes if the poles are not installed immediately, elevate the power line above the level of the tree canopy, taking	Review of documentation from VAFB. Review plans and specifications Onsite verification.	Prior to land use clearance for construction of power line. Prior to construction or ground breaking. During construction.	SBC P&D and EQAP Biologist

Mitigation Measure	Mitigation Requirements and Timing	Method of Verification	Timing of Verification	Party Responsible for Verification
	into consideration future growth of the canopy, and fit wires with some type of device to make them more visible, such as bright-colored plastic balls. ~~If the pole lines are of a type that raptors might nest on, investigate the feasibility of~~ Pole designs will either discourage raptor nesting or be made suitable for nesting by fitting the poles with 3 ft. by 3 ft. nesting platforms a minimum of 4 feet above the tops of the poles as recommended by the California Department of Fish and Game (CDFG). CDFG and the U.S. Fish and Wildlife Service (USFWS) will be contacted for review and approval of pole design at the time the power line to Valve #2 is deemed necessary.			
TB-3	Immediately (within 48 hours) prior to each critical pole placement activity, including excavation, foundation installation, pole placement, and stringing, ~~construction~~ applicant-funded surveys within the disturbance area shall be conducted by a SBC- and VAFB-approved wildlife biologist to document and remove individuals of wildlife species encountered, including reptiles, amphibians, and badgers and other burrowing animals, as appropriate to suitable habitat outside the area of impact. The construction area ~~should~~ shall be regularly monitored to ensure that wildlife species do not enter areas where they would be exposed to hazards.	Periodic site visits by qualified biologist prior to and during construction activities.	Prior to and during construction and ground disturbance activities.	SBC EQAP Biologist
TB-4	All ground disturbance activities shall occur, if feasible, during the dry season (generally April 1 through November 1). Work can continue during the rainy season if a County and CCC (if required) approved erosion and sediment control plan is in place. Applicant shall submit construction plans and schedule to SBC and CCC (if required) for review and approval prior to land use clearance.	Site inspection prior to construction.	Prior to construction or ground disturbing activities.	SBC EQAP Biologist
TB-5	Site-specific measures consistent with the Restoration, Erosion Control, and Revegetation Plan (RECRP) approved under Point Pedernales FDP Condition H-1 shall be updated and implemented as applicable to new areas of ground disturbance along the existing ROW. Erosion and sediment control measures (e.g., water bars, silt fencing, dust control, and/or other appropriate measures) shall be implemented at any drainages; along portions of the affected project area that intersect slopes greater than a 2-to-1 incline; and within 200 feet of downslope water bodies. Appropriate erosion and sediment control measures shall be installed prior to ground disturbance and maintained until after the rainy season or until vegetation has become re-established in the disturbed areas. The applicant shall submit erosion and sediment control plans and specifications to SBC for approval prior to land use clearance.	Periodic site inspections during construction on areas being disturbed.	Prior to and during construction during the rainy season and maintained until after the rainy season or until vegetation has become re-established in the disturbed areas.	SBC EQAP Biologist
TB-6	Applicant shall prepare and submit as an update to the RECRP (FDP Condition H-1 and applicable CDP conditions ~~approved under PXP~~), ~~a Standard Maintenance and Repair Plan that will include~~ plans for restricting work areas, delineating construction zones, biological surveys of disturbance areas, and	Plan approval by SBC P&D Department (EQAP) and periodic inspections	Prior to issuance of the coastal development permit and any future land use	SBC EQAP Biologist

Mitigation Measure	Mitigation Requirements and Timing	Method of Verification	Timing of Verification	Party Responsible for Verification
	impact minimization efforts, including scheduling. Where ground disturbances are required, the Plan would specifically include: • Restrict construction activities, equipment and personnel to existing disturbed areas (such as roads, pads, or otherwise disturbed areas) to the maximum extent feasible. • Clearly mark and delineate in the field the limits of the construction zone. Personnel or equipment in native habitats outside the construction limits shall be prohibited. • Biologically sensitive resources, such as occurrences of sensitive plant species including sand mesa manzanita, La Purisima manzanita,Gaviota tarplant, coast buckwheat (which may support El Segundo blue butterfly) and black-flowered figwort as well as individual oak trees, shall be identified through surveys conducted by a qualified biologist acceptable to the resource agencies prior to ground disturbance and shall be clearly marked on work or construction plans so they may be avoided. • Where avoidance of biologically sensitive features is infeasible, the plan shall specify means by which impacts on the features would be minimized and their survival and recovery facilitated (such as preserving the root system and root crown of resprouting species such as sand mesa manzanita).	during construction.	clearances for grading.	
TB-7	Site-specific measures listed in the approved RECRP (FDP Condition H-1 and applicable CDP conditions) shall be updated and implemented as applicable for new areas of ground disturbance along the existing pipeline right-of-way. Prior to the issuance of a Land Use Permit, an updated RECRP ~~a Habitat Revegetation, Restoration, and Monitoring Plan (HRRMP)~~shall be submitted to SBC Planning and Development for approval. SBC Planning and Development shall consult with responsible resource agencies (including, but not limited to: CDFG, CCC, U.S. Army Corps of Engineers) to obtain their concurrence or identify any necessary modifications to the proposed plan. Once approved, the plan shall be implemented by PXP and monitored by SBC Planning and Development through advanced written updates of construction status and plans. Success of the restoration and revegetation plans should be monitored by a qualified independent biologist. The plan shall contain, but not be limited to, the following: • Procedures for stockpiling and replacing topsoil, replacing and stabilizing backfill, such as at stream crossings, steep or highly erodible slopes, and in dune areas. Additionally, provisions ~~should~~ shall be made for recontouring to approximate the original topography. Excess fill shall be disposed of offsite unless suitable arrangements are made with the property owner. Excess fill shall not be deposited in any drainage, or on any unstable slope. Topsoil shall be salvaged, protected, and replaced. This shall include at a minimum the upper 6-12 inches of topsoil in all areas of open land, other than road shoulders. Final construction plans shall designate areas of topsoil storage and protection, and procedures	Plan approval by SBC P&D Department (EQAP) and periodic site inspections during construction.	Prior to the issuance of the coastal development permit and any future land use clearances for grading. Prior to and during construction or ground disturbing activities.	SBC EQAP Biologist

Mitigation Measure	Mitigation Requirements and Timing	Method of Verification	Timing of Verification	Party Responsible for Verification
	for handling excess trench spoils. Within wetland areas, topsoil salvage shall be as described above except that wetland topsoil shall be stored separately from all other spoil piles. It shall be labeled with signs as "wetland topsoil." The plan shall contain specific provisions for protection of topsoil stockpiles (such as covering them or using a tackifier or temporary hydromulch) if the soil is to be left for an extended period of time to prevent loss of topsoil due to erosion. Stockpiles shall not be placed in biologically sensitive areas. • Specific plans for control of erosion, gully formation, and sedimentation, including, but not limited to, sediment traps, check dams, diversion dikes, culverts, and slope drains. Plans would also include, where applicable, dikes and catch basins proposed along the pipeline route, to ensure protection and maintenance of the height of berms and containment capacity of the basins, for the life of project. A soil conservation program, to be applied in areas of 20 percent (or greater) slopes along the pipeline corridor, detailing site specific techniques, such as use of jute or excelsior netting, to stabilize soil and sand and encourage revegetation of steeper slopes. Plans shall identify areas with high erosion potential and the specific control measures for these sites. • Procedures for containing sediment and allowing continued downstream flow at stream or biologically significant drainage crossings (identified in the Point Pedernales EIS/EIR [84-EIR-7]), including scheduling construction activities during periods of historical low-flow and having erosion control structures or sediment retention devices in place prior to start of construction. Existing water levels in all streams shall be maintained at all times during construction. • Procedures for timely re-establishment of vegetation that replicates indigenous and naturalized communities disturbed. These should include: measures preventing invasion and/or spread of undesired plant species; restoration of wildlife habitat; restoration of native communities and native plant species propagated from locally-acquired existing plant species, including any sensitive species (such as sand mesa manzanita, La Purisima manzanita, and black-flowered figwort); and replacement of trees at the appropriate rate. RECRP performance criteria for weed invasion shall be updated to require action to control any and all invasive noxious weeds (listed as of 2007 by the California Invasive Plant "Council) that could interfere with revegetation efforts. Examples include, but are not limited to, Cape ivy (*Delairea odorate*) and onion weed (*Asphodelus fistulosus*). • Procedures for minimizing tree removal, tree root and branch damage, and removal of or damage to other significant plant species including confining disturbance to the approved right-of-way (ROW); providing for onsite monitoring of construction by a qualified independent local biologist; and flagging significant species and areas that should be avoided. • Procedures for restoration of riparian corridor stream banks and streambed substrates and elevation, emphasizing natural and existing materials, shall be included as well as methods for minimizing exposure of riparian habitats to disturbance during construction. • Monitoring procedures and minimum performance			

Mitigation Measure	Mitigation Requirements and Timing	Method of Verification	Timing of Verification	Party Responsible for Verification
	criteria to be satisfied for revegetation and erosion control are specified in Table 5 of the existing RECRP. These criteria shall be updated as necessary ~~the performance criteria~~ for each vegetation type, including percent coverage that must be achieved, monitoring methods and frequencies, and quantitative thresholds for success, reevaluation, or remedial action. Updates to the existing RECRP shall ~~should~~ consider the current level of disturbance and the condition of adjacent habitats. Consistent with the RECRP, monitoring shall ~~should~~ continue for 3-5 years, depending on habitat, or until performance criteria are met. Appropriate remedial measures, such as replanting, erosion control or weed (including invasive exotic species) control, shall be identified, using the existing RECRP as a guideline, and implemented if it is determined that performance criteria are not being met.			
TB-8	Prior to ground disturbance or other activities, a qualified botanist shall survey all proposed construction, staging and access areas for presence of state or federally-listed plant species and for coast buckwheat, which may support El Segundo blue butterfly. Colonies shall be mapped and clearly marked and numbers of individuals in each colony and their condition determined and recorded. To the maximum extent feasible, construction areas and access roads shall avoid loss of individual plant and or damage to habitats supporting federal or state-listed plants.	Review of reports and on site inspections prior to and during construction for avoidance of listed plant species.	Prior to and during construction or ground disturbing activities.	SBC EQAP Biologist (with special botanical qualifications)
TB-9	Where impacts to these species are unavoidable, the applicant shall develop and implement a site- and species-specific salvage, propagation, replanting, and monitoring ~~program~~ plan consistent with the requirements of the RECRP that would utilize both seed and salvaged (excavated) plants constituting an ample and representative sample of each colony of the species that would be impacted. The ~~program~~ plan shall include measures to perpetuate to the maximum extent feasible the genetic lines represented on the impacted sites by obtaining an adequate sample prior to construction, propagating them and using them in the restoration of that site. The ~~program~~ plan shall be approved by the County, CCC, ~~U.S. Fish and Wildlife Service~~ USFWS and CDFG prior to its implementation. Activities involving handling of federal and/or state-listed plant species may require permits including a memorandum of understanding from USFWS and/or CDFG. The plan shall incorporate provisions for recreating suitable habitat and measures for re-establishing self-sustaining colonies of seaside bird's beak, beach spectacle-pod and Surf thistle should they be impacted on the site. The plan shall include provisions for monitoring and performance assessment including standards that would allow annual assessment of progress, and provisions for remedial action, should the species fail to re-establish successfully.	Program plan approval by USFWS and CDFG; field verification by EQAP biologist.	Prior to construction or ground disturbing activities.	SBC EQAP Biologist (with special botanical qualifications

Mitigation Measure	Mitigation Requirements and Timing	Method of Verification	Timing of Verification	Party Responsible for Verification
TB-10	All routine pipeline repair and maintenance activities occurring within the beach and foredune habitats at landfall (Wall/Surf Beach) need to be scheduled to avoid the breeding season (March 1 to September 30) of the western snowy plover and California least tern. A contingency plan for emergency repairs in this area during the nesting season needs to be developed in coordination with 30 CES/CEVPN at VAFB and with the U.S. Fish and Wildlife Service (USFWS). This may require Section 7 consultation. Schedule and timing restrictions for this shall be included in updated RECRP ~~Standard Maintenance and Repair Plan~~ (Mitigation Measure TB-6) to be submitted for SBC review and approval prior to land use clearance. The plan shall include impact avoidance measures to be implemented in the event that emergency repairs cannot be scheduled to avoid the breeding season.	Standard Maintenance and Repair Plan will include timing restrictions. Plan approval by SBC P&D Department (EQAP).	Prior to construction or ground disturbing activities.	SBC P&D and EQAP Biologist
TB-11	The November 2004 Core Oil Spill Response Plan and July 2005 Supplement shall be revised and updated to address increased potential spill volumes and updated procedures for oil and produced water spill clean up beneath ground surface and in sensitive habitats including rivers and streams. This plan shall include updated, site-specific measures for spill containment along watercourses and at other sensitive habitats. It shall specify that sensitive habitats shall be avoided to the maximum extent feasible during oil spill clean up activities. It shall include specific measures to avoid impacts on listed endangered and threatened species during response and repair operations and minimize impacts on riparian and other native habitats. The plan shall include identification of specific access points at locations where containment and clean up efforts can be initiated under different scenarios. ~~The~~Access points shall be reviewed and, if necessary, additional access points shall be ~~need to be~~identified immediately adjacent to pipeline river crossings and points where spilled oil could enter the Santa Ynez River, San Antonio Creek, Santa Maria River, Nipomo Creek, and Los Berros Creek. These updates~~This plan~~ shall be reviewed and approved by SBC ~~the P&D Department~~ prior to land use permit approval.~~construction.~~	Plan approval by SBC P&D	Prior to construction	SBC P&D
TB-12	The Core Oil Spill Response Plan and its Supplement include species- and site-specific procedures for collection, transportation, and treatment of all potentially affected native wildlife, including sensitive species, for topsoil salvage and replacement, and procedures to minimize the loss of native seedbanks and prevent the spread of non-native weeds. Where disturbance to any habitats~~disturbance~~ cannot be avoided as determined by a P&D-approved biologist, these stipulations for development and implementation of these site-specific habitat restoration plans and other site- and species-specific measures for mitigating impacts on	The plan review by the same federal, state, and local agencies as in Measure TB-6a (above) prior to approval by the lead agencies.	Prior to construction or ground disturbing activities.	SBC P&D

Mitigation Measure	Mitigation Requirements and Timing	Method of Verification	Timing of Verification	Party Responsible for Verification
	local populations of all sensitive wildlife species and to restore native plant and animal communities to prespill conditions shall be implemented. ~~November 2004 Core Oil Spill Response Plan and July 2005 Supplement shall be updated to provide stipulations for development and implementation of site-specific habitat restoration plans and other site-specific and species-specific measures appropriate for mitigating impacts on local populations of sensitive wildlife species and to restore native plant and animal communities to prespill conditions.~~ Access and egress points, staging areas, and material stockpile areas that avoid sensitive habitats shall be identified prior to ground disturbance. ~~The Core Oil Spill Response Plan and its Supplement shall include species- and site-specific procedures for collection, transportation, and treatment of all potentially affected native wildlife, including sensitive species, and for topsoil salvage and replacement. The plan shall be reviewed by the federal, state, and local agencies identified in Measure TB-11 prior to approval by the lead agencies.~~			
TB-13	Prior to construction or any ground disturbance activity, the applicant shall ~~develop~~ identify low impact clean up procedures from the ~~for inclusion in the~~ Core Oil Spill Response Plan, and/or updated measures, to be implemented. Where feasible, low-impact site-specific clean up techniques such as hand cutting contaminated vegetation and using low-pressure water flushing from boats shall be specified ~~in the Oil Spill Response Plan~~ to remove spilled material from particularly sensitive wildlife habitats (e.g., coastal estuaries) because procedures such as shoveling, bulldozing, raking, and draglining can cause more damage to a sensitive habitat than the oil spill itself. As described in the Oil Spill Response Plan, the ~~shall evaluate~~ non-clean up option for all native and/or ecologically vulnerable habitats, such as coastal estuaries, shall be considered. Prior to approval of the Land Use Permit, the applicant shall revise the OSRP to update the low-impact clean up procedures consistent with current technology. These strategies shall be reviewed and revised during the required future Plan updates to include best available practices.	The plan review by the same federal, state, and local agencies as in Measure TB-6a (above) prior to approval by the lead agencies.	Prior to construction or ground disturbing activities.	SBC P&D
TB-14	The applicant shall ~~develop and implement a spill response training program~~update the OSRP to ensure that spill response personnel ~~shall be~~are adequately trained for response in terrestrial environments and spill containment and recovery equipment shall be inspected at least annually and maintained at full readiness. Drills shall be conducted at least annually and the results evaluated so that spill response personnel are familiar with the equipment and with the project area, including sensitive terrestrial biological resources. Rehabilitation centers, within the project area, for birds and other wildlife species affected by spilled material shall be involved in the	Program adequacy shall be determined by the lead and responsible agencies.	Prior construction or ground disturbing activities and subsequently on an annual basis.	SBC P&D

Mitigation Measure	Mitigation Requirements and Timing	Method of Verification	Timing of Verification	Party Responsible for Verification
	drills. If a rehabilitation center is not available in the project area, the applicant shall contribute a pro-rata share of funds necessary to cover the costs of establishing and operating a bird and wildlife rehabilitation center.			
TB-15 (VAFB Onshore and Power Line – Option 2b Alternatives only)	If construction activities are scheduled to occur during the breeding season of yellow warblers or yellow-breasted chat (March 1 through September 30), pre-construction surveys shall be carried out by a qualified biologist to determine if nests of any of these species are present within 100 meters from these locations. If nests are found, construction activities shall be postponed until after the end of the breeding seasons of these species, on October 1. Results of surveys and recommended actions shall be submitted to SBC for review and approval prior to construction.	Survey by a qualified biologist.	Prior to construction activities within 100 meters of habitat.	SBC EQAP Biologist
TB-16 (VAFB Onshore and Power Line – Option 2b Alternatives only)	Prior to commencement of boring, a detailed site-specific Frac-Out Contingency Plan shall be developed that would include, but is not limited to the following, site analysis to determine optimum depth to prevent "frac-outs", use of fluorescent dye in drilling fluids, seasonal restrictions on work to be conducted, mapped locations of sensitive resources, measures to reduce the project footprint. The plan shall also contain methods to identify, report, and respond to "frac-outs," including notification procedures, response equipment staging, and site-specific clean-up procedures.	Plan approval by SBC P&D Department, Energy Division (EQAP).	Prior to commence-ment of boring.	SBC P&D and EQAP Biologist.
TB-17 (VAFB Onshore and Power Line – Option 2b Alternatives only)	All boring activities shall be monitored to ensure all precautionary measures are taken to prevent release of drilling fluids into aquatic and terrestrial habitats. Prior to construction, bore crews and monitors shall receive specific training in operational methods to reduce the incidence of frac outs, and in frac out response and reporting procedures. Documentation that training has been completed shall be submitted to SBC and CCC for review and approval prior to construction.	Verification of training (monitor participates) followed by periodic onsite inspections during boring activities.	Prior to and during any boring.	SBC P&D and EQAP Biologist.
TB-18 (VAFB Onshore, Casmalia, and Emulsion Pipeline Replacement Alternatives only)	Erosion and sediment control measures, including the use of silt fencing, dust control, and other appropriate measures, shall be implemented at drainages; along portions of the~~ROW~~ right-of-way that intersect slopes greater than a 2-to-1 incline; and within 200 feet of downslope water bodies. Appropriate erosion and sediment control measures shall be installed prior to ground disturbance and maintained until revegetation of the disturbed area is considered successful. Applicant shall submit erosion and sediment control plans and specifications to SBC for approval prior to land use clearance.	Periodic site visits prior to and during construction activities.	Prior to and during construction and ground disturbance activities.	SBC EQAP Biologist

Mitigation Measure	Mitigation Requirements and Timing	Method of Verification	Timing of Verification	Party Responsible for Verification
TB-19 (VAFB Onshore, Casmalia, and Emulsion Pipeline Replacement Alternatives only)	Drainages shall be restored to original contours after construction activities in order to preserve downstream biological resources and minimize sedimentation. Plans for drainage recontouring shall be included in the ~~HRRMP~~restoration and revegetation plan (TB-7) and submitted to SBC/CCC for review and approval prior to land use clearance.	Periodic site visits by qualified biologist prior to and during construction activities.	Prior to and during construction and ground disturbance activities.	SBC EQAP Biologist
TB-20 (VAFB Onshore, Casmalia, and Emulsion Pipeline Replacement Alternatives only)	All ground disturbances activities shall occur during the dry season (generally April 1 through November 1).	Periodic site visits by qualified biologist prior to and during construction activities.	Prior to and during construction and ground disturbance activities.	SBC EQAP Biologist
TB-21 (VAFB Onshore, Casmalia, and Emulsion Pipeline Replacement Alternative only)	Applicant-funded SBC/CCC-qualified biological monitors shall be on-site during construction activities to ensure avoidance of individual animals and minimization of habitat destruction.	Periodic site visits by qualified biologist prior to and during construction activities.	Prior to and during construction and ground disturbance activities.	SBC EQAP Biologist
TB-22 (VAFB Onshore, Casmalia, and Emulsion Pipeline Replacement Alternatives only)	A construction spill response plan shall be prepared prior to the onset of construction to ensure a prompt and effective response to any accidental spills or leaks of diesel, gasoline, oil or other contaminating materials. Examples of measures would include the following: All equipment will be inspected for fuel, lubricant, and hydraulic fluid leaks prior to and during the work. Any leaks will be repaired immediately. Drip pans will be used to capture leaked fluids until the repair is completed. Fueling of stationary equipment will be by fuel truck and no equipment shall be fueled or maintained within 100 feet of drainages. Fueling or maintenance will occur over a drip pan or in a lined fueling area. Plan to be submitted to SBC for review and approval prior to land use clearance.	Plan approval by SBC P&D Department, Energy Division (EQAP) and appropriate agencies.	Plan approval prior to construction activities.	SBC P&D and EQAP Biologist
TB-23 (VAFB Onshore, Casmalia, and Emulsion Pipeline Replacement Alternatives only)	Preconstruction surveys shall be conducted by SBC/CCC-approved biologists with suitable experience to determine the presence of California red-legged frogs and other sensitive species no more than 30-days prior to construction. If surveys indicate that California red-legged frogs would likely be present in the work areas in or near stream crossings or riparian vegetation, construction activities shall be postponed and federal and state agencies shall be contacted to coordinate suitable protection measures (such as relocations, through authorization for incidental take, or avoidance) for implementation by the applicant. If southwestern pond turtles, two-	Survey by qualified biologist prior to construction activities.	Prior to construction and ground disturbance activities.	SBC EQAP Biologist (with special CRLF qualifications)

Mitigation Measure	Mitigation Requirements and Timing	Method of Verification	Timing of Verification	Party Responsible for Verification
	striped garter snakes or other sensitive species are encountered in work areas they shall be relocated or otherwise protected from harm by means acceptable to CDFG. Preconstruction survey documentation shall be submitted to SBC/CCC for review and approval prior to the commencement of construction.			
TB-24 (VAFB Onshore, Casmalia, and Emulsion Pipeline Replacement Alternatives only)	Before any construction activities begin on the project, the biological monitor(s) shall conduct an employee training session for all construction crews and others present during construction. At a minimum, the training shall include a discussion of the biology, identification, and habitat needs of California red-legged frogs and the importance of their habitat, their status under the California Endangered Species and Federal Endangered Species Acts, and measures taken for the protection of these species and their habitat as part of the project. Upon completion of the orientation, employees shall sign a form stating that they attended the program and understand all protection measures for the species. Documentation of training shall be submitted to SBC/CCC for approval prior to construction.	Verification through completing a sign-up form for all attendees during training.	Prior to construction and ground disturbance activities.	SBC EQAP Biologist
TB-25 (VAFB Onshore, Casmalia, and Emulsion Pipeline Replacement Alternatives only)	Construction shall be scheduled to avoid the rainy season (after first soaking rains through April) when California red-legged frogs would be most likely to be moving between different bodies of water. Construction shall be completed between April 1 and November 1. If necessary, the project proponent shall seek approval from the Corps and the USFWS to work outside of this time period.	Periodic site visits by qualified biologist prior to and during construction activities.	Prior to any construction and ground disturbance activities.	SBC EQAP Biologist
TB-26 (VAFB Onshore, Casmalia, and Emulsion Pipeline Replacement Alternatives only)	An applicant-funded qualified SBC/CCC-approved California red-legged frog biologist shall be present throughout the construction phase to monitor for the species and to implement additional mitigation for the species. The approved biologist shall have the authority to halt any action that might result in impacts that exceed the levels anticipated during review of the action by the Corps and the USFWS. Documentation shall be included as part of SBC Environmental Quality Assurance Program (EQAP).	Periodic site visits by qualified biologist prior to and during construction activities.	Prior to and during construction and ground disturbance activities.	SBC EQAP Biologist (with special CRLF qualifications)
TB-27 (VAFB Onshore, Casmalia, and Emulsion Pipeline Replacement Alternatives only)	The pipeline trench shall be provided with escape ramps constructed of earth fill to prevent entrapment of sensitive species or other animals during the construction phase of the project. The ramps shall be located at no greater than 1,000-foot intervals and be constructed at less than 45 degrees inclination. Include plans and specifications as part of TB-6 plan submitted by applicant to SBC/CCC for review and approval prior to land use clearance.	Periodic site visits by qualified biologist during construction activities.	During construction and ground disturbance activities.	SBC EQAP Biologist
TB-28 (VAFB Onshore, Casmalia, and Emulsion Pipeline	All trenches, open pipes and culverts, or similar structures at the construction site open for one or more overnight periods shall be thoroughly inspected for trapped animals by an SBC/CCC-qualified, applicant-funded biologist before the pipe is subsequently buried, capped, or otherwise used or moved in any way. Pipes in, or adjacent to, trenches	Periodic site visits by qualified biologist during construction activities.	During construction and ground disturbance activities.	SBC EQAP Biologist

Mitigation Measure	Mitigation Requirements and Timing	Method of Verification	Timing of Verification	Party Responsible for Verification
Replacement Alternatives only)	left overnight shall be capped by the applicant and/or their contractors. If an animal is discovered inside a pipe during construction, that section of pipe shall not be moved, or if necessary, moved only once, to remove it from the path of construction until the animal has voluntarily escaped. Include plans and specifications as part of TB-6 plan submitted by applicant to SBC/CCC for review and approval prior to land use clearance.			
TB-29 (VAFB Onshore, Casmalia, and Emulsion Pipeline Replacement Alternatives only)	Applicant shall ensure that all trash that may attract predators shall be properly contained, removed from the work site, and disposed of regularly. Following construction, all trash and construction debris shall be removed from work areas. Include plans and specifications as part of TB-6 plan submitted by applicant to SBC/CCC for review and approval prior to land use clearance.	Periodic site visits by qualified biologist during construction activities.	During construction and ground disturbance activities.	SBC EQAP Biologist
TB-30 (VAFB Onshore, Casmalia, and Emulsion Pipeline Replacement Alternatives only)	If dewatering is necessary, intakes shall be completely screened with wire mesh (not larger than five millimeters mesh size) to prevent California red-legged frogs from entering the pump system. Water shall be released or pumped downstream at an appropriate rate to maintain downstream flows during construction. No water containing any sediment shall be allowed to flow back into any flowing water. Upon completion of construction, any barriers to flow shall be removed in a manner that would allow flow to resume with the least disturbance to the substrate. Include plans and specifications as part of TB-6 plan submitted by applicant to SBC/CCC for review and approval prior to land use clearance. Verify compliance as part of EQAP.	Periodic site visits by qualified biologist during construction activities.	During construction and ground disturbance activities.	SBC EQAP Biologist
TB-31 (VAFB Onshore, Casmalia, and Emulsion Pipeline Replacement Alternatives only)	An SBC-approved biologist shall permanently remove from within suitable habitat in the disturbance corridor any individuals of exotic species, such as bullfrogs, crayfish, and non-native fishes, to the maximum extent possible. Include plans and specifications as part of TB-6 plan submitted by applicant to SBC/CCC for review and approval prior to land use clearance.	Periodic site visits by qualified biologist during construction activities.	During construction and ground disturbance activities.	SBC EQAP Biologist (with special CRLF qualifications)
TB-32 (VAFB Onshore, Casmalia, and Emulsion Pipeline Replacement Alternatives only)	Surveys in suitable habitat shall be conducted on a regular basis (twice a week at night) during the construction phase to ensure that California red-legged frogs are not present in the work areas. Include plans and specifications as part of TB-6 plan submitted by applicant to SBC/CCC for review and approval prior to land use clearance.	Periodic site visits by qualified biologist during construction activities.	During construction and ground disturbance activities.	SBC EQAP Biologist (with special CRLF qualifications)

Mitigation Measure	Mitigation Requirements and Timing	Method of Verification	Timing of Verification	Party Responsible for Verification
TB-33 (VAFB Onshore, Casmalia, and Emulsion Pipeline Replacement Alternatives only)	If construction work is scheduled to occur during the period April 1 to August 1, a qualified avian biologist shall survey riparian habitat within 100 feet of the right-of-way. If surveys reveal Cooper's hawks, yellow warblers, or yellow-breasted chats are nesting within 100 feet of the right-of-way, construction activities in those areas shall be postponed until after the conclusion of the nesting period, April 1 to August 1. Include plans and specifications as part of TB-6 plan submitted by applicant to SBC/CCC for review and approval prior to land use clearance.	Periodic site visits by qualified biologist during construction activities.	During construction and ground disturbance activities.	SBC EQAP Biologist (with special field ornithology qualifications)
TB-34 (VAFB Onshore, Casmalia, and Emulsion Pipeline Replacement Alternatives only)	Drainage and wetland crossings shall be revegetated with an appropriate assemblage of native riparian and wetland species suitable for the area. A species list and restoration and monitoring plan shall be included with the project proposal for approval by SBC/CCC. This plan must include, but not be limited to, location of restoration, species to be used, restoration techniques, timing of restoration, identifiable success criteria for completion, and remedial actions if the success criteria are not achieved. Include plans and specifications as part of TB-6 plan submitted by applicant to SBC/CCC for review and approval prior to land use clearance.	The restoration and monitoring plan shall be approved by SBC P&D Department (EQAP).	Prior construction and ground disturbance activities.	SBC P&D and EQAP Biologist
TB-35 (Emulsion Pipeline Replacement Alternative only)	Avoid scheduling construction activities between Catchment Basins #8 and #9 when aggregations of monarch butterflies are present, typically during the fall and winter months. Do not remove or trim trees within or surrounding the aggregation site if it would significantly alter temperature or humidity within the aggregation site, due to altered air flow patterns. Include schedule for this area in construction plan (TB-6) and submit to SBC for review and approval prior to land use clearance.	Periodic site visits by qualified biologist prior to and during construction activities.	Prior to and during construction and ground disturbance activities.	SBC EQAP Biologist

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5.3 Geological Resources

This section describes the geologic setting, faults, seismicity, and other geologic considerations pertaining to the proposed project. Ground disturbances would be associated with the modifications at Valve Site #2, installation of power poles and the substation, and pipeline repair and maintenance activities. Discussions of the physiography, stratigraphy, and related geotechnical properties (e.g., erosion, slope stability, expansive/ collapsible soils) are included for the offshore bottomhole locations and existing pipeline route. A probabilistic seismic hazard analysis is provided for the entire project area. This section also describes general geohazards associated with the seismic setting (e.g., ground accelerations, liquefaction). Specific probabilities of pipeline and associated facility failure 5.1, Risk of Upset/Hazardous Materials.

5.3.1 Environmental Setting

5.3.1.1 Physiography

The project site is located in the Santa Maria Basin region. Within the basin, the project pipeline traverses the offshore Mainland Shelf, Lompoc Valley, Burton Mesa, Purisima Hills, Solomon Hills, Casmalia Hills, and the Santa Maria Valley. The Mainland Shelf area is a relatively flat area with slopes less than one degree from the shoreline to approximately 330 to 360 feet (100 to 110 meters) of water depth. Water depths along the offshore pipeline route vary from sea level to 243 feet at Platform Irene (Arthur D. Little, 1985).

The pipeline landfall is located approximately 1.4 miles (4.3 kilometers) north of Surf on a 400-foot (124-meter) wide, gently sloping, sandy beach. The onshore pipeline from landfall to the Lompoc Oil and Gas Plant (LOGP) traverses easterly, roughly paralleling the north margin of the Lompoc Valley. The pipeline then traverses northeastward and eastward through a portion of Burton Mesa, a mildly dissected planar surface that is tilted slightly to the south and stretches from the Purisima Hills on the north and east to the Lompoc Valley on the south. From the LOGP northward, the pipeline traverses approximately one mile of highlands and bedrock ridges before descending into the San Antonio Valley and Harris Canyon (Arthur D. Little, 1985). From Orcutt northward, the pipeline traverses the relatively flat Santa Maria River Valley.

5.3.1.2 Stratigraphy

The bedrock stratigraphy of the onshore and offshore portions of the Santa Maria Basin is relatively similar. The bulk of the offshore sequence comprises Pliocene and Miocene age strata that correlate with the onshore Careaga sand, Foxen claystone, Sisquoc Formation laminated diatomite and diatomaceous shale, and Monterey shale (Dibblee, 1988). The offshore Pleistocene and Holocene section is composed of marine unconsolidated muds, silts, and sands, which mantle underlying Tertiary bedrock (Payne, et al., 1979). The offshore unconsolidated sediments are generally less than 100 feet thick in the vicinity of Platform Irene. The thickness of these sediments generally decreases, and the grain size increases toward shore. The sediments range from sandy and clayey silts to silty fine sand and then fine sand as one progresses from the top of the continental shelf toward shore (Arthur D. Little 1985).

Only three main stratigraphic units are crossed along the pipeline corridor from landfall to the LOGP. Between landfall and the location where the alignment climbs out of the Lompoc Valley, the alignment weaves in and out of poorly defined contacts between recent stream alluvium, stream terrace and alluvial fan deposits, and Orcutt Sands. The alignment across the Burton Mesa is underlain by the Orcutt Sand composed of friable to locally indurated aeolian sand, except in channel crossings where thin alluvium deposits are present. From LOGP to Orcutt, the pipeline crosses Orcutt Sand, Paso Robles Formation, the Careaga Sand, the Sisquoc Formation, and Foxen Claystone of the Burton Mesa and Purisima Hills. The pipeline then crosses unconsolidated alluvium of the San Antonio Valley and Harris Canyon (Arthur D. Little, 1985). From Orcutt northward, the pipeline primarily traverses the alluvial-filled Santa Maria Valley.

5.3.1.3 Erosion

The onshore surficial soil deposits are generally erodible; however, vegetative cover generally arrests erosion. Wind erosion (aeolian) is prevalent at the pipeline landfall location, where extensive dunes are present. In addition, potential erosion may occur along slopes located approximately one-half mile south of Orcutt (Arthur D. Little, 1985). Generally, the unconsolidated, uncemented and granular nature of all the formations renders them susceptible to erosion, particularly on slopes.

5.3.1.4 Scour

Scour as discussed in this section is defined as removal of soil particles along stream channels caused by concentrated flow. In addition, scour is caused in the littoral zone by wave action along the oceanfront. The former type of scour is prevalent throughout the Santa Ynez River floodplain and seems to be the primary cause of the destruction of the former 35th Street Bridge across the river, movements in the railroad trestle at the mouth of the Santa Ynez River, and maintenance problems with the 13th Street Bridge. Alluvial/stream channel deposits are subject to scour and redeposition during periods of high surface runoff. The depth of scour and erosion is variable. Limited information suggests that the depth of scour in a stream channel can be as much as three to four times the height of rise in river stage. The pipeline crosses the Santa Ynez and Santa Maria floodplains in areas susceptible to scour during flood conditions. In addition, scour is expected at areas of concentrated flow where stream channels enter the floodplains (Arthur D. Little, 1985; Staal, Gardner & Dunne, 1991) or along smaller drainage channels such as San Antonio Creek.

5.3.1.5 Slope Stability

The onshore and offshore sediments are locally prone to landslides. Onshore, the occurrence of landslides is related to a variety of factors, including excess precipitation, changes in drainage characteristics, excess load, removal of lateral or underlying support at the toe of a slope, oversteepening of a slope, exposure of bedding planes that dip out of slope, removal of vegetation, seismic activity, or a combination of these factors.

Landslides can be classified into four general types: falls, rotational slides, translational slides, and flows. Rotational slides predominate in the shale and claystone formations and associated soils where weathered material exhibits large dessication cracks during dry periods. Such cracks facilitate infiltration of precipitation following dry periods, which in turn can lead to temporary saturated conditions along the contact between weathered and unweathered material, increased hydraulic head, decreased shear strength of the weathered material, and increased likelihood of failure. Translational landslides typically occur along bedding planes in the Sisquoc and

Monterey Formations. These rock units contain abundant interbeds of diatomite and bentonite, which when saturated with water, expand and form lubricated surfaces which act as sliding planes for landslides.

A review of aerial photographs indicate that a number of small to large landslides exist along the pipeline route in the southern project area. The slides are located in three general areas, including: (1) the north-facing slopes of the Lompoc Terrace; (2) near major drainage channels; and (3) in the Purisima Hills (Arthur D. Little, 1985).

Offshore, thick deposits of unconsolidated sediments are prone to failure. This primarily occurs in steeply sloping areas but can also occur on slopes of only a few degrees. Areas with evidence of previous instability have a high potential for future instability and thus such areas are potential geologic hazards to the project pipeline. However, no areas of mass movement have been mapped in the vicinity of the pipeline. Most mass transport areas in the vicinity of the proposed project are located further seaward along the shelf-slope break and associated submarine canyons (Arthur D. Little, 1985).

5.3.1.6 Seafloor Channels and Buried Channels

Offshore, steep slopes and steep-walled submarine canyons are potential geologic hazards to the existing pipeline due to potential turbidity currents and debris flows. Buried channels are features that were cut during periods of lower sea level and subsequently infilled with sediments by transgressing seas or by shifting submarine canyon/fan systems. Shallow buried channels are potential geologic hazards because of potential contrasts in geotechnical properties between the infilling sediments and the surrounding sediments. However, the offshore pipeline route is not located in the immediate vicinity of either buried or seafloor channels (Arthur D. Little, 1985). Also, as per the 1985 Point Pedernales EIR/EIS geology technical appendix, there are no rocky outcroppings which could present a geological constraint along the offshore pipeline route.

5.3.1.7 Shallow Gas, Gasified Sediments, and Seeps

Gas within shallow sediments can occur in three forms: 1) as pockets or zones within unconsolidated sediments (gasified sediments); 2) as zones within the upper portions of consolidated formations (shallow formational gas); and 3) as gas seeps either in the form of gas bubbles (water column anomalies) or tar mounds on the sea floor. All three types of gas occurrences are found throughout the offshore site vicinity. Shallow formational gas is widespread throughout the eastern portion of the Central Santa Maria Basin. Gasified sediment zones are considered potential geologic hazards because: 1) large contrasts in load-bearing capacity may exist within these zones or between these zones and the surrounding sediments; 2) dissolved gas in interstitial spaces can contribute to spontaneous liquefaction of sediments when subjected to cyclic loading under abnormal conditions; and 3) interstitial gas could contribute to spontaneous slope failure by effectively lowering the shear strength of the sediments. Short zones of gasified sediments are present along the offshore pipeline route. These zones occur in areas of very gentle (less than one percent) seafloor slopes. On sloping ground, liquefaction induced by gasified sediments could result in slope failure. Shallow formational gas is present beneath the pipeline route at depths of 300 feet (90 meters) or more (Arthur D. Little, 1985).

5.3.1.8 Expansive/Collapsible Soils

Certain soils, when exposed to wetting as a result of natural conditions or construction activities, undergo volume change. This volume change is generally limited to the uppermost few feet (less than 10 feet or 3 meters) and is critical in the engineering design of structures. In general, clays are expansive and loose deposits of sand or silt are collapsible. The pipeline traverses cohesionless deposits formed of sands, silty sands, and sandy silts over most of its onshore alignment. Silts and clays are also locally present. In general, the bearing capacity and settlement characteristics of soils along the alignment are good. However, the Orcutt Sand, intermittently present from landfall at Surf, eastward and northward to the San Antonio Valley, is subject to collapse. Only in limited zones of clay are expansive clays present, such as in the Purisima Hills between Lompoc and Orcutt (Arthur D. Little, 1985).

The oil plant portion of the LOGP facility has experienced subsidence (settlement) since installation. Subsidence has occurred near the crude tank and the processing equipment as well as the control building. Ground elevation monitoring since 1992 has measured settlement ranging from 0.3 to 1.3 feet (0.09 to 0.4 meters). These areas have required remedial action to prevent damage to the facility, which has ranged from additional bracing to subsurface grouting to form columns down to stable soils (about 50 feet or 15.2 meters). Settlement began to decrease in 1998 and the rate of settlement in late 2005 is generally very low. The gas plant (installed after the oil plant) was completely excavated before installation and therefore has not exhibited any subsidence issues. Orcutt Sand and alluvial fan and valley fill areas are present at and to the south of the LOGP facility.

5.3.1.9 Liquefaction

Liquefaction is the almost complete loss of strength of saturated sandy or silty soil accompanying ground shaking during an earthquake. On sloping ground, liquefaction usually results in slope failure called lateral spreading. The unconsolidated offshore sediments are generally not dense and, therefore, are susceptible to liquefaction. Although there is no historic evidence of liquefaction along the onshore project route, most of the low coastal plains and valley bottoms underlain by alluvium, such as the Santa Ynez River, San Antonio Creek, Santa Maria River, and Sisquoc River flood plains have a moderate potential for liquefaction. The remainder of the onshore sediments is generally not susceptible to liquefaction, as groundwater is generally deeper than 50 feet (15.2 meters) along the pipeline route. However, local high groundwater conditions may create conditions susceptible to liquefaction (Arthur D. Little, 1985; Staal, Gardner & Dunne, 1991).

5.3.1.10 Faulting and Seismicity

This section describes faults and associated seismicity that may have an impact on the proposed projects. The determination of which faults are relevant is based on the recency of activity, the potential for causing surface faulting, and the potential for generating earthquakes that could cause damaging ground motion. Specifically, faults are either active, potentially active, or inactive. These faults can be classified as historically active, active, potentially active, or inactive, based on the following criteria (CGS, 1999):

- Faults that have generated earthquakes accompanied by surface rupture during historic time (approximately the last 200 years) and faults that exhibit aseismic fault creep, but in which no earthquakes have been observed, are defined as **Historically Active**.

- Faults that show geologic evidence of movement within Holocene time (approximately the last 11,000 years) are defined as **Active**.
- Faults that show geologic evidence of movement during the Quaternary (approximately the last 1.6 million years) are defined as **Potentially Active**.
- Faults that show direct geologic evidence of inactivity during all of Quaternary time or longer are classified as **Inactive**.

Although it is difficult to quantify the probability that an earthquake will occur on a specific fault, this classification is based on the assumption that if a fault has moved during the Holocene epoch, it is likely to produce earthquakes in the future. Table 5.3.1 is a summary of active and potentially active faults that may have an impact on the project. Many of these faults are located within Santa Barbara and San Luis Obispo Counties.

Table 5.3.1 Summary of Significant Faults and Associated Maximum Earthquakes for the Project Area and Study Region

Fault or Fault Systems	Activity [1]	Fault Length, miles/km	Maximum Estimated Magnitude [2]
Hosgri Fault	PA-A	108/172	7.3
Santa Lucia Bank Fault	PA-A	68/114	7.5
Unnamed Faults on Santa Lucia Bank	PA-A	48/80	7.5
Offshore Lompoc Fault	A	12/20	6.5
Offshore Purisima Fault	PA	16/26	6.5
Point Conception (F-1) Fault Zone	A	12/20	6.5
Molino Fault	A	5/9	6.0
Santa Ynez Fault (with South Branch)	PA-A	83/133	6.9
Lompoc-Solvang (Santa Ynez R.) Fault	I	-	-
Pacifico Fault	I	-	-
Honda Fault	I	-	-
Lions Head	I	26/41	-
Pezzoni-Casmalia Fault	I-PA (?)	18/29	6.5
Los Alamos-Baseline Fault System	A-PA	36/55	7.0
Santa Maria River-Foxen Canyon - Little Pine Fault System	PA	62/100	7.4
Santa Maria/Bradley Canyon Faults	I	-	-
Orcutt Oil Field Faults (except north trace)	I	-	-
Arroyo Parida-Santa Ana Fault	PA	43/69	6.7
Big Pine Fault	PA-A	26/41	6.7
Rinconada Fault (northern segment)	PA	119/190	7.5
South Cuyama, Ozena, Panza Faults, etc.	PA (?)	21/35	6.75
San Andreas Fault Zone (Carrizo-Cholame segments)	A	678/1130	7.3-7.4
White Wolf-Pleito Fault	A	57/95	7.2
Garlock Fault	PA-A	158/252	7.3

Source: USGS Hazard Maps (1996), Arthur D. Little (1995).

1. *A-Fault shows evidence of displacement or seismicity within the last 11,000 years (Holocene Epoch); active. PA-Fault shows evidence of displacement older than 11,000 years, but younger than approximately 500,000 years; potentially active. I-Fault shows no evidence of displacement within the last 500 years; inactive.*
2. *Magnitude estimate from CGS (2003), Petersen, et. al (1996) for onshore faults; and Slemmons (1977) length-magnitude relationships for offshore faults. Magnitudes are surface wave magnitudes, (Mw).*

No active faults traverse the project pipeline route; however, several potentially active faults do traverse the route, including the Lion's Head, Casmalia, Santa Maria, Bradley Canyon, and Santa Maria River faults (California Department of Mines and Geology (CDMG), 1994).

Table 5.3-1 also lists the maximum estimated earthquake considered capable of occurring on faults in the Central Santa Maria Basin region. These magnitudes are based on seismological data such as maximum historical earthquakes and on geologic data such as fault length and fault displacement parameters (Petersen et al, 1996; CGS, 2003). The maximum estimated magnitudes for offshore faults were calculated using empirical data of Slemmons (1977) of fault length and surface wave magnitude relationships (Arthur D. Little, 1985).

Offshore faults potentially capable of generating strong ground motion at project facilities include the Hosgri, Offshore Lompoc, Offshore Purisima, and Santa Lucia Bank faults. Several major unnamed faults are also present offshore west of the Santa Lucia Bank fault. Onshore faults potentially capable of generating strong ground motion at project facilities include the Santa Ynez, Pezzoni-Casmalia, Santa Maria River-Foxen Canyon-Little Pine, Rinconada, Bradley Canyon, and San Andreas faults. The Santa Maria River, Pezzoni-Casmalia, and Bradley Canyon faults, which traverse the project pipeline, are potentially capable of surface rupture (Arthur D. Little, 1985; Staal, Gardner & Dunne, 1991; County of Santa Barbara, 1979).

Earthquake epicenters in the regional vicinity of the site are scattered throughout Santa Barbara and San Luis Obispo Counties, with a cluster of epicenters located offshore of southeastern Santa Barbara County. Notable features of the seismicity in this region include: 1) the relatively low level of activity (both frequency and magnitude) compared to the eastern Santa Barbara Basin; 2) the general random distribution of epicenters; and 3) the occurrence of a swarm of earthquakes in the vicinity of the Santa Lucia Bank in October and November of 1969. Except for perhaps the Santa Lucia Bank swarm, none of the earthquake trends are readily correlated to known faults (Schell, 1979). This may be due to long recurrence intervals for major faults, or to the poor location accuracy of seismographic networks in the area (Arthur D. Little, 1985).

The largest earthquakes in the region were the 1812, 1857, and 1927 earthquakes. The 1812 earthquake probably occurred within the Western Transverse Ranges geomorphic province (USGS, 1976). The magnitude and epicenter of this event are poorly understood, but based on reports of damage and the occurrence of tsunamis, it appears to have been a shallow-focus, large-magnitude earthquake (magnitude greater than 7.0), which occurred offshore in the Santa Barbara Basin. Several major faults in the vicinity of the presumed epicenter location are sizeable enough to have generated such a large earthquake, and thus no correlation can be made with confidence (Arthur D. Little, 1985).

The 1857 earthquake of magnitude approximately 7.9 occurred on the San Andreas fault. The 1927 event of magnitude 7.3 (Gutenberg and Richter, 1954) was probably associated with one of the northwesterly-trending faults of the California Continental Borderland (Gawthrop, 1978; Hanks, 1979; Schell, 1979; Yerkes, 1980) and caused damage in the town of Surf. Although the source of the earthquake is controversial, the presence of long active and potentially active faults, such as the Santa Lucia Bank faults, the Hosgri fault, and the Offshore Lompoc fault, indicates that earthquakes in the 7.5 magnitude range can be generated by more than one source in this region (Arthur D. Little, 1985).

Other notable earthquake events in the project region were the 1902 and 1915 Los Alamos earthquakes of approximate magnitude of 5.5. These events were probably associated with onshore faults in the Los Alamos area, which show evidence of very young, probably Holocene, near-surface displacements (Guptil, et al., 1980).

An example of the effects of a small to moderate magnitude earthquake on nearby oil platforms and related facilities is provided by the August 13, 1978 earthquake that occurred in the Santa Barbara Basin. The magnitude of the event was approximately 5.4 (Lee et al., 1979; Miller and Felszeghy, 1978). Strong-motion instruments recorded peak ground accelerations of approximately 0.44 g (acceleration of gravity) at the University of California and approximately 0.21 g in downtown Santa Barbara. The earthquake caused almost no damage to the 14 offshore oil platforms in the Santa Barbara Channel. At the ARCO and Aminoil onshore oil production and storage facilities, minor damage was reported, consisting of minor cracks in concrete, broken water lines, downed power lines, and minor landslides along the bluffs. The large oil storage tanks sustained no damage (Arthur D. Little, 1985).

As an example of the anticipated degree of ground motion in the project vicinity, a probabilistic seismic hazard analysis was performed by The Earth Technology Corporation (1984), for the existing Platform Irene location. Results indicate that 0.15 g, 0.20 g, and 0.25 g ground motions were possible with return periods of 200, 400, and 600 years, respectively. The study indicated that future seismic activity may be greater than that recorded in the last 50 years. For example, a maximum or rare event of magnitude 7.5 on the Hosgri fault could substantially affect Platform Irene to higher degrees than the probabilistic analysis suggests. Using a deterministic analysis, the study indicated that medium level ground motion for a magnitude 7.5 event would increase the expected acceleration to 0.30 g for the 200, 400, and 600 year ground motions (Arthur D. Little, 1985).

Similarly, Staal, Gardner & Dunne, Inc. (1991) performed a probabilistic seismic hazard analysis for the Sisquoc Pipeline, which extends from the Santa Maria Pump Station to Sisquoc Pump Station. This study indicated that significant ground shaking could be expected during the life of that pipeline in response to nearby or distant earthquakes. Based on this analysis, estimated peak horizontal bedrock accelerations with a 10 percent probability of exceedance in 50 years are estimated to range from approximately 0.3 g to approximately 0.6 g. Peak horizontal accelerations in alluvial materials are typically about one-third lower than those estimated for bedrock sites. This range is consistent with those typically estimated for other areas of southern California near major active and potentially active faults. In addition, this range in peak ground accelerations is less than those used to develop Uniform Building Code seismic zone IV design criteria (in which the project is located). Therefore, it was concluded that the potential hazard due to ground shaking is low.

5.3.2 Regulatory Setting

The criteria used to estimate fault activity in California are described in the Alquist-Priolo Special Studies Zones Act of 1972, which addresses only surface fault-rupture hazards. The legislative guidelines to determine fault activity status are based on the age of the youngest geologic unit offset by the fault. An active fault is described by the CDMG as a fault that has "had surface displacement within Holocene time (about the last 11,000 years)". A potentially active fault is defined as "any fault that showed evidence of surface displacement during

Quaternary time (last 1.6 million years)." As indicated above in the *Faulting and Seismicity* section, this report identifies potentially active faults in the southern project area as those with evidence of displacement or associated seismicity within the last 500,000 years.

The Seismic Hazards Mapping Act of 1990 (Public Resources Code Sections 2690 and following as Division 2, Chapter 7.8), as supported by the Seismic Hazards Mapping Regulations (California Code of Regulations, Title 14, Division 2, Chapter 8, Article 10), were promulgated for the purpose of protecting public safety from the effects of strong ground shaking, liquefaction, landslides, or other ground failures, or other hazards caused by earthquakes. Special Publication 117, Guidelines for Evaluating and Mitigating Seismic Hazards in California (CDMG, 1997), constitutes the guidelines for evaluating seismic hazards other than surface fault-rupture, and for recommending mitigation measures as required by Public Resources Code Section 2695(a).

The California Coastal Act of 1976 created the California Coastal Commission, which is charged with the responsibility of overseeing development permits for coastal projects and for determining consistency between Federal and State coastal management programs. Also in 1976, the state legislature created the California State Coastal Conservancy to take steps to preserve, enhance, and restore coastal resources and to address issues that regulation alone cannot resolve. The Coastal Act created a unique partnership between the State (acting through the California Coastal Commission) and local government to manage the conservation and development of coastal resources through a comprehensive planning and regulatory program. The California Coastal Commission uses the Coastal Act policies as standards in its coastal development permit decisions and for the review of local coastal programs (LCPs), which are prepared by local governments. Among many issues, the LCPs require protection against loss of life and property from coastal hazards, including geologic hazards. This requirement is implemented locally through the Santa Barbara County (SBC) Comprehensive Plan, Seismic Safety and Safety Element.

5.3.3 Significance Criteria

As specified in the SBC Environmental Thresholds and Guidelines Manual (as updated through October 2006), geologic impacts would be considered significant if a proposed project:

- Is located on land having substantial geologic constraints, such as active or potentially active faults, compressible/collapsible soils, landslides, or severe erosion.
- Would result in potentially hazardous geologic conditions, such as the construction of cut slopes exceeding a grade of 1.5:1 (horizontal:vertical).
- Proposes construction of a cut slope over 15 feet in height, as measured from the lowest finished grade.
- Is located on slopes exceeding 20 percent grade.

5.3.4 Impact Analysis for the Proposed Project

Geologic impacts of the proposed project are primarily associated with pipeline replacement activities due to maintaining the pipeline over a longer lifetime and remediation activities associated with pipeline rupture and resultant oil spills. In addition, continued use and the extended lifetime of the LOGP may result in additional or prolonged ground settlement at the facility. The following describes these potential geologic impacts.

Impact #	Impact Description	Phase	Residual Impact
GR.1	Remediation activities associated with a pipeline spill could increase slope failures, erosion, sedimentation, and gullying.	*Increased throughput* *Extension of Life*	*Class II*

Landfall to LOGP Pipelines

Oil and/or produced water spills from the pipelines could result from third-party activities, corrosion, or seismic-induced failures (see Section 5.1). Cleanup activities related to pipeline spills could potentially induce or accelerate gullying, soil erosion, increased sedimentation in streams, and slope failures in or near the areas impacted by a spill or by cleanup activities (such as equipment staging, transportation or affected materials storage, etc.). Such impacts are evident along the pipeline corridor related to construction activities conducted on the Vandenberg Air Force Base (VAFB) (near Valve Site #3 between catchment basins 5 and 6).

Drainage crossings along the existing pipeline corridor, such as those at Valve Site #3 or before Valve Site #6 along the Platform Irene to LOGP pipelines, also would be susceptible to increased gullying, soil erosion, sedimentation, and slope failure in the event of spill response activities and associated pipeline repair. The 1985 Point Pedernales EIR/EIS (Arthur D. Little) classified stream crossing impacts to be significant but mitigable.

Although the potential for these impacts exists with the current Point Pedernales operations, a greater amount of oil transmitted through the pipeline, as indicated in Section 5.1, Risk of Upset/Hazardous Materials, would result in an increase in potential spill volumes, thereby exacerbating an existing significant impact.

LOGP to Summit Pipeline

Impacts would be similar to those described for the pipelines from landfall to LOGP. Potential stream crossing impacts and slope impacts would exist in the Purisima Hills and in the Casmalia Solomon Hills for the LOGP-Orcutt pipeline segments and at the Santa Maria River and along the Nipomo Creek for the Orcutt to Summit pipeline sections. The 1985 Point Pedernales EIR/EIS classified stream crossing impacts as significant but mitigable.

Mitigation Measures

GR-1 Best Management Practices (BMPs), such as temporary berms and sedimentation traps, such as silt fencing, straw bales, and sand bags, shall be installed to minimize erosion of soils and sedimentation in nearby drainages. The BMPs shall be included in the Oil Spill Response Plan (OSRP). The BMPs shall include maintenance and inspection of the berms and sedimentation traps during rainy and non-rainy periods, as well as revegetation of impacted areas. Revegetation shall address plant type as well as monitoring to ensure appropriate coverage of exposed areas and shall be consistent with existing project revegetation plans.

Residual Impacts

By implementing erosion control measures and revegetating disturbed areas, geologic impact GR.1 would be *significant but mitigable (Class II)*.

Impact #	Impact Description	Phase	Residual Impact
GR.2	Ground-disturbing construction activities could result in geologic disturbances such as slope failure, gullying, erosion, and sedimentation.	*Construction*	*Class II*

Ground-disturbing construction activities at Valve Site #2 could cause gullying, erosion, and sedimentation, which could adversely affect the nearby Santa Ynez River. These construction activities would include areas adjacent to the construction or from the installation of power poles along 13th Street, north of Renwick Avenue or along Terra Road. A gully currently exists north of Terra Road due to construction related-activities at VAFB. Similar impacts could occur as a result of the proposed project construction activities and would be considered significant.

Grading associated with new substation construction would result in a temporary, minor increase in exposure of soils to wind and water erosion. This would result in a minor increase in potential siltation of nearby drainages. In addition, substation construction would result in an incremental increase in structures subject to seismically induced ground failure. The proposed structure would be constructed in accordance with SBC building requirements and Uniform Building Code seismic requirements.

All LOGP and pump station upgrades and modifications would occur within the existing boundaries of the facilities and would therefore have minimal, if any, impact on the geologic environment. Equipment would either be placed on existing pads or previously graded or disturbed areas.

Mitigation Measures

See Mitigation Measure GR-1 above.

Residual Impacts

The proposed mitigation measure, consisting of erosion control measures and revegetation, would render the onshore portion of this geologic impact *significant but mitigable (Class II)*.

Impact #	Impact Description	Phase	Residual Impact
GR.3	Upgrades and modifications of facilities at LOGP could result in new, continued or accelerated ground settlement.	*Construction*	*Class II*

Minor modifications and upgrades of existing equipment is planned at LOGP. The actual installation of the equipment, particularly the associated heavy equipment traffic, could potentially trigger or renew ground settlement at the facility.

Mitigation Measures

GR-2 The 2007 grouting program shall be completed prior to any equipment additions/modifications at the LOGP. If deemed necessary by the County System Safety and Reliability Review Committee (SSRRC), based on equipment weights and foundation requirements, an elevation survey shall be conducted before and during the equipment ~~recommissioning~~additions/modification period followed by routine post-construction monitoring as deemed appropriate by the SSRRC. The elevation survey should use existing benchmarks to continue the subsidence monitoring currently being conducted at LOGP. ~~and a pre- and post-recommissioning monitoring plan shall be developed. The plan shall require a baseline survey 30 days prior to construction and once per month during LOGP equipment recommissioning/modifications. Post-commissioning survey frequency shall be based on the settlement results measured during recommissioning. The plan shall include contingencies for soil grouting or other ground stabilization measures to prevent damage to the facility.~~

Residual Impact

With the incorporation of Mitigation Measure GR-2, this impact is considered *significant but mitigable (Class II).*

Impact #	Impact Description	Phase	Residual Impact
GR.4	Ground-disturbing maintenance activities could result in geologic disturbances such as slope failure, gullying, erosion, and sedimentation.	*Extension of Life*	*Class II*

Extending the life of the facilities would extend the risk of geologic disturbance. Pipeline maintenance and repair activities, such as excavation and replacement of pipeline segments, could result in gullying, erosion, sedimentation, and/or slope failure. While these activities pose the same risk under current operations, the extension of life of the facilities due to the Tranquillon Ridge Project would extend the potential for these types of disturbances. Onshore pipeline replacement would most likely occur in the following areas of potential pipeline damage.

- Topographic lows or troughs where external corrosion is more pronounced;
- Areas of collapsible soils, such as the Orcutt Sands, located intermittently from the landfall at Surf eastward and northward to the San Antonio Valley;
- Unstable slopes, such as along north-facing slopes of the Lompoc Terrace, near major drainage channels, and in the Purisima Hills;
- Stream channel crossings, where the pipeline is susceptible to scour; and
- Floodplains of San Antonio Creek, Santa Ynez River, and Santa Maria River, where the pipeline is susceptible to scour and liquefaction.

Removal of vegetation and repair work in these excavation areas could increase the potential for short-term erosion and result in siltation of nearby rivers, creeks, and drainages. Grading that would occur as part of these activities could occur on slopes of over 20 percent, thus contributing to the potential for erosion. Therefore, geologic impacts would be potentially significant.

Offshore pipeline replacement would most likely occur in the following areas.

- The littoral zone, where the pipeline is susceptible to scour;
- Unstable slopes, such as in steeply sloping areas and areas of previous instability;
- Areas of gasified sediments, which can contribute to differential settlement, liquefaction, and slope failure;
- Areas of liquefiable soils; and
- Potentially active fault crossings, such as possible offshore extensions of the onshore Santa Ynez River/Lompoc-Solvang or Honda faults and possible southerly extensions of the offshore Hosgri, Purisima, or Offshore Lompoc faults.

Substantial alteration of the existing bottom topography is not anticipated during pipeline repair operations. Underwater depositional processes would be temporarily disrupted by repair operations, but would be reestablished within a short period of time. No regional, long-term depositional disruptions would occur. Therefore, geologic impacts would be adverse but not significant.

Mitigation Measures

See Mitigation Measure GR-1 above.

Residual Impact

Implementation of the proposed mitigation measure, consisting of erosion control measures and revegetation, would render the impact *significant but mitigable (Class II)*.

Impact #	Impact Description	Phase	Residual Impact
GR.5	Scouring along drainage areas could cause impacts to the pipeline and increase pipeline failure probabilities.	*Extension of Life*	*Class II*

Platform Irene to LOGP

Scouring along drainage areas in the vicinity of the pipeline could weaken the integrity of the pipeline and increase the likelihood of failure. Gullying, or scouring, is evident along several areas of the pipeline right-of-way, particularly between catchment basins 5 and 6, due to activities at VAFB. The pipeline also crosses numerous creeks and drainage areas that could be affected in the event of a large rain event. Extension of the pipeline operating life due to the Tranquillon Ridge Project would increase the possibility of scour-related pipeline failures. This would be considered a significant impact.

LOGP to Summit Pipeline

Impacts are similar to the discussion regarding the Platform Irene to LOGP pipelines. Numerous creek and drainage crossings exist along the pipeline route that could present a significant impact to the pipeline integrity.

Mitigation Measures

GR-3 The applicant shall implement a creek and drainage maintenance program to monitor and repair potential scour areas that could affect the pipeline integrity. The plan shall include annual surveys of the pipeline route and any adjacent drainages within 500 feet that are up slope of the pipeline right-of-way. Any areas that exhibit scouring or erosion shall be documented. Areas that exhibit increased scour should be addressed through stabilization or other appropriate permanent erosion control measures.

Residual Impact

The proposed mitigation measure, consisting of establishment of pipeline right-of-way surveys and permanent erosion control measures, would reduce the potential for scour-related pipeline failures and render the impact *significant but mitigable (Class II).*

Impact #	Impact Description	Phase	Residual Impact
GR.6	Earthquake-induced tsunami could cause scour and endanger worker safety.	*Operation*	*Class III*

An offshore earthquake with sufficient magnitude could trigger a tsunami resulting in surge waves and flooding along low-lying areas of the coast from Point Pedernales to the existing PXP Pipeline landfall. Areas likely to be affected by a tsunami include the Santa Ynez River Valley and the beach. The coast of central and southern California is characterized by a broad off-shore shelf which would reflect most of the energy of distantly generated tsunamis back out to sea. Due to this minimizing effect of the broad continental borderland on distantly generated tsunami waves, local offshore fault zones represent the most likely sources of significant tsunami waves impacting the VAFB coastline. Near shore underwater landslides in the Channel Islands could also be a source of tsunami waves impacting the VAFB coastline due to underwater unstable cliffs (www.dailynexus.com/news/20058651/html). There has only been one recorded tsunami in the lower 48 states that has resulted in human casualties. The tsunami occurred in 1964 in Crescent City, California, and was caused by the Good Friday Earthquake in Alaska. There were 12 fatalities and approximately $15 million in damages (http://en.wikipedia.org). The tsunami's largest wave was approximately 21 feet tall (http://tvhs.tvusd.k12.ca.us/…). In 1927, the Lompoc Earthquake caused a small tsunami along the California coastline. The coast at the western end of Santa Barbara County and southern part of San Luis Obispo County was sparsely inhabited at this time, but it was reported by railroad workers that a small tsunami, approximately six feet high, occurred near Pismo shortly after the earthquake (http://projects.crustal.ucsb.edu/sb_eqs/1927/small_tsunami.html).

Tsunami inundation maps are being created for the California coastline based on the latest research from National Oceanic & Atmospheric Administration (NOAA) and U.S. Geologic Service (USGS). According to The Tsunami Threat to California: Findings and Recommendations on Tsunami Hazards and Risks dated December 2005 by the State of California Seismic Safety Commission, "Present building codes and guidelines do not adequately address the impacts of tsunamis on structures. Currently available tsunami inundation maps are not appropriate for code or guideline applications." In the unlikely event of a tsunami occurring along the California coastline, the Pacific Tsunami Warning Center (operated by NOAA) would likely be able to provide advance notice; thereby, providing time for project-related construction, drilling, or operation activities to prepare.

In the event of an earthquake-induced tsunami, seawater run-up/surge could reach and flood Valve #1 and maybe Valve #2. Scour from the surge could undermine and expose the pipeline and possibly cause rupture. In addition, workers in low-lying areas could be injured or killed by the surge. However, the probability of a tsunami occurring during the life of the proposed project (30 years) is considered to be very low.

Mitigation Measures

GR-4 The applicant shall conduct a study to determine the probable maximum tsunami and evaluate potential flooding and scour in the Santa Ynez River valley and at project facilities, as appropriate. The scour analysis shall determine a minimum burial depth to protect the pipe. In addition, the Applicant shall include in the Project Safety Plan a discussion of tsunami hazards, training and ensure that work crews receive tsunami-warning notifications from the Pacific Tsunami Warning Center (operated by NOAA) in accordance with the safety plan. If no such Project Safety Plan is prepared, a tsunami safety plan is herein required and shall include a protocol for workers to follow in the event of a tsunami. The tsunami plan shall be submitted to SBC P&D for review and approval prior to land use clearance.

Residual Impact

Although the probability of a tsunami occurring of the life of the proposed project is considered to be very low, Mitigation Measure GR-4 is required to mitigate the potential impact to the maximum extent feasible. This impact is considered *adverse but not significant (Class III)*.

5.3.5 Impact Analysis for the Alternatives

Detailed descriptions of the various alternatives are provided in Chapter 3.0, Alternatives. This section provides a discussion of the geological impacts of the various alternatives.

5.3.5.1 No Project Alternative

Scenarios 2 and 3. As discussed in Section 3.2, under the No Project Alternative Scenarios 2 and 3, production of the federal portion of the Tranquillon Ridge field would and would not occur, respectively. However, no extension of life of Point Pedernales facilities (Platform Irene, pipelines, and LOGP) is assumed under either scenario. Impacts GR.1 through GR.5 for the proposed Tranquillon Ridge Project would not occur under the No Project Alternative Scenarios 2 and 3 since there would be no new construction, and the oil production rates would be the same as the current operations (i.e., baseline). However, as identified under Impact GR.6, the existing pipeline facilities would still be a risk for tsunami scour and potential pipeline and valve damage.

Options for Meeting California Fuel Demand. The relative geologic and soil impacts associated with the various options for meeting California fuel demand are summarized in Table 5.3.2.

Table 5.3.2 No Project Alternative Comparison to Options for Meeting California Fuel Demand, Geologic Resources

Source of Energy		Impacts
Other Conventional Oil & Gas		
	Domestic onshore crude oil and gas	Likely to displace, rather than eliminate, geologic and soil related impacts.
	Increased marine tanker imports of crude oil	Eliminate or displace geologic and soil related impacts.
	Increased gasoline imports[1]	Eliminate or displace geologic and soil related impacts.
	Increased natural gas imports (LNG)	Eliminate or displace geologic and soil related impacts.
Alternatives to Oil and Gas		
	Fuel Demand Reduction: increased fuel efficiencies, conservation, electrification[2]	
	Alternative transportation modes	Proposed project impacts would be eliminated.
	Implementation of regulatory measures	Proposed project impacts would be eliminated.
	Coal, Nuclear, Hydroelectric	Proposed project impacts would be eliminated; however, could introduce power facility construction and operation impacts which could likely be greater than the proposed project.
	Alternative Transportation Fuels	
	Ethanol/Biodiesel[3]	Proposed project impacts would be reduced. Potential soil disturbance impacts because of new plant construction.
	Hydrogen[2]	Proposed project impacts would be reduced. Potential soil disturbance impacts because of hydrogen delivery infrastructure development.
	Other Energy Resources[2]	
	Solar[2,4]	Increased construction impacts because of solar facility infrastructure construction.
	Wind[2,4]	Increased construction impacts because of wind facility infrastructure construction.
	Wave[2,4]	Increased construction impacts because of wave facility infrastructure construction, including potential offshore geologic impacts.

Footnotes:
1. Pipeline and tanker truck import from out-of-State assumed.
2. Assumes that Tranquillon Ridge production would not be replaced with other petroleum-based energy supply.
3. Assumes ethanol and biodiesel used as blends only and therefore would reduce, but not eliminate Tranquillon Ridge or equivalent production.
4. Assumes, large centralized facilities.

5.3.5.2 VAFB Onshore Alternative

The VAFB Onshore Alternative consists of the following major components: the drilling and production facilities, 20-inch oil emulsion and 8-inch gas pipelines, and an overhead 69kV power line and associated substation. In addition, a pipeline tie-in station and associated power line and substation would be required. The near-coast project components just north of La Honda Canyon and along Surf and Coast Roads would be constructed on Holocene and Pleistocene dune sand; the pipelines traverse about 200 feet of alluvium at Bear Creek. The new pipelines from the northern end of Coast Road to the connection at the existing PXP pipeline traverse Monterey Shale for about 0.5-mile along Highway 246 and then pass through Holocene alluvium in the Santa Ynez River valley. The drilling and production area would disturb and grade about 25-acres of unconsolidated dune sand that overlies Monterey Shale. No steep slopes or landslide-prone areas are crossed by the VAFB Onshore Alternative.

Geologic impacts of the VAFB Onshore Alternative are primarily associated with construction and operation of the drilling and production facilities, pipeline construction and maintenance, and construction of the overhead 69kV power line. In addition, remediation activities associated with pipeline rupture and resultant oil spills could result in geologic impacts. The following describes these geologic impacts associated with the VAFB Onshore Alternative. Impact GR.1, oil spill clean-up impacts, and Impact GR.3, LOGP settlement, would be the same as the proposed project. Impact GR-8, offshore pipeline installation impacts, would not apply to the VAFB Onshore Alternative.

Impact GR.2 – Ground Disturbance during Construction: Grading and construction of the drilling and production facilities could cause gullying, erosion, and sedimentation, which could adversely affect the nearby drainages. Trenching for the pipelines, power pole installation, and temporary stockpiles could also cause erosion and sedimentation along these linear project components, potentially impacting other drainages including Bear Creek and Santa Ynez River. <u>Finally, grading of the electrical substations and pipeline tie-in station could cause further erosion and sedimentation.</u> Gully erosion is likely in the poorly consolidated sediments throughout the alternative and wherever the protective vegetative cover is removed. These impacts could occur as a result of the alternative construction activities and would be considered significant, but mitigable (*Class II*). However, given that the VAFB Onshore Alternative would require extensive ground disturbance in comparison to the proposed project, Impact GR.2 is considered more severe for the alternative. Operational maintenance and repair activities that disturb the soil or remove vegetation would have the same impacts. With the implementation of Mitigation Measure GR-1, consisting of erosion control measures and revegetation, this geologic impact is considered *significant but mitigable (Class II)*.

Impact GR.4 – Ground Disturbance during Maintenance Activities: Drainage crossings along the proposed pipeline corridor, including Bear Creek and Santa Ynez River, would be susceptible to increased gullying, soil erosion, sedimentation, and slope failure in the event of spill response activities and associated pipeline repair. Given the crossing of the Santa Ynez River, this impact is considered more severe for the VAFB Onshore Alternative than the proposed project. With the implementation of Mitigation Measure GR-1, consisting of erosion control measures and revegetation, this geologic impact is considered *significant but mitigable (Class II)*.

Impact GR.5 – Scour: Scouring along drainage areas in the vicinity of the pipelines could weaken the integrity of the pipeline and increase the likelihood of failure. Gullying, or scouring, is evident along several areas of existing pipeline rights-of-way within VAFB, due to activities at the VAFB. The pipelines would cross the Santa Ynez River, Bear Creek, and several drainage areas that could be affected in the event of a large rain event. Similar to the proposed project, this would be considered a *significant but mitigable* impact (*Class II*). However, given the crossing of the Santa Ynez River, this impact is considered more severe for the VAFB Onshore

Alternative than the proposed project. With the implementation of Mitigation Measure GR-3, consisting of establishment of pipeline right-of-way surveys and permanent erosion control measures, this geologic impact is considered *significant but mitigable (Class II)*.

Impact GR.6 – Tsunami: An offshore earthquake or landslide with sufficient magnitude could trigger a tsunami resulting in surge waves and flooding along low-lying areas of the coast from Point Pedernales to the existing PXP Pipeline landfall. Areas likely to be affected by a tsunami include the Santa Ynez River Valley and the beach.

In the event of an earthquake or landslide induced tsunami, seawater run-up/surge could reach and flood the Santa Ynez River valley. Scour from the surge could undermine and expose the pipeline and possibly cause rupture. In addition, workers in low-lying areas, such as the drilling and production site, could be injured or killed if the run-up washes into the drilling/production facility. The surge could also possibly undermine the integrity of the drilling and production facilities, causing a possible oil spill. However, the probability of a tsunami occurring during the life of the alternative (30 years) is considered to be very low.

Although the probability of a tsunami occurring of the life of the alternative is considered to be very low, Mitigation Measure GR-4 (including study of the drilling and production site) would be required to mitigate potential impacts to the maximum extent feasible. This impact is considered *adverse but not significant (Class III)*.

Impact #		Phase	Residual Impact
GR.7	Liquefaction could jeopardize the integrity of the VAFB Onshore Alternative pipelines at the Santa Ynez River valley and Bear Creek crossings.	*Operation*	*Class II*

Liquefaction often results in loss of ground bearing capacity and/or lateral spreading, both of which could result in damage to the pipelines crossing the Santa Ynez River valley. During loss of ground bearing capacity, large deformations can occur within the soil mass, allowing the pipeline to settle or become buoyant and float upward. The most serious liquefaction hazard results from burial of the pipeline in a competent soil that overlies deeper liquefiable soil layers. Liquefaction of the deeper layers may result in substantial lateral spreading of the upper competent soil. Lateral spreading can extend several hundred feet back from a slope and displacements of tens of feet may occur if soil conditions are especially favorable for liquefaction and if earthquake shaking is of sufficient duration. Lateral spreading along the alternative pipelines is particularly likely at the north and south margins of Santa Ynez Valley and perhaps at Bear Creek.

Mitigation Measures

GR-5 Reduce Liquefaction Hazard. Final geotechnical investigations shall be conducted in the areas underlain by alluvium and dune sand at the Santa Ynez River and Bear Creek crossings. The results and recommendations of the geotechnical investigations shall be incorporated into the final pipeline design. If moderate to high liquefaction potential is confirmed by the geotechnical analyses, then design measures shall be implemented at the corresponding locations. Appropriate design is dependent on site-specific conditions and could include deep burial of the pipeline below liquefiable layers, densification of the ground above the pipeline to mitigate uplift, and selection of thick-walled, ductile steel pipe. The applicant shall submit the final geotechnical studies and design recommendations to SBC for review and approval prior to land use clearance.

Residual Impact

With the implementation of Mitigation Measure GR-5, the potential for liquefaction and lateral spreading damage to the pipelines is considered *significant but mitigable* (*Class II*).

5.3.5.3 Casmalia East Oil Field Processing Location

For this alternative, Impacts GR.1, oil spill, GR.3, LOGP settlement, and GR.6, tsunami impacts, would be the same as for the proposed project. Impact GR.7, liquefaction at Santa Ynez River, would not apply to the Casmalia Alternative since it does not cross the river.

Impact GR.2 – Ground-disturbing Construction Activities: Excavations and grading associated with the new pipeline and Casmalia processing facility construction would result in an increase in removal of vegetation and temporary exposure of soils to wind and water erosion. This would result in an increase in potential siltation of nearby drainages. In addition, grading would potentially result in additional permanent changes in topography and an incremental increase in persons and structures subject to seismically induced ground failure.

The location of the new pipeline would partly follow the current pipeline ROW. The pipeline would also traverse a new area west of Orcutt in order to connect the existing pipelines to the new Casmalia facility. No additional faults would need to be traversed in order to install these new pipelines. The closest fault is the Los Alamos fault at approximately six miles away (USGS web site information, http://www.data.scec.org/faults/nwfault.html).

The areas traversed by the existing LOGP to Orcutt pipeline and new pipeline to connect Orcutt to Casmalia could traverse areas that have landslide potential, particularly in the Purisima Hills areas. Several slide areas have been identified in the Purisima Hills area near to the pipeline ROW (Arthur D. Little, 1985). Expansive and collapsible soils could be present for the new pipeline. Orcutt Sand is present in areas north of Lompoc and in the San Antonio Valley which is susceptible to sliding. Expansive clays are also present in the Purisima Hills.

Mitigation Measures

In addition to mitigation measure GR-1 mentioned above, the Casmalia alternative would also require the following mitigation measure:

GR-6 Ensure that all pipeline and facility construction areas have adequate review by geotechnical engineers and geologists for expansive/collapsible soils and for potential areas of slope instability prior to construction. The geotechnical report shall be submitted to SBC for review and approval prior to land use clearance.

Residual Impact

The ground-disturbing construction would be similar in nature to the proposed project but with more construction and a greater amount of earth disturbance. The impact would remain *significant but mitigable (Class II)*. If this alternative is selected, a more detailed geologic impacts evaluation would be necessary as part of a separate CEQA review.

Impact GR.4 – Ground Disturbance During Maintenance Activities: Pipeline maintenance activities would be similar in nature to the proposed project, but potentially more frequent due to the greater length of the pipeline connecting the LOGP to the Casmalia site. The impact would remain *significant but mitigable (Class II).*

Impact GR.5 – Scour: Scour along drainages would be more severe for the Casmalia alternative because of the additional length of pipeline associated with this alternative. This impact is considered to be *significant but mitigable (Class II).*

5.3.5.4 Alternative Power Line Routes to Valve Site #2

Impacts GR.1, oil spill remediation, GR.3, LOGP settlement, GR.4, ground disturbance during maintenance activities, GR.5, scour, and GR.6, tsunami impacts, would be the same as for the proposed project regardless of power line route alternative. Impact GR.2, ground disturbance during construction, is discussed below for each of the power line alternatives.

Alternative Power Line Route – Option 2a

The impacts associated with this alternative are similar to the proposed project (installation of poles and substation). Geologic impacts resulting from installation of new pole lines across an agricultural field or crossing of the river on pole lines would be the same as those described in Impact GR.2. As more poles would be installed with this alternative versus the proposed project (the power line length would be increased, see Figure 5.3.3), there would be a slight increase of severity versus severity of the proposed project. Mitigation Measure GR-1 would also be applicable to this alternative.

Alternative Power Line Route – Option 2b

Geologic impacts as a result of installing new pole lines across an agricultural field would be the same as those described in Impact GR.2. Directional boring under the river would result in temporarily stockpiled soil associated with boring operations. Exposure of these soils would result in an increase in potential erosion and associated siltation of nearby drainages. Impacts would be *significant but mitigable (Class II).* Mitigation measure GR-1 would also be applicable to this alternative.

Underground Power Line along Terra Road

This alternative involves burying the portion of the power line that runs along Terra Road to Valve Site #2. This alternative would require the construction of a trench from the intersection of Terra Road and 13th Street to Valve Site #2. The trench would follow the existing roadway. It is estimated that approximately two months would be needed to install this underground cable using a backhoe and other small construction equipment.

Construction associated with the installation of the power line could generate erosion, gullying, and sedimentation of nearby drainages. These effects could be caused by the removal of vegetation, the stockpiling of excavated materials, the storage of materials and construction equipment, and grading of areas and the movement of vehicles on unpaved and graded areas. These activities would increase the potential for short-term erosion and siltation of the nearby

Santa Ynez River and adjoining creeks and drainages. Such erosion impacts would be considered significant over the short term. No long-term impacts associated with the power line presence are expected.

Mitigation Measure GR-1, mentioned above would be required. The proposed mitigation measure, consisting of establishment of erosion control measures and revegetation, would render Impact GR.2 *significant but mitigable (Class II);* however, this impact would be more severe for the underground alternative than the overhead power line alternatives, including the proposed project.

5.3.5.5 Replacement of Oil Emulsion Pipeline from Platform Irene to LOGP

Impacts GR.3, LOGP settlement, and GR.6, tsunami, would be the same as the proposed project. Impact GR.7, liquefaction at Santa Ynez River, would not apply to the Emulsion Pipeline Replacement Alternative since it does not cross the river.

Impact GR.1 – Remediation Activities: Impacts due to remediation activities would be less than the proposed project because there is a reduction in the probability of a spill. However, the impact would still be *significant but mitigable (Class II).* Mitigation Measure GR-1 would be applicable.

Impact GR.2 – Ground-disturbing Construction Activities: Although Valve Site #2 construction would not occur under this alternative and would therefore not result in ground disturbances, this alternative would result in greater ground disturbances than the proposed project due to new trenching and grading to install the pipeline. Pipeline replacement between landfall at Wall/Surf Beach and the LOGP would occur within the existing right-of-way.

Construction associated with installing and replacing the pipeline could generate erosion, gullying, and sedimentation of nearby drainages. These effects could be caused by the removal of vegetation, the stockpiling of excavated materials, the storage of materials and construction equipment, grading, and the movement of vehicles on unpaved and graded areas. These activities would increase the potential for short-term erosion and siltation of the nearby Santa Ynez River and adjoining creeks and drainages. Many stream crossings have steep slopes; areas at Valve Site #3, have slopes ranging up to 15 percent, Valve Site #6 slopes up to 10 percent, Santa Lucia Canyon, slopes upwards of 15 percent, and before Valve Site #9 just north of Highway 1 slopes of close to 15 percent. Any of these areas could contribute to the potential for erosion as well as landslides due to construction-related activities. Such erosion impacts would be considered significant over the short term.

Mitigation Measures

Mitigation Measure GR-1, mentioned above, and the following mitigation measure would be required:

GR-7 Geotechnical analyses shall be completed in existing erosion-prone areas (as described by Coastal Geoscience, Inc., 2001) to determine proper pipeline burial depth.

Residual Impact

The proposed mitigation measures, consisting of geotechnical analyses in erosion prone areas, establishment of erosion control measures, and revegetation, would render the potential onshore construction impacts *significant but mitigable (Class II)*. However, given that construction associated with the Emulsion Pipeline Replacement Alternative would be much more extensive than for the proposed project, this impact is considered to be more severe for the alternative.

Impact GR.4 – Ground Disturbance During Maintenance Activities: Impacts related to the extension of life issues and pipeline maintenance would be less than the proposed project due to the less frequent maintenance requirements associated with a new pipeline. However, any maintenance activities would still be subject to Mitigation Measure GR-1. Annual geologic monitoring indicates that the onshore portion of the pipeline has performed in a fundamentally sound manner from a geotechnical standpoint (Russell Consulting, 2006). Therefore, no long-term geological impacts associated with the pipeline presence are expected for a new pipeline.

Impact GR.5 – Scour: Scour along drainages would be more severe for the Emulsion Pipeline Replacement Alternative than the proposed project because of the additional construction associated with this alternative. This impact is considered to be *significant but mitigable (Class II)*.

Impact #	Impact Description	Phase	Residual Impact
GR.8	Pipeline installation offshore could result in increased resuspension of bottom sediment material, increased bottom sediment drift, and decreased stability of sediments within the offshore pipeline ROW.	*Construction*	*Class II*

Replacement of the existing pipeline from Platform Irene to the landing at Wall/Surf Beach would occur within the existing ROW. Installation of the pipeline would involve jetting, which could affect bottom sediment stability. The bathemetry could also be altered by the construction and pipeline laying activities. Pipelines lying on the sea floor also could entrap migrating bottom sediments and cause mounding above the pipeline. Also, minor erosion could occur due to deflection and concentration effects. Bottom substrate could be disturbed and resuspended during pipeline laying activities. From a geotechnical standpoint, the existing pipeline appears to have performed satisfactorily since initial construction except for the issue of unsupported spans, which may have contributed to the 1997 release from the emulsion pipeline. An unsupported span could have occurred as a result of shifting bottom sediment due to the presence of the pipeline. As a result of this issue, replacement of the pipeline within the existing corridor would result in significant geohazard impacts.

Mitigation Measures

GR-8 Pipeline surveys shall be conducted to confirm the absence of unsupported spans after installation of the offshore pipeline and at periodic intervals during the life of the facility. Initial surveys shall be conducted annually, but may be reduced in frequency at the discretion of the Minerals Management Service, California State Lands Commission, and Santa Barbara County.

Residual Impact

The residual impact would be considered *significant but mitigable (Class II)*.

5.3.5.6 Alternative Drill Muds and Cuttings Disposal

Inject Drill Muds and Cuttings into Reservoir

No additional geologic impacts would occur as a result of injecting muds and cuttings into the subsurface. Impacts GR.1, GR.2, GR.3, GR.4, GR.5, and GR.6 would be the same as the proposed project.

Transport Drill Muds and Cuttings to Shore for Disposal

No additional geologic impacts would occur as a result of transportation of muds and cuttings to shore for disposal. Impacts GR.1, GR.2, GR.3, GR.4, GR.5 and GR.6 would be the same as the proposed project.

5.3.6 Cumulative Impacts and Mitigation Measures

Cumulative projects that could impact the current analysis include both offshore oil and gas projects, and onshore development projects, as discussed in Sections 4.2 through 4.4. Potential cumulative impacts associated with these off- and onshore projects are discussed separately below.

5.3.6.1 Offshore Oil and Gas Projects

The proposed project would involve minimal new disturbances, primarily related to construction activities at Valve Site #2. Due to the limited scope of these activities, regional geologic impacts resulting from the proposed project would not be expected. Although some of the potential federal outer continental Shelf (OCS) could involve new land disturbances (development of the Santa Maria, Lion Rock, Point Sal, and Purisima Point Units and Lease OCS-P 0409), none of their onshore components would be located in close proximity to the proposed project, and with implementation of appropriate BMPs and project-specific mitigation measures during construction, their cumulative geologic impacts would not be expected to be significant. Potential offshore oil and gas development projects located in State waters would be located a substantial distance away from the proposed project, and would involve minimal to no new land disturbances. Therefore, their cumulative geologic impacts would not be expected to be significant.

The proposed project and each of the cumulative offshore oil and gas projects outlined in Sections 4.2 and 4.3 would involve repair and maintenance activities, which could require ground disturbing activities, and could result in erosion and possible sedimentation. In general, however, such repairs and maintenance would be expected to be highly localized in nature, and with the implementation of appropriate erosion control measures, BMPs, and other required mitigation measures, cumulative geologic impacts, and the proposed project's incremental contribution to them, would not be considered significant.

5.3.6.2 Onshore Projects

Ground disturbance and potential erosion associated with the proposed project would likely be limited in scope and localized. Potential erosional impacts due to sedimentation in nearby drainages can be reduced to a level of less than significant through implementation of standard erosion control measures. Therefore, although ground disturbance associated with pipeline repair or soil remediation may occur simultaneously with construction of some of the other potential onshore development projects outlined in Section 4.4, potential cumulative erosion and sedimentation impacts, and the proposed project's incremental contribution to them, would not be expected to be cumulatively significant.

5.3.7 Mitigation Monitoring Plan

Mitigation Measure	Mitigation Requirements and Timing	Method of Verification	Timing of Verification	Party Responsible For Verification
GR-1	Best Management Practices (BMPs), such as temporary berms and sedimentation traps, such as silt fencing, straw bales, and sand bags, shall be installed to minimize erosion of soils and sedimentation in nearby drainages. The BMPs shall be included in the Oil Spill Response Plan (OSRP). The BMPs shall include maintenance and inspection of the berms and sedimentation traps during rainy and non-rainy periods, as well as revegetation of impacted areas. Revegetation shall address plant type as well as monitoring to ensure appropriate coverage of exposed areas and shall be consistent with existing project revegetation plans.	Review of OSRP. Site inspections during remediation activities	Prior to issuance of coastal development permit or land use clearance for grading.	SBC P&D CCC
GR-2	The 2007 grouting program shall be completed prior to any equipment additions/modifications at the LOGP. If deemed necessary by the County System Safety and Reliability Review Committee (SSRRC), based on equipment weights and foundation requirements, an elevation survey shall be conducted before and during the equipment ~~recommissioning~~additions/modification period followed by routine post-construction monitoring as deemed appropriate by the SSRRC. The elevation survey should use existing benchmarks to continue the subsidence monitoring currently being conducted at LOGP~~and a pre- and post-recommissioning monitoring plan shall be developed. The plan shall require a baseline survey 30-days prior to construction and once per month during LOGP equipment recommissioning/modifications. Post-commissioning survey frequency shall be based on the settlement results measured during recommissioning. The plan shall include contingencies for soil grouting or other ground stabilization measures to prevent damage to the facility.~~	Annual erosion control survey reports	Annually	SBC P&D

Mitigation Measure	Mitigation Requirements and Timing	Method of Verification	Timing of Verification	Party Responsible For Verification
GR-3	The applicant shall implement a creek and drainage maintenance program to monitor and repair potential scour areas that could affect the pipeline integrity. The plan shall include annual surveys of the pipeline route and any adjacent drainages within 500 feet that are up slope of the pipeline right-of-way. Any areas that exhibit scouring or erosion shall be documented. Areas that exhibit increased scour should be addressed through stabilization or other appropriate permanent erosion control measures.	Review of creek and drainage maintenance program Annual surveys following construction	Annually	SBC P&D <u>CCC</u>
GR-4	The applicant shall conduct a study to determine the probable maximum tsunami and evaluate potential flooding and scour in the Santa Ynez River valley and at project facilities, as appropriate. The scour analysis shall determine a minimum burial depth to protect the pipe. In addition, the Applicant shall include in the Project Safety Plan a discussion of tsunami hazards, training and ensure that work crews receive tsunami-warning notifications from the Pacific Tsunami Warning Center (operated by NOAA) in accordance with the safety plan. If no such Project Safety Plan is prepared, a tsunami safety plan is herein required and shall include a protocol for workers to follow in the event of a tsunami. The tsunami plan shall be submitted to SBC P&D for review and approval prior to land use clearance.	Review of tsunami probability and scour analysis	Prior to land use clearance	SBC P&D <u>CCC</u>
GR-5 (VAFB Onshore Alternative only)	Reduce Liquefaction Hazard. Final geotechnical investigations shall be conducted in the areas underlain by alluvium and dune sand at the Santa Ynez River and Bear Creek crossings. The results and recommendations of the geotechnical investigations shall be incorporated into the final pipeline design. If moderate to high liquefaction potential is confirmed by the geotechnical analyses, then design measures shall be implemented at the corresponding locations. Appropriate design is dependent on site-specific conditions and could include deep burial of the pipeline below liquefiable layers, densification of the ground above the pipeline to mitigate uplift, and selection of thick-walled, ductile steel pipe. The applicant shall submit the final geotechnical studies and design recommendations to SBC for review and approval prior to land use clearance.	Review of geotechnical investigations	Prior to land use clearance	SBC P&D <u>CCC</u>

Mitigation Measure	Mitigation Requirements and Timing	Method of Verification	Timing of Verification	Party Responsible For Verification
GR-6 (Casmalia Alternative only)	Ensure that all pipeline and facility construction areas have adequate review by geotechnical engineers and geologists for expansive/collapsible soils and for potential areas of slope instability prior to construction. The geotechnical report shall be submitted to SBC for review and approval prior to land use clearance.	Plan check review. Site inspection during construction	Before permit issuance. Site inspection during construction.	SBC P&D
GR-7 (Emulsion Pipeline Replacement Alternative only)	Geotechnical analyses shall be completed in existing erosion-prone areas (as described by Coastal Geoscience, Inc., 2001) to determine proper pipeline burial depth.	Plan check review. Site inspection during construction	Before permit issuance. Site inspection during construction.	SBC P&D CCC
GR-8 (Emulsion Pipeline Replacement Alternative only)	Pipeline surveys shall be conducted to confirm the absence of unsupported spans after installation of the offshore pipeline and at periodic intervals during the life of the facility. Initial surveys shall be conducted annually, but may be reduced in frequency at the discretion of the Minerals Management Service, California State Lands Commission and Santa Barbara County.	Annual survey	During operation	MMS CSLC SBC P&D CCC

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5.4 Onshore Water Resources

The following sections summarize the environmental setting, project-related impacts, alternative projects' impacts, and cumulative impacts to onshore water resources, which include both surface and groundwaters in the area affected by the proposed project.

5.4.1 Environmental Setting

The environmental setting of the proposed project area, including the onshore water resources associated with existing facilities, is described in detail in the 1985 Point Pedernales EIR/EIS a (Arthur D. Little, 1985). Surface water and groundwater resources within the Santa Ynez River basin were described by Upson and Thomasson (1951) and Miller (1976), respectively, and onshore water resources in San Antonio Creek Valley and Santa Maria Valley were described by Muir (1964) and Worts (1951), respectively. Recent (ca. 1998-1999) information concerning the health of the Santa Ynez, San Antonio, and Santa Maria watersheds is listed on websites maintained by University of California, Davis and by the U.S. Environmental Protection Agency (EPA). Information from these sources concerning the environmental setting for surface waters and groundwaters is presented in the following sections.

5.4.1.1 Surface Waters

Wall/Surf Beach to LOGP

The onshore portion of the oil emulsion pipeline and the Lompoc Oil and Gas Plant (LOGP) processing facility are located in the Lompoc Subarea of the Santa Ynez River Basin in Santa Barbara County (SBC). The river and associated tributaries are the dominant surface water features within the project area. The river basin is situated between the east-west trending Santa Ynez Mountain and San Rafael Mountain ranges. The head of the basin occurs 60 miles east of the mouth of the Santa Ynez River within the Headwater Subarea of the river basin. Three dams in the upper reaches of the river are used for water supply for the South Coast of SBC.

The basin itself is a narrow, nearly flat, alluvial plain with a total area of approximately 800 square miles. Surface water drainages are limited to the distance between the crest of the mountain range and the shoreline. Therefore, most drainages are short, steep, and small. The major tributaries are Lompoc Canyon, La Salle Canyon, Sloans Canyon, San Miguelito Creek, and Salsipuedes Creek from the south, and Oak Canyon, Santa Lucia Canyon, Davis Creek, Purisima Canyon, and Cebada Canyon to the north. Throughout most of its length, the river is dry during most of the year, with large flows only in response to winter storms and spilling from upstream dams.

The Santa Ynez River basin is susceptible to severe flooding in response to heavy rainfall and water releases from upstream dams. Peak flows may reach 100,000 cubic feet per second (cfs). Flooding has potential for substantial soil erosion within the flood plain.

Within the project area, rainfall typically occurs only during November through April, with high annual variability. The average rainfall at Lompoc is approximately 23 inches, with a range of approximately 6 to 30 inches per year. In response to seasonal rainfall, stream flow and the presence of surface waters are also highly variable throughout most of the basin. In contrast, perennial flow exists near the mouth of the Santa Ynez River and other areas subject to groundwater discharge, irrigation runoff, and effluent discharge from the Lompoc Regional Wastewater Treatment Plant. Flow volumes and water quality characteristics within the river basin are highly variable.

Surface water quality in the project area is typical of surface waters in the river basin. No major industrial waste sources discharge directly to the Santa Ynez River. In accordance with a National Pollutant Discharge Elimination System (NPDES) permit, the Lompoc Wastewater Treatment Plant discharges approximately 5 million gallons per day (MGD) of treated municipal wastewaters at a location approximately three miles from the river mouth. Water quality in the river has been characterized as “less serious problems-low vulnerability” (i.e., to stressors such as pollutant loadings above permitted discharge limits and urban runoff potential; EPA, 1999). However, the Santa Ynez River is on the 2002 Section 303(d) list as an impaired water body. Nutrients, sedimentation/siltation, and salinity/ total dissolved solids (TDS)/chlorides are parameters of concern. Major ions include sodium, chloride, bicarbonate, and sulfate. Waters are suitable for most irrigation and agricultural uses but only marginally suitable for domestic uses because of high TDS levels.

The onshore portion of the pipeline is north of and generally parallel to the Santa Ynez River before turning north near Valve Site #6. From landfall to Route 1, the pipeline crosses 14 drainages, with drainage areas ranging from 18 to 9,100 acres. All but two are considered minor, with drainage areas less than 200 acres. Surface waters in these minor drainage areas are classified as ephemeral (i.e., seasonal), and natural runoff occurs only during the rainy season.

Surface waters in the western end of the land portion of the pipeline near the mouth of the Santa Ynez River are fed by groundwater, irrigation tail water, and effluent from the Lompoc Wastewater Treatment Plant. During portions of the year (e.g., summer), the presence of a sand bar at the mouth of the river prevents exchange between the river and ocean. Following winter storms, high river flows will breach and erode the sand bar, allowing the river to drain to the ocean. While the river mouth is open, exchanges with ocean waters result in increases in salinity within portions of the rivers affected by estuarine circulation (e.g., mixing of lower density river water and higher density seawater).

A small water body is also located immediately north of the mouth of the river, between the back dunes of the beach and the railroad tracks. This water body appears to be part of the estuarine system within the lower Santa Ynez River, although exchange between this water body and the river probably occurs episodically due to formation of a sand berm at the connection to the river mouth. Based on the species of vegetation present, waters within this feature are expected to be brackish. The onshore portion of the pipeline passes within 0.5 kilometers of this portion of the estuary.

Proceeding inland from the railroad tracks, the pipeline route between Catchment Basins #2 and #8 is one kilometer or more from the Santa Ynez River. The direction of surface water flow in the area of the pipeline route is generally southwestward, towards the river. The pipeline crosses a small drainage near Catchment Basin #4, where the pipeline daylights and is suspended at an elevation of approximately 50 feet over the floor of the canyon (see Figure 5.4-1).

According to the 1985 Point Pedernales EIR/EIS, this unnamed canyon drains an area of 213 acres, with an average flow of 15.4 acre-feet per year (AFY), although streamflow is classified as ephemeral (HDR, 1984). Eight catchment basins, with varying capacities, have been constructed along the portion of the pipeline between Valve Site #1 (at the beach landing) and Valve Site #5 (Figure 5.4-2).

Between Catchment Basins #8 and #12, the pipeline route is within approximately 0.5 kilometers of the Santa Ynez River. The pipeline also crosses Oak Canyon near Basin 12 before turning north and away from the river. Oak Canyon and related tributaries drain an area of approximately 1800 acres with an average flow of 70 acre-feet per year (Arthur D. Little, 1985). Streamflow in Oak Canyon is classified as ephemeral, and has been diverted into a diked channel along the eastern side of the valley floor (HDR, 1984).

Near Valve Site #8, the pipeline route crosses Santa Lucia Canyon, which drains an area of approximately 9,000 acres and has an average flow of 373 acre-feet per year. The stream is classified as intermittent/perennial. Santa Lucia Canyon drains to the Santa Ynez River. Approximately mid-way between Valve Sites #8 and 9, the pipeline route passes within one kilometer of a wetlands area classified as an ephemeral stream (HDR, 1984) with a small (less than 30 acres) drainage area. From Valve Site #9 to the Lompoc Oil and Gas Plant, the pipeline crosses a number of small drainages with ephemeral flow, and Davis Creek, with a drainage area of 3,660 acres and intermittent/perennial flow from underground return flow of golf course irrigation water (HDR, 1984). No catchment basins occur along this portion of the pipeline route.

No specific data are available to characterize water quality within these smaller drainage systems. Large portions of the Oak Canyon and Santa Lucia Canyon drainage areas are undeveloped without significant sources of industrial discharges or agricultural or urban runoff. Portions of the Davis Creek drainage area could be affected to a relatively greater extent by urban runoff and, therefore, surface water quality may reflect inputs of nutrients, bacteria, pesticides, and organophosphorus herbicides that are common in urbanized watersheds.

LOGP to Suey Junction

The oil pipeline corridor from LOGP to Suey Junction crosses 26 drainages within the San Antonio and Santa Maria watersheds. San Antonio Creek Valley drains a 154 square mile area, and includes drainages associated with Purisima Hills, San Antonio Creek, Harris Canyon, Long Canyon, and Graciosa Canyon consisting primarily of agricultural uses and urban riparian habitat. Most of these drainages are small and ephemeral or intermittent, and they are affected primarily by seasonal precipitation events. Annual average rainfall in this area is approximately 15 inches. San Antonio Creek is on the 2002 Section 303(d) list as an impaired water body. Boron and sedimentation/siltation are parameters of concern. No other specific water quality data are available for these drainages; however, many are likely affected by runoff from adjacent agricultural operations.

Suey Junction to Summit Pump Station

Onshore water resources associated with the ConocoPhillips pipeline between Suey Junction and Summit Pump Station are described briefly below; additional information is provided in the Sisquoc Pipeline SEIR (Arthur D. Little and SAIC, 2000). The pipeline crosses two drainage basins between the Suey Junction and the Summit Pumping Station. Nearly 95 percent of the pipeline runs through the Santa Maria River Basin, while the remaining 5 percent lies in the Central Coastal Basin.

The Santa Maria River drainage basin is dominated by a broad alluvial plain and extends from northern SBC to southern San Luis Obispo County. The Santa Maria River originates in the foothills of the San Rafael Mountains at the junction of the Cuyama River and the Sisquoc River. It continues west along the northern boundary of Santa Maria, past the town of Guadalupe, through a coastal estuary, and into the Pacific Ocean. Large areas along the river valleys are irrigated cropland, while surrounding hills are used for rangeland.

The drainage area at Guadalupe is approximately 1,700 square miles. Based on USGS data from 1941 to 1987, average flow on the Santa Maria River at Guadalupe is approximately 30 cfs. Highest flows are in March, which averages 137 cfs. Summer flows are minimal. The August average is near zero. The Santa Maria River is capable of high flows, with three instances of discharges above 20,000 cubic feet per second at Guadalupe since 1959 (USGS, 2006).

Water quality and water supply are major concerns within the watershed. Erosion and nutrient loadings are important issues. Water quality in the Santa Maria River basin reflects the influences of local topography and land use. The Santa Maria River is on the 2002 Section 303(d) list as an impaired water body. Fecal coliform and nitrate are parameters of concern.

Water quality in the mountainous areas of the basin is generally high because of its low dissolved mineral content. Surface flows are diverted for domestic use, irrigation, and for percolation and recharge of groundwater basins. Beneficial uses for the Santa Maria River include: municipal and domestic supply, agricultural supply, industrial service supply, groundwater recharge, freshwater replenishment, recreation, commercial and sport fishing, warm and cold fresh water habitat, terrestrial wildlife habitat, migration of aquatic species, and habitat that supports rare, threatened, or endangered species (Regional Water Quality Control Board (RWQCB, 1994).

The pipeline crosses Nipomo Creek twice and runs parallel to it for much of its route, crossing 14 minor drainages that empty into the Nipomo Creek. Nipomo Creek begins in the hills north of Santa Maria near the Nipomo Mesa and flows into the Santa Maria River. Nipomo Creek is on the 2002 Section 303(d) list as an impaired water body. Fecal coliform is the parameter of concern. Although the RWQCB has not designated specific beneficial uses, the Creek is assigned the designations of municipal and domestic water supply as well as protection of both recreation and aquatic life (RWQCB, 1994).

Only five percent of the pipeline route lies in the Central Coastal Drainage Basin, which extends north to Carmel in Monterey County. This section of pipeline approaches but does not cross the Los Berros Creek near the Summit Pump Station. It does, however, cross a drainage approximately 1,500 feet from the creek. The Los Berros Creek is the southernmost waterway in the Central Coastal Basin. Near the Summit Pump Station, the Los Berros Creek meanders along the edge of agricultural land, passes through the Pismo Dunes Natural Preserve, and empties into the Pacific Ocean. Beneficial uses for the Central Coastal drainage include: municipal and domestic supply, agricultural supply, groundwater recharge, recreation, commercial and sport fishing, warm and cold fresh water habitat, terrestrial wildlife habitat, migration of aquatic species, and habitat that supports rare, threatened, or endangered species (RWQCB, 1994).

The Los Berros Creek has historical peak flow of 691 cubic feet per second, a historic annual average flow of 1.3 cubic feet per second, and a historic rainy season (November through April) average flow of 2.7 cubic feet per second (USGS, 2000; County of San Luis Obispo, 1968-1998).

5.4.1.2 Groundwater

Surf Beach to LOGP

Portions of the proposed project are located within the Lompoc Subarea of the Santa Ynez River basin. The geological units of the basin can be divided into two parts: underlying, non-water bearing, consolidated rocks, and an overlying, water bearing, unconsolidated deposit. The underlying consolidated rocks form an effective lower boundary for the usable aquifer.

The lower portion of the younger alluvium under the Lompoc Plain is up to 180 feet thick, comprises most of the water-bearing zone, and is the most utilized aquifer in the Lompoc area (Miller, 1976). The upper portion of the alluvium has a lower permeability, but supplies a few domestic wells, whereas the river channel deposits are permeable but not tapped by wells in the Lompoc Plain. The lower terrace deposits that underlie alluvium deposits on the southern portion of the plain are up to several thousand feet thick, moderately permeable, and tapped by many wells with yields up to several hundred gallons per minute (Miller, 1976).

The aquifer of the Santa Ynez River Basin is bounded below and laterally to the north, south, and east by largely impermeable consolidated formations, and on the west by the ocean. These conditions create a general flow direction from east to west, with unconsumed groundwater discharging to the ocean. Prior to reaching the ocean, the aquifers discharge to streams where the water level in the stream is lower than the adjacent water table. Aquifer recharge is from infiltration of rainwater, seepage from streams, and return flows from irrigation and wastewater discharges (Arthur D. Little, 1985).

Depth to groundwater varies from zero near the ocean to over 400 feet in upland areas of the basin. For much of the Lompoc Plain, depth to groundwater ranges from 15 to 50 feet. Seepage from the Santa Ynez River to groundwater occurs consistently in portions of the river downstream from the city of Lompoc and intermittently in the rest of the river. Average annual recharge to groundwater in the Lompoc Plain from the Santa Ynez River, local tributaries, rain infiltration, and underflow is approximately 14,000 acre-feet, whereas removal is due to pumping, evapotransporation, streamflow, and underflow to the ocean. The net consumptive use from the Lompoc Basin was estimated to be 22,459 acre-feet in 2000 (SBC, 2001a).

Groundwater within the Lompoc Subarea is used extensively for agriculture (an estimated 70 percent), as well as some municipal, industrial, and military requirements. In contrast, groundwaters generally are not suitable for drinking water due to high TDS, as well as sulfate, chloride, and iron concentrations. Previous studies had shown a progressive deterioration of groundwater quality within the Santa Ynez River Basin, associated with increasing chloride ion concentrations due to agricultural recycling (Evenson, 1965). The effects of saltwater intrusion in the western portion of the basin are considered negligible.

The project area lies in the Lompoc Groundwater Basin, which consists of three hydrologically connected sub-basins: Lompoc Plain, Lompoc Terrace, and Lompoc Uplands. These basins, specifically Lompoc Plain and Lompoc Upland, are in equilibrium as natural recharge is augmented with periodical water releases from Cachuma Reservoir (Santa Barbara County Public Works, 2006).

LOGP to Suey Junction

Groundwater resources between the LOGP and Orcutt Pump Station are described in Arthur D. Little (1985). Groundwaters in the San Antonio basin are pumped for agricultural as well as some municipal and industrial uses. Depth to groundwater along the pipeline typically ranges from 20 to greater than 100 feet. Therefore, San Antonio Creek is generally above the water table, except at Barka Slough. Surface water bodies, when present, may recharge the groundwater. Groundwater quality in the San Antonio groundwater basin is similar to that of the Santa Ynez River basin, and is characterized by high TDS concentrations.

Suey Junction to Summit Pump Station

Groundwater in the Santa Maria River basin is used heavily for agriculture and, until 1997, as municipal water supply for the City of Santa Maria. Since 1997 and for the foreseeable future, the City of Santa Maria will rely on State Water for 100 percent of its municipal supply while groundwater will be used to flush lines and remain an emergency backup supply. Surface waters recharge groundwater, except in the western portion of the basin where impermeable beds underlie the river. Due to inadequate recharge, water shortages occur during the dry season, even during years of average rainfall. Groundwater quality in the Santa Maria groundwater basin is similar to that of the Santa Ynez River basin and is characterized by high TDS concentrations.

5.4.2 Regulatory Setting

Federal

Clean Water Act. The Clean Water Act (CWA) (33 U.S.C. Section 1251 et seq., formerly the Federal Water Pollution Control Act of 1972 was enacted with the intent of restoring and maintaining the chemical, physical, and biological integrity of the waters of the United States. The CWA requires states to set standards to protect, maintain, and restore water quality through the regulation of point source and certain non-point source discharges to surface water. Those discharges are regulated by the National Pollutant Discharge Elimination System (NPDES) permit process (CWA Section 402). In California, NPDES permitting authority is delegated to, and administered by, the nine Regional Water Quality Control Boards (RWQCB).

Projects that disturb one or more acres are required to obtain NPDES coverage under the California General Permit for Discharges of Storm Water Associated with Construction Activity. The Construction General Permits require the development and implementation of a Storm Water Pollution Prevention Plan (SWPPP) describing Best Management Practices (BMPs) to be used during construction to protect storm water runoff. The SWPPP must contain a visual monitoring program; a chemical monitoring program for "non-visible" pollutants to be implemented if there is a failure of BMPs; and a sediment monitoring plan if the site discharges directly to a water body listed on the 303(d) list for sediment.

Section 404 of the CWA authorizes the U.S. Army Corps of Engineers (USACE) to regulate the discharge of dredge or fill material to the waters of the U.S. and adjacent wetlands. The limits of nontidal waters extend to the Ordinary High Water (OHW) line, defined as the line on the shore established by the fluctuation of water and indicated by physical characteristics, such as natural line impressed on the bank, changes in the character of the soil, presence of debris. The USACE issues individual site-specific or general (Nationwide) permits for such discharges. A Section 404 permit would likely be required for the proposed project construction.

Section 401 of the CWA requires that any activity, including river or stream crossings during road, pipeline, or transmission line construction, which may result in a discharge into a State waterbody must be certified by the RWQCB. This certification, usually triggered by the need for a 404 Permit, ensures that the proposed activity not violate State and/or federal water quality standards.

Section 303(d) of the federal Clean Water Act (CWA, 33 USC 1250, et seq., at 1313(d)), requires States to identify waters that do not meet water quality standards after applying certain required technology-based effluent limits ("impaired" water bodies). States are required to compile this information in a list and submit the list to USEPA for review and approval. This list is known as the Section 303(d) list of impaired waters. As part of this listing process, States are required to prioritize waters/watersheds for future development of Total Maximum Daily Loads (TMDLs). A TMDL is a written plan that describes how an impaired waterbody will meet water quality standards (www.swrcb.ca.gov/tmdl/docs/tmdl_factsheet.pdf). The State Water Resources Control Board (SWRCB) and Regional Water Quality Control Boards (RWQCB) have ongoing efforts to monitor and assess water quality, to prepare the Section 303(d) list, and to subsequently develop TMDLs.

State

California Streambed Alteration Agreement. Section 1601 of the California Fish and Game Code requires an agreement between the Department of Fish and Game and a public agency proposing to substantially divert or obstruct the natural flow or effect changes to the bed, channel, or bank of any river, stream, or lake. The agreement is designed to protect the fish and wildlife values of a river, lake, or stream.

California Porter Cologne Water Quality Control Act. The Porter Cologne Water Quality Control Act of 1967, Water Code section 13000 et seq., requires the State Water Resources Control Board (SWRCB) and the nine RWQCBs to adopt water quality criteria to protect State waters. These criteria include the identification of beneficial uses, narrative and numerical water quality standards, and implementation procedures. The Porter Cologne Water Quality Control Act also regulates the discharge of pollutants or dredging and filling into the waters of the United States, which includes wetlands.

Section 1601 of the California Fish and Game Code requires an agreement between the Department of Fish and Game and a public agency proposing to substantially divert or obstruct the natural flow or effect changes to the bed, channel, or bank of any river, stream, or lake. The agreement is designed to protect the fish and wildlife values of a river, lake, or stream.

The California Coastal Act addresses several issues that relate to surface waters. Specific sections of the Act, addressing flood hazards and disturbances, maintenance of biological productivity, and possible impacts from runoff, could be applicable to the proposed project.

These include Section 30233 (diking, filling, or dredging of open coastal waters); Section 30231 (biological productivity); and Section 30240 (environmentally sensitive habitat areas).

Onshore re-injection of produced waters requires approval from the Department of Conservation, Division of Oil, Gas, and Geothermal Resources (DOGGR) under provisions of the Public Resources Code and a permit reviewed by RWQCB.

Regulations covering oil spills are discussed in Section 5.1, Risk of Upset.

Regional and Local

Most counties in California have floodplain and drainage regulations that regulate floodplain development. These regulations generally prohibit floodplain development that will result in flooding of the development, and prohibit floodplain development that will result in adverse flooding impacts on other property. For instance, floodplain encroachments that raise water levels on other property are generally prohibited, as are diversions and concentrations of flow.

Policies adopted by SBC address siting criteria for new structures, including avoidance of geological hazards and locations overlying regional groundwater basins (County of Santa Barbara, 2000).

5.4.3 Significance Criteria

Significant impacts to onshore water resources would result from any of the following events or conditions:

- Violation of any water quality standards or waste discharge requirements;
- Substantial depletion of groundwater supplies or interfere substantially with groundwater recharge such that there would be a net deficit in aquifer volume or a lowering of the local groundwater table level (e.g., the production rate of pre-existing nearby wells would drop to a level which would not support existing land uses or planned uses for which permits have been granted);
- Substantial alteration of the existing drainage pattern of the site or area, including through the alteration of the course of a stream or river, or substantially increase the rate or amount of surface runoff in a manner which would result in flooding on- or off-site;
- Create or contribute runoff water exceeding the capacity of existing or planned stormwater drainage systems or provide substantial additional sources of polluted runoff;
- Other substantial degradation of water quality in surface water such as streams, lakes, ponds and wetlands, and groundwater
- Location of facilities in flood-prone area or alterations to the course or flow of floodwater;
- Substantial flooding, erosion, or siltation; and/or
- Alteration of stream flow characteristics that result in erosion, sedimentation or flooding downstream.

The above criteria are based on CEQA significance criteria. These criteria cover the Santa Barbara significance criteria for water quality, listed below, as they are applicable to the proposed project.

According to Santa Barbara County ~~Significance~~Environmental Thresholds and Guidelines Manual, a significant water quality impact is presumed to occur if the project:

- Is located within an urbanized area of the county and the project construction or redevelopment individually or as a part of a larger common plan of development or sale would disturb one (1) or more acres of land;
- Increases the amount of impervious surfaces on a site by 25% or more;
- Results in channelization or relocation of a natural drainage channel;
- Results in removal or reduction of riparian vegetation or other vegetation (excluding non-native vegetation removed for restoration projects) from the buffer zone of any streams, creeks or wetlands;
- Is an industrial facility that falls under one or more of categories of industrial activity regulated under the NPDES Phase I industrial storm water regulations (facilities with effluent limitation; manufacturing; mineral, metal, oil and gas, hazardous waste, treatment or disposal facilities; landfills; recycling facilities; steam electric plants; transportation facilities; treatment works; and light industrial activity);
- Discharges pollutants that exceed the water quality standards set forth in the applicable NPDES permit, the Regional Water Quality Control Board's (RWQCB) Basin Plan or otherwise impairs the beneficial uses of a receiving waterbody; or
- Results in a discharge of pollutants into an "impaired" waterbody that has been designated as such by the State Water Resources Control Board or the RWQCB under Section 303 (d) of the Federal Water Pollution Prevention and Control Act (i.e., the Clean Water Act).
- Results in a discharge of pollutants of concern to a receiving water body, as identified ~~in~~by the RWQCB.

5.4.4 Impact Analysis for the Proposed Project

The following sections discuss potential impacts to onshore water resources, mitigation measures (where appropriate), and residual impacts associated with the proposed project. Because the proposed project largely would use existing facilities (e.g., LOGP and pipelines), requirements for new facilities or equipment with potentials for impacting onshore water resources are minimal. Impacts from the existing Point Pedernales facilities and operations are discussed in the 1985 Point Pedernales EIR/EIS. Impacts associated with the proposed project are related to changes in the present facilities or operating conditions, and are described below.

Impact #	Impact Description	Phase	Residual Impact
OWR.1	Project-related construction could cause erosion or siltation resulting in substantial degradation of surface water quality.	*Construction*	*Class II*

The proposed project may require~~s~~ new construction activities related to the installation of pumps and associated equipment at Valve Site #2 and the installation of power poles and a substation to connect the pumps to the existing power lines along Ocean Avenue. These construction activities have the potential for disturbances to existing soil conditions, changes in local surface water flow patterns, or surface water impoundment and increased siltation of drainages and the Santa Ynez River. Construction activities associated with Valve Site #2 would occur within the disturbed site and no additional vegetation removal would be required. Vegetation removal associated with the proposed project is limited to power line installation. Assuming 45 power poles total, the disturbance would be approximately 0.33 acre of vegetation and wildlife habitat. Construction of the proposed transformer station would result in temporary impacts to 4,200 square feet and permanent loss of 150 square feet of vegetation or wildlife habitat (depending on location), for a total of less than 0.1 acre of impact. Installation of power poles immediately adjacent to the Santa Ynez River could cause run-off into the river from excavated or disturbed areas or soil storage piles associated with pole installation. These impacts would be considered potentially significant.

Mitigation Measures

Mitigation Measures OWR-1, GR-1, AG-6, AG-7, TB-18 and TB-22 would reduce the magnitude of potential impacts to onshore water quality associated with disturbances to soils and vegetation during construction.

OWR-1 Prepare a Stormwater Pollution Prevention Plan (SWPPP) that describes Best Management Practices (BMPs) to be implemented for the purpose of minimizing soil loss and other construction-related sources of water pollution for any new construction associated with the project. The SWPPP will be prepared in accordance with RWQCB guidelines and will designate BMPs that will be followed during construction activities. Erosion-minimizing efforts may include measures such as avoiding excessive disturbance of steep slopes; using drainage control structures (e.g., coir rolls or silt fences) to direct surface runoff away from disturbed areas; strictly controlling soil stockpiling and vehicular traffic; implementing a dust-control program during construction; restricting access to sensitive areas; using vehicle mats in wet areas; and revegetating disturbed areas following construction. Erosion-control measures will be installed before extensive clearing and grading begins, and before the onset of winter rains. The SWPPP BMPs shall specify that the staging of construction materials, equipment, and excavation spoils, and refueling of equipment will be performed at least 100 feet outside of drainage channels and intermittent streams, where these receive overland runoff. Mulching, seeding, or other suitable stabilization measures will be used to protect exposed areas during and after construction activities. If required, concrete washout stations will be established to avoid direct release to surface water or to areas where groundwater could become contaminated. The SWPPP shall be submitted to SBC/CCC for review and approval prior to construction.

Residual Impact

With the implementation of the erosion and siltation mitigation measures, the residual impact is considered to be *significant but mitigable (Class II).*

Impact #	Impact Description	Phase	Residual Impact
OWR.2	A rupture or leak from the emulsion, produced water or dry oil pipelines could substantially degrade surface and groundwater quality.	*Increased Throughput Extension of Life*	*Class I*

A spill or large leak of crude oil or oil emulsion could allow either emulsion or dry oil to be released into the environment, which could substantially degrade surface and groundwater quality in nearby drainages and streams or rivers. Because the potential for spills already exists within the project area, the possible significance of a spill to onshore water resources associated with the proposed project is related to the incremental change in the size of the spill event. Small leaks or spills, which are contained and cleaned up quickly, may have minor or negligible impacts to onshore water resources. In contrast, large spills, or pipeline ruptures, which spread to surface waters and/or groundwater may substantially degrade water quality, with potential long-term impacts to beneficial uses and biological resources. Since the potential impacts to water resources associated with the baseline conditions are considered locally and regionally significant (Arthur D. Little, 1985), an increase in spill size would increase the severity of an already significant impact. In addition, the proposed project increases the lifetime probability of leaks or spills. Therefore, the impacts associated with the proposed project are considered significant.

Each of the oil emulsion, produced water, and gas pipelines from Platform Irene to LOGP, and the crude oil pipeline from LOGP to Summit Junction, has the potential to rupture or leak. Gas leaks would have negligible impacts to water resources because leaked materials would volatilize and, therefore, not directly affect surface or groundwater. In contrast, both produced water and oil emulsion spills could affect surface and groundwaters depending on the location and size of the spill. Although the proposed project would treat produced water to achieve compliance with offshore receiving water criteria in accordance with the National Pollutant Discharge Elimination System (NPDES) permit, onshore spills still may contain some soluble hydrocarbons with the potential for affecting surface and/or groundwater quality. Under worst-case conditions, maximum estimated spill volumes of oil or oil/water emulsion would be lost from a pipeline rupture immediately adjacent to surface waters at a location with no containment basins to impede oil dispersion. Although some of the more toxic components of oil would be lost rapidly due to weathering (e.g., volatilization), spills reaching the Santa Ynez River could have significant, long-term and widespread impacts to water quality and, consequently, sensitive biological resources. Similarly, subsurface (i.e., underground) spills, or surface spills in areas with porous surface soils and a shallow aquifer, could result in significant, long-term contamination of groundwater.

Increased throughput of oil emulsion, produced water, and crude oil would increase the maximum potential spill volumes. Further, the oil content of the emulsion would increase from present levels of 12~~10~~ percent to approximately 40~~34~~ percent. Consequently, the total mass of oil released by an oil emulsion spill would be greater than under existing conditions.

The total physical capacity of the emulsion pipeline between Platform Irene and the LOGP is 46,000 barrels. However, due to the onshore terrain (and pipeline path), and the series of existing check valves in the pipeline, only a portion of the total pipeline volume would be lost in the event of a spill. The specific volume would depend on the time between leak occurrence and system shutdown and the pumping rate. Maximum possible spill volumes for different pipe segments are presented in Section 5.1, Risk of Upset.

At Valve Site #2, the worst-case emulsion spill volume is 2,054 barrels. As mentioned previously, the probability of a rupture at this location would increase to 8.9 percent over the life of the project. (The probability of leaks from pumps would approach 100 percent due to potential failure of the new pumps, although leaks would not likely affect onshore water resources.) Surface water resources at this location would also be vulnerable for three reasons. Valve Site #2 does not have an adjacent catchment basin, the facility is within one kilometer directly upslope from the lower portion of the Santa Ynez River, and oil emulsion spilled at this location could flow directly along, and on top of, the road to the river without substantial impediment by local terrain or sorption by surface soils.

Oil from a surface spill would disperse and weather. Weathering would, in turn, affect the long-term persistence and toxicity of oil. The oil emulsion would have a lower viscosity than crude oil, which would increase the potential for transport in surface flows (e.g., runoff) or movement towards and with groundwaters. On the other hand, the soluble and more toxic components of crude oil (e.g., benzenes and other lower molecular weight aromatic compounds) would be lost more readily due to volatilization from an emulsion than from crude oil. Consequently, the toxicity of a potential spill may be reduced somewhat by natural weathering processes during dispersion. In contrast, insoluble oil fractions retained in low energy aquatic environments, due to burial in bottom sediments or trapped by aquatic vegetation, can affect water quality for periods up to several years. The possible dispersion and fate of a subsurface (underground) spill would be different and would depend in part on soil permeability and depth to groundwater. In most areas along the pipeline, groundwater occurs at depths greater than 75 feet below ground surface (U.S.G.S., unpublished data); therefore, an oil spill would not immediately contact groundwater. However, in some areas where the water table is shallow and soil is permeable (i.e., at the coastline), oil or produced water spills could affect groundwater.

In the event of a spill, containment facilities and cleanup procedures can reduce the potential impacts of the spill to onshore water resources. The success of the cleanup effort in preventing or minimizing impacts of the spill would depend on the volume and location of the spill, and the time needed to initiate the response action. A number of facilities, spill prevention methods, and response plans presently exist to minimize impacts from spills. These include: containment basins constructed along the pipeline route to retain and/or retard dispersion of spills; spill prevention and cleanup plans with regular preparedness reviews; monitoring, including regular pipe pigging to detect areas of significant corrosion within the pipeline; and automated leak detection and valving systems (e.g., SCADA - Supervisory Control and Data Acquisition) capable of detecting appreciable fluid losses from the pipeline and isolating specific pipeline sections in the event of spill to minimize spill volumes. The existing catchment basins along the onshore portion of the pipeline adjacent to the Santa Ynez River (see Figure 5.4-2) would be used to retain and prevent dispersion of the spill.

PXP has prepared an Oil Spill Response Plan which includes a Groundwater Protection Plan. This plan calls for regular monitoring for leaks, subsurface investigation to assess the extent of contamination, and preparation of leak-specific remedial action plans (excavation and disposal, in-situ treatment, etc.). In the event that leaks reach the groundwater table, owners of wells that could potentially be affected will be notified, and remedial action plans developed. Since known existing irrigation and water supply wells in the down-gradient sensitive areas pump from below the water table surface, it is unlikely that water supply from these would be adversely affected. Should this occur, however, the groundwater protection plan calls for backup water supplies, reconditioning the contaminated well, or installation of a new well.

The corrosion program for the 8-inch produced water return pipeline is summarized in Table 5.1.2c~~a~~. The water pipeline has not experienced any leaks or failures to date.

There are no anticipated changes to the corrosion control program, however, the frequency of the maintenance pigging may increase or decrease based on pipeline parameters. If, for example, the pipeline smart pigging demonstrates increased corrosion rates, then pigging would occur more frequently. A recent Smart Pig Survey (2005) showed evidence of corrosion. A section of pipe has been repaired and as a result of a confirmation dig for the identified anomalies, a monolithic isolation flange and pipe spool were replaced in 2005 at valve site #1. The internal corrosion survey conducted in 2005 using a high resolution pig showed 21 anomalies between 30 and 60 percent of wall thickness; the majority of anomalies (>99 percent) were between 10 and 29 percent of wall thickness.

Mitigation Measures

In addition to Mitigation Measure Risk-1, the following mitigation measures are proposed.

OWR-2 The applicant shall construct a berm around Valve Site #2 with sufficient capacity to retain 150 percent of the maximum spill volume associated with this portion of the onshore pipeline (see Section 5.1, Risk of Upset). The applicant shall submit specific plans for the catchment basin at Valve Site #2 to SBC/CCC for review and approval prior to land use clearance. The berm shall be installed prior to operations.

OWR-3 Update the Oil Spill Contingency Plan and the November 2004 Oil Spill Response Plan and July 2005 Supplement to address the SCADA system and GR.1-related requirements for the proposed project. Conduct annual readiness exercises and audits to ensure that containment and cleanup equipment is readily available close to areas with greatest vulnerability to spills (e.g., along the lower sections of the Santa Ynez River).

OWR-4 PXP shall ensure that catchment basins located along the Santa Ynez River section of the pipeline are cleaned and surveyed periodically to ensure that they are capable of holding at least 110 percent of the associated release volume from nearby pipeline segments. Prior to land use clearance, PXP shall provide volume calculations to SBC for each of the catchment basins for the following leak scenarios: (1) 11 minutes of pumping time for a worst case leak in accordance with the MMS Oil Spill Response Plan, Volume 2, worst case scenario, and (2) 20 minutes of pumping time for a small leak as detected by the PXP leak detection system. The total pipeline emulsion fluids, including produced water, shall be included in the calculations. If it is determined that the volume of any of the catchment basins is insufficient to fully contain the leak scenarios analyzed, the catchment basin(s) shall be expanded. Plans for catchment basin(s) expansion shall be submitted to SBC for review and approval prior to land use clearance.

OWR-5 Ensure that any pipeline replacement within stream beds is engineered such that the replacement pipeline and any pipeline support structures are protected from scour and erosion effects of a 100-year flood discharge. Plans demonstrating these requirements shall be submitted to SBC/CCC for review and approval prior to land use clearance.

Residual Impact

These mitigation measures, in combination with the mitigation measures listed in Section 5.1, Risk of Upset, Section 5.2, Terrestrial Biology, and Section 5.3, Geological Resources, would reduce the severity of potential spill impacts to onshore water resources. However, even with implementation of these mitigation measures, the potential for impacts to surface water and groundwater resources from oil emulsion or dry oil spills would remain *significant (Class I).*

Impact #	Impact Description	Phase	Residual Impact
OWR.3	Continued monitoring and pipeline maintenance and replacement activities associated with the onshore pipeline system could cause disturbances to soils that could cause erosion and subsequent siltation resulting in degradation of surface water quality.	*Extension of Life*	*Class II*

Extending the life of the facility would extend the risk of ground disturbances that could occur due to pipeline maintenance and repair activities. These ground disturbances could result in erosion, and siltation of nearby drainages and surface water bodies. These would be due primarily to the required excavation and replacement of pipeline segments. These activities are associated with the current operations. However, the extension of life of the facilities due to the Tranquillon Ridge Project would extend the potential for these types of disturbances. This issue is also discussed in Sections 5.2 (Terrestrial Biology) and 5.3 (Geological Resources). These impacts would be considered significant.

Mitigation Measures

Implementation of Mitigation Measure OWR-1 and GR-1 would reduce potentials for causing significant erosion or siltation associated with excavation along the pipeline right-of-way, along with the following measure:

OWR-6 If soil excavation is needed to expose buried pipeline or cleanup a spill within a stream bed, the area shall be restored to the maximum extent feasible to pre-spill conditions after excavation is completed.

Residual Impact

With implementation of Mitigation Measures OWR-1, OWR-6, and GR-1 the residual impact would be *significant but mitigable (Class II).*

Impact #	Impact Description	Phase	Residual Impact
OWR.4	Remediation activities associated with a pipeline spill could increase erosion and siltation and substantially degrade surface water quality.	*Increased throughput Extension of Life*	*Class II*

Remediation activities related to a release from the emulsion, produced water or dry oil pipelines would involve the mobilization of equipment, booms, and might also involve the construction of berms, modification of drainage or steam/river terrain and the travel of construction equipment off road. These activities could result in erosion and siltation of nearby drainages and surface water bodies as well as permanent changes to drainage and stream/river bed characteristics, which could adversely impact surface water quality. These activities are associated with the current operations and are considered to be potentially significant. With the increased throughput associated with the Tranquillon Ridge Project, these potential significant impacts would increase in severity. In addition, the extension of life of the facilities due to the Tranquillon Ridge Project would extend the potential for these types of disturbances. This issue is also discussed in Sections 5.2 (Terrestrial Biology) and 5.3 (Geological Resources). These impacts would be considered significant.

Mitigation Measures

Implementation of Mitigation Measures OWR-1, GR-1 and OWR-6 would reduce the potential for causing significant erosion or siltation associated with spill remediation activities along the pipeline right-of-way.

Residual Impacts

The residual impact is expected to be *significant but mitigable (Class II)*.

Impact #	Impact Description	Phase	Residual Impact
OWR.5	Increased water injection rates could potentially infiltrate fresh water aquifers.	*Extension of Life*	*Class III*

Increased throughput of crude oil could increase the volume of produced water disposal via onshore injection, which could infiltrate fresh water aquifers. Produced water would be separated from the crude oil at the LOGP and transported to Platform Irene and/or the onshore Lompoc Oil Field and injected into existing designated disposal wells. An increase in produced water could potentially exceed the safe capacity of each onshore injection well. This scenario could allow produced water to infiltrate fresh water aquifers, which would contaminate them with non-potable water.

To increase groundwater protection, the Safe Drinking Water Act (SDWA) of 1974 established a federal Underground Injection Control (UIC) program, which established minimum requirements for effective state UIC programs. Because ground water is a major source of drinking water in the United States, the UIC program requirements were designed to prevent contamination of Underground Sources of Drinking Water (USDW) resulting from the operation of injection wells. A USDW is defined as an “aquifer or its portion which supplies any public water system, or contains less that 10,000 milligrams per liter total dissolved solids and is not an exempt aquifer” (Groundwater Protection Council).

In California, all Class II injection wells are regulated by DOGGR, under provisions of the state Public Resources Code and the federal Safe Drinking Water Act. Class II injection wells fall under the Division's Underground Injection Control (UIC) program, which is monitored and audited by the U.S. Environmental Protection Agency. The Division received EPA primary authority “primacy” for regulation of Class II wells in 1983. The main features of the UIC program include permitting, inspection, enforcement, mechanical integrity testing, plugging and abandonment oversight, data management, and public outreach. In California, Class II injection wells have an outstanding record for environmental protection. A peer review conducted by a national organization, the Ground Water Protection Council, found that the division has an excellent program that effectively protects underground sources of drinking water (Ground Water Protection Council, 2000).

The DOGGR is the state agency responsible for approving injection wells within the state of California. The DOGGR imposes well construction, monitoring, testing, and operational requirements that make it unlikely that fresh water aquifers would be affected from the injection of produced water.

Mitigation Measures

No mitigation measures are proposed because of existing regulatory oversight of injection wells.

Residual Impact

Impact OWR.5 associated with injection of produced water into the Lompoc Oil Field would be *adverse but not significant (Class III)*.

Impact #	Impact Description	Phase	Residual Impact
OWR.6	~~Continued use of groundwater by LOGP~~The project could contribute or lead to groundwater basin ~~an~~ overdraft~~condition~~.	*Extension of Life*	*Class III*

The proposed project would extend LOGP’s contribution to withdrawals from the Lompoc groundwater basin over the longer life of the project. Continued operation of LOGP beyond its current permitted life would continue the consumption of this resource. However, the groundwater basin is not currently in an overdraft condition. Further, the LOGP annual usage is comparable to a small office building according to their water supplier (MHCSD, 2002), represents only a small fraction of overall consumption, and is less than SBC’s threshold of significance for extractions from the Lompoc Basin. Therefore, the impact would be considered less than significant.

Mitigation Measures

No mitigation measures have been proposed because of the nominal contribution of the LOGP.

Residual Impact

The impact from the proposed project would be minimal; therefore, it is considered *adverse but not significant (Class III).*

5.4.5 Impact Analysis for the Alternatives

Detailed descriptions of the various alternatives have been provided in Chapter 3.0. This section provides a discussion of the onshore water resource impacts of the various alternatives.

5.4.5.1 No Project Alternative

Scenarios 2 and 3. As discussed in Section 3.2, under the No Project Alternative Scenarios 2 and 3, production of the federal portion of the Tranquillon Ridge field would and would not occur, respectively. However, no extension of life of Point Pedernales facilities (Platform Irene, pipelines, and LOGP) is assumed under either scenario.

Impact OWR.1 - Construction Related Impacts: Construction of the power line and installation of the pumps at Valve Site #2 would not occur under either Scenario 2 or 3 ~~the No Project Alternative~~. Therefore, this impact would not occur.

Impact OWR.2 - Spill Related Impacts, OWR.4 - Remediation Impacts, and OWR.5 - Water Injection Impacts: The oil spill remediation and water injection impacts associated with increased throughput in the emulsion, produced water or dry oil pipelines would be the same as the baseline, therefore, these impacts would not occur.

Impact OWR.3 - Pipeline Maintenance: Impacts associated pipeline maintenance would not be applicable to ~~this alternative~~ Scenarios 2 and 3 because the production would not extend beyond that expected for the Point Pedernales operations; existing pipeline maintenance impacts would not increase beyond baseline conditions.

Impact OWR.6 - Contribution to Groundwater Basin Overdraft: This impact would not apply to ~~this alternative~~Scenarios 2 and 3 because there would be no extension of life of the project; therefore, the project would not impact the overdraft of the Lompoc Groundwater Basin beyond the current operations.

Options for Meeting California Fuel Demand. The relative onshore water resource impacts associated with the various options for meeting California fuel demand are summarized in Table 5.4.1.

Table 5.4.1 No Project Alternative Comparison to Options for Meeting California Fuel Demand, Onshore Water Resources

Source of Energy		Impacts
Other Conventional Oil & Gas		
	Domestic onshore crude oil and gas	Likely to displace, rather than eliminate, onshore water resource impacts.
	Increased marine tanker imports of crude oil	Would eliminate proposed project onshore water resource impacts.
	Increased gasoline imports[1]	Likely to displace, rather than eliminate, onshore water resource impacts.
	Increased natural gas imports (LNG)	Likely to displace, rather than eliminate, onshore water resource impacts.

Table 5.4.1 No Project Alternative Comparison to Options for Meeting California Fuel Demand, Onshore Water Resources

Source of Energy	Impacts
Alternatives to Oil and Gas	
Fuel Demand Reduction: increased fuel efficiencies, conservation, electrification[2]	
Alternative transportation modes	Proposed project impacts would be eliminated.
Implementation of regulatory measures	Proposed project impacts would be eliminated.
Coal, Nuclear, Hydroelectric	Would eliminate proposed project impacts, but could introduce power facility construction and operation impacts which could likely be greater than proposed project.
Alternative Transportation Fuels	
Ethanol/Biodiesel[3]	Groundwater depletion impacts could be greater for ethanol production. Other proposed project onshore water resource impacts could be reduced.
Hydrogen[2]	Proposed project impacts would be eliminated. Potential onshore water resource impacts due to hydrogen delivery infrastructure development.
Other Energy Resources[2]	
Solar[2,4]	Proposed project onshore water resource impacts would be eliminated. Solar onshore water resource impacts and their severity would depend upon facility infrastructure siting.
Wind[2,4]	Proposed project onshore water resource impacts would be eliminated. Wind onshore water resource impacts and their severity would depend upon facility infrastructure siting.
Wave[2,4]	Proposed project onshore water resource impacts would be eliminated. Wave onshore water resource impacts and their severity would depend upon facility infrastructure siting.

Footnotes:
1. Pipeline and tanker truck import from out-of-State assumed.
2. Assumes that Tranquillon Ridge production would not be replaced with other petroleum-based energy supply.
3. Assumes ethanol and biodiesel used as blends only and therefore would reduce, but not eliminate Tranquillon Ridge or equivalent production.
4. Assumes, large centralized facilities.

5.4.5.2 VAFB Onshore Alternative

The following sections summarize the environmental setting and potential impacts to onshore water resources in the area affected by the Vandenberg Air Force Base (VAFB) Onshore Alternative.

Environmental Setting

The VAFB Onshore Alternative ~~onshore portion of the~~oil emulsion and gas pipelines,~~and~~ drilling/processing facility, power lines, pipeline tie-in station, and electrical substations are located within the southern part of the Central Coast Hydrologic Region of the South Coast and Santa Ynez Hydrologic Units in southern Santa Barbara County.

Topographic features within the alternative area are dominated by a rugged Pacific seacoast to the west, the Santa Ynez Mountains to the east, and the Santa Ynez River to the north. Precipitation in this area ranges from approximately 10 inches near the coast to 18 inches in the nearby Lompoc Hills. Average precipitation is approximately 15 inches. Most precipitation falls in the winter months, November through April. Watercourses within the alternative area are typically dry during the summer months and have flows that rise and fall in response to precipitation with the potential of producing high volumes of runoff during wet years.

Surface Waters

There are several localized drainage areas associated with this alternative that are characterized by high intensity, short duration runoff events, due to the relatively short distance from the top of the Santa Ynez Mountains to the Pacific Ocean. The major stream system within the alternative area is the Santa Ynez River north of Highway 246 and south of the existing PXP pipelines.

The major components of the VAFB Onshore Alternative are south of the Santa Ynez River with one crossing by the alignment of the pipelines as they head north along 13th Street to connect to the existing PXP pipelines at the tie-in station. The Santa Ynez River basin and associated tributaries are discussed in detail above in Section 5.4.1.

The alternative drilling and production area is located in a sub-watershed of the Arguello Hydrologic Area, South Coast Hydrologic Unit, just north of La Honda Canyon. From this point, the pipelines head north traversing an unnamed tributary, Spring Canyon, and Bear Creek. It is at this juncture that the pipeline alignment passes into the Lompoc Canyon sub-watershed of the Santa Ynez River Super Planning Watershed, Lompoc Hydrology Study Area, Santa Ynez Hydrology Unit. The pipelines continue north to parallel Highway 246 then east and north again at the base of Lompoc Canyon to parallel 13th Street in a northeasterly direction crossing the Santa Ynez River before connecting to the existing PXP pipelines at the tie-in station.

Surface water quality for the Santa Ynez River is described in Section 5.4.1. Processed wastewater from Space Launch Complex 3 is discharged into Bear Creek. Water quality sampling of Bear Creek indicated that aluminum, iron, manganese, and mercury greatly exceeded water quality criteria. Turbidity and chlorophyll *a* levels were also high (Tetra Tech, 2006). Lower Spring Canyon also receives processed waste water. Potential pollutants from this source include chlorine, perchlorate, other products of launch vehicle emissions, and sediment (Tetra Tech, 2006).

Groundwater

The associated groundwater basin for the VAFB Onshore Alternative is the Lompoc Groundwater Basin of the Santa Ynez River Basin. The general direction of groundwater flow is from east to west, parallel to the Santa Ynez River. The Lompoc Groundwater Basin consists of three hydrologically connected subbasins: the Lompoc Plain, Lompoc Terrace, and Lompoc Uplands. The three subbasins encompass about 76 square miles, but only the Lompoc Plain and Terrace subbasins are associated with this alternative.

The Lompoc Plain sub-basin surrounds the lower reaches of Santa Ynez River and is bordered on the north by the Purisima Hills, on the east by the Santa Rita Hills, on the south by the Lompoc Hills and on west by the Pacific Ocean. This alluvial basin is divided into three horizontal zones: an upper, middle and main zone. Based on previous hydrologic and water quality studies, these zones have only limited points of hydrologic continuity and exchange. This basin is basically in equilibrium as during periods of dry climate, water is released from Lake Cachuma to recharge groundwater levels in the eastern portion of the subbasin.

Alternative components that traverse the area surrounding Bear Canyon lie within the Lompoc Terrace groundwater basin. This basin was formed by a down-faulted block capped with permeable sediments on south VAFB south of the Lompoc Plain. This basin consists of Orcutt Sand deposits which overlay both the Graciosa and Cebada members of the Careaga Formation. The Careaga Formation is a marine formation which can yield small to moderate quantities of water. The thickness of the formation in the Terrace is 400-500' and usable groundwater in storage is estimated to be around 60,000 acre-feet. The Lompoc Plain subbasin is in equilibrium as natural recharge is augmented with periodic releases from Cachuma Reservoir.

The City of Lompoc and the surrounding incorporated communities receive their water from wells drilled in the Lompoc Plain and Lompoc Upland ground water basins. South VAFB derives all of its water from the Lompoc Terrace Basin. Total VAFB groundwater usage is approximately 4,300 AFY.

Water quality in the shallow zone of the Lompoc Plain tends to be poorest near the coast and in heavily irrigated areas of the subbasin. TDS concentrations of up to 8,000 mg/L near the coast were measured in the late 1980s. The poor quality water in this area is attributed to upwelling of poor quality connate (waters trapped in sediment layers) waters, reduction in fresh water recharge from the Santa Ynez River beginning in the early 1960s, agricultural return flows, and downward leakage of seawater from an overlying estuary in the western portion of the basin. The presence of elevated boron and nitrates (constituents common in seawater and agricultural return flow, respectively) supports this conclusion.

Groundwater of the Lompoc Terrace is generally of better quality than that of the Lompoc Plain, averaging less than 700 mg/L TDS. Some of the natural seepage from these subbasins is of excellent quality.

Impact Analysis

***Impact OWR.1 – Construction Related Impacts*:** The VAFB Onshore Alternative requires new construction activities related to the drilling and production facility, new pipelines, ~~and transmission~~power lines, pipeline tie-in station, and electrical substations; therefore, Impact OWR.1 is considered to be more severe for the alternative than the proposed project. These construction activities have the potential for disturbances to existing soil conditions, changes in local surface water flow patterns, or increased siltation of drainages including the Santa Ynez River, which could be subject to spills of drilling mud from a directional drill or bore. These impacts would be considered potentially significant.

Mitigation Measures

Mitigation Measure OWR-1 would reduce the magnitude of potential impacts to onshore water quality associated with disturbances to soils and vegetation during construction. With regard to the VAFB Alternative, the required SWPPP shall specifically address containment and clean-up of potential spills of mud from construction of the crossing of the Santa Ynez River, and from adverse effects of other new creek and drainage crossings. The following mitigation measure would also apply:

OWR-7 The applicant shall schedule construction activities during the dry season, unless otherwise approved by SBC, CCC, CDFG, and USFWS. Construction time restrictions shall be included in the contractor bid solicitation packages and depicted on construction plans which will be provided to SBC prior to construction.

Residual Impact

With the implementation of Mitigation Measures OWR-1 and OWR-7, impacts are considered to be *significant but mitigable (Class II).*

Impact OWR.2 - Spill Related Impacts: A spill or large leak of oil could be released into the environment, which could substantially degrade surface and groundwater quality in nearby drainages and streams or rivers. Small leaks or spills, which are contained and cleaned up quickly, may have minor or negligible impacts to onshore water resources. In contrast, large spills, or pipeline ruptures, which spread to surface waters and/or groundwater may substantially degrade water quality, with potential long-term impacts to beneficial uses and biological resources. Therefore, the impacts associated with the alternative are considered significant.

Mitigation Measures

Mitigation Measures OWR-3 and OWR-5, as well as the following mitigation measures would apply.

OWR-8 Install catchment basins to prevent spills from entering the Santa Ynez River. Basin volumes shall be designed in accordance with Mitigation Measure OWR-5. Catchment basin design and construction plans shall be submitted to SBC for review and approval prior to land use clearance.

OWR-9 Implement an oil-spill response and containment plan, including catchment basins as necessary, for the drilling and production facility. The plan shall be submitted to SBC/CCC for review and approval prior to land use clearance.

Residual Impact

These mitigation measures would reduce the severity of potential spill impacts to water resources. However, the potential for impacts to surface water and groundwater resources would remain *significant (Class I)*. Because spill frequencies due to the increased pipeline lengths associated with the VAFB Onshore Alternative would increase in comparison to the proposed project, this impact is considered more severe for the alternative.

***Impact OWR.3 - Pipeline Maintenance*:** Ground disturbances resulting from pipeline repair and maintenance could result in erosion and siltation of nearby drainages and surface water bodies. These would be due primarily to the required excavation and replacement of pipeline segments. These impacts would be considered significant. Implementation of Mitigation Measure OWR-1 and OWR-6 would reduce the potential for causing significant erosion or siltation associated with excavation along the pipeline right-of-way. The residual impact is expected to be *significant but mitigable (Class II)*. The severity of this impact would be slightly greater than the proposed project because of the increased pipeline lengths associated with the VAFB Onshore Alternative.

Impact OWR.4 - Spill Remediation Impacts: Remediation activities related to a release of oil from the pipeline,~~or~~ drilling/production facility, or tie-in station would involve the mobilization of construction equipment, possible modification of drainage or stream/river terrain, and the travel of construction equipment off road. These activities could result in erosion and siltation of nearby drainages and surface water bodies as well as permanent changes to drainage and stream/river bed characteristics, which could adversely impact surface water quality. These activities are considered to be potentially significant. Implementation of Mitigation Measures OWR-1 and OWR-6 would reduce the potential for significant erosion or siltation caused by spill remediation activities along the pipeline right-of-way. Residual impacts are expected to be *significant but mitigable (Class II)*. The severity of this impact would be similar to the proposed project.

***Impact OWR.5 - Water Injection Impacts*:** Produced water disposal via onshore injection, if used, could infiltrate and contaminate fresh water aquifers. The discussion in Section 5.4.4 of this EIR related to the Safe Drinking Water Act (SDWA) of 1974, and regulation of injection wells by the Department of Conservation, Division of Oil, Gas, and Geothermal Resources, applies to this alternative. The residual impact associated with injection of produced water would be *adverse but not significant (Class III)*. No mitigation measures are proposed. If Produced Water Scenarios 2 or 3 are implemented (onshore injection of produced water) the severity of this impact would be greater for the VAFB Onshore Alternative in comparison to the proposed project because a greater volume of water would be injected onshore with the alternative, whereas for the proposed project, most produced water would be injected (or discharged) offshore.

Impact OWR.6 - Contribution to ~~Lompoc~~ Groundwater Basin Overdraft: This impact would be the same for the VAFB Onshore Alternative as the proposed project.

Impact #	Impact Description	Phase	Residual Impact
OWR.7	Potential "frac-out" of boring muds could cause siltation and degrade surface water quality.	*Construction*	*Class II*

Directional drilling under the Santa Ynez River would be utilized to install the VAFB Onshore Alternative pipelines. Drilling has the potential to indirectly impact surface water quality through the inadvertent release of drilling muds through natural subsurface fractures (frac-out). Drilling muds typically consist of a mixture of bentonite and water. Bentonite is an inert clay material and is considered essentially nontoxic to aquatic organisms although it can have adverse physical effects on organisms that get coated. Due to the larger diameter bore that would be required to install the VAFB Onshore Alternative pipelines, the risk of frac-out is considered greater for the alternative than the proposed project power line.

Mitigation Measures

Mitigation Measures TB-16 and TB-17 would minimize impacts associated with a frac-out. The following measure would reduce impacts associated with soil erosion and sedimentation:

OWR-10 The applicant shall monitor boring operations, immediately cleaning spilled drilling muds, restricting construction activities to avoid potential conflicts with special status species, and use of best management practices to prevent or minimize soil erosion and effects of siltation on surface waters.

Residual Impact

The residual impact would be considered *significant but mitigable (Class II)*.

~~Impact #~~	~~Impact Description~~	~~Phase~~	~~Residual Impact~~
~~OWR.8~~	~~The VAFB Onshore Alternative would contribute to the possible overdraft of the Lompoc groundwater basin.~~	~~*Operations*~~	~~*Class III*~~

~~The VAFB Onshore Alternative would contribute to the overdraft of the Lompoc groundwater basin. As mentioned in the environmental setting above, the groundwater basin is presently in a state of overdraft with net extractions exceeding recharge by 913 acre-feet per year in 2000. Construction and operation of the VAFB Onshore Alternative would continue the consumption of an overused resource. However, the alternative drilling and production site, the major user of groundwater for the alternative, is located within the Lompoc Terrace. As noted above, the Lompoc Terrace has experienced an average gain of 33 AFY between 1975 and 2000.~~

~~Mitigation Measures~~

~~No mitigation measures have been identified.~~

~~Residual Impact~~

~~Impact OWR.8 is considered *adverse but not significant (Class III)*.~~

Impact #	Impact Description	Phase	Residual Impact
OWR.8~~9~~	Scour from large flood events could uncover, expose, and place the pipeline at risk for rupture at Santa Ynez River and Bear Creek crossings.	*Operations*	*Class II*

Flood scour at river crossings could result in pipeline rupture and subsequent contamination of river flows. This impact would be considered significant.

Mitigation Measures

Mitigation Measure OWR-11 applies.

OWR-11 The pipelines shall be placed below the 100-year depth of scour at all river crossings. The river cross section topography shall not be altered in a manner that would result in increased levels of scour or erosion. Pipeline construction plans for the Santa Ynez River and Bear Creek crossings shall be submitted to SBC for review and approval prior to land use clearance.

Residual Impact

With the implementation of Mitigation Measure OWR-11, this impact is considered to be *significant but mitigable (Class II)*.

Impact #	Impact Description	Phase	Residual Impact
OWR.9~~10~~	Disturbance of sites contaminated with hazardous substances could result in contamination of surface water and groundwater.	*Construction*	*Class II*

There are currently 136 sites identified as hazardous substance release sites by the federal Installation Restoration Program (IRP) on VAFB. These sites are remediated through the Federal Facilities Site Remediation Agreement (FFSRA), a working agreement between the U.S. Air Force, the RWQCB Central Region, and the Department of Toxic Substances Control. In addition to IRP sites, there are additional Areas of Concern, where potential hazardous material releases are suspected, and Areas of Interest, which have a potential for the presence of a hazardous substance. Activities associated with the installation of an onshore drilling and production facility, and associated pipelines may encounter contaminated soils or sites in at least two locations (Ryan, 2006). Disturbance of these sites may result in contamination of surface and/or groundwater.

Mitigation Measure

Mitigation Measure OWR-12 applies.

OWR-12 The applicant shall work with the U.S. Air Force, the RWQCB Central Region, and the Department of Toxic Substances Control to identify Federal Installation Restoration Program (IRP) sites, Areas of Concern and Areas of Interest within the construction area, and characterize the nature and extent of hazardous substances that may be present at each. In conjunction with the USAF, the RWQCB Central Region, and the Department of Toxic Substances Control, the applicant shall develop a plan of action to avoid and/or minimize any contamination of groundwater or surface water that may result from construction in these areas. Permits/approvals from these respective agencies shall be provided to SBC prior to construction.

Residual Impact

Mitigation Measure OWR-12 would reduce this impact to *less than significant with mitigation (Class II).*

5.4.5.3 Casmalia East Oil Field Processing Location

This alternative would involve the relocation of the LOGP facility to the Casmalia East location identified in the North County Siting Study (SBC, 2000). The pipelines would also be routed to the north along Harris Grade Road, Highway 135 and then east to the Casmalia East location.

Building a new processing site at Casmalia East near Orcutt, and trenching for new pipelines from this processing site to the LOGP would result in extensive ground disturbance. It is likely that this new construction would result in significant impacts on unnamed tributaries to Graciosa Creek along the pipeline route. New impacts on water resources would likely be greater than the proposed project’s construction activities due to the extensive ground disturbance involved with this alternative, and because new tributaries would be crossed by the pipeline array in addition to existing crossings along the pipe corridor.

Impact OWR.1 - Construction Related Impacts: Impacts associated with construction of the power line and installation of the pumps at Valve Site #2 would still occur under this alternative. Impacts would be of the same type but of greater severity, as construction would require more earth disturbances and more opportunity for erosion and drainage siltation. Impacts would remain *significant but mitigable (Class II)* and Mitigation Measure OWR-1 would still apply.

Impact OWR.2 - Spill Related Impacts: Oil spill impacts associated with increased throughput in the emulsion, produced water or dry oil pipeline would be the same as the proposed project. The impact would be considered *significant (Class I)*. Mitigation Measures OWR-2 through OWR-6 would apply to this alternative. The impact associated with extension of life would also apply to this alternative.

Impact OWR.3 - Pipeline Maintenance: Impacts associated with pipeline maintenance would be applicable to this alternative because the production would extend beyond that expected for the Point Pedernales operations. Impacts would remain *significant but mitigable (Class II)* and Mitigation Measure OWR-9 would still apply.

Impact OWR.4 - Remediation Impacts: Impacts associated with spill remediation would still be applicable due to the increased throughput and extension of life issues of this alternative. Impacts would be considered *significant but mitigable (Class II)*. Mitigation Measure GR-1 would still apply.

Impact OWR.5 - Water Injection Impacts: Impacts associated with water injection into the aquifers would be similar to the proposed project, as there would be an increase in injection rates. However, given the permitting, monitoring, and reporting requirements of CDOGGR, impacts would be considered to be *adverse but not significant (Class III).*

Impact OWR.6 - Contribution to Groundwater Basin Overdraft: This impact would be the same as for the proposed project, *adverse but not significant (Class III)*, but for a different aquifer.

5.4.5.4 Alternative Power Line Routes to Valve Site #2

Impacts OWR.2 through OWR.6 would remain the same as the proposed project for all of the alternative power line routes discussed below.

Alternative Power Line Route – Option 2a

Impact OWR.1 - Construction Related Impacts: Impacts associated with construction would be the same as the proposed project. The installation of power poles for crossing the Santa Ynez River, and the relocation of the power line to the west side of 13^{th} Street would not increase the severity of this impact over that for the proposed project. The impact would be considered *significant but mitigable (Class II)*. Mitigation Measure GR-1 would apply to this alternative.

Alternative Power Line Route – Option 2b

Impact OWR.1 - Construction Related Impacts: With this option the power line would be placed under the Santa Ynez River via a directional bore. The boring activities would require two 150 foot by 150 foot work areas on either side of the Santa Ynez River adjacent to the proposed power line route. These areas would temporarily expose stockpiled or disturbed soils to wind and water erosion, which could result in an increase in potential siltation within the river. The disturbed area of the project would also require the implementation of a SWPPP. This is considered *significant but mitigable (Class II).* Mitigation Measure GR-1 would still apply.

Impact OWR.7 – Frac-out of Boring Muds: Spills or losses through the formation (i.e., frac out) of drilling fluids could affect surface water resources. Drill muds typically consist of a mixture of bentonite and water. Bentonite is an inert clay material and is considered essentially nontoxic to aquatic organisms although it can have adverse physical effects on organisms that get coated. Nevertheless, drilling muds losses could cause temporary and localized increases in turbidity and suspended solids concentrations and promote siltation within the Santa Ynez River. Therefore, impacts to onshore water resources would be potentially *significant but mitigable (Class II)* with the implementation of Mitigation Measure OWR-9.

Underground Power Line along Terra Road

Impact OWR.1 - Construction Related Impacts: Trenching, required for installing of power lines to Valve Site #2, would temporarily disturb soils along the power line route. Soils removed during trenching would be susceptible to erosion and transport during storm events. Impacts from erosion and siltation could be minimized by scheduling construction during summer and fall, and using construction BMPs (erosion control measures). Impacts would remain *significant but mitigable (Class II)* and Mitigation Measures OWR-1 and GR-1 would still apply. The severity of this impact would be greater than for the proposed project due to the more extensive construction.

5.4.5.5 Replacement of Oil Emulsion Pipeline from Platform Irene to LOGP

Impact OWR.1 - Construction Related Impacts: This alternative would not include construction at Valve Site #2 but rather would include the replacement of the existing crude oil pipeline from Platform Irene to the LOGP with a new pipeline. Installation of a new pipeline would involve excavation along the present pipeline route, removing the existing oil emulsion pipeline, and replacing it with a new pipeline. Therefore, all ground disturbances associated with construction of a new pipeline would occur within the previously disturbed ROW. This section addresses potential impacts to onshore water resources associated with the installation of a replacement pipeline between pipeline landfall at Wall/Surf Beach to the LOGP.

Impacts to onshore water resources from construction of a replacement pipeline would be comparable to those associated with installation of the original pipeline, which was evaluated in 1985 Point Pedernales Project EIR/EIS. Excavation, minor grading, and vegetation removal associated with replacement pipeline construction would temporarily expose disturbed soils to wind and water erosion, and thereby result in a minor increase in potential siltation of the nearby Santa Ynez River and adjoining creeks and drainages. With the exception of localized, erosion-prone areas, replacement of the pipeline within the existing corridors would result in less than significant impacts.

Impacts to erosion-prone areas, such as portions of Oak Canyon and Santa Lucia Canyon, would be considered potentially significant, although the impacts could be reduced to insignificance by implementing Mitigation Measures OWR-1, OWR-7, GR-1 through GR-4, and TB-4 and TB-5, which address using best management practices to prevent or minimize soil erosion and effects of siltation on surface waters. These mitigation measures include: development of a SWPPP, limiting construction to the dry season; installing sediment retention and flow diversion devices at the construction site; and mulching slopes and revegetating immediately following construction. These potentials for impacts associated with erosion and siltation would be considered short-term, and expected to persist until vegetation is re-established in disturbed areas along the pipeline route. Construction impacts on water quality would be considered *significant but mitigable (Class II)*. The severity of this impact would be substantially greater than for the proposed project due to the greater area of construction.

Impact OWR.2 - Spill Related Impacts: Oil spill impacts associated with increased throughput in the emulsion, produced water or dry oil pipeline would be the same as the proposed project. The impact would be considered *significant (Class I)*. Mitigation Measures OWR-2 through OWR-5 would apply to this alternative. The impact associated with extension of life would also apply to this alternative. The degree of this impact would be less than for the proposed project due to the reduced risk of spill from the new portion of the pipeline.

Impact OWR.3 - Pipeline Maintenance: Impacts associated with pipeline maintenance would be applicable to this alternative because the production would extend beyond that expected for the Point Pedernales operations. However, impacts would be less severe as fewer pipeline maintenance activities would be expected with the newer pipeline. Impacts would remain *significant but mitigable (Class II)* and Mitigation Measures OWR-8 and OWR-9 would still apply.

Impact OWR.4 - Remediation Impacts: Impacts associated with oil spill remediation would still be applicable due to the increased throughput and extension of life issues of this alternative. Impacts would be considered *significant but mitigable (Class II).* Mitigation Measures OWR-1, GR-1 and OWR-9 would still apply.

Impact OWR.5 - Water Injection Impacts: Impacts associated with water injection into the aquifers would be the same as the proposed project, as there would be an increase in injection rates over current operations. However, given the permitting, monitoring, and reporting requirements of CDOGGR, impacts would be considered *adverse but not significant (Class III).*

Impact OWR.6 - Contribution to Groundwater Basin Overdraft: This impact would be the same as the proposed project: adverse but not significant (Class III).

5.4.4.6 Alternative Drill Muds and Cuttings Disposal

Inject Drill Muds and Cuttings into Reservoir

Onshore activities under this alternative would be the same as for the proposed project. Therefore, impacts on onshore water resources would be the same as for the proposed project.

Transport Drill Muds and Cuttings to Shore for Disposal

Onshore disposal activities would not affect onshore water resources; therefore, its impacts would be the same as for the proposed project. Since the material would be disposed of onshore, the potential for some impact exists. However, as the disposal would be to a licensed facility, it is assumed no new impacts to water resources would occur.

5.4.6 Cumulative Impacts

5.4.6.1 Offshore Oil and Gas Projects

The majority of the offshore oil and gas development projects discussed in Sections 4.~~1~~2 and 4.~~2~~3 would primarily use existing infrastructure. However, within the northern Santa Maria Basin, exceptions could potentially include development of the federal OCS Santa Maria, Lion Rock, Point Sal, and Purisima Point Units and Lease OCS-P 0409. Collectively, if implemented, these potential projects could involve up to three new offshore platforms and three associated off- to onshore pipelines (see Section 4.2~~1~~.5). Production of the Santa Maria, Lion Rock, Point Sal, and Purisima Point Units and Lease OCS-P 0409 would be hypothetically sent to a new onshore processing facility in Casmalia. These cumulative oil and gas development projects would increase the severity of impacts to onshore water quality due to an oil or produced water spill. Although it is assumed that these potential projects would be subject to the same or similar onshore water resources mitigation measures as recommended for the proposed project, their cumulative impacts, and the proposed project's incremental contribution to them, would still be considered significant.

The remainder of the cumulative offshore oil and gas projects would occur in the southern Santa Maria Basin and Santa Barbara Channel, and their production would be transported to and processed at existing facilities located along Santa Barbara's south coast. Consequently, these projects would not be expected to have any geographic overlap with the watersheds affected by the proposed project. Therefore, the proposed project would not incrementally contribute to the potential onshore water resources cumulative impacts associated with these projects.

5.4.6.2 Onshore Projects

Proposed onshore development projects in the study area would locally increase impervious ground cover reducing rates of groundwater recharge and increasing storm water run-off. Due to the limited new impervious surfaces associated with the proposed project, the proposed project's incremental contribution would not be considered cumulatively significant. As noted in Section 5.2, Terrestrial Biology, due to the limited amount and duration of both construction-related grading and maintenance-related grading, the proposed project's incremental contribution to cumulative water quality impacts due to sedimentation also would not be considered significant. The potential onshore development projects outlined in Section 4.4~~3~~ would be subject to the same stormwater runoff regulations that apply to the proposed project construction, which would serve to mitigate these impacts. Of the three onshore projects associated with the Santa Ynez River, two may affect the volume of water currently reaching the lower reaches of the river. The third project is not expected to affect reaches of the river below Bradbury Dam (the Bee Rock Quarry Expansion Project) (County of Santa Barbara, 2006). Project-specific mitigation measures related to the two projects that may affect the downstream reaches of the river, if approved, would be assumed to reduce all or some of the adverse onshore water resources impacts associated with their implementation; consequently, cumulatively significant impacts would not be anticipated to occur. Implementation of the proposed project would not affect the volume of water received by the lower reaches of the river. Therefore, it would not incrementally contribute to any cumulative impacts~~would not be expected to be significant~~ related to surface water flows in the Santa Ynez River.

5.4.7 Mitigation Monitoring Plan

Mitigation Measure	Mitigation Requirements and Timing	Method of Verification	Timing of Verification	Party Responsible For Verification
OWR-1	Prepare a Stormwater Pollution Prevention Plan (SWPPP) that describes Best Management Practices (BMPs) to be implemented for the purpose of minimizing soil loss and other construction-related sources of water pollution for any new construction associated with the project. The SWPPP will be prepared in accordance with RWQCB guidelines and will designate BMPs that will be followed during construction activities. Erosion-minimizing efforts may include measures such as avoiding excessive disturbance of steep slopes; using drainage control structures (e.g., coir rolls or silt fences) to direct surface runoff away from disturbed areas; strictly controlling soil stockpiling and vehicular traffic; implementing a dust-control program during construction; restricting access to sensitive areas; using vehicle mats in wet areas; and revegetating disturbed areas following construction. Erosion-control measures will be installed before extensive clearing and grading begins, and before the onset of winter rains. The SWPPP BMPs shall specify that the staging of construction materials, equipment, and excavation spoils, and refueling of equipment will be performed at least 100 feet outside of drainage channels and intermittent streams, where these receive overland runoff. Mulching, seeding, or other suitable stabilization measures will be used to protect exposed areas during and after construction activities. If required, concrete washout stations will be established to avoid direct release to surface water or to areas where groundwater could become contaminated. The SWPPP shall be submitted to SBC/CCC for review and approval prior to construction.	Review and approval of plans. Inspection of BMPs	Prior to construction	SBC P&D CCC
OWR-2	The applicant shall construct a berm around Valve Site #2 with sufficient capacity to retain 150 percent of the maximum spill volume associated with this portion of the onshore pipeline (see Section 5.1, Risk of Upset). The applicant shall submit specific plans for the catchment basin at Valve Site #2 to SBC/CCC for review and approval prior to land use clearance. The berm shall be installed prior to operations.	Plan review prior to land use clearance.	Site inspections before construction sign-off. Berm installation before operation of facilities.	SBC P&D B&S CCC
OWR-3	Update the Oil Spill Contingency Plan and the November 2004 Oil Spill Response Plan and July 2005 Supplement to address the SCADA system and GR.1-related requirements for the proposed project and conduct annual readiness exercises and audits to ensure that containment and cleanup equipment is readily available close to areas with greatest vulnerability to spills (e.g.,	Review of OSCP and attendance at training drills.	Annual readiness exercises and spill prevention and cleanup equipment audits.	SBC P&D CCC

Mitigation Measure	Mitigation Requirements and Timing	Method of Verification	Timing of Verification	Party Responsible For Verification
	along the lower sections of the Santa Ynez River).			
OWR-4	PXP shall ensure that catchment basins located along the Santa Ynez River section of the pipeline are cleaned and surveyed periodically to ensure that they are capable of holding at least 110 percent of the associated release volume from nearby pipeline segments. Prior to land use clearance, PXP shall provide volume calculations to SBC for each of the catchment basins for the following leak scenarios: (1) 11 minutes of pumping time for a worst case leak in accordance with the MMS Oil Spill Response Plan, Volume 2, worst case scenario, and (2) 20 minutes of pumping time for a small leak as detected by the PXP leak detection system. The total pipeline emulsion fluids, including produced water, shall be included in the calculations. If it is determined that the volume of any of the catchment basins is insufficient to fully contain the leak scenarios analyzed, the catchment basin(s) shall be expanded. Plans for catchment basin(s) expansion shall be submitted to SBC for review and approval prior to land use clearance.	Review and approval of calculations and expansion plans. Inspection of basins.	Calculation and plan review prior to land use clearance. Periodic inspection of pipeline route.	SBC P&D <u>CCC</u>
OWR-5	Ensure that any pipeline replacement within stream beds is engineered such that the replacement pipeline and any pipeline support structures are protected from scour and erosion effects of a 100-year flood discharge. Plans demonstrating these requirements shall be submitted to SBC/<u>CCC</u> for review and approval prior to land use clearance.	Review and approval of plans.	Prior to land use clearance	SBC <u>CCC</u>
OWR-6	If soil excavation is needed to expose buried pipeline or cleanup a spill within a stream bed, the area shall be restored to the maximum extent feasible to pre-spill conditions after excavation is completed.	Construction drawings. Part of spill report..	Immediately after spill occurrence.	SBC P&D
OWR-7 (VAFB Onshore and Emulsion Pipeline Replacement Alternatives only)	The applicant shall schedule construction activities during the dry season, unless otherwise approved by SBC, <u>CCC,</u> CDFG, and USFWS. Construction time restrictions shall be included in the contractor bid solicitation packages and depicted on construction plans which will be provided to SBC prior to construction.	Schedule restrictions shall be part of contractor bid solicitation packages and construction plans.	Review of solicitation packages and construction plans.	SBC P&D <u>CCC</u>
ORW-8 (VAFB Onshore Alternative only)	Install catchment basins to prevent spills from entering the Santa Ynez River. Basin volumes shall be designed in accordance with Mitigation Measure OWR-5. Catchment basin design and construction plans shall be submitted to SBC for review and approval prior to land use clearance.	Plan review and approval	Prior to land use clearance	SBC P&D
OWR-9 (VAFB Onshore Alternative only)	Implement an oil-spill response and containment plan, including catchment basins as necessary, for the drilling and production facility. The plan shall be submitted to SBC/<u>CCC</u> for review and approval prior to land use clearance.	Plan review and approval	Prior to land use clearance	SBC P&D <u>CCC</u>

Mitigation Measure	Mitigation Requirements and Timing	Method of Verification	Timing of Verification	Party Responsible For Verification
OWR-10 (VAFB Onshore and Power Line Route – Option 2b Alternatives only)	The applicant shall monitor boring operations, immediately cleaning spilled drilling muds, restricting construction activities to avoid potential conflicts with special status species, and use of best management practices to prevent or minimize soil erosion and effects of siltation on surface waters.	Review of Frac-out Contingency Plan and site inspections during construction.	Prior to construction and during construction.	SBC P&D B&S CCC
OWR-11 (VAFB Onshore Alternative only)	The pipelines shall be placed below the 100-year depth of scour at all river crossings. The river cross section topography shall not be altered in a manner that would result in increased levels of scour or erosion. Pipeline construction plans for the Santa Ynez River and Bear Creek crossings shall be submitted to SBC for review and approval prior to land use clearance.	Plan review and approval	Prior to land use clearance	SBC P&D
OWR-12 (VAFB Onshore Alternative only)	The applicant shall work with the U.S. Air Force, the RWQCB Central Region, and the Department of Toxic Substances Control to identify Federal Installation Restoration Program (IRP) sites, Areas of Concern and Areas of Interest within the construction area, and characterize the nature and extent of hazardous substances that may be present at each. In conjunction with the USAF, the RWQCB Central Region, and the Department of Toxic Substances Control, the applicant shall develop a plan of action to avoid and/or minimize any contamination of groundwater or surface water that may result from construction in these areas. Permits/approvals from these respective agencies shall be provided to SBC prior to construction.	Permit issuance	Prior to construction	U.S. Air Force, RWQCB, Department of Toxic Substances Control

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Figures 5.4-1: Photograph of Pipeline Route Crossing Small Drainage Feature Near Basin 4.

Figures 5.4-2: Example of a Catchment Basin (Basin 1) Adjacent to Onshore Portion of the Pipeline Route. *(A weired Concrete Outlet is Shown Near the Upper Left Corner of the Photograph.)*

Source: MRS, 2002.

PREPARED BY Aspen Environmental Group

Figures 5.4-1 & 5.4-2
Photographs

5.5 Marine Biology

5.5.1 Environmental Setting

The proposed project area, located slightly north of Point Arguello, is an oceanographically complex and dynamic region of the continental shelf. The region is characterized by strong seasonal coastal upwelling and high primary production (Brink et al., 1984; Dugdale and Wilkerson, 1990). Further, the project area is situated at a zone of biotic transition between two zoogeographic provinces, the Oregonian Province north of Point Conception and the Californian Province to the south (Valentine, 1966; Newman, 1979). Studies conducted in this region of central California have shown that this area supports abundant and diverse biological assemblages (e.g., Hyland et al., 1991; Montagna, 1991; Hardin et al., 1994).

The proposed project area is located in the southern offshore portion of the Santa Maria Basin. The Basin encompasses a majority of the continental margin between Point Conception and Monterey, including an onshore component between the Santa Ynez and San Rafael Mountains (McCulloch et al., 1982).

The continental shelf is oriented along a northwest to southeast axis between Point Conception and Point Arguello and along a north-to-south axis between Point Arguello and Point San Luis. The shelf extends seaward to approximately 110 meters (m) and varies in width from approximately 4 kilometers (km) in the Point Conception area to approximately 20 km between Point Arguello and Point San Luis (Uchupi and Emery, 1963). In the Point Arguello area, the slope drops rapidly to approximately 1,000 m and is cut by the Arguello Canyon; northward, the slope is less steep and is interrupted by the Santa Lucia Bank (Uchupi and Emery, 1963). Eastward of the bank is a sea valley that acts as a depositional sink for fine-grained sediments (Hyland et al., 1990). Four offshore platforms (Platforms Harvest, Hermosa, Hidalgo, and Irene) are presently located in the area. Their locations are shown in Figure 2-1.

5.5.1.1 Plankton

Plankton are organisms that have either limited or no swimming ability. They generally drift or float with ocean currents. Phytoplankton and zooplankton are the two broad categories of plankton. Phytoplankton, or plant plankton, form the base of the food web by photosynthesizing organic matter from water, carbon dioxide, and light. They are usually unicellular or colonial algae and support zooplankton, fish, and through their decay, large quantities of marine bacteria.

Zooplankton, or animal plankton, can spend their entire life as plankton (holoplankton) or spend a portion of their life cycle as plankton (meroplankton). Meroplankton are larval stages of benthic invertebrates while ichthyoplankton are larval stages of fish. Zooplankton are a primary link between phytoplankton and larger marine organisms in marine food webs.

Generally, plankton distribution, abundance, and productivity are dependent on several environmental factors. These factors include light, nutrients, water quality, terrestrial runoff, and upwelling. Plankton distribution tends to be very patchy and characterized by high seasonal and inter-annual variability. Because phytoplankton are photosynthetic, they are generally limited to the photic zone while zooplankton can occur throughout the water column from surface to bottom.

Phytoplankton

The phytoplankton community off the California coast primarily consists of diatoms, dinoflagellates, silicoflagellates, and coccolithophores (Hardy, 1993). Phytoplankton communities are typically described in terms of productivity, standing crop, and species composition.

Productivity, which is a measure of growth or new plant material per unit time, is extremely variable off the California coast (Owen, 1980). The highest productivity levels occur within approximately 50 km of the coastline (Owen, 1974) and tend to be the highest in upwelling areas, or approximately six times higher than the open ocean (Riznyk, 1974). Springtime primary production levels are approximately 5 times higher than summer and ten times higher than winter (Oguri and Kanter, 1971).

Standing crop, or the amount of phytoplankton cells present in the water, is also extremely variable and heterogeneous off the California coast. Owen (1974) reported the highest standing crop values during the summer (range of 2.50 to 3.00 mg/m^3) and lowest values during the winter months (range of 0.30 to 0.40 mg/m^3). Palaez and McGowan (1986) also reported high densities of phytoplankton in spring and summer that decreased in the fall. The lowest densities occurred in the late fall and early winter (Palaez and McGowan, 1986). They attributed the seasonal differences to ocean circulation patterns and the low nutrient content of waters off the California coast during the winter months.

Phytoplankton biomass has been reported to be higher near Point Conception than in locations north or south because of greater upwelling off the Point (Owen, 1974; Goericke et al., 2005; Sydeman and Hyrenbach, 2002). Biomass reached peak levels during summer (July to September) and decreased from October to December and with distance from shore. Highest biomass values were reported during August and in the upper 20 m of the water column (Owen and Sanchez, 1974). Even during the 1998 El Nino, a warm-water period, there was high ocean productivity in the vicinity of Point Conception (Sydeman and Hyrenbach, 2002).

Data from several studies indicate that the composition of the phytoplankton community is similar along the entire coast of California (e.g., Bolin and Abbott, 1963; Allen, 1945). The diatom *Chaetoceros* was the most abundant species found along the coast (Bolin and Abbott, 1963; Cupp, 1943). Other dominant species included the diatoms *Skeletonema*, *Nitzschia*, *Eucampia*, *Thalassionema*, *Rhizosolenia* and *Asterionella*, and the dinoflagellates *Ceratium*, *Peridinium*, *Noctiluca*, and *Gonyaulax* (Bolin and Abbott, 1963).

Zooplankton

Zooplankton are those animals that spend part (meroplankton) or all (holoplankton) of their life cycle as plankton. Their temporal and spatial distributions are dependent on a number of factors including currents, water temperature, and phytoplankton abundance (Loeb et al., 1983). Spring blooms occur for both meroplankton and holoplankton while fall blooms tend to be restricted to the holoplankton. The meroplankton include the larvae of many commercial species of fish, lobster, and crabs. Like phytoplankton, spatial distribution of zooplankton is extremely patchy.

Based on data collected by the California Cooperative Oceanic Fisheries Investigations (CalCOFI), McGowan and Miller (1980) reported a high degree of variability in species composition in offshore waters and that dominant species vary widely even from sample to sample. Fleminger (1964) reported 190 species and 65 genera of calanoid copepods. Kramer and Smith (1972) estimated that 546 invertebrate and 1,000 species of fish larvae occur in the California Current System. Major zooplankton groups off the California coast include copepods, euphausiids, chaetognaths, mollusks, thaliaceans, and fish larvae.

In studies conducted north of Point Conception, Icanberry and Warrick (1978) identified 94 taxonomic zooplankton categories. Dominant categories included calanoid copepod nauplii and copepodites, thalicians, *Oikopleura*, *Euphausia*, calyptopis, cyclopoid and harpacticoid copepodites, and the copepod *Acartia tonsa*. Zooplankton production was highest during June and July and in early Spring during periods that coincide with upwelling periods and increased levels of phytoplankton (Icanberry and Warrick, 1978; Smith, 1974).

During the 1990s zooplankton studies off southern California documented a marked decline in zooplankton stock that correlated with increased sea temperatures (NOAA, 2006). Roemmich and McGowan (1995) demonstrated that since 1951, the biomass of macrozooplankton in waters off Southern California decreased by 80 percent. Recent surveys indicate that zooplankton biomass has recovered from the dramatic decline of the 1990's (Goericke et al., 2005).

Ichthyoplankton

Ichthyoplankton, or fish eggs and larvae, are a major component of the zooplankton community. With the exception of a few fish species, most fish that occur in central California are present as larvae or eggs in the plankton community. The spatial and temporal distribution and composition of the ichthyoplankton are generally due to the spawning habits and the requirements of adult fish. Seasonal patterns of ichthyoplankton composition in nearshore waters are strongly influenced by the spawning cycles of demersal fish species and the northern anchovy, *Engraulis mordax*, while further offshore, composition is influenced by pelagic and migratory species and rockfish (*Sebastes* spp). Like phytoplankton and zooplankton, the spatial distribution of ichthyoplankton is patchy and influenced by several environmental factors.

In CalCOFI samples collected offshore California, ichthyoplankton densities were highest during January to March (Loeb et al., 1983). This was due to the peak spawning season for the northern anchovy, Pacific hake, Pacific mackerel, and the Pacific sardine. Larvae of these species comprised up to 84 percent of the samples. Generally, they found that ichthyoplankton densities decreased from north to south and inshore to offshore between San Francisco and Baja California.

In a summary of CalCOFI fish larvae data, Ahlstrom (1965) found that twelve taxa made up over 90 percent of the larvae collected. The most abundant was the northern anchovy, *Engraulis mordax.* Other common larval species were the Pacific hake, *Merluccius productus*; rockfish, *Sebastes* spp.; flatfish, *Citharichthys spp*.; and the California smoothtongue, *Leuroglossas stilbius*. Anchovy and rockfish larvae were abundant from the winter to spring seasons. Spawning varied by season with no discernible pattern within the California Current system (Kramer and Ahlstrom, 1968; Ahlstrom et al., 1978).

In a year-round study off of Point Arguello, the white croaker, *Genyonemus lineatus*, and the northern anchovy, *Engraulis mordax* were the most abundant fish larvae collected (Chambers Consultants, 1980). A more recent study sampled planktonic fish eggs and larvae off Point Arguello in the vicinity of the proposed project as well as off San Miguel Island, Anacapa Island and Big Sycamore Canyon at the south end of the Santa Barbara Channel (Watson et al., 2002). This study found that season was the most important factor in species composition of the ichthyoplankton. Northern anchovy, Pacific hake, white croaker, speckled sanddab (*Citharichthys stigmaeus*), and California halibut (*Paralichthys californicus*) eggs occurred most frequently and were among the most abundant during the winter surveys. In the summer, senorita (*Oxyjulis californica*), California sheephead (*Semicossyphus pulcher*), white seabass (*Atractoscion nobilis*) and California barracuda (*Sphyraeena argentea*) eggs were abundant as were northern anchovy, speckled sanddab and California halibut eggs. The most abundant fish larvae in winter surveys were northern anchovy, California smoothtongue, northern lampfish (*Stenobrachius leucopsarus*), Pacific hake, and rockfishes. Northern anchovy and rockfish larvae were common in summer. The most common nearshore fish larvae at the mainland sites were rockfishes, white croaker and English sole (*Parophys vetulis*). The study found that the area around Vandenberg Air Force Base near the proposed project was not particularly productive for fish eggs and larvae. The Vandenberg study site is a high-energy area with strong currents, strong sand transport and relatively poor fish habitat.

Table 5.5.1a-d shows recent CalCOFI data on fish larvae collected from the four stations nearest to Platform Irene (Jacobson, 2007). The closest of these stations is 14 nautical miles from Platform Irene. Although no data are available on the ichthyoplankton in the immediate vicinity of Platform Irene, these data would be expected to be representative of ichthyoplankton species at Platform Irene because of the homogeneity of this offshore habitat. The most abundant taxa in these samples were Pacific hake, northern lampfish, California smoothtongue, northern anchovy, and rockfishes. These species would all be expected to be abundant in the vicinity of Platform Irene. However, Platform Irene itself represents hard bottom habitat and supports an assemblage of fish that includes species attracted to reef habitat. Therefore, the ichthyoplankton assemblage at Platform Irene also might be expected to include the larvae of hard bottom species in addition to the more widespread species that dominated the CalCOFI samples.

5.5.1.2 Fish

The fish population in the project area consists of both year-round residents and seasonal migrants. Over 600 species of fish have been reported in the Pacific OCS region (United States Department of Interior (USDOI), 1996). Large numbers of shellfish and other invertebrate species such as crabs, shrimp, bivalves, and squid also occur in the area. A wide variety of habitats are available in the region for fish resources and their distribution in the area fluctuates in accordance with food availability, environmental conditions, and migration (USDOI, 1996).

With respect to fish distribution in the area, the offshore environment can generally be divided into two zones. They are the benthic or shelf and pelagic zones. Demersal or benthic species are those that live on or near the sea floor while pelagic fish species occur in the water column.

Table 5.5.1a CalCOFI data of Fish Larvae Collected from Line 80, Station 51

Line 80

Station 51

Distance from platform = 14.0 nautical miles

Year	2002			2003				2004				2005				2006			
Date (YYMMDD)	020206	020713	021121	030211	030416	030726	031031	040117	040403	040724	041115	050115	050427	050712	051117	060216	060413	060720	061101
Total Eggs Std (# per 10 sq yd)	2888	742.45	30.59	107.26	7.225	1355.5	56.55	1029.2	105.57	1673.52	178.08	79.92	1397.8	155.91	176.72	394.25	545.67	471.24	35.44
Total Larvae Std (# per 10 sq yd)	40.23	9.58	13.11	217.98	7.225	8.24	0	139.49	68.85	31.92	42.4	128.76	188.16	5.196	0	95.45	33.84	558.36	0
Small Plankton Volume (# per 10 sq yd)	44	73	25	120	384	88	57	55	94	72	48	24	210	286	12	33	77	177	6
Argentines																			
Argentina sialis North-Pacific argentine	0	0	0	0	0	0	0	0	4.59	0	0	0	0	0	0	0	0	0	0
Microstoma spp Argentine	0	0	0	0	0	0	0	0	4.59	0	0	0	0	0	0	0	0	0	0
Croakers																			
Genyonemus lineatus White croaker	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4.15	0	0	0
Cusk eels																			
Brosmophycis marginata Red brotula	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3.96	0
Flatfish																			
Citharichthys sordidus Pacific sanddab	0	0	0	0	0	0	0	11.31	0	0	25.44	4.44	0	0	0	0	0	0	0
Citharichthys stigmaeus Speckled sanddab	0	0	0	0	0	0	0	0	0	0	8.48	0	0	0	0	0	0	0	0

Table 5.5.1a CalCOFI data of Fish Larvae Collected from Line 80, Station 51 (cont'd)

Hippoglossina stomata Bigmouth flounder	0	0	0	0	0	0	0	0	0	0	4.24	0	0	0	0	0	0	0	0
Leuroglossus stilbius California smoothtongue	0	0	0	6.92	0	0	0	3.77	0	0	0	0	0	0	0	8.3	0	0	0
Lyopsetta exilis Slender sole	0	0	0	0	0	0	0	0	9.18	0	0	0	0	0	0	0	8.46	0	0
Paralichthys californicus California flounder	0	0	0	0	0	0	0	0	0	0	0	4.44	0	0	0	0	0	3.96	0
Parophrys vetulus English sole	0	0	0	0	0	0	0	0	4.59	0	0	0	0	0	0	0	0	0	0
Gobies																			
Rhinogobiops nicholsii Blackeye goby	0	0	0	0	0	4.12	0	0	0	0	4.24	0	0	0	0	0	0	0	0
Hakes																			
Merluccius productus	8.94	0	0	0	0	0	0	109.33	9.18	4.56	0	39.96	35.84	0	0	29.05	12.69	0	0
North Pacific hake	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hatchetfish																			
Sternoptyx spp hatchetfish	0	0	0	0	0	0	0	0	0	4.56	0	0	0	0	0	0	0	0	0
Herning/sardine/pilchard																			
Engraulis mordax Californian anchovy	0	0	4.37	76.12	0	0	0	0	9.18	9.12	0	4.44	134.4	0	0	0	0	542.52	0

Table 5.5.1a CalCOFI data of Fish Larvae Collected from Line 80, Station 51 (cont'd)

Lanternfish																			
Stenobrachius leucopsarus Northern lampfish	8.94	4.79	0	13.84	7.225	0	0	0	4.59	0	0	35.52	0	0	0	0	4.23	0	0
Mackerels																			
Scomber japonicus Chub mackerel	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3.96	0
Trachurus symmetricus Pacific jack mackerel	4.47	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3.96	0
Medusafish																			
Icichthys lockingtoni Medusafish	4.47	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Poachers																			
Odontopyxis trispinosa Pygmy poacher	0	0	0	0	0	0	0	0	4.59	9.12	0	0	0	0	0	0	0	0	0
Rockfish																			
Sebastes jordani Shortbelly rockfish	0	0	0	41.52	0	0	0	0	0	0	0	17.76	0	0	0	0	0	0	0
Sebastes levis Cowcod	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4.23	0	0
Sebastes spp rockfish	13.41	4.79	8.74	79.58	0	4.12	0	15.08	18.36	0	0	22.2	0	5.196	0	53.95	4.23	0	0

Table 5.5.1a CalCOFI data of Fish Larvae Collected from Line 80, Station 51 (cont'd)

Sculpin																			
Clinocottus analis Woolly sculpin	0	0	0	0	0	0	0	0	0	0	0	0	8.96	0	0	0	0	0	0
Ruscarius creaseri Roughcheek sculpin	0	0	0	0	0	0	0	0	0	0	0	0	8.96	0	0	0	0	0	0
Snailfish																			
Liparis mucosus Slimy snailfish	0	0	0	0	0	0	0	0	0	4.56	0	0	0	0	0	0	0	0	0

Table 5.5.1b CalCOFI data of Fish Larvae Collected from Line 80, Station 55

Line 80 Stataion 55 Distance from platform = 18.0 nautical miles																		
Year	2002				2003			2004				2005			2006			
Date (YYMMDD)	020206	020408	020714	021121	030416	030726	031031	040117	040404	040724	041115	050427	050713	051117	060216	060413	060720	061102
Total Eggs Std (# per 10 sq yd)	573.68	338.91	10.617	16.725	573.42	397.92	218.4	914.48	630.47	76.441	495.93	7191.2	0	0	635.11	1747.2	142	0
Total Larvae Std (# per 10 sq yd)	198.58	280.81	0	8.362	140.84	0	12.6	129.22	167.47	28.665	175.64	576.43	9.703	64.914	137.32	82.806	79.877	0
Small Plankton Volume (# per 10 sq yd)	882	235	80	77	242	69	23	57	78	136	67	86	181	123	68	305	99	86
Argentines																		
Argentina sialis North-Pacific argentine	0	0	0	0	0	0	0	0	0	9.555	0	9.449	0	0	0	0	0	0
Blacksmelts																		
Lipolagus ochotensis Eared blacksmelt	0	19.366	0	0	20.12	0	0	9.94	9.851	0	0	0	0	0	0	0	0	0
Cusk eels																		
Cataetyx rubrirostris Rubynose brotula	0	0	0	0	0	0	0	0	0	0	0	9.449	0	0	0	0	0	0
Flatfish																		
Citharichthys sordidus Pacific sanddab	0	9.683	0	0	0	0	0	4.97	0	0	10.331	0	0	24.342	0	0	0	0
Citharichthys stigmaeus Speckled sanddab	0	19.366	0	0	0	0	0	0	0	0	0	0	0	16.228	0	0	8.875	0
Leuroglossus stilbius California smoothtongue	11.032	19.366	0	0	0	0	4.2	99.4	29.553	0	51.659	37.798	0	0	51.495	41.403	0	0

Table 5.5.1b CalCOFI data of Fish Larvae Collected from Line 80, Station 55 (cont'd)

Gobies																		
Lythrypnus zebra Zebra goby	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8.875	0
Rhinogobiops nicholsii Blackeye goby	0	0	0	0	0	0	0	0	0	0	20.663	0	0	0	0	0	0	0
Greenlings																		
Oxylebius pictus Painted greenling	0	9.683	0	0	0	0	0	0	0	0	0	9.449	0	0	0	0	0	0
Hakes																		
Merluccius productus North Pacific hake	88.259	9.683	0	0	0	0	0	0	59.106	0	0	28.349	0	0	51.495	24.841	0	0
Hatchetfish																		
Argyropelecus sladeni Sladen's hatchet fish	0	0	0	0	0	0	4.2	0	0	0	0	0	0	0	0	0	0	0
Hernings/sardines																		
Engraulis mordax Californian anchovy	0	48.415	0	0	0	0	0	0	9.851	9.555	10.331	463.04	0	0	0	0	35.501	0
Sardinops sagax South American pilchard	0	0	0	0	30.18	0	0	0	0	0	0	0	0	0	0	0	0	0
Lanternfish																		
Protomyctophum crockeri California flashlightfish	0	9.683	0	0	20.12	0	0	0	0	0	0	0	0	0	0	0	0	0
Stenobrachius leucopsarus Northern lampfish	33.097	77.465	0	0	40.24	0	0	4.97	19.702	0	20.663	0	0	0	0	0	0	0
Tarletonbeania crenularis Blue lanternfish	0	0	0	8.362	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 5.5.1b CalCOFI data of Fish Larvae Collected from Line 80, Station 55 (cont'd)

Ragfish																		
Icosteus aenigmaticus Ragfish	0	9.683	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Rockfish																		
Scorpaenichthys marmoratus Cabezon	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8.582	0	0	0
Sebastes aurora Aurora rockfish	0	0	0	0	0	0	4.2	0	9.851	0	0	0	0	0	0	0	0	0
Sebastes jordani Shortbelly rockfish	22.064	0	0	0	30.18	0	0	0	0	0	0	0	0	0	0	0	0	0
*Sebastes spp_* rockfish	44.129	48.415	0	0	0	0	0	9.94	29.553	9.555	61.991	18.899	9.703	24.342	25.747	16.561	26.625	0

Table 5.5.1c CalCOFI data of Fish Larvae Collected from Line 76.7, Station 51

Line 76.7 Station 51 Distance from platform = 26.4 nautical miles																				
Year	2002				2003				2004				2005				2006			
Date (YYMMDD)	020209	020412	020716	021124	030215	030419	030729	031103	040120	040408	040727	041118	050118	050430	050715	051120	060220	060416	060723	061105
Total Eggs Std (# per 10 sq yd)	0	55.56	9.938	13.59	219.74	139.7	5211	613.28	1730.6	666.62	0	298.84	201.4	9577	115.6	259.62	281.82	329.5	128.63	30.36
Total Larvae Std (# per 10 sq yd)	21.394	120.4	228.6	0	146.49	18.62	0	18.87	145.39	259.24	57.586	38.56	222.6	308.9	28.9	17.905	217.14	50.691	36.75	0
Small Plankton Volume (# per 10 sq yd)	87	129	175	35	108	96	141	102	50	90	104	29	183	187	207	179	38	120	136	49
Argentines																				
Argentina sialis North-Pacific argentine	0	0	0	0	0	0	0	0	4.69	0	0	0	0	9.362	0	0	0	0	0	0
Blacksmelts																				
Lipolagus ochotensis Eared blacksmelt	0	0	0	0	0	0	0	0	23.45	0	0	0	0	0	0	0	41.58	0	0	0
Blennies																				
Hypsoblennius jenkinsi Mussel blenny	0	0	0	0	0	0	0	9.435	0	0	0	0	0	0	0	0	0	0	0	0
Neoclinus stephensae Yellowfin fringehead	0	0	0	0	0	0	0	0	0	0	9.597	0	0	0	0	0	0	0	0	0
Croakers																				
Genyonemus lineatus White croaker	0	0	0	0	9.155	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 5.5.1c CalCOFI data of Fish Larvae Collected from Line 76.7, Station 51 (cont'd)

Cataetyx rubrirostris Rubynose brotula	0	0	0	0	0	0	0	0	0	0	0	0	0	9.362	0	0	0	0	0	0
Flatfish																				
Citharichthys sordidus Pacific sanddab	0	0	0	0	0	0	0	0	0	0	0	9.64	0	0	0	0	0	0	0	0
*Citharichthys spp_* Sanddab	0	0	0	0	0	0	0	0	4.69	0	0	0	0	0	0	0	0	0	0	0
Citharichthys stigmaeus Speckled sanddab	0	0	0	0	0	0	0	0	0	0	9.597	0	0	0	0	0	0	0	0	0
Leuroglossus stilbius California smoothtongue	0	9.259	0	0	0	0	0	0	14.07	0	0	19.28	196.1	56.17	0	0	18.48	0	0	0
Lyopsetta exilis Slender sole	0	0	0	0	0	0	0	0	0	9.258	0	0	0	0	0	0	0	0	0	0
Gobies																				
Rhinogobiops nicholsii Blackeye goby	0	0	0	0	0	0	0	0	4.69	0	0	0	0	0	0	0	0	0	0	0
Hakes																				
Merluccius productus North Pacific hake	0	18.52	0	0	9.155	0	0	0	60.97	203.69	0	0	5.3	103	0	0	83.16	0	0	0
Hatchetfish																				
Argyropelecus sladeni Sladen's hatchet fish	0	0	0	0	0	0	0	0	0	0	0	0	0	9.362	0	0	0	0	0	0
Hernings/sardines																				
Engraulis mordax Californian anchovy	0	0	0	0	45.779	0	0	0	4.69	0	0	0	0	112.3	19.26	0	0	0	18.375	0

Table 5.5.1c CalCOFI data of Fish Larvae Collected from Line 76.7, Station 51 (cont'd)

Sardinops sagax South American pilchard	0	18.52	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lanternfish																				
Stenobrachius leucopsarus Northern lampfish	10.697	46.3	0	0	9.155	9.311	0	0	18.76	37.034	0	4.82	10.6	0	0	0	27.72	33.794	0	0
Tarletonbeania crenularis Blue lanternfish	0	0	0	0	0	0	0	0	4.69	0	0	0	0	0	0	0	0	0	0	0
Pearleyes																				
Benthalbella dentata Northern pearleye	0	0	0	0	0	0	0	0	0	0	0	0	5.3	0	0	0	0	0	0	0
Poachers																				
Odontopyxis trispinosa Pygmy poacher	0	0	0	0	0	0	0	0	0	0	0	4.82	0	0	0	0	0	0	0	0
Rockfish																				
Sebastes diploproa Splitnose rockfish	0	0	208.7	0	0	0	0	0	0	0	9.597	0	0	0	0	0	0	0	0	0
Sebastes goodei Chilipepper	0	0	0	0	0	0	0	0	0	0	0	0	5.3	0	0	0	0	0	0	0
Sebastes jordani Shortbelly rockfish	0	0	0	0	9.155	0	0	0	4.69	0	0	0	0	0	0	0	9.24	0	0	0
Sebastes paucispinis Bocaccio	0	0	0	0	9.155	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sebastes spp rockfish	10.697	27.78	19.88	0	54.935	9.311	0	9.435	0	9.258	28.793	0	0	9.362	9.632	17.905	36.96	16.897	18.375	0

Table 5.5.1d CalCOFI data of Fish Larvae Collected from Line 76.7, Station 55

Line 76.7 Station 55 Distance from platform = 28.6 nautical miles																				
Year	2002				2003				2004				2005				2006			
Date (YYMMDD)	020209	020412	020716	021124	030214	030418	030729	031103	040120	040408	040726	041118	050118	050430	050715	051119	060220	060416	060723	061104
Total Eggs Std (# per 10 sq yd)	475.3	150.08	0	17.51	2765	83.99	0	0	277.3	476.57	0	71.626	201.08	24181	0	18.444	214.37	1122.7	9.5	0
Total Larvae Std (# per 10 sq yd)	223.1	56.28	21.346	17.51	113.7	83.99	34.84	18.3	450.6	323.39	176.04	17.906	443.29	1075.8	8.669	18.444	242.33	27.72	9.5	21.8
Small Plankton Volume (# per 10 sq yd)	91	177	132	67	29	170	468	622	123	111	164	64	53	156	282	304	150	34	115	36
Argentines																				
Argentina sialis North-Pacific argentine	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	9.5	0
Bigscales																				
Melamphaes lugubris Highsnout bigscale	0	0	0	0	0	0	0	0	8.665	0	0	0	0	0	0	0	0	0	0	0
Blacksmelts																				
Lipolagus ochotensis Eared blacksmelt	19.4	0	0	0	0	0	0	0	121.3	25.53	0	0	22.85	19.04	0	0	9.32	0	0	0
Blennies																				
Hypsoblennius gilberti Rockpool blenny	0	0	0	0	0	0	0	0	0	0	9.78	0	0	0	0	0	0	0	0	0
Croakers																				
Genyonemus lineatus White croaker	0	0	0	0	0	0	0	0	0	0	0	0	13.71	0	0	0	0	0	0	0

Table 5.5.1d CalCOFI data of Fish Larvae Collected from Line 76.7, Station 55 (cont'd)

Flatfish																				
Citharichthys sordidus Pacific sanddab	0	9.38	0	0	0	0	8.709	0	17.33	0	78.24	0	0	0	0	0	0	0	0	0
Citharichthys stigmaeus Speckled sanddab	0	0	0	0	0	0	0	0	0	0	39.12	0	9.14	0	0	0	0	0	0	0
Leuroglossus stilbius California smoothtongue	9.7	18.76	0	0	0	0	0	0	17.33	127.65	0	0	36.56	28.56	0	0	27.961	0	0	0
Lyopsetta exilis Slender sole	0	0	0	0	0	8.399	0	0	0	0	0	0	0	0	0	0	0	4.62	0	0
Parophrys vetulus English sole	0	0	0	0	0	0	0	0	0	0	0	0	4.57	0	0	0	0	0	0	0
Gobies																				
Rhinogobiops nicholsii Blackeye goby	0	0	0	0	0	0	0	0	0	0	0	0	0	9.52	0	0	0	0	0	5.45
Greenlings																				
Hexagrammos decagrammus Kelp greenling	19.4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Oxylebius pictus Painted greenling	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4.62	0	0
Hakes																				
Merluccius productus North Pacific hake	48.5	9.38	0	0	0	0	0	0	8.665	136.16	0	0	50.27	95.2	0	0	9.32	0	0	0
Hatchetfish																				
Argyropelecus hemigymnus Half-naked hatchetfish	0	0	0	0	0	0	0	0	0	0	0	8.953	0	0	0	0	0	0	0	0

Table 5.5.1d CalCOFI data of Fish Larvae Collected from Line 76.7, Station 55 (cont'd)

Hernings/sardines																				
Engraulis mordax Californian anchovy	29.1	0	0	0	12.18	0	0	0	0	0	29.34	0	4.57	904.4	0	0	0	0	0	0
Sardinops sagax South American pilchard	0	0	0	0	0	16.8	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lanternfish																				
Protomyctophum crockeri California flashlightfish	0	0	0	8.757	0	0	0	0	0	0	9.78	0	0	0	0	0	0	0	0	0
Stenobrachius leucopsarus Northern lampfish	0	18.76	0	0	4.06	42	0	0	251.3	8.51	0	8.953	251.35	9.52	0	9.222	195.73	9.24	0	0
Symbolophorus californiensis Bigfin lanternfish	0	0	0	8.757	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tarletonbeania crenularis Blue lanternfish	0	0	0	0	0	0	0	0	8.665	0	0	0	0	0	0	0	0	0	0	0
Ribbonfish																				
Trachipterus altivelis King-of-the-salmon	0	0	0	0	0	0	0	0	8.665	0	0	0	0	0	0	0	0	0	0	0
Rockfish																				
Sebastes aurora Aurora rockfish	19.4	0	0	0	0	0	0	0	0	0	0	0	4.57	0	0	0	0	4.62	0	0
Sebastes diploproa Splitnose rockfish	0	0	21.346	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sebastes jordani Shortbelly rockfish	0	0	0	0	12.18	16.8	0	0	0	0	0	0	4.57	0	0	0	0	0	0	0

Table 5.5.1d CalCOFI data of Fish Larvae Collected from Line 76.7, Station 55 (cont'd)

Sebastes paucispinis Bocaccio	0	0	0	0	4.06	0	0	0	0	0	0	0	13.71	0	0	9.222	0	0	0	0
Sebastes spp rockfish	77.6	0	0	0	81.2	0	26.13	18.3	8.665	17.02	9.78	0	22.85	9.52	8.669	0	0	4.62	0	16.35
Viperfish																				
Chauliodus macouni Pacific viperfish	0	0	0	0	0	0	0	0	0	8.51	0	0	0	0	0	0	0	0	0	0
Wrasses																				
Oxyjulis californica Señorita	0	0	0	0	0	0	0	0	0	0	0	0	4.57	0	0	0	0	0	0	0

Demersal Fish

The offshore benthic environment generally consists of sandy, muddy, or rocky substrates. Important commercial or recreational fish species found beyond the tidal and wave zone include flatfishes, rockfishes, lingcod, and cods. In shallower water, common fish species are the perches, smelts, skates, rays, and flatfishes. Several researchers (e.g., Bence et al., 1992; Wakefield, 1990; Caillet et al., 1992) have reported that demersal fish species distributions are based on depth or depth-related factors. General depth distributions for fish common to the project area are summarized in Table 5.5.2.

Table 5.5.2 Depth Distribution of Demersal Fish Found in the Project Area

Water Depth			
50 to 200 m	**200 to 500 m**	**500 to 1200 m**	**1200 to 3200 m**
Sand dabs *Citharichthys sordidus*	Sablefish *Anoplopoma fimbria*	Thornyheads *Sebastolobus* spp.	Rattails *Coryphaenoides filifer*
English sole *Pleuronectes vetulus*	Pacific hake *Merluccius productus*	Pacific hake *Merluccius productus*	Thornyheads *Sebastolobus* spp.
Rex sole *Errex zachirus*	Slickhead *Alepocephalus tenebrosus*	Slickhead *Alepocephalus tenebrosus*	Finescale codling *Antimora microlepis*
Rockfish *Sebastes* spp.	Eelpouts *Lycenchelys jordani*	Rattails *Coryphaenoides filifer*	Eelpouts *Lycenchelys jordani*
Pink surfperch *Zalembius rosaceus*	Rockfish *Sebastes* spp.		
Plainfin midshipman *Porichthys notatus*	Thornyheads *Sebastolobus* spp.		
White croakers *Genyonemus lineatus*			

Fish densities on the continental shelf between 50 and 200 m water depth are generally high, with flatfish densities being highest for species such as Pacific sanddabs and English and Dover sole. Rockfish, as a group, have historically been abundant on the shelf and at depths to 270 m (Bence et al., 1992). However, significant declines have been reported for many rockfish species in recent years (Love et al., 1998; Ralston, 1998). Rockfish biomass and commercial harvests have decreased substantially since the 1960s (Bloeser, 1999). Fish densities and biomass on the upper and middle slope are relatively high with rockfish, sablefish, and flatfish such as Dover sole dominating (SAIC, 1992). At deeper depths (greater than 1,500 m), the numbers of fish species, densities, and biomass are typically low. Rattails and slickheads are the most common species at this depth (SAIC, 1992).

Pelagic Fish

Pelagic fish are those species associated with the ocean surface or the water column. Water depth, distance from shore, and other environmental factors generally govern distribution of pelagic fish. Ocean waters up to depths of approximately 200 m are referred to as the epipelagic zone. In this zone, waters are typically well lighted, well mixed, and support photosynthetic algal communities. Water depths from 200 to approximately 1,000 m are referred to as the mesopelagic zone, while depths greater than 1,000 m are called the bathypelagic zone. With increasing depths, light, temperature, and dissolved oxygen concentrations decrease as pressure increases. Hence, complete darkness, low temperature, low oxygen concentrations, and high pressure characterize the bathypelagic zone.

Pelagic fishes in the project area are a mix of year-round residents and migrants from several different habitats. Species include large predators (e.g., tunas, sharks, swordfish) and forage fish (e.g., northern anchovy, Pacific sardine, Pacific saury, Pacific whiting). The distributional ranges for pelagic fishes are generally quite extensive and cover much of the coastal California region. Many fish in the pelagic zone such as albacore tuna and Pacific salmons migrate over vast areas in the Pacific.

Common epipelagic fish in the region include the mackerel, *Scomber japonicus*; and salmon, *Onchorhyncus* spp.; and schooling fish such as Pacific herring, *Clupea pallasii*; northern anchovy, *Engraulis mordax*; and rockfish, *Sebastes* spp. Bence et al. (1992) reported approximately 140 epipelagic species from midwater trawls. In those trawls, juvenile rockfish, Pacific herring, and northern anchovy were the dominant species. Other epipelagic species common to the area included medusafish, *Icichthys lockingtoni*; Pacific sardine, *Sardinops sagax*; Pacific saury, *Cololabis saira*; Pacific argentines, *Argentina sialis*; and tunas (ARPA, 1995). Epipelagic species such as albacore tuna (*Thunnus alalunga*) and salmon are important commercial and recreational fish species.

Love et al. (1999) conducted mid-water trawls from 1995 to 1997 in the Santa Barbara Channel and the southern portion of the Santa Maria Basin. Over the three years, 49 taxa were collected. The taxa represented during each of the three years did not change substantially, but the number of specimens of each species and their rank order varied from year to year (Love et al., 1999). The ten most common species captured during the surveys are listed in Table 5.5.3.

Table 5.5.3 Mid-Water Fish Species Found in the Santa Barbara Channel and Southern Santa Maria Basin (Love et al., 1999)

Family	Species	Common Name
Merlucciidae	*Merluccius productus*	Pacific Hake
Bathylagidae	*Leuroglossus stibius*	California smoothtongue
Engraulidae	*Engraulis mordax*	Northern anchovy
Argentinidae	*Argentina sialis*	Pacific argentine
Paralichthyidae	*Citharichthys stigmaeus*	Speckled sanddab
Paralichthyidae	*Citharichthys* spp.	Other sanddabs
Pleuronectidae	*Lyopsetta exilis*	Slender sole
Scorpaenidae	*Sebastes jordani*	Shortbelly rockfish
Scorpaenidae	*Sebastomus* spp.	

Love et al. (1999) reported that most taxa occurred infrequently or in low abundance. Many of the taxa occurred in only one year during the three-year study. Rockfish species were also rarely collected during the study.

Less is known on the pelagic fish in the mesopelagic and bathypelagic zones. Typical species in the area include the blacksmelt, *Bathylagus milleri*; northern lampfish, viperfish, and the lanternfish (Cross and Allen, 1993). Examples of bathypelagic fish include dragonfish, hatchetfish, and bristlemouth (Cross and Allen, 1993).

Oil and Gas Production Platforms

A wide variety of fish occur beneath offshore platforms. Love et al. (1999) conducted surveys at seven platforms between 1995 and 1997. Four of the platforms (Hermosa, Hidalgo, Harvest, and Irene) surveyed were located in the western Santa Barbara Channel or southern Santa Maria Basin area. Love et al. (1999) found different fish assemblages at midwater and bottom levels around all of the platforms surveyed. Although midwater and bottom assemblages were dominated by rockfishes, the midwater was dominated by rockfish young of the year (YOY) or juveniles up to two years old. Larger rockfish were rarely seen at the midwater level. However, larger or adult fish were dominant around the bottoms of the platforms. While fish density was higher in the midwater, the total biomass was greater at the bottom because of the larger fish. Also, there was a consistently greater number of fish species on the bottom compared to the midwater for each of the platforms surveyed. Love et al. (1999) attributed this to the wider variety of habitat types found on the bottom environment.

The fish communities residing beneath each of the platforms were different. Generally, higher densities of young of the year rockfish were found beneath platforms north of Point Conception compared to those in the Santa Barbara Channel. This was attributed to the northerly platforms being located in the more productive waters of the California Current (Love et al., 1999). Fish species found at the midwater and bottom levels beneath Platform Irene are listed in Table 5.5.4.

Table 5.5.4 Fish Species Found at Midwater and Bottom Levels Beneath Platform Irene From Love et al. (1999)

Midwater Habitat 1996-1997				Bottom Habitat 1995-1997			
Species	**No.**	**Density 100m^2**	**Biomass kg/100m^2**	**Species**	**No.**	**Density 100m^2**	**Biomass kg/100m^2**
Rockfish YOY	2331	690.96	4.17	Rockfish YOY	1392	303.00	0.34
Widow rockfish	2319	586.46	17.20	Copper rockfish	519	104.32	19.03
Bocaccio	223	71.93	3.70	Vermillion rockfish	334	66.93	19.44
Blacksmith	120	51.69	0.32	Lingcod	177	34.10	8.11
Pile perch	10	5.33	0.93	Pacific sanddab	96	20.90	0.57
Copper rockfish	7	3.51	0.38	Halfband rockfish	67	13.86	0.15
Painted greenling	4	2.32	0.23	Pile perch	64	13.35	2.07
Blue rockfish	4	2.09	0.40	Painted greenling	53	10.95	0.54
Cabezon	3	1.57	0.09	Rosy rockfish	20	4.24	0.09
Yellowtail rockfish	3	1.24	0.06	Brown rockfish	9	1.90	0.42
Northern anchovy	2	0.73	0.00	Rubberlip surfperch	8	1.74	0.51
Calico rockfish	1	0.51	0.06	Bocaccio	7	1.49	0.34
				Calico rockfish	6	1.31	0.04
				Canary rockfish	5	1.09	0.21
				Sebastomus group	4	0.81	0.01
				Gopher rockfish	3	0.62	0.04
				Widow rockfish	3	0.41	0.02
				Yellowtail rockfish	2	0.41	0.12
				Kelp greenling	1	0.22	0.03
				Flag rockfish	1	0.19	0.03
				Yelloweye rockfish	1	0.22	0.03

At Platform Irene, YOY rockfish, and adults and subadults of copper and vermilion rockfishes were the most abundant species. The YOY rockfish consisted of bocaccio and widow rockfish. Platform Irene was also unique among the platforms surveyed in that large numbers of juvenile lingcod were associated with the platform (Love et al., 1999).

Fifty-two fish species were identified at the bottom of the seven platforms surveyed by Love et al. (1999). Thirty species were rockfishes. They made up 92.1 percent of all fishes identified on the bottom and 83.2 percent of the biomass. Halfbanded, greenspotted, copper, vermilion, widow, calico, flag, and bocaccio were the most commonly observed rockfishes. Several species of these rockfish were closely associated with the portions of the platform structure.

Endangered and Threatened Fish Species

The steelhead, *Oncorhynchus mykiss*, was listed as an endangered species in the Southern California Ecologically Significant Unit (ESU) (from the Santa Maria River south to Malibu Creek) in August, 1997 (NMFS, 1999). At the time they were originally listed, steelhead were thought to be extinct in streams south of Malibu Creek, but spawning recently has been confirmed in Topanga Creek in Santa Monica Bay in Los Angeles County and San Mateo Creek in San Diego County (Hogarth, 2002 and 2005). As a result, the range of the southern steelhead ESU has been extended south to the United States - Mexican border. Steelhead are migratory anadromous rainbow trout. They hatch in fresh water, descend to the ocean, and return to fresh water to spawn. Depending on the stream, steelhead can be either summer or winter migrators but regardless of migration period, spawning usually takes place from March to early May (NMFS, 1999). NMFS (1999) identifies river reaches and estuarine areas as critical habitats for the steelhead. Steelhead can migrate extensively at sea (Eschmeyer and Herald, 1983). Additional information on the steelhead is provided in Section 5.2, Terrestrial and Freshwater Biology.

In 2001, the Natural Resources Defense Council, Center for Biological Diversity and Center for Marine Conservation petitioned NMFS to list the southern population of *Sebastes paucispinis* or bocaccio, as threatened under the Endangered Species Act (ESA). NMFS conducted a status review (MacCall and He, 2002) and determined that listing was not warranted at this time. Bocaccio remains a Species of Concern, but it has no protection status under the ESA. Bocaccio commonly occurs beneath platforms in the Santa Barbara Channel and the Santa Maria Basin. As reported by Love et al. (1999), YOY bocaccio was a dominant species beneath Platform Irene.

5.5.1.3 Marine Mammals

Twenty-seven marine mammal species were reported by Dohl et al. (1983a) in central California. They reported three categories of marine mammals in central California: 1) migrants that pass through the area, 2) seasonal visitors that remain for a few weeks to feed on a particular food source, or 3) residents of the area. Of the 27 species, 21 were cetaceans (i.e., whales, dolphins, and porpoises), five were pinnipeds (i.e., seals and sea lions), and one was a fissiped (the sea otter). Marine mammals are generally characterized by large distribution ranges (Gaskin, 1982). The central California area represents a region of overlap. It is an area where populations of marine mammals having different ranges intermingle (Dohl et al., 1983a). Several marine mammal species reach the southern limit of their ranges in central California while other species are at their northern range limits (Hubbs, 1960; Bonnell and Daily, 1993).

Boreal species of marine mammals, which are found in the cooler waters of the North Pacific, occur in central California during winter through early summer. They are found in areas of coastal upwelling and in the coolest waters of the California current. Examples of boreal species include Dall's porpoises, harbor porpoises, and the northern fur seals.

In late summer and autumn, marine mammals found in warmer waters to the south are found in central California. Examples include the California sea lions, northern elephant seals, bottlenose dolphins, and pilot whales.

Some species, for example the southern sea otter, are endemic to coastal central California and occur year-round. Several species are largely restricted to the waters of the California Current and occur in high numbers off of central California. These species include the California sea lion, and during its migration, the California gray whale (Dohl et al., 1983a).

Bonnell and Dailey (1993) list 39 species of marine mammals in the eastern North Pacific. Of the 39 species, 32 of them are cetaceans followed by six species of pinnipeds and one species of fissiped, the sea otter. A listing of these species and their abundance and status is provided in Table 5.5.5.

Table 5.5.5 Cetaceans of the Eastern North Pacific and Their Status off South Central California (Adapted from Bonnell and Dailey, 1993)

Common Name	Scientific Name	Abundance	Status
Cetaceans **Baleen Whales (Suborder Mysticeti)**			
Blue whale	*Balaeoptera musculus*	Population highest in summer due to northward migration from subtropics	E
Fin whale	*B. physalus*	Population highest in summer due to northward migration from subtropics	E
Sei whale	*B. borealis*	Rare. Seen only during summer months during migration	E
Bryde's whale	*B. edeni*	Rare. Single sighting occurred near San Diego	NA
Minke whale	*B. acutorostrata*	Migratory population; common, peak abundance during spring and summer	NA
Humpback whale	*Megaptera novaeangliae*	Migratory population; common with peak abundance during summer and autumn	E
Gray whale	*Eschrichtius robustus*	Common during migration in winter and spring	NA
Northern right whale	*Balaena glacialis (also referred to as Eubalaena glacialis)*	Rare. Only two sightings in southern California	E
Order Cetacea **Tooth Whales (Suborder Odontoceti)**			
Sperm whale	*Physeter macrocephalus*	Rare on continental shelf but abundant in deeper waters. Occasional visitor.	E
Common dolphin	*Delphinus delphis*	Common. Year-round resident	NA
Northern right-whale dolphin	*Lissodelphis borealis*	Common in the winter and spring	NA
Pacific white-sided dolphin	*Lagenorhynchus obliquidens*	Common. Year-round resident	NA

Table 5.5.5 Cetaceans of the Eastern North Pacific and Their Status off South

Common Name	Scientific Name	Abundance	Status
Risso's dolphin	*Grampus griseus*	Common. Year-round resident with peak population in summer and autumn	NA
Dall's porpoise	*Phocoenoides dalli*	Common. Year-round resident with peak population in autumn and winter	NA
Bottlenose dolphin	*Tursiops truncatus (also referred to as T. gilli)*	Common. Year-round resident	NA
Harbor porpoise	*Phocoena phocoena*	Common along the central California Coast, north of Point Conception	NA
Short-finned pilot whale	*Globicephala macrorhynchus (also referred to as G. scammonii)*	Small year-round population with increases during winter	NA
Killer whale	*Orcinus orca*	Occasional visitor to area from northern latitudes. Not common	NA
False killer whale	*Pseudorca crassidens*	Occurs primarily in tropical to warm temperate waters. Occasional visitor to area	NA
Cuvier's beaked whale	*Ziphius cavirostris*	Occurs in tropical and warm temperate waters. Have been recorded in area	NA
Baird' beaked whale	*Berardius bairdii*	Rare. Endemic to Arctic and cool temperate waters	NA
Hubb's beaked whale	*Mesoplodon carhubbsi*	Rare. Known primarily from stranding records	NA
Ginkgo-toothed beaked whale	*M. ginkgodens*	Rare. Known primarily from stranding records	NA
Hector's beaked whale	*M. hectori*	Rare. Known primarily from stranding records	NA
Blainville's beaked whale	*M. densirostris*	Rare. Possible visitor to area	NA
Bering Sea beaked whale	*M. stejnegeri*	Rare. Possible visitor to area	NA
Dwarf sperm whale	*Kogia simus*	Occurs in tropical and warm temperate waters. Sightings and strandings have occurred in California	NA
Pygmy sperm whale	*K. breviceps*	Occurs in tropical and warm temperate waters. Sightings and strandings have occurred in California	NA
Striped dolphin	*Stenella coeruleoalba*	Occasional visitor to area. Known from sightings and strandings	NA
Spinner dolphin	*S. longirostris*	Occurs in tropical waters; possible visitor to area	NA
Spotted dolphin	*S. attenuata*	Occurs in tropical waters; possible visitor to area	NA
Rough-toothed dolphin	*Steno bredanensis*	Occurs in tropical waters; possible visitor to area	NA

NA = Not Applicable; E = Endangered

Cetaceans

Cetaceans (whales, dolphins, and porpoises) occur in the project area year-round. The species present may vary from season to season or from year to year, but there are cetaceans always utilizing the waters offshore central California. Cetacean population levels are at their lowest in spring and are at their highest level during the autumn (Dohl et al., 1983a). Five species of porpoises represent the major cetacean fauna found off of central California. They are the Pacific white-sided dolphin *Lagenorhynchus obliquidens*, the northern right whale dolphin *Lissodelphis borealis*, Risso's dolphin *Grampus griseus*, Dall's porpoises *Phocoenoides dalli*, and the harbor porpoise *Phocoena phocoena*. These five species accounted for more than 95 percent of cetaceans observed off the central California coast. These species vary in their patterns of usage of the area and periods of peak abundances (Dohl et al., 1983a). Baleen whales are not a major component of the area's cetacean fauna. However, four species, the California gray whale *Eschrichtius robustus*, the humpback whale *Megaptera novaeangliae*, the blue whale *Balaeoptera musculus*, and the fin whale *B. physalus* occur in the project area (Dohl et al., 1983a). The majority of these whales use the coastal waters as migratory routes or are seasonal visitors. The California gray whale is the most common baleen whale that passes through the area twice each year on their annual migration. The majority are found close to shore over continental shelf waters (Herzing and Mate, 1984; Reilly, 1984; Rice et al. 1984; Rugh, 1984; Dohl et al., 1983a; Sund and O'Connor, 1974). During migration, the majority of the animals are 1.5 to 1.8 km offshore (0.8 to 1 nautical miles) and less than 20 percent are as close as 0.9 km (0.5 nautical mile) (Dohl et al., 1983a).

Generally, the abundance of baleen whales in the area peaks during the winter and spring migration seasons. However, as overall populations of certain species increase (e.g., gray whales and humpback) larger numbers are becoming resident to areas offshore California (Dohl et al., 1983a). Both species have historically appeared off central California as they primarily migrate through the area to winter off of Baja California. Blue and fin whales have also been observed offshore central California. Their numbers appear to be increasing outside of the normal peak abundance periods of summer through autumn.

Pinnipeds

Six pinniped species occur off central California (see Table 5.5.6). The pinnipeds are the California sea lion *Zalophus californianus*, the Northern (Steller) sea lion *Eumetopias jubatus*, the northern fur seal *Callorhinus ursinus*, the Guadalupe fur seal *Arctocephalus townsendi*, the northern elephant seal *Mirounga angustirostris*, and the harbor seal *Phoca vitulina* (Bonnell et al., 1983). The total population size for the California continental shelf is estimated to exceed 50,000 animals in the fall and nearly 50,000 animals during the spring. At least 30,000 pinnipeds are estimated to occur in the area all year-round.

Table 5.5.6 Pinnipeds of the Eastern North Pacific and Their Status Off California (Adapted from Bonnel and Dailey, 1993)

Common Name	Scientific Name	Abundance	Status
California sea lion	*Zalophus californianus*	Abundant, year-round resident	NA
Northern (Steller) sea lion (eastern stock)	*Eumetopias jubatus*	Occasional visitor to area from northern latitudes. Not common	T
Northern fur seal	*Callorhinus ursinus*	Common, year-round resident	NA
Guadalupe fur seal	*Arctocephalus townsendi*	Occasional visitor to area from southern breeding grounds. Not common	T
Northern elephant seal	*Mirounga angustirostris*	Year-round resident. Common	NA
Pacific harbor seal	*Phoca vitulina*	Year-round resident. Common	NA

T = Threatened Species; NA = Not Applicable

The offshore pinniped population in the proposed project area is predominately composed of northern fur seals or California sea lions. When one population is at its peak, the other is at its low for the area (Bonnell et al., 1983). Northern fur seals reach their peak in winter and spring, as migrants from the Bering Sea join the resident fur seals in the area. California sea lions reach their peak in fall (see Figure 5.5-1), as the breeding population disperses northward from rookery islands (e.g., San Clemente, Santa Barbara, and San Nicolas Islands) in the Southern California Bight (Barlow et al., 1997). A northern fur seal rookery is located on San Miguel Island. In 2005, a census resulted in a pup count of 2,356 (Carretta et al., 2006). The San Miguel Island breeding population is considered a separate stock of northern fur seals from the Bering Sea population. The population for the San Miguel Island stock of the northern fur seal was estimated at 9,424.

The northern elephant seal and the harbor seal are common to the project area. Rookery and haul-out areas for both species have been reported in several locations in central California and the Channel Islands (Barlow et al., 1997). In 1997, the northern or Steller sea lions were classified into two separate stocks. For the eastern Pacific ~~US~~ stock, which was classified as threatened, lions are expected to occur in the project area.

Fissipeds

The southern sea otter, *Enhydra lutris nereis*, population consists of between 2,000 and 3,000 individuals (USFWS, 2000; USGS, 2006). Excluding the translocated colony at San Nicolas Island, the range of the mainland population extends from Half Moon Bay in the north to about Gaviota in the south (USFWS, 2000).

The southern sea otter population is estimated to have numbered approximately 150,000 animals and ranged from about Prince William Sound in Alaska to Morro Hermoso in Mexico (Kenyon, 1969). The present population is descendent from a remnant group of 100 to 150 animals that were initially sighted at Bixby Creek. Since that time, substantial changes have occurred in the distribution and density of sea otters within the California range. As the population increased in size, range expansion to the south was consistently more rapid than it was to the north. By the 1980s, the range had increased to about Point Ano Nuevo to the north and Point Sal to the south. By 1995, sea otters were common as far south as Point Arguello and in 1998, they had increased their range to south of Point Conception. In recent years, they have been observed as far south as Carpinteria (USGS, 1999).

Sea otter males move seasonally. The movements of the males coincide with the breeding season (June to November) and the non-breeding season (November to May). During the breeding season, the size of the southernmost group declines dramatically, due to a northward movement of animals towards the center of the range (Bonnell et al., 1983; Estes and Jameson, 1983). This movement of males from the population fronts into the more established areas occupied by females during the summer and fall breeding season is a feature of the sea otter's annual cycle (Bonnell et al., 1983).

In California, sea otters feed almost entirely on macroinvertebrates (Ebert, 1968; Estes et al., 1981). In rocky areas along the central California coast, major prey items include abalones, crabs, and sea urchins. In sandy areas, prey items include clams, snails, octopus, scallops, sea stars, and echiuroid worms (Boolootian, 1961; Ebert, 1968; Estes, 1980; Estes et. al., 1981; Wendell et al., 1986). These species occur at water depths ranging from the littoral zone to approximately 100 m (328 feet). Most of the otters forage between shore and the 20 m (65 feet) water depth (USFWS, 2000).

Spring sea otter counts offshore California in the last 10 years have ranged between 2,090 in 1999 to 2,825 in 2004 (USGS, 2006). The most recent spring survey in May 2006 counted 2,692 sea otters. Since 1997, sea otter counts east of Point Conception have increased. In the Spring 1997 survey, 60 independent sea otters were counted east of Point Conception and in the Spring 2006 survey, 93 sea otters were counted east of the Point (USGS, 1999, 2000 and 2006).

5.5.1.4 Marine Turtles

Marine turtles are infrequent visitors to the project area but they have occasionally been reported in central California. Four species, all of which are protected under the Endangered Species Act, can occur in the project area. The four species are the green turtle *Chelonia mydas*, the olive ridley turtle *Lepidochelys olivacea*, the leatherback turtle *Dermochelys coriacea*, and the loggerhead turtle *Caretta caretta* (see Table 5.5.7) (Hubbs, 1977).

Table 5.5.7 Marine Turtles That May Occur in the Proposed Project Area

Common Name	Scientific Name	Status
Green turtle	*Chelonia mydas*	T
Olive ridley turtle	*Lepidochelys olivacea*	T
Leatherback turtle	*Dermochelys coriacea*	E
Loggerhead turtle	*Caretta caretta*	T

T-Threatened Species, E-Endangered

Of the four species, three of them (green, olive ridley, and loggerhead) are listed as threatened species. The leatherback is listed as an endangered species.

While marine turtles are seldom seen at sea locally, strandings have occurred in central California (NOAA, 1997). Fourteen marine turtle strandings were reported on SBC beaches during the 1982-1995 period. Of the 14 strandings, 9 were leatherbacks, 3 were loggerhead, and 2 were green turtles (NOAA, 1997). In the last 5 years, there have only been two strandings of sea turtles on SBC beaches (J.Cordaro, NMFS, pers. comm. 2006). Both strandings were olive ridleys. One was at Thousand Steps Beach in 2002, and the other was at Ellwood Beach in 2004. At the nearby Diablo Canyon Nuclear Power Plant, one green turtle was reported in 1994 and 1997 (NOAA, 1997; Port San Luis Harbor District, 1997). In 2005, a total of 10 sea turtle strandings were reported to the California Sea Turtle Stranding Network (NOAA, 2005). Of these recent sea turtle strandings in California, 5 were green sea turtles, 3 were leatherbacks and 2 were olive ridley turtles. General distribution information for marine turtles is provided below.

Green Sea Turtles (Chelonia mydas)

Green sea turtles are generally tropical and occur worldwide in waters above 20°C. California represents the northern end of their range, so they are infrequent visitors to the area. However, green turtles have been reported as far north as Redwood Creek in Humboldt County and off the coast of Washington and Oregon (Green et al., 1991; Smith and Houck, 1983). The green sea turtle nests on sandy tropical beaches throughout the eastern, central, and western Pacific Ocean.

There are no nesting sites on the US Pacific mainland (Eckert, 1993; Mager, 1984). Green sea turtles are benthic herbivores and subsist primarily on algae and sea grasses (Eckert, 1993).

In SBC, green turtle strandings were reported on a Santa Barbara beach and in Summerland in 1989. In San Luis Obispo County, green turtles were reported at the Diablo Canyon Nuclear Power Plant in 1994 and as recently as 1997 (NOAA, 1997; Port San Luis Harbor District, 1997). Green turtles are listed as a threatened species except for breeding colonies of green turtles in Florida and the Pacific Coast of Mexico, which are listed as an endangered species.

Olive Ridley Sea Turtle (Lepidochelys olivacea)

The olive ridley is a widely distributed tropical species. However, it has frequently been reported in cooler northern latitudes (Eckert, 1993). Off the western coast of the US, they have been reported as far north as the Gulf of Alaska, Washington, Oregon, and California by several investigators (Green et al., 1991; Marquez, 1990; Stinson, 1984; Houck and Joseph, 1958; NOAA, 1997). Stinson (1984) reported frequent sightings of olive ridley turtles around Point Conception. Generally, however, the range of olive ridley turtles in the eastern North Pacific extends from Columbia to Mexico (USDOI/MMS, 1996). Two olive ridley turtles were stranded on SBC beaches in the last 5 years (J. Cordaro, NMFS, pers. com., 2006).

The olive ridley sea turtle is omnivorous, feeding on crustaceans, fish, jellyfish, sea grasses and algae (Ernst and Barbour, 1972). The olive ridley is listed as a threatened species. However, breeding colonies off the coast of Mexico are listed as an endangered species.

Leatherback Sea Turtle (Dermochelys coriacea)

Leatherback sea turtles have the most extensive range of any reptile. In the eastern Pacific, they have been reported as far north as the Aleutian Islands and British Columbia and as far south as Chile (Mager, 1984; Smith and Houck, 1983; Hodge, 1979). Stinson (1984) reported that the leatherback is the most common sea turtle north of Mexico and that most sightings in the Point Conception area occur during July to September. Dohl et al. (1983a) and Green et al. (1989) have also reported that the leatherback is the most common sea turtle off the coast of California. During a three-year survey, leatherback sea turtles were occasionally sighted off the coast of central California (Dohl et al., 1983a). The majority of their sightings occurred during the summer and fall seasons in deeper waters over the continental slope.

Leatherback sea turtles are omnivores and feed principally on soft prey items such as jellyfish and tunicates (Mager, 1984). Nine strandings of leatherback sea turtles were reported on SBC beaches between 1982 and 1995 (NOAA, 1997). Leatherback turtles are a listed endangered species throughout their range.

Loggerhead Sea Turtles (Caretta caretta)

Loggerhead turtles are circumglobal, inhabiting the continental shelves, bays, estuaries, and lagoons in the temperate, subtropical, and tropical waters of the Atlantic, Pacific, and Indian Oceans (Dodd, 1990; Mager, 1984). Southern California is considered to be the northern limit of loggerhead sea turtle distribution (Stebbins, 1966). However, in the eastern Pacific along the west coast of the US, loggerheads have stranded on beaches as far north as Alaska, Washington and Oregon (Ekert, 1993; Green et al., 1991).

Loggerhead sea turtles are omnivorous and feed on a wide variety of marine life including shellfish, jellyfish, squid, sea urchins, fish, and algae (Carr, 1952; Mager, 1984). However, with the exception of juveniles, loggerhead turtles generally feed on benthic invertebrates found in hard bottom habitats (Ekert, 1993).

Three loggerhead strandings were reported on Santa Barbara County (SBC) beaches between 1982 and 1995 (NOAA, 1997). They are listed as a threatened species throughout their entire distributional range.

5.5.1.5 Seabirds

Shorebirds, including the federal threatened western snowy plover, are discussed in Section 5.2, Terrestrial and Freshwater Biology. Section 5.2 also discusses the State and federal endangered California least tern, which breeds on the mainland shore in the project area.

The seabird fauna of central California is large and diverse. Species found off the Point Conception area are far ranging species and come from all corners of the Pacific Ocean, Bering Sea, Arctic Ocean, inland North America, and the North Atlantic. Jones et al. (1981) reported 102 species of seabirds in central California. The seabird fauna, however, is dominated by approximately 30 species that reach their highest numbers in areas of coastal upwelling in central California (Briggs et al., 1981). In a three-year survey for seabirds off of central and northern California, Dohl et al. (1983b) reported up to 35 common species and 34 uncommon or rare species. They also reported that the seabird fauna of central California is dominated by cool-water species (e.g., boreal North Pacific) but includes subtropical species during the late summer and autumn months. According to Dohl (1983b), the number of seabirds present in central California is similar to that found in Oregon, the Gulf of Alaska, and Bering Sea and is higher than those published for southern California.

Seabirds occur year-round in the project area and the species present vary according to the season (Briggs et al., 1981). Dohl et al. (1983b) reported the highest density of seabirds during the summer and autumn is due to the presence of migrants, winter visitors, and nesting residents at the same time. The lowest density of seabirds occurred during the winter. The dominant species in the area are provided by season in Table 5.5.8 (Dohl et al., 1983b).

Table 5.5.8 Seasonal Distribution of Coastal Seabirds in the Project Area (Briggs et al., 1981; Dohl et al., 1983b)

Winter	Spring	Summer	Autumn
Arctic Loon	Arctic Loon	Sooty Shearwater	Arctic Loon
Cassins's Auklet	Sooty Shearwater	Phalaropes	Sooty Shearwater
Common Murre	Phalaropes	Brown Pelican	Phalaropes
Western Gull	Bonaparte's Gull	Brandt's Cormorant	Cassin's Auklet
Western Grebe	Western Grebe	Western Gull	Common Murre
Brandt's Cormorant	Brandt's Cormorant	Heerman's Gull	California Gull
Pelagic Cormorant	Surf Scoter	Pigeon Guillemot	Western Gull
Surf Scoter	Western Gull	Pelagic Cormorant	Western Grebe
California Gull	Common Murre	Ashy Storm-Petrel	Brown Pelican
Herring Gull	Pigeon Guillemot	Rhinoceros Auklet	Brandt's Cormorant
Xantus' Murrelet	Pelagic Cormorant	California least tern	Heerman's Gull
	Ashy Storm-Petrel		Bonaparte's Gull

Table 5.5.8 Seasonal Distribution of Coastal Seabirds in the Project Area (Briggs et al., 1981; Dohl et al., 1983b)

Winter	Spring	Summer	Autumn
	Rhinoceros Auklet		
	Xantus' Murrelet		

According to Sowls et al. (1980), 17 seabird species nest on the central and northern California coastline. The most numerous of the nesting residents are the murre, Cassin's Auklet, Brandt's Cormorant, and the Western Gull. The largest nesting sites off the California coast are located in northern California with the Farallon Islands being the most important location. However, Sowls et al. (1980) estimated that approximately 7 percent of the seabird population breeds in central California between Ventura and Monterey counties with the majority occurring on the Channel Islands. In the area from Morro Bay south to Point Conception, Chambers Consultants and Planners (1980) reported that very few seabirds breed in coastal mainland habitats due to human disturbances. Seabird species that nest on some of the northern Channel Islands are provided in Table 5.5.9.

Table 5.5.9 Seabirds That Nest on the Northern Channel Islands (Sowls et al., 1980; Carter et al., 1992)

San Miguel/Prince Island	Anacapa Island	Santa Rosa/Santa Cruz Islands
Brandt's Cormorant	Brown Pelican	Brandt's Cormorant
Pelagic Cormorant	Brandt's Cormorant	Pelagic Cormorant
Black Oystercatcher	Double-Crested Cormorant	Black Oystercatcher
Western Gull	Pelagic Cormorant	Western Gull
Cassin's Auklet	Black Oystercatcher	Cassin's Auklet
Ashy Storm Petrel	Western Gull	Ashy Storm Petrel
Pigeon Guillemot	Pigeon Guillemot	Pigeon Guillemot
Xantus' Murrelet	Xantus' Murrelet	Xantus' Murrelet
Leach's Storm Petrel		
Black Storm Petrel		
Double-Crested Cormorant		
Rhinoceros Auklet		
Tufted Puffin		

Endangered or Threatened Seabirds

The federally threatened western snowy plover and State and federal endangered California least tern are discussed in Section 5.2, Terrestrial and Freshwater Biology.

The California brown pelican (*Pelecanus occidentalis californicus*) is a Federal and State listed endangered species and ranges from British Columbia to southwest Mexico. In the US, the California brown pelican nests only on Anacapa and Santa Barbara Islands off the southern California coast.

The listing of California brown pelican was based primarily on serious declines in the southern California population due to bioaccumulation of chlorinated hydrocarbon pesticides (DDT, DDE, dieldrin, and endrin) in the pelican's food chain (USDOI/MMS, 1996). Bioaccumulation of these pesticides resulted in serious eggshell thinning and poor reproductive success (Schreiber and Risebrough, 1972). Food scarcity, primarily anchovies, also contributed to the species' decline (Keith et al., 1971).

The breeding season for California brown pelicans extends from March through early August. Preferred nesting habitat is on offshore islands. In 1991, approximately 12,000 breeding birds were reported at two colonies on Anacapa and Santa Barbara Islands (Carter et al., 1992). Nesting attempts and success is variable from year to year. In 2002, the number of nests and fledglings produced by the southern California nesting population was estimated at 6,440 nests and 3,220 fledglings on Anacapa Island and 1,050 nest attempts on Santa Barbara Island (Natural Resource Trustees, 2005; Gress, 2006). On West Anacapa Island, there were 2,700 nest attempts and 1,910 fledglings in 2003, 7,630 nest attempts and 7,600 fledglings in 2004, and 4,930 nest attempts and 7,640 fledglings in 2005 (Gress, 2006). On Santa Barbara Island, there were 780 nest attempts in 2003, 2,040 nest attempts in 2004, and 1,200 nest attempts in 2005 (Gress, 2006). In 2006, California brown pelicans were observed nesting on Prince Island off San Miguel Island (UCSC, 2006). The California brown pelicans occur in coastal areas as far north as British Columbia and as far south as southwestern Mexico. Offshore rocks and coastal habitats such as rocky shores, sandy beaches, and piers provide important roost sites in the project area. They feed by plunge diving from heights of up to 15 to 20 m above the ocean surface and feed primarily on small schooling fish (e.g., anchovies) (USDOI, FWS, 1982). Pelicans return to specific roosts each day and do not normally remain at sea overnight. These roosts are usually in regions of high oceanic productivity and isolated from predation pressure and human disturbances.

The State of California listed Xantus' murrelet (*Synthliboramphus hypoleucus)* as threatened in 2004. Xantus' murrelets range from Baja California to Oregon and Washington. Xantus' murrelets are common spring and summer residents to the Channel Islands and nearshore islands and offshore mainland waters (Lehman, 1994). <u>The Channel Islands harbor almost half of the world's total population of 10,000 to 15,000 birds (Graham, 2007).</u> They nest colonially in only 12 to 15 locations, including Santa Barbara, Anacapa, San Miguel, Santa Catalina, San Clemente, and Santa Cruz Islands. Santa Barbara Island contains the largest breeding concentration of this species in the world (McChesney et al., 2000; Burkett et al., 2003). <u>The closest Xantus' murrelet breeding colony to Platform Irene (about 42 miles away) is San Miguel Island, which supports 10 to 50 breeding pairs.</u> During the breeding season, this species forages from these nest sites, particularly in the area between Santa Barbara and Santa Catalina Islands and the mainland, but densities are low (Mills et al., 2005). <u>The foraging range of Xantus' murrelets during the breeding season has been studied by shipboard and aerial surveys and by radio tracking of nesting birds at Santa Barbara Island. Foraging patterns varied in different years. In 1975 to 1978, shipboard and aerial surveys during the breeding season found murrelets concentrated within 12 miles (20 km) of the Santa Barbara Island colony and they also occurred in high density just northwest of the Coronado Islands (Carter et al., 2000; Karnovsky et al., 2005). During the 1996 and 1997 breeding season, radio-marked murrelets from Santa Barbara Island were found relatively far from Santa Barbara Island. Some birds from the Santa Barbara Island colony were found north of Pt. Conception in 1996 and 1997, indicating birds from the Santa Barbara Island colony may forage in the vicinity of Platform Irene during the breeding season. Radio-tracking of Xantus' murrelets from the San Miguel Island, Santa Cruz Island, and Anacapa Island colonies has not been done, but because these islands are closer to Platform Irene</u>

than Santa Barbara Island, it is possible that at least some individuals from these colonies would forage near Platform Irene in some years. Ship and aerial surveys during the 1999-2001 breeding season found few birds in the southern portion of the Southern California Bight and an extension of birds to the north from Santa Barbara Island, with some birds observed near Point Conception (Karnovsky et al., 2005). When breeding is finished, usually by mid-summer, Xantus' murrelets disperse and range from southern Baja California to Vancouver Island, British Columbia (Karnovsky et al., 2005). Xantus' murrelet is known to occur in the vicinity of Platform Irene, but at low densities. ~~In late summer, fall, and early winter birds disperse widely (Lehman, 1994)~~

Marbled murrelets (*Brachyramphus marmoratus*) are very rare late summer, fall, and winter visitors to nearshore waters in Southern California, including several of the Channel Islands (Lehman, 1994). They breed in old-growth coniferous forests along the north coast of California northward through coastal British Columbia and Alaska. The breeding range in California is north of Monterey County.

California Species of Special Concern that may occur in the project area include ashy storm-petrel (*Oceanodroma homochroa*), black storm-petrel (*O. melania*), double-crested cormorant (*Phalacrocorax auritus*), and California gull (*Larus californicus*). Ashy storm-petrels are residents of pelagic waters off central and Southern California and northern Baja California Norte, Mexico. Ashy storm-petrels nest on several of the Channel Islands (Carter et al. 1992) and forage widely over the ocean around these islands. Ashy storm-petrels' year-round range extends from Cape Mendocino, California to northern Baja California, Mexico. Breeding colony surveys from 1989-1991 estimated a worldwide breeding population of 7,207 birds with 43 percent of the breeding population found on the northern Channel Islands (Jensen et al., 2005). At-sea sightings indicate that areas of high ashy storm-petrel density occur along the continental slope of Central California with notable concentrations between Point Arena and Monterey Bay and in the Southern California Bight. Sightings also occur on the shelf between Point Buchon and Point Conception (Jensen et al., 2005). At-sea densities in the vicinity of Platform Irene from year round shipboard surveys conducted between 1975 and 1997 ranged from 0.055 to 0.91 birds per square kilometer.

Black storm-petrels migrate northward to central and Southern California during the spring and early summer and breed on some of the Channel Islands, especially Santa Barbara Island (Carter et al., 1992). Black storm-petrels forage widely over the ocean around the islands. Double-crested cormorants nest on most or all of the Channel Islands and occasionally along cliff faces on the mainland. They regularly forage throughout the nearshore waters of central and southern California, including nearshore island and mainland waters, and commonly roost on mainland beaches and piers. California gulls winter along the Pacific Coast of North America, including the Channel Islands, and breed well inland. Summer birds (mostly non-breeding immatures) congregate on beaches in large numbers.

5.5.1.6 Benthic Invertebrates

The benthos consists of organisms that live in or on the ocean floor. Benthic habitats are often classified according to substrate type, either unconsolidated sediments (e.g., gravel, sand, or mud) or rock. The former category is often referred to as soft bottom and the latter hard bottom or rocky substrate. Each support their own characteristic biological community. In addition to substrate, water depth and water temperature play important roles in the distribution of benthic organisms. Distance from shore, food availability, and water quality are also important factors that influence the distribution of benthic organisms. Benthic organisms can be epifaunal (attached or motile species that inhabit rock or sediment surfaces) or infaunal (live in rock or soft sediments) (Thompson et al., 1993).

Intertidal and Shallow Subtidal

Soft Substrate

Sandy beaches occur along shoreline segments of the project area. Because of the difficulties in conducting ecological studies in sand, far less is known about invertebrate communities that live there than those found on rocky substrates. Sand dwelling organisms are very motile and cannot be easily monitored over time. Immigration and emigration rates are high and often contribute to the high level of temporal and spatial patchiness in density that is often reported (Thompson et al., 1993). Studies are also difficult to conduct in unstable sediments in a high-energy environment.

Although not obvious, vertical zonation of invertebrates occurs on sandy beaches. The invertebrates that live in sand (infauna) are quite motile and change position with respect to tidal level. Also, certain species will be found higher or lower than others. Common invertebrates in the upper intertidal are several species of amphipods in the genus *Orchestoidea*; the predatory isopod, *Excirolana chiltoni*; and several species of polychaetes (e.g., *Excirolana chiltoni*, *Euzonus mucronata*, and *Hemipodus borealis*). The middle intertidal is characterized by species such as the sand crab, *Emerita analoga* and the polychaete *Nephtys californiensis*. *Emerita* is generally the most abundant of the common middle intertidal organisms, often comprising over 99 percent of the individuals on a given beach (Straughan, 1983).

In the low intertidal, polychaetes and nemerteans dominate (Straughan, 1982). Also, the large sand crab, *Blepharipoda occidentalis*, and the Pismo clam, *Tivela stultorum* can be found. *Tivela,* however, was once more abundant in the intertidal. Its present reduction in population is probably the result of overharvesting and predation.

In shallow water (<10 m) epifaunal (organisms which live on the sediment or rock surfaces) communities are generally well developed (Thompson et al., 1993). With increasing depth, the density of epifaunal species decline while that of infauna increases, probably because of the greater stability of sediments (Barnard, 1963). Also, with depth, polychaetes become more dominant over crustaceans (Oliver et al., 1980). Physical changes to nearshore subtidal habitats are associated with increasing depth. One of the most important is a decrease in wave surge and, as a result, finer sediments that influence the distribution of epifaunal species in nearshore environments (Thompson et al., 1993). Merrill and Hobson (1970) have shown that the shoreward limit of the sand dollars (*Dendraster excentricus*) occurs near the break line with the inner most population consisting of small juveniles. Seaward, they found that sand dollars become progressively larger and more abundant.

The effects of wave action on benthic infauna are not well known. However, several studies indicate the declines in the abundance of tube-building polychaetes in shallow water (< 10 m) are due to increasing substrate disturbance (Oliver et al., 1980; Davis and VanBlaricom, 1978).

The composition of invertebrate assemblages on a sandy beach correlate to slope and sand texture. Within a beach, crustaceans and molluscs tend to be more common on the steeper, coarser, and dryer upper intertidal zone. Polychaetes and nemerteans are the dominant invertebrates in the lower intertidal where slope is not as steep and the sand usually finer and wetter (Wenner, 1988; McLachlan and Hesp, 1984; Straughan, 1982).

Straughan (1982) conducted comprehensive intertidal surveys in central and southern California over a 12-year period. At a sampling site in northern Santa Barbara County, annelids and crustaceans dominated along a transect extending from the supratidal to intertidal areas. Common species Straughan reported are listed in Table 5.5.10.

Table 5.5.10 List of Soft-Bottom Intertidal Species Collected at a Northern Santa Barbara Location (from Straughan, 1982)

Annelida	Crustacea
Cerebratulus californiensis	*Archaeomysis grebnitzki*
Dispio uncinata	*A. maculata*
Eteone dilatae	*Emerita analoga*
Euzonus dillonensis	*Eohaustorius sawyeri*
E. mucronata	*E. washingtonianus*
Hemipodus californiensis	*Excirolana chiltoni*
Lumbrineris zonata	*Lepidopa californica*
Lumbrineridae	*Orchestoidea benedicti*
Nemertea sp.	*O. columbiana*
Nephtys californiensis	*O. corniculata*
Nephtys sp.	*Synchelidium sp.*
Opheliidae	Insecta/Arachnida
Orbinia johnsoni	Anthomyiidae
Orbiniidae	Calliphoridae larvae
Paranemertes californica	Cyclorrhapha larvae
Pygospio californica	Ephydridae larvae
Scoloplos armiger	Sarcophagidae pupae
S. acmeceps	Mollusca
Zygeupolia rubens	*Collisella strigatella*
	Siliqua patula

At offshore monitoring stations located at 18 m water depth in central California, approximately 97 benthic infaunal species were found (ABC, 1995). Rank order and the relative abundance of these species which are commonly found in central California are listed in Table 5.5.11. Annelid worms were the most abundant group found at the stations.

Epifaunal species collected at these stations include the echinoderms, Amphiodia occidentalis and Dendraster excentricus; the arthropod, Heterocrypta occidentalis; and the molluscs, Nassarius fossata, N. perpinguis, Olivella baetica, and Polinices lewisii (ABC, 1995).

Rocky Substrates

California rocky intertidal areas are characterized by diverse assemblages of algae, invertebrates, and fish (Ricketts et al., 1985; Foster et al. 1991). The majority of intertidal species are restricted to certain elevations along the shoreline. While the vertical distribution of intertidal species is largely determined by the ability to withstand desiccation, other important factors that determine vertical zonation are competition, predation, and available microhabitats. On wave-exposed shores, wave run-up and splash enable species to survive at higher elevations than those normally found in protected, non-splash areas.

Table 5.5.11 Dominant Soft-Bottom Infaunal Species Reported From Five Monitoring Stations Located in Central California (N = Nemertea, A = Annelida, M = Mollusca, Ar = Arthropoda) (ABC, 1995)

Species	Total	Percent of Total
Carinoma mutabilis (N)	407	13.9
Lumbrineris tetraura (A)	377	12.9
Tellina modesta (M)	372	12.7
Magelona sacculata (A)	292	10.0
Prionospio pygmaea (A)	281	9.6
Glycera capitata (A)	144	4.9
Glycinde picta (A)	109	3.7
Nephtys caecoides (A)	74	2.5
Odostomia sp. (M)	74	2.5
Leitoscoloplos pugettensis (A)	57	1.9
Chaetozone setosa (A)	55	1.8
Chione undatella (M)	51	1.7
Typosyllis fastigiata (A)	46	1.5
Nemertea sp. (N)	32	1.0
Macoma secta (M)	30	1.0
Mediomastus californiensis (A)	30	1.0
Spiophanes bombyx (A)	30	1.0
Chone magna (A)	27	1.0
Onuphis vexillaria (A)	22	1.0
Photis macinerreyi (Ar)	21	1.0
Thalenessa spinosa (A)	21	1.0

The diversity of algae and invertebrate species tends to increase from high to low elevations. Generally, because the high intertidal is only occasionally wet, it is sparsely covered by species such as the blue-green algae, *Bangia* sp. and *Enteromorpha* sp. In these areas, *Littorina* sp. (periwinkle snail) can be found in rock crevices and *Tegula funebralis* (turban snail) and *Pachygrapsus crassipes* (shore crab) can be found in the shade or crevices. The rock lice, *Ligia occidentalis* can also be found in the splash zone. In the intertidal, algal cover is more conspicuous with clumps of *Fucus* and *Pelvetia* (rockweeds) and *Endocladia* (red algae). The intertidal can also be inhabited by a variety of limpets, *Chthamalus* sp. (acorn barnacle), *Mytilus californianus (*mussels), *Pisaster ohcraceus* (starfish), and various encrusting algae. In the lower intertidal, species such as *Mazzaella flaccida* and *Mastocarpus papillatus* are present. Rock-encrusting algae, *Pagurus* spp. (hermit crab), snails, motile and tube-forming worms, encrusting bryozoans, sponges, tunicates, and *Strongylocentrus* spp. (urchins) are also common beneath the blades of upright algae. In the low intertidal, fish species such as *Xiphister* sp. (prickleback) can be found under cobbles, in pockets of water, and under dense algal cover. In the lower intertidal, red algae increase and species such as *M. flaccida*, *M. papillatus*, *Gastroclonium subarticulatum* and *Chondracanthus canaliculatus* are common. *Phyllospadix* spp. (surfgrass) can fringe the shoreline at the lower boundary of the intertidal zone.

The vertical zonation of typical rocky intertidal organisms along the California coast is shown in Figure 5.5-2.

Currently, all major species of abalone in central and southern California are depleted, a result of cumulative impacts from commercial harvest, increased market demand, sport fishery expansion, an expanding population of sea otters, pollution of mainland habitat, disease, loss of kelp populations associated with El Niño events, and inadequate wild stock management (CDFG, 2001).

The red abalone is associated with rocky kelp habitat ranging from Oregon into Baja California. In northern and central California they are found from the intertidal to the shallow subtidal depths. In southern California they are exclusively subtidal, restricted to upwelling locations along the mainland and the northwestern Channel Islands. Two canopy forming kelps, bull kelp and giant kelp, are primary components of the red abalone habitat and diet (CDFG, 2001). It is possible that red abalone could be present in the subtidal areas along the coast in the project area.

Pink abalones occur from Point Conception to the central Baja California peninsula, Mexico. Its depth range extends from the lower intertidal zone to almost 200 feet, but most are found from about 20 to 80 feet. It has the broadest distribution of the southern California abalones (CDFG, 2001). It is unlikely that pink abalones are within the project area since it is north of Point Conception.

Green abalone is found on open coast shallow rocky habitat from Point Conception, California to Bahia Magdalena, Baja California, including parts of the Channel Islands. The species is associated with the warm-temperate California region from Baja California to southern California. Green abalone is commonly found in rock crevices, under rocks and other cryptic cavities from the low intertidal to subtidal zones. They are mostly found between 10 and 20 foot depths, often associated with surf grass beds, but is sometimes seen at 50 and 60 foot depths (CDFG, 2001). It is unlikely that green ~~pink~~ abalone are within the project area since it is north of Point Conception.

Black abalone are reported from as far north as Oregon, but most are found south of San Francisco Bay to southern Baja California including the offshore islands. By the mid- 1990s, only remnant populations existed at the Farallon and Channel Islands, and along the mainland southern California shoreline they were totally absent. Black abalone populations monitored biannually by the Channel Islands National Park experienced huge declines on the Channel Islands in the mid 1980s. This decline was the result of a disease, known as “withering foot disease.” Their decline on the mainland was first noted by MMS in 1992 at Point Conception. The progress of the disease steadily moved up the coast and by 1997, according to biannual MARINe (Multi-Agency Rocky Intertidal Network) data, rocky intertidal habitats nearest the project were at 5 to 10 percent of their original numbers. The decline has progressed further up the coast over the past decade; numbers of animals in the area of the project have stayed about the same or declined slightly. No new sustained recruitments of juveniles have been observed either along the Central Coast or the islands and repopulation at this point is unlikely (Miner et al., 2005). Small populations exist in central and northern California. An essential habitat includes rocky intertidal areas, often within the high energy surf zone (CDFG, 2001). In 1998, NMFS added black abalone to the candidate species list for possible listing under the federal Endangered Species Act and in April 2007 published a request for information pertaining to the listing in the Federal Register (http://www.epa.gov/fedrgstr/EPA-SPECIES/2007/April/Day-13/e6966.htm).

The white abalone (*Haliotis sorensoni)* is a federal endangered species and is discussed below.

Deep-Benthic Assemblages

Soft-Bottom

In a comprehensive three-year benthic infauna study offshore Point Conception (California Monitoring Program Phase II), Hyland et al. (1991) reported over 886 species representing 15 phyla. The 10 most abundant species reported by Hyland et al. (1991) for a transect located just north of Platform Irene are provided in Table 5.5.12.

Table 5.5.12 Ten Most Abundant Soft-Bottom Infaunal Species, by Water Depth, off the Coast of Point Arguello (Hyland et al., 1991)

Station R-4 (90 m)	Station R-5 (180 m)	Station R-6 (410 m)
Photis lacia (A)	*Mediomastus ambiseta* (P)	*Chloeia pinnata* (P)
Mediomastus ambiseta (P)	*Chloeia pinnata* (P)	*Nephtys cornuta* (P)
Myriochele sp. M (P)	*Tharyx* spp. (P)	*Tectidrilus diversus* (O)
Chloeia pinnata (P)	*Photis californica* (A)	*Chaetozone* nr. *setosa* (P)
Photis spp. (A)	*Minuspio lighti* (P)	*Huxleyia munita* (P)
Photis californica (A)	*Spiophanes berkeleyorum* (P)	*Cossura rostrata* (P)
Typhlotanais sp. A (T)	*Photis lacia* (A)	*Maldane sarsi* (P)
Sphiophanes missionensis (P)	*Prochelator* sp. A (P)	*Minuspio* sp. A (A)
Praxillella pacifica (P)	*Spiophanes missionensis* (P)	*Cossura candida* (P)
Minuspio lighti (P)	*Levinsenia gracilis* (P)	*Cossura pygodactyla* (P)
All Fauna (419 species)	All Fauna (358 species)	All fauna (215 species)

(A = Amphipoda, Oligochaeta, P = Polychaeta, T = Tanaidacea

Crustaceans (34 percent) and polychaetes (31 percent) were the most dominant taxa followed by gastropods (10 percent) and bivalves (8 percent). Together these four classes accounted for 83 percent of all taxa. Hyland et al. (1991) revealed patterns of decreasing infaunal abundances and diversity with increased water depth. Fauchald and Jones (1978) and SAIC (1986) have also reported similar patterns in the California Offshore Monitoring Program (CAMP) Phase I reconnaissance study.

The project area in the Santa Maria Basin is located at the boundary separating the Oregonian and Californian Provinces. Therefore, the composition of the infauna found in the CAMP Phase II Monitoring Program shows affinities with each province (Hyland et al., 1990). The majority of species (67 percent) occurring in the project area have northern faunal affinities (Oregonian Province), 27 percent with primarily southern affinities (Californian Province), while 31 percent are endemic to the region (Hyland et al., 1990).

A site-specific biological survey of the Platform Irene site and the pipeline routes to shore was performed prior to construction of the platform and pipelines (McClelland Engineers, 1984). ROV reconnaissance and bottom still photography indicated a relatively featureless seafloor consisting of medium to fine grain sand and sedimentary materials. Rocky areas were observed along the pipeline corridor in about 30 feet of water.

Hard Substrate

Hard-bottom habitats in deep waters of the project area are rare. Generally, when they occur, they are discontinuous patches of exposed rock separated by soft bottom composed of mud and fine sands (BBA/ROS, 1986; Steinhauer and Imamura, 1990; SAIC and MEC, 1995). Several qualitative surveys of hard-bottom communities in this region of the Santa Maria Basin have been conducted over the years (e.g., Nekton, 1981; Dames and Moore, 1982; 1983; Nekton and Kinnetic Laboratories, 1983; and SAIC, 1986). However, in the comprehensive MMS-sponsored CAMP, Phases II and III, nine rocky reefs were quantitatively surveyed for 10 years from 1986 to 1995. The goal of the hard-bottom studies was to determine the cumulative effects of offshore drilling and production activities on the hard-substrate communities. Impacts to hard-bottom communities, especially epifauna, were of particular interest, because of the greater sensitivity of many of these species to increased particulate flux, the importance of their trophic role, and the general rarity of these communities in the area.

From CAMP Phase II, Hardin et al. (1994) reported 263 taxa from low-relief (<0.5 m) and 222 taxa from high-relief (>1.0 m) structures. The ten most dominant species (mean percent cover) are provided in Table 5.5.13.

Table 5.5.13 The Ten Most Abundant Hard-Bottom Taxa in Low Relief (0.2-0.5 m) and High-Relief (>1.0 m) Habitats Near Platform Hidalgo (adapted from Hardin et al., 1994)

Taxa	Taxon Group	Mean Percent Cover
Low Relief		
Ophiuroidea, unidentified	Ophiuroidea	5.8
Florometra serratissima	Crinoidea	2.7
Paracyathus stearnsii	Anthozoa	1.5
Metridium giganteum	Anthozoa	1.2
Sabellidae, unidentified	Polychaeta	1.1
Ophiacantha diplasia	Ophiuroidea	1.1
Caryophyllia sp.	Anthozoa	1.0
Pyura haustor	Urochordata	0.8
Terebellidae, unidentified	Polychaeta	0.8
Sponge, white encrusting	Porifera	0.7
High Relief		
Amphianthus californicus	Anthozoa	4.6
Ophiuroidea, unidentified	Ophiuroidea	3.5
Sabellidae, unidentified	Polychaeta	2.4
Desmophyllum cristagalli	Anthozoa	2.1
Galatheidae, unidentified	Decapoda	1.7
Metridium giganteum	Anthozoa	1.7
Lophelia californica	Anthozoa	1,6
Sponge, white encrusting	Porifera	1.5
Stomphia didemon	Anthozoa	1.6
Florometra serratissima	Crinoidea	1.3

No one taxon dominated in percent cover on the hard-substrate in the project area. However, most of the cover that was found consisted of a turf composed of komokoiacea foraminerferans and hydroids. The turf varied in percent cover but, generally, it occupied most of the rock surfaces that were absent large epifauna. The 15 most abundant taxa in low-relief habitats totaled approximately 19.3 percent cover, and the 15 most abundant taxa in high-relief habitat totaled approximately 26.6 percent cover (Hardin et al., 1994). Despite the lack of dominance by any one taxon, of the 22 taxa comprising the 15 most abundant species, 10 were anthozoans. Anthozoans were followed by poriferans, ophiuroids, polychaetes, and urochordates.

Two surveys of hard-bottom habitats in the northern Santa Maria Basin off the coast of the Point San Luis - Montana de Oro area were conducted in 1999. The goal of the surveys was to characterize hard-bottom communities in submarine cable corridors proposed for installation in 2000. Twenty-two transects were surveyed at water depths ranging from 35 to 125 m. Relief height ranged from 0.5 m to 35+ m.

The species in the survey area were similar to those found on the CAMP, Phase II. However, there were substantial differences in dominant species and epifaunal percent cover. While anthozoa was the most common taxon as found in CAMP Phase II, percent cover of species such as *Stylantheca porphyra* (purple encrusting hydrocorals), *Balanophyllia elegans* (orange cup coral), *Paracyathus stearnsii* (brown cup coral), *Corynactis california* (club-tipped anemone), and *Epizoanthus* sp. (zoanthid anemones) were much higher (Morro Group, 2000). Percent cover typically reached 100 percent. At higher relief locations, these species (especially *Corynactis*) formed a solid carpet that extended for hundreds of meters. *Stylaster californicus* (formerly *Allopora californica*) or California hydrocoral, also occurred in the survey area at water depths <45 m.

Endangered or Threatened Marine Invertebrates

In May 2001, white abalone (*Haliotis sorensoni)* became the first marine invertebrate to be listed as a Federal endangered species. White abalone is a mollusk that occurs on rocky habitat from Point Conception to Baja California at 60 to 200 ft (24 to 60 m) depths (Hobday and Tegner, 2000). White abalone has been recorded in water as shallow as 25 ft (7.5 m) in the Santa Barbara Channel (Aspen, 2005), but is primarily found in depths greater than about 75 feet (CDFG, 2001). White abalone typically are found in open low relief rock or boulder habitat surrounded by sand (Hobday and Tegner, 2000). There has been a greater than 99 percent decline in both the abundance and density of white abalone in California since the 1970s (Hobday and Tegner, 2000). The abalone fishery contributed to the decline of white abalone by overharvesting and reduced the density to the point where recruitment success has been unlikely.

It is unlikely that white abalones are within the project area, because it is north of Point Conception.

5.5.1.7 Underwater Noise from Oil and Gas Production

Underwater noise caused by oil and gas production, from sources like vessel traffic, helicopters, and pumps or other equipment for production or shipping, may potentially disturb marine mammals and seabirds. Underwater noise from Platform Irene and its operation follows one of two basic pathways, above-water noise that passes through the atmosphere to the sea and that which is transmitted directly into the sea via mechanical vibration. The man-made sources occur in combination with the natural wind and wave-generated noise.

Ambient underwater noise related to wind is caused primarily by wave action and spray. Wind is the major contributor to natural noise between roughly 100 cycles per second or Hertz (Hz) and 30 kHz, while wave generated noise is a significant contributor in the infrasonic range (under 20 Hz). Levels of wind-generated ambient noise are concentrated at frequencies below 1 kHz, and when the wind speed is 5 knots (9 km/h) the natural noise level at 1 kHz is about 56 dB. Ambient wind noise generally increases with wind speed by 5 dB for each doubling of wind speed (WDCS, 2003). Surf noise is not dominant at Platform Irene because the platform is roughly four miles from Point Pedernales.

Current sound levels associated with the operation of Platform Irene are typical of other electric-powered production platforms off Santa Barbara County. Steady operation of Platform Irene causes underwater vibration through the platform legs and the production system. Compared to platforms that self-generate power, Platform Irene has fewer mechanical noise sources. A previous study of electric-drive production platforms in the Santa Barbara Channel shows that platforms similar to Platform Irene cause continuous spectrum underwater noise of less than 100 dB (Gales, 1981). When engaged in drilling and production, higher levels of low frequency noise occur, especially with tonal components between 5 and 10 Hz, but none of the Santa Barbara area drilling platforms studied caused levels over 130 dB at any frequency (Gales, 1981). This data is relevant because it was measured at a distance of approximately 100 feet, in water depths of approximately 200 feet, and Platform Irene is at a depth of about 240 feet.

Helicopter and supply boat noise substantially increase local noise levels when maneuvering near the platform. Helicopter noise is around 75 dBA for an overflight at 1,000 feet above the water, and although it would vary over time with arrivals and departures, broadband underwater noise levels probably reach short-term peaks as high as 165 dB (WDCS, 2003; Chambers Group, 1987). Supply boats and the vessel propulsion machinery (especially cavitation associated with propellers) are also a major, but variable, existing source of up to about 132 dB when measured near the vessel (Gales, 1981). Other equipment on the platform causes less noise than helicopter operation, but is steadier, with a maximum above-water noise level of about 90 dBA (Behrens, 2006). Surface sound levels including helicopter noise are also addressed in Section 5.10, Noise.

5.5.2 Regulatory Setting

5.5.2.1 Federal Laws and Policies

Outer Continental Shelf Lands Act

Under the Outer Continental Shelf Lands Act (OCSLA), the Department of the Interior (DOI) is required to:

- Manage the orderly leasing, exploration, development, and production of oil and gas resources on the Federal OCS;
- Ensure the protection of the human, marine, and coastal environments;
- Ensure that the public receives a fair and equitable return for these resources; and
- Ensure that free-market competition is maintained.

Within the DOI, the MMS is charged with the responsibility of managing and regulating the development of the OCS oil and gas resources in accordance with the provisions of the OCSLA. The MMS operating regulations are presented in Chapter 30, CFR Part 250.

In many instances, the MMS develops protective measures that are applied to specific lease blocks. For example, if the MMS Regional Manager (RM) has reason to believe that biological populations or habitats exist and require protection, the RM shall provide the lessee notice that the lessor is invoking the provisions of a biological resource stipulation and the lessee shall comply with the following requirement: Prior to any drilling activity or the construction or placement of any structure for exploration or development on lease areas including, but not limited to, well drilling and pipeline and platform placement, the lessee must conduct site-specific surveys as approved by the RM and in accordance with prescribed biological survey requirements to determine the existence of any special biological resource including, but not limited to: (1) very unusual, rare, or uncommon ecosystems or ecotones; and (2) a species of limited regional distribution that may be adversely affected by any lease operation. If the results of the survey suggest the existence of a special biological resource that may be adversely affected by any lease operation, the lessee shall: (1) relocate the site of operation so that the resource identified is not adversely affected; (2) modify operations so that the biological resource or habitat is not adversely affected; or (3) establish to the satisfaction of the RM on the basis of the site-specific survey, either that the operation will not have a significant adverse effect upon the resource or that a special biological resource does not exist.

National Environmental Policy Act (NEPA)

NEPA requires all Federal agencies to use a systematic, interdisciplinary approach to protect the human environment. The approach ensures the integrated use of natural and social sciences in any planning and decision making that may have an impact on the environment. The NEPA also requires the preparation of a detailed EIS on any major Federal action that may have a significant impact on the environment. The EIS must address any adverse environmental effects that cannot be avoided or mitigated, alternatives to the proposed action, the relationship between short-term resources and long-term productivity, and irreversible and irretrievable commitments of resources.

In 1979, the Council on Environmental Quality (CEQ) established uniform procedures for implementing the procedural provisions of NEPA. These regulations provide for the use of the NEPA process to identify and assess reasonable alternatives to proposed actions that avoid or minimize adverse effects upon the quality of the human environment. “Scoping” is used to identify the scope and significance of important environmental issues associated with a proposed Federal action through coordination with Federal, State, and local agencies; the general public; and any interested individual or organization prior to the development of an impact statement. The process also identifies and eliminates from further detailed study, issues that are not significant or that have been covered by prior environmental review.

Marine Mammal Protection Act (MMPA)

Under the MMPA of 1972, the Secretary of Commerce is responsible for the protection of all cetaceans and pinnipeds (except walruses) and has delegated this authority to the National Marine Fisheries Service (NMFS). The Secretary of Interior is responsible for walruses, polar bears, sea otters, manatees, and dugongs and has delegated this authority to the US Fish and Wildlife Service (USFWS).

The MMPA established a moratorium on the taking of marine mammals in waters under US jurisdiction. The Act defines "take" as hunt, capture, or kill or attempt to harass, hunt, capture, or kill any marine mammal." "Harassment" is defined as any act of pursuit, torment, or annoyance that has the potential to injure a marine mammal or marine mammal stock in the wild; or has the potential to disturb a marine mammal or marine mammal stock in the wild by causing disruption of behavioral patterns, including, but not limited to, migration, breathing, nursing, breeding, feeding, or sheltering. The moratorium may be waived when the affected species or population stock is within its optimum sustainable population range and would not be disadvantaged by the authorized taking. The Act directs the Secretary, upon request, to authorize the unintentional taking of small numbers of marine mammals incidental to activities other than commercial fishing when, after notice and opportunity for public comment, the Secretary finds that the total of such taking during the five-year (or less) period would have a negligible impact on the affected species.

The Act also specifies that the Secretary shall withdraw, or suspend for a specified period of time, permission to take marine mammals due to incidental activities if the applicable regulations regarding methods of taking, monitoring, or reporting are not being complied with, or the taking is having, or may be having, more than a negligible impact on the affected species or stock.

In 1994, a new subparagraph (D) was added to Section 101(a)(5) to simplify the process of obtaining "small take" exemptions when unintentional taking is by incidental harassment only. Specifically, the incidental take of small numbers of marine mammals by harassment can now be authorized for periods of up to one year without rulemaking, as required by Section 101(a)(5)(A), which remains in effect for other authorized types of incidental taking.

To ensure that activities on the OCS adhere to MMPA regulations, MMS must actively seek information concerning impacts of OCS activities on local species of marine mammals.

Endangered Species Act (ESA)

The Endangered Species Act of 1973, as amended, establishes protection and conservation of threatened and endangered species and the ecosystem on which they depend. The US Fish and Wildlife Service and the NMFS administer the Act. Section 7 of the Act governs interagency cooperation and consultation between federal agencies to ensure that activities do not jeopardize the existence of threatened or endangered species or result in adverse or modification or destruction of their critical habitat. Section 10 of the ESA addresses compliance for non-federal entities for projects with no federal nexus.

Magnuson-Stevens Act

The Magnuson-Stevens Fishery Conservation and Management Act of 1976 (MSFCMA) is the cornerstone legislation of fisheries management in US jurisdictional waters. Its purpose was to stop overfishing by foreign fleets and aid in the development of the domestic fishing industry. The Act gave the US sole management authority over all living resources within the 200-nautical mile exclusive economic zone of the US. The Act created eight regional Fishery Management Councils (FMCs) and mandated a continuing planning and management program for marine fisheries by the FMCs. The Act, as amended, requires that a Fishery Management Plan (FMP) based upon the best available scientific and economic data be prepared for each commercial species or group of related species of fish that is in need of conservation and management within each respective region. The regional council for the Pacific OCS is the Pacific Fishery Management Council. In accordance with the Act, the councils report directly to the US Secretary of Commerce whose job is to review, approve and prepare fishery management plans. In reality, this function is delegated to the Administrator of the NOAA and the NMFS.

The Act has been amended several times. In 1996, Federal law governing fisheries management underwent a major overhaul. The amendments, termed the Sustainable Fisheries Act (SFA) of 1996, identified fish habitat as critical to healthy fish stocks and sustainable fisheries. The SFA implemented a program to designate and conserve Essential Fish Habitat (EFH) for species managed under a FMP. EFH is defined as "those waters and substrate necessary for spawning, breeding, feeding, or growth to maturity." The intention is to minimize any adverse effects on habitat caused by fishing or nonfishing activities and to identify other actions to encourage the conservation and enhancement of such habitat. The documents prepared for West Coast groundfish EFH include all species of rockfish managed by the Council (Bloeser, 1999). The 2006 reauthorization of the Magnusun-Stevens Act redefined annual catch limits, expanded fisheries management tools (e.g., recreational fishing data collection), and addressed international over fishing and by catch issues.

Oil Pollution Act (OPA)

The OPA of 1990 establishes a single uniform Federal system of liability and compensation for damages caused by oil spills in US navigable waters. OPA requires removal of spilled oil and establishes a national system of planning for and responding to oil spill incidents. OPA includes provisions to:

1) Improve oil-spill prevention, preparedness, and response capability;
2) Establish limitations on liabilities for damages resulting from oil pollution;
3) Provide funding for natural resource damage assessments;
4) Implement a fund for the payment of compensation for such damages; and
5) Establish an oil pollution research and development program.

The Secretary of Interior is given the authority over offshore facilities and associated pipelines for all Federal and State waters, including responsibility for spill prevention, oil-spill contingency plans, oil-spill containment and clean-up equipment, financial responsibility certification, and civil penalties. The US Coast Guard is responsible for enforcing vessel compliance with the OPA.

Clean Water Act

The Federal Water Pollution Control Act (FWPCA) of 1972, as amended, is commonly referred to as the CWA. It authorizes the USEPA to issue National Pollutant Discharge Elimination System (NPDES) permits to regulate discharges into waters of the US. USEPA, Region 9, has jurisdiction for NPDES permitting of the proposed project. Section 403 addresses impacts from discharges on marine resources. To receive a discharge permit, proposed discharges must not result in an unreasonable degradation of the marine environment. Section (c) lists guidelines for determining degradation of ocean waters. In May 2000, President Clinton issued his Marine Protected Area Executive Order that required EPA to use its existing authority under the Clean

Water Act to protect ocean waters. Discharges from Platform Irene into ocean waters must comply with Section 403 of the CWA.

Marine Plastic Pollution Research and Control Act

The Marine Plastic Pollution Research and Control Act (MPPRCA) of 1987 implements Annex V of the International Convention of the Prevention of Pollution from Ships (MARPOL). Fixed and floating platforms, drilling rigs, manned production platforms, and support vessels operating under a Federal oil and gas lease are required to develop waste management plans and to post placards reflecting discharge limitations and restrictions.

Coastal Zone Management Act (CZMA)

In accordance with the CZMA and the Coastal Zone Act Reauthorization Amendments of 1990 (CZARA), OCS oil and gas exploration and development activities affecting the coastal zone must be carried out consistent with California's Coastal Management Program (CCMP) (i.e., the policies of the California Coastal Act). The CCMP sets forth objectives, policies, and standards regarding coastal uses and resources.

Coast Guard Regulatory Authority

Primary responsibility for the enforcement of US maritime laws and regulations falls upon the US Coast Guard. The Coast Guard's responsibilities for regulating activities on the OCS, the continental shelf, and in ports and harbors, as applicable to the proposed action, are presented in Title 33 CFR, chapters 1-199; Title 43 USC section 1331; Title 46 USC, Parts A and B; and OPA 90. The Coast Guard is responsible for managing and regulating provisions for safe navigation of vessels in US waters, as well as the enforcement of environmental and pollution prevention regulations. As such, the Coast Guard provides for the regulation and enforcement of hazardous working conditions on the OCS, for the management and regulations of measures for pollution prevention in territorial waters, and for ensuring the implementation of the Oil Pollution Act signed in August 1990 (OPA 90) and the Marine Plastics Research and Control Act (MPPRCA) provisions.

5.5.2.2 State and Local Laws and Policies

California Endangered Species Act (CESA)

The California Endangered Species Act (CESA) generally parallels the main provisions of the Federal Endangered Species Act and is administered by the California Department of Fish and Game (CDFG). Under the CESA, an "endangered species" is defined as a species of plant, fish, or wildlife that is "in serious danger of becoming extinct throughout all, or a significant portion of its range" and is limited to species or subspecies native to California. The CESA establishes a petitioning process for the listing of threatened or endangered species. The CDFG is required to adopt regulations for this process and establish criteria for determining whether a species is endangered or threatened.

The CESA prohibits the "taking" of listed species except as otherwise provided in State law. Unlike its Federal counterpart, the CESA applies the take prohibitions to species petitioned for listing (i.e., State candidates). CDFG code defines "take" as "hunt, pursue, catch, capture, or kill, or attempt to hunt, pursue, catch, capture, or kill." State lead agencies are required to consult with the CDFG to ensure that any action it undertakes is not likely to jeopardize the continued existence of any endangered or threatened species or result in destruction or adverse modification of essential habitat. A “lead agency” as defined under the CEQA as the public agency that has principal responsibility for carrying out or approving a project that may have a significant effect on the environment.

California Environmental Quality Act (CEQA)

The goal of CEQA (Pub. Res. Code §21000 et seq.) is to develop and maintain a high-quality environment. It directs California's public agencies to identify the significant environmental effects of their actions and avoid or mitigate those significant environmental effects, where feasible. The California Resources Agency administers CEQA. CEQA requires that an Environmental Impact Report (EIR) be prepared for any major project that may cause significant impacts to the environment. If it is determined that a project has no significant environmental effects and is not exempt from CEQA, then the lead agency must adopt a Negative Declaration to that effect. The purpose of an EIR is to provide State and local agencies and the general public with detailed information on the potentially significant environmental effects which a proposed project is likely to have, to list ways in which the significant environmental effects may be minimized, and indicate alternatives to the project.

California Coastal Act of 1976, Public Resources Code Section 30000 et seq.

The California Coastal Act (Division 20 of the Public Resources Code, Section 30000, et seq.) became law in 1976 as a means of providing a comprehensive framework for the protection and management of coastal resources. The main goals of the Act are to protect and restore coastal zone resources; assure balanced and orderly utilization of such resources; maximize public access to and along the coast; assure priority for coastal-dependent and coastal-related development; and encourage cooperation between state and local agencies toward achieving the Act’s objectives.

The Coastal Act contains policies to guide local and state decision-makers in the management of coastal and marine resources. The policies are organized into chapters by topics relating to public access; recreation; marine environment; land resources; and development. The act also contains provisions for development controls and land-use entitlements for certain types of new development in the coastal zone.

The Coastal Act, which is administered by the California Coastal Commission, also identifies protective measures for nearshore marine resources. For example:

Coastal Act section 30230 states:

> *“Marine resources shall be maintained, enhanced, and where feasible, restored. Special protection shall be given to areas and species of special biological or economic significance. Uses of the marine environment shall be carried out in a manner that will sustain the biological productivity of coastal waters and that will maintain healthy populations of all species of marine organisms adequate for long-term commercial, recreational, scientific, and educational purposes.”*

Coastal Act section 30231 states:

> *"The biological productivity and the quality of coastal waters, streams, wetlands, estuaries, and lakes appropriate to maintain optimum populations of marine organisms and for the protection of human health shall be maintained and, where feasible, restored through, among other means, minimizing adverse effects of waste water discharges and entrainment, controlling runoff, preventing depletion of ground water supplies and substantial interference with surface water flow, encouraging waste water reclamation, maintaining natural vegetation buffer areas that protect riparian habitats, and minimizing alteration of natural streams."*

Coastal Act section 30260 states:

> *"Coastal-dependent industrial facilities shall be encouraged to locate or expand within existing sites and shall be permitted reasonable long-term growth where consistent with this division. However, where new or expanded coastal-dependent industrial facilities cannot feasibly be accommodated consistent with other policies of this division, they may nonetheless be permitted in accordance with this section and Sections 3026l and 30262 if (1) alternative locations are infeasible or more environmentally damaging; (2) to do otherwise would adversely affect the public welfare; and (3) adverse environmental effects are mitigated to the maximum extent feasible."*

California Regional Water Quality Control Board (RWQCB)

The RWQCB determines permit requirements on a case-by-case basis. They require a Waste Discharge Permit (WDP) if the action creates problems or if the action becomes permanent. The duration and size of a project are important factors and concerns may include the amount of water quality degradation.

The Water Quality Control Plan developed by the Central Coast RWQCB established water quality standards for the region. The plan incorporates the California Ocean Plan that establishes standards to protect the quality of ocean waters for use and enjoyment by the people of California. The Ocean Plan, which is administered by the State Water Resources Control Board, is reviewed periodically to guarantee that the current standards are adequate and are not allowing degradation to marine species or posing a threat to public health (State Water Resources Control Board, 2005~~1990~~). In general, Chapters I, II, and III establish discharge standards for non-point discharges to marine waters. For example:

The California Ocean Plan, Chapter I, Beneficial Uses states:

> *"The beneficial uses of the ocean waters of the State that shall be protected include industrial water supply, water contact and non-contact recreation, including aesthetic enjoyment, navigation, commercial and sport fishing, mariculture, preservation and enhancement of Areas of Special Biological Significance, rare and endangered species, marine habitat, fish migration, fish spawning and shellfish harvesting."*

The California Ocean Plan, Chapter II, Water Quality Objectives states, in part, in Section E Biological Characteristics, that:

1) *Marine communities, including vertebrate, invertebrate, and plant species shall not be degraded.*

2) *The natural taste, odor, and color of fish, shellfish, or other marine resources used for human consumption shall not be altered.*

3) *The concentration of organic materials in fish, shellfish or other marine resources used for human consumption shall not bioaccumulate to levels that are harmful to human health.*

The California Ocean Plan, Chapter III, General Requirements for Management of Waste Discharge to the Ocean states, in part, in Section B that waste discharged to the ocean must be essentially free of the following:

1) *Material that is floatable or will become floatable upon discharge.*

2) *Settleable material or substances that may form sediments which will degrade benthic communities or other aquatic life.*

3) *Substances that will accumulate to toxic levels in marine waters, sediments or biota.*

4) *Substances that significantly decrease the natural light to benthic communities and other marine life.*

5) *Materials that result in aesthetically undesirable discoloration of the ocean surface.*

The Basin Plan for the Central Coast Region identifies the following existing beneficial uses for the coastal waters contained within the project area (RWQCB, 1994).

Water Contact Recreation (REC-1): Uses of water for recreational activities involving body contact with water, where ingestion of water is reasonably possible. These uses include, but are not limited to, swimming, wading, water skiing, skin and scuba diving, surfing and fishing.

Marine Habitat (MAR): Uses of water that support marine ecosystems including, but not limited to, preservation or enhancement of marine habitats, vegetation such as kelp, fish, shellfish, or wildlife such as marine mammals and shorebirds.

Shellfish Harvesting (SHELL): Uses of water that support habitats suitable for the collection of filter-feeding shellfish such as clams, oysters, and mussels, for human consumption, commercial, or sport purposes. This includes waters that have in the past, or may in the future, contain significant shell fisheries.

Ocean Commercial and Sport Fishing (COMM): Uses of water for commercial or recreational collection of fish, shellfish, or other organisms including uses involving organisms intended for human consumption or bait purposes.

Wildlife Habitat (WILD): Uses of water that support terrestrial ecosystems including, but not limited to, preservation and enhancement of terrestrial habitats, vegetation, wildlife (e.g., mammals, birds, reptiles, amphibians, invertebrates), or wildlife water and food sources.

Lempert-Keene-Seastrand Oil Spill Prevention and Response Act

Under the Lempert-Keene-Seastrand Oil Spill Prevention and Response Act, the California Department of Fish and Game became the State lead agency in spill response and created the Office of Oil Spill Prevention and Response (OSPR). The Act requires that persons causing a spill begin immediate cleanup, follow approved contingency plans, and fully mitigate impacts to wildlife. Under an Interagency Agreement with OSPR, the California Coastal Commission (CCC) operates an oil spill program and maintains an oil spill staff. Before and after a spill, CCC staff are involved in review and comment to both State (e.g., OSPR) and Federal (e.g., U.S. Coast Guard) agencies on contingency plans and regulations related to marine vessels, marine facilities and marine vessel routing.

Santa Barbara County

The coastal reaches adjacent to the Tranquillon Ridge Field fall under the jurisdiction of SBC. Consequently, SBC is one of the agencies responsible for reviewing project actions including integration of policies established by the California Coastal Act. An Energy Division was established within the SBC's Planning and Development Department to participate in environmental reviews and permitting of major oil and gas development projects. The Division also ensures that oil and gas projects are developed and operated in compliance with the permit conditions imposed by the County decision-makers, including the Board of Supervisors and the Planning Commission. As an example, Condition N-1 of PXP's Final Development Plan for the Point Pedernales Project requires that PXP contribute annually to the Coastal Resource Enhancement Fund (CREF) as compensation for unmitigable significant visual resource impacts and oil spill impacts to biological resources. The CREF was developed by the County and designed to be used for enhancement of coastal recreation, aesthetics, tourism and/or environmentally sensitive resources through yearly fee assessments which are currently distributed annually through a competitive proposal process. The County also considers other applicant contributions and mitigations in developing the CREF assessments, if such measures would have a direct correlation to the affected resource(s).

5.5.3 Significance Criteria

Changes or impacts to marine biological resources will be considered significant if the impacts cause:

- Adverse change to or the reduction in a population or habitat used by a State or Federally listed endangered, threatened, regulated or sensitive species. Any "take" of a listed species shall be considered significant.
- Adverse change to or the reduction in a population or habitat of a species that is recognized as biologically or economically significant in local, State, or Federal policies, statutes or regulations.
- Adverse change in community composition or ecosystem relationships for species that are recognized for scientific, recreational, ecological, or commercial importance.
- Any impedance of fish or wildlife migration routes that lasts for a period that significantly disrupts migration.
- Any alteration or destruction of habitat that prevents re-establishment of biological communities that inhabited the area prior to the project.

- Long-term (more than one year) loss or disturbance to biological communities or to ecosystem relationships.

Changes in marine biological resources caused by the project will be considered significant if the changes:

- Last longer than a month for toxicological impacts (e.g., those caused by oiling events or toxicity caused by the discharge of drilling muds and cuttings).
- Last longer than one year for impacts caused by habitat disturbance (e.g., discharge of drilling fluids and construction activities) or habitat reduction (e.g., damage to hard-bottom structures during construction activities).

In addition, the analysis considers the following County of Santa Barbara Thresholds of Significance:

An impact is considered significant if it would:

- Substantially reduce or eliminate species diversity or abundance
- Substantially reduce or eliminate quantity or quality of nesting areas
- Substantially limit reproductive capacity through losses of individuals or habitat
- Substantially fragment, eliminate, or otherwise disrupt foraging areas and/or access to food sources
- Substantially limit or fragment range and movement (geographic distribution or animals and/or seed dispersal routes)
- Substantially interfere with natural processes, such as fire or flooding, upon which the habitat depends.

5.5.4 Impact Analysis for the Proposed Project

Impact #	Impact Description	Phase	Residual Impact
MB.1	Oil spills from the project may impact benthic and intertidal organisms, fish, marine mammals, marine birds, and marine turtles. Oil spills from the project may impact plankton.	*Increase Throughput* *Extension of Life*	*Class I* *Class III*

The degree of impacts to marine biota from an oil spill will depend on several factors. Among them are the location, volume, rate, and type of oil that is spilled; amount of weathering, evaporation, and dispersion of oil in the water column and shoreline; and the amount of oil that is contained and cleaned immediately after the spill. Oil effects to marine biota include mortality or can be sublethal by inhibiting growth and reproduction. Oil can also bioaccumulate in certain marine species and can also cause histological damage, alter physiology and metabolism, and decrease reproductive capacity (NRC, 1985). In the section that follows, impacts that could occur to marine biota from an oil spill in the project area are described. It should be recognized that much of the discussion is based on studies documenting spills, such as the Exxon Valdez spill, that are much larger than a spill that would be expected from the proposed project. The impacts of the large spills are included because they are the best studied and also because they demonstrate the worst case of impacts that can occur from an oil spill. Realistically, the impacts of a worst case spill from the proposed project are likely to be similar to those of the 1997 Torch/Platform Irene spill. The primary impacts of the Torch/Platform Irene spill were to seabirds, sand and gravel beach habitats and rocky intertidal shoreline habitats (Torch/Platform Irene Trustee Council 2006). The impact classification is derived from the application of the significance criteria provided in Section 5.5.3.

The maximum oil spill volumes estimated for the Tranquillon Ridge Project are 7,900 bbls for the offshore pipeline and 4,500 bbls for Platform Irene (see Table 5.1.29). Oil spill modeling was conducted as part of this EIR, and the results are shown in Appendix G. The oil spill modeling showed that in the event of a spill, the likely areas that would be impacted would be the area from Point Sal to Point Conception. This is consistent with what was observed for the 1997 oil spill from the Point Pedernales oil emulsion pipeline. The MMS Oil Spill Risk Analysis (OSRA) modeling showed that there was a greater than 40 percent chance that the area from Point Sal to Point Conception would be affected in the event of a worst case oil spill.

The modeling also showed that under certain weather and ocean conditions, portions of the western Channel Islands (San Miguel and Santa Rosa Islands) could be affected by an offshore oil spill. The MMS OSRA modeling results showed that there was less than a 30 percent change that oil would impact the western most Channel Islands. These impact probabilities were based upon the assumption that no action was taken to contain the spill, and therefore represent very conservative estimates of impact areas.

The remainder of the impact discussion focuses on the types of impacts that could occur to marine organisms in the event of an oil spill from the project. In addition, clean up operations can have impacts to the marine environment. The potential impacts associated with various types of oil spill clean up methods are discussed in detail in Appendix E of this EIR.

Benthic Communities

Spilled oil that is not recovered by mechanical means, or does not evaporate or wash ashore, is eventually incorporated into bottom sediments. Oil can reach the benthos or ocean floor by the formation of nonbuoyant residues, adsorption onto particulate matter, or through incorporation in the food chain by ingestion and subsequent sinking of fecal pellets (Jordan and Payne, 1980). Contrary to oil in water that can dilute and disperse, oil that is incorporated into sediments can become a chronic pollutant source. It can be ingested by benthic organisms or incorporated into organisms by contact with gill membranes.

Adsorption onto particulate matter is a common pathway for the transport of oil to the benthic environment (Jordan and Payne, 1980). The amount of oil deposited on the seafloor after a spill can vary in relation to the nature and quantity of suspended particulate matter in the water column. For example, the large amounts of oil that settled to the benthic environment following the Santa Barbara Channel oil spill in 1969 were attributed to the mixing and adsorption of oil into sediments (Kolpack, 1971; McAuliffe et al., 1975). Mixing and absorption of oil into sediment during the *Amoco Cadiz* spill (1978) off the Brittany coast, the *Tsesis* spill (1980) in the Baltic Sea, and the *IXTOC I* blowout (1979) in the Gulf of Mexico also contributed to the sinking and accumulation of oil in bottom sediments (Hess, 1978; Boehm, et al., 1980; Boehm and Fiest, 1980).

Although no direct impacts to subtidal abalone have been documented in any spill, including the Torch/Platform Irene spill, there is some potential that spilled oil could impact abalone that might be in the project area. The most likely area to be impacted in the event of an oil spill is from Point Sal to Point Conception. Red abalone would be the only ~~benthic~~ subtidal species that would likely occur in this area. There is also a chance that a project-related oil spill could reach the northern Channel Islands where abalone populations potentially could be affected. As is true for the mainland coast between Point Sal and Point Conception, red abalone is the subtidal species most likely to be affected if oil from a project spill reached San Miguel or Santa Rosa Islands. However, there is a slight chance that a spill that reached the Channel Islands could affect the Federal endangered white abalone. White abalone have not been observed at San Miguel or Santa Rosa Islands but suitable habitat for this species does occur there (Hobday and Tegner 2000). Smothering is the most common cause of mortality for abalone and would be limited to direct contact with weathered tar balls from the oil spill (MMS 2001). During past oil spill responses, oil has collected in the nearshore kelp canopies. Recovery of the oil has been hindered by the kelp because it has fouled skimming equipment, thereby requiring the kelp to be cut to recover the oil. This has amplified the impacts to marine organisms by increasing the exposure of kelp-associated organisms to released oil (CDFG, 2002). Given that a number of abalone species are kelp-associated organisms, clean up of spilled oil in nearshore kelp areas could increase the impacts to abalone.

The severity of oil spill impacts to benthic organisms can vary according to the degree of weathering of the oil and the location of the spill. Impacts to benthos are more likely to occur from a nearshore pipeline break and in shallow waters in general. Oil that sinks quickly before it has weathered would contain appreciable amounts of toxic hydrocarbons that may be accumulated by benthic organisms resulting in mortalities. Weathered oil, although not as toxic, could potentially smother sessile organisms associated with hard substrates. Hence, the potential impacts of spilled oil to benthic communities are considered to be significant because if spilled oil did become incorporated into sediments or if abalone were impacted, the impacts could persist for more than a year.

Intertidal

When spilled oil reaches the shoreline or intertidal zone, it becomes concentrated in a narrow zone. Because of the shallow water depth, hydrocarbon concentrations can reach toxic levels. Thus, intertidal biota are exposed to higher concentrations of oil for a longer period of time than most other marine organisms. Impacts to the intertidal biota can be caused by physical smothering and hydrocarbon toxicity.

The severity and duration of impacts to the intertidal biota is, in large part, a function of the biological and geomorphologic characteristic of the shoreline habitat. Based on the shoreline ranking system for oil spill sensitivity developed by Gundlach and Hayes (1978), habitats with a low energy regime are characterized by high biological populations, high oil residence time, and high sensitivity to oil. Recovery of such areas can take several years. Gravel and mixed sand/gravel beaches have relatively small biological populations, but oil impacting these habitats is resistant to cleaning. Despite intensive cleanup and remediation of gravel and cobble beaches oiled by the *Exxon Valdez* spill in Prince William Sound, oil remained in sediments eight years after the spill (Hayes and Michel, 1998).

Shoreline types in the project area consist primarily of sandy beaches and rocky intertidal habitat. The Torch pipeline spill of September 28, 1997 oiled approximately forty miles of coastline, stretching from the northern end of Minuteman Beach to Boat House. Approximately 100 acres of sandy beach were disturbed by oiling and cleanup operations. In addition, another 263 acres of sandy beach were very lightly oiled (less than or equal to 10 percent oiling by area), but were relatively undisturbed by heavy equipment during cleaning operations (OSPR 1999). Following the spill, certain beaches and rocky areas were not cleaned due to inaccessibility (SBC, 1997, 2001). Two intertidal sites (Boat House and Stairs) within the exposure zone were surveyed by Raimondi et al. (1999) after the spill for the MMS. There was no confirmation that spilled oil had reached the two intertidal sites and no confirmation that spilled oil had caused significant biological changes at either site. At the Boat House study site, there were no significant changes in percent cover for four common species (the algae, *Endocladia* and *Pelvetia*, and mussels and barnacles). At the Stairs study site, a statistically significant decrease that coincided with the spill was detected for barnacles. However, the decrease was not attributed to the oil spill because no visible oil was observed at the study site (Raimondi et al., 1999). In addition, a statistically significant decrease in barnacles was found during the same sampling period at another Santa Barbara County site located well outside the spill zone (Raimondi et al., 1999). At Point Arguello just north of the Boat House, large amounts of fresh oil and tar were observed on rocks throughout the middle to lower intertidal zone. "Sticky globs of tar were seen on black abalone and seastars. Tar covered the respiratory pores of some abalone. Based on these observations, some mortality may have occurred" (Raimondi et al., 1999; OSPR, 1998). <u>In addition to occurring along the mainland coast in the project area, black abalone occur on the Channel Islands. If a project-related oil spill reached San Miguel and/or Santa Rosa Islands, this declining species could potentially be affected.</u>

For rocky intertidal habitats, the agencies that conducted the Natural Resources Damage Assessment of the 1997 spill reported very "light oiling" in numerous locations throughout the rocky intertidal habitat within the 40-mile oil exposure zone. While it is true that "light oiling" can occur from natural seeps, the NRDA agencies attributed the light oiling to the spill.

In addition to the direct impacts of oil, clean up operations can have additional impacts on intertidal communities (MMS, 2005). For example, hot water wash used in cleanup of the Exxon Valdez spill had adverse impacts on the intertidal area. In another example, Rolan and Gallagher (1991) found that for the Esso Bernicia spill in the Shetland Islands of Great Britain, the biological communities of the rocky intertidal returned to nearly normal populations within 1 year, with the exception of areas that had been mechanically cleaned. Cleaned areas still had not recovered after 9 years.

After the 1969 Santa Barbara Channel oil spill, effects to several intertidal species were recorded. Impacts included smothering of barnacles (*Chthalamus fissus*), mortality of surfgrass (*Phyllospadix torreyi*) and algae such as *Hesperophycus harveyanus*, and reduced reproduction in the stalked barnacle (*Pollicipes polymerus*) (Straughan, 1971). There may have been impacts on additional intertidal biota, but the lack of pre-spill data and heavy rains and flooding at the time hampered a complete impact assessment (Straughan, 1971). Should an oil spill reach shore, intertidal biota could experience significant impacts because changes could occur in the community composition that would last more than one year. The probability of an oil spill from the project pipeline land falling in the Point Arguello region is discussed in Appendix G, Oil Spill Trajectory Analysis.

Plankton

Laboratory studies, field enclosure studies, and field studies conducted during oil spills have shown that oil spills have measurable effects upon marine phytoplankton and zooplankton. Impacts to phytoplankton include mortality, reduced growth and reduced photosynthesis. In some instances, growth stimulation has occurred at low hydrocarbon concentrations (Spies, 1985). Impacts to zooplankton include mortality and sublethal effects such as lowered feeding and reproductive rates and altered metabolism. Early life stages such as eggs, embryos, and larvae of zooplankton are considered to be more susceptible than adults to oil spills because of their higher sensitivity to toxicants and higher likelihood of exposure to oil at the surface of the ocean. The lethal and sublethal effects of oil on plankton depend on the persistence of sufficiently high concentrations of petroleum hydrocarbons in the water column. The effects would most likely be short-lived because of the limited residence time of oil in the water column in an open ocean environment. Most of the components of crude oil are insoluble in seawater and because oil floats on the sea surface, impacts to the water column would be limited. Aromatic hydrocarbons, such as benzene and toluene, ~~that~~ which are considered to be most toxic to marine life evaporate quickly as the spill weathers in the marine environment. Other weathering processes such as spreading, dissolution, dispersion, emulsification, photochemical oxidation, and microbial degradation decrease the volume of spilled oil and increase the viscosity and specific gravity of the spilled oil. Also, the short generation time of plankton would result in short term recovery and preclude long term effects. Impacts are considered to be adverse but not significant.

Fish

The majority of fish data regarding oil effects have been obtained in the laboratory. Field data generally consist of reports on fish kills and some measurements of sublethal effects. Field data regarding effects other than massive fish kills are extremely difficult to obtain because of the difficulty in quantitatively sampling fish populations. In laboratory studies, typical responses to toxic hydrocarbon concentrations include a brief period of increased activity, followed by reduced activity, twitching, narcosis, and eventually death (NRC, 1985). Sublethal effects include histological damage, altered physiological and metabolic patterns, decreased growth and reproduction, and vulnerability to disease (NRC, 1985). Among fishes, benthic species are more sensitive than pelagic species and intertidal species are the most tolerant (Rice et al., 1979). In general, early life stages of fishes such as embryos and larvae are more sensitive to petroleum hydrocarbons than later life stages.

Although sensitivity is demonstrated in laboratory studies, only in a few instances have adverse effects been observed on fish following major oil spills. Examples include the *Florida* spill off West Falmouth, Massachusetts, and the *Amoco Cadiz* spill off the coast of Brittany. Sublethal effects were also documented in both cases. In the *Florida* spill, killifishes from contaminated marshes had a lower rate of lipogenesis than their counterparts from uncontaminated sites (Sabo and Stegeman, 1977). In the *Amoco Cadiz* spill, a large number of histological abnormalities were noted in estuarine flatfish (*Pleuronectes platessa*) (Haensly et al., 1982). According to Straughan (1971), there were no indication of fish kills or other evidence of effects on fishes from the Santa Barbara Channel blowout in 1969. No impacts to fishes were documented from the Torch/Platform Irene oil spill, the previous spill with impacts most likely to be similar to a spill from the proposed project.

Although damage to fish populations following oil spills has rarely been documented, several species were severely impacted from the *Exxon Valdez* spill. Juvenile pink (*Oncorhynchus gorbuscha*) and sockeye (*O. nerka*) salmon were directly affected by the spill in 1989 and their eggs may have been affected through 1993 (Spies, 1996). Exposure to oil was documented by oil in the stomachs of salmon fry, measurements of polynuclear aromatic hydrocarbons (PAH) in salmon fry, and by increases in P450[1] and bile hydrocarbon metabolites in Dolly Varden (*Salvelinus malva*) (Spies, 1996). Impacts on growth were shown for pink salmon, Dolly Varden, and cutthroat trout (*O. clarki*) even though changes in food availability were not detected (Spies, 1996).

An estimated 40 to 50 percent of the egg biomass of the Pacific herring (*Clupea pallasi*) deposited within Prince William Sound was exposed to oil during developmental stages (Brown et al., 1996). The resulting 1989 year class of herring showed sublethal effects such as premature hatch, low weights, reduced growth, and increased morphologic and genetic abnormalities (Brown et al., 1996). The 1989 year class recruiting as 4-year old adults in 1993 was one of the smallest cohorts observed in Prince William Sound, and it returned to spawn with an adult herring population that was reduced by approximately 75 percent (Brown et al., 1996).

Adult fish, due to their mobility, may be able to avoid or minimize exposure to spilled oil. However, there is no conclusive evidence that fish will avoid spilled oil (NRC, 1985). Egg and larval stages would also not be able to avoid exposure to spilled oil. Because fish species can be economically important and because long-term loss can result from an oil spill, impacts to fish are considered to be significant.

Marine Mammals

Marine mammals that could be impacted by an oil spill include cetaceans (whales and dolphins), pinnipeds (seals), and fissipeds (sea otter). Animals that are unable to avoid contact with oil could be impacted by fouling, inhalation, or ingestion that could result in sublethal or lethal effects. Reviews on the effects of oil on marine mammals have been conducted by Geraci and St. Aubin (1982, 1985, 1990), Englehardt (1983), and the NRC (1985).

It is unlikely that oil spills would substantially threaten cetaceans (NRC, 1985). However, a massive oil spill could result in fouling of the baleen, toxicity from ingestion, respiratory difficulties, and irritation of membranes that contact oil. Although some observations suggest that cetaceans would avoid surfacing in oil slicks by staying submerged longer, other observations suggest that some cetaceans may not avoid oil-covered waters (NRC, 1985). Oil does not tend to cling to cetacean skin as it does to pelage of other marine mammal species. Geraci and St. Aubin (1982) suggest that oil fouling of cetacean skin and accidental ingestion would not reach toxic levels and that any irritation would likely be temporary. Should an oil spill occur in the project area, the species that would most likely be impacted, depending on the time of year, are the gray whale, blue, humpback, and fin whales. The blue, humpback, and fin whales are presently listed as endangered species.

[1] Cytochrome P450, a family of over 60 enzymes the body uses to break down toxins and make blood.

Although seals apparently have the ability to detect and avoid oil slicks (USDOI, 1983), Cowell (1979) reported that breeding seals swam through oil to reach rookery beaches during the breeding season. Davis and Anderson (1976) found no differences in the growth and mortality of oiled and unoiled grey seal pups. LeBoeuf (1971) reported similar results from the 1969 Santa Barbara Channel blowout with elephant seal pups. According to Brownell, (1971) and Geraci and Smith (1977), no deaths to marine mammals could be linked to the 1969 spill. However, wildlife survey capabilities at that period of time were less extensive than they are today. Geraci and Smith (1977) reported that surface contact with oil has a much greater impact on seals than absorption of the petroleum. In controlled experiments, seals that were exposed to floating oil resulted in reversible eye damage (in the wild, "reversible" eye damage could significantly affect an animal's ability to function). The project area occurs in a foraging area for pinnipeds (e.g., California sea lions). Also, oil spill trajectory analyses indicate that oil released from a spill in the project area can come ashore exposing adults and subadults to potentially long term lethal and sublethal effects. Particularly severe effects could occur if oil contacted pinniped colonies on San Miguel Island. The northern fur seal colony on San Miguel Island would be especially vulnerable to an oil spill because the San Miguel island population represents a separate stock of this species and because fur-bearing marine mammals are particularly susceptible to the physical effects of oil. Onshore clean up activities would also be extremely disruptive to pinniped populations. DeLong (1975) reported that seals disturbed on San Miguel Island retreated into the sea and did not return for several days. Such impacts could result in significant behavior impacts should a spill occur during the breeding season (Davis and Anderson, 1976). Trampling or abandonment of pups could result in mortality.

A marine mammal (sea otters and pinnipeds) injury assessment survey was conducted during the 1997 Point Pedernales spill. The purpose of the survey was to assess the degree of exposure and oil-related injuries to sea otters and pinnipeds from the spill. With respect to pinnipeds, it was concluded that pinnipeds were exposed to oil from the spill and that one female California sea lion likely died as a result of oil exposure (CDFG et al., 1998). The conclusion for the death from oil exposure was based on oil in the mouth and coat of the dead animal, the oil on the dead animal was a positive match with the spilled source oil, and the animal had distended pulmonary alveoli and edema that is often associated with exposure to petroleum hydrocarbons (CDFG et al., 1998). CDFG et al. (1998) concluded that pinnipeds in the proximity of the spill most likely were exposed to oil and suffered sub-lethal injuries.

Sea otters, a threatened species, have steadily increased in numbers in the Purisima Point to Point Conception area and have extended their range eastward. A breeding colony also resides in the Purisima Point region. An oil spill, should one occur, has the potential to impact a high number of sea otters in this region.

Oil spill impacts to sea otters are well documented (Costa and Kooyman, 1982; Siniff, 1982; Davis et al., 1988). After exposure to oil, death usually results from either an increase in metabolic rate, hypothermia, or inhalation of volatile vapors (Geraci and Williams, 1990). An oil spill that occurs during the non-breeding season (November to May) could kill more sea otters than one that occurs during the breeding season (June to November). This is because during the non-breeding season, sea otters extend their range and have been reported as far east as Carpinteria. The range of this southernmost group, which consists mostly of young males, retracts to the center of the range north of Point Arguello during the breeding season from June to November. In any case, sea otters in the Purisima Point to Point Conception region are vulnerable to oil spills. Of the 364 oiled otters that were processed at oiling centers following the *Exxon Valdez* oil spill, only 53 percent were rehabilitated (Geraci and Williams, 1990). Nearly 1,000 sea otter carcasses were recovered within a few months of the *Exxon Valdez* spill (Loughlin et al., 1996). Total sea otter fatalities from this spill were estimated at 2,800 (Garrott et al., 1993).

No sea otter fatalities were reported in the project area from the September 1997 spill. Field observations from the marine mammal injury assessment survey suggested possible oil exposure to sea otters but there were no indications of anomalies or change in the number of sea otters in the area. There were no direct observations of oiled sea otters or death in the spill area. It is likely, however, that sea otters in the proximity of the spill were exposed to oil and may have experienced sub-lethal effects, but they did not experience acute effects or death as a result of the spill (CDFG et al., 1998).

In addition to sea otters, the harbor seal *Phoca vitulina* and the Steller sea lion *Eumetopias jubatus*, were impacted by the *Exxon Valdez* oil spill (Loughlin et al., 1996). Tissue from animals found dead in spill areas contained elevated levels of hydrocarbons. Also, population declines for both species were noted in Prince William Sound after the oil spill (Loughlin et al., 1996).

In summary, the marine mammal species that occur in the project area exhibit varying degrees of vulnerability to oil spills. Impacts can be caused either by oil contact or by ingestion. There is evidence that cetacean species may avoid contact with oil at sea; however, pinniped species and sea otters could potentially suffer lethal and long term sublethal effects resulting in significant impacts. Onshore cleanup activities, depending on location, could disrupt pinniped haul-out and rookery areas and could also result in a significant impact.

Marine Birds

Oil spills pose a significant threat to marine birds. Bourne (1976), Holmes and Cronshaw (1977), Brown (1982), Hunt (1985), NRC (1985) and others have reviewed oil spill effects on marine birds. Due to the migratory nature of many bird species, the severity of oil spill impacts on marine birds would depend on the time of the year, the species present, and their numbers. According to Holmes and Cronshaw (1977), these factors accounted for the relatively low number of marine birds (3,600) that were killed during the Santa Barbara blowout in 1969.

Oil on a marine bird clogs and damages the fine structure of the feathers which is responsible for maintaining water repellency and heat insulation. In addition to coating by oil, marine birds are also subject to chronic, long term effects from oil that remains in the environment. For example, small amounts of oil on a bird's plumage may be transferred to eggs during incubation. This contact has been shown to kill developing embryos (Albers, 1978; Szaro et al., 1978). Birds can also consume oil through their diet or through preening which results in physiological stress (Holmes and Cronshaw, 1977; Brown, 1982).

An oil spill that affects bird habitat (e.g., shoreline, marshes) can pose long-term problems (Albers, 1984). Birds have been observed to leave an area that has been affected by a spill (Hope et al., 1978; Chapman, 1981). Such movement away from their habitat could result in severe impacts should it occur during the breeding or nesting season (Albers, 1984).

The endangered brown pelican and the California least tern could be severely impacted by an oil spill. The brown pelican, an offshore forager, is highly susceptible to oil ingestion and fouling. Effects of oil contamination on the overall population could be significant as the species continues to recover from the effects of DDT contamination. The California least tern is a coastal inhabitant but forages offshore. It also is highly susceptible to oil spills because it skims the ocean surface for prey with occasional diving. Should a spill reach the coastal habitat, significant mortality also can occur. In addition, the State threatened Xantus' murrelet, a species of alcid, breeds on the Channel Islands and occurs in the project area in the vicinity of Platform Irene. Oil pollution has been listed as a major threat to Xantus' murrelets (Burkett et al 2003). Alcids appear to be extremely susceptible to oiling and often comprise the bulk of seabird mortality from oil spills in western North America (Carter et al 2000). A spill from Platform Irene could contact individuals of Xantus' murrelet that might be foraging in the vicinity of the platform. In addition, under certain weather and ocean conditions, portions of San Miguel Island, where Xantus' murrelets breed, could be contacted by oil from a Platform Irene spill. Impacts to these species are considered to be significant and not mitigable.

The Torch spill released an estimated 162 to 1,242+ barrels of crude oil (County of Santa Barbara, 2001a)[2]. Surveys for dead or live oiled seabirds that were beached were conducted from September 29 to October 5, 1997. A summary of the oiled birds that were found during the surveys is shown in Table 5.5.14. Of the 140 birds that were collected during the survey, 122 were either dead or died after sampling. It needs to be noted that the 140 birds collected during the surveys is a conservative number of oiled birds. For example, it does not include birds that may have been missed by the surveyors, dead or oiled birds that drifted to sea or beyond the survey area and did not reach the shoreline, or birds that reached the shoreline in the survey area but were removed by scavengers or predators such as vultures and coyotes. Various methods and studies were used to estimate the number of affected birds missed by the survey for each of the areas listed above. Ford Consulting (1998) estimated that 353 birds died from oiling and were not recovered during the surveys. The total number of birds impacted by the 1997 Torch spill has been estimated at 635 to 815 (OSPR, 1998).

Table 5.5.14 A Summary of the Oiled Birds Recovered from the Torch Pipeline Spill (from Ford Consulting, 1998)

Species	Dead	Live-Died	Live-Released	Total
Red-Throated Loon	1	1	0	2
Pacific Loon	1	0	0	1
Common Loon	0	1	0	1
Eared Grebe	0	1	2	3
Western Grebe	6	5	0	11
Brandt's Cormorant	34	1	1	36
Common Murre	28	21	0	49
Rhinoceros Auklet	1	0	0	1
Pigeon Guillemot	1	0	0	1
American Coot	1	0	0	1
Sooty Shearwater	2	0	0	2
Black-Vented Shearwater	1	0	0	1
Brown Pelican	0	0	2	2

[2] The CDFG's official spill volume from the Torch Point Pedernales pipeline was 163 barrels (bbl) (CDFG, 1989). The 1,242 bbl estimate is from Santa Barbara County and is based on additional factors that were not taken into account with the CDFG official number. These include drainage from the landward side of the pipeline, oil between pigs 1 and 2, and oil behind pig 2.

Table 5.5.14 A Summary of the Oiled Birds Recovered from the Torch Pipeline Spill (from Ford Consulting, 1998)

Species	Dead	Live-Died	Live-Released	Total
Western Gull	3	0	7	10
Heermann's Gull	2	0	2	4
California Gull	1	0	2	3
Ring-Billed Gull	1	0	0	1
Elegant Tern	0	1	0	1
Northern Phalarope	1	1	0	2
Sanderling	1	0	2	3
Unknown	5	0	0	5
Total	90	32	18	140

Although deaths from oiling for the endangered brown pelican and snowy plover were not reported from the spill, Ford Consulting (1998) estimated that 14 brown pelicans and 13 snowy plovers were fouled by oil from the pipeline rupture. Because an oil spill could have long-term impacts on bird populations and could impact listed species, an oil spill could have significant impacts on marine birds.

Marine Turtles

Oil spills can adversely affect marine turtles by toxic external contact, toxic ingestion or blockage of the digestive tract, disruption of salt gland function, asphyxiation, and displacement from preferred habitats (Vargo et al., 1986; Lutz and Lutcavage, 1989). Turtles may become entrapped by tar and oil slicks and rendered immobile (Witham, 1978; Plotkin and Amos, 1988). Small juvenile turtles are particularly vulnerable to contacting or ingesting oil because the currents that concentrate oil spills also form the debris mats in which they are found (Carr, 1980; Collard and Ogren, 1990). Contact with oil may not cause direct or immediate death but cumulative sublethal effects, such as salt gland disruption or liver impairment could impair the marine turtle's ability to function effectively in the marine environment (Vargo et al., 1986; Lutz and Lutcavage, 1989).

Although oil spills can adversely affect marine turtles, this species rarely occurs in the project area. In the 13-year period from 1982-1995, fourteen strandings were reported on SBC beaches. Between 2001 and 2005, there were only two reported strandings of marine turtles on SBC beaches. Although they are rare in the project area, oil spill impacts to marine turtles are considered to be adverse and significant because of their threatened and endangered status.

Mitigation Measures

Although the technology has improved in recent years, complete containment and cleanup of an oil spill at sea is nearly impossible. The effectiveness of offshore containment and cleanup equipment and procedures is largely dependent on the type of oil, volume, sea state (e.g., swells, wind waves, chop, etc.), and proper use of the equipment. A major spill from the Point Pedernales offshore facilities would likely result in shoreline contamination, regardless of the sea and weather conditions, due to the proximity of land and prevailing winds and currents in the area.

With respect to wind wave conditions, the containment effectiveness of booms begins to lessen at a significant wave height of 2 feet. Above 2 feet, booms and skimmers are ineffective;

however, it is likely that a slick would be dispersed and mixed into the water column. For long-period swell conditions, booms and skimmers can retain effectiveness in significant wave heights greater than 2 feet. High winds can cause some type of booms to lay over, allowing oil to splash and flow over the boom. High winds can also affect the deployment or shape of the deployment and thus the containment effectiveness of the boom. For more information on oil spill cleanup methods see Appendix E.

MB-1a The November 2004 Core OSRP and July 2005 Supplement shall be updated to incorporate changes in platform activities that result from the proposed project. For example, the plan shall incorporate detailed response procedures for marine oil spills resulting from a blowout if wells producing the Tranquillon-Ridge field are expected to be free flowing. Worst-case discharge scenarios shall be updated accordingly. In addition, lessons learned from the cleanup of the 1997 oil spill shall be incorporated into the Response Plan. The efficacy of various containment and cleanup techniques applied during the 1997 spill shall be evaluated with regard to potential future spills. Hindcasts of the observed oil-spill trajectory shall be used to improve site-specific trajectory models. Potential ecological damage resulting from cleanup techniques applied in 1997 shall be discussed. <u>The updated OSRP shall specifically detail methods to reduce impacts to sea otters and pinniped colonies should a spill occur. This discussion shall include methods for preventing oil from reaching pinniped colonies and places where otters congregate, and detailed protocols for handling and rehabilitation of oiled otters and pinnipeds. Specific methods to avoid disturbing pinniped colonies during cleanup activities shall be identified. The updated OSRP shall also re-evaluate the toxicity of Corexit 9527 and its inclusion as a potential dispersant for the Tranquillon Ridge project, based on current information.</u>

The personnel and training sections of the OSRP shall be updated to identify training requirements for all personnel who would respond to oil spills. At a minimum, new personnel shall be trained immediately in the overall operational aspects of oil spill response, including the proper use of all equipment that would be utilized in spill response. Annual training for all personnel shall also be included in the OSRP. The annual training shall include training in the operation of new equipment that may be utilized in oil spill response, retraining in the operation of existing equipment, and review of the oil spill response requirements that are identified in the OSRP.

Most of the County's western coast is considered relatively unaffected by oil deposition. A UCSB researcher who studies sandy beach invertebrates uses Surf Beach for a clean control as a counterpoint to her studies conducted at South Coast beaches (CDFG, 1999). However, some portions of the shoreline within the potential spill zone of Platform Irene and the Point Pedernales Pipeline are subject to tar deposition (i.e., tarballs) from natural offshore oil seeps. The amount, variability, and chemical fingerprint of the tar normally present in the intertidal zone in the spill zone are not well documented. If oil from an offshore spill reached the shore, it could be difficult to differentiate residues of the spilled oil from any naturally occurring tar, particularly in areas of light oiling. Because the baseline condition of the shore is not well documented, determining the extent of shoreline clean-up needed to restore the environment to prespill conditions following a spill can be problematic. After the 1997 spill, the question of whether any of the oil on the beach was from sources other than the spill came up in several contexts. Lack of a full understanding of baseline oiling conditions could result in either inadequate oil removal or excessive disturbance to intertidal environments from an overly aggressive clean-up effort.

MB-1b In order to provide a baseline for shoreline clean-up efforts in the event of a spill, the applicant shall contribute to the funding of a program to document the amount, variability, and chemical fingerprint of the tar normally present in the intertidal zone within the potential oil spill zone. The program shall include both visual observations and chemical sampling of tar along five segments (equal to one mile each) of shoreline located within the area of the coast located between Point Sal and Point Conception. The program shall continue for as long as Tranquillon Ridge Field development is occurring or until analysis of the collected data indicates that extension of sampling will not significantly increase understanding of the pattern of tar deposition and improve documentation of the baseline.

The amount of tar shall be estimated and its chemical fingerprint determined, based on the shoreline tar sampling protocol used by the U.S. Geological Survey (USGS) in its MMS-funded study "Submarine Oil and Gas Seeps of the Southern Offshore Santa Maria Basin, California" (2001 to 2004). The program shall document visual observations and chemical sampling. The samples shall be analyzed for chemical fingerprint in the USGS laboratory. If analysis by the USGS is not available, another comparable fingerprinting method may be substituted. Annual cost of the applicant's contribution to this program shall not exceed $100,000. The program shall be developed in cooperation with Santa Barbara County's Department of Planning and Development, and shall be coordinated by the Energy Division. The Energy Division shall evaluate the program on an annual basis in coordination with staffs of the California State Lands Commission, California Coastal Commission, Department of Fish and Game Office of Spill Prevention and Response, and Minerals Management Service. If new information indicates that changes to the methodology or protocol would improve the efficiency or accuracy of determining baseline oiling conditions, the County shall revise the program. Any revisions to the program shall not cause the annual cost to the applicant to exceed the $100,000 limitation.

MB-1c PXP shall make a yearly contribution not to exceed $90,000 (in 2007 dollars) toward establishing a marine mammal and sea bird impact mitigation fund. The funding shall be used for either facilities construction or operating costs associated with the rescue and rehabilitation of injured marine mammals and sea birds. This yearly contribution shall be credited toward PXP's annual Coastal Resource Enhancement Fund (CREF) assessment for environmentally sensitive resource impacts, as currently required by Condition N-1 of PXP's Final Development Plan for the Point Pedernales Project.

Mitigation Measure TB-14 would also apply to this impact to address impacts to marine birds from an oil spill. Mitigation Measure OWR-2, which covers the leak detection system, would also serve to reduce the likelihood of a spill to the marine environment.

Residual Impact

Because there are limitations to thorough containment and cleanup of an offshore oil spill, *significant and not mitigable impacts (Class I)* remain for benthic organisms, intertidal communities, marine mammals, marine turtles, and marine birds.

Impact #	Impact Description	Phase	Residual Impact
MB.2	The discharge of drilling muds and cuttings from Platform Irene may potentially impact marine organisms in the project area.	*Drilling phase*	*Class III*

Benthic Organisms

Drill cuttings discharged and deposited beneath Platform Irene may potentially bury benthic organisms. Also, even small quantities of drilling muds deposited on the seafloor could adversely affect certain benthic organisms.

Drilling muds, which consist primarily of barite and bentonite clays, are used in the drilling process for a variety of purposes. Drilling muds cool and lubricate the drill bit and drill string, seal and control hydrostatic pressure in the hole, and they remove cuttings from beneath the drill bit and transport them to the surface. Cuts are the chips and small fragments of drilled rock brought to the surface by the flow of drilling mud as it is circulated. In accordance with NPDES permit requirements on the west coast of the US, only water-based drilling muds can be discharged to the ocean. Drilling muds that are contaminated or contain mineral or diesel oil will be transported to shore for disposal and not discharged into the ocean. The estimated 30-well program would consist of drilling operations for approximately 60 to 90 days per well, with an occasional short break between wells. The permitted limit under the NPDES general permit is 105,000 barrels per year of muds and 30,000 barrels per year of cuttings. Assuming that drilling operations start in the third quarter of 2007, the following muds and cuttings volumes are expected to be discharged per year. These volumes are well below the NPDES muds and cuttings limits noted.

- 2007, starting 3rd quarter: Muds 28,000 bbls; cuttings 3,000 bbls
- 2008: Muds 52,000 bbls; cuttings 7,000 bbls
- 2009: Muds 48,000 bbls; cuttings 5,000 bbls
- 2010: Muds 46,000 bbls; cuttings 5,000 bbls

The deposition of drill cuttings could impact benthic organisms by smothering or by altering the character of the sediments near the drill site. The magnitude and extent of cuttings accumulation would, however, depend on a number of variables including water depth, type of formation that is drilled, hydrodynamic regime, and the volume of cuttings that are discharged. Zingula and Larson (1977) reported that the typical size for a cuttings pile in the Gulf of Mexico was approximately 50 m in diameter and up to 1 m in height. Where currents are strong, as in the project area, there may be no visible buildup of cuttings on the seafloor (Ray and Meek, 1980; BNEML/WHOI, 1983).

Only a few studies have examined the effects of burial of benthic organisms by drill cuttings or drilling muds. Hence, results from studies of benthic impacts from disposal of dredged materials have been used to infer impacts from the deposition of drill cuttings (Maurer, 1983). The results indicate that the effects of burial largely depend on the thickness of the material deposited, and the burrowing capabilities and the tolerances of the benthic organisms. In the Santa Barbara Channel, Zingula and Larson (1977) reported that piles of cuttings were colonized by motile benthic organisms from surrounding areas within a few months after completion of drilling.

Sessile organisms such as sea pens were subject to burial within 100 m of a drilling unit and their absence persisted up to a year after the completion of drilling (EG&G, 1982).

In 1996, Platforms Hazel, Hilda, Hope, and Heidi (collectively known as the 4H platforms), located in the eastern portion of the Santa Barbara Channel were removed. The platforms were located in water depths ranging from 29 m (95 feet) to 46 m (150 feet). Beneath the platforms, shell mounds ranged from 6.7 to 8.5 m (20 to 28 feet) in height and from 56.9 to 70.1 m (185 to 230 feet) in width. The estimated volume of material within the mounds ranged from 5,352 to 10,704 m^3 (7,000 to 14,000 yd^3) (de Wit, 2001). The shell mounds beneath each of the four platforms had similar physical characteristics and were comprised of three distinct layers: 1) an upper layer of shell hash approximately 0.3 to 2.1 m (1 to 7 feet) thick, 2) an intermediate layer of drill cuttings approximately 0 to 5.5 m (1 to 18 feet) thick, and 3) the underlying natural seafloor sediments (de Wit, 2001). The shell hash layer was composed of mussel, clam, and barnacle shells with varying amounts of clay infilling while the intermediate layer consisted of drilling muds and cuttings. Pockets of oil sheen or petroleum odor were also present within this layer.

Modeling results provided in Appendix D indicate that the majority of drilling muds and cuttings will be deposited close to Platform Irene. Results indicate that over half of the muds will be deposited within 1.7 km and over 80 percent will be deposited within 3.6 km of the Platform. Less than 0.4 percent is expected to travel farther than 10 km before being deposited on the seafloor. Based on the depositional pattern, drilling muds plumes would seldom enter into State waters. This is partially due to the along-shore alignment of ocean currents in the area.

The discharge of drilling muds and cuttings from the proposed project would affect soft-bottom benthic organisms in the immediate vicinity of Platform Irene. Benthic organisms, especially those within 1.7 km of the Platform, could potentially be buried beneath the accumulation of discharged materials. The discharge of muds and cuttings would be gradual and occur over a 7 to 8 year period. Rock outcrops have not been identified in the vicinity of Platform Irene so it is very unlikely that drill cuttings from discharges would impact hard-bottom organisms. Because the area affected by the deposition is small relative to the entire project area, the impacts caused by the discharge of drillings muds and cuttings are considered to be adverse but not significant.

Drilling muds are a mixture of barite, bentonite clays, and a variety of special purpose additives. In laboratory studies, both lethal and sublethal effects on benthic organisms have been noted from thin layers (1 mm) of drilling muds layered over natural sediments or a mixture (0.3 percent) of drilling muds with natural sediments (NRC, 1983; Neff, 1983, 1985). The different species that have been tested have shown varying tolerances to drilling muds. Some species were unaffected by mixtures up to 20 to 30 percent or more of drilling muds and natural sediment. It is not known if the effects that have been noted are due to toxicity of drilling muds components, altered sediment properties, or a combination of these factors.

Based on chemical analyses of sediments collected at shell mounds beneath the 4H platforms in the Santa Barbara Channel, deWit (2001) reported that ERL (Effects Range Low, after Long et al., 1995; chemical concentrations below ERL are not expected to have an effect) concentrations were exceeded for all analyses except for Mercury (Hg), DDT, and PCBs. At one of the platforms (Hazel), sediments exceeded the ERL or ERM (Effects Range Medium, after Long et al., 1995; chemical concentrations at which effects are expected to occur) for 14 analytes.

Elutriate bioassay testing indicated that sediment from Platform Hazel was toxic to mysid shrimp. The 96-hour LC50 (lethal concentration resulting in 50 percent mortality) was 48.57 percent meaning that sediment elutriate diluted to 48.57 percent killed 50 percent of the test organisms. The toxicity was thought to be due to the synergistic effects of high sediment concentrations for several trace metals and organic compounds (de Wit, 2001). Species associated with the shell mounds included the bat star *Asterina miniata*, the gorgonian coral *Lophogorgia chilensis*, the coral *Coenocyathus stearnsii*, and the anemone *Corynactis californica*.

Because there are inherent problems with laboratory toxicity studies, several field studies have been conducted near drilling operations to evaluate impacts of discharged drilling muds or cuttings on benthic organisms. According to Carney (1985), most of these studies have had design limitations whereby subtle impacts could not be resolved from natural, background variability. In general, when impacts have been reported on benthic organisms, they have been noted only in the immediate vicinity of recent drilling operations where visual, physical, or chemical evidence of persistent accumulation of drilling muds or cuttings are observed. However, in other studies, impacts were not detected even though drilling muds were present in sediments (BNEML/WHOI, 1983; Nekton and KLI, 1984).

The effects of drilling muds and cuttings on hard-bottom biota were studied in detail during the comprehensive California Monitoring Program (CAMP), Phases II and III, which lasted from 1986 to 1995. CAMP, sponsored by MMS, monitored discharges from Platforms Harvest, Hidalgo, and Hermosa. The conclusion provided at the end of the study was that platform discharges had not caused changes to nearby hard-bottom communities (Diener and Lissner, 1995). There was no consistent pattern of response for a single taxon over the three habitat types (deep high and low relief, and shallow low relief). Statistical tests concluded that the cumulative distribution of responses could have been due to chance alone (Diener and Lissner, 1995). Based on the results of CAMP Phases II and III, and the absence of hard-bottom habitat in the project area, adverse impacts to hard-bottom epibiota due to drilling muds and cuttings are not expected to occur.

Based upon laboratory bioassay studies, de Wit (2001) reported toxic sediments beneath Platform Hazel located in the eastern Santa Barbara Channel. Toxic effects were not observed in the field. The toxic sediments that were tested in the laboratory were collected in shell mounds measuring 56.9 to 70.1 m (185 to 230 feet) wide and 6.7 to 8.5 m (20 to 28 feet) in height. Should toxic impacts to benthic organisms occur beneath Platform Irene, they are expected to be restricted to depositional areas having high concentrations of drilling muds. Because of the highly localized nature of potential impacts, they are considered adverse but not significant.

Drilling muds and cuttings would be discharged from Platform Irene in accordance with the guidelines established in the general National Pollutant Discharge Elimination System (NPDES) permit. The permit does not allow the discharge of drilling muds containing free oil or oil-based fluids or toxic additives or "pills" (e.g., diesel oil). Also, based on the results of toxicological tests, the permit also contains limits on the levels of mercury and cadmium in drilling muds that can be discharged on the OCS. These metallic contaminants appear only in barite (barium sulfate), a weighting agent commonly used in drilling mud. Additionally, under the new NPDES permit, the platform operator is required to demonstrate compliance with limits for both drilling fluids and cuttings by conducting and reporting the results of drilling fluids bioassays for each mud system that is used and discharged on the OCS. The NPDES permit requires monitoring from 0-80 percent of total well footage using bioassays if a non-generic mud is used. If a generic mud (EPA approved and certified) is used in the 0-80 percent well footage zone, no bioassay is required, but monitoring is still required via sheen testing, receiving water sheen, foam and floating solids, recording volumes discharged, barite cadmium and mercury analyses. ~~Drilling fluid samples for the bioassays are to be taken at the time that maximum well footage is reached for each generic mud system used[3] and discharged.~~ The NPDES general permit specifies that drilling mud and cuttings should be sampled when drilling progresses to at least 80 percent of the permitted well footage as this is the point at which most or all of the additives of a mud system will have been added which, in turn, would be the point at which the toxicity level for any given mud system would be at its highest. Other monitoring required during the drilling of any well includes static sheen testing, observations of the receiving water (the ocean) for sheen and foam and floating solids, recording the volumes of drilling muds and cuttings which have been discharged, and the number of days discharge of both muds and cuttings occurred.

PXP also implements mud bioassay testing. As stated by PXP, "if the bioassay results indicate a problem, the fluid is not discharged and is either injected in a well at the facility or sent to shore for disposal. Any drilling fluids (muds or cuttings) fall in the well drilling fluids category of NPDES Permit CAG 280000. Work over activities fall into another category: Well Treatment, Completion and Workover Fluids (WTCF). These WTCF generally are not discharged separately. Oil and grease testing is required for WTCF as well as receiving water observations and volumes. Generally, these fluids are commingled with production or injected into a disposal well."

Because of the strict toxicological requirements that must be satisfied, significant impacts are not expected to occur.

Plankton

The discharge of drilling muds and cuttings from Platform Irene would increase turbidity in the water column and decrease water clarity in waters adjacent to the platform. Elevated turbidity or an increase in suspended matter could inhibit photosynthesis by phytoplankton and could interfere with zooplankton interactions. Discharged muds, however, tend to dilute rapidly and to concentrations that are much lower than those known to be toxic to marine organisms in 96-hour bioassays (NRC, 1983). Plankton in waters close to Platform Irene may be affected by the discharge of drilling muds. However, due to the intermittent discharge of drilling muds, the shunting system, the rapid descent of most mud solids to the bottom, and the rapid dispersion of suspended mud in the water column, any impact should be localized and transient.

Field studies have shown that water clarity may be affected up to 2000 meters (m) from a drill site for surface bulk drilling muds discharges. However, shunting of discharges to 150 feet below the ocean's surface would significantly diminish the dispersion of drilling muds. Since plankton are carried by currents, those in the receiving waters near the discharge would be exposed to elevated turbidity for as long as it takes for the plume to disperse to background levels. Petrazzuolo (1983) and Neff (1985) have reported that this dispersion would occur within a few minutes to a few hours. Hence, the impacts to plankton are considered to be adverse but not significant.

[3] Maximum well footage is the depth that you can drill to with a given drilling mud.

Fish

The discharge of drilling muds could affect fishes due to increased turbidity or to the toxic properties of certain mud components. Most of the fishes would probably avoid the plume during a bulk discharge. Drilling muds contain some toxic components; however, the concentrations that fish could be exposed to in the water column, except within a few meters of the discharge pipe, would be lower than levels known to kill fishes in laboratory studies. Also, the duration of the exposure from any particular discharge would be much shorter than any exposure used in laboratory bioassays (typically 96 hour). Sublethal effects (e.g., altered metabolism, physiology, behavior) can occur at lower concentrations and over shorter exposure intervals that those known to cause mortality (Petrazzuolo, 1983). Also, larval fish can be more sensitive to drilling muds than adult fish. Because they are planktonic, they would not be able to minimize exposure by swimming out of a drilling muds plume. Although drilling muds discharges are unlikely to result in mortality to adult fish in the discharge area, sublethal impacts to fish larvae can occur. However, the number of fish affected would be small because muds discharges are discrete events of short duration.

Drilling muds and cuttings could potentially affect fishes by ingestion of prey that have bioaccumulated toxins from the discharges. However, the biological assessment for the General NPDES permit for OCS operations in southern California concluded that direct toxicity to fish or their food base should be minimal (SAIC, 2000a,b). Because all discharges resulting from the project will be required to meet NPDES water quality criteria that are designed to protect biological resources, potential impacts to fish are expected to be adverse but not significant.

Marine Mammals

The discharge of drilling muds and cuttings would increase turbidity in the vicinity of Platform Irene. Reduced visibility may interfere with foraging activity in the vicinity of the platform after a bulk discharge. Reduced water clarity could also reduce the feeding ability of visually foraging species such as the California sea lion.

The impacts to marine mammals due to the ingestion of prey contaminated with trace metals are not well documented. However, studies of trace metals and their occurrence in food chains in the vicinity of ocean outfalls indicate that the potential for bioaccumulation in marine mammals is low (Schafer et al., 1982). The impacts to marine mammals due to the discharge of drilling muds and cuttings would be adverse but not significant.

Marine Birds

The discharge of drilling muds and cuttings would result in turbid waters in the vicinity of Platform Irene. Marine birds may avoid feeding in the area because of the reduced visibility of prey. Drilling muds discharges, however, would be intermittent and the resulting plume would be localized. Muds discharges would not reduce the ability of marine birds to find sufficient prey and feed because the birds would be able to forage in adjacent areas. Also, because little or no bioaccumulation of metals is anticipated in fishes, marine birds should not accumulate metals from drilling discharges. Impacts to marine birds from the discharge of drilling muds and cuttings are therefore considered to be adverse but not significant.

Intertidal Habitats

Discharges of drilling muds and cuttings from drilling activities are unlikely to have any impacts on intertidal organisms because of the distance of the discharge point to shore and because of the direction of the prevailing currents. Should discharges be transported shoreward, drilling muds would be substantially diluted by the time they reached shore. Dilution, combined with the short duration and intermittent nature of muds discharges and the low toxicity of drilling muds, make the possibility of adverse impacts to the intertidal habitat very unlikely. Hence, impacts to the intertidal habitat from the discharge of drilling muds and cuttings are considered to be adverse but not significant.

Mitigation Measures

MB-2 The shunt depth (150 feet below the sea surface) for the discharge of drilling muds and cuttings shall be continued for the proposed project. The shunt depth shall be stated in the development plan that is submitted to MMS prior to drilling.

Residual Impact

Drilling muds discharged from Platform Irene would dilute rapidly and the dispersion would be limited to a few kilometers (km) from the platform. The majority of drill cuttings would be deposited in the immediate vicinity of the platform. The impacts to marine organisms caused by the discharge of drilling muds and cuttings are considered to be *adverse but not significant (Class III)*.

Impact #	Impact Description	Phase	Residual Impact
MB.3	Discharge of produced water from Platform Irene may potentially impact marine organisms in the project area.	*New Operations*	*Class III*

Produced water refers to the water resulting from the oil and gas extraction process. It is the largest single source of material discharged during oil and gas operations. Typically, produced water consists of formation water, injection water, and chemicals that are used in the oil and water separation process (USDOI/MMS, 1996).

Produced water generally represents a small portion of the initial fluid extracted from a well. As a reservoir becomes depleted, however, the amount of formation water extracted generally increases. Constituents found in produced water are iron, calcium, magnesium, sodium, bicarbonate, sulfates, and chloride. Produced water can also contain entrained petroleum hydrocarbons, including the lighter BTEX and PAH fractions, and measurable trace metal concentrations. Relative to ambient water, produced water contains increased organic salts and trace metals, decreased dissolved oxygen, and is higher in temperature. These same properties may adversely affect the marine environment (USDOI/MMS, 1996).

In the proposed project, approximately 40,000 barrels per day (~~bbls~~bpd) of produced water could be piped to Platform Irene for disposal after it is processed and treated onshore at the LOGP. The temperature of the produced water plume discharged from Platform Irene would be 120 to

160°F[4]. The applicant is authorized to discharge to the ocean from the platform in accordance with the General NPDES Permit. A part of the produced water that would be shipped to Platform Irene may still be injected into Point Pedernales reservoir wells, as is currently the operation, to enhance current Point Pedernales production. Offshore water injection would be conducted as authorized by the MMS. During processing, all impurities would be removed from the produced water in accordance with NPDES requirements prior to it being piped to Platform Irene for disposal. ~~Also, the salinity and temperature (after treatment) of the produced water from Platform Irene, when it is discharged, will be approximately equal to ambient seawater (Brandsma, 2001).~~ The salinity after treatment of the produced water will be approximately equal to ambient seawater, but the temperature will be 160° F, well above ambient seawater temperature. Modeling studies conducted for Platform Irene indicate rapid dilution (10-fold within 10 m and ~~50~~over 200-fold within 100 m) (Brandsma, ~~2001~~2007a). Because of the rapid rate of dilution, impacts to plankton, seabirds, marine mammals, and benthic organisms are not expected to occur. Results of produced water modeling are provided in Appendix F.

The modeling, discussed in Appendix F, shows that all constituent concentrations are far below the NPDES permit limits at distances well within the 100-meter mixing zone. NPDES permit limits apply to the edge of the 100-meter mixing zone. Most constituents regulated under the NPDES discharge permit are diluted below the permit limits at distances within 10 meters of the discharge point for the maximum centerline concentration. The distances are less than 10 meters based upon average concentrations in the plume. However, for this analysis, centerline concentrations have been used because they represent a "worst-case" scenario. The volume of the plume that would be above the current NPDES permit limits can be conservatively estimated, assuming the plume is a cone that is 10 m long with a radius of 10 m at its widest point. This would give a volume of approximately 1,000 cubic meters.

In the center of the plume, less than 10 meters from the discharge point, arsenic, copper, mercury, silver, and zinc concentrations could exceed the NPDES limits established for receiving waters. For the NPDES general permit, limits are either Federal limits or California Ocean Plan limits, whichever is more restrictive. For arsenic and copper, the California Ocean Plan limits of 1 ug/l and 3 ug/l respectively are more stringent than the Federal limits of 36 and 3.1 ug/l. Therefore, the California Ocean Plan limits apply. California Ocean Plan limits apply at the end of the zone of initial dilution, which would be equivalent to the NPDES general permit 100-m mixing zone. However, ongoing initial dilution rapidly reduces these concentrations and all constituent concentrations are reduced to levels below the receiving-water limits at distances beyond 10 m of the discharge point.

Although the discharge values for produced water constituents would be within NPDES permit limits, concerns remain regarding the toxicity and the bioaccumulation potential of the fish populations that occur beneath the platforms. Love et al. (1999) surveyed the rockfish aggregations residing at mid-water and bottom levels beneath Platform Irene. At Platform Irene, the young-of-the-year (YOY) rockfish, and adults and subadults of copper and vermilion

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[4] The current temperature of oil/water emulsion from Platform Irene well production ranges from 170 to 185 degrees F. The emulsion is sent via pipeline to LOGP for processing/separation and the produced water leaves LOGP at a temperature of approximately 145 degrees F and arrives at Platform Irene for discharge between 115 to 130 degrees F. The exact temperature of future discharges will vary as conditions, configurations, flow rates, and other variables change, but with the blending of the fluids, the maximum temperature of the discharge stream is estimated at 160 degrees F. At this temperature, PXP discharges are compliant with the NPDES permit.

rockfishes were the most abundant species. The YOY rockfish consisted of bocaccio, blue, olive, yellowtail, and widow rockfish. During the three-year survey, a total of 21 species of fish were observed at Platform Irene. Platform Irene was also unique among the platforms surveyed in that large numbers of juvenile lingcod were associated with the platform (Love et al., 1999).

Since the produced water would be discharged at a mid-water depth (180 [55 m] feet below the sea surface) and will not impinge upon bottom waters (Brandsma, ~~2001~~ 2007a), only the mid-water population of fishes is of potential concern. Generally, Love et al. (1999) found that mid-water depths (>20-30 m) were dominated by YOY and juvenile (<10 cm) rockfishes. Rockfishes larger than 20 centimeters (cm) were rarely seen in the mid-water. Rockfish YOY, widow rockfish, bocaccio, and blacksmith were the dominant fish observed at mid-water depths at Platform Irene.

Although the produced water will be discharged at a relatively high temperature of 160^{o} F, dilution will be extremely rapid. Modeling shows that with a discharge at 160^{o} F, the elevation in temperature would be less than 10^{o} F within 10 m of the discharge and would reach ambient temperatures within 50 m of the discharge (Brandsma, 2007b). Fishes likely would avoid the elevated temperatures in the immediate discharge area.

For the most part, the effects of produced water on marine biota, especially Pacific coast fish, have not been studied. However, studies conducted on Gulf of Mexico species provide insights to possible impacts to the biota in the project area (Neff, 1997). Because chemical concentrations within produced water from different regions can vary dramatically, the applicability of most of these tests to the California OCS is questionable, but they do provide information on possible impacts to project area organisms. In bioassay studies conducted on brown and white shrimp, barnacles, and crested blennies exposed to formation water from the Buccaneer Field in Texas, the blennies were the least sensitive species and the white shrimp the most sensitive with an LC50 value of 37,000–92,000 ppm (Rose and Ward, 1981). In an earlier study conducted by Zein-Elden and Keney (1978) using produced water treated with biocides, the LC50 values (96 hr) for juvenile white shrimp ranged from 1,750–6,500 parts per million (ppm). Because the produced water was treated with biocides, these values represent a conservative estimate of the toxicity to the juvenile white shrimp.

Studies conducted by Anderson *et al*. (1974) and Rice *et al*. (1976, 1979, 1981) examined the effects of the water soluble fractions of oil and treated ballast water on marine organisms. Although not produced water, these studies provide insight into the acute lethal toxicity of produced water. Rice *et al*. (1979), using the water soluble fractions of Cook Inlet crude oil on Alaskan species, found that the sensitivity increased from lower to higher invertebrates and then to fish. LC50 values for pelagic fish and shrimp were 1–3 ppm. Benthic fish, crabs, and scallops had LC50 (96 hr) values of 3–8 ppm for total aromatic hydrocarbons. Using ballast water toxicity tests with shrimp and fish, Rice *et al*. (1981) reported an LC50 range of 0.8–3.2 ppm for total aromatic hydrocarbons.

In studies on the accumulation of hydrocarbons in the water column on sediments, fish, benthos, plankton, and the fouling community in the Buccaneer Field in Texas, Middleditch (1981) found that measurable quantities of hydrocarbons occur only very near to the platform. No concentration gradient was detected. There was no evidence of hydrocarbon accumulation in the biota except for the platform fouling community.

Based on the dilution modeling performed by Brandsma (~~2001~~ 2007a), produced-water concentrations that approach these toxicity levels will only occur within 10 m of the discharge point, if at all. Moreover, elevated constituent concentrations will occur only within the limited volume of water occupied by the discharge plume. The cross-sectional dimension of the plume 20 m from the discharge point is on the order of 30 m or less, and at a cross-sectional distance of 10 meters, the concentrations are all less than the current NPDES discharge limits. Due to the very limited water volume occupied by the plume and mobile nature of fish, it is highly unlikely that fish will remain stationary within the effluent plume for considerable periods of time. Hence, toxicological effects on these fish species are not expected to occur.

Neff (1997), in his review of produced water in the Santa Barbara Channel, summarized the potential effects of arsenic, barium, cadmium, mercury, phenols, and BTEX and PAH compounds to marine organisms. His conclusions were as follows:

- Arsenic concentrations in produced water are low. In some cases, concentrations can be 30 times higher than that found in seawater. However, a five-fold dilution would decrease the concentration in the receiving water to less than the marine chronic water quality criterion. Two studies of arsenic bioaccumulation in bivalves and fish in the Gulf of Mexico indicated that arsenic is not accumulated above background concentration ranges.
- Barium concentrations in produced water are high, relative to seawater (greater than 1,000 times). However, mixing with sulfate-rich seawater rapidly dilutes high barium concentrations and results in precipitation of dissolved barium as barite that has low solubility in seawater (ca. 50 ug/L). The solubility of remaining dissolved barium sulfate of 1.05 x 10-10 is below the threshold of toxic effects for marine organisms. Tissue concentrations of barium in soft tissues in fish and bivalves located adjacent to produced water discharges in the Gulf of Mexico were not different from reference samples.
- Cadmium concentrations from offshore California produced water can range from below the detection limit to 15 ug/L. Although the levels can be higher than background levels of 0.02 ug/L, rapid dilution lowers these concentrations to background concentrations. Cadmium levels in produced water are always below the acute water quality criterion of 43 ug/L and usually below the chronic criterion of 9 ug/L. There was no evidence from bioaccumulation studies in the Gulf of Mexico that organisms exposed to produced water with these cadmium concentrations would accumulate cadmium above background levels.
- Mercury, predominately in the inorganic form, occurs in produced waters from offshore California in very low concentrations. In some cases, they may be 20–50 times higher than that found in seawater. However, it is expected to dilute rapidly in receiving water. There was no evidence in studies conducted in the Gulf of Mexico that mercury would bioaccumulate in marine organisms over background levels.
- The phenols and alkylated homologues present in produced waters dilutes rapidly after discharge. A combination of photolysis and microbial degradation remove these compounds from the water column at a rate as high as 5 percent an hour. In Gulf of Mexico studies, there was no indication that phenol was bioaccumulated from produced waters.
- Although BTEX compounds may attain high concentrations in produced waters, these compounds are known to dilute so rapidly that instances of exceeding water quality criteria for these compounds near produced water discharges are rare. There are also no documented cases that confirm that contamination levels in marine organism tissue represent a risk to human health.

- There is limited PAH concentration data for produced water from offshore California. However, levels up to 25 ug/L have been observed. This concentration is on the low end of produced waters observed in the Gulf of Mexico. PAHs are efficiently bioaccumulated by marine organisms and while there is evidence of accumulation in organisms exposed to produced waters in the Gulf of Mexico, there is no indication of deleterious impacts to receptor organisms or for biomagnification in the food chain to harmful levels.

Marine Resource Specialists (2005) conducted a study of the effect of produced water discharges to federally managed fish species along the California Outer Continental Shelf. The study focused on the toxicity and bioaccumulation potential of produced-water discharges to the fish populations that live within the 100 meter mixing zone beneath oil and gas platforms because those fishes could be exposed to contaminant concentrations higher than the limits in the NPDES general permit. The study consisted of three components: (1) determination of threshold concentrations for chemical constituents that could potentially induce lethal, sublethal and bioaccumulative effects in marine fishes, (2) determination of nominal and peak chemical concentrations in produced water samples collected from platform discharges along the Pacific OCS, and (3) modeling of near-field plume dispersion to determine maximum contaminant concentrations within the 100 meter mixing zone. At Platform Irene, young-of-the-year rockfishes were the fishes most likely to be exposed to produced water plumes. The quantitative exposure assessment found only one produced-water constituent, undissociated sulfide, that had the potential to impact federally managed fish species along the Pacific Outer Continental Shelf. However, the likelihood of an actual substantive adverse impact on federally managed finfish is probably minimal because there were several significant limitations associated with the sulfide assessment that resulted in an unduly conservative evaluation of fish exposure.

Section 2.3.1.2 of this EIR presents the typical composition of the current produced water before treatment. These data represent samples taken at the onshore facility without treatment for ocean discharge and before the planned upgrades to the produced water treatment system. Contaminants in produced water before treatment exceed NPDES general permit limits. Any produced water discharged to the ocean as part of the proposed project would be in compliance with the limits in the NPDES general permit.

The rates of dilution and dispersion of chemicals in produced water following discharge to the ocean are influenced by the density of the produced water relative to that of the receiving water, discharge depth, vertical stratification of the water column, and current speed and direction. Produced waters from offshore the Point Arguello Field have salinities lower than ambient seawater and temperatures much higher. Hence, produced water will be ~~slightly~~ buoyant and dilute rapidly within a short distance from point of discharge (Neff, 1997). Also, surface and near-surface current velocities are generally more than 10 cm/sec and often exceed 30 cm/sec, ensuring rapid mixing of produced water plumes with ambient sea water. At Platform Irene, ~~100-fold dilution will occur within 10 m to several thousand fold~~over 200-fold dilution would occur within 100 m from the point of discharge. Hence, fish residing beneath the platforms are not expected to bioaccumulate the chemical constituents found in the discharged produced water.

Based on the available information, produced water effects to marine organisms and fish occurring beneath Platform Irene are considered adverse but not significant.

Mitigation Measures

MB-3 The shunt depth (180 feet [55 m] below the sea surface) for the discharge of produced water shall be continued for the proposed project. The shunt depth shall be stated in the development plan that is submitted to MMS prior to drilling.

Residual Impact

Because of the rapid dilution and dispersion of produced water discharged at Platform Irene, impacts to marine organisms are considered to be *adverse but not significant (Class III)*.

Impact #	Impact Description	Phase	Residual Impact
MB.4	Noise caused by drilling activities may potentially disturb marine mammals and marine birds in the project area.	*Drilling*	*Class III*

Noise caused by drilling equipment, vessels, and helicopters may potentially disturb marine mammals and seabirds. The degree of noise impact would depend on the sound level and the proximity of the emitted sound to the marine mammals and marine birds. The existing noise levels at Platform Irene are presented in Section 5.5.1.7.

~~The literature indicates that while marine mammals hear man-made noises and sounds generated by construction activities, there is no indication that they are affected deleteriously by the noise (Richardson et al., 1995).~~

Above-water Noise

Noise associated with drilling operations or from helicopters that may service drill rigs or platforms could disturb foraging seabirds near the drilling sites or helicopter flight corridors. The occurrence of helicopter and supply boat noise would increase with additional trips, but the peak noise levels occurring as a result of each trip would not change. Helicopter noise is around 75 dBA for an overflight at 1,000 feet above the water. Low-flying aircraft, especially helicopters, can frighten large numbers of feeding or resting seabirds or short-term diving activities as they pass nearby, resulting in a flight response. However, the localized disturbance is likely to be very brief. The current Marine Biology Impact Reduction Plan for the Point Pedernales Project requires a minimum flight altitude of 1,000 feet as well as avoidance of sensitive habitat areas. The low-frequency sounds emitted during drilling operations have not been shown to displace marine birds from offshore areas along the California coast (USDOI/MMS, 1996).

Underwater Noise

Marine mammals may be disturbed by drilling noises as well as the noise of increased vessel operations. NOAA Fisheries has adopted 160 dB as an acceptable level of impulsive underwater sound (IPD, 2007; NMFS, 2007; Shor, 2004). Based on available scientific evidence, acoustic harassment of marine mammals would not be expected to occur below this conservative level. ~~Drilling rigs vessels may produce noise up to 174 dB (CSLC, 2006). However, drilling from platforms has been found to generate considerably less noise than drilling from mobile vessels (Richardson et al., 1995).~~ No noise measurements have been made at Platform Irene. As discussed in Section 5.5.1.7, Platform Irene would be expected to emit noises typical of other electric-powered platforms off California. Gales (1982) measured noises of 119 to 127 dB near platforms and man-made islands off California where drilling and/or production were occurring. He measured noise at 14 oil and gas platforms off Santa Barbara County during January 1981. Of the 14 Santa Barbara platforms, one was a drilling platform (Hondo) and 3 were engaged in drilling and production (Holly, Henry, Hope). The other 10 platforms were in production only. Gales made magnetic tape recordings of the underwater noise at the platforms from a boat drifting freely with all motors secured. The hydrophone was lowered over the side to a depth of 100 feet. The distance of the hydrophone from the platform varied between 50 and 200 feet, but was 100 feet in most cases. In addition, a continuous graphic record of noise on Platform Hondo was obtained by suspending a hydrophone to a depth of 30 feet below the platform.

The noise levels varied between the platforms. Drilling platforms were not necessarily noisier than production platforms. Platform Henry, which was engaged in drilling and production, was one of the noisier platforms, but Platform Holly, also engaged in drilling and production, was one of the quieter platforms. Platform Henry used a gas turbine engine rather than electric engines for power, and thus would be expected to be noisier than Platform Irene, which has electric power. Gales found that platform noise was so weak that it was nearly undetectable even alongside the platform during sea states of 3 feet or greater. The loudest noises were related to vessel activity near the platforms. Work boats near the platforms produced sounds of 110 to 130 dB while maneuvering, with a maximum noise level of 132 dB. In general, platform noise was less than 130 dB at a distance of 100 feet from the platform. The noise from Platform Irene during drilling is expected to be well below the threshold of 160 dB that is considered acoustic harassment.

Although noise associated with drilling at Platform Irene would not be expected to approach 160 dB, it still may be at a level that could have behavioral effects on marine mammals. Studies of the reaction of cetaceans to drilling noise suggest that cetaceans may avoid stationary industrial activities such as dredging, drilling and production when the received sounds are strong but not when the sounds are barely detectable (Richardson et al., 1995). Whales seem most responsive when the sound level is increasing or when a noise source first starts up, such as during a brief playback experiment or when migrating whales are swimming toward a noise source. Malme et al (1983) documented the responses of migrating gray whales to underwater playbacks of noise from drilling and production platforms (Richardson et al 1995). Whales exposed to playbacks of drilling platform noise from a point south of Monterey, California, showed a statistically significant change in behavior in the form of slowing down or slightly changing course at a distance of 2 to 3 km (Malme et al 1983). Behavior interpreted as avoidance occurred at 250 meters. In these and other experiments, approximately 50 percent of gray whales showed avoidance to playbacks of drilling platform noises at a level of 117 dB and production platforms at a level of 123 dB (Richardson et al 1995). The loudest noises measured by Gales (1983) at a distance of approximately 100 feet from southern California oil platforms was 130 dB. This noise would be expected to diminish to the 120 dB that is the approximate threshold for observed avoidance behavior at a distance of about 1000 feet (300 meters) from the platform. Gales (1983) estimated the distance that oil platform sounds would be audible to marine mammals. In the acoustic environment of southern California, he estimated that platform noises would not be detectable to whales beyond a distance of about 1.5 kilometers. These data suggest that behavioral effects of platform noise would be limited to about 300 meters and, at most, 1 to 3 kilometers from the platform.

The limited available data suggest that stationary industrial activities producing continuous noise result in less dramatic reactions by cetaceans than do moving sound sources, particularly ships. Some cetaceans may partially habituate to continuous noise. Sea otters have been observed to show no evidence of changes in behavior during underwater playbacks of drillship, semisubmersible, and production platform sounds (Richardson et al., 1995). Pinnipeds are often observed around offshore platforms and do not seem disturbed by drilling noises. These data suggest that drilling sounds from Platform Irene will be below the level determined to constitute acoustic harassment and are unlikely to have a significant adverse impact on marine mammals because behavioral responses, if any, would only occur within a few hundred meters or, at most, within three kilometers of the platform.

Marine mammals also could be disturbed by vessels traveling to and from Platform Irene. Vessels are major contributors to overall background noise in the sea (Richardson et al., 1995). Sound levels and frequency characteristics are roughly related to ship size and speed. The dominant sound source is propeller cavitation. In general, pinnipeds and odontocetes tend to be tolerant of vessels. The level of avoidance of baleen whales to vessels appears to be related to the speed and direction of approaching vessels (Richardson et al., 1995). Whales often move away in response to strong or rapidly changing vessel noise, especially when a boat approaches directly. Gray whales have been observed to change course at a distance of 650 to 1,000 ft (200 to 300 m) in order to move around a vessel in their paths. On the other hand, some gray whales have not been observed to react until a ship is within 50 to 100 ft (15 to 30 m). Humpback whales have been observed to avoid vessels and change behavior when a boat approached within a half mile.

As shown in Table 2.2 of the Project Description, during normal operations there would be no increase in boat traffic to Platform Irene. During drilling of new wells, there would be an increase from 107 trips per year to 120 vessel trips per year, which is within the permitted FDP limits. Tug and crewboats have been found to emit sounds of 150 to 165 dB, just barely at the level considered to constitute acoustic harassment (Chambers Group, 1987). Actual sound level measurements of work boats associated with Santa Barbara platforms ranged from 110 to 132 dB (Gales 1982). Because the additional vessels represent a temporary incremental increase in boat traffic in the project area, the disturbance to marine mammals from vessel noise would be an insignificant impact.

Because of the localized and temporary nature of the disturbance and the existing mitigation measures, noise impacts to marine mammals and seabirds caused by new operations and drilling activities are considered to be adverse but not significant.

Mitigation Measures

No mitigation measures have been identified.

Residual Impact

Because of the temporary (vessels) or low dB level (drilling) nature of the disturbance, noise or sound impacts from new operations and drilling to marine mammals and marine birds are *adverse but not significant (Class III)*.

Impact #	Impact Description	Phase	Residual Impact
MB.5	Increased vessel traffic resulting from the proposed project drilling, production, and oil clean up response may impact marine mammals and marine turtles.	*Drilling*	*Class II*

Marine Mammals

Watkins (1986), Malme et al. (1989), and Richardson et al. (1991) have reported that noise from vessels elicit a startle reaction from gray whales and mask their reception capabilities. They also reported that avoidance and approach responses vary according to whale activity. Migrating gray whales have been observed to avoid the approach of vessels to within 200-300 m (Wyrick, 1954) or to within 350-550 m (Bogoslovskaya et al., 1981). Based upon the results of Wyrick (1954) and Bogoslovskaya et al. (1981), noise effects on gray whales from vessels can be expected to be limited to within 200-550 m of approaching vessels and to be sublethal and temporary. However, collisions between vessels and gray whales occur frequently. Twelve collisions resulting in six deaths of gray whales occurred off southern California between 1975 and 1980 (Patten et al., 1980). Young gray whales, especially, are more likely to be hit by moving vessels (Laist et al. 2001). In addition, three blue whales died offshore southern California during a two-week period in September 2007 and these deaths were attributed to ship strikes.

A gray whale calf was severely injured offshore Morro Bay, California during installation of a trans-Pacific cable. The injury consisted of a severely cut tail stock and flukes completely severed off the animal. The extent of the injury (severing of the caudal peduncle) was consistent with a propeller strike (Harvey, 2001). Although the carcass of the calf was never recovered, it is unlikely that the injured calf traveled far from the location where it was observed (Harvey, 2001).

The frequency and duration of offshore support vessels would increase during the drilling of new wells although the increase would be within permitted levels. Support boat traffic during well drilling would increase from 107 trips per year to 120 trips per year. Since collisions between vessels and gray whales, a federally protected marine mammal species, and blue whales can result in severe injury or death, collisions are considered to be a significant impact. However, according to PXP, there have not been any collisions between their supply vessels and marine mammals. The supply vessels travel at the relatively slow speed of about 10 knots and stay in established vessel traffic corridors. In theory, the potential for a collision could be further reduced if supply vessels only traveled during the day. However, it is not feasible to limit these trips to daylight hours. The trip to and from Platform Irene takes 8 to 10 hours each way and because of the rough sea conditions in the Platform Irene area, trips are planned to load and unload during the calmest wind and sea conditions, which usually are in the early morning. To minimize trip time and be able to unload at the platform in the morning, the vessels must travel during at least a portion of the night.

Very little information describing pinniped responses to vessels is available. Johnson et al. (1989) reported that northern fur seals can be wary and show an avoidance reaction to vessels at distances of up to one mile. Wickens (1994), however, reported that fur seals are often attracted to fishing vessels to feed. Sea lions in the water often tolerate close and frequent approaches by vessels, especially around fishing vessels. Sea lions hauled-out on land are more responsive and react when boats approach within 100 to 200 m (Peterson and Bartholomew, 1967). Also, harbor seals often move into the water in response to boats. Even small boats that approach within 100 m displace harbor seals from haulout areas and less severe disturbance can cause alert reactions without departure (Bowles and Stewart, 1980; Allen et al., 1984; Osborn, 1985).

Dolphins of many species tolerate or even approach vessels. Reactions to boats often appear to be related to the dolphins' activity. Resting and foraging dolphins tend to avoid boats while socializing dolphins may approach them (Richardson et al., 1995).

Riedman (1983) reported that while sea otters often allow close approaches by small boats, they tend to avoid high activity areas. He also noted that some rafting sea otters exhibit mild interest in boats at distances of a few hundred meters and are not alarmed. Garshelis and Garshelis (1984) reported that sea otters in Alaska tend to avoid areas with frequent boat traffic. Udevitz et al. (1995) reported that sea otters tend to move away from approaching boats.

Marine Turtles

Noise from service-vessel traffic may elicit a startle reaction from marine turtles and produce a temporary sublethal stress (NRC, 1990). Service vessels could also collide with and injure marine turtles at the sea surface, but they are estimated to be at the sea surface for less than 4 percent of the time (Byles, 1989; Lohoefener et al., 1990). Vessel-related injuries have not been reported in project waters but have been noted in the Gulf of Mexico. In the Gulf of Mexico, nine percent of stranded turtles examined showed signs of vessel injuries (USDOC, 1989).

Although marine turtles could be harmed or killed by project related vessels, collision impacts are considered to be adverse but not significant. Marine turtles are very rare in the project area and collisions with vessel traffic are not expected to occur.

Mitigation Measures

In addition to Mitigation Measure MB-1c, the following mitigation measure is required:

MB-4 A marine mammal observer shall be employed on each vessel servicing Platform Irene as described herein. The observer shall be provided training which focuses on the identification of marine mammal species, the specific behavior of species common to the project area, and awareness of seasonal concentrations of marine mammals. The marine mammal observer shall be placed on all support vessels during the spring and fall gray whale migration periods and during periods/seasons having high concentrations of marine mammals in the project area, such as the early summer blue whale migration. The observer shall have no other responsibilities during periods when the vessels are in transit.

The observer shall have unobstructed views onboard each vessel and serve as lookout so that collisions with marine mammals can be avoided. Additionally, vessel operators or the applicant shall develop, submit for approval, and implement a contingency plan that focuses on avoidance procedures when marine mammals are encountered at sea. Minimum components of the plan include:

a) Vessel operators will make every effort to maintain a distance of 1,000 feet from sighted whales and other threatened or endangered marine mammals or marine turtles.

~~b) Support vessels will not cross directly in front of migrating whales or any other threatened or endangered marine mammals or marine turtles.~~ Vessel operators shall avoid travelling through blue whale feeding grounds and shall adjust transit routes to avoid large-scale krill populations during the annual blue whale migration period in the Santa Barbara Channel.

c) When paralleling whales, support vessels will operate at a constant speed that is not faster than the whales.
d) Female whales will not be separated from their calves.
e) Vessel operators will not herd or drive whales.
f) If a whale engages in evasive or defensive action, support vessels will drop back until the animal moves out of the area.
g) Any collisions with marine wildlife will be reported promptly to the Federal and State agencies listed below pursuant to each agency's reporting procedures.

Stranding Coordinator, Southeast Region
National Marine Fisheries Service
Long Beach, CA 90802-4213
(310) 980-4017

Enforcement Dispatch Desk
California Department of Fish and Game
Long Beach, CA 90802
(562) 590-5132 or (562) 590-5133

California State Lands Commission
Environmental Planning and Management Division
Sacramento, CA 95825-8202
(916) 574-1890

~~**MB-5** PXP shall make a yearly contribution of $90,000 toward establishing a marine mammal and sea bird impact mitigation fund. The funding shall be used for either facilities construction or operating costs associated with the rescue and rehabilitation of injured marine mammals and sea birds. This yearly contribution shall be in lieu of the applicant's annual three (3) point Coastal Resource Enhancement Fund (CREF) assessment for biological resource impacts, as currently required by Condition N-1 of PXP's Final Development Plan for the Point Pedernales Project.~~

Residual Impact

Trained vessel operators and marine mammal observers onboard support vessels and the implementation of a contingency plan that focuses on avoidance of marine mammals and marine turtles reduce the probability for collisions. Financial support of existing or new marine mammal rescue and rehabilitation efforts (Mitigation Measure MB-1c) will partially mitigate the effects of vessel-mammal collisions that do occur. With implementation of these measures, the impact is *significant but mitigable (Class II).*

Impact #	Impact Description	Phase	Residual Impact
MB.6	The uptake of sea water may result in impingement and entrainment of marine organisms.	*All operations*	*Class III*

Seawater will be taken up at Platform Irene for firewater, washdown water, drilling, and workover ~~and cooling~~water. Seawater use will not increase under the proposed project. The intake of seawater subjects organisms in the water column to impingement and entrainment. Impingement occurs when large organisms, such as fishes and large planktonic invertebrates, become stuck on the intake screen. Entrainment is the drawing of small planktonic organisms through the screens and onto the platform. Seawater intake requirements for the proposed Project range from approximately 78.8 million gallons per year to 138.6 million gallons per year. Platform Irene has three intake sources, two at 120 foot water depth and one at 37 foot water depth. All use 20 inch diameter pipes and are screened. Individual slot velocities are less than 0.35 cubic feet per second. The low intake velocities greatly reduce the chances of entrainment.

Studies of impingement and entrainment by the once-through cooling systems of coastal power plants have identified significant adverse impacts on the marine environment primarily from entrainment (California Energy Commission, 2005). The loss of zooplankton, phytoplankton, and fish eggs and larvae represents the loss of productivity of hundreds of acres of coastal habitat. The intake of large amounts of seawater removes the young of fishes and invertebrates and also represents a loss to coastal food chains because many species feed on the plankton. However, these power plants take hundreds of millions of gallon per day of water into their cooling systems. The operations at Platform Irene would take, ~~on the average~~at maximum seawater usage, less than 0.4 million gallons per day. Washdown water is approximately 6800 bbl per day, but only runs continuously when the platform is drilling. Firewater pumps are tested once per week for 30 minutes for a total of 90,000 gallons per week. Seawater uptake for cooling is a maximum of 500 barrels per day when the water-cooled heat exchanger is in use; however, electric fans are currently used.[5] Because of the small volume of seawater intake, impacts would be adverse but insignificant.

Mitigation Measures

No mitigation measures are proposed.

Residual Impact

Because of the small volume of seawater intake, impacts would be adverse but *insignificant (Class III)*.

Impact #	Impact Description	Phase	Residual Impact
MB.7	Lighting on Platform Irene may have adverse effects on fishes and zooplankton	*All operations*	*Class III*

Existing exterior lighting on Platform Irene conforms with platform lighting standards required by the MMS, Occupational Safety and Health Administration (OSHA), and the Coast Guard.

[5] The water-cooled heat exchanger could be used in the future when ambient air temperatures warrant (electric fans aren't as effective on warm days).

Table 5.5.15 describes the amount of existing lighting on Platform Irene. All exterior lighting is directed inward toward the platform. No changes to existing levels of platform lighting are proposed or needed for the Tranquillon Ridge project.

Table 5.5.15 Existing Exterior Lighting on Platform Irene

Platform Area	Number of Lights	Watts per Light	Total Watts
Production Deck	60	150	9000
	16	400	6400
Sub Deck	11	150	1650
	6	250	1500
Weld Shop	6	400	2400
Quarters Area	40	150	6000
Cranes	6	250	1500
	2	15	30
	2	strobes	--
Rig Floor	23	250	5750
	6	80	480
Derrick	20	70	1400
TOTAL			**36,110**

Artificial lighting at sea may have adverse impacts on marine organisms. Some forage fishes and plankton species may be attracted to the artificial lights of the platform, making them more vulnerable to predation (Shaw et al 2002). Bright lights at sea can attract predators such as marine birds, marine mammals and large predatory fishes that use the illumination of the lights to feed on fishes and plankton (N. Davis, Chambers Group, personal observations). Predator attraction to bright lights has been observed on brightly lit dive boats and fishing vessels, but not specifically at oil platforms.

In addition to attracting predators, artificial light may interfere with diel vertical migration by zooplankton and some species of fish. Diel vertical migration by zooplankton to deep, poorly illuminated habitats during the day is thought to reduce the probability of attack by visual predators (De Robertis 2002). Zooplankton and some pelagic fishes come up into the phytoplankton- rich surface waters to feed when it is dark and they cannot be seen by visual predators. The migration responds to changes in light intensity and water column temperature structure (Record and de Young 2006). Artificial lighting from oil platforms might interfere with the light intensity cues of vertically migrating fishes and zooplankters, and prevent them from feeding in the nutrient and phytoplankton-rich surface waters at night.

The impacts of artificial lighting on fishes and zooplankton, if they occur, would be limited to the approximately 100 meter illuminated area around the platform. Because of the limited spatial effects of the lighting compared to the widespread distribution of zooplankton and pelagic fishes and the speculative nature of these impacts, lighting impacts on zooplankton and fish are considered to be *adverse but not significant (Class III).*

Mitigation Measures

No mitigation measures are identified.

Residual Impact

Because of the localized spatial extent of lighting, impacts on fishes and zooplankton would be adverse but *insignificant (Class III).*

Artificial Lighting Impacts to Xantus' Murrelet and Other Seabirds

Night lighting on offshore platforms has the potential to attract seabirds, especially nocturnal seabirds such as alcids, storm-petrels and shearwaters. Intense source points of light, such as oil platforms, can attract marine birds from large areas (Montevecchi, 2006). A large vertical structure with a bright source of light in an environment that is otherwise flat and dark at night presents a conspicuous visual cue and a sharp contrast to the nocturnal darkness (Wiese et al., 2001). The attraction to light by some nocturnal feeding seabirds has been hypothesized to result from their exploitation of vertically migrating bioluminescent prey and from a predilection to orient to star patterns (Montevecchi, 2006).

Artificial night lighting attracts seabirds and disrupts their normal breeding and foraging activities (Wolf, 2007). Seabirds have been known to circle oil platforms and flares and to fly directly into lights (Wiese et al., 2001). Migrating passerines (land birds) and seabirds have been observed to circle platforms continuously for hours to days[6] and to fall to the ocean or land on the platforms exhausted and emaciated (Montevecchi, 2006; Wolf, 2007). This continuous circling within the illumination or around artificial lights by birds is known as light entrapment. Seabirds also may collide with lights or structures around lights (Montevecchi, 2006; Wolf, 2007). In 1991, two Ashy storm-petrels (*Oceanodroma homochroa*) were recovered dead on Platform Hondo in the Santa Barbara Channel, although it is not known what killed them (Carter et al., 2000). A potential indirect effect of light attraction is that it can make the seabirds more vulnerable to predators either by illuminating them so that they can be seen by visually foraging predators such as owls and peregrine falcons or by exhausting them through light entrapment and making them less able to escape (Wolf, 2007).

On May 14 through 16, 2007, biologists from Storrer Environmental Services made nighttime observations of birds and bird behavior at Platform Irene (Storrer, 2007a, b). The drill tower and support cranes were illuminated and there were numerous exterior safety lights on all three decks of the platform. Cumulatively, the artificial lighting illuminated an area around the platform of approximately 100 yards. Storrer observed aggregations of Wilsons phalaropes (*Phalaropus tricolor*) circling the platform, 10 to 30 feet above the water. He observed about 300 total phalaropes circling continuously until the first light of dawn. At no time did they land on the water to forage (phalaropes feed by sitting on the water and spinning around picking prey from the water's surface). Storrer also observed flocks of passerines that appeared to be attracted to the lights on the platform. Evidence of disorientation (e.g., flying directly toward, and making contact with, high intensity lights and also flying toward banks or rows of lights, then straight up just in front of the lights) was observed. Fatigue also appeared to manifest as the survey progressed: birds landed on the deck and on equipment, appearing wet and listless and were easily approached. One Nashville warbler (*Vermivora rufivapilla*) was captured by hand and examined for injuries. It appeared tired but not injured. In addition, a sooty shearwater (*Puffinus*

[6] Birds entrained in intense artificial light often circle the source for hours to days, especially during overcast conditions, when they are reluctant to fly outside the sphere of illumination into darkness.

griseus) was found on deck and easily captured by hand. The shearwater was released and flew away the next morning. No mortality or injury to any birds was observed.

The Xantus' murrelet (*Synthlioramphus hypoleucus*) is among the least numerous of alcids and has been adversely affected by predators on its nesting islands (Karnovsky et al., 2005). The Xantus' murrelet is a nocturnally foraging seabird susceptible to light attraction (Wolf, 2007; Carter et al., 2000; Tuchton and Jacobson, 2005). Researchers at the San Benito Islands in Baja California, where the species has a sizable breeding population, have repeatedly seen murrelets suffer injury at light sources due to exhaustion from continual attraction and fluttering near lights or collision with lighted structures (Tuchton and Jacobson, 2005). Artificial light pollution is listed as a major threat to Xantus' murrelets in the *Status Review of Xantus' Murrelet* (Burkett et al., 2003) which provided evidence for the State to list the species as threatened. The California Department of Fish and Game has promulgated regulations requiring a permit for squid fishing using light attraction to reduce potential impacts on seabirds (CDFG, 2007; 14 CCR 149).

In addition to Xantus' murrelet, the ashy storm-petrel which nests on the northern Channel Islands and may also nest on Vandenberg Air Force Base (Jensen et al., 2005) could be affected by the night lighting of Platform Irene (Wolf, 2007).

Conclusion: Storrer's observations indicate that night lighting on Platform Irene does appear to attract birds. It is not known if birds attracted by platform lights eventually suffer increased mortality or reduced breeding success because of the expenditure of time and energy during light entrapment. However, the waste of time and energy caused by light entrapment could keep migrating seabirds from reaching their breeding grounds. Furthermore, the holding or trapping effect of intense light can deplete the energy reserves of migrating birds and could have repercussions on survival and subsequent reproduction. Breeding seabirds may be more likely to suffer adverse effects because light entrapment increases their time away from their nests, leaving the nests vulnerable to predation. In addition, time and energy spent circling lights may prevent breeding birds from capturing enough food to feed their young. However, even if birds that spend time entrapped by platform lights do become more vulnerable to predation or suffer reduced breeding success, it is not known if such effects are significant at the population level.

The artificial night lighting on Platform Irene could have an adverse effect on individuals and potentially on populations of sensitive bird species, specifically the threatened Xantus' murrelet and the ashy storm-petrel, a California Species of Special Concern. These species are known to occur in some years in relatively low densities in the vicinity of Platform Irene during both the breeding and non-breeding seasons, and are nocturnal foragers known to be attracted to artificial lighting. At this time, existing information is insufficient to determine whether the impact of Platform Irene illumination on seabirds is significant. Although the platform lights do appear to attract seabirds, it is not known whether such attraction significantly disrupts migration or foraging behavior. Xantus' murrelets primarily nest and forage to the south of Platform Irene, in the Southern California Bight (approximately from Point Conception south to just south of San Diego). Platform Irene and several other platforms much closer to the Xantus' murrelet nesting areas, have been operating for 20 years or longer with no indication that the platform lighting has significantly affected the Xantus' murrelet or other seabird species. The California Department of Fish and Game has stated that:

> "The Department is not aware of any interactions between offshore oil platforms, including Platform Irene, and Xantus' murrelets, though field studies have not been conducted. There is also a general lack of information on the nighttime habits of murrelets and their interactions with oil production platforms. Because field studies have not occurred, it is unknown if the impacts that have been seen between these birds and vessels on the ocean surface may also be occurring on the waters surrounding Platform Irene." (CDFG, 2007)

While the CDFG has not determined that Xantus' murrelets are being taken as a result of interactions with night-lighting on Platform Irene, they have recognized that "…because the murrelets are known to seasonally inhabit the waters adjacent to Platform Irene, these birds are known to be attracted to night-lighting, and Platform Irene uses 36,000 watts in total of high intensity lights, there is potential for impacts to murrelets" (CDFG, 2007). In light of this potential, the CDFG has recommended certain measures be taken when murrelets are present in the area to minimize the potential impacts. These measures include:

1. Minimize use and wattage of night lighting to the extent feasible while not compromising safety, spill detection capabilities, or platform operations.

2. Shield lights, cover filaments, direct downward as much as feasible.

3. Vessels associated with the platform comply with low wattage / shielding / filament-covering measures.

4. Develop a monitoring program for the waters around Platform Irene that includes Xantus' murrelet, ashy storm petrel, and Cassin's auklet. This program will be developed with input from murrelet experts and take into consideratiuon various murrelet behaviors, along with their seasonal movements.

A protocol for monitoring the Xantus' murrelet and other seabird species at Platform Irene that incorporates the elements listed above should be developed by PXP in coordination with CCC, MMS, and CDFG staff. Lights on Platform Irene already are shielded and directed downward to the extent feasible. PXP should reduce wattage on the platform where feasible and investigate the potential for vessel operators to reduce and shield their vessel lights when in service to Platform Irene at night including during night-time transit to and from the platform. These lighting and seabird monitoring measures should be detailed and implemented through the Coastal Commission's consistency review process.

5.5.5 Impact Analysis for the Alternatives

Detailed descriptions of the various alternatives have been provided in Chapter 3.0. This section provides a discussion of the marine biology impacts of the various alternatives.

5.5.5.1 No Project Alternative

Scenarios 2 and 3. As discussed in Section 3.2, under the No Project Alternative Scenarios 2 and 3, production of the federal portion of the Tranquillon Ridge field would and would not

occur, respectively. However, no extension of life of Point Pedernales facilities (Platform Irene, pipelines, and LOGP) is assumed under either scenario.

Impact MB.1 – Oil Spills: Impacts to marine organisms resulting from oil spills would be reduced to what exists for the current operations (i.e., baseline).

Impact MB.2 – Muds Discharge: Impacts due to the discharge of drilling muds and cuttings into the ocean would be reduced from those for the proposed project. ~~This alternative~~ Scenarios 2 and 3 would eliminate the 22 to 30 wells to be drilled under the proposed project over a 15 year period. Hence, the volume of drilling muds and cuttings that would be discharged into marine waters would be reduced substantially. Impacts caused by the release of muds and cuttings would occur over a shorter period of time and be reduced because of the smaller volume that would be discharged. This impact would still be considered *adverse but not significant (Class III).* Mitigation Measure MB-2 would apply to Scenarios 2 and 3 ~~this alternative~~.

Impact MB.3 – Produced Water Discharge*:* Impacts associated with the discharge of produced water would be no more than the current operations. The majority of the produced water would continue to come from Point Pedernales Field wells. The Tranquillon Ridge wells would not increase the produced water levels above the peak levels that would occur for just the Point Pedernales Field. PXP is not currently discharging all of its produced water at Platform Irene. If, in the future, PXP chooses to treat the produced water to NPDES permit standards, it would then be discharged at the platform. This could occur with or without the Tranquillon Ridge project and would not require new permits or approvals. Implementation of ~~this alternative~~ Scenarios 2 and 3 would not affect impacts related to produced water discharge. This impact is adverse, but not significant (Class III).

Impact MB.4 – Noise: Impacts associated with noise disturbance to marine mammals and marine birds are less than the proposed project. Noise impacts for the proposed project are primarily due to increased drilling activities and vessel and aircraft traffic to support the drilling operations. Under ~~this alternative~~ Scenarios 2 and 3, ~~no~~ drilling activities would ~~occur~~ be the same as, or less than, current operations (primarily well workovers) and would ~~Noise impacts would~~ still occur ~~during this~~ over a shorter ~~drilling~~ period as operations decline. This impact would still be considered *adverse but not significant (Class III).*

Impact MB.5 – Vessel Traffic: Impacts due to vessel and marine mammal collisions would be less than the proposed project. The reduced number of wells would reduce the number of vessel trips thereby reducing the potential for collisions. This impact would still be considered *significant but mitigable (Class II).* Mitigation Measures MB-1c and MB-4 ~~and MB-5~~would apply to ~~this alternative~~ Scenarios 2 and 3.

Impact MB.6 - Impingement and Entrainment: Impingement and entrainment from seawater uptake at Platform Irene would remain the same as existing conditions (baseline).

Impact MB.7: The impacts of lighting on non-avian marine organisms would remain the same as the existing conditions (baseline) and would be the same as for the proposed Project, *adverse but not significant (Class III).*

Options for Meeting California Fuel Demand. The relative impacts to marine biology associated with the various options for meeting California fuel demand are summarized in Table 5.5.16.

Table 5.5.16 No Project Alternative Comparison to Options for Meeting California Fuel Demand, Marine Biology

Source of Energy	Impacts
Other Conventional Oil & Gas	
Domestic onshore crude oil and gas	Would eliminate marine biology impacts.
Increased marine tanker imports of crude oil	Marine biology impacts would be increased.
Increased gasoline imports[1]	Would eliminate marine biology impacts.
Increased natural gas imports (LNG)	Marine biology impacts would increase with LNG tankering and/or development of offshore ports.
Alternatives to Oil and Gas	
Fuel Demand Reduction: increased fuel efficiencies, conservation, electrification[2]	
Alternative transportation modes	Proposed project impacts would be eliminated.
Implementation of regulatory measures	Proposed project impacts would be eliminated.
Coal, Nuclear, Hydroelectric	Proposed project impacts would be eliminated. Marine biology impacts unlikely for coal or hydroelectric. Coastal nuclear plants could result in marine biology impacts.
Alternative Transportation Fuels	
Ethanol/Biodiesel[3]	Proposed project impacts would be reduced.
Hydrogen[2]	Proposed project impacts would be eliminated.
Other Energy Resources[2]	
Solar[2,4]	Proposed project marine biology impacts would be eliminated.
Wind[2,4]	Proposed project marine biology impacts would be eliminated. Development of offshore wind infrastructure could result in marine biology impacts.
Wave[2,4]	Proposed project marine biology impacts would be eliminated. Development of wave energy extraction infrastructure could result in marine biology impacts.

Footnotes:
1. Pipeline and tanker truck import from out-of-State assumed.
2. Assumes that Tranquillon Ridge production would not be replaced with other petroleum-based energy supply.
3. Assumes ethanol and biodiesel used as blends only and therefore would reduce, but not eliminate Tranquillon Ridge or equivalent production.
4. Assumes, large centralized facilities.

5.5.5.2 VAFB Onshore Alternative

Development of the Tranquillon Ridge Field from VAFB would reduce or eliminate impacts to marine resources from the proposed project. The only potential impacts to marine resources from the VAFB Onshore Alternative would be the potential discharge of produced water from Platform Irene (if the NPDES permit is modified to allow it) under Produced Water Scenario 1 or a spill from a pipeline rupture or due to upset conditions at the drilling/production site if the oil reaches ocean waters.

Impact MB.1 - Oil Spills: The VAFB Onshore Alternative would reduce the risk of oil spills compared to the proposed project. The risk of an oil spill from Platform Irene or associated offshore pipelines would be reduced to the baseline conditions. There is a small chance that an oil spill from a rupture of the new pipeline or upset conditions at the drilling/production site could reach ocean waters. The chances of oil from the onshore pipeline or drilling/production sites reaching the ocean are nominal because the alternative facilities would be landward of the railroad tracks. The railroad tracks run along a berm that forms a partial barrier to flows. However, under high flow conditions, spilled oil might reach ocean waters via one of the drainages crossed by the pipeline. Spilled oil that did reach the ocean from this alternative would be close to important seabird and shorebird areas at the Santa Ynez River mouth, Point Pedernales, Point Arguello and Rocky Point as well as areas frequented by sea otters and harbor seals. Mitigation Measure MB-1 would apply. For the VAFB Onshore Alternative, the Oil Spill Response Plan should specifically detail methods to keep oil spilled into creeks and drainages from reaching the ocean and on ways to protect sensitive marine resources along the southern VAFB coast should spilled oil enter the ocean (see Mitigation Measure CRF/KH-3). Although mitigation measures would reduce potential oil spill impacts, such impacts cannot be completely avoided. Therefore, oil spill impacts have the potential to be *significant (Class I).*

Impact MB.2 – Muds Discharge*:* The discharge of drilling muds and cuttings into the ocean at the platform would be eliminated. Therefore, impacts to the marine biota would not occur.

Impact MB.3 - Produced Water Discharge: Under Produced Water Scenarios 2 and 3, treated produced water would be re-injected onshore either at the onshore drilling and production site or the LOGP. Under either of these scenarios, no impacts associated with the Tranquillon Ridge Project would occur to marine life from produced water discharges. Under Produced Water Scenario 1, produced water from the VAFB Onshore Alternative would be treated at the LOGP and then sent to Platform Irene where it would either be re-injected or possibly discharged to the ocean. If produced water were re-injected, impacts to marine life would not be expected. If produced water were discharged to the ocean (requiring a modification to the NPDES discharge permit or a new individual permit, see Section 5.6.5.2), the impacts would be similar to those described for Impact MB.3 of the proposed project and Mitigation Measure MB.3 would apply.

Impact MB.4 - Noise*:* Impacts to marine organisms from noises associated with offshore activities such as drilling and vessel traffic would remain the same as the existing (baseline) condition. The VAFB Onshore Alternative would not have the potential for noise impacts to marine animals.

***Impact MB.5 - Vessel Traffic*:** No vessel traffic would be associated with the VAFB Onshore Alternative. Therefore, there would be no potential for impacts to marine organisms from vessel traffic associated with this alternative.

Impact MB.6 Impingement and Entrainment. <u>The VAFB Onshore Alternative would not require the use of Platform Irene (except for disposal under Produced Water Scenario 1). Therefore, there would be little potential for impingement and entrainment under this alternative.</u> Impingement and entrainment from seawater uptake at Platform Irene would be the same as existing baseline conditions.

Impact MB.7: The impacts of lighting on non-avian marine organisms would remain the same as the existing conditions (baseline) and would be the same as for the proposed project, *adverse but not significant (Class III).*

5.5.5.3 Casmalia East Oil Field Processing Location

There are no additional impacts identified for this alternative. Impacts MB.1 through MB.~~6~~7 would be the same as identified for the proposed project. Mitigation Measures MB-1, MB-2, MB-3 and MB-4~~, and MB-5~~ would apply.

5.5.5.4 Alternative Power Line Routes to Valve Site # 2

There are no additional impacts identified for this alternative. Impacts MB.1 through MB.~~6~~7 would be the same as identified for the proposed project. Mitigation Measures MB-1 through MB-4~~5~~ would apply.

5.5.5.5 Replacement of Oil Emulsion Pipeline from Platform Irene to LOGP

Potentially, hard-bottom habitats could be impacted from pipeline installation activities. However, surveys indicate that hard-bottom habitats do not occur along the proposed pipeline corridor. Hence, impacts to hard bottom communities are not expected due to this alternative.

Impact MB.1 – Oil Spills: Impacts to marine organisms from oil spills remain the same as for the proposed project. However, due to the newer pipe, the spill frequency would be reduced. This impact would still be considered *significant (Class I)*. Mitigation Measure MB-1 would apply to this alternative.

Impact MB.2 – Muds Discharge: Impacts resulting from the discharge of drilling muds and cuttings into the ocean remain the same as for the proposed project *(Class III)*.

Impact MB.3 – Produced Water Discharge: Impacts due to the discharge of produced water remain the same as for the proposed project *(Class III)*.

Impact MB.4 – Noise: Impacts associated with noise disturbance to marine mammals and marine birds would increase. Installation of the emulsion pipeline is estimated at 7.5 weeks and would require additional equipment and more boat trips than for the proposed project. Noise caused by construction activities and helicopters would increase along the pipeline corridor during the installation phase. The literature indicates that marine species could be displaced from the installation corridor to adjacent areas but there is no indication that they would be affected deleteriously by the noise (Richardson et al., 1995). Because the noise generated from this alternative would be highly localized and short-term in nature, adverse impacts to the marine mammals and marine birds in the area are not expected to occur from this alternative. This impact would still be considered *adverse but not significant (Class III).*

Impact MB.5 – Vessel Traffic: Impacts to marine mammals caused by collisions or encounters with offshore vessels could increase. Additional vessels such as tug boats, supply boats, and barges would be needed during the pipeline installation phase. However, the installation phase is estimated at 7.5 weeks so the likelihood of marine mammal collisions with vessels due to this alternative is low. Mitigation Measures MB-1c and MB-4 ~~and MB-5~~ would apply to this alternative. This impact would still be considered *significant but mitigable (Class II).*

Impact MB.6 - Impingement and Entrainment: Impingement and entrainment of marine organisms due to seawater intake at Platform Irene would be the same as for the proposed project. Impacts would be *adverse but insignificant (Class III).*

Impact MB.7: The impacts of lighting on Platform Irene on non-avian marine organisms would be the same as for the proposed Project. Additional offshore lighting on construction vessels would have the potential to attract seabirds and affect other marine organisms during night-time construction activities. Impacts to non-avian marine organisms are *adverse but not significant (Class III).*

Impact #	Impact Description	Phase	Residual Impact
MB.~~7~~8	The burial of the pipeline would disturb soft-bottom habitats.	*Construction*	*Class III*

The burial of the pipeline from the shoreline to 4,000 feet offshore would disturb soft-bottom habitats and potentially destroy populations of benthic invertebrates residing along the installation corridor.

Divers using hand-held air jets would bury the pipeline to a depth of 3 to 6 feet. The air jets pump seawater under the pipeline to displace sand. The displacement causes the pipeline to settle to the desired depth beneath the surface of the sediments.

The damage to the benthic invertebrates due to the physical disturbance caused by pipeline installation would be adverse but not significant. The area impacted by habitat disturbance would be limited to the pipeline corridor. Although benthic invertebrates would be killed, because areas adjacent to the corridor would not be disturbed, recolonization and recruitment of benthic invertebrates into disturbed areas is expected to occur rapidly. The number of invertebrate organisms that will be lost would be comparatively low and represent species that are not considered rare or endangered. Loss of these organisms is unavoidable but the invertebrate community should recover within a few months after installation is completed.

Several factors are reported to be important in determining the rate at which a disturbed site is recolonized by species. A mobile adult stage of nearby species and small areas of disturbance allow for faster recolonization. Dauer and Simon (1976), Levin (1984), and de Groot (1979a) reported that the recolonization process is highly influenced by the similarity of the new altered substrate to nearby unaltered sediments. In extreme cases of sediment disturbance, de Groot (1979b) estimated two to three years for recovery following sand and gravel mining, and Pfitzenmeyer (1970), found that infaunal populations recovered to their original condition in 18 months after dredge spoil disposal.

Other studies of dredged areas have found rapid recovery (Harrison, 1967; Cronin et al., 1971; Conner and Simon, 1979). In several cases, while the biomass may reach pre-dredging condition, the diversity and distribution of species do not always replicate the pre-existing condition (May, 1973; Oliver et al., 1977; de Groot, 1979a). This was largely attributed to opportunistic species that were able to move rapidly into unoccupied areas and were the first organisms to settle (Desbruyers et al., 1980; Levin and Smith, 1984; Grassle, 1985).

Compared to sand and gravel mining and dredging spoil operations, the area disturbed by pipeline installation would be small. Also, sediments that would be displaced and deposited during the burial process would be similar in nature to adjacent locations. Because of the fairly short time observed with more extensive projects such as sand and gravel mining and dredge spoil disposal, it is estimated that recovery from disturbance caused by pipeline burial would occur on a time scale of months rather than years. Hence, impacts to benthic invertebrates from the installation of the new emulsion pipeline are considered to be *adverse but not significant (Class III).*

Mitigation Measures

No mitigation measure has been identified.

Residual Impact

Because of the temporary and localized nature of the disturbance, impacts to benthic invertebrates caused by the installation of the new emulsion pipeline are considered to be *adverse but not significant (Class III).*

5.5.5.6 Alternative Drill Muds and Cuttings Disposal

Inject Drill Muds and Cuttings into Reservoir

Impact MB.1 – Oil Spills: All impacts to marine organisms resulting from oil spills remain the same as for the proposed project.

Impact MB.2 – Muds Discharge: The discharge of drilling muds and cuttings into the ocean would be eliminated. Therefore, impacts to the marine biota would not occur.

Impact MB.3 – Produced Water Discharge: Impacts associated with the discharge of produced water remain the same as for the proposed project.

Impact MB.4 – Noise: Impacts associated with noise disturbance to marine mammals and marine birds essentially remain the same as for the proposed project.

Impact MB.5 – Vessel Traffic: Impacts due to vessel and marine mammal collisions remain the same as for the proposed project.

Impact MB.6 - Impingement and Entrainment: The impacts of seawater intake at Platform Irene would be the same as for the proposed project.

Impact MB.7 - Lighting: The impacts of lighting on non-avian marine organisms would be the same as for the proposed project, *adverse but not significant (Class III).*

Impact MB.8~~7~~ – **Pipeline Burial:** ~~Pipeline burial would disturb soft bottom habitats,~~ This impact would not apply to this alternative.

Transport Drill Muds and Cuttings to Shore for Disposal

Impact MB.1 – Oil Spills: All impacts to marine organisms resulting from oil spills remain the same as for the proposed project.

***Impact MB.2 – Muds Discharge**:* The discharge of drilling muds and cuttings into the ocean at the platform would be eliminated. Therefore, impacts to the marine biota would not occur.

Impact MB.3 – Produced Water Discharge: Impacts associated with the discharge of produced water remain the same as for the proposed project.

Impact MB.4 – Noise: Impacts associated with noise disturbance to marine mammals and marine birds would be the same as the proposed project. Noise impacts for the proposed project are primarily due to increased drilling and vessel operations, and aircraft traffic. Under this alternative, vessel trips would be the same because the muds and cuttings would be taken ashore on the return trips of the regularly scheduled supply boats. This impact is considered *adverse but not significant (Class III)*.

Impact MB.5 – Vessel Traffic: Impacts due to vessel and marine mammal collision would be the same as for the proposed project. As discussed above for Impact MB.4, vessel trips would remain the same as the proposed project. This impact is considered *significant but mitigable (Class II) with mitigation*. Mitigation Measures MB-1c and MB-4 ~~and MB-5~~would apply to this alternative.

Impact MB.6 - Impingement and Entrainment: The impacts of seawater intake at Platform Irene would be the same as for the proposed project.

Impact MB.7 - Lighting: The impacts of lighting on non-avian marine organisms would be the same as for the proposed project, *adverse but not significant (Class III).*

***Impact MB.~~7~~8* - Pipeline Burial**: ~~would disturb soft bottom habitats~~This impact would not apply to this alternative.

Impact #	Impact Description	Phase	Residual Impact
MB.~~8~~9	Marine organisms would be impacted by accidental discharge of drilling muds and cuttings during transit to shore.	*Drilling*	*Class III*

This alternative would eliminate the localized impacts to marine resources of discharge of muds and cuttings at the platform. With this alternative, there would be a risk of an accidental release of drilling muds during a vessel accident (e.g., a collision). In addition, the risk of accidental spills would increase as the muds and cuttings are transferred to and from the boats. Spillage in tranquil sea conditions where dilution and dispersion are reduced could result in impacts to shoreline biota. However, there is a low risk of a drilling muds release during transit to shore and if released, the volume would be small and impacts transitory. This impact to kelp and other nearshore resources is considered to be *adverse but not significant (Class III).*

Mitigation Measures

See Mitigation Measures MWQ-3 and MWQ-4.

Residual Impact

Because any release would be of limited volume, impacts to the shoreline biota associated with this alternative are deemed to be *adverse but not significant (Class III*).

5.5.6 Cumulative Impacts

For marine biology issues, the relevant cumulative projects addressed are limited to the offshore oil and gas projects summarized in Sections 4.2 and 4.3. The onshore development projects discussed in Section 4.4 would not impact marine biology.

Under the cumulative project scenario, several offshore energy projects could occur in the same area as the proposed project. As outlined by the MMS (MMS, 2005), the following cumulative or compounding impacts related to marine biology could potentially occur:

Impact MB.1 – Oil Spills: Oil spills resulting from the proposed project may impact marine organisms in the project area. The additional cumulative projects outlined in Section 4.2 and 4.3 would increase the probability for oil spills to occur and the potential size of those spills. Hence, oil spill impacts to marine organisms would increase significantly, and the proposed project's incremental contribution to these impacts would also be considered significant.

Impact MB.2 – Muds Discharge: Each of the additional cumulative projects would be expected to discharge drilling muds and cuttings. The impacts from the discharges would be expected to be the same as for the proposed project. Because of the dilution and localized dispersion of each discharge, drilling muds or cutting depositions would not be expected to compound or accumulate in any specific area. Hence, cumulative impacts, including the proposed project's contribution to them, would not be expected to be significant.

Impact MB.3 – Produced Water Discharge: The discharge of produced water from Platform Irene may potentially impact marine organisms in the project area. Each of the cumulative projects would be expected to discharge produced water. Because of the dilution and localized dispersion of each produced water discharge, impacts would not be expected to compound or accumulate in any specific area. Therefore, cumulative impacts, and the proposed project's incremental contribution to them, would not be expected to be significant.

Impact MB.4 – Noise: Noise caused by future offshore development activities would disturb marine mammals and seabirds. The additional future offshore projects in the northern Santa Maria Basin that are summarized in Sections 4.2 and 4.3 would increase the number of vessels and aircraft that operate in the project area. The number of these trips could increase substantially. However, because noise and sounds generated from the proposed project are highly localized and/or short-term in nature, its incremental contribution would not be expected to significantly compound or accumulate noise-related impacts. Cumulative impacts would not be expected to be significant.

Impact MB.5 – Vessel Traffic: Increased vessel traffic resulting from the proposed project may impact marine mammals. Vessel traffic would also increase as the result of development of the additional offshore energy projects outlined in Sections 4.2 and 4.3. The probability for collisions between project vessels and marine mammals could increase substantially. With implementation of the mitigation measures outlined in Section 5.5.4, the proposed project's incremental contribution to these cumulative impacts would not be expected to be significant. Similarly, overall cumulative vessel traffic impacts associated with future offshore development would not be anticipated to be significant if mitigating measures such as those outlined in Section 5.5.4 were applied.

Impact MB.7 - Lighting: As presented in Sections 4.2 and 4.3, there is limited potential for the development of new offshore light sources in offshore California federal and State leases. While most of the cumulative projects would involve the use of existing platforms, pipelines, and processing facilities to the maximum extent feasible, or the development of the offshore leases from an onshore location, Section 4.2.5 describes the potential for up to four new platforms offshore of the Gaviota Coast (one platform) and northern Santa Maria Basin (three platforms) The proposed project would not involve a new offshore light source, but a continuation of the existing lighting conditions on Platform Irene. All of the existing offshore oil platforms in the Southern California Bight and Santa Maria Basin have the potential to adversely affect seabirds, including the State threatened Xantus' murrelet and ashy storm petrels, a California Species of Special Concern. In addition, vessels operating in these areas, especially fishing vessels that use bright lights to assist with fishing, have the potential to attract and harm seabirds. Because of its distance from Xantus' murrelet nesting areas on the Channel Islands, the contribution of Platform Irene lighting on potential impacts related to artificial lighting to this species would be nominal compared to platforms in the Southern California Bight, which are closer to the nesting islands and within the usual foraging range of breeding birds.

5.5.7 Mitigation Monitoring Plan

Mitigation Measure	Plan Requirements and Timing	Method of Verification	Timing of Verification	Party Responsible For Verification
MB-1a	The November 2004 Core OSRP and July 2005 Supplement shall be updated to incorporate changes in platform activities that result from the proposed project. For example, the plan shall incorporate detailed response procedures for marine oil spills resulting from a blowout if wells producing the Tranquillon-Ridge field are expected to be free flowing. Worst-case discharge scenarios shall be updated accordingly. In addition, lessons learned from the cleanup of the 1997 oil spill shall be incorporated into the Response Plan. The efficacy of various containment and cleanup techniques applied during the 1997 spill shall be evaluated with regard to potential future spills. Hindcasts of the observed oil-spill trajectory shall be used to improve site-specific trajectory models. Potential ecological damage resulting from cleanup techniques applied in 1997 shall be discussed. The updated OSRP shall specifically detail methods to reduce impacts to sea otters and pinniped colonies should a spill occur. This discussion shall include methods for preventing oil from reaching pinniped colonies and places where otters congregate, and detailed protocols for handling and rehabilitation of oiled otters and pinnipeds. Specific methods to avoid disturbing pinniped colonies during cleanup activities shall be identified. The updated OSRP shall also re-	Review of OSRP and annual training logs.	Prior to drilling followed by annual audits of the OSRP and training logs and manuals	SBC P&D, CSLC, CCC, CDFG, MMS

Mitigation Measure	Plan Requirements and Timing	Method of Verification	Timing of Verification	Party Responsible For Verification
	evaluate the toxicity of Corexit 9527 and its inclusion as a potential dispersant for the Tranquillon Ridge project, based on current information. The personnel and training sections of the OSRP shall be updated to identify training requirements for all personnel who would respond to oil spills. At a minimum, new personnel shall be trained immediately in the overall operational aspects of oil spill response, including the proper use of all equipment that would be utilized in spill response. Annual training for all personnel shall also be included in the OSRP. The annual training shall include training in the operation of new equipment that may be utilized in oil spill response, retraining in the operation of existing equipment, and review of the oil spill response requirements that are identified in the OSRP.			
MB-1b	In order to provide a baseline for shoreline clean-up efforts in the event of a spill, the applicant shall contribute to the funding of a program to document the amount, variability, and chemical fingerprint of the tar normally present in the intertidal zone within the potential oil spill zone. The program shall include both visual observations and chemical sampling of tar along five segments (less than or equal to one-mile each) of shoreline located within the area of the coast located between Point Sal and Point Conception. The program shall continue for as long as Tranquillon Ridge Field development is occurring or until analysis of the collected data indicates that extension of sampling will not significantly increase understanding of the pattern of tar deposition and improve documentation of the baseline. The amount of tar shall be estimated and its chemical fingerprint determined, based on the shoreline tar sampling protocol used by the U.S. Geological Survey (USGS) in its MMS-funded study “Submarine Oil and Gas Seeps of the Southern Offshore Santa Maria Basin, California” (2001-2004). The program shall document visual observations and chemical sampling. The samples shall be analyzed for chemical fingerprint in the USGS laboratory. If analysis by the USGS is not available, another comparable fingerprinting method may be substituted. Annual cost of the applicant’s contribution to this program shall not exceed $100,000. The program shall be developed in	Receive funding	Prior to production	SBC P&D, CSLC, CCC, CDFG, MMS

Mitigation Measure	Plan Requirements and Timing	Method of Verification	Timing of Verification	Party Responsible For Verification
	cooperation with Santa Barbara County's Department of Planning and Development, and shall be coordinated by the Energy Division. The Energy Division shall evaluate the program on an annual basis in coordination with staffs of the California State Lands Commission, California Coastal Commission, Department of Fish and Game Office of Spill Prevention and Response, and Minerals Management Service. If new information indicates that changes to the methodology or protocol would improve the efficiency or accuracy of determining baseline oiling conditions, the County shall revise the program. Any revisions to the program shall not cause the annual cost to the applicant to exceed the $100,000 limitation			
MB-1c	PXP shall make a yearly contribution not to exceed $90,000 (in 2007 dollars) toward establishing a marine mammal and sea bird impact mitigation fund. The funding shall be used for either facilities construction or operating costs associated with the rescue and rehabilitation of injured marine mammals and sea birds. This yearly contribution shall be credited toward PXP's annual Coastal Resource Enhancement Fund (CREF) assessment for environmentally sensitive resource impacts, as currently required by Condition N-1 of PXP's Final Development Plan for the Point Pedernales Project.	Annual payment.	Annual	SBC
MB-2	The shunt depth (150 feet below the sea surface) for the discharge of drilling muds and cuttings shall be continued for the proposed project. The shunt depth shall be stated in the development plan that is submitted to MMS prior to drilling.	Site inspection	Prior to drilling activities	MMS
MB-3	The shunt depth (180 feet (55 m) below the sea surface) for the discharge of produced water shall be continued for the proposed project. The shunt depth shall be stated in the development plan that is submitted to MMS prior to drilling.	Site inspection	Prior to production	MMS
MB-4	A marine mammal observer shall be employed on each vessel servicing Platform Irene as described herein. The observer shall be provided training, which focuses on the identification of marine mammal species, the specific behavior of species common to the project area, and awareness of seasonal concentrations of marine mammals. The marine mammal observer shall be placed on all support vessels during the spring and fall gray whale migration periods and during periods/seasons having high concentrations of marine mammals in the project area, such as the early summer blue whale migration. The	Review of training plans and annual training logs	Prior to drilling activities	MMS

Mitigation Measure	Plan Requirements and Timing	Method of Verification	Timing of Verification	Party Responsible For Verification
	observer shall have no other responsibilities during periods when the vessels are in transit. The observer shall have unobstructed views onboard each vessel and serve as lookout so that collisions with marine mammals can be avoided. Additionally, vessel operators or the applicant shall develop, submit for approval, and implement a contingency plan that focuses on avoidance procedures when marine mammals are encountered at sea. Minimum components of the plan include: a) Vessel operators will make every effort to maintain a distance of 1,000 feet from sighted whales and other threatened or endangered marine mammals or marine turtles. b~~) Support vessels will not cross directly in front of migrating whales or any other threatened or endangered marine mammals or marine turtles.~~ Vessel operators shall avoid travelling through blue whale feeding grounds and shall adjust transit routes to avoid large-scale krill populations during the annual blue whale migration period in the Santa Barbara Channel. c) When paralleling whales, support vessels will operate at a constant speed that is not faster than the whales. e) Female whales will not be separated from their calves. f) Vessel operators will not herd or drive whales. g) If a whale engages in evasive or defensive action, support vessels will drop back until the animal moves out of the area. Any collisions with marine wildlife will be reported promptly to the Federal and State agencies pursuant to each agency's reporting procedures.			
~~MB-5~~	~~PXP shall make a yearly contribution of $90,000 toward establishing a marine mammal and sea bird impact mitigation fund. The funding shall be used for either facilities construction or operating costs associated with the rescue and rehabilitation of injured marine mammals and sea birds. This yearly contribution shall be in lieu of the applicant's annual three (3) point Coastal Resource Enhancement Fund (CREF) assessment for biological resource impacts, as currently required by Condition N-1 of PXP's Final Development Plan for the Point Pedernales Project.~~	~~Annual payment.~~	~~Annual~~	~~SBC~~

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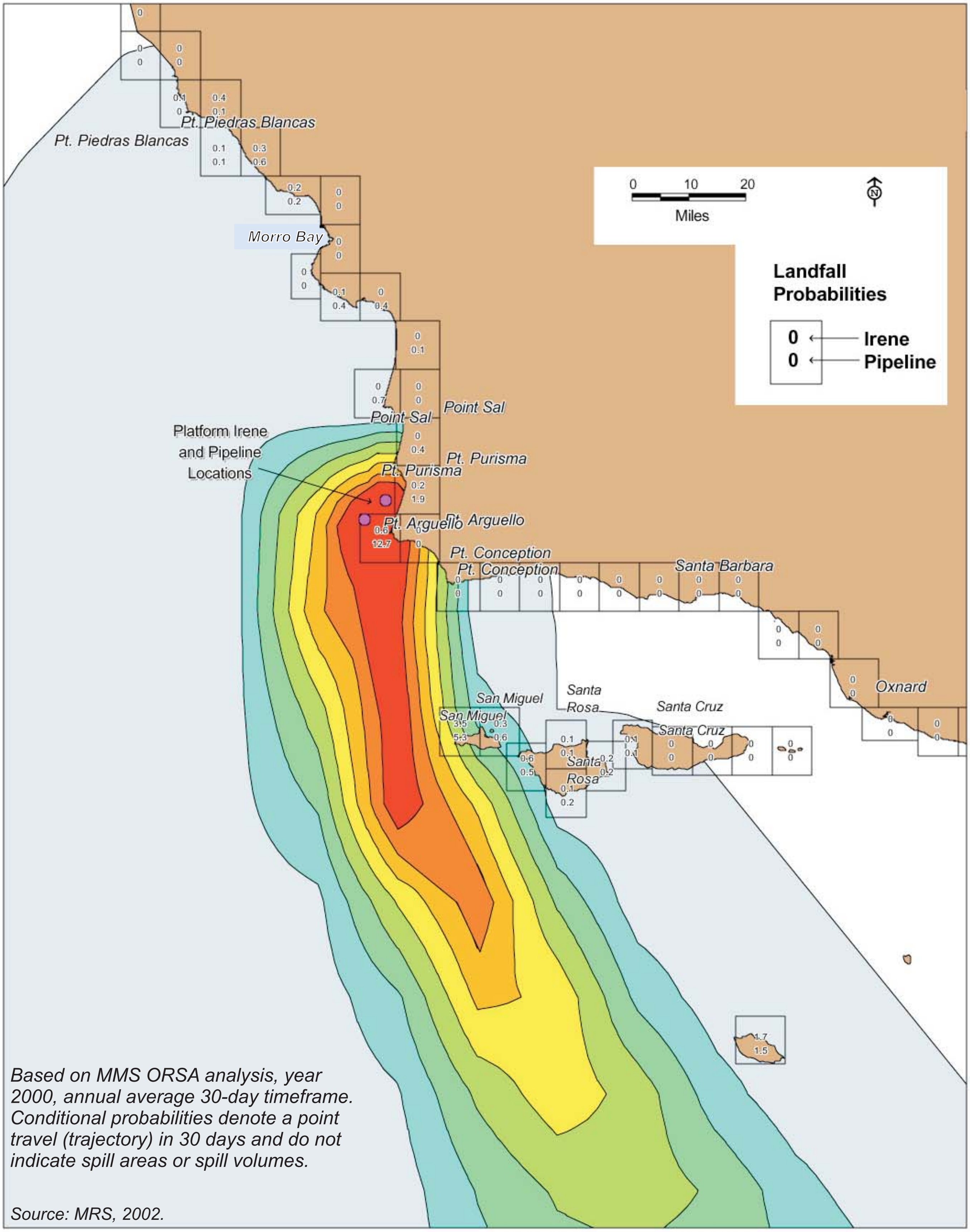

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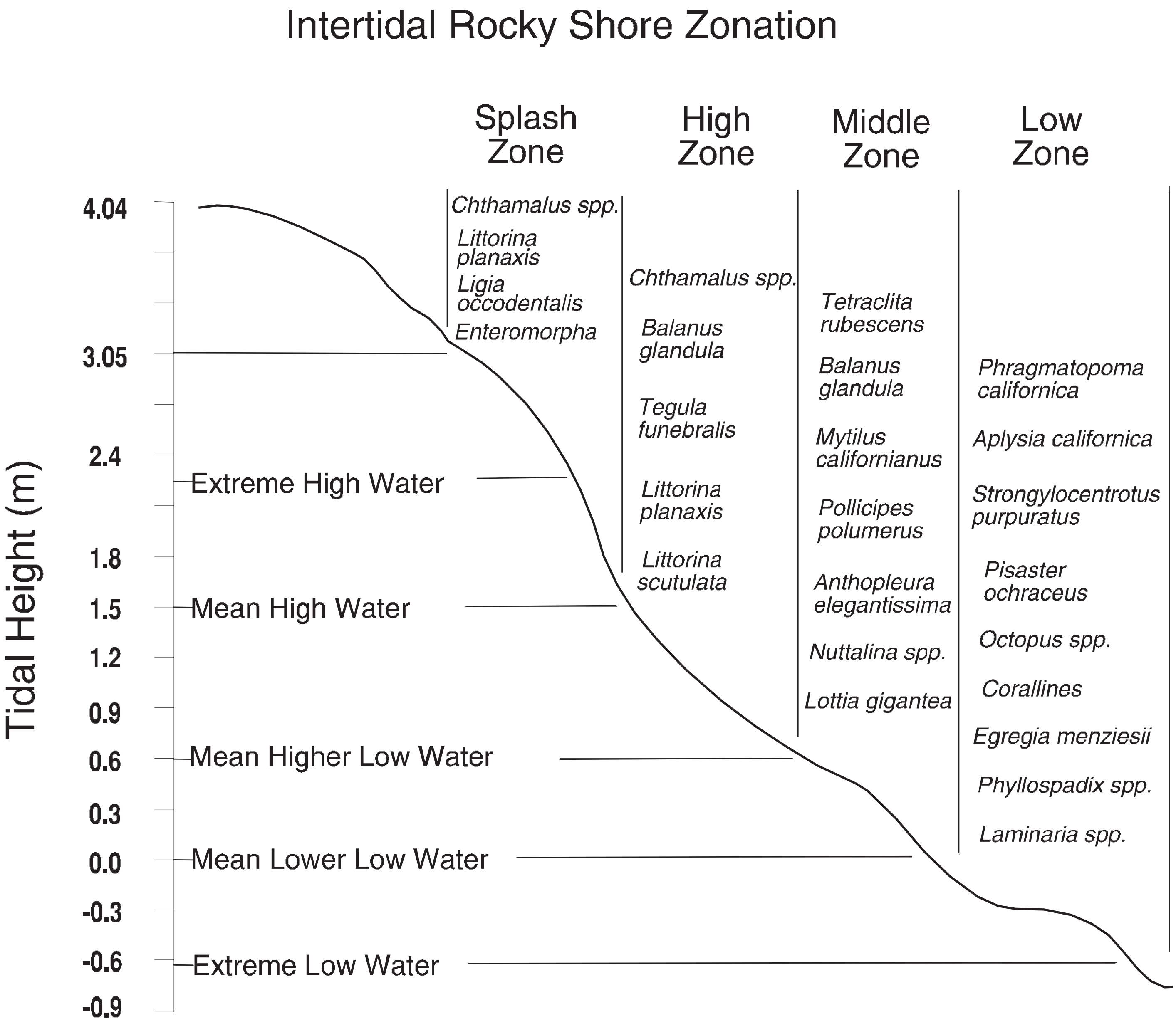
Figure 5.1-1
MMS OSRA Probabilities (5) of Oil Spill Impact for Platform Irene and Pipeline



Source: MRS, 2002.

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Figures 5.5-2
Intertidal Zonation of a Rocky Shore in Southern Calironia

5.6 Oceanography and Marine Water Quality

This section describes the marine water and sediment quality in the southern Santa Maria Basin (SMB) where the offshore activities of the proposed project would take place. It also includes a description of regional meteorology and physical oceanography because they largely determine the proposed project's marine impacts. The additional directional drilling and production from Platform Irene are not expected to materially affect the oceanic flow field or meteorological conditions in the project area. However, periods of extreme wind or sea conditions could limit or delay cleanup of an offshore oil spill and surface currents and winds dictate the trajectory of an oil spill. Subsurface flow disperses drilling muds, cuttings, and produced water discharged from Platform Irene. The oceanic flow field (major currents, eddies, etc.) also establishes the baseline physical and chemical properties of the receiving waters for spills or other discharges. Water quality parameters such as temperature, salinity, and turbidity near Platform Irene would be impacted by the increased discharge of drilling fluids and produced water.

5.6.1 Environmental Setting

Platform Irene lies six miles west of Point Pedernales in an oceanographically complex region. Flow around the platform constantly changes in response to competing geophysical forces. As presented in Section 5.6.1.2, the proposed project's 15 or more years of drilling would encompass a broad range of meteorological and oceanographic conditions including major El Niño events that significantly alter the ocean environment over year-long periods.

5.6.1.1 Sources of Data

A large number of oceanographic studies have been conducted on the continental shelf adjacent to Platform Irene. Figure 5.6-1 shows the location of measurements collected during the field studies listed in Table 5.6.1. Taken as a whole, these studies adequately characterize regional oceanographic processes and water-quality properties in the region. However, individual studies are not sufficiently comprehensive for a complete environmental assessment and some of their limitations are outlined below. Technical results from these individual studies are assimilated in the subsections that follow.

Santa Barbara Channel – Santa Maria Basin Coastal Circulation Study (SBCh-SMB)

This multi-year observational study was conducted by Scripps Institution of Oceanography under the auspices of the MMS. Measurements, which include current-meter moorings, surface drifters, and hydrographic transects, emphasized a description of the surface circulation within the Santa Barbara Channel (SBCh). Interim results were summarized by Dever et al. (1998), Harms and Winant (1998), Hendershott and Winant (1996), and Winant et al. (1999). Results from these measurements were incorporated in the MMS Oil Spill Risk Analysis (OSRA) numerical model used to compute oil-spill trajectories and risk of impingement on coastlines. As described in the following sections, there are discrepancies between the model results and drifter data. Recent research papers using oceanographic data collected during this program include Pidgeon and Winant (2005), Winant et al. (2003), and Dever and Winant (2002).

Table 5.6.1 Oceanographic Data Collected in the Studies Identified in Figure 5.6-1

Acronym	Study Title	Benthic Biology	Current Flow	Winds & Climatology	Waves	Sediment Chemistry	Water Quality	Tissue Body Burden	Coliform
Avila	Avila Beach County Water District								X
CalCOFI	California Cooperative Oceanic Fisheries Investigations[1]						X		
CaMP	California Monitoring Program[2]	X	X	X	X	X	X		
CCCCS	Central California Coastal Circulation Study[3]		X	X			X		
DCNPP	Diablo Canyon Nuclear Power Plant	X	X			X	X		
MB/C	Morro Bay/Cayucos Offshore Monitoring[4]	X	X			X	X		X
NDBC	NOAA Data Buoy Center[5]			X	X				
NS&T	NOAA National Status & Trends (Mussel Watch)[6]					X		X	
OPUS	Organization of Persistent Upwelling Structures[7]		X	X			X		
PB	Pac Baroness Survey[8]	X				X		X	
PH	Platform Harvest[9]			X	X				
SCS	Monitoring of Coastal Contaminants Using Sand Crabs							X	
SCODE	SuperCODE[10]		X	X					
SBCh-SMB	Santa Barbara Channel – Santa Maria Basin Coastal Circulation Study[11]		X	X					
SMW	State Mussel Watch[12]							X	
SSLO	South San Luis Obispo County Sanitation District[13]	X				X			
USMR	Unocal Santa Maria Refinery[14]	X	X						
WIS	Wave Information Study[15]				X				

[1] *SIO, 2000*
[2] *Hyland et al., 1990; Coats et al., 1991; Savoie et al., 1991; Steinhauer et al., 1994*
[3] *Chelton et al., 1987; Chelton et al., 1988*
[4] *MRS, 2001*
[5] *NODC, 1992*
[6] *BOS, 1991a*
[7] *Atkinson et al., 1986*
[8] *Hyland et al., 1989*
[9] *Seymour, 1996*
[10] *Denbo et al., 1984*
[11] *Hendershott and Winant, 1996*
[12] *SWRCB, 1988*
[13] *ABC, 1995*
[14] *KLI, 1996*
[15] *Jensen et al., 1989*

The MMS sponsored a related modeling investigation of the flow regime within the SBCh (Gunn et al., 1987; Oey et al., 2004). Although flow-field results do not encompass the SMB where Platform Irene is located, oil spills associated with the proposed project could be transported into the SBCh. Also, potential spills from the existing offshore oil facilities within the SBCh could have a cumulative effect on the marine environment along the shorelines surrounding the proposed project. Fifteen current-meter moorings were deployed in the SBCh during 1984 to initialize the circulation model. These data were augmented by five hydrographic surveys and three surface-drifter studies.

Wave Information Study (WIS)

In late 1976, the U.S. Army Corps of Engineer's Waterways Experiment Station embarked upon a Wave Information Study (WIS) to establish the wave climatology for U.S. coastal waters. In March 1989, the seventeenth in a series of reports was published which presented hindcast shallow-water wave data for 134 shoreline segments north of Point Conception (Jensen et al., 1989). Coastline Section Number 132 extends between Point Arguello and Purisima Point and encompasses the shoreline adjacent to Platform Irene and the landing site for the offshore pipeline that transports crude oil to the LOGP. Wave statistics were computed at a depth of 10 m from atmospheric pressure and wind velocity data collected over a 20-year period. These near-shore wave statistics were derived from offshore wave climatology that excluded waves generated by distant tropical storms and southern-hemisphere swell. A new Pacific basin hindcast for 1995-2004 has been done. Wave models based on wave buoy data recently were assessed using satellite altimeter data (Baird and Associates, 2005).

Platform Harvest

A directional wave gauge array was installed on Platform Harvest in 1992. Although the wave record is limited compared to the WIS, it measures all incident waves regardless of origin, including those from tropical and southern-hemisphere storms. Also, the array is capable of high directional resolution on the order of 1 degree (°). Seymour (1996) provided a deep-water summary of wave climatology based on data from this and other wave gauges.

NOAA Data Buoy Center (NDBC)

Two NDBC ocean buoys have collected meteorological and oceanographic data over a long period near the Rocky Point project area. NDBC Buoy 46023 lies northwest of Point Arguello and is the closest buoy to Platform Irene. A smaller NDBC buoy (46011) lies directly offshore of Point Sal in shallower water. Finally, Buoy 46062 lies southwest of Point Buchon. Wind climatology from these and other NDBC buoys has been summarized by Caldwell et al. (1986), Miller et al. (1991), Dorman and Winant (1995), and Winant and Dorman (1997). Data from Buoy 46011 also was summarized recently by Goericke et al. (2004, 2005).

California Cooperative Oceanic Fisheries Investigations Program (CalCOFI)

The California Cooperative Oceanic Fisheries Investigations (CalCOFI) program was organized in the late 1940s and constitutes one of the most extensive long-term hydrographic data sets in existence. CalCOFI Line 80 is a cross-shelf transect that extends offshore from Point Conception. Line 77 lies to the north and extends offshore Point Buchon. Data on salinity, temperature, oxygen, nutrients (silicate, phosphate, nitrate, and nitrite), and primary productivity have been collected for decades along these CalCOFI lines (SIO, 2000). The closest CalCOFI station to Platform Irene is Line 80 Station 51, which is 14 nautical miles from Platform Irene. Between 1955 and 1971, drift bottles were released in this area and those data are summarized by Crowe and Schwartzlose (1972), Schwartzlose and Reid (1972), and Reid (1965). More recently, the CalCOFI hydrographic data has been used to describe the central-coast flow regime by Chelton (1984) and Hickey (1979). The state of the California Current using data that includes data collected along Line 77 and Line 80 is summarized yearly in CalCOFI Reports. Recent summaries include Goerkicke et al. 2004, 2005; Venrick et al. 2003; and Schwing et al. 2002.

Organization of Persistent Upwelling Structures Program (OPUS)

The Organization of Persistent Upwelling Structures (OPUS) program was designed to synoptically sample the physical and biological processes associated with a localized persistent upwelling system near Point Arguello (Atkinson et al., 1986). Current meter moorings were deployed offshore of Purisima Point and hydrographic observations and current-velocity profiles were collected in the winter of 1983 when anomalous oceanographic conditions associated with an El Niño were extant (Brink and Muench, 1986; Barth and Brink, 1987; Dugdale and Wilkerson, 1989).

California Monitoring Program (CaMP)

The MMS and the National Biological Service performed long-term oceanographic studies in the southern SMB between 1983 and 1995. This California Monitoring Program (CaMP) investigated the fate and effects of petroleum development activities in the region between Point Arguello and Point Conception (Hyland et al., 1990). Long-term current-meter moorings were deployed to augment water quality, sediment chemistry, and marine biological measurements. The influence of wind forcing and transient eddies on the local flow regime and upwelling was examined by SAIC (1995), Savoie et al. (1991), Bernstein et al. (1991), and Coats et al. (1991).

Central California Coastal Circulation Study (CCCCS)

The MMS-sponsored Central California Coastal Circulation Study (CCCCS; Chelton et al., 1987) was conducted along the central California continental shelf and slope between Point Conception and San Francisco Bay. Extensive hydrographic (water property) surveys were conducted over 18 months in 1984 and 1985 in conjunction with moored current meter and surface drifter deployments along the south central coast. Results from the CCCCS were presented by Chelton et al. (1988) and drifter data was presented by Chelton (1987).

State Mussel Watch (SMW)

The State Mussel Watch Program is a long-term marine water quality monitoring program administered by the State Water Resources Control Board (SWRCB) and conducted by the California Department of Fish and Game (CDFG). Pollutant concentrations in marine organisms have been measured at a number of sites since 1977. Figure 5.6-1 shows that sampling Station 449 at Point Arguello is closest to Platform Irene and is within the Tranquillon Ridge Field (SWRCB, 1988). In more recent years, the SMW focused on sampling polluted areas. Station 449 has not been sampled since 1978. Station 450 at Point Conception was sampled most recently in 1991 (SWRCB, 1995).

National Status and Trends (NS&T)

The goal of ~~the~~ NOAA's National Status and Trends (NS&T) Program is to quantify the current status of environmental quality of U.S. coastal waters. The Mussel Watch component of the NS&T Program analyzed contaminants both in the California mussel (*Mytilus californianus*) collected at 29 sites along the west coast of North America, and in the edible blue mussel (*Mytilus edulis*) collected at 31 sites. California mussels were collected in 1990 within the Tranquillon Ridge Lease Area at Station PCPC at Point Conception (BOS, 1991). The most recent samples collected at Station PCPC were in 2000, 2002, and 2004. Another component of the NS&T Program is the Benthic Surveillance Project which collected and analyzed surficial sediment chemistry at a number of sites along the California coast, including site SLUOB within

San Luis Obispo Bay located north of the project area (Figure 5.6-1). Benthic surveillance data was collected at most sites between 1984 and 1988. Sediments at Site SLUOB were collected in 1988. Since that time, sediment collection ceased at sites where sediment had been sampled in a prior year. NOAA continues to sponsor the collection and analysis of mussel tissue nationwide. Site SLUOB has not been sampled since 1988.

Monitoring of Coastal Contaminants using Sand Crabs

Recently the Central Coast Regional Water Quality Control Board has investigated the use of sampling the contaminant levels in the sand crab, *Emerita analoga*, as a way of monitoring for pollutants (Dugan et al., 2005). The pilot studies included samples of sand crabs at Surf Beach and Jalama in the general vicinity of the Tranquillon Ridge Project.

NPDES Monitoring Programs (Avila, DCNPP, MB/C, SSLO, SMR)

Water quality monitoring is usually required when wastewater is discharged into the ocean through an outfall. A number of point source discharges are located along the south central coast of California. They provide a valuable long-term source of data on sediment and water quality near the study area. However, because monitoring is conducted around a point source, results are limited spatially.

The South San Luis Obispo County Sanitation District (SSLO) discharges wastewater through an outfall in 60 feet of water offshore of Oceano. They conduct benthic surveys that include biological assessments and physicochemical analyses of sediments around the outfall on a triennial basis (ABC, 1995).

The Santa Maria Refinery (SMR) Ocean Monitoring Program is conducted near an ocean outfall extending 2,000 feet offshore of Oso Flaco Lake south of Oceano. The outfall was completed in 1954 and benthic monitoring has been conducted since the initial discharge (Rechnitzer and Limbaugh, 1956, 1959). Early studies included current measurements and fluorescent dye studies in addition to marine biological surveys. Recent NPDES monitoring focused only on benthic measurements (KLI, 1996).

Other NPDES water-quality monitoring programs are conducted by the City of Morro Bay and Cayucos Sanitary District (MB/C) and Avila Beach dischargers. The Diablo Canyon Nuclear Power Plant conducts an extensive monitoring program around its thermal discharge although distribution of monitoring reports is limited.

Platform Discharges Monitoring Programs

In 1989, MMS, Pacific OCS Region and EPA Region 9 signed a Memorandum of Agreement (MOA) detailing the role each agency would play in conducting NPDES inspections and sampling at the offshore oil and gas platforms (MMS, 2005). A workplan is created annually by EPA and MMS that gives the details of the inspection and sampling efforts and includes the number, location, and type of samples to be taken. Inspections and sampling are unannounced.

5.6.1.2 Oceanographic Setting

An abrupt change in coastline orientation occurs between Point Arguello and Point Conception (see Figure 5.6-1). This large-scale change in coastal configuration induces much of the complexity in wind, wave, and oceanic flow fields near the Platform Irene. Coastal isobaths, or depth contours, are aligned along a north-south axis in the southern SMB and Platform Irene lies at the southernmost reaches of the basin. To the southeast, the coastline of the Santa Barbara Channel (SBCh) is oriented along an east-west axis. The Tranquillon Ridge Field lies within the transition zone between the SMB and SBCh. Within this area isobaths are aligned along a northwest-southeast axis.

This coastal transition zone is influenced by markedly different physical processes than those that dominate within the two adjacent regions. Along the central California coast to the north, physical processes are strongly influenced by seasonally varying winds that blow uniformly to the south over a wide geographic area. The large-scale oceanic flow field beyond the continental slope is dominated by the southward-directed California Current. Waves generated over a large fetch, or length of water over which a given wind has blown, impinge on the coastline from directions that encompass an azimuth of effectively 180 degrees. In contrast, the SBCh is sheltered from waves generated by distant storms to the north and the Channel Islands limit wave propagation from the south. Similarly, the east-west coastal configuration blocks the large-scale southward-directed winds that prevail outside the SBCh. Finally, the California Current separates from the coast near Point Arguello leaving other processes to control the flow within the Channel.

Despite their complexity, it is important to quantify physical processes within the project area. Surface flow fields determine the transport of spilled oil and the likelihood of impingement on adjacent coastlines. Subsurface flows dictate the transport and dispersion of additional drilling fluids that would be discharged from Platform Irene during the proposed extended reach drilling. They also determine the fate and effects of additional produced waters discharged from the platform during the production phase. Finally, the seastate, as determined by prevailing winds and waves, affects the efficacy of oil-spill contingency plans that rely on chemical dispersants or containment for cleanup.

Ocean Circulation

The flow field near the project area is influenced by a number of competing physical processes. Processes operating on the open-ocean flow field at distant locations exert their influence locally through major ocean currents that traverse the North Pacific Ocean. Beyond the continental slope (>100 km), the diffuse southward-flowing California Current represents the eastern limb of the clockwise-flowing gyre, or circular ocean current, that covers much of the North Pacific Basin. Before turning south to form the California Current, subarctic water is carried along at high latitudes and is exposed to precipitation, atmospheric cooling, and nutrient regeneration. As a result, waters of the California Current are characterized by a seasonally-stable low salinity (32 to 34 percent), low temperature (13°C to 20°C), and high nutrient concentrations. They undergo less seasonal variation than surface waters at similar latitudes on the eastern seaboard.

Immediately shoreward of the California Current, along the central California continental slope and shelf, is a northward-flowing counter current that carries water out of the SBCh. These southern waters are warmer, more saline and less oxygenated than offshore waters. This northward-flowing Davidson countercurrent exhibits strong seasonal variability in intensity but maintains a sustained northward flow at depth in the SMB despite reversals observed elsewhere along the California coast (Chelton et al., 1988; Coats et al., 1991, Hendershott, 2001).

Seasonal variability in the Davidson Current coincides with large-scale fluctuations in coastal winds along the central California coast. On average, winds are directed toward the south, parallel to the coast (Dorman and Winant, 1995). The northward-flowing Davidson Current is strongest when these southward winds relax between December and February. A rapid spring transition to stronger southward winds occurs between March and June when the Davidson Current weakens and can even turn southward near the sea surface. These strong southward winds in the spring also induce intense upwelling near Point Arguello. During upwelling, surface water near the coast is transported offshore and is replaced by cool, nutrient-rich water from deep offshore.

Significant interannual (year-to-year) variations in oceanographic properties and marine zoogeography also occur within the SMB. These large amplitude variations are associated with the El Niño - Southern Oscillation, which cycles at a period of 3 to 5 years (Graham and White, 1988). During El Niño periods, such as between 1997 and 1998, basin-wide changes in the dynamic balance of wind-driven currents results in modified flow patterns along the coastline of western North and South America (Chelton et al., 1982; Dever, 2001a). Changes within the SMB include an anomalous strengthening of Davidson Current outflow from the SBCh. This increased outflow carries warm, saline sub-tropical waters northward into the SMB. It coincides with increased winter storm activity, reductions in zooplankton biomass, and the introduction of tropical marine organisms typically found much farther south.

Superimposed on these large-scale oceanic flows are a variety of transient phenomena including intense eddies, swirls, filaments, meanders, and narrow jets of flow. These mesoscale (medium-sized) turbulent features are often observed in satellite imagery and are capable of transporting significant quantities of heat, nutrients, and pollutants to offshore waters (Savoie et al., 1991). Winds, tides, and waves also mix and transport nearshore waters within the surfzone. Tidal currents mix ocean waters near the coast, although they are not responsible for significant net transport. At shorter periods, shoaling (effects on waves when they start to feel the bottom as they approach the shore) and surface gravity waves mix coastal seawater in both the horizontal and vertical directions. Because of the semi-arid climate, substantial drainage from onshore is rare and regional water properties are largely determined by oceanographic processes. Nevertheless, river runoff during intense winter storms can significantly impact marine waters within localized areas of the California coast, including the southern SMB (Hickey, 2000).

Long-term current monitoring near Point Arguello has yielded a consistent picture of the flow near the project area (SAIC, 1995; Savoie et al., 1991; Bernstein et al., 1991; Coats et al., 1991). While subsurface currents are directed toward the northwest throughout the year, monthly-averaged surface currents reverse during spring upwelling when southward-directed winds intensify. Between approximately April and June, isolated two-to-five-day events of intense southward winds are followed, after approximately 17 hours, by southward current flow that has an offshore component (Savoie et al., 1991). The intensification of southward winds also causes upwelling that can be seen in satellite imagery as a cold-water plume extending offshore near Point Conception (Svejkovsky, 1988; Shears and Kenyon, 1989). These distinct upwelling events increase the rate of new biological production (Dugdale and Wilkerson, 1989) and affect the distribution of water-mass properties (Reid, 1965).

The flow regime within the transition zone immediately south of the SMB differs from the rest of the California coast. To the north, surface flows are predominantly southward throughout the year (Strub et al., 1987a and b; Hendershott, 2001). However, distant forcing, in the form of sea-level differences, contributes significantly to the flow dynamics within the southern SMB and SBCh. The SBCh is relatively sheltered from the strong southeastward-directed prevailing winds and the influence of the sea-level differences is revealed in the predominantly counterclockwise flow pattern (Caldwell et al., 1986; Brink and Muench, 1986; Harms and Winant, 1994, 1998). The influence of sea-level differences is particularly evident within the southern SMB and SBCh when southward-directed upwelling winds along the central coast relax (Hendershott, 2001).

Surface Transport

The fate and effects of accidental oil spills that could be caused by the proposed project are largely dictated by transport along the ocean surface. Even seafloor releases from the 20-inch crude-oil pipeline that extends onshore from Platform Irene would rapidly rise to the sea surface. Precisely such a spill occurred along this pipeline in 1997 when somewhere between 163 and 1242+ barrels of crude flowed from a break located midway along the line. Most of the crude remained offshore but some of the spilled crude washed ashore along a 15-mile stretch of beach near the mouth of the Santa Ynez River where the pipeline reaches landfall (See Figure 5.6-1).

The trajectories of drifters released near the project area generally reflect the surface flow patterns measured by long-term current-meter moorings (Crowe and Schwarzlose, 1972; Schwartzlose and Reid, 1972; Chelton, 1987; Winant et al., 1999). Namely, northwestward transport is observed throughout much of the year except during strong upwelling events that are most prevalent between April and June. Prevailing winds near Point Arguello are directed to the southeast except during brief, 3- to 4-day periods when winter storms disrupt the normal pattern as they pass through the region. More extended periods of northward- or eastward-directed winds also occur but on the whole, these wind conditions occur only approximately 10 percent of the time. Surface currents near the project area are generally directed to the northwest, in opposition to, and uncoupled with the prevailing southeastward winds (Savoie et al., 1991; SAIC, 1995). During the spring and early summer, brief episodes of intensified southward-directed winds result in a reversal of surface currents. For periods of up to a week, near-surface flows turn toward the southeast in opposition to the northwestward current direction that is maintained throughout most of the water column.

The opposing directions of the wind and surface currents near Point Arguello are evident in drifter studies. CalCOFI drifter bottles released north of the SBCh in December 1969 migrated northward at speeds exceeding 15 cm/s. However, at other times of the year, drift bottles released near Point Conception were recovered both to the north and to the south near San Diego. For release points near Point Arguello in 1984, many of the CCCCS surface drifters traveled south in response to strong southward directed winds (Chelton, 1987). It was only during a brief period when southward winds weakened in July that the majority of drifters moved northward. However, the CCCCS drifter design is susceptible to a downwind motion of approximately 0.5 percent of the wind speed and thus may not accurately represent surface currents alone.

The drifters used in the SBCh-SMB coastal circulation study were designed to minimize the influence of wind and wave drift in favor of tracking surface currents over a depth of approximately 1 m (Davis et al., 1982). As a result, flow statistics derived from the drifters compared well with that of the moored current meters (Dever et al., 1998). Discrepancies in mean flow direction have been ascribed to sampling bias (Dever, 2001b). Beginning in January 1995, many of these drifters were deployed within the SMB, including locations near the Tranquillon Ridge Field. Few of the drifters released near the Point Arguello – Point Conception region beached before exiting the region (Dever et al., 2000; Winant et al., 1999). In a manner consistent with the long-term current meter data collected as part of CaMP, initial offshore movement was followed by northward movement into the SMB in fall and winter. Spring and summer deployments were more likely to show southward flow toward San Miguel Island. Few drifters moved eastward into the SBCh.

The complex interaction between winds and surface currents near Point Conception makes predictions of oil spill trajectories difficult. During much of the year, but especially in the fall and winter, the northwestward surface flow is in direct opposition to the prevailing winds. Certainly these surface currents, as determined by current meters and drifters, have a direct bearing on the fate and effects of potential oil spills resulting from the proposed project. However, winds also influence the spread and trajectory of oil slicks on the sea surface. Empirical data from the open ocean suggests that the leading edge of an oil slick would drift at approximately 3 percent of the wind speed and oil-following drifters have been evaluated based on their ability to match this "3 percent rule" (Reed et al., 1988). However, there is no rigorously defensible theoretical basis or empirical data to support the application of this rule in coastal flow regimes. In the literature, estimates of the influence of wind on surface oil slicks vary from 1 percent to 6 percent. Part of the difficulty in estimating wind influence is that winds also drive ocean currents that move oil slicks and the two effects cannot always be easily separated.

An oil-spill risk analysis (OSRA) was performed using the MMS numerical model for the SBCh area (Arguello Inc., 2000). It calculated probabilities of shoreline impact after applying a drift equivalent to 3.5 percent of the prevailing wind velocity in its trajectory computations. Because of the heavy influence of southward-directed winds near Point Conception, the model results indicated that the probability of shoreline impacts along the Channel Islands to the south was far higher than at sites along the central coast to the north. The influence of southward directed winds in the model effectively overcame the northwestward surface currents observed throughout much of the year in the field programs (Browne, 2001). In addition, current averaging weakened the influence of northward-directed currents in the model. This contrasts with drifters deployed during the SBCh-SMB coastal circulation study, which tended to travel toward the south only approximately 31 percent of the time and only approximately 15 percent of these intersected the shoreline.

Clearly, the complexity of opposing winds and currents near the project area makes the reconciliation between OSRA model results and observations difficult. Because the applicability of the "3 percent wind rule" in complex coastal flow regimes has not been rigorously quantified, this environmental analysis considers the possibility for spilled oil to travel from the project area toward the north. In particular, if the spill occurs during a period when southward-directed winds weaken or clock around to the north, oil transport will be dominated by the prevailing northward surface current flow.

Similarly, the environmental assessment for the proposed project does not rely solely on shoreline impact probabilities determined exclusively from available drifter trajectories. Drifters, with their measurable mass and finite vertical profile below the sea surface, cannot capture the behavior of an oil slick that is typically only a few millimeters thick (Reed et al., 1988). Furthermore, dispersion and weathering affect the spread of oil on the sea surface, and buoys cannot capture the changing slick dynamics across a wide range of winds, waves, and currents. Goodman et al. (1995) and Simecek-Beatty (1994) tested the oil-tracking ability of several drifter designs, including the Davis et al. (1982) design used in the SBCh-SMB coastal circulation study. They found that Davis-type drifters lagged behind simulated oil slicks presumably because they are optimized to track surface currents with minimal influence by winds and waves. In cases where winds opposed surface currents, the Davis-type drifters moved into the prevailing wind and in a direction opposite of the simulated oil slicks made from wood chips. This is similar to the case in the southern SMB where the northward-flowing Davidson current often opposes the prevailing southward-directed winds.

Subsurface Transport

Subsurface currents are more important in determining the fate of drill muds and produced water discharged from Platform Irene. As described in Appendix D, drill-muds depositional patterns are less influenced by surface flow direction or the opposing winds. Consequently, drill-muds transport estimates are not subject to the same discrepancies between observations and modeling as are oil-spill trajectories. The subsurface flow in the project area is predominantly upcoast, regardless of the intensity of the southward-directed upwelling winds (Savoie et al., 1991; Hendershott, 2001). Therefore, drilling muds discharged at depth from the platforms would most often be transported to the north. This finding has been independently confirmed through a comparison of muds-trajectory modeling and drill-muds accumulations within seafloor sediment traps near platforms to the south of the project area (Coats, 1991) and for Platform Irene itself (Appendix D). On Platform Irene, drill muds are discharged from the platform The discharge point is at a depth of 46 m (150 feet) below the sea surface. The modeling results in Appendix D predicted that about half of the drilling mud would be deposited over a 9-km^2 area within about 1.7 km of the platform. Over 80 percent of the mud would be deposited within a 40-km^2 area within about 3.6 km of the platform. Less than 0.4 percent of the mud would travel farther than 10 km before being deposited on the seafloor. If produced water is discharged from the platform, the discharge point is at a depth of 55 m (180 feet) where the discharge would remain nearly neutrally buoyant (Brandsma, ~~2001~~ 2007a).

Mesoscale Flow Variability

Transient medium-sized turbulent features such as eddies, swirls, meanders and narrow jets of flow are superimposed on the larger scale current flows. Short-duration contaminant discharges are likely to be entrained within a single eddy as it propagates along the coastline while discharges that occur for a longer duration are likely to encounter a larger number of flow features and thus would be dispersed over a larger area of the ocean.

The persistence of these central-coast flow features can be determined from the time-lagged correlations shown in Figure 5.6-2. Over periods of less than two days, flow velocities remain somewhat coherent as a relatively slow-moving eddy or flow jet propagates along the coast. Between two and six days, the correlation between the velocity fields is lost because more than one turbulent feature occurs in the area. Therefore, contaminants discharged over a period of more than two days would be carried within a greater number of independent flow cells and would be dispersed over a larger area of coast.

Wave Climatology

The ambient sea state at the time of an oil spill determines the effectiveness of dispersants and booms deployed to contain the oil offshore (Lunel, 1995). Upon reaching the coastline, high surf determines the intertidal distribution of oil and the ability of cleanup crews to reach the affected area.

As with the flow field, wave climatology in the southern SMB reflects a transition from the sheltered environment of the SBCh and the exposed coastal region of the central California coast. Maximum design wave heights for 100-year return periods along the central California coast are 60 feet compared to 45 feet in the SBCh. Offshore platforms built within the SBCh do not have to withstand the same level of wave forces because of the sheltering effects from the Channel Islands and the orientation of the coastline (API, 1987). Without the benefit of island sheltering, Platform Irene experiences comparatively high structural loading from waves. Along the adjacent shoreline, energetic wave action forms a harsh intertidal environment for benthic organisms although the influence of waves generated by intense winter storms traversing far to the north is limited by the orientation of the coastline. Nevertheless, as a result of the comparatively high energy flux in the surf zone, intertidal organisms along sand beaches tend to be burrowers adapted to high turbidity and mechanical disturbance. The high wave-energy flux has enhanced erosion along this section of the California coast and much of the shoreline consists of rocky bluffs rather than the sand beaches that are prevalent in the SBCh.

Four primary meteorological sources generate waves in the SMB: extratropical winter cyclones in the northern hemisphere, northwesterly winds during the spring transition and summer, tropical disturbances offshore Mexico, and extratropical storm swell generated in the southern hemisphere during summer. The first two are the primary sources for the wave climate along the central California coast although the last two occasionally generate significant swell from the south.

Winter Storm Waves: These waves are generated by extratropical winter cyclones and are often accompanied by local rainfall along the coast. Extratropical storms are associated with low-pressure systems that develop along the polar front in the Pacific Ocean and propagate westward toward the central coast. Thus, major wave events often coincide with an increased marine discharge of terrestrial sediments eroded by heavy rainfall. These storms occur predominantly in winter (December through March) (Noble Consultants, 1995).

Northwesterly Winds: With the exception of major winter storm events, the principal mechanism for generating waves over the central California continental shelf is prevailing northwesterly winds. These winds dominate during the spring and summer when a high-pressure system is established over the eastern North Pacific Ocean. The winds are highly coherent along the central coast and generate wind waves over a large fetch (an area of the sea surface over which seas are generated by a wind having a constant direction and speed) (Chelton et al., 1987). These locally generated waves tend to be of shorter period and smaller significant wave height than those generated by major winter storms.

Southerly Swell: Large swell generated to the south can occur on occasion during summer months. One large event occurred in late July 1996 from a storm 400 miles south of Tahiti. The Harvest Platform wave gauge recorded significant wave heights of over 2 m. These long period waves (20-second significant period) arrived from directions ranging between 200°T (degrees from True north) and 230°T. Nevertheless, major wave events arriving from the south are rare, so deepwater wave climatology is directionally bimodal with the majority of events arriving directly from the west (270°T) or from the northwest (300°T) (Seymour, 1996).

Deepwater waves arriving from certain directions never reach some coastal locations because of their coastline orientation and the presence of major coastal promontories such as Point Arguello and Purisima Point (see Figure 5.6-1). Coastal (Wave Information Study [WIS]) Station 132 (Purisima Point) is adjacent to the project area and has a nearly north-south orientation (183°T); (Jensen et al., 1989). Blocking by major promontories to the north limits the wave window to 183 - 343°T. At the pipeline landfall near the Santa Ynez River mouth, some of the deepwater wave energy generated to the north is blocked by the coastline so that almost all (~89 percent) waves of significant amplitude arrive directly from the west (approximately 270°T). Most of the remaining waves arrive from the northwest (300 to 343°T). These waves impinge on the coastline at an oblique angle and drive much of the longshore circulation within the littoral zone.

Along this section of coastline, approximately 19 percent of the waves in 30-foot water depths have significant heights that exceed 10 feet. These waves have a dominant period of approximately 13 seconds. For return periods between 5 and 20 years, maximum significant wave heights are close to 18 feet. Offshore oil-spill cleanup operations involving a boom and skimmer have been hampered in seas exceeding 10 feet (McDonald, 1995). This suggests that offshore cleanup operations could be limited approximately 18 percent of the time and on occasion, offshore cleanup would be untenable.

Winds

Figure 5.6-3 typifies the annual trend in the wind regime near Platform Irene (Savoie et al., 1991). The 1989 record for NDBC Buoy 23 shows that winds were largely directed toward the southeast along a principle axis of 143°T. Between January and March, the passage of occasional winter storms induces brief and occasionally very intense northwesterly winds. Beginning in April, and throughout the summer, southeastward winds intensify in response to the spring transition after a high-pressure cell forms over the eastern North Pacific Ocean.

Local sea level pressure variations match the wind fluctuations. The largest pressure variations occur in the winter and are caused by the passage of low pressure systems associated with storms (Dorman, 2001). The strongest winter winds are associated with the lowest pressures. In contrast, pressure variations are reduced and the mean pressure is higher in the summer.

Water Level

The shoreline near the pipeline landfall north of the Santa Ynez River mouth experiences astronomical tides of diurnal inequality wherein two daily sets of tidal extrema have unequal amplitude. Tidal amplitudes for this section of the central California coast are listed in Table 5.6.2 as estimated from the closest benchmark tide station at Port San Luis near Avila Beach. Storm surge along this section of open coastline is small (less than 1 foot) compared to the 7-foot variation in astronomical tides. An analysis of coastal sea level data from Port San Luis (Savoie et al., 1991) revealed that sea level rose by only approximately 0.7 foot during the severe storm of 18 January 1988. This storm produced one of the lowest barometric pressures ever recorded at NDBC Buoy 46023, and generated the largest significant wave heights of any storm between 1900 and 1995 (Seymour, 1996).

Table 5.6.2 Estimated Tidal Amplitudes at the Port San Luis Tidal Benchmark

Datum	Amplitude, feet	Amplitude, meters
Extreme High (observed 18 January 1973)	7.80	2.37
Mean Higher High Water (MHHW)	5.39	1.64
Mean High Water (MHW)	4.68	1.43
Mean Tide Level (MTL)	2.86	0.87
Mean Sea Level (MSL)	2.83	0.86
Mean Low Water (MLW)	1.04	0.32
Mean Lower Low Water (MLLW)	0.00	0.06
Extreme Low (observed 8 January 1988)	-2.20	-0.67

Onshore Runoff

The major source of freshwater input to coastal waters within the southern SMB is the Santa Ynez River, although the more distant Santa Maria River also provides significant input (Figure 5.6-1). During times of high discharge, the Santa Ynez River brings increased sediment loads as well as contaminants from agricultural and urban runoff to the coastal environment. The Santa Ynez River Basin has a Mediterranean climate, so runoff is episodic and streamflow within the Santa Ynez watershed rapidly rises and falls in response to precipitation (SYRTAC, 1999). Most of the rainfall occurs in winter and the majority of runoff occurs in the winter and spring months. Low or no flow occurs in the summer. River discharge data demonstrate that major floods occur every few years during El Niño conditions.

The river discharge results in temporary localized salinity reductions and increased particulate loads within the coastal waters of the southern SMB. Plumes from individual rainfall events persist for approximately two to five days. Because deposition rapidly removes suspended sediment from the water column, the depth and area influenced by river turbidity is smaller than the footprint of reduced salinity associated with freshwater discharge. The Santa Ynez River plume also substantially affects coastal circulation patterns within the upper 5 m of the water column (Hickey, 2000). Upon discharge into the coastal ocean, the plume forms a buoyant water mass that is particularly sensitive to changes in local wind conditions. During winter, when the principal river discharge events occur, winds with a northward component are generally associated with storms, increased rainfall, and northward (upcoast) surface flow in the southern SMB. In contrast, river discharge resulting from late-season rainfall can be carried southward and upwelling-favorable wind conditions tend to spread plumes farther offshore. In high-discharge El Niño years such as 1998, the Santa Ynez River discharge plume can even impact the western Channel Islands well to the south (Hickey, 2000).

5.6.1.3 Seawater Quality

Coastal seawater and sediment quality is determined by a number of factors, including oceanographic processes, contaminant discharge, and freshwater inflow. Petroleum development activities, commercial and recreational vessels, natural hydrocarbon seeps, river runoff, municipal wastewater outfalls and minor industrial outfalls all contribute to increased nutrients, trace metals, synthetic organic contaminants, and pathogens in offshore waters and sediments. However, compared to coastal waters of the Southern California Bight, anthropogenic (human-induced) inputs into the waters of the SMB are minor and its marine waters are considered relatively pristine.

Seawater Properties

Other than the presence of specific contaminants that are described below, marine water quality is largely determined by five seawater properties: temperature, salinity, turbidity, alkalinity, and dissolved oxygen. Ambient seawater properties in the southern SMB are governed by seasonal and interannual variations in large-scale circulation patterns, wind stress, wave climatology, and runoff from land.

The vertical density structure or stratification of coastal waters dictates the amount of vertical mixing within the water column (Fischer et al., 1979). Highly stratified waters inhibit vertical exchange of nutrients, and other water properties, and can reduce vertical spread of contaminants introduced by a point source. Density stratification is primarily determined by the temperature structure. During periods when the upper water column is well mixed with uniform thermal structure and weak stratification, enhanced vertical mixing is expected. In the fall and winter, convective cooling and mechanical wind stirring drive the main thermocline to great depth (50 m) leaving the nearshore water columns with little vertical stability. In spring, a shallow thermocline (<10 m) forms near the shore in response to deep onshore transport during upwelling. This shallow seasonal thermocline is maintained throughout the summer and may even reach the surface as upwelling continues to bring cold nutrient-rich water onshore at depth.

Upwelling is an important feature of this coastal region and is largely responsible for its productive fishery. The presence of nutrient-rich water near the sea surface significantly enhances primary productivity (phytoplanktonic blooms) that is otherwise limited by the lack of nutrients within the photic zone. Phytoplankton are the foundation of the marine food web and their increased abundance results in the greater diversity and biomass of marine organisms along the central California coast.

Typically, the coolest coastal sea-surface temperatures (near 11°C) occur in spring and early summer when upwelling is prevalent. Increased insolation throughout the summer and the decline in upwelling-favorable winds in the fall results in a seasonal temperature maximum in September and October of around 17°C.

The onshore movement of deep cool water during upwelling is also reflected in the salinity and density distribution. The dense near-bottom water mass is more saline, which attests to its origin in the Southern California Bight. The northward flowing Davidson Current brings this cool saline water into the southern SMB. During upwelling, coastal salinity exhibits a seasonal maximum as a result of onshore flow at depth.

In addition to nutrients, high dissolved oxygen levels are also necessary for a healthy marine ecosystem. Pollutants that are high in organic compounds can locally deplete oxygen levels and have a deleterious effect on marine organisms. In general however, surface waters are saturated with oxygen due to rapid exchange with the overlying atmosphere. The oxygen concentration at saturation is largely determined by sea surface temperature. Below this surface maximum, oxygen steadily decreases with depth due to losses from biotic respiration and decomposition. The rates of chemical and biological oxygen demand decrease exponentially with depth.

Coastal dissolved-oxygen concentrations vary seasonally and range from 6 to 8 milligrams per liter (mg/L) near the surface. Surface levels are lowest in the fall when surface temperature is highest. This reflects the inverse relationship between oxygen saturation and temperature. Under the stratified conditions during upwelling, dissolved oxygen decreases strongly with depth and declines to 5 mg/L in as little as 45 m. These low oxygen concentrations are a consequence of the onshore movement of deeper oxygen-poor water. These deep waters have not been in contact with the atmosphere and ongoing respiration and decomposition has resulted in undersaturated oxygen levels along with the enhanced nutrient levels.

The highest alkalinity (pH) levels also occur during spring upwelling when increased photosynthesis consumes CO_2 and produces oxygen near the surface. As the ratio of respiration to photosynthesis increases with depth, there is an increase in CO_2 and a decline in alkalinity. Alkalinity can also be affected by discharge of waste into the ocean but tends to have only a localized effect on open-ocean waters.

Turbidity decreases the clarity of seawater and is largely determined by the concentration of suspended particulate matter. Turbidity dictates the depth of the photic zone. Within the photic zone, ambient light intensity exceeds roughly 1 percent of surface illumination, which is the minimum necessary for phytoplankton growth. Turbidity is increased in coastal waters as a result of phytoplankton blooms, storm runoff, sediment resuspension, and discharge of wastewater. Substantial sediment input from onshore occurs in the form of large isolated pulses rather than a steady discharge of material. Intense storm events occasionally punctuate the prevailing semi-arid climate and result in mass runoff with profound increases in coastal turbidity. Turbidity near the seafloor is also caused by wave-induced sediment resuspension. Near the shoreline, this is apparent as a decrease in transmissivity near the seafloor during periods of high wave activity. When this coincides with upwelling, turbidity is also higher near the sea surface which creates the mid-depth maximum in transmissivity commonly observed in vertical profiles.

Trace Metals

Ambient trace metal concentrations in the water column are generally below the detection limit of standard methods. Because these and other contaminants are difficult or impossible to measure directly in seawater, resident California mussels (*Mytilus californianus*) have been used as sentinel organisms to indirectly monitor water quality. Like most filter feeders, mussels are capable of concentrating contaminants by factors of 10^2 to 10^5 in their tissues. Bivalves accumulate contaminants directly from seawater and from ingested food. They provide a time-integrated measure of the abundance of bioavailable contaminants in the water column.

Based on analysis of mussel tissue, trace-metal concentrations in the marine waters of the southern SMB are somewhat lower than many other regions offshore California. Trace metal data derived from the State Mussel Watch Program are summarized in Figure 5.6-4. The Figure shows box plots of the distribution of the 19 to 27 samples collected between 1978 and 1992 at Stations 437, 438, and 449 (SWRCB, 1988). For comparison, Elevated Data Levels (EDLs) are also shown. They reflect concentrations below which 85 percent (EDL 85) and 95 percent (EDL 95) of the 400 or so samples collected statewide were distributed.

Median concentrations in the southern SMB were well below the top 15 percent of samples collected statewide (EDL 85). The concentrations of these ten trace metals were frequently higher in bivalves and sediments found in other California coastal regions; especially those collected in urban areas. In the SMB, the maximum observed concentrations of cadmium, lead, manganese, silver, and mercury, were at or below the EDL 85. This reflects the south central coast's relative remoteness from industry. A few samples from the SMB had maximum concentrations in aluminum, chromium, copper, nickel, and zinc that exceeded the EDL 85, but these concentrations were generally not within the top 5 percent of statewide samples (EDL 95). Also, these elements occur naturally in sediments and are widely distributed in the mineralogy of the region. Their variability in bivalve tissue probably reflects the degree of sediment incorporation into the bivalves rather than bioavailability or the influence of anthropogenic sources.

Tissue samples collected in the NS&T program (BOS, 1991) at the San Luis Obispo Bay site (SLSL in Figure 5.6-1), were comparable with those of the State Mussel Watch Program. Copper was an exception with elevated mean concentrations near 11.3 micrograms per gram dry weight (mg/g) or parts per billion (ppb). In addition, iron, total butyltin, and selenium were analyzed in NS&T samples but did not exhibit elevated concentrations compared to other west coast sites.

Waterborne Bacteria

Bacteria levels in the southern SMB vary widely and often increase after significant rainfall. This increase is due to the runoff of contaminants accumulated onshore. The extent to which bacterial pathogens survive after their introduction into the marine environment is currently the subject of investigation. Some studies have indicated that bacteria in seawater can remain infectious but undetectable by standard techniques used for microbiological monitoring (Grimes et al., 1986). Standard techniques report the most probable number of coliform organisms per 100 milliliters of water sample (MPN/100mL) and have detection limits near 2 MPN/100mL. The California Ocean Plan's bacterial limits for water contact areas are 1000 total coliform organisms per 100mL, 200 MPN/mL for fecal coliform and 35 per 100mL for enterococcus. While coliform densities in the water column are typically near the detection limit, surfzone samples adjacent to creeks and rivers often exceed bacterial standards during periods of high runoff (MRS, 2001). Treated effluent discharged from wastewater point sources in the region is low in bacteria and has little tangible effect on marine water quality.

Excess nutrients in near-surface waters can lead to blooms of toxin-producing dinoflagellates in the form of red tides that result in deleterious impacts on water quality. Phytoplankton productivity is normally limited by the availability of the micronutrient nitrates, phosphates, and silicates in the upper water column. Upwelling is an important mechanism for adding nutrients to the euphotic zone. Nutrients are also added to coastal waters by wave-induced resuspension of organic material contained within seafloor sediments. Onshore runoff and sewage discharge can also introduce unhealthy amounts of nitrogen, which is usually the most limiting nutrient for primary production.

Petroleum Hydrocarbons

Petroleum hydrocarbons are an organic contaminant that can be of anthropogenic or natural origin. The principal sources of petroleum hydrocarbons in the southern SMB include:

- Urban runoff of road material, auto exhaust, lubricating oils, gasoline, diesel fuel, and tire particles;
- Atmospheric deposition from the combustion of fossil fuels;

- Vessel leaks, spills, and exhaust;
- Leaching of creosote from wooden pilings;
- Oil and grease contained in municipal sewage effluent; and
- Natural oil seeps.

Despite these diverse sources, hydrocarbon concentrations in tissue samples collected in the southern SMB were near background levels as compared to the elevated levels in samples collected within the Southern California Bight (BOS, 1991). Also, oil and grease concentrations in wastewater discharged by ocean outfalls in the region are consistently small and did not contribute significantly to overall hydrocarbon levels in the water column (MRS, 1996).

Petroleum hydrocarbons have also been introduced along this section of the central California coast by major oil spills. A spill of 163 to 1242+ barrels occurred in September 1997 when the pipeline that carries crude oil from Platform Irene ruptured at a flange (CSB, 2001). Some of the oil was recovered offshore under relatively calm conditions. Another spill near the study region was associated with the sinking of the freighter Pac Baroness offshore Point Conception in 1987 (see Figure 5.6-1) (Hyland et al., 1989). An initial oil spill of 20,000 gallons (476 bbls) was accompanied by a partial release of the copper ore cargo. A similar potential exists for a future release of up to 3.1 million gallons (74,000 bbls) of crude oil from the oil tanker Montebello which lies in 900 feet of water after being sunk during World War II offshore Cambria.

Two other onshore spills that recently impacted near-shore waters along the central coast occurred at Avila Beach and the Guadalupe Dunes Oil Field just north of the Santa Maria River. Shallow groundwater at the Guadalupe Field was contaminated with approximately 6 million gallons of diluent at a number of beach sites. Prior to remediation, diluent was released into the marine environment on several occasions (ADL, 1998a). Similarly, prior to cleanup, subsurface onshore hydrocarbon contamination at Avila Beach extended below the beach. There is some evidence that during periods of high wave erosion, the nearshore hydrocarbon plume daylighted and contaminated marine waters (ADL, 1998b).

Perhaps the most significant long-term source of hydrocarbons within the marine waters of SBCh and sediments of the SMB and SBCh is natural oil seeps. The presence of naturally occurring petroleum products within the study region is suggested by the presence of tar balls and tar mats commonly observed along the shoreline of the south central California coast. The prevalence of oil seeps in the region is also suggested by the local place name Pismo Beach. "Pismo" derives from the Chumash word *pismu*, which describes the naturally-occurring asphaltum tar that Native Americans used to caulk plank canoes. MMS has partnered with USGS and the County of Santa Barbara to determine the location, activity, and destination of oil from natural seeps in the western Santa Barbara Channel and southern Santa Maria Basin. The Hydrocarpon Seeps Project at UCSB estimates the seepage at Coal Oil Point to be 100 barrels per day (County of Santa Barbara 2002). As seep bubbles rise to the ocean surface, substantial amounts of hydrocarbons dissolve in the water column, forming a subsurface gradient of dissolved hydrocarbons, principally methane. As the hydrocarbon-rich zone spreads out, methane concentrations decrease due to dilution and outgassing to the atmosphere. A large part of the elevated total hydrocarbon concentrations found in deep-water surficial sediments of the southern SMB derive from seep-related petroleum components. For that reason, elevated hydrocarbon concentrations arising from natural seeps need to be included in the determination of background concentrations for impact evaluations (Steinhauer et al., 1994).

5.6.1.4 Sediment Quality

Chemical analysis of seafloor sediments provides insight into the overall health of the marine environment because environmental contaminants tend to accumulate in the particulates that are deposited on the seafloor over long periods. However, for most elements, low levels of anthropogenic sediment contamination are difficult to detect because natural background concentrations vary with grain size, carbon content, and mineralogy.

To assess whether sediment contaminant levels are environmentally significant, they can be compared with sediment guidelines advanced by the National Oceanic and Atmospheric Administration (NOAA) (Long and Morgan, 1991; Long et al., 1995) and by the Florida Coastal Management Program (MacDonald, 1993). These guidelines are based on correlations between chemical concentrations and observed biological effects. Differences in the two sets of guidelines arise from the databases used and the assumptions applied in the analyses of the toxicity data. The NOAA guidelines identify Effects Range-Low (ERL) and Effects Range-Median (ERM) values. ERL guidelines reflect levels below which adverse effects are not expected to occur. ERM guidelines represent the concentration above which adverse effects are expected. The State of Florida (MacDonald, 1993) developed sediment guidelines that are somewhat more conservative than those of NOAA. These guidelines describe a Threshold Effects Level (TEL) and the Probable Effects Level (PEL). The guidelines are compared with background concentrations measured in marine sediment samples collected within the southern SMB in Table 5.6.3.

For all but two contaminants, measured background concentrations were well below the lowest threshold limit (TEL). Chromium concentrations in deep (CaMP) sediments and within Estero Bay (MB/C) slightly exceeded the TEL but were well below the ERL. Nickel was even more elevated and exceeded the ERL. These trace metals were also elevated in mussel tissue within the study area compared to other tissue samples collected statewide (Figure 5.6-4). As described above, elevated tissue levels probably reflect the incorporation of sediments into the bivalve's gut rather than dissolution in tissue.

The elevated chromium and nickel concentrations within the sediments of the southern SMB are increasing (MRS, 2001). Onshore erosion around abandoned chromite mines within the San Luis Obispo County watershed has been identified as the probable source of the increase observed in regional marine sediments (RWQCB, 1999; MRS, 2000). Although there is no evidence that current levels are impacting marine organisms, projected increases are causing measured concentrations to rapidly approach the marine toxicological benchmarks listed in Table 5.6.3. At current accumulation rates, nickel would be expected to have reached the ERM, where marine biological impacts were probable by 2004. If chromium concentrations continue to increase at approximately 2 mg/Kg each year, contaminant levels could begin to affect marine organisms by the year 2010.

Table 5.6.3 Comparison of Background Concentrations and Sediment Guidelines (in milligrams per kilogram dry weight [mg/kg] or parts per million [ppm] unless otherwise indicated)

	Sediment Criteria				Background				
Constituent	**TEL**[a]	**ERL**[b]	**PEL**[a]	**ERM**[b]	**SSLO**[c]	**SMR**[d]	**MB/C**[e]	**CaMP**[f]	**SLUOB**[g]
Grain Size (Ø)					3.03	2.73	2.75	4.0	NA
TOC					2706	ND[h]	NA[i]	NA	NA
BOD					178	45	36	NA	NA
TKN					51	122	139	NA	NA
Ammonia					1.22	2.77	NA	NA	NA
Oil & Grease					NA	2.12	<20	NA	NA
Chromium	52	81	160	370	3.08	10.1	57.1	121	130
Cadmium	0.68	1.20	4.21	9.60	0.17	0.25	<0.5	0.56	0.39
Copper	19	34	108	270	0.9	7.2	3.8	16	7.5
Lead	30	47	112	218	1.5	4.1	2.8	14	4.9
Mercury	0.13	0.15	0.70	0.71	ND	ND	ND	0.072	0.075
Nickel	16	21	43	52	3.4	3.7	47	42	30
Silver	0.73	1.00	1.77	3.70	0.005	ND	<0.25	0.11	0.6
Zinc	124	150	271	410	9.93	22.6	17.3	72	43.6
p,p'-DDE (ppb)	2.1	2.2	374.2	27.0	NA	NA	ND	NA	1.0
Total DDT (ppb)	3.9	1.6	51.7	46.1	NA	NA	ND	NA	6.9
Total PCB (ppb)	21.6	22.7	188.8	180.0	NA	NA	ND	NA	5.6
Total PAH (ppb)	1684	4022	16771	44792	NA	NA	ND	0.08	NA

[a] *Threshold Effect Level (TEL) and the Probable Effects Level (PEL) of MacDonald (1993).*
[b] *Effects Range-Low (ERL) and Effects Range-Median (ERM) of Long et al. (1995).*
[c] *South San Luis Obispo County (SSLO) wastewater outfall at Oceano (ABC, 1995).*
[d] *Unocal Santa Maria Refinery (SMR) receiving water monitoring program (KLI, 1996).*
[e] *Morro Bay/Cayucos (MB/C) sanitary district offshore monitoring program (MRS, 2001).*
[f] *California Monitoring Program (CaMP) surficial sediment chemistry (Steinhauer et al., 1994).*
[g] *Sediment data collected in 1988 at the National Status and Trends Benthic Surveillance Site (SLUOB) within San Luis Obispo Bay (BOS, 1991).*
[h] *Not Detected (ND).*
[i] *Not Available (NA).*

However, significant marine biological impacts from increasing chromium and nickel concentrations are unlikely because the minerals are not readily bioavailable and their threshold effects levels have a low degree of confidence. The incidence of effects in the toxicological studies used to establish the threshold levels for chromium was '*greatly influenced and exaggerated by data from multiple tests conducted in only two field surveys*' (Long et al., 1995). Similarly, nickel exhibits a very weak relationship between the incidence of effects and concentrations in the database used to establish the toxic-effect ranges. Because of these weak toxicological relationships, specification of nickel and chromium concentrations that induce adverse reactions in marine biota is highly uncertain. Much of this uncertainty arises from wide variability in nickel and chromium bioavailability. Nickel and chromium fines adhering to surface of sediment particles are much more likely to impact organisms that ingest or encounter the sediments. Conversely, nickel and chromium that are bound into the mineralogy of particles eroded onshore probably have little adverse effect on marine organisms.

It is not clear why nearshore sediment samples collected in 1995 at the San Luis Obispo County and SMR sites had low nickel and chromium concentrations (Table 5.6.3). By comparison, offshore chromium concentrations in samples collected at MB/C, CaMP, and SLUOB consistently exceeded 57 mg/Kg. This concentration is approximately three and a half times higher than average chromium concentrations within the Southern California Bight and was approximately twice the concentration (29 mg/Kg) that would be considered enriched in the Bight (Schiff and Gossett, 1998). Nevertheless, measurements listed in Table 5.6.3 indicate that sediment chromium and nickel concentrations are spatially variable within the SMB decrease to the south toward the SBCh. Consequently, sediments below Platform Irene probably have lower concentrations of nickel and chromium because it is remote from the chromite mines near San Luis Obispo County.

5.6.1.5 Offshore Petroleum Production and Development

Offshore oil development and production activities can also affect the quality of seawater and marine sediments. The ongoing activities on Platform Irene and along the pipeline corridor are of particular interest for this environmental assessment.

Marine Oil Spills

The proposed project would extend the ongoing offshore operations of Platform Irene by an additional 30 years. These expanded operations would increase the risk of an accidental oil spill to marine waters. Three subsea pipelines currently transit the 10.5 miles (16.8 km) of seafloor between Platform Irene and the coast. The volumes of crude oil emulsion, produced water, and gas transferred along these pipelines are likely to increase as a result of the proposed project. Currently, a spill from the 20-inch diameter crude oil line represents the greatest hazard to the marine environment. The offshore section of this pipeline can contain more than 18,000 bbls of oil emulsion at any one time (Table 5.1.18). The two smaller pipelines transport lower volumes of produced water and gas and present less risk to the marine environment.

A marine spill that occurred along the 20-inch crude-oil transmission line in 1997 attests to the risk associated with operations on Platform Irene. On September 28, 1997, the seafloor pipeline ruptured approximately 2.5 miles from shore in a water depth of 120 feet (CSB, 1997). Although the spill was initially limited by an automatic shutdown triggered by the abrupt pressure release, an operator on the Platform overrode the shutdown and reinitiated pumping from the platform into the ruptured pipeline. As a result, approximately 163 to 1242+ barrels of crude oil spilled into the ocean.[1] Mild oceanographic conditions facilitated the offshore recovery of some of the spilled oil but oil eventually washed ashore just south of Point Sal and onto the beaches south of Point Arguello. The sandy beaches at and south of the Santa Ynez River mouth were the most heavily oiled.

Generally, marine oil spills do not severely degrade open-ocean water quality except during and for a few weeks after the spill. Most of the components of crude oil are insoluble in seawater and because the spill floats on the sea surface, impacts to the water column are limited. Also, aromatic hydrocarbons, such as benzene and toluene, that are considered to be most toxic to marine life evaporate quickly as the spill weathers in the marine environment. Other weathering processes such as spreading, dissolution, dispersion, emulsification, photochemical oxidation, and microbial degradation decrease the volume of the oil slick and increase the viscosity and specific gravity of the spilled oil. Thus, mortality of marine organisms arising from the physical effects of smothering and coating is of greatest concern from weathered oil. However,

[1] The CDFG official spill volume from the Torch Point Pedernales pipeline was 163 barrels (bbl) (CDFG, 1989). The 1,242 bbl estimate is from Santa Barbara County and is based on additional factors that were not taken into account with the CDFG official number. These include drainage from the landward side of the pipeline, oil between pigs 1 and 2, and oil behind pig 2.

toxicological effects from exposure to aromatic hydrocarbons can be significant if unweathered oil reaches the shoreline, particularly in areas with rocky shorelines, enclosed embayments, estuaries, and wetlands. The movement of spilled oil into the SBCh and its islands can be problematic in this regard.

Produced Water Discharges

Prior to 1991, produced water was discharged from Platform Irene. Currently, however, there is no marine discharge of produced water although NPDES General Permit CAG 280000 for such disposal applies to Platform Irene. The existing LOGP treatment facilities are incapable of removing contaminants to the level specified in the NPDES discharge permit and the 25,000 Bpd of produced water that is presently piped to the platform, is reinjected downhole into the reservoir formation. The produced water treatment system at the LOGP currently is being upgraded and any produced water that is discharged from Platform Irene would be in compliance with the current NPDES general permit, which specifies allowable concentrations for specified contaminants. If ocean discharge resumes, the majority of this could be discharged through a 32-cm (12.75-inch) diameter ocean outfall oriented downward at a depth of 55 m below the Platform. However, a part of the produced water that would be shipped to Platform Irene may still be injected into Point Pedernales reservoir wells, as is currently the operation, to enhance current Point Pedernales production. The new pump system is expected to be capable of injecting 40,000 bbls/day.

On Pacific OCS platforms that discharge produced water, each platform operator conducts self-monitoring of these discharges pursuant to the requirements of the EPA's applicable NPDES permit. The MMS and EPA may also conduct compliance monitoring of the produced water discharges from offshore platforms in the Pacific OCS as part of a Memorandum of Agreement that has been in effect since 1989 (Panzer, 2000). A work plan is agreed upon each year specifying the number of inspections and sampling. Constituents of concern include free and dissolved oil and grease, heavy metals, cyanide, organic compounds, added treatment chemicals, and radioactivity. A study of produced-water discharges from platforms in southern and central California found that concentrations of most trace metals and cyanide were below detection limits beyond the initial dilution zone (SCCWRP, 1994). Cadmium was below detection limits in all samples. Nickel was detected in 50 percent of the samples, the most of any metal, and cyanide was detected in 25 percent of the samples. Zinc accounted for 60 percent, and nickel accounted for 30 percent, of the total mass of metals discharged. However, the mass emission of metals was negligible compared to the discharge from other point sources in the region.

All of the platforms discharging produced water had measurable concentrations of oil and grease, and 75 percent had measurable concentrations of phenols. Oil and grease and phenols were the dominant constituents in produced waters. Also, produced water has a lower dissolved-oxygen concentration than receiving ocean water. Produced water contains trace concentrations of naturally occurring radium but radioactivity in produced water from California platforms is much lower than for Gulf of Mexico platforms where excessive levels can make disposal problematic. Mean total radioactivity in produced water from two California platforms ranged from below the method detection limit to 154 picoCurries/liter (pCi/L) (Neff, 1997). For comparison, drinking-water standards in California limit combined gross α and β radioactivity to 65 pCi/L. Radioactivity levels in coastal ocean waters are generally below 1 pCi/L.

Initial mixing and dispersion govern the fate of produced water discharged into the marine environment. Initial mixing occurs immediately after discharge. It is driven by the turbulence caused by the momentum of the discharge jet and instability of the buoyant effluent plume as it rises through the water column. Produced water discharged off the California coast is generally less saline and warmer than ambient seawater. This results in a buoyant discharge plume that aids in the initial mixing of the effluent. Modeling suggests that initial mixing occurs rapidly and results in dilutions of 30- to 100-fold within a few tens of meters from the outfall (Neff, 1997). Slower-paced dispersion further reduces the concentration of contaminants as the oceanic flow field transports the produced-water plume. ~~However, f~~ For Platform Irene, the produced water salinity ~~and temperature are~~ would be close to the ambient values~~, and~~ but the temperature would be 160^0 F. Therefore, the plume would be ~~nearly neutrally~~ buoyant at discharge depth~~.~~ ~~Consequently,~~ and it would ~~not~~ receive the additional benefit of buoyancy-induced mixing.

Discharge of Drilling Muds and Cuttings

Muds and cuttings would also be discharged offshore as part of the proposed project under the NPDES General Permit covering discharges from oil and gas operations in Federal Waters offshore of the State of California. Materials that do not meet the discharge requirements would be transported to shore for disposal at a permitted site. There are a wide variety of generic drill muds available for use offshore California (CSA, 1993). In the course of the drilling process, operators recycle drill muds until formulations change due to changing down-hole drilling conditions. Bulk discharges of 1,000 to 2,000 bbls of mud occur several times in the course of drilling a well, including a last time when the well is completed (EPA, 2000a). Typical bulk discharge rates for platforms on the California OCS range from 75 to 700 bbls (3,150 to 29,400 gallons) per hour per platform (CSA, 1985). In addition to these large bulk discharges, drill cuttings along with a small volume of mud that adheres to the cuttings are discharged continuously throughout drilling.

The most frequent additives to generic water-based drill muds are barite, clay, caustic soda, lignite, lignosulfonate, cellulose polymer, and soda ash or sodium bicarbonate. For special applications, other additives include defoamers, emulsifiers, and detergents. At least 50 additives were found to be practically non-toxic or only slightly toxic to marine organisms based on 96-hour acute bioassay tests on Mysid shrimp (CSA, 1993). In those tests, the lethal concentration (LC50) at which 50 percent of the specimens died was greater than 1,000 ppm for slightly toxic compounds and greater than 10,000 ppm for non-toxic compounds. A drill mud is less toxic as the concentration where 50 percent mortality (LC50) increases, because less dilution is required to prevent 50 percent mortality.

Tests for toxicity and free oil in discharged drilling muds are required as part of the NPDES discharge monitoring program. Toxicity is determined by conducting a 96-hour acute toxicity bioassay on muds collected after the wells have been drilled to at least 80 percent of their target depth (Panzer, 2000). Most of the potentially toxic additives are added in these later stages of drilling. The General Permit (EPA, 2004) specifies a conservative minimum LC50 of 30,000 ppm for a suspended particulate phase test on muds.

Diesel and mineral oils are occasionally added to water-based drill muds to free stuck drill pipe, although this practice is uncommon along the California OCS. Diesel oil is not approved for discharge in ocean waters and diesel-contaminated muds must be transported to shore for recycling. In contrast, marine discharge of water-based muds with low concentrations of mineral oil is permitted under the General NPDES Permit (EPA, 2000b) when the mineral oil is used as a carrier fluid (transporter fluid), lubricity additive, or pill. Mineral oil contains low concentrations of aromatic hydrocarbons and is much less toxic than diesel fuel. Free oil can be also introduced into drilling muds by drilling through an oil-bearing formation. If mineral oil or other hydrocarbons are discharged with drill muds, their concentrations must be less than approximately 2 percent based on a free-oil static sheen test. Excessive discharge of free oil is also monitored by examining the ocean surface for evidence of sheens near the discharge point (cuttings chute).

Analyses of drill muds and cuttings discharged in the southern SMB indicate that the volume of metal and hydrocarbon contaminants has been small relative to contributions from natural sources (Steinhauer et al., 1992). Barium, lead, and zinc had higher concentrations in discharged muds than in ambient marine sediments but total input was comparable to the flux from coastal rivers that drain into the southern SMB. Also, all three constituents are relatively insoluble in seawater and remain inert in marine sediments. Barium in the form of barite ($BaSO_4$) and bentonite clay were the major inorganic constituents of drill muds. They are used as the viscosifying and weighting agents in drill muds and are relatively benign. The excess lead and zinc that have been detected in drilling muds arose from the pipe dope used to lubricate the threads of drill pipe, not drilling mud additives (Steinhauer et al., 1994).

Other drilling muds constituents of concern include cement, mercury, and cadmium. Cement is used in cementing of well casings, well workovers, and completions. Because of its high alkalinity, cement can be harmful to the marine ecosystem. Other than mercury and cadmium, heavy metals are generally not monitored in drilling muds and cuttings (Panzer, 2000). The other metals present in drill muds include silver, arsenic, copper, nickel and vanadium but are typically present only at very low concentrations. These metals arise from trace impurities in the barite or in other minor additives used in the drilling process.

The NPDES General Permit prohibits the discharge of drill muds containing chrome lignosulfonate due to the potential release of hexavalent chromium, a toxic form of chromium (MMS, 2001). Lignosulfonate is a thinning agent that controls the viscosity of water-based drill muds. Chrome-free lignosulfonate and other thinning products that have less potential to produce marine toxic effects are also available. In the past, lignosulfonate was added to muds in approximately 70 percent of the wells drilled offshore California and it accounted for approximately one percent of the total solids discharged (CSA, 1985). Chrome-based thinning products accounted for approximately 32 percent of the lignosulfonate used. Chrome-based lignosulfonates are more effective than other thinning products in the high downhole temperatures experienced when drilling deep wells. Other common lignosulfonates are complexed with metals such as iron, manganese, and zirconium. The 2004 NPDES General Permit allows the use of eight generic mud types determined by the EPA to be of low toxicity.

The dispersion of drill muds and cuttings depends on the depth of the discharge (shunt depth), the prevailing flow field, and the physical characteristics of the drill muds and the receiving waters (see Appendix D). On Platform Irene, spent drill muds and cuttings would be discharged 150 ft (46 m) below the sea surface. The temperature and density of drill muds generally increase with increasing drilling depth. Even after dilution with seawater at the shale shaker, the discharged material would be a few degrees warmer than ambient seawater temperatures.

Because of the shunt depth, most of the heavier muds aggregates are deposited on the seafloor directly below and within 500 m of the discharge point. The heavier rock cuttings are not expected to be transported more than 200 m beyond the discharge point (de Margerie, 1989). Approximately 80 percent of the particulates are removed by these near-field depositional processes (CSA, 1985). Lightweight floccules formed from the remaining suspended particulates would be carried upward toward the sea surface by the buoyant plume of warm water associated with the discharge. They can be carried over four miles from the platform before being deposited on the seafloor (Coats, 1994; Pickens, 1992; Appendix D herein).

Other Discharges

Offshore oil and gas development can also result in a variety of other discharges to the marine environment. In addition to the discharges described above, treated sewage and desalinization brines are the only discharges from offshore platforms that have a significant enough volume to potentially impact marine resources (SAIC, 2000). Other discharges, such as deck drainage, blowout prevention fluid, fire-control system test water, and non-contact cooling water constitute relatively minor discharge volumes. Table 5.6.4 summarizes current discharges from Platform Irene and projected discharges under the proposed project. Seawater use is not expected to increase under the proposed project, but it may approach the upper end of the current range (12,000 bbls/day) during drilling and well workover. When drilling is not occurring, seawater use would be at the bottom end of the current range (6,000 bbls/day).

Table 5.6.4 Current and Proposed Discharges from Platform Irene

Discharge Stream	Current Volume/Frequency	Proposed Volume/Frequency
Sanitary Waste	100-200 bbls/day(max 600bbl/day in 2006)	100-200 bbls/day (max about 600 bbls/day)
Fire water/cooling	6,860 to 12,000 bbls/day	6,860 to 12,000 bbls/day
Drilling Muds	11,600 bbls (2006 through July)	Below permitted limit of 105,000 bbls/year
Drill Cuttings	1,800 bbls (2006 through July)	Below permitted limit of 30,000 bbls/yr
Produced Water	None	Below permitted limit of 153,000 bbls/day

Sanitary and domestic wastes are typically treated with chlorine prior to discharge. Enough chlorine must be added to kill coliform bacteria but not so much that it affects marine organisms. Chlorine levels are required to remain between 1 and 10 ppm (Panzer, 2000). Some platforms discharge desalinization brines, which are generated from the desalinization process used to produce drinking water. Platform Irene does not discharge the desalinization brine, but rather sends it ashore with the produced water. Under the proposed project, desalinization brine from Platform Irene will continue to be sent ashore with the produced water. Although the flow rates are highly variable, offshore platforms can discharge up to 200,000 Gpd of desalinization brine. These discharges are more saline than seawater, which would normally make them denser than receiving waters. However, their generally higher temperature results in a buoyant plume upon discharge. The ensuing momentum- and buoyancy-induced mixing rapidly dilutes the discharge to background levels within 100 m of the discharge (MMS, 2001).

5.6.2 Regulatory Setting

Several Federal and State laws pertain to marine water quality. This section describes the relevance of these statutes to the proposed project.

5.6.2.1 Federal Regulations

The Clean Water Act

The 1972 Federal Water Pollution Control Act and its amendments in 1977, collectively known as the Clean Water Act, established national water-quality goals. The Act also created a National Pollutant Discharge Elimination System (NPDES) of permits that specified minimum standards for the quality of discharged waters. It required states to establish standards specific to water bodies and designated the types of pollutants to be regulated, including total suspended solids and oil. The Act authorized the U.S. Environmental Protection Agency (EPA) to issue the NPDES permits and Region 9 of the EPA has jurisdiction for permitting discharges associated with the proposed project.

Under NPDES, all point sources that discharge directly into waterways are required to obtain a permit regulating their discharge. Each NPDES permit specifies effluent limitations for particular pollutants, and monitoring and reporting requirements for the proposed discharge. Chapter 27 of the Clean Water Act deals with Ocean Dumping and Section 1412 describes the following criteria for evaluating permit applications.

- The need for the proposed dumping;
- The effect of such dumping on human health and welfare, including economic, esthetic, and recreational values;
- The effect of such dumping on fisheries resources, plankton, fish, shellfish, wildlife, shore lines and beaches;
- The persistence and permanence of the effects of the dumping;
- The effect of dumping particular volumes and concentrations of such materials;
- Appropriate locations and methods of disposal or recycling, including land-based alternatives and the probable impact of requiring use of such alternate locations or methods upon considerations affecting the public interest;
- The effect on alternate uses of oceans, such as scientific study, fishing, and other living resource exploitation, and non-living resource exploitation;
- The effect of such dumping on marine ecosystems, particularly with respect to
  - The transfer, concentration, and dispersion of such material and its by products through biological, physical, and chemical processes;
  - Potential changes in marine ecosystem diversity, productivity, and stability; and
  - Species and community population dynamics.

Permit issuance, receipt of monitoring data submitted by permittees, compliance monitoring, and enforcement are the primary responsibility of States when the discharge occurs within the 3-mile territorial limit. The MMS and the EPA Region 9 coordinate the Federal government's monitoring of offshore oil and gas discharges in Federal Waters of the SMB. MMS's periodic presence on the platforms is a vehicle to perform inspections, collect samples, and to provide transportation for EPA during those occasions when they conduct inspections (Panzer, 2000).

Pacific OCS platforms are also required to periodically submit Discharge Monitoring Reports (DMRs) to Region 9 of the EPA. The reporting requirements depend on whether the NPDES discharge permit issued to the operator was a General Permit or an Individual Permit. The General Permit was issued in February 1982 and when it lapsed in June 1984, it was administratively extended until a new General Permit could be developed. In the interim, a series of Individual Permits were issued that were uniformly more strict and required monitoring of a greater number of produced water parameters. This two-tiered system of permits rapidly became unwieldy for EPA because each individual permit had to be reevaluated and reissued every five years. For this and other reasons, a new General Permit was developed (SAIC, 2000). The new general permit became effective on December 1, 2004.

The Marine Plastic Pollution Research and Control Act

Originally enacted as the Act to Prevent Pollution from Ships, it prohibited any discharge of oil from a ship within 12 nautical miles of land, unless it did not exceed 15 ppm or the ship has oil-water separating equipment. The act was amended in 1987 to prohibit the discharge of plastic, garbage, and floating dunnage within three nautical miles of land. Beyond three miles, garbage must be ground to less than one inch but discharge of plastic and floating dunnage is still restricted. This Act requires manned offshore platforms, drilling rigs, and support vessels operating under a Federal oil and gas lease to develop waste management plans and to post placards reflecting discharge limitations and restrictions on plastics and other forms of solid wastes. These requirements are enforced by the U.S. Coast Guard.

The Oil Pollution Act

The Oil Pollution Act of 1990 established a system of liability and compensation for damages caused by oil spills in U.S. navigable waters. It also required removal of spilled oil and established a national system of planning for and responding to oil spill incidents. The Act included provisions to provide funding for natural resource damage assessments and to establish an oil pollution research and development program.

The Secretary of Interior is responsible for spill prevention, oil-spill contingency plans, oil-spill containment and clean-up equipment, financial responsibility certification, and civil penalties for offshore facilities and associated pipelines in all Federal and State Waters. The U.S. Department of Transportation (Coast Guard) was designated as the lead agency for offshore oil spill response, which includes responsibility for coordination of federal responses to marine emergencies. The U.S. Coast Guard is also responsible for enforcing vessel compliance with the Act.

5.6.2.2 State and Local Laws and Policies

Lempert-Keene-Seastrand Oil Spill Prevention and Response Act

Under the Lempert-Keene-Seastrand Oil Spill Prevention and Response Act, the California Department of Fish and Game became the State lead agency in spill response and created the Office of Oil Spill Prevention and Response (OSPR). The Act requires that persons causing a spill begin immediate cleanup, follow approved contingency plans, and fully mitigate impacts to wildlife. Under an Interagency Agreement with OSPR, the California Coastal Commission (CCC) operates an oil spill program and maintains an oil spill staff. Before and after a spill, CCC staff are involved in review and comment to both State (e.g., OSPR) and Federal (e.g., U.S.

Coast Guard) agencies on contingency plans and regulations related to marine vessels, marine facilities and marine vessel routing.

California Coastal Act

The California Coastal Act (Division 20 of the Public Resources Code, Section 30000, et seq.) became law in 1976 as a means of providing a comprehensive framework for the protection and management of coastal resources. The main goals of the Act are to protect and restore coastal zone resources; assure balanced and orderly utilization of such resources; maximize public access to and along the coast; assure priority for coastal-dependent and coastal-related development; and encourage cooperation between state and local agencies toward achieving the Act's objectives.

The Coastal Act, which is administered by the California Coastal Commission, identifies protective measures for nearshore marine resources that include maintaining good ocean water quality:

Coastal Act section 30230 states:

> *"Marine resources shall be maintained, enhanced, and where feasible, restored. Special protection shall be given to areas and species of special biological or economic significance. Uses of the marine environment shall be carried out in a manner that will sustain the biological productivity of coastal waters and that will maintain healthy populations of all species of marine organisms adequate for long-term commercial, recreational, scientific, and educational purposes."*

Coastal Act section 30231 states:

> *"The biological productivity and the quality of coastal waters, streams, wetlands, estuaries, and lakes appropriate to maintain optimum populations of marine organisms and for the protection of human health shall be maintained and, where feasible, restored through, among other means, minimizing adverse effects of waste water discharges and entrainment, controlling runoff, preventing depletion of ground water supplies and substantial interference with surface water flow, encouraging waste water reclamation, maintaining natural vegetation buffer areas that protect riparian habitats, and minimizing alteration of natural streams."*

California Harbors and Navigation Code

Discharges from vessels within territorial waters are regulated by the California Harbors and Navigation Code. One of its purposes is to prevent vessel discharges from adversely affecting the marine environment. Section 151 regulates oil discharges and imposes civil penalties and liability for cleanup costs when oil is intentionally or negligently deposited on the waters of the State of California.

California Ocean Plan

Since 1973, the California State Water Resources Control Board (SWRCB) and its nine Regional Water Quality Control Boards (RWQCBs) have been delegated the responsibility for administering permitted discharge into the coastal marine waters of California. The Porter-Cologne Water Quality Act provided a comprehensive water quality management system for the protection of California waters and regulated the discharge of oil into navigable waters by

Table 5.6.5 California Ocean Plan Water Quality Standards

A. Bacterial Characteristics
   1. Water-Contact Standards
      Within a zone bounded by the shoreline and a distance of 1,000 feet from the shoreline or the 30-foot depth contour, whichever is further from the shoreline and in areas outside this zone used for water contact sports, as determined by the Regional Board, but including all kelp beds, the following bacterial objectives shall be maintained throughout the water column:
      30-day Geometric Mean - the following standards are based on the geometric mean of the five most recent samples from each site:
         Total coliform density shall not exceed 1,000 per 100ml;
         Fecal coliform density shall not exceed 200 per 100 ml; and
         Enterococcus density shall not exceed 35 per 100 ml.
      Single Sample Maximum:
         Total coliform density shall not exceed 10,000 per 100 ml;
         Fecal coliform density shall not exceed 400 per 100 ml;
         Enterococcus density shall not exceed 104 per 100 ml; and
         Total coliform density shall not exceed 1000 per 100 ml when the fecal coliform/total coliform ratio exceeds 0.1
      The "Initial Dilution Zone" of wastewater outfalls shall be excluded from designation as "kelp beds" for purposes of bacterial standards and Regional Boards should recommend extension of such exclusion zone where warranted to the State Board (for consideration under Chapter III.H.). Adventitious assemblages of kelp plants on waste discharge structures (e.g., outfall pipes and diffusers) do not constitute kelp beds for purposed of bacterial standards.
   2. Shellfish Harvesting Standards
      At all areas where shellfish may be harvested for human consumption, as determined by the Regional Board, the following bacterial objectives shall be maintained throughout the water column:
      The median total coliform density shall not exceed 70 per 100 ml and not more than 10 percent of the samples shall exceed 230 per 100 ml.

B. Bacterial Assessment and Remedial Action Requirements
   Describes guidelines for monitoring enterococcus bacteria. (See Plan for full description).

C. Physical Characteristics
   1. Floating particulates and grease and oil shall not be visible.
   2. The discharge of the waste shall not cause aesthetically undesirable discoloration of the ocean surface.
   3. Natural light shall not be significantly reduced at any point outside the initial dilution zone as a result of the discharge of waste.
   4. The rate of deposition of inert solids and the characteristics of inert solids in ocean sediments shall not be changed such that benthic communities are degraded.

D. Chemical Characteristics
   1. The dissolved oxygen concentration shall not at any time be depressed more than 10 percent from which occurs naturally, as a result of the discharge of oxygen demanding waste materials.
   2. The pH shall not be changed at any time more than 0.2 units from that which occurs naturally.
   3. The dissolved sulfide concentration of waters in and near sediments shall not be significantly increased above that present under natural conditions.
   4. The concentration of substances set forth in Chapter Ii, Table B in marine sediments shall not be increased to levels which would degrade indigenous biota.
   5. The concentration of organic materials in marine sediments shall not be increased to levels which would degrade marine life.
   6. Nutrient materials shall not cause objectionable aquatic growths or degrade indigenous biota.

E. Biological Characteristics
   1. Marine communities, including vertebrate, invertebrate and plant species, shall not be degraded.
   2. The natural taste, odor and color of fish, shellfish, or other marine resources used for human consumption shall not be altered.
   3. The concentration of organic materials in fish, shellfish or other marine resources used for human consumption shall not be bioaccumulated to levels that are harmful to human health.

F. Radioactivity
   1. Discharge of radioactive waste shall not degrade marine life.

imposing civil penalties and damages for negligent or intentional oil spills. The State board prepares and adopts the California Ocean Plan (SWRCB, 2005), which incorporates the State water quality standards that apply to all NPDES permits (Table 5.6.5). In April 1991, the SWQRCB and other State environmental agencies were incorporated into the California Environmental Protection Agency.

The standards identified in the California Ocean Plan are consistent with the limitations specified in the NPDES General Permit. This determination was made when the CCC (2001) concurred with the EPA's consistency certification that the proposed activities are consistent with the enforceable policies of California's Coastal Management Program which incorporates the Ocean Plan. Tables 5.6.5 and 5.6.6 show the California Ocean Plan water quality standards and the criteria for contaminants that may be in drilling muds or produced water discharged from Platform Irene, respectively.

Table 5.6.6 California Ocean Plan Criteria (6-Month Median) for Contaminants that may be in Platform Irene Discharges

Constituent	Ocean Plan Criteria (ug/L)
Ammonia	600
Arsenic	8
Cadmium	1
Copper	3
Cyanide	1
Lead	2
Mercury	0.04
Nickel	5
Selenium	15
Silver	0.7
Zinc	20
Hexavalent Chromium	2

Source: SWRCB 2005

Central Coast Basin Plan

The Central Coast Region of the RWQCB has established a Water Quality Control Plan (Basin Plan) for the coastal waters that include the Tranquillon Ridge Field (RWQCB, 1994). The standards of the RWQCB incorporate the applicable portions of the Ocean Plan and are more specific to the beneficial uses of marine waters adjacent to the project site. These water quality objectives and toxic material limitations are designed to protect the beneficial uses of ocean waters within specific drainage basins. The Basin Plan identifies the following existing beneficial uses for the coastal waters contained within the project area (RWQCB, 1994).

Water Contact Recreation (REC-1): Uses of water for recreational activities involving body contact with water, where ingestion of water is reasonably possible. These uses include, but are not limited to, swimming, wading, water skiing, skin and scuba diving, surfing and fishing.

Non-Contact Water Recreation (REC-2): Uses of water for recreational activities involving proximity to water, but not normally involving body contact with water, where ingestion of water is reasonably possible. These uses include, but are not limited to, picnicking, sunbathing, hiking, beachcombing, camping, boating, tidepool and marine life study, hunting, sightseeing, and aesthetic enjoyment in conjunction with the above activities.

Industrial Service Supply (IND): Uses of water for industrial activities that do not depend primarily on water quality including, mining cooling water supply, hydraulic conveyance, gravel washing, fire protection, or oil well repressurization.

Navigation (NAV): Uses of water for shipping, travel, or other transportation by private, military, or commercial vessels. The RWQCB interprets NAV as any natural body of water that has sufficient capacity to float watercraft for the purposes of commerce, trade, transportation, and pleasure.

Marine Habitat (MAR): Uses of water that support marine ecosystems including, but not limited to, preservation or enhancement of marine habitats, vegetation such as kelp, fish, shellfish, or wildlife such as marine mammals and shorebirds.

Shellfish Harvesting (SHELL): Uses of water that support habitats suitable for the collection of filter-feeding shellfish such as clams, oysters, and mussels, for human consumption, commercial, or sport purposes. This includes waters that have in the past, or may in the future, contain significant shell fisheries.

Ocean Commercial and Sport Fishing (COMM): Uses of water for commercial or recreational collection of fish, shellfish, or other organisms including uses involving organisms intended for human consumption or bait purposes.

Wildlife Habitat (WILD): Uses of water that support terrestrial ecosystems including, but not limited to, preservation and enhancement of terrestrial habitats, vegetation, wildlife (e.g., mammals, birds, reptiles, amphibians, invertebrates), or wildlife water and food sources.

The Basin Plan states that, in addition to the provisions of the Ocean Plan, the following objectives shall also apply to all ocean waters:

- The mean annual dissolved oxygen concentration shall not be less than 7.0 mg/L, nor shall the minimum dissolved oxygen concentration be reduced below 5.0 mg/L at any time.
- The pH value shall not be depressed below 7.0, nor raised above 8.5.
- Radionuclides shall not be present in concentrations that are deleterious to human, plant, animal, or aquatic life; or result in the accumulation of radionuclides in the food web to an extent which presents a hazard to human, plant, animal, or aquatic life.

Water Quality Control Plan for Control of Temperature in the Coastal and Interstate Waters and Enclosed Bays and Estuaries of California (Thermal Plan)

The California Thermal Plan specifies that existing discharges shall comply with limitations necessary to assure protection of the beneficial uses and areas of special biological significance. New discharges with elevated temperature shall be discharged to the open ocean away from the shoreline to achieve dispersion through the vertical water column and shall be a sufficient distance from areas of special biological significance to assure the maintenance of natural temperatures in these areas. The maximum temperature of new thermal waste discharges shall not exceed the natural temperature of receiving waters by more than 20 degrees Fahrenheit (F) and shall not result in increases in the natural water temperature exceeding 4 degrees F at the

<u>shoreline, the surface of any ocean substrate, or the ocean surface beyond 1,000 feet from the discharge system.</u>

5.6.3 Significance Criteria

This section describes criteria for evaluating the significance of project-related activities or incidents that may result in impacts on marine water and sediment quality. A project activity would be deemed to have a significant impact if it leads to violation of water quality standards or waste discharge requirements. However, most marine water-quality standards apply to continuous point-source discharges, namely ocean outfalls. Because project-related marine water quality impacts are likely to differ from those of typical ocean discharges, evaluation of their significance must also consider their persistence, extent, and amplitude. Namely, significant marine impacts are:

- Persistent and not reversed by natural dispersive processes within a few days;
- Extend beyond the project area;
- Cause physicochemical changes that impact the marine ecosystem; or
- Are measurably different from ambient background conditions.

Class III impacts, which are adverse but not significant, are limited to those that cause no more than short-term changes over small areas, or are indistinguishable from natural variation in the marine environment.

If the intentional release of produced water or drill muds does not conform to the requirements of an NPDES discharge permit or other common water-quality standards and guidelines, then it is assumed that it could have a significant water-quality impact. Interpretation of unacceptable changes in seawater properties promulgated in existing guidelines, regulations, standards, and discharge requirements often requires some judgement. In these cases and in non-point-source cases, such as accidental spills, marine water quality impacts would be considered significant if they exceed either of the following threshold criteria.

1. Project-related activities cause significant impacts if they result in changes to marine water or sediment quality that exceed established standards beyond a region immediately adjacent to proposed project. The region of allowed impact is assumed to extend a lateral distance equal to the local water depth or within a defined zone of initial dilution for a particular discharge, such as the 100-m zone around Platform Irene.
2. Projected-related changes in water properties are also considered significant if they are large compared to natural background variability in the surrounding marine environment, last more than two days, or cause permanent deleterious effects in marine organisms.

Allowing the region of impact to extend to a lateral distance equal to the water depth derives from the concept of a "zone-of-initial dilution" that is applied to point-source discharges. Within this zone, turbulent mixing processes are thought to drive an initial rapid dispersion of contaminants. Within this mixing zone, exceptions to the water-quality limitations are allowed to occur while contaminants are being dispersed. "Large" project-related anomalies beyond this zone can be evaluated from a statistical hypothesis test that compares the amplitude of the water-property anomaly with 95 percent confidence levels about mean conditions measured within any given season. This approach has been successfully used to identify discharge-related anomalies along the central coast (MRS, 2001) and the 95 percent confidence level is consistent with the Ocean Plan's definition of "significant" differences (SWRCB, 2005). The two-day criterion for significance was based on analyses of mesoscale flow variability where longer-term changes would influence multiple coastal-flow features and thus have wider-spread impacts (see Figure 5.6-2 and the accompanying text). The last consideration is also the subject of Section 5.5, Marine Biology. Water-quality impacts that impinge on marine sanctuaries or sensitive habitats would also be considered significant.

Thresholds for significant aesthetic impacts on marine water quality are set by Ocean-Plan prohibitions on visual observations of oil sheens or floating debris on the sea surface (See Table 5.6.4). Also, the Ocean Plan relates significant marine-water-quality impacts to a degradation in the composition of resident marine communities; namely resulting from contamination levels leading to chronic or acute toxic effects. This is reflected in the water quality objective of maintaining all surface waters free of contaminants in concentrations toxic to aquatic life as stated in the Water Quality Control Plan (RWQCB, 1994). Except for chromium and nickel, which are naturally elevated in ambient sediments, the toxicity of drill muds deposited on the seafloor can be evaluated by comparing contaminant concentrations with the effects levels listed in Table 5.6.3. Significant impacts would be expected if concentrations exceeded the ERM guideline for any compound that had well-established toxicity benchmarks.

5.6.4 Impact Analysis for the Proposed Project

The primary impacts to marine water and sediment quality from the proposed Tranquillon Ridge Project arise from three sources. First, the project would increase the potential for an accidental marine release of crude oil from the platform, the seafloor ~~transmission~~ pipeline, or supply boats. Second, during directional drilling, the discharge of drilling fluid would increase particulate loads near Platform Irene. Finally, during production of the Tranquillon Ridge Field, produced water could be discharged into the marine environment near Platform Irene and accidental releases of produced water could occur along the ~~transmission~~ pipeline as it transits the seafloor to the platform.

Impact #	Impact Description	Phase	Residual Impact
MWQ.1	Accidental discharge of petroleum hydrocarbons into marine waters would adversely affect marine water quality.	*Increased Throughput Extension of Life*	*Class I*

The proposed project would increase the likelihood of an accidental release of crude oil to the marine environment. Increased activities offshore as a result of the proposed project would increase the frequency of spills. Also, an increase in the oil percentages in the pipeline would increase the amount of oil that could be spilled into the marine environment if a spill were to occur. In addition, the longer life associated with Platform Irene and the Platform Irene to LOGP pipeline would increase the probabilities of a spill over the facility lifetime. Spill frequencies and lifetime probabilities are shown in the Table 5.1.27. The combined probability of oil leaks, ruptures, blowouts, and spills from Platform Irene and the offshore portion of the wet-oil ~~transmission~~ pipeline would approximately double under the proposed project. In addition, the expanded new production would increase the concentration of crude in the oil emulsion transported to shore. Because of increased crude concentrations, offshore oil spills associated with a rupture of the ~~transmission~~ pipeline would induce greater deleterious effects within marine waters. Finally, the frequency and duration of trips made by offshore support vessels would increase under the proposed project. Although vessel trips would not increase above the permitted limit, during the drilling of new wells, the number of vessel trips per year would increase from 107 to 120. The increased vessel traffic would increase the risk of a vessel accident and an attendant spill although its volume would be limited compared to other oil-spill scenarios.

The proposed project would ~~double the frequency~~ quadruple the probability of an oil spill beyond current baseline conditions (an increase from 5.4% to 22.1%; see Table 5.1.28). In accordance with the significance criteria described in Section 5.6.3, impacts to marine water quality from a large crude-oil spill (>100 bbls) must be considered potentially significant. A large spill, such as the spill in 1997, would meet all of the threshold criteria for a significant water-quality impact. Namely, it introduced hydrocarbon contaminants that were persistent, extended well beyond the project area, impacted the marine ecosystem, and measurably departed from background concentrations. Spilled oil produces several impacts to marine water quality that are explicitly addressed in the California Ocean Plan (Table 5.6.5). Surface slicks limit equilibrium exchange of gases at the ocean-atmosphere interface. This reduces near-surface oxygen concentrations, particularly with the increased biochemical oxygen demand of crude-oil emulsions. As the seawater-oil emulsion mixes into the water column, turbidity would increase and toxic hydrocarbons would be released into the water column and seafloor sediments. Weathering can widely disperse tar balls, which may eventually be ingested by pelagic and benthic biota with adverse effects. Although a surface slick can disperse within a few hours of a spill in harsh sea states, lingering effects could persist for much longer periods. For example, it took approximately two years for mussel tissue burdens of aromatic hydrocarbons to return to background levels after the Exxon Valdez Oil Spill (Boehm et al., 1995). Although this spill was much larger (about 6,000 times larger) than that projected for the Tranquillon Ridge Project, monitoring results indicate the potential for long-term effects. Because there is an increased likelihood of a large oil spill as a result of the proposed project, and because such a spill would result in tangible damage to marine water quality, in excess of levels identified in regulatory criteria, accidental discharges of petroleum hydrocarbons into marine waters are considered a significant adverse impact.

The results of an oil-spill trajectory analysis for Platform Irene and its pipelines is presented in Section 5.1, Risk of Upset. Ocean impact areas were found to be similar for spills from Platform Irene and from the oil-emulsion pipeline. Oil spills were far more likely to travel due south from the site of the spill. Spills could potentially extend substantial distances and impact ocean areas south of the Channel Islands. There is a tangible probability that they would impact the Channel Islands Marine Sanctuary. To the north, only open-ocean areas south of Point Sal were likely to be impacted by oil spills resulting from the proposed project. However, as described in Section 5.6.1.2, uncertainty concerning the influence of wind drift on spilled oil, limitations in the model, and the prevailing northward surface current flow suggest that oil spilled within the project area could also impact coastlines to the north.

Mitigation Measures

Mitigation Measure MB-1 requires an update to the November 2004 Core Oil Spill Response Plan and July 2005 Supplement to incorporate changes in platform activities that result from the proposed project, and serves to ameliorate marine water quality impacts should a spill occur. The following mitigation would help reduce the likelihood of an oil spill similar to the one that occurred in 1997. This measure would also serve to mitigate oil spill impacts to marine biology and commercial and recreational fishing.

MWQ-1 Offshore inspections of the wet-oil pipeline shall continue to be conducted on a regular basis as determined by the County and/or other regulatory agency throughout the life of the project. Inspections shall use the best available technology to identify unsupported spans and deteriorating or inadequate welds. When structural anomalies or unsupported spans are identified that compromise the integrity of the pipeline as determined by the County and/or other regulatory agency, flow through the pipeline flow shall cease until repairs can be effected, spans can be supported, or problematic pipeline components can be replaced. If the leak detection system causes an unexplained shutdown of flow through the offshore pipeline, flow shall remain shutdown until the entire length of pipe is inspected. The applicant shall submit annual inspection reports the parities responsible for verification. These requirements shall be referenced in the project's Safety, Inspection, Maintenance, and Quality Assurance Program (SIMQAP).

Residual Impact

Marine water-quality impacts associated with accidental oil spills are categorized as *significant* (*Class I)* because the proposed mitigation measures would not be completely effective in reducing the significant risk of a spill, nor would they adequately eliminate the significant effect of a spill on marine water quality. A large spill (>100 bbls) would violate many of the water quality standards. It would generate visible surface sheens, significant reductions in the penetration of natural light, reductions in dissolved oxygen, degradation of indigenous biota, and hydrocarbon contamination within the water column and marine sediments. The duration and area of the impact would be largely dictated by the size of the spill. Impacts would last from days to weeks and extend for tens of kilometers.

Mitigation of water-quality impacts from a major marine oil spill (> 100 bbls) is largely a function of the efficacy of the spill-response measures. The effectiveness of spill cleanup measures is dependent on the response time, availability and type of equipment, size of the spill, and the weather and sea state during the spill. Only some of these aspects are within the control of the spill-response team. In addition, many oil spill response measures have impacts of their own. Appendix E provides additional information on the impacts associated with various oil spill response measures.

Under the regulatory-based significance criteria described in Section 5.6.3, even small oil spills could be considered potentially significant. Many regulations and guidelines establish limits based on the presence of a visible sheen on the ocean surface. This criterion is reflected in the static sheen test for free oil identified in the NPDES General Permit (EPA, 2004), USCG regulations, and the aesthetic criterion C.1 in the Ocean Plan Standards (see Table 5.6.4). Adverse aesthetic impacts from a visible sheen would occur upon discharge of a very small amount of free-phase hydrocarbons into calm marine waters. Because sheens are so thin, as little as 0.5 ounces of oil can form a rainbow sheen covering 500 ft^2 of calm ocean surface area (Taft et al., 1995).

Impact #	Impact Description	Phase	Residual Impact
MWQ.2	Reduced marine water and sediment quality would result from increased oceanic discharge of drilling fluids.	*Drilling*	*Class II*

Under the proposed project, drilling muds and cuttings would either be discharged to the ocean at Platform Irene or re-injected. The increased discharge of drilling muds, cuttings, and completion fluids would negatively impact seawater and sediment quality. Marine impacts arise because unmitigated discharge of used drilling fluids can harm marine organisms, reduce aesthetic benefits, and disrupt the benthic habitat. However, the magnitude and spatial extent of these impacts would be largely ameliorated in the proposed project through the NPDES Permit requirements.

For example, the toxicity of discharged muds is regulated by limiting muds additives to those predetermined to have low toxicities. Also, muds bioassays are periodically conducted ~~prior to discharge~~ as part of the NPDES monitoring program. Marine impacts are further limited by shunting the drilling fluids so that they discharge well below the sea surface. Platform Irene's muds-discharge pipe extends 150 feet below the sea surface.

Shunted discharge avoids large increases in near-surface turbidity that are caused by the introduction of suspended drilling particulates in the upper water column. Shallow turbidity increases impacts to primary productivity (phytoplankton growth), which depends on the penetration of ambient light within the photic zone. Because of this, avoiding reductions in ambient light is listed as Water-Quality Standard C.3 in the California Ocean Plan (see Table 5.6.4). Mitigating the occurrence of shallow turbidity plumes also conforms to aesthetic water-quality standards relating to floating particulates (Standard C.1) and visible discoloration (Standard C.2).

Deep discharge also limits the seafloor area impacted by the muds deposition. Avoiding degradation in the benthic community is designated as Water-Quality Standard C.4 in Table 5.6.4. The area of a depositional footprint is largely dictated by the amount of the time that drilling particulates remain suspended. Thus, rapid deposition from a discharge close to the seafloor may avoid impacts to sensitive benthic communities that reside on distant hard substrate features. However, discharges shunted too close to the seafloor would increase localized impacts to benthic organisms that reside immediately below the platform. Consequently, an intermediate shunt depth is optimal. The shunt depth on Platform Irene is 92 feet above the seafloor (150 feet below sea surface).

The seafloor area affected by the deposition of drilling particulates can be determined from modeling. The discharge of drilling fluids produces two distinct plumes within the water column. A dense plume that contains over 90 percent of the discharged cuttings descends rapidly to the seafloor in a convective jet. Large particles within this plume that are not immediately deposited on the seafloor below the platform are carried short distances away by prevailing currents. The depositional pattern of these heavy particulates depends largely on water depth, discharge (shunt), current speed, and the muds density. A second plume consisting of lightweight flocs (small aggregates of tiny sedimentary grains) of drilling mud particles also forms upon discharge. This plume remains suspended in the water column and can impact distant benthic communities (Hyland et al., 1994).

Appendix D presents site-specific modeling of drill-muds dispersion that was conducted as part of this environmental assessment. Results indicate that the deposition of drilling flocs far from Platform Irene would be negligible. Because of the along-shore alignment of prevailing currents, tangible deposition would not occur in State Waters or in the Channel Islands Marine Sanctuary (see Figure D-1).

Because most of the drill-muds flocs would settle to the seafloor within two days, impacts to marine water quality would be temporary and below the Threshold Criterion 2 in Section 5.6.3, and as such are considered to be adverse but not significant. Deposition on the seafloor would increase trace-metal concentrations in marine sediments. However, as noted in Section 5.6.1.5, the contribution would be small compared to natural sources and major constituents, such as barium, are relatively inert. Consequently, chemical toxicity from trace-metal accumulations resulting from the muds discharge would pose little threat to benthic organisms.

Mitigation Measures

No additional mitigation is required beyond the requirements imposed by the NPDES discharge permit.

Residual Impact

Ocean discharge of drilling fluids as part of the proposed project would not result in significantly increased marine impacts. Provisions contained in the NPDES discharge permit limit the use of toxic additives and require bioassay monitoring. Fluids would be discharged at mid-depth and disperse rapidly within the energetic flow field. Shunting would reduce turbidity impacts to the photic zone near the sea surface and diminish benthic impacts resulting from the deposition of muds and cuttings on the seafloor. The majority of marine water- and sediment-quality impacts would be limited to an area of less than 100 m around Platform Irene. Therefore, marine water and sediment quality impacts from project-related discharges of drilling fluids are considered *significant but mitigable* (*Class II*).

Impact #	Impact Description	Phase	Residual Impact
MWQ.3	Reduced marine water quality would result from the oceanic discharge of produced water.	*New Operations*	*Class II*

An additional 40,000 bpd of treated produced water could be discharged 55 m below the sea surface at Platform Irene as part of the proposed project (in addition to produced water discharges resulting from Platform Irene Point Pedernales Field development). The applicant is authorized to discharge to the ocean from the platform in accordance with the General NPDES Permit. A part of the produced water that would be shipped to Platform Irene may still be injected into Point Pedernales reservoir wells, as is currently the operation, to enhance current Point Pedernales production. Offshore water injection would be conducted as authorized by the MMS. Ocean discharge would locally alter the physical properties of the receiving seawaters and introduce contaminants. Produced water is warmer and lower in dissolved-oxygen concentration than the receiving water. ~~However, upon discharge, the produced water would have reached a temperature close to ambient seawater after transit along the subsea pipeline from the onshore treatment facility.~~ The produced water plume discharged from Platform Irene would be ~~nearly neutrally~~ buoyant because its ~~salinity and~~ temperature would be much warmer than ambient seawater (120 to 160°F[2]), although its salinity would ~~both~~ be close to that of ambient seawater. In addition, the concentrations of some trace metals are higher in produced water and radioactivity may be elevated although not to the levels observed in the Gulf of Mexico.

However, contaminant levels would be reduced by onshore treatment and rapid initial dilution would further minimize water quality impacts. If produced-water contaminants are restricted to levels comparable to those specified for the new general discharge permit, then there would be a low reasonable potential to exceed Federal receiving-water criteria (SAIC, 2000). Produced-water discharges would be diluted by at least 10-fold within 10 m and more than ~~50~~ 200-fold beyond 100 m (Brandsma, ~~2001,~~2007a). Because produced water dilutes rapidly, it is unlikely that its discharge would cause contaminant concentrations to measurably exceed ambient levels over areas that exceed the Threshold Criterion 1 in Section 5.6.3. Although the produced water would be discharged at an elevated temperature, dilution would rapidly reduce the temperature of the plume. Modeling shows that the elevation in temperature would be less than 10° F within 10 m of the discharge and would reach ambient temperature within 50 m of the discharge (Brandsma, 2007b) Therefore, with implementation of NPDES permit requirements this impact is considered to be significant but mitigable (Class II).

Except for zinc and barium, there is little indication that metals accumulate in bottom sediments around produced-water discharges. Barium concentrations in produced water are more than 1000-times higher than in seawater. However, when produced water mixes with sulfate-rich seawater much of the dissolved barium precipitates as barite. The solubility of barium sulfate is below the toxic effects threshold for marine organisms (SAIC, 2000). Similarly, sediment zinc concentrations comparable to the 76 mg/Kg measured near Platform Hidalgo (Steinhauer et al., 1994) are lower than the lowest zinc toxic-effect level for marine organisms (TEL of 124 mg/Kg in Table 5.6.3).

Discharge of trace-metals, hydrocarbons, and radioactive materials within produced waters are all limited in the General NPDES permit for California OCS waters (EPA, 2000b).

Mitigation Measures

In addition to implementation of NPDES permit requirements, Mitigation Measure MB-3 would also apply to this impact.

Residual Impact

Marine water and sediment quality impacts from the discharge of produced water would be localized and of limited magnitude. Consequently, the residual impact is considered *significant but mitigable (Class II)* based on the significance thresholds in Section 5.6.3.

2 The current temperature of oil/water emulsion from Platform Irene well production ranges from 170 to 185 degrees F. The emulsion is sent via pipeline to LOGP for processing/separation and the produced water leaves LOGP at a temperature of approximately 145 degrees F and arrives at Platform Irene for discharge between 115 to 130 degrees F. The exact temperature of future discharges will vary as conditions, configurations, flow rates, and other variables change, but with the blending of the fluids, the maximum temperature of the discharge stream is estimated at 160 degrees F. At this temperature, PXP discharges would be compliant with the NPDES permit.

Impact #	Impact Description	Phase	Residual Impact
MWQ.4	Reduced marine water quality would result from additional discharges of sanitary wastes, desalinization brine, and other materials from Platform Irene.	*Drilling Extension of Life*	*Class II*

The expanded offshore activities associated with the proposed project would increase the volume of other wastes discharged from Platform Irene. Table 5.6.4 above shows the current and proposed volumes of wastes discharged from the platform. As presented in Table 2.2 of the Project Description, Section, 2.0, PXP estimates that annual muds and cuttings disposal volumes for the period of 2008 through 2010 will be 48,700 bbls/yr and 5,700 bbls/yr, respectively; well below the NPDES permit limits specified in Table 5.6-4. Impacts from the ocean discharge of materials related to field development and production, namely, drilling fluid and produced water, were addressed in Impacts MWQ.2 and MWQ.3. Other wastes include platform deck drainage, sanitary wastes, fire-control system water, cooling water[3], and antifoulants and trace metals leaching from the drilling rig and support vessels. Platform deck drainage water can contain contaminants, such as trace metals, petroleum hydrocarbons, and other toxic substances and particulates. The discharge of sanitary wastes, if inadequately disinfected, can degrade marine water quality by introducing pathogens. Tributyltin and other antifouling agents in paints on the bottom of support vessels can leach into seawater with deleterious effects. Similarly, sacrificial anodes on vessel hulls and the platform jacket dissolve continuously and release copper and zinc. Finally, fire-control systems are regularly tested during fire drills aboard platform service vessels and Platform Irene, itself. Although they commonly use seawater, contaminants that have accumulated on the decks can be washed overboard during the drills.

Impacts to marine water quality resulting from these discharges are likely to be transient and localized. Moreover, the additional discharge due to expanded platform operations in the proposed project area represents a small incremental increase relative to current conditions. The NPDES General Permit addresses the following miscellaneous discharges: deck drainage, domestic and sanitary waste, blowout preventer fluid, desalination unit discharge, fire control system water, non-contact cooling water, ballast and storage displacement water, bilge water, boiler blowdown, test fluids, diatomaceous earth filter media, bulk transfer material overflow, uncontaminated water, water flooding discharges, laboratory waste, excess cement slurry, hydrotest water, and H_2S gas processing waste water.

Presently, the discharge of most of these wastes is controlled. For example, the platform drainage system limits the release of major contaminants by processing the discharge through oil-water separators and other treatment processes. In addition, overboard deck discharges are monitored visually for free oil and grease. Sanitary wastes are biodegraded and disinfected prior to discharge. There will be no biocides in these discharges other than chlorine. Currently, PXP adds small amounts of chlorine for three consecutive days per month, during which time they sample the discharge for residual chlorine. They are evaluating changing to a weekly dosing or a continuous dosing to be more effective. All discharges are in compliance with the NPDES permit. In 2006 the residual chlorine ranged from 0.1 to 1.0 mg/L. The minute amount of

[3] Seawater uptake for cooling is a maximum of 500 barrels per day when the cooled heat exchanger is in use; however, electric fans are currently used. The water cooled heat exchanger could be used in the future when ambient air temperatures warrant (electric fans are not as effective on warm days).

antifoulants and trace metals released into the marine environment as a result of the project activities is not expected to generate concentrations toxic to marine organisms in the open-ocean waters near Platform Irene (CSA, 1995). As such the impact is considered to be adverse but not significant.

Mitigation Measures

No mitigation measures beyond the NPDES permit restrictions currently imposed on the offshore facility are required.

Residual Impact

Because the increased water quality impacts from additional discharges under the proposed project are limited in magnitude, spatial extent, and duration, and are mitigated through NPDES permit requirements, the residual impact is considered *significant but mitigable (Class II)*.

5.6.5 Impact Analysis for the Alternatives

Detailed descriptions of the various alternatives have been provided in Chapter 3.0. This section provides a discussion of the marine water quality impacts of those alternatives.

5.6.5.1 No Project Alternative

Scenarios 2 and 3. As discussed in Section 3.2, under the No Project Alternative Scenarios 2 and 3, production of the federal portion of the Tranquillon Ridge field would and would not occur, respectively. However, no extension of life of Point Pedernales facilities (Platform Irene, pipelines, and LOGP) is assumed under either scenario.

Impact MWQ.1 - Impacts due to Oil Spills: Spill volumes under ~~this alternative~~ Scenarios 2 and 3 would be the same as under the current operations; therefore, current impact levels would persist.

Impact MWQ.3 - Impacts due to Discharges of Produced Water: Produced water quantities on Platform Irene would be no greater than the peak production from the Point Pedernales Field, and would likely not be discharged, but injected. Impacts would remain the same as for the existing Point Pedernales Project.

Impacts MWQ.2 and MWQ.4 - Impacts due to Discharges of Drilling Fluids, and Other Wastes: Water quality impacts from the controlled discharges of drilling fluids and other wastes would be significantly reduced compared to the proposed project since fewer wells would be drilled and, therefore, less fluids would be discharged. The impacts would be considered *adverse but not significant (Class III)*. In addition, extension of life impacts would not occur under this alternative.

Options for Meeting California Fuel Demand. The relative impacts to marine water quality associated with the various options for meeting California fuel demand are summarized in Table 5.6.7.

Table 5.6.7 No Project Alternative Comparison to Options for Meeting California Fuel Demand, Oceanographic & Marine Water Quality

Source of Energy		Impacts
Other Conventional Oil & Gas		
	Domestic onshore crude oil and gas	Would eliminate marine water quality impacts.
	Increased marine tanker imports of crude oil	Marine water quality impacts would be increased.
	Increased gasoline imports[1]	Would eliminate marine water quality impacts.
	Increased natural gas imports (LNG)	Marine water quality impacts would increase with LNG tankering and/or development of offshore ports.
Alternatives to Oil and Gas		
	Fuel Demand Reduction: increased fuel efficiencies, conservation, electrification[2]	
	Alternative transportation modes	Proposed project impacts would be eliminated.
	Implementation of regulatory measures	Proposed project impacts would be eliminated.
	Coal, Nuclear, Hydroelectric	Proposed project impacts would be eliminated. Marine water quality impacts unlikely for coal or hydroelectric. Coastal nuclear plants could result in marine water quality impacts.
	Alternative Transportation Fuels	
	Ethanol/Biodiesel[3]	Proposed project impacts would be reduced.
	Hydrogen[2]	Proposed project impacts would be eliminated.
	Other Energy Resources[2]	
	Solar[2,4]	Proposed project marine water quality impacts would be eliminated.
	Wind[2,4]	Proposed project marine water quality impacts would be eliminated. Development of offshore wind infrastructure could result in marine water quality impacts.
	Wave[2,4]	Proposed project marine water quality impacts would be eliminated. Development of wave energy extraction infrastructure could result in marine water quality impacts.

Footnotes:
1. Pipeline and tanker truck import from out-of-State assumed.
2. Assumes that Tranquillon Ridge production would not be replaced with other petroleum-based energy supply.
3. Assumes ethanol and biodiesel used as blends only and therefore would reduce, but not eliminate Tranquillon Ridge or equivalent production.
4. Assumes, large centralized facilities.

5.6.5.2 VAFB Onshore Alternative

Development of the Tranquillon Ridge Field from VAFB would reduce or eliminate impacts to marine water quality from the proposed project. The only potential impacts to marine water quality from the VAFB Onshore Alternative would be the potential discharge of produced water from Platform Irene (if the NPDES permit is modified to allow it) under Produced Water Scenario 1 or a spill from a pipeline rupture or due to upset conditions at the drilling/production site if the oil reaches ocean waters.

Impact MWQ.1 - Impacts due to Oil Spills: The VAFB Onshore Alternative would reduce the risk of oil spills compared to the proposed project. The risk of an oil spill from Platform Irene or associated offshore pipelines would be reduced to the baseline conditions. There is a small chance that an oil spill from the rupture of the new pipeline or upset conditions at the drilling/production site could reach ocean waters. The chances of oil from the onshore pipeline and drilling/production site reaching the ocean are nominal because the alternative facilities would be landward of the railroad tracks. The railroad tracks run along a berm that forms a partial barrier to flows. However, under high flow conditions spilled oil might reach ocean waters via one of the drainages crossed by the pipeline. Spilled oil that did reach the ocean from this alternative would have the potential to result in significant degradation of marine water quality. Mitigation Measure MB-1 requires an update to the Oil Spill Response Plan and serves to ameliorate marine water quality impacts should a spill occur. For the VAFB Onshore Alternative, the Oil Spill Response Plan should specifically detail methods to keep oil spilled into creeks and drainages from reaching the ocean (see Mitigation Measure CRF/KH-3). Oil spill impacts have the potential to be *significant (Class I).*

Impact MWQ.3 - Impacts due to Discharges of Produced Water: Under Produced Water Scenarios 2 and 3, treated produced water would be re-injected onshore either at the onshore drilling and production site or the LOGP. Under either of these scenarios, no impacts associated with ~~Tranquillon Ridge development~~ the VAFB Onshore Alternative would occur to marine water quality from produced water discharges. Under Produced Water Scenario 1, produced water from the VAFB Onshore Alternative would be treated at the LOGP and then sent to Platform Irene where it would either be re-injected or discharged to the ocean. If produced water were re-injected, impacts to marine water quality would not be expected. Under current regulations/permits, discharges at Platform Irene of produced water from the Tranquillon Ridge Field would be prohibited unless that produced water was produced from wells drilled from Platform Irene. To discharge produced water at Platform Irene from wells drilled onshore, the existing discharge permit would need to be modified or a new discharge permit would need to be obtained (E. Bromley, USEPA, personal communication, 2006). Modifying the existing permit or obtaining a new discharge permit is feasible, but could be a lengthy process and would require the approval of the California Coastal Commission in addition to approval of USEPA. If a new or modified permit were obtained to allow discharge of produced water from Platform Irene, the impacts would be similar to those described for MWQ.2 of the proposed project and Mitigation Measure MB-3 would apply.

Impacts MWQ.2 and MWQ.4 - Impacts due to Discharges of Drilling Fluids, and Other Wastes: No ocean discharge of drilling fluids or other wastes would occur for the VAFB Onshore Alternative. Therefore, there would be no impact to marine water and sediment quality from these discharges for the VAFB Onshore Alternative. Water quality impacts from the controlled discharges of drilling fluids and other wastes would be significantly reduced compared to the proposed project since fewer wells would be drilled and, therefore, less fluids would be discharged. Impacts associated with discharge of drilling fluids and other wastes would be associated with the baseline condition and not the onshore alternative. The impacts of discharging drilling fluids and other wastes would be considered *adverse but not significant (Class III).* In addition, extension of life would not occur under this alternative.

5.6.5.3 Casmalia East Oil Field Processing Location

There are no additional impacts identified for this alternative. The proposed project's marine water quality impacts remain unchanged under this alternative.

5.6.5.4 Alternative Power Line Routes to Valve Site #2

There are no additional impacts identified for this alternative. The proposed project's marine water quality impacts remain unchanged under this alternative.

5.6.5.5 Replacement of Oil Emulsion Pipeline from Platform Irene to LOGP

Under this alternative Impacts MWQ.1 through MWQ.4 would be similar to the proposed project. An oil spill would be less likely to occur because of adding new oil emulsion pipeline sections. However, water quality impacts from a spill would be widespread and containment and cleanup would remain uncertain, leaving it as a significant (Class I) impact. Measures designed to mitigate marine water-quality impacts (MB-1 and MWQ-1) would still apply. No increased risk from shallow geophysical hazards would arise because the new emulsion line would occupy the existing pipeline corridor. Along this corridor, the seafloor consists of a firm sandy bottom with few rocky outcrops, gas pockets, or relict slumps.

The produced-water pipeline would not be replaced. Consequently, water-quality impacts from the controlled discharge of produced water (Impact MWQ.3), drilling fluids (Impact MWQ.2), and other wastes (Impact MWQ.4) would be the same as the proposed project (*Class II*).

The only additional potential impacts from this alternative would arise during the pipeline installation phase. Specifically, the lay vessel-pull installation method would contribute to limited increase in the load of suspended sediments within the water column. Turbidity increase would occur only during the 53 construction days and would be localized around the pipeline sections as they are set on the seafloor offshore or are jetted-in within 4,000 feet of the shoreline. Temporary increases in concentration of suspended sediments may also be expected near the seafloor when the vessel anchors are set and where the anchor chains contact the seafloor while the lay vessel is moored. Additional minor water quality impacts would arise from deck wash and other contaminants discharged from the lay vessel, tug boats, and support vessels.

Impact #	Impact Description	Phase	Residual Impact
MWQ.5	Marine water-quality impacts would result from seafloor sediments resuspended during the installation of a new offshore pipeline.	*Construction*	*Class III*

The short-lived increase in turbidity associated with the installation of the pipeline would be confined to the seafloor portion of the construction operation. The plume of resuspended ambient sediments stirred up by placing the pipeline on the seafloor would consist largely of medium to fine sands. These sands would rapidly redeposit within a few tens of meters of the disturbance area. Under quiescent flow conditions, the time it takes suspended sediment to settle depends on grain size, shape, and the concentration of suspended solids. The fine quartz sands found close to shore along the central coast (Morro Group, Inc., 2000) would settle 15 m in approximately 15 minutes assuming low solids concentrations (USACOE, 1984). The very fine sands found farther offshore (>70-m water depth) would settle 15 m in approximately 45 minutes under the same ambient conditions. With naturally occurring turbulence and greater particle concentrations, actual settling times would be longer. However, it is unlikely that suspended seafloor sediments would extend more than a few meters above the bottom and construction-related increases in turbidity are likely to persist for less than a day. Similarly, the lateral extent of tangible near-bottom increases in turbidity around the pipeline corridor would also be limited to a few tens of meters. Consequently, the turbidity plume is not likely to violate Ocean Plan prohibitions on aesthetically undesirable discoloration of the ocean surface or significant reductions in the penetration of ambient light.

The greatest volume of seafloor sediments would be suspended during burial of the pipeline near the surf zone where hydraulic jetting is proposed under this alternative. However, ambient turbidity is already elevated close to shore due to natural disturbances such as resuspension from shoaling waves and onshore runoff. Temporary increases in turbidity within this dynamic environment are not likely to be measurably different from increases that occur naturally during coastal storms. Therefore, the impact is determined to be adverse but not significant.

Mitigation Measures

To mitigate this impact to the maximum extent feasible, Mitigation Measures MWQ-1 and MB-1 would apply.

Residual Impact

Turbidity increases associated with pipeline installation would be temporary and confined to the seafloor near the pipeline corridor. Consequently, Impact MWQ.5 *would be adverse but not significant (Class III).*

5.6.5.6 Alternative Drill Muds and Cuttings Disposal

Two alternative disposal methods for drilling fluids would eliminate impacts to marine water quality caused by the ocean discharge of drilling fluid (Impact MWQ.2). However, other Class II impacts to water quality would be the same as for the proposed project (Impacts MWQ.1, Oil Spills, MWQ.3, Produced Water Discharge, and MWQ.4, Produced Water Treatment). Measures designed to mitigate marine water-quality impacts (MWQ-1 and MB-3) would still apply.

Inject Drill Muds and Cuttings into a Reservoir

Under this alternative, all of the muds and cuttings would be injected into a reservoir at Platform Irene. New grinders and pumps would have to be installed on the platform. Reinjecting all drilling muds into underground formations can be difficult to achieve in some offshore oil fields (MMS, 2001). Even after extensive pretreatment of the muds, including grinding and dilution, the solids content can quickly plug most permeable formations after initial pumping (Amstutz, 1980). Consequently, mud reinjection is unusual on the Pacific OCS. However, it is currently being practiced on the SYU platforms in the SBCh. The effectiveness of this approach is dependent on the availability of cavernous underground formations or high vug densities (pore densities in the formation). Even if injectivity tests confirm a well's high permeability and porosity, and thus its ability to accept the disposal material, the injection of muds into near surface formations could conceivably result in impacts to marine water quality as described in the following impact statement.

Impact #	Impact Description	Phase	Residual Impact
MWQ.6	Marine water-quality impacts could result from the marine release of interstitial waters contaminated by drill-muds injection into a near surface formation.	*Drilling*	*Class III*

Although injection would probably not directly impact marine water quality, it could contaminate the interstitial and groundwater below the seafloor if the material was injected into a near surface formation. If interstitial waters are contaminated with oil or other contaminants, these contaminants may seep into marine waters. However, marine impacts resulting from this seepage are expected to be less severe than the intentional open-ocean discharge of drilling fluids under the proposed project (MWQ.2). Nevertheless, in the proposed project, muds and cuttings would be monitored for low-level contamination before being discharged in the open ocean under controlled conditions; namely a specific location and shunt depth. This would result in smaller more-localized impacts to marine water quality than an uncontrolled release ("frac-out") of possibly more-contaminated drill muds over wide areas of the seafloor.

Based upon the MMS requirements for injection of muds and cuttings, extensive evaluation of the injection formation would occur before any injection would occur. It is highly unlikely that the MMS would approve the use of a near surface formation due to the low fracture pressures that typically exist with these types of formations. Typically, muds and cuttings are injected into deep formations that are thousands of feet below the seafloor, which virtually eliminates the possibility of seepage to the ocean.

The impact associated with injection of muds and cuttings into a near surface formation is considered to be adverse but not significant.

Mitigation Measures

No mitigation is required beyond those specified in current underground injection control regulations.

Residual Impact

Underground injection control regulations require that muds and cuttings be reinjected into a deep formation that is isolated from the seafloor. Consequently, the possibility of the marine release of contaminated groundwater is remote. This also requires that the integrity of the well-bore and cap rock is sufficient to prevent near-surface formations from being fractured. Overall, reinjecting contaminated muds and cuttings into a deep formation would largely eliminate the likelihood of contaminants entering the marine environment. With proper care taken during reinjection, the likelihood of water quality contamination is low and if a release should occur, dilution within ground and interstitial waters should limit marine water quality impacts. Consequently, this impact is deemed *adverse but not significant (Class III*).

Transport Drill Muds and Cuttings to Shore for Disposal

Under the proposed project, drilling muds and cuttings would be transported to shore only when they become contaminated. Contamination may occur after a diesel pill is used to free stuck pipe or when hydrocarbons are encountered when drilling though production zones. Under this alternative, all drilling fluids, even those with low chemical-contamination levels, would be transported to shore for disposal. The alternative would reduce marine water-quality impacts caused by the discharge of small amounts of hydrocarbons adhering to muds and cuttings that pass the free-oil test. It would also reduce turbidity and deposition of drilling particulates proximal to the platform (MWQ.2). However, vessel transportation may still result in marine water-quality impacts as described below.

Impact #	Impact Description	Phase	Residual Impact
MWQ.7	Marine water quality would be impacted by accidental discharge of drill muds and cuttings during transit to shore.	*Drilling*	*Class III*

This alternative would increase the risk of an accidental release of drill muds as a result of a vessel collision. In addition, there is a risk of accidental spills while the muds and cuttings are transferred to and from the boats. Spills that occur in a protected harbor during offloading or near the sensitive intertidal zone during transit along the coast will result in short-term impacts to marine water quality that would exceed impacts that arise from muds that are intentionally discharged offshore at depth. For example, water quality impacts caused by accidental spillage would diminish the penetration of ambient light within the euphotic zone. Similarly, the increased turbidity caused by a drilling-fluid spill near the coast can negatively impact filter-feeding organisms. Moreover, in contrast to the muds discharged offshore under the proposed project, the containerized muds shipped to shore may contain additional contaminants that would not be allowed under the NPDES discharge permit. However, there is a low risk of a drill-mud release during transit to shore and if released, the volume would be small and impacts transitory. Because temporary impacts from an accidental release of drilling fluid are not likely to be any more significant than those that result from the long-term release under the proposed project, water-quality impacts from this alternative are considered to be *adverse but not significant*.

Mitigation Measures

To mitigate this impact to the maximum extent feasible, the following mitigation measures would apply:

MWQ-2 The applicant shall regularly inspect all Baker tanks, bins, and hoses used to transfer muds and cuttings to the transport vessels and immediately repair of damaged components or require these inspection and repair tests within their contractual agreements with the vessel operators. Inspection records shall be submitted to MMS on a regular basis.

MWQ-3 The applicant shall collect and dispose onshore, all wastewater generated by cleaning the boats, transport containers, and mud-transfer equipment or require these inspection and repair tests within their contractual agreements with the vessel operators. The applicant shall keep all disposal records to be available for inspection.

Residual Impact

By mitigating the impact to the maximum extent feasible, the low likelihood of an accidental release of spent drilling fluids during transit would be reduced to negligible levels. Because any release would be of limited volume, adverse marine water-quality impacts associated this alternative are deemed to be *adverse but not significant (Class III*).

5.6.6 Cumulative Impacts and Mitigation Measures

Cumulative projects that could impact existing oceanographic and marine water quality conditions include only those potential offshore oil and gas projects summarized in Sections 4.2 and 4.3. The potential onshore development projects discussed in Section 4.4 would not impact marine water quality. As such, only the cumulative impacts associated with the offshore oil and gas projects are discussed below.

Other than impacts from multiple oil spills, cumulative impacts to marine water quality would not be expected to be significant with implementation of NPDES permit requirements. The marine water-quality impacts described above are too localized to be compounded by impacts from other offshore oil and gas projects in adjacent offshore lease blocks. Impact footprints that result from the discharge of drill muds, produced water, and other wastes from Platform Irene are largely contained within 100 meters (327 feet). Even for the distant deposition of drilling particulates, as described in Appendix D, almost no particulates would travel beyond 3 or 4 kilometers (1.9 to 2.5 miles) before being deposited on the seafloor.

The probability of two or more oil spills occurring simultaneously is extremely small, but lingering effects from one spill could compound the impacts from another. In addition, the large spatial extent of an oil spill associated with the proposed project encompasses many of the other offshore-development projects in the area (see Figures 4-1 and 4-2). Spills that are caused by different projects could easily impact the same region. However, water-quality impacts from oil spills are comparatively short-lived, on the order of weeks, and it is unlikely that another spill would occur in the same area within that time. In contrast, oil-spill impacts to marine sediments are much longer lived and it is conceivable that multiple spills could result in hydrocarbon accumulation within marine sediments.

Nevertheless, there is a low likelihood that the proposed project would cause a spill that followed soon after another spill and that impacted the same oceanic region where water-quality, sediment-quality, or organisms had yet to substantially recover from the previous spill. Consequently, the proposed project would not induce significant additional adverse impacts to marine sediments due to cumulative effects, over and above the adverse impacts from a single major spill. This is not to say that the marine impacts from an oil spill are not significant, only that the incremental contribution of a project-related spill are not significantly more considerable when viewed in conjunction with potential sediment and water-quality impacts from the other projects addressed in the cumulative analysis. However, given that the impacts to marine water quality from any major spill would be significant, the cumulative impact would be considered significant.

5.6.7 Mitigation Monitoring Plan

Mitigation Measure	Mitigation Requirements and Timing	Method of Verification	Timing of Verification	Party Responsible For Verification
MWQ-1	Offshore inspections of the wet-oil pipeline shall continue to be conducted on a regular basis as determined by the County and/or other regulatory agency throughout the life of the project. Inspections shall use the best available technology to identify unsupported spans and deteriorating or inadequate welds. When structural anomalies or unsupported spans are identified that compromise the integrity of the pipeline as determined by the County and/or other regulatory agency, flow through the pipeline flow shall cease until repairs can be effected, spans can be supported, or problematic pipeline components can be replaced. If the leak detection system causes an unexplained shutdown of flow through the offshore pipeline, flow shall remain shutdown until the entire length of pipe is inspected. The applicant shall submit annual inspection reports the parities responsible for verification. These requirements shall be referenced in the project's Safety, Inspection, Maintenance, and Quality Assurance Program (SIMQAP).	Review of inspection and repair records.	During Operations	MMS CSLC SBC P&D SBC B&S
MWQ-2 (Onshore Mud Disposal Alternative only)	The applicant shall regularly inspect all Baker tanks, bins, and hoses used to transfer muds and cuttings to the transport vessels and immediately repair of damaged components or require these inspection and repair tests within their contractual agreements with the vessel operators. Inspection records shall be submitted to MMS on a regular basis.	Review of applicant's inspection records and unannounced inspection by verifying party.	During Operations	MMS or designated monitor
MWQ-3 (Onshore Mud Disposal Alternative only)	The applicant shall collect and dispose onshore, all wastewater generated by cleaning the boats, transport containers, and mud-transfer equipment or require these inspection and repair tests within their contractual agreements with the vessel operators. The applicant shall keep all disposal records to be available for inspection.	Periodic monitoring in the field and inspection of disposal records.	During Operations	RWQCB or designated monitor

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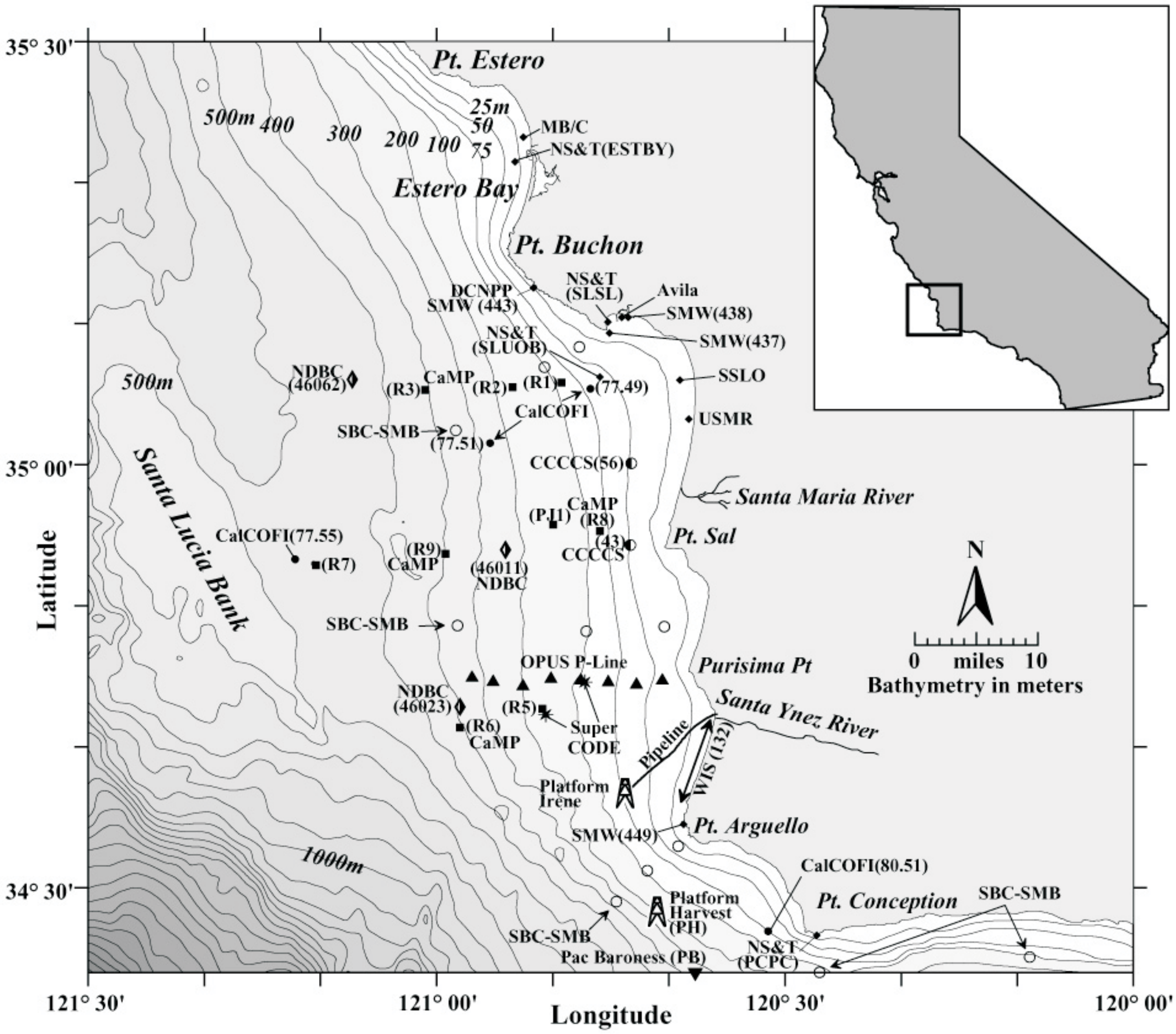

Acronyms for the studies shown in this Figure are defined in Table 5.6.1.

Source: MRS, 2002.

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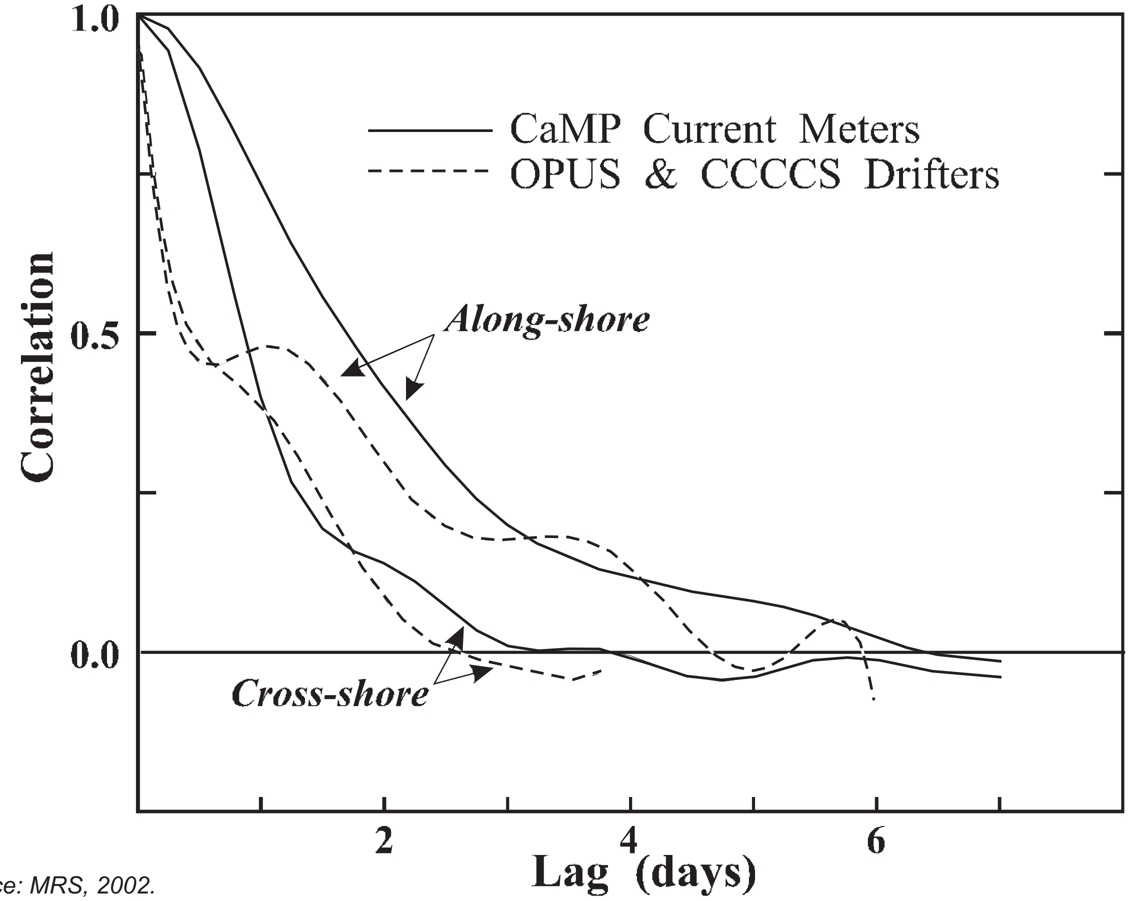
Figures 5.6-1

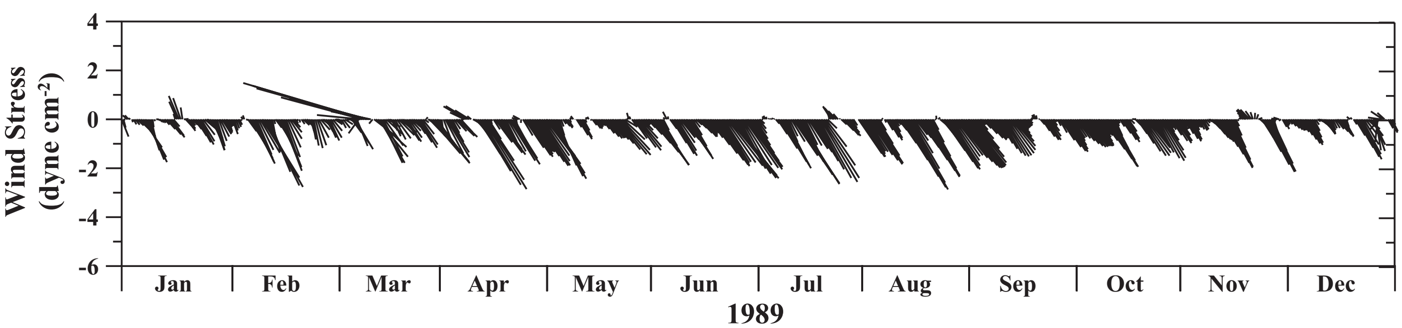
Location of Oceanographic Studies Conducted Near Platform Irene



Source: MRS, 2002.

Figures 5.6-2

Time-lagged Correlation of Velocity from Near-Surface Moored Current Meters and from Surface Drifters along the Central Coast



Source: MRS, 2002.

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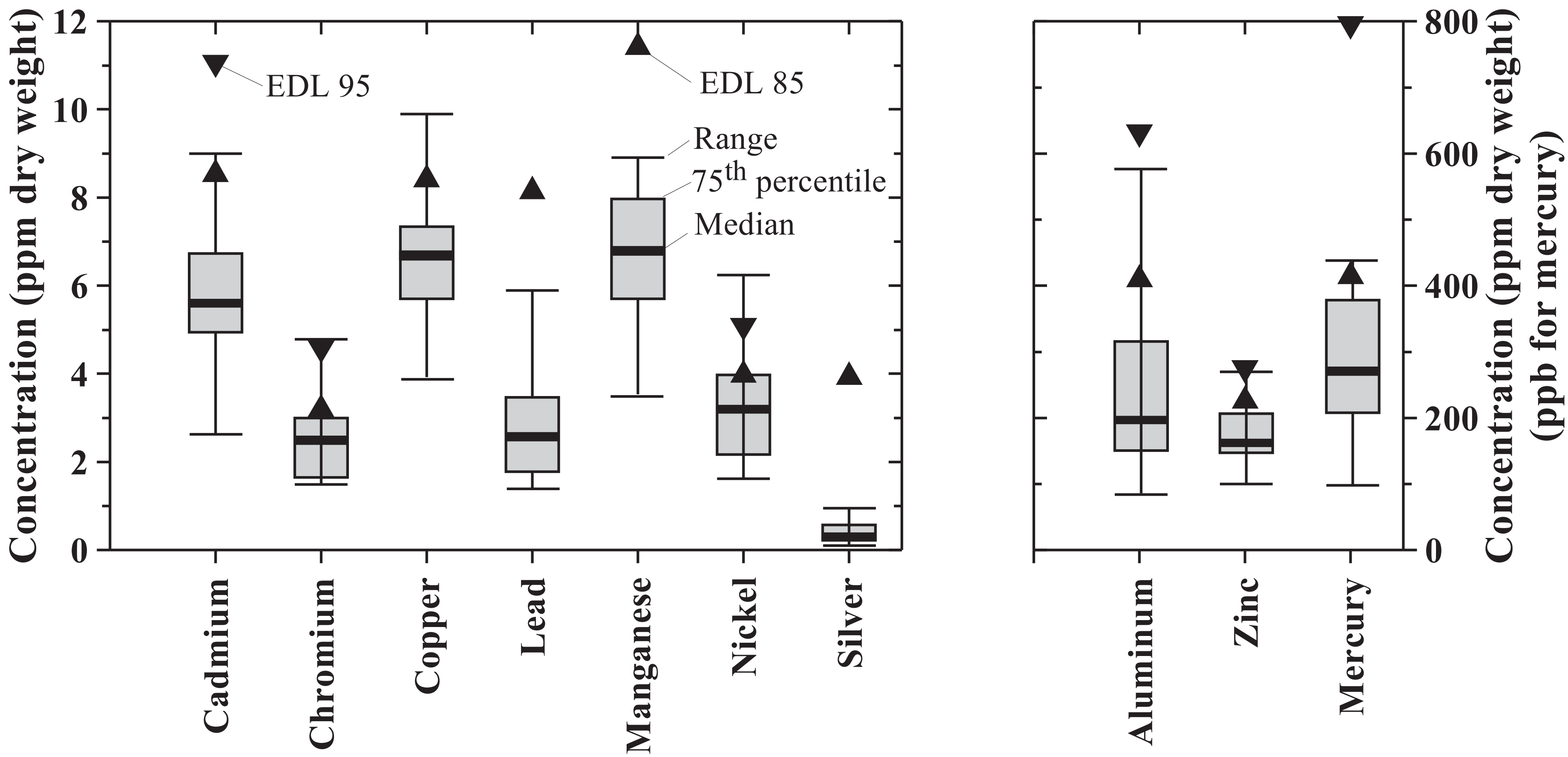
Figures 5.6-3

Wind Stress Recorded at Buoy 46023 near Platform Irene



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Figures 5.6-4
Distribution of Trace Metal Concentrations in Mussels Collected in the Study Region Compared to Statewide Levels

5.7 Commercial and Recreational Fishing

5.7.1 Environmental Setting

Commercial and recreational fishing activities occur at various locations in the project area. In addition, there has been historic kelp harvesting in the area. This section describes the techniques and intensity of commercial and recreational fishing that occur in the proposed project area.

5.7.1.1 Commercial Fishing

A wide variety of finfish and shellfish species are harvested commercially in the proposed project area. The majority of fish commercially harvested in this area are landed in the Ports of Morro Bay and Port San Luis/Avila to the north and Santa Barbara and Ventura to the south. Over 100 different species were harvested commercially in the four ports (i.e., Santa Barbara, Ventura, Morro Bay, and San Luis/Avila) for the four-year period from 2002 to 2005 (CDFG, 2003-2006). The top 20 species harvested commercially in the project area for the four-year period from 2002 to 2005 and landed at the four ports are listed in Table 5.7.1. The 20 species comprise 97.0 percent by weight and 93.2 percent in dollar value of the commercial fish harvested in the four ports. The top 20 species harvested commercially in the Santa Barbara Channel from 2001 to 2005 are listed in Table 5.7.2.

Table 5.7.1 Rank Order of the Top Twenty Commercial Fish Species Harvested in the Project Area from 2002 to 2005

Total Weight (Tons)			Dollar Value (M)		
Species	**Weight**	**Percent**	**Species**	**Value**	**Percent**
Squid, market	36183	63.7	Squid, market	15.06	26.4
Urchin, red	9747	17.2	Urchin, red	12.65	22.2
Shrimp, Pacific ocean	1312	2.3	Lobster, California spiny	7.10	12.5
Crab, rock unspec.	1232	2.2	Crab, rock unspec.	3.07	5.4
Sole, Dover	1184	2.1	Halibut, California	2.55	4.5
Tuna, albacore	884	1.5	Prawn, spot	1.81	3.2
Sea cucumber	652	1.2	Cabezon	1.57	2.7
Prawn, ridgeback	512	0.9	Prawn, ridgeback	1.52	2.7
Thornyhead longspine	487	0.9	Salmon, Chinook	1.32	2.3
Lobster, California spiny	478	0.8	Swordfish	1.27	2.2
Halibut, California	341	0.6	Seabass, white	1.26	2.2
Seabass, white	317	0.6	Tuna, albacore	1.22	2.1
Sablefish	316	0.6	Shrimp, Pacific Ocean	1.10	1.9
Sole, petrale	292	0.5	Sea Cucumber	1.08	1.9
Rockfish, bank	279	0.5	Rockfish, brown	0.88	1.5
Salmon, Chinook	231	0.4	Rockfish, grass	0.86	1.5
Sardine, Pacific	226	0.4	Sole, Dover	0.80	1.4
Rockfish, blackgill	167	0.3	Thornyhead, longspine	0.67	1.2
Thornyhead, shortspine	158	0.3	Sole, petrale	0.64	1.1
Swordfish	156	0.3	Sablefish	0.60	1.1

Based on combined landings at Morro Bay, Port San Luis/Avila, Santa Barbara, and Ventura (CDFG, 2003-2006).

Table 5.7.2 Rank Order of the Top Twenty Commercial Fish Species Harvested in the Santa Barbara Area from 2001 to 2005

Total Pounds (Tons)			Dollar Value (M)		
Species	**Weight**	**Percent**	**Species**	**$ Value**	**Percent**
Squid, market	134,611	70.8 %	Squid, market	46.58	44.2 %
Sardine, Pacific	20,014	0.10 %	Urchin, red	21.22	20.1 %
Urchin, red	15,500	<0.08 %	Lobster, California spiny	10.9	10.4 %
Anchovy, northern	12,085	0.06 %	Crab, rock unspec.	4.17	4.0 %
Crab, rock unspec	1,654	0.01 %	Halibut, California	4.15	3.9 %
Sea cucumber	1,424	<0.01 %	Prawn, spot	2.81	2.7 %
Lobster, California spiny	752	<0.01 %	Sea cucumber	2.47	2.3 %
Prawn, ridgeback	670	<0.01 %	Prawn, ridgeback	1.99	1.9 %
Halibut, California	567	<0.01 %	Seabass, white	1.90	1.8 %
Tuna, albacore	428	<0.01 %	Sardine, Pacific	1.82	1.7 %
Seabass, white	364	<0.01 %	Anchovy, northern	1.67	1.6 %
Shark, thresher	155	<0.01 %	Swordfish	1.82	1.0 %
Prawn, spot	150	<0.01 %	Sheephead, California	0.80	0.8 %
Sheephead, California	119	<0.01 %	Thornyheads	0.64	0.6 %
Swordfish	110	<0.01 %	Tuna, albacore	0.51	0.5 %
Crab, spider	190	<0.01 %	Rockfish, grass	0.48	0.4 %
Whelk, Kellet's	48	<0.01 %	Shark, thresher	0.37	0.3 %
Shark, Pacific angel	44	<0.01 %	Cabezon	0.36	0.3 %
Salmon, chinook	41	<0.01 %	Crab, spider	0.22	0.2 %
Cabezon	35	<0.01 %	Salmon, Chinook	0.18	0.2 %

Based on combined landings at Santa Barbara, Oxnard, Ventura, and Port Hueneme. 1 ton = 0.9 metric ton.
Source: CDFG, 2002-2006

Over the four-year period from 2002 to 2005, a total of 56,807 tons of fish were harvested at the four ports (Port San Luis/Avila, Morro Bay, Santa Barbara, and Ventura). The four-year catch was valued at $61.17 million. The fish species that are landed at each of the four ports vary. This is largely due to differences in the fishing fleet at each port, area fished by fishers, and commercial facilities available at each of the ports. The top ten commercial species that were caught in the project area and landed at each of the ports for the four-year period from 2002 to 2005 and their value are provided in Table 5.7.3.

Table 5.7.3 Top Ten Commercial Species for 2002-2005 Harvested in the Project Area and Landed at Port San Luis/Avila, Morro Bay, Santa Barbara, and Ventura

Port San Luis/Avila		Morro Bay		Santa Barbara		Ventura	
Weight (tons)	**Value ($M)**	**Weight (tons)**	**Value ($M)**	**Weight (tons)**	**Value ($M)**	**Weight (tons)**	**Value ($M)**
Sole, Dover (863.0)	Rockfish, brown (0.65)	Squid, market (1250.9)	Prawn, spot (1.13)	Urchin, red (9604.5)	Urchin, red (12.44)	Squid, market (32149.0)	Squid, market (13.41)
Squid, market (825.4)	Cabezon (0.62)	Shrimp, Pacific Ocean (918.4)	Salmon, chinook (0.98)	Squid, market (1957.9)	Lobster, California spiny (5.73)	Tuna, albacore (356.7)	Lobster, California spiny (1.36)
Shrimp, Pacific Ocean (392.5)	Sole, Dover (0.60)	Tuna, albacore (364.2)	Shrimp, Pacific Ocean (0.82)	Crab, rock unspecified (950.8)	Crab, rock unspecified (2.39)	Prawn, ridgeback (190.9)	Halibut, california (1.32)

Table 5.7.3 Top Ten Commercial Species for 2002-2005 Harvested in the Project Area and Landed at Port San Luis/Avila, Morro Bay, Santa Barbara, and Ventura

Port San Luis/Avila		Morro Bay		Santa Barbara		Ventura	
Weight (tons)	**Value ($M)**	**Weight (tons)**	**Value ($M)**	**Weight (tons)**	**Value ($M)**	**Weight (tons)**	**Value ($M)**
Thornyhead longspine (333.4)	Thornyhead longspine (0.49)	Sole, Dover (320.4)	Cabezon (0.74)	Sea Cucumber (519.5)	Halibut, California (1.11)	Halibut, California (180.8)	Seabass, white (0.64)
Rockfish, bank (49.7)	Sablefish (0.36)	Sole, petrale (219.7)	Tuna, albacore (0.59)	Lobster, California spiny (387.5)	Prawn, ridgeback (0.88)	Crab, rock unspecified (169.2)	Prawn, ridgeback (0.63)
Sablefish (49.7)	Squid, market (0.29)	Salmon, chinook (156.7)	Squid, market (0.58)	Prawn, ridgeback (317.0)	Squid, market (0.78)	Seabass, white (156.8)	Swordfish (0.56)
Tuna, albacore (126.8)	Shrimp, Pacific Ocean (0.28)	Thornyhead longspine (153.6)	Swordfish (0.48)	Seabass, white (143.9)	Sea Cucumber (0.78)	Sea Cucumber (130.4)	Tuna, albacore (0.43)
Sardine, Pacific (112.4)	Rockfish, gopher (0.28)	Sablefish (129.9)	Sole, petrale (0.48)	Halibut, California (139.9)	Seabass, white (0.54)	Sardine, Pacific (113.8)	Crab, rock unspecified (0.38)
Thornyhead shortspine (104.1)	Crab, Dungeness (0.25)	Rockfish, blackgill (81.5)	Rockfish, grass (0.44)	Shark, thresher (95.9)	Prawn, spot (0.35)	Urchin, red (109.3)	Tuna, bigeye (0.29)
Crab, rock unspecified (82.6)	Rockfish, bank (0.24)	Swordfish (75.4)	Rockfish, gopher (0.27)	Salmon, chinook (37.5)	Rockfish, grass (0.26)	Lobster, California spiny (89.9)	Sea Cucumber (0.29)

Source: CDFG, 2003-2006.

The total volume and dollar value of the catch landed at each port for the five individual years between 2001 and 2005 are provided in Tables 5.7.4 and 5.7.5. Volumes and values for Port San Luis/Avila were not individually recorded in 2001 and are not included. Of the four ports, Ventura ranked first in volume of commercial catch. The ports of Santa Barbara, Morro Bay, and Port San Luis/Avila followed in that order. The volume of catch landed at Ventura was nearly double the combined landings for the other three ports. Santa Barbara ranked first in dollar value of commercial catch. Santa Barbara was followed by Ventura, Morro Bay, and Port San Luis/Avila. For the period of 2001 to 2005, the Santa Barbara catch totaled ~~190,209~~ 17,054 tons for a value of $31.89 ~~105~~million.

The high volume and dollar value of commercial catch landed at Santa Barbara are largely due to non-finfish species. Urchin, lobster, prawn, and crab, which are of high commercial value, were the top five species landed, either by volume or dollar value, during the five-year period. A high percentage of these species is landed at nearby Santa Barbara. It should be noted that the commercial and recreational abalone fishery in southern and central California was closed to all fishing under emergency action by the California Fish and Game Commission in May 1997. By legislative action in January 1998, the closure was extended indefinitely. Under the new legislation, the Fish and Game Commission may lift all or part of the closure as specified in the Abalone Recovery and Management Plan that was adopted in December 2005.

Table 5.7.4 Dollar Value ($M) of Fish Harvested in the Project Area and Landed At Port San Luis/Avila, Morro Bay, Santa Barbara, and Ventura Over a Five-Year Period

Port	2001	2002	2003	2004	2005	Total
Port San Luis/Avila	*	$1.86	$1.70	$1.26	$0.71	$5.53
Morro Bay	$3.44	$2.49	$1.76	$2.20	$2.18	$12.07
Santa Barbara	$5.36	$6.73	$6.57	$6.51	$6.72	$31.89
Ventura	$3.07	$3.65	$5.64	$5.42	$5.78	$23.56
Total	$11.87	$14.73	$15.67	$15.39	$15.39	$73.05

** No specific information available for Port San Luis/Avila for 2001.*
Source: CDFG, 2003-2006

Table 5.7.5 Volume (Tons) of Fish Harvested in the Project Area and Landed At Port San Luis/Avila, Morro Bay, Santa Barbara, and Ventura Over a Five-Year Period

Port	2001	2002	2003	2004	2005	Total
Port San Luis/Avila	*	1570	1444	816	90	3,920
Morro Bay	1315	826	1112	1582	832	5,667
Santa Barbara	2631	3087	3486	3901	3949	17,054
Ventura	8181	7851	7993	8705	9565	42,295
Total	12,127	13,334	14,035	15,004	14,436	68,936

** No specific information available for Port San Luis/Avila for 2001.*
Source: CDFG, 2003-2006

Commercial fishers utilize several types of fishing gear in the project area. Gear categories include trawls, pots and traps, gillnets, diving, trolling and hook and line.

Bottom trawls are designed to maintain contact with the seafloor. Although there are several types of trawls depending on the species fished, in their most basic form they are funnel-shaped nets that are towed over the seafloor. As they are towed over the seafloor surface, the rope, chain, or line (e.g., tickler chain, bridles, etc.) that precedes the net opening scare prey up off the ocean bottom. As the trawl is towed forward, prey is captured in the netting that follows. The opening of the trawl is maintained by a headrope with floats on the top, a footrope with weights on the bottom, and doors to each side that spread the net horizontally on the seafloor. Bottom trawls are used throughout the proposed project area. Species caught by bottom trawls include flatfish (e.g., Dover sole and rex sole), rockfish, prawns, and sablefish.

Pots and traps come in a variety of shapes and sizes. In the project area, they are used primarily to capture crabs, lobsters, and to a lesser extent, prawns and certain fish species. Typically, several pots or traps are attached to a heavy groundline with an anchor or heavy weights attached at both ends. The ends of the line are connected to a surface buoy containing markers such as flags, radar reflectors, or even lights. Crab pots in particular are set in hard-bottom habitats. They can be set individually or in groups attached to a common groundline. During installation and retrieval of traps and pots, they can be dragged several meters along the bottom. Pots and traps are generally used at water depths <200 m near hard bottom habitat or along edges of canyons. However, pot fishing for sablefish can occur at depths up to 500 m along the edge of the continental shelf.

Gill nets consist of a vertical wall of netting. Weights and anchors on the bottom horizontal line anchor the bottom portion of the net to the seafloor while a series of floats on the top lead line lift the upper portion of the net towards the ocean surface. Gill nets are used for a wide variety of fish including halibut, yellowtail, and rockfish. Presently, however, set and drift gill nets for rockfish and lingcod are restricted from use in waters <70 fathoms (420 feet) south of Point Sal and in waters <40 fathoms (280 feet) from Point Sal north to Point Piedras Blancas.

Several fishing methods that use hooks attached to lines are utilized in the area for specific fisheries. Vertical longlines employ a series of hooks attached to a weighted line and are suspended vertically in the water column. Vertical longlining is commonly used to fish for rockfish over hard-bottom structures. Horizontal bottom longlines are similar to vertical longlines except that the hooks lay on the seafloor. Weighted ends keep the line on the seafloor. Horizontal longlines are used to catch bottom fish such as halibut.

Trolling consists of towing a baited hook or lure behind a boat. Pelagic fish such as salmon or albacore tuna are the primary target catch in the project area. Trolling commonly occurs in the water column high off the bottom, but in certain years, trolling for salmon can occur close to bottom.

Although there are several variations, seines are used to encircle schools of pelagic fish species. Seines generally fish from the surface and are essentially round haul nets. The webbing of the net is laid out to encircle the prey species. Floats along the upper lead line keep the top end of the net at the water surface. Metal rings are sewn along the bottom edge and a cable is passed through the rings. When the cable is drawn tight, the net "purses" (Fields, 1965). Seines are used in the project area to capture squid and other pelagic species such as mackerel and anchovy. Squid, which is an important commercial species in southern California, is landed exclusively by purse seines (Vojkovich, 1998). In prior years, high-intensity lamps were used to attract squid to the surface and a brail net was the only net used to scoop the squid onto the ship (Kato and Hardwick, 1975). Due to economics, however, brail vessels could not compete with the more efficient seiners (Vojkovich, 1998).

In the project area, sea urchins were the top-ranked species in both pounds harvested and dollar value of the harvest. Urchins are harvested along the mainland coast and around the Channel Islands in hard-bottom areas. They are harvested by divers to a depth of approximately 65 feet.

5.7.1.2 Recreational Fishing

Recreational fishing activities in the project area occur from a variety of platforms. They include private or charter vessels, piers, or from the shoreline (e.g., beaches, jetties, breakwaters). Other than fishing logs maintained by the commercial passenger fishing vessel (CPFV) fleet, reliable recreation fish landing data for specific locations of the coast are not available. Estimates of total marine recreational fin fish landings are provided by the California Recreational Fisheries Survey (CRFS), developed by the California Department of Fish and Game and the Pacific States Marine Fisheries Commission, to produce data to manage fisheries sustainability. Fish landed (numbers of fish) by the CPFV fleet that fish in the project area and estimates from the CRFS are provided in Table 5.7.6. The numbers provided in the table are conservative estimates of CPFV catch landings because not all CPFV operators participate in the logbook program

(Thompson, 1999). Table 5.7.7 presents the recreational fishing rank for Santa Barbara Channel for the period of 1997 to 2003.

Table 5.7.6 Annual Recreation Fish Landing by Species (number of fish) for the Commercial Passenger Fishing Vessel (CPFV) Fleet (2001) and Party Boats and Charter Boats (2004-2005)

2001[1]		2004[2,3]		2005[2]	
Hueneme, Oxnard, Ventura, S. Barbara	Avila, M. Bay	Santa Barbara/Ventura	San Luis Obispo/Santa Cruz	Santa Barbara/Ventura	San Luis Obispo/Santa Cruz
Rockfish (142,084)	Rockfish (102,888)	Rockfish (211,000)	Rockfish (183,000)	Rockfish (151,000)	Rockfish (149,000)
Barred Bass (50,219)	Albacore (8,902)	Barred Bass (59,000)	Kelp greenling (2,000)	Barred Bass (9,000)	Lingcod (9,000)
Whitefish (49,333)	Cabezon (743)	Kelp Bass (25,000)	Lingcod (1,000)	Kelp Bass (7,000)	Mackerel (8,000)
Kelp Bass (34,673)	Lingcod (729)	Whitefish (6,000)	Halibut (1,000)	Whitefish (4,000)	
Barracuda (20,444)	Unspecified Fishes (196)	Barracuda (5,000)	Mackerel (1,000)	Barracuda (3,000)	
Halfmoon (13,199)	Unspecified Flatfishes (114)	Blackfish (5,000)		Mackerel (3,000)	
Scorpionfish (8,738)	California Halibut (56)	Mackerel (3,000)		Sheephead (1,000)	
Sheephead (8,086)	Halfmoon (15)	Bonito (3,000)		Lingcod (1,000)	
White Seabass (4,336)	Pacific Mackerel (8)	Halfmoon (1,000)			
Albacore (3,509)	Whitefish (6)				

Source: CDFG, 2001, California Recreational Fisheries Survey Recreational Information Network
[1] 2001 was the last year the Annual Report of Statewide Landings by the CPFV Fleet separated the landings by port.
[2] CRFS provides estimates in thousands only.
[3] 2004 was the first year the CRFS divided the California coast into divisions.

Table 5.7.7 Ranking of Fish Recreationally Harvested in the Santa Barbara Channel from 1997 to 2003

Taxon	SB Channel Total[1]	Island Fraction[2]	Mainland/Open Fraction
Rockfish	724,782	64.3 %	35.7 %
Kelp Bass	251,840	40.9 %	59.1 %
Barred Sand Bass	249,997	8.5 %	91.5 %
Ocean Whitefish	168,015	84.6 %	15.4 %
Barracuda	119,611	48.6 %	51.4 %
Rock Scallop	67,804	98.3 %	1.3 %
Scorpionfish	53,964	70.4 %	29.6 %
Sheephead	30,157	87.2 %	12.8 %
Halfmoon	29,798	87.0 %	13.0 %
Mackerel	26,157	8.3. %	91.7 %
Yellowtail	24,397	86.1 %	13.9 %
Lobster	23,124	99.6 %	0.4 %
Other Fish	88,911	69.7 %	30.3 %
Taxa Total	1,858,557	56.8 %	43.2 %

[1] Total fish count over five years based on CPFV logs.
[2] Fraction of the Santa Barbara Channel fish caught in the seven blocks (684 though 690) that encompass the Channel Islands and cover 12.8 percent of the Channel area.
Source: CSLC, 2006.

As a group, rockfish dominate the CPFV catch and CRFS estimates for the Santa Barbara and San Luis Obispo areas. Rockfish landed at Port San Luis/Avila and Morro Bay accounted for over 80 percent of the catch for 2001, 2004, and 2005. Thompson (1999) has estimated that private boats and the CPFV fleet land an equal number of rockfish. Combined they account for 20 percent of the rockfish caught offshore California while commercial trawlers account for 54 percent and hook and line vessels 16 percent (Thompson, 1999).

Non-finfish species are also harvested in the project area. Species and their numbers as reported by recreational charter boats to the CDFG for the 50 statistical fish blocks around Platform Irene are listed in Table 5.7.8 (CDFG, 2001b). The CDFG noted that the numbers provided in the table are conservative counts, as most recreational fishers do not report catch to local authorities. The data, however, provide valuable insights to target species and catch trends over the four-year period. The top-three species harvested were the rock scallop, spiny lobster, and abalone. These species were harvested by recreational divers at the western end of the Channel Islands and below Point Conception at subtidal water depths.

Table 5.7.8 Non-Finfish Species Collected by Recreational Fishers in the Proposed Project Area

Name		Year				
Common	**Scientific**	**1995**	**1996**	**1997**	**1998**	**Total**
Abalone	*Haliotis* spp.	1				1
Abalone, green	*Haliotis fulgens*	50	50			100
Abalone, pink	*Haliotis corrugata*	80				80
Abalone, red	*Haliotis rufescens*	2,321	3,156	1,029		6,506
Abalone, threaded	*Haliotis assimilis*		1			1
Clam, CA jackknife	*Tagelus californianus*	22				22
Cucumber, sea	Holothuroidea		540	294	22	856
Limpet	Archaeogastropoda			50		50
Lobster, CA spiny	*Panulirus interruptus*	2,615	1,935	2,606	2,204	9,370
Mussel	*Mytilus* spp.		15			15
Scallop, rock	*Crassadoma gigantea*	15,444	14,635	14,189	7,940	52,208
Snail, sea	Gastropoda		25			25
Urchin, red	*Strongylocentrotus franciscanus*	317	165	250	60	792

Source: CSLC, 2001b

5.7.1.3 Commercial Kelp Harvesting

Kelp Species

In southern California, kelp beds are primarily composed of the giant kelp *Macrocystis pyrifera*, while in the central California region (Point Montara south to Point Arguello), the kelp beds are a mix of the giant kelp and the bull kelp *Nereocystic luetkeana*.

The giant kelp *Macrocystis pyrifera* occurs from Baja California to Santa Cruz in central California (Druehl, 1970). Populations of the giant kelp commonly form dense patches that are referred to as kelp beds. Wave exposure and rocky substrates generally control their distribution. Except for a specialized population of giant kelp that grow on sand near Santa Barbara, the kelp holdfast attach to solid substrates or rock for attachment (North, 1971). Giant kelp can occur in the intertidal zone in protected areas, but the shoreward boundary of giant kelp is largely determined by where the largest waves normally break (Seymore et al., 1989; Graham, 1997). The outer limit of giant kelp beds is largely determined by water clarity (Dean and Deysher, 1983). In turbid waters, the offshore edge of kelp beds occurs at depths of approximately 50 to 60 feet, while in clear waters around the Channel Islands, the offshore edge of kelp beds extend to more than 100 feet (North, 1971).

Giant kelp is very productive. Gerald (1976) reported that productivity varied between 0.4 wet kg/m^2 and 3.0 wet kg/m^2 with an average of 23 wet kg/m^2/year or 102.4 tons/acre/year. Conversely, there are many factors that cause mortality to giant kelp. Storms and large swells that can dislodge plants cause the greatest mortality (Cowen et al., 1982; Dayton et al., 1984; Foster and Schiel, 1985; Dayton, 1985; North, 1986; Seymour et al., 1989). Storms can cause a gradient of damage from single plants and holdfasts to cleared areas several acres in size (Dayton et al., 1984).

The bull kelp *Nereocystis luetkeana* ranges from Alaska south to San Luis Obispo County, CA (Hawkes et al., 1978; Scagel et al., 1987). In central California south of Carmel, both giant and bull kelp occur together, forming very dense kelp beds. Like the giant kelp, bull kelp is associated with hard substrates for attachment and other environmental factors (McLean, 1962; Foreman, 1970). Bull kelp generally occurs at water depths of 13 to 72 feet (McLean, 1962; Nicholson, 1970; Vadas, 1972).

The productivity of bull kelp is also high. Gotshall et al. (1986) monitored bull kelp at Diablo Cove in San Luis Obispo County. Over a 12-year period, productivity of bull kelp averaged 9 kg/m^2 or 40.5 tons/acre. During the same period, productivity ranged from a high of 45 kg/m^2 (200 tons/acre) to a low of 1.09 kg/m^2 (4.8 tons/acre). The most influential factor for bull kelp survival is light availability (Vadas, 1972). Reduction of light caused by plankton blooms, storm turbulence, overcast or foggy conditions, or overshadowing by other algae can inhibit growth substantially (Vadas, 1972; Dayton et al., 1984; Miller and Estes, 1989). Nutrient levels and water temperature are also important to the survival of bull kelp (Dawson, 1966; Jackson, 1983).

Unlike the giant kelp, storms have varying effects on bull kelp. While spring storms cause mortality on young and juvenile plants, summer storms had little effect on this species (Foreman, 1970). Bull kelp, by nature, is more abundant in high disturbance areas with extremely large swells. Because of the resilience and strength of the stipe of this plant, it is able to survive under these extreme conditions. Koehl and Wainwright (1977) reported that bull kelp stipes can stretch approximately 38 percent. During winter storms, bull kelp canopies are removed by wave action. Because this plant is an annual species, this result is consistent with its life history. By late fall, photosynthetic activity has decreased resulting in weakened plants and holdfasts. The increase in wave energy during the winter months, in combination with the shortened day length, results in the death of this species as part of its life cycle.

Kelp Harvesting

Kelp has been harvested commercially along the coast of California since the early 1900s (Scofield, 1959). Beginning in 1911, many small companies began harvesting along the coast between Santa Barbara and San Diego. In the early years, kelp was harvested for the extraction of potash and acetone. These chemicals were used to manufacture explosives during World War

I (Scofield, 1959; McPeak and Glantz, 1984; Neushul, 1987; Tarpley and Glantz, 1992). In the 1920s, P.R. Park, Inc. of San Diego began harvesting kelp for use as an additive to livestock and poultry food and Kelco of San Diego began harvesting and processing giant kelp for the extraction of algin (Tarpley and Glantz, 1992).

Kelco, now known as ISP Alginates, had harvested and processed giant kelp since 1929. Over the years, they had developed many applications for the compound algin, which is found in the cells of the kelp (CDFG, 2000). Algin has many applications. It is mostly used as a thickening, stabilizing, suspending, and gelling agent and is used in a wide range of foods such as desserts, gels, dairy products, and salad dressings. It also has industrial applications and is used in paper coatings, textile printing and welding-rod coatings. Algin is also used in pharmaceutical, cosmetic, and dental products. In recent years, the annual sales of algin products manufactured in California was $40 million (CDFG, 2000).

Initially, ISP Alginates only harvested kelp beds near San Diego. However, as production needs increased or kelp productivity near San Diego decreased, ISP Alginates extended their harvest area to include the project area (CDFG, 2000). However, since 2005, due to economic reasons, ISP Alginates moved to Scotland and is no longer operating off of California (MMS, 2006; NOAA 2006).

Mariculture companies also use giant kelp commercially as food for their abalone stock. Abalone aquaculture businesses range in size from large companies to small hobby operations. In 1999, the combined abalone aquaculture firms accounted for less than 1.7 percent of the annual kelp harvest (CDFG, 2000). However, their harvest is expected to increase in future years as the supply of wild abalone decreases worldwide. The Cultured Abalone of Santa Barbara leases bed 27 north of Santa Barbara, immediately off the Goleta coast. Since 1966, its kelp harvest has increased by 15 percent annually in response to a growing abalone market (CDFG, 2000). In 1999, the Cultured Abalone harvested 560 tons of kelp. Its kelp harvest is expected to increase by 15 percent annually (CDFG, 2000).

Kelp harvest data for 2000 to 2005 from five kelp beds located in the project area are provided in Table 5.7.9.

Table 5.7.9 Kelp Harvest in Metric Tons for Beds in the Project Area

	Kelp Bed Numbers				
Year	**32**	**33**	**115**	**117**	**118**
2000	0	0	0	0	0
2001	0	1,770	0	100	0
2002	0	0	0	400	0
2003	0	0	2,454	0	0
2004	2,767	0	580	250	0
2005	3,258	2,925	5,969	0	0
Total	6,025	4,695	9,003	750	0

Source:. Data sets were provided by the Santa Barbara Coastal Ecosystem LTER, funded by the US National Science Foundation (OCE 9982105).

Kelp Harvesting Vessels

The vessels used for harvesting commercial kelp beds range in length from 140 to 180 feet. The majority of the length of the vessel comprises the bin for holding the cut kelp (CDFG, 2000). Kelp is cut by reciprocating blades mounted at the base of a conveyor system (drapers) located at the stern end of the ship. The draper system is lowered into the water to a depth of 3 feet, and the harvest ship moves stern-first through the kelp bed. As the kelp is cut, it is brought aboard on the conveyor system and deposited in the bin. The harvest vessels can carry as much as 600 tons of kelp which can be collected in a day (CDFG, 2000). The large harvest vessels have a draft of approximately 12 feet and work at water depths greater than 30 feet.

Kelp harvest vessels used by abalone aquaculturists are smaller than those used by the commercial harvesters. The smaller vessels are capable of working in shallower waters because of their shallow draft. They typically carry between 15 and 25 tons of kelp. Kelp is also harvested by hand from smaller boats to supply abalone farms. It is either cut at the surface using a knife attached to a pole, or cut beneath the water surface by a diver. The cut fronds are bundled together and pulled aboard the boat by hand.

5.7.1.4 Recreational Kelp Harvesting

Very little information is available on the quantity of kelp harvested for recreational purposes. However, several Native American Indian tribes and Asian groups do utilize kelp as a food source. The kelp that is collected can be drift kelp that has washed up onto the beach or fresh kelp that is harvested during low tides. In addition to kelp, local Asian groups harvest seaweeds such as *Porphyra* spp. and *Ulva* spp. in the project area during spring low tides. These algae are utilized as a food source.

Other recreational uses of kelp include its use as an ingredient in a form of ceramic art called Sagger firing and by gardeners for use as compost (CDFG, 2000). It has been estimated that less than 25 tons of kelp is collected annually by recreational users (CDFG, 2000).

5.7.2 Regulatory Framework

5.7.2.1 Federal Laws and Policies

The Outer Continental Shelf Lands Act (OCSLA)

Under the OCSLA, the Department of Interior (DOI) is required to:

- Manage the orderly leasing, exploration, development, and production of oil and gas resources on the Federal Outer Continental Shelf (OCS);
- Ensure the protection of the human, marine, and coastal environments;
- Ensure that the public receives a fair and equitable return for these resources; and
- Ensure that free-market competition is maintained.

Within the DOI, the Minerals Management Service (MMS) is charged with the responsibility of managing and regulating the development of the OCS oil and gas resources in accordance with the provisions of the OCSLA. The MMS operating regulations are presented in Chapter 30, CFR, Part 250.

National Environmental Policy Act (NEPA)

NEPA requires all Federal agencies to use a systematic, interdisciplinary approach to protect the human environment. The approach ensures the integrated use of natural and social sciences in any planning and decision making that may have an impact on the environment. NEPA also requires the preparation of a detailed Environmental Impact Statement (EIS) on any major Federal action that may have a significant impact on the environment. The EIS must address any adverse environmental effects that cannot be avoided or mitigated, alternatives to the proposed action, the relationship between short-term resources and long-term productivity, and irreversible and irretrievable commitments of resources.

In 1979, the Federal Council on Environmental Quality (CEQ) established uniform procedures for implementing the procedural provisions of NEPA. These regulations provide for the use of the NEPA process to identify and assess reasonable alternatives to proposed actions that avoid or minimize adverse effects upon the quality of the human environment. “Scoping” is used to identify the scope and significance of important environmental issues associated with a proposed Federal action through coordination with Federal, State, and local agencies; the general public; and any interested individual or organization prior to the development of an impact statement. The process also identifies and eliminates from further detailed study, issues that are not significant or that have been covered by prior environmental review.

Magnuson-Stevens Act

The Magnuson-Stevens Act of 1976 is the cornerstone legislation of fisheries management in US jurisdictional waters. Its purpose was to stop overfishing by foreign fleets and aid in the development of the domestic fishing industry. The Act gave the US sole management authority over all living resources within the 200-nautical mile exclusive economic zone of the US. The Act created eight regional Fishery Management Councils (FMCs) and mandated a continuing planning and management program for marine fisheries by the FMCs. The Act, as amended, requires that a Fishery Management Plan (FMP) based upon the best available scientific and economic data be prepared for each commercial species or group of related species of fish that is in need of conservation and management within each respective region. The regional council for the Pacific OCS is the Pacific Fishery Management Council. In accordance with the Act, the councils report directly to the US Secretary of Commerce whose job is to review, approve and prepare fishery management plans. In reality, this function is delegated to the Administrator of the National Oceanic and Atmospheric Administration (NOAA) and the National Marine Fisheries Service.

The Act has been amended several times. In 1996, federal law governing fisheries management underwent a major overhaul. The amendments, termed the Sustainable Fisheries Act (SFA) of 1996, identified fish habitat as critical to healthy fish stocks and sustainable fisheries. The SFA implemented a program to designate and conserve Essential Fish Habitat (EFH) for species managed under a FMP. EFH is defined as “those waters and substrate necessary for spawning, breeding, feeding, or growth to maturity.” The intention is to minimize any adverse effects on habitat caused by fishing or nonfishing activities and to identify other actions to encourage the conservation and enhancement of such habitat. A number of FMPs that apply to the west coast have been developed. These include the West Coast Groundfish FMP, the Coastal Pelagics FMP, and the Pacific Salmon FMP. The documents for West Coast groundfish EFH include all species of rockfish managed by the Council (Bloeser, 1999).

Coastal Zone Management Act (CZMA)

In accordance with the CZMA and the Coastal Zone Act Reauthorization Amendments of 1990, OCS oil and gas exploration and development activities affecting the coastal zone must be carried out consistent with the California Coastal Management Program (CCMP) (i.e., the policies of the California Coastal Act). The CCMP sets forth objectives, policies, and standards regarding coastal uses and resources.

Coast Guard Regulatory Authority

Primary responsibility for the enforcement of U.S. maritime laws and regulations falls upon the U.S. Coast Guard. The Coast Guard's responsibilities for regulating activities on the OCS, the continental shelf, and in ports and harbors, as applicable to the proposed action, are presented in Title 33 CFR, chapters 1-199; Title 43 USC section 1331; Title 46 USC, Parts A and B; and OPA 90. The Coast Guard is responsible for managing and regulating provisions for safe navigation of vessels in US waters, as well as the enforcement of environmental and pollution prevention regulations. As such, the Coast Guard provides for the regulation and enforcement of hazardous working conditions on the OCS, for the management and regulations of measures for pollution prevention in territorial waters, and for ensuring that the provisions of the Oil Pollution Act signed in August 1990 (OPA 90) and the Marine Plastic Pollution and Control Act are implemented.

5.7.2.2 State and Local Laws and Policies

California Environmental Quality Act (CEQA)

The goal of CEQA (Pub. Res. Code §21000 et seq.) is to develop and maintain a high-quality environment. It directs California's public agencies to identify the significant environmental effects of their actions and avoid or mitigate those significant environmental effects, where feasible. The California Resources Agency administers CEQA. CEQA requires that an EIR be prepared for any major project and states the likely environmental impacts of that project. If it is determined that a project has no significant environmental effects and is not exempt from CEQA, then the lead agency must adopt a negative declaration to that effect. The purpose of an EIR is to provide State and local agencies and the general public with detailed information on the potentially significant environmental effects which a proposed project is likely to have and to list ways which the significant environmental effects may be minimized and indicate alternatives to the project.

California State Lands Commission (CSLC)

Pursuant to Public Resources Code section 6873.5(b), the CSLC shall (prior to the adoption of a form of lease for leasing offshore tide and submerged lands between the mean high tide line and the three-mile jurisdictional limit) consider the potential impacts of the proposed lease on the fisheries and marine habitat within the area being considered for leasing. This EIR provides information relevant to such consideration for the proposed project.

California Coastal Act of 1976, Public Resources Code Section 30000 et seq.

The California Coastal Act (Division 20 of the Public Resources Code, Section 30000, et seq.) became law in 1976 as a means of providing a comprehensive framework for the protection and management of coastal resources. The main goals of the act are to protect and restore coastal zone resources; assure balanced and orderly utilization of such resources; maximize public access to and along the coast; assure priority for coastal-dependent and coastal-related development; and encourage cooperation between State and local agencies toward achieving the Act's objectives.

The Coastal Act contains policies to guide local and State decision-makers in the management of coastal and marine resources. The policies are organized into chapters by topics relating to public access; recreation; marine environment; land resources; and development. The act also contains provisions for development controls and land-use entitlements for certain types of new development in the coastal zone.

The California Coastal Act, which is administered by the California Coastal Commission, also identifies protective measures for nearshore marine resources. For example:

Coastal Act section 30230 states:

> *"Marine resources shall be maintained, enhanced, and where feasible, restored. Special protection shall be given to areas and species of special biological or economic significance. Uses of the marine environment shall be carried out in a manner that will sustain the biological productivity of coastal waters and that will maintain healthy populations of all species of marine organisms adequate for long-term commercial, recreational, scientific, and educational purposes."*

Coastal Act section 30234 states:

> *"Facilities serving the commercial fishing and recreational boating industries shall be protected and, where feasible, upgraded. Existing commercial fishing and recreational boating harbor space shall not be reduced unless the demand for those facilities no longer exists or adequate substitute space has been provided. Proposed recreational boating facilities shall, where feasible, be designed and located in such a fashion as not to interfere with the needs of the commercial fishing industry."*

Coastal Act section 30234.5 states:

> *The economic, commercial, and recreational importance of fishing activities shall be recognized and protected.*

California Regional Water Quality Control Board (RWQCB)

The California RWQCB determines permit requirements on a case-by-case basis. A Water Discharge Permit is required if the action creates problems or if the action becomes permanent. The duration and size of a project are important factors and concerns may include the amount of water quality degradation.

The Water Quality Control Plan developed by the Central Coast RWQCB established water quality standards for the region. The plan incorporates the California Ocean Plan that establishes standards to protect the quality of ocean waters for use and enjoyment by the people of California. The Ocean Plan, which is administered by the State Water Resources Control Board, is reviewed periodically to guarantee that the current standards are adequate and are not allowing degradation to marine species or posing a threat to public health (State Water Resources Control

Board, 2001). In general, Chapters I, II, and III establish discharge standards for non-point discharges to marine waters. For example:

The California Ocean Plan, Chapter I, Beneficial Uses states:

> *"The beneficial uses of the ocean waters of the State that shall be protected include industrial water supply, water contact and non-contact recreation, including aesthetic enjoyment, navigation, commercial and sport fishing, mariculture, preservation and enhancement of Areas of Special Biological Significance, rare and endangered species, marine habitat, fish migration, fish spawning and shellfish harvesting."*

The California Ocean Plan, Chapter II, Water Quality Objectives states, in part, in Section E Biological Characteristics, that:

1) *Marine communities, including vertebrate, invertebrate, and plant species shall not be degraded.*

2) *The natural taste, odor, and color of fish, shellfish, or other marine resources used for human consumption shall not be altered.*

3) *The concentration of organic materials in fish, shellfish or other marine resources used for human consumption shall not bioaccumulate to levels that are harmful to human health.*

The Central Coast RWQCB's Water Quality Control Plan (Basin Plan) applies to the coastal waters that include the Tranquillon Ridge Field (RWQCB, 1994). The standards of the RWQCB incorporate the applicable portions of the Ocean Plan and are more specific to the beneficial uses of marine waters adjacent to the project site. These water quality objectives and toxic material limitations are designed to protect the beneficial uses of ocean waters within specific drainage basins. The Basin Plan identifies the following existing beneficial uses for the coastal waters contained within the project area (RWQCB, 1994).

- Water Contact Recreation: Uses of water for recreational activities involving body contact with water, where ingestion of water is reasonably possible. These uses include, but are not limited to, swimming, wading, water skiing, skin and scuba diving, surfing and fishing.
- Marine Habitat: Uses of water that support marine ecosystems including, but not limited to, preservation or enhancement of marine habitats, vegetation such as kelp, fish, shellfish, or wildlife such as marine mammals and shorebirds.
- Shellfish Harvesting: Uses of water that support habitats suitable for the collection of filter-feeding shellfish such as clams, oysters, and mussels, for human consumption, commercial, or sport purposes. This includes waters that have in the past, or may in the future, contain significant shell fisheries.
- Ocean Commercial and Sport Fishing: Uses of water for commercial or recreational collection of fish, shellfish, or other organisms including uses involving organisms intended for human consumption or bait purposes.

Santa Barbara County (SBC)

The coastal reaches adjacent to the Tranquillon Ridge Field fall under the jurisdiction of SBC. Consequently, SBC is one of the agencies responsible for reviewing project actions including integration of policies established by the California Coastal Act. An Energy Division was established within the SBC's Planning and Development (P&D) Department to participate in environmental reviews and permitting of major oil and gas development projects. The Division also ensures that oil and gas projects are developed and operated in compliance with the permit conditions imposed by the SBC decisionmakers, including the Board of Supervisors and the Planning Commission.

5.7.3 Significance Criteria

Changes or impacts to commercial and recreational fishing or kelp harvesting will be considered significant if:

- Loss of fishing grounds or kelp harvesting areas exceed 10 percent during the proposed project.
- More than 10 percent of fishers are precluded from fishing in a specific area for most or all of a fishing season.
- Kelp beds lessees are not able to harvest for most or all of a kelp season (e.g., one year).
- Fish or kelp resources of commercial importance have the potential to be reduced by more than 10 percent in a specific area.
- The project results in the loss or damage to any commercial or recreational fishing or kelp harvesting equipment.

5.7.4 Impact Analysis for the Proposed Project

Impact #	Impact Description	Phase	Residual Impact
CRF/KH.1	Oil spills may potentially impact commercial and recreational kelp harvests in the proposed project area.	*Increased Throughput* *Extension of Life*	*Class III*

The effects of oil spills on beds of *Macrocystis* have been examined several times along the Pacific coast. After the tanker *Tampico* spill in 1957 in Baja California, North et al. (1964) reported high mortality of invertebrates but no damage to *Macrocystis*. Within five months of the spill, they reported increased amounts of algal vegetation, including *Macrocystis*. North et al. (1964) reported that the oil had killed sea urchins that had been maintaining the bottom and once killed, *Macrocystis* and other algal species began to develop. The kelp had recruited and produced a canopy in the cove approximately 18 months following the spill.

The 1969 Santa Barbara crude oil spill impacted a large portion of the mainland coast and Channel islands (Foster et al., 1971a). There was little damage to the *Macroscystis* beds even though considerable quantities of crude oil fouled the surface canopies (Foster et al., 1971b). The partially weathered crude oil appeared to stay on the surface of the water and did not stick to the fronds of the giant kelp.

Also, there are extensive natural gas and oil seeps that occur near kelp beds in the Santa Barbara Channel (Mertz, 1959). The seeps often produce continuous oil slicks on the surface of the water and tar mounds on the ocean bottom within kelp bed communities (Spies and Davis, 1979). The natural seeps do not appear to cause visible damage to *Macrocystis* and extensive canopies regularly develop in these beds.

The literature indicates that an oil spill or its cleanup cause little damage to kelp beds. Should damage occur, such as from the *Tampico* spill, recruitment and recolonization occurs rapidly and within one year. Hence, impacts to kelp and commercial and recreational kelp harvesting operations are adverse but not significant.

Mitigation Measures

Mitigation Measures MB-1a and MB-1b in Section 5.5, Marine Biology, would mitigate Impact CRF/KH.1 to the maximum extent feasible in accordance with County policies.

Residual Impact

Because of the temporary nature of the disturbance, oil spill impacts to commercial and recreational kelp harvesting operations are *adverse but not significant (Class III)*.

Impact #	Impact Description	Phase	Residual Impact
CRF/KH.2	Oil spills may potentially impact commercial and recreational fishing in the proposed project area.	*Increased Throughput* *Extension of Life*	*Class I*

A wide variety of fish and shellfish species are commercially harvested in the project area. As described in Marine Biology Impact MB-1, biota residing in the intertidal and shallow subtidal habitat are vulnerable to oil spills. Several species are commercially and recreationally harvested in the intertidal zone. Sea urchins, for example, ranked first in pounds landed and dollar value over the five-year period from 1995 to 1999. Sea urchins alone accounted for almost half (46.5 percent) of the dollar value of the commercial catch during the five years. In pounds landed, it accounted for 41.6 percent of the total catch. Mass mortalities of invertebrates such as sea urchins, abalone, and lobsters were reported following the *Tampico* spill in Baja California (North et al. 1964). Although abalone is not presently harvested in the project area, both sea urchins and lobsters are high value species that are harvested both commercially and recreationally in the area. In the event of an oil spill, there could be impacts to abalone, sea urchins, and lobster. Smothering is the most common cause of mortality and would be limited to direct contact with weathered tar balls from the oil spill. Although not high value species, other intertidal or shallow subtidal organisms that are harvested include sea cucumbers and whelks. Results of the oil spill trajectory analyses (Figure 5.1-1) indicate that key areas for harvesting these species along the northern and western edge of San Miguel and Santa Rosa Islands (between 0.3 and 5.3 percent probability) and the coastline between Point Arguello and Point Conception (between 0.0 and 12.7 percent probability) may be impacted by oil spills. The degree of oiling and the oil spill impacts depend on several factors. They include location of spill, volume, type of oil, amount of weathering, evaporation, dispersion of oil into the water column or shoreline, and the amount of oil that is contained and cleaned immediately after a spill. For the spills that occurred on the Pacific and Gulf of Mexico OCS between 1971 and 1999, the mean volume of oil spills was 159 barrels (MMS, 2001). Large spills (e.g. >2000 barrels) are rare and unlikely to occur; however, the Santa Barbara oil spill of 1969 was estimated at 80,900 barrels (MMS, 2001). The spill from the 1997 rupture of the Torch Pedernales pipeline in the project area was estimated at 163 to 1,242+ barrels (SBC, 2001)[1]. While the probability for oil

[1] The CDFG official spill volume from the Torch Point Pedernales pipeline was 163 barrels (bbls) (CDFG, 1989). The 1,242 bbl estimate is from SBC and is based upon additional factors that were not taken into account with the CDFG official number. These include drainage from the landward side of the pipeline, oil between pigs 1 and 2, and oil behind pig 2.

contacting and fouling the shoreline or shallow subtidal areas where commercial or recreational species are harvested is low, it nevertheless can occur. While contaminated shorelines may be cleaned, in some instances, depending on substrate type, oil may persist in sediments for several years.

On rocky cobble beaches in Prince William Sound, oil was clearly visible in sediments eight years after the *Exxon Valdez* spill that occurred in 1989 (Hayes and Michel, 1998). A surface sheen in intertidal waters caused by the release of hydrocarbons from oiled sediments was noticeable eight years after the spill (Hayes and Michel, 1998). In addition to direct oiling effects, impacts caused by the cleanup method, or sublethal effects such as histological damage, altered physiological and metabolic patterns, decreased growth and reproduction, vulnerability to diseases, or even area closures can continue for several years (NRC, 1985; Coats et al., 1999). Oil spill impacts to commercial and recreational fisheries in the intertidal environment or shallow subtidal may be long lasting and can result in loss of areas for most if not all of a harvesting season. Hence, impacts to commercial or recreational fishing in intertidal or shallow subtidal areas are considered to be significant.

Damage to fish populations were documented from the *Exxon Valdez* oil spill (Spies, 1996). Juvenile pink and sockeye salmon were directly affected by the spill in 1989 and their eggs may have been affected through 1993 (Spies, 1996). Other indications of exposure to oil included the presence of oil in the stomachs of salmon fry, measurements of polynuclear aromatic hydrocarbons in salmon fry, and increases in P450[2] and bile hydrocarbon metabolites in Dolly Varden (Spies, 1996). Impacts to growth were also shown for pink salmon, Dolly Varden and cutthroat trout even though changes in food availability were not detected (Spies, 1996).

Brown et al. (1996) estimated that 40 to 50 percent of the egg biomass of Pacific herring in Prince William Sound was exposed to oil during developmental stages. The resulting 1989 year class showed sublethal effects such as premature hatch, low weights, reduced growth, and increased morphologic and genetic abnormalities (Brown et al., 1996). The 1989 year class recruiting as 4-year old adults in 1993 was one of the smallest to return to spawn in Prince William Sound with an adult population that had already been reduced by approximately 75 percent (Brown et al., 1996).

Adult fish, due to their mobility, may be able to avoid or minimize exposure to spilled oil. However, there is no conclusive evidence that fish will avoid spilled oil (NRC, 1985). Egg and larval stages would also not be able to avoid exposure to spilled oil. Because losses to commercial and recreational fish resources and losses due to closure of fishing areas for most or all of a fishing season can occur, impacts to commercial and recreational fishing from oil spills are considered to be significant. Fish harvested from contaminated areas may also be reduced in value and fishing gear can be damaged due to oil fouling, causing additional significant impacts. <u>Further, response, cleanup and repair vessels that do not adhere to the Vessel Traffic Corridor restrictions can cause the loss or destruction of fishing gear.</u>

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[2] Cytochrome P450, a family of over 60 enzymes the body uses to break down toxins and make blood.

Mitigation Measures

See Mitigation Measures MB-1a and MB-1b in Section 5.5, Marine Biology. Condition M-8 of the PXP FDP (see Appendix M), requires PXP to cooperate with the Santa Barbara Channel Vessel Traffic Corridor Program; no additional mitigation is required.

Residual Impact

Because there are limitations to thorough containment and cleanup of an offshore oil spill, *significant impacts (Class I)* remain for commercial and recreational fisheries in the intertidal zone.

Impact #	Impact Description	Phase	Residual Impact
CRF/KH.3	The discharge of drilling muds and drill cuttings from Platform Irene may potentially impact kelp communities in the project area.	*Drilling*	*Class III*

The discharge of drilling muds and drill cuttings at Platform Irene would result in increased turbidity in ocean waters near the platform. However, the mud discharges would not affect the photosynthetic ability of kelp due to the great distance between the discharge point and the kelp beds along the shoreline. Because of the intermittent nature of the drilling mud discharges, the rapid descent of most mud solids to the ocean bottom, and the dispersion of suspended mud particles, these impacts are considered to be potentially adverse but not significant.

Mitigation Measures

No mitigation measures have been identified.

Residual Impact

Because of the temporary nature of the disturbance, drilling mud or drill cuttings impacts to commercial and recreational kelp harvesting operations are *adverse but not significant (Class III)*.

Impact #	Impact Description	Phase	Residual Impact
CRF/KH.4	Marine vessel traffic to and from Platform Irene could cause loss or damage to commercial fishing gear in the project area.	*Drilling* *Extension of Life*	*Class III*

Supply boats servicing Platform Irene use Port Hueneme as the shore based facility. The supply boat traffic from Port Hueneme crosses nearshore set gear fishing areas such as Hueneme Flats, and could cause damage to the fishing gear. If support vessels hit fishing gear, the gear can be damaged or lost. With the increase in the number of supply boat trips during the drilling phase, the likelihood of supply boats impacting commercial fishing gear would increase. In addition, with the Tranquillon Ridge project, supply boats would continue to service the platforms for a longer period of time due to the extension of its life.

In 1983 the Joint Oil/Fisheries Liaison Office, a private nonprofit service, was formed along with the Joint Oil/Fisheries Committee of South Central California to provide an inter-industry communications link and dispute resolution/mediation process between the offshore oil and gas industry and the commercial fishing industry in the Santa Barbara Channel and Santa Maria Basin.

To reduce the conflict between support vessel traffic and the commercial fishing industry, a Vessel Traffic Corridor Program was developed by the Joint Oil/Fisheries Committee of South Central California, and went into effect in August 1984. These vessel traffic corridors are approximately 1,500 feet wide. Use of these corridors is voluntary. PXP has stated that the supply boats servicing Platform Irene currently use and will continue to use the defined corridors from Port Hueneme to the shipping lanes.

Use of mooring areas along the coast also poses a potential conflict with nearshore commercial fishing. One mooring location of particular concern is Cojo anchorage, which is in a prime set gear fishing area. Support vessels that service the oil platforms in the Southern and Central Santa Maria Basin use the Cojo anchorage as a safe anchoring spot during rough weather. As the vessels move in and out of Cojo Bay, it is possible that they could impact set fishing gear, resulting in damage or loss of the gear.

Given that the support vessels servicing Platform Irene use the vessel traffic corridors and the fact that there is a Joint Oil/Fisheries Liaison Office that provides dispute resolution/mediation, this impact is considered adverse but not significant.

Mitigation Measures

CRF/KH-1 Disputes over damage to commercial fishing gear resulting from support vessel traffic to and from Platform Irene shall be submitted to the Joint Oil/Fisheries Committee for resolution.

Residual Impact

Given the use of the vessel traffic corridors and the dispute resolution/mediation process, this impact is considered *adverse but not significant (Class III).*

Impact #	Impact Description	Phase	Residual Impact
CRF/KH.5	The deposition of shells, or shell mounds, could prevent commercial trawling activities beneath Platform Irene	*Drilling* *Extension of Life*	*Class III*

Epibiota such as mussels and barnacles fall from their attachment points on submerged portions of a platform and can accumulate on the seafloor. The accumulation or deposits of shells, referred to as shell mounds, also contain drilling related discharges such as drilling muds and drill cuttings (deWit, 2001). In 1996, Platforms Hazel, Hilda, Hope, and Heidi (collectively known as the 4H platforms), located in State Waters in the eastern portion of the Santa Barbara Channel were removed. The platforms were located in water depths ranging from 95 feet (29 m) to 150 feet (46 m). The shell mounds beneath the platforms ranged from 20 to 28 feet (6.7 to 8.5 m) in height and from 185 to 230 feet (56.9 to 70.1 m) in width. The estimated volume of material within the mounds ranged from 7,000 to 14,000 yd^3 (5,352 to 10,704 m^3) (de Wit, 2001). Compared to samples collected at a reference site, chemical analyses of sediments collected within the shell mounds indicated elevated levels of metals, hydrocarbons, and PCB’s. Elutriate bioassay testing also showed that shell mound sediments collected at Platform Hazel were toxic enough at 48 percent concentration to kill 50 percent of mysid shrimp (*Mysidopsis bahia*) within 96 hours (deWit, 2001).

Several trawl tests were conducted after the platforms were removed. The purpose of the tests was to demonstrate that permit conditions requiring that the sites could be trawled had been satisfied. The tests were all unsuccessful and trawling could not be conducted in the shell-mound area beneath the former 4H platforms. Various alternatives regarding the fate of the shell mounds are being examined by the CSLC (CSLC, 2001). Alternatives range from mitigation for the loss of trawling grounds, modifications to the mounds, or complete removal of the mounds (CSLC, 2001).

Love et al. (1999) surveyed the mussel mounds beneath seven platforms in the Santa Barbara Channel and the Santa Maria Basin. The mound beneath Platform Irene was one of the seven mounds that were surveyed. Because the focus of the study conducted by Love et al. (1999) was to document fish assemblages associated with mussel mounds, the physical and chemical character of the mound is not provided. However, their survey confirms the presence of a mound beneath Platform Irene, but found that the shell mound was small in size.

In 2001 the MMS conducted multibeam hydrographic surveys around and under eight oil platforms in the Santa Barbara Channel and Santa Maria Basin. The study found that the size, height, or volume of the mounds under the platforms may be related to platform age. The oldest platform (Houchin) has the largest mound and the 3 youngest platforms (Gail, Hermosa, and Hidalgo) either have the smallest mounds or none. Other factors must influence the size, height, and volume of the mounds because three platforms (Gina, Henry, and Grace) were installed within a year of each other and have mounds with significantly different heights and volumes (MMS, 2001).

The study also found that the size and volume of the mounds under the offshore platforms may be related to the geographic location of the platforms. The largest mounds are under Platforms Henry and Houchin, which are located near one another in Central Santa Barbara Channel. Platforms Gina and Grace, located in the Southern Santa Barbara Channel, have mounds of similar size and volume. Although located far apart, Platforms Gail and Hondo are both located in deep water (740’ and 835’, respectively) and have similar-sized mounds. The two platforms surveyed in the Santa Maria Basin (Hermosa and Hidalgo) have very small or no mounds (MMS, 2001).

Recent data suggest that the shell mounds at Platform Irene cannot be removed using technology that is available today. Feasibility studies for the Chevron 4H shell mounds indicate that 135 feet of water is the practical limit for removal of shell mounds based upon currently available technology. The shell mound located at Platform Irene, which lies in 242 feet of water, could not be removed with technology that is available today. Although the “best available technology” may change in 15-25 years, removal of the mounds may be neither feasible nor environmentally preferred when Irene is abandoned. This would have to be determined as part of the environmental review that would be conducted for the abandonment of Platform Irene.

~~It is likely that with~~The Tranquillon Ridge Project would extend the expected life of Platform Irene~~ will be extended~~. This extension of life could lead to an increase in the size and volume of the shell mound beneath the platform. However, the extent to which the shell mound may change due to the extended life of Platform Irene is unknown. This potential increase in the size of the shell mound was found to be an adverse but not significant impact on commercial fishing since a shell mound already exists at the platform site.

Mitigation Measures

CRF/KH-2 At the time of platform abandonment, the applicant shall ensure that the environmental review of the abandonment activities pursuant to the National Environmental Policy Act (NEPA) and California Environmental Quality Act (CEQA), as appropriate, includes an analysis as to whether or not the shell mounds should be removed or modified so they do not interfere with commercial trawling activities. This subsequent NEPA/CEQA review shall evaluate the best available technologies for removal or modification of the shell mounds. The best available technology shall be determined by the applicant and the permitting agencies, in consultation with the Joint Oil/Fisheries Liaison Office and shall be implemented.

Residual Impact

Because a shell mound already exists at the platform site, the residual impact due to an increase in the size of the shell mound due to extension of life is *adverse but not significant (Class III).*

5.7.5 Impact Analysis for the Alternatives

Detailed descriptions of the various alternatives have been provided in Chapter 3.0. This section provides a discussion of the commercial and recreational fishing/kelp harvesting impacts from the various alternatives.

5.7.5.1 No Project Alternative

Scenarios 2 and 3. As discussed in Section 3.2, under the No Project Alternative Scenarios 2 and 3, production of the federal portion of the Tranquillon Ridge field would and would not occur, respectively. However, no extension of life of Point Pedernales facilities (Platform Irene, pipelines, and LOGP) is assumed under either scenario. Impacts CRF/KH.1 and CRF/KH.2, which address oil spills, would not apply to Scenarios 2 and 3 ~~the No project Alternative~~ because oil production would be ~~the same as~~ comparable to current operations (i.e., baseline).

Impact CRF/KH.3 – Drilling Muds Discharge: Impacts due to the discharge of drilling muds and drill cuttings into the ocean would be the same as current operations (baseline). ~~This alternative~~Scenarios 2 and 3 would eliminate the drilling of 22 to 30 wells into the Tranquillon Ridge Field. Hence, the volume of drilling muds and drill cuttings that would be discharged into marine waters would be reduced substantially. Impacts caused by the release of muds and cuttings would occur over a shorter period of time and be reduced because of the smaller volume that would be discharged. This impact to commercial and recreational kelp harvesting would still be considered *adverse but not significant (Class III).*

Impact CRF/KH.4 – Marine Vessel Traffic Impacts to Fishing Gear: Impacts to fishing gear due to the marine vessel traffic would be reduced compared to the proposed project. ~~This alternative~~Scenarios 2 and 3 would reduce the number of marine vessel trips due to a shorter drilling period (2 years versus 15 years), and there would be no extension of life for the platform.

This impact to commercial fishing would still be considered *adverse but not significant (Class III).*

Impact CRF/KH.5 – Shell Mounds: Impacts associated with the deposition and accumulation of shells and drill cuttings beneath Platform Irene would be less than the proposed project. Because of the reduction in the number of production wells, the volume of drill cuttings that would be discharged into the marine environment would be substantially less. Also, because the period of production would be shortened, the volume of shell material that would fall to the seafloor from Platform Irene would be the same as for the current operations (i.e., baseline). Hence, impacts to trawling activities caused by the shell deposition or shell mounds would be less than for the proposed project. This impact would still be considered *adverse but not significant (Class III).*

Options for Meeting California Fuel Demand. The relative impacts to fisheries and kelp harvesting associated with the various options for meeting California fuel demand are summarized in Table 5.7.10.

Table 5.7.10 No Project Alternative Comparison to Options for Meeting California Fuel Demand, Commercial & Recreational Fishing/Kelp Harvesting

Source of Energy	Impacts
Other Conventional Oil & Gas	
Domestic onshore crude oil and gas	Would eliminate fisheries/kelp impacts.
Increased marine tanker imports of crude oil	Fisheries/kelp impacts would be increased.
Increased gasoline imports[1]	Would eliminate fisheries/kelp impacts.
Increased natural gas imports (LNG)	Fisheries/kelp impacts would increase with LNG tankering and/or development of offshore ports.
Alternatives to Oil and Gas	
Fuel Demand Reduction: increased fuel efficiencies, conservation, electrification[2]	
Alternative transportation modes	Proposed project impacts would be eliminated.
Implementation of regulatory measures	Proposed project impacts would be eliminated.
Coal, Nuclear, Hydroelectric	Proposed project impacts would be eliminated. Fisheries/kelp impacts unlikely for coal or hydroelectric. Coastal nuclear plants could result in fisheries/kelp impacts.
Alternative Transportation Fuels	
Ethanol/Biodiesel[3]	Proposed project impacts would be reduced.
Hydrogen[2]	Proposed project impacts would be eliminated.
Other Energy Resources[2]	
Solar[2,4]	Proposed project fisheries/kelp impacts would be eliminated.
Wind[2,4]	Proposed project fisheries/kelp impacts would be eliminated. Development of offshore wind infrastructure could result in fisheries/kelp impacts.

Table 5.7.10 No Project Alternative Comparison to Options for Meeting California Fuel Demand, Commercial & Recreational Fishing/Kelp Harvesting

Source of Energy		Impacts
	Wave[2,4]	Proposed project fisheries/kelp impacts would be eliminated. Development of wave energy extraction infrastructure could result in fisheries/kelp impacts.

Footnotes:
1. Pipeline and tanker truck import from out-of-State assumed.
2. Assumes that Tranquillon Ridge production would not be replaced with other petroleum-based energy supply.
3. Assumes ethanol and biodiesel used as blends only and therefore would reduce, but not eliminate Tranquillon Ridge or equivalent production.
4. Assumes, large centralized facilities.

5.7.5.2 VAFB Onshore Alternative

Development of the Tranquillon Ridge Field from VAFB would reduce or eliminate impacts to commercial and recreational fishing and kelp harvesting from those for the proposed project. The only potential impacts to fishing and kelp harvesting from the VAFB Onshore Alternative would be if oil spilled from a pipeline rupture or due to upset conditions at the drilling/production site reaches ocean waters.

Impact CRF/KH.1 – Spill Impacts to Kelp: The VAFB Onshore Alternative would reduce the risk of oil spills compared to the proposed project. The risk of an oil spill from Platform Irene or associated offshore pipelines would be reduced to the baseline conditions. There is a small chance that an oil spill from the rupture of the new pipeline or due to upset conditions at the drilling/production site could reach ocean waters. The chances of oil from the onshore pipeline or drilling/production site reaching the ocean are nominal because the alternative facilities would be landward of the railroad tracks. The railroad tracks run along a berm that forms a partial barrier to flows. However, under high flow conditions, spilled oil might reach ocean waters via one of the drainages crossed by the pipeline. If spilled oil from the new onshore pipeline did reach the ocean, it could be more likely to reach kelp beds than a spill from Platform Irene because the oil would enter the ocean close to shore and the nearshore kelp beds. Mitigation Measure MB-1 would apply. In addition for the VAFB Onshore Alternative, the following mitigation measure would apply:

Mitigation Measures

CRF/KH-3 The Oil Spill Response Plan shall be revised to specifically detail methods to keep oil spilled into creeks and drainages from reaching the ocean and ways to protect kelp beds and important nearshore fishing areas along the southern VAFB coast should spilled oil enter the ocean. The Plan shall be submitted to SBC for review and approval prior to land use clearance.

Residual Impact

Because of the temporary nature of the disturbance, oil spill impacts to commercial fishing and kelp harvesting operations are *adverse but not significant (Class III)*. However, to mitigate Impact CRF/KH.1 to the maximum extent feasible, Mitigation Measures CRF/KH-3 and MB-1 would be required.

Impact CRF/KH.2 – Spill Impacts to Fishing: As described above under Impact CRF/KH.1, the VAFB Onshore Alternative would reduce the risk of oil spills compared to the proposed project. The risk of an oil spill from Platform Irene or associated offshore pipelines would be reduced to the baseline conditions. There is a small potential that oil spilled from the alternative facilities could reach the ocean via creeks or other drainages. Oil entering the ocean from onshore might have a greater chance to impact nearshore areas frequented by fishermen than a spill from Platform Irene. Therefore, although the chance of a spill would be greatly reduced compared to the proposed project, if substantial oil did enter the ocean, impacts on nearshore fishing areas might be greater. Mitigation Measures MB-1 and CRF/KH-3 would apply. Because there are limitations for thorough containment and cleanup of an oil spill, *significant impacts (Class I)* remain for commercial and recreational fisheries in the intertidal zone.

Impact CRF/KH.3 – Drilling Muds Discharges: There would be no offshore discharge of drill muds and cuttings associated with the VAFB Onshore Alternative. Therefore, discharge of drilling muds would have no potential to impact fishing or kelp harvesting.

Impact CRF/KH.4 – Marine Vessel Traffic Impacts to Fishing Gear: No vessel traffic would be associated with the VAFB Onshore Alternative. Therefore, there would be no potential for impacts to fishing gear from vessel traffic associated with this alternative. Impacts to fishing gear from vessel traffic associated with Platform Irene would remain the same as the existing (baseline) condition. Impacts to fishing gear are considered *adverse but not significant (Class III).*

Impact CRF/KH.5 – Shell Mounds: ~~Impacts associated with the deposition and accumulation of shells and drill cuttings beneath Platform Irene would be less than the proposed project.~~No ocean discharge of drilling wastes is associated with the VAFB Onshore Alternative. Therefore, the VAFB Onshore Alternative would not result in any new drill cutting discharges from Platform Irene compared to the baseline condition. Also, because the period of production from the platform would not be extended, the volume of shell material that would fall to the seafloor from Platform Irene would be the same as for the current operations (i.e., baseline). Hence, impacts to trawling activities caused by the shell deposition or shell mounds would be less than the proposed project. This impact would still be considered *adverse but not significant (Class III)* but none of the impacts would be associated with the VAFB Onshore Alternative.

5.7.5.3 Casmalia Canyon/Oil Field Processing Location

There are no additional impacts identified for this alternative. The proposed project's commercial and recreational fishing and kelp harvesting impacts remain unchanged under this alternative.

5.7.5.4 Alternative Power Line Routes to Valve Site #2

There are no additional impacts identified for this alternative. The proposed project's commercial and recreational fishing and kelp harvesting impacts remain unchanged under this alternative.

5.7.5.5 Replacement of Oil Emulsion Pipeline from Platform Irene to LOGP

Impact CRF/KH.1 – Spill Impacts to Kelp: Impacts to commercial and recreational kelp harvesting from oil spills remain the same as for the proposed project. However, due to the newer pipe, the spill frequency would be reduced. This impact would still be considered *adverse but not significant (Class III).*

Impact CRF/KH.2 – Spill Impacts to Fishing: Impacts to commercial and recreational fishing resulting from oil spills remain the same as for the proposed project. However, due to the newer pipe, the spill frequency would be reduced. This impact would still be considered *significant (Class I).*

Impact CRF/KH.3 – Drilling Muds Discharge: Impacts resulting from the discharge of drilling muds and drill cuttings into the ocean remain the same as the proposed project *(Class III)*.

Impact CRF/KH.4 – Marine Vessel Traffic Impacts to Fishing Gear: Impacts to fishing gear due to the marine vessel traffic would be increased over the proposed project due to the marine vessel traffic that would be needed to install the offshore pipeline. Fishing would be pre-empted in a 3 to 4 mile area for approximately 2 months. The pre-empted area would be approximately 2 percent of the available tow area between Point Conception and Oceano. Given the short duration of the installation activities and the limited area that would be pre-empted, this impact to commercial fishing would still be considered *adverse but not significant (Class III).*

Impact CRF/KH.5 – Shell Mounds: Impacts resulting from the deposition and accumulation of shells and drill cuttings beneath Platform Irene remain the same as the proposed project *(Class III).*

5.7.5.6 Alternative Drill Muds and Cuttings Disposal

Inject Drill Muds and Cuttings into Reservoir

Impact CRF/KH.1 – Spill Impacts to Kelp: Impacts to commercial and recreational kelp harvesting from oil spills remain the same as for the proposed project *(Class III).*

Impact CRF/KH.2 – Spill Impacts to Fishing: Impacts to commercial and recreational fishing resulting from oil spills remain the same as for the proposed project *(Class I).*

Impact CRF/KH.3 – Drilling Muds Discharge: Impacts due to the discharge of drilling muds and drill cuttings into the ocean would be eliminated.

Impact CRF/KH.4 – Marine Vessel Traffic Impacts to Fishing Gear: Impacts to commercial fishing gear from marine vessel traffic would be the same as for the proposed project *(Class III).*

Impact CRF/KH.5 – Shell Mounds: Impacts resulting from the deposition and accumulation of shells and drill cuttings beneath Platform Irene would be reduced because the cuttings would not be discharged into the ocean. The accumulation of shells would remain the same as the proposed project *(Class III).*

Transport Drill Muds and Cuttings to Shore for Disposal

Impact CRF/KH.1 – Spill Impacts to Kelp: Impacts to commercial and recreational kelp harvesting from oil spills remain the same as for the proposed project *(Class III).*

Impact CRF/KH.2 – Spill Impacts to Fishing: Impacts to commercial and recreational fishing resulting from oil spills remain the same as for the proposed project *(Class I).*

Impact CRF/KH.3 – Drilling Muds Discharge: Impacts due to the discharge of drilling muds and drill cuttings into the ocean would be reduced because they would be shipped ashore for disposal. In the unlikely event that muds and accidentally dropped in the ocean from a supply boat they could cause impacts to fishing and/or kelp harvesting. Therefore, this alternative would eliminate discharges of drilling mud and drill cuttings into the ocean except as a result of an accident during transit on the supply boat. Releases near shore could impact kelp beds or fishing areas. However, there is a low risk of a drill-mud release during transit to shore and if released, the volume would be small and impacts transitory. Because temporary impacts from an accidental release of drilling fluid are not likely to be any more significant than those that result from the long-term release under the proposed project, fishing and kelp harvesting impacts from this alternative are considered to be *adverse but not significant (Class III)*.

Impact CRF/KH.4 – Marine Vessel Traffic Impacts to Fishing Gear: Impacts to commercial fishing gear from marine vessel traffic would be the same as for the proposed project because the drill muds and cuttings would be transported to shore on the return trips of the scheduled supply boat trips. This alternative would not require any additional supply boat trips over the proposed project. This impact to commercial fishing would still be considered *adverse but not significant (Class III).*

Impact CRF/KH.5 – Shell Mounds: Impacts resulting from the deposition and accumulation of shells and drill cuttings beneath Platform Irene would be reduced because the cuttings would not be discharged into the ocean. The accumulation of shells would remain the same as the proposed project *(Class III).*

5.7.6 Cumulative Impacts

The onshore development projects discussed in Section 4.4 would not impact commercial and recreational fishing, and kelp harvesting. Therefore, only the cumulative impacts associated with the potential offshore oil and gas projects discussed in Sections 4.2 and 4.3 are discussed below.

***Impact CRF/KH.1 – Spill Impacts to Kelp*:** The potential future offshore energy projects outlined in Sections 4.2 and 4.3 would increase the probability for oil spills. However, the literature indicates that oil spills do not cause major impacts to kelp beds and, should damage occur, recruitment and recolonization occurs rapidly. Therefore, cumulative oil spills impacts to commercial and recreational kelp harvesting, including the proposed project's incremental contribution to them, would not be expected to be significant.

***Impact CRF/KH.2 – Spill Impacts to Fishing*:** Oil spills may potentially impact commercial and recreational fishing in the proposed project area. The additional potential offshore oil and gas development projects described in Sections 4.2 and 4.3 would increase the probability for oil spills. Therefore, oil spill impacts to commercial and recreational fishing would likely increase. By increasing the cumulative probability of oil spills, cumulative impacts to commercial and recreational fishing, including the incremental contribution of the proposed project, would be expected to be significant.

***Impact CRF/KH.3 – Drilling Muds Discharges*:** The discharge of drilling muds and drill cuttings from Platform Irene may potentially impact kelp communities in the project area. Each of the other potential offshore oil and gas development projects located within the project area would also be expected to discharge drilling muds and cuttings. The impacts from the discharges of these other potential projects would be expected to be similar to the proposed project, provided that they are discharged in accordance with NPDES permit requirements. Because of the dilution and dispersion of each discharge, drilling muds or drill cutting depositions are not expected to compound or accumulate in any specific area. Transport of discharged materials to shoreline kelp communities is unlikely. Hence, the cumulative impacts, including the proposed project's incremental contribution to them, would not be expected to be significant with implementation of NPDES Permit requirements.

Impact CRF/KH.4 – Marine Vessel Traffic Impacts to Fishing Gear: Each of the potential offshore oil and gas development projects considered in the cumulative analysis would increase the number of marine vessels moving between ports and the platforms. These increases would increase the likelihood of impacts to fishing gear. Use of established vessel traffic corridors and the dispute resolution process through the Joint Oil/Fisheries Committee would serve to minimize these impacts. With implementation of these measures, cumulative impacts to commercial fishing, including the proposed project's incremental contribution to them, would not be expected to be significant

Impact CRF/KH.5 – Shell mounds: The deposition of shells and cuttings is a local area impact that is confined to the area surrounding a platform. The size of the accumulated shell mound surrounding a platform can affect trawling activities after platform decommissioning. As discussed in Section 5.7.4, the physical size of the shell mound associated with Platform Irene is anticipated to be, to some extent, a function of the Platform's age, although this cannot be predicted with absolute certainty. Similarly, the shell mounds associated with other existing platforms located in the northern and southern Santa Maria Basin would be anticipated to follow the same pattern. If all of the potential future offshore development projects located in the northern Santa Maria Basin were to occur, up to three new platforms could be constructed (see Section 4.3), each of which would eventually develop its own shell mound. However, the age and respective size of these shell mounds would be anticipated to be substantially less than the one associated with Platform Irene at the time of its decommissioning. Assuming that the other existing and potential future platforms within the southern and northern Santa Maria Basin are subject to the same types of mitigation measures as the proposed project, cumulative impacts, including the incremental contribution of the proposed project to this impact, would not be expected to be significant.

5.7.7 Mitigation Monitoring Plan

Mitigation Measure	Plan Requirements and Timing	Method of Verification	Timing of Verification	Party Responsible For Verification
CRF/KH-1	Disputes over damage to commercial fishing gear resulting from support vessel traffic to and from Platform Irene shall be submitted to the Joint Oil/Fisheries Committee for resolution.	Review of dispute resolution documentation	During Operations	CSLC SBC
CRF/KH-2	At the time of platform abandonment, the applicant shall ensure that the environmental review of the abandonment activities pursuant to the National Environmental Policy Act (NEPA) and California Environmental Quality Act	Abandonment EIR/EIS Process	During preparation of the abandonment EIR/EIS	MMS and all responsible agencies

Mitigation Measure	Plan Requirements and Timing	Method of Verification	Timing of Verification	Party Responsible For Verification
	(CEQA), as appropriate, includes an analysis as to whether or not the shell mounds should be removed or modified so they do not interfere with commercial trawling activities. This subsequent NEPA/CEQA review shall evaluate the best available technologies for removal or modification of the shell mounds. The best available technology shall be determined by the applicant and the permitting agencies, in consultation with the Joint Oil/Fisheries Liaison Office and shall be implemented.			
CRF/KH-3 (VAFB Onshore Alternative only)	The Oil Spill Response Plan shall be revised to specifically detail methods to keep oil spilled into creeks and drainages from reaching the ocean and ways to protect kelp beds and important nearshore fishing areas along the southern VAFB coast should spilled oil enter the ocean. The Plan shall be submitted to SBC for review and approval prior to land use clearance.	Plan review and approval	Prior to land use clearance	SBC

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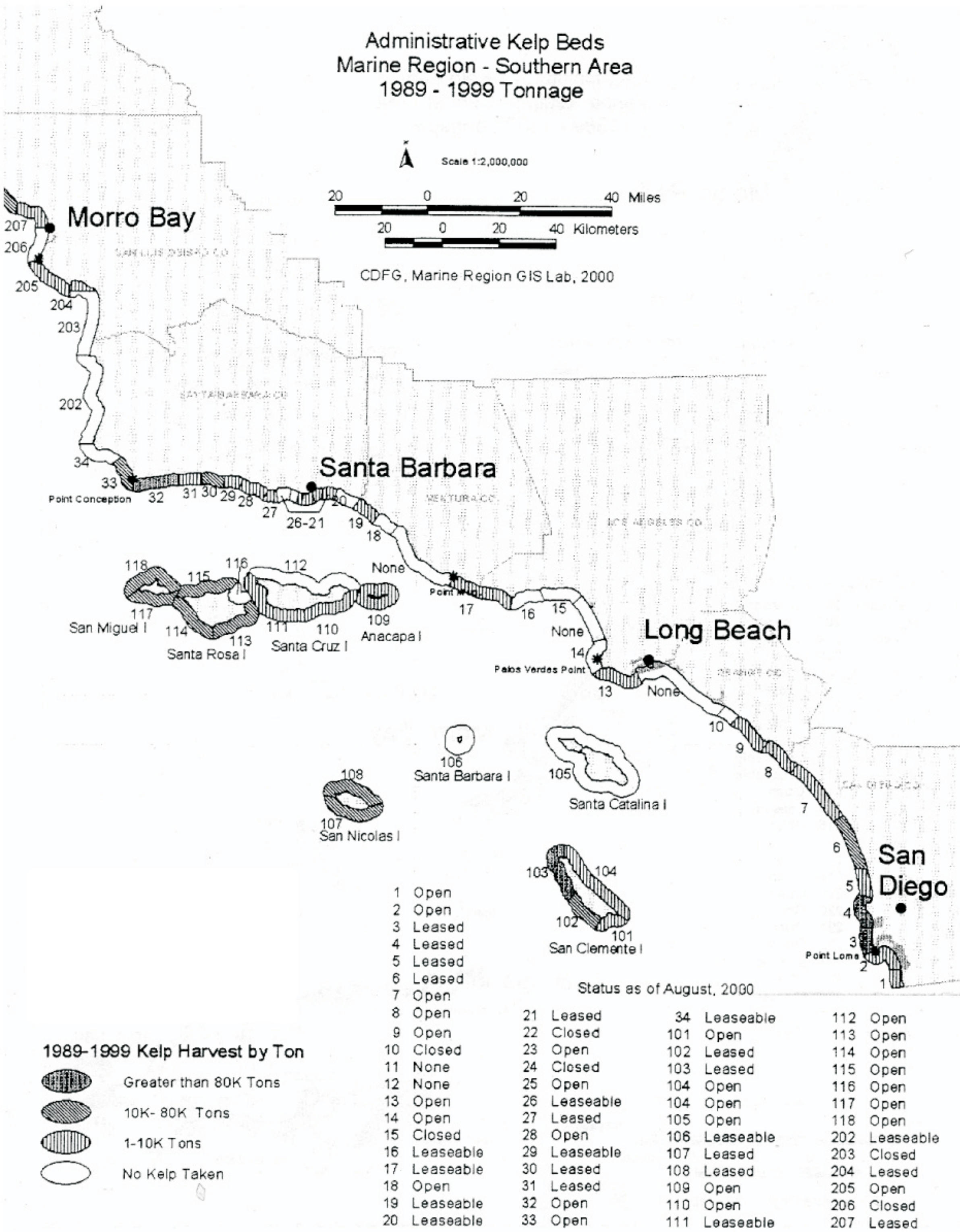

Source: MRS, 2002.

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Figures 5.7-1

Location and Yield from Kelp Beds in Southern California (CDFG, 2000)

5.8 Air Quality

This section describes environmental and regulatory settings related to air quality in the project area, identifies air quality impacts of the proposed project, the alternatives and the cumulative impacts in the area, and lists potential mitigation measures. This section also addresses greenhouse gas emissions associated with the proposed project.

5.8.1 Environmental Setting

5.8.1.1 Regional Overview

The proposed project would be located within the South Central Coast Air Basin (SCCAB) in northwestern Santa Barbara County (SBC). ~~and southwestern San Luis Obispo County. However, no impacts have been identified for facilities in San Luis Obispo County, and therefore only SBC is included in the discussion.~~SBC has a Mediterranean climate characterized by mild winters, when most rainfall occurs and warm, dry summers. The influence of the Pacific Ocean causes mild temperatures year-round along the coast, while inland areas experience a wider range of temperatures. The mean maximum temperatures between 1979 and 1989 at the Vandenberg Air Force Base (VAFB) Weather Station varied from 60°F to 68°F; the mean minimum was from 45° to 55°F; and the annual mean temperature averaged over that period was 61.8°F. Precipitation is confined primarily to the winter months. Occasionally, tropical air masses result in rainfall during summer months. At the VAFB Weather Station, mean precipitation for the same years ranged from 0.02 inches in July to 14 inches in December. Annual precipitation in the region varies widely over relatively short distances mainly because of topographical effects. The long-term annual total precipitation along the north coast is approximately 12 inches, but on mountaintops, totals are nearly 30 inches.

The regional climate is dominated by a strong and persistent high-pressure system, which frequently lies off the Pacific Coast (generally referred to as the Pacific High). The Pacific High shifts northward or southward in response to seasonal changes or the presence of cyclonic storms. In its usual position to the west, the high produces an elevated temperature inversion. An inversion is characterized by a layer of warmer air above cooler air near the ground surface. Normally, air temperature decreases with altitude. In an inversion, the temperature of a layer of air increases with altitude. The inversion acts like a lid on the cooler air mass near the ground, preventing pollutants in the lower air mass from dispersing upward beyond the inversion "lid." This results in higher concentrations of pollutants trapped below the inversion.

Atmospheric stability is a primary factor that affects air quality in the study region. Atmospheric stability regulates the amount of air exchange (referred to as mixing) both horizontally and vertically. Restricted mixing (that is, a high degree of stability) and low wind speeds are generally associated with higher pollutant concentrations. These conditions are typically related to temperature inversions that cap the pollutants emitted below or within them.

The airflow plays an important role in the movement of pollutants. Local winds are normally controlled by the location of the Pacific High. Wind speeds typical of the region are generally light, another factor that contributes to higher levels of pollution since low wind speeds minimize dispersion of pollutants. The sea breeze is typically northwesterly throughout the year; however, local topography causes variations. During summer months, these northwesterly winds are stronger and persist later into the night. For example, Lompoc experiences predominant winds from the west-northwest throughout the year with an average annual speed of 9.7 miles per hour (mph) with the maximum wind speeds reaching 62 mph. When the Pacific High weakens, a Santa Ana condition can develop with air traveling westward into the county from the east. Stagnant air often occurs at the end of a Santa Ana condition, causing a buildup of pollutants offshore. The dominant wind patterns in the area are presented in Figure 5.8-1.

Several types of inversions are common to the area. In winter, weak surface inversions occur, caused by radiation cooling of air in contact with the cold surface of the earth. During the spring and summer, marine inversions occur when cool air from over the ocean intrudes under the warmer air that lies over the land. During the summer, the Pacific High can cause the air mass to sink, creating a subsidence inversion.

Topography plays a significant role in affecting the direction and speed of winds. During the months of May to October, it is common in the project area for an inversion layer to form. Year round, light onshore winds hamper the dispersion of primary pollutants and the orientation of the inland mountain ranges interrupt air circulation patterns. Pollutants become trapped, creating ideal conditions for the production of secondary pollutants.

5.8.1.2 Air Quality

Air quality is determined by measuring ambient concentrations of air pollutants that are known to have adverse health effects. For regulatory purposes there are only several air pollutants for which standards have been set. These pollutants are generally recognized as “criteria pollutants.” For most criteria pollutants, regulations and standards have been in effect, in varying degrees, for more than 25 years, and control strategies are designed to ensure that the ambient concentrations do not exceed certain thresholds. Another class of air pollutants that are subject to regulatory requirements are called hazardous air pollutants (HAPs) or air toxics. Substances that are especially harmful to health, such as those considered under U.S. Environmental Protection Agency’s (EPA) hazardous air pollutant program or California's AB 1807 and/or AB 2588 air toxics programs, are considered to be air toxics. Regulatory air quality standards are based on scientific and medical research. These standards establish minimum concentration of an air pollutant in the ambient air that could start to cause adverse health effects.

For air toxics emissions, however, the regulatory process usually assesses the potential impacts to public health in terms of “risk” (such as the Air Toxics “Hot Spots” Program in California), or the emissions may be controlled by prescribed technologies (as in the new federal approach for controlling hazardous air pollutants).

The degree of air quality degradation for criteria pollutants is determined by comparing the ambient pollutant concentrations to health-based standards developed by government agencies. The current National Ambient Air Quality Standards (NAAQS) and California Ambient Air Quality Standards (CAAQS) for “criteria pollutants” are listed in Table 5.8.1. Ambient air quality monitoring for criteria pollutants is conducted at numerous sites throughout the state. Table 5.8.2 presents relevant data from several monitoring stations located in the proposed project area. A summary of the attainment status for SBC is provided in Table 5.8.3. Ambient air quality in the county is generally good (i.e., within applicable ambient air quality standards), with the exception of particulate matter with an aerodynamic diameter of ten microns or less (PM_{10}), and ozone (O_3).

Table 5.8.1 National and California Ambient Air Quality Standards for Criteria Pollutants

Pollutant	Averaging Time	California Standards [3] [1]	National Standards [2]	
			Primary [4]	Secondary [3,5]
Ozone (O_3)	1 hour 8 hour	0.09 ppm (180 μg/m^3) 0.070 ppm	NS 0.08 ppm	NS 0.08 ppm
Carbon Monoxide (CO)	8 hour 1 hour	9.0 ppm (10 mg/m^3) 20.0 ppm (23 mg/m)	9.0 ppm (10 mg/m^3) 35 ppm (40 mg/m^3)	NS[6] NS
Nitrogen Dioxide (NO_2)	Annual Avg. 1 hour	NS 0.25 ppm (470 μg/m^3)	0.053 ppm (100 μg/m^3) NS	0.053 ppm (100 μg/m^3) NS
Sulfur Dioxide (SO_2)	Annual Avg. 24 hour 3 hour 1 hour	NS 0.05 ppm [7] (131 μg/m^3) NS 0.25 ppm (655 μg/m^3)	80 μg/m^3 (0.03 ppm) 365 μg/m^3 (0.14 ppm) NS NS	NS NS 1300 μg/m^3 (0.5 ppm) NS
Suspended Particulate Matter – PM_{10}	Ann.Arith.Mean 24 hour	20 μg/m^3 50 μg/m^3	~~50 μg/m^3~~NS 150 μg/m^3	~~50 μg/m^3~~NS 150 μg/m^3
Fine Particulate Matter – $PM_{2.5}$	Ann.Arith.Mean 24 hour	12 μg/m^3 NS	15 μg/m^3 ~~65~~ 35 μg/m^3	15 μg/m^3 ~~65~~ 35 μg/m^3
Sulfates (SO_4^{-2})	24 hour	25 μg/m^3	NS	NS
Lead (Pb)	30-day Avg. Calendar Qtr.	1.5 μg/m^3 NS	NS 1.5 μg/m^3	NS 1.5 μg/m^3
Hydrogen Sulfide (H_2S)	1 hour	0.03 ppm (42 μg/m^3)	NS	NS
Vinyl Chloride	24 hour	0.010 ppm (26 μg/m^3)	NS	NS
Visibility Reducing Particles	1 Observation	Insufficient amount to reduce the prevailing visibility [8] to less than 10 miles when the relative humidity is less than 70 percent (CA only).		

Note: μg/m^3 = microgram/cubic meter; ppm = parts per million by volume

1. *California standards for O_3, CO, SO_2 (l-hour), NO_2, and PM_{10} are values that are not to be exceeded. SO_4^{-2}, Pb, H_2S, Vinyl Chloride, and visibility-reducing particles standards are not to be equaled or exceeded. Sulfates are pollutants that include SO_4^{-2} ion in their molecule.*
2. *National Standards, other than ozone, particulate matter, and those based on annual averages or annual arithmetic means, are not to be exceeded more than once a year. The ozone and particulate matter standards are attained when statistically-determined concentrations are above the standard.*
3. *Concentration expressed first in units in which it was promulgated. Equivalent units given in parentheses are based upon reference temperature of 25°C and a reference pressure of 760 mm of mercury. All measurements of air quality are to be corrected to a reference temperature of 25°C and a reference pressure of 760 mm of mercury (1,013.2 millibar); ppm in this table refers to ppm by volume or micromoles of pollutant per mole of gas.*
4. *National Primary Standards: The levels of air quality necessary, with an adequate margin of safety, to protect the public health. Each state must attain the primary standards no later than three years after that state's implementation plan is approved by the EPA.*
5. *National Secondary Standards: The levels of air quality necessary to protect the public welfare from any known or anticipated adverse effects of a pollutant. Each state must attain the secondary standards within a "reasonable time" after the implementation plan is approved by the EPA.*
6. *NS = No Standard.*
7. *At locations where the state standards for ozone and/or PM_{10} are violated. National standards apply elsewhere.*
8. *Prevailing visibility is defined as the greatest visibility, which is attained or surpassed around at least half of the horizon circle, but not necessarily in continuous sectors.*

Table 5.8.2 Ambient Air Quality Summary for Project Area – 2003 to 2005

Pollutant	Year	Maximum Observed Concentration (Number of Standard Exceedances)*			
		Lompoc OGP	Lompoc S H Street	VAFB STS Power	Santa Maria – Broadway
Ozone, ppm					
1-hour 8-hour	2003	0.107 (1 day) 0.080 (0)	0.071 (0) 0.060 (0)	0.089 (0) 0.077 (0)	0.065 (0) 0.060 (0)
1-hour 8-hour	2004	0.097 (1 day) 0.089 (2 days)	0.084 (0) 0.075 (0)	0.090 (0) 0.083 (0)	0.074 (0) 0.064 (0)
1-hour 8-hour	2005	0.072 (0) 0.069 (0)	0.064 (0) 0.052 (0)	0.072 (0) 0.066 (0)	0.063 (0) 0.061 (0)
CO, ppm					
8-hour	2003	NA	1.71 (0)	0.36 (0)	1.13 (0)
8-hour	2004	NA	1.26 (0)	0.36 (0)	0.95 (0)
8-hour	2005	NA	1.07 (0)	0.70 (0)	0.94 (0)
NO_2, ppm					
1-hour Annual Avg.	2003	0.024 (0) 0.002	0.051 (0) 0.006	0.023 (0) 0.001	0.056 (0) 0.011
1-hour Annual Avg.	2004	0.022 (0) 0.002	0.036 (0) 0.006	0.023 (0) 0.001	0.050 (0) 0.010
1-hour Annual Avg.	2005	0.020 (0) 0.002	0.035 (0) 0.006	0.019 (0) 0.001	0.048 (0) 0.010
SO_2, ppm					
24-hour Annual Avg.	2003	0.002 (0) NA	0.003 (0) 0.001	0.001 (0) NA	NA NA
24-hour Annual Avg.	2004	0.002 (0) NA	0.002 (0) NA	0.002 (0) NA	NA NA
24-hour Annual Avg.	2005	0.001 (0) NA	0.003 (0) NA	0.001 (0) NA	NA NA
PM_{10}, µg/m^3					
24-hour Annual Avg	2003	NA NA	57.1 (1 day) 22.1	97.8 (1 day) 13.6	58.0 (1 day) 24.4
24-hour Annual Avg	2004	NA NA	52.3 (1 day) 20.1	38.1 (0) 18.0	52.0 (1 day) 24.1
24-hour Annual Avg	2005	NA NA	86.6 (1 day) 17.5	41.8 (0) 15.3	43.0 (0) 21.4
$PM_{2.5}$, µg/m^3					
24-hour Annual Avg	2003	NA NA	NA NA	NA NA	20.5 (0) 8.6
24-hour Annual Avg	2004	NA NA	NA NA	NA NA	16.6 (0) 7.6
24-hour Annual Avg	2005	NA NA	NA NA	NA NA	29.8 (0) NA

Sources: Air Resources Board Air Quality Data Annual Summaries 2003-2005 from http://www.arb.ca.gov.
*Notes: * Number or percent of exceedances of the most restrictive standard (usually, the State Standard)*
NA – No data available
State MG – State Annual Mean Geometrical
National MA – National Mean Arithmetic

Table 5.8.3 Attainment Status of Santa Barbara County, All Monitoring Stations

Air Basin	**O_3**		**CO**		**NO_2**		**SO_2**		**PM_{10} $PM_{2.5}$**	
	State	*Fed*	*State*	*Fed*	*State*	*Fed*	*State*	*Fed*	*State*	*Fed*
Santa Barbara County	N	A	A	A	A	U/A	A	U/A	N U/A	~~U~~A U/A

Sources: 1. U.S. EPA, http://www.epa.gov/region09/air/maps/maps_top.html, page updated August 15, 2006.
2. ARB, http://www.arb.ca.gov/desig/adm/adm.htm, page last updated February 3, 2006.
Note: A = Attainment of Standards; N = Non-Attainment; U = Unclassified; U/A = Unclassified/Attainment. Attainment status of federal 8-hour ozone standard is included here.

Criteria pollutants are also categorized as inert or photochemically reactive, depending on their subsequent behavior in the atmosphere. By definition, inert pollutants are relatively stable and their chemical composition remains stable as they move and diffuse through the atmosphere. However, the primary photochemical pollutants may react to form secondary pollutants. For these pollutants, adverse health effects may be caused directly by the emitted pollutant or by the secondary pollutants.

Inert Pollutants

Criteria pollutants that are considered to be inert include carbon monoxide (CO), nitrogen dioxide (NO_2), sulfur dioxide (SO_2), PM_{10}, lead, sulfates and H_2S. Fine particulate matter of 2.5 microns or less ($PM_{2.5}$) is also a criteria pollutant, but its presence is affected as much by inert emissions as it is by the reaction of precursors.

Carbon monoxide is formed primarily by the incomplete combustion of organic fuels. The SBC is in attainment of the California and National one-hour and eight-hour CO standards. High values are generally measured during winter when dispersion is limited by morning surface inversions. Seasonal and diurnal variations in meteorological conditions lead to lower values in summer and in the afternoon.

Nitric oxide (NO) is a colorless gas formed during combustion processes which rapidly oxidizes to form NO_2, a brownish gas. SBC is in attainment for all the California and National nitrogen dioxide standards. The highest nitrogen dioxide values are generally measured in urbanized areas with heavy traffic.

Sulfur dioxide is a gas produced primarily from the combustion of sulfurous fuels by stationary sources and by mobile sources. SBC has been in attainment of the California and National sulfur dioxide standards over the past ten years.

The largest PM_{10} emissions appear to originate from soils (via roads, construction, agriculture, and natural windblown dust). Other sources of PM_{10} include sea salt, particulate matter released during combustion processes, such as those in gasoline and diesel vehicles, and wood burning. Also, nitrogen oxides (NO_x) and sulfur oxides (SO_x) are precursors in the formation of secondary PM_{10} and $PM_{2.5}$. SBC is in exceedance of the California 24-hour PM_{10} standard.

Lead is a heavy metal that in ambient air occurs as a lead oxide aerosol or dust. Since lead is no longer added to gasoline or to paint products, lead emissions have reduced significantly in recent years. SBC is in attainment with the NAAQS and the CAAQS for lead.

Sulfates are aerosols (i.e., wet particulate) that are formed by sulfur oxides in moist environments. They exist in the atmosphere as sulfuric acid and sulfate salts. The primary source of sulfate is from the combustion of sulfurous fuels. SBC is in attainment for the California sulfate standard and there has been a steady decrease in ambient concentrations since the last violation in 1984.

Hydrogen sulfide (H_2S) is an odorous, toxic, gaseous compound that can be detected by humans at very low concentrations. The gas is produced during the decay of organic material and is also found naturally in petroleum. SBC is in attainment of the H_2S standard.

Photochemical Pollutants

Ozone is formed in the atmosphere through a series of complex photochemical reactions involving oxides of nitrogen (NO_x), reactive organic compounds (ROC), and sunlight occurring over a period of several hours. Since ozone is not emitted directly into the atmosphere, but is formed as a result of photochemical reactions, it is classified as a secondary or regional pollutant. Because these ozone-forming reactions take time, peak ozone levels are often found downwind of major source areas.

SBC is designated non-attainment for the State 1-hour ozone standard, but SBC is classified as in attainment for the federal 8-hour standard.

Toxic Air Contaminants

Toxic Air Contaminants (TACs) are hazardous air pollutants that are known or suspected to cause cancer, genetic mutations, birth defects, or other serious illnesses to people. TACs may be emitted from three main source categories: (1) industrial facilities; (2) internal combustion engines (stationary and mobile); and (3) small “area sources” (such as solvent use). The California Air Resources Board (CARB) publishes lists of Volatile Organic Compound Species Profiles for many industrial applications and substances.

Generally, TACs behave in the atmosphere in the same general way as inert pollutants (those that do not react chemically, but preserve the same chemical composition from point of emission to point of impact). The concentrations of toxic pollutants are therefore determined by the quantity and concentration emitted at the source and the meteorological conditions encountered as the pollutants are transported away from the source. Thus, impacts from toxic pollutant emissions tend to be site-specific and their intensity is subject to constantly changing meteorological conditions. The worst meteorological conditions that affect short-term impacts (low wind speeds, highly stable air mass, and constant wind direction) occur relatively infrequently.

Greenhouse Gases

Greenhouse gases (GHGs) are defined as any gas that absorbs infrared radiation in the atmosphere. Greenhouse gases include, but are not limited to, water vapor, carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). These greenhouse gases lead to the trapping and buildup of heat in the atmosphere near the earth’s surface, commonly known as the Greenhouse

Effect. There is increasing evidence that the Greenhouse Effect is leading to global warming and climate change (U.S. EPA, ~~February~~200~~0~~6).

The primary source of GHG in the United States is energy-use related activities, which include fuel combustion, as well as energy production, transmission, storage and distribution. These energy related activities generated 85 percent of the total U.S. emissions on a carbon equivalent basis in 1998 and 86 percent in 2004. Fossil fuel combustion represents the vast majority of the energy related GHG emissions, with CO_2 being the primary GHG. The total 1998 U.S. GHG emissions associated with energy related activities included 6,006 million tons of CO_2 (or 5,448.3 teragrams [Tg][1]) and 12.3 million tons (11.2 Tg) of methane (Inventory of U.S. Greenhouse Gases Emissions and Sinks: 1990-2004, EPA, April 2006). The CO_2 emissions increased to 6,419 million tons (5,835.3 Tg) and methane emissions decreased to 11.3 million tons (10.3 Tg) for all energy related activities in 2004. Much smaller quantities of N_2O are caused by mobile fossil fuel combustion and have been decreasing similar to the trend in methane. Figure 5.8-2 shows the relative trend of U.S. GHG emissions for energy related activities from 1998 through 2004.

~~The total U.S. GHG emissions associated with energy related activities was 5,752.3 teragrams (Tg) of carbon equivalent (Tg CO_2 Eq) in 1998, of which 5,448.3 Tg was CO_2 emissions (Inventory of U.S. Greenhouse Gases Emissions and Sinks: 1990-2004, EPA, April 2006). These emissions grew to 6,108.2 Tg CO_2 Eq for all energy related activities in 2004, of which 5,835.3 Tg was CO_2 emissions. Figure 5.8-2 shows the relative breakdown of U.S. GHG emissions for energy related activities in 1998.~~

Eighty-six percent of the energy consumed in the U.S. in 2004 was from fossil fuels such as coal, natural gas and petroleum. The remaining 14 percent was supplied by nuclear electric power (8 percent) and renewable sources (6 percent) (U.S. EPA, 2006).

5.8.1.3 Regional Emissions

Emissions within SBC are estimated periodically by the Santa Barbara County Air Pollution Control District (APCD). These estimates are used to address federal and state clean air mandates. Table 5.8.4 lists the estimated emissions for SBC by source category.

Table 5.8.4 Regional Emissions Inventory (Tons Per Year) for Santa Barbara County

1996 Emission Sources[a]	**ROC**	**CO**	**NO_x**	**SO_2**	**PM_{10}**
Stationary Sources	2,838	1,551	2,159	552	554
Petroleum Activities	*1,112*	*104*	*1,143*	*9*	*14*
Petroleum Activities % of Total	*2.5*	*0.1*	*6.9*	*1.0*	*0.1*
Area-Wide Sources	3,420	9,433	2,653	8	10,584
Mobile Sources	8,907	82,532	12,878	305	572
Natural Sources	29,295	11,404	1,058	0.0	1,843
SBC Total	44,460	103,369	16,589	865	13,553
a. For Clean Air Plan (CAP) base year 1996.					
~~2000~~ 2002 Emission Sources[b]	**ROC**		**NO_x**		
Stationary Sources	~~3,667~~3,211		~~2,097~~2,469		

[1] One tera-gram is one trillion (10^{12}) grams.

Petroleum ~~Activities~~Production and Marketing	*~~1,224~~892*		*~~776~~27*		
Petroleum Activities % of Total	*2.~~8~~0*		*~~4.4~~0.2*		
Area-Wide Sources	~~3,064~~3,732		~~350~~412		
Mobile Sources	~~8,687~~7,889		~~13,804~~12,412		
Natural Sources	~~28,930~~28,608		~~1,365~~882		
SBC Total	~~44,348~~43,440		~~17,615~~16,156		

b. Updated inventory available for ozone precursors only, from Clean Air Plan (CAP) base year ~~2000~~2002, as in ~~2004~~ 2007 CAP.

In SBC the highest contributors to the ROC emissions are natural sources, primarily seeps of different oil and gas constituents through voids in the ground. Carbon monoxide and NO_x emissions mostly occur due to mobile sources (e.g., on-road vehicles). The majority of SO_x emissions come from mineral processes, specifically from diatomaceous earth processing. PM_{10} emissions are mostly due to road dust.

5.8.1.4 Study Area Baseline Emissions

The current level of air emissions at the following facilities represents the baseline for the proposed project and modification of the associated facilities: Platform Irene, the LOGP, and the associated pipelines. Also, the baseline is characterized by current emissions from several mobile sources such as helicopters and supply-boats servicing Platform Irene, as well as emissions from mobile ~~services~~ sources including commuters, LPG/NGL, sulfur and miscellaneous trucks servicing the LOGP.

Table 5.8.5 summarizes the estimated current emissions of the operating equipment at the facilities that are covered under the appropriate APCD Permits to Operate (PTO). Emissions from all sources were summarized as part of annual operating reports provided to the APCD for 2005. The stationary project emissions are comprised of the following categories of equipment emissions:

Platform Irene	LOGP
Engines (Cranes) Flare Fugitive Components Supply Boat Pigging Equipment Sumps/Tanks/Separators Solvent Usage	Heater Treaters Thermal Oxidizer (Heating Medium Heater) Flare Fugitive Emissions (including pipelines) Pigging Sumps Solvent Usage

Table 5.8.5 Point Pedernales Current Emissions

Facility	NO_x, (tons/yr)	ROC, (tons/yr)	CO, (tons/yr)	SO_x, (tons/yr)	PM_{10}, (tons/yr)
Platform Irene [a]	12.52	26.05	2.66	1.04	1.01
LOGP [b]	2.53	35.86	0.89	0.58	0.61

Sources: PXP annual report to SBCAPCD for Platform Irene, 2006; PXP report to SBCAPCD for LOGP, 2006.
a. Includes emissions from supply boats.
b. Includes emissions from pipelines.

Emissions that comprise the project air quality baseline are within the permitted limits established by the SBCAPCD. Table 5.8.6 below summarizes the limits stated by SBCAPCD in the appropriate PTO.

Table 5.8.6 Point Pedernales Permitted Emissions Levels

Facility	NO_x, tons/yr (lbs/day)	ROC, tons/yr (lbs/day)	CO, tons/yr (lbs/day)	SO_2, tons/yr (lbs/day)	PM_{10}, tons/yr (lbs/day)
Platform Irene – PTO 9106[a]	45.64 (1187.40)	28.01 (231.40)	13.87 (165.70)	9.30 (66.40)	4.66 (80.10)
LOGP – PTO 6708[b]	8.25 (45.00)	43.66 (263.65)	5.89 (32.19)	3.48 (18.72)	2.17 (11.81)

Sources: SBC APCD, Permits to Operate #6708 and #9106, 2003.
a. Includes emissions from supply boats.
b. Includes emissions from pipelines, emissions from trucks are exempt.

5.8.1.5 Emissions Reductions Requirements

Increases in emissions of any non-attainment pollutant or its pre-cursor from a new or modified project that exceed the thresholds identified in the APCD Rule 802(E) are required to be mitigated. When the Point Pedernales Project was permitted, project emissions did not exceed the existing thresholds for emission reductions. However, subsequent modifications triggered offset requirements for ROC~~, NAROC (non-alkane ROC), and NOx~~ only under SBCAPCD rules.

Mitigation was required in 1986 for the Point Pedernales Project pursuant to CEQA and to achieve maximum feasible mitigation requirements. In particular, an agreement between the operator and the SBCAPCD in 1986, entitled “Emission Reduction Agreement-Union Oil Point Pedernales Project,” established these emission mitigations. Mitigations for emissions from Platform Irene were also included through offsets as part of the permitting of onshore sources. The 1986 agreement was amended in 1996 to give credit for the shutdown of the Battles Gas Plant. Under CEQA, reducing existing sources of emissions on a 1:1 basis mitigated total project emissions increases. Mitigation of project emissions was required to maintain consistency with the 1986 Air Quality Attainment Plan (AQAP).

Emission offsets were originally obtained for the project through electrification of internal combustion engines, installation of emission reduction technologies (such as Pre-Stratified Charge) on other engines and installation of vapor recovery systems. Since that time, the Battles Gas Plant shutdown provided a “swap” for the above-listed offsets along with electrification of compressors. Any new ROC emissions subject to APCD permit as a result of the project will be subject to offset requirements per APCD rules.

5.8.2 Regulatory Setting

Federal, state, and local agencies have established standards and regulations that will affect the proposed project. A summary of the regulatory setting for air quality is provided below.

5.8.2.1 Federal Regulations

The Federal Clean Air Act of 1970 directs the attainment and maintenance of the NAAQS. The 1990 Amendments to this Act included new provisions that address air emissions that affect local, regional and global air quality. The main elements of the 1990 Clean Air Act Amendments are summarized below:

- Title I Attainment and maintenance of NAAQS
- Title II Motor vehicles and fuel reformulation
- Title III Hazardous air pollutants
- Title IV Acid deposition
- Title V Facility operating permits
- Title VI Stratospheric ozone protection
- Title VII Enforcement

The U.S. EPA is responsible for implementing the Federal Clean Air Act and establishing the NAAQS for criteria pollutants. In 1997 EPA adopted revisions to the Ozone and Particulate Matter Standards contained in the Clean Air Act. These revisions included a new 8-hour ozone standard and a new particulate matter standard for particles below 2.5 micron in diameter. These standards were suspended, however, when in May 1999 the U.S. Court of Appeals for District of Columbia remanded the new ozone standard. In January 2001 EPA issued a Proposed Response to Remand, where it stated that the revised ozone standard should remain at 0.08 ppm. In February 2001 the U.S. Supreme Court upheld the constitutionality of the Clean Air Act as EPA had interpreted it in setting health-protective air quality standards for ground-level ozone and particulate matter.

5.8.2.2 State Regulations

California Air Resources Board (CARB).

The CARB established the CAAQS. Comparison of the criteria pollutant concentrations in ambient air to the CAAQS determines State attainment status for criteria pollutants. The CARB has jurisdiction over all air pollutant sources in the state; it has delegated to local air districts the responsibility for stationary sources and has retained authority for emissions from mobile sources. The CARB in partnership with the local air quality management districts within California has developed a pollutant monitoring network to aid attainment of CAAQS. The network consists of numerous monitoring stations located throughout the state, which monitor and report various pollutants concentrations in ambient air.

California Clean Air Act (CCAA) (California Health and Safety Code, Division 26).

This act went into effect on January 1, 1989, and was amended in 1992. The CCAA mandates achieving the health-based CAAQS at the earliest practical date.

Air Toxics "Hot Spots" Information and Assessment Act of 1987 (California Health & Safety Code, Division 26, Part 6). The Hot Spots Act requires an inventory of air toxics emissions from individual facilities, an assessment of health risk, and notification of potential significant health risk.

The California Global Warming Solutions Act of 2006, Assembly Bill (AB 32), (California Health & Safety Code Sections 38500, et seq).

Following Executive Order S-3-05 in June 2005, which declared California's particular vulnerability to climate change, AB 32 was signed by Governor Arnold Schwarzenegger on September 27, 2006. In passing the bill, the California Legislature found that "*Global warming poses a serious threat to the economic well-being, public health, natural resources, and the environment of California. The potential adverse impacts of global warming include the exacerbation of air quality problems, a reduction in the quality and supply of water to the state from the Sierra snowpack, a rise in sea levels resulting in the displacement of thousands of coastal businesses and residences, damage to marine ecosystems and the natural environment, and an increase in the incidences of infectious diseases, asthma, and other human health-related problems*" (California Health & Safety Code, Division 25.5, Part 1).

In response to global warming, AB 32 requires the CARB to adopt a statewide greenhouse gas emissions limit equivalent to the statewide GHG emissions levels in 1990 to be achieved by 2020 and requires the CARB to adopt rules and regulations to achieve the maximum technologically feasible and cost-effective GHG emission reductions. By January 1, 2008, CARB is scheduled to adopt regulations requiring mandatory GHG emissions reporting and define the statewide GHG emissions cap for 2020. The remainder of the timeline for implementation would have CARB adopting a plan by January 1, 2009 that would indicate how emission reductions will be achieved from significant sources of GHGs via regulations, market mechanisms, and other actions. Then, during 2009, ARB staff would draft rule language to implement its plan and hold public workshops on each measure including market mechanisms (CARB, 2006).

Strategies that the state should pursue for managing GHG emissions in California are identified in the California Climate Action Team's Report to the Governor (CalEPA, 2006). Many focus on generally reducing consumption of petroleum across all areas of the California economy. Improvements in transportation energy efficiency (fuel economy) and alternatives to petroleum-based fuels are to provide substantial reductions by 2020. Oil and gas extraction is an industry that directly contributes approximately three percent of California GHG emissions (CalEPA, 2006). As such, the state plans to mandate GHG emissions reporting for the oil and gas industry and more aggressive strategies to reduce venting and leaks in oil and gas systems.

The Calderon Bill (SB 1889), (California Health & Safety Code Sections 25531-25543).

This bill, signed by Governor Pete Wilson in September 1996, sets forth changes in the following four areas: provides guidelines to identify a more realistic health risk; requires high risk facilities to submit an air toxic emission reduction plan; holds air pollution control districts accountable for ensuring that the plans will achieve their objectives; and requires high risk facilities to achieve their planned emissions reduction.

CARB Airborne Toxic Control Measure (ATCM) for Stationary Compression Ignition Engines.

The ATCM for Stationary Compression Ignition Engines was adopted by CARB in 2004 to reduce diesel PM emissions from new and in-use stationary diesel engines. The ATCM requires emergency standby and prime diesel engines to meet stringent operating requirements and emission standards.

CARB Portable Equipment Registration Program and Airborne Toxic Control Measure (ATCM) for Diesel Particulate Matter from Portable Engines.

The Portable Engine ATCM affects all diesel-fueled portable engines that are 50 horsepower and larger. Included are engines that are registered under CARB's Portable Equipment Registration Program (PERP), engines that are permitted by the districts, and engines that were historically exempt from district permits. The ATCM requires all portable engines to meet the most stringent of the federal or California emission standards for nonroad engines in effect at the time of registration in the Portable Equipment Registration Program or permitting. After 2010, all fleets of portable engines are required to meet diesel PM emission averages that become more stringent after 2013.

Previously-exempt emergency and prime diesel engines rated at greater than 50 brake-horsepower were required to obtain SBCAPCD permits in 2005. For Platform Irene and LOGP, these sources were considered "exempt" in the 2003 permits but are now included in APCD permits issued December 2006. The diesel stationary engines under permit are subject to the ATCM for Stationary Compression Ignition Engines described above, which also primarily focuses on PM emissions control.

5.8.2.3 County Rules and Regulations

Local APCDs in California have jurisdiction over stationary sources in their respective areas and must adopt plans and regulations necessary to demonstrate attainment of federal and state air quality standards. As directed by the Federal and State Clean Air Acts, local air districts are required to prepare plans with strategies for attaining and maintaining state and federal ozone standards. The 1998 Clean Air Plan and subsequent updates, including the ~~most recent~~ August ~~2004~~ 2007 Clean Air Plan ~~adopted in December 2004~~, outline the steps to be taken to ensure that ozone levels attain the state standards. The ~~2004~~ 2007 CAP begins with county-wide emissions from a 2000 base year and uses projections of population growth and trends in energy and transportation demand to predict future emissions and determine the control strategies needed to eventually achieve attainment. The control strategies are then either codified into the SBCAPCD rules and regulations or otherwise set forth as formal recommendations from SBCAPCD to other agencies. In the project area, air quality rules and regulations are promulgated by the SBCAPCD. In order to ultimately achieve the air quality standards, the rules and regulations limit emissions and permissible impacts from proposed projects. Some rules also specify emission controls and control technologies for each type of emitting source. The regulations also include requirements for obtaining an Authority to Construct (ATC) permit and a PTO.

The SBCAPCD has jurisdiction over air quality attainment in the SBC portion of the SCCAB. All aspects of the proposed project and alternatives occurring in SBC must obtain a SBCAPCD permit, if applicable.

SBCAPCD also has jurisdiction over outer continental shelf (OCS) sources located within 25 miles of the seaward boundaries of the State of California (Rule 903).

5.8.3 Significance Criteria

5.8.3.1 Significance Criteria for Construction

Emissions from construction are normally short-term. Currently, neither the County nor the SBCAPCD have daily or quarterly quantifiable emission thresholds established for short-term construction emissions. NO_x and ROC emissions from construction equipment and PM_{10} impacts from dust emissions are discussed and mitigation measures are proposed as per AQAP policies.

5.8.3.2 Significance Criteria for Operation

Quantitative significance criteria have been developed for air quality impacts by the SBC P&D (Environmental Thresholds and Guidelines, 2006). According to the SBC guidelines, proposed project air quality impacts are considered significant if the project:

- Interferes with the progress toward attainment of the ozone standard by releasing emissions, which equal or exceed the established long-term quantitative thresholds for NO_x and ROC. The quantitative threshold for NO_x and ROC is 25 lbs/day of either contaminant from motor vehicle trips only.
- Equals or exceeds the daily trigger for offsets set in the SBCAPCD New Source Review Rule 802, for any pollutant from all project sources, mobile and stationary, which are 80 lbs/day PM_{10} or 55 lbs/day NO_x or ROC.
- Equals or exceeds the state or federal ambient air quality standards for any criteria pollutant (as determined by modeling).

The SBC P&D guidelines specify screening ~~Criteria for triggering~~modeling ~~have been established~~for CO under certain circumstances, although Santa Barbara County has attained the CO standards for many years. ~~A project would have a significant air quality impact if it causes, by adding to the existing background CO levels, a CO "hot spot" where California one-hour standard of 20 ppm of CO is exceeded.~~Screening criteria for potential CO impacts are the following:

- If a project contributes less than 800 peak hour trips, then CO modeling is not required.
- Projects contributing more than 800 peak hour trips to an existing congested intersection at level of service (LOS) D* or below, or will cause an intersection to reach LOS of D or below, may be required to model for CO impacts.

The following issues should be discussed only if they are applicable to the project:

- Emissions which may affect sensitive receptors (e.g., children, elderly or acutely ill);
- Toxic or hazardous air pollutants in amounts which may increase cancer risk for the affected population; or
- Odor or another air quality nuisance problem impacting a considerable number of people.

5.8.3.3 Significance Criteria for Health Risks

The SBCAPCD has established criteria for determining the significance of potential health risks associated with toxic emissions from a project. These criteria have been developed for both carcinogenic and non-carcinogenic compounds, as well as for acute and chronic exposure as follows:

Potential Health Risk	Criterion
Cancer Risk	10 in one million (1×10^{-5})
Health Hazard Index	1.0

* See Section 5.9, Transportation/Circulation, for explanation of LOS levels.

A cancer risk of 10 in one million represents the number of potential excess cancer cases (10) per million individuals exposed. The health hazard index is the cumulative ratio of the estimated exposure level to a chemical-specific health threshold. The health hazard index is the sum of the ratios for all chemicals present. Therefore, potential health hazards can be significant even if the threshold for a single chemical is not exceeded, but the sum of the exposure ratios exceeds one.

5.8.4 Impact Analysis for the Proposed Project

The proposed project would have construction and operation air quality impacts. The remainder of this section is broken down into construction and operational impacts. Detailed calculations of the emissions are presented in Appendix C.

5.8.4.1 Construction Impacts

Impact #	Impact Description	Phase	Residual Impact
Air.1	Construction activities would generate air emissions.	*Construction*	*Class III*

Construction (short-term) emissions would occur during the following activities:

1. Modifications at Platform Irene:
   - equipment modifications;
   - additional helicopter and supply boat trips to support modification activities (offsite).

2. Modifications at Valve Site #2:
   - delivery and installation of the new pumps;
   - construction of the power lines and transformer.

3. Modifications at the LOGP:
   - delivery and installation of the new/replacement pumps, upgrades to the existing equipment (e.g., heat exchangers plates).

The addition of shipping pumps at Platform Irene and modifications at the LOGP are estimated to take approximately nine ~~months~~weeks. The short-term construction air quality impacts are summarized in Table 5.8.7. See Appendix C for detailed calculations.

Table 5.8.7 Summary of the Proposed Project Emissions – Construction

Location and Construction Activity	Total (Annual) Emissions (tons/yr)				
	CO	ROC	NO_x	SO_2	PM_{10}
LOGP & Valve Station #2	~~8.02~~ 1.62	~~1.39~~ 0.28	~~19.37~~ 3.92	~~2.00~~ 0.40	~~1.52~~ 0.31
LOGP & Valve Station #2 – Fugitive Dust	-	-	-	-	0.01
Platform Irene	0.08	0.03	0.20	0.02	0.03
Offsite – onshore and offshore	~~3.14~~ 3.09	~~0.74~~ 0.36	~~2.18~~ 1.92	~~0.05~~ 0.04	~~0.16~~ 0.09
Construction Total Emissions	**~~11.26~~ 4.79**	**~~2.16~~ 0.67**	**~~21.75~~ 6.04**	**~~2.07~~ 0.46**	**~~1.71~~ 0.44**

Construction emissions are short-term and would be within the levels established for the county-wide emission inventory of construction activities. Consistent with the 2006 SBC P&D Environmental Thresholds and Guidelines Manual, Interim Revision to Air Quality Sub-Sections, these impacts are considered to be adverse but not significant.

In accordance with County AQAP policies, the following mitigation measure is recommended to mitigate Impact Air.1 to the maximum extent feasible.

Mitigation Measures

Air-1 PXP shall prepare and submit Dust Control and Reduction Plan to SBCAPCD prior to land use clearance. PXP shall implement dust reduction measures during construction. The following APCD Standard Dust Mitigation Measures shall be implemented:

1. Dust generated by the development activities shall be retained onsite and kept to a minimum by following the dust control measures listed below. Reclaimed water shall be used whenever possible.
   a. During clearing, grading, earth moving or excavation, water trucks or sprinkler systems are to be used in sufficient quantities to prevent dust from leaving the site and to create a crust, after each day's activities cease.
   b. After clearing, grading, earth moving or excavation is completed, the disturbed area must be treated by watering, or revegetating; or by spreading soil binders until the area is paved or otherwise developed so that dust generation would not occur.
   c. During construction, water trucks or sprinkler systems shall be used to keep all areas of vehicle movement damp enough to prevent dust from leaving the site. At a minimum, this would include wetting down such areas in the late morning and after work is completed for the day. Increased watering frequency will be required whenever the wind speed exceeds 15 mph.
2. Importation, exportation and stockpiling of fill material:
   a. Soil stockpiled for more than two days shall be covered, kept moist, or treated with soil binders to prevent dust generation.
   b. Trucks transporting fill material to and from the site shall be tarped from the point of origin.
   c. If the construction site is greater than five acres, gravel pads must be installed at all access points to minimize tracking of mud onto public roads.
3. Activation of increased dust control measures:
   a. The contractor or builder shall designate a person or persons to monitor the dust control program and to order increased watering, as necessary, to prevent transport of dust offsite. Their duties shall include holiday and weekend periods when work may not be in progress. The name and telephone number of such persons shall be provided to the APCD.

Residual Impact

Impact Air.1, construction air quality impacts, is considered *adverse but not significant (Class III).*

5.8.4.2 Operational Impacts

No increase in operational emissions is expected for the Point Pedernales Pipeline due to the increase in throughput because no new equipment that could generate emissions and no new piping that could generate fugitive emissions are proposed. Fugitive hydrocarbon emissions from the piping at the facilities or the pipelines connecting them would not increase due to the throughput increase.

Operational air impacts are expected from emissions associated with the new well development, increased oil production and treatment. The emissions sources would include the following:

1. Platform Irene:
   - emissions from diesel equipment for drilling of new wells (well logging unit, acidizing pump, cement pump);
   - exhaust vapors from mud-gas separator and mud degasser as muds are recycled;
   - emissions from additional (over the current levels) supply boat and helicopter trips related to increased drilling activities;
   - fugitive emissions from additional well-related equipment and piping.
2. Valve Site #2:
   - fugitive emissions from the new pumps.
3. The LOGP:
   - increased over the current heater treaters operation (all three heater treaters could be operating, compared to only one at a time during the current operations);
   - increased over the current level truck traffic (LPG/NGL, amine and sulfur, etc.).

Impact #	Impact Description	Phase	Residual Impact
Air.2	Increased oil processing and drilling of the new Tranquillon Ridge Unit wells at Platform Irene would result in an increase in operational air emissions.	*Drilling* *Increased Throughput* *Extension of Life*	*Class II*

Operational emissions associated with Tranquillon Ridge project were estimated with the following assumptions:

For Platform Irene:

- peak daily emissions include emissions from the drilling equipment (i.e., well logging unit, acidizing pump, and cement pump);
- emissions from testing of emergency drill generator are already a part of the baseline and are not a part of the proposed project;
- peak daily emissions include emissions from drilling muds due to associated off gassing during muds recycling;
- peak daily emissions that include one supply boat trip and three helicopter trips would remain the same as current, and are not a part of the proposed project. Only annual number of helicopter and boat trips will increase over the current level due to the proposed project;
- fugitive emissions from additional well piping are estimated, emissions would be more accurately known when the wells are installed;
- added fugitive emissions from additional well leaking components was estimated for 20 additional wells.

For the LOGP and Valve Site #2:

- all three heater treaters would be in operation at the same time (currently there is only one heater treater operating at one time);
- fugitive emissions at the LOGP (including pipelines), emissions from pigging, thermal oxidizer, flare, solvent usage and sumps would remain the same;

- addition of pumps and valving at Valve Site #2 would increase fugitive emissions as a function of the new leak paths counts;
- LPG/NGL truck emissions would increase due to increase in trips to a total of 5 trips per week.

Due to the proposed project, the identified emissions of both criteria pollutants and GHGs would continue beyond the projected lifetime of the approved Point Pedernales Project; therefore the continued air emissions would be considered an extension of life impact to air quality.

Criteria Pollutants

The project would generate air emissions above the current emissions from the existing facilities that are significant because the peak day emissions of NO_x are estimated to be considerably higher than ~~the significance trigger of~~ 55 lbs/day and total ROC emissions would be over 55 lbs/day. See Table 5.8.8 for the summary of the proposed project emissions.

Table 5.8.9a compares the current Point Pedernales Project emissions and the proposed project air emissions with the offsets that are presently in place for the Point Pedernales Project. The SBC-approved FDP requires that the ~~permitted~~ NO_x and ROC emissions ~~from the FDP~~ be mitigated at a ratio of at least 1:1. Table 5.8.9a shows that previous ~~Emission~~ emission offsets are in place ~~at the required permitted~~ to mitigate the current plus project-related emissions ~~level~~. The current Point Pedernales Project emissions of NO_x and ROC that include the permitted and exempt emissions (including emissions from trucks, helicopters and PTO exempt equipment) are within the previous offset credit. If the proposed project estimated emissions are added to the current Point Pedernales Project actual emissions, the resulting total emissions are still within the previous offset credit provided for NO_x and ROC ~~according to the FDP requirement~~. The proposed project emissions from the LOGP heater treaters are already accounted for in the current ~~would also be within the allowable~~ PTO emission limits and are covered by offsets originally assigned to the facility., and any new ROC emissions as a result of the project will be subject to offset requirements per APCD rules. Also, as shown in Section 1.2, the APCD would need to approve PTO changes for the equipment changes and higher oil and gas throughput associated with the proposed project.

Oil and gas production and processing facilities could produce emissions that have unpleasant odors and are a nuisance to the public. The changes in the equipment, the increased oil and gas production and the higher oil and gas throughput due to the project would not significantly increase the odorous emissions from the project facilities (fugitive emissions are only minimally increased over current fugitive emissions). Therefore, the proposed project would not increase existing odor or other air quality nuisance problems.

The project is expected to generate fewer vehicle trips than the trigger for CO modeling of 800 daily trips, thus modeling is not required.

The proposed project operational ROC and NO_x estimated emissions are higher than the significance trigger of 55 lbs/day. Emissions reductions would be required for NO_x to mitigate this impact. Previous offset credits provide sufficient reductions to mitigate current plus project NO_x emissions. ~~In addition~~However, offsets would be required for ROC emissions by the SBCAPCD as part of the PTO.

Table 5.8.8 Summary of the Proposed Project Emissions – Operation

Location and Activity or Equipment	Peak Daily Emissions, lbs/day					Annual Emissions, tons/yr				
	CO	ROC	NO_x	SO_2	PM_{10}	CO	ROC	NO_x	SO_2	PM_{10}
LOGP and Valve Site #2 Additional Emissions										
Heater treaters (2 additional units in operation)	14.13	1.31	20.43	9.60	5.76	2.579	0.238	3.728	1.752	1.051
Additional truck trips	~~1.44~~ 2.97	~~0.32~~ 0.31	~~0.14~~ 2.37	0.01	~~0.00~~ 0.09	~~0.075~~ 0.154	~~0.017~~ 0.016	~~0.007~~ 0.123	0.001	~~0.000~~ 0.005
Additional fugitive emissions (Valve Site #2)	-	0.06	-	-	-	-	0.011	-	-	-
Platform Irene Additional Emissions										
Emissions from drilling muds	-	1.00	-	-	-	-	0.040	-	-	-
Drilling equipment emissions	32.06	12.06	88.89	2.22	10.58	1.144	0.430	3.170	0.079	0.377
Additional helicopter trips (do not contribute to peak day)[a]	-	-	-	-	-	3.844	1.355	0.019	0.010	0.013
Additional boat trips (do not contribute to peak day)[a]	-	-	-	-	-	1.238	0.305	~~0.305~~ 4.264	0.412	0.483
Fugitive emissions (new wells)	-	~~39.00~~ 42.90	-	-	-	-	~~7.118~~ 7.829	-	-	-
Total Proposed Project Operational Emissions	**~~47.64~~ 49.16**	**~~53.78~~ 57.63**	**~~109.46~~ 111.69**	**11.84**	**~~16.34~~ 16.43**	**~~8.88~~ 8.96**	**~~9.52~~ 10.22**	**~~7.23~~ 11.31**	**2.25**	**~~1.92~~ 1.93**
SBC Significance Criteria	**n/a**	**55**	**55**	**n/a**	**80**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**
Significant?		**~~No~~Yes**	**Yes**		**No**					

a. Helicopter and supply boat maximum permitted daily trips already occur during current operations, and are, therefore, a part of the baseline.

Table 5.8.9a Comparison of Current Emissions and Project Emissions – Operation

Facility or Type of Emissions	Annual Emissions, tons/yr				
	CO	ROC	NO_x	SO_2	PM_{10}
Current LOGP - Permitted Equipment (reported to SBCAPCD for 2005)	0.89	35.86	2.53	0.58	0.61
Current LOGP - Exempt Equipment (estimate from PTO 6708, Dec. 2006 ~~for 2003~~)	~~0.83~~ 0.23	~~0.42~~ 0.15	~~3.31~~ 0.18	~~0.22~~ <0.01	~~0.22~~ 0.01
Current Platform Irene – Permitted Equipment (reported to SBCAPCD for 2005)	2.66	26.05	12.52	1.04	1.01
Current Platform Irene – Exempt Equipment (estimate from PTO 9106 ~~for 2003~~, Dec. 2006)	~~4.10~~ 2.58	~~4.27~~ 3.70	~~11.24~~ 11.77	~~0.70~~ 0.24	~~0.68~~ 0.19
Total Current Operational Emissions	~~8.48~~ 6.36	~~66.60~~ 65.76	~~29.60~~ 19.45	~~2.54~~ 1.86	~~2.52~~ 1.82
Proposed Project Operational Emissions (Table 5.8-8)	~~8.88~~ 8.96	~~9.52~~ 10.22	~~7.23~~ 11.31	2.25	~~1.92~~ 1.93
Total Current + Proposed Project	**~~17.36~~ 15.32**	**~~76.11~~ 75.99**	**~~36.83~~ 30.76**	**~~4.79~~ 4.11**	**~~4.44~~ 3.75**
Permitted Point Pedernales Emissions[a]	23.76	75.25	74.86	13.73	8.06
Previous Offset Credit[b]	**n/a**	**166.03**	**82.52**	**n/a**	**n/a**

a. Includes also permitted Orcutt Pump Station emissions, does not include PTO Exempt emissions
b. Source: PTO 6708, 2003.

Greenhouse Gases (GHGs)

The increased oil and gas production from the proposed Tranquillon Ridge Project would generate additional greenhouse gases above and beyond what occurs for current operations.~~as a result of the increase in production resulting from the proposed project.~~ GHG emissions from the Tranquillon Ridge operations were estimated using the emissions by the source categories approach discussed above. ~~The following~~Table 5.8.9b presents the GHGs ~~are~~ that would be produced ~~and accounted for~~ as a result of ~~any of the energy activities associated with~~ the additional production resulting from the proposed project.

Table 5.8.9b: Additional Operation GHG Emissions – Proposed Project Only[a]

Location and Activity or Equipment	**Annual Emissions (tons/yr)[b]**			
	CO_2 -	**% of Total Contribution**	**Methane**	**% of Total Contribution**
PLATFORM IRENE ADDITIONAL EMISSIONS				
Emissions from Drilling Muds	-	-	0.160	.55%
Drilling Equipment	182.9	1.28%	0.023	.08%
Fugitive Emissions	-		28.470	98.68%
Platform Irene Subtotal	182.9	1.28%	28.650	99.31%
LOGP AND VALVE SITE #2 ADDITIONAL EMISSIONS				
Heater Treaters	13,355.5	93.65%	0.002	.007%
Fugitive Emissions (Valve Site #2)	-	-	0.044	.15%
LOGP/Valve Site #2 Subtotal	13,355.5	93.65%	0.046	.16%
TRANSPORTATION ADDITIONAL EMISSIONS				
Truck Trips	29.2	.20%	0.001	.003%
Helicopter Trips	436.4	3.06%	0.134	.46%
Boat Trips	257.8	1.81%	0.016	.06%
Transportation Subtotal	723.4	5.07%	0.151	.52%
PROPOSED PROJECT TOTAL	14,261.8	100%	28.85	100%

a. Source: Appendix C, Greenhouse Gases Operating Emissions Summary – Proposed Project
b. Assumes GHG emissions during peak production (see Figure 2-3 of Project Description).

During the peak year of the proposed Tranquillon Ridge project, which would include drilling and production, the increase in GHG would be approximately 14,262 tons/year of CO_2 and 29 tons/year of methane (see Table 5.8.9b). The major proposed project contributor to CO_2 would be the return to full-time service of two heater treaters (93.7%), whereas, the major contributor to methane would be fugitive emissions at Platform Irene (98.7%). Over the life of the proposed project, GHG emissions would track the production curve illustrated in Figure 2-3 of the Project Description. Peak-year GHG emissions would occur over the approximate first 12 years of the project at which time GHG emissions would start to diminish as production volumes decline (see Figure 2-3).

The U.S. GHG emissions for all energy-related activities in 2004 was 6,430 million tons (5,835 teragrams [Tg]) of CO_2 and 11.3 million tons (10.3 Tg) of methane, whereas the California GHG inventory for oil and gas extraction activities in 2004 for CO_2 was 14.5 million tons (13.2 Tg). The GHG emissions resulting from current operations of the Point Pedernales Project are included in these inventories; in 2006, estimated GHG emissions (CO_2 and methane) were

11,762 tons/year for LOGP and Platform Irene. The Tranquillon Ridge project operations would add very little GHGs to the U.S. and California inventories (see Table 5.8.9c~~b~~) and, potentially, could reduce overall greenhouse gas emissions if it displaced another source of oil with higher emissions (e.g., imported oil).

- ~~CO_2 emissions from fuel combustion due to transportation activities (e.g., supply boat, LPG/NGL/sulfur trucks, trucks for transport of project-generated wastes to a disposal facility)~~
- ~~SO_2 emissions from fuel combustion due to transportation activities (same transportation activities as for CO_2 emissions).~~
- ~~NO_x emissions from fuel combustion due to transportation activities (same transportation activities as for CO_2 emissions).~~

~~During the peak year of the proposed Tranquillon Ridge Project, which would include drilling and production, the increase in GHG would be approximately 15,000 tons of CO_2, 29 tons of methane, 7 tons of NO_x, and 2 tons of SO_2. This compares with U.S. GHG emissions for all energy related activities in 2004 of 6,430 million tons (5,835 Tg) of CO_2, 11.3 million tons (10.3 Tg) of methane, and 198 million tons (0.18 Tg) of N_2O. The Tranquillon Ridge project operations would add very little GHGs to the U.S. inventory (less than 0.0002 percent).~~

Table 5.8.9c~~b~~ Comparison of GHG Emissions Inventory and Project Emissions – Operation

Source Category	CO_2 (tons/yr)	~~CH4~~Methane (tons/yr)
U.S. Energy-Related Activities in 2004 [a]	6.43×10^9	11.3×10^6
California-wide Oil and Gas Extraction in 2004 [b]	14.5×10^6	na
Proposed Project during Peak Year [c]	~~15.3~~ 14.3×10^3	29
Percentage of Proposed Project contribution to U.S. and California-wide Oil and Gas Extraction in 2004	U.S.: 0.0002% CA: 0.1 ~~.11~~%	U.S.: 0.0003% CA: na

Sources:
a. U.S. EPA, 2006.
b. CEC, 2006. Subset of Energy Industrial Sector reported in CO_2-equivalent tons, which includes the effects of methane, and includes current Pt. Pedernales GHG emissions.
c. See~~Appendix C. Proposed project includes drilling equipment, helicopter, and boat emissions at Platform Irene, heater emissions from LOGP, and fugitive emissions~~Table 5.8.9b.
na: Not Available

The crude oil would most likely be refined initially at the Santa Maria Refinery ~~, but could be potentially~~ and then transported to Bay Area facilities for additional refining and distribution. These refineries produce a number of petroleum products (such as gasoline, jet fuel, diesel fuel, asphalt, etc.), using crude oil as the primary feed stock. As discussed in Section 5.16, Energy and Mineral Resources, in 2005, California's petroleum refineries processed approximately 674,276,000 barrels of crude oil into a variety of products, with gasoline representing about half of the total product volume. In 2005, California oil refineries received 39.5% or 266,052,000 barrels of crude from Californian petroleum sources and 60.5% or 408,224,000 barrels from imported sources outside of California. At peak Tranquillon Ridge Field production (27,000 barrels per day), annual production would reach 9,855 thousand barrels or approximately 3.7% of annual California production (266,052 thousand barrels in 2005), representing about 1.5% of the crude oil received by California refineries (674,276,000 barrels in 2005).

The end use of the fossil fuel produced from the proposed Tranquillon Ridge project would also generate GHGs, but ~~would not~~ it is too speculative to conclude that the proposed project would result in any overall change to the U.S. or California GHG inventories~~ inventory~~. Rather than estimating GHG emissions from a myriad of possible future end uses, the GHG emissions from end use combustion of the project's 5 mmscfd of natural gas[2] and the various petroleum products yielded from the peak production of 27,000 barrels per day[3] were estimated based on full oxidation of the natural gas and crude oil that would be produced by the proposed project. This approach results in an estimated 5.38 million tons of CO_2 (4.88 Tg of CO_2) per year (CCAR 2007, U.S. EPA 2007). This is a gross estimate of GHG emissions from the eventual use of crude oil and natural gas generated by the proposed project. Determining the exact products yielded and emissions throughout the production period is speculative depending on the refineries processing the oil and the ultimate consumption of the products.

GHG emissions from the Tranquillon Ridge project could be offset by reducing GHG emissions from existing PXP sources or other activities related to oil and gas production. PXP could decommission or retrofit control measures for other facilities currently emitting greenhouse gases. In addition, opportunities for GHG control at Platform Irene or LOGP include reducing methane venting and leaks, capturing waste gas instead of flaring, electrifying stationary sources, retrofitting platform crane engines from liquid fuel to bio-fuel or natural gas firing, retrofitting process heaters to ultra-low emitting units, or improving energy efficiency of equipment or vessels. For example, cogeneration power at LOGP could offset up to 3.5 megawatts of electricity otherwise generated by the utilities, which may eliminate as much as about 10,000 tons of CO_2 annually that would otherwise be emitted by the electricity generators. Carbon capture and sequestration from combustion sources at LOGP may also be an economically viable option if enhanced oil production can be accomplished by injecting the GHG emissions into the wells. However, it is not generally known whether this type of sequestration would permanently prevent release of carbon dioxide. Determining the net GHG reductions that could be achieved through sequestration would require additional study because of the high level of energy demanded by sequestration and uncertainties about the permanence of storage. Other potential GHG offsetting measures may include PXP's contribution to a carbon offset fund and to reforestation and habitat restoration efforts. Before implementing any of these options, PXP would need to conduct a review of its existing GHG emissions. GHG reduction options would then need to be compared and ranked for relative capital costs, GHG abatement amounts, and feasibility. The magnitude of actual GHG reductions possible from existing Platform Irene and LOGP sources would likely be small compared to the estimated GHG emissions from end-use combustion of the project's natural gas and petroleum products.

PXP has committed to preparing a greenhouse gas audit of its project facilities and to implementing feasible measures at those facilities to reduce GHG emissions, up to a total cost of \$20 per ton of GHG emissions attributable to Tranquillon Ridge project operations for one year (14,925.35 tons CO_2 = \$298,507). PXP will measure, and the SBCAPCD will verify, residual GHG emissions that would occur after implementation of the measures identified in the greenhouse gas audit. PXP will then offset these residual emissions each year at a rate of \$10

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2 CO_2 from end use of natural gas:

$(5 \times 10^6$ scf/day)*(1,030 Btu/scf)*(53.05 kg $CO_2/10^6$ Btu)*(365 day/yr)*(1.102 ton/10^3 kg) =

= 99.72×10^6 kg CO_2/yr = 0.099 million metric tons CO_2/yr

= 109,900 ton CO_2/yr

3 CO_2 from end use of crude oil, assuming 16 degrees API (or specific gravity of 0.959):

(27,000 bbl/day)*(42 gal/bbl)*(0.959*8.337 lb/gal)*(0.868 lb C/lb)*(44 lb CO_2/12 lb C)*(365 day/yr) =

= $10{,}530 \times 10^6$ lb CO_2/yr = 4.779 million metric tons CO_2/yr

= 5,266,000 ton CO_2/yr

per ton (in 2008 dollars) for the life of the project. The annual funds will be offered to an entity such as the Climate Trust or California Wildfire ReLeaf for GHG mitigation projects.

Mandatory GHG emission reporting may be required as a result of rulemaking expected to occur by 2008 under the California Global Warming Solutions Act of 2006 (AB 32). The California Climate Action Team's Report to the Governor also indicates that a model rule to reduce venting and leaks in oil and gas systems would be developed to be considered for adoption by local air districts (CalEPA, 2006); however, the SBCAPCD's Fugitive Inspection and Maintenance rule (Rule 331) already requires reduction of venting and leaks. Project-related facilities could be subject to these requirements. In addition, PXP would likely be affected by future mandatory improvements in transportation energy efficiency (fuel economy) and alternatives to petroleum-based fuels for their truck and boat trips. GHG emission reductions required as a result of the rules and regulations under AB 32 could occur as early as 2009 (CARB, 2006). Section 5.8.2.2 identifies how this rulemaking activity will reduce the potential impacts of GHG emissions.

Mitigation Measures

Air-2 PXP shall ensure that emission reductions are provided to fully mitigate increases in operational criteria pollutant emissions associated with the proposed project consistent with SBCAPCD Rules and Regulations. The documentation supporting the available emission mitigations for operations shall be submitted to the SBCAPCD prior to land use clearance. No operations shall occur until the applicable project Permits to Operate are modified.

Residual Impact

Emissions would be less than the SBC significance criteria with the application of mitigations. Therefore, the operational air quality impacts are considered to be *significant but mitigable (Class II)*. As the emissions in the years beyond the previously expected life of the Point Pedernales Project would be below the significance criteria (after the application of mitigation), the impacts due to extension of life are also considered to be *significant but mitigable (Class II)*.

Impact #	Impact Description	Phase	Residual Impact
Air.3	Increased health risks from the increased air emissions due to the expected increase in equipment operation and oil volumes processed.	*Increased Throughput* *Extension of Life*	*Class III*

A health risk assessment is not required for Platform Irene as per PTO 9106, Section 6.4. Health risk from Hazardous Air Pollutants (HAPs) is evaluated based on the population that is continuously exposed to the emissions of HAPs. The platform is located offshore, therefore no permanent population would be continuously exposed to the HAPs.

For the LOGP facility, a cancer risk of approximately 0.1 per million, occurring on the site's property boundary, was estimated by the SBCAPCD based on the 1992 HAPs inventory. This cancer risk is primarily due to emissions of benzene and acrolein. In addition, chronic and acute non-carcinogenic risks, or hazard indices, were estimated to be 0.008 and 0.2, respectively.

The current LOGP estimated emissions of HAPs (based on the 1994 AB2588 Toxic Inventory) are given in Part 70 PTO 6708 (see Appendix C). These emissions were estimated based on the facility's total potential to emit. Emissions from the proposed project plus the current emissions are not expected to be higher than the permitted emissions or the total potential to emit (which are the same), see Table 5.8.9a. Therefore, the HAPs emissions are not expected to be higher than the worst-case scenario, and the health risks would not be higher than the ones listed in Table 5.8.10 under Current Estimate. Due to the proposed project, the identified emissions HAPs would continue beyond the projected lifetime of the approved Point Pedernales Project, therefore the continued health risks would be present and considered a project-related extension of life health impact. The current risk estimates are below the criteria of the SBCAPCD, and will continue to be below significance levels beyond the projected Point Pedernales Project lifetime; therefore, if the Tranquillon Ridge project is implemented, the health risks from the proposed project are *adverse but not significant (Class III)*.

Table 5.8.10 Health Risk Impacts Summary

Potential Health Risk	Criterion	1992 Inventory	Current Estimate *
Cancer Risk	10 in one million (1×10^{-5})	0.01×10^{-5}	0.3×10^{-5}
Chronic Health Hazard Index	1.0	0.008	0.013
Acute Health Hazard Index	1.0	0.2	0.3

a. Estimated using the worst-case emissions data from PTO 6708, Risk Assessment Procedures for Rules 1401 and 212 South Coast Air Quality Management District, Air Toxics "Hot Spots" Program Risk Assessment Guidelines, 1992.

Mitigation Measures

No mitigation measures have been identified.

Residual Impact

Impact Air.3 is considered *adverse but not significant (Class III)*.

5.8.5 Impact Analysis for the Alternatives

Detailed descriptions of the various alternatives have been provided in Chapter 3.0. This section provides a discussion of the air quality impacts of the various alternatives.

5.8.5.1 No Project Alternative

Scenarios 2 and 3. As discussed in Section 3.2, under the No Project Alternative Scenarios 2 and 3, production of the federal portion of the Tranquillon Ridge field would and would not occur, respectively. However, no extension of life of Point Pedernales facilities (Platform Irene, pipelines, and LOGP) is assumed under either scenario.

Impact Air.1 – Construction Emissions**:** These impacts would be eliminated. There would be no construction emissions associated with ~~the No Project Alternative~~ Scenarios 2 and 3 since none of the new facilities would be built.

Impact Air.2 – Operational Emissions: Operational emissions would be the same as the current operations. Although emissions would be reduced, the emissions for ~~this alternative~~ Scenarios 2 and 3 would still exceed the significance threshold. Therefore, the operational emissions would still be considered *significant but mitigable (Class II)*. Mitigation Measure Air-2 would apply.

Impact Air.3 – Health Risk: This impact would be eliminated because the operation at the LOGP would be the same as current operations (i.e., baseline).

Options for Meeting California Fuel Demand. The relative air quality impacts associated with the various options for meeting California fuel demand are summarized in Table 5.8.11.

Table 5.8.11 No Project Alternative Comparison to Options for Meeting California Fuel Demand, Air Quality

Source of Energy	Impacts
Other Conventional Oil & Gas	
Domestic onshore crude oil and gas	Likely to displace air quality impacts.
Increased marine tanker imports of crude oil	Air quality impacts would be greater because crude would be transported via tanker instead of pipeline.
Increased gasoline imports[1]	Production impacts would be displaced. If gasoline imported via tanker trucks, air quality impacts would be greater.
Increased natural gas imports (LNG)	Air quality impacts would increase with LNG tankering and/or development of offshore ports.
Alternatives to Oil and Gas	
Fuel Demand Reduction: increased fuel efficiencies, conservation, electrification[2]	
Alternative transportation modes	Proposed project impacts would be eliminated.
Implementation of regulatory measures	Proposed project impacts would be eliminated.
Coal, Nuclear, Hydroelectric	Proposed project impacts would be eliminated. Facility construction could result in air quality impacts. Coal transportation to power plants would result in increased emissions and coal combustion would result in increased emissions in comparison to oil and gas. Nuclear facility operations would result in emissions.
Alternative Transportation Fuels	
Ethanol/Biodiesel[3]	Ethanol feed-stock production and ethanol transportation would result in increased emissions.
Hydrogen[2]	Proposed project impacts would be eliminated. Fuel burned for hydrogen production would result in emissions.
Other Energy Resources[2]	
Solar[2,4]	Proposed project impacts would be eliminated. Construction of solar facility infrastructure could result in air quality impacts. Emissions due to operations would be nominal in comparison to oil and gas.
Wind[2,4]	Proposed project impacts would be eliminated. Construction of wind facility infrastructure could result in air quality impacts. Emissions due to operations would be nominal in comparison to oil and gas.
Wave[2,4]	Proposed project impacts would be eliminated. Construction of wave facility infrastructure could result in air quality impacts. Emissions due to operations would be nominal in comparison to oil and gas.

Footnotes:
1. Pipeline and tanker truck import from out-of-State assumed.
2. Assumes that Tranquillon Ridge production would not be replaced with other petroleum-based energy supply.
3. Assumes ethanol and biodiesel used as blends only and therefore would reduce, but not eliminate Tranquillon Ridge or equivalent production.
4. Assumes, large centralized facilities.

5.8.5.2 VAFB Onshore Alternative

The VAFB Onshore Alternative would include the construction of the drilling and production facilities within a 25-acre site, and installation of approximately 10 miles of emulsion and gas pipelines and 6 miles of overhead 69 kV transmission line and associated substation. In addition, a pipeline tie-in station and associated power line and substation would be required. These facilities would be operating for approximately 30 years. The air quality impacts associated with this alternative are described below.

Impact Air.1 – Construction Emissions: Construction impacts would cause substantial quantities of additional air emissions for the alternative drilling and production facilities, pipelines, tie-in station, ~~and transmission~~ power lines, and substations. Construction of the VAFB Onshore Alternative facilities would involve site and right-of-way grading, activity on dirt roads and disturbed areas, equipment transport, worker transport, and use of heavy equipment. Emissions from offshore construction under the proposed project would not occur. However, LOGP modifications would still occur. It is assumed that construction of the VAFB Onshore Alternative facilities would generate similar emissions as original construction of the LOGP facility and pipelines. As described for the Casmalia East Oil Field Processing Alternative, construction of the Lompoc HS&P facility and pipelines caused emissions that warranted implementation of feasible mitigation measures for NO_x and ROC. PM_{10} emissions could be mitigated by using the available dust controls in Mitigation Measure Air-1. Because the construction activities would be short-term, it is expected that construction of the drilling and production facility, pipelines, and transmission line would have adverse but not significant air quality impacts (*Class III*).

In accordance with County AQAP policies, the following mitigation measures are recommended to mitigate Impact Air.1 to the maximum extent feasible.

Mitigation Measures

Mitigation Measure Air-1 would apply, in addition to the following mitigation measures:

Air-3 PXP shall implement the following SBC NO_x reduction emissions measures:
- Engines and emission systems shall be maintained,
- High pressure fuel injectors shall be installed, and
- Reformulated diesel fuel shall be used.

The documentation supporting the implementation of the NO_x reduction measures shall be submitted to the SBC P&D and the SBCAPCD prior to land use clearance. No operations shall occur until the applicable project Permits to Operate are modified.

Air-4 PXP shall provide emission mitigations for the construction activities consistent with SBCAPCD Rules and Regulations. The documentation supporting the available emission mitigations for construction shall be submitted to the SBCAPCD and SBC P&D prior to land use clearance. No operations shall occur until the applicable project Permits to Operate are modified.

Residual Impact

The residual impacts of this alternative would be considered to be *adverse but not significant* (*Class III*).

Impact Air.2 – Operational Emissions: Operation of the drilling and production facility would involve fuel consumption and the associated combustion emissions for drilling wells, oil and gas production and transport, produced water handling, and other utility functions. Similar to drilling equipment emissions shown for the proposed project (Table 5.8.8) and current emissions from LOGP and Platform Irene (Table 5.8.9a), peak daily emissions of the VAFB Onshore Alternative drilling and production facility would exceed the significance threshold and trigger the need for offsets under SBCAPCD rules. Fugitive emissions would also occur with the wells. Operational emissions at Platform Irene under this alternative would be less than under the proposed project because ~~drilling activity,~~ helicopter and boat emissions would not be necessary. Although some emissions of the proposed project would not occur under this alternative, the emissions for this alternative would still be expected to exceed the significance threshold due to the new sources related to onshore drilling and production. The SBCAPCD would require permits and mitigation for new stationary source emissions associated with the alternative drilling and production facility. Therefore, the operational emissions would still be considered *significant but mitigable (Class II)*. Mitigation Measure Air-2 would apply.

Impact Air.3 – Health Risk: This impact as it relates to alternative operations would be similar to that which would occur under the proposed project, since the alternative drilling and production facility would be surrounded by unpopulated portions of the military base. Because health risk impacts are based on the population that is continuously exposed to the emissions of HAPs or air toxics, and no permanent population would be continuously exposed to the HAPs, the health risks from the VAFB Onshore Alternative site would be adverse but not significant. Accidental release of HAPs from the onshore drilling and production facility would be subject to SBCAPCD permitting requirements, which may require additional analysis of health risks. The current risk estimates for LOGP are below the criteria of the SBCAPCD, and will continue to be below significance levels beyond the projected Point Pedernales Project lifetime, therefore the health risks from the VAFB Onshore Alternative, including modifications to LOGP, are *adverse but not significant (Class III)*.

The federal Installation Restoration Program (IRP) is implemented at DOD facilities to identify, characterize, and restore hazardous substance release sites. There are currently 136 IRP sites throughout VAFB. The IRP sites are remediated through the Federal Facilities Site Remediation Agreement (FFSRA), a working agreement between the USAF, the RWQCB – Central Region, and the Department of Toxic Substances Control. In addition to IRP sites, there are areas identified as Areas of Concern (AOCs), where potential hazardous material releases are suspected; and Areas of Interest (AOIs), defined as areas with the potential for use and/or presence of a hazardous substance. Activities associated with the installation of an onshore drilling operation and associated pipeline may encounter contaminated soils or sites in at least two locations (Ryan, August 28, 2006). Disturbance of these locations during construction could pose potential health risks to construction personnel. With implementation of Mitigation Measure OWR-12, this impact is considered *significant but mitigable* (*Class II*).

5.8.5.3 Casmalia East Oil Field Processing Location

If this alternative is selected, a more detailed air quality impacts evaluation would be necessary. Impacts Air.1, Air.2, and Air.3 would change as described below.

Impact Air.1 - Construction Emissions: It is assumed that construction of the new facility at Casmalia East site would generate similar emissions as construction of the LOGP facility.

Construction of the Lompoc oil and gas processing facility and pipelines, and addition of the gas processing ~~facilities~~ emissions were deemed significant in the 1985 Point Pedernales EIR/EIS and 1993 Point Pedernales SEIR due to PM_{10} emissions. Construction of the onshore pipelines and the Lompoc HS&P facility, and 1994 modifications at the Lompoc HS&P combined was estimated to generate approximately 114 tons per year of PM_{10}. Although these emissions would not be deemed significant under the current SBCAPCD significance criteria, PM_{10} emissions could be feasibly be reduced by using the available dust controls. Because emissions associated with construction activities would be short-term, with the recommended implementation of Mitigation Measures Air-1, Air-3, and Air-4, this impact would be *adverse but not significant (Class III)*.

Impact Air.2 –Operational Emissions: Operations of the new facility would be similar to the proposed LOGP operations. The only additional source of emissions would be the new segments of pipelines proposed to connect the current LOGP site to the Casmalia East site. These emissions were calculated based on the estimated pipeline length of 15 miles, and similar number of connections and valves as on the wet oil and gas pipelines between Platform Irene and the LOGP facility. The emissions are summarized in Table 5.8.1~~1~~2.

Table 5.8.1~~1~~2 Estimated Emissions from Additional Pipeline Segments Compared to the Proposed Project Emissions – Operations

Part of Project Or Type	Peak Daily Emission (lbs/day)					Annual Emissions (tons/yr)				
	CO	ROC	NO_x	SO_2	PM_{10}	CO	ROC	NO_x	SO_2	PM_{10}
Proposed Project	~~47.64~~ 49.16	~~53.78~~ 53.73	~~109.46~~ 111.69	11.84	~~16.35~~ 16.43	~~8.88~~ 8.96	~~9.52~~ 9.51	~~7.23~~ 11.31	2.25	~~1.92~~ 1.93
Casmalia Alternative Emissions Increase	-	8.52	-	-	-	-	1.55	-	-	-
Total Project w/Alternative	~~47.64~~ 49.16	~~62.30~~ 62.25	~~109.46~~ 111.69	11.84	~~16.35~~ 16.43	~~8.88~~ 8.96	11.07	~~7.23~~ 11.31	2.25	~~1.92~~ 1.93
Daily Triggers	n/a	55	55	n/a	80	n/a	n/a	n/a	n/a	n/a
Current Emissions[a]						~~8.48~~ 8.60	66.60	~~29.60~~ 29.77	2.54	2.52
Current + Project w/Alternative						~~17.36~~ 17.56	~~77.67~~ 77.66	~~36.83~~ 41.08	4.79	~~4.44~~ 4.45
Previous Offset Credit	n/a	n/a	n/a	n/a	n/a	n/a	166.03	82.52	n/a	n/a

a. Current Emissions are reported annually, Peak Daily Emissions are not reported and therefore are not available.

The additional pipelines would only contribute to ROC emissions. These additional emissions as seen from Table 5.8.12~~1~~ are small. The proposed project operational NO_x and ROC emissions would be above the significance limits of 55 lbs/day. The project ROC emissions with this alternative would be higher than the proposed project, therefore, the impacts are considered *significant but mitigable (Class II)*. Mitigation Measure Air-2 would apply to this alternative.

Impact Air.3 – Health Risk: The HAPs emissions associated with the Casmalia Alternative are expected to be slightly greater than the proposed project since both a down-scaled LOGP and Casmalia processing plant would be in operation. However, the current risk estimates for the LOGP are well below the criteria of the SBCAPCD. Therefore, the health risks for the Casmalia Alternative are considered *adverse but not significant (Class III).*

5.8.5.4 Alternative Power Line Routes to Valve Site #2

Impacts Air.2 and Air.3 would be the same as the proposed project for all alternative power line routes. Impact Air.1 would change as described below.

Alternative Power Line Route – Option 2a

Impact Air.1 – Construction Emissions: Air emissions associated with constructing the power line according to this alternative route are expected to be very similar to the proposed project (see Table 5.8.7). Although the power line would originate from a different point, the length of the route is similar in length to the proposed power line. Therefore, the number of poles to be installed and the number and types of equipment would be the same. The trenching equipment emissions and fugitive dust emissions would be slightly reduced because this alternative does not involve trenching to underground small portions of the power line to avoid interference with the VAFB power lines. Because air emissions due to construction would be less than for the proposed project, due to less trenching, these emissions would also be adverse but not significant; therefore, Impact Air.1 would be *not significant (Class III*), which is the same as the proposed project. Mitigation Measure Air-1 would apply to this alternative.

Alternative Power Line Route – Option 2b

Impact Air.1 – Construction Emissions: This alternative uses the same route as Option 2a except the crossing of the Santa Ynez River would be via an underground bore. Table 5.8.13~~2~~ presents a summary of construction air emissions for this alternative. It is assumed that in addition to the other construction equipment there would also be a boring rig and a mud-handling pump. The additional equipment is needed to make a boring under the Santa Ynez River. The construction emissions would be slightly higher than for the proposed project due to the boring operations.

Table 5.8.13~~2~~ Summary of Project with Alternative Route Option 2b Emissions – Construction

Location and Construction Activity – Route Option 2b	Total (Annual) Emissions (tons/yr)				
	CO	ROC	NO_x	SO_2	PM_{10}
Proposed Project	~~11.84~~ 4.79	~~2.29~~ 0.67	~~22.10~~ 6.04	~~2.07~~ 0.46	~~1.74~~ 0.44
Alternative Route 2b	0.05	0.01	0.06	0.01	0.00
Proposed Project with Alternative	~~11.89~~ 4.84	~~2.30~~ 0.68	~~22.16~~ 6.10	~~2.07~~ 0.47	~~1.74~~ 0.44

The construction emissions associated with this alternative would be short-term; therefore, Impact Air.1 is considered *adverse but not significant (Class III)*, which is the same as the proposed project. Mitigation Measure Air-1 would apply to this alternative.

Underground Power Line along Terra Road

Impact Air.1 – Construction Emissions: Table 5.8.14~~3~~ presents a summary of the construction air emissions for this alternative. It is assumed that in addition to the other construction equipment there would also be two backhoes or trenchers, one cable lay crane and two dump trucks, which would contribute to onsite equipment emissions.

The construction emissions associated with this alternative would be short-term; therefore, Impact Air.1 is considered *adverse but not significant (Class III)*, which is the same as the proposed project. Mitigation Measure Air-1 would apply to this alternative.

Table 5.8.14~~3~~ Summary of Proposed Project with Underground Power Line Alternative Emissions – Construction

Location and Construction Activity – Underground Route	Total (Annual) Emissions (tons/yr)				
	CO	ROC	NO_x	SO_2	PM_{10}
Proposed Project	~~11.84~~ 4.79	~~2.29~~ 0.67	~~22.10~~ 6.04	~~2.07~~ 0.46	~~1.74~~ 0.44
Power Line Alternative – Underground, Emissions Increase	0.31	0.08	0.83	0.08	0.19
Total: Proposed Project with Power Line Alternative	~~12.15~~ 5.10	~~2.37~~ 0.75	~~22.93~~ 6.87	~~2.15~~ 0.54	~~1.93~~ 0.63

5.8.5.5 Replacement of Oil Emulsion Pipeline from Platform Irene to LOGP

Impacts Air.2 and Air.3 would remain the same as for the proposed project. Impact Air.1 would change as discussed below.

Impact Air.1 - Construction Emissions: Emissions would increase due to additional air emissions associated with construction of the replacement pipeline.

Additional air emissions are expected due to removal of the existing emulsion pipeline and construction of the replacement pipeline. The new emulsion pipeline operational air impacts are assumed to be the same as the emissions from the existing pipeline.

The following emissions would be generated during construction of the replacement pipeline:

1. Offshore construction equipment emissions
2. Onshore construction equipment emissions
3. Fugitive dust emissions - onshore only (excavation, stockpiling, travel on unpaved roads)
4. Emissions due to offsite travel

Table 5.8.15~~4~~ presents a summary of the estimated construction (short-term) air emissions if this alternative is selected. See Appendix C for detailed calculations.

Construction emissions are short-term. To feasibly reduce construction emissions Mitigation Measure Air-1, dust control methods; Mitigation Measure Air-3, NO_x reduction measures; and Mitigation Measure Air-4, emission reductions for construction would be recommended. The residual impacts associated with construction emissions are considered *adverse but not significant (Class III).*

5.8.5.6 Alternative Drill Muds and Cuttings Disposal

Impacts Air.1 and Air.3 would be the same as for the proposed project. Impact Air.2 would change as discussed below.

Inject Drill Muds and Cuttings into Reservoir

Impact Air.2 – Operational Emissions: This alternative would require a diesel slurry pump and piping connections to an injection well head, modifications that would occur at the platform. Air emissions would increase due to the need to operate the slurry pump at Platform Irene under this alternative. Emissions due to exhaust vapors from mud-gas separator and mud degasser would still remain the same as in the proposed project. Table 5.8.16~~5~~ compares the total project emissions from drilling for this alternative.

Table 5.8.15~~4~~ Summary of Emissions due to Replacement of Emulsion Pipeline – Construction

Location and Construction Activity	Total Emissions (tons per year)				
	CO	ROC	NO_x	SO_2	PM_{10}
Onshore Equipment	2.34	0.60	5.65	0.55	0.59
Offshore Equipment	12.49	2.53	28.23	2.34	1.95
Fugitive Dust (onshore only)	0.00	0.00	0.00	0.00	2.01
Offsite – onshore and offshore	2.22	~~0.56~~ 0.39	~~3.44~~ 3.32	0.20	~~0.28~~ 0.25
Total Emissions – from Alternative only	17.05	~~3.68~~ 3.52	~~37.32~~ 37.20	3.08	~~4.82~~ 4.79
Total Emissions – from Proposed Project[a]	~~11.84~~ 4.79	~~2.29~~ 0.67	~~22.10~~ 6.04	~~2.07~~ 0.46	~~1.74~~ 0.44
Total Emissions – Project with Alternative	~~28.89~~ 21.85	~~5.98~~ 4.19	~~59.42~~ 43.23	~~5.15~~ 3.54	~~6.56~~ 5.23

a. See Table 5.8.7.

Table 5.8.16~~5~~ Comparison of Current Emissions to Total Project Emissions with Mud and Cutting Injection Alternative – Operation

Part of Project or Type	Peak Daily Emissions, lbs/day					Annual Emissions, tons/yr				
	CO	ROC	NO_x	SO_2	PM_{10}	CO	ROC	NO_x	SO_2	PM_{10}
Proposed Project	~~47.6~~ 49.2	~~53.8~~ 53.7	~~109.5~~ 111.7	11.8	~~16.3~~ 16.4	~~8.88~~ 8.96	~~9.52~~ 9.51	~~7.23~~ 11.31	2.25	~~1.92~~ 1.93
Mud Injection Alternative	53.4	20.1	148.2	3.7	17.6	5.88	2.21	16.30	0.41	2.65
Total Project w/Mud Injection Alternative	~~101.1~~ 102.6	~~73.9~~ 73.8	~~257.6~~ 259.8	15.5	~~34.0~~ 34.1	~~14.76~~ 14.83	11.73	~~23.53~~ 27.60	2.66	4.57
Significance Triggers	n/a	55	55	n/a	80	n/a	n/a	n/a	n/a	n/a
Current Emissions[a]						~~8.48~~ 8.60	66.60	~~29.60~~ 29.77	2.54	2.52
Current + Project w/Alt						~~23.24~~ 23.44	78.32	~~53.13~~ 57.38	5.20	~~7.09~~ 7.10
Previous Offset Credit	n/a	n/a	n/a	n/a	n/a	n/a	166.03	82.52	n/a	n/a

a. Current Emissions are reported annually, Peak Daily Emissions are not reported and therefore are not available.

With this alternative, NO_x and ROC emissions are expected to be higher than the daily triggers of 55 lbs/day. GHG emissions would be slightly increased as well. Application of Mitigation Measure Air-2 would reduce the emissions to below the significance criteria. Therefore, this impact is considered *significant but mitigable (Class II)*.

Transport Drill Muds and Cuttings to Shore for Disposal

Impact Air.2 – Operational Emissions: This section addresses the impacts on air quality due to pollutant emissions associated with transporting of muds and cuttings to shore for disposal. The muds and cuttings would be kept in containers on the platform. The supply boat that delivers materials to Platform Irene would transport these containers back to shore on the return trip.

It is expected that during drilling of each well, the supply boat would transport the drill muds and cuttings in bins or containers to Port Hueneme. Then the containers would be loaded onto trucks and transported to a waste disposal facility. The drill muds could be transported via vacuum trucks. The potential impacts would result from truck emissions. Emissions due to exhaust vapors from the mud-gas separator and mud degasser will remain the same as in the proposed project. Additional emissions from the proposed project with this alternative are summarized in Table 5.8.17~~6.~~

Table 5.8.17~~6~~ Comparison of Current Emissions to Total Project Emissions with Onshore Muds and Cuttings Disposal Alternative – Operation

Part of Project Or Type	Peak Daily Emissions, lbs/day					Annual Emissions, tons/yr				
	CO	ROC	NO_x	SO_2	PM_{10}	CO	ROC	NO_x	SO_2	PM_{10}
Proposed Project	~~47.6~~ 49.2	~~53.8~~ 53.7	~~109.5~~ 111.7	11.8	~~16.3~~ 16.4	~~8.88~~ 8.96	~~9.52~~ 9.51	~~7.23~~ 11.31	2.25	~~1.92~~ 1.93
Onshore Mud Disposal Alternative	194.3 ~~94.2~~	20.7 ~~22.2~~	160.8 ~~9.4~~	0.2 ~~0.9~~	6.3 ~~0.3~~	2.72 ~~1.32~~	0.29 ~~0.31~~	2.25 ~~0.13~~	0.00 ~~0.01~~	0.09 ~~0.00~~
Total Project w/Alternative	~~141.8~~ 243.5	~~76.0~~ 74.5	~~118.8~~ 272.5	~~12.7~~ 12.0	~~16.6~~ 22.7	~~10.20~~ 11.68	~~9.83~~ 9.80	~~7.36~~ 13.56	~~2.27~~ 2.26	~~1.93~~ 2.02
Daily Triggers	n/a	55	55	n/a	80	n/a	n/a	n/a	n/a	n/a
Current Emissions[a]						~~8.48~~ 8.60	66.60	~~29.60~~ 29.77	2.54	2.52
Total w/Project & Alternative						~~18.68~~ 20.28	~~76.42~~ 76.40	~~36.96~~ 43.33	~~4.81~~ 4.80	~~4.44~~ 4.54
Previous Offset Credit	n/a	n/a	n/a	n/a	n/a	n/a	166.03	82.52	n/a	n/a

a. Current Emissions are reported annually, Peak Daily Emissions are not reported and therefore are not available.

It was assumed that the cuttings and muds from drilling of one well would be trucked in one week from Port Hueneme to a distance 120 miles from the port. It was estimated that the muds and cuttings from drilling of the longest well would require 106 vacuum trucks (for muds) and 93 trucks for cuttings transportation. It is assumed that 30 wells would generate approximately 75,000 tons of muds, and each well therefore would generate approximately 1,670 tons of cuttings and 10,600 barrels of muds (see Appendix D).

Offsite truck emissions contribute less than one percent to the total project emissions. The proposed project with the addition of this alternative would have NO_x and ROC emissions greater than the significance triggers of 55 lbs/day. Therefore, Impact Air.2 is considered to be significant. Application of the emissions mitigations consistent with SBC standard permit conditions would reduce the emissions to below the significance criteria. Therefore, impacts would be considered *significant but mitigable (Class II)*. Mitigation Measure Air-2 would apply.

5.8.6 Cumulative Impacts

Cumulative projects that could impact the current analysis include both offshore oil and gas projects, and the other onshore development projects discussed in Section 4. Each of these is discussed separately below.

5.8.6.1 Offshore Oil and Gas Projects

There are a considerable number of potential offshore oil and gas development projects in the proposed project area. The exact schedule and air emissions that could be generated by these projects are uncertain at this time. All of the activities for the potential offshore oil and gas development projects outlined in Sections 4.2 and 4.3 of this document would occur in the same air basin as the Tranquillon Ridge Field development. The majority of air emission impacts would be associated with the installation and operation of new platforms, pipelines, and onshore processing facilities. Construction of the new onshore facilities that may be required for the new offshore oil and gas projects are likely to have short-term air quality impacts. Mitigation measures consistent with County policies such as emission reductions for dust control would be applied, and the cumulative construction emissions would be considered less than significant. The proposed project's contribution to these cumulative effects would be nominal because of the limited construction proposed.

It is assumed that the operational emissions associated with the potential future offshore oil and gas development projects would be similar to the proposed project's Platform Irene emissions, as well as its corresponding air emissions at the LOGP. The operation of the cumulative effect of these potential projects would represent a substantial increase in emissions within the air basin. However, in order to obtain a Permit to Operate (PTO) from SBCAPCD, new facilities would be required to offset new emissions increases. If the facilities do not have the required offsets that cover their respective operational emissions, these facilities would not be allowed to operate. However, given the limited available emission reductions in SBC, it may be difficult to permit this level of new emissions. The biggest source of NO_x emissions on offshore platforms that generate their own electrical power is associated with turbines used for power generation. Using grid power on the platforms, as is done on Platform Irene, could reduce these emissions. Therefore, cumulative operational emissions, including those associated with the incremental contribution of the proposed project, would not be considered significant if grid power is used.

The proposed project would not be a significant contributor to the cumulative effects on air quality, given the low level of new emissions and the fact that previous offset credits are in place and new offsets will be required for these emissions increases.

Following Executive Order S-3-05 in June 2005, which declared California's particular vulnerability to climate change, AB 32 was signed by Governor Arnold Schwarzenegger on September 27, 2006. In passing the bill, the California Legislature found that "*Global warming poses a serious threat to the economic well-being, public health, natural resources, and the environment of California. The potential adverse impacts of global warming include the exacerbation of air quality problems, a reduction in the quality and supply of water to the state from the Sierra snowpack, a rise in sea levels resulting in the displacement of thousands of coastal businesses and residences, damage to marine ecosystems and the natural environment, and an increase in the incidences of infectious diseases, asthma, and other human health-related problems*" (California Health & Safety Code, Division 25.5, Part 1). It is assumed that the GHG emissions associated with the potential future offshore oil and gas development projects would be similar to the proposed project's Platform Irene emissions, as well as its corresponding GHG emissions at the LOGP and project transportation (trucks, helicopters, and boats). As presented in Table 5.8.9c, the U.S. GHG emissions for all energy related activities in 2004 was 6,430 million tons (5,835 Tg) of CO_2 and 11.3 million tons (10.3 Tg) of methane. The proposed project's contribution during peak production to the U.S. GHG inventory for CO_2 would be 0.0002 percent and 0.0003 percent for methane. The California GHG inventory for oil and gas extraction activities in 2004 for CO_2 was 14.5 million tons (13.2 Tg). The proposed project's contribution to the California CO_2 emissions would be 0.11 percent. Assuming that GHG

<u>emissions from potential future offshore oil and gas development projects would be similar to the proposed project's, their corresponding contribution to the U.S. and California GHG inventories would be comparable.</u>

5.8.6.2 Onshore Projects

Construction of the onshore development projects outlined in Section 4.4 would generate air emissions, some of which would be mitigated by project-specific mitigation measures. Construction of many of these projects would be expected to be consistent with adopted County policies, such as emission reductions for dust control, which would ensure that cumulative construction air quality impacts would not be significant. Additionally, the operational emissions of these onshore projects would not be considered significant since each individual project would not be allowed to operate without a PTO.

Proposed cumulative development and its associated air emissions have been accounted for in the 2004 Clean Air Plan and subsequent updates. Therefore, the onshore cumulative projects would be consistent with the air quality planning document used to bring the region into attainment with ambient air quality standards, and would be expected to produce long-term air quality impacts that are not significant. Therefore, cumulative air quality impacts, including the proposed project's incremental contribution to them, would not be considered significant.

5.8.7 Mitigation Monitoring Plan

Mitigation Measure	Mitigation Requirements and Timing	Method of Verification	Timing of Verification	Party Responsible For Verification
Air-1	PXP shall prepare and submit Dust Control and Reduction Plan to SBCAPCD prior to land use clearance. PXP shall implement dust reduction measures during construction. The following APCD Standard Dust Mitigation Measures shall be implemented: 1. Dust generated by the development activities shall be retained onsite and kept to a minimum by following the dust control measures listed below. Reclaimed water shall be used whenever possible. a. During clearing, grading, earth moving or excavation, water trucks or sprinkler systems are to be used in sufficient quantities to prevent dust from leaving the site and to create a crust, after each day's activities cease. b. After clearing, grading, earth moving or excavation is completed, the disturbed area must be treated by watering, or revegetating; or by spreading soil binders until the area is paved or otherwise developed so that dust generation would not occur. c. During construction, water trucks or sprinkler systems shall be used to keep all areas of vehicle movement damp enough to prevent dust from leaving the site. At a minimum, this would include wetting down such areas in the late morning and after work is completed for the day. Increased watering frequency	Review and approval of the Dust Control Plan. Compliance with the Plan shall be verified by construction site visits.	Prior to land use clearance Periodically during construction	SBCAPCD SBC P&D

Mitigation Measure	Mitigation Requirements and Timing	Method of Verification	Timing of Verification	Party Responsible For Verification
	will be required whenever the wind speed exceeds 15 mph. 2. Importation, exportation and stockpiling of fill material: a. Soil stockpiled for more than two days shall be covered, kept moist, or treated with soil binders to prevent dust generation. b. Trucks transporting fill material to and from the site shall be tarped from the point of origin. c. If the construction site is greater than five acres, gravel pads must be installed at all access points to minimize tracking of mud onto public roads. 3. Activation of increased dust control measures: a. The contractor or builder shall designate a person or persons to monitor the dust control program and to order increased watering, as necessary, to prevent transport of dust offsite. Their duties shall include holiday and weekend periods when work may not be in progress. The name and telephone number of such persons shall be provided to the APCD.			
Air-2	PXP shall ensure that emission reductions are provided to fully mitigate increases in operational criteria pollutant emissions associated with the proposed project consistent with SBCAPCD Rules and Regulations. The documentation supporting the available emission mitigations for operations shall be submitted to the SBCAPCD prior to land use clearance. No operations shall occur until the applicable project Permits to Operate are modified.	Review of the supporting documentation for the mitigations	Prior to land use clearance	SBCAPCD SBC P&D
Air-3 (VAFB Onshore, Casmalia, and Emulsion Pipeline Replacement Alternatives only)	PXP shall implement the following SBC NOx reduction emissions measures: - Engines and emission systems shall be maintained, - High pressure fuel injectors shall be installed, and - Reformulated diesel fuel shall be used. The documentation supporting the implementation of the NOx reduction measures shall be submitted to the SBC P&D and the SBCAPCD prior to land use clearance. No operations shall occur until the applicable project Permits to Operate are modified.	Review and approval of the documentation. Compliance with the measures shall be verified by construction site visits	Prior to land use clearance Periodically during construction	SBCAPCD SBC P&D
Air-4 (VAFB Onshore, Casmalia, and Emulsion Pipeline Replacement Alternatives only)	PXP shall provide emission mitigations for the construction activities consistent with SBCAPCD Rules and Regulations. The documentation supporting the available emission mitigations for construction shall be submitted to the SBCAPCD and SBC P&D prior to land use clearance. No operations shall occur until the applicable project Permits to Operate are modified.	Review of the submitted documentation.	Prior to land use clearance	SBCAPCD, SBC P&D

5.8.8 References

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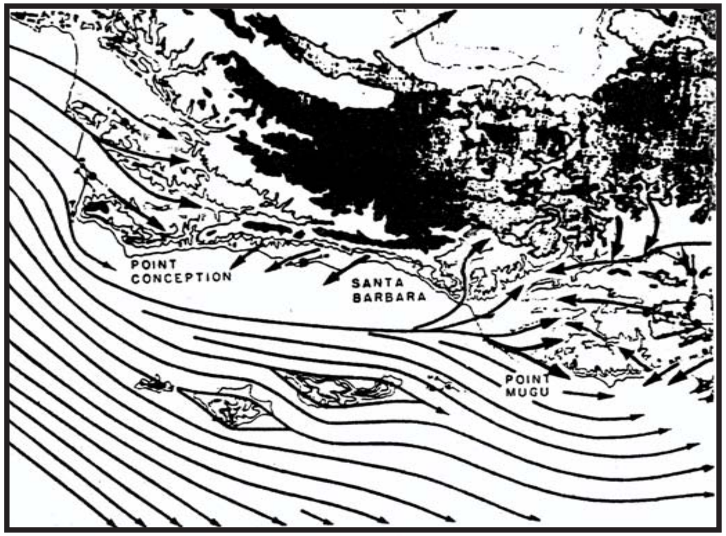
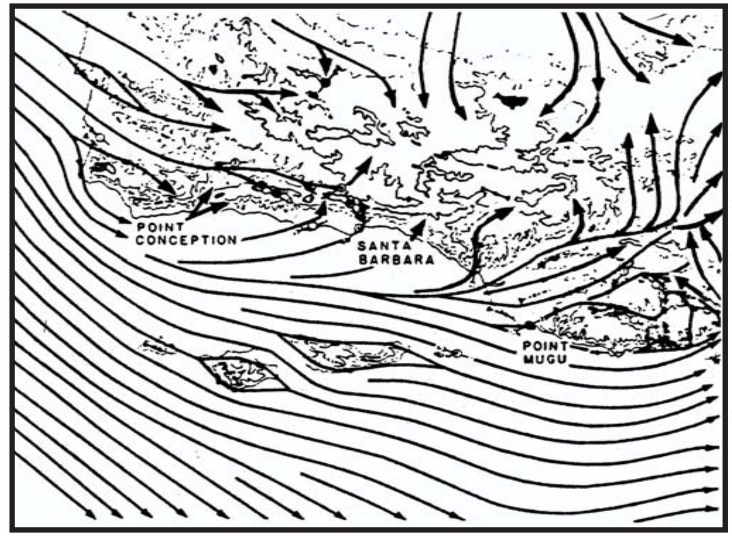


Summer Night



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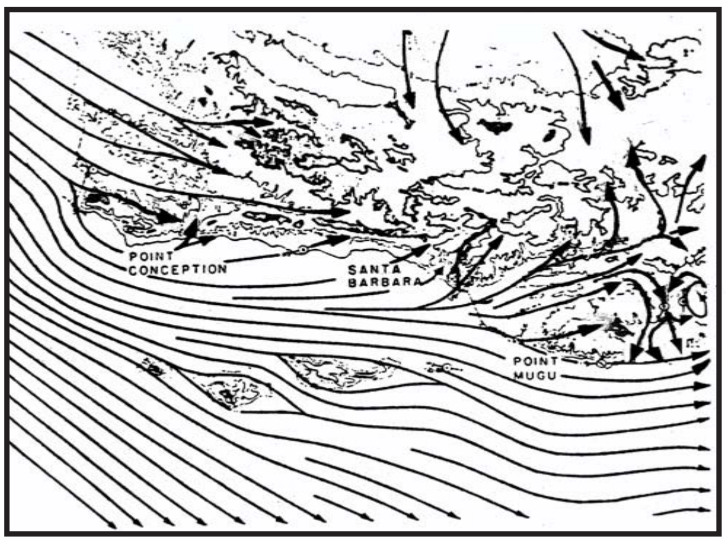
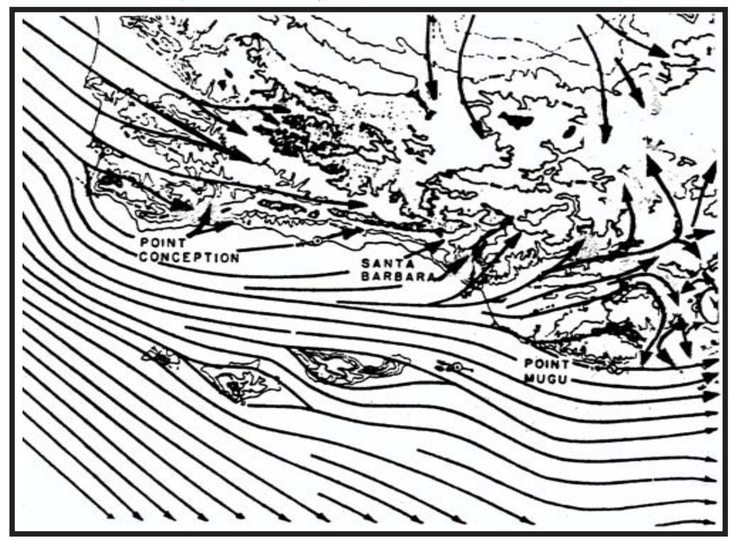


Winter Night



Winter Day

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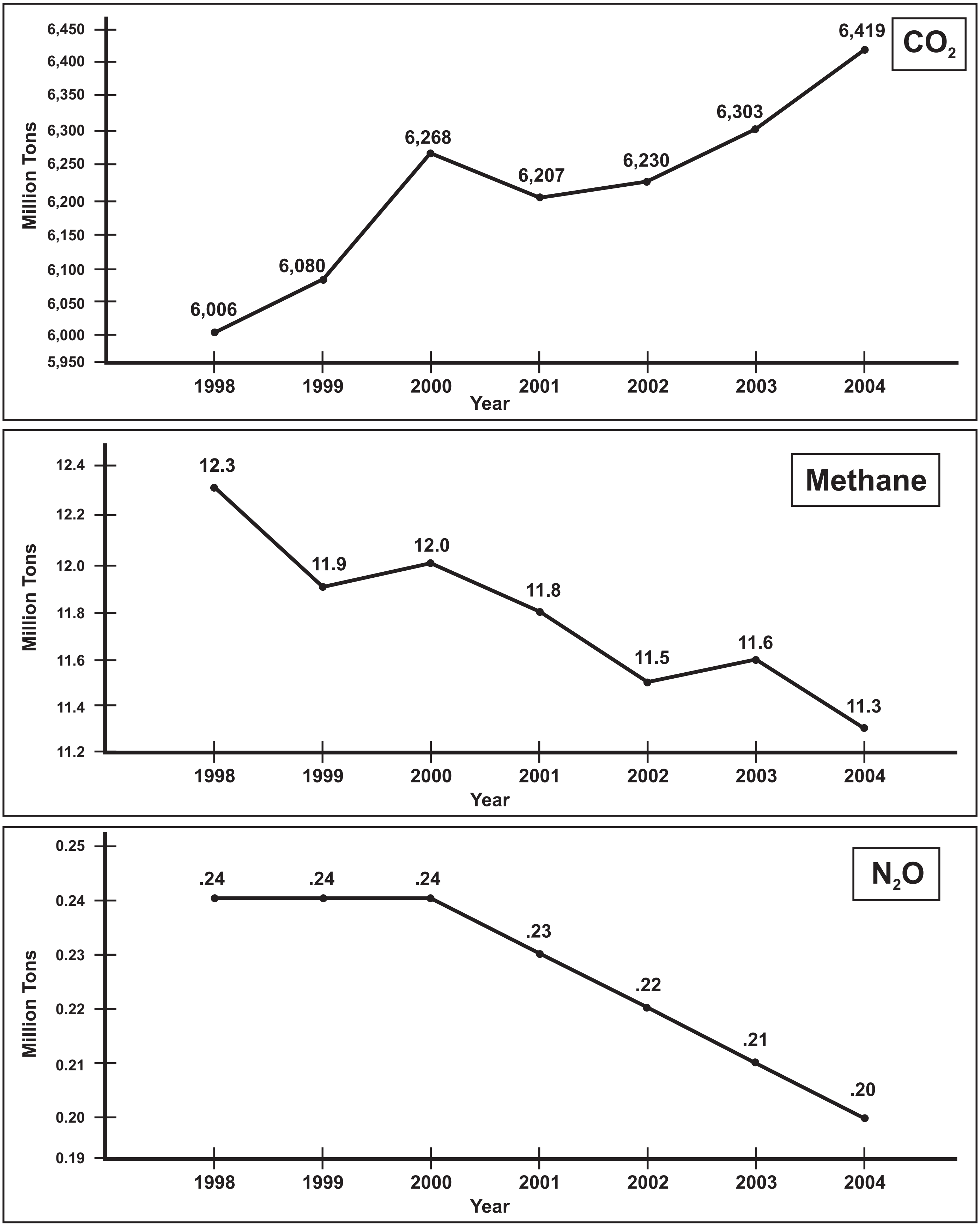
Figure 5.8-1
Typical Regional Wind Patterns



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Source: US EPA, 2006

Figure 5.8-2
Trend of U.S. GHG Emissions for Energy Related Activities 1998 through 2004

5.9 Traffic

This section describes both the onshore and offshore transportation systems in the vicinity of the proposed project and the impacts of the proposed project. The analysis in this section is based on field surveys, a review of local and regional maps, and discussions with appropriate agencies.

5.9.1 Environmental Setting

This section is divided into two parts. The first part covers baseline onshore traffic and the second covers the baseline offshore traffic in the vicinity of the proposed project.

5.9.1.1 Onshore Traffic

Roadway and Intersection Classification

Circulation conditions are often described in terms of levels of service (LOS). LOS is a means of describing the amount of traffic on a roadway versus the design capacity of the roadways. The design capacity of a roadway is defined as the maximum rate of vehicle travel that can reasonably be expected along a section of roadway. Capacity is dependent on a number of variables including road classification and number of lanes, weather, and driver characteristics. The LOS rating uses qualitative measures that characterize operational conditions within a traffic stream and their perception by motorists. These measures include freedom of movement, speed and travel time, traffic interruptions, types of vehicle, comfort, and convenience. Ideal conditions for a roadway would include good lane widths and roadside clearances, the absence of trucks or other heavy vehicles, and level terrain. LOS is generally a function of the ratio of traffic volume (V) to the capacity (C) of the roadway or intersection, which provides the V/C ratio (see Table 5.9.1).

Table 5.9.1 Traffic Conditions Along Project Related Routes

Road/Route	Class	ADT	ADT LOS	Peak Hr	Design Cap	V/C Ration	Ref.
State Highway 1 from Gaviota to Orcutt							
Las cruces, jct. Rte. 101	Major - 2 Lanes	7,700	A	850	16,000	0.48	1
Jalama Road	Major - 2 Lanes	7,900	A	930	16,000	0.49	1
Lompoc, south jct. Rte. 246	Major - 4 Lanes	16,300	A	1,700	31,900	0.51	1
Lompoc, north jct. Rte. 246	Major - 4 Lanes	16,000	A	1,300	31,900	0.50	1
Lompoc, Santa Ynez River bridge	Major - 4 Lanes	20,000	B	1,600	31,900	0.63	1
Lompoc-Casmalia Road,	Major - 4 Lanes	20,000	B	1,700	31,900	0.63	1
Pine Canyon Road	Major - 4 Lanes	16,100	A	1,400	31,900	0.50	1
Vandenberg Air Force Base, main gate	Major - 4 Lanes	15,200	A	1,600	31,900	0.48	1
South jct. Rte. 135; Vandenberg, north	Major - 4 Lanes	16,200	A	1,550	31,900	0.51	1
Orcutt, jct. Rte. 135 north	Major - 4 Lanes	2,400	A	300	31,900	0.08	1
Clark Ave	Major - 4 Lanes	3,800	A	450	31,900	0.12	1
State Hwy 246 (Ocean Ave) from Hwy 1 West to Surf							
Lompoc west of City Limits	Major - 2 Lanes	6,200	A	900	16,000	0.35	1
W. Ocean Ave: E of Floradale	Major - 2 Lanes	5,375	A	538	16,000	0.34	2
W. Ocean Ave: E of Arguello	Major - 2 Lanes	2,718	A	272	16,000	0.17	2
Harris Grade Road from Hwy 1 to State Hwy 135							
North of State Hwy 1	Major - 2 Lanes	8,223	A	822	16,000	0.51	2
N of Rucker Rd	Major - 2 Lanes	1,663	A	166	16,000	0.10	2

Table 5.9.1 Traffic Conditions Along Project Related Routes

Road/Route	Class	ADT	ADT LOS	Peak Hr	Design Cap	V/C Ration	Ref.
State Hwy 135 East from Harris Grade Road to Hwy 101							
Los Alamos, jct. Rte. 101	Major - 2 Lanes	5,500	A	490	16,000	0.34	1
Old State Highway	Major - 2 Lanes	3,200	A	310	16,000	0.20	1
Old Route 1/Cabrillo Highway	Major - 2 Lanes	2,700	A	290	16,000	0.17	1
State Hwy 135 West from Harris Grade Road to Hwy 1							
San Antonio Road	Major - 2 Lanes	2,700	A	290	16,000	0.17	1
South jct. Rte. 1	Major - 2 Lanes	2,700	A	270	16,000	0.17	1
State Hwy 135 from Highway 1 to Clark Ave							
Orcutt, north jct. Rte. 1;	Major - 4 Lanes	14,800	A	1,400	31,900	0.46	1
East Clark Avenue	Major - 4 Lanes	19,000	A	2,150	31,900	0.60	1
Clark Ave in Orcutt from State Hwy 135 to Hwy 101							
Clark Ave: W of Blosser	Major - 2 Lanes	2,459	A	246	16,000	0.15	2
Clark Ave W of 101	Major - 4 Lanes	18,207	A	1,821	31,900	0.57	2

References: *1 = Caltrans, 2005; 2 = Santa Barbara Public Works Traffic Volumes (2006).*
V/C = the volume to capacity ratio, capacity is based on roadway class with LOS of E.
ADT = Average Daily Traffic Harris Grade Road peak hour based on 10% of Annual Average Daily Trips (AADT).

Trucks impact LOS by occupying more roadway space and by having poorer operating qualities than passenger cars. Because heavy vehicles accelerate more slowly than passenger cars, gaps form in traffic flow that affect the efficiency of the roadway. Also, intersections present a number of variables that can influence LOS including curb parking, transit buses, turn lanes, signal spacing, pedestrians, and signal timing.

The Transportation Research Board has developed the Highway Capacity Manual that details the procedures to be used in predicting LOS for a range of roadways and intersections. The LOS of a roadway is defined by scales ranging from A to F, with A indicating excellent traffic flow quality and F indicating stop-and-go traffic. Level E is normally associated with the maximum design capacity that a roadway can accommodate. The highest quality of traffic service occurs on roadways when motorists are able to drive their desired speed without strict enforcement and are not delayed by slow-moving vehicles more than 30 percent of the time. This condition is representative of LOS A. The classifications of LOS B and C are characterized when average drivers are delayed up to 45 and 60 percent of the time, respectively, by slow moving vehicles. LOS D is characterized by 31 to 70 percent of the signal cycles having one or more vehicles that wait through at least one signal cycle. When an area drops to LOS E, the speed of traffic is restricted 71 to 100 percent of the time; and intersection signal cycles have one or more vehicles waiting through more than one signal cycle during peak traffic periods. The LOS of A, B, and C are generally considered satisfactory.

Santa Barbara County Planning and Development (SBC P&D) uses the County's thresholds for V/C ratios to calculate LOS. As discussed above, LOS is determined not only by traffic volumes, but also by a number of roadway conditions and intersection details. Determining a roadway's potential to present a traffic flow problem is a time-consuming process; therefore, a screening approach is often recommended. The screening approach involves comparing the roadway class with a traffic volume level for each level of service. The screening levels are developed by making generic assumptions for the data input in the Highway Capacity Manual calculations.

Table 5.9.2 shows the screening volume levels that are proposed for this study. Note that the screening tool is for roadways and not for intersections.

Table 5.9.2 LOS Screening Classifications, Roadway Daily Volumes

Roadway Class	LOS (high values)				
	A	B	C	D	E
Arterial - 4 Lanes	23,900	27,900	31,900	35,900	39,900
Arterial - 2 Lanes	12,000	14,000	16,000	18,000	20.000
Major - 4 Lanes	19,200	22,300	25,500	28,700	31,900
Major - 2 Lanes	9,600	11,200	12,800	14,400	16,000
Collector	7,100	8,200	9,400	10,600	11,800

Source: Based on SBC Public Works Department Roadway Design Capacities.

In addition, LOS values are often developed by the respective county engineering and public works departments to address future land use and impacts on requirements of future roadway projects. These analyses are normally conducted as part of a community plan and are available for only limited locations in the proposed project area. They generally utilize the detailed approach given in the Highway Capacity Manual and include both roadways and intersections.

Existing Conditions

Routes that could be affected by the proposed project include major routes to and from the pipeline route areas and major roads accessing the LOGP. Major roads that then connect these areas to Highway 101 for north or south travel are also included. These routes are shown on Appendices A and B and include the following:

- *State Highway 1* can be used for travel to Highway 101 North in Orcutt or for travel south at Las Cruces (near Gaviota). Highway 1 also passes directly through the middle of the City of Lompoc along East Ocean Avenue and north along North H Street. It is a four-lane road from southern Lompoc north until Orcutt. It is a two-lane road south of Lompoc until Highway 101.

- *Highway 246*, also called West Ocean Avenue, can be used to access the western part of the pipeline route via VAFB, south entrance at 13th Street. The state-maintained Highway 246 ends at the western limit of the City of Lompoc, but West Ocean Avenue continues as a two-lane road from Highway 1 west to Ocean Beach Park on the coast.

- *Harris Grade Road* passes directly in front of the LOGP. From the plant, travel north on Harris Grade Road connects to Highway 135. Traveling south connects to Highway 1 just north of the City of Lompoc and Highway 1 Santa Ynez River crossing. This is a two-lane road.

- *Highway 135* travels east from Harris Grade Road to connect with Highway 101 at Los Alamos. Westward travel on Highway 135 from Harris Grade Road joins with Highway 1 north of VAFB. Highway 135 continues south of Orcutt where it branches off from Highway 1 in an east and then northerly direction. Here it connects with Clark Avenue where the route can continue to Highway 101. This is a two-lane road.

- *Clark Avenue* is an east/west road that connects Highway 1 and Highway 135 with Highway 101 passing through the southern part of the community of Orcutt. This is a four-lane road except for the western segments, which have two lanes.

Existing traffic circulation and roadway operating conditions for the proposed project area were compiled for the roadways and intersections along the transportation routes in the vicinity of the project. Average daily traffic (ADT) rates and peak hour traffic flow measurements were used to classify the road segments according to the LOS shown in Table 5.9.2. The LOS provides an indication of the extent to which the roads are currently congested. Information was obtained for the State highways (Highway 1, 135 and 246) from CalTrans, and for major roads and arterial roads from the SBC Public Works Department. For areas where peak hour traffic was not available, it was assumed to be 10 percent of ADT. Table 5.9.1 lists the segments of each route, along with the corresponding traffic volumes, LOS classification, and volume to capacity ratios.

All routes that could reasonably be affected by the proposed project show acceptable LOS levels. The most congested area is along Highway 1 through the City of Lompoc (East Ocean Avenue and North H Street). The segment at the Santa Ynez River shows the most congested area with an LOS B level and a V/C ratio of 0.63. These are based on 2005 CalTrans traffic counts.

Roadways within VAFB are under the control of the military. Traffic counts are not available for these facilities. Coast Road south of Bear Creek Road is a main thoroughfare and critical infrastructure for Base operations.

Future Conditions

Future conditions of the roadways are important in understanding the potential impacts of a proposed project. Most of the routes examined in this document are CalTrans governed and maintained roadways. Traffic data from CalTrans from 1999 and 2005 were compared. The past growth rate of a maximum of 1.8 percent per year was extrapolated to estimate future traffic conditions on the area roadways under CalTrans jurisdiction. SBC circulation studies were also used. These studies generally use a traffic model to develop estimates of future roadway traffic volumes to assist in the planning of future projects. The models utilize inputs such as projected land use and increased growth, population projections, and building activity projections; however, circulation is examined only on selected routes. It was considered that traffic volumes would grow in the area at the same rate as population over the next 10 years (or an annual growth rate of approximately 0.9 percent to 2016 [Department of Finance, 2004]).

Table 5.9.3 lists the projected future traffic conditions and LOS for the proposed project area in the year 2016.

Growth rates of traffic are estimated to range from a low of approximately 2 percent annually to a high of close to 7 percent annually. Future development and growth in the area over the next 10 years is estimated to produce LOS ratings of LOS C for Highway 1 through the City of Lompoc. The areas immediately around the Santa Ynez Bridge and the Casmalia Road would produce highest LOS levels of LOS C with V/C ratios as high as 0.75. It is estimated that Highway 135 near Clark Avenue could also produce a LOS C level with a V/C ratio of 0.71.

Truck Traffic

Truck traffic affects the LOS of a roadway by affecting traffic flow. Information on truck traffic is available from CalTrans for Highways 1, 135 and 246. Table 5.9.4 lists the truck traffic percentages for each highway segment. For comparison, trucks comprise approximately 2 percent of traffic on local urban arterial roads under normal conditions. A method for estimating the truck traffic effects on the LOS is included in the Highway Capacity Manual. Essentially, for each 10 percent increase in truck traffic, the LOS volume rating is decreased by approximately 5 percent.

Table 5.9.3 Tranquillon Ridge EIR Traffic/Circulation: Area Routes and Future LOS Classifications – 10 year projection

Road/Route	Class	Current ADT	Future ADT	Future ADT LOS	V/C Ratio	Ref.
State Highway 1 from Gaviota to Orcutt growth			***1.8 percent annual growth***			
Las Cruces, jct. Rte. 101	Major - 2 Lanes	7,700	9,204	A	0.58	1
Jalama Road	Major - 2 Lanes	7,900	9,443	A	0.59	1
Lompoc, south jct. Rte. 246	Major - 4 Lanes	16,300	19,483	B	0.61	1
Lompoc, north jct. Rte. 246	Major - 4 Lanes	16,000	19,125	A	0.60	1
Lompoc, Santa Ynez River bridge	Major - 4 Lanes	20,000	23,906	C	0.75	1
Lompoc-Casmalia Road	Major - 4 Lanes	20,000	23,906	C	0.75	1
Pine Canyon Road	Major - 4 Lanes	16,100	19,244	B	0.60	1
Vandenberg Air Force Base, main gate	Major - 4 Lanes	15,200	18,169	A	0.57	1
South jct. Rte. 135; Vandenberg, north	Major - 4 Lanes	16,200	19,364	B	0.61	1
Orcutt, jct. Rte. 135 north	Major - 4 Lanes	2,400	2,869	A	0.09	1
Clark Ave.	Major - 4 Lanes	3,800	4,542	A	0.14	1
State Hwy 246 (Ocean Ave) from Hwy 1 West to Surf growth			***1.8 percent annual growth***			
Lompoc west of City Limits	Major - 2 Lanes	6,200	7,411	A	0.46	1
W. Ocean Ave: E of Floradale	Major - 2 Lanes	5,375	6,425	A	0.40	2
W. Ocean Ave: E of Arguello	Major - 2 Lanes	2,718	3,249	A	0.20	2
Harris Grade Road from Hwy 1 to State Hwy 135 growth			***3.9 percent annual growth***			
North of State Hwy 1	Major - 2 Lanes	8,223	12,056	C	0.75	2
N of Rucker Rd	Major - 2 Lanes	1,663	2,438	A	0.15	2
State Hwy 135 East from Harris Grade Rd to Hwy 101 growth			***1.8 percent annual growth***			
Los Alamos, jct. Rte. 101	Major-2 Lanes	5,500	6,574	A	0.41	1
Old State Highway	Major - 2 Lanes	3,200	3,825	A	0.24	1
Old Route 1/Cabrillo Highway	Major - 2 Lanes	2,700	3,227	A	0.20	1
State Hwy 135 West from Harris Grade Road to Hwy 1 growth			***1.8 percent annual growth***			
San Antonio Road	Major - 2 Lanes	2,700	3,227	A	0.20	1
South jct. Rte. 1	Major - 2 Lanes	2,700	3,227	A	0.20	1
State Hwy 135 from Highway 1 to Clark Ave growth			***1.8 percent annual growth***			
Orcutt, north jct. Rte. 1	Major - 4 Lanes	14,800	17,690	A	0.55	1
East Clark Avenue	Major - 4 Lanes	19,000	22,711	C	0.71	1
Clark Ave in Orcua from State Hwy 135 to Hwy 101 growth			***2.1 percent annual***			
Clark Ave: W of Blosser	Major - 2 Lanes	2,459	3,027	A	0.19	2
Clark Ave W of 101	Major - 4 Lanes	18,207	22,413	C	0.70	2

References: *1 = Caltrans, 2005; 2 = Santa Barbara Public Works Traffic Volumes (2006).*
V/C = the volume to capacity ratio, capacity is based on roadway class with LOS of E.
ADT = Average Daily Traffic
Percent growth based on peak past 5 year growth in traffic volumes along route. Clark Ave. route based on estimated population growth in Orcutt Area.
Growth number based on data available from CalTrans over past 5 years. Ten year growth numbers not available.

Table 5.9.4 Truck Traffic Volumes

Route	Peak Truck Traffic, % of AADT
State Highway 1 from Gaviota to Orcutt	10.1
State Highway 246 (Ocean Avenue) from Highway 1 West to Surf	4.0
Harris Grade Road from Highway 1 to State Highway 135	7.0
State Highway 135 East from Harris Grade Road to Highway 101	10.2
State Highway 135 West from Harris Grade Road to Highway 1	11.5
State Highway 135 from Highway 1 to Clark Avenue	4.5

Source: CalTrans 2004 Annual Average Daily Truck Traffic Volumes.

Proposed Roadway Projects

According to the SBC Land Use Element and the Lompoc City General Plan, there are no projects proposed for the roadways which would be affected by the proposed project discussed in this EIR. However, in the SBC Year 2030 Study (1999), for the Lompoc area, it states that some road improvements along Highway 1 through the City of Lompoc would be needed due to increased traffic congestion.

Rail Facilities

A mainline for the Union Pacific Railroad (UPRR) runs parallel to the coastline within the project area. The railway carries both passenger and freight traffic. There are three Amtrak trains per day in each direction and seven regularly scheduled freight trains per day. In addition, there may be other scheduled freight trains on the line in peak demand periods. There is a spur line that travels parallel to West Ocean Avenue from the City of Lompoc west to the main rail line. There is also an Amtrak passenger railroad station on the west side of Coast Road at Surf Beach.

Current Point Pedernales Project Operations

PXP currently operates facilities at the LOGP along Harris Grade Road and along the pipeline route between Ocean Beach Park area and the LOGP. Currently, the LOGP facility generates vehicle trips due to employee commuting and due to transport of gas liquids and sulfur. These vehicle trips are shown in Table 5.9.5 below.

Table 5.9.5 Current Point Pedernales Project Vehicle Volumes

Vehicles	Annual Average Trip, one-way	Average Daily Trips, One-way	Comments
LOGP			
LOGP Commuters	9490	26.0	Based on 26 workers currently employed.
Trucks – Gas Liquids	278	0.8	Based on monthly reports to SBC for the year 2005.
Trucks – Sulfur	24	0.1	Based on monthly reports to SBC for the year 2005.
Trucks – misc. (vacuum trucks, etc.)	104	0.3	Estimated at 2 per week.

Table 5.9.5 Current Point Pedernales Project Vehicle Volumes

Vehicles	Annual Average Trip, one-way	Average Daily Trips, One-way	Comments
Platform Irene			
Commuters	2616	7.2	Based on 654 helicopter round trips per year (2005) and an estimated 2 persons per trip.
Trucks – Materials related to supply boats	214	0.6	Based on 107 one-way supply boat trips per year and an estimated two truck loads of materials per supply boat.
Supply Boats – Marine Traffic	107	0.29	Based on 107 one-way supply boat trips per year.

Current ConocoPhillips Pipeline Operations

The operation of ConocoPhillips Pipeline system has minimal traffic requirements. At any given time there may be a number of trucks that are used to service the various pump stations and pipeline route for maintenance and repair activities.

5.9.1.2 Offshore Traffic

The U.S. Coast Guard's recommended traffic corridors are located approximately 13 miles to the south of Platform Irene and 5.6 miles south of Point Conception, running in an approximately east-west direction in the Santa Barbara Channel and in a north-south direction west of Point Conception (see Figure. 5.9-1). The Coast Guard Marine Waterways Division estimates that traffic within the main northbound and southbound lanes can run up to 30 to 50 vessels per day for both directions combined. Fishing and pleasure boat traffic along the coast is limited, but traffic is estimated to be on the order of five craft per day between Platform Irene and the shoreline. Supply boat traffic to Platform Irene for current operations averages approximately 50 return trips per year.

Helicopter round trips associated with operation of the Point Pedernales Project in 2005 numbered approximately 654 with a daily maximum of six one-way trips, which is below the permitted annual number of 2,190 trips.

5.9.2 Regulatory Setting

The transportation system requirements for the proposed project are subject to the policies and plans of SBC and CalTrans.

SBC outlines policies and standards in the Circulation Element of the SBC Comprehensive Plan. The standards provide guidance in defining whether a proposed project is consistent with established roadway capacity levels and intersection LOS. Project consistency with roadway standards is based on the number of ADTs contributed by the project and the potential for exceedances of acceptable capacity, design capacity, and the estimated future volumes for roadways in the project area. In addition, the SBC Environmental Thresholds and Guidelines Manual defines the impact thresholds for determining significance of proposed projects.

Maximum load limits for trucks and safety requirements for oversized vehicles are generally regulated by CalTrans for operation on highways, and by the counties and cities for their roads.

5.9.3 Significance Criteria

Transportation/Circulation significance criteria have been established in SBC. These are included in the SBC's Environmental Thresholds and Guidelines ~~Guidance~~Manual. The main criterion is based on the V/C ratio (see Table 5.9.1). Impacts are regarded as significant when the addition of project traffic to an intersection increases the peak hour V/C ratio by the value provided in Table 5.9.6 or sends at least 5, 10, or 15 peak hour trips to a LOS F, E or D, respectively.

Table 5.9.6 Significance Criteria

Peak Hour LOS (including project)	Increase in V/C	Additional Trips
A	0.20	-
B	0.15	-
C	0.10	-
D	-	15
E	-	10
F	-	5

Transportation impacts would be considered significant by the SBC Circulation Element of the SBC Comprehensive Plan if a project leads to any of the following:

- Project access to a major road would require a driveway that would create an unsafe condition or a new traffic signal or major revisions to an existing traffic signal.
- Project adds traffic to a roadway that has design features or receives use that would be incompatible with substantial increases in traffic. This could be indicated by exceedance of the Circulation Element Capacity designation for the roadway.
- Project traffic would utilize a substantial portion of an intersection's capacity that is currently at an acceptable LOS (LOS A through C) but is projected to have an LOS D or less (V/C of 0.81).

Offshore transportation impacts would be considered significant if a project leads to any of the following:

- The project disrupts commercial shipping, fishing, or recreational traffic due to an oil spill of sufficient volume to require mobilization of oil spill response crews or other emergency response activity.
- The project alters normal commercial maritime traffic due to construction, maintenance, or other project-related transportation activities (i.e., increased boat trips to Platform Irene).

Marine traffic significance criteria were developed by the preparer of this EIR because SBC does not have significance thresholds for marine traffic.

5.9.4 Impact Analysis for the Proposed Project

This section addresses the impacts on onshore vehicular and offshore marine vessel traffic associated with the proposed project. Attention is focused primarily on roadway conditions and marine traffic in the immediate vicinity of the proposed project area. Due to the location of the proposed project, impacts associated with private property access restrictions, parking restrictions, and pedestrian circulation are not applicable in this analysis. All construction activities would take place at locations where public access is restricted: at Platform Irene, at Valve Site #2 on VAFB, and at the LOGP. While the installation of power lines along 13th Avenue between Ocean Avenue and Terra Road may require a temporary lane closure for one day, off-site vehicle trips would constitute the majority of the impact to roadway networks surrounding the project area.

While the well drilling phase of the Tranquillon Ridge Project would be spread over 15 years, the addition of shipping pumps at Platform Irene is~~are~~ estimated to take approximately 9 weeks ~~months~~ to complete. The addition of booster pumps and associated equipment including the power pole installation at and to Valve Site #2 is estimated to take 14 weeks. Installation of the transformer is estimated to take 4 weeks.

The applicant would be required to comply with all existing federal lease stipulations, including movement restrictions, governing Platform Irene that apply to missions that originate from VAFB.

Impact #	Impact Description	Phase	Residual Impact
T.1	Onshore construction associated with the project would temporarily add to local road traffic.	*Construction*	*Class III*

Construction traffic would increase local road traffic but would not change the LOS of any roadways. As shown in Table 2.8, the modifications at Valve Site #2 and the LOGP would require an estimated 40 construction workers. Even if every worker were to drive a vehicle, the increase in traffic would not change the LOS of the adjacent West Ocean Avenue (Highway 246) west of Lompoc near Valve Site #2 or on Highway 1 across the Santa Ynez River, the busiest roadway south of the LOGP. Therefore, this impact is considered adverse but not significant.

Mitigation Measures

In accordance with SBC policies, the following mitigation measure is required to mitigate Impact T.1 to the maximum extent feasible.

T-1 PXP shall include a restriction on delivery of equipment and supplies to non-rush hour periods (rush hour periods are considered to be 7a.m. to 9a.m. and 4p.m. to 6p.m.) in the project construction plans that are sent out in the contractor bid packages. The construction plans shall be submitted to SBC Planning and Development for approval prior to land use clearance.

Residual Impact

During ~~the estimated nine months of~~ construction at LOGP (nine weeks) and Valve Site #2 (14 weeks), adjacent roadways would experience a temporary increase in vehicle volume. The impact would be considered *adverse but not significant (Class III).*

Impact #	Impact Description	Phase	Residual Impact
T.2	Increased production at LOGP would increase facility truck traffic on local roads.	*Increased Throughput Extension of Life*	*Class III*

Operational traffic would increase local road traffic but would not change the LOS of any roadways. The increased pipeline throughput would result in increased production of LPG/NGL and possibly sulfur products. These truck trips would increase from 2.9 per week to 5 per week. This impact to traffic represents an increase of less than 0.1 percent in daily vehicle trips on Harris Grade Road, which would not change the LOS. Therefore, this impact is considered adverse but not significant. Additional traffic safety impacts are discussed in Section 5.1, Risk of Upset/Hazardous Materials of this EIR.

Mitigation Measures

In accordance with SBC policies, the following mitigation measure is required to mitigate Impact T.2 to the maximum extent feasible.

T-2 PXP shall include a restriction on LPG/NGL and sulfur truck traffic at the LOGP to non-rush hour periods (rush hour period are considered to be 7a.m. to 9a.m. and 4p.m. to 6p.m.) in their contracts with vendors. The applicant shall also document arrival and departure times for these trucks. This requirement shall be included in the Traffic Management Plan (TMP). The revised TMP shall be submitted to SBC Planning and Development for approval prior to land use clearance.

Residual Impact

A small increase in roadway traffic would result from operation of the Point Pedernales Project with Tranquillon Ridge production due to increased transportation of NGL/LPGs. This impact would be considered *adverse but not significant (Class III).*

Impact #	Impact Description	Phase	Residual Impact
T.3	Increased offshore drilling activity would increase offshore traffic.	*Drilling*	*Class III*

The proposed project would increase supply boat traffic servicing Platform Irene only during the drilling phase of the project. Supply boat traffic would increase from the current average of one one-way trip every 3 to 4 days to an average of one one-way trip every 3 days. Existing marine traffic (project- and non-project-related) between Platform Irene and the shoreline is estimated at five vessels per day. Project-related marine traffic is estimated to be 3.3 vessels per week, based on average 2006 supply boat trips. Once drilling operations are complete, the supply boat traffic would be the same as for the current operations. The impact during drilling would represent a one percent increase over existing levels. Because the projected ocean traffic is minimal and the area large, this small increase would not affect commercial or recreational boat traffic.

During drilling only, helicopter traffic would increase to six one-way trips per day every day. Although this increase is within the limits of the existing Point Pedernales FDP, it represents an adverse but not significant impact.

Mitigation Measures

In accordance with SBC and Coastal Act policies, the following mitigation measure is required to mitigate Impact T.3 to the maximum extent feasible.

T-3 Require supply boats from Port Hueneme to use the Coast Guard's recommended marine traffic corridors to the maximum extent feasible.

Residual Impact

The impact caused by an increase in marine traffic would be small and therefore considered *adverse but not significant (Class III)*.

Impact #	Impact Description	Phase	Residual Impact
T.4	An oil spill from the proposed Tranquillon Ridge project could result in the disruption of commercial shipping, fishing, and recreational marine traffic, and onshore transportation infrastructure.	*Increased Throughput Extension of Life*	*Class I*

An oil spill could result in the closure of the Coast Guard's recommended marine traffic corridors through the Santa Barbara Channel and restrict boating along up to 70 miles of coastline and San Miguel, Santa Rosa, and western Santa Cruz Islands (see Appendix G regarding oil spill modeling), a regionally significant impact. Estimated daily shipping traffic in the main traffic corridors consists of 30 to 50 vessels per day. Commercial/recreational fishing vessel traffic is estimated at five vessels per day between Platform Irene and the shoreline. An oil spill could disrupt marine traffic for a number of days, due to clean-up activities. Depending on the location of the spill, marine traffic might have to use routes outside of the Coast Guard's recommended marine traffic corridors. Also, commercial/recreational fishing boat traffic could be precluded from areas around the spill during the cleanup activities (see Section 5.7, Commercial and Recreational Fishing/Kelp Harvesting, for impacts on fishing). If an oil spill reaches the shoreline, adjacent roadways would be affected by spill clean up response activities. The degree of the severity of roadway disruptions would be dependent on location.

Mitigation Measures

Refer to Sections 5.5, Marine Biology, and 5.6 Oceanography and Marine Water Quality of this EIR for specific spill-related mitigation measures. Mitigation measures directly applicable include MB-1a~~2~~ (contingency planning), MWQ-1 (updated Oil Spill Response Plan), and MWQ-3 (increased inspection frequency).

Residual Impacts

The proposed mitigation measures would not be completely effective in reducing the significant risk of a spill, nor would they adequately eliminate the significant effect of a spill on marine recreational or commercial traffic. Mitigating impacts from a marine oil spill is largely a function of the effectiveness of the spill-response measures. The effectiveness of spill cleanup measures is dependent on the response time, availability and type of equipment, the size of the spill, and the weather and sea conditions during the spill. Only some of these aspects are within the control of the spill response team. Therefore, residual impacts are considered *significant (Class I)*.

5.9.5 Impact Analysis for the Alternatives

Detailed descriptions of the various alternatives have been provided in Chapter 3. This section provides a discussion of the transportation impacts of these alternatives.

5.9.5.1 No Project Alternative

Scenarios 2 and 3. As discussed in Section 3.2, under the No Project Alternative Scenarios 2 and 3, production of the federal portion of the Tranquillon Ridge field would and would not

occur, respectively. However, no extension of life of Point Pedernales facilities (Platform Irene, pipelines, and LOGP) is assumed under either scenario.

Impact T.1 – Onshore Construction Traffic: The traffic impacts due to construction would not occur since none of the proposed facilities would be built under the No Project Alternative Scenarios 2 and 3.

Impact T.2 – Operational Truck Traffic: Truck traffic associated with Scenarios 2 and 3 would be the same as for current operations; slightly lower for a shorter project life than for the proposed project (10 versus 30 years).

Impact T.3 – Marine Traffic: The marine traffic impacts associated with increased drilling would not occur under the No Project Alternative. The current level of marine traffic associated with drilling at Platform Irene fluctuates as needed for maintenance of the existing Point Pedernales Field wells, with greater traffic during times of well workovers. However, this traffic is considered to be within baseline levels. ~~be fewer than the proposed project because only three new wells would be drilled instead of the proposed 22 to 30 wells. The impact would still be considered *adverse but not significant (Class III)*, except the duration of the impact would be shorter since fewer wells would be drilled. Mitigation Measure T-3 would apply.~~

Impact T.4 – Accidental Oil Spills: Marine traffic impacts due to an accidental oil spill would be the same as for current operations and would not increase due to increased spill risk associated with extension of the platform's operating lifetime.

Options for Meeting California Fuel Demand. The relative traffic impacts associated with the various options for meeting California fuel demand are summarized in Table 5.9.7.

Table 5.9.7 No Project Alternative Comparison to Options for Meeting California Fuel Demand, Traffic

Source of Energy	Impacts
Other Conventional Oil & Gas	
Domestic onshore crude oil and gas	Likely to displace onshore transportation impacts.
Increased marine tanker imports of crude oil	Would increase offshore transportation impacts.
Increased gasoline imports[1]	Would increase onshore transportation impacts if tanker trucks are used.
Increased natural gas imports (LNG)	Would increase offshore transportation impacts if tankers are used.
Alternatives to Oil and Gas	
Fuel Demand Reduction: increased fuel efficiencies, conservation, electrification[2]	
Alternative transportation modes	Proposed project impacts would be eliminated.
Implementation of regulatory measures	Proposed project impacts would be eliminated.
Coal, Nuclear, Hydroelectric	Proposed project impacts would be eliminated. Construction of facility infrastructure could generate traffic impacts. Coal delivery to power plants could result in increased operation traffic.

Table 5.9.7 No Project Alternative Comparison to Options for Meeting California Fuel Demand, Traffic

Source of Energy	Impacts
Alternative Transportation Fuels	
Ethanol/Biodiesel[3]	Transportation impacts would increase due to increased truck traffic.
Hydrogen[2]	Proposed project impacts would be eliminated. Potential traffic impacts due to hydrogen delivery infrastructure development and operation.
Other Energy Resources[2]	
Solar[2,4]	Proposed project impacts would be eliminated. Construction of solar facility infrastructure could result in traffic impacts. Operational traffic impacts would be nominal.
Wind[2,4]	Proposed project impacts would be eliminated. Construction of wind facility infrastructure could result in traffic impacts. Operational traffic impacts would be nominal.
Wave[2,4]	Proposed project impacts would be eliminated. Construction of wave facility infrastructure could result in traffic impacts. Operational traffic impacts would be nominal.

Footnotes:
1. Pipeline and tanker truck import from out-of-State assumed.
2. Assumes that Tranquillon Ridge production would not be replaced with other petroleum-based energy supply.
3. Assumes ethanol and biodiesel used as blends only and therefore would reduce, but not eliminate Tranquillon Ridge or equivalent production.
4. Assumes, large centralized facilities.

5.9.5.2 VAFB Onshore Alternative

The VAFB Onshore Alternative would include the construction of drilling and production facilities within a 25-acre site, and installation of approximately 10 miles of emulsion and gas pipelines and 6 miles of overhead 69 kV transmission line. In addition, a pipeline tie-in station, and associated electrical substation and power line would be required. These alternative facilities would be operating for approximately 30 years. Construction equipment, materials, and personnel would need to be transported to the site(s). It is assumed that the drilling/production facility operations would also require 24-hour day staffing similar to the LOGP. The traffic impacts associated with this alternative are described below.

***Impact T.1 – Onshore Construction Traffic*:** This impact would be similar to that for the proposed project except under this alternative, the construction traffic at the VAFB drilling/ production site and tie-in station would be over a longer duration and would be a higher frequency than the proposed project. Access to the VAFB site would occur through Lompoc, where the busiest roadways (such as Highway 1 over the Santa Ynez River bridge) would experience a traffic increase. Heavy equipment and the drilling rig would need to travel to and from the site over VAFB roadways, West Ocean Avenue (Highway 246), and Highway 1. Mitigation Measure T-1 would apply. Because Coast Road south of Bear Creek Road is a main thoroughfare and critical infrastructure for the Base, Mitigation Measure T-4 would also apply.

Mitigation Measures

T-4 Consultation with VAFB shall be conducted to develop a Construction Traffic Management Plan that minimizes conflicts to Base operations during alternative construction and operation. In addition, the Plan shall address traffic related to potential oil spill clean-up operations. The VAFB-approved plan shall be provided to SBC prior to land use clearance for review and approval.

Residual Impact

With the implementation of the noted mitigation measures, this impact would be considered *significant but mitigable (Class II).*

Impact T.2 – Operational Truck Traffic: The traffic impacts due to the operation of the VAFB Onshore Alternative drilling and production facility would occur on West Ocean Avenue (Highway 246), 13th Street, Coast Road, and Surf Road within VAFB. Traffic within VAFB would need to conform to Base operations. Under the VAFB Onshore Alternative, truck traffic at the LOGP would be similar to that of the proposed project. Workers and trucks traveling to the VAFB drilling and production facility would increase local road traffic, but would not significantly change the level of service (LOS) of any roadways. Mitigation Measures T-2 and T-4 would apply. The impact at the VAFB site would still be considered *adverse but not significant (Class III).*

Impact T.3 – Marine Traffic: The marine traffic impacts associated with the proposed project would not occur under the VAFB Onshore Alternative, but rather would be the same as the No Project Alternative. As under the No Project Alternative, the impact would still be considered *adverse but not significant (Class III).*

Impact T.4 – Accidental Oil Spills: The traffic impacts due to an accidental oil spill or release would be greater than what exists for the current operations (i.e., baseline) or the proposed project because offshore oil and gas production would occur onshore at VAFB. An oil spill, sour gas release, or fire caused by the VAFB Onshore Alternative facilities could temporarily close transportation infrastructure at VAFB, including portions of Coast Road, Surf Road, ~~and~~ Bear Creek Road, and 13th Street. Such an event would temporarily disrupt Base operations. As noted for marine oil spills under the discussion of the proposed project, mitigating the effects of an accidental release depends on variables that are not entirely within the control of the spill response team. The impacts to VAFB operations are considered *significant (Class I).* Mitigation Measure T-4 would apply.

5.9.5.3 Casmalia East Oil Field Processing Location

For this alternative, Impacts T.3, Marine Traffic, and T.4, Accidental Oil Spill, would be the same as for the proposed project. Mitigation Measure T-3 would apply. The other impacts associated with this alternative are discussed below.

Impact T.1 – Onshore Construction Traffic: This impact would be the same as the proposed project for Valve Site #2 and along the power line route. However, under this alternative the construction traffic at the LOGP would be over a longer duration and would be a higher frequency than the proposed project due to the dismantling activities, which would take approximately 6 months, require a work force of 60, and add 104 daily one-way vehicle trips during the first 5 months and 165 trips during the final month. Near the LOGP, the busiest roadway (Highway 1 over the Santa Ynez River bridge) would experience an increase in V/C of 0.005, which would not change the LOS although peak hour traffic could increase by as much as 5 percent. Based on the significance criteria this would be considered *adverse but not significant (Class III)*.

Additionally, construction of a new processing facility in Casmalia and connecting pipeline from the LOGP would add to local traffic, affecting more roadways and occurring over a longer duration than the proposed Tranquillon Ridge Project. It would take 6 months and require an average work force of 60, working 6 days a week. The pipeline construction would take 9 to 10 weeks and require a work force of 22. During the first month, these projects would require an estimated 243 daily one-way vehicle trips, including truck trips used for constructions and materials handling. For the remainder of construction, the projects would require 164 daily one-way vehicle trips.

Construction in and around Casmalia and Orcutt would affect Casmalia Road, State Highways 1 and 135, and Clark Avenue. Casmalia Road would experience an increase in V/C of 0.02, which would not change the level of service. Highway 1 between Casmalia Road and Clark Avenue would experience an increase in V/C of 0.02, which would not change the level of service. The busiest section of Clark Avenue would experience an increase in V/C of 0.02, which would not change the LOS. None of the roads would experience a change in LOS or exceed the significance criteria; therefore, the impacts would be *adverse but not significant (Class III)*. Mitigation T-1 would apply.

Impact T.2 – Operational Truck Traffic: The traffic impacts due to increased throughput would be the same as the proposed project except they would no longer occur at the LOGP, but rather would occur at the new Casmalia East site. The impact at the new site would still be considered *adverse but not significant (Class III)*. Mitigation Measure T-2 would apply.

5.9.5.4 Alternative Power Line Routes to Valve Site #2

For all power line routes, Impacts T.2, Operational Truck Traffic; T.3, Marine Traffic; and T.4, Accidental Oil Spill, would remain the same as for the proposed project. Mitigation Measures T-2 and T-3 would apply. The other impacts associated with each of the power line alternatives are discussed below.

Alternative Power Line Route – Option 2a

Impact T.1, Onshore Construction Traffic would be the same as for the proposed project. Mitigation Measure T-1 would apply.

Alternative Power Line Route – Option 2b

Impact T.1 – Onshore Construction Traffic: This alternative would have slightly greater truck traffic during the installation of the power line due to the need to directionally bore under the Santa Ynez River. It is estimated that an additional 10 truck trips would be needed for this operation. While the construction traffic impacts would be slightly greater than the proposed project, they would not result in an increase in the LOS for the subject roads. As such the impact is considered *adverse but not significant (Class III)*. Mitigation Measure T-1 would apply.

Underground Power Line along Terra Road

Impact T.1 – Onshore Construction Traffic: This alternative would have slightly less construction traffic than the proposed project since there would be no traffic associated with the delivery of the power poles for this portion of the route. The rest of the construction equipment and traffic would remain the same. Even with this slight decrease in construction traffic, the impacts would remain *adverse but not significant (Class III)*. Mitigation Measure T-1 would apply.

5.9.5.5 Replacement of Oil Emulsion Pipeline from Platform Irene to LOGP

Impact T.2, Operational Truck Traffic, would remain the same as for the proposed project. Impact T.4, Accidental Oil Spill, would be slightly less than the proposed project because of the approximate 10 percent decrease in spill risk; however, spill volumes would be the same. The other impacts associated with this alternative are discussed below.

Impact T.1 – Onshore Construction Traffic: The impact would be the same as the proposed project for the LOGP. Under this alternative there would be no construction traffic impacts associated with Valve Site #2. However, this alternative would result in increased traffic from commuters and the delivery of equipment and supplies associated with the onshore construction of the new emulsion pipeline.

The construction of the onshore pipeline replacement would require approximately 60 workers per day, 6 days per week. A worst-case commuting scenario would be one vehicle per worker, which would not change the level of service on any roadway in the project region near the City of Lompoc. The onshore pipeline replacement would require the transportation of construction related heavy machinery to the project site totaling an additional 14 vehicle trips to transport. The onshore pipeline replacement would also require 12.1 miles, or 64,000 feet, of pipe to be transported via rail to Lompoc, where it would be temporarily stored on a rail spur. From there, trucks would haul pipe to the project site at a rate of 100 feet per truck trip. Because this work would be spread over 10 weeks, this alternative would require approximately ten truck trips per day**.** As compared with traffic data in Table 5.9.1, this increase, including the worst case transportation of construction equipment, would not exceed the significance criteria for any part of the proposed travel route.

The offshore pipeline replacement would require approximately 60 workers per day for 7 days per week. Since the workers would remain aboard the barge during construction and leave periodically via helicopter for breaks, commuting road traffic would be limited to approximately ten vehicles per day around the Santa Maria Airport. The offshore pipeline replacement would require approximately 10.1 miles, or 53,300 feet, of pipe to be transported to Port Hueneme, where it would be loaded on barges for transport to the project site. The conveyance from Los Angeles would be either rail or 550 truck trips to Port Hueneme. As shown in Table 5.9.8, roads accessing Port Hueneme experience existing congestion. The Ventura County General Plan (2005) identifies measures for widening Hueneme Road and Las Posas Road. Assuming these improvements occur on schedule, an increase of 550 truck trips over project construction would not exceed the significance criteria for any part of the proposed travel route, even in the unlikely event that all the truck trips would occur in one day. Based on existing roadway conditions, an increase of more than 15 truck trips per day would be adverse but not significant.

Table 5.9.8 Traffic Counts on Route to Port Hueneme

Road/ Route	Class	ADT	ADT LOS	Peak Hour	Design Cap	V/C Ratio	Ref.
Port Hueneme to Ventura/Los Angeles County Border							
Hueneme Rd.	Major - 2 Lanes	10,200	C	1,020	16,000	0.64	1
Las Posas Rd.	Major - 2 Lanes	13,600	D	1,360	16,000	0.85	1
101 Southbound at Las Posas Rd.	Freeway 6 - Lanes	139,000	C		195,000	0.71	2
101 Southbound at Kanan Rd.	Freeway - 8 to 10 Lanes	182,000	B		292,500	0.62	2

References
1. Traffic counts from Ventura County General Plan Update (2005).
2. Traffic counts from CalTrans (2005). Design capacity based on an average 32,500 cars per lane per day.

Because the level of service criteria could be exceeded on the Las Posas Road portion of the transportation route, the residual impact would be considered *significant but mitigable (Class II).* Mitigation Measure T-1 would apply.

Impact T.3 – Marine Traffic: This impact would be greater than the proposed project due to the construction of the offshore pipeline. The offshore pipeline would be installed using ~~a dynamic positioning lay vessel~~ the pull barge method. The duration of the offshore pipeline construction would be about 2 months. One supply boat would travel to the project site from Port Hueneme every 5 days. Two supply barges would transport 10.1 miles, or 53,300 feet, of pipe from Port Hueneme over a total of 50 round trips. The presence of project vessels would limit marine traffic in the project area but only temporarily and only over a relatively sparsely used area. The traffic between the project site and Port Hueneme would be limited to at most three vessels in a single day, which would generate only a slight increase over current marine traffic. Therefore, these impacts are considered *adverse but not significant (Class III)*. Mitigation Measure T-3 would apply.

5.9.5.6 Alternative Drill Muds and Cuttings Disposal

Inject Drill Muds and Cuttings into Reservoir

The injection of muds and cuttings into the Point Pedernales Reservoir would not result in any additional impact to traffic.

Transport Drill Muds and Cuttings to Shore for Disposal

Impacts T.1, Construction Truck Traffic; T.3, Marine Traffic; and T.4, Accidental Oil Spill, would remain the same as for the proposed project. Mitigation Measures T-2 and T-3 would apply. The other impacts associated with this alternative are discussed below.

Impact T.2 – Operational Truck Traffic: Drilling 30 wells over a 15 year period would produce an estimated 75,000 metric tons (10,607 barrels) of muds per well (see Appendix D). One vacuum truck hauls approximately 100 barrels of muds, so the muds from one well would require 106 vacuum trucks. Approximately 1,670 tons of cuttings would be produced per well. One haul truck can carry 18 tons of cuttings, so the cuttings from one well would require 93 haul trucks. (Refer to Chapter 3.0, Alternatives, for a detailed description of this alternative.) The operational truck traffic impacts associated with this alternative would increase throughout the proposed project as a result of the trucks that would be required to haul waste from Port Hueneme to the landfill. Truck traffic from Port Hueneme would exit the port at Hueneme Road, heading east for several miles. They would turn left at Las Posas Road and enter the ramp of southbound Highway 101. The trucks would then take Highway 101 south to Los Angeles County.

In a worst-case scenario, all the waste from each well would be offloaded and stored at Port Hueneme and then transported from the port over the course of one work week, which would require 40 truck return trips per day. The proposed project would result in traffic increases of 0.4 percent, 0.3 percent, 0.03 percent, and 0.02 percent at Hueneme Road, Las Posas Road, Highway 101 at Las Posas Road, and Highway 101 at Kanan Road, respectively. This transportation event would occur following the drilling of each of 30 wells. As shown in Table 5.9.7, a potentially significant impact could occur because an increase of 15 truck trips per day would exceed the significance criteria on the Las Posas Road part of the proposed travel route.

Rather than 40 truck return trips per day, a more realistic scenario is that the trucks would haul waste twice a week for the approximate three-month drilling period for each well, which coincides with the 2 weekly supply boat trips. This truck schedule would mean an increase in truck trips in a single day. The small traffic increases of this scenario would not affect the LOS of any of these roadways, nor would they exceed the significance criteria. Therefore, the impact would remain *adverse but not significant (Class III).* Mitigation Measure T-1 would apply.

5.9.6 Cumulative Impacts

Cumulative projects relevant to the current analysis include both offshore oil and gas projects, and onshore development projects. Each of these is discussed separately below.

The cumulative traffic impacts associated with the cumulative projects discussed in Section 4.0 could be significant if simultaneous construction activities lowered the Level of Service (LOS) of roadways in the vicinity of the proposed project. Simultaneous construction projects in the study area and the proposed project could create significant cumulative impacts to traffic.

5.9.6.1 Offshore Oil and Gas Projects

Potential offshore oil and gas development projects would involve marine traffic. While the exact timing of these developments is unknown, it is it assumed that maximum marine traffic would occur during the drilling or operational phases of each cumulative project. As discussed in Sections 4.2 and 4.3, the majority of future offshore development would use existing platforms, pipelines, and onshore facilities. Therefore, construction activities would only generate a major increase in marine traffic for new platform development projects. However, if all of the potential offshore oil and gas projects in the northern Santa Maria Basin were to occur within a similar time frame, the marine traffic associated with their construction and operation could generate substantial volumes of marine vessel traffic. Assuming that these potential offshore projects would be subject to the same or similar types of mitigation measures associated with existing offshore oil and gas development projects, such as maximum use of designated marine vessel traffic corridors, cumulative impacts, including the proposed project's incremental contribution to them, would not be considered significant.

An oil spill from the proposed project could result in the disruption of commercial shipping, fishing, and recreational marine traffic, and onshore transportation infrastructure. An oil spill could result in the closure of the Coast Guard's recommended marine traffic corridors through the Santa Barbara Channel and restrict boating along up to 70 miles of coastline. If a spill were to occur within southern VAFB or come onshore along southern VAFB, oil spill clean up response times could be hindered if mission critical operations were underway, as was the case in 1997. Therefore, the cumulative impacts to offshore and onshore transportation infrastructure, including the contribution of the proposed project, would be considered significant.

5.9.6.2 Onshore Projects

Onshore potential development projects primarily include pending or approved residential and commercial projects in the Santa Maria area, and multiple types of development and redevelopment projects in the City of Lompoc and the unincorporated area of Lompoc surrounding the LOGP (see Table 4.2 and Figures 4-3 and 4-4) ~~and between the City of Lompoc and the LOGP~~. Traffic projections are only available for the Bluffs at Mesa Oaks and the Providence Landing residential developments. If construction of these two projects were to occur at the same time as the proposed project, the cumulative impact to Highway 1 at the Santa Ynez River bridge and along Harris Grade Road could be significant, although the proposed project's contribution would be minor. Mitigation Measure T-1 would apply.

The other potential onshore development projects would likely use Highways 1 and 246 for ingress and egress to the development sites in the Lompoc area and if construction of some of these projects is scheduled at the same time as the proposed project, cumulative impacts could be significant along the Lompoc-Casmalia section of Highway 1, although the proposed project's contribution would be minor. Mitigation Measure T-1 would apply.

Additionally, two proposed residential developments are planned for the same stretch of Harris Grade Road that serves as the route for LOGP's NGL/LPG truck traffic. The increased risk of a NGL/LPG spill or accident from cumulative ~~the increased~~ construction related traffic and subsequent increase in daily residential traffic is discussed in Section 5.1, Risk of Upset.

As outlined in Section 4.4, the existing Guadalupe Restoration Project is currently utilizing up to 30 truck trips per day to transport up to 850,000 cubic yards of Non-Hazardous Hydrocarbon Impact Soil (NHIS) from the Guadalupe Oil Field to the City of Santa Maria Landfill (County of San Luis Obispo, 2006). The approved and certified Final Supplemental Environmental Impact Report (FSEIR) prepared for this increase concludes that the proposed truck traffic increase would be adverse but mitigable to a level of less than significant; the FSEIR additionally concludes that cumulative project impacts on Betteravia Road could be significant if one or more large development projects in that area are constructed at the same time (Marine Research Specialists, et al., 2005). However, the proposed project's contribution to cumulative transportation impacts associated with currently planned development projects in the Orcutt and Santa Maria area, including those along Betteravia Road, would be negligible. Therefore, the proposed project's incremental contribution to these cumulative impacts would not be expected to be significant.

5.9.7 Mitigation Monitoring Plan

Mitigation Measure	Mitigation Requirements and Timing	Method of Verification	Timing of Verification	Party Responsible For Verification
T-1	The applicant shall include a restriction on delivery of equipment and supplies to non-rush hour periods (rush hour periods are considered to be 7a.m. to 9a.m. and 4p.m. to 6p.m.) in the project construction plans that are sent out in the contractor bid packages. The construction plans shall be submitted to SBC Planning and Development for approval prior to land use clearance.	EQAP inspections during construction.	During Construction	SBC P&D
T-2	The applicant shall include a restriction on LPG/NGL and sulfur truck traffic at the LOGP to non-rush hour periods (rush hour period are considered to be 7a.m. to 9a.m. and 4p.m. to 6p.m.) in their contracts with vendors. The applicant shall also document arrival and departure times for these trucks. This requirement shall be include in the Traffic Management Plan (TMP). The revised TMP shall be submitted to SBC Planning and Development for approval prior to land use clearance.	Annual audit of shipping records.	During Operations	SBC P&D
T-3	Require supply boats from Port Hueneme to use the Coast Guard's recommended marine traffic corridors to the maximum extent feasible.	Annual audit of marine vessel contracts	During Operations	SBC P&D
T-4 (VAFB Onshore Alternative only)	Consultation with VAFB shall be conducted to develop a Construction Traffic Management Plan that minimizes conflicts to Base operations during alternative construction and operation. In addition, the Plan shall address traffic related to potential oil spill clean-up operations. The VAFB-approved plan shall be provided to SBC prior to land use clearance for review and approval.	Submit construction Traffic Management Plan to VAFB for review and approval. Once approved by VAFB, submit to SBC for review and approval	Prior to land use clearance	SBC P&D

5.9.8 References

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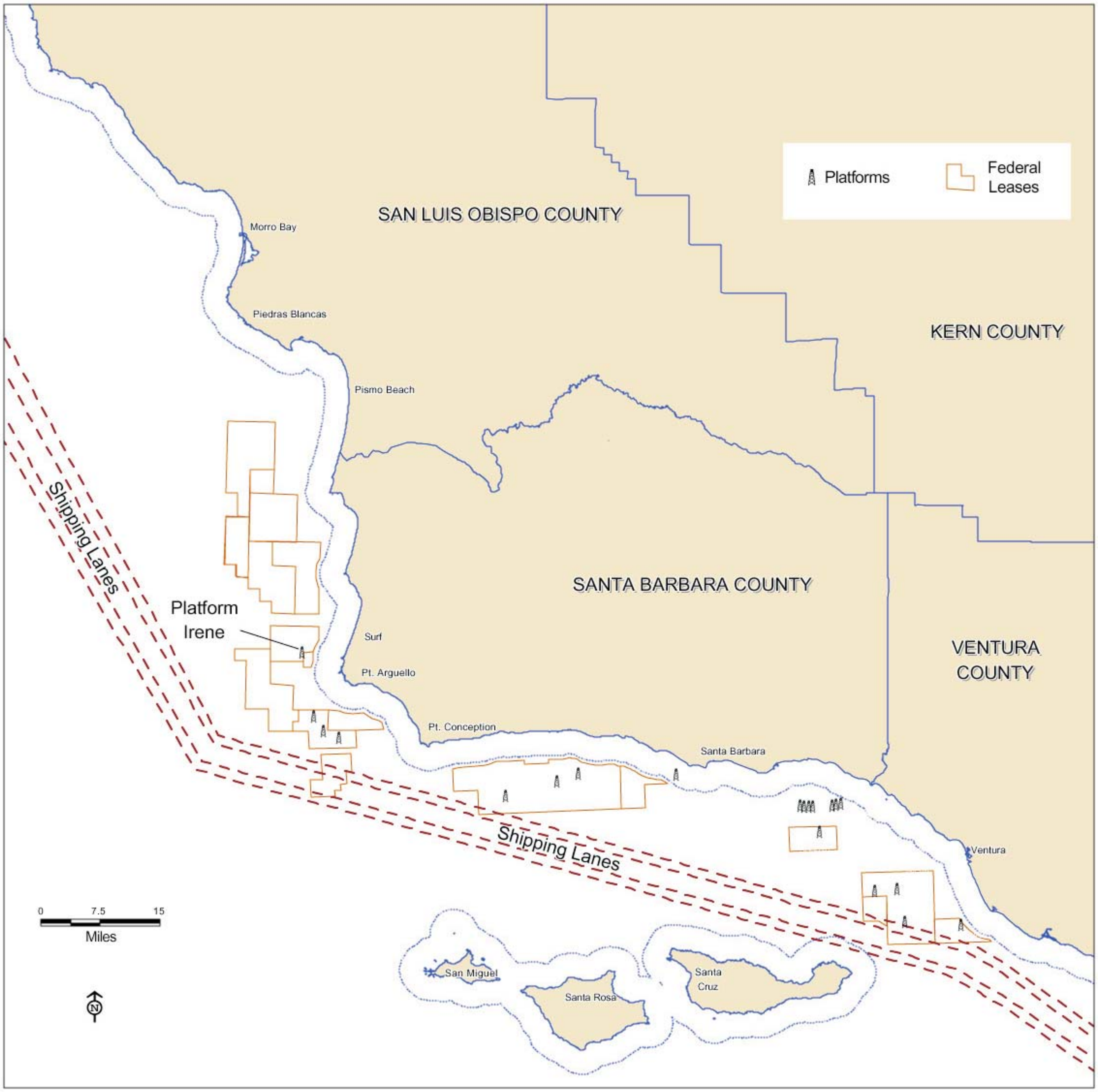

Source: MRS, 2002.

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Figures 5.9-1
Shipping Lanes in the Project Area

5.10 Noise

This section describes the noise currently in the vicinity of the proposed project and the potential impacts associated with the project. The following section is based on information from the Environmental Impact Report (EIR) prepared for the previously proposed project in 2002 (Arthur D. Little et al., 2002), updated noise levels within the project region, and discussions with appropriate agencies.

5.10.1 Environmental Setting

5.10.1.1 Definition

Noise is defined as unwanted sound that is heard by people or wildlife and that interferes with normal activities or otherwise diminishes the quality of the environment. Sources of noise may be transient (e.g., the passing of a train or aircraft through the area) or continuous (e.g., the hum of distant traffic or the operation of air conditioning equipment). Sources of noise may have a broad range of sounds and be generally nondescript or have a specific, readily identifiable sound, such as a car horn. The sources of noise may also be steady or impulsive. These characteristics all bear on the perception of the acoustic environment.

Noise is usually measured as sound level on a logarithmic decibel (dB) scale, with the frequency spectrum adjusted by the A-weighting network. The dB is a unit division on a logarithmic scale that represents the intensity of sound relative to a reference intensity near the threshold of normal human hearing. The A-weighting network is a filter that approximates the response of the human ear at moderate sound levels. The resulting unit of measure is the A-weighted decibel, or dBA.

To analyze the overall noisiness of an area, noise events are combined for an instantaneous value or averaged over a specific time period (e.g., one hour, multiple hours, 24 hours). The time-weighted measure is referred to as Equivalent Sound Level and represented by L_{eq}. The equivalent sound level is defined as the same amount of sound energy averaged over a given time period. The percentage of time that a given sound level is exceeded can also be represented. For example, L_{10} is a sound level that is exceeded 10 percent of the time over a specified period.

5.10.1.2 Effects on Wildlife

Wildlife response to noise is dependent not only on the magnitude but also the characteristic of the sound, or the sound frequency distribution. Wildlife is affected by a broader range of sound frequencies than humans. Noise is known to affect an animal's physiology and behavior, and chronic noise-induced stress is deleterious to an animal's energy budget, reproductive success, and long-term survival (Radle, 2001). Noise impacts to marine wildlife are detailed in Section 5.5, Marine Biology.

5.10.1.3 Effects on Humans

Human response to noise is dependent not only on the magnitude but also on the characteristic of the sound, or the sound frequency distribution. Generally, the human ear is more susceptible to higher frequency sounds than lower frequency sounds. This is reflected in the A-weighting which essentially assigns a weighting of zero to sounds with a frequency below ten cycles per second and has a maximum weighting for sounds with a frequency in the 2,000 to 5,000 cycles-per-second range.

Human response to noise is also dependent on the time of day and expectations based on location and other factors. For example, a person sleeping at home might react differently to the sound of a car horn than to the same sound while driving during the day. The regulatory process has attempted to account for these factors by developing overall noise ratings such as Community Noise Equivalent Level (CNEL) and the Day-Night Average Noise Level (L_{dn}) which incorporate penalties for noise occurring at night. The L_{dn} rating is an average of noise over a 24-hour period in which noises occurring between 10:00 p.m. and 7:00 a.m. are increased by 10 dBA. The CNEL is similar but also adds a weighting of 3 dBA to noises that occur between 7:00 p.m. and 10:00 p.m. Average noise levels over daytime hours only (7:00 a.m. to 7:00 p.m.) are represented as L_d and nighttime noises as L_n. Figure 5.10-1 is a scale showing typical noise levels encountered in common daily activities.

The effects of noise are considered in two ways: how a proposed project may increase existing noise levels and affect surrounding land uses; and how a proposed land use may be affected by existing surrounding land uses. The Santa Barbara County (SBC) Comprehensive Plan Noise Element focuses on particular types of land uses when measuring the effects of noise. These “sensitive receptors” include residences, transient lodging (e.g., hotels, motels), hospitals, nursing homes, convalescent hospitals, schools, libraries, houses of worship, and public assembly places.

The proposed project consists of several separate construction and operational elements. Some of these elements have a potential to impact sensitive resources in the area which are discussed below.

5.10.1.4 Regional Overview

Intrusive noise sources within the proposed project area include highways, railroads, aircraft, industrial activities, and marine vessel traffic. Secondary sources include agricultural machinery. The existing noise levels in the proposed project area are primarily due to highway and rail routes that traverse the project area and, to a lesser extent, the marine and air transportation activities associated with the current offshore exploration and development. An additional noise source is aircraft and missile operations at Vandenberg Air Force Base (VAFB).

Specifically, the following sensitive receptors were identified:

Sensitive Receptor	Nearest Project Site	Distance from Project*
Ocean Beach County Park	Valve Site #2 and pipeline	4,300 feet
Residences in Mission Hills	LOGP	8,000 feet
Residences in Vandenberg Village	LOGP and pipeline	4,600 feet and 1,800 feet
Burton Mesa Ecological Preserve	LOGP and pipeline	2,000 feet and inside Preserve

* Distance from the project is defined as the shortest distance from the nearest project component.

5.10.1.5 Background Noise Sources

Existing noise levels in the project area due to transportation and stationary sources have been compiled as contours in the SBC Comprehensive Plan Noise Element (1986). Major sources of noise in the study region are minimal and include occasional aircraft flight activities, road traffic, and breaking waves along the beach.

Current traffic on Harris Grade Road in the study region near the LOGP is approximately 8,200 Annual Average Daily Trips (AADT) with a truck volume of approximately 7 percent (SBC Traffic and Engineering Department, 2006). Based on this traffic volume and the National Standard Vehicle Noise Emission Levels at an assumed speed of 40 mph, a sound level of 60 dBA would occur at approximately 150 feet from the roadway center.

Sources of noise at the LOGP include compressors and pumps, which are constant, and alarms and loudspeakers, which are intermittent. Residents in Vandenberg Village have reported hearing loudspeakers and alarms at the LOGP, but none were detected during the period of noise sampling in August 2006. PXP now uses pagers for on-site communications instead of the loudspeaker.

Baseline noise levels were measured during the day, in the evening, and at night at ten locations in the study area. The data collected included L_{eq}, maximum levels, and minimum levels. Noise sources associated with the maximum reading were generally produced by ocean surf for locations near the beach or traffic on nearby local roads for other areas. Background noise levels measured in the study area are shown below in Table 5.10.1. Figure 5.10-2 shows the locations of background noise monitoring.

Table 5.10.1 Baseline Noise Levels in the Study Area

		L_{eq}, dbA			
#	**Location**	**Day**	**Eve.**	**Night**	**CNEL**
1	Santa Ynez River Estuary at Ocean Beach Park	51.8	53.1	45.5	55.8
2	Valve Site #2	37.0	44.8	47.6	53.5
3	Intersection of 13th St. and Terra Rd.	55.2	45.4	38.2	52.3
4	Top of Greenbriar Rd. in Vandenberg Village	36.9	44.5	30.8	38.8
5	Top of Firestone Rd. in Vandenberg Village	37.8	35.3	23.4	36.6
6	Tamarack Ct. cul-de-sac in Vandenberg Village	37.3	35.7	26.8	37.1
7	Manzanita Rd. cul-de-sac in Vandenberg Village	39.4	41.7	32.7	40.9
8	LOGP fence line	57.8	52.2	47.6	57.7
9	Corner of Rucker Rd. and Calle Lindero in Mission Hills	54.2	58.1	46.1	55.0
10	End of Via Lato off Calle Lindero in Mission Hills	51.9	53.1	48.4	55.5

Source: Locations #1 to 3: Arthur D. Little, Inc., 2001;
Locations #4 to 10: Brown-Buntin Associates, 2006.
Day is between 7 a.m. and 5 p.m., evening is between 5 p.m. and 10 p.m., night is between 10 p.m. and 7 a.m.

5.10.2 Regulatory Setting

Noise is regulated at the Federal, State, and local levels through regulations, policies, and/or local ordinances. Local policies are commonly adaptations of Federal and State guidelines, based on prevailing local conditions or special requirements. These guidelines have been developed at the federal level by the U.S. Environmental Protection Agency (EPA), the Federal Aviation Administration (FAA), the Federal Highway Administration and Department of Transportation; and at the state level by the now defunct California Office of Noise Control and by CalTrans.

5.10.2.1 Federal Jurisdiction

The FAA maintains jurisdiction over flight patterns for all aircraft. Federal Air Regulation (FAR) 36 establishes noise level criteria and measurement procedures for civilian fixed wing aircraft. No specific regulations have been adopted for civilian helicopters.

The Federal Highway Administration (FHWA) has established traffic noise design levels for use in the planning and design of federally funded highway projects (Program Manual, Volume 7, Chapter 7). These are based on hourly L_{eq} or hourly L_{10} levels for interior and exterior exposure of surrounding land uses. These levels are based on the category of activity through which the freeway passes. These categories range from A, for areas of extraordinary significance, to E for interior noise impacts as described below. Category D is applicable to undeveloped lands and has no specific L_{eq} or L_{10} value.

Category	Category Description	L_{eq}	L_{10}
A	Tracts of land in which serenity and quiet are of extraordinary significance. May include parks, open spaces, or historic districts.	57	60
B	Picnic areas, recreation areas, playgrounds, and other parks. Also, residences, hotels/motels, churches, libraries, and hospitals.	67	70
C	Developed lands.	72	75
E	Residences, hotels/motels, churches, libraries, and hospitals.	52 (interior)	55 (interior)

Under the authority of the Noise Control Act of 1972, the U.S. EPA has established noise emission criteria and testing methods (40 CFR Chapter 1, Subpart Q). These criteria apply to interstate rail carriers, and a limited number of construction and transportation equipment.

The Department of Transportation has established allowable noise levels for motor vehicles (49 CFR Chapter III, Part 325). These standards address measurement protocols for measuring highway noise, instrumentation and stationary testing procedures. In addition, the Department of Defense has established noise compliance requirements.

5.10.2.2 State Jurisdiction

The California Administrative Code, Title 4, which applies to airports operating under permit from the CalTrans Division of Aeronautics, defines a noise-impacted zone as any residential or other noise-sensitive use with CNEL 65 and above. The California Administrative Code, Title 2, establishes CNEL 45 as the maximum allowable indoor noise level resulting from exterior noise sources for multi-family residences.

The California Streets and Highways Code, Section 216 (Control of Freeway Noise in School Classrooms) requires, in general, that CalTrans abate noise to 55 dBA, L_{10}, or 52 dBA, L_{eq} or less. CalTrans Policy and Procedure Memorandum P74-47 (Freeway Traffic Noise Reduction, September 24, 1974) outlines the CalTrans policy and responsibilities related to transportation noise. In the California Government Code, Section 65302, CalTrans is also required to provide cities and counties with a noise contour map along state highways. The State Motor Vehicle

Code includes regulation(s) related to the selling and use of vehicles that do not meet specified noise limits.

5.10.2.3 Local Jurisdiction

SBC's regulations regarding industrial facilities specify 75 dB L_{dn} as the maximum volume of sound measured at any point along the property line of an industrial facility (Energy Division, 2000). The SBC Noise Element includes a recommended policy that states:

> *"In the planning of land use, 65 dB Day-Night Average Sound Level should be regarded as the maximum noise exposure compatible with noise-sensitive uses unless noise mitigation features are included in project designs."*

Policy No. 9 of the Noise Element states:

> *"Noise level limits, applicable to new noise sources, should be incorporated into all commercial and industrial zoning districts and into conditional use permits."*

The conditions of approval for the Point Pedernales Project Final Development Plan require a noise monitoring and control plan; establish maximum noise levels, construction hours and noise limitations; require the minimization of equipment noise and vibration; and impose nighttime restrictions in residential districts. Some of these conditions require the following:

> *"The best available technology... shall be used to minimize noise impacts." (K-1)*

> *"... sound levels during operation do not exceed 70 dBA at or beyond the property line or pipeline easement..." (K-2)*

> *"...No nearby residents shall be subjected to greater than a 9 dBA increment above the baseline ambient noise level, nor greater than a 3 dBA increase in day-night sound levels...." (K-2)*

> *"If complaints arise concerning activities occurring during [9:00 p.m. to 7:00 a.m.], PXP shall take additional feasible steps to <u>reduce</u> the noise levels or further restrict the offending activity." (K-5)*

5.10.3 Significance Criteria

There are two criteria for judging noise impacts. First, noise levels for the proposed project must comply with relevant Federal, State, or local standards or regulations. Noise impacts to the surrounding community are enforced through the local noise ordinance and supported by nuisance complaints and subsequent investigation.

The SBC Noise Thresholds (1995) provide the basis for defining potential significant impacts, which are based in part on the SBC's Comprehensive Plan Noise Element policies. A significant impact would be caused by any one of the following:

- Construction. Noise from grading and construction exceeds 65 dBA at sensitive receptors (SBC, 1995).
- Operations. If noise levels produced by a project and experienced by sensitive receptors exceed 65 dBA CNEL in exterior living areas (including open patios, porches, decks, etc.) adjacent to

residential structures, or the noise levels experienced by sensitive receptors increases substantially as determined on a case-by-case level (SBC, 1995).

- Adopted noise element policies, standards, or ordinances would be exceeded in noise level, timing, or duration (SBC Comprehensive Plan Noise Element).

The second criterion for measuring project impact is the increase in noise level above the existing ambient level as a result of a new noise source. The degree of impact is hard to assess because of the highly subjective character of individuals' reactions to changes in noise. Most people begin to notice changes in environmental noise levels at approximately 5 dBA. Typically, average changes in noise levels less than 5 dBA cannot be definitely considered as producing an adverse impact. For changes in levels above 5 dBA, it is difficult to quantify the impact beyond recognizing that greater noise level changes would result in greater impacts.

In community noise impact analysis, long-term noise increases of 5 to 10 dBA are considered to have "some impact." Noise level increases of more than 10 dBA are generally considered severe. In the case of short-term noise increases, such as those from construction activities, the 10 dBA threshold between "some" and "severe" is replaced with a criterion of 15 dBA. These noise-averaged thresholds should be lowered when the noise level fluctuates, when the noise has an irritating character such as considerable high frequency energy, or if it is accompanied by subsonic vibration. In these cases the impact must be individually estimated.

5.10.4 Impact Analysis for the Proposed Project

This section characterizes the noise impacts generated by the proposed project.

Impact #	Impact Description	Phase	Residual Impact
N.1	Drilling associated with the proposed project would increase ambient noise levels due to drilling rig operation and additional helicopter and supply boat trips.	*Drilling*	*Class III*

Increased noise from drilling and production would be audible to sensitive receptors but would not exceed the County's significance thresholds. Sensitive receptors at or near the platform include platform employees and boaters who occasionally approach the platform. The employees are required to wear hearing protection in high noise areas. Boaters approach the platform only on occasion and would not be subjected to prolonged periods of high noise levels. The underwater noise impacts associated with well drilling are addressed in Section 5.5, Marine Biology.

The project would require additional helicopter and supply boat trips during drilling. While helicopter routes in the past have originated in Lompoc, they now originate from Santa Maria Airport and pass to the north of restricted air space area R-2516 over VAFB (see Figure 5.10-3). Although the present flight path is designed to limit flights over urban areas and sensitive wildlife areas on VAFB, the noise from the additional flights could disturb users of Waller Grove County Park, and Santa Maria and Rancho Maria Golf Courses depending on flight paths used. Also, immediately north of restricted area R-2516 is Oso Flaco Lake Park in San Luis Obispo County, whose users and wildlife could be disturbed by such flight noise. Numbers of helicopter flights would almost double (from a current level of 3.2 average to 6.0 average one-way flights per day) during drilling. Although the annual number of helicopter trips will increase, there would be no daily increase during normal operations. Therefore, because areas are already experiencing some helicopter noise due to current operations, the impacts would be considered adverse but not significant.

Potential noise impacts could be kept to a minimum by maintaining overland flight height minimums. Presently, helicopters to Platform Irene fly at 1,000 feet unless safety conditions, such as reduced visibility from fog, dictate otherwise.

As mentioned in the Regulatory Setting, the FAA's minimum flight heights do not apply to helicopters. The Federal Highway Administration (FHWA) has established traffic noise based on hourly L_{eq} or hourly L_{10} levels for exterior exposure of surrounding land uses of 57 and 60 dBA, respectively. These noise levels are the most restrictive levels that could be applied to aircraft noise levels, although they were originally designed to address highway noise.

Noise levels from passing helicopters vary depending on aircraft model and atmospheric conditions. One study shows a range between 68 and 78 dBA during a flyover at 1,300 feet (Polysonics Corp., 2001). The Polysonics study also noted that the passing helicopter noise was only detectable for 30 seconds. The 78 dBA was for a military Blackhawk helicopter, which would be much louder than the civilian Sikorsky S76A that would be used by PXP. The maximum noise level for the Siskorsky S76A would be 75 dBA traveling at an airspeed of 145 knots and at an elevation of 1,000 feet.

Using the aircraft-specific noise levels from the Sikorsky S76A, and the duration measurements from the Polysonics study, it is clear that doubling the number of aircraft flights from a current level of 3.2 average to 6.0 average one-way flights per day, would have almost no impact on time-averaged noise levels, such as the CNEL and L_{eq}. Three additional flights would only add a maximum of 1.5 minutes per day of elevated noise levels at any one location along the flight path. In the calculation of the CNEL or Leq, increases in noise are mathematically indistinguishable within the number of significant digits used to present noise modeling results. For any given hour, elevated noise levels would also represent far less than 10 percent of the hour, which would mean that increases in aircraft flights would not exceed applicable L_{10} noise thresholds (the L_{10} is defined as the noise level that cannot be exceeded more than 10 percent of the time during an hour). Therefore, potential noise impacts would be considered insignificant. Furthermore, PXP is required to maintain the current 1,000 foot minimum flight levels.~~ as long as the increased helicopter flights~~ To ensure continued adherence to the required flight level, Mitigation Measure N-1 is recommended.

Mitigation Measures

N-1 PXP shall ~~establish~~ adhere to overland flight height minimums of 1,000 feet, when feasible with the approval of the FAA, and shall not fly over Oso Flaco Lake.

Residual Impact

Mitigation Measure N-1 would mitigated this impact to the maximum extent feasible. Noise impacts at Platform Irene and onshore due to helicopter flights are considered *adverse but not significant (Class III)*.

Impact #	Impact Description	Phase	Residual Impact
N.2	Construction noise would temporarily increase ambient daytime noise levels.	*Construction*	*Class III*

Construction noise would be audible to sensitive receptors but would not exceed County noise thresholds for construction. Construction noise would occur at Valve Site #2 during the installation of three new 1,250-horsepower electrical pumps and electrical transmission infrastructure, and at the LOGP during facility modifications. These construction-related noise levels would be temporary in nature. The only noise-sensitive area in the vicinity of Valve Site #2 is Ocean Beach County Park, approximately one mile away. A residence lies one mile to the southeast of the nearest approach of the power line route. In a worst case scenario, these construction activities are projected to temporarily increase daytime ambient noise levels at either sensitive receptor by approximately 4 dBA.

Modifications at the LOGP are projected to last up to nine weeks ~~months~~. If the produced water treatment facilities are installed at the same time as other LOGP modifications, ambient noise levels would increase at sensitive receptors in Vandenberg Village. Construction noise at the LOGP is estimated to impact residences on Tamarack Court, lower St. Andrew's Way, and Firestone Road, the nearest of which is 4,600 feet from the LOGP (Location #6), which could experience daytime ambient noise level increases of 18 dBA (see Table 5.10.2.). Residences along Calle Lindero and Rucker Road in Mission Hills (Location #9) could experience increases of 14 dBA. Because these noise increases would not cause noise levels to exceed the construction significance criterion of 65 dBA, these temporary construction impacts would be considered adverse but not significant.

Table 5.10.2 LOGP Construction Noise Calculations Experienced by Nearest Sensitive Receptor

Equipment	Number	Fraction of Time Generating Peak Noise During Day	Reference distance from noise source, ft	Sound Level at reference distance, dBA	Distance from LOGP, ft	Sound Level at distance, dBA	Total Day Energy
Backhoe	2	0.25	50	85	4,600	46	1.87E+04
A-frame Truck	3	0.25	50	91	4,600	52	1.12E+04
Dump Truck	2	0.25	50	91	4,600	52	7.44E+04
Concrete Truck	2	0.25	50	91	4,600	52	7.44E+04
15-Ton Crane	2	0.25	50	86	4,600	47	2.35E+04
Welding Machine	4	0.25	50	78	4,600	39	7.45E+03
Total							3.10E+05
Total dBA without background							55
Total dBA with background and CNEL correction							55

Source: Background is assumed to be 37 dBA as measured in 2006.
Day is between 7 a.m. and 5 p.m., evening is between 5 p.m. and 10 p.m., night is between 10 p.m. and 7 a.m.
Assumes that installation of produced water treatment facility coincides with other LOGP modifications.

SBC (1990, rev. 1995) requires an onsite noise study and noise attenuation barriers for projects exceeding 65 dBA at the construction boundaries. While noise at the proposed project site boundary would likely exceed 65 dBA, the nearest sensitive receptor is 4,600 feet from the project site, and offsite noise would be less than 65 dBA. Therefore, an onsite noise study and noise attenuation barriers were deemed not applicable.

Mitigation Measure

N-2 Construction activities shall be limited to 7:00 a.m. and 4:00 p.m., Monday through Friday. Construction equipment maintenance shall be limited to the same hours. Non-noise generating construction activities such as interior painting are not subject to these restrictions. Signs shall note appropriate contact information for a complaint to be filed. Signs stating these restrictions shall be provided by the applicant and posted on site. Signs shall be in place prior to issuance of Land Use Permit and throughout grading and construction activities. All complaints received shall be forwarded to SBC within 24 hours of receipt by PXP.

Residual Impact

Mitigation Measure N-2 would help reduce noise impacts experienced by sensitive receptors to the maximum extent feasible. Impact N.2 is considered *adverse but not significant (Class III).*

Impact #	Impact Description	Phase	Residual Impact
N.3	Operations noise from pumps would increase long-term ambient noise levels.	*Extension of Life*	*Class III*

Operational noise would be audible to sensitive receptors but would not exceed County noise thresholds for operations. The operation of <u>new</u> electric pumps at Valve Site #2 ~~is baseline noise and would continue~~ <u>would introduce an increase in the baseline ambient noise level</u>. At a distance of approximately one mile, the increase in ambient noise level at Valve Site #2 would be inaudible over the surf noise at the sensitive receptor Ocean Beach County Park. Nighttime noise levels at this sensitive area would increase by an estimated 2 dBA (which is not a perceptible change); therefore, this impact is considered adverse but not significant.

Two heater treaters would be brought back into service at the LOGP with the proposed project, increasing the ambient noise levels at sensitive receptors in Vandenberg Village. Residences on Firestone Road (Location #5), which are in the line of sight of the LOGP, could experience respective day, evening, and nighttime ambient noise level increases of 1, 5, and 3 dBA from the current background levels of 38, 36, and 27 dBA. Residences along Calle Lindero and Rucker Road in Mission Hills could experience daytime, evening, and nighttime ambient noise level increases of 1, 2, and 2 dBA, respectively. These increases in ambient noise level in Vandenberg Village would be minimally perceptible and do not exceed the significance criterion for long-term impacts; therefore, the impact is considered adverse but not significant.

Mitigation Measures

No mitigation measures have been identified.

Residual Impact

The potential increase in long-term noise levels due to the proposed project is minimal and is therefore considered *adverse but not significant (Class III)*.

5.10.5 Impact Analysis for the Alternatives

Detailed descriptions of the various alternatives have been provided in Chapter 3.0, Alternatives. This section provides a discussion of the noise impacts of the various alternatives.

5.10.5.1 No Project Alternative

Scenarios 2 and 3. As discussed in Section 3.2, under the No Project Alternative Scenarios 2 and 3, production of the federal portion of the Tranquillon Ridge field would and would not occur, respectively. However, no extension of life of Point Pedernales facilities (Platform Irene, pipelines, and LOGP) is assumed under either scenario.

Impact Noise.1 – Offshore Noise: Impacts associated with noise from Platform Irene, supply boats, and helicopters would be the same as the proposed project (Class III) during operations. However, the duration of these impacts would be substantially less because operations would be significantly shorter under the No Project scenario (10 versus 30 years). Mitigation Measure N-1 would still be applicable.

Impacts Noise.2, Construction Noise, and Impact Noise.3, Operations Noise, would not occur since the pumps at Valve Site #2 would not be installed and modifications to the LOGP would not occur.

Options for Meeting California Fuel Demand. The relative noise impacts associated with the various options for meeting California fuel demand are summarized in Table 5.10.3.

Table 5.10.3 No Project Alternative Comparison to Options for Meeting California Fuel Demand, Noise

Source of Energy		Impacts
Other Conventional Oil & Gas		
	Domestic onshore crude oil and gas	Likely to displace, rather than eliminate, noise impacts.
	Increased marine tanker imports of crude oil	Would increase offshore noise impacts.
	Increased gasoline imports[1]	Would increase onshore noise impacts if tanker trucks are used.
	Increased natural gas imports (LNG)	Offshore noise impact would increase with LNG tankering and/or development of offshore ports.
Alternatives to Oil and Gas		
	Fuel Demand Reduction: increased fuel efficiencies, conservation, electrification[2]	
	Alternative transportation modes	Proposed project impacts would be eliminated.
	Implementation of regulatory measures	Proposed project impacts would be eliminated.

Table 5.10.3 No Project Alternative Comparison to Options for Meeting California Fuel Demand, Noise

Source of Energy	Impacts
Coal, Nuclear, Hydroelectric	Proposed project impacts would be eliminated. Construction and operation of power facility infrastructure could generate noise impacts.
Alternative Transportation Fuels	
Ethanol/Biodiesel[3]	Noise impacts would increase due to ethanol/biodiesel facility construction and operation, and required truck transport.
Hydrogen[2]	Proposed project impacts would be eliminated. Potential noise impacts due to hydrogen delivery infrastructure development and operation.
Other Energy Resources[2]	
Solar[2,4]	Proposed project impacts would be eliminated. Construction of solar facility infrastructure could result in noise impacts.
Wind[2,4]	Proposed project impacts would be eliminated. Construction and operation of wind facility infrastructure could result in noise impacts.
Wave[2,4]	Proposed project impacts would be eliminated. Construction of wave facility infrastructure could result in noise impacts.

Footnotes:
1. Pipeline and tanker truck import from out-of-State assumed.
2. Assumes that Tranquillon Ridge production would not be replaced with other petroleum-based energy supply.
3. Assumes ethanol and biodiesel used as blends only and therefore would reduce, but not eliminate Tranquillon Ridge or equivalent production.
4. Assumes, large centralized facilities.

5.10.5.2 VAFB Onshore Alternative

The VAFB Onshore Alternative would include the construction of the drilling and production facilities within a 25-acre site, and installation of approximately 10 miles of emulsion and gas pipelines and 6 miles of overhead 69 kV transmission line. In addition, a pipeline tie-in station, and associated electrical substation and power line would be required. These facilities would be operating for approximately 30 years. The noise impacts associated with this alternative are described below.

***Impact Noise.1 – Offshore Noise*:** The VAFB Onshore Alternative would not generate any offshore noise impacts since all operations would be onshore. Impacts associated with noise from Platform Irene, supply boats, and helicopters would be the same as the baseline or No Project Alternative (*Class III*) and Mitigation Measure N-1 would still be applicable.

Impact Noise.2 – Construction Noise: Onshore construction noise would occur primarily on VAFB property away from sensitive receptors in Vandenberg Village or Lompoc. The alternative pipeline and ~~transmission~~ power line alignments are primarily located within rural areas within VAFB or along Highway 246 west of 13th Street. Construction of the new pipelines and power line would occur near Ocean Beach County Park, the only sensitive noise receptor in the area. However, construction would be temporary and therefore this impact is considered *adverse but not significant (Class III)*. Construction traffic, including delivery of heavy equipment and the drilling rig, would need to pass through Lompoc, but the noise of this traffic would not be steady since individual equipment and machines would be discernible. Although onshore construction noise would be greater for the alternative than for the proposed project, the noise impact would be *adverse but not significant (Class III)*. Mitigation Measure N-2 would be applicable for construction traffic and activities near sensitive receptors.

Impact Noise.3 – Operations Noise: Operation of the alternative would occur within VAFB, which is not near any sensitive receptors (whereas for the proposed project, drilling/production operations would occur on Platform Irene). Noise from this activity would be inaudible at Ocean Beach County Park, approximately six miles away. The noise impacts from operation of new pumps at the LOGP would be similar to those described above for the proposed project. Therefore, the impact would be *adverse but not significant (Class III)*.

5.10.5.3 Casmalia Canyon/Oil Field Processing Location

Impact Noise.1 - Offshore Noise*,* would be the same as for the proposed project (Class III). Mitigation Measure N-1 would still be applicable.

Impact Noise.2 - Construction Noise*,* would increase for sensitive receptors in Vandenberg Village, Mission Hills, and Casmalia due to the construction of new pipelines, a new oil and gas plant, and the partial dismantling of the LOGP. Construction and abandonment activities for this alternative would increase noise levels at sensitive receptors around the LOGP to levels considerably above those detailed for the proposed project's construction activities and discussed above (see Impact N.4). The construction activities would generate noise levels of 94 dBA at the LOGP, 58 dBA at Mission Hills residences 8,500 feet away, and 51 dBA at Vandenberg Village residences 5,000 feet away (Arthur D. Little, 1985). Therefore, the areas of Mission Hills and Vandenberg Village that were discussed in Impact Noise.4 would experience adverse but not significant noise impacts due to the dismantling of the LOGP, since noise levels would be less than 65 dBA. It is estimated that the partial dismantling at LOGP would last for 6 months.

The potential new processing facility site in Casmalia is located in a sparsely populated area. Its construction would create similar noise levels to the LOGP abandonment, or 94 dBA. The town of Casmalia is located at a distance of 9,500 feet to the west; the railroad tracks and Black Road at 5,500 feet to the west; and Rancho Maria Golf Club at 7,500 feet to the north. The noise created at these receptors would be less than 65 dBA and therefore considered adverse but not significant.

The new pipeline section would be constructed from Orcutt Pump Station to the Casmalia East Site, passing primarily through unpopulated land. The route would pass within approximately 2,000 feet from the Rancho Maria Golf Club, where noise levels would reach 55 dBA during construction (Arthur D. Little, 1985). Closer to the Orcutt Pump Station, at least one half mile of pipeline would likely occur within 500 feet or less of the residential area near Clark Avenue in Orcutt where intermittent street noise already exceeds 65 dBA. Furthermore, the noise would not be steady since individual equipment and machines would be discernible. This noise impact would only occur during construction and therefore would be temporary.

The noise impact would remain *adverse but not significant (Class III).* Mitigation Measure N-2 would still be applicable.

Impact Noise.3 - Operations Noise, would be similar to the proposed project. While some equipment would be removed from the LOGP, compressors and pumps would remain to allow for shipping of the produced oil and gas to the Casmalia processing site. Any decrease in noise level from the proposed project would be minor since the pumps and compressors are the major sources of noise at the facility. Therefore, the impact would remain *adverse but not significant (Class III).*

5.10.5.4 Alternative Power Line Routes to Valve Site #2

Impact Noise.1 - Offshore Noise, would be the same as for the proposed project (Class III). Mitigation Measure N-1 would still be applicable. Impact Noise.2 for all of the alternative power line routes is discussed below.

Alternative Power Line Route – Option 2a

Impact Noise.2 – Construction Noise: Power Line Option 2a would involve ground disturbance from constructing a new substation and installing new power poles. The proposed substation would be located in a farm field north of Ocean Avenue and west of an abandoned road. Approximately 15 to 20 power poles would be installed for the proposed power line that would connect the new substation to the power pole line along the pipeline ROW. The proposed power line would be placed in a hay field, across the Santa Ynez River, and then parallel to an existing VAFB power pole line. The relocation of the power poles and the pole crossing of the Santa Ynez River would not increase the noise levels over what was discussed for the proposed project. Therefore, the impact is considered to be *adverse but not significant (Class III).*

Alternative Power Line Route – Option 2b

Impact Noise.2 – Construction Noise: Ground disturbances associated with Power Line Option 2b would be the same as Option 2a except that the proposed power line would cross the Santa Ynez River by directional boring under the river instead of being hung on new power poles. The directional bore would involve excavating two bore pits, one on each side of the river, and then boring under the river to a minimum depth of 50 feet. This option would create somewhat more noise than the proposed project due the use of the horizontal drill for boring the Santa Yenz River but would remain *adverse but not significant (Class III)* given the distance of boring location from the nearest sensitive receptor (Ocean Beach County Park).

Underground Power Line along Terra Road

Impact Noise.2 – Construction Noise: With this alternative the power line to Valve Site #2 would be placed underground. This would involve the use of a backhoe for digging the trench. This activity would be expected to generate noise levels of approximately 85 dBA at 50 feet from the construction equipment. This would result in a projected increase in daytime noise levels at Ocean Beach County Park of approximately 4 dBA. Noise impacts would be greater than for the proposed project but still *adverse but not significant (Class III).*

5.10.5.5 Replacement of Oil Emulsion Pipeline from Platform Irene to LOGP

This section addresses the impacts associated with the replacement of the wet oil pipeline from the LOGP to Platform Irene. The existing pipeline route, which includes three pipelines, consists of an offshore segment and an onshore segment. The offshore segment passes over sandy bottom from Platform Irene to within 4,000 feet of the shoreline, from which point it is buried until the landfall north of the Santa Ynez River mouth. The onshore segment extends from the landfall to the LOGP, passing through mostly unpopulated areas.

Impact Noise.1 - Offshore Noise, would be the same as for the proposed project (*Class III*). Mitigation Measure N-1 would be applicable.

Impact Noise.2 - Construction Noise (Valve Site #2 and LOGP), would be less than the proposed project since the installation of pumps and electrical infrastructure at Valve Site #2 would not occur. LOGP modifications would remain, so the impact would be considered *adverse but not significant (Class III).*

Impact Noise.3 - Operation Noise, would be less than the proposed project since the pumps would not be installed at Valve Site #2. Operational noise at the LOGP would remain, so the impact would be considered *adverse but not significant (Class III).*

Impact #	Impact Description	Phase	Residual Impact
N.4	Construction activities along the pipeline route would temporarily increase ambient noise levels near Surf Beach and Ocean Beach Park, at residences along the north edge of Vandenberg Village and at Cabrillo High School, and at the residential complex at the Lompoc Federal Penitentiary.	*Construction*	*Class III*

Increased noise levels from pipeline construction would be audible at sensitive receptors but would be below the County's significance thresholds. Offshore noise would be generated by boats laying underwater pipeline and would affect sensitive receptors at Surf Beach and Ocean Beach Park as the construction nears landfall. Onshore noise would be generated by construction equipment and would affect sensitive receptors at the residences along the northern edge of Vandenberg Village, Cabrillo High School in Vandenberg Village, and the residential complex at the Lompoc Federal Penitentiary.

As explained in Chapter 3.0, Alternatives, onshore pipeline construction would proceed at 0.25 mile per day from Surf to LOGP. The active construction area would extend three miles and be less than 100 feet wide. (Refer to Section 3.0 for a detailed description of this alternative.)

Noise levels created by the pipeline replacement would be temporary. Offshore and onshore construction would occur approximately one mile from Ocean Beach Park and would generate a slight increase in daytime noise levels. Construction noise would be nearly inaudible at Wall/ Surf Beach over the ambient surf noise. Onshore construction would also occur within 2,000 feet of residences in Vandenberg Village, within 2,000 feet of Cabrillo High School in Vandenberg Village, and within 1,600 feet of the Lompoc Federal Penitentiary residential complex. These construction activities are projected to increase daytime ambient noise levels at these sensitive receptors by the amounts shown in the table below.

Although several residences in Vandenberg Village may experience substantial noise increases, the noise levels would remain below the construction significance criterion of 65 dBA and would be temporary; therefore, the impact would be adverse but not significant.

Table 5.10.4~~3~~ Projected Noise Increases due to Emulsion Pipeline Replacement

Sensitive Receptor	Existing Daytime Ambient Noise	Daytime Ambient Noise Levels with Alternative	Temporary Noise Increase from Construction[2]
Residences in Vandenberg Village	37 dBA[1]	59 dBA	22 dBA
Cabrillo High School	46 dBA[2]	56 dBA	10 dBA
Residential complex at Lompoc Federal Penitentiary	50 dBA[2]	59 dBA	9 dBA
Ocean Beach Park	52 dBA[3]	56 dBA	4 dBA

[1]*Noise data gathered in 2006.*
[2]*Noise data and projections from the 1985 Point Pedernales EIS/EIR*
[3]*Noise data gathered in 2001.*

Mitigation Measures

See Mitigation Measure N-2, limiting operating hours of construction.

Residual impact

The impact from temporary noise level increases at the sensitive receptors would be *adverse but not significant (Class III).*

5.10.5.6 Alternative Drill Muds and Cuttings Disposal

Inject Drill Muds and Cuttings into Reservoir

Impact N.1 - Offshore Noise, would increase in this alternative due to the operation of new pumps and grinders at the platform but would remain *adverse but not significant (Class III)*.

All other noise impacts would be the same as for the proposed project.

Transport Drill Muds and Cuttings to Shore for Disposal

This alternative is essentially the same as the proposed project with the exception of offshore activities. Onshore activities under this alternative are the same as for the proposed project. Therefore, noise impacts would be the same as for the proposed project.

5.10.6 Cumulative Impacts

Cumulative projects that could impact the current analysis include the potential offshore oil and gas development projects outlined in Sections 4.2 and 4.3, as well as the onshore development projects summarized in Section 4.4.

5.10.6.1 Offshore Oil and Gas Projects

As summarized in Sections 4.2 and 4.3, the major possible offshore oil and gas-related development projects in the northern and southern Santa Maria Basin include the Rocky Point, Lion Rock, Point Sal, Santa Maria, Purisima Point, Bonito and Sword Units, and Lease OCS-P

0409. While these activities could generate localized noise impacts, they would not be in the immediate vicinity of the proposed project and, therefore, would not generate significant adverse cumulative noise impacts. Cumulative impacts, including the proposed project's incremental contribution to them, would not be expected to be significant.

5.10.6.2 Onshore Projects

As summarized in Section 4.4, potential onshore development in the immediate vicinity of the proposed project primarily include planned residential and commercial construction projects in the Orcutt and Santa Maria area, and numerous development and redevelopment projects in ~~between~~ the City of Lompoc and the unincorporated area of Lompoc surrounding the LOGP. If modifications to the LOGP coincide with construction of the projects located in the Lompoc area, sensitive receptors could be exposed to cumulatively significant noise impacts, although these exposures would be temporary. With implementation of project-specific mitigation measures (e.g., N-2), the proposed project's incremental contribution to cumulative noise impacts would not be expected to be significant.

5.10.7 Mitigation Monitoring Plan

Mitigation Measure	Mitigation Requirements and Timing	Method of Verification	Timing of Verification	Party Responsible For Verification
N-1	PXP shall ~~establish~~ adhere to overland flight height minimums of 1,000 feet, when feasible with the approval of the FAA, and shall not fly over Oso Flaco Lake.	Flight records shall be maintained for six months and shall be provided to P&D upon request.	Operations	SBC P&D
N-2	Construction activities shall be limited to 7:00 a.m. and 4:00 p.m., Monday through Friday. Construction equipment maintenance shall be limited to the same hours. Non-noise generating construction activities such as interior painting are not subject to these restrictions. Signs stating these restrictions shall be provided by the applicant and posted on site. Signs shall note appropriate contact information for a complaint to be filed. Signs shall be in place prior to issuance of Land Use Permit and throughout grading and construction activities. All complaints received shall be forwarded by the applicant to SBC within 24 hours of their receipt.	Periodic inspection and response to complaints	Prior to and during construction	SBC P&D

5.10.8 References

Arthur D. Little, Inc. 1985. Union Oil Project/Exxon Project Shamrock and Central Santa Maria Basin Area Study: Final Environmental Impact Statement/Environmental Impact Report. Prepared for County of Santa Barbara, U.S. Mineral Management Service, California State Lands Commission, California Coastal Commission, and California Office of Offshore Development.

Aspen Environmental Group. 1996. Pacific Pipeline Project Final Environmental Impact Statement/Subsequent Environmental Impact Report. Appendix E-2, Noise. SCH#92013018. Prepared by Aspen Environmental Group of Agoura Hills, California for the California Public Utilities Commission, USDA Forest Service, and Angeles National Forest.

Newman, J. Steven; Rickely, Edward J.; Brand, Tyrone L.; Beattie, Kristy R. 1984. Noise Measurement Flight Test: Data/Analyses Sikorsky S-76A Helicopter. U.S. Department of Transportation Federal Aviation Administration. January.

Radle, Autumn Lyn. April 17, 2001. The Effect of Noise on Wildlife: A Literature Review. World Forum for Acoustic Ecology, University of Oregon. http://interact.uoregon.edu/MediaLit/FC/readings/radle.html

Santa Barbara County. 1990. Standard Conditions of Approval and Standard Mitigation Measures. Prepared by Planning and Development Department (revised 1995).

____. 1995. Environmental Thresholds and Guidelines Manual. Prepared by Planning and Development Department.

____. 2000. Draft North County Siting Study. Prepared by the Energy Division of the Planning and Development Department.

____. 2001. Personal communication with Brad Probst, Traffic and Engineering Department. January 22.

Common Outdoor Noise Levels	Noise Level (dBA)	Common Indoor Noise Levels
	110	Rock Band
Jet Flyover at 1,000 feet		
	100	
		Inside Subway Train (New York)
Gas Lawnmower at 3 feet		
	90	
Diesel Truck at 50 feet		
Noisy Urban Daytime		Food Blender at 3 feet
		Garbage Disposal at 3 feet
	80	
		Shouting at 3 feet
Gas Lawnmower at 100 feet		
	70	Vacuum Cleaner at 10 feet
Commercial Area		
Heavy Traffic at 300 feet		Normal Speech at 3 feet
	60	
		Large Business Office
Quiet Urban Daytime		
	50	Dishwasher Next Room
Quiet Urban Nighttime		Small Theater, Large Conference
	40	Room (Background)
Quiet Suburban Nighttime		
		Library
	30	Bedroom at Night
Quiet Rural Nighttime		Concert Hall (Background)
	20	
		Broadcast and Recording Studio
	10	
		Threshold of Hearing
	0	

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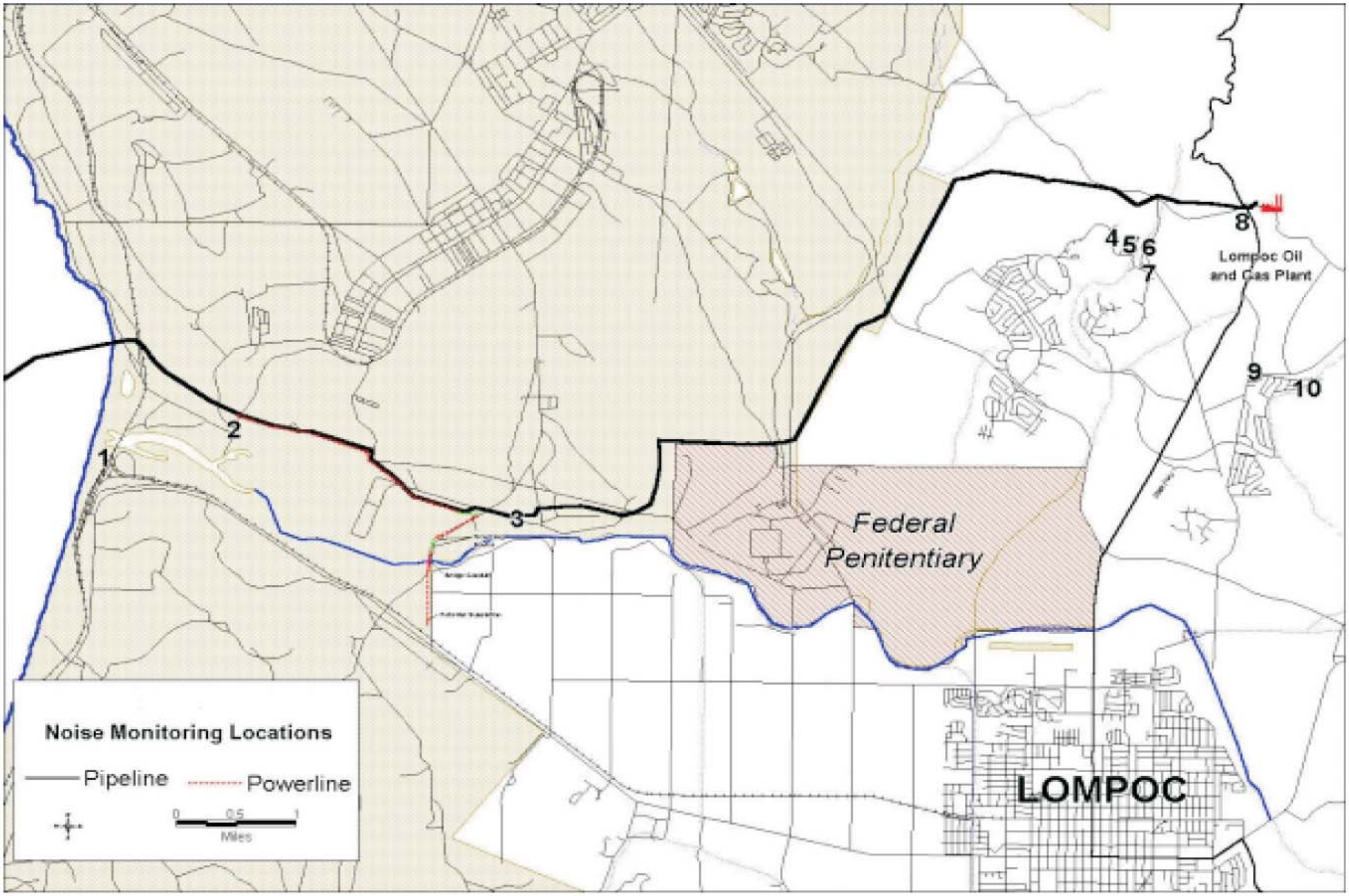
Figure 5.10-1
Common Environmental Noise Levels



Source: MRS, 2002.

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Figure 5.10-2
Noise Monitoring Locations

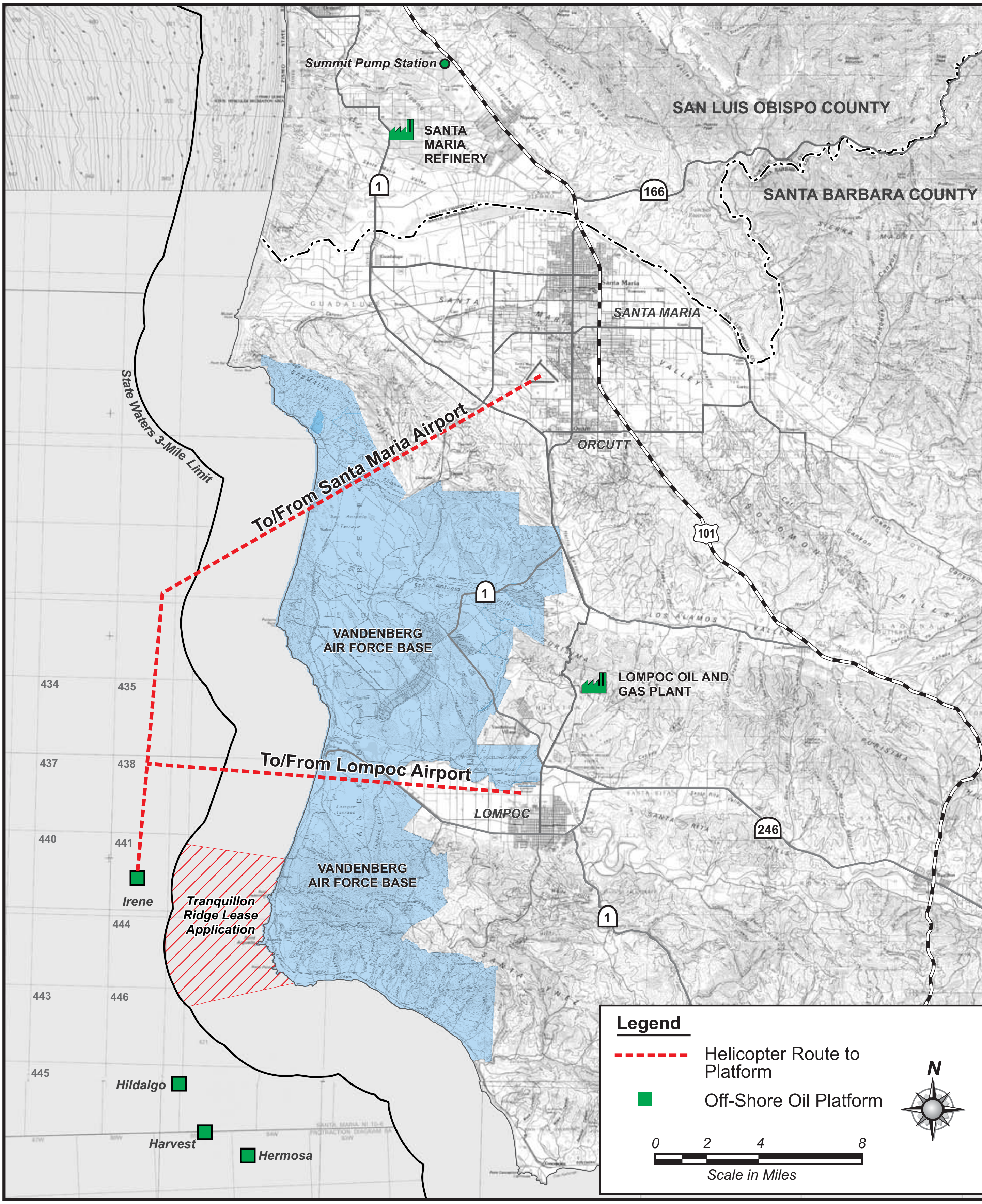

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Figure 5.10-3

Helicopter Route to Platform Irene

5.11 Fire Protection and Emergency Response

This section addresses the fire protection and emergency response resources related to the proposed project. These resources include the existing services and capabilities of nearby fire departments and neighboring oil and gas facilities, the internal fire protection plans, and the systems and design of the facilities and their associated pipelines. The emergencies that would require summoning these available resources include fire, oil spill, hazardous substance release, or another event that could lead to these emergency situations, such as an earthquake, traffic accident, pipeline rupture, etc. This section also evaluates the impacts of the proposed project and alternatives on these services and capabilities and presents criteria used to determine significant impacts of the project.

5.11.1 Environmental Setting

5.11.1.1 Fire Fighting Capabilities in the Project Area

Santa Barbara County (SBC) operates many fire stations within County borders, and the cities of Lompoc and Santa Maria operate their own fire stations near the project area. The City of Lompoc and SBC have a mutual aid agreement that allows city and county fire departments to cooperate with one another. Therefore, the Lompoc City Fire Stations could also respond during an emergency along the pipeline route or at the LOGP. The closest fire stations to the LOGP and the route of the pipelines evaluated in this EIR are listed in Table 5.11.1 with street address, equipment, number of personnel, and proximity to the projects. Figure 5.11-1 presents the location of each of the fire stations in relation to the project area (locations are numbered as in Table 5.11.1).

SBC Fire Station Number (No.) 51 near Lompoc is the closest to the LOGP and would be first to respond to the LOGP in the event of a fire. The fire station is located within 10 miles (within 15 minutes response time) from most of the pipeline routes addressed in this document. The next nearest fire stations to the LOGP are located in the City of Lompoc, including Lompoc Fire Station No. 1 ~~51~~ (5.3 miles from LOGP) and Lompoc City Fire Station No. 2 (7.5 miles from LOGP). Furthermore, as presented in Table 5.11.1, Vandenberg Air Force Base (VAFB) Fire Department also has emergency response capabilities. SBC Fire Station No. 31 in Buellton could also be alerted to respond to an emergency at the LOGP.

In addition to the county and city emergency response equipment, oil facilities are required by Federal, State, and local regulations to maintain onsite fire fighting equipment as well as materials to control oil spills or other hazardous materials releases. PXP has fire fighting and emergency response capabilities at the LOGP in accordance with these regulations.

Other facilities in the vicinity that also have fire fighting and emergency response capabilities include the Orcutt Pump Station and the Santa Maria Pump Station. These capabilities are also listed in Table 5.11.1. Fire fighting capabilities at the Santa Maria and Sisquoc Pump Stations are described in the Tosco Sisquoc Pipeline EIR (91-FDP-03, 2/1992) and the Tosco Sisquoc Pipeline Public Draft SEIR (00-EIR-09, 12/2000).

Table 5.11.1 Facilities in the Area with Fire Fighting and Emergency Response Capabilities

Fire Station/ Facility	Address	Distance Miles[1]	Fire-fighting Equipment/Personnel	Emergency or Spill Response Capabilities
1. Lompoc, Fire Station No. 51 (SBC)	749 Burton Mesa Rd., Lompoc	5.3	1 engine, 1 reserve engine, 1 Captain, 2 engineers and 2 firefighter/paramedics	Paramedic unit
2. Buellton, Fire Station No. 31 (SBC)	168 W. Highway 246, Buellton	20	Engine/brush-fire engine (1250 gpm), reserve engine, reserve personnel (10-15 people), 1 Captain, 1 engineer, 1 firefighter and 1 firefighter/paramedic	HazMat response truck[3] HazMat team[3]
3. SM Airport, Fire Station No. 21 (SBC)	3339 Terminal Dr., Santa Maria	18	Engine (1500 gpm), crash rescue truck, 1 Captain, 1 engineer, and 1 firefighter	
4. Santa Maria, Fire Station No. 22 (SBC)	1596 Tiffany Park Ct., Santa Maria	17	Engine (1500gpm), brush fire engine, 1 Captain, 1 engineer, 1 firefighter, and 1 firefighter/paramedic	
5. Sisquoc, Fire Station No. 23 (SBC)	5003 Depot Ave., Sisquoc	28	Engine (1250 gpm), fire/foam tender (2800 gallons of water or 6,000 gallons of AFFF foam) [2] 1 Captain, 1 engineer, and 1 firefighter	
6. Los Alamos, Fire Station No. 24 (SBC)	99 Centennial, Los Alamos	16	Engine (1500 gpm), brush fire engine, 1 Captain, 1 engineer, and 1 firefighter	Paramedic engine
7. Nipomo (SLO County)	450 Pioneer St. Nipomo	31	Type A pumper with foam capability, [2] Minimum of 2 personnel per 24-hour shift	
8. Lompoc City Station No.1	115 South "G" St., Lompoc	8	1 Engine, aerial ladder truck in reserve, 3 personnel, reserve personnel	
9. Lompoc City Station No. 2	1100 North "D" St., Lompoc	7.5	1 Engine, reserve personnel	
10. City of Santa Maria, Fire Station No. 1	206 E. Cook St., Santa Maria	21	Engine (1500 gpm) with three personnel, Reserve engine (1500 gpm) unstaffed, Wildland engine (5 gpm, 4-wd) cross-staffed with the 3 personnel from the engine	
11. Lompoc Oil and Gas Plant	3602 Harris Grade Road, Lompoc	0	Fire water system including water tank, fire hydrants and pumps, foam concentrate tank, foam discharge system, fire detection system, flammable gases detectors	Sorbent boom; sorbent pads, empty sand bags, rakes, shovels, pitch forks, 6 SCBAs; fire fighting turnouts, tri-monitors, fire extinguishers, portable tanks, gas or diesel trash pumps; emergency response (ER) trailer; ER suitcase; pickup truck, foreman's vehicle, cell phones, radio base station
12. Lompoc Field	Mobile	0-10	Fire extinguishers	Radio base station; half-ton truck w/radio; two ¾ ton trucks w/radio & cell phone 15 ton stinger w/radio; 15 ton stage-crane truck, utility truck; two half-ton trucks; three ¾-ton trucks, two-wheel gas trailer; two-wheel grease trailer

Table 5.11.1 Facilities in the Area with Fire Fighting and Emergency Response Capabilities

Fire Station/ Facility	Address	Distance Miles[1]	Fire-fighting Equipment/Personnel	Emergency or Spill Response Capabilities
				plastic trash bags, excelsior, solvent, brooms, bales, various hand tools; assorted pipe plugs, clamps, fittings; pipe cutters, pipe tape, primer, coat line pipe; 3-in-1 gas analyzer, H_2S analyzers; air compressors; two-wheel air compressor trailer
13. Orcutt Pump Station and field	201 South Broadway, Orcutt	16		Sieve nets, plastic buckets with lids, aquarium-type air pumps with associated plastic tubing, gang valves, air stones, and batteries; fiberglass/plywood storage box; three 1-ton trucks; three ¾-ton trucks; two 2.5-ton A-frames; hydro crane; two 2-wheel air compressors; half-ton truck
14. Santa Maria Pump Station	1580 Battles Rd. Santa Maria	23	400 gallon foam system [2] 200 gallons of foam in storage [2] Fire water tank, 364,000 gal Fire detection system with audio alarm Fire hydrants Manually activated foam discharge outlets	**<u>Response Trailer[4]:</u>** 23 lengths boom; 6 bundles sorbent pads; 1 roll excelsior with net; dip nets with handles, 7 metal stakes; 2 steel culverts, 10 pairs waders, wader suspenders, 1 portable tank (600 gallon), shovels, rakes, gloves; 4 trailer-mounted portable lights, 6 respirators; 4 radios and radio base station **<u>Storage Container[4]:</u>** Rubber boots, Tyvec Suits, XC rain suits, flotation vests, work vests, garbage cans, utility brushes, fence posts, rakes, shovels, brooms, tarps, fencing, plastic swimming pools, spool 1" rope, waders, wheelbarrows; can liners, Sol-vex and examination gloves, protective goggles roll sorbent pad SPC 150, 500 ft. Minimax 17 boom
15. Vandenberg Air Force Base Fire Department	Multiple locations	4-10	5 Type 1 engines and 1 truck company at 3 locations 1 Hazmat squad 5 Airport crash/fire/rescue companies 3 Water Tenders 1 hand crew and 1 truck company (6 locations)	

Source: PXP, 2005a; Santa Barbara County Fire Department; City of Lompoc Fire Department; City of Santa Maria Fire Department; Unocap Emergency Response Plan, May 2000.
gpm – gallons per minute
1. *The distance shown is from a fire station/response facility to the LOGP facility.*
2. *Specialized Oil Fire Fighting Equipment.*
3. *Denotes the equipment that might be on a delayed response.*
4. *The full list of contents can be found in UNOCAP Sisquoc to Santa Maria Station & Point Pedernales LOGP to Orcutt Pump Station Emergency Response Plan, Revised May 1, 2000.*

5.11.1.2 Fire Protection Capabilities at the LOGP

The LOGP has a Fire Protection Plan approved by the Santa Barbara County Fire Department (SBCFD). The LOGP is designed with fire prevention as a prime concern using concepts such as early ignition detection and fire spread prevention at the basis of the design. The Fire Protection System is shown in Figure 5.11-2 on the plant plot plan. Sources of open flame are grouped together and segregated from areas with potentially flammable materials. The electrical installation was designed to conform to the National Electric Code (NEC) and National Fire Protection Association ~~Agency~~ (NFPA) requirements. Potential ignition sources include the heater treaters, thermal oxidizer, reclaim heater, glycol heater, flare, and occasional vehicles traveling through the facility. A network of fire and flammable gas detectors located throughout the plant enhances early fire detection.

Spills and leaks of chemicals, oil and other hydrocarbon materials are cleaned up as soon as reasonably possible after they are detected. Almost all of the LOGP facility is subject to the SBC Air Pollution Control District Fugitive Hydrocarbon Inspection and Maintenance Program, which requires the timely repair of leaking components. Oil and chemical soaked rags are kept in suitable containers in the facility prior to disposal. Grass and brush within 100 feet of the facility perimeter is mowed to a height of 6 inches or less.

There is a road immediately adjacent to the LOGP that surrounds the entire facility. Additionally, there is a road within 1,000 feet of the LOGP that also surrounds the entire facility. Both roadways are maintained at a minimum of 20-feet wide with paved or all weather surfaces able to support 20-ton County fire apparatus.

Water is supplied to the LOGP from the existing PXP water system in the Lompoc Field. Firewater at the LOGP is stored in two water tanks with respective capacities of 210,000 and 420,000 gallons. The tanks are kept full by an automatic level control system. The 210,000-gallon tank has a 4-inch National Standard male thread outlet for fire department engine use with the outlet within 10 feet of the fire engine parking area. The mobile fire equipment includes twenty-four 20-pound dry chemical extinguishers, seven 10-pound dry chemical extinguishers, two 5-pound dry chemical extinguishers, one 14-pound Halon extinguisher and one 17-pound Halon extinguisher, and two portable 150-pound dry chemical extinguishers.

The fire water system includes the water tanks, foam system, pumps, valving, fire monitors and detectors, hose reels, and fire hydrants and is shown in Figure 5.11-2. Two fire pumps with diesel engines are designed to deliver 2500 gallons per minute (gpm) each at 150 pounds per square inch (psi). The fire pumps and pump controllers comply with all requirements of NFPA Standard 20. The fire system water mains comply with all requirements of NFPA Standard 24. All the valves meet NFPA Standards 22 and 24 requirements and are UL listed. The fire hydrants are UL listed and installed in accordance with NFPA Standard 24. All of the fire monitors have approved adjustable fog nozzles attached. All of the monitors and hose reels have foam capability.

The control room is part of the main office structure. A loss of power to the control room results in the automatic shutdown of the entire facility. The control room is equipped with a smoke detection system that will initiate facility shutdown. Facility shutdown can also be initiated by flame or gas detection. Windows and frames on the plant side of the control building are explosion-resistant.

All of the bermed or diked areas hold at least 1 1/2 times the volume of the largest vessel or tank within the dike/berm. To prevent fire from spreading, the areas are sloped to prevent spills from pooling around or under any vessel or tank. All onsite drainage is collected in either the berm around the 100,000 barrels (bbl) oil surge tank or the retention basin, which is located away from the process equipment to the south of the facility.

The fire protection system is designed for a worst-case release from the largest vessel, which is the oil surge tank with 100,000 bbls capacity and 134 feet in diameter, and subsequent fire. The oil surge tank is protected by a fixed foam system as shown on Figure 5.11-2. There are three foam chambers mounted on the tank. A header is installed outside the bermed area to control the foam application. There is a 3,000-gallon atmospheric foam concentrate tank that is kept 1/3 full of foam concentrate. The concentrate is pumped into a distribution loop, which parallels the water mains. There is a "light water" pressure control valve and proportioner at each monitor, hose reel and the surge tank foam system. The concentrate pumps are run by an electric motor. Both pumps are a part of the emergency power system. The foam system, including foam pumps, tank, piping, proportioners, and applicators comply with NFPA Standard 11. An additional 1,200 gallons of foam concentrate is stored in 55-gallon drums.

The incoming and outgoing oil and gas pipelines are equipped with automatic shutdown valves. These valves will close in the event of high vessel pressure or high levels. The valves also can be closed by activating the emergency shutdown system in the control room or in the plant. The incoming oil line automatic valve is located downstream of the first oil/water separator. Each vessel, tank, and pump is equipped with manual valves, which will isolate individual pieces of equipment.

The emergency power generator is equipped with both manual and automatic startup, synchronizing, and shutdown. These functions are provided by a switchgear, which feeds the essential loads of the facility including flammable gas detectors, the H_2S detectors, and the flame detectors. Essential loads also include the facility's leak detection August Control System, power to the control building, power to the instrument air, and the electrical panel for the diesel firewater pumps.

PXP holds monthly safety meetings at each work site that include fire prevention. The LOGP also has periodic unannounced fire drills to ensure that the employees know their area of responsibility in the event of a fire. In the event of a small fire, employees will attempt to extinguish it using fire extinguishers and/or hose reels. In the event of a major fire, employees will activate the emergency system shutdown, with subsequent initiation of the ERP. It should be noted that since 1992[1] there has not been a fire event at the LOGP that was connected to the equipment failure or leaks. The only one recorded fire event at the LOGP was a grass brush fire outside the facility fence. <u>This fire burned 9.700 acres and was caused by a spark from a Torch/Nuevo power pole line in the Lompoc Field, igniting brush nearby underneath the pole. The District Attorney filed a complaint that Torch/Nuevo failed to clear brush under the poles in violation of Sections of the County Code (SBC Planning Commission, 2002). According to the</u>

[1] The SBCFD database goes back only to 1992.

Santa Barbara County Planning Commission Staff Report (June 2002), the response by Torch/Nuevo to the fire was considered satisfactory as they provided fire response activities and resources considered to be appropriate given the nature of the fire. The fire proved extremely hard to fight; however, the report indicated that the difficulty was not attributed to a lack of dedicated resources from Torch/Nuevo.

The LOGP facility is required to operate according to the safety rules contained in the PXP Safety Inspection, Maintenance and Quality Assurance Program (SIMQAP), as defined by the Point Pedernales Project Final Development Plan (FDP) Conditions. This program covers the LOGP, the three pipelines connecting the LOGP to Platform Irene, and the sales gas pipeline, and is required to be implemented during construction and operations.

The program is a dynamic document that is required to be regularly updated for new procedures, safety and maintenance technologies and processes, and then reviewed and approved by the County's Systems Safety and Reliability Review Committee (SSRRC), which includes the SBCFD.

5.11.1.3 Fire Protection at Platform Irene

Figures 5.11-3a and 5.11-3b show the main fire protection equipment on both decks of the platform. This equipment includes fire and smoke/heat detectors, fire monitors, combustible gas detectors, fire alarms and alarm pulls, fire extinguishers, hose reels, and breathing apparatus systems. Foam concentrate is stored in a 300-gallon tank. Foam can be delivered to hose reels, spraying systems, and to sprinklers, which are strategically located throughout the platform. Water to the foam system can be supplied by two electrical firewater pumps or by a new vertical turbine pump with a diesel engine. All three pumps use seawater. In addition, the two electrical firewater pumps can also utilize water from the 8-inch produced water return pipeline.

Because of the specifics of the offshore location, personnel are instructed to evacuate in case of any major emergency including a large fire. Survival capsules are provided for these types of emergencies.

5.11.1.4 Fire Protection at Orcutt Pump Station

The entire Orcutt Pump Station, including all pumps, sumps, equipment and aboveground piping, is curbed, guttered, and sloped so that any oil spilled will drain into a large pit. The magnitude of a spill that could occur from a leak at the pump station is approximately 160 bbls (UNOCAP ERP, 2000), given the pump station flowrate, oil volumes contained in station piping, leak detection system recognition and response times, and valve closure time (approximately 50 seconds).

Fire water for the pump station is supplied by the water district. The fire system includes 250-gallons of fire foam, a foam proportionator, a 1,000-gpm fire pump, a diesel emergency power generator, and several strategically located foam monitors, fire hoses and hydrants. The single oil storage tank (23,000 bbls) located at the pump station has sufficient secondary containment and is equipped with three foam injectors, each with a foam maker.

Risk analysis of the pump station has concluded (UNOCAP ERP, 2000) that the impacts from accidents such as a fire or oil spill would be limited to the facility itself. The pump station safe operation is maintained through ConocoPhillips SIMQAP that is updated on a regular basis in the same fashion as the LOGP SIMQAP.

5.11.1.5 Emergency Response

PXP and ConocoPhillips have implemented a three-tier emergency response organization following the Incident Command approach (see Table 5.11.2). PXP's Incident Commander (IC) will be the first PXP employee at the scene of an emergency incident and will take command until relieved by a more senior company employee. After conducting preliminary reconnaissance and reporting the situation to the IC, the first level of response will be mobilized by activating the Immediate Response Team. The team made up of PXP employees will be the first to respond to any incident, regardless of size. For minor incidents, this Level One response will likely be sufficient. The Point Pedernales onshore pipeline and facility personnel can field two shifts of the Immediate Response Team with the assistance of the District personnel. In the event of any emergency, including an oil spill at Platform Irene, the Clean Seas organization will also be among the first responders. ConocoPhillips would follow the same approach at its facilities. This approach is detailed in the UNOCAP Sisquoc Pipeline and Point Pedernales Pipeline Project Emergency Response Plan (PXP ERP 2004, with minor updates in May and August 2005).

The second level of response would be used when the magnitude of the incident or its impacts indicate the need for additional personnel. In a Level Two response, the District Sustained Response Team will augment the response with members drawn from the PXP or Conoco Phillips Santa Maria District employees.

The third level of response is initiated when the size of the incident dictates the need for a major sustained response effort. In a Level Three response, the Unified Command would be mobilized. This team is made up of specialists and specifically trained employees from various State and County agencies and contract companies.

The organization and resources available for each level of response are described in detail in the Lompoc Oil and Gas Plant Emergency Response Plan (LOGP ERP) revised by PXP in December, 2004 with minor updates in May and August of 2005, and in the UNOCAP ERP. The Oil Spill Response Plan developed for Platform Irene (November 2004) details the oil spill response at the platform and includes available company and outside resources. In the event that emergency assistance is needed, PXP has formal relationships with other firms and organizations in the local petroleum industry.

The SBC Area Oil and Gas Industry Emergency Response Plan (P-4 Plan) may be activated during an emergency that involves more than one onshore facility or involves offsite impacts to or threatens the public, livestock, property, or the environment. The P-4 Plan would be activated when the required response to an emergency incident is beyond the capabilities of the responsible company to mitigate effectively. The P-4 Plan may also be activated at any time that industry-mutual assistance is required. Mutual aid would be requested via the agreed upon P-4 mutual aid agreement.

The P-4 Plan is to be used by industry in coordinating its response, sharing resources, and functioning within the governmental command system present at an incident. It is activated at the discretion of the company or Agency Unified Command in command of emergency response activities. PXP and ConocoPhillips are members of Clean Seas and can call upon that organization's resources to assist in the clean up of a spill. If an oil spill were to occur at Platform Irene or offshore pipelines or at the Santa Ynez River at a time when there is enough flow to carry oil toward the ocean, assistance would be sought from Clean Seas for containment and cleanup operations. Other petroleum companies with emergency response capabilities operating in the Santa Maria Basin can also be called upon if assistance is needed.

Information in the event evacuation is required because of a hazardous material release can be found in the Santa Barbara County Hazardous Material Emergency Response Area Plan (September 2003) at the following website: http://www.sbcfire.com/hm/hazmatrespplan03.pdf. The discussion below summarizes the specific instructions for the public. The effectiveness of sheltering-in-place is dependent on initial public information and periodic informational updates. The public should be instructed to do the following:

- Close all internal and external doors and close and lock all windows
- Stop drafts: use wet towels in gaps under doors and duct tape (or other thick tape) around sides/cracks on doors and windows.
- Turn off outside ventilation (e.g., heat, air conditioner) and close vents to the outside.
- Turn off all sources of ignition, if it is safe to do so (e.g., heating systems, open flame, electrical appliances, and vehicles).
- Turn home air-conditioners and switch inlets to closed position. Seal any gaps around air-conditioners window units with tape and plastic sheeting, wax paper, or aluminum wrap.
- Turn off and cover exhaust fans in kitchens, bathrooms, dryer vents and other spaces.
- Turn off clothes dryer.
- Close fireplace dampers.
- Hold a wet cloth or handkerchief over nose and mouth.
- For a higher degree of protection, stay in the bathroom, close the door, turn on the cold water in the shower on a strong spray to "wash" the air.
- If an explosion is possible outdoors, close drapes, curtains, and shades over windows. Stay away from windows to prevent potential injury from flying glass.
- Minimize the use of elevators in buildings. Elevators tend to "pump" outdoor air through a building as they travel up and down.
- Once the toxic cloud passes and all steps have been taken to ensure that the incident will not recur, ventilation must be increased by opening windows and doors, turning on ventilation systems and moving occupants outdoors.

According to the above County plan, Primary and Alternative evacuation routes will vary by location and type of incident, weather, wind direction, topography, time of day, and numbers of people to be evacuated. The direction to travel on the routes is dependent upon the criteria mentioned earlier and the location of mass care reception centers determined at the time of the incident in concert with the Multi-Hazard Functional Plan.

Table 5.11.2 Level of Emergency Classification

Level of Emergency	Criteria	Incident Commander (IC)	Typical Fire Dept Response	Notification
1. Initial Response Minor On-Site Incident	1. Oil spill or produced water spill >1 bbl outside secondary containment designated for that vessel, system or pipeline, or >5 bbl inside secondary containment designated for that vessel, system or pipeline, unless it impacts or potentially impacts state or marine waters, in which case go to level 3. 2. Two combustible gas or fire eye alarms. 3. Verified high level combustible gas (50% LEL) alarm. 4. Single held detector with a LEL reading >50%. 5. Smoke investigation. 6. Fire reported out. 7. Hazardous material release outside secondary containment designed for that vessel, system or pipeline. 8. Bomb or extortion threat.	Highest ranking on-duty operations person until relieved by Fire Department	One Engine Code 2	9-1-1 and the facility notification
2. Sustained Response On-Site Incident	1. Oil or produced water spill >5 bbls, unless it impacts or potentially impacts state or marine waters, in which case go to level 3. 2. Any toxic gas release >10 ppm by fixed or hand-held monitor. 3. More than two combustible gas or fire eye alarms. 4. Fire. 5. Hazardous materials release requiring hazardous materials emergency response from emergency rescue personnel or contractors. 6. Sour gas in sales line. 7. Earthquake or flooding damages. 8. Activation of Emergency Shutdown for plant and/or pipeline.	Highest ranking on-duty operations person until relieved by Fire Department	1st alarm 3 engines, Chief Officer Code 3	9-1-1; Off duty personnel; Community notification; Agency notification as required
3. Major Incident with Public Exposure Potential (off site impacts)	1. Oil spill or produced water spill impacting or potentially impacting State or marine waters, or threatened release of oil or produced water impacting or potentially impacting state or marine waters. 2. Fire with potential for spreading. 3. Explosion. 4. Hazardous materials release or gas leak with off-site potential. 5. Civil disturbance. 6. State of War. 7. Highway 101 closure or impact on other significant access routes or roads.	Highest ranking on-duty operations person until relieved by Fire Department and potentially: Responsible party Sheriff's Department CHP Federal On-Scene Coordinator State On-Scene Coordinator	2nd alarm or greater, additional engines and/or specialized equipment/ resources 2 Chief Officers	9-1-1; Off duty personnel; Community notification; Agency notification as required

Source: PXP, 2005b. See Guidance Matrix below for term definitions.

Table 5.11.2 Level of Emergency Classification

Guidance Matrix for Emergency Incident Transition – Definition of Terms

These definitions are provided to define terminology in the guidance matrix for emergency Incident Transition ("matrix").

Combustible gas. A gas that burns, including the fuel gases, hydrogen, hydrocarbon, carbon monoxide, or a mixture of these.

Emergency rescue personnel. Any public employee, including but not limited to any fireman, firefighter, or emergency rescue personnel, or personnel of a local EMS agency or poison control center, who responds to any condition caused, in whole or in part, by a hazardous material that jeopardizes, or could jeopardize public health or safety or the environment.

Hazardous material. Any material that, because of its quantity, concentration, or physical or chemical characteristics poses a significant present or potential hazard to human health and safety or to the environment if released into the workplace or the environment. Hazardous materials include, but are not limited to, hazardous substances, hazardous waste, and any material which a handler or the administering agency has a reasonable basis for believing that it would be injurious to the health and safety of persons or harmful to the environment if released into the workplace or the environment.

Hazardous material emergency response. Includes, but not limited to, assessment, isolation, stabilization, containment, removal, evacuation, neutralization, transportation, rescue procedures, or other activities necessary to ensure the public safety during a hazardous materials emergency.

Marine waters. Those waters subject to tidal influence.

Oil. Any kind of petroleum, liquid hydrocarbons, or petroleum products or any fraction or residues therefrom, including but not limited to, crude oil, bunker fuel, gasoline, diesel fuel, aviation fuel, oil sludge, oil refuse, oil mixed with waste, and liquid distillates from unprocessed natural gas.

Oil spill. Any release of oil or produced water.

Potential release. "Threatened release".

Produced water. The water remaining after being separated through oil and gas processing.

Release. Any spilling, leaking, pumping, pouring, emitting, emptying, discharging, injecting, escaping, leaching, dumping, or disposing into the environment.

Secondary containment. Containment designated for that vessel, system, or pipeline.

Sour gas. Natural gas that contains corrosive, sulfur bearing compounds, such as hydrogen sulfide (H_2S) and mercaptans.

Threatened release. A condition creating a probability of harm, when the probability and potential extent of harm make it reasonably necessary to take immediate action to prevent, reduce, or mitigate damages to persons, property, or the environment.

Toxic gas. Gases which are extremely hazardous and may be fatal if inhaled or absorbed through skin.

Waters of the state. Any surface water or groundwater, including saline waters, within the boundaries of the state.

Vandenberg Air Force Base (VAFB) is the primary response agency during incidents that occur within the boundaries of the Base or on joint-jurisdictional property. VAFB may lend assistance to the County when the emergency/disaster is beyond the scope of civil authority resources. Requests for assistance may go directly to VAFB if immediate help is needed to save lives, prevent human suffering, or mitigate great property damage.

5.11.2 Regulatory Setting

There are numerous codes and standards that apply to fire protection and emergency response for facilities such as the ones affected by the proposed project. The applicable rules and regulations are listed in Table 5.11.3. Fire protection systems associated with the project must be detailed in the fire protection plan and include systems and design that ensure compliance ~~to~~ with a range of codes and standards. These are specified by the NFPA, American National Standards Institute (ANSI), Industrial Risk Insurers (IRI), American Petroleum Institute (API), SBCFD Criteria and Guidelines, and the Uniform Fire Code (UFC).

Table 5.11.3 Project Applicable Standards and Codes

Code/Standard	Description
ANSI B31.4	Liquid Petroleum Transportation Piping Systems
API RP 500	Classification of Hazardous Areas in Petroleum Pipeline Facilities
API Pub 2004	Inspection for Fire Protection
API Pub 2510	Design and Construction of LPG Installations
API Pub 2510A	Fire-Protection Considerations for the Design and Operation of LPG Storage Facilities
IRI IM.2.5.2	Plant Layout and Spacing for Oil and Chemical Plants
NFPA Standard 11	Low Expansion Foam and Combined Agent Systems
NFPA Standard 15	Water Spray Fixed Systems
NFPA Standard 22	Water Tanks for Private Fire Protection
NFPA Standard 24	Installation of Private Fire Service Mains and Their Appurtenances
NFPA Standard 25	Inspection, Testing and Maintenance of Water-Based Fire Protection Systems
NFPA Standard 30	Flammable and Combustible Liquids Code
NFPA Standard 58	Standard for the Storage and Handling of Liquefied Petroleum Gases
NFPA Standard 70	National Electric Code
SBC Code Chapter 15	Amendments to the UFC
SBC Permit Conditions	Various
SBC Public Works Engineering Design Standards	Roadways
SBCFD Standard 2A	Fire Protection Water Regulations Flows and Hydrant Spacing
SBCFD Standard 3	Fire Protection Hazard Area Requirements
SBCFD Standard 6	Hazardous Materials Conditions
SBCFD Standard 7	Alarms & Signaling Systems
SBCFD	Evacuation Near Flammable or Combustible Pipeline
UFC Article 02, Division II	Special Procedures
UFC Article 04	Permitting
UFC Article 09	Definitions and Abbreviations
UFC Article 10	Fire Protection
UFC Article 11	General Precautions Against Fire
UFC Article 12	Maintenance of Exits and Occupant Load Control
UFC Article 13	Smoking
UFC Article 14	Fire Alarm Systems
UFC Article 49	Welding and Cutting

Table 5.11.3 Project Applicable Standards and Codes

Code/Standard	Description
UFC Article 79	Flammable and Combustible Liquids
UFC Article 80	Hazardous Materials
UFC Article 85	Electrical Systems

IRI Guideline 17 indicates that fire water supplies should be capable of supplying at least 500 gallons per minute for 4 hours for pumping stations (IRI 17.3.3) and 3,000 gallons per minute for 4 hours to all areas of an oil storage terminal (IRI 17.3.4). These total a supply of 120,000 to 720,000 gallons of water.

Foam is frequently used in combination with the cooling water to extinguish fires associated with crude oil storage tanks. Foam can be applied to a liquid spill to suffocate a fire or prevent ignition of the flammable material spill. NFPA Standard 11 is applicable to foam application for protection of outdoor vertical atmospheric storage tanks containing flammable and combustible liquids by means of fixed foam discharge outlets. It specifies that application rates of foam should be at least 0.1 gpm/ft^2 of liquid surface area of the fixed-roof tank to be protected. NFPA 11 also states that for extinguishing crude petroleum fixed-roof storage tank fires, the adequate foam supply should last 30 to 55 minutes, depending on the type of foam outlet (NFPA 11, 3-3). For floating roof storage tanks, the adequate foam supply should last for at least 20 minutes with an application rate of 0.3 gpm. For dike fires, NFPA requires a foam supply with a minimum discharge rate of 0.16 gpm/ft^2 (for foam monitors) and minimum discharge time of 30 minutes for Class I hydrocarbons fires (NFPA 11, 3-7). Minimum foam application rate and discharge time for non-diked spill for adequate fire protection are 0.10 gpm/ft^2 and 15 minutes, respectively.

Safe equipment spacing requirements for petrochemical plants are given in IRI Guidelines IM2.5.2, NFPA Fire Protection Handbook, and Standard 30. Specific requirements for spacing of the vessels containing pressurized LPG are given in the API standard 2510. The applicable requirements to the proposed project spacing are summarized in Table 5.11.4.

IRI IM2.5.2 also gives guidelines for the overall oil and chemical plants layout. The most important of these include the following:

- There should be at least two entrances to the plant;
- The overall site should be subdivided into general areas (blocks) with a maximum size of 300 feet x 600 feet;
- Access roadways should be provided between the blocks to allow access to each block from at least two directions; and
- Road widths and clearances should be sized to handle large moving equipment and emergency vehicles.

Table 5.11.4 a-e Applicable NFPA, API and IRI Equipment Spacing Requirements

a. Inter-Unit Spacing Requirements (feet)

	Flares	Loading Racks	Service Buildings	Control Rooms	Fire Water Pumps	Process Units High Hazard	Pressure Storage Tanks	Atmospheric Storage Tanks
Flares	-							
Loading Racks	300	50						
Service Buildings	300	200	-					
Control Rooms	300	200	-	-				
Fire Water Pumps	300	200	50	50	-			
Process Units High Hazard	300	200	400	300	300	200		
Pressure Storage Tanks	400	350	350	350	350	350	*	
Atmospheric Storage Tanks	300	250	250	250	350	350	*	*

- = there is no spacing requirement
** = see table C (Storage Tanks Spacing Requirements)*

b. Intra-Unit Spacing Requirements (feet)

	Compressors	Pipe racks	Fired Heaters	Heat Exchanges	High Hazard Pumps	Emergency controls	Analyzer rooms
Compressors	30						
Pipe racks	50	-					
Fired Heaters	50	50	25				
Heat Exchanges	30	10	50	5			
High Hazard Pumps	30	15	50	15	5		
Emergency controls	50	50	50	50	50	-	
Analyzer rooms	50	50	50	50	50	-	-

c. Storage Tanks Spacing Requirements (feet)

	Floating Roof Tanks 3,000<C<10,000 bbls	Floating Roof Tanks 10,000<C<300,000 bbls	Pressure Storage vessels – Drums and Bullets
Floating Roof Tanks 3,000<C<10,000 bbls	0.5 D		
Floating Roof Tanks 10,000<C<300,000 bbls	D	D	
Pressure Storage vessels – Drums and Bullets	1.5 D 100' min.	1.5 D 100' min.	D

Source: IRI, 1993 to 1995, IM2.5.2.
C = tank capacity; D = tank diameter

d. Atmospheric Storage Tanks Spacing Requirements

	Required Distance (feet)
Between Adjacent Tanks (Shell-to-Shell)	1/6 sum of adjacent tank diameters but not less than 3 feet
From Property Line that Is or Can be Built Upon, Including the Opposite Side of a Public Way – With Protection for Exposures	½ times diameter of tank or 175 feet for tanks over 3,000,000 gal (72,000 bbls) capacity
From Property Line that Is or Can be Built Upon, Including the Opposite Side of a Public Way – No Protection for Exposures	Diameter of tank but need not to exceed 175 feet but no less than 5 feet
From Nearest Side of any Public Way or from Nearest Important Building on the Same Property	1/6 times diameter of tank but no less than 5 feet or 60 feet for tanks over 3,000,000 gal capacity

Source: NFPA, 2000.

e. Pressurized LPG Tanks Spacing Requirements

	Required Distance (feet)
Between Adjacent Tanks (Shell-to-Shell)	5 feet or ¾ of larger tank diameter
Adjoining Property Line	75 feet (for 30,000-70,000 gallon tanks)
Control buildings	50 feet
Other buildings	100 feet
Process vessels	50 feet
Flares and other equipment with open flames	100 feet
Fired equipment including process furnaces	50 feet
Rotating equipment, **except pumps taking suction from LPG tanks**	50 feet 10 feet
Loading facilities	50 feet

Source: API, 1995.

5.11.3 Significance Criteria

The SBC's Environmental Thresholds and Guidelines Manual (as updated through October 2006) does not contain any significance criteria for fire protection or emergency response as a separate issue area. Therefore, a set of criteria has been developed, with input from the SBCFD, against which the significance of the proposed project impacts to fire or other emergency protection can be judged. This document evaluates fire protection impacts for two general major areas: the general adequacy and design of onsite fire protection systems and the general adequacy of emergency response capabilities. By examining these two areas, the following significance criteria were developed. The proposed project would be considered to have a significant impact in the fire protection and emergency response area if:

- The project site does not contain adequate fire water and/or fire foam supplies to meet the recommended NFPA Standards and the IRI guidelines.
- The project equipment layout does not meet the API, NFPA, and IRI recommendations for equipment spacing (see Table 5.11.4).

- The project facilities do not have sufficient capabilities in early fire detection and fire spread prevention as per the NFPA requirements.
- The project site is located more than 10 miles (15 minutes) from an emergency response location with both hazmat (spill response) or fire fighting capabilities (i.e., a fire station or facility with fire fighting and emergency response capabilities), accessibility to the site is difficult or limited, and the site does not have an adequately developed emergency response plan.

5.11.4 Impact Analysis for the Proposed Project

This section characterizes the fire protection and emergency response impacts generated by the proposed project. ~~Modifications of equipment and operations at Orcutt, Santa Maria, and Sisquoc Pump Stations are minor and could be handled within the requirements of the ConocoPhillips SIMQAP, therefore these changes are not expected to have any impact on the fire protection or emergency response.~~

Impact #	Impact Description	Phase	Residual Impact
Fire.1	Due to equipment modifications at Valve Site #2 the increased potential for upset conditions at the site could create impacts to fire protection and emergency response resources.	*Operations*	*Class III*

Installation of three new pumps on the emulsion pipeline at Valve Site #2 is not expected to significantly increase the risk of fire or oil spills. All appropriate fire and oil spill prevention measures would be undertaken by PXP during the installation as well as during the new operations, as required in the LOGP SIMQAP, which covers Valve Site #2 and the pipelines from Platform Irene.

Valve Site #2 can be accessed by emergency personnel and equipment within 15 minutes. Operation of the new pumps at Valve Site #2 would increase the probability of an oil spill at this location (see Section 5.1, Risk of Upset/Hazardous Materials). This increase in the probability of an oil spill would represent an increase in the demands on emergency response services. PXP is required by the Point Pedernales Final Development Plan (FDP) and LOGP Safety Inspection, Maintenance and Quality Assurance Program (SIMQAP) to follow a number of measures that would serve to reduce the impacts of the proposed project, and therefore decrease the demands on the emergency response services. These measures include remote controls for the pumps to allow for automatic shutdown in response to various malfunctions (e.g., high vibration, low suction pressure, high and low discharge pressure, high bearing and case temperatures, low and high voltage, and overload). Given the high water content of the produced oil in the emulsion pipeline, fire is not expected to be an issue in the event of an oil spill.

Because there are sufficient resources to respond to an upset condition and these resources are located within 15 minutes response time from the valve site, and the likelihood of a fire is low; the impacts to fire protection and emergency response from the installation of the new pumps at Valve Site #2 are considered adverse but not significant.

Mitigation Measure

As with any major equipment and operation changes at oil and gas facilities, it is necessary to alter the fire protection, oil spill, and emergency response plans if the changes affect the contents of the plans. Therefore the following mitigation measure is required to mitigate the impact to the maximum extent feasible in accordance with Santa Barbara County (SBC) policies:

Fire-1 PXP shall review and revise the Fire Protection Plan, Emergency Response Plan, and Oil Spill Response Plan that apply to all the facilities which will have equipment or operations modifications due to the proposed project. The plans shall be submitted to the SBC Fire Department and P&D for review and approval prior to land use clearance.

Residual Impact

Impact Fire.1 is considered *adverse but not significant (Class III).*

Impact #	Impact Description	Phase	Residual Impact
Fire.2	Operation of the new power line to Valve Site #2 could result in impacts to fire protection and emergency response resources due to addition of an ignition source into a high fire hazard area.	*Operations*	*Class III*

Overhead power lines always pose a fire risk when, during severe wind conditions, a line could break, fall, and cause a brush fire. The LOGP and pipeline route are located in a high fire hazard area. Chaparral provides the most widespread wildland fuel threat in Santa Barbara County. These communities are characterized by woody shrubs of chamise, ceanothus and Manzanita, which dominate dry rocky slopes and provide erosion control and watershed protection. As discussed in Section 5.2, Terrestrial and Freshwater Biology, Burton Mesa chaparral is most commonly observed in the pipeline corridor east of Oak Canyon as the pipeline crosses the Burton Mesa Reserve north of the Lompoc Federal Penitentiary in a northeasterly direction, and north of the LOGP over Harris Grade. The Burton Mesa Reserve is an area approximately 6,000 acres in size that surrounds Vandenberg Village and extends generally from the eastern property line of VAFB and eastward to Mission Hills and bounded on the north and south by the LOGP and Highway 1, respectively. This plant community is the dominant feature between the VAFB eastern property line and the LOGP, and north of the LOGP over Harris Grade. Grasslands and fields present the potential for fast moving wildland fires that can transition into heavier fuel beds and tree canopies.

According to California Department of Fish and Game, July 2005, on the Burton Mesa Ecological Reserve and adjacent La Purisima Mission State Historic Park, 28 fires have occurred over the past 53 years, not including fires entirely on Vandenberg Air Force Base. All of the fires since 1950 have been ignited as a result of human activity or elements. As discussed earlier, the most recent fire, the Harris Grade fire that burned 11,000 acres in 2000 was caused by a spark from a Torch power pole line in the Lompoc Field, which ignited brush under the pole. The probability of this type of fire could be minimized by clearing vegetation in the vicinity of the power lines (see Mitigation Measure Fire-2).

Another possible fire from a power line could occur when a pole is impacted by a vehicle, causing a line break that causes a fire. All of the power poles would be cemented in the ground and would meet all the design requirements of PG&E regarding exposure to wind. The location of the power poles would be in a remote area on VAFB that is not subject to high levels of traffic, which minimizes the likelihood of a vehicle impacting a power pole.

Because of the low likelihood of fire, adequate response capabilities, and adequate response time, the impacts to fire protection and emergency response resources are considered to be adverse but not significant.

Mitigation Measure

As with Impact Fire.1, the existing LOGP Fire Protection Plan must be revised to reflect changes in the project operations. Therefore, the following measure is recommended to mitigate this impact to the maximum extent feasible in accordance with SBC policies.

Fire-2 The applicant shall update the LOGP Fire Protection Plan <u>(FDP Condition P-10)</u> to include the power line, in particular, the Flammable Vegetation Management <u>Plan, and Fire Prevention and Inspection Program</u> parts of the plan, to minimize possibility of a brush fire. The applicant shall submit the updated Fire Protection Plan to SBC Fire Department for review and approval prior to land use clearance.

Residual Impact

Impact Fire.2 is considered *adverse but not significant (Class III).*

Impact #	Impact Description	Phase	Residual Impact
Fire.3	Increased risk of upset due to increased oil flow rates through the project pipelines and pipeline facilities could create impacts to fire protection and emergency response resources.	*Increased Throughput* *Extension of Life*	*Class III*

Increased flow rates would increase spill volumes by 114 barrels (bbls). In the worst-case scenario, rates would increase by 688 bbls, if the SCADA system is not operational (see Section 5.1, Risk of Upset/Hazardous Materials) over current operations, which could result in a larger area being impacted as a result of a spill. This rate increase could increase the size of the area that the emergency responders would have to manage. However, the change in spill volumes is relatively small (3.6 to 10.9 percent), and response capabilities are currently available for spill volumes that could occur with the proposed project. The increase in spill volume above baseline volumes would not necessitate increasing the response capabilities in the region. Given the nature of the crude oil (high water content), it is highly unlikely that a fire would result in the event of a spill (see Section 5.1, Risk of Upset/Hazardous Materials). The Point Pedernales Project facilities originally have been designed to handle flowrates higher than expected with the proposed project's flowrates. The existing facilities' Fire Protection and Emergency Response Plans have been developed for flowrates up to 36,000 barrels per day (bpd) of dry oil; therefore these plans would be applicable for the expected increase in flow rates. However, the Orcutt Pump Station is limited by the SBCAPCD PTO 7511 to a throughput of 9,125,000 bbls per year (which averages 25,000 bpd). If the crude oil flow rate through the pump station is increased, ConocoPhillips' SIMQAP would have to be updated as required to reflect the operation, maintenance, or safety changes.

With the proposed project, the expected life of the Point Pedernales facilities would be extended, thereby extending the need to maintain the required fire protection and emergency response capabilities for these facilities; however, the pipeline facilities represent only a very small portion of the local response services scope of work. The public response services are partially funded by PXP to provide the services, and this funding would continue if the facilities' life term is extended. Extension of life of the PXP pipelines is therefore viewed as not significant. Because of the low likelihood of fire, adequate response capabilities and response time, the impacts associated with the increased throughput and extension of life are considered to be adverse but not significant.

Mitigation Measures

No mitigation measure has been identified.

Residual Impact

Impact Fire.3 is considered *adverse but not significant (Class III).*

Impact #	Impact Description	Phase	Residual Impact
Fire.4	Increased likelihood of upset conditions due to equipment modifications at the LOGP and potential increase of wet oil and sour gas quantities processed at the facility could create impacts to fire protection and emergency response.	*Operations Increased Throughput Extension of Life*	*Class III*

The LOGP facility has a fire detection system that is designed to detect flame sources early. The major vessels and equipment spacing satisfies the applicable requirements.

The grading under the LPG/NGL vessels is sufficiently sloped towards the retention basin outside the southern boundary of the facility to prevent liquid pooling under the vessels. Other storage tanks, vessels, and equipment are provided with secondary containment dikes to prevent fire spreading to other areas of the facility.

The LOGP facility is within the required response time (less than 15 minutes) from several fire stations: Lompoc Station No. 51 (SBC) and City of Lompoc Stations No.1 and No.2. Combined with the resources onsite, these fire stations have sufficient fire fighting and emergency response capabilities. The facility has an emergency response plan that is approved by and coordinated with the SBCFD. The site has good access for the fire and other emergency vehicles.

The LOGP facility has a sufficient supply of water and foam for fire fighting purposes, which was determined in the Torch Fire Protection Plan for LOGP (May 1998 revision) and updated by PXP in March 2005.

Equipment spacing at the LOGP facility satisfies the American Petroleum Institute (API), National Fire Protection Association ~~Agency~~(NFPA), and Industrial Risk Insurers (IRI) recommendations. The most important or hazardous equipment and the applicable distances are listed in Table 5.11.5. This table shows that the facility satisfies the applicable spacing requirements.

Table 5.11.5 Equipment Spacing at the LOGP

Equipment or Vessel	Distance from Other Equipment, feet	Minimum Required Distance, feet	Requirement Satisfied?
Oil Storage Tank 100,000 bbls [b, c]	200 – facility fence-line and any vessels or equipment	175	Yes
LPG Storage Tanks [d]	>200 – flare, 150 – heater treaters	100 – any open flame source	Yes
	95 – LPG loading racks	50 - loading racks	Yes
	>300 – any buildings at facility	50 – control building 100 – other buildings	Yes Yes
	>150 – gas processing equipment	50 – process equipment	Yes
Flare [a]	>300 – LPG loading racks	300	Yes
Firewater Pumps [a]	>300 – any equipment	300 – flare 200 - loading racks	Yes Yes

Notes: a, b, c, d letters correspond to the specific tables in Table 5.11.4.

The LOGP facility would continue to require response services for a longer period of time than projected in the approved Point Pedernales Project. This constitutes an extension of life impact. However, the public response services are partially funded by PXP to provide response services to the LOGP and other related facilities. This funding would continue to be provided if the life of the facilities is extended.

Equipment changes that are connected with the increased oil and gas throughput are minor and would not have significant impact to the fire protection or emergency response. The LOGP facility along with its fire protection system was designed to process a maximum of 36,000 bpd of dry oil, therefore operation at higher oil and gas processing rates would not have a significant impact on fire protection or emergency response. Also, the facility's Fire Protection and Emergency Response Plans were developed for maximum flowrates of 36,000 bpd of dry oil, therefore these plans would be applicable for the expected increase in oil flow rates. Because of adequate facility design, sufficient response capabilities and response time the impacts on the fire protection and emergency response resources for the LOGP facility are considered adverse, but not significant.

Mitigation Measures

No mitigation measures have been identified.

Residual Impact

Impact Fire.4 is *adverse but not significant (Class III).*

5.11.5 Impact Analysis for the Alternatives

Detailed descriptions of the various alternatives have been provided in Chapter 3.0. This section provides a discussion of the fire protection and emergency response impacts of the various alternatives.

5.11.5.1 No Project Alternative

Scenarios 2 and 3. As discussed in Section 3.2, under the No Project Alternative Scenarios 2 and 3, production of the federal portion of the Tranquillon Ridge field would and would not

occur, respectively. However, no extension of life of Point Pedernales facilities (Platform Irene, pipelines, and LOGP) is assumed under either scenario. With ~~the No Project Alternative~~ Scenarios 2 and 3, Impacts Fire.1 through Fire.4 would not occur because there would not be changes at Valve Site #2, including installation of a new power line, and no changes in oil flow rates over current conditions (i.e., baseline).

Options for Meeting California Fuel Demand. The relative fire protection and emergency services impacts associated with the various options for meeting California fuel demand are summarized in Table 5.11.6.

Table 5.11.6 No Project Alternative Comparison to Options for Meeting California Fuel Demand, Fire Protection and Emergency Response

Source of Energy		Impacts
Other Conventional Oil & Gas		
	Domestic onshore crude oil and gas	Likely to displace, rather than eliminate, fire protection and emergency response impacts.
	Increased marine tanker imports of crude oil	Would likely displace fire protection impacts, but would increase emergency response impacts proportionately to increased oil spill risk.
	Increased gasoline imports[1]	Would increase fire protection and emergency response impacts, especially if tanker trucks are used.
	Increased natural gas imports (LNG)	Would increase fire protection and emergency response impacts due to either increased tanker trucks or tankering.
Alternatives to Oil and Gas		
	Fuel Demand Reduction: increased fuel efficiencies, conservation, electrification[2]	
	Alternative transportation modes	Proposed project impacts would be eliminated.
	Implementation of regulatory measures	Proposed project impacts would be eliminated.
	Coal, Nuclear, Hydroelectric	Proposed project impacts would be eliminated. Construction and operation of power facility infrastructure could generate fire protection and emergency response impacts.
	Alternative Transportation Fuels	
	Ethanol/Biodiesel[3]	Fire protection and emergency response impacts would increase due to increased truck traffic.
	Hydrogen[2]	Proposed project impacts would be eliminated. Potential fire protection and emergency response impacts due to operation of hydrogen delivery systems.
	Other Energy Resources[2]	
	Solar[2,4]	Proposed project impacts would be eliminated. Operational fire protection and emergency response impacts would be nominal.
	Wind[2,4]	Proposed project impacts would be eliminated. Operational fire protection and emergency response impacts would be nominal.
	Wave[2,4]	Proposed project impacts would be eliminated. Operational fire protection and emergency response impacts would be nominal.

Footnotes:
1. Pipeline and tanker truck import from out-of-State assumed.
2. Assumes that Tranquillon Ridge production would not be replaced with other petroleum-based energy supply.
3. Assumes ethanol and biodiesel used as blends only and therefore would reduce, but not eliminate Tranquillon Ridge or equivalent production.
4. Assumes, large centralized facilities.

5.11.5.2 VAFB Onshore Alternative

The VAFB Onshore Alternative would require the construction and operation of a drilling and production facility, 10 miles of pipelines, and six miles of power line and associated substation on southern VAFB. In addition, a pipeline tie-in station, and associated electrical substation and power line would be required. The onshore drilling and production site would be located directly west of Space Launch Complex 5 (SLC-5) on southern VAFB. SLC-6 is located south of Honda Canyon, south of the alternative drilling and production site. The alternative drilling/ production site could impose severe safety considerations on some VAFB operations, especially during launch windows (see Risk of Upset/Hazardous Materials Section 5.1.5.2). The fire protection and emergency services impacts are as follows:

Impact Fire.1, Valve Site #2 upset conditions, would not apply to the VAFB Onshore Alternative. Impact Fire.4, LOGP risk of upset, would be the same as for the proposed project.

Impact Fire.2 - Power Line Operations would introduce risks similar to the proposed project due to the new power lines ~~route from the new substation to the VAFB onshore~~to the alternative drilling/production site and pipeline tie-in station. Possible fire from a power line could occur when a pole is impacted by a vehicle or blown down by high winds, causing a line break that causes a fire. Such was the case for the December 22, 1977 Honda Canyon fire. This fire, which eventually burned approximately 9,000 acres, injured 65 people and took 4 lives, started when hurricane-force winds blew a power pole and transformer down in a dry brushy draw on south VAFB near Honda Ridge Road (http://lompoconline.com/ Ron_Fink/fire.html). As a result of this tragedy, significant changes were made in the wild fire management program at VAFB. In addition to the Santa Barbara County Fire Department, there are ten other fire agencies providing fire protection within the County of Santa Barbara: Of the eleven fire protection agencies, only the USDA Forest Service, Santa Barbara County Fire Department and the VAFB Fire Department have wildland fire protection as part of their primary mission. Both the USDA Forest Service – Los Padres National Forest and the DOD VAFB Fire Department staff 20-person inter-regional “Hotshot” handcrews. Hotshot crews are highly trained and organized wildland firefighting crews that are extremely versatile. Currently, VAFB Fire Department response capabilities include 5 Type 1 engines and 1 truck company at 3 locations, 1 Hazmat squad, 5 Airport crash/fire/rescue companies, 3 Water Tenders, 1 hand crew and 1 truck company (6 locations). VAFB also participates with the City of Lompoc in a Mutual Aid agreement.

As discussed for the proposed project, the risk of fire from overhead power lines could be minimized by clearing vegetation in the vicinity of the new power lines. All of the power poles would be secured to cement foundations and would meet all the design requirements of PG&E regarding exposure to wind. The location of the power poles would be in a remote area on VAFB that is not subject to high levels of traffic, which minimizes the likelihood of a vehicle impacting a power pole.

Because of the low likelihood of fire, adequate response capabilities, and adequate response time, the impacts to fire protection and emergency response resources are considered to be *adverse but not significant* (*Class III*). Mitigation Measures Fire-1 and Fire-2 would apply to mitigate this impact to the maximum extent feasible in accordance with SBC policies.

Impact Fire.3 - Pipeline Risk of Upset would not occur offshore but would increase onshore. The new pipelines,~~and~~ drilling/production site, and pipeline tie-in station associated with this alternative would generate risks to public safety and Base personnel (see Section 5.1.5.2, Risk of Upset/Hazardous Materials). In the event of an oil spill, there would need to be emergency response capabilities similar to what is required for the proposed project. Catchment basins would need to be included in the pipeline design in accordance with Mitigation Measures OWR-5 and OWR-12. Impact Fire.3 would stay the same as for the proposed project, *adverse but not significant (Class III)*.

Impact #	Impact Description	Phase	Residual Impact
Fire.5	Pipeline and production/processing facilities construction could create short-term impacts to fire protection and emergency response.	*Construction*	*Class II*

Construction of the new onshore pipeline, production/processing facilities, and power lines would be short-term and is not expected to have significant impacts on emergency response resources. The Applicant would be required to follow all fire and oil spill prevention measures, and other safety precautions required by regulations for excavation.

The construction of the pipeline would require hot work for welding, which has the potential to start fires. In addition, movement of the construction equipment could result in sparks that have the potential to start fires. Although the pipeline construction would occur within high fire hazard areas, it would be near existing roadways and UPRR right-of-way, reducing the likelihood of a spark-generated fire and providing adequate emergency response accessibility. Further, a VAFB fire station is located on Coast Road, in close proximity to alternative facilities.

Mitigation Measures

Fire-3 All construction equipment shall be equipped with the appropriate spark arrestors and functioning mufflers. The applicant~~PXP~~ shall submit the pipeline construction procedures to the SBC Fire Department for review and approval prior to land use clearance.

Fire-4 A fire watch with appropriate fire fighting equipment (i.e., hydrants, water truck, etc.) shall be available at the project site at all times when welding or grinding activities are taking place. Further, welding or grinding shall not occur when sustained winds exceed 15-20 mph, as determined by SBC Fire Department, unless an SBC Fire Department approved wind shield is on site. The applicant~~PXP~~ shall submit the pipeline construction procedures to the SBC Fire Department for review and approval prior to land use clearance.

Fire-5 All rubber-tired construction vehicles shall be equipped with appropriate fire fighting equipment, such as shovels and axes or pulaskis, to aid in the prevention or containment of fires. The applicant~~PXP~~ shall submit the pipeline construction procedures to the SBC Fire Department for review and approval prior to land use clearance.

Residual Impact

The residual impact for Impact Fire.5 is considered *significant but mitigable (Class II)*.

5.11.5.3 Casmalia East Oil Field Processing Location

Impacts Fire.1 to Fire.3 would be the same as for the proposed project.

***Impact Fire.4 – LOGP Upset*:** The part of Impact Fire.4 that is related to increased throughput would be eliminated because the processing facilities that pose the greatest risk of upset and demand for emergency resources would be moved to Casmalia. Because there still would be pumps and compressors at the LOGP site beyond the currently projected life of the Point Pedernales facilities, and these remaining facilities would have fire protection and emergency response requirements, the part of Impact Fire.4 related to extension of life would remain, though greatly reduced in magnitude.

Impact Fire.5 – Construction Risk of Upset: Construction of the Casmalia Alternative pipeline would be short-term and is not expected to have significant impacts on emergency response resources. The construction of the pipeline would require hot work for welding, which has the potential to start fires. In addition, movement of the construction equipment could result in sparks that have the potential to start fires. Since the pipeline construction would occur within high fire hazard areas, the impact due to construction is considered *significant but mitigable (Class II)* with the implementation of Mitigation Measure Fire-3, Fire-4, and Fire-5.

Impact #	Impact Description	Phase	Residual Impact
Fire.6	Construction of Casmalia site facilities and dismantling of the LOGP could create short-term impacts to fire protection and emergency response.	*Construction*	*Class III*

Increased truck traffic involved in materials and equipment deliveries and the removal of refuse from dismantling of the LOGP could increase the likelihood of road accidents. During the LOGP dismantling, open-flame cutting (if used) of equipment and piping that were used for oil processing would increase the likelihood of fire. Open flame work (e.g., welding) at the new facility site that is located in a high fire hazard area could also increase the likelihood of fire. Trenching to install new pipelines would increase risk of damaging other hazardous pipelines or power cables and could result in a fire or explosion. The California Fire Marshal Report on hazardous liquids pipelines states that third-party damage is one of the leading causes of pipeline failure (see Section 5.1, Risk of Upset/Hazardous Materials). However, PXP is required to follow California Code of Regulations, Title 1, Division 5, §§4215-4217, regarding notifications of the Underground Service Alert (USA) prior to beginning excavations, markings of the existing pipelines in the vicinity of the project site, and other safety measures during excavations. Dismantling the old facilities is expected to have similar impacts as constructing the new facilities at Casmalia site. Both constructing and dismantling would be short-term, however. Any adverse impacts would be mitigated by appropriate construction techniques and safety measures; therefore, the impact would be adverse but not significant.

Mitigation Measures

Fire-6 For the new facilities, PXP shall follow all appropriate fire protection and safety measures outlined in the Point Pedernales Project Final Development Plan (FDP), Systems Safety and Reliability, Part P. PXP shall submit the construction procedures to the SBC Systems Safety Reliability Review Committee (SSRRC) for review and approval prior to land use clearance.

Residual Impact

Impact Fire.6 is *adverse but not significant (Class III).*

Impact #	Impact Description	Phase	Residual Impact
Fire.7	Operation of the new oil and gas facility at Casmalia East site could create long-term impacts to fire protection and emergency response.	*Operations Extension of Life*	*Class II*

Operating the new oil and gas facility at the Casmalia site could create significant impacts to ~~the~~ fire protection or emergency response resources due to the increased demand that an oil and gas processing facility would have on fire protection services in the southern Orcutt/Santa Maria area. The facility would generate potential fire hazards due to releases of crude oil, produced gas and natural gas liquids. The facility would also generate toxic gas hazards due to a potential release of produced gas or acid gas, which could be generated as part of the produced gas treatment process.

Under this alternative, the majority of the LOGP facility would be dismantled. However, crude oil shipping pumps and produced gas compressors would still remain at the site. Therefore, fire protection and emergency response requirements would still remain at the LOGP site, but they would be substantially reduced. A new processing facility at Casmalia would shift the primary emergency response capabilities from the Lompoc area to the Santa Maria area. The new site is within 8 to 10 miles from the fire stations in Santa Maria, which can provide response to the Casmalia site within 15 minutes. Fire stations located in Lompoc (17 to 18 miles from the new site) would serve as secondary response services. The Orcutt/Santa Maria fire stations currently do not have resources to be the primary responder to an oil and gas processing facility emergency situation other than fire (e.g., HazMat teams, spill response capabilities).

The new facility would also extend the life of the remaining Point Pedernales facilities. Because the existing response resources could not provide adequate emergency response to the Casmalia area, impacts to fire protection and emergency response resources are considered to be significant.

Mitigation Measures

Mitigation Measure Fire-6 is applicable to operations of the new facilities as well as for construction. In addition, the following mitigation measures are required.

Fire-7 The new facility shall be designed in accordance with all applicable fire protection and emergency response standards. The new facility should be designed with all early fire detection and prevention of fire spread as the basis of the fire safety design. The facility should have adequate supply of water and oil fire fighting foam as per the National Fire Protection Association ~~Agency~~ (NFPA) requirements (i.e., Standards 11, 15, 22, 24, 25). The facility layout should provide sufficient access for emergency response vehicles and provide adequate equipment spacing as per the American Petroleum Institute (API) and Industrial Risk Insurers (IRI) guidelines (IRI IM 2.5.2). The new facility should have fire detection monitors positioned in the locations most likely to be affected by fire. All appropriate equipment such as crude oil storage tanks should have sufficient secondary containment. Grading under liquefied petroleum gas (LPG) storage vessels should be sloped to allow any spilled flammable liquids to flow outward from the vessel and into an impoundment area. The applicant shall submit all appropriate documentation for the new facility to the SSRRC for review and approval prior to land use clearance

Fire-8 Fire protection, oil spill, and emergency response plans of the new facility shall be developed or adjusted using the similar LOGP plans and coordinated with the SBC Fire Department. These plans shall address the fire prevention measures at the facility, the fire suppression systems, the specific hazards at the facility, and fire and emergency response training and planning. The Fire Protection, Oil Spill Response, and Emergency Response Plans shall be submitted to the SBC Fire Department for review and approval prior to land use clearance.

Fire-9 The facility operators/owners shall provide funding to the SBC Fire Department to provide adequate staffing and equipment for the Santa Maria Fire Station to address the emergency response requirements of the Casmalia oil and gas processing facility. The facility operators/owners shall enter into an agreement with the SBC to provide the reasonable share of funds for fire protection and emergency response. The operators/owners shall provide documentation of the monetary deposits into the appropriate funds prior to land use clearance.

Residual Impact

With incorporation of the measures listed above and Mitigation Measure Fire-3, Impact Fire.7 would be reduced to a *less than significant level (Class II).*

Impact #	Impact Description	Phase	Residual Impact
Fire.8	Operation of the sour gas pipeline to the new plant at Casmalia East site could create long-term impacts to fire protection and emergency response.	*Operations*	*Class II*

This alternative would require that a new sour gas pipeline be built from the LOGP to the Casmalia oil and gas processing facility. This pipeline would have similar hazard zones to the sour gas pipeline from Platform Irene to the LOGP. However, the risk to public safety that is associated with this pipeline would be greater (see Section 5.1, Risk of Upset/Hazardous Materials). The pipeline would be in close proximity to a number of residences in southern Orcutt. The pipeline would present both fire and toxic hazards that would place additional requirements on fire protection and emergency response. For a major portion of this pipeline, the Santa Maria Fire Station No. 22 would be the primary responder. The Santa Maria fire stations do not currently have resources to be the primary responder to an oil and gas processing facility emergency situation (e.g., HazMat teams, oil spill response capabilities) (see Table 5.11.1). Because the adequate response resources are not available, this impact is considered to be significant.

Mitigation Measures

Mitigation Measure Fire-9 would apply, along with these additional measures.

Fire-10 The sour gas pipeline shall be equipped with a leak detection system that is capable of detecting leaks as small as ¼ inch. The pipeline shall be equipped with remotely operated block valves to limit the volume of material release in the event of a leak or rupture. The applicant shall submit documentation for the pipeline controls design to the SBC SSRRC for review and approval prior to land use clearance.

Fire-11 The pipeline shall be constructed following all applicable standards for sour gas pipeline service. The applicant shall submit all pipeline documentation (e.g. route, materials of construction, operation procedures) to the SBC SSRRC for review and approval prior to land use clearance.

Mitigation Measure Risk-3 (see Section 5.1, Risk of Upset/Hazardous Materials) requires that the route of the LOGP-Casmalia pipeline to be not closer than 2,500 feet from southern Orcutt.

Residual Impact

With incorporation of the mitigation measures listed above and Mitigation Measure Risk-3, the residual impact would be considered *less than significant (Class II)*.

5.11.5.4 Alternative Power Line Routes to Valve Site #2

Impacts Fire.1, Fire.3, and Fire.4 would stay the same as for the proposed project. The magnitude of Impact Fire.2 would greatly decrease as installation of a portion of the power line below ground, as opposed to above ground, would eliminate addition of a new ignition source to a portion of the power line route, which is located in high fire hazard area.

5.11.5.5 Replacement of Oil Emulsion Pipeline from Platform Irene to LOGP

Impacts Fire.1 and Fire.2 would not occur because Valve Site #2 modifications would not be needed. Impact Fire.4 would be the same as for the proposed project. Impacts Fire.6, Fire.7, and Fire.8 (Casmalia construction and operations) would not apply to this alternative.

Impact Fire.3 – Pipeline Risk of Upset would stay the same as for the proposed project as discussed below. The replacement pipeline would be designed, maintained and operated using the LOGP SIMQAP. Since the replacement pipeline would follow the same right-of-way as the existing pipeline, the same catchment basins would be available to contain spills in the vicinity of Santa Ynez River. The pipeline valves would use the same valve sites, and the same control and leak detection system would be in place. The existing pipeline operation has a risk of fire or oil spill. However, these risks are a part of the baseline for this analysis. The replacement pipeline would have greater wall thickness and fewer anomalies due to corrosion and erosion, therefore, the replacement pipeline is expected to have a decreased spill probability (~10 percent). However, the potential spill volume would be the same and in the event of an oil spill there would still need to be emergency response capabilities similar to what is required for the proposed project. Therefore, Impact Fire.3 would stay the same as for the proposed project, *adverse but not significant (Class III)*.

Impact Fire.5 – Construction Risk of Upset: Construction of the replacement emulsion pipeline would be short-term and is not expected to have significant impacts on emergency response resources. There is a potential of encountering and damaging the existing Point Pedernales pipelines during excavation; however, the pipelines would not be in operation during construction. The applicant would be required to follow all fire and oil spill prevention measures and other safety precautions required by regulations for excavation. This would include draining the existing pipelines prior to beginning the excavation work for the new pipeline.

The construction of the pipeline would require hot work for welding, which has the potential to start fires. In addition, movement of the construction equipment could result in sparks that have the potential to start fires. Since the pipeline construction would occur within high fire hazard areas, the impact due to construction is considered *significant but mitigable (Class II)* with the implementation of Mitigation Measures Fire-3, Fire-4, and Fire-5.

5.11.565 Alternative Drill Muds and Cuttings Disposal

Onshore activities under these alternatives are the same as for the proposed project. Therefore, Impacts Fire.1 through Fire.4 would be the same as for the proposed project.

5.11.6 Cumulative Impacts

5.11.6.1 Offshore Oil and Gas Projects

Potential offshore oil and gas development projects within the proposed project area could include the Rocky Point, Lion Rock, Point Sal, Santa Maria, Purisima Point, Bonito and Sword Units, and Lease OCS-P 0409 (see Section 4.2). The hazardous nature of these ~~facilities~~ projects would require well-developed fire protection and emergency response services. These new oil and gas ~~facilities~~ projects could require significant additions to existing response services in the VAFB and Lompoc area; however, with project-specific requirements such as expanded or new fire protection and emergency response facilities, services and personnel, cumulative impacts would not be considered significant. Although the proposed project would prolong the life of the Point Pedernales Project, and thus its need for such services, with project-specific mitigation measures for the other potential offshore oil and gas-related projects in the area, its incremental contribution to cumulative impacts would not be considered significant. The other offshore and onshore oil and gas development projects discussed in Sections 4.3 and 4.4, respectively, are a substantial distance away from the proposed project; consequently, no overlap with their related fire protection and emergency response services would be anticipated to occur.

5.11.6.2 Onshore Projects

The potential onshore development projects discussed in Section 4.4 would put additional strains on existing fire protection and emergency response services; however, the proposed project's contribution to this impact is not expected to be significant. The fire protection services in Lompoc and Santa Maria are ~~adequate~~ expected to be augmented to service the future cumulative onshore developments. In addition, as presented in Section 4.4, a new County fire station and sheriff substation, to be located near the intersection of Burton Mesa Boulevard and Harris Grade Road, are currently under review. This would provide sufficient fire protection capabilities to service the additional onshore developments in the proposed project area. Therefore, the cumulative impacts on fire protection and emergency responses resources from the future onshore development would not be expected to be significant.

5.11.7 Mitigation Monitoring Plan

Mitigation Measure	Mitigation Requirements and Timing	Method of Verification	Timing of Verification	Party Responsible For Verification
Fire-1	PXP shall review and revise the Fire Protection Plan, Emergency Response Plan and Oil Spill Response Plan that apply to all the facilities which will have equipment or operations modifications due to the proposed project. The plans shall be submitted to the SBC Fire Department and P&D for review and approval prior to land use clearance.	The plans shall be reviewed prior to Land Use clearance.	Compliance with the plans shall be verified by annual drill and audit.	SBCFD
Fire-2	The applicant shall update the LOGP Fire Protection Plan (FDP condition P-10) to include the power line, in particular, the Flammable Vegetation Management Plan, and Fire Prevention and Inspection Program parts of the plan to minimize possibility of a brush fire. The applicant shall submit the updated Fire Protection Plan to SBC Fire Department for review and approval prior to land use clearance.	Prior to Land Use clearance.	Compliance with the Fire Protection Plan shall be verified through regular drills.	SBCFD
Fire-3 (VAFB Onshore, Casmalia, and Emulsion Pipeline Replacement Alternatives only)	All construction equipment shall be equipped with the appropriate spark arrestors and functioning mufflers. The applicant ~~PXP~~ shall submit the pipeline construction procedures to the SBC Fire Department for review and approval prior to land use clearance.	Prior to Land Use clearance.	Review during construction	SBCFD and EQAP monitor
Fire-4 (VAFB Onshore, Casmalia, and Emulsion Pipeline Replacement Alternatives only)	A fire watch with appropriate fire fighting equipment (i.e., hydrants, water truck, etc.) shall be available at the project site at all times when welding or grinding activities are taking place. Further, welding or grinding shall not occur when sustained winds exceed 15-20 mph, as determined by SBC Fire Department, unless an SBC Fire Department approved wind shield is on site. The applicant ~~PXP~~ shall submit the pipeline construction procedures to the SBC Fire Department for review and approval prior to land use clearance.	Prior to Land Use clearance.	Review during construction	SBCFD and EQAP monitor

Mitigation Measure	Mitigation Requirements and Timing	Method of Verification	Timing of Verification	Party Responsible For Verification
Fire-5 (VAFB Onshore, Casmalia, and Emulsion Pipeline Replacement Alternatives only)	All rubber-tired construction vehicles shall be equipped with appropriate fire fighting equipment, such as shovels and axes or pulaskis, to aid in the prevention or containment of fires. The applicant ~~PXP~~ shall submit the pipeline construction procedures to the SBC Fire Department for review and approval prior to land use clearance.	Prior to Land Use clearance.	Review during construction	SBCFD and EQAP monitor
Fire-6 (Casmalia Alternative only)	For the new facilities, PXP shall follow all appropriate fire protection and safety measures outlined in the Point Pedernales Project Final Development Plan (FDP), Systems Safety and Reliability, Part P. PXP shall submit the construction procedures to the SBC Systems Safety Reliability Review Committee (SSRRC) for review and approval prior to land use clearance.	Prior to Land Use clearance, and regularly during operations.	Compliance with the new FDP shall be verified through regular facility audits.	SSRRC (includes SBCFD)
Fire-7 (Casmalia Alternative only)	The new facility shall be designed in accordance with all applicable fire protection and emergency response standards. The new facility should be designed with all early fire detection and prevention of fire spread as the basis of the fire safety design. The facility should have adequate supply of water and oil fire fighting foam as per the National Fire Protection Association ~~Agency~~ (NFPA) requirements (i.e., Standards 11, 15, 22, 24, 25). The facility layout should provide sufficient access for emergency response vehicles and provide adequate equipment spacing as per the American Petroleum Institute (API) and Industrial Risk Insurers (IRI) guidelines (IRI IM 2.5.2). The new facility should have fire detection monitors positioned in the locations most likely to be affected by fire. All appropriate equipment such as crude oil storage tanks should have sufficient secondary containment. Grading under liquefied petroleum gas (LPG) storage vessels should be sloped to allow any spilled flammable liquids to flow outward from the vessel and into an impoundment area. The applicant shall submit all appropriate documentation for the new facility to the SSRRC for review and approval prior to land use clearance	Prior to Land Use clearance.	Through review of the facility documentation, such as facility plot plans, P&IDs, etc.	SSRRC

Mitigation Measure	Mitigation Requirements and Timing	Method of Verification	Timing of Verification	Party Responsible For Verification
Fire-8 (Casmalia Alternative only)	Fire protection, oil spill, and emergency response plans of the new facility shall be developed or adjusted using the similar LOGP plans and coordinated with the SBC Fire Department. These plans shall address the fire prevention measures at the facility, the fire suppression systems, the specific hazards at the facility, and fire and emergency response training and planning. The Fire Protection, Oil Spill Response, and Emergency Response Plans shall be submitted to the SBC Fire Department for review and approval prior to land use clearance.	Prior to Land Use clearance.	Compliance with the plans is verified through regular drills.	SBCFD
Fire-9 (Casmalia Alternative only)	The facility operators/owners shall provide funding to the SBC Fire Department to provide adequate staffing and equipment for the Santa Maria Fire Station to address the emergency response requirements of the Casmalia oil and gas processing facility. The facility operators/owners shall enter into an agreement with the SBC to provide the reasonable share of funds for fire protection and emergency response. The operators/owners shall provide documentation of the monetary deposits into the appropriate funds prior to land use clearance.	Prior to issuance of the FDP.	Review of monetary deposits into the appropriate accounts.	SBCFD
Fire-10 (Casmalia Alternative only)	The sour gas pipeline shall be equipped with a leak detection system that is capable of detecting leaks as small as ¼ inch. The pipeline shall be equipped with remotely operated block valves to limit the volume of material release in the event of a leak or rupture. The applicant shall submit documentation for the pipeline controls design to the SBC SSRRC for review and approval prior to land use clearance.	Prior to Land Use clearance.	Review prior to construction and operation	SSRRC
Fire-11 (Casmalia Alternative only)	The pipeline shall be constructed following all applicable standards for sour gas pipeline service. The applicant shall submit all pipeline documentation (e.g., route, materials of construction, operation procedures) to the SBC SSRRC for review and approval prior to land use clearance.	Prior to Land Use clearance.	Review prior to and during construction	SSRRC

5.11.8 References

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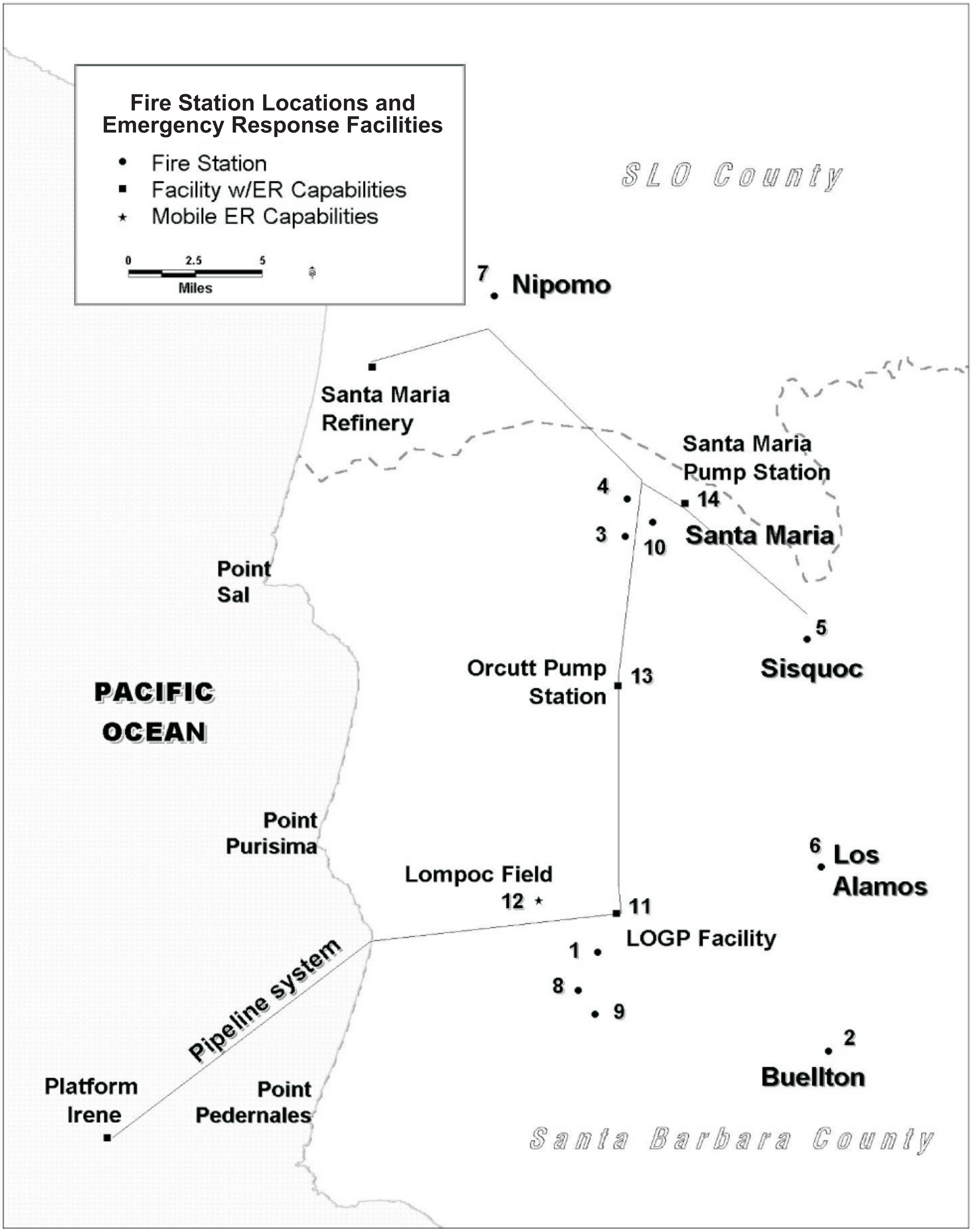

Source: MRS, 2002.

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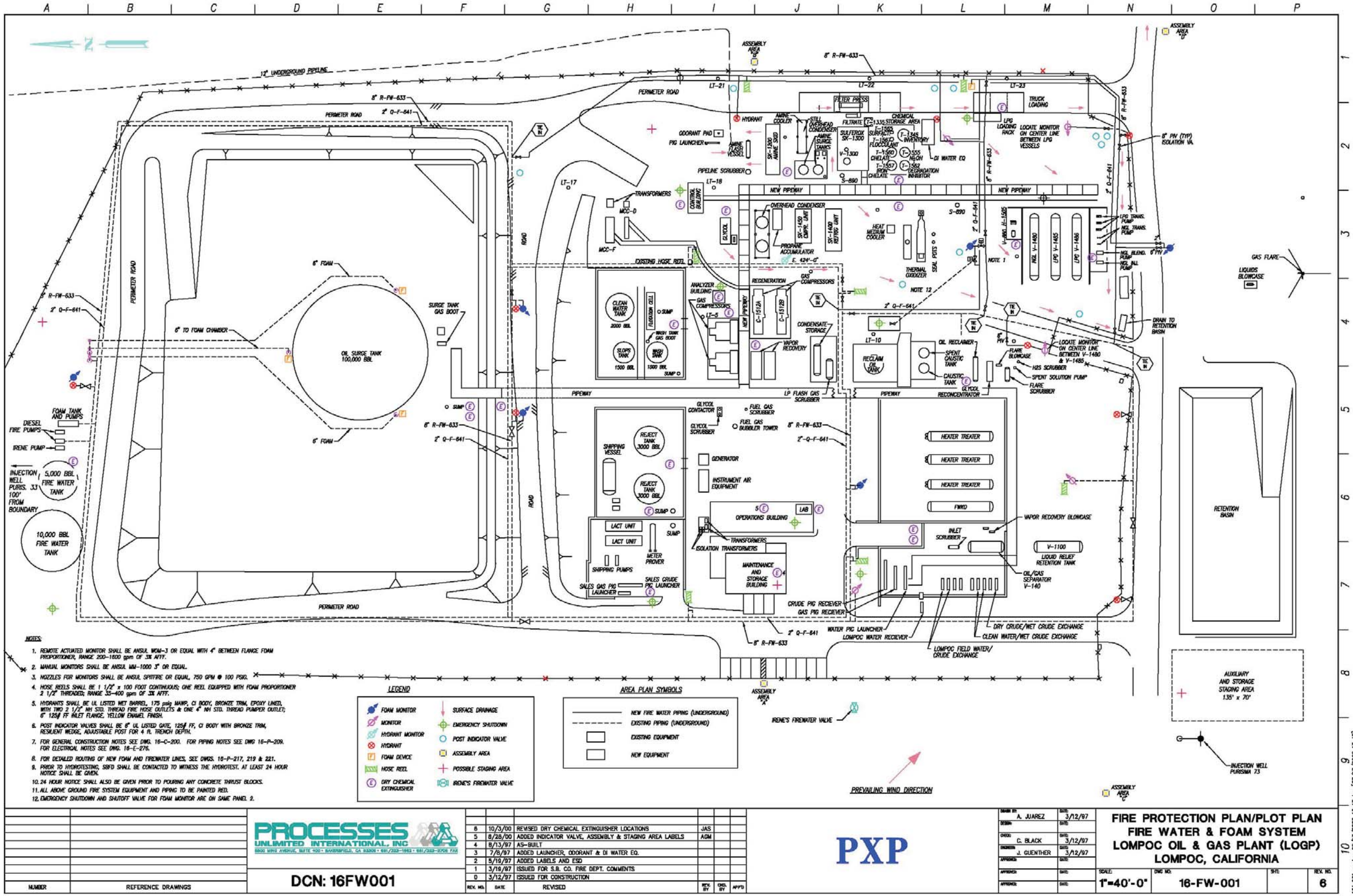
Figures 5.11-1

Fire Station Locations and Emergency Response Facilities



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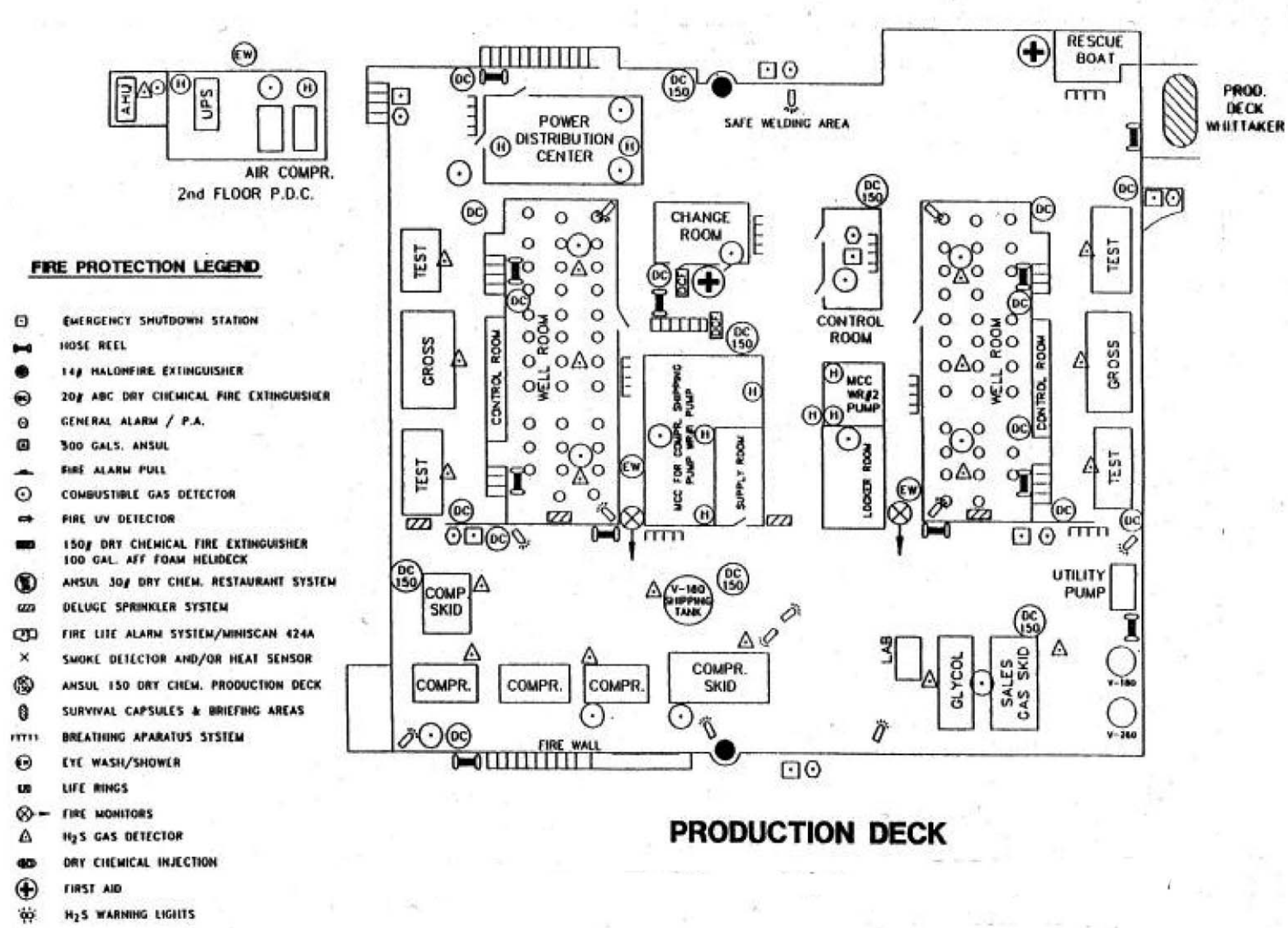
Figures 5.11-2

Fire Protection Equipment - Lompoc Oil and Gas Plant



Source: MRS, 2002.

Figure 5.11-3a

Fire Protection Equipment - Platform Irene Production Deck

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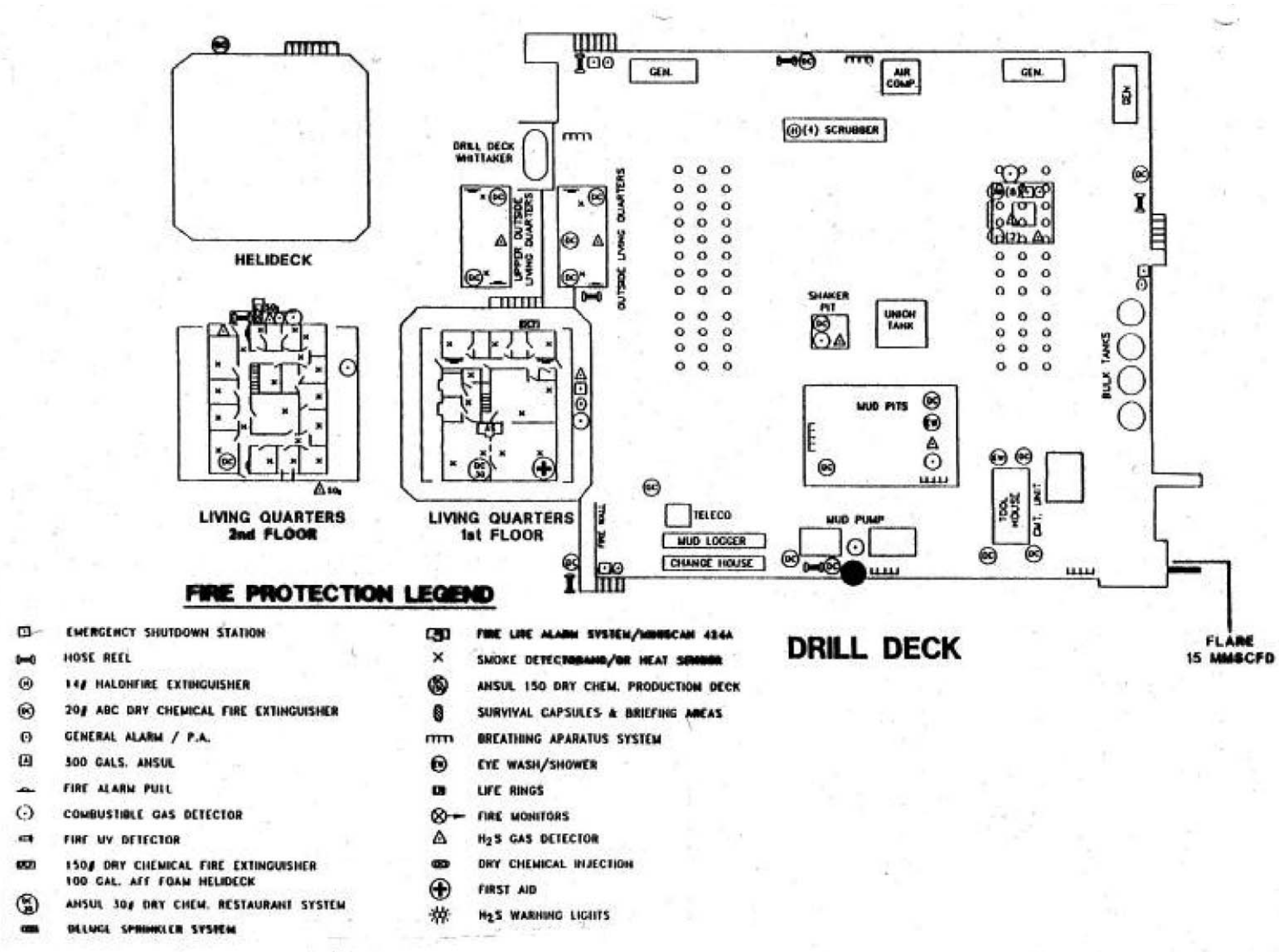

Source: MRS, 2002.

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Figure 5.11-3b

Fire Protection Equipment - Platform Irene Drill Deck

5.12 Cultural Resources

Humans have been living along the Santa Barbara coast for more than 10,000 years. The analysis of cultural resources, including both prehistoric and historic sites, can provide valuable information about the cultural heritage of both local and regional populations. Prehistoric sites range from small lithic scatters left behind by early stone-tool makers to the remains of large village sites found along the coast. Historic resources include small adobe homes as well as large historic districts encompassing numerous architectural structures and acres of land. Although cultural resources are primarily found on land, submerged resources such as shipwrecks, archaeological sites, and isolated artifacts are also known to occur in the waters off California.

5.12.1 Environmental Setting

5.12.1.1 Prehistoric and Historic Setting

The proposed project area was part of the territory occupied by speakers of the Chumash Purisimeño language at the time of European contact. Purisimeño, a subgroup of the Chumash language family, takes its name from the Mission La Purísima Concepción, founded in 1787 (Glassow 1996). Early historians and ethnographers have left behind little information about the Purisimeño Chumash, who have often been considered similar to the better known Barbareño, Inezeño, and Ventureño Chumash located in the Santa Barbara, Santa Ynez, and Ventura areas.

The chronological sequence developed by Chester King for the Santa Barbara Channel region is generally applicable to the territory of the Purisimeño Chumash. This scheme divides regional prehistory into three major periods: the Early Period, beginning ca. 8,000 years before present (B.P.), the Middle Period, beginning ca. 3,350 B.P., and the Late Period beginning ca. 800 B.P. (King 1974, 1979, 1981). Post-Pleistocene changes in climate and environment are reflected in the local archaeological record by approximately 8,000 B.P., the beginning of the Early Period. The Early Period of the Santa Barbara Channel mainland was originally defined by Rogers (1929), who called it the “Oak Grove” Period. The diagnostic feature of this period is the milling stone, which was used to grind hard seeds into flour. Toward the end of the Early Period, there is evidence of sea mammal procurement (Glassow et al., 1990) and the introduction of mortars and pestles for acorn production (Glassow, 1996).

The Middle Period (3,350 to 800 B.P.) is characterized by larger and more permanent settlements. Materials from Middle Period sites reflect a greater reliance on marine resources and include marine shells, fish remains, fishhooks, and harpoons. Toward the end of this period the plank canoe was developed, making ocean fishing and trade with the Channel Islands safer and more efficient (Arnold 1987). Terrestrial resources continued to be exploited as evidenced by the presence of contracting-stemmed and corner-notched projectile points from Middle Period sites (Bamforth 1984) and carefully shaped mortars (Glassow, 1996).

The Late Period (800 to 150 B.P., or approximately A.D. 1150 to 1800) was a time of increased social and economic complexity. The population increased, and permanent and semi-permanent villages clustered along the Santa Barbara Channel and on the Channel Islands. Trade networks, probably controlled by village chiefs, expanded and played an important part in local Chumash culture, reinforcing status differences and encouraging craft specialization. Terrestrial as well as marine resources were exploited. Acorns were processed using stone pestles and mortars, and deer were hunted with the bow and arrow. During this period there was an increase in the number of residential base camps and in the diversity of site settings.

Ethnohistoric data concerning Chumash settlements are most thorough in the vicinity of Mission San Luis Obispo. Some of the larger villages were apparently occupied all year, while some of the small villages were probably occupied only part of the year since residents regularly visited with relatives at neighboring settlements.

Archaeological information has revealed some distinctions between the Purisimeño and their neighbors to the south (Glassow 1996; SAIC 1991). The Purisimeño north of Point Conception relied more on shellfish and terrestrial mammals than on fish and marine animals. There is currently no firm evidence that the Purisimeño manufactured or used the plank canoe, which was very important to the Barbareño and Ventureño Chumash. In addition, Purisimeño population density was lower, and villages tended to be smaller.

Spanish influence in the region began in A.D. 1542, when the mariner Juan Cabrillo explored the California coast. The first Spanish expedition through what is now VAFB occurred in 1769, when the small Chumash Indian village of *Nocto* was noted near Point Arguello. The first Spaniards settling in the area were associated with two missions constructed in the Santa Ynez Valley: Mission la Purísima Concepción in 1787 and Mission Santa Ynez in 1804. These missions were the centers of Spanish influence in the region and affected native patterns of settlement, culture, trade, industry, and agriculture. Following the Mexican Revolution of 1821, California became part of the Republic of Mexico. Legal secularization in Mexico later resulted in confiscation of mission lands, which were then granted or sold for farming and ranching.

Secularization of lands and a focus on cattle raising marked the Rancho Period. The shift from stock raising to farming and more intensive land uses marks the advent of the American Period. Major forces of regional change during the last 100 years have been the railroads, maritime shipping, agribusiness concerns, the military, and the oil industry. Although oil development was occurring before the turn of the century, its rapid expansion and significant effect on the local economy began in the early 1900s. The military also became important to the local economy with the establishment of Camp Cooke in the 1940s, which later became VAFB and the headquarters for the 30th Space Wing.

5.12.1.2 Offshore Cultural Resources

The identification of offshore cultural resources within the project area was conducted in conjunction with the 1985 Point Pedernales EIR/EIS, which evaluated the construction of Platform Irene and the offshore pipeline route. This investigation included a review of literature and historic accounts relevant to the study region as well as available geophysical data (e.g., side-scan sonar, magnetometer and sub-bottom profiles) to locate potentially significant cultural resources within the project area. Construction of the offshore pipeline followed mitigation measures stipulated by the Minerals Management Service (MMS) by avoiding all potentially significant cultural resources. Therefore, there are no known potentially significant cultural resources within the original construction corridor of the offshore pipeline.

There are no known shipwrecks within 4 miles of Platform Irene, according to a recent Marine Cultural Resource Inventory for a proposed telecommunications system (SAIC 2000). This study reviewed the California State Land Commission's (CSLC) shipwreck database, U.S. Department of the Interior MMS's shipwreck database, and various other regional and local archives (see Figure I-13 of SAIC 2000). There is one shipwreck reported in the CSLC database about one mile south of the pipeline landfall site. No other submerged cultural resources are recorded in the project area.

5.12.1.3 Cultural Resources along the Pipelines from Landfall to LOGP

A site records and literature search at the Central Coastal Information Center (CCIC) at the University of California, Santa Barbara (UCSB) was performed on January 25, 2001 (SAIC 2001) to identify all recorded archaeological sites and surveys within a ¼ mile corridor of either side of the existing pipeline from its onshore presence near Valve Site #1 to the LOGP. A supplemental records search was performed at the CCIC on August 16, 2006. At least 30 cultural resource studies have been conducted within this 1/2-mile corridor, including 18 surveys, six testing and evaluation projects, one data recovery mitigation project, and one archaeological monitoring project. Of these studies, 12 were directly related to Union Oil Company's construction of Platform Irene, the LOGP, and the pipeline that connects the two. The area surrounding the existing pipeline, therefore, has been thoroughly studied.

According to the CCIC, 39 prehistoric sites, four historic sites, and one site with prehistoric and historic remains are located within a 1/2-mile corridor along the existing pipeline from landfall to the LOGP (44 total sites; see Table 5.12.1). Half of the sites are located within 200 feet of the existing pipeline and many fall within its original right-of-way. Of the 22 sites located within 200 feet of the existing pipeline, archaeological excavations were conducted at 20 of them to evaluate site significance and/or to conduct data recovery mitigation investigations associated with the Union Oil Pipeline Project (see Table 5.12.1). Most of these tested sites were determined to be potentially significant historic resources based on the CEQA guidelines outlined below (see Section 5.12.2).

Table 5.12.1 Archaeological Sites Within a ½-Mile Corridor Along the Existing Pipeline from Landfall to LOGP

Site	Within 200 ft of Existing Pipeline	Tested[1]	Site Significance[2]	Brief Site Description
SBA-0580	-	-	-	Prehistoric site with hammerstones and chert cobbles
SBA-0687	X	X	P	Middle Period deposit; possibly reoccupied small camp
SBA-0689	X	X	P	Multi-component site with diverse assemblage
SBA-0912	-	-	-	Light surface scatter of flaked stone and shell
SBA-0913	X	X	P	Low-density surface & subsurface deposits; possible hunting camp
SBA-0914	X	X	P	Two loci, representing two brief site occupations (low-density)
SBA-0915	-	-	-	Light surface scatter of flaked stone
SBA-1040	X	-	-	High density shell midden; possible village site
SBA-1742	-	X	P	Reoccupied Early Period site; probably seasonal base camp
SBA-1743	X	X	P	Low-density site; partially disturbed by fuel break
SBA-1744	-	-	-	Moderate-density scatter of flaked stone material

Table 5.12.1 Archaeological Sites Within a ½-Mile Corridor Along the Existing Pipeline from Landfall to LOGP

Site	Within 200 ft of Existing Pipeline	Tested[1]	Site Significance[2]	Brief Site Description
SBA-1761	-	-	-	Light surface scatter of flaked stone and shell
SBA-1762	X	X	P	Low-density deposit of flakes and shell
SBA-1860	X	X	P	Prehistoric deposit; possibly a small temporary campsite
SBA-1888	X	X	P	Moderately dense and diverse deposit; mainly Late Period single component site
SBA-1889	-	-	-	Light surface scatter of flaked stone
SBA-1890	-	-	-	Light surface scatter of flaked stone and shell
SBA-1891	X	X	P	Moderate-density shell and flake stone deposit; possible habitation site
SBA-1896	X	X	P	Subsurface prehistoric deposit; possibly briefly occupied campsite
SBA-1909	-	-	-	Low-density deposit of flaked stone
SBA-1910	X	X	N	Redeposited site material with prehistoric & modern debris
SBA-1917	X	X	P	Low-density, low diversity deposit; probably reused short term camp
SBA-1991	X	X	P	Four loci; only Locus A tested (low-density deposit)
SBA-1992	X	X	P	Low-density scatter within a disturbed context
SBA-1993	X	X	P	Low-density deposit within a disturbed context
SBA-1994	-	X	P	Low-density flake deposit with non-cultural shell
SBA-1995	X	X	N	Small, low-density site within a disturbed context
SBA-1996	X	X	P	Low-density prehistoric deposit associated with stabilized coastal dune
SBA-2120/H	X	X	P	Subsurface low-density prehistoric temporary camp; also 1940's debris
SBA-2126	X	X	P	Buried, low-density prehistoric deposit; possible reoccupied small camp
SBA-2225H	-	-	-	Brick retaining wall and historic debris
SBA-2263	-	X	-	Two loci; probably representing temporary camps
SBA-2264H	X	X	N	Collection of industrial debris; probably remains of a steam-driven oil pumping station
SBA-2265	-	X	-	Two loci; probably representing temporary camps
SBA-2362H	-	-	-	Corral/pasture with historic debris
SBA-2487	-	-	-	Light surface scatter of flaked stone and shell
SBA-2634H	-	-	S	Shipwreck of side-wheel steamer, "Yankee Blade"; off Destroyer Rock (NRHP listing)
SBA-2695	-	-	N	Low-density complex lithic scatter
SBA-2877	-	-	-	Sparse lithic scatter on a coastal terrace
SBA-2878	-	-	-	Sparse lithic and shell scatter on a coastal terrace
SBA-2881	X	-	-	Light density lithic scatter on a west-facing knoll
SBA-3173	-	-	-	Light surface scatter of flaked stone
SBA-3408	-	-	-	Light surface scatter of flaked stone
SBA-3420	-	-	-	Light surface scatter of flaked stone

1. *Investigated during site significance archaeological testing (URS Corporation 1986) and/or data recovery mitigation investigations (SAIC 1991) associated with the Union Oil Pipeline project.*
2. *Determined significant (S), potentially significant (P), not significant (N), unknown significance or not evaluated (-) based on report information (URS Corporation 1986, SAIC 1991) or site record forms.*

In addition to the 44 archaeological sites, 26 isolated artifacts have been recorded within the 1/2-mile corridor and consisted of flaked stone tools or debris, a steatite fragment, a sandstone cobble, a sandstone hammerstone, and a historic brass pipe valve cover (see Table 5.12.2). All but three of the artifacts were located and collected during construction monitoring of the Union Oil Pipeline Project. There is also potential for unrecorded archaeological sites in areas adjacent to the Santa Ynez River that could be buried within the floodplain by alluvial sediments since the sites were occupied. These floodplain areas are considered highly sensitive for cultural resources based on the number of archaeological sites recorded in similar environmental contexts.

Table 5.12.2 Artifacts Sites Within a ½-Mile Radius of the Existing Pipeline from Landfall to LOGP

Isolate	Within 200 ft of Existing Pipeline	Artifact	Associated Project
ISO-053	X	*Monterey chert biface*	Union Oil Pipeline
ISO-054	X	Steatite fragment	Union Oil Pipeline
ISO-055	X	Monterey chert chopper	Union Oil Pipeline
ISO-056	X	Monterey chert flake	Union Oil Pipeline
ISO-057	-	Monterey chert flake	Union Oil Pipeline
ISO-058	X	Monterey chert flake	Union Oil Pipeline
ISO-059	X	Non-cultural mudstone	Union Oil Pipeline
ISO-060	X	Sandstone hammerstone	Union Oil Pipeline
ISO-061	X	Chert drill	Union Oil Pipeline
ISO-062	X	Brass pipe valve cover	Union Oil Pipeline
ISO-063	X	Monterey chert flakes (2)	Union Oil Pipeline
ISO-064	X	Chert core/hammerstone	Union Oil Pipeline
ISO-065	X	Monterey chert hammerstone	Union Oil Pipeline
ISO-066	X	Franciscan chert projectile point	Union Oil Pipeline
ISO-067	X	Monterey chert flakes (2)	Union Oil Pipeline
ISO-068	X	Monterey chert flake	Union Oil Pipeline
ISO-069	X	Monterey chert blade	Union Oil Pipeline
ISO-070	X	Monterey chert core	Union Oil Pipeline
ISO-071	X	Sandstone cobble	Union Oil Pipeline
ISO-072	-	Monterey chert flake	Union Oil Pipeline
ISO-073	X	Monterey chert flake	Union Oil Pipeline
ISO-077	-	Chert biface (not collected)	Union Oil Pipeline
ISO-242	X	Chert flake (not collected)	Cable Replacement and Fiber Optics
ISO-243	-	Chert flake (not collected)	Cable Replacement and Fiber Optics
ISO-245	X	Chert projectile point (not collected)	Union Oil Pipeline
ISO-528	X	Franciscan chert core	Central Coast Aqueduct Project

There are no known historic standing structures, National Historic Landmarks (NHL), California State Historical Landmarks (CHL), or listings on the National Register of Historic Places (NRHP) or the CCIC's Historic Property Data File within a 1/2-mile corridor around the existing pipeline from landfall to the LOGP. No other known historic architectural resources are located within the 1/2-mile corridor along the existing pipeline from landfall to the LOGP, so no historic architectural resources would be affected by the project.

5.12.1.4 Cultural Resources along the Pipeline from LOGP to the Summit Pump Station (ConocoPhillips)

A site records and literature search at the CCIC at UCSB was performed on April 19, 2001 (SAIC 2001) to identify all recorded archaeological sites and surveys within a 1/2-mile corridor around the existing pipeline from the LOGP to the Summit Pump Station. A supplemental records search was performed at the CCIC on August 16, 2006. At least 49 cultural resource studies have been conducted within this 1/2-mile corridor, including 33 surveys, eight testing and evaluation projects, one data recovery mitigation project, two impact analyses, and two archaeological monitoring projects. Of these studies, three were directly related to the Union Oil Pipeline Project, and two were associated with replacing a small portion of the existing pipeline near the Summit Pump Station. According to the CCIC, most of the existing pipeline route from the LOGP to the Orcutt Pump Station has been previously surveyed for cultural resources. However, most of the existing pipeline route from the Orcutt Pump Station to the Summit Pump Station (approximately 17 miles) has never been surveyed for cultural resources, as this pipeline was built before CEQA review was required.

According to the CCIC, 18 prehistoric sites, nine historic sites, and two sites with prehistoric and historic remains have been recorded within a 1/2-mile corridor around the existing pipeline from the LOGP to the Summit Pump Station (see Table 5.12.3). Seven of these sites are located within 200 feet of the existing pipeline, including six that may fall within its original right-of-way. According to site record information, only six of the 29 archaeological sites within the 1/2-mile corridor have been previously evaluated for site significance (see Table 5.12.3).

Table 5.12.3 Archaeological Sites Within a ½-Mile Corridor Along the Existing Pipeline from LOGP to the Summit Pump Station

Site	Within 200 ft of Existing Pipeline	Tested[1]	Site Significance[3]	Brief Site Description
SLO-0097	-	-	-	Prehistoric habitation site
SLO-0141H	-	-	-	Dana Adobe built between 1841 & 1849 (NRHP-listed)
SLO-0525	-	-	-	Bedrock mortar and prehistoric midden
SLO-0753	-	-	-	Low-density lithic scatter
SLO-0804	-	-	-	Possibly ethnohistoric Chumash village of Nipomo
SLO-0805	-	-	-	Low-density lithic and shell scatter
SLO-0806	-	-	-	Low-density lithic and shell scatter
SLO-0807	-	-	-	Low-density lithic and shell scatter
SLO-1238	-	-	-	Low-density lithic scatter
SLO-1258	-	-	-	Low-density lithic scatter
SLO-1291	-	-	-	Low-density lithic scatter
SLO-1301	-	-	-	Low-density lithic scatter
SLO-1318H	X	-	-	Concrete pier foundation of a hay barn & associated debris
SLO-1319H	X	-	-	Part of the Pacific Coast Railroad bed
SLO-1320H	X	-	-	Part of the Pacific Coast Railroad bed
SLO-1618	-	-	-	Low-density shell scatter
SLO-1620	-	-	-	Low-density lithic scatter
SLO-1725	-	-	-	Low-density lithic scatter

Table 5.12.3 Archaeological Sites Within a ½-Mile Corridor Along the Existing Pipeline from LOGP to the Summit Pump Station

Site	Within 200 ft of Existing Pipeline	Tested[1]	Site Significance[3]	Brief Site Description
SLO-1726	-	-	-	Prehistoric quarry site and small shell scatter
SLO-1765	-	X[2]	P	Possible Early Period residential base camp
SLO-1803	-	-	-	Bedrock mortar site
SBA-1810	X	X[1]	P	Low-density lithic deposit
SBA-1970H	-	X[1]	N	Light scatter of bottle glass, porcelain, & Pismo clam
SLO-2030H	X	-	-	Scatter of historic debris (possibly associated with NRHP-listed Dana Adobe)
SLO-2031H	-	-	-	Historic quarry site (possibly associated with NRHP-listed Dana Adobe)
SBA-2121/H	X	X[1]	N	Historic debris and subsurface prehistoric site
SBA-2122/H	-	X[1]	N	Collapsed metal water tank, agricultural debris, & a prehistoric flake tool
SBA-2123H	-	X[1]	N	Historic artifacts in drainage
SBA-2124H	X	-	-	Historic artifact scatter

[1] *Investigated during site significance archaeological testing (URS Corporation 1986) and/or data recovery mitigation investigations (SAIC 1991) associated with the Union Oil Pipeline Project.*
[2] *Investigated during the Central Coastal Aqueduct Pipeline project.*
[3] *Determined significant (S), potentially significant (P), not significant (N), unknown significance or not evaluated (-) based on report information (URS Corporation 1986, SAIC 1991) or site record forms.*

There are no known NHL, CHL, or listings on the CCIC's Historic Property Data File within the 1/2-mile corridor along the existing pipeline from the LOGP to the Summit Pump Station. There is one listing on the NRHP, the Dana Adobe, which falls within the 1/2-mile corridor. The Dana Adobe was built in the 1840's near Nipomo Creek, approximately 1,000 feet from the existing pipeline. Two of the archaeological sites noted above (CA-SLO-2030H and -2031H) may be associated with the occupation of the adobe.

5.12.2 Regulatory Setting

Cultural resources include prehistoric and historic archaeological sites, districts, and objects; standing historic structures, buildings, districts, and objects; and locations of important historic events, or sites of traditional/cultural importance. Section 15064.5 (CEQA Guidelines, revised April 20, 2001) indicates a project may have a significant environmental effect if it causes "substantial adverse change" in the significance of an historical resource. Historical resources are defined in CEQA Guidelines section 15064.5 as the following:

1. A resource listed in, or determined to be eligible by the State Historical Resources Commission for listing in the California Register of Historical Resources (Pub. Res. Code §5024.1, Title 14 CCR, section 4850 et seq.).

2. A resource included in a local register of historical resources, as defined in section 5020.1(k) of the Public Resources Code or identified as significant in an historical resource survey meeting the requirements of section 5024.1(g) of the Public Resources Code, shall be presumed to be historically or culturally significant. Public agencies must treat any such resource as significant unless the preponderance of evidence demonstrates that it is not historically or culturally significant.

3. Any object, building, structure, site, area, place, record, or manuscript which a lead agency determines to be historically significant or significant in the architectural, engineering, scientific, economic, agricultural, educational, social, political, military, or cultural annals of California may be considered to be an historical resource, provided the lead agency's determination is supported by substantial evidence in light of the whole record. Generally, a resource shall be considered by the lead agency to be "historically significant" if the resource meets the criteria for listing on the California Register of Historical Resources (Pub. Res. Code §5024.1, Title 14 CCR, section 4852) including the following:

   a. is associated with events that have made a significant contribution to the broad patterns of California's history and cultural heritage;
   b. is associated with the lives of persons important in our past;
   c. embodies the distinctive characteristics of a type, period, region, or method of construction, or represents the work of an important creative individual, or possesses high artistic values; or
   d. has yielded, or may be likely to yield, information important in prehistory or history.

The California Coastal Commission (CCC) is responsible for implementing the policies of the Coastal Act of 1976, including those pertaining to cultural resource investigations conducted for impact analysis purposes pursuant to CEQA, NEPA, and the National Historic Preservation Act (NHPA). If any project-related direct impacts on cultural resources occur in the coastal zone, then they are subject to Coastal Commission Guidelines. According to the Coastal Act, "where development would adversely impact archaeological or paleontological resources as identified by the State Historic Preservation Officer, reasonable mitigation measures shall be required" (Pub. Res. Code § 30244).

Santa Barbara County also has policies (ordinances, General Plan, and CEQA Guidelines) that echo CEQA and reflect local policy on the preservation and enhancement of historical resources.

5.12.3 Significance Criteria

Section 15064.5 (CEQA Guidelines, revised October 26, 1998) indicates a project may have a significant environmental effect if it causes "substantial adverse change" in the significance of an "historical resource" or a "unique archaeological resource" as defined or referenced in CEQA Guidelines section 15064.5[b, c] (1998). Such changes include "physical demolition, destruction, relocation, or alteration of the resource or its immediate surroundings such that the significance of an historical resource would be materially impaired" (CEQA Guidelines 1998 section 15064.5 [b]).

Under CEQA, an impact on cultural resources is considered significant, therefore, if it adversely affects a resource that is listed in or eligible for listing in the California Register of Historical Resources or is otherwise considered a unique or important archaeological resource. In general, a project may have an adverse effect on a cultural resource if it would:

- Cause a substantial adverse change in the significance of a historical resource as defined in CEQA Guidelines section 15064.5;
- Cause a substantial adverse change in the significance of an archeological resource pursuant to CEQA Guidelines section 15064.5;
- Directly or indirectly destroy a unique paleontological resource or site or unique geologic feature;

- Disturb any human remains, including those interred outside of formal cemeteries; or
- Cause substantial physical damage to a resource considered to be important under the county guidelines.

Guidelines for Santa Barbara County follow many of the same criteria as CEQA. A significant resource:

a) possesses integrity of location, design, workmanship, material, and setting;

b) is at least 50 years old; and

c) is associated with a person or event that is important, was designed by an important person, is associated with a style, has outstanding design, conveys a sense of time and place, and is able to yield information important to a community or traditional way of life.

The guidelines also identify levels of significance, ranging from exceptional to little. Integrity also is rated by levels ranging from pristine to fair.

5.12.4 Impact Analysis for the Proposed Project

Impacts of this project on cultural resources are primarily associated with ground disturbance from new construction and accidental spills. New construction is limited to upgrades in pipeline systems (i.e., pump installation at Valve Site #2 and associated power line poles) and the potential need for pipeline maintenance and repair. The proposed project also includes modifications to the LOGP, but these modifications would not involve ground disturbance and, therefore, would not impact cultural resources.

5.12.4.1 Offshore Facilities

The proposed Tranquillon Ridge Project involves directional drilling of a maximum of 30 wells from Platform Irene into California State Lands, using extended-reach technology. No impacts on cultural resources would occur because access to the wells would be entirely through underground approach, several thousand feet below the ocean floor. Therefore, no mitigation measures are required.

Oil and gas from the wells would be transported to the LOGP for processing and distribution via the existing pipelines from Platform Irene offshore to landfall near Wall/Surf Beach. Since no new construction is necessary, no impacts on cultural resources would occur. Therefore, no mitigation measures are required.

5.12.4.2 Onshore Facilities

Impact #	Impact Description	Phase	Residual Impact
CR.1	Pipeline maintenance and repair would result in ground disturbance and potential impacts on cultural resources.	*Extension of Life*	*Class II*

There are 22 recorded archaeological sites located within 200 feet of the existing oil pipeline between landfall and the LOGP. Although these sites were previously disturbed by the construction of the existing pipeline, most are determined to be a potentially significant historic resource. No new modifications are proposed for this pipeline, but pipeline maintenance and repair, if needed, would result in ground disturbance and potentially significant impacts on any cultural resource in the affected areas. The proposed project would extend the life of the existing Point Pedernales project, thus extending the need for repair and maintenance activities along the pipeline by 20 years above that of the existing PXP project. Impacts on a potentially significant cultural resource would be considered significant.

Mitigation Measures

CR-1 PXP shall prepare and submit grading plans showing all ground disturbances within 200 feet of a recorded archaeological site. The grading plans shall be submitted to P&D prior to issuance of coastal development permit or land use clearance for grading.

All ground disturbance within 200 feet of a recorded archaeological site shall be monitored by a County-qualified archaeologist and, if prehistoric, by a Native American observer, unless the resource has been previously determined to have no potential for significance because it is re-deposited, an isolated occurrence, modern, or otherwise lacks data potential.

CR-2 PXP shall revise grading plans to include note for protocols to follow during unexpected discovery of archaeological resources. The grading plans shall be submitted to P&D prior to issuance of coastal development permit or land use clearance for grading. Prior to construction all crew members shall receive training on unanticipated cultural resource discovery protocols.

In the event of an unanticipated cultural resource discovery during construction, all ground disturbances within 200 feet of the discovery shall be halted or re-directed to other areas until the discovery has been documented by a county-qualified archaeologist, and its potential significance evaluated consistent with Santa Barbara County Cultural Resource Guidelines. Resources considered significant shall be avoided by project redesign. If avoidance is not feasible, the cultural resource shall be subject to a Phase 3 data recovery mitigation program (with Native American monitoring, if applicable), consistent with Santa Barbara County Cultural Resource Guidelines.

CR-3 If pipeline maintenance and repair are planned on a segment of the unsurveyed pipeline route, then a Phase 1 archaeological surface survey shall be conducted prior to land use clearance for grading to identify any cultural resources that may be affected. If a cultural resource is encountered during the survey, it shall be documented by a County-qualified archaeologist and its potential significance evaluated in terms of applicable criteria prior to maintenance and repair work. Resources considered significant shall be avoided or subject to a Phase 3 data recovery program (with Native American monitoring, if applicable), consistent with Santa Barbara County Cultural Resource Guidelines.

Residual Impact

With implementation of the above mitigation measures, the residual impact is considered to be *significant but mitigable (Class II).*

Impact #	Impact Description	Phase	Residual Impact
CR.2	Modifications to Valve Site #2 and installation of power poles would result in ground disturbance and potential impacts on cultural resources.	*Construction*	*Class II*

Modifications to Valve Site #2, located between landfall and the LOGP, would include installing: three new booster pumps; additional electrical transformers; switchgear, and associated power lines; and a transformer station to serve the pumps. All modifications to Valve Site #2 involving ground disturbance would be accommodated within the existing footprint of Valve Site #2, in an area that was previously disturbed during initial construction of the station and with no known cultural resources. The proposed Onshore Water Resources Mitigation Measure OWR-1, which would involve the construction of a berm around Valve Site #2, would occur within the existing disturbed area. Due to the lack of recorded sites and previous disturbance at this location, no impacts on cultural resources would occur.

Power line installation to Valve Site #2 would involve ground disturbance from constructing a new transformer station, installing new power poles, and a minor amount of backhoe trenching.

The proposed transformer station would be located in a farm field on the northwest corner of Renwick and Ocean Avenues. This location has been previously surveyed and there are no known cultural resources present. Therefore, impacts on cultural resources are not expected.

Approximately 13 to 15 power poles spaced 350 to 400 feet apart would be installed for the proposed 5,600 foot-long power line that would connect the new transformer station to the power pole line along the pipeline right-of-way and Terra Road. The proposed power line would be placed along Renwick Avenue and the east side of 13th Street within existing road shoulders. The new power poles would cause ground disturbance up to 10 to 12 feet deep. The route of the proposed power line that is located along the roadways was previously surveyed by County-qualified archaeologists, and there are no known cultural resources present within the corridor. Due to the absence of archaeological sites within the corridor, no impacts on cultural resources would occur.

Approximately three to five proposed power poles would be installed to support the proposed power line crossing of the Santa Ynez River. The new power poles would cause ground disturbance up to 10 to 12 feet deep. Approximately 300 feet of backhoe trenching would also be needed for undergrounding the power line under the VAFB power line immediately north of the river. Although there are no recorded cultural resources within the proposed power pole locations or within the small trenching area, there is a potential for unrecorded sites because these areas have never been surveyed for cultural resources. Areas adjacent to the Santa Ynez River are considered highly sensitive for cultural resources based on the number of archaeological sites recorded in similar environmental contexts. It is possible that ground disturbance associated with the proposed power poles or the proposed trenching could result in significant impacts on unknown cultural resources. Impacts on a potentially significant cultural resource would be considered potentially significant.

Approximately 600 feet of backhoe trenching would be needed for undergrounding the power line under 13th Street to connect the line with power poles along the pipeline right-of-way. The trenching locations were previously surveyed by County-qualified archaeologists, and there are no known cultural resources present at either location. However, it is possible that ground disturbance associated with the power line undergrounding and power pole locations could result in significant impacts to unknown cultural resources buried in the floodplain. Impacts on a potentially significant cultural resource would be considered potentially significant.

Most of the proposed ground disturbances would occur in areas without recorded archaeological sites resulting in less than significant impacts on cultural resources; however, the remote potential for encountering unknown cultural deposits exists. If these remains were unexpectedly disturbed, impacts could be potentially significant, depending on the type of resource impacted and the condition of the resource. The proposed pole line across Santa Ynez River and trenching in the area immediately adjacent to the river would be in the areas that have not been previously surveyed. Therefore, there is a potential for significant impact to cultural resources.

Mitigation Measures

Mitigation Measures CR-2 (described above) and CR-4 (below) would be applicable.

CR-4 A Phase 1 archaeological surface survey shall be conducted at unsurveyed areas of ground disturbance associated with installation of the power pole line across the Santa Ynez River and proposed trenching areas prior to land use clearance to identify any cultural resources that may be affected during construction. If a cultural resource is encountered during the survey, it shall be shall be avoided by power pole and/or trench relocation. If archaeological site avoidance is technologically infeasible due to topographic or engineering constraints, the site's potential significance shall be evaluated pursuant to Santa Barbara County Cultural Resource Guidelines and CEQA Guidelines Section 15064.5 criteria. Resources considered significant and unavoidable shall be subject to a Phase 3 data recovery program (with Native American monitoring, if prehistoric), consistent with Santa Barbara County Cultural Resource Guidelines, and if located on VAFB, shall incorporate the investigation methodology reviewed and approved by VAFB environmental management staff. To comply with VAFB requirements, any trenching or excavation in a floodplain on VAFB shall require archaeological monitoring.

Residual Impact

Potential impacts on unknown cultural resources could occur, but implementation of the above mitigation measures would minimize potential impacts by avoiding any significant resources identified during an intensive archaeological survey by power pole and/or trench location redesign, or by mitigating the impacts through a data recovery program. Due to the limited size of a given power pole and trench excavation area, it is reasonable to assume that they could be feasibly relocated to avoid most archaeological site areas. After application of mitigation measures the residual impact would be less than significant. Therefore, Impact CR.2 is considered to be *significant but mitigable (Class II).*

Impact #	Impact Description	Phase	Residual Impact
CR.3	Containment and cleanup activities associated with an accidental oil spill would result in ground disturbance and potential impacts on cultural resources.	*Increased Throughput* *Extension of Life*	*Class I*

The proposed project would extend the expected life of the onshore oil pipelines and would increase oil throughput from Platform Irene to the Summit Pump Station, which would amplify the magnitude of a potential spill. A pipeline leak or rupture would potentially lead to an oil spill anywhere along the onshore pipeline route, and activities related to oil spill containment and cleanup would potentially impact cultural resources. Impacts on a potentially significant cultural resource would be considered significant.

The nature of oil spill containment and cleanup activities and their potential for impacting cultural resources are inferred from the OSRP prepared by PXP for operations on Platform Irene and the Point Pedernales 20-inch oil pipeline (PXP, November 2004). Containment activities that would potentially affect cultural resources include the use of heavy earth moving equipment (e.g., graders, scrapers, front-end loaders) or manual excavation to remove oil-contaminated material. Soil removal by manual or mechanized means poses potential significant impacts on any cultural resource in the affected areas. Water flooding is another cleanup method whereby subsurface oil is forced to the surface by water pumped into the groundwater table. Although drilling holes for water flooding would potentially impact sites, flooding (in most cases) would be preferable to soil removal because it is likely that drilling would result in relatively low levels of subsurface disturbance. Staging areas for containment and cleanup equipment as well as vehicle and heavy equipment access and parking should not result in heavy subsurface impacts unless the area must be graded for equipment access. Significant impacts on surface assemblages may occur.

Mitigation Measures

CR-5 The Oil Spill Response Plan (OSRP) shall be revised to include procedures for minimizing impacts on cultural resources during oil spill containment and cleanup activities. These procedures shall include contacting a County-qualified archaeologist and Native American monitor in the event of a spill. To the extent possible, heavy earth moving equipment or manual excavation shall be minimized at archaeological sites. If unanticipated cultural resources are discovered during containment and cleanup activities, then a county-qualified archaeologist shall document the discovery at the earliest time it is deemed safe to do so. It is possible that post-cleanup archaeological excavations (with Native American monitoring, if applicable) shall be necessary to help mitigate impacts from the containment/cleanup ground disturbances. The revised OSRP shall be submitted to P&D prior to issuance of coastal development permit or land use clearance for grading.

Residual Impact

Implementation of the above mitigation measure would ensure that impacts from an oil spill would be minimized to the extent possible. However, certain impacts to significant cultural resources during or as the result of an oil spill cleanup might not be feasibly reduced to an adverse but not significant level. Although the likelihood of an accidental oil spill is low, there is a potential for *significant unavoidable adverse impacts* on cultural resources. Therefore, even after application of mitigation measures, the residual impact would be significant.

Impact #	Impact Description	Phase	Residual Impact
CR.4	Pipeline repair associated with an accidental produced water spill from the pipeline would result in ground disturbance and potential impacts on cultural resources.	*Extension of Life*	*Class II*

The proposed project would extend the expected life of the onshore produced water pipeline. A pipeline leak or rupture would potentially lead to a produced water spill, but, unlike an oil spill, no containment and cleanup activities that would involve ground disturbance would be needed. Pipeline repair would result in ground disturbance and potentially impact cultural resources, as described under Impact CR.1. Impacts on a potentially significant cultural resource would be considered significant.

Mitigation Measures

Mitigation Measures CR-1 and CR-2 would be applicable.

Residual Impact

With implementation of the above mitigation measures, the residual impact is considered to be *significant but mitigable (Class II).*

5.12.5 Impact Analysis for the Alternatives

Detailed descriptions of the various alternatives have been provided in Chapter 3.0, Alternatives. This section provides a discussion of the cultural resource impacts of the various alternatives.

5.12.5.1 No Project Alternative

Scenarios 2 and 3. As discussed in Section 3.2, under the No Project Alternative Scenarios 2 and 3, production of the federal portion of the Tranquillon Ridge field would and would not occur, respectively. However, no extension of life of Point Pedernales facilities (Platform Irene, pipelines, and LOGP) is assumed under either scenario. Under ~~the No Project Alternative~~ Scenario 2, only the portion of the Tranquillon Ridge Field in Federal waters would be developed, to the extent allowed by the existing Point Pedernales Project permits. With ~~the No project Alternative~~ either Scenario 2 or 3, modifications to Valve Site #2 and associated power lines would not be constructed. ~~This alternative~~ Neither Scenario 2 nor 3 would ~~not~~ extend the life of the Point Pedernales facilities, and oil throughput rates would be comparable to existing conditions. Therefore, there would be no new impacts on cultural resources, and no mitigation measures would be required.

Options for Meeting California Fuel Demand. The relative impacts to cultural resources associated with the various options for meeting California fuel demand are summarized in Table 5.12.4.

5.12.5.2 VAFB Onshore Alternative

Cultural resource impacts of the onshore drilling alternative would result from the disturbance of historic and pre-historic sites or paleontological resources by the construction and maintenance of facilities, and by containment or cleanup activities necessitated by accidents. There may also be adverse effects of industrial development and activity on the aesthetic qualities of culturally significant sites and landscapes.

Table 5.12.4 No Project Alternative Comparison to Options for Meeting California Fuel Demand, Cultural Resources

Source of Energy		Impacts
Other Conventional Oil & Gas		
	Domestic onshore crude oil and gas	Likely to displace, rather than eliminate, spill related impacts. Development of new production could have increased construction impacts depending on resources present on-site.
	Increased marine tanker imports of crude oil	Likely to displace, rather than eliminate, spill related impacts.
	Increased gasoline imports[1]	Likely to displace, rather than eliminate, spill related impacts.
	Increased natural gas imports (LNG)	Likely to displace, rather than eliminate, spill related impacts.
Alternatives to Oil and Gas		
	Fuel Demand Reduction: increased fuel efficiencies, conservation, electrification[2]	
	Alternative transportation modes	Proposed project impacts would be eliminated.
	Implementation of regulatory measures	Proposed project impacts would be eliminated.
	Coal, Nuclear, Hydroelectric	Proposed project impacts would be eliminated; however, coal, nuclear, and hydroelectric infrastructure development could introduce construction and operation impacts.
	Alternative Transportation Fuels	
	Ethanol/Biodiesel[3]	Proposed project oil spill impacts would be reduced. Potential ethanol/biodiesel spill impacts could occur. Potential increased construction impacts because of new plant construction.
	Hydrogen[2]	Oil spill impacts would be eliminated. Potential construction related impacts due to hydrogen delivery infrastructure development.
	Other Energy Resources[2]	
	Solar[2,4]	Would greatly reduce oil spill impacts to cultural resources. Potential increased construction impacts because of solar facility infrastructure construction.
	Wind[2,4]	Would greatly reduce oil spill impacts to cultural resources. Potential increased construction impacts because of wind facility infrastructure construction.
	Wave[2,4]	Would greatly reduce oil spill impacts to cultural resources. Potential increased construction impacts because of wave facility infrastructure construction.

Footnotes:
1. Pipeline and tanker truck import from out-of-State assumed.
2. Assumes that Tranquillon Ridge production would not be replaced with other petroleum-based energy supply.
3. Assumes ethanol and biodiesel used as blends only and therefore would reduce, but not eliminate Tranquillon Ridge or equivalent production.
4. Assumes, large centralized facilities.

The same impacts and mitigation measures that apply to the proposed project would also apply to the existing onshore PXP facilities whose operation would be prolonged by the onshore drilling alternative. These impacts would be predominantly to sites that have been previously disturbed by the construction and operation of the existing facilities. That disturbance was largely mitigated as required by the original Point Pedernales project approvals. The primary difference between the proposed project and this alternative is the potential for adverse effects on previously unaffected cultural sites and landscapes.

To assist the evaluation of the impacts associated with the construction and operation of new facilities under the onshore drilling alternative, record searches were performed at the Central Coastal Information Center (CCIC) on August 16, 2006 and at VAFB on August 23, 2006. From the resulting mapped and textual information, summarized in Table 5.12-54, there are at least 109 known archaeological sites within 0.5 miles of alternative facilities, and 44 sites that may be considered significant or potentially significant, within 200 feet of the areas potentially subject to disturbance by the onshore drilling alternative. The number of sites potentially affected is a minimum estimate because previously undiscovered sites are likely to exist in the affected areas.

To facilitate comparisons, the following section parallels that of the proposed project in terms of the types of impacts to cultural resources, uses the same numbering for those impacts, and concludes whether the impacts would be less than, similar to, or more severe than those of the proposed project. Impacts that are qualitatively different are assigned new numbers.

Table 5.12.54 Archaeological Sites Within a ½-Mile Corridor Around the VAFB Onshore Alternative Construction Footprint

Site	Within 200 ft of Scenario 1 or DPA[1]	Tested	Site Significance[2]	Brief Site Description[3]
SBa-0212				NA
SBa-0246				NA
SBa-0530	x	x	P	Light to heavy density shell midden, some small animal bones and moderate chert chippings
SBa-0531	x	x	P	Some fossilized tree and root, moderate levels of chert chipping waste and scattered surface artifacts
SBa-0533				NA
SBa-0534	x	x	S	Trace to moderate density chipping fragments (Monterey chert)
SBa-0536		x	P	Fossil forest area, as well as cultural remains
SBa-0537	x			NA
SBa-0538				NA
SBa-0539		x	S	Light to moderate density shell midden and chipping detritus as well as human remains
SBa-0549	x	x	P	Trace to heavy density chipping detritus and some cultural artifacts
SBa-0668				NA

Table 5.12.54 Archaeological Sites Within a ½-Mile Corridor Around the VAFB Onshore Alternative Construction Footprint

Site	Within 200 ft of Scenario 1 or DPA[1]	Tested	Site Significance[2]	Brief Site Description[3]
SBa-0669		x	P	Light density shell midden and light density chipping detritus
SBa-0670	x	x	S	Light to moderate density shell midden, chipping detritus and some animal bones
SBa-0671		x	P	Light density shell scatter and trace fire cracked rock
SBa-0672				NA
SBa-0673		x	P	Surface shell deposits and trace chipping detritus
SBa-0674	x	x	P	Light density chipping fragments
SBa-0675				NA
SBa-0676	x	x	P	Low densities of prehistoric and cultural remains present due to transplantation
SBa-0677		x	P	Dense deposit of shellfish and lithic debitage
SBa-0678		x	S	Light to heavy density chipping fragments and cultural artifacts
SBa-0679		x	P	Light to moderate density chipping detritus and some cultural artifacts
SBa-0680	x	x	P	Chert flakes and some small mammal bones
SBa-0681	x	x	P	surface distribution of chipping detritus
SBa-0682	x	x	P	Chipping waste and small artifacts
SBa-0683		x	P	Trace amounts of flake and scattered artifacts remains
SBa-0684		x	P	Trace density of chipping detritus, trace amounts of shell and some mammal bone
SBa-0685				NA
SBa-0686				NA
SBa-0689		x	P	Trace density of chipping detritus (surface scatter)
SBa-0773H	x			NA
SBa-0915		x	P	Light density flake
SBa-0921	x	x	P	Light surface density chipping waste of Monterey chert
SBa-0922		x	P	Trace surface chipping detritus
SBa-0923	x	x	P	Moderate density surface chipping waste (Monterey chert)
SBa-0924				NA
SBa-0925				NA
SBa-0931	x	x	P	Various cultural remains and debitage as well as trace amounts of shell
SBa-0932	x			NA
SBa-0933				NA

Table 5.12.54 Archaeological Sites Within a ½-Mile Corridor Around the VAFB Onshore Alternative Construction Footprint

Site	Within 200 ft of Scenario 1 or DPA[1]	Tested	Site Significance[2]	Brief Site Description[3]
SBa-0946				NA
SBa-1119		x	P	Moderate amount of mytilus, trace barnacle and trace chipping detritus
SBa-1120	x	x	P	Light, scattered shell
SBa-1121			P	Trace shell (weathered) and trace chert flakes
SBa-1122	x	x		Light density moderately weathered shell
SBa-1123				NA
SBa-1124	x	x	P	Two intact shells recovered from site, nothing else
SBa-1125H	x	x	P	Flakes and some marine shell
SBa-1126	x			NA
SBa-1127				NA
SBa-1128	x	x	S	Marine terrace with no shell and some chert flakes
SBa-1129	x	x	S	Marine terrace with some shell and weathered burnt bone
SBa-1130				NA
SBa-1144H	x	x	P	Cypress trees and some automobile parts
SBa-1145H		x	P	Intact historical refuse features present
SBa-1166	x			NA
SBa-1680				NA
SBa-1761		x	P	Some shell and low density flake
SBa-1815	x	x	P	Many chert flakes and some tools
SBa-1816		x	P	Chert flakes, some shell and charcoal
SBa-1819H		x	P	Model-T car parts dump with some scattered trash and broken glass
SBa-1891		x	P	Moderate density shell and flake deposit
SBa-1908	x	x	P	Trace chert flakes
SBa-1940				NA
SBa-2126	x	x	P	Deposits of lithics and shell unearthed by trenching
SBa-2146		x	P	Trace chert flakes and localized concentrations of shell
SBa-2147		x	P	Light to moderate Monterey chert flakes and some tools
SBa-2148	x	x	P	Small scatter of shellfish, fire affected rock and cultural remnants
SBa-2154		x	P	Low density scatter of Monterey chert flakes
SBa-2229		x	P	Flaked stone artifacts, marine shell and some bone remains
SBa-2230	x	x	P	Trace cultural remnants and unmodified cobble
SBa-2231H	x	x	P	Trace density of lithic debitage, some projectile point fragments and historical

Table 5.12.54 Archaeological Sites Within a ½-Mile Corridor Around the VAFB Onshore Alternative Construction Footprint

Site	Within 200 ft of Scenario 1 or DPA[1]	Tested	Site Significance[2]	Brief Site Description[3]
				artifacts
SBa-2325	x			NA
SBa-2333				NA
SBa-2412	x	x	P	Light scatter of Monterey chert, and small mammal bones
SBa-2425				NA
SBa-2500				NA
SBa-2611				NA
SBa-2612	x	x	P	Some shell scatter and cultural artifacts recovered
SBa-2833				NA
SBa-2840	x			NA
SBa-2841	x			NA
SBa-2916				NA
SBa-2917				NA
SBa-2918H		x	P	Historic structure foundation and some cultural remnants
SBa-2920H	x			NA
SBa-2921				NA
SBa-2930				NA
SBa-2931				NA
SBa-2932				NA
SBa-2933				NA
SBa-2934				NA
SBa-2940	x			NA
SBa-2941	x			NA
SBa-2942	x	x	P	Sparse lithic scatter and some flake
SBa-2943				NA
SBa-2944		x	P	Sparse lithic scatter and some low density flake
SBa-2945				NA
SBa-2946H	x	x	P	Trash scatter with remnants of a corral structure
SBa-2947				NA
SBa-2948		x	P	Sparse lithic scatter and moderate density flake/debitage
SBa-2949				NA
SBa-2949				NA
SBa-2950				NA
SBa-2950				NA
SBa-2952	x			NA
SBa-2953	x			NA

Table 5.12.54 Archaeological Sites Within a ½-Mile Corridor Around the VAFB Onshore Alternative Construction Footprint

Site	Within 200 ft of Scenario 1 or DPA[1]	Tested	Site Significance[2]	Brief Site Description[3]
SBa-3107H	x	x	P	Large scatter of historical artifacts associated with the demolition of 2 structures

1: Within 200 feet of pipeline scenario 1 or drilling/production area (see VAFB alternative description in Section 3.3.3).
2: P indicates potential significance in the absence of other documentation; S indicates determined significant
3: NA indicates site description not available

Impact CR.1 – Pipeline Maintenance and Repair: As for the proposed project, Impact CR.1 (Class II) and corresponding Mitigation Measures CR-1 through CR-3 would apply to maintenance and repair actions for all existing facilities that would continue to operate under this alternative. However, additional impacts would occur because of the large number of "new" (previously unaffected) sites that would be present along the alignment of new pipelines (see Table 5.12-54). It is assumed that these impacts would be *significant but mitigable (Class II)*, but the need for a greater level of mitigation, including new surveys, monitoring, evaluation, data recovery and/or avoidance measures should be recognized. Overall, the impacts of pipeline maintenance and repair would be substantially greater for this alternative than for the proposed project.

Impact CR.2 – Installation of Power Poles: The installation of power poles for the onshore drilling alternative would entail many more poles, and hence more extensive ground disturbance than for the proposed project. Numerous sites are known to exist along the corridor that would be used for construction; additional sites could be discovered during construction. Corresponding Mitigation Measures CR-2 and CR-4 would apply as for the proposed project, and the impacts are considered *significant but mitigable (Class II)*. However, the impacts would be quantitatively greater, affecting a larger number of sites, than for the proposed project.

Impact CR.3 – Oil Spill Containment and Cleanup Activities: As for the proposed project, the onshore drilling alternative would have a continuing risk of oil spills, with resulting incidental impacts on cultural resources due to ground disturbance during spill containment and cleanup actions. However, the likelihood of an oil spill affecting cultural resources would be greater because of the additional 10 miles of new pipeline. Mitigation Measure CR-5 would also apply to this alternative, but new procedures and contingencies applicable to the variety of new sites potentially affected would need to be incorporated into the OSRP. As for the proposed project, the residual impacts are considered *significant and unavoidable (Class I)*, due to the impossibility of protecting potentially significant cultural resources while conducting emergency response to an oil spill. Compared to the proposed project, many more new sites would be at risk from oil spills. Hence, the impact would be substantially more severe than for the proposed project.

Impact CR.4 – Produced Water Spill: Impacts associated with the risk of produced water spills along the new pipeline route would be similar to those discussed for the proposed project, and similarly mitigated by Mitigation Measures CR-1 and CR-2. However, the impacts would be quantitatively greater because of the greater length of pipelines and the greater likelihood of impact to an archaeological site. These impacts are considered *significant but mitigable (Class II)*.

Impact #	Impact Description	Phase	Residual Impact
CR.5	Disturbance or destruction of cultural sites that may contain significant or potentially significant cultural materials due to the construction of new drilling/production/processing facilities, ~~and~~ pipelines, power lines, tie-in station, and electrical substations.	*Construction*	*Class I or II*

As presented in Table 5.12-54, there are 44 archaeological sites that are considered significant or potentially significant along the VAFB Onshore Alternative pipeline and power line alignments, drilling/production site, tie-in station, and electrical substations. Construction may remove or destroy cultural materials, and would alter the spatial relationships and context of those materials. Because of the extent of grading and excavation required to construct the new facilities, there would be a high potential for the destruction of cultural materials and alteration of their context, which may not be fully mitigable by measures implemented after the fact. Given prevailing substrates of unconsolidated sand on old dunes, in close proximity to the coastline as well as sources of fresh water, the potential for undiscovered, buried cultural materials to exist is high. Sedimentary deposits containing paleontological materials are also likely to be encountered. Although Mitigation Measures CR-1 through CR-4 would apply in principle, a comprehensive cultural resources mitigation plan would be needed to provide maximum feasible mitigation. The general requirements for such a plan are described below. The residual impacts are considered *significant and unavoidable (Class I)* or *significant but mitigable (Class II)* depending upon the significance and integrity of the sites. An example of a Class I impact would be the destruction of a site with human remains due to both the archaeological importance and the importance to Native Americans in the region. A Class II impact could occur to sites that are neither unique or of exceptional significance (per Santa Barbara County, Cultural Resources Guidelines). Without more intensive analysis at these sites, all sites that are not clearly insignificant have been considered to be significant. However, without additional analyses, it is not possible at this time to determine the level of significance.

Mitigation Measure

CR-6 Prior to the approval of a Final Development Plan for the onshore drilling alternative, a comprehensive cultural resources mitigation plan shall be submitted to the County of Santa Barbara and the Vandenberg Air Force Base Cultural Resources Program Manager for review and approval. The plan shall include at minimum the following elements:

1. A complete inventory of previously known sites, their characteristics, and potential significance that may exist within 200 feet of potential ground disturbance.
2. Results of a Phase I archaeological survey covering all previously unsurveyed areas within 200 feet of identified construction footprints and corridors.
3. Procedures for monitoring during construction, the evaluation of newly discovered cultural or paleontological materials, and mitigation through avoidance, in situ preservation, research, or data recovery, as warranted before

construction is allowed to continue. These procedures shall incorporate Native American representation.

Residual Impact

With implementation of the above mitigation measure, the residual impact is considered to be *significant and possibly unavoidable (Class I or II).* Without a more intensive analysis based on actual construction plans and initial evaluations of cultural sites, including evaluation of the level of significance, it cannot be assumed that impacts would be fully mitigable.

Impact #	Impact Description	Phase	Residual Impact
CR.6	Aesthetic impacts on VAFB cultural sites and landscapes.	*Construction and Operation*	*Class III*

This impact would be unique to the onshore drilling alternative and is due to industrial equipment and activity which may degrade the public's experience of cultural sites and the landscape as a whole. For Native Americans in particular, the region has unique spiritual importance. Under CEQA Guidelines Section 15064.5, a substantial adverse change in the significance of an archaeological or historical resource is considered significant. Given that there is considerable development in the surrounding coastal region, including existing roads, the railroad, and launch facilities, and limited public accessibility, the impact of new construction is considered adverse but not significant.

Mitigation Measures

No mitigation measures have been identified for this impact.

Residual Impact

Impact CR.6 is considered *adverse but not significant (Class III).*

5.12.5.3 Casmalia East Oil Field Processing Location

For the Casmalia Alternative, Impact CR.1, pipeline maintenance and repair, Impact CR.2, installation of power poles, Impact CR.3, oil spill clean up activities, and Impact CR.4, produced water spill, would be more severe than the proposed project, because of the additional length of pipeline. Impact CR.5, destruction of VAFB cultural sites and Impact CR.6, VAFB cultural sites and landscapes, do not apply to the Casmalia Alternative.

Impact CR.5 - Facility and Pipeline Construction: Building a new processing site, the Casmalia East Site near Orcutt, and trenching for a new pipeline from this processing site to the LOGP would result in extensive ground disturbance that would not occur under the proposed project. Four recorded archaeological sites are located within 200 feet of the proposed pipeline route, and there are potential unrecorded sites because approximately seven miles of the proposed pipeline and the site of the new processing facility have never been surveyed for cultural resources. This new construction would likely result in potentially significant but mitigable impacts on cultural resources along the pipeline route and at the new facility location. Impacts on cultural resources would be much greater than the proposed project due to the extensive ground disturbance involved with this alternative.

Mitigation Measures

Mitigation Measures CR-1, CR-2, CR-3, CR-4 and CR-5 would be applicable, along with the following measure:

CR-7 A Phase I archaeological surface survey shall be conducted along the new pipeline right-of-way and at the location of the new processing site prior to land use clearance to identify any cultural resources that may be affected during construction. If a cultural resource is encountered during the survey, it shall be documented by a County-qualified archaeologist and its potential significance evaluated in terms of applicable criteria prior to any construction activities. Resources considered significant shall be avoided or subject to a Phase 3 data recovery program (with Native American monitoring, if applicable), consistent with Santa Barbara County Cultural Resource Guidelines.

Residual Impact

Potential impacts on recorded and unknown cultural resources could occur, but implementation of the above mitigation measures would minimize potential impacts by avoiding any significant resources identified during an intensive archaeological survey, or by mitigating the impacts through a data recovery program, when appropriate. After application of mitigation measures, Impact CR.5 would be considered *significant but mitigable (Class II).*

5.12.5.4 Alternative Power Line Routes to Valve Site #2

For the power line routing alternatives, Impact CR.1, pipeline maintenance and repair, Impact CR.3, oil spill clean up activities, and Impact CR.4, produced water spill, would be the same as for the proposed project. Impact CR.5, facility and pipeline construction, and Impact CR.6, VAFB cultural sites and landscapes, do not apply to the power line routing alternatives. The applicability of Impact CR.2, installation of power poles, to each of the power line alternatives is discussed below.

Alternative Power Line Route – Option 2a

Proposed ground disturbances associated with Power Line Option 2a would be the same as Impact CR.2 of the proposed project, except Power Line Option 2a would involve ground disturbance from constructing a new substation and installing new power poles to connect it to the existing power pole line along the pipeline right-of-way. The proposed substation would be located in a farm field north of Ocean Avenue and west of an abandoned road. This location has been previously surveyed by County-qualified archaeologists, and there are no known cultural resources present. Due to the absence of archaeological sites at this location, no additional impacts on cultural resources would occur.

Approximately 15 to 20 power poles would be installed for the proposed power line that would connect the new substation to the power pole line along the pipeline right-of-way. The proposed power line would be placed within a hay field, across the Santa Ynez River, and then parallel to an existing VAFB power pole line. The proposed power line would be approximately 6,400 feet in length and have new power poles placed every 350 to 400 feet. The new power poles would cause ground disturbance up to 10 to 12 feet deep. Although there are no known cultural resources present along the proposed power pole line route, unknown sites could be present because only portions of this route have been intensively surveyed by County-qualified archaeologists. Areas adjacent to the Santa Ynez River are considered highly sensitive for cultural resources based on the number of archaeological sites recorded in similar environmental contexts. It is possible that ground disturbance associated with the proposed power poles could result in significant impacts on unknown cultural resources as for the proposed project (see Impact CR.2). Impacts on a potentially significant cultural resource would be considered potentially significant but mitigable.

Mitigation Measures

Mitigation Measures CR-1, CR-2, CR-3, CR-4, and CR-5 would be applicable to Power Line Option 2a.

Residual Impact

Potential impacts on unknown cultural resources could occur, but implementation of the above mitigation measures would minimize potential impacts by avoiding any significant resources identified during an intensive archaeological survey by power pole location redesign, or by mitigating the impacts through a data recovery program. Due to the limited size of a given power pole excavation area, it is reasonable to assume that the pole locations could be feasibly relocated to avoid most archaeological site areas. The residual impact for cultural resource impacts associated with this alternative would be considered to be *significant but mitigable (Class II)*.

Alternative Power Line Route – Option 2b

Ground disturbances associated with Power Line Option 2b would be the same as Option 2a except that the proposed power line would cross the Santa Ynez River by directional boring under the river instead of being hung on new power poles. The directional bore would involve excavating two bore pits, one on each side of the river, and then boring under the river to a minimum depth of 50 feet. There are no known cultural resources along this river segment, and the depth of the bore should take it under any potentially unrecorded sites along the riverbed. However, proposed bore pit areas have not been subject to an intensive survey by County-qualified archaeologists, and areas adjacent to the Santa Ynez River are considered highly sensitive for cultural resources based on the number of archaeological sites recorded in similar environmental contexts. It is possible that ground disturbance associated with the proposed bore pits could result in significant impacts on cultural resources (see Impact CR.2). Impacts on a potentially significant cultural resource would be considered potentially significant but mitigable. Additional impacts for this alternative (CR.1, CR.3, and CR.4) would be same as the proposed project impacts.

Mitigation Measures

Mitigation Measures CR-1, CR-2, CR-3, CR-4 and CR-5 would be applicable.

Residual Impact

Potential impacts on unknown cultural resources could occur, but implementation of the above mitigation measures would minimize potential impacts by avoiding any significant resources identified during an intensive archaeological survey by bore pit location redesign, or by mitigating the impacts through a data recovery program. Due to the limited size of a bore pit excavation area, it is reasonable to assume that the bore pit locations could be feasibly relocated to avoid most archaeological site areas. The residual impact for cultural resource impacts associated with this alternative would be considered to be *significant but mitigable (Class II).*

Underground Power Line along Terra Road

Impact #	Impact Description	Phase	Residual Impact
CR.7	Trenching along Terra Road would result in ground disturbance and potential impacts on cultural resources.	*Construction*	*Class II*

Proposed ground disturbances associated with this alternative would be the same as Impact CR.2 of the proposed project, except installing a power line from Valve Site #2 to a new transformer would involve one to three miles of trenching along Terra Road. Four potentially significant archaeological sites (CA-SBA-913, -1917, -689, and -2126) are located within this road right-of-way and would be impacted by the proposed trenching. Impacts on a potentially significant cultural resource would be considered *significant but mitigable (Class II).* Impacts on cultural resources would be greater than the proposed project, because the trench would require more ground disturbance than the proposed project's power poles.

Impacts CR.1, CR.3, CR.4 would be same as the proposed project impacts.

Mitigation Measures

Mitigation Measures CR-1, CR-2, CR-3, CR-4 and CR-5 would be applicable, along with the following measure:

CR-8 Avoid impacts on known cultural resources by rerouting the trench so that no ground disturbance occurs within 200 feet from established site boundaries of CA-SBA-913, -1917, -689, and -2126. PXP shall submit plans that demonstrate avoidance of known cultural sites prior to issuance of coastal development permit or land use clearance for grading.

Residual Impact

With implementation of the above mitigation measures, the residual impact would be less than significant and Impact CR.7 would be considered *significant but mitigable (Class II).*

5.12.5.5 Replacement of Oil Emulsion Pipeline from Platform Irene to LOGP

For the Emulsion Pipeline Replacement Alternative, Impact CR.1, pipeline maintenance and repair, Impact CR.3, oil spill clean up activities, and Impact CR.4, produced water spill, would be the same as the proposed project. Impact CR.6, VAFB cultural sites and landscapes, and Impact CR.7, trenching along Terra Road, do not apply to the Emulsion Pipeline Replacement Alternative.

Impact CR.1 - Pipeline Maintenance Ground Disturbance: As a new pipeline would be installed with this alternative, pipeline maintenance related ground disturbances would be reduced over those of the proposed project because the integrity of the pipeline would be improved over the existing pipeline, which has a history of corrosion problems. Although highly reduced, maintenance may still be needed for the new pipeline, therefore, Impact CR.1 would be the same as for the proposed project, and Mitigation Measures CR-1 through CR-4 would still apply.

Impact CR.2 – Installation of Power Poles**:** ~~The installation of power poles would be the same as the proposed project, which would result in *significant but mitigable impacts (Class II)* with application of Mitigation Measures CR-2 and CR-4.~~ As the new pipeline would be able to operate at higher pressures, installation of the modifications to Valve Site #2 would not be required. Therefore, ~~this portion of~~ Impact CR.2 would be eliminated under this alternative.

Impacts CR.3 and CR.4 – Spill Related Impacts to Cultural Resources**:** The probability of an oil spill occurring would be slightly less for this alternative. However, as the new pipeline would be the same size as the current pipeline, spill volumes would remain the same. Therefore, these two impacts would be applicable to this alternative (Class I and Class II, respectively). Mitigation Measure CR-5 would be applicable.

Impact CR.5 – Facility and Pipeline Construction: There are 29 recorded sites within ½ mile of the existing PXP pipeline corridor. However, because the new emulsion line would be placed within the same corridor of the existing PXP pipelines and this corridor has been previously disturbed by construction activities associated with the existing pipelines, it is unlikely that any new cultural sites would be disturbed and, therefore, this impact would be significant but mitigable.

Impact #	Impact Description	Phase	Residual Impact
CR.8	Offshore oil emulsion pipeline replacement would result in seafloor disturbance and potential impacts on cultural resources.	*Construction*	*Class II*

This alternative involves replacing the existing offshore oil emulsion pipeline with a new pipeline from Platform Irene to landfall instead of using the existing pipeline as per the proposed project. The offshore pipeline is approximately 10.1 miles long and has a landfall approximately 1/2 mile north of the Santa Ynez River. The existing offshore pipeline would be removed prior to the installation of the new emulsion pipeline. The new pipeline would be installed on the seafloor adjacent to the current pipeline corridor alongside the existing three pipelines and power line. In the surf zone (shore to 4,000 feet offshore), divers would use hand held "air jets" to pump seawater under the pipeline to displace the sand and bury the pipeline to a depth of three to six feet.

There are no known potentially significant cultural resources within the original construction corridor of the offshore pipeline. No impacts to cultural resources, therefore, are expected from seafloor disturbance within the original pipeline construction corridor. If seafloor disturbance occurs adjacent to the original construction corridor, it is possible that construction activities would impact unrecorded cultural resources. Impacts on a potentially significant cultural resource would be considered potentially significant but mitigable.

Mitigation Measures

The following mitigation measure is proposed:

CR-9 The original offshore construction corridor shall be mapped and labeled on appropriate offshore Project maps. All seafloor disturbances from construction activities associated with the new pipeline shall be confined within the original pipeline construction corridor to avoid impacts on potentially significant cultural resources.

Applicant shall submit plans that demonstrate avoidance of known cultural sites prior to issuance of coastal development permit or land use clearance for grading.

Residual Impacts

With implementation of the above mitigation measures, the residual impact would be less than significant and Impact CR.8 would be considered *significant but mitigable (Class II).*

Impact #	Impact Description	Phase	Residual Impact
CR.9	Onshore oil emulsion pipeline removal and replacement would result in ground disturbance and potential impacts on cultural resources.	*Construction*	*Class II*

This alternative involves replacing the existing onshore oil emulsion pipeline between landfall and the LOGP with a new pipeline instead of using the existing pipeline as per the proposed project. The new onshore pipeline would be installed in the same corridor as the existing pipelines, using the same right-of-way that was used for the initial pipeline installation. Normally a 100-foot wide right-of-way would be required during construction to accommodate clearing and right-of-waying, ditching, hauling, and stringing, welding, and traffic. The right-of-way can be reduced to 40 feet for distances up to 200 feet to avoid impact to a localized environmental concern (i.e., archaeological site, cluster of trees).

There are 22 recorded archaeological sites located within 200 feet of the existing oil pipeline between landfall and the LOGP. Although these sites were previously disturbed by the construction of the existing pipeline, most are determined to be a potentially significant historic resource. Oil pipeline removal and replacement would result in ground disturbance and potential impacts on any cultural resource in the affected areas. Impacts on a potentially significant cultural resource are considered to be *significant but mitigable (Class II).* Impacts on cultural resources would be greater than the proposed project due to the extensive ground disturbance involved with this alternative.

Mitigation Measures

Mitigation measures CR-1 and CR-2 would be applicable along with the following measures:

CR-10 The normal 100-foot wide right-of-way shall be reduced to a 40-foot wide right-of-way when within 200 feet of a recorded archaeological site unless the resource has been previously determined to have no potential for significance because it is re-deposited, an isolated occurrence, modern, or otherwise lacks data potential. PXP shall submit plans that demonstrate avoidance of known cultural sites prior to issuance of coastal development permit or land use clearance for grading.

CR-11 Develop a Cultural Resources Monitoring Plan to prepare for archaeological and Native American monitoring activities during construction. This plan shall be submitted to P&D prior to issuance of coastal development permit or land use clearance for grading. PXP shall arrange for archaeological monitoring as per the construction monitoring plans.

Residual Impacts

With implementation of the above mitigation measures, the residual impact would not be significant and Impact CR.9 would be considered *significant but mitigable (Class II).*

5.12.5.6 Alternative Drill Muds and Cuttings Disposal

Inject Drill Muds and Cuttings into Reservoir

Impacts on cultural resources would be the same as the proposed project.

Transport Drill Muds and Cuttings to Shore for Disposal

Impacts on cultural resources would be the same as the proposed project.

5.12.6 Cumulative Impacts and Mitigation Measures

Cumulative projects that could impact the current analysis include the potential offshore oil and gas projects discussed in Sections 4.2~~1~~ and 4.~~2~~3, and the onshore development projects outlined in Section 4.4. The cumulative impacts of these potential off- and onshore development projects are discussed separately below.

5.12.6.1 Offshore Oil and Gas Projects

No impacts to offshore cultural resources from construction and routine operation would occur from the proposed project. Therefore, the proposed project would have no incremental contribution to cumulative impacts associated with cultural resources under normal operating conditions.

As presented in Sections 4.2 and 4.3, there area several potential offshore oil and gas development projects that could occur in the proposed project area. These future energy projects would increase the potential for accidental oil spills, although the chance of an oil spill is still remote. Similar to the proposed project, pipeline maintenance and repair, as well as containment and cleanup of potential oil spills, have the potential to impact recorded and unrecorded cultural resources. Most adverse impacts on cultural resources from pipeline replacement and repair could be mitigated to less than significant levels through implementation of mitigation measures such as those addressed and recommended in this document. However, an oil spill clean-up may lead to a significant and unavoidable impact on cultural resources if a significant cultural resource was affected by the clean-up activities.

Most adverse impacts on cultural resources from future offshore energy projects would be mitigated to a less than significant level through mitigation measures such as those discussed in this document; however, it is possible that impacts from an oil spill cleanup would not be feasibly lowered to a less than significant level. Due to the cumulative impact on cultural resources of the other future probable energy projects in combination with the proposed project, there is a potential for significant cumulative impacts to occur. The proposed project's contribution to this cumulative impact, although unlikely, would also be potentially significant.

5.12.6.2 Onshore Projects

As outlined in Section 4.4, there are several proposed development projects located in the Lompoc and Orcutt/Santa Maria area that would involve various amounts of ground disturbance. Some of this development would occur on previously undisturbed land (i.e., no previous ground disturbance), and are considered archaeologically sensitive (e.g., near waterways where prehistoric populations may have lived). Ground disturbance associated with these development projects have the potential to impact both recorded and unrecorded cultural resources; however, it is anticipated that adverse impacts on significant cultural resources could be mitigated to less than significant levels. Therefore, no cumulative impacts to cultural resources would be expected from these potential onshore development projects, and the proposed project would not incrementally add to any potential cumulative impacts.

5.12.7 Mitigation Monitoring Plan

Mitigation Measure	Mitigation Requirements and Timing	Method of Verification	Timing of Verification	Party Responsible For Verification
CR-1	PXP shall prepare and submit grading plans showing all ground disturbances within 200 feet of a recorded archaeological site. The grading plans shall be submitted to P&D prior to issuance of coastal development permit or land use clearance for grading. All ground disturbance within 200 feet of a recorded archaeological site shall be monitored by a County-qualified archaeologist and, if prehistoric, by a Native American observer, unless the resource has been previously determined to have no potential for significance because it is re-deposited, an isolated occurrence, modern, or otherwise lacks data potential.	Grading Plan review. EQAP monitoring.	Throughout ground disturbance activities.	SBC P&D
CR-2	PXP shall revise grading plans to include note for protocols to follow during unexpected discovery of archaeological resources. The grading plans shall be submitted to P&D prior to issuance of coastal development permit or land use clearance for grading. Prior to construction all crew members shall receive training on unanticipated cultural resource discovery protocols. In the event of an unanticipated cultural resource discovery during construction, all ground disturbances within 200 feet of the discovery shall be halted or re-directed to other areas until the discovery has been documented by a county-qualified archaeologist, and its potential significance evaluated consistent with Santa Barbara County Cultural Resource Guidelines. Resources considered significant shall be avoided by project redesign. If avoidance is not	Grading Plan review. Crew Training sign-in log. EQAP monitoring.	Prior to (crew training) and throughout ground disturbance activities.	SBC P&D

Mitigation Measure	Mitigation Requirements and Timing	Method of Verification	Timing of Verification	Party Responsible For Verification
	feasible, the cultural resource shall be subject to a Phase 3 data recovery mitigation program (with Native American monitoring, if applicable), consistent with Santa Barbara County Cultural Resource Guidelines.			
CR-3	If pipeline maintenance and repair are planned on a segment of the unsurveyed pipeline route, then a Phase 1 archaeological surface survey shall be conducted prior to land use clearance for grading to identify any cultural resources that may be affected. If a cultural resource is encountered during the survey, it shall be documented by a County-qualified archaeologist and its potential significance evaluated in terms of applicable criteria prior to maintenance and repair work. Resources considered significant shall be avoided or subject to a Phase 3 data recovery program (with Native American monitoring, if applicable), consistent with Santa Barbara County Cultural Resource Guidelines.	PXP shall submit results of Phase 1 survey to P&D.	Plan review. Any recommenda-tions resulting from Phase 1 report to apply throughout ground disturbance activities.	SBC P&D
CR-4	A Phase 1 archaeological surface survey shall be conducted at unsurveyed areas of ground disturbance associated with installation of the power pole line across the Santa Ynez River and proposed trenching areas prior to land use clearance to identify any cultural resources that may be affected during construction. If a cultural resource is encountered during the survey, it shall be shall be avoided by power pole and/or trench relocation. If archaeological site avoidance is technologically infeasible due to topographic or engineering constraints, the site's potential significance shall be evaluated pursuant to Santa Barbara County Cultural Resource Guidelines and CEQA <u>Guidelines</u> Section 15064.5 criteria. Resources considered significant and unavoidable shall be subject to a Phase 3 data recovery program (with Native American monitoring, if prehistoric), consistent with Santa Barbara County Cultural Resource Guidelines, and if located on VAFB, shall incorporate the investigation methodology reviewed and approved by VAFB environmental management staff. To comply with VAFB requirements, any trenching or excavation in a floodplain on VAFB shall require archaeological monitoring.	PXP shall submit results of Phase 1 surveys to P&D.	Plan review. Any recommenda-tions resulting from Phase 1 report to apply throughout ground disturbance activities.	SBC P&D

Mitigation Measure	Mitigation Requirements and Timing	Method of Verification	Timing of Verification	Party Responsible For Verification
CR-5	The Oil Spill Response Plan (OSRP) shall be revised to include procedures for minimizing impacts on cultural resources during oil spill containment and cleanup activities. These procedures shall include contacting a County-qualified archaeologist and Native American monitor in the event of a spill. To the extent possible, heavy earth moving equipment or manual excavation shall be minimized at archaeological sites. If unanticipated cultural resources are discovered during containment and cleanup activities, then a county-qualified archaeologist shall document the discovery at the earliest time it is deemed safe to do so. It is possible that post-cleanup archaeological excavations (with Native American monitoring, if applicable) shall be necessary to help mitigate impacts from the containment/cleanup ground disturbances. The revised OSRP shall be submitted to P&D prior to issuance of coastal development permit or land use clearance for grading.	Revised OSRP review. EQAP monitoring during spill clean up	Revised OSRP review. During spill clean-up	SBC P&D
CR-6 (VAFB Onshore Alternative only)	Prior to the approval of a Final Development Plan for the onshore drilling alternative, a comprehensive cultural resources mitigation plan shall be submitted to the County of Santa Barbara and the Vandenberg Air Force Base Cultural Resources Program Manager for review and approval. The plan shall include at minimum the following elements: 1. A complete inventory of previously known sites, their characteristics, and potential significance that may exist within 200 feet of potential ground disturbance. 2. Results of a Phase 1 archaeological survey covering all previously unsurveyed areas within 200 feet of identified construction footprints and corridors. 3. Procedures for monitoring during construction, the evaluation of newly discovered cultural or paleontological materials, and mitigation through avoidance, in situ preservation, research, or data recovery, as warranted before construction is allowed to continue. These procedures shall incorporate Native American representation.	Review of cultural resources mitigation plan.	Any recommendations resulting from Phase 1 report to apply throughout ground disturbance activities.	SBC P&D VAFB

Mitigation Measure	Mitigation Requirements and Timing	Method of Verification	Timing of Verification	Party Responsible For Verification
CR-7 (Casmalia Alternative only)	A Phase 1 archaeological surface survey shall be conducted along the new pipeline right-of-way and at the location of the new processing site prior to land use clearance to identify any cultural resources that may be affected during construction. If a cultural resource is encountered during the survey, it shall be documented by a County-qualified archaeologist and its potential significance evaluated in terms of applicable criteria prior to any construction activities. Resources considered significant shall be avoided or subject to a Phase 3 data recovery program (with Native American monitoring, if applicable), consistent with Santa Barbara County Cultural Resource Guidelines.	PXP shall submit results of Phase 1 surveys to P&D.	Plan review. Any recommenda-tions resulting from Phase 1 report to apply throughout ground disturbance activities.	SBC P&D
CR-8 (Under-ground Power Line Alternative only)	Avoid impacts on known cultural resources by rerouting the trench so that no ground disturbance occurs within 200 feet from established site boundaries of CA-SBA-913, -1917, -689, and -2126. Applicant shall submit plans that demonstrate avoidance of known cultural sites prior to issuance of coastal development permit or land use clearance for grading	Grading Plan review. EQAP monitoring.	Plan review. Avoidance throughout ground disturbance activities.	SBC P&D
CR-9 (Emulsion Pipeline Replacement Alternative only)	The original offshore construction corridor shall be mapped and labeled on appropriate offshore Project maps. All seafloor disturbances from construction activities associated with the new pipeline shall be confined within the original pipeline construction corridor to avoid impacts on potentially significant cultural resources. Applicant shall submit plans that demonstrate avoidance of known cultural sites prior to issuance of coastal development permit or land use clearance for grading.	Plan review.	Plan review. Avoidance throughout ground disturbance activities.	SBC P&D
CR-10 (Emulsion Pipeline Replacement Alternative only)	The normal 100-foot wide right-of-way shall be reduced to a 40-foot wide right-of-way when within 200 feet of a recorded archaeological site unless the resource has been previously determined to have no potential for significance because it is re-deposited, an isolated occurrence, modern, or otherwise lacks data potential. Applicant shall submit plans that demonstrate avoidance of known cultural sites prior to issuance of coastal development permit or land use clearance for grading.	Plan review. EQAP monitoring.	Plan review. Avoidance throughout ground disturbance activities.	SBC P&D

Mitigation Measure	Mitigation Requirements and Timing	Method of Verification	Timing of Verification	Party Responsible For Verification
CR-11 (Emulsion Pipeline Replacement Alternative only)	Develop a Cultural Resources Monitoring Plan to prepare for archaeological and Native American monitoring activities during construction. This plan shall be submitted to P&D prior to issuance of coastal development permit or land use clearance for grading. Applicant shall arrange for archaeological monitoring as per the construction monitoring plans.	Plan review. EQAP monitoring.	Plan review. Throughout ground disturbance activities.	SBC P&D

5.12.8 References

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5.13 Aesthetics/Visual Resources

The visual resources section evaluates the existing visual resources of the project area and the potential for the proposed project and its alternatives to impact these visual resources. The project consists of several separate construction and operational elements; some of these elements have a potential to impact visual resources in the area and are discussed below. The following section is based on the proposed Final Environmental Impact Report (EIR) prepared for the proposed project in 2002 (Arthur D. Little et al., 2002), and site reconnaissance of those elements of the proposed project and its alternatives that are located within Vandenberg Air Force Base (VAFB).

5.13.1 Environmental Setting

5.13.1.1 Regional Overview

The visual character and resources of the project area are described in considerable detail in the original Point Pedernales Project Environmental Impact Report/Environmental Impact Statement (EIR/EIS) that was prepared in 1985. Santa Barbara County (SBC) and the southern part of San Luis Obispo County have a unique and diverse scenic beauty that is highly valued by tourists and the counties' residents. There is a great diversity in topography within the area, which includes coastal headlands, bluffs, dunes and terraces, inland valleys, foothills, mountains, and mesa-like formations. The most obvious features in the project area are the Santa Ynez Mountains, Santa Rita Hills, Purisima Hills, Solomon Hills, Casmalia Hills and the broad valleys around Lompoc. Along the coast east of Point Conception, the crest of the east-west trending Santa Ynez Mountains is especially dominant. Elevations can reach 2,500 feet, with canyons being V-shaped and sharply incised by numerous steep, short drainages. Along the ridges, exposed rock outcroppings are characteristic, as are exposed strata striking steeply and running transverse to the major ridges.

North of Point Conception to Point Sal, the mountains along the coast are muted in form, lower, less massive, and less angular than the Santa Ynez Mountains. This is also true within the Santa Maria Basin, where the Santa Rita, Purisima, Solomon and Casmalia Hills are low and rolling, generally being less than 800 feet in elevation. The most picturesque of the valleys are the Santa Rita Valley, San Antonio Valley, Los Alamos Valley and the valleys enclosing the Santa Ynez River and Highway 1. The Santa Ynez Valley contains the largest percentage of lands rated with high scenic value in SBC (Arthur D. Little et al., 2002).

Relief for the coastal foothills east of Point Conception is generally approximately 400 feet, rising from an elevation of approximately 200 feet at the upper edge of the coastal terrace, to knolls generally not exceeding 600 feet in elevation. The coastal terrace, where there is one, ranges from 100 to 200 feet in elevation and varies considerably in width, from several thousand feet to 100 feet or less. North of the Santa Ynez River, wide sandy beaches and foredunes are prevalent up to where the Casmalia Hills abruptly drop 1,000 feet directly to the sea at Point Sal.

Native vegetation is mainly comprised of shrub, oak, woodland, and modified grassland communities distributed unevenly over coastal bluffs, dunes, ravines and terraces, and across the interior hills, valleys and mesas.

Along the sandy beaches and foredunes from Point Conception to Pismo Beach, there are mats of native succulent herbs and introduced species such as ice plant and beach grass. Coastal bluff scrub occupies sea bluffs and coastal canyon walls. These low-growing vegetative types immediately along the coast are generally muted in color, form and texture. In places, patches of vegetation contrast highly with the exposed parts of the dunes, introducing strong, interesting patterns to foreground views. In general, the patterns created by the numerous species comprising chaparral are subtle and serve as a visual backdrop for conspicuous and interesting rock outcrops and exposed strata.

Most of the study area is uninhabited, generally supporting cattle ranching and some crop production. Extensive areas serve as grazing, irrigated cropland, and dry farming within the interior and coastal valleys and along the foothills and coastal terrace. The occurrences of irrigated and non-irrigated cropland strongly influence the landscape character of the study area. The croplands form conspicuous patterns of introduced species. Where there are orchards or croplands, their foliage contrasts sharply with the background of grassland that is dun-colored from April through November. Areas used for dry farming or flower production also offer significant color contrast due to the exposure of soil during tilling and colorful displays when the flowers are in bloom. Practices associated with agriculture have altered the natural vegetative patterns of the area. Orchards, vineyards, croplands, and grazed fields have imparted new patterns to the land. Fences, windbreaks, and decorative plantings are now notable characteristics of ranchlands. The resulting pastoral landscape has become highly valued by the public.

The region is a semi-arid area dissected by numerous small streams, which generally flow for limited periods during the winter and spring. Inland, many streams run westerly and, in some cases, flank major and secondary travel routes. Notable among these are the Santa Ynez River, El Jaro Creek, Jalama Creek, the Santa Maria River, and San Antonio Creek. These streams are seldom visible from the road.

The Pacific Ocean, readily visible from most vantage points along the coast, offers a seemingly limitless expanse which serves, for viewing positions east of Point Conception, as a setting for the distant Channel Islands. From points along the coast, occasional marine traffic far out at sea is visible. Platform Irene is the only permanent non-natural and clearly visible visual attribute in the offshore part of the project area.

The Union Pacific Railroad and numerous dirt and paved roads are prominent within the area. Seldom are these elements aesthetically pleasing by themselves, but they may reinforce the attractive patterns in the landscape essentially established by other elements. Transmission lines and utilities are evident throughout the area. Although integral to the development of rural areas, there are indications that they are not accepted as aesthetic landscape features. Many SBC policies specifically are directed toward screening or otherwise obscuring these elements from views.

Often the visually pleasing character of the area is affected by features associated with the oil and gas production in the area (i.e., oil and gas plants, pump stations, valve sites, exposed portions of pipelines and offshore platforms). However, for some people, these industrial features are associated with the history of the region's development and are considered visually interesting.

A significant part of the study area lies within the VAFB boundaries. With the exception of power and communication lines and VAFB facilities, most of this land is undeveloped. In a few cases, tall launch facilities are within the view of sensitive travelling routes and public access areas (35th Street, Terra Road, Highway 246, Ocean Beach County Park, the beach area from Surf Beach to Civilian Beach, and Point Sal Beach). The launch facilities are incongruous with their rural, coastal setting and, as for other facilities having an industrial character, they are not compatible with the scenic agricultural features inherent to the area.

5.13.1.2 Study Area

The environmental setting of the study area describes the general area of the project with its visual characteristics and all the points from which elements of the proposed project could be visible to the public, including views from travel routes leading to these affected views. Figure 5.13-1 shows the observer view positions described in this section, numbered 1 through 9. As defined, the study area consists of several areas corresponding to several parts of the project:

- Platform Irene and ocean around Platform Irene accessible to public and private marine traffic. Ocean shore with adjoining areas accessible to the public include the Union Pacific Railroad, Surf Beach and Ocean Beach County Park from where Platform Irene is visible.
- The electric substation at Surf Beach (Surf Substation) and areas from where the station is visible, such as Surf Beach, portions of the Union Pacific Railroad, the Amtrak Station at Surf, and Ocean Avenue.
- Areas along the pipeline routes from Platform Irene and the Lompoc Oil and Gas Plant (LOGP) facility including the Valve Site #2.
- Areas along the heavily traveled scenic routes, such as Highway 1, Route 246, and Ocean Avenue from where Valve Site #2 or the proposed power line route can be visible.
- The LOGP facility and areas and roads, such as Harris Grade Road, from where the LOGP can be seen or from which facility lighting is visible during nighttime hours.

A vast panorama of the Pacific Ocean dominates views to the west from the ocean shore and beaches in the project area, including Surf Beach and Ocean Beach County Park. Platform Irene is visible from all of Surf Beach, Ocean Beach County Park and the parts of the railroad adjacent to these areas (see Figure 5.13-2). The negative visual impact of the platform was discussed in the 1985 Point Pedernales EIR/EIS and was characterized as unavoidable and significant (Class I).

To mitigate the significant aesthetic impact of the Surf Substation, a landscape plan was required, but has been only partially implemented after its construction in 1986. Plantings to screen the facility from the west were not successfully implemented. Furthermore, as it was concluded in the 1985 Point Pedernales Project EIR/EIS, even the required landscaping was not expected to be able to mitigate this significant impact to a level of less than significant. The Surf Substation is still visible from Surf Beach, the westernmost end of Ocean Avenue and from the Union Pacific Railroad and Amtrak Station located next to it (see Figure 5.13-3).

Low rolling hills frame the views to the east from the ocean shore, with the Santa Ynez River Valley in the middle. The vegetation is limited to grasses and brush 2 to 3 feet high with few trees. Figure 5.13-4 shows a common view of the area with the Santa Ynez River in the mid-ground. Figure 5.13-5 shows views of Santa Ynez River from Valve Site #2.

Valve Site #2 cannot be seen from Surf Beach or from the Union Pacific Railroad because it is hidden by the landscape. Structures at Valve Site #2 do not exceed 7 feet in height. Valve Site #2 is barely visible from Ocean Beach County Park and from Ocean Avenue near the park. From the closest place to the valve site on Ocean Avenue, the site appears to be a small yellow area on the otherwise green background (see Figure 5.13-6). The view is obscured due to the distance, which is 0.8 miles from the point on Ocean Avenue closest to the valve site (extension of Route 246). At the western end of Lompoc where some residences exist, the views of Valve Site #2 and Terra Road are not obstructed. However, the distance between the valve site and the closest residences (over five miles) does not allow the valve site or any details of the site to be distinguished with the naked eye. The view of the valve site and Terra Road from Ocean Avenue near the western side of Lompoc is obstructed by vegetation and trees (see Figure 5.13-7).

Since its installation in 1986, some of the onshore portion of the Point Pedernales Project pipeline corridor between Platform Irene and the LOGP has been successfully revegetated. The only visible attributes of the pipelines are the pipeline bridge that is visible from Terra Road (see Figure 5.13-8) and the pipeline markers ("lollypops") placed in several locations along the whole onshore pipeline route. In other areas, such as the oak-covered hills north of Vandenberg Village, the corridor has not been effectively revegetated and remains visually distinct from the surrounding terrain.

The LOGP is located in a valley that is hidden from most of the sensitive views by vegetation and landscape features such as hills. The facility is not visible from Highway 1, or from residences at Vandenberg Village or the Village Country Club except along Firestone Road. Figure 5.13-9 shows the view from Firestone Road. At night the LOGP is illuminated with high-pressure sodium lighting to maintain safe working conditions for the operators and can be seen directly from the same point on Firestone Road. The glare from the plant lighting can be seen at night from several locations around the plant including travel routes, residences in Vandenberg Village Country Club and Mission Hills, the City of Lompoc, and Highway 101 north of Los Alamos. See Figure 5.13-10 for a timed-exposure photograph from Firestone Road. This effect is intensified during periods of low fog, which reflects the glare of LOGP's nighttime lighting. Due to limited lighting during fog conditions, a photograph would not portray the actual view that can be observed during fog.

The facility is exposed to public views from several locations on Harris Grade Road and some small roads in close vicinity of the plant. Figure 5.13-11 shows a view of the LOGP from the nearest point on Harris Grade Road. The tallest structures at the plant are the Natural Gas Liquids (NGL) stabilization columns, which are approximately 55 feet high. Although thick foliage of trees surrounds the plant and hides it from most Harris Grade Road views, there are places along the road from which the plant is in full view.

5.13.2 Regulatory Setting

This visual impacts assessment was conducted in conformance with California Environmental Quality Act (CEQA) requirements. Appendix G (Part I [a]) of the CEQA Guidelines defines a project as having a significant visual effect on the environment if it would have a "substantial adverse effect on the scenic vista." Specifically, Appendix G Part I (Aesthetics) of the Guidelines (sample environmental checklist), in addressing the California Code of Regulations Section 15382, identifies four areas of concern regarding a project's potential impact on aesthetics:

- Have a substantial adverse affect on a scenic vista.
- Substantially damage scenic resources including but not limited to, trees, rock outcroppings, and historic buildings within a state scenic highway.
- Substantially degrade the existing visual character or quality of the site and its surroundings.
- Create a new source of substantial light or glare, which would adversely affect day or nighttime views in the area.

In many areas of SBC, visual attributes and locations are designated as scenic. County policies, such as the Open Space Element of the County Comprehensive Plan and Local Coastal Plan adopted by the SBC Board of Supervisors, protect areas from adverse visual impacts. Also, the California Department of Transportation has created a State Scenic Highway System, which includes a list of highways that are either eligible for designation as scenic highways or have been so designated. These highways are identified in Section 263 of the California Streets and Highways Code.

An objectionable public view is addressed through "visual sensitivity" or the relative degree of public interest in a visual resource and concern over adverse changes in the quality of that resource (U.S. Department of the Interior [DOI], Bureau of Land Management [BLM], 1986; Department of Agriculture, Forest Service [U.S. Forest Service], 1977). The assessment of visual sensitivity establishes the most important viewing positions available to the public. Indicators of visual sensitivity are listed in Table 5.13.1 and reflect the concepts and methods of several federal agencies (U.S. Forest Service, U.S. Department of Agriculture Soil Conservation Service, BLM, and U.S. Department of Transportation [DOT]).

Table 5.13.1 Indicators of Visual Sensitivity

HIGH SENSITIVITY
• Views of and from areas the aesthetic values of which are protected in laws, public regulations and policies, and public planning documents. • Views of and from designated areas of aesthetic, recreational, cultural, or scientific interest, including national, state, county, and community parks, reserves, memorials, scenic roads, trails, interpretive sites of scientific value, scenic overlooks, recreation areas, and historic structures, sites, and districts. • Views from resort areas or urban residential subdivisions. • Views from national- or state-designated scenic highways or roads, or designated scenic highways or roads of regional importance and from segments of travel routes, such as roads, rail lines, pedestrian and equestrian trails, and bicycle paths near designated areas of aesthetic, recreational, cultural, or scientific interest leading directly to them. Views seen while approaching an area of interest may be closely related to the appreciation of the aesthetic, cultural, scientific, or recreational significance of that destination.

Table 5.13.1 Indicators of Visual Sensitivity

MODERATE SENSITIVITY
• Views from segments of travel routes near highly sensitive use areas of interest, serving as a secondary access route to those areas. • Views from rural residential areas and segments of roads near them, which serve as their primary access route. • Views of and from undesignated but protected or popularly used or appreciated areas of aesthetic, recreational, cultural or scientific significance at the local, county, or state level. • Views from highways or roads locally designated as scenic routes and of importance only to the local population, or informally designated as such in literature, road maps and road atlases. • Views from travel routes, such as roads, trails, bicycle paths, and equestrian trails leading directly to protected or popularly used undesignated areas important for their aesthetic, recreational, cultural, or scientific interest. • Views of and from religious facilities and cemeteries.
LOW SENSITIVITY
• Views from travel routes serving as secondary access to moderately sensitive areas. • Views from farmsteads, groupings of fewer than four residences, industrial, research/development, commercial, and agricultural use areas.

The California Coastal Commission (CCC) will have consistency review authority for the proposed project. In addition, portions of the project are within the coastal zone and therefore, are subject to CCC review on appeal of revisions to the existing Point Pedernales Project's Final Development Plan (FDP). Therefore, policies put forward by the California Coastal Act, California Public Resources Code, Division 20, should be adhered to, including Section 30251 'Scenic and Visual Qualities,' where it is stated that the scenic and visual qualities of coastal areas shall be considered and protected as a resource of public importance, and that permitted development shall be sited and designed to protect views to and along the ocean and scenic coastal areas, to minimize the alteration of natural land forms, to be visually compatible with the character of surrounding areas.

5.13.3 Significance Criteria

Determination of the proposed project's beneficial or adverse aesthetic effects is highly subjective. To aid this determination, SBC has adopted Environmental Thresholds and Guidelines (as revised through October 2006) that help identify whether or not a project would create a significant impact on visual resources.

The project is deemed to have a potentially significant effect if:

- The project site has significant visual resources […] that are publicly visible, and it has the potential to degrade or significantly interfere with the public's enjoyment of the site's existing visual resources;
- The project has a potential to impact visual resources of the Coastal Zone or other visually important area (e.g., mountainous area, public park, urban fringe, or scenic travel corridor); and the project has a potential to conflict with the policies set forth in the Local Coastal Plan (LCP), the Comprehensive Plan, or any applicable community plan to protect the identified views;
- The project has a potential to create a significantly adverse aesthetic impact through obstruction of public views, incompatibility with surrounding uses, structures, or intensity of development, removal of significant amounts of vegetation, loss of important open space, substantial alteration of natural character, lack of adequate landscaping, or extensive grading visible from public areas.

5.13.4 Impact Analysis for the Proposed Project

The following sections discuss potential impacts to visual resources, mitigation measures (where appropriate), and residual impacts associated with the proposed project. Because the proposed project largely would use existing facilities (e.g., platform, LOGP and pipelines), requirements for new facilities or equipment with the potential to impact visual resources are minimal. Impacts from the existing Point Pedernales Project facilities and operations are discussed in the 1985 Point Pedernales Project EIR/EIS. The impacts associated with the proposed project are related to changes in the present facilities or operating conditions, and are described below.

Impact #	Impact Description	Phase	Residual Impact
Visual.1	Visual impacts due to long-term continued presence of the project facilities visible from Coastal Zone (Platform Irene and Surf Substation).	*Extension of Life*	*Class I*

The presence of the offshore platform, which is visible from the public beach by marine recreational users and from the Union Pacific Railroad, creates a negative aesthetic impact. This impact was classified as significant in the 1985 Point Pedernales EIR/EIS. The proposed project would continue but not worsen this impact due to the extended life of Platform Irene. If the development of the proposed project is successful, Platform Irene would be in service longer than the projected lifetime of the approved Point Pedernales Project. This extension of life of the platform is considered a significant visual impact since it would extend the time over which the platform structure would be visible from public areas in the coastal zone.

The Surf Substation provides power to Platform Irene. The substation, which is visible from several public areas, such as Ocean Beach County Park, Surf Beach, and portions of the Union Pacific Railroad and Ocean Avenue, creates a negative aesthetic impact. This impact was also classified as significant in the 1985 Point Pedernales Project EIR/EIS. A landscaping plan was partially implemented after construction of the substation to shield the substation from the public views. However, the substation still remains visible, and it was concluded in the Point Pedernales Project EIR/EIS that the proposed landscaping plan would not mitigate this impact to a level of less than significant. The life of the substation would be extended for the same period of time as the life of the platform. This extension of life of the substation would extend the significant visual impact of the substation since it would extend the time over which the substation structures would be visible from public areas in the Coastal Zone.

As part of the existing Point Pedernales Project (FDP condition N-1), the applicant is providing funds to the Coastal Resource Enhancement Fund (CREF) to mitigate visual and other impacts to the coastal area. This fund was established by SBC to help offset visual and other impacts to the coastal areas. Permit condition N-1 establishes that funding to the CREF shall continue for the life of the project. As long as the current Point Pedernales FDP is active, annual contributions to CREF would continue.

Mitigation Measures

Visual-1 The applicant shall prepare and implement a visual mitigation plan for the Surf Substation that provides for better screening of the facility. The plan shall address measures to reduce the visual impact of the facility including, but not limited to, painting of substation substructures and re-landscaping. The plan shall be submitted to SBC P&D for approval prior to land use clearance.

Residual Impact

Although the proposed mitigation measure could reduce the visual impact of the Surf Substation, the presence of Platform Irene in the offshore area due to extension of life of the facilities is considered an *unavoidable significant (Class I)* visual impact.

Impact #	Impact Description	Phase	Residual Impact
Visual.2	Visual impacts due to installation of new equipment at Valve Site #2 and the LOGP.	*Operations Construction*	*Class III*

Three additional pumps to be installed at Valve Site #2 would be placed within the same fenceline as the valve site equipment. The pumps would be 7 feet in height from the grade, which is approximately one foot taller than the existing aboveground pipelines with valves. The valve site, which is located on VAFB, is barely visible from public places such as Ocean Avenue and Ocean Beach County Park. Given the low profile of the facility and its remote location, the visual impacts of the pump installation at the Valve Site #2 are considered adverse but less than significant with implementation of Mitigation Measure Visual-2, as outlined below.

The tallest structures at the LOGP reach 40 to 55 feet. Under the proposed project, only minor equipment modifications would be made at LOGP; therefore, these changes would not have a dominant visual effect. There may be additional lighting required for the nighttime operation of the upgraded facilities. However, additional night lighting would not be noticeable amidst other lighting at the LOGP. Therefore, no new visual impacts would occur as a result of the proposed project.

Mitigation Measures

Pursuant to the SBC Standard Mitigation Measures, the following mitigation measure is proposed:

Visual-2 To minimize visual effects, all new equipment shall be painted in colors that are compatible with the surroundings. The applicant shall submit the painting plans for the new facilities to SBC P&D before land use clearance. In addition, future painting plans for any existing portions of the LOGP shall be submitted to SBC for review and approval prior to commencing with painting.

Residual Impact

Mitigation Measure Visual-2, is required to mitigate Impact Visual.2 to the maximum extent feasible in accordance with County policies. This impact is considered *adverse but less than significant (Class III)*.

Impact #	Impact Description	Phase	Residual Impact
Visual.3	Visual impacts due to the new transformer station and power lines to Valve Site #2.	*Operations*	*Class II*

Construction activities related to installation of the new transformer station and the power line to Valve Site #2 would have adverse visual impacts in the area due to presence of cranes and other machinery. However, construction would be short-term and would not create a lasting visual impact.

The long-term presence of the new power line with the 60-foot poles could create an adverse visual impact in an area that is mostly unpopulated. The presence of a potential new transformer station would have an adverse but less than significant visual impact since it would be located in the area where other structures related to the electricity transmission (poles) already exist (see Figure 5.13-3).

There are several existing power lines that have 60-foot poles in the immediate area of a portion of the proposed power line: along Renwick Road, along 13th Street after the bridge and in the fields west from 13th Street before the Santa Ynez River bridge. Most of these power lines belong to VAFB; however, utilization of these poles for the proposed power line would not be allowed by the owner. Based upon the significance criteria, another power line with similar size poles, although visible from public routes, would not change the visual quality of these areas since they already contain several pole lines of similar or greater size.

The portion of the proposed power line along Terra Road would be in an area where currently there are no other poles or man-made structures (see Figure 5.13-4). The poles that would follow the existing pipeline right-of-way and Terra Road would be expected to be barely visible or not visible from the eastern part of Ocean Avenue because the view is mostly blocked by vegetation along the road. However, the poles could be visible from several coastal areas, such as Ocean Beach County Park, Surf Beach, and the western part of Ocean Avenue. Although the distance from the Coastal Zone to Valve Site #2 and the proposed power line is more than one mile, the area around the valve site and along Terra Road is visually sensitive and scenic. Because the area along Terra Road and in the vicinity of Valve Site #2 is highly scenic and is close to visually sensitive resources of the Coastal Zone, the visual impact from the presence of the new power line on poles in the area would be significant.

Mitigation Measures

Visual-3 Prior to constructing the power line to Valve Site #2, the applicant shall enter into discussions with VAFB to determine the feasibility of placing the power line on the 13th Street bridge or using the existing VAFB power poles for crossing the Santa Ynez River. The applicant shall also use existing poles to the maximum extent feasible for approaching the existing pipeline corridor's dirt road. The applicant shall utilize one of these options if they are allowed by VAFB. The applicant shall submit documentation to the SBC P&D from VAFB detailing their position on using the 13th Street bridge or the existing power poles for crossing the Santa Ynez River by the power line to Valve Site #2. This documentation shall be submitted to SBC P&D prior to land use clearance for construction of the power line to Valve Site #2.

Residual Impact

With implementation of the above mitigation measure, residual impacts would be considered *significant but mitigable (Class II).*

Impact #	Impact Description	Phase	Residual Impact
Visual.4	Visual impacts due to long-term continued presence of the LOGP.	*Extension of Life*	*Class I*

The LOGP creates nighttime glare from the light of the facility that can be seen through most of the Lompoc area, (including public viewsheds), and as far away as Highway 101 north of Los Alamos. This glare reduces the darkness of the night sky and could obscure the stars and other astronomical phenomena. The glare degrades the public's enjoyment of viewing the nighttime sky from many public areas, and therefore adversely impacts visual resources of several visually important areas. The glare is also incompatible with the mostly dark nighttime sky of the undeveloped areas near Lompoc that are in the public viewshed. The lights at the LOGP are needed to allow for the safe operation of the facility at night and to comply with Occupational Health and Safety (OSHA) regulations. The proposed project would prolong the life of the LOGP facilities beyond the projected lifetime of the approved Point Pedernales Project. This extension of life of the LOGP is considered a significant visual impact since it would extend the time over which the nighttime glare would be visible throughout most of the Lompoc area.

Mitigation Measures

Visual-4 The applicant shall implement a lighting plan that would minimize nighttime glare. The applicant shall submit the plan to SBC P&D for review and approval prior to land use clearance. The plan shall include the facility lighting placement and design.

Residual Impact

Although Mitigation Measure Visual 4 could potentially reduce the nighttime glare due to the extension of life of the LOGP, even the most rigorous lighting plan can not completely eliminate nighttime glare from an oil facility that complies with OSHA's lighting requirements. Therefore, Visual Impact 4 would still be considered *significant and unavoidable (Class I)*.

5.13.5 Impact Analysis for the Alternatives

Detailed descriptions of the various alternatives are provided in Chapter 3.0. This section provides a discussion of the visual resource impacts of the various alternatives.

5.13.5.1 No Project Alternative

Scenarios 2 and 3. As discussed in Section 3.2, under the No Project Alternative Scenarios 2 and 3, production of the federal portion of the Tranquillon Ridge field would and would not occur, respectively. However, no extension of life of Point Pedernales facilities (Platform Irene, pipelines, and LOGP) is assumed under either scenario. There would be no new visual impacts associated with either Scenario 2 or 3 ~~the No Project Alternative~~. Under ~~this alternative, all visual impacts that could occur from the proposed project,~~ Scenarios 2 and 3, Impacts Visual.1 through Visual.4, would be eliminated because no new structures would be built and the life of the Point Pedernales facilities would not be extended.

Options for Meeting California Fuel Demand. The relative visual impacts associated with the various options for meeting California fuel demand are summarized in Table 5.13.2.

Table 5.13.2 No Project Alternative Comparison to Options for Meeting California Fuel Demand, Aesthetics / Visual Resources

	Source of Energy	Impacts
Other Conventional Oil & Gas		
	Domestic onshore crude oil and gas	Likely to displace, rather than eliminate, visual impacts. Development of new production could have increased visual impacts depending on proximity of sensitive viewsheds.
	Increased marine tanker imports of crude oil	Likely to displace, rather than eliminate, visual impacts.
	Increased gasoline imports[1]	Likely to displace, rather than eliminate, visual impacts.
	Increased natural gas imports (LNG)	Likely to displace, rather than eliminate, visual impacts. If offshore LNG facilities built, new visual impacts could be introduced.
Alternatives to Oil and Gas		
	Fuel Demand Reduction: increased fuel efficiencies, conservation, electrification[2]	
	Alternative transportation modes	Proposed project impacts would be eliminated.
	Implementation of regulatory measures	Proposed project impacts would be eliminated.
	Coal, Nuclear, Hydroelectric	Proposed project impacts would be eliminated; however, coal, nuclear, and hydroelectric infrastructure development could introduce new visual impacts.
	Alternative Transportation Fuels	
	Ethanol/Biodiesel[3]	New ethanol/biodiesel facilities could introduce new visual impacts.
	Hydrogen[2]	New hydrogen facilities could introduce new visual impacts.
	Other Energy Resources[2]	
	Solar[2,4]	Visual impacts could be greater.
	Wind[2,4]	Visual impacts could be greater.
	Wave[2,4]	Visual impacts could be greater.

Footnotes:
1. Pipeline and tanker truck import from out-of-State assumed.
2. Assumes that Tranquillon Ridge production would not be replaced with other petroleum-based energy supply.
3. Assumes ethanol and biodiesel used as blends only and therefore would reduce, but not eliminate Tranquillon Ridge or equivalent production.
4. Assumes, large centralized facilities.

5.13.5.2 VAFB Onshore Alternative

Under the VAFB Onshore Alternative, an onshore directional drilling and production site would be placed approximately seven miles south of the Santa Ynez River on VAFB. An estimated 25 acres of a 75-acre site would be needed for development. The site would be located west and north of Surf Road, east of Coast Road, and south of Delphy Road. The drilling and production site is primarily undeveloped and characterized by native and non-native coastal vegetation and small dunes. The area is located on a hill sloping upwards to the east, which blocks most views of the site from Coast Road. There are several small VAFB buildings that flank the sides of Surf Road which are painted in a light green/gray color. Space Launch Complex (SLC)-5, a large facility that is highly industrial in appearance, is located approximately one-third of a mile to the east of Surf Road, but is not visible from the site itself due to the hilly topography of the area. There are multiple power lines suspended on wooden poles located south, southeast and east of the site. Several of the lines transect each other southeast of site. Public access to this portion of VAFB is strictly prohibited by the Air Force. This site is located on top of a steep coastal terrace that has little beach area at its base and blocks viewing of the site from near-shore locations. The Union Pacific Railroad (UPRR) is located west of Coast Road, from which train passengers can view limited portions of the site; full views of the site, however, are blocked by hills. Due to the remote location of the site within VAFB, the site would be considered to have a low viewing sensitivity per the indicators for viewing sensitivity outlined in Table 5.13-1.

Between the proposed drilling and production site and Highway 246 the areas for potential pipeline and ~~transmission~~ power line placement are primarily located within or adjacent to existing roads, existing power line rights-of-way, and the UPRR right-of-way. This area of VAFB is predominantly undeveloped. The vast majority of facilities and operations within this area support the site-specific activities associated with SLC-3 through SLC-6. Ocean Beach County Park, Surf Beach, and Amtrak's Surf Station are located south of the mouth of the Santa Ynez River. No other publicly accessible areas or recreational facilities are located within the area of the potential pipeline and transmission line right-of-way. Open space and agricultural uses flank the south side of Highway 246 between the coast and 13th Street, and open space associated with the floodplain of the Santa Ynez River is adjacent to the north side of Highway 246 in this area. Open space and agricultural uses (grazing and field production) surround both sides of 13th Street between Highway 246 and the existing PXP pipeline right-of-way.

Impact Visual.1 - Long-term Presence of Facilities Visible from Coastal Zone: Impacts associated with the long-term continued use of project-related facilities would be less than for the proposed project, since Platform Irene would be removed in approximately ten years (assuming no offshore discharge), instead of 30 years as with the proposed project. However, under the VAFB Onshore Alternative, the Surf substation would remain for the projected 30-year project life, a new six mile 69 kV power line tying into a new 115 kV/69 kV substation, at or near Surf Beach would be required, and the construction of new pipelines and tie-in facilities would be needed. These features would be constructed within, and visible from, the Coastal Zone; consequently, their impacts would be *unavoidable and significant* (*Class I*).

Impact Visual.2 – Installation of New Project Features – Valve Site #2 and LOGP: Under this alternative, facility additions, upgrades and replacements at Valve Site #2 ~~and the LOPG~~ would not be necessary; however, upgrades to LOGP would still occur. Under this alternative, no new pumps and electrical connections at Valve Site #2 would be needed; at a conceptual level, it is assumed that the installation of such features would be undertaken at this alternative's pipeline tie-in location. See Impact Visual.5 for a discussion of the tie-in station visual impacts. ~~Therefore, no impacts would occur.~~

Under this alternative the same LOGP upgrades as described for the proposed project would be required. Upgrades at the LOGP are not expected to increase the existing facility's visual bulk and industrial character; therefore, impacts would be considered *adverse but less than significant*

(Class III). Mitigation Measure Visual-2 would apply to mitigate this impact to the maximum extent feasible in accordance with County policy.

Impact Visual.3 – New Transformer Substation and Power Lines at Valve Site #2: Under this alternative, the new ~~transformer~~ substation and power lines at Valve Site #2 that are associated with the proposed project would not be extended to Valve Site #2, but would be terminated at the tie-in station ~~needed~~. ~~However~~ In addition, this alternative would require a new power ~~transmission~~ line to connect the drilling and production facility to a new substation near the existing Surf substation. Construction of the line would be temporary in nature and therefore the visual impacts of these activities would be *adverse but less than significant* (*Class III*).

As noted above, there are several existing power lines within the project area, including a line that flanks the west side of Coast and Surf Roads. In addition, existing power lines parallel 13th Street. The majority of ~~this area is~~ the two alternative power line alignments (production/ processing site power line and tie-in station power line) are not accessible or readily viewed by the public and therefore, for the majority of the two rights-of-way, the introduction of ~~a~~ new power lines would not significantly alter the existing visual attributes. However, within the vicinity of Ocean Beach County Park and the existing Surf substation, the public would have immediate views of the power line. ~~However, g~~ Given the presence of existing power lines in the immediate area, this impact is considered *adverse but not significant (Class III*).

Impact Visual.4 - Continued Presence of the LOGP: Under this alternative, operations of the LOGP would be extended as for the proposed project. Impacts would be the same as for the proposed project and would be *unavoidable and significant* (*Class I*).

Impact #	Impact Description	Phase	Residual Impact
Visual.5 ~~nighttime~~	New oil and gas facilities due to their tall structures and glare from lighting could impact visual resources in the area.	*Operations*	*VAFB - Class I or II ~~III~~* *~~Casmalia~~ LOGP - Class I*

The VAFB Onshore Alternative would require construction and operation of a new drilling and production facility. The facility would include up to 30 well slots, production well heads, piping and well test facilities, an oil dehydration facility including a Wet Lease Automatic Custody Transfer (LACT), and a gas compression and dew point control plant. These facilities would require approximately 25 acres of land. It is assumed that the drilling rig would be approximately 180 to 200 feet high. At least one tank up to approximately 50 feet in height could also be needed. In addition, pipeline tie-in facilities would be constructed west of 13th Street at approximately Milepost 4.5 of the existing PXP pipeline right-of-way.

Due to their ~~its~~ heights, the drilling rig and tank would be visible to military personnel and VAFB contractors from Coast, Delphy, and Surf Roads. However, these views would be limited to the short period of time that moving vehicles pass by the site; the roads immediately paralleling the site are estimated to be one-half to three-quarters of a mile in length. Surf Road also passes SLC-5 directly east of the site. The existing on-site buildings appear to be used only periodically for maintenance, storage and operational activities, and do not have any windows that would provide views of the site; consequently, there would be no effect on people temporarily occupying the buildings. The drilling rig and tank would be partially visible to train passengers traveling along the UPRR via Amtrak. However, due to the topography of the area and the speed at which trains typically pass by the site, views of the drilling rig and tank would not be anticipated to last for more than a few seconds. Due to the site's proximity on top of a coastal bluff, the drilling rig and tank would not be visible from the immediate coast line or near shore locations, and would be expected to be at least partially ~~substantially~~ obscured from view from locations farther offshore due to distance, the height of the coastal bluff, and existing space launch facilities. However, the degree to which the drilling rig and tank would be visible to mariners and from Ocean Beach Park, Highway 246 (Ocean Avenue), the Amtrak Station, and Surf Beach cannot be predicted with certainty without a detailed viewshed simulation and analysis, which is outside of the scope of this alternatives analysis. Consequently~~Therefore~~, it is possible that the overall visual effects of the drilling rig and tank ~~w~~could be found to be ~~*considered adverse but less than significant*~~ *unavoidable and significant* (*Class I*)~~ III)~~ or a potentially *significant but mitigable impact (Class II*), depending on VAFB's final requirements. It is noted, however, that placement and operation of the drilling rig and tank would require VAFB review and approval, which would be assumed to include further consideration of visual effects, as well as safety measures, such as lighting and height restrictions, to avoid conflicts with Base operations.

During construction of the production site, activities would be partially ~~substantially~~ screened by the area's hilly topography and public views from the UPRR would be minimal. Views of the construction site from Coast, Delphy, and Surf Roads by military personnel and VAFB contractors would also be limited by topography. As the result of the area's natural screening and the temporary nature of construction related activities, impacts to aesthetic resources would be anticipated to be *adverse but less than significant* (*Class III*). However, as addressed in the preceding paragraph, a detailed viewshed simulation and analysis would be required for this alternative to fully calibrate potential visual resources impacts due to construction-related activities.

During operation, the alternative production/processing site would introduce a new industrial feature to an area that is ~~predominantly un~~sporadically developed with Base launch sites and their supporting facilities. In addition, the tie-in substation would introduce an industrial facility within a portion of the Base that is predominantly agricultural and open space not within the coastal zone. Although public viewing of the alternative sites is highly limited, and surrounding VAFB features, such as SLC-5, are also industrial in nature, the loss of open space and introduction of new man-made, heavy industrial structures ~~w~~could be considered to be a potentially *significant and adverse impact (Class I*), or a potentially *significant and mitigable impact (Class II)* to the area's existing aesthetic attributes.

~~Additionally~~Nighttime lighting of the facility would be anticipated to be similar to the OSHA requirements associated with the LOGP, and would introduce a significant new source of light and glare to an area that is otherwise unlighted at nighttime. Operation of the drilling rig may also require twilight and nighttime obstruction lighting. The U.S. Department of Transportation, Federal Aviation Administration's (FAA's) "Advisory Circular for Obstruction Marking and Lighting" specifies that temporary and permanent structures that exceed an overall height of 200 feet above ground level, or exceed any obstruction standard contained in Title 14 Code of Federal Regulations Part 77, should normally be marked and/or lighted (FAA, 2000). In general, the U.S. Department of the Air Force (Air Force), which has jurisdictional authority over the site, follows the FAA standards contained within the "Advisory Circular for Obstruction Marking and Lighting." However, the Air Force retains the right to determine its own lighting specifications when the FAA's standards conflict with Air Force-related operations and requirements (U.S. Air Force, 1997). VAFB has indicated that due to the site's location within a special use air space, it will determine its own lighting specifications for the drilling rig and facility if this alternative is carried forward for review and approval (Schobel, 2007). Consequently, the specific lighting scheme required for this alternative cannot be precisely determined at this time. Nonetheless, it can be reasonably assumed that some type of safety and obstruction lighting will be needed, and that this lighting would be partially visible from public access points, such as Highway 246 (Ocean Avenue) and Surf Beach. Although the specific intensity and visibility of the lighting cannot be predicted, it may incrementally add to the existing lighted features of VAFB, and could be found to result in either a potentially *significant and unavoidable impact (Class I)*, or a potentially *significant but mitigable impact (Class II)*, depending on VAFB's final lighting requirements.

Mitigation Measures

To mitigate this impact to the maximum extent feasible, implementation of Mitigation Measure Visual-2 (facility painting to blend project features in with the surrounding environment) would be required. In addition, implementation of Mitigation Measure Visual-4 (a lighting plan) would reduce nighttime light and glare; however, ~~based upon the visual effects of the LOGP,~~ it is assumed that even the most rigorous lighting plan cannot completely eliminate the nighttime glare from an oil facility in compliance with OSHA's lighting requirements. It is also noted that VAFB would have approval authority over the facility's twilight and nighttime lighting requirements, ~~However, given the remote location of the drilling/production site to public viewers, with the exception of intermittent train passengers, this impact would be considered *adverse but less than significant (Class III)*. It is noted that review and approval by VAFB would additionally be required for construction and operation of the facility,~~ and this review and approval process may result in ~~that~~ additional mitigation measures to minimize ~~associated with~~ light and glare effects, or alternatively render certain mitigation infeasible. ~~may be required as the result of that process.~~

Residual Impact

Given the uncertainty in VAFB mitigation requirements and lack of a detailed viewshed simulation and analysis, Impact Visual.5 is considered potentially ~~*adverse but less than*~~ *significant and unvoidable (Class I ~~III~~) or potentially significant and mitigable (Class II)* for the VAFB Onshore Alternative.

Impact #	Impact Description	Phase	Residual Impact
Visual.6	Visual impacts due to new pipeline installation construction activities.	*Construction*	*Class II*

Under the VAFB Onshore Alternative, two new pipelines (an oil emulsion line and gas line) would be required to connect the drilling and production site to the existing PXP pipelines. Although construction of these pipelines would introduce activities and equipment that would detract from public views, the visual effects would be temporary in nature and the VAFB area is not readily viewed by the public; however, the public would have visual access to the pipeline right-of-way along Highway 246. Following construction and successful restoration of the right-of-way, there would be no visual impacts.

Mitigation Measures

Visual-5 Revegetation Plans shall be prepared (or existing PXP Revegetation Plans updated) to include new revegetation efforts, including a schedule for achieving revegetation milestones. The updated plans shall be submitted to SBC for review and approval prior to land use clearance. A bond equivalent to the cost of installation and maintenance shall be provided. Initial pipeline right-of-way revegetation shall be completed within 90 days of the commencement of pipeline operations.

Residual Impact

After implementation of the proposed mitigation measure, the visual impact from construction of the pipeline would be *significant but mitigable (Class II)*.

5.13.5.3 Casmalia East Oil Field Processing Location

Under this alternative, Impacts Visual.1 and Visual.3 would be the same as for the proposed project. The portion of Impact Visual.2 related to equipment modifications at the LOGP would be eliminated since a large portion of the equipment would be removed and the remaining compressor facility would have a much smaller footprint. All of the tall equipment, which can be seen from the various public viewing points would be removed. This portion of Impact Visual.2 would become beneficial.

Impact Visual.4 – Continued Presence of the LOGP: With this alternative, a pump and compressor station would still remain at the LOGP site. The station would be required to have nighttime lights to allow for its safe operation at night and to comply with Occupational Safety and Health Administration (OSHA) regulations. The lights would be shielded to the highest extent feasible that still provides lighting compliant with OSHA regulations; however, these lights are expected to create a nighttime glare, which would still be visible through most of the Lompoc area. If this alternative prolongs the life of the Point Pedernales Project facilities, the pump and compressor station at the LOGP site would continue to create nighttime glare for a longer period of time than was projected for the approved Point Pedernales Project. Although the glare would be visible from fewer public areas, and its severity would be expected to be reduced, the glare would still significantly degrade visual resources in the area. Therefore, with this alternative, Impact Visual.4 would be considered significant and unavoidable *(Class I*), but less severe than for the proposed project.

Impact Visual.5 – Construction and Operation of New Oil and Gas Facility: The new oil, gas and produced water processing facility associated with the Casmalia Alternative would not be expected to be visible from the major travel routes in the area such as Highways 1, 101, and 135 due to distance and the area's hilly landscape. Depending on its location within the Casmalia Oil Field, the new facility could be visible from the Union Pacific Railroad. The new facility would not be visible from the Coastal Zone or any public recreation places. There is a possibility that glare from the facility at the Casmalia site location could impact the southern Orcutt area and portions of public travel routes (e.g., Highway 101). The site is more distant from Orcutt than the LOGP is from Vandenberg Village and is more shielded by the mountainous canyon topography surrounding the site, which would reduce the visual impact. However, the glare would still be visible at night, particularly during foggy conditions. Therefore, this alternative would interfere with the public's enjoyment of important visual resources and produce a significant visual impact.

The Casmalia East site has been previously altered from its natural state by past development. In its North County Siting Study (County of Santa Barbara, 2000), the County determined that a developed oil field site such as Casmalia East would be an environmentally preferred location for an oil and gas processing facility both because of the visually protected canyon location and because the change in the visual/aesthetic regime would be less dramatic.

This alternative would not result in the obstruction of public views. This alternative would result in loss of open space but not in the public's viewshed. Therefore, there would be adverse but less than significant visual impacts associated with the construction and operation of the new oil and gas facility at the Casmalia East site.

Mitigation Measure Visual-2 would apply for all equipment for the new facilities. Mitigation Measure Visual-4 would help reduce nighttime glare of the new facility. Implementation of Mitigation Measure Visual-4, (Lighting Plan), would reduce glare; however, even the most rigorous lighting plan can not completely eliminate nighttime glare from an oil facility in compliance with OSHA's lighting requirements. Therefore, the residual impact would still be considered *significant (Class I)* for the Casmalia Alternative since the glare from the processing facility could be visible from the southern Orcutt area.

Impact Visual.6 – New Pipeline Construction Activities: Under the Casmalia Alternative, new pipelines would need to be constructed from the LOGP to the Casmalia site. From the LOGP, the pipelines would initially follow the existing ConocoPhillips pipeline right-of-way to Orcutt. The pipelines would then run west to the Casmalia site. A new dry oil pipeline would also have to be built from the Casmalia site to the ConocoPhillips Orcutt Pump Station. Although construction of these pipelines would introduce activities and equipment that would detract from public views, the visual effects would be temporary in nature. Following construction and successful restoration of the right-of-way, there would be no visual impacts. This visual impact is considered *significant but mitigable (Class II)* with the implementation of Mitigation Measure Visual-5.

5.13.5.4 Alternative Power Line Routes to Valve Site #2

Impacts Visual.1, Visual.2, and Visual.4 would remain the same as for the proposed project under any of the power line routes alternatives. Impact Visual.3 would change as discussed below.

Alternative Power Line Route – Option 2a

This alternative involves a different power line route that would supply electricity to Valve Site #2. The portion of the power line route from the point where the line taps into the existing power line to the intersection of 13th Street with Terra Road would be different than in the proposed project. The portion of the power line route from the 13th Street and Terra Road intersection to Valve Site #2 would be the same as in the proposed project.

The power line proposed in this alternative is parallel to two existing similarly sized pole lines that also cross Santa Ynez River. The addition of another pole line in an area where several other pole lines already exist, although adverse, would not be considered a significant visual impact since it would not change the visual quality of the area. Therefore, Impact Visual.3 is considered *adverse but not significant (Class III)* for this portion of the power line.

Impact Visual.3 from the portion of the power line along Terra Road is not affected by this alternative, and would still be visually significant and require mitigation (see Mitigation Measure Visual-3).

Alternative Power Line Route – Option 2b

This alternative is similar to Option 2a, except that the power line would be placed beneath the Santa Ynez River. Impact Visual.3 would remain as in the proposed project, *significant but mitigable (Class II).* Mitigation Measure Visual-3 would still apply.

Underground Power Line along Terra Road

This alternative involves installing approximately 2.2 miles of the power line to Valve Site #2 underground instead of installing it aboveground, as for the proposed project. The underground power cable would not be visible when the power cable route along the pipeline right-of-way and Terra Road is revegetated. Under this alternative, the poles along the existing pipeline right-of-way from the intersection of Terra Road and 13th Street to Valve Site #2 would not be installed. Approximately 1.2 miles of the power line would remain aboveground on poles. Visual impacts associated with this alternative would therefore be *less than significant (Class III).*

5.13.5.5 Replacement of Oil Emulsion Pipeline from Platform Irene to LOGP

Under this alternative, Impacts Visual.1 and Visual.4 would remain the same as for the proposed project. Impact Visual.2 would be reduced since there would be no new equipment installation at Valve Site #2. Impact Visual.3 would be eliminated since the new pipeline could deliver the oil emulsion to the LOGP without the use of additional pumps, and therefore the ~~transformer station of~~ substation and the power line to Valve Site #2 would not be installed. Impact Visual 5, new oil and gas facilities, does not apply to the Emulsion Pipeline Replacement Alternative.

Impact Visual.6 – New Pipeline Construction Activities: During construction of the offshore replacement pipeline there would be heavy machinery present in the Coastal Zone and in the areas visible from the Coastal Zone and public use areas, such as Ocean Beach County Park. Although unpleasing to the view, this machinery would only be present for 2 to 2½ months. This short-term visual impact is considered to be adverse but not significant.

Excavation and clearing to replace the pipeline would be done in previously disturbed areas. Construction of the onshore portion of the replacement pipeline would require an approximately 100-foot wide right-of-way. Only a 40 to 50-foot wide strip of the 100-foot construction right-of-way would be cleared of vegetation; the additional 50 feet would be “masked” by either walking or rolling over existing vegetation to provide room for equipment movement along the right-of-way and material staging. After completion of the pipeline installation, the trench would be filled and the ground graded to the pre-construction condition. However, the 50-foot wide strip along the length of the pipeline where vegetation was removed would remain visible from several public areas, such as Highway 1 and public roads in Lompoc. This strip of bare ground would create a negative visual impact due to removal of significant amounts of vegetation and substantial alteration of natural character visible from public areas. This visual impact is considered *significant but mitigable (Class II)* with the implementation of Mitigation Measure Visual-5.

5.13.5.6 Alternative Drill Muds and Cuttings Disposal

For this alternative, Impacts Visual.1 through Visual.4 would be the same as for the proposed project. Impacts Visual.5 and Visual.6 would not apply to this alternative because it would not involve construction of a new oil and gas processing plant or replacement of the existing Point Pedernales Project wet oil pipeline.

5.13.6 Cumulative Impacts

Cumulative projects that could impact the current analysis include the potential offshore oil and gas projects discussed in Sections 4.2 and 4.3, and the onshore development projects outlined in Section 4.4. The cumulative impacts of these potential off- and onshore development projects are discussed separately below.

5.13.6.1 Offshore Oil and Gas Projects

There are several potential offshore oil and gas development project in the vicinity of the proposed project. As discussed in Sections 4.2 and 4.3, some of these potential projects would be developed from existing platforms and onshore facilities, while others would require new off- and onshore facilities (the Santa Maria, Lion Rock, Point Sal and Purisima Point Units and Lease OCS-P 0409). The cumulative impacts associated with extending the lives of the area's existing platforms, including the incremental contribution of the proposed project, and the possible introduction of new platforms, would be considered significant.

5.13.6.2 Onshore Projects

A discussion of the potential onshore development projects located within the vicinity of the proposed project is provided in Section 4.4. Several of these potential development projects are either in close proximity to the existing LOGP, or would be visible from the same public viewing areas as the LOGP. These projects would result in a cumulative loss of open space and additional nighttime lighting and glare, and would also alter the overall visual character of the Lompoc area from semi-rural to urban. These cumulative visual impacts, combined with the extended life of the LOGP, would be expected to be significant within the Lompoc viewshed. As discussed in Section 5.13.4, the proposed project's contribution (LOGP nighttime glare) would be considered significant.

5.13.7 Mitigation Monitoring Plan

Mitigation Measure	Mitigation Requirements and Timing	Method of Verification	Timing of Verification	Party Responsible For Verification
Visual-1	The applicant shall prepare and implement a visual mitigation plan for the Surf Substation that provides for better screening of the facility. The plan shall address measures to reduce the visual impact of the facility including, but not limited to, painting of substation substructures	Review of the plans. Review of implementation efforts.	Prior to land use clearance. Annually during operations.	SBC P&D

Mitigation Measure	Mitigation Requirements and Timing	Method of Verification	Timing of Verification	Party Responsible For Verification
	and re-landscaping. The plan shall be submitted to SBC P&D for approval prior to land use clearance.			
Visual-2	To minimize visual effects, all new equipment shall be painted in colors that are compatible with the surroundings. The applicant shall submit the painting plans for the new facilities to SBC P&D before land use clearance. In addition, future painting plans for any existing portions of the LOGP shall be submitted to SBC for review and approval prior to commencing with painting.	Review of the plans. Review of the finished facilities.	Prior to land use clearance. After completion of painting implementation.	SBC P&D
Visual-3	Prior to constructing the power line to Valve Site #2, the applicant shall enter into discussions with VAFB to determine the feasibility of placing the power line on the 13th Street bridge or using the existing VAFB power poles for crossing the Santa Ynez River. The applicant shall also use existing poles to the maximum extent feasible for approaching the existing pipeline corridor's dirt road. The applicant shall utilize one of these options if they are allowed by VAFB. The applicant shall submit documentation to the SBC P&D from VAFB detailing their position on using the 13th Street bridge or the existing power poles for crossing the Santa Ynez River by the power line to Valve Site #2. This documentation shall be submitted to SBC P&D prior to land use clearance for construction of the power line to Valve Site #2.	Review of documentation from VAFB.	Prior to land use clearance approval for construction of power line to Valve Site #2.	SBC P&D
Visual-4	The applicant shall implement a lighting plan that would minimize nighttime glare. The applicant shall submit the plan to SBC P&D for review and approval prior to land use clearance. The plan shall include the facility lighting placement and design.	Review of plan	Prior to land use clearance	SBC P&D
Visual-5 (VAFB Onshore, Casmalia, and Emulsion Pipeline Replacement Alternatives only)	Revegetation Plans shall be prepared (or existing PXP Revegetation Plans updated) to include new revegetation efforts, including a schedule for achieving revegetation milestones. The updated plans shall be submitted to SBC for review and approval prior to land use clearance. A bond equivalent to the cost of installation and maintenance shall be provided. Initial pipeline right-of-way revegetation shall be completed within 90 days of the commencement of pipeline operations.	Review of the submitted plan. Monitoring of revegetation progress.	The plan shall be submitted prior to land use clearance approval. Monitoring shall be done periodically during installation and prior to release of the maintenance bond.	SBC P&D

5.13.8 References

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U.S. Department of the Interior, Bureau of Land Management, 1986; Department of Agriculture, Forest Service, 1977.

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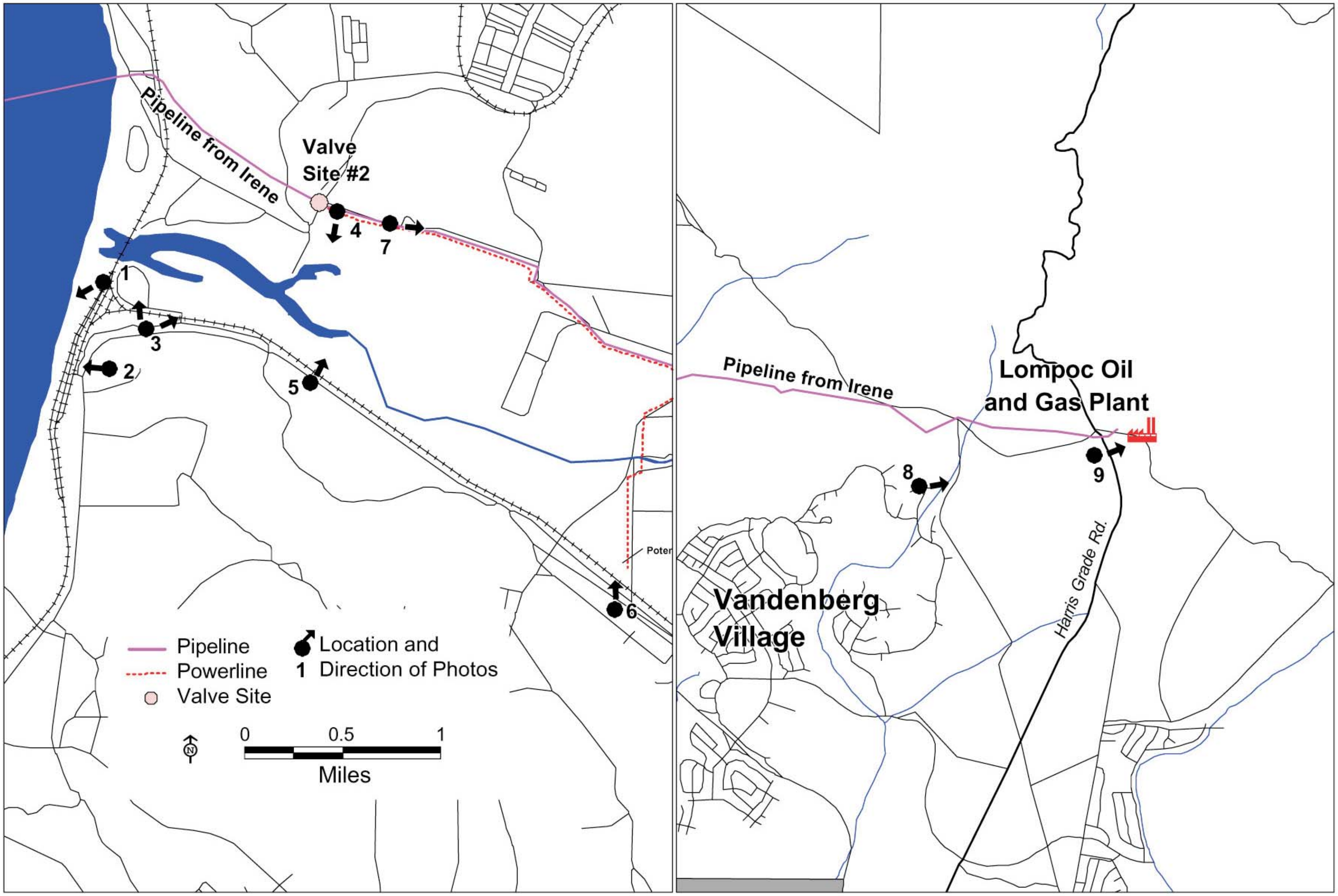

Source: MRS, 2002.

PREPARED BY Aspen Environmental Group

Figure 5.13-1
Map of View Positions for the Photos

Figures 5.13-2: Platform Irene and Coastline (View Position 1)
(View west from Surf Beach with dunes in the foreground, Pacific Ocean and Platform Irene n the background)

Figures 5.13-3: View of Surf Substation (View Position 2)
(View of Surf Substation looking west from the west end of Ocean Avenue. The low vegetation is in the foreground, the substation is in the mid-ground and the ocean is in the background.)

Source: MRS, 2002.

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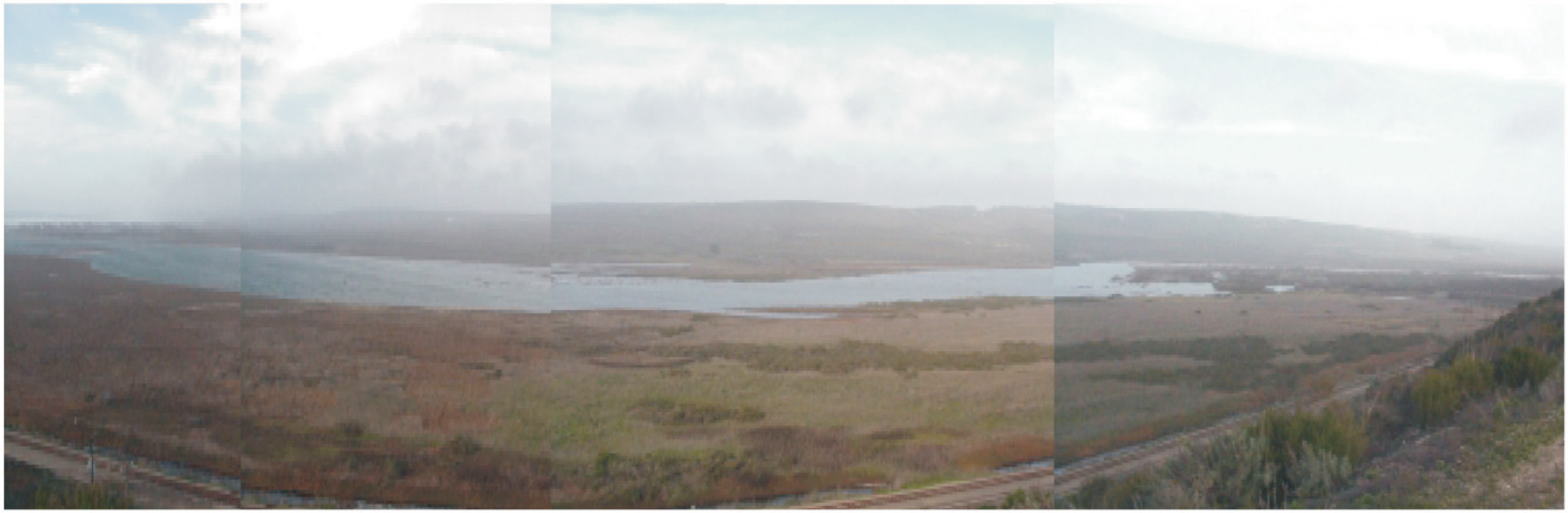
Figures 5.13-2 & 5.13-3
Photographs



(View from Ocean Avenue near Ocean Beach Park looking northeast towards Valve Site #2 and Terra Road. Union Pacific Railroad is in the foreground, the Santa Ynez River estuary is in the mid-ground, and the hills behind Terra Road are in the backgound.)

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Figure 5.13-4

View of Santa Ynez River from Ocean Avenue Near Ocean Beach Park (View Position 3)

Figures 5.13-5: View of Santa Ynez River and Hills from Valve Site #2 (View Position 4)
(View south from Valve Site #2)

Figures 5.13-6: Route 246 to Valve Site #2 (View Position 5)
(View of Surf Substation looking west from the west end of Ocean Avenue. The low vegetation is in the foreground, the substation is in the mid-ground and the ocean is in the background.)

Source: MRS, 2002.

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Figures 5.13-5 & 5.13-6
Photographs

Figures 5.13-7: View from Ocean Avenue near 13th Street and Renwick Road (View Position 6)
(View north from Ocean Avenue with the road in the foreground, power lines and vegetation along the road in the mid-ground, and the hills north of Terra Road visible in the background.)

Figures 5.13-8: View of Pipeline Bridge Near Catchment Basin 4 (View Position 7)
(Pipelines rack crossing over drainage, view from Terra Road east with the road continuing on the left in the background, three pipelines on the right fore- and mid-ground.)

Source: MRS, 2002.

PREPARED BY Aspen Environmental Group

Figures 5.13-7 & 5.13-8
Photographs

Figures 5.13-9: View with LOGP in Background (View Position 8)
(View from Firestone Road looking northeast with the LOGP in the background.)

Figures 5.13-10: View of LOGP at Night (View Position 8)
(View from Firestone Road looking northeast with the LOGP in the background.)

Source: MRS, 2002.

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Figures 5.13-9 & 5.13-10
Photographs

Figures 5.13-11: View of LOGP from Harris Grade Road (View Position 9)
(View looking northwest from Harris Grade Road onto the LOGP.)

Source: MRS, 2002.

PREPARED BY Aspen Environmental Group

Figure 5.13-11
Photograph

5.14 Recreation/Land Use/Policy Consistency Analysis

This section describes recreational resources and land uses in the vicinity of the proposed project area, and the impacts of the proposed project and its alternatives. The analysis is based upon a review of the Final Environmental Impact Report (EIR) prepared for the proposed project in 2002 (Arthur D. Little et al., 2002), review of local, regional, and federal resource statistics and recreation maps, and discussions with appropriate agencies. The last part of this section provides a policy consistency analysis.

5.14.1 Environmental Setting

The environmental setting section is divided into two major parts covering recreation and land use. The following discussion is focused on recreational resources and land uses in Santa Barbara County (SBC); however, a discussion of coastal recreational opportunities within southern San Luis Obispo County is also included because an offshore oil spill could potentially affect these resources. Please refer to Section 5.1 (Risk of Upset) and Appendix G for a discussion of the potential trajectories of an offshore oil spill.

5.14.1.1 Recreation

California ranks first in the nation for the total number of residents that participate in marine recreation annually (12.2 percent); estimated beach visitation rates throughout the State, for local residents and regional and out-of-State visitors, range from 150 million to more than 378 million annually (National Oceanic and Atmospheric Administration [NOAA], 2006). In 2000, it was estimated that at a State level 61, 18, 11 and 10 percent of all beach visits within the State were for the purposes of beach-related marine activities, recreational boating, recreational fishing, and “other” activities, respectively (Kildow and Colgran, 2005). Within the category of beach-related marine activities, 51.4, 32.1, 7.7, and 7.0, 1.3, and 0.5 percents were attributed to beach visits, swimming, surfing, waterside visits (besides beach visits), snorkeling, and diving, respectively (Kildow and Colgran, 2005). Within the categories of recreational boating and fishing, the estimated proportion of marine-oriented activity days for 2000 was as follows: recreational fishing – 49 percent; motor boating – 28 percent; sailing – 16 percent; and, personal watercraft – 7 percent (Kildow and Colgran, 2005).

Western Santa Barbara and San Luis Obispo Counties contain a varied and scenic physical environment, ranging from coastal bluffs, sand dunes, and beaches to inland mountains and forests. The coastal area offers broad, sweeping vistas of the coastal range and Pacific Ocean and, between Santa Barbara and Point Conception, views of the Channel Islands. The coastal area is largely undeveloped in SBC and built up in and around Pismo Beach; the region contains several existing oil processing and missile launch facilities interspersed with coastal parks and agriculture.

Outdoor recreation resources include State, county, and locally managed public and private parks, reserves, golf courses, and recreational clubs along shoreline and inland areas. Recreational activities include boating, diving, surfing, swimming, sunbathing, nature observation, hiking, camping, biking, and off-road vehicle use. (Recreational fishing is discussed in Section 5.7.) Table 5.14-1 provides a listing of the primary public beaches associated with Santa Barbara and San Luis Obispo Counties.

Table 5.14-1 Primary Public Beaches in Santa Barbara and San Luis Obispo Counties

County	Beach Name	Water Body	Nearest City or Community
Santa Barbara County	Arroyo Burro Beach	Pacific Ocean	Santa Barbara
	Arroyo Quemada Beach	Pacific Ocean	Santa Barbara
	Butterfly Beach	Pacific Ocean	Montecito
	Carpinteria City Beach	Pacific Ocean	Carpinteria
	Carpinteria State Beach	Pacific Ocean	Carpinteria
	East Beach at Mission Creek	Pacific Ocean	Santa Barbara
	East Beach at Sycamore Creek	Pacific Ocean	Santa Barbara
	El Capitan State Beach	Pacific Ocean	Santa Barbara
	Gaviota State Beach	Pacific Ocean	Santa Barbara
	Goleta Beach	Pacific Ocean	Goleta
	Guadalupe Dunes	Pacific Ocean	Guadalupe
	Hammond's Beach	Pacific Ocean	Montecito
	Hope Ranch Beach	Pacific Ocean	Santa Barbara
	Jalama Beach	Pacific Ocean	Lompoc
	Leadbetter Beach	Pacific Ocean	Santa Barbara
	Point Sal State Beach	Pacific Ocean	Guadalupe
	Ocean Beach	Pacific Ocean	Lompoc
	Refugio State Beach	Pacific Ocean	Santa Barbara
	Rincon Beach	Pacific Ocean	Carpinteria
	Sands Beach at Coal Oil Point	Pacific Ocean	Goleta
	Surf Beach	Pacific Ocean	Surf
San Luis Obispo County	Avila Beach	Avila Bay	Avila Beach
	Cayucos	Pacific Ocean	Cayucos
	Moonstone Beach	Pacific Ocean	Cambria
	Morro Bay City Beach	Morro Bay	Morro Bay
	Olde Port Beach	Port San Luis	Avila Beach
	Pismo Beach	Pacific Ocean	Pismo Beach
	Pismo State Beach	Pacific Ocean	Oceano
	Shell Beach	Pacific Ocean	Pismo Beach

Source: Kildrow, J. and Colgan, C. 2005. California's Ocean Economy, A Report to the Resources Agency, State of California. Prepared by the National Ocean Economics Program. July 2005. (As excerpted from the California Coastal Commission's "Beach Access Guide.")

California ranks second and third in the nation for the total number of residents that participate in marine diving (of any kind) and surfing, respectively; on an annual basis it is estimated that within California more than 870,000 individuals dive in coastal waters and that 750,000 individuals surf (Pendleton and Rooke, 2006; Warshaw, 2005). Within the project area popular surfing locations west of Gaviota include the Hollister Ranch shoreline, which is generally limited to boat access, Jalama Beach, and Pismo Beach in San Luis Obispo County. Diving is popular all along the coastal kelp beds and reefs in depths of 60 feet or less. Access to diving areas west of Gaviota and north to Point Sal is by boat only, but shore entry is possible at any of the beach or park locations. Boats can be launched from the Channel Islands, Ventura and Santa Barbara Harbors, Goleta and Gaviota Piers, and at Port San Luis Obispo. Sites for State Marine Reserves and a park have been proposed near San Miguel, Santa Rosa, and Santa Cruz islands.

Visitation to the Channel Islands for hiking, camping, swimming, and kayaking is estimated at 30,000 visitors per year, and 60,000 in the waters surrounding the islands for whale watching, sportfishing, diving (both free divers and SCUBA divers), and pleasure boating (National Parks Service [NPS], 2006). In 1999, 25 commercial passenger fishing vessel operators accounted for 176,700 person-days of activity in the Channel Islands National Marine Sanctuary (CINMS)

(158.8 thousand person-days of fishing, and 17.9 thousand person-days of consumptive diving) (NOAA, 2006). In addition, private boats accounted for 261.2 thousand person-days of activity within the CINMS (214 thousand person-days of fishing, and 47.2 thousand person-days of consumptive diving) (NOAA, 2006). Consumptive diving refers to the take (i.e., the capture and removal) of either plant or wildlife species, or any other type of naturally occurring object or material that may be encountered while diving, while non-consumptive diving refers to passive diving activities such as marine life observation.

The City of Santa Barbara Harbor Department estimates daily pleasure boating in the Santa Barbara Channel at hundreds of vessels per day during the boating season (March 1st through December 1st), and over a thousand vessels per day during the peak season (Labor Day through Memorial Day) (City of Santa Barbara Harbor Department, 2006). Between July 2004 and June 2005, the Santa Barbara Harbor (Harbor) registered 14,200 recreational vessels using its slips, with over 1,100 recreational vessels checking into the Harbor each month between April and October (City of Santa Barbara Harbor Department, 2006).

Recreational uses of Santa Barbara Channel include whale watching, recreational boating (including motorized and non-motorized vessels), sportfishing, and consumptive and non-consumptive diving. Skin and SCUBA diving take place from the shoreline, private boats, and "party boats." Boats may be launched at any of the region's ports and harbors or at Gaviota pier; smaller boats are also launched from the shore. Most diving occurs in kelp beds or rocky reef areas to depths of 60 feet (Arthur D. Little, et. al., 2002). Between January 2005 and January 2006, it is estimated that 9,000 or more recreational fishing trips for all types of species and all types of fishing (private boats, chartered boats and "party boats") occurred each month; during this same period, the peak period for these activities occurred between May and September, with over 44,000 marine recreational fishing trips for all modes of fishing made each month (California Department of Fish and Game [CDFG], 2006).

South of Point Conception, Gaviota State Park, El Capitan State Beach and Refugio State Beach are the closest coastal recreational areas related to the proposed project area. El Capitan State Beach provides opportunities for swimming, fishing, surfing, kayaking, picnicking and camping, as well as hiking and biking (California Department of Parks and Recreation, 2007a). A bike trail connects this area with Refugio State Beach, which is located 2.5 miles to the west. Refugio State Beach provides camp sites and picnic areas, and is commonly used for fishing, swimming, surfing, kayaking, biking and hiking (California Department of Parks and Recreation, 2007b). Gaviota State Park includes a pier that is used by divers and surfers, and additionally provides opportunities for hiking, swimming, surfing, camping, picnicking and fishing (California Department of Parks and Recreation, 2007c). All three of these areas offer concessionary stands for food and supplies, and are accessed by thousands of visitors each year (California Department of Recreation, 2006, 2007a, 2007b, 2007c).

Jalama Beach lies north of Point Conception on 23.5 acres of coast and is a popular location for camping, surfing, and nature observation. Jalama Beach Park includes barbeque grills, benches and picnic tables, bike trails, bird watching, boating, fishing, horseshoe pits, a playground, concessionary stand, restaurants, surfing, swimming, and 98 sites for tent and recreational vehicle camping; there is a $6.00 fee for day use of the facility (SBC, 2006a). For the calendar year 2005, approximately 76,000 vehicles entered Jalama Beach Park (Stone, 2006). The County's standard for estimating the number of visitors at County-operated beaches and parks is

22.5 visitors per vehicle; consequently, the total number of people that visited Jalama Beach Park in the year 2005 is estimated to be 190,000. Peak attendance occurs during the summer months and declines during the winter months.

Surf Beach lies west of Lompoc on Vandenberg Air Force Base (VAFB) property. Parking facilities were developed to serve the Amtrak station, but the site is also used for coastal access. Annual visitation data is not available but is estimated to be a fraction of the attendance at nearby Ocean Beach County Park, one half mile to the north.

Ocean Beach County Park is located west of Lompoc on 36 acres adjacent to the coast. The park provides safe coastal access with a wheelchair accessible ramp that passes under a train trestle. The park contains a sand dune/wetland environment with the Santa Ynez River mouth as a northern boundary. The park features barbeque grills, benches and picnic tables, bike trails, bird watching, a playground and restrooms; there is no fee for day use of the park (SBC, 2006a). This normally windy and isolated area is used mostly by fishermen, windsurfers, and family picnickers. With peak attendance during summer months and lowest attendance in winter months, average attendance per day is 330 people, based on 4,000 monthly vehicle trips and 2.5 visitors per vehicle (Olgin, 2006).

Beginning in the summer of 2000, both Ocean Beach County Park and Surf Beach access was restricted by VAFB as a result of United States Fish and Wildlife Service's order to protect an endangered shorebird, the snowy plover, during its nesting season. The complete or partial closure of the beaches occurred again in 2001 and will occur each year for the foreseeable future.

Rancho Guadalupe Dunes County Park, located south of the boundary between Santa Barbara and San Luis Obispo Counties, provides beach access, bike and equestrian trails, fishing, bird watching and hiking. There is no fee for day use of the park (SBC, 2006a).

Point Sal State Beach is located north of VAFB, near the City of Guadalupe. It is made up of 140 acres, including two miles of ocean frontage; recreational activities include fishing, beach combing, hiking, natural study, photography, picnicking and sunbathing (California Department of Parks and Recreation, 2007d). The coastline of Point Sal State Beach is part of one of twelve stretches of the State's coastline that is included in the State Park System's State Seashores program, which has been established to preserve outstanding natural, scenic, and recreational values of California's coast (California Resources Agency, 2007). It is also included in the California Natural Area Coordinating Council's Inventory of California Natural Areas (California Department of Parks and Recreation, 2006). In addition, the Nipomo Dunes-Point Sal Coastal Area was designated a National Natural Landmark in 1974 (U.S. Department of the Interior, National Parks Service, 2007).

Nipomo Dunes Complex, which partially overlaps Pismo State Beach, is the largest coastal dune ecosystem in western North America and extends 10 miles from the Callender Dunes in the north to the Mussel Rock Dunes in the south and comprises approximately 12,000 acres. The Nipomo Dunes Complex contains one of the most unique and fragile ecosystems in the state and is a heavily utilized recreational resource, owing primarily to the off-road vehicle use described ~~above~~ below.

Pismo State Beach stretches 23 miles along the coast in San Luis Obispo County. Recreation activities include camping, hiking, swimming, surfing, bicycling, horseback riding, bird watching, and observation of the annual winter migration of millions of monarch butterflies (the park has the largest over-wintering colony in the U.S.). It also features an eight-mile section on which cars and off-road vehicles are permitted. Cars and RVs are permitted on the northern section of the State beach while off-road vehicles use the southern dunes State Vehicular Recreation Area (SVRA). Camping is permitted in parts of the dunes area. The gates for vehicle access to the beach are found in the communities of Grover Beach and Oceano. Annual visitation rates of Pismo State Beach and the SVRA have been steadily rising in the past three to four years; in 2005 an estimated 2.6 million visitors accessed the area, with 2.1 million people using the SVRA and .5 million people using the Pismo State Beach facilities (Bellman, 2006).

Avila Beach and Port San Luis lies three miles north of Pismo Beach on a south-facing coastline of hills, cliffs, and sandy beaches. Recreational activities include kayaking, boating, swimming, surfing, and nature observation. From 1998 to 2000, visitor numbers at these locations were lower than normal due to an oil spill remediation effort that closed the main beach and much of the town (Arthur D. Little, et. al., 2002). However, since completion of remedial activities, recreational uses of, and annual visitor numbers at, these areas has increased substantially, including the main beach and Avila Pier, as well as a new two-acre beach-front park and a new plaza area managed by the San Luis Obispo County Parks Department (Jenny, 2006; Ziehn, 2006).

Montana de Oro State Park lies six miles southwest of Morro Bay and covers approximately 8,000 acres of cliffs, sandy beaches, coastal plains, streams, and hills. Recreational activities include mountain biking, equestrian, surfing, camping, and nature observation.

The sole inland recreation resource adjacent to the project area is the Burton Mesa Ecological Reserve, a California Department of Fish and Game (CDFG) managed area adjacent to the Lompoc Oil and Gas Plant (LOGP) and surrounding three sides of Vandenberg Village. It covers approximately 5,000 acres of sensitive ecological habitat and provides passive recreational opportunities such as walking, hiking, naturalist activities such as bird watching, and bicycling (Arthur D. Little et al., 2002).

Current Point Pedernales Facility Operations

The project site is located in northwestern SBC. The pipelines and power cables come ashore from Platform Irene north of the Santa Ynez River near Ocean Beach County Park. This park is located on the beach at the end of State Highway 246.

From its landfall north of the Santa Ynez River, the pipeline traverses largely undeveloped land owned by VAFB. The pipeline crosses the Burton Mesa Ecological Reserve before reaching the LOGP. From the LOGP, the pipeline continues north over Harris Grade.

Current drilling and production operations could cause a blowout or other accident, resulting in an offshore oil spill with the potential for temporarily interfering with recreational use of marine and shoreline recreational resources and facilities. The applicant currently makes annual payments to the County's Coastal Resources Enhancement Fund (CREF) to offset its contribution to cumulative recreation impacts. While Ocean Beach Park is the nearest onshore recreational area, Gaviota State Park and Jalama Beach County Park to the south, and Point Sal

State Beach and the Rancho Guadalupe Dunes Reserve to the north could also be adversely affected by an oil spill (see Figure 5.14-1). San Miguel, Santa Rosa, and Santa Cruz Islands and the CINMS could also be affected by an oil spill. The extent of a spill's impacts would depend on the volume of spill, its origin and trajectory, and the effectiveness of containment and cleanup activities.

Aquatic recreation activities such as surfing, scuba diving, swimming, and boating as well as shoreline recreation activities (both passive and active) could be adversely impacted for an extended period of time in the event of an oil spill from current operations. During the 1997 spill, for example, Surf Beach was used as a spill response staging area, and both Surf Beach and Ocean Beach County Park were closed to the public. The impacts to diving in the project area could be similarly restrictive, but the coastline north of Point Conception is infrequently used for diving due to limited access and unfavorable diving conditions. San Miguel Island also features some popular diving spots that are sometimes inaccessible due to ocean conditions but could be affected by a spill.

In addition to directly affecting on- and offshore recreational resources, a spill would require a cleanup work force whose temporary housing and the use of some public and private campground space could create a temporary adverse impact to recreational facilities.

An onshore oil spill from pipelines might arise from accidental events such as pipeline leaks and ruptures. A pipeline spill from current operations could adversely affect Ocean Beach Park because of its proximity to the pipeline's landfall or because it lies downstream from the potential spill zone. A pipeline spill from onshore operations could also adversely affect the Burton Mesa Ecological Reserve near LOGP. There are no attendance data available for the Reserve, but proposed recreational improvements, which include parks, campsites, sports fields, and barbeque pits, would greatly increase the number of recreational users. In general, onshore spills are more easily controlled than offshore spills, which are dispersed through wave action and ocean water currents, so the impacts to recreational activities in the Reserve would be short-term.

5.14.1.2 Land Use

SBC contains approximately 1,383,000 acres, 90 percent of which are in non-intensive uses. The Los Padres National Forest, covering approximately 44 percent of the central and eastern county (608,520 acres), is the largest single land use in the County. Recreation, protected watershed for reservoirs in the Santa Maria and Upper Santa Ynez Valleys, and limited grazing and mining are provided within this national forest (Arthur D. Little et al., 2002).

Of the 982,000 acres outside of the national forest, over 70 percent is in private agricultural cultivation or grazing uses, 10 percent is included in Vandenberg Air Force Base (VAFB) on the western coast of SBC, and the remainder is developed with urban and transportation uses (Arthur D. Little et al., 2002).

The project area additionally includes the cities of Lompoc, Santa Maria and Guadalupe, and the unincorporated communities of Vandenberg Village, Missions Hills, Mesa Oaks and Orcutt. The north county area is rural in character and includes many properties with agricultural preserve status.

The Williamson Act enables agricultural property owners to enter into contracts with the County, which limit the development potential of property to agricultural uses in return for decreased property taxes. Area/community goals, as referenced under local land use plans/policies, emphasize preservation and expansion of agriculture, containment of urban development within prescribed geographic limits, and protection of the SBC's natural environment.

Coastal lands in the northern county are primarily undeveloped and a large strip extending from Point Sal State Beach south to Jalama Beach County Park is within the restricted area of VAFB, with the exception of Ocean County Park at the Santa Ynez River mouth. From Point Sal northward, coastal sand dunes extend into San Luis Obispo County. Rancho Guadalupe Dunes County Park is located south of the Santa Maria River mouth where beach access is provided.

VAFB represents the second largest individual land use in the North County, occupying 5.6 percent of the SBC's lands. A large amount of VAFB land is open space. Uses on the VAFB include: a central area for VAFB support (including Air Force facilities), contractor areas and military housing; an airfield northwest of the central area; and, missile launch facilities to the southwest and northwest. A railroad corridor passing through the coastal area is allocated to the Union Pacific Railroad.

Land along the northern and eastern perimeters of the VAFB is primarily open space and grazing land. The Lompoc Federal Penitentiary is located adjacent to the east boundary of VAFB and south of Vandenberg Village, and occupies 3,500 acres. In general, a buffer comprising large agricultural areas is provided between the urban centers of Vandenberg Village, Mission Hills, the City of Lompoc and VAFB.

Since agriculture is a significant use in the North County, long-term stability of agricultural lands is a major determinant of future land use development in this area. Under recent trends, agriculturally zoned lands have gradually been converted to urban uses. Please refer to Section 5.15 (Agricultural Resources) for a discussion of the agricultural characteristics of the study area.

According to the SBC Open Space Element, the greatest possibilities for SBC urban expansion exist in the Santa Maria-Orcutt Study Area. This is due to a large amount of acreage being described as very suitable for urban expansion in this region. Of these lands, approximately 40 percent are in agricultural use.

The LOGP is located outside of urbanized areas in the Lompoc valley, is zoned M-CR (Coastal Related Industry), and is contained within the Lompoc Oil Field boundaries. The majority of the pipelines from Platform Irene to the LOGP are on VAFB, with the remainder of the route on land zoned for agricultural uses.

5.14.2 Regulatory Setting

The California Public Resource Code Section 30260 (contained within Article 7 [Industrial Development] of the California Coastal Act) states the following:

- Section 30260. Coastal-dependent industrial facilities shall be encouraged to locate or expand within existing sites and shall be permitted reasonable long-term growth where consistent with this division. However, where new or expanded coastal-dependent industrial facilities cannot feasibly be accommodated consistent with other policies of this division, they may nonetheless be permitted in accordance with this section and Sections 30261 and 30262 if (1) alternative locations are infeasible or more environmentally damaging; (2) to do otherwise would adversely affect the public welfare; and (3) adverse environmental effects are mitigated to the maximum extent feasible.

The following are policies adopted by SBC to address land use issues.

Consolidation Policies: In 1987, the Board of Supervisors adopted revisions to the Comprehensive Plan policies and implementing ordinances that address consolidation of oil and gas processing facilities and sites. These revisions (for the Coastal Zone) were certified by the California Coastal Commission (CCC) in 1988. The consolidation policies require shared use of existing facilities that are situated on county-designated consolidated sites. Consolidation is intended to free more land for other uses, to provide wider buffers and separations between oil and gas processing and other land uses, and to reduce environmental impacts by reducing unnecessary redundancy of facilities. In 1986, the County added policies to its Coastal Plan and Land Use Element for the purpose of requiring maximum feasible consolidation of offsite pipelines and pipeline corridors.

SBC required the LOGP site to operate as a consolidated facility as a condition of the discretionary permit issued for the Point Pedernales Project. Permit conditions require consolidation or co-location on or adjacent to an existing processing facility to accommodate new production unless doing so would be infeasible or more environmentally damaging than other alternative sites. The County has also acknowledged that, under certain circumstances, two or three consolidated sites might be more appropriate than one site in the North County to serve offshore gas production.

***Land Use Element*:** This plan is designed to preserve and enhance the qualities that make SBC unique by encouraging a balanced and diverse economy, promoting local self-sufficiency, encouraging a balance in housing and jobs, stressing long-term productivity, living within limits of available resources and services, providing moderate, orderly growth in harmony with our surroundings, and to provide for protection of the natural and historical heritage which has enriched the lives of residents and visitors throughout the years. One of the goals of the plan addresses the relationship between development and the environment and states: "Environmental constraints on development shall be respected. Economic and population growth shall proceed at a rate that can be sustained by available resources."

The SBC Land Use Element, as amended, contains the following parks and recreation policies applicable to the proposed project and its alternatives:

- Opportunities for commercial and sport fishing should be preserved and improved where appropriate;
- Opportunities for hiking and equestrian trails should be preserved, improved, and expanded wherever compatible with surrounding uses.

Land Use Development Policies (LUDP): There are a number of land use development polices that would be applicable to the proposed project and its alternatives. They include the following:

LUDP 10

Impacts of oil, gas, and produced-water pipelines outside of industrial facilities shall be minimized by requiring the use of available or planned common carrier and multiple-user pipelines to the maximum extent feasible. New pipeline construction shall be permitted only if the Planning Commission determines that the use of available or planned common carrier and multiple-user pipelines is not feasible or is not environmentally preferable to alternative proposals. New pipelines that are permitted shall be constructed, operated and maintained as common carrier or multiple-user pipelines unless the Planning Commission determines it is not feasible. New multiple-user pipelines shall provide equitable access to all shippers with physically compatible stock on a nondiscriminatory basis.

New pipelines shall be restricted to approved corridors that have undergone comprehensive environmental review unless the Planning Commission determines that such corridors are not available, safe, technically feasible, or the environmentally preferred route for the proposed pipeline. The required environmental review for proposed pipelines shall include analysis to determine what cumulative impacts might result in adding future pipelines to that corridor.

The design of new common carrier and multiple-user pipelines shall take into account the reasonable, foreseeable needs of other potential shippers. If other pipeline projects are expected to be located in the same corridor, the proposed projects shall be required to coordinate concurrent or "shadow" construction with the other projects where practical.

Permits for new pipeline construction shall require engineering of pipe placement and burial within the corridor to minimize incremental widening of the consolidated corridor during subsequent pipeline projects, unless the proposed route is determined to be unacceptable for additional pipelines. (86-GP-18)

LUDP 11

For the purpose of ensuring safe, orderly, and planned development of oil and gas resources, the Board of Supervisors designates the northwestern and midwestern portion of SBC as the North County Consolidation Planning Area, or NCCPA (as defined under the section "Other Definitions" in this element) and subjects oil and gas development in this planning area to the following policy:

a. Due to estimated oil and gas reserves located offshore, the County has prepared a study entitled *Siting Gas Processing Facilities: Screening & Siting Criteria.* That study is incorporated herein by reference to guide a comprehensive analysis of alternative sites should the county receive an application for a Development Plan to construct or expand a facility in the NCCPA for treatment or processing either onshore or offshore gas production. The criteria are designed to optimize public safety, environmental protection, and the benefits of consolidation (89-GP-9).

LUDP 12

Proposals for expansion, modification, or construction of new oil and gas processing facilities, oil storage facilities, or pipeline terminals which receive oil from offshore fields exclusively or from both offshore and onshore fields, shall be conditioned to require transportation of oil by pipeline to processing facilities and final refining destination, except as provided in this policy.

"Final Refining Destination" shall mean a refinery in California where refining of the subject oil into products is accomplished. Exceptions: Oil shall be considered to reach its final refining destination if (a) the oil has been transported out of the State of California, and does not reenter before final refining; or (b) the oil has been transferred to truck or train after leaving the County by pipeline and does not reenter the County by truck or train, and is not transferred to a marine terminal vessel for further shipment to a port in California prior to final refining.

Crude oil received onshore from offshore production facilities may be transported by highway or rail if the Director determines that the oil is so highly viscous that pipeline transport is infeasible, taking into account available options such as modifications to existing pipelines, blending of NGLs, etc.

Any shipment of oil by highway or rail under this policy shall be limited to that fraction of the oil that cannot be feasibly transported by pipeline and shall not exceed the limits of permitted capacity for those transportation modes. The shipper or carrier shall mitigate to the maximum extent feasible any environmental impacts caused by the alternate transportation mode.

Temporary transport of oil by waterborne vessel may be authorized under an emergency permit if the Governor of the State of California declares a state of emergency pursuant to Public Resources Code Sec. 30262(a)(8) for an emergency that disrupts the pipeline transportation of oil produced offshore Santa Barbara County. In such a case, the oil transported by alternate mode shall be limited to that fraction which cannot feasibly be transported by pipeline. Transport by the alternate mode shall cease immediately when it becomes technically feasible to resume pipeline transport.

LUDP 13

Oil and gas facilities shall be dismantled and removed, their host sites cleaned of contamination and reclaimed to natural conditions, or conditions to accommodate reasonably foreseeable development, in an orderly and timely manner that avoids long-term impacts to health, safety, and welfare of the public and environment.

Local Coastal Plan (LCP)*:* Public Resources Code Section 30250(b) (contained within Article 6 [Development] of the California Coastal Act) states, "Where feasible, new hazardous industrial development shall be located away from existing developed areas." LCP Policy 6-13D states that "No lands designated for recreational, educational, commercial, resort/visitor serving commercial, or residential use shall be redesignated for use as an oil storage facility site. Any redesignation from uses other than those prohibited shall be accompanied by mitigation to fully offset the land use impacts of that redesignation."

Land Use and Zoning Designations: The majority of the Study Area is regulated under SBC's Land Use and Development Code (LUDC). The LUDC combines the County's Inland Zoning Ordinance, Article III and Coastal Zoning Ordinance, Article II into one document. All requirements of the Inland and Coastal zoning ordinances remain the same with this reformatting. The LUDC (outside the Coastal Zone) became effective January 1, 2007. The portions of the Study Area within the Coastal Zone will continue to be ~~are~~ regulated under the SBC's Coastal Zoning Ordinance, Article II until the Coastal portions of the LUDC are certified by the Coastal Commission. Oil and gas processing facilities serving offshore production are permitted only in the Coastal-Related Industry (M-CR) zone district. The LOGP site is the only site within the northern section of SBC that is currently designated for M-CR. Any new oil and gas processing facility serving offshore production would require a rezoning of land to M-CR.

5.14.3 Significance Criteria

SBC does not have adopted thresholds of significance specific to recreation or land use (SBC, 2006b). The SBC "Environmental Thresholds and Guidelines Manual" chapter for coastal resources addresses issues regarding coastal protection structures, such as seawalls, and its chapter for quality of life addresses issues related to "individuals, families, communities, and other social groupings and the way in which these groups function" (SBC, 2006b). In lieu of adopted SBC thresholds of significance for recreation and land use, the CEQA Guidelines provide the following thresholds of significance for recreation and land use:

Recreation:

A proposed project may have a significant impact on recreational facilities and opportunities if it would:

a) increase the use of existing neighborhood and regional parks or other recreational facilities such that a substantial physical deterioration of the facility would occur or be accelerated.

b) include recreational facilities or require the construction or expansion of recreational facilities that might have an adverse physical effect on the environment.

Land Use:

A proposed project may have a significant impact on land use if it would:

a) physically divide an established community.

b) conflict with any applicable land use plan, policy, or regulation of an agency with jurisdiction over the project (including, but not limited to the general plan, specific plan, local coastal program, or zoning ordinance) adopted for the purpose of avoiding or mitigating an environmental effect.

c) conflict with any applicable habitat conservation plan or natural communities conservation plan.

5.14.4 Impact Analysis for the Proposed Project

The following sections discuss potential impacts to recreation and land use, mitigation measures to reduce potential impacts to less than significant (where applicable and appropriate), and residual impacts associated with the proposed project. Because the proposed project would largely use existing facilities (e.g., platform, LOGP and pipelines), requirements for new facilities or equipment with potentials for impacting recreational activities or land use are minimal. Impacts from the existing Point Pedernales Project facilities and operations are discussed in the EIR that was prepared in 2002 for the Tranquillon Ridge Oil and Gas Development Project, LOGP Produced Water Treatment System Project, and Sisquoc Pipeline Bi-Directional Flow Project (Arthur D. Little et al., 2002). The potential impacts associated with the proposed project are related to changes to existing facilities and operating conditions, and are described below.

5.14.4.1 Recreation

Impacts could come from construction, normal operations, abandonment, accidents, and/or catastrophic events. Onshore construction and facility-specific modification activities along the pipeline route and at the processing facilities would be temporary in nature and would not be expected to adversely affect recreational resources or their tourist-related attractions.

To offset impacts due to the Point Pedernales project to recreation resources in the project area, the applicant is already contributing annually to the SBC Coastal Resource Enhancement Fund (CREF). Condition N-1 of the Point Pedernales Final Development Plan (FDP) requires annual contributions for the life of the project, which would be extended under the proposed Tranquillon Ridge project.

Impact #	Impact Description	Phase	Residual Impact
Rec.1	The proposed project would increase the likelihood and volume of an oil spill, which could result in public access restrictions to coastal and inland recreational resources.	*Increased Throughput Extension of Life*	*Class I*

The increased throughput between Platform Irene and LOGP and the extension of life of the facilities and pipelines would increase the probability and volume of an oil spill. An offshore spill caused by an accident or failure at Platform Irene or in the offshore pipeline could lead to beach closures and boating restrictions during spill response and cleanup, as well as a lingering public perception that recreational resources are polluted, even after the cleanup period. These short- and long-term effects would be expected to result in corresponding impacts on local and regional tourism, particularly as they relate to coastal resources and attractions. The primary recreation resources within the immediate project are shown in Figure 5.14-1.

The duration and extent of beach closures would depend on the volume of the spill and prevailing ocean and local weather conditions. As discussed in Appendix G, a worst-case scenario oil spill could reach recreational resources as far north as Montana de Oro State Park near Morro Bay and as far south as the Santa Barbara Channel Islands. The coastline east of Point Conception, including Gaviota State Park and El Capitan and Refugio State Beaches would likely avoid direct spill impacts. The area from Point Sal to Point Arguello is at greatest risk from a spill due to its proximity to the Point Pedernales Project facilities; therefore Ocean Beach County Park, Point Sal Beach State Park, and Jalama Beach County Park would be impacted more than other recreation areas, with as much as 7,900 bbls of oil reaching the beaches if there were a shoreline failure of the oil emulsion pipeline. In addition to impacts directly related to beach closures and restrictions, other types of offshore recreational activities and visitor (tourist) attractions, such as SCUBA diving, snorkeling, whale watching and non-commercial fishing would also be affected. Resulting impacts to recreational resources and tourism due to an offshore oil spill would be considered *significant and unavoidable* (*Class I*).

An onshore spill near the pipeline landfall could pose a similarly adverse effect on the recreational utilization of Ocean Beach Park. As detailed in Section 5.1, Risk of Upset, the worst-case scenario for a spill near the beach is in excess of 7,900 bbls of crude oil emulsion. An onshore spill further inland could adversely affect recreational resources such as the Burton Mesa Ecological Reserve, the Santa Ynez River, and Ocean Beach Park (via a spill into the river). Section 5.1, Risk of Upset, contains estimated probabilities of spill landfall for a variety of spill locations. An oil spill would likely degrade the environment and create a safety concern at a number of recreational areas. In addition, oil spill response activities could also affect recreational resources. During the 1997 spill, Surf Beach was used as a spill response staging area, and both Surf Beach and Ocean Beach County Park were closed to the public. Therefore the impact of an oil spill on recreation and tourism would be considered significant.

Compared with the baseline likelihood of an oil spill, the impact of the proposed Tranquillon Ridge Project would increase the impact slightly due to the increase in oil throughput through the pipeline and potentially increased spill size. However, the effects of restricted recreational use of Ocean Beach County Park and Surf Beach would be minimal during those periods of the year when public access to the beach is restricted to protect nesting snowy plovers.

Mitigation Measures

See Marine Biology Mitigation Measure MB-1a~~2~~, and Marine Water Quality Mitigation Measures MWQ-1, MWQ-2, MWQ-3. ~~and Commercial and Recreational Fishing Mitigation Measure CRF/KH-1.~~

Residual Impact

As addressed in the Final EIR prepared for the Tranquillon Ridge Oil and Gas Development Project, LOGP Produced Water Treatment System Project, and Sisquoc Pipeline Bi-Directional Flow Project (Arthur D. Little et al., 2002), the existing Point Pedernales Project could result in potentially significant, unavoidable impacts to recreation in the event of an oil spill (or spills). Implementation of the proposed project would maintain, and slightly increase these impacts for the duration of its operational lifetime. Therefore, with implementation of the above mitigation measures, potential impacts to recreation and tourism due to an oil spill would continue to be considered *significant (Class I).*

5.14.4.2 Land Use

Construction at the LOGP and Valve Site #2 would occur in existing developed sites and would not result in the loss of any open space, change the existing land use at these sites, or disrupt or divide the physical arrangement of an established community. The project would require the construction of power lines on poles. Construction of this line would not result in any loss of open space, would be consistent with the existing land use, and would not disrupt or divide the physical arrangement of an established community. Other than construction, the project does not require any additional workers over what exists for the current operations. Therefore, the project would not induce any growth.

The LOGP and associated pipelines are in close proximity to a number of residential areas such as Vandenberg Village. These residential areas experience nighttime glare from the facility (see Section 5.13, Visual Resources), as well as occasional noise from alarms and radios, particularly at night. While the nighttime noise measurements conducted as part of this EIR show that the levels are well below the significance threshold, they do present a level of nuisance to the residential areas. Nighttime noise and visual glare has been an issue for a number of the local residents since the LOGP became operational. The applicant has worked with the residents to reduce the level of nighttime glare and noise to the extent feasible without compromising the safety of the operations. The nighttime lighting at the LOGP has been reduced to the minimum levels allowed by OSHA (see Mitigation Measure Visual-4).

The County of Santa Barbara has also implemented permit conditions in the Point Pedernales Project FDP to mitigate the visual impacts of the project. In particular, FDP condition N-1 requires that the operator contribute funds to the CREF for the life of the project. These funds are used to enhance coastal recreation, aesthetics, tourism and environmentally sensitive resources, including a means of compensating for the Class I visual impacts associated with the project.

5.14.5 Impact Analysis for the Alternatives

Detailed descriptions of the various alternatives have been provided in Chapter 3.0. This section provides a discussion of the recreational and land use impacts of the various project alternatives.

5.14.5.1 No Project Alternative

Scenarios 2 and 3. As discussed in Section 3.2, under the No Project Alternative Scenarios 2 and 3, production of the federal portion of the Tranquillon Ridge field would and would not occur, respectively. However, no extension of life of Point Pedernales facilities (Platform Irene, pipelines, and LOGP) is assumed under either scenario. Under ~~the No Project Alternative~~ Scenario 2, only the portion of the Tranquillon Ridge Field that is located in Federal Waters would be developed to the extent allowed by the existing Point Pedernales Project permits. ~~In addition~~Under either Scenarios 2 or 3, the pumps and associated power line at Valve Site #2 would not be installed. In the event that the proposed project is not implemented there is the possibility that the Tranquillon Ridge Field could be developed from an onshore site, as currently proposed by Sunset/ExxonMobil (see Section 3.2, No Project Alternative Scenario 1). Section 5.14.5.2, below, addresses the potential impacts that could occur from such development.

***Impact Rec.1 – Oil Spill*:** This impact would be eliminated under Scenario 3 of the No Project Alternative ~~for the Tranquillon Ridge Project~~ since no additional production of the Federal portion of the Tranquillon Ridge Field would occur. While under Scenario 2 there is a small probability that additional production from that the portion of the field located in Federal Waters could occur, total Platform Irene crude oil production volumes would be similar to current operations (i.e., the baseline).

~~The~~ No Project Alternative Scenarios 2 and 3 would not result in a substantial loss of open space, induce population growth, create incompatibilities with existing land uses or development, or disrupt or divide the physical arrangement of an established community.

Options for Meeting California Fuel Demand. The relative land use and recreational impacts associated with the various options for meeting California fuel demand are summarized in Table 5.14.2.

5.14.5.2 VAFB Onshore Alternative

Under the VAFB Onshore Alternative, an onshore directional drilling and production site would be placed approximately seven miles south of the Santa Ynez River on VAFB. An estimated 25 acres of a 75-acre site would be needed for development. The site would be located west and north of Surf Road, east of Coast Road, and south of Delphy Road. The site is primarily undeveloped and characterized by native and non-native coastal vegetation and small dunes. Several small VAFB structures (buildings) flank the sides of Surf Road, and Space Launch Complex 5 (SLC-5) is located approximately one-third of a mile to the east. Additionally, there are multiple power lines suspended on wooden poles located south, southeast and east of the site.

Table 5.14.2 No Project Alternative Comparison to Options for Meeting California Fuel Demand, Recreation / Land Use / Policy Consistency

	Source of Energy	Impacts
Other Conventional Oil & Gas		
	Domestic onshore crude oil and gas	Likely to displace, rather than eliminate, recreation/land use impacts. Development of new production could have increased recreation/land use impacts depending on proximity of recreational resources and sensitive receptors.
	Increased marine tanker imports of crude oil	Spill impacts to recreation could increase with marine tankering.
	Increased gasoline imports[1]	Likely to displace, rather than eliminate, recreation/land use impacts.
	Increased natural gas imports (LNG)	Spill impacts to recreation could increase with marine tankering or if offshore facilities are built.
Alternatives to Oil and Gas		
	Fuel Demand Reduction: increased fuel efficiencies, conservation, electrification[2]	
	Alternative transportation modes	Proposed project impacts would be eliminated.
	Implementation of regulatory measures	Proposed project impacts would be eliminated.
	Coal, Nuclear, Hydroelectric	Proposed project impacts would be eliminated; however, coal, nuclear, and hydroelectric infrastructure development could introduce new recreational/land use impacts.
	Alternative Transportation Fuels	
	Ethanol/Biodiesel[3]	Proposed project impacts would be reduced. Potential construction and operation impacts because of new plant development.
	Hydrogen[2]	Proposed project impacts would be eliminated. Potential construction and operation impacts due to hydrogen delivery infrastructure development.
	Other Energy Resources[2]	
	Solar[2,4]	Recreation/land use impacts could be greater.
	Wind[2,4]	Recreation/land use impacts could be greater.
	Wave[2,4]	Recreation/land use impacts could be greater.

Footnotes:
1. Pipeline and tanker truck import from out-of-State assumed.
2. Assumes that Tranquillon Ridge production would not be replaced with other petroleum-based energy supply.
3. Assumes ethanol and biodiesel used as blends only and therefore would reduce, but not eliminate Tranquillon Ridge or equivalent production.
4. Assumes, large centralized facilities.

Public access to this portion of VAFB is prohibited by the Air Force, and there are no recreational facilities located within or near the site. This site is located on top of a coastal terrace that has little to no beach area under it, and blocks viewing of the site from near-shore locations.

Between the proposed drilling and production site and Highway 246 the areas for potential pipeline and ~~transmission~~ power line placement are primarily located within or adjacent to existing road, utility, and railroad rights-of-way within a portion of the VAFB that is predominantly undeveloped. The vast majority of facilities and operations within this area support launch activities associated with SLC-3 through SLC-6. Ocean Beach County Park, Surf Beach, and Amtrak's Surf Station are located south of the mouth of the Santa Ynez River. No other publicly accessible areas or recreational facilities are located within the area of the potential pipeline and ~~transmission~~ power line alternative right-of-way. Open space and agricultural uses flank the south side of Highway 246 between the coast and 13th Street, and open space associated with the floodplain of the Santa Ynez River is adjacent to the north side of Highway 246 in this area. Open space and agricultural uses (grazing and field production) surround both sides of 13th Street between Highway 246 and the existing PXP pipeline right-of-way, the location of the alternative tie-in station. Power lines also parallel 13th Street in this area. There are no public recreational facilities or opportunities located within the alternative pipeline right-of-way area of this alternative east of Ocean Beach County Park.

The alternative drilling and production site, tie-in station, and pipeline and ~~transmission~~ power line corridors would be located in publicly restricted areas of VAFB that are largely undeveloped. Development in this "South Base" area of VAFB is specific to military operations and the operations of SLC-3 through SLC-6. ~~Construction and o~~Operation of this alternative would ~~not substantially increase the~~ require a permanent staff for the production/processing facility comparable to Platform Irene (approximately 15 employees). The addition of this permanent staff within VAFB ~~employment, in comparison to the proposed project, and~~ would not be anticipated to conflict with military operations. Therefore, this alternative would not induce substantial population growth, conflict with or be incompatible with existing land uses, or disrupt or divide the physical arrangement of an established community. No impacts would be anticipated to occur. It is noted, however, that construction and operation of this alternative would require U.S. Air Force approval, including its assessment of land use compatibility and the need for facility-specific land use-related restrictions or conditions of approval, as warranted to protect current and future military operations. Please refer to Section 5.15 (Agricultural Resources) for an assessment of this alternative's potential impacts on agricultural activities.

Construction of this alternative would dedicate approximately 75 acres of undeveloped land on VAFB to project-related operations, including an estimated 25 acres of development. However, VAFB, as a whole, contains large acreages of open space areas that are protected for the purposes of military operations and these open space lands are not available to, or accessible by, the public. Additionally, per standard County and Coastal Commission approvals, at the end of this alternative's production life (estimated to be 30 years), the Applicant would be required to restore the area to pre-project conditions. It would be anticipated that the U.S. Air Force would require post-operation site restoration as well. Therefore, impacts associated with the loss of substantial amount of open space would be less than significant (*Class III*).

Impact REC.1 – Oil Spill: Potential impacts to recreation resulting from an oil spill would be less than for the proposed project since the alternative facilities would be located landward of the railroad tracks until Highway 246. The railroad runs along a berm that forms a partial barrier to flows. However, there is a small potential for spilled oil to reach Ocean Beach County Park and/or Surf Beach if the pipelines are placed on the northern side of Highway 246 or if high flow conditions result in the breach of the UPRR created berm. Therefore, this impact is still considered *significant and unavoidable (Class I)*. Although it is assumed that mitigation measures similar to those that would be required for the proposed project would be applied to this alternative by the U.S. Air Force and SBC (as allowed by its jurisdictional authority), no additional mitigation measures have been identified to reduce potential impacts to less than significant.

Impact #	Impact Description	Phase	Residual Impact
Rec.2	Pipeline and power line construction could interfere with or restrict recreational activities along the pipeline/power line routes.	*Construction*	*Class III*

During construction of the pipelines and power ~~transmission~~ line to the new substation adjacent to the Surf substation, access to portions of Ocean Beach County Park and Surf Beach would be restricted or temporarily prohibited. These restrictions and possible preclusions would be limited in duration. Therefore, impacts to recreation would be adverse but not significant.

Mitigation Measures

No potentially adverse, significant impacts associated with onshore pipeline construction that would require mitigation have been identified. Therefore, no mitigation measures are necessary.

Residual Impact

The impact to recreation due to pipeline construction would be *adverse but not significant (Class III)*.

5.14.5.3 Casmalia East Oil Field Processing Location

A new processing facility at the Casmalia East Oil Field would be built in a location where there is currently oil and gas development. The area that would need to be developed would be approximately 20 acres in size. Construction of the site would result in temporary disturbances, such as increased noise levels and traffic volumes, to nearby land uses for the duration of construction-related activities. However, operation of the site would not result in the loss of any open space, change existing land uses, induce population growth, or disrupt or divide the physical arrangement of an established community. A new facility at the Casmalia East site would result in some nighttime glare affecting the surrounding areas, such as parts of the community of Orcutt (see Section 5.14.4.2).

Under this alternative new emulsion and sour gas pipelines would need to be constructed from the LOGP to the Casmalia site. From the LOGP the pipelines would initially follow the existing ConocoPhillips pipeline right-of-way to Orcutt. The pipelines would then run west to the Casmalia site. A new dry oil pipeline would have to be built from the Casmalia site to the ConocoPhillips Orcutt Pump Station. Areas along the existing and new pipeline corridors include a variety of land uses, but are primarily devoted to agriculture (including livestock grazing), limited onshore oil production, open space, and single family residences (SBC, 2000). There are no established public recreational facilities located within, or immediately adjacent to, the existing and new pipeline corridors. Construction of the pipelines from the LOGP to the Casmalia site could result in temporary disturbances to nearby residents and land uses for the duration of construction. However, the pipelines would not result in the permanent loss of any open space, induce population growth, change the existing land uses of these sites, or disrupt or divide the physical arrangement of an established community.

Impact Rec.1 – Oil Spill: This impact would be the same as for the proposed project since the potential oil spill volumes would be the same (*Class I*).

Impact Rec.2 – Pipeline Construction: This impact would not apply to the Casmalia Alternative since there are no recreational areas between the LOGP and the Casmalia Alternative processing site.

5.14.5.4 Alternative Power Line Routes to Valve Site #2

The installation of the power lines below ground as opposed to above ground, or the alternative power line configurations as specified (Options 2a and 2b) would not change the recreation or land use analyses developed above for the proposed project. Therefore, the impacts for these alternatives would be identical to those for the proposed project. Impact Rec.1 and the associated mitigation measures would still apply. Impacts would be *significant* (*Class I*)

5.14.5.5 Replacement of Oil Emulsion Pipeline from Platform Irene to LOGP

This alternative would involve the replacement of the wet oil pipeline from LOGP to Platform Irene. The existing pipeline route, which includes three pipelines, is located in unpopulated areas, and passes through the Burton Mesa Ecological Reserve to the north of Vandenberg Village, north of the Santa Ynez River ~~Preserve~~, and along the ocean floor from north of Ocean Beach County Park to Platform Irene.

Impact Rec.1 - Oil Spill: This impact would be the same as for the proposed project since oil spill volumes would be the same as the proposed project. The impact would be *significant (Class I)*. As referenced above, the existing pipeline corridor traverses undeveloped areas; consequently, its replacement would not result in the loss of any open space, change existing land uses, induce population growth, or disrupt or divide the physical arrangement of an established community. No impacts to land use would occur.

Impact Rec.2 – Pipeline Construction: Access to a number of recreational areas could be restricted or prohibited during pipeline construction. Access to portions of Ocean Beach County Park and Surf Beach would be restricted during the period when the pipeline was being installed across the beach and through the surf zone. Access to portions of the Burton Mesa Ecological Reserve could also be restricted during onshore pipeline construction activities. However, these restrictions would be limited in duration, lasting no more than a week. Therefore, the impacts to recreation would be *adverse but not significant (Class III).*

5.14.5.6 Alternative Drill Muds and Cuttings Disposal

***Impact Rec.1 – Oil Spill*:** For all of the muds and cuttings disposal alternatives, this impact would remain the same as the proposed project: *significant (Class I).*

Inject Drill Muds and Cuttings into Reservoir

The injection of muds and cuttings into the Point Pedernales Reservoir alternative would not result in any additional impact to recreational resources or land use. This alternative would require a pump and piping connections to an injection well head, modifications that would occur at the platform; activities at the platform would not result in the loss of any open space, change existing land uses, induce population growth, disrupt or divide the physical arrangement of an established community, or reduce or degrade the recreational value of a recreational use.

Transport Drill Muds and Cuttings to Shore for Disposal

This section addresses the impacts on recreational resources and land use associated with the onshore disposal of drilling muds and cuttings alternative. Drilling an estimated 22 to 30 wells would require the use and disposal of drill muds and cuttings. This alternative would involve the transport of the waste from the platform via the regular supply boats (two return trips per week) to Port Hueneme for offloading. All waste would then be trucked to a landfill in Kern County.

Impact #	Impact Description	Phase	Residual Impact
Rec.3	Muds and cuttings spilled near the shore could disrupt recreational activities such as SCUBA diving.	*Drilling*	*Class III*

In the unlikely event that drill muds and cuttings were accidentally spilled, marine water quality could be temporarily fouled, lowering visibility for divers (see Section 5.6, Marine Water Quality). Since the supply boats would not traverse areas commonly associated with diving, the likelihood that a spill would impact recreational resources is small and the effects would be temporary. However, to ensure that potential impacts to recreation are minimized to the extent feasible, Mitigation Measure REC-1, below, is recommended.

Mitigation Measures

In addition to Mitigation Measures MWQ-~~6~~2 and MWQ-3 in Section 5.6, Marine Water Quality, the following mitigation measure would apply:

REC-1 During project construction and operation, the applicant shall require project vessels to travel in recommended marine traffic corridors.

Residual Impact

Mitigation Measures REC-1, MWQ-2, and MWQ-~~6~~3 are required to mitigate Impact Rec.3 to the maximum extent feasible in accordance with County policies. This impact is considered *adverse but not significant (Class III).*

5.14.6 Cumulative Impacts

5.14.6.1 Offshore Oil and Gas Projects

As discussed in Section 4.2, future development of the undeveloped federal outer continental shelf (OCS) leases is currently in question as a result of litigation and continuing objections from the State of California. However, in the event development activities were allowed to move forward, potential federal offshore oil and gas projects would be developed using both existing and new offshore platforms, associated pipelines and onshore facilities. While the exact timing of these developments is unknown, it is possible that they could occur during the drilling or operational phases of the proposed project. Additionally, several offshore oil and gas development projects are proposed in State waters, as outlined in Section 4.3. However, none of these potential projects would occur in close proximity to the proposed project.

The marine traffic associated with construction and operation of the undeveloped federal offshore OCS leases would increase boat traffic. The number of helicopters servicing these projects would also increase. These increases in marine traffic and helicopter trips would increase annoyances to recreational boaters and visitors accessing nearby public beaches and coastal parks, during both construction and operation. If full development of all of the undeveloped federal OCS leases were to occur, these increases could be potentially significant. However, as outlined in Section 5.9, Traffic, the increase in marine traffic and helicopter trips due to the proposed project would not be expected to be significant, nor would its incremental contribution to cumulative impacts be anticipated to be significant.

The proposed project and majority of cumulative projects would be producers of oil and gas within the Santa Maria Basin. In the unlikely event of an oil spill, there could be significant impacts to recreational areas, such as Ocean Beach County Park and the Burton Mesa Ecological Reserve. An oil spill from these projects could also affect recreational resources as far south as the Channel Islands and southern Santa Barbara County. Further, the cumulative projects along the southern Santa Barbara coastline could affect the Santa Maria Basin shoreline under certain seasonal conditions including tide and weather. The probability of a simultaneous spill of two or more facilities is very small, but still probable. Therefore, the cumulative impacts on recreation resources and related cumulative effects on tourism due to an oil spill, including the incremental contribution of the proposed project, would be considered significant.

If the federal OCS undeveloped leases of the northern Santa Maria Basin were approved for construction and operation (the Santa Maria, Lion Rock, Point Sal and Purisima Point Units and Lease OCS-P 0409), a new onshore processing facility in the Casmalia area could potentially be needed (MMS, 2005). Although potential cumulative land use-related impacts associated with this facility cannot be reasonably projected at this time, the proposed project's onshore facilities would be located a substantial distance away from the Casmalia facility, and, therefore, the proposed project would not be anticipated to incrementally contribute any land use-related cumulative impacts.

5.14.6.2 Onshore Projects

Potential onshore development in the proposed project area is discussed in Section 4.4. As summarized in Table 4.2~~3~~, the majority of this development is residential and commercial in nature, although other types of development and redevelopment projects are also either pending or have been approved for construction. It has been projected that City of Lompoc's population may increase by 21,000 by the year 2030 per an extrapolation of data for 1990-1999 prepared by the California Department of Finance (Arthur D. Little, et al., 2002). Consequently, future development projects, including residential developments, would be expected to result in more people sharing existing recreational resources. This increased demand would result in a parallel increase in the number of people who could be fully or partially prohibited from using local recreational areas if an oil spill were to occur. These displaced persons would, in turn, further increase the physical demands placed on the remaining recreational facilities available locally and regionally. However, recreational effects due to an oil spill would be temporary in nature, and as demonstrated by the recovery of recreational uses in the Avila Beach area (see Section

5.14.1.1), long-term impacts would be minimal. Therefore, cumulative recreational impacts and related cumulative effects on tourism due to an oil spill, including the proposed project's incremental contribution to them, would not be considered significant. Additionally, the proposed project would not place any long-term increased demand on local and regional recreational facilities because it would not increase in the number of permanent workers needed for its construction or operation.

As addressed in Section 5.14.6.3, above, if the Santa Maria, Lion Rock, Point Sal and Purisima Point Units and Lease OCS-P 0409 were to be developed, a new onshore processing facility in the Casmalia area could potentially be needed. Development of these projects would also be expected to increase local populations within the northern Santa Barbara County area due to the labor force needed for facility construction and operations. While the construction workforce would be temporary, the operations workforce would be present for an extended period of time; however, this population increase would not be expected to be substantial and would likely be similar to the permanent labor force needed for operation of the LOGP. Although the potential cumulative land use-related impacts associated with the onshore elements of these potential offshore projects cannot be reasonably projected at this time, the proposed project's onshore facilities would be located a substantial distance away from the Casmalia facility, and therefore, would not be anticipated to incrementally contribute to any land use-related cumulative impacts.

5.14.7 Mitigation Monitoring Plan

Mitigation Measure	Mitigation Requirements and Timing	Method of Verification	Timing of Verification	Party Responsible For Verification
REC-1 (Drilling Muds Disposal Alternative only)	During project construction and operation, the applicant shall require supply boats to travel in recommended marine traffic corridors.	Periodic inspection	Prior to and during drilling	SBC P&D

See Sections 5.5, Marine Biology, and 5.6, Marine Water Quality, for mitigation measures related to recreational impacts due to oil spills.

5.14.8 Policy Consistency Analysis

5.14.8.1 Coastal Act and Coastal Plan Policies

The following policies are applicable to the section of the proposed project within the Coastal Zone. This includes Valve Site #2, Valve Site #1 and the Point Pedernales Project pipelines and facilities west of Valve Site #2.

Coastal Act Policy 30232

Protection against the spillage of crude oil, gas, petroleum products, or hazardous substances shall be provided in relation to any development or transportation of such materials. Effective containment and clean up facilities and procedures shall be provided for accidental spills that do occur.

Potential coastal resources that may be at risk due to an oil spill include: marine biota (including sea otters, other marine mammals, marine birds, sea turtles, amphibians [such as red-legged frogs, which utilize brakish coastal lagoons], fish, abalone, and plants); water resources; environmentally sensitive habitat areas (including rocky intertidal and sandy beach habitat, and estuaries and wetlands); commercial fishing; access and recreation; and, cultural resources (California Coastal Commission, 2006). Relevant Sections of the Coastal Act that are associated with these resources include the following:

- Marine Resources and Water Quality: Coastal Act Sections 30230 and 30231
- Environmentally Sensitive Habitat Areas: Coastal Act Section 30240
- Commercial Fishing: Coastal Act Sections 30230 and 30234.5
- Access and Recreation: Coastal Act Sections 30210, 30211, 30212, and 30220
- Cultural Resources: Coastal Act Section 30244.

The largest oil spill in the Pacific Outer Continental Shelf (OCS) region occurred in 1969, when an estimated 80,000 barrels of crude oil were released into the Santa Barbara Channel. Between 1970 and 1999, 843 oil spills occurred within the Pacific OCS that ranged between one and 163 barrels; most of these spills were less than one barrel in volume (California Coastal Commission [CCC], 2006). The largest of these oil spills (163 barrels) occurred in September 1997 due to a failed flange along the subsea, off- to onshore wet oil pipeline of Platform Irene. Despite favorable weather conditions and rapid response and recovery efforts, which included state-of-the-art response equipment, the Platform Irene pipeline rupture resulted in the oiling of approximately 17 miles of the Santa Barbara coastline, including the estuaries of San Antonio Creek, Honda Creek, and the Santa Ynez River (CCC, 2006). The oil spill resulted in significant adverse impacts to this area, including, but not limited to, Pismo clam and spiny sand crab mortality, injury of rocky intertidal species, such as black abalone and mussel beds, and the oiling of between 635 and 815 seabirds (CCC, 2006).

As noted by the CCC (2006), even small-scale oil spills can cause significant impacts to sensitive coastal resources, depending on the timing and location of a given spill. For example, a spill that occurs in close proximity to a bird refuge would likely have a greater adverse impact during the nesting season than during other times of the year.

As illustrated in the above example, the potential impacts of an oil spill can be highly variable. Key elements include the volume and type of oil spilled, the probability of the spill occurring (both as an isolated event and in combination with other potential spills), the geographic trajectory (movement) of the spill, the location of sensitive resources within the path of the spill's trajectory, local and regional climatic and oceanographic (wave and current) conditions, and available prevention and response technologies and capabilities (including the use of mechanical response equipment, chemical dispersants and *in situ* burning).

The proposed project would result in an increased throughput of oil and would extend the life over which the oil emulsion ~~dry oil,~~ and produced water pipelines would operate. Currently, to reduce the risk of a spill, pipeline inspections and corrosion prevention measures are implemented and a Supervisory Control and Data Acquisition (SCADA) System is in place to monitor the pipeline. In addition, 12 secondary containment basins are located at strategic locations (predominately in the vicinity of the Santa Ynez River) to contain the oil in the event of a spill. An Oil Spill Response Plan (OSRP) is also in place to address response to, clean up of, and restoration of, spill affected areas. To provide further protection against crude oil spills the EIR identifies the need for an additional catchment basin at Valve Site #2, annual inspection and maintenance of the pipeline, and additional updates to the OSRP.

Based upon the above listed prevention and response measures, the proposed project would provide for protections against the spillage of crude oil, gas, petroleum, products, or other hazardous substances, and may be consistent with the first sentence of this policy. However, based upon previous oil spills that have occurred within the Santa Barbara Channel, including the 1997 oil spill associated with Platform Irene, the CCC (2006) has determined that "effective containment and clean up" of a significant oil spill cannot be met using the spill response strategies that are currently available. Therefore, the proposed project may be inconsistent with the second sentence of this policy.

Platform Irene is located in Federal waters and is considered coastal-dependent, which is defined as any type of "development or use which requires a site on, or adjacent to, the sea to be able to function at all" (California Coastal Act Section 30101). The LOGP is zoned M-CR (Coastal Related Industry), and is contained within the boundaries of the Lompoc Oil Field outside of the Coastal Zone. Coastal-related development refers to "any use that is dependent on a coastal-dependent development or use" (California Coastal Act Section 30101.3). ~~The proposed project is considered a "coastal-dependent" industrial development.~~ Section 30260 of the Coastal Act, in conjunction with Coastal Act Sections 30261 and 30262, allows for CCC approval of coastal-dependent industrial developments that are inconsistent with the policies of the Coastal Act if: "(1) alternative locations are infeasible or more environmentally damaging; (2) to do otherwise would adversely affect public welfare; and, (3) adverse environmental effects are mitigated to the maximum extent feasible." Due to the potential policy inconsistency outlined above, it is presumed that the proposed project would require CCC consideration and approval under Sections 30260, 30261 and 30262 of the Coastal Act. A discussion of consistency with Coastal Act Policies 30260 and 30262 is provided at the end of Section 5.14.8.1, below. Coastal Act Policy 30261 does not apply to the proposed project because it does not include any proposed use of existing or new tanker facilities.

Coastal Act Policy 30250

(a) New residential, commercial, or industrial development, except as otherwise provided in this division, shall be located within, contiguous with, or in close proximity to, existing developed areas able to accommodate it or, where such areas are not able to accommodate it, in other areas with adequate public services and where it will not have significant adverse effects, either individually or cumulatively, on coastal resources. In addition, land divisions, other than leases, for agricultural uses, outside existing developed areas shall be permitted only where 50 percent of the usable parcels in the area have been developed and the created parcels would be no smaller than the average size of surrounding parcels.

(b) Where feasible, new hazardous industrial development shall be located away from existing developed areas.

The proposed project would primarily use the existing Point Pedernales Project infrastructure. New construction at Valve Site #2 would be adjacent to the existing development within previously disturbed areas. The proposed project may be consistent with this policy.

Coastal Plan Policy 2-6

Prior to issuance of a development permit, the County shall make the finding, based on information provided by environmental documents, staff analysis, and the applicant, that adequate public or private services and resources (i.e., water, sewer, roads, etc.) are available to serve the proposed development. The applicant shall assume full responsibility for costs incurred in service extensions or improvements that are required as a result of the proposed project. Lack of available public or private services or resources shall be grounds for denial of the project or reduction in the density otherwise indicated in the land use plan. Where an affordable housing project is proposed pursuant to the Affordable Housing Overlay regulations, special needs housing or other affordable housing projects which include at least 50 percent of the total number of units for affordable housing or 30 percent of the total number of units affordable at the very low income level are to be served by entities that require can-and-will-serve letters, such projects shall be presumed to be consistent with the water and sewer service requirements of this policy if the project has, or is conditioned to obtain all necessary can-and-will-serve letters at the time of final map recordation, or if no map, prior to issuance of land use permits. (amended by 93-GP-11)

The portion of the Point Pedernales Project facilities within the Coastal Zone does not generate a demand for water, wastewater disposal, or solid waste disposal. The facilities are accessed via New Terra Road on Vandenberg Air Force Base (VAFB). This existing road provides adequate access. Emergency response and fire protection services would be provided by the applicant and by SBCFS No. 51 (first responder) and Lompoc City Fire Station No. 2. An Emergency Response Plan (ERP) is in place for the existing Point Pedernales Project and would need to be updated to address new equipment and operating conditions associated with the proposed project. Public services are available and adequate to serve the proposed project, thus the project may be consistent with this policy.

Coastal Plan Policy 2-11

All development, including agriculture, adjacent to areas designated on the land use plan or resource maps as environmentally sensitive habitat area shall be regulated to avoid adverse impacts on habitat resources. Regulatory measures include, but are not limited to, setbacks, buffer zones, grading controls, noise restrictions, maintenance of natural vegetation, and control of runoff.

The Santa Ynez River estuary is designated as Environmentally Sensitive Habitat (ESH). The existing Point Pedernales Project pipelines and associated facilities were sited to minimize impacts to the river. In addition, catchment basins were required along the pipeline route in the vicinity of the river to collect and contain oil in the event of a leak or rupture. Installation of new pumps at Valve Site #2 would increase the risk of a spill over current conditions. To further minimize spill related impacts, the EIR identifies the need for installation of a new catchment basin or berm at Valve Site #2, and revision to the OSRP to address protection and restoration of sensitive resources. With incorporation of these measures, the proposed project may be consistent with this policy.

Coastal Act Policy 30253
New development shall:

1. *Minimize risks to life and property in areas of high geologic, flood, and fire hazard.*

2. *Assure stability and structural integrity, and neither create nor contribute significantly to erosion, geologic instability, or destruction of the site or surrounding area or in any way require the construction of protective devices that would substantially alter natural landforms along bluffs and cliffs.*

The existing Point Pedernales Project facilities are located within a designated high fire hazard area and traverse areas with high geologic hazards. Because the proposed project involves minimal new development and would use the existing Point Pedernales Project facilities, exposure to new hazard areas would be minimal. Risks associated with existing geologic and fire hazards are addressed in Section 5.3 (Geological Resources) and Section 5.11 (Fire Protection and Emergency Response); these analyses conclude that no impacts that cannot be mitigated to a level of less than significant would occur. Therefore, the proposed project may be consistent with this policy.

Coastal Plan Policy 3-9
Water, gas, sewer, electrical, or crude oil transmission and distribution lines which cross fault lines, shall be subject to additional safety standards, including emergency shutoff where applicable.

The project pipeline route does not cross any active faults. However, the existing pipeline does cross several potentially active faults. The existing Point Pedernales Project FDP required the installation and use of a leak detection system along the pipeline which allows the applicant to monitor and if necessary isolate the pipeline segments in the event of an upset condition. Since PXP acquired the Point Pedernales facilities, they have upgraded the pipeline leak detection system above what the previous owners had operated (see Section 2.0, Project Description). The proposed project would use the existing pipelines and would be monitored using an upgraded ~~the current~~ leak detection system (see Mitigation Measure Risk-1). The proposed project may be consistent with this policy.

~~*Coastal Act Policy 30231*~~
~~*The biological productivity and the quality of coastal waters, streams, wetlands, estuaries, and lakes appropriate to maintain optimum populations of marine organisms and for the protection of human health shall be maintained and, where feasible, restored through, among other means, minimizing adverse effects of wastewater discharges and entrainment, controlling runoff, preventing depletion of groundwater supplies and substantial interference with surface waterflow, encouraging wastewater reclamation, maintaining natural vegetation buffer areas that protect riparian habitats, and minimizing alteration of natural streams.*~~

~~The proposed project would result in an increased throughput of oil and would extend the life over which the oil emulsion, dry oil, and produced water pipelines would operate. If a rupture or leak of the pipelines were to occur, significant degradation could occur to surface water, groundwater, and wetland resources in the project area. Currently to reduce the risk of a spill, pipeline inspections and corrosion prevention measures are implemented. In addition, 12 secondary containment basins are located at strategic locations (predominately in the vicinity of the Santa Ynez River) to contain the oil in the event of a spill. An OSRP is also in place to~~

~~address response to, clean up of, and restoration of, spill affected areas. To further reduce potential water quality impacts from the proposed project the EIR identifies the need for an additional catchment basin at Valve Site #2, annual inspection and maintenance of the pipeline, and additional updates to the OSRP.~~

~~Implementation of existing FDP measures and proposed new measures, combined with the small increase in the probability of an oil spill (an increase of 1.6 percent for ruptures and 6.9 percent for leaks of the onshore pipeline; and an increase of 8.5 percent for ruptures and large spills, and 4.4 percent for leaks and small spills for the offshore pipeline and Platform Irene), may allow for a finding of potential consistency with this policy. However, the permitting agency's ability to enforce these critical measures is crucial to a finding of potential consistency.~~

<u>Coastal Act Policy 30251</u>
The scenic and visual qualities of coastal areas shall be considered and protected as a resource of public importance. Permitted development shall be sited and designed to protect views to and along the ocean and scenic coastal areas to minimize the alteration of natural land forms, to be visually compatible with the character of surrounding areas, and, where feasible, to restore and enhance visual quality in visually degraded areas. <u>New development in highly scenic areas such as those designated in the California Coastline Preservation and Recreation Plan prepared by the Department of Parks and Recreation and by local government shall be subordinate to the character of its setting.</u>

The modifications to Valve Site #2 would be adjacent to and compatible with existing development on the site. The Surf Substation, which was constructed as a part of the original Point Pedernales Project, is currently visible from Ocean Avenue (Highway 246). As a part of the condition effectiveness review, the SBC determined that the landscaping at the substation is not meeting the original intent of the landscaping condition, which was to screen the facility from view. The proposed project would extend the life of this facility and its visual impacts. Full compliance with the existing FDP conditions would be needed in order to find consistency with this policy.

Implementation of the proposed project would additionally extend the life of Platform Irene, which is visible from several locations along the northern Santa Barbara coastline (Coastal Zone), including Ocean Beach County Park and other public venues when local weather conditions (visibility) permit. Although Platform Irene is considered part of the existing landscape of the proposed project area, its placement and operation was considered a Class I visual impact (an unavoidable and significant impact) in the Point Pedernales Project's original environmental review document, and its extended life expectancy under the proposed project has also been found to be a Class I impact in this environmental review document (please refer to Section 5.13, Aesthetics/Visual Resources).

Because the proposed project would not alter the existing offshore visual attributes of the proposed project area, it may be consistent with this policy. However, if the CCC determines that the extended life of Platform Irene would result in a significantly prolonged visual impact, the proposed project may be considered inconsistent with this policy. As addressed above, under Coastal Act Policy 30232, if the CCC determines that the proposed project would be inconsistent with this policy, approval could still be granted if "(1) alternative locations are infeasible or more environmentally damaging; (2) to do otherwise would adversely affect public welfare; and (3) adverse environmental effects are mitigated to the maximum extent feasible" (Coastal Act Section 30260).

Coastal Plan Policies 3-13 and 3-14

3-13. Plans for development shall minimize cut and fill operations. Plans requiring excessive cutting and filling may be denied if it is determined that the development could be carried out with less alteration of the natural terrain.

3-14. All development shall be designed to fit the site topography, soils, geology, hydrology, and any other existing conditions and be oriented so that grading and other site preparation is kept to an absolute minimum. Natural features, landforms, and native vegetation, such as trees, shall be preserved to the maximum extent feasible. Areas of the site which are not suited for development because of known soils, geologic, flood, erosion, or other hazards shall remain in open space.

Only a minor amount of grading would be required to construct the new project facilities associated with the proposed project. With the exception of the new power line to serve Valve Site #2, grading would occur in previously disturbed areas. Grading for installation of the power line would not require excessive cuts or fills and would occur in relatively level areas.

Pipeline repair and maintenance activities could result in additional vegetation removal and ground disturbance. The EIR includes a mitigation measure that requires use of existing poles and/or mounting the power line on the 13th Street bridge if feasible and if not feasible, implementation of erosion control measures, protective fencing, and restoration of the disturbed areas. The proposed mitigation measures in addition to the existing Point Pedernales Project FDP conditions would reduce potential impacts to a less than significant level. Therefore, the proposed project may be consistent with these policies.

Coastal Plan Policy 3-19

Degradation of the water quality of groundwater basins, nearby streams, or wetlands shall not result from development of the site. Pollutants, such as chemicals, fuels, lubricants, raw sewage, and other harmful waste, shall not be discharged into or alongside coastal streams or wetlands either during or after construction.

Construction related discharges are expected to be minimal and controlled through the implementation of erosion and sediment control measures as specified in the EIR. Potential discharges during pipeline repair and maintenance would also be minimized through implementation of erosion and sediment control measures as required in this EIR.

The proposed project would result in an increased throughput of oil and would extend the life over which the oil emulsion ~~dry oil,~~ and produced water pipelines would operate. If a rupture or leak of the pipelines were to occur significant degradation could occur to surface water, groundwater, and wetland resources in the project area. Currently, to reduce the risk of a spill, pipeline inspections and corrosion prevention measures are implemented. In addition, 12 secondary containment basins are located at strategic locations (predominately in the vicinity of the Santa Ynez River) to contain the oil in the event of a spill. An OSRP is also in place to address response to, clean up of, and restoration of, spill affected areas. To further reduce potential water quality impacts from the proposed project the EIR identifies the need for an additional catchment basin at Valve Site #2, annual inspection and maintenance of the pipeline, and additional updates to the OSRP.

Implementation of existing FDP measures and proposed new measures, combined with the small increase in the probability of a spill (an increase of 1.6 percent for ruptures and 6.9 percent for leaks of the onshore pipeline; and an increase of 8.5 percent for ruptures and large spills, and 4.4 percent for leaks and small spills for the offshore pipeline and Platform Irene) may allow for a finding of potential consistency with this policy. However, the permitting agency's ability to enforce these critical measures is crucial to a finding of potential consistency.

~~***Coastal Act Policy 30251***~~

~~*The scenic and visual qualities of coastal areas shall be considered and protected as a resource of public importance. Permitted development shall be sited and designed to protect views to and along the ocean and scenic coastal areas, and, where feasible, to restore and enhance visual quality in visually degraded areas. New development in highly scenic areas such as those designated in the California Coastline Preservation and Recreation Plan prepared by the Department of Parks and Recreation and by local government shall be subordinate to the character of its setting.*~~

Coastal Plan Policies 4-2, 4-3 and 4-7

4-2. All commercial, industrial, planned development, and greenhouse projects shall be required to submit a landscaping plan to the County for approval.

4-3. In areas designated as rural on the land use plan maps, the height, scale, and design of structures shall be compatible with the character of the surrounding natural environment, except where technical requirements dictate otherwise. Structures shall be subordinate in appearance to natural landforms; shall be designed to follow the natural contours of the landscape; and shall be sited so as not to intrude into the skyline as seen from public viewing places.

4-7. Utilities, including television, shall be placed underground in new developments in accordance with the rules and regulations of the California Public Utilities Commission, except where the cost of undergrounding would be so high as to deny service.

Modifications to Valve Site #2 would be adjacent to and compatible with existing development on the site. The Surf Substation, which was constructed as a part of the original Point Pedernales Project, is visible from Ocean Avenue (Highway 246). As a part of the condition effectiveness review, SBC determined that the landscaping at the substation was not meeting the original intent of the landscaping condition, which was to screen the facility from view. The proposed project would extend the life of this facility and its visual impacts.

The EIR includes a mitigation measure (Visual-3) that requires use of existing poles and/or mounting the power line on the 13th Street bridge if feasible~~ and if not feasible~~. Implementation of this measure and/or undergrounding visually sensitive portions of the line (e.g., along New Terra Road) would reduce the visual impacts of the new power line. Full compliance with the existing FDP conditions would be required to reduce the visual impact of the Surf Substation and in order to make a finding of potential consistency with these policies.

Coastal Plan Policy 6-3

All oil and gas development in areas designated as environmentally sensitive habitats in the land use plan shall be subject to environmental review.

The proposed project would use the existing Point Pedernales Project infrastructure. The project would include the installation of additional pumps at Valve Site #2. The facilities are located in proximity to the Santa Ynez River in an area designated as ESH in the land use plan. Impacts of the proposed project have been analyzed in this EIR pursuant to the requirements of this policy. A number of additional mitigation measures have been identified in this EIR (additional catch basin at Valve Site #2, pipeline inspections, and updates to the OSRP) to reduce impacts to the river. With implementation of these measures the proposed project may be consistent with this policy.

Coastal Plan Policy 6-4

Upon completion of production, the area affected by the drilling, processing, or other related petroleum activity, shall be appropriately contoured, reseeded, and landscaped to conform with the surrounding topography and vegetation.

The existing FDP requires that immediately following shutdown of the facility, the applicant remove any and all abandoned processing facilities and unburied portions of the pipeline between Surf and Orcutt, recontour the site, and revegetate the site in accordance with a SBC approved revegetation plan. This condition would continue to apply to the proposed project. However restoration activities would occur later than originally projected when the Point Pedernales Project FDP was approved since the proposed project would extend the life of the Point Pedernales Project by 10 to 25 years (or more). These requirements would also be addressed in the Demolition and Reclamation permit. The proposed project may be consistent with this policy.

Coastal Plan Policy 6-6B

Except for facilities not directly related to oil and gas processing as referenced in Policy 6-11B (Marine Terminals), this policy applies to areas of the Coastal Zone that are outside the South Coast Consolidation Planning Area (SCCPA). The SCCPA is the unincorporated area from Point Arguello to the western boundary of the City of Santa Barbara, and from the ridge of the Santa Ynez Mountains to the three-mile offshore limit, as approved by the SBC Board of Supervisors on December 14, 1987 (SBC Board of Supervisors Resolution #87-616).

If new sites for processing facilities to serve offshore oil and gas development are needed, expansion of facilities on existing sites or on land adjacent to existing sites shall take precedence over opening up additional areas, unless it can be shown that the environmental impacts of opening up a new site are less than the impacts of expansion on or adjacent to existing sites. Consideration shall also be given to economic feasibility.

The proposed project would use the existing Point Pedernales Project infrastructure. New development (additional pumps and processing equipment) would be located adjacent to the existing facilities at Valve Site #2 and the LOGP. The addition of equipment at these two sites would have minimal environmental effects. Extension of electric transmission lines would create additional visual impacts. Use of existing VAFB transmission lines, mounting the lines on the 13th Street Bridge across the Santa Ynez River where feasible and/or undergrounding the most visually sensitive portion of the line (as identified in the EIR) would reduce the visual impacts. The proposed project may be consistent with this policy.

Coastal Plan Policy 6-6F

Review of Oil and Gas Facility Permits. (Added 12/14/87, B/S Resol #87-616) - The Planning Commission shall review permits that are approved after August 12, 1985 for new or modified oil and gas facilities when throughput, averaged (arithmetic mean) over any twelve (12) consecutive months, does not exceed 3 percent of the facility's maximum permitted operating capacity. The review shall be conducted in a duly-noticed public hearing to determine if facility abandonment or facility modifications are appropriate.

This requirement is included as a condition of approval (Condition R-1) for the existing Point Pedernales Project FDP and would continue to apply to the proposed project, rendering it consistent with this policy.

Coastal Plan Policy 6-8

If an onshore pipeline for transporting crude oil to refineries is determined to be technically and economically feasible, proposals for expansion, modification, or construction of new oil and gas processing facilities shall be conditioned to require transportation of oil through the pipeline when constructed, unless such condition would not be feasible for a particular shipper (Revised 6/18/84, B/S Resol #84-284; 11/19/91. B/S Resol #91-670).

a) Pipeline transportation of crude oil to a refining center served by a pipeline is presumed to be technically and economically feasible and the required method of transportation to that center (Revised 6/18/84, B/S Resol #84-284).

b) Pipeline transportation of crude oil is presumed to be feasible for a particular shipper if a pipeline is in operation to the refining center of the shipper's choice (Revised 6/18/84, B/S Resol #84-284).

c) Crude oil processing facilities shall be conditioned to require that each shipper's oil leaving those facilities be transported by pipeline when a pipeline is in operation to the refining center of the shipper's choice (Revised 6/18/84, B/S Resol #84-284).

d) Until pipelines become available, and for refining centers not served by pipeline, other modes of oil transportation are allowed consistent with County policies. Rail is not preferred for large volume shipments of oil (Revised 6/18/84, B/S Resol #84-284).

e) For refining centers served by pipeline, other modes of transportation up to the limits of permitted capacity for those modes, and with assurances that the shipper or transportation facility operator can and will mitigate the environmental impacts caused by the alternate transportation mode, are allowed under the following circumstances:

1) Pipeline unavailability or inadequate capacity; or

2) A refinery upset lasting no longer than two (2) months and only where the alternate refining center is not served by pipeline; or

3) An emergency which may include a national state of emergency (Revised 6/18/84, B/S Resol #84-284).

Processed oil exiting the LOGP is transported via an existing pipeline system to the Santa Maria Refinery, located in San Luis Obispo County and then to San Francisco Bay area refineries. ConocoPhillips takes possession of the oil at a custody transfer point adjacent to the LOGP. Although PXP has stated that new oil and gas development from the proposed project would be transported using the existing pipeline infrastructure in place for the Point Pedernales Project, PXP does not own the oil once it is in the ConocoPhillips pipeline system, and thus cannot guarantee the oil would always be shipped to refineries via pipeline, as it is today. However, SBC Condition Q-5 of both the Point Pedernales Project's FDP and ConocoPhillips FDP requires that all oil processed at the LOGP be transported from the facility in accordance with Coastal Policy 6-8, and that transportation by a mode other than pipeline may be permitted only in accordance with Coastal Zoning Ordinance Section 35-154.5 (i), applicable Local Coastal Plan policies, and control measure R-12 of the Air Quality Attainment Plan, as applicable. Coastal Zoning Ordinance 35-154.5 (i)/LUDC Section 35.51.070.B.9 requires that all oil produced offshore and processed at a County-approved facility be transported from that facility and out of the County by pipeline. Because both PXP and ConocoPhillips would continue to be required to transport oil processed at the LOGP from there and out of the County by pipeline, the proposed project may be consistent with this policy.

Coastal Plan Policy 6-14

Except for pipelines exempted from coastal development permits under Section 30610(c) and (e) of the Coastal Act as defined by the State Coastal Commission's Interpretive Guidelines, a survey shall be conducted along the route of any pipeline in the coastal zone to determine what, if any, coastal resources may be impacted by construction and operation of a pipeline. The costs of this survey shall be borne by the applicant. (This survey may be conducted as a part of environmental review if an EIR is required for a particular project.) The survey shall be conducted by a consultant selected jointly by the applicant, the County and the Department of Fish and Game. If it is determined that the area to be disturbed will not revegetate naturally or sufficiently quickly to avoid other damage, as from erosion, the applicant shall submit a revegetation plan. The plan shall also include provisions for restoration of any habitats which will be disturbed by construction or operation procedures.

For projects where a revegetation plan and/or habitat restoration plan has been deemed necessary, one year after completion of construction, the area crossed by the pipeline shall be resurveyed to assess the effectiveness of the revegetation and restoration plan. This survey shall continue on an annual basis to monitor progress in returning the site to pre-construction conditions or until the County feels no additional progress is possible.

The County may require the posting of a performance bond by the applicant to ensure compliance with these provisions.

The proposed project would use the existing Point Pedernales Project pipelines. In addition, a Restoration, Erosion Control and Revegetation Plan was required to address restoration of the lands disturbed during construction of the Point Pedernales Project facilities. Since the proposed project is proposing to use these existing pipelines, it may be consistent with this policy. However, it should be noted that it has been over 10 years since the original Point Pedernales Project was constructed, and, to date, restoration requirements for the pipeline corridor have not be fully achieved, although recent efforts have resulted in additional restoration and an increased likelihood of success, if continued.

Coastal Plan Policy 6-14A

Impacts of new pipelines outside of industry facilities shall be minimized by requiring the use of available or planned common carrier or multiple-user pipelines to the maximum extent feasible. New pipeline construction shall be permitted only if the Planning Commission determines that the use of available common carrier or multiple-user pipelines is not feasible or is not the environmentally preferred alternative. New pipelines that are permitted shall be constructed, operated, and maintained as common carrier or multiple-user pipelines unless the Planning Commission determines that it is not feasible. New multiple-user pipelines shall provide equitable access to all shippers with physical compatible stock on a nondiscriminatory basis. To determine physical compatibility of stocks, the Planning Commission shall consider available information on the physical and chemical characteristics of the stocks, including but not limited to API gravity, sulfur and water content, viscosity, and pour point. (Added 7/28/86, B/S Resol 86-380; Revised 12/22/86, B/S Resol #86-656).

Since the proposed project proposes to use the existing Point Pedernales Project pipelines, it may be consistent with this policy.

Coastal Plan Policies 6-18 and 6-19

6-18. For pipeline segments passing through important coastal resource areas, including recreation, habitat, and archaeological areas, the segment, in the case of a break, shall be isolated by automatic shutoff valves.

6.19. Unavoidable routing through recreation, habitat, or archaeological areas, or other areas of significant coastal resource value, shall be done in a manner that minimizes the impacts of a spill, should it occur, by considering spill volumes, durations, and trajectory. Appropriate measures for cleanup or structures such as catch basins to contain a spill shall be included as part of an oil spill contingency plan.

Currently to reduce the risk of a spill, pipeline inspections and corrosion prevention measures are implemented. In addition, 12 secondary containment basins are located at strategic locations (predominately in the vicinity of the Santa Ynez River) to contain the oil in the event of a spill. As required by the existing Point Pedernales Project FDP, a leak detection system is in place and seven remotely operated valves are located along the pipeline to isolate the pipeline segments in the event of a leak or rupture. An OSRP is also in place to address response to, clean up of, and restoration of, spill affected areas. To further reduce potential water quality impacts from the proposed project the EIR identifies the need for an additional catchment basin at Valve Site #2, annual inspection and maintenance of the pipeline, and additional updates to the OSRP. With implementation of existing FDP conditions and proposed new mitigation measures, the proposed project may be consistent with this policy.

<u>Coastal Act Policies 30230, 30231, and 30240</u>

30230. Marine resources shall be maintained, enhanced, and, where feasible, restored. Special protection shall be given to areas and species of special biological or economic significance. Uses of the marine environment shall be carried out in a manner that will sustain the biological productivity of coastal waters and that will maintain healthy populations of all species of marine organisms adequate for long-term commercial, recreational, scientific, and educational purposes.

30231. The biological productivity and the quality of coastal water, streams, wetlands, estuaries, and lakes appropriate to maintain optimum populations of marine organisms and for the protection of human health shall be maintained and, where feasible, restored through, among other means, minimizing adverse effects of waste water discharges and entrainment, controlling runoff, preventing depletion of ground water supplies and encouraging waste water reclamation, maintaining natural vegetation buffer areas that protect riparian habitats, and minimizing alteration of natural streams.

30240. (a) Environmentally sensitive habitat areas shall be protected against any significant disruption of habitat values, and only uses dependent on such resources shall be allowed within such areas.

(b) Development in areas adjacent to environmentally sensitive habitat areas and parks and recreation areas shall be sited and designed to prevent impacts which would significantly degrade such areas, and shall be compatible with the continuance of such habitat areas.

The proposed project would include the installation of 3 new booster pumps at Valve Site #2. Installation of these pumps would be within the existing foot print of Valve Site #2.

The proposed project would result in an increased throughput of oil and would extend the life over which the oil emulsion, dry oil, and produced water pipelines would operate. If a rupture or leak of the pipelines were to occur, significant degradation could occur to marine and coastal waters<u>, including onshore surface water, groundwater and wetland resources.</u> The addition of pumps at Valve Site #2 increases the risk of a spill or rupture at the site. Currently, to reduce the risk of a spill, pipeline inspections and corrosion prevention measures are implemented. In addition, 12 secondary containment basins are located at strategic locations (predominately in the vicinity of the Santa Ynez River) to contain the oil in the event of a spill. An OSRP is also in place to address response to, clean up of, and restoration of, spill affected areas. To further reduce potential water quality impacts from the proposed project the EIR identifies the need for an additional catchment basin at Valve Site #2, annual inspection and maintenance of the pipeline, and additional updates to the OSRP.

Implementation of existing FDP measures and proposed new measures, combined with the small increase in the probability of a spill (an increase of 1.6 percent for ruptures and 6.9 percent for leaks of the onshore pipeline; and an increase of 8.5 percent for ruptures and large spills, and 4.4 percent for leaks and small spills for the offshore pipeline and Platform Irene) <u>may</u> allow for a finding of potential consistency with this policy. <u>However, the permitting agency's ability to enforce these critical measures in crucial to a finding of potential consistency.</u>

Coastal Plan Policy 9-4
All permitted industrial and recreational uses shall be regulated both during construction and operation to protect critical bird habitats during breeding and nesting seasons. Controls may include restriction of access, noise abatement, restriction of hours of operations of public or private facilities.

Construction activities at Valve Site #2 are not expected to adversely affect critical bird habitats (e.g., for the American Peregrine Falcon, Western Snowy Plover, California Least Tern and California Brown Pelican) due to the distance (over 1,000 feet) between these habitats and Valve Site #2 (please refer to Section 5.2, Terrestrial and Freshwater Biology for a discussion of critical bird habitats).

The proposed project would result in an increased throughput of oil and would extend the life over which the oil emulsion, dry oil, and produced water pipelines would operate. If a rupture or leak of the pipelines were to occur significant damage could occur to the critical bird habitats listed above. Currently to reduce the risk of a spill, pipeline inspections and corrosion prevention measures are implemented. In addition, 12 secondary containment basins are located at strategic locations (predominately in the vicinity of the Santa Ynez River) to contain the oil in the event of a spill. An OSRP is also in place to address response to, clean up of, and restoration of, spill affected areas. The existing Point Pedernales Project FDP also requires implementation of a Marine Biology Impact Reduction Plan. The plan restricts helicopter overflights of sensitive bird habitats on VAFB. To further reduce potential impacts to critical bird habitats from the proposed project the EIR identifies the need for an additional catchment basin at Valve Site #2, annual inspection and maintenance of the pipeline, and additional updates to the OSRP to specifically address clean up and restoration of sensitive habitats.

Implementation of existing FDP measures and proposed new measures, combined with the small increase in the probability of a spill (an increase of 1.6 percent for ruptures and 6.9 percent for leaks of the onshore pipeline; and an increase of 8.5 percent for ruptures and large spills, and 4.4 percent for leaks and small spills for the offshore pipeline and Platform Irene) may allow for a finding of potential consistency with this policy. However, the permitting agency's ability to enforce these critical measures is crucial to a finding of potential consistency.

Coastal Plan Policy 9-14
New development adjacent to or in close proximity to wetlands shall be compatible with the continuance of the habitat area and shall not result in a reduction in the biological productivity or water quality of the wetland due to runoff (carrying additional sediment or contaminants), noise, thermal pollution, or other disturbances.

No new physical development would occur within close proximity to the Santa Ynez River estuary. Modifications at Valve Site #2 are at least 1,300 feet from any mapped wetlands (please refer to Section 5.2, Terrestrial and Freshwater Biology for a discussion of wetlands).

The proposed project would result in an increased throughput of oil and would extend the life over which the oil emulsion, dry oil, and produced water pipelines would operate. If a rupture or leak of the pipelines were to occur significant degradation could occur to marine and coastal waters. The addition of pumps at Valve Site #2 increases the risk of a spill or rupture at the site. Currently to reduce the risk of a spill, pipeline inspections and corrosion prevention measures are implemented. In addition, 12 secondary containment basins are located at strategic locations (predominately in the vicinity of the Santa Ynez River) to contain the oil in the event of a spill. An OSRP is also in place to address response to, clean up of, and restoration of, spill affected areas. To further reduce potential water quality impacts from the proposed Tranquillon Ridge Project the EIR identifies the need for an additional catchment basin at Valve Site #2, annual inspection and maintenance of the pipeline, and additional updates to the OSRP.

The implementation of existing FDP measures and proposed new measures, combined with the small increase in the probability of a spill (an increase of 1.6 percent for ruptures and 6.9 percent for leaks of the onshore pipeline; and an increase of 8.5 percent for ruptures and large spills, and 4.4 percent for leaks and small spills for the offshore pipeline and Platform Irene) may allow for a finding of potential consistency with this policy. However, the permitting agency's ability to enforce these critical measures is crucial to a finding of potential consistency.

Coastal Plan Policies 9-35 and 9-36

9-35. Oak trees, because they are particularly sensitive to environmental conditions, shall be protected. All land use activities, including cultivated agriculture and grazing, should be carried out in such a manner as to avoid damage to native oak trees. Regeneration of oak trees on grazing lands should be encouraged.

9-36. When sites are graded or developed, areas with significant amounts of native vegetation shall be preserved. All development shall be sited, designed, and constructed to minimize impacts of grading, paving, construction of roads or structures, runoff, and erosion on native vegetation. In particular, grading and paving shall not adversely affect root zone aeration and stability of native trees.

The proposed project would not require removal of any oak trees and new development at Valve Site #2 would occur in a previously disturbed area containing little to no native vegetation. The proposed project may be consistent with these policies.

Coastal Plan Policies 10-2, 10-3, and 10-5

10-2. When developments are proposed for parcels where archaeological or other cultural sites are located, project design shall be required which avoids impacts to such cultural sites if possible.

10-3. When sufficient planning flexibility does not permit avoiding construction on archaeological or other types of cultural sites, adequate mitigation shall be required. Mitigation shall be designed in accord with guidelines of the State Office of Historic Preservation and the State of California Native American Heritage Commission.

10-5. Native Americans shall be consulted when development proposals are submitted which impact significant archaeological or cultural sites.

There are 29 recorded archaeological sites located along the Point Pedernales Project pipeline corridor, several of which are located within the Coastal Zone. No recorded sites are known to occur within areas proposed for new disturbance at Valve Site #2, and surveys conducted in this area did not reveal the presence of any resources. Measures have been included in the EIR to address encountering previously unknown cultural deposits in the vicinity of the new construction.

The known sites could be impacted during future repair and maintenance activities and by spill related clean up activities. To minimize disturbance to these known resources, the EIR requires pipeline monitoring within 200 feet of any known site during pipeline maintenance and appropriate data recovery if resources are encountered. Containment and clean up activities in an emergency response condition could significantly impact cultural resources. To help reduce this impact the EIR requires updating the OSRP to provide procedures for minimizing impacts, however avoidance and or data recovery may not be feasible depending on the extent and magnitude of the spill.

Implementation of existing FDP measures and proposed new measures, combined with the small increase in the probability of an onshore spill (an increase of 1.6 percent for ruptures and 6.9 percent for leaks of the onshore pipeline) may allow for a finding of potential consistency with this policy. However, the permitting agency's ability to enforce these critical measures is crucial to a finding of potential consistency.

Coastal Act Policy 30253.3

New development shall be consistent with requirements imposed by an air-pollution control district or the State Air Resources Control Board as to each particular development.

As required by SBC Air Pollution Control District (SBCAPCD) rules, the proposed project would be required to obtain an "authority to construct" and "permit to operate" to allow for new emissions from the facilities. According to the EIR analysis, increased emissions associated with the proposed project would be fully mitigated by the existing available emission credits originally required as a condition of approval of the Point Pedernales Project FDP. Conditioning of the proposed project to ensure that total emissions do not exceed the available emission credits may allow it to be consistent with this policy.

Coastal Act Policy 30260

Coastal-dependent industrial facilities shall be encouraged to locate or expand within existing sites and shall be permitted reasonable long-term growth where consistent with this division. However, where new or expanded coastal-dependent industrial facilities cannot feasibly be accommodated consistent with other policies of this division, they may nonetheless be permitted in accordance with this section and Sections 30261 and 30262 if (1) alternative locations are infeasible or more environmentally damaging; (2) to do otherwise would adversely affect the public welfare; and (3) adverse environmental effects are mitigated to the maximum extent feasible.

Platform Irene is located in Federal waters and is considered coastal-dependent, which is defined as any type of "development or use which requires a site on, or adjacent to, the sea to be able to function at all" (California Coastal Act Section 30101). The LOGP is zoned M-CR (Coastal Related Industry), and is contained within the boundaries of the Lompoc Oil Field outside of the Coastal Zone. Coastal-related development refers to "any use that is dependent on a coastal-dependent development or use" (California Coastal Act Section 30101.3). The off- to onshore pipelines connecting Platform Irene to the LOGP traverse lands both within and outside of the Coastal Zone. Although the LOGP is neither designated Coastal-Dependent nor a Consolidated Oil and Gas Processing Facility, it does serve offshore oil and gas development and is the only existing facility within the North County that is approved for this purpose. The proposed project would expand some features of the approved Point Pedernales Project; however, all proposed facility modifications would occur within the footprint of the existing facilities (i.e., Platform Irene, Block Valve #2 and LOGP), with the exception of a new power line to Block Valve #2 if installation of pumps is required at this location in the future. The proposed project would also extend the operational lifetime of these facilities and infrastructure; however, the proposed project does not result in any significant impacts that do not already exist for the Point Pedernales project. Further, as identified throughout Section 5, mitigation is proposed to mitigate the proposed project to the maximum extent feasible in accordance with County policy. Therefore, the proposed project may be found consistent with this policy.

Coastal Act Policy 30262

(a) Oil and gas development shall be permitted in accordance with Section 30260, if the following conditions are met:

(1) The development is performed safely and consistent with the geologic conditions of the well site.

(2) New or expanded facilities related to that development are consolidated, to the maximum extent feasible and legally permissible, unless consolidation will have adverse environmental consequences and will not significantly reduce the number of producing wells, support facilities, or sites required to produce the reservoir economically and with minimal environmental impacts.

(3) Environmentally safe and feasible subsea completions are used if drilling platforms or islands would substantially degrade coastal visual qualities, unless the use of those structures will result in substantially less environmental risks.

(4) Platforms or islands will not be sited where a substantial hazard to vessel traffic might result from the facility or related operations, as determined in consultation with the United States Coast Guard and the Army Corps of Engineers.

(5) The development will not cause or contribute to subsidence hazards unless it is determined that adequate measures will be undertaken to prevent damage from that subsidence.

(6) With respect to new facilities, all oilfield brines are reinjected into oil-producing zones unless the Division of Oil, Gas, and Geothermal Resources of the Department of Conservation determines to do so would adversely affect production of the reservoirs and unless injection into other subsurface zones will reduce environmental risks. Exceptions to reinjections will be granted consistent with the Ocean Waters Discharge Plan of the State Water Resources Control Board and where adequate provision is made for the elimination of petroleum odors and water quality problems.

(7) (A) All oil produced offshore California shall be transported onshore by pipeline only. The pipelines used to transport this oil shall utilize the best achievable technology to ensure maximum protection of public health and safety and of the integrity and productivity of terrestrial and marine ecosystems.

(B) Once oil produced offshore California is onshore, it shall be transported to processing and refining facilities by pipeline.

(C) The following guidelines shall be used when applying subparagraphs (A) and (B):

(i) "Best achievable technology," means the technology that provides the greatest degree of protection taking into consideration both of the following: (I) Processes that are being developed, or could feasibly be developed, anywhere in the world, given overall reasonable expenditures on research and development. (II) Processes that are currently in use anywhere in the world. This clause is not intended to create any conflicting or duplicative regulation of pipelines, including those governing the transportation of oil produced from onshore reserves.

(ii) "Oil" refers to crude oil before it is refined into products, including gasoline, bunker fuel, lubricants, and asphalt. Crude oil that is upgraded in quality through residue reduction or other means shall be transported as provided in subparagraphs (A) and (B).

(iii) Subparagraphs (A) and (B) shall apply only to new or expanded oil extraction operations. "New extraction operations" means production of offshore oil from leases that did not exist or had never produced oil, as of January 1, 2003, or from platforms, drilling island, subsea completions, or onshore drilling sites, that did not exist as of January 1, 2003. "Expanded oil extraction" means an increase in the geographic extent of existing leases or units, including lease boundary adjustments, or an increase in the number of well heads, on or after January 1, 2003.

(iv) For new or expanded oil extraction operations subject to clause (iii), if the crude oil is so highly viscous that pipelining is determined to be an infeasible mode of transportation, or where there is no feasible access to a pipeline, shipment of crude oil may be permitted over land by other modes of transportation, including trains or trucks, which meet all applicable rules and regulations, excluding any waterborne mode of transport.

(8) If a state of emergency is declared by the Governor for an emergency that disrupts the transportation of oil by pipeline, oil may be transported by a waterborne vessel, if authorized by permit, in the same manner as required by emergency permits that are issued pursuant to Section 30624.

(9) In addition to all other measures that will maximize the protection of marine habitat and environmental quality, when an offshore well is abandoned, the best achievable technology shall be used.

(b) Where appropriate, monitoring programs to record land surface and near-shore ocean floor movements shall be initiated in locations of new large-scale fluid extraction on land or near *shore before operations begin and shall continue until surface conditions have stabilized. Costs of monitoring and mitigation programs shall be borne by liquid and gas extraction operators.*

(c) Nothing in this section shall affect the activities of any state agency that is responsible for regulating the extraction, production, or transport of oil and gas.

The Development and Production Plan for the proposed project, including any necessary modifications to Platform Irene's drilling equipment and procedures, and proposed well site locations, would be reviewed and approved by the U.S. Department of the Interior, Minerals Management Service (MMS) prior to its implementation. The MMS's review and approval process would include provisions for the safe development of each well site. Onshore, construction and operation of the proposed project would be consistent with the geologic conditions of the proposed project area with implementation of Mitigation Measures GR-1 though GR-3.

Expanded facilities and infrastructure associated with the proposed project would be consolidated within the boundaries of the existing Point Pedernales Project facilities (i.e., Platform Irene, Block Valve #2, and LOGP), with the exception of a new power line to Block Valve #2 if future pump installation at this valve site is required. Further, in addition to the implementation of the County Safety Inspection Maintenance and Quality Assurance Program (SIMQAP) for the Point Pedernales project (FDP Condition P-2), Mitigation Measures Risk-1 and Risk-2 are required to ensure that the best available technology is utilized to operate these facilities in the safest manner possible.

Implementation of the proposed project would extend the presence (lifetime) of Platform Irene, which would prolong the platform's significant and unavoidable visual effects along the North County coastline. However, the proposed project would not exacerbate Platform Irene's existing visual impacts. As addressed in Section 3.3.2 (Tranquillon Ridge Field Development from Subsea Completion with Connection to Platform Irene), subsea completions are not considered feasible because down-hole submersible pumps and gas lift must be used to enhance and fully develop the oil and gas reservoirs of the Tranquillon Ridge Field. Subsea completions would result in significant adverse impacts to the marine environment due to the flow lines that would have to be laid along the sea floor from each subsea location to Platform Irene, or from each subsea location to shore. Additionally, subsea completions would result in significantly higher air quality emissions in comparison to the proposed project due to the need to mobilize and operate drill ships during both well drilling and operation (e.g., well servicing). Therefore, the proposed project would be environmentally preferable to subsea completions.

The proposed project would not involve the siting of a new platform; Platform Irene would be used, the location of which has been approved by all applicable regulatory agencies having jurisdiction over marine vessel traffic and related hazards. Continued marine vessel traffic to and from Platform Irene could cause loss or damage to commercial fishing gear in the project area; however, disputes over damage to commercial fishing gear resulting from support vessel traffic to and from Platform Irene would be submitted to the Joint Oil/Fisheries Committee for resolution per the requirements of Mitigation Measure CRF/KH-1 (FDP Condition M-3). Additionally, marine traffic requirements stipulated by the existing Point Pedernales Project's FDP would apply, including notification of construction activities (FDP Condition M-2), cooperation with the Santa Barbara Channel Vessel Traffic Corridor Program (FDP Condition M-8) and procedures for the safe mooring of support vessels (FDP Condition M-9).

As addressed in Section 5.3 (Geological Resources), proposed upgrades and modifications to the LOGP could result in new, continued or accelerated ground settlement. However, with implementation of Mitigation Measure GR-2, potential impacts would be reduced to a level of less than significant, and existing monitoring for subsidence at the LOGP would continue to identify and correct any future hazards. As addressed above, potential offshore hazards related to geologic resources, including subsidence, would be reviewed and conditioned, as needed, by the MMS to minimize potential hazards.

Currently, a portion of the Point Pedernales Project's produced water is sent back to Platform Irene through an 8-inch pipeline and injected into the Point Pedernales Field through wells A-10 and A-11. The pressure from the pumps onshore (at the LOGP) provides the injection pressure needed to re-inject water into these wells. No ocean outfall disposal of produced water is currently undertaken, although offshore discharge is permitted pursuant to the existing National Pollution Discharge Elimination System (NPDES) permit. The remainder of the produced water is injected onshore into wells at the Lompoc oil field under approvals from the Department of Conservation's Division of Oil, Gas and Geothermal Resources. For the Tranquillon Ridge project, PXP proposes to discharge produced water in accordance with the NPDES permit, although some portion may continue to be injected, both onshore and offshore.

Under the proposed project, all recovered and processed crude oil would be transported via pipeline. Requirements of the Point Pedernales Project's existing FDP for pipeline operation would apply to the proposed project, including those conditions related to the use, testing, periodic auditing and upgrading of Best Available and Safest Technology (FDP Condition P-17), a facility-wide Supervisory Control and Data Acquisition System (FDP Condition P-16), implementation of the SIMQAP for the Point Pedernales project (FDP Condition P-2), and on-going reviews and approvals as needed by the SBC Systems Safety and Reliability Review Committee (FDP Condition P-1).

Decommissioning of the proposed project would be subject to the County's regulatory requirements, as well as the stipulations of other State and federal regulatory agencies having jurisdiction over permanent shut-down of such facilities. Environmental review under the California Environmental Quality Act (CEQA) and National Environmental Policy Act (NEPA) would be required for permanent shut-down, and it would be anticipated that this review would include measures to protect marine habitat and environmental quality to the maximum extent feasible, including the application of best achievable technology for offshore well abandonment.

Per the conditions of the Point Pedernales Project's existing FDP, as well as the mitigation measures recommended in this EIR, off- and onshore monitoring and the implementation of mitigation measures for resource-specific environmental protection and restoration/stabilization would occur throughout construction and operation of the proposed project.

It is not anticipated that any of the requirements or activities associated with the proposed project would conflict with, or otherwise affect, the actions of any State agency having regulatory authority over the extraction, production or transport of oil and gas. All such agencies have been provided with the CEQA notifications and documents associated with the proposed project's environmental review process and provided with the opportunity to express concerns. Any future conflicts that may arise could be resolved through the proposed project's regulatory permit acquisition process and related permit compliance procedures.

Implementation of existing FDP measures and the proposed new mitigation measures provided for in this EIR, in combination with the regulatory review and approval processes that must be completed, may allow for a finding of potential consistency with this policy.

5.14.8.2 Comprehensive Plan Policies

The following policies apply to those portions of the proposed project within the inland areas of SBC (including the increased throughput and extension of life aspects).

Land Use Element

Land Use Development Policies

4. *Prior to issuance of a development permit, the County shall make the finding, based on information provided by environmental documents, staff analysis, and the applicant, that adequate public or private services and resources (i.e., water, sewer, roads, etc.) are available to serve the proposed development. The applicant shall assume full responsibility for costs incurred in service extensions or improvements that are required as a result of the proposed project. Lack of available public or private services or resources shall be grounds for denial of the project or reduction in the density otherwise indicated in the land use plan.*

The LOGP is located within the Lompoc Groundwater Basin. Water for the LOGP is currently and would continue to be supplied by the Mission Hills Community Service District. Wastewater disposal is provided by a private on-site septic system. Fire protection is provided by Lompoc Fire Station No. 51. The proposed project would not introduce any new development or personnel that would increase water demand, wastewater disposal, or fire protection needs above existing levels.

Access to the LOGP is from Harris Grade Road. The proposed project would increase Liquified Petroleum Gas (LPG) and Natural Gas Liquids (NGL) truck trips from the LOGP from 2.9 to 5 trips per week. However, the increase in truck trips would not change the roadway's Level of Service (LOS). All other services (e.g., electricity, solid waste disposal) are available and adequate to serve the projects; therefore, the proposed project may be consistent with this policy.

10. *Impacts of oil, gas, and produced-water pipelines outside of industry facilities shall be minimized by requiring the use of available or planned common carrier and multiple-user pipelines to the maximum extent feasible.*

When the Point Pedernales project was originally approved, Union Oil Company built and operated the pipelines that transported the Point Pedernales crude oil from the County to the Santa Maria Refinery in San Luis Obispo County. Since then, the portion of the Point Pedernales pipeline system north of the LOGP was taken over by ConocoPhillips. ConocoPhillips takes possession of the crude oil at a custody transfer point adjacent to the LOGP. ConocoPhillips currently continues to move the crude oil to the Santa Maria Refinery and to Bay area refineries via pipeline. Although PXP has stated that new oil and gas development from the proposed project would be transported using the existing pipeline infrastructure in place for the Point Pedernales Project, PXP does not own the oil once it is in the ConocoPhillips pipeline system and cannot guarantee the oil will always be shipped to refineries via pipeline, as it is today.

The County-approved Point Pedernales Development Plans for both PXP and ConocoPhillips have the same requirement regarding oil transportation. This requirement is Condition Q-5 for both permits and reads as follows:

> All oil processed by the Lompoc HS&P Facility shall be transported from the facility in accordance with County Local Coastal Plan Policy 6-8. Transportation by a mode other than pipeline may be permitted only in accordance with Coastal Zoning Ordinance Section 35-154.5 (i), applicable Local Coastal Plan policies and control measure R-12 of the Air Quality Attainment Plan, to the extent is it applicable.[1]

Similar to Land Use Development Policy 12, Local Coastal Plan Policy 6-8 requires that proposals to expand, modify, or construct new oil and gas processing facilities be conditioned to require pipeline transport of the processed oil to refinery centers. Coastal Zoning Ordinance 35-154.5 (i)/LUDC Section 35.51.070.B.9 requires that all oil produced offshore and processed at a County-approved facility be transported from that facility and the County by pipeline. Because both PXP and ConocoPhillips would continue to be required to transport oil processed at the LOGP from there and out of the County by pipeline, the proposed project may be consistent with this policy. ~~New oil and gas development from the proposed project would be transported using the existing pipeline infrastructure in place for the Point Pedernales Project. Therefore, the proposed project may be consistent with this policy.~~

11. *For the purpose of ensuring safe, orderly, and planned development of oil and gas resources, the Board of Supervisors designates the northwestern and midwestern portion of the county as the North County Consolidation Planning Area, or NCCPA (as defined under the section "Other Definitions" in this element) and subjects oil and gas development in this planning area to the following policies:*

    a. *Due to estimated oil and gas reserves located offshore, the County has prepared a study entitled Siting Gas Processing Facilities: Screening & Siting Criteria. That study is incorporated herein by reference to guide a comprehensive analysis of alternative sites should the county receive an application for a Development Plan to construct or expand a facility in the NCCPA for treating or processing either onshore or offshore gas production. The criteria are designed to optimize public safety, environmental protection, and the benefits of consolidation. (89-GP-9)*

The Supplemental EIR for the previously approved Unocal gas plant at the LOGP evaluated the proposed site and several other sites using the above-referenced siting study criteria. The LOGP site was identified as the environmentally superior location for processing gas from the Point Pedernales Project. Therefore, the proposed project may be consistent with this policy.

12. *Proposals for expansion, modification, or construction of new oil and gas processing facilities, oil storage facilities, or pipeline terminals which receive oil from offshore fields exclusively or from both offshore and onshore fields, shall be conditioned to require transportation of oil by pipeline to processing facilities and final refining destination, except as provided in this policy.*

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1 Currently, Lompoc HS&P = Lompoc Oil and Gas Plant (LOGP) and SBC CZO Section 35-154.5(i) = LUDC Section 35.51.070.B.9.

"Final Refining Destination" shall mean a refinery in California where refining of the subject oil into products is accomplished. Exceptions: Oil shall be considered to reach its final refining destination if (a) the oil has been transported out of the State of California, and does not reenter before final refining; or (b) the oil has been transferred to truck or train after leaving the County by pipeline and does not reenter the County by truck or train, and is not transferred to a marine terminal vessel for further shipment to a port in California prior to final refining.

Crude oil received onshore from offshore production facilities may be transported by highway or rail if the Director determines that the oil is so highly viscous that pipeline transport is infeasible, taking into account available options such as modifications to existing pipelines, blending of NGLs, etc.

Any shipment of oil by highway or rail under this policy shall be limited to that fraction of the oil that cannot be feasibly transported by pipeline and shall not exceed the limits of permitted capacity for those transportation modes. The shipper or carrier shall mitigate to the maximum extent feasible any environmental impacts caused by the alternate transportation mode.

Temporary transport of oil by waterborne vessel may be authorized under an emergency permit if the Governor of the State of California declares a state of emergency pursuant to Public Resources Code Sec. 30262(a)(8) for an emergency that disrupts the pipeline transportation of oil produced offshore Santa Barbara County. In such a case, the oil transported by alternate mode shall be limited to that fraction which cannot feasibly be transported by pipeline. Transport by the alternate mode shall cease immediately when it becomes technically feasible to resume pipeline transport.

~~New oil and gas development from the proposed project would be transported using the existing pipeline infrastructure in place for the Point Pedernales Project. Thus~~ As discussed for Land Use Development Policy 10, the proposed project may be consistent with this policy.

13. *Oil and gas facilities shall be dismantled and removed, their host sites cleaned of contamination and reclaimed to natural conditions, or conditions to accommodate reasonably foreseeable development, in an orderly and timely manner that avoids long-term impacts to health, safety, and welfare of the public and environment.*

The proposed project would be required to comply with the Point Pedernales Project's FDP, which includes conditions for abandonment and site restoration immediately following permanent shut down of the facility. FDP Condition R-2 (Site Restoration) requires that the facility owner post a performance bond to ensure compliance with Condition R-2 until site restoration is complete, as determined by SBC. Therefore, the proposed project may be consistent with this policy.

Hillside and Watershed Protection Policies

1. *Plans for development shall minimize cut and fill operations. Plans requiring excessive cutting and filling may be denied if it is determined that the development could be carried out with less alteration of the natural terrain.*

2. *All developments shall be designed to fit the site topography, soils, geology, hydrology, and any other existing conditions and be oriented so that grading and other site preparation is kept to an absolute minimum. Natural features, landforms, and native vegetation, such as trees, shall be preserved to the maximum extent feasible. Areas of the site which are not suited to development because of known soil, geologic, flood, erosion or other hazards shall remain in open space.*

Only a minor amount of grading would be required to construct the new facilities associated with the proposed project. With the exception of the new power line to serve Valve Site #2, grading associated with the proposed project would occur in previously disturbed areas. Grading for installation of the power line would not require excessive cuts or fills and would occur in relatively level areas. In addition, the EIR identifies that grading impacts could be further reduced by mounting the proposed power line on existing poles and/or crossing the Santa Ynez River attached to the 13th Street bridge, if feasible.

Pipeline repair and maintenance activities could result in additional vegetation removal and ground disturbance. Implementation of erosion control measures, protective fencing, and restoration of the disturbed areas, as required in this EIR and the existing Point Pedernales Project FDP, would reduce potential impacts to a less than significant level. Therefore, the proposed project may be consistent with these policies.

7. *Degradation of the water quality of groundwater basins, nearby streams, or wetlands shall not result from development of the site. Pollutants, such as chemicals, fuels, lubricants, raw sewage, and other harmful waste, shall not be discharged into or alongside coastal streams or wetlands either during or after construction.*

Construction related discharges are expected to be minimal and controlled through the implementation of erosion and sediment control measures as specified in the EIR. Potential discharges during pipeline repair and maintenance would also be minimized through implementation of erosion and sediment control measures as required in this EIR.

The proposed project would result in an increased throughput of oil and would extend the life over which the oil emulsion, dry oil, and produced water pipelines would operate. If a rupture or leak of the pipelines were to occur significant degradation could occur to surface water, groundwater, and wetland resources in the project area. Currently to reduce the risk of a spill, pipeline inspections and corrosion prevention measures are implemented. In addition, 12 secondary containment basins are located at strategic locations (predominately in the vicinity of the Santa Ynez River) to contain the oil in the event of a spill. An OSRP is also in place to address response to, clean up of, and restoration of, spill affected areas. To further reduce potential water quality impacts from the proposed Tranquillon Ridge Project the EIR identifies the need for an additional catchment basin at Valve Site #2, annual inspection and maintenance of the pipeline, and additional updates to the OSRP.

Implementation of existing FDP measures and proposed new measures, combined with the small increase in the probability of a spill (an increase of 1.6 percent for ruptures and 6.9 percent for leaks of the onshore pipeline; and an increase of 8.5 percent for ruptures and large spills, and 4.4 percent for leaks and small spills for the offshore pipeline and Platform Irene) may allow for a finding of potential consistency with this policy. However, the permitting agency's ability to enforce these critical measures is crucial to a finding of potential consistency.

Streams and Creeks Policies

1. *All permitted construction and grading within stream corridors shall be carried out in such a manner as to minimize impacts from increased runoff, sedimentation, biochemical degradation, or thermal pollution.*

No new construction is proposed within any stream corridors. There are numerous stream crossings along the Point Pedernales Project pipeline corridor. Future repair and maintenance activities could involve grading and construction within these stream corridors. Implementation of erosion and sediment control measures and restoration activities required under the current FDP and this EIR would allow for a finding of consistency with this policy.

Historical and Archaeological Sites Policies

2. *When developments are proposed for parcels where archaeological or other cultural sites are located, project design shall be required which avoids impacts to such cultural sites if possible.*

3. *When sufficient planning flexibility does not permit avoiding construction on archaeological or other types of cultural sites, adequate mitigation shall be required. Mitigation shall be designed in accord with guidelines of the State Office of Historic Preservation and the State of California Native American Heritage Commission.*

5. *Native Americans shall be consulted when development proposals are submitted which impact significant archaeological or cultural sites.*

There are 29 recorded archaeological sites located along the Point Pedernales Project pipeline corridor. No recorded sites are known to occur within areas proposed for new disturbance (the power line route, Valve Site #2, and the LOGP) and surveys conducted in these areas did not reveal the presence of any resources. Measures have been included in the EIR to address encountering previously unknown cultural deposits in the vicinity of the new construction.

The known sites could be impacted during future repair and maintenance activities and by spill related clean up activities. To minimize disturbance to these known resources, the EIR requires pipeline monitoring within 200 feet of any known site during pipeline maintenance and appropriate data recovery if resources are encountered. Containment and clean up activities in emergency response condition could significantly impact cultural resource. To help reduce this impact the EIR requires updating the OSRP to provide procedures for minimizing impacts; however, avoidance and or data recovery may not be feasible depending on the extent and magnitude of the spill.

The implementation of existing FDP measures and proposed new measures, combined with the small increase in the probability of an onshore spill (an increase of 1.6 percent for ruptures and 6.9 percent for leaks of the onshore pipeline) may allow for a finding of potential consistency with this policy. However, the permitting agency's ability to enforce these critical measures is essential to a finding of potential consistency.

<u>Parks and Recreation Policies</u>

1. *Opportunities for commercial and sport fishing should be preserved and improved where appropriate.*

The increased throughput between Platform Irene and LOGP and the extension of life of the offshore and onshore facilities and pipelines would increase the probability and volume of an oil spill. An offshore spill caused by an accident or failure at Platform Irene or in the offshore pipeline could lead to <u>commercial and </u>recreational boating and fishing restrictions or preclusions during oil spill response and cleanup activities.

Currently to reduce the risk of an oil spill, pipeline inspections and corrosion prevention measures are implemented. In addition, 12 secondary containment basins are located at strategic locations (predominately in the vicinity of the Santa Ynez River) to contain the oil in the event of a spill. An OSRP is also in place to address response to, clean up of, and restoration of, spill affected areas.

The implementation of existing FDP measures and proposed new measures, combined with the small increase in the probability of a spill (an increase of 1.6 percent for ruptures and 6.9 percent for leaks of the onshore pipeline; and an increase of 8.5 percent for ruptures and large spills, and 4.4 percent for leaks and small spills for the offshore pipeline and Platform Irene) may allow for a finding of potential consistency with this policy. However, the permitting agency's ability to enforce these critical measures is crucial to a finding of potential consistency.

4. *Opportunities for hiking and equestrian trails should be preserved, improved, and expanded wherever compatible with surrounding uses.*

The increased throughput between Platform Irene and LOGP and the extension of life of the off- and onshore facilities and pipelines would increase the probability and volume of an oil spill. An onshore oil spill could adversely affect (temporarily restrict or preclude the use of) hiking trails, as well as equestrian uses (where permitted), within the Burton Mesa Ecological Reserve, the Santa Ynez River, and Ocean Beach Park. In addition, oil spill response activities could affect these uses.

As addressed above under Parks and Recreation Policy 1, implementation of existing FDP measures (facility inspections, pipeline corrosion prevention measures, secondary containment basins, and the project's OSRP) and proposed new measures, combined with the small increase in the probability of a spill (an increase of 1.6 percent for ruptures and 6.9 percent for leaks of the onshore pipeline; and an increase of 8.5 percent for ruptures and large spills, and 4.4 percent for leaks and small spills for the offshore pipeline and Platform Irene) may allow for a finding of potential consistency with this policy. However, the permitting agency's ability to enforce these critical measures is crucial to a finding of potential consistency.

<u>Visual Resources Policies</u>

1. *All commercial, industrial, and planned developments, shall be required to submit a landscaping plan to the County for approval.*

Landscaping plans were required and previously submitted and approved for the Surf Substation and the LOGP. ~~However, these plans were never fully implemented.~~ The condition effectiveness review (Condition B-2 analysis) prepared by SBC for the Point Pedernales Project

FDP determined that the landscaping was not effectively screening the substation and visual impacts of the substation are therefore not being fully mitigated. Therefore, for the proposed project to be consistent with this policy, ~~full~~ more effective implementation of the existing FDP conditions would be required.

2. *In areas designated as rural on the land use plan maps, the height, scale, and design of structures shall be compatible with the character of the surrounding natural environment, except where technical requirements dictate otherwise. Structures shall be subordinate in appearance to natural landforms; shall be designed to follow the natural contours of the landscape; and shall be sited so as not to intrude into the skyline as seen from public viewing places.*

5. *Utilities, including television, shall be placed underground in new developments in accordance with the rules and regulations of the California Public Utilities Commission, except where cost of undergrounding would be so high as to deny service.*

Both Valve Site #2 and the LOGP are located in areas designated as rural on the land use plan maps. Modifications at Valve Site #2 and the LOGP would be located adjacent to existing industrial development and would be compatible in design and scale with the existing development. The new power line to serve Valve Site #2, particularly the section of the line from the intersection of 13th Street and New Terra Road to the valve site is located in a relatively open, undeveloped area comprised of agricultural uses and native vegetation (coastal sage scrub). With the exception of the existing Point Pedernales Project pipeline infrastructure (Valve Site #2, the catch basins and the access road), minimal development is located in the area. The power line poles would be 60 feet in height and would be located every 350 to 400 feet. Because the majority of the vegetation is low growing coastal sage scrub, the power lines and poles would not be subordinate in appearance to the natural landforms and would intrude into the skyline. Therefore, the proposed project may be inconsistent with this policy. Use of existing transmission lines poles and mounting of the power line on the 13th Street bridge across the Santa Ynez River if feasible and undergrounding the power line in areas of visual sensitivity (e.g., along New Terra Road) may allow for a finding of consistency with this policy.

Lompoc Area-Land Use

The unique character of the area should be protected and enhanced with particular emphasis on protection of agricultural lands, grazing lands, and natural amenities.

Residential, commercial and industrial growth should be confined to urban areas.

Commercial and industrial development that complements and expands the existing agricultural industry of the area should be encouraged.

Industrial development should be light intensity.

The LOGP site has a land use overlay designation of Petroleum Resource Industry, and a zoning designation of M-CR (Coastal Related Industry). New construction associated with the proposed project would occur within the existing confines and developed area of the LOGP. Thus, the proposed project may be consistent with these policies.

Provision should be made for the systematic re-establishment of lands that have been misused by destruction of natural habitats, inappropriate construction, erosion, grading, mining, or waste disposal.

Changes in natural or re-established topography, vegetation, biological communities should be minimized in an attempt to avoid the destruction of natural habitats.

With the exception of the new power line to Valve Site #2, all new development associated with the proposed project would be within existing disturbed areas. Due to the small area of disturbance associated with each pole installation (approximately 315 square feet for the pole footing and machinery maneuvering), it is expected that biological impacts associated with the power line poles would also be minimal and/or impacts could be avoided through siting. To further minimize biological impacts, the EIR includes a measure which would require use of existing poles and/or mounted on the 13th Street bridge to cross the Santa Ynez River (please refer to Section 5.2, Terrestrial and Freshwater Biology for a discussion of these impacts and associated mitigation measures).

The existing Point Pedernales Project FDP conditions require restoration of any impacted biological resources. These conditions would continue to apply to the proposed project in association with future repair and maintenance activities. In addition, to further reduce impacts during repair and maintenance, the EIR identifies the need for development and implementation of a Pipeline Maintenance and Repair Plan.

Containment and clean up activities of an oil spill could significantly impact biological resources along the pipeline and in the proximity of the LOGP. To help reduce this impact the EIR requires updating the OSRP to provide procedures for minimizing impacts and restoring affected resources. Implementation of existing FDP measures and proposed new measures, combined with the small increase in the probability of a spill (an increase of 1.6 percent for ruptures and 6.9 percent for leaks of the onshore pipeline) may allow for a finding of potential consistency with this policy. However, the permitting agency's ability to enforce these critical measures is crucial to a finding of potential consistency.

Lompoc Area -Environment

Growth and employment must be consistent with the preservation and enhancement of resources and environmental quality.

The proposed project would primarily use the existing Point Pedernales Project facilities, thereby minimizing impacts due to new development. The existing Point Pedernales Project FDP conditions and the additional mitigation measures recommended in this EIR require the preservation and restoration of environmental resources. Therefore, the proposed project may be consistent with this policy.

Pollution of streams, sloughs, drainage channels, underground water basins, estuaries, the ocean, and areas adjacent to such waters should be minimized.

Please refer to the discussion under Hillside and Watershed Policy 7.

The groundwater resources should be protected against prolonged overdrafting.

The County should plan for and encourage the maximum conservation of water.

Please refer to the discussion under Land Use Development Policy 4. No increase in project-related water demand is expected. Continued compliance with FDP Condition F-6 (water conservation) would also be required. Therefore, the proposed project may be consistent with these policies.

Good air quality should be maintained as one of our greatest assets.

Implementation of the air quality measures identified in this EIR and the conditions of approval that would likely be specified by the SBCAPCD's "authority to construct" and "permit to operate" would minimize air quality impacts of the proposed project. Therefore, the proposed project may be consistent with this policy.

Excessive noise should be eliminated through the development of noise pollution standards.

Construction related noise levels at sensitive receptors nearest to the LOGP would increase above existing levels but would not exceed 65 decibels on the A-weighted scale (dBA). Operational noise would also not exceed the 65 dBA level, and the increase above current noise levels would be minimally perceptible. Nuisance noise levels would be mitigated to the maximum extent feasible by the existing FDP noise conditions and construction noise would be further minimized by limiting construction hours. Thus, the proposed project may be consistent with this policy.

Noise Element

1) *In the planning of land use, 65 dB Day-Night Average Sound Level should be regarded as the maximum exterior noise exposure compatible with noise-sensitive uses unless noise mitigation features are included in project designs.*

Noise sensitive land uses in the vicinity of Valve Site #2 include Ocean Beach County Park and in the vicinity of the LOGP include residence in Mission Hills and Vandenberg Village and the Burton Mesa Ecological preserve. Due to the distance (over 5,000 feet from Valve Site #2 and over 4,000 feet from the LOGP to the closest residence) between the proposed project sites and the sensitive receptors, no exceedance of the 65 decibels day/night noise level (dB L_{dn}) would occur. Therefore, the proposed project may be consistent with this policy.

Circulation Element

B. Roadway Standards:
The policy capacities provided in this Element shall be used as guidelines for evaluating consistency with this section of this Element. A project's consistency with this section shall be determined as follows:

a. *A project that would contribute ADTs to a roadway where the Estimated Future Volume does not exceed the policy capacity would be considered consistent with this section of this Element.*

The proposed project would result in an increased production of LPG and NGL and possibly sulfur products from the LOGP. Access to the facility is from Harris Grade Road. It is estimated that truck traffic would increase from 2.9 per week to 5 per week in response to increase LPG, NGL and sulfur production. The estimated future traffic volumes on Harris Grade Road would not exceed the policy capacity. Thus, the proposed project may be consistent with this policy.

Energy Element

POLICY 5.3: Cogeneration - The County shall encourage installation and use of cogenerating systems where they are cost-effective and appropriate.

The proposed project does not include the installation and use of a cogenerating system. Several other SBC oil and gas development projects (e.g. the Santa Ynez Unit and the Point Arguello Project) operate cogeneration facilities and rely on the electricity produced through these facilities. Under the proposed project the Point Pedernales Project facilities would still be fully dependent on the area's existing power grid for electricity. However, at the time the Point Pedernales Project was approved, the SBCAPCD was strongly in favor of reducing new air emissions by using utility grid power for the Point Pedernales Project facilities. In light of this previous decision by the County, the proposed project may be consistent with this policy.

However, as discussed in Section 5.16.4, the applicant will be required to prepare an Energy Efficiency Study for LOGP (see Mitigation Measure Energy-1).

POLICY 4.1: Construction - Encourage recycling and reuse of construction waste to reduce energy consumption associated with extracting and manufacturing virgin materials.

The proposed project largely depends on existing infrastructure, thereby avoiding energy use to fabricate and install new production facilities and reduce the amount of construction waste generated. Therefore, the proposed project may be consistent with this policy.

Agricultural Element

GOAL I. Santa Barbara County shall assure and enhance the continuation of agriculture as a major viable production industry in Santa Barbara County. Agriculture shall be encouraged. Where conditions allow, (taking into account environmental impacts) expansion and intensification shall be supported.

Policy IA. The integrity of agricultural operations shall not be violated by recreational or other non-compatible uses.

GOAL II. Agricultural lands shall be protected from adverse urban influence.

Policy II.D. Conversion of highly productive agricultural lands whether urban or rural, shall be discouraged. The County shall support programs which encourage the retention of highly productive agricultural lands.

Pipelines associated with the proposed project traverse a variety of agricultural resources, including lands mapped as prime farmland (1.77 miles), farmland of State-wide importance (0.46 miles, unique farmland (0.85 miles), farmland of local importance (4.52 miles), grazing land (11.1 miles), and farmland of local potential (1.08 miles). Lands adjacent to Valve Site #2 are designated as grazing land according to the Department of Conservation. Development of new electrical pumps at the valve site would be immediately adjacent to existing equipment in an existing disturbed area. Therefore, no impacts to agricultural resources are expected. The proposed power line serving Valve Site #2 would require construction of a small substation (40 feet by 40 feet) to be built on cultivated lands (currently used for hay production), and placement of power line and poles across other cultivated lands. The new poles would be located immediately adjacent to existing VAFB power lines. As identified in the EIR impacts could be further reduced by using existing poles if feasible.

The LOGP has a land use designation of Agriculture but has a land use overlay designation of Petroleum Resource Industry, and a zoning designation of M-CR (Coastal-Related Industry). The site has been used for oil and gas related processing since 1987. Modifications at the LOGP would be within the existing disturbed area of the site. In total approximately 0.33 acres of agricultural land would be disturbed as a result of new construction associated with the proposed project power line and substation. The small amount of agricultural land displaced by the proposed project and the minor amount of construction and operation traffic generated by the project would not adversely impact agricultural production.

Pipeline repair and maintenance activities along the pipelines could result in the disruption of agricultural activities and the removal of topsoil which could adversely affect productivity. To address this potential loss in productivity the EIR requires compensation for crops taken out of production, soil replacement, and crop replanting (please refer to Section 5.15, Agricultural Resources).

The proposed project would result in an increased throughput of oil and would extend the life over which the oil emulsion, dry oil, and produced water pipelines would operate. If a rupture or leak of the pipelines were to occur significant degradation could occur to marine and coastal waters. The addition of pumps at Valve Site #2 increases the risk of a spill or rupture at the site. Currently to reduce the risk of a spill, pipeline inspections and corrosion prevention measures are implemented. In addition, 12 secondary containment basins are located at strategic locations (predominately in the vicinity of the Santa Ynez River) to contain the oil in the event of a spill. An OSRP is also in place to address response to, clean up of, and restoration of, spill affected areas. To further reduce potential impacts from the proposed Tranquillon Ridge Project the EIR identifies the need for an additional catchment basin at Valve Site #2, annual inspection and maintenance of the pipeline, and additional updates to the OSRP. Specifically, the EIR includes a mitigation measure requiring that the OSRP incorporate specific clean up techniques on agricultural lands (e.g., minimizing removal of top soil).

The implementation of existing FDP measures and proposed new measures, combined with the small increase in the probability of an onshore spill (an increase of 1.6 percent for ruptures and 6.9 percent for leaks of the onshore pipeline) may allow for a finding of potential consistency with this policy. However, the permitting agency's ability to enforce these critical measures is crucial to a finding of potential consistency.

Hazardous Waste Element

2-2 All businesses that generate hazardous wastes including home occupations, but excluding normal household activities, shall provide the County with information regarding the type, amount and management of all hazardous wastes generated. Such information shall be required as part of the EHD hazardous waste generator permit program and shall be updated annually.

2-3 All hazardous waste treatment, storage, and disposal facilities in the County shall provide the County with information regarding their operations and treatment, storage, and disposal capacity. Such information shall be updated annually.

As required pursuant to the original FDP for the Point Pedernales Project facilities and subsequent amendments (e.g., for the Gas Plant), a Hazardous Material and Waste Management Plan and Business Plan has been prepared for the LOGP. This document would need to be updated to address production and processing from the proposed project. Review and approval of this plan prior to land use clearance for the proposed project would allow for a finding of potential consistency with this policy.

8-1 Any land use permit for a hazardous waste generator or a hazardous waste facility shall require submittal of an emergency response plan prior to operations, if such a plan is required under Chapter 6.95 (section 25500 et seq.) of the California Health and Safety Code.

As required pursuant to the original FDP for the Point Pedernales Project facilities and subsequent amendments (e.g., for the Gas Plant), an ERP has been prepared. This document would need to be updated to address production and processing from the proposed project. Review and approval of this plan prior to land use clearance for the proposed project would allow for a finding of potential consistency with this policy.

Seismic Safety and Safety Element (Safety Element Supplement)

***Policy Hazardous Facility Safety 1-A,* Risk Estimates**
The County shall employ accurate estimates of risk associated with hazardous facilities to inform discretionary land-use decisions where substantial, preliminary evidence indicates involuntary public exposure to significant risk may result from the land-use decision.

A risk analysis has been prepared and included in the EIR for the Tranquillon Ridge Project consistent with the requirements of this policy.

***Policy Hazardous Facility Safety 2-B,* Unacceptable Risk Involving Modifications to Existing Development**
Proposed modifications to existing development that require a discretionary land-use permit and meet any of the following three criteria shall represent an unacceptably high level of risk and constitute a prima facie standard for denial.

(1) Modifications that increase risk and the resulting mitigated risk registers in the red zone of the County's risk thresholds, unless the proposed modification is required to comply with law, the modification does not increase significant risk to highly sensitive land uses, and no other feasible alternatives are achievable.

(2) Modifications that increase risk and the resulting mitigated risk registers in the red zone of the County's risk thresholds, unless the proposed modification is made to an urban dependent land use and highly sensitive land uses are not exposed to significant risk as a result of the modification.

(3) Modifications that increase risk and the resulting, mitigated risk registers in the amber zone of the County's risk thresholds if exposure of a highly sensitive land use would occur as result of project approval.

Based on the risk analysis conducted in the EIR (please refer to Section 5.1), under current operating conditions the frequency versus number of "fatalities" curves register in the green region for pipeline operations from Platform Irene to the LOGP and the LOGP to the Summit Pump Station. Under current operating conditions the frequency versus number of "injuries" curves register in the amber region for Platform Irene to LOGP pipeline operations, and in the green region for LOGP to Summit Pump Station.

The proposed project would extend the life of the Point Pedernales Project facilities and the duration during which the public would be exposed to significant risks during operation of the Platform Irene to LOGP pipeline (injuries). To reduce risks (injuries) associated with Platform Irene to LOGP operations, the EIR includes a mitigation measures that would require that the applicant implement a sour gas pipeline operation pressure limit as a function of sour gas hydrogen sulfide (H_2S) concentration, not to exceed 600 psig at 8,000 ppm H_2S. Current FDP conditions also require development and implementation of a Safety Inspection, Maintenance, and Quality Assurance Program with review and oversight by the SBC Systems Safety and Reliability Review Committee.

With implementation of the proposed mitigation measures the proposed project would not increase risks above current operating levels. Thus, the proposed project may be consistent with this policy.

Conservation Element

Mineral Resources

"No Mineral Resource Extraction should be permitted in the County if significant adverse impacts on the air, water, or land environment would result, if flooding and erosion problems would be increased, or if polluting emissions likely to be generated directly or indirectly by the activity in question would result in adopted federal or State environmental quality standards being exceeded."

By using the existing Point Pedernales Project infrastructure the proposed project would minimize new construction impacts. Impacts associated with new development at Valve Site #2, the LOGP, and along the new power line corridor would be either less than significant, or with implementation of the mitigation measures identified in the EIR, could be reduced to a less than significant level.

The proposed project would result in an increased throughput of oil and would extend the life over which the oil emulsion ~~dry oil,~~ and produced water pipelines would operate. If a rupture or leak of the pipelines were to occur, significant degradation could occur to marine and coastal waters. The addition of pumps at Valve Site #2 increases the risk of a spill or rupture at the site. Currently to reduce the risk of a spill, pipeline inspections and corrosion prevention measures are implemented. In addition, 12 secondary containment basins are located at strategic locations (predominately in the vicinity of the Santa Ynez River) to contain the oil in the event of a spill. An OSRP is also in place to address response to, clean up of, and restoration of, spill affected areas. To further reduce potential impacts from the proposed Tranquillon Ridge Project the EIR identifies the need for an additional catchment basin at Valve Site #2, annual inspection and maintenance of the pipeline, and additional updates to the OSRP.

Implementation of existing FDP measures and proposed new measures, combined with the small increase in the probability of a spill (an increase of 1.6 percent for ruptures and 6.9 percent for leaks of the onshore pipeline; and an increase of 8.5 percent for ruptures and large spills, and 4.4 percent for leaks and small spills for the offshore pipeline and Platform Irene) may allow for a finding of potential consistency with this policy. However, the permitting agency's ability to enforce these critical measures is crucial to a finding of potential consistency.

Ecological Systems

The Conservation Element contains descriptions of the ecological systems in SBC and recommendations for their use and protection. The components associated with the proposed project run adjacent to, and traverse a number of sensitive habitats including (but not limited to) the riparian and wetland areas associated with the Santa Ynez River, areas containing Burton Mesa chaparral, coastal dune scrub, oak savannah and woodlands, and vernal pools. Please refer to Section 5.2, Terrestrial and Freshwater Biology, for a description of all sensitive habitats associated with the proposed project.

Proposed project components would primarily be within existing disturbed areas and would use existing pipeline infrastructure, thereby minimizing impacts to sensitive habitats.

The proposed power line alignment to Valve Site #2 would require siting of support poles near the Santa Ynez River and spanning the river. Impacts to the sensitive biological resources in and along the river would be reduced by mounting the power line on the 13th Street Bridge and/or using existing poles, if feasible. If this measure is not feasible impacts could be reduced by locating the pole footing outside of sensitive riparian and wetland areas, timing the construction to avoid the breeding seasons for sensitive birds, and by placing the power line at height above the river that minimizes bird collisions.

The existing Point Pedernales Project FDP conditions require restoration of any impacted biological resources. These conditions would continue to apply to the proposed project in association with future repair and maintenance activities. In addition, to further reduce impacts during repair and maintenance, the EIR identifies the need for development and implementation of a Pipeline Maintenance and Repair Plan.

Containment and clean up activities of an oil spill could significantly impact biological resources along the pipeline corridor. To help reduce this impact the EIR requires updating the OSRP to provide procedures for minimizing impacts and restoring affected resources. Implementation of existing FDP measures and proposed new measures, combined with the small increase in the probability of a spill (an increase of 1.6 percent for ruptures and 6.9 percent for leaks of the onshore pipeline; and an increase of 8.5 percent for ruptures and large spills, and 4.4 percent for leaks and small spills for the offshore pipeline and Platform Irene) may allow for a finding of potential consistency with this policy. However, the permitting agency's ability to enforce these critical measures is crucial to a finding of potential consistency.

5.14.8.3 Other Plans and Policies

1998 Clean Air Plan

The purpose of the 1998 Clean Air Plan is to continue to improve air quality in SBC as required by both the California Clean Air Act (CCAA) of 1988 and the Federal Clean Air Act Amendments (FCAAA) of 1990.

As required by SBCAPCD rules, the proposed project would be required to obtain an "authority to construct" and "permit to operate" to allow for new emissions from the facilities. According to the EIR analysis, increased emissions associated with the proposed project would be fully mitigated by the existing available emission credits originally required as a condition of approval of the Point Pedernales Project FDP. Conditioning of the proposed project to ensure that total emissions do not exceed the available emission credits may allow it to be consistent with the Clean Air Plan.

AB 32 - California Global Warming Solutions Act of 2006

AB 32 was approved in September 2006 and is codified in the State's Health and Safety Code, Division 25.5, beginning with Section 38500. AB 32 requires that the California Air Resources Board (CARB) develop regulations intended to reduce emissions of greenhouse gases within the State. The legislation provides guidance and sets out a timeline for CARB to develop and implement these regulations. Major deadlines are:

June 30, 2007	Develop a list of greenhouse gas reduction measures that can be implemented prior to adoption of the specific regulations;
January 1, 2009	Identify mechanisms for reducing significant greenhouse gas emissions to 1990 levels by 2020 (Scoping Plan);
January 1, 2010	Adopt greenhouse gas emission reduction regulations;
January 1, 2011	Adopt greenhouse gas emission limits and reduction measures (to become effective on January 1, 2012).

Section 38562(a)(3) specifically requires that CARB ensure credit is given for voluntary greenhouse gas emission reductions implemented by regulated entities before the emission limits become effective in 2012. Additional information about AB 32 is provided in Section 5.8.2.2 of this EIR.

Although AB 32 does not set regulations for greenhouse gases, it does provide the basis for those regulations and timing for their adoption. The legislation recognizes the detrimental effects of global warming and provides for the State's regulation of emissions that contribute to global warming in order to reduce those effects. As discussed in Section 5.8 of this EIR, the proposed project would emit carbon dioxide, a greenhouse gas, primarily from the heater treaters at the LOGP. Even though the project's contribution to total State, national, and global greenhouse gas emissions would be relatively small, and the specific regulations are not yet in place, there may be opportunities for PXP to achieve consistency with the goals and objectives of AB 32 in the short term through implementation of the greenhouse gas reduction measures identified in the planned GHG audit discussed in Section 5.8.4.2 of this EIR.

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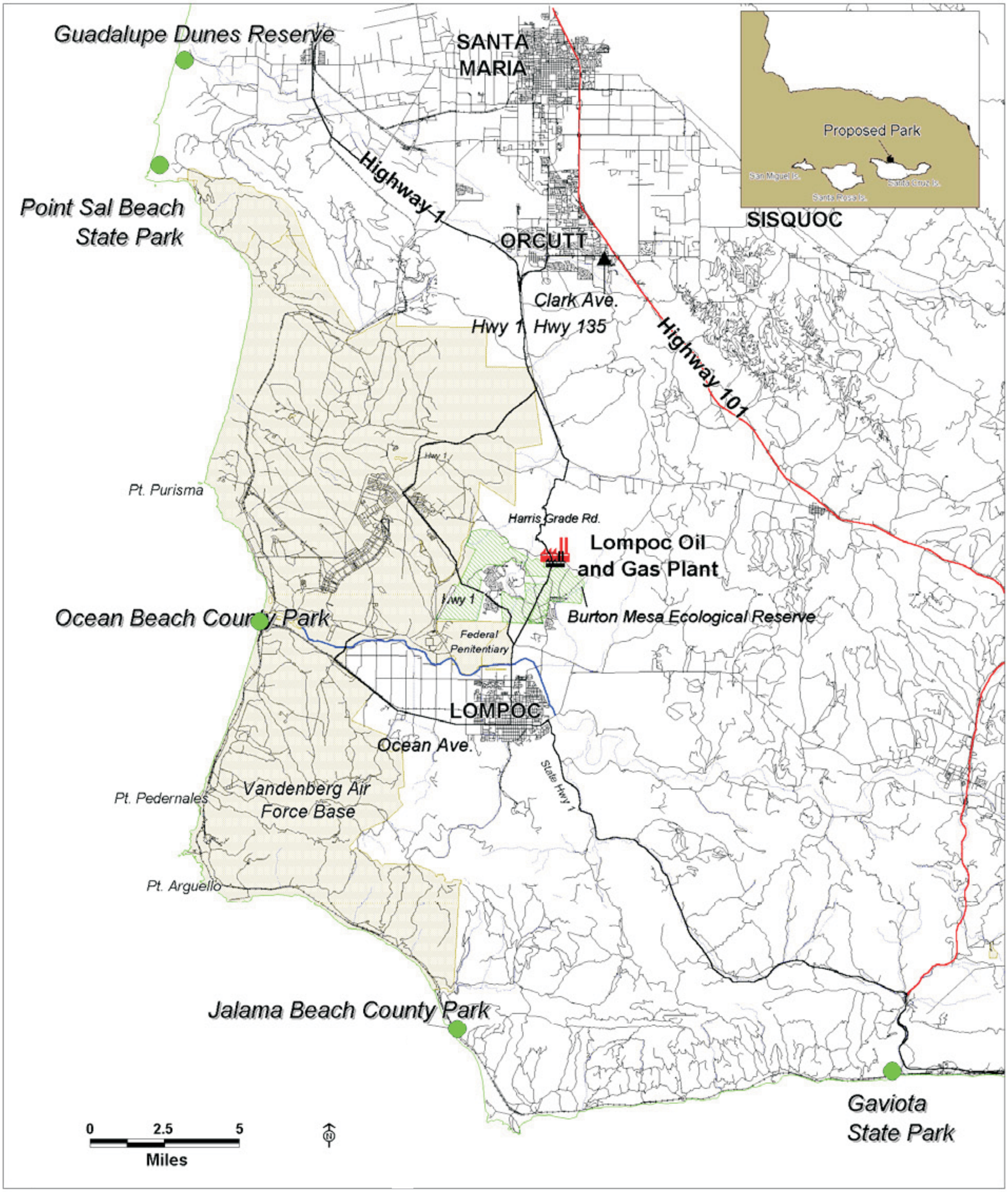

Source: MRS, 2002.

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Figure 5.14-1
Coastal Beaches and Parks

5.15 Agricultural Resources

Large portions of Santa Barbara and San Luis Obispo County lands are devoted to various agricultural crops and other farm-use categories. In 2002, Santa Barbara County (SBC) agricultural crops were valued at $775 million (CDFA, 2006). The agricultural industry dominated SBC's economy with a gross production of $997,600,578 in 2005 (Santa Barbara County, 2006). In SBC as a whole, approximately 48 percent of the land is devoted to agricultural use, essentially all of which is privately owned lands with the exception of some lands on Vandenberg Air Force Base (VAFB) (CDFA, 2006). The top five crops for SBC include strawberries, wine grapes, broccoli, head lettuce, and cauliflower (CDFA, 2006). Recent data for San Luis Obispo County indicate that the County has approximately 1,010,291 acres of agricultural land (FMMP, 2006) and a crop value of $479 million (CDFA, 2006).

5.15.1 Environmental Setting

SBC, San Luis Obispo County, the California Department of Conservation, and U.S. Department of Agriculture utilize nine different land mapping categories to describe farmland and non-farmlands, as follows.

- *Prime Farmland*. Land with the best combination of physical and chemical features able to sustain long-term production of agricultural crops. This land has the soil quality, growing season, and moisture supply needed to produce sustained high yields.
- *Farmland of Statewide Importance*. Land similar to Prime Farmland that has a good combination of physical and chemical characteristics for the production of agricultural crops. This land has minor shortcomings, such as greater slopes or less ability to store soil moisture than Prime Farmland.
- *Unique Farmland.* Lesser quality soils used for the production of the state's leading agricultural crops. This land is usually irrigated, but may include non-irrigated orchards or vineyards as found in some climatic zones in California.
- *Farmland of Local Importance.* Land of importance to the local agricultural economy as determined by each county's board of supervisors and a local advisory committee. SBC considers all dry land (grains, cereals, beans) and permanent pasture (other than those not eligible for Prime or Statewide designation) to be farming areas. San Luis Obispo County considers dairies, dry land farming, aquaculture, and uncultivated areas with soils as qualifying for *Prime Farmland* and *Farmland of Statewide Importance*.
- *Local Potential.* These are areas with soils that qualify for Prime or Statewide Importance designations, but which are not cultivated or irrigated. Only certain counties, such as San Luis Obispo, have chosen to use the Local Potential designation.
- *Grazing Land.* Land on which the existing vegetation is suited to the grazing of livestock. This category is used only in California and was developed in cooperation with the California Cattlemen's Association, University of California Cooperative Extension, and other groups interested in the extent of grazing.
- *Urban and Built-Up Land.* Land occupied by structures with a building density of at least 1 unit to 1.5 acres, or approximately six structures to a 10-acre parcel.
- *Other Land.* Land that does not meet the criteria of any other category.
- *Water.* Water areas with an extent of at least 40 acres.

The SBC Comprehensive Plan, Agricultural Element (1991) has two additional land use categories related to agriculture:

- *Agriculture I.* Land of five or more acres, minimum parcel size, located inside urban, inner rural, and rural neighborhood areas. Both prime and non-prime farmland are included.
- *Agriculture II.* Land of 40 or more acres, minimum parcel size located outside urban, inner rural, and rural neighborhood areas. General agriculture is permitted, including livestock operations, grazing, and beef production, as well as more intensive agriculture uses.

The SBC Comprehensive Plan, Land Use Element (1991) has an additional land use category related to agriculture:

- **Agricultural Commercial.** Land of 40 to 320 acres, minimum parcel size located within rural, inner-rural or existing developed rural neighborhoods, or urban areas, which is subject to or eligible for Williamson Act Contract.

The San Luis Obispo County General Plan Agricultural and Open Space Element (1998) contains a general description of the main types and uses of agricultural land within the County.

5.15.1.1 Irrigated Lands

- **Row Crops Terrain and Soils.** Property sizes generally range from 10 acres to hundreds of acres. Characterized by various types of vegetables, seed crops, orchards, and other irrigated specialty crops.
- **Specialty Crops and Forage Lands.** Property sizes generally range from 20 to a few hundred acres. Characterized by irrigated orchards, including alfalfa and pasture, and vineyards such as wine grapes, avocados, citrus, and apples.

5.15.1.2 Dry Farm Lands

- **Mixed Croplands.** Property sizes generally range from 40 acres to several hundred acres. Characterized by dry farm orchards and vineyards and specialty or high value field crops.
- **Dry Croplands.** Property sizes generally range from 80 to several thousand acres. These areas are characterized by grain and hay production that is widespread in the northeastern part of the county. Barley, wheat, and oat hay are the principal crops. Other crops include dry beans and safflower.
- **Ranchlands for Grazing.** Property sizes generally range from 100 acres to thousands of acres, depending on the carrying capacity of the rangelands. Grazing land accounts for a large percentage of the privately owned land in the County. Cattle ranching is the predominant use on these lands.

5.15.1.3 Overall Project Area

The existing pipelines, pump stations, and oil plant are primarily in areas designated as "Other Land" per the farmland mapping categories. However, the PXP and ConocoPhillips pipeline that would transport the Tranquillon Ridge produced crude and gas to the Lompoc Oil and Gas Plant (LOGP) and Summit Pump Station (oil only), respectively, would cross approximately:

- 1.77 miles of Prime Farmland;
- 0.46 miles of Farmland of Statewide Importance;
- 0.85 miles of Unique Farmland;
- 4.52 miles of Farmland of Local Importance;

- 11.1 miles of Grazing Land; and
- 1.08 miles of Farmland of Local Potential.

The portion of the pipeline in SBC falls primarily in lands designated as Agriculture II per the County Land Use Element. The portion of the pipeline in San Luis Obispo County is a mix of Irrigated Lands and Dry Farm Lands. Based upon review of aerial photos, these lands appear to be in current agricultural production.

5.15.1.4 PXP Pipelines

The proposed project would extend the life of the existing PXP onshore oil pipelines. From landfall to the LOGP, the pipeline alignment crosses approximately:

- 1.3 miles of Farmland of Local Importance (two separate land areas); and
- 2.56 miles (two separate land areas) of land designated as Grazing Land.

The pipeline comes within a half mile of three other land areas designated Farmland of Local Importance as well as a land area designated Prime Farmland. This segment of pipeline contains Valve Site #2. Valve Site #2 and the LOGP reside within land designated as Grazing Land.

5.15.1.5 ConocoPhillips Pipelines

The ConocoPhillips pipeline from LOGP to the Summit Pump Station in which the dehydrated Tranquillon Ridge crude would be transported would cross approximately:

- 1.77 miles of Prime Farmland;
- 0.46 miles of Farmland of Statewide Importance;
- 0.85 miles (two separate land areas) of Unique Farmland;
- 3.22 miles of Farmland of Local Importance;
- 8.5 miles of designated Grazing Land; and
- 1.08 miles of Farmland of Local Potential.

Orcutt and Summit pump stations are situated within Grazing Land.

5.15.2 Regulatory Setting

5.15.2.1 California Laws and Policies

Williamson Act

The Williamson Act, or the California Land Conservation Act of 1965, encourages and enables local governments to enter into contracts with private landowners to restrict specific parcels of land to agricultural or related open space use. In return, landowners receive property tax assessments that are much lower than normal because they are based upon farming uses rather than full market value. Local governments receive a subsidy for forgone property tax revenues from the state via the Open Space Subvention Act of 1971.

California Coastal Act of 1976

The California Coastal Act also contains provisions to protect agricultural productivity in the coastal zone. The act has specific guidance measures to avoid the conversion of prime agricultural land.

The maximum amount of prime agricultural land shall be maintained in agricultural production to assure the protection of the area's agricultural economy, and conflicts shall be minimized between agricultural and urban land uses through all of the following:

> "…(e) By assuring that public service and facility expansions and nonagricultural development do not impair agricultural viability, either through increased assessment costs or degraded air and water quality (§30241 California Public Resources Code)."

Further, the Coastal Act calls for the protection of the long-term productivity of soils and timberlands (§30243 California Public Resources Code).

5.15.2.2 Local Laws and Policies

Santa Barbara County Policies and Regulations

The following paragraphs describe relevant Santa Barbara Agricultural Element Goals and Policies.

Goal I. Santa Barbara County shall assure and enhance the continuation of agriculture as a major viable production industry in Santa Barbara County. Agriculture shall be encouraged. Where conditions allow, (taking into account environmental impacts) expansion and intensification shall be supported.

Policy I.A. The integrity of agricultural operations shall not be violated by recreational or other non-compatible uses.

Policy I.D. The use of the Williamson Act (Agricultural Preserve Program) shall be strongly encouraged and supported. The County shall also explore and support other agricultural land protection programs.

Goal II. Agricultural lands shall be protected from adverse urban influence.

Policy II.D. Conversion of highly productive agricultural lands whether urban or rural, shall be discouraged. The County shall support programs that encourage the retention of highly productive agricultural lands.

Goal III. Where it is necessary for agricultural lands to be converted to other uses, this use shall not interfere with remaining agricultural operations.

Goal VI. The County should make effective provision for access to agricultural areas and for the necessary movement of agricultural crops and equipment.

San Luis Obispo County Goals and Policies

The following paragraphs describe relevant San Luis Obispo County Agricultural Element Goals and Policies.

Goal AG2. Conserve Agricultural Resources.

a. Maintain the agricultural land base of the county by clearly defining and identifying productive agricultural lands for long-term protection.

b. Conserve the soil and water that are the vital components necessary for a successful agricultural industry in this County.

c. Establish land-use policies in this element that support the needs of agriculture without impeding its long-term viability.

Goal AG3. Protect Agricultural Lands.

a. Establish criteria in this element for agricultural land divisions that will promote the long-term viability of agriculture.

b. Maintain and protect agricultural lands from inappropriate conversion to non-agricultural uses. Establish criteria in this element and corresponding changes in the Land Use Element and Land Use Ordinance for when it is appropriate to convert land from agricultural to non-agricultural designations.

c. Maintain and strengthen the County's agricultural preserve program (Williamson Act) as an effective means for long-term agricultural land preservation.

d. Provide incentives for landowners to maintain land in productive agricultural uses.

Policy AGP18. Location of Improvements.

a. Locate new buildings, access roads, and structures so as to protect agricultural land.

Policy AGP24. Conversion of Agricultural Land.

a. Discourage the conversion of agricultural lands to non-agricultural uses through the following actions:

   1. Work in cooperation with the incorporated cities, service districts, school districts, the County Department of Agriculture, the Agricultural Liaison Board, Farm Bureau, and affected community advisory groups to establish urban service and urban reserve lines and village reserve lines that will protect agricultural land and will stabilize agriculture at the urban fringe.

   2. Establish clear criteria in this plan and the Land Use Element for changing the designation of land from Agriculture to non-agricultural designations.

   3. Avoid land redesignation (rezoning) that would create new rural residential development outside the urban and village reserve lines.

   4. Avoid locating new public facilities outside urban and village reserve lines unless they serve a rural function or there is no feasible alternative location within the urban and village reserve lines.

5.15.3 Significance Criteria

With respect to land use and agricultural resources, SBC's Environmental Thresholds and Guidelines Manual (as updated through October 2006), states that a project would normally have a significant effect on the environment if it would:

- Convert prime agricultural land to non-agricultural use or impair the agricultural productivity of prime agricultural land;
- Conflict with agricultural preserve programs; or
- Affect any unique or other farmland of State or Local Importance.

5.15.4 Impact Analysis for the Proposed Project

The primary project activities that could affect agricultural activities and productivity include the following:

- Modification of Valve Site #2;
- Pipeline repair and maintenance;
- Increased truck trips to the LOGP;
- Increase in life expectancy of the Point Pedernales facilities;
- Increase in the potential magnitude of a pipeline leak/spill; and
- Increase in oil throughput from Platform Irene to LOGP over current operations.

Impact #	Impact Description	Phase	Residual Impact
AG.1	Addition of power poles and substation to Valve Site #2 could disturb farm operations.	*Construction*	*Class III*

Modifications to Valve Site #2 would include installing new electrical pumps, a substation and a power line to provide electricity for the pumps. These modifications would take approximately 14 weeks. The proposed power line route would involve ground disturbance from constructing a new substation, installing new power poles, and a minor amount of backhoe trenching. The proposed substation would be located in a farm field on the northwest corner of Renwick and Ocean Avenues. Under this option power poles would be placed in lands designated as prime farmland, farmland of local importance, and grazing land. The proposed substation would occupy approximately 1,600 square feet of prime farmland (approximately 0.04 acre). The impact to agriculture of installing power poles and the substation is anticipated to be minor. Trenching along 13th Street is assumed to occur within the road shoulder and is not anticipated to disturb adjacent farmland. Because of the ~~very~~ small areas of agricultural land that would be converted to non-agricultural use relative to the existing operation, the impacts on agriculture resources would be adverse but not significant.

Mitigation Measures

No mitigation measures have been identified.

Residual Impact

Because of small area that will be impacted by construction of the substation, the impacts to agricultural resources are considered to be *adverse but not significant (Class III).*

Impact #	Impact Description	Phase	Residual Impact
AG.2	Increased truck trips during construction and operation. Increased traffic unlikely to interfere with farm operations.	*Construction* *Increased Throughput* *Extension of Life*	*Class III*

Increased truck trips to the LOGP are anticipated due to minor modifications needed to accommodate increased production at the plant. Up to five additional truck trips (round trips) per week are anticipated to result from increased production. Valve #2, power line, and LOGP construction would last approximately nine weeks ~~months~~ and require approximately 40 daily truck trips. This small increase in traffic is not expected to hinder the movement of farm equipment or generate dust that could impair the existing agricultural productivity of agricultural land under production. Additionally, no agricultural land conversion is anticipated. Increased truck trips to the LOGP would result in an adverse but not significant impact to agricultural resources.

Mitigation Measures

No mitigation measures have been identified.

Residual Impact

Given the small increase in project-related traffic, impacts to agricultural activities/lands are considered *adverse but not significant (Class III).*

Impact #	Impact Description	Phase	Residual Impact
AG.3	Potential degradation and reduced productivity of agricultural land from a pipeline leak or rupture resulting in an oil or produced water spill.	*Increased Throughput* *Extension of Life*	*Class II*

The 1985 Point Pedernales EIR/EIS identified the long-term risk of upset as a significant but mitigable impact on agricultural resources. With the proposed project, the life of the facilities would be extended beyond the lifetime of the existing Point Pedernales Project. However, based on the risk analysis (evaluated in Section 5.1, Risk of Upset), the rate of pipeline failure would change very little from that calculated for the pipeline when built. Because the amount of oil relative to water would be higher in the emulsion pipeline from Platform Irene to LOGP, and the volumes transported would be higher, the amount of oil in such a spill would be proportionately larger. Oil spills can directly affect agricultural operations by reducing the availability or quality of soil, water, nutrients, and oxygen to plant root systems, hindering growth and possibly causing mortality in crops exposed to oil. Further, recovery of affected soils would be slow due to lingering toxicity and altered soil characteristics. Indirect effects from oil spill cleanup could include clearing and grading for access and removal of oiled crops and soil. These potential impacts would result in impaired agricultural productivity of prime agricultural land and potential removal of prime soils. The extended timeframe of spills potentially resulting in this circumstance would be a potentially significant but mitigable impact.

Mitigation Measures

AG-1 PXP shall revise the Point Pedernales Oil Spill Response Plan (OSRP) and submit to SBC for review and approval. The Plan shall include specific cleanup techniques for agricultural lands, focusing on minimizing removal of top soil. ~~The OSRP shall include a compensation plan for the purchase of agricultural crops lost/damaged and for replacement of removed top soil with equivalent imported soils.~~

Residual Impact

Adoption of measures to minimize damage from spill cleanup (as described in AG-1) would potentially offset the increased probabilities of spill and increase spill volumes associated with the proposed action to increase throughput. With implementation of Mitigation Measure AG-1, Impact AG.3 would be *adverse but not significant with mitigation (Class II).*

Impact #	Impact Description	Phase	Residual Impact
AG.4	Potential loss of agricultural productivity during pipeline repair and maintenance.	*Extension of Life*	*Class II*

Some of the pipeline located within agricultural lands could be affected by pipeline repair and maintenance activities; therefore, agricultural lands could be taken out of production for an unknown time period. This possible loss of agricultural productivity of prime agricultural land represents a potentially significant but mitigable impact.

Mitigation Measures

~~**AG-2** Monetary Payment for Lost Agricultural Productivity. Landowners shall receive compensation for the loss of any crops directly resulting from pipeline replacement activities. Compensation will take into account the duration of lost agricultural productivity.~~

AG-2~~3~~ Soil Replacement and Replanting. All soils within agricultural lands disturbed by pipeline replacement activities shall be replaced and if necessary enriched to support their former crops (or cattle grazing areas). All disturbed areas shall be restored in accordance with land owner agreements. ~~replanted at a 1:1 ratio. Applicant shall prepare and submit for SBC review and approval, a soil preservation plan that describes activities, including soil replacement, soil enrichment, and replanting (at a 1:1 ratio) to take place after pipeline replacement activities~~.

Residual Impact

With the implementation of Mitigation Measure AG-2 ~~through AG-3~~, Impact AG.4 is *adverse but not significant with mitigation (Class II).*

5.15.5 Impact Analysis for the Alternatives

Detailed descriptions of the various alternatives are provided in Chapter 3.0, Alternatives. This section provides a discussion of the agricultural impacts of the various alternatives.

5.15.5.1 No Project Alternative

Scenarios 2 and 3. As discussed in Section 3.2, under the No Project Alternative Scenarios 2 and 3, production of the federal portion of the Tranquillon Ridge field would and would not occur, respectively. However, no extension of life of Point Pedernales facilities (Platform Irene, pipelines, and LOGP) is assumed under either scenario. Under Scenarios 2 and 3, ~~the No Project Alternative~~ all of the impacts identified for the proposed project (Impacts AG.1 to AG.4) would be eliminated. Operational impacts previously identified for the original Point Pedernales Project would continue, including pipeline repairs and maintenance until production and processing ends.

Options for Meeting California Fuel Demand. The relative agricultural impacts associated with the various options for meeting California fuel demand are summarized in Table 5.15.1.

Table 5.15.1 No Project Alternative Comparison to Options for Meeting California Fuel Demand, Agricultural Resources

Source of Energy	Impacts
Other Conventional Oil & Gas	
Domestic onshore crude oil and gas	Likely to eliminate or displace agricultural impacts.
Increased marine tanker imports of crude oil	Likely to eliminate or displace agricultural impacts.
Increased gasoline imports[1]	Likely to eliminate or displace agricultural impacts.
Increased natural gas imports (LNG)	Likely to eliminate or displace agricultural impacts.
Alternatives to Oil and Gas	
Fuel Demand Reduction: increased fuel efficiencies, conservation, electrification[2]	
Alternative transportation modes	Proposed project impacts would be eliminated.
Implementation of regulatory measures	Proposed project impacts would be eliminated.
Coal, Nuclear, Hydroelectric	Proposed project impacts would be eliminated; however, coal, nuclear, and hydroelectric infrastructure development could introduce new agricultural impacts.
Alternative Transportation Fuels	
Ethanol/Biodiesel[3]	Loss of agricultural lands could occur due to ethanol/biodiesel infrastructure development. Ethanol/biodiesel could have potential economic benefits for certain segments of agricultural industry; however, could displace agricultural lands from food production.
Hydrogen[2]	Potential construction related impacts due to hydrogen delivery infrastructure development.
Other Energy Resources[2]	
Solar[2,4]	Proposed project impacts would be eliminated. Loss of agricultural lands could occur due to facility siting.

Table 5.15.1 No Project Alternative Comparison to Options for Meeting California Fuel Demand, Agricultural Resources

Source of Energy		Impacts
	Wind[2,4]	Proposed project impacts would be eliminated. Loss of agricultural lands could occur due to facility siting; however 90+% of the wind facility site could still be available for agricultural production.
	Wave[2,4]	Not likely to result in agricultural impacts.

Footnotes:
1. Pipeline and tanker truck import from out-of-State assumed.
2. Assumes that Tranquillon Ridge production would not be replaced with other petroleum-based energy supply.
3. Assumes ethanol and biodiesel used as blends only and therefore would reduce, but not eliminate Tranquillon Ridge or equivalent production.
4. Assumes, large centralized facilities.

5.15.5.2 VAFB Onshore Alternative

The VAFB Onshore Alternative would be located primarily within VAFB and along the public Highway 246 corridor. The VAFB Onshore Alternative crosses approximately:

- 0.5 miles of land designated as Prime Farmland,
- 2 miles of Farmland of Local Importance, and
- 1 mile of Grazing Land.

However, only two small land areas of prime farmland and farmland of local importance on the south and north sides, respectively, of the Santa Ynez River appear to be under active cultivation. The impacts of the alternative on agricultural lands are discussed below.

***Impact AG.1 – Impacts to Agriculture from Installation of Power Poles and Substation*: ** The new six-mile 69 kV transmission line would be constructed along Coast Road, Bear Creek Road, and Surf Road. No grazing or agricultural activities occur in this area. The alternative power line to the tie-in station would involve ground disturbance from constructing a new substation, installing new power poles, and a minor amount of backhoe trenching. One of two possible substation sites could be used, one located in a farm field on the northwest corner of Renwick and Ocean Avenues, and the other located in a farm field north of Ocean Avenue and west of an abandoned road. Under either substation scenario, power poles would be placed in lands designated as prime farmland, farmland of local importance, and grazing land. The alternative substation would occupy approximately 1,600 square feet of prime farmland (approximately 0.04 acre). The impact to agriculture of installing power poles and the substation is anticipated to be minor. Trenching along 13th Street is assumed to occur within the road shoulder and is not anticipated to disturb adjacent farmland. Because of the small areas of agricultural land that would be converted to non-agricultural use relative to the existing operation, the impacts on agriculture resources would be adverse but not significant.

***Impact AG.2 – Impacts to Agriculture due to Interference with Agricultural Operations Resulting from Increased Truck Traffic*: ** Impacts associated with increased truck trips due to construction of the alternative pipelines would be substantially greater than the proposed project, since construction of 10 miles of new pipeline and 6 miles of new transmission line would generate extensive construction traffic which would continue for a much longer duration in different agricultural areas that include prime farmland and unique farmland, which are currently under cultivation. However, all access routes and staging areas would be located in previously disturbed areas, which are devoid of agricultural resources. The impacts would be temporary and therefore are considered to be *adverse but not significant (Class III).*

Impact AG.3 - Impacts to Agriculture from Crude Oil and Produced Water Spills would be the same as the proposed project. Mitigation Measure AG-1 would apply.

Impact AG.4 – Impacts to Agricultural Productivity during Pipeline Repair and Maintenance: Impacts associated alternative pipeline repair and maintenance would be slightly greater than the proposed project, given the additional length of pipeline.

Mitigation Measures

Mitigation Measures AG-1 through AG-3 are applicable as well as the following mitigation measure.

AG-4 PXP shall prepare and submit for review and approval, a grazing land preservation plan that describes activities, including soil replacement, soil enrichment, and replanting to take place after pipeline replacement activities. The plan shall be submitted to SBC for review and approval prior to land use clearance.

Residual Impact

Implementation of AG-1 through AG-4 would lessen the impacts of this alternative. Impact AG.4 would therefore be considered *adverse but not significant with mitigation (Class II).*

Impact #	Impact Description	Phase	Residual Impact
AG.5	Directional drilling locations could reduce farmland areas.	*Construction*	*Class II*

Under the VAFB Onshore Alternative, drilling sites would be placed on either side of the river. These sites would disturb prime farmland, farmland of local importance, and grazing land. However, because of the small areas of prime agricultural land that would be involved and subsequent restoration of the sites, these drilling locations represent potentially significant but mitigable impacts to agriculture.

Mitigation Measures

Mitigation Measures AG-2 through AG-4 are appropriate for this impact.

Residual Impact

With the implementation of Mitigation Measures AG-2 through AG-4, Impact AG.5 is considered *adverse but not significant with mitigation (Class II).*

Impact #	Impact Description	Phase	Residual Impact
AG.6	Potential loss of agricultural productivity during pipeline and facility construction.	*Construction*	*Class II*

The pipeline to be constructed is approximately 10 miles long. It is assumed that a 50-foot wide construction corridor would be required to accommodate clearing, ditching, and vehicles associated with construction. Agricultural land disturbance is estimated at 21 acres, including approximately 6 acres of grazing land, 12 acres of farmland of local importance, and 3 acres of prime farmland would be disturbed. However, as stated above, only two small areas of the land designated as prime farmland and farmland of local importance appear to be in active cultivation.

Mitigation Measures

Mitigation Measures AG-2 through AG-4 would apply.

Residual Impact

Impact AG.6 is considered *significant but mitigable (Class II).*

5.15.5.3 Casmalia East Oil Field Processing Location

Under this alternative, Impacts AG.1, AG.3 and AG.4 would be the same as for the proposed project. Mitigation Measures AG-1 through AG-3 would apply. Impact AG.2 would change as described below. Impact AG.5, related to directional drilling, would not apply to the Casmalia effect. Impact AG.6 addresses the agricultural lands associated with the Casmalia Alternative.

***Impact AG.2 – Impacts to Agriculture due to Interference with Agricultural Operations Resulting from Increased Truck Traffic*:** Impacts associated with truck trips would be greater under this alternative than under the proposed project due to additional pipeline installation, dismantling activities at the LOGP, and construction activity at the Casmalia East site. With this alternative, dismantling work would take place at the LOGP and require approximately 104 to 165 daily one-way trips to the LOGP site for approximately 6 months. At the Casmalia East site, new truck trips would result from the construction and operation of the new oil processing facility. Because this is a new facility many more construction related truck trips would be necessary than under the proposed project. It is estimated that as many as 243 one-way trips would be generated during the first month of construction, dropping to 164 daily one-way trips for the remaining 5 months of construction. Construction traffic would be *adverse but not significant (Class III).*

Since the precise configuration of the alternative Casmalia East facility site is uncertain, the exact route to be used during operation is unknown. Heavy project-related truck traffic along Highway 1, Black Road, and Lompoc-Casmalia Road could interfere with local agricultural operations (i.e., by the creation of dust, hindering movement of farm equipment) resulting in impaired agricultural productivity of prime agricultural land. Based on the traffic analysis in Section 5.9, operational traffic would adversely affect local roadways and intersections, but *would not be significant (Class III).*

Impact AG.6 – Agricultural Productivity during Pipeline Construction: Under this alternative, new oil and gas pipelines would be built from the LOGP to a new site at Casmalia. A new oil and gas facility identical to the LOGP would be built at Casmalia. The new pipes would follow existing pipelines from LOGP to 5,000 to 7,000 feet south of Orcutt and then turn west to Casmalia. The new pipeline route would fall mostly within farmland designated as Grazing Land and not Prime, Unique, or Farmland of Local Importance. However, the pipeline route does pass through or near prime farmland along Highway 135. Therefore, impacts of converting prime agricultural land to non-agricultural land use or impairing the productivity of this farmland could be considered potentially significant but mitigable. Implementation of Mitigation Measures AG-1 through AG-4 would lessen the impacts of this alternative. The impact would therefore be considered *adverse but not significant with mitigation (Class II).*

5.15.5.4 Alternative Power Line Routes to Valve Site #2

Under this alternative, including all power line options, Impacts AG.2, AG.3 and AG.4 would be the same as for the proposed project. Mitigation Measures AG-1 through AG-3 would apply. Impact AG.1 and Impact AG.5 (Alternative Power Line Route – Option 2b only) would change as described below.

Alternative Power Line Route – Option 2a

***Impact AG.1 – Impacts to Agriculture from Installation of Power Poles and Substation*:** Power Line Option 2a would involve ground disturbance from constructing a new substation and installing new power poles. The proposed substation would be located in a farm field north of Ocean Avenue and west of an abandoned road. Under this option, power poles would be placed in lands designated as prime farmland, farmland of local importance, and grazing land. The impact to agriculture of installing power poles and the substation is anticipated to be minor. The proposed substation would disturb approximately 1,600 square feet of prime farmland (approximately 0.04 acre). Because of the ~~very~~ small areas of prime agricultural land that would be involved, the impacts on agriculture would be *adverse but not significant (Class III)*. However, the impacts would be slightly greater than for the proposed project.

Alternative Power Line Route – Option 2b

Alternative power line route Option 2b is identical to Option 2a, except the power line would be placed under the Santa Ynez River using a directional bore. The directional bore would involve excavating two bore pits, one on each side of the river, and an additional work area in the hay field north of the river. Impact AG.2 would be the same as for Option 2a.

Impact AG.5 – Impacts to Farmland due to Drilling: Under this option, power poles would be placed in lands designated as prime farmland, farmland of local importance, and grazing land. The impact of installing power poles to agriculture is anticipated to be minor. However, the proposed substation and one of the bore pits would disturb approximately half an acre of prime farmland. The remaining bore pit and work area would disturb approximately 1.72 acres of farmland of local importance. Because of the small areas of prime agricultural land that would be involved and subsequent restoration of the drilling sites, Impact AG.5 is considered *significant but mitigable impacts (Class II)*. Mitigation Measures AG-2 through AG-4 would apply.

Underground Power Line along Terra Road

Impact AG.1 – Impacts to Agriculture from Installation of Power Poles and Substation: Impacts associated with the installation of the power poles and substation would be the same as the proposed project. Since the section of the power line route along Terra Road does not contain any agricultural land undergrounding the power line at this location has no effect on Impact AG.1. Therefore, the impact would be considered *adverse but not significant (Class III).*

5.15.5.5 Replacement of Oil Emulsion Pipeline from Platform Irene to LOGP

Impact AG.5, related to directional drilling, would not apply to the Emulsion Pipeline Replacement Alternative.

***Impact AG.1 – Impacts to Agriculture from Installation of Power Poles and Substation*:** Impacts associated with the installation of the power poles and substation would not occur under this alternative since the new pipeline would be capable of delivering the oil to the LOGP without the need for the new pumps at Valve Site #2.

***Impact AG.2 – Impacts to Agriculture due to Interference with Agricultural Operations Resulting from Increased Truck Traffic*:** Impacts associated with increased truck trips due to increased production and construction of valve site facilities would be substantially the same as the proposed project, though construction traffic would continue for a much longer duration. Impacts would be *adverse but not significant (Class III).*

Impact AG.3 - Impacts to Agriculture from Crude Oil and Produced Water Spills would be the same as the proposed project. Mitigation Measure AG-1 would apply.

Impact AG.4 – Impacts to Agricultural Productivity During Pipeline Repair and Maintenance: Impacts associated pipeline repair and maintenance would be similar but less than the proposed project, as the newer pipeline would require less repair and maintenance. The impact would be considered *adverse but not significant (Class II)* with the implementation of Mitigation Measures AG-2 and AG-3.

Impact AG.6 – Agricultural Productivity during Pipeline Construction: From landfall to the LOGP, the pipeline alignment crosses approximately:

- 1.3 miles of Farmland of Local Importance (two separate land areas), and
- 2.56 miles (two separate land areas) of land designated as Grazing Land.

The onshore portion of the pipeline that would be replaced under this alternative is 12.1 miles long. Typically, a 100-foot wide right-of-way would be needed to accommodate clearing, ditching, and vehicles associated with construction. Land disturbance is estimated at 147 acres, of which approximately 31 acres of grazing land and 16 acres of Farmland of Local Importance would be disturbed. Construction is estimated to take 9 to 10 weeks, assuming 22 persons per shift and 10-hour shifts. The construction right-of-way will be either graded or “matted” to accommodate the pipeline trench and equipment. “Matting” involves flattening existing vegetation to allow passage of vehicles. Both grading and matting would take agricultural land out of production. Productivity would be lost until the right-of-way was stabilized, replanted, and the new plants mature and begin producing crops. Nearby agricultural lands may be affected by erosion resulting from grading and the movement of construction vehicles. In addition, some agricultural operations (pesticide spraying, fertilizing) could be hindered by the presence of construction equipment and construction crews. This would be a potentially significant but mitigable impact.

Mitigation Measures

Mitigation Measures AG-2 through AG-4 and GR-1 would be applicable, along with the following measure.

AG-5 Pipeline sedimentation basins and traps shall be inspected, cleaned, and if necessary replaced. Silt fences shall be inspected monthly during dry periods and immediately after each rainfall. Sediment must be removed when more than 1/3 filled, until vegetation is reestablished in the area of the disturbed soil. Straw bales shall be inspected weekly and after each rain. Sediment shall be removed when it reaches a depth of 6 inches, until vegetation is reestablished.

Residual Impact

With the implementation of Mitigation Measures AG-2 through AG-4 and GR-1 (identified under the proposed project) and AG-5, the residual impacts would be *adverse but not significant with mitigation (Class II)*.

5.15.5.6 Alternative Drill Muds and Cuttings Disposal

Inject Drill Muds and Cuttings into Reservoir

This alternative is essentially the same as the proposed project with the exception of offshore activities. Onshore activities under this alternative are the same as for the proposed project. Therefore, impacts on agricultural resources would be the same as for the proposed project.

Transport Drill Muds and Cuttings to Shore for Disposal

This alternative is essentially the same as the proposed project with the exception of offshore activities. Onshore disposal activities would not affect agricultural resources and agricultural impacts would be the same as for the proposed project.

5.15.6 Cumulative Impacts

Cumulative projects that could impact the current analysis include the potential offshore oil and gas projects discussed in Sections 4.2 and 4.3, and the onshore development projects outlined in Section 4.4. The cumulative impacts of these potential off- and onshore development projects are discussed separately below.

5.15.6.1 Offshore Oil and Gas Projects

As outlined in Sections 4.2 and 4.3, several offshore energy-related projects could potentially be developed in the proposed project area. These projects would use both existing and new platforms, pipelines and onshore facilities. Introducing new onshore facilities and extending the lifespan of existing onshore facilities would increase the potential for disturbing agricultural production during both construction and operation. Therefore, these potential projects could have significant cumulative impacts on agricultural resources. However, the proposed project's contribution to these impacts, while adverse, would not be considered significant with implementation of the mitigation measures identified in Section 5.15.4.

The potential offshore oil and gas development projects outlined in Sections 4.2 and 4.3 would also increase the potential for accidental oil spills, although the probability of an oil spill would be low. Similar to the proposed project, containment and cleanup of potential oil spills has the potential to impact agricultural productivity. However, because an onshore oil spill moves slowly across the land due to the viscous nature of the Santa Maria Basin crude, agricultural areas that would be impacted would be minimized. Further, if a spill resulting from the offshore development projects reached the shoreline, it is unlikely that it would affect agricultural resources, given the low density of agricultural lands on the immediate shoreline. Therefore, cumulative oil spill impacts to agricultural lands, and the proposed project's incremental contribution to them, would not be expected to be significant.

5.15.6.2 Onshore Projects

The majority of the potential onshore development projects located in the Lompoc area that are discussed in Section 4.4 fall within lands designated as Urban and Built-Up Land or Other Land. Therefore, agricultural impacts from these projects would be minimal. The cumulative projects identified in the Orcutt-Santa Maria area could have a significant cumulative permanent loss of agricultural lands impact. However, the proposed project would have no contribution to this permanent loss because it does not propose any new development within this area. The proposed project would only contribute to temporary disruptions to agricultural productivity due to pipeline maintenance and repair activities, or an oil spill. Due to the temporary nature of these impacts, the proposed project's incremental contribution would not be considered significant with implementation of the mitigation measures identified in Section 5.14.4.

5.15.7 Mitigation Monitoring Plan

Mitigation Measure	Mitigation Requirements and Timing	Method of Verification	Timing of Verification	Party Responsible For Verification
AG-1	PXP shall revise the Oil Spill Response Plan (OSRP) and submit for review and approval. Plan shall include specific cleanup techniques for agricultural lands focusing on minimizing removal of top soil~~. OSRP shall include compensation plan for the purchase of agricultural crops lost/damaged and replacement of removed top soil with equivalent imported soils.~~	Revised OSRP shall be reviewed and approved.	PCDP/LUP	SBC P&D Fire
~~AG-2~~	~~Monetary Payment for Lost Agricultural Productivity. Landowners shall receive compensation for the loss of any crops directly resulting from pipeline replacement activities. Compensation will take into account the duration of lost agricultural productivity.~~	~~Crop compensation plan shall be reviewed and approved.~~	~~Prior to issuance of coastal development permits or grading permits.~~	~~SBC P&D~~
AG-2~~3~~	Soil Replacement and Replanting. All soils within agricultural lands disturbed by pipeline replacement activities shall be replaced and if necessary enriched to support their former crops (or cattle grazing areas). All disturbed areas shall be restored in accordance with land owner agreements. ~~replanted at a 1:1 ratio. Applicant shall prepare and submit for review and approval, a soil preservation plan that describes activities, including soil replacement, soil enrichment, and replanting (at a 1:1 ratio) to~~	Plan shall be reviewed and approved	Plan prior to land use clearance during restoration.	SBC P&D

Mitigation Measure	Mitigation Requirements and Timing	Method of Verification	Timing of Verification	Party Responsible For Verification
	~~take place after pipeline replacement activities.~~			
AG-4 (VAFB Onshore, Casmalia, Power Line Route, and Emulsion Pipeline Replacement Alternatives only)	PXP shall prepare and submit for review and approval, a grazing land preservation plan that describes activities, including soil replacement, soil enrichment, and replanting to take place after pipeline replacement activities. The plan shall be submitted to SBC for review and approval prior to land use clearance.	Plan shall be reviewed and approved	Plan prior to land use clearance during restoration.	SBC P&D
AG-5 (Emulsion Pipeline Replacement Alternative only)	Pipeline sedimentation basins and traps shall be inspected, cleaned, and if necessary replaced. Silt fences shall be inspected monthly during dry periods and immediately after each rainfall. Sediment must be removed when more than 1/3 filled, until vegetation is reestablished in the area of the disturbed soil. Straw bales shall be inspected weekly and after each rain. Sediment shall be removed when it reaches a depth of 6 inches, until vegetation is reestablished.	EQAP Inspection	During and post-construction	SBC P&D

5.15.8 References

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5.16 Energy and Mineral Resources

This section evaluates the existing energy and mineral resources such as oil, natural gas and electricity in the State of California. The consumption and generation of energy by the proposed project has also been evaluated, including an assessment of energy saving alternatives. The section has also evaluated the potential for the proposed project to impact the State energy resources since the project is expected to result in higher energy consumption than the baseline, as well as increased production of energy resources such as oil and natural gas.

5.16.1 Environmental Setting

5.16.1.1 Regional Overview

The major sources and uses of energy in California include electricity, natural gas, and petroleum-based fuels. Table 5.16.1 summarizes the State energy sources and their production and consumption in California.

Table 5.16.1 California Energy Sources and Consumption in 2005

Type of Energy Source	Produced Instate	Imported (US or Foreign)	Total Consumed
Electricity, Gigawatt-hours (GWh)	225,788 (78%)	62,456 (22%)	288,244
Natural Gas, billion ft^3	316.5 (14%)	1,963.3 (86%)	2,280
Petroleum-based fuels[a] (1,000 barrels)	266,052 (39.5%)	408,224 (60.5%)	674,276

Sources: California Energy Commission (CEC) web site www.energy.ca.gov/html/energysources.html, California Independent Petroleum Association web site.

a. Fuels derived from liquid unrefined crude oil, including natural gas liquids, liquefied petroleum gas, or the energy fraction of methyltertiarybutylether (MTBE) or other ethers that are not attributed to natural gas.

Electricity production in California is mostly fueled by natural gas, hydropower, and nuclear energy. Other energy sources that are used for electricity production include solar and wind power, biomass/waste, geothermal energy, coal, and oil. Natural gas is the number one fuel used to produce electricity in California with oil-based fuels (such as fuel oil) being the least used for electricity production. Electricity produced with natural gas as a fuel accounts for more than ~~37.7~~ 48.1 percent (108,686 GWh/year) of all electricity produced in the State.

According to the California Division of Oil, Gas, and Geothermal Resources, California is estimated to have 3.6 trillion cubic feet (ft^3) of natural gas in onshore reserves, and as much as 2.1 trillion ft^3 of natural gas in offshore reserves. California produces approximately 0.9 billion ft^3 per day of natural gas, which constitutes approximately 13 percent of the total natural gas consumed in California. It is estimated (by the California Energy Commission [CEC]) that the State's natural gas use will increase from 6,600 million standard cubic feet per day (mmscfd) in 2006 to 7,100 mmscfd in 2016. The annual average natural gas demand growth for electricity generation is expected to grow 1.5 percent per year through 2013.

In 2005 California's petroleum refineries processed ~~approximately~~ 674,276~~000~~ thousand barrels ~~per day (bpd)~~ of crude oil into a variety of products, with gasoline representing about half of the total product volume. In 2005, California oil refineries received 39.5 percent or 266,052 thousand barrels of crude from Californian petroleum sources and 60.5 percent or 408,224 thousand barrels from imported sources outside of California. The quality of the average crude refined in California, especially that received from in-State production, has historically been heavier and more sulfurous than from other sources. The State's complex refineries have adapted to processing low-to-medium quality crude oil into highway fuels. However, a refiner's crude oil slate is influenced by several factors, including the price differential between higher-quality and lower-quality crudes. Production peaked in California in 1983. California crude oil production has declined 34 percent since 1986 and declined 19 percent between 1998 and 2004 even though value of oil increased by 210 percent.

A summary of energy consumption in California by consumption sector is presented in Table 5.16.2. The Residential Sector consumed the highest percentage (38 percent) of natural gas followed by the Industrial (26 percent), Mining (21 percent), and Commercial Sectors (13 percent) respectively. The Commercial Sector had the highest percentage of electricity consumption (37 percent) followed by Residential (31 percent), Industrial (16 percent), and Agriculture (7 percent). In the Industrial Sector, the Petroleum Refining and Oil and Gas Extraction sub-sectors are among the highest consumers of both electricity and natural gas. In 1997, the Petroleum Refining sub-sector consumed 7,774 GWh of electricity and 162.5 billion ft^3 of natural gas, and the Oil and Gas Extraction sub-sector consumed 3,816 GWh and 215.7 billion ft^3, respectively.

Table 5.16.2 California Energy Consumption by Sector

Sector or Sub-sector	Natural Gas Consumption 2001, (10^6 Therms)[1] (% of Total)	Electricity Consumption 2005, Million kWh[2] (% of Total)
Residential	5,129 (38%)	84,527 (31%)
Commercial	1,778 (13%)	101,393 (37%)
Industrial	3,503 (26%)	44,586 (16%)
Mining	2,856 (21%)	6,559 (2%)
Agriculture	143 (1%)	19,502 (7%)
Other	162 (1%)	15,818 (6%)
Total Consumption	13,571	272,385

Sources: CEC, California Energy Demand 2006-2016, Staff Energy Forecast Report, September 2005; CEC web site www.energy.ca.gov/electricity/consumption_by_sector.html
Numbers may not add due to rounding.

According to the CEC, Santa Barbara County consumed 2,750 million kWh of electricity in 2000 and 15 billion ft^3 of natural gas was consumed in 1997.

The CEC publishes biennial Energy Outlook reports where historical energy consumption rates and predictions for the future are published. According to the CEC, California's total natural gas consumption decreased by 1.1 percent and electricity consumption increased by 0.6 percent between the years 2000-2004.

5.16.1.2 Energy Consumption by the Point Pedernales Project

The operation of the Point Pedernales Project requires consumption of energy resources including electricity, natural gas, diesel and gasoline.

The Point Pedernales facilities consume electricity and are fully dependent on the grid for electricity, unlike the offshore and onshore facilities of the Santa Ynez Unit project or the onshore facilities of the Point Arguello project, which rely on electricity produced onsite through co-generation. The ongoing operations of Platform Irene, the LOGP, and Orcutt Pump Station require a continuous electricity supply to operate electrical pumps, gas compressors, control systems and other electrical equipment, and to provide sufficient lighting for night time operations. Platform Irene consumes approximately 42,500 megawatt-hours/year (4.85 megawatts [MW] X 24 hours/day X 365 days/year), the LOGP consumes approximately 11,000 megawatt-hours/year (1.25 MW)[1]. Reducing demand for electricity from the grid has been one of several energy-efficient strategies implemented by the State of California over the past several decades (e.g., Title 24, Energy-efficient Building Standards). The Point Pedernales facilities are compliant with the energy-efficient building standards; however, they do not employ photo-voltaic, co-generating, or other equipment that would help reduce demand for electricity from the grid. (See Section 5.16.4 for a discussion of electricity conservation technologies considered for the Point Pedernales facilities.)

In 2000, the County conducted a review of the effectiveness of the Point Pedernales project Final Development Plan permit conditions. Condition Q-4 requires that "cost-effective energy conservation techniques shall be incorporated into project design." The 2000 study found the following regarding the LOGP: "[The] two Sales Gas compressor motors have a 94% efficiency rate, [the] two propane refrigerant compressor motors have a 95.1% efficiency rate, and [the] three water injection pump motors have a 93% efficiency rate. … Other energy reduction components at [LOGP] include reduced-voltage controllers to minimize power consumption during start-up, high-pressure sodium vapor outdoor lights, indoor fluorescent lighting, and two large capacitor banks that are sized to optimize the plant's Power Factor, which reduces overall power consumption." The efficiency ratings noted above were termed "high" by a Gas Company representative (SBC 2000).

Natural gas serves as fuel for the flare and flare pilot at Platform Irene, and for several equipment pieces at the LOGP including three heater treaters, thermal oxidizer (heat medium heater), and oil reclaimer. Diesel fuel is necessary to operate the two cranes at the platform. The supply boat to Platform Irene requires diesel fuel as well. In addition, both Platform Irene and the LOGP have diesel firewater pumps and diesel emergency power generators. The helicopters used for transportation of workers to the platform ~~also~~ use ~~gasoline~~jet fuel. Workers at the LOGP and platform workers use gasoline for their commute.

5.16.1.3 Energy Production by the Point Pedernales Facilities

The main business of the Point Pedernales facilities is the production, treatment and sales of crude oil, natural gas, and natural gas liquids. Crude oil is sold to the Santa Maria Refinery where it is converted to gasoline and other petroleum-based fuels. A portion of the produced natural gas is consumed at the LOGP site, and the remainder of it is sold to the gas utilities from where it can be directly used by consumers or used for electricity production. Natural gas liquids are sold and are used as fuel for different purposes. In 2005, the LOGP natural gas sales

[1] Year 2006 data.

averaged 2.6 mmscfd, crude oil sales averaged 7,000 bpd, and natural gas liquids averaged 105,000 gallons per month.

To operate, Point Pedernales facilities consume petroleum-based fuels. These facilities also produce petroleum and natural gas. The proposed project is expected to increase overall crude oil production from Platform Irene by 170 to 200 million barrels and 40 to 50 billion cubic feet of natural gas. Natural gas liquids production would also increase somewhat (as a function of both crude oil and natural gas production increases).

Crude oil is a raw material in the manufacturing of petroleum-based products, such as diesel and gasoline. The natural gasoline portion in the crude oil ranges from 5 to 7 percent. When reformulation processes are involved, the gasoline fraction could increase up to 70 percent. The diesel fuel fraction could range from 7 to 20 percent[2]. As such, the proposed Tranquillon Ridge Project would be a net producer of petroleum based fuels, generating between 5.9 and 7.5 billion gallons of fuel per year. In 2005, the State of California consumed 31.4 billion gallons of crude oil. Therefore, the fuels produced from the Tranquillon Ridge Project would provide approximately 69 to 87 days of fuel supply for California based on year 2005 consumption data.

With the development of Tranquillon Ridge Field~~Unit~~, the LOGP natural gas sales could reach 5 to 6 mmscfd. Currently, the LOGP natural gas sales are 2.6 mmscfd. With the proposed project, LOGP heater treaters could consume an additional 0.8 to 1.0 mmscfd of natural gas over the existing firing rates as additional oil from Tranquillon Ridge is processed. The Tranquillon Ridge Project is expected to produce between 80 and 85 percent more natural gas than the project would consume. During the peak year of production, the project would provide approximately 2.2 billion standard cubic feet of natural gas, which is about 0.1~~01~~ percent of the total annual demand for natural gas within the State of California. The natural gas produced from the Tranquillon Ridge would be used to supply the local gas distribution system in Santa Barbara County. During the peak years of gas production, the Tranquillon Ridge Project would provide approximately ~~25~~14.7 percent of the natural gas demand in Santa Barbara County.

5.16.2 Regulatory Setting

~~The energy and mineral resources impacts assessment has been conducted in conformance with the CEQA Guidelines. There are other numerous~~ Several acts and regulations ~~that~~ govern energy production, utilization, conservation and development of new sources are listed below.

The State of California adopted the Warren-Alquist Act (1974) in an effort to encourage conservation of the non-renewable energy resources. The State Energy Resources Conservation and Development Commission was created as a result of this act. This act has been codified in the Public Resources Code - Division 15, Energy Conservation and Development. Other statutes related to efficient utilization of energy resources and energy conservation include:

- Financial Code - Division 15.5,
  Section 32000 et seq. - State Assistance Fund for Energy, California Business and Industrial Corporation

[2] Source: http://tonto.eia.doe.gov/oog/info/state/ca.html, 2000 Weekly California Refinery Production and Stocks Level. California Energy Commission.

- Government Code – Title 2,
  Section 14450 et seq. Part 5, Chapter 4 - California Transportation Research and Innovation Program
  Section 15814.10 et seq. Part 10b, Chapter 2 - Energy Conservation in Public Buildings
  Section 15814.30 et seq. Part 10b, Chapter 2.8 - Energy Efficiency in Public Buildings
- Public Resources Code - Division 3
  Section 3800 et seq., Chapter 6 - Disposition of Geothermal Revenues
- Public Resources Code - Division 6,
  Section 6801 et seq. Part 2, Chapter 3 - Oil and Gas and Mineral Leases
- Public Resources Code - Division 16,
  Section 26000 et seq. - California Alternative Energy Source and Advanced Transportation Authority Act
- Public Resources Code - Division 16.5,
  Section 26400 et seq. - Energy and Resources Fund
- Public Utilities Code - Division 1,
  Section 330 et seq. Part 1, Chapter 2.3 - Electrical Restructuring
  Section 445 et seq. Part 1, Chapter 2.5 - Public Utilities Commission Reimbursement Fees
  Section 701 et seq. Part 1, Chapter 4 - Regulation of Public Utilities
  Section 1001 et seq. Part 1, Chapter 5 - Certificates of Public Convenience and Necessity
  Section 2801 et seq. Part 2, Chapter 7 - Private Energy Producers
- Revenue and Taxation Code – Division 2
  Section 40001 et seq. - Part 19, Energy Resources Surcharge Law
- Vehicle Code – Division 3
  Section 5205.5 and 21655.9 et seq. - Vehicle Code
- Vehicle Code – Division 12
  Section 28110 et seq. - Chapter 5, Article 16 - Methanol or Ethanol Fueled Vehicles

In 2002, the State of California enacted several new laws (Senate Bill 1038 and Senate Bill 1078) implementing California's Renewables Portfolio Standard and establishing the process by which utilities will procure electricity for their customers. Additional legislation was passed in 2006 (Senate Bill 107 and Senate Bill 1250) modifying the Renewable Energy Program's funding eligibility and requirements. The goal of these laws is to establish a competitive, self-sustaining renewable energy supply for California while increasing the near-term quantity of renewable energy generated in-state. A summary is presented below; however, for a detailed discussion of the guidelines for implementation and administration of the Renewable Energy Program see http://www.energy.ca.gov/renewables/.

The Energy Commission's Renewable Energy Program provides funding to support existing, new, and emerging renewable energy resources with the goal of establishing a competitive, self-sustaining renewable energy supply for California while increasing the near-term quantity of renewable energy generated in-state. Funding is provided through program elements of the Renewable Energy Program, including the Existing Renewable Facilities Program, New Renewable Facilities Program, Emerging Renewables Program, and Consumer Education Program. The Energy Commission has provided this funding since 2003 pursuant to SB 1038. This law, in conjunction with the Reliable Electric Service Investments Act, continues the collection of a non-bypassable system benefit charge initiated in 1998 under Assembly Bill (AB)

1890, and authorizes the Energy Commission to continue the expenditure of these funds to support existing, new, and emerging renewable resources.

In addition, the Energy Commission is charged with implementing California's Renewables Portfolio Standard (RPS). The RPS was initiated under SB 1078 and required retail sellers of electricity to increase the amount of renewable energy they procure each year by at least 1 percent until 20 percent of their retail sales are served with renewable electricity by December 31, 2017. Recent legislation (Senate Bill 107, 2006) accelerated this RPS goal to 2010. The Energy Commission is charged with certifying eligible renewable energy resources that satisfy RPS procurement requirements, developing an accounting system to verify retail sellers' compliance with the RPS, and awarding supplemental energy payments (SEPs) to cover the above market cost to procure new and repowered eligible renewable energy resources. Renewable energy resources eligible to satisfy RPS procurement requirements may also qualify for funding under other elements of the Renewable Energy Program.

In addition to the above, the Santa Barbara County Comprehensive Plan contains an Energy Element (Element) which was adopted by the County of Santa Barbara Board of Supervisors on December 13, 1994, and amended December 1, 1998 (County Santa Barbara, 1994a). The Element includes, as a separate document, an Implementation Plan and several supporting technical appendices which were also adopted on December 13, 1994. The Element represents the long range planning guide for encouraging energy efficiencies and alternative energies in Santa Barbara County. Although the Element encourages the use of alternative energy to diversify the County’s energy base, it remains neutral with respect to specific alternative energy sources and technologies, and does not encourage alternative energy as a substitute for sound, economical practices of energy conservation (County of Santa Barbara, 1994b).

The Element contains eight goals that collectively provide for an “economically and environmentally sound future through sustainable development and the efficient use of energy” (County of Santa Barbara, 1994b). Each goal is focused on increased energy efficiencies within the context of a particular application, from reduction of the use of non-renewable energy resources to implementation of incentive programs to promote energy efficiency. Goal 5, Alternative Energy, encourages the use of alternative energy for environmental and economic benefits and accompanying Policy 5.3, Cogeneration, states that the “County shall encourage installation and use of cogenerating systems where they are cost-effective and appropriate.”

Please refer to Section 5.8.2.2, Air Quality, Regulatory Setting, for a discussion of regulatory requirements associated with Assembly Bill 32 for greenhouse gas emissions.

5.16.3 Significance Criteria

Santa Barbara County Environmental Thresholds and Guidelines Manual (as revised through July 2003) does not include significance criteria for energy resources as a separate issue area. ~~Title 14 of California Code of Regulations §15387 (also contained in CEQA Handbook, Statutes and Guidelines, Appendix I – Environmental Checklist Form) contains checklist questions for determination of environmental impacts. Checklist questions were analyzed in the following areas: Energy and Mineral Resources an Utilities and Service Systems (namely, Power and Natural Gas Utilities). Based on these questions, a~~ CEQA Guidelines Sections 15064 and 15382, and Appendices F and G provide guidance for determination of environmental impacts. A comprehensive set of criteria was developed based on the referenced CEQA information, against which the significance of the proposed project's impacts to energy resources can be judged. The proposed project would be considered to have a significant impact on energy resources if any of the circumstances listed below occur:

- The project conflicts with the adopted California energy conservation plans.
- The project would use non-renewable energy resources in a wasteful and inefficient manner.
- The project would result in a substantial increase in demand upon existing power or natural gas utilities.
- The project would result in a need for new systems or supplies or substantial alterations to the existing power and natural gas utilities.

5.16.4 Impact Analysis for the Proposed Project

In general, a project would have impacts in the energy and mineral resources issue area if it involves a change in consumption or generation of energy. Consumption of energy resources needs to be evaluated against production or generation of the same energy resources. Energy and mineral resources impacts of the proposed project have been analyzed and are discussed below, including an assessment of energy saving alternatives (see Impact Energy.2).

Impact #	Impact Description	Phase	Residual Impact
Energy.1	Impacts to energy resources due to electricity and fuel consumption during construction phase.	*Construction*	*Class III*

Construction of the Tranquillon Ridge Project would consume energy in the form of diesel and gasoline. Minimal electricity usage due to construction activities is expected.

Diesel usage would increase during construction at Platform Irene due to additional supply boat trips to transport construction materials to the platform. Diesel would also be consumed due to deliveries of materials and transportation of construction equipment by diesel trucks to the onshore construction sites (i.e., Valve Site #2), the new transformer and power line sites, and the LOGP. Construction equipment that would be used for installation of the new equipment or fixtures at the construction sites would consume diesel fuel. ~~Gasoline~~Jet fuel would be used due to additional helicopter trips to support drilling ~~construction~~ activities at Platform Irene. Gasoline would also be consumed due to construction worker commuting.

Construction would be short term and is not expected to require unusually high amounts of energy resources, or result in the use of energy in a wasteful or inefficient manner. Also, the energy used by the construction activities would not conflict with energy conservation plans. Therefore, the construction impacts on energy are considered to be adverse but not significant.

Mitigation Measures

No mitigation measures have been identified.

Residual Impact

The residual impacts for energy and mineral resources due to the consumption of electricity and fuel during construction are considered *adverse but not significant (Class III)*.

Impact #	Impact Description	Phase	Residual Impact
Energy.2	Impacts due to increased electricity and natural gas consumption by additional or upgraded equipment and due to increased operation of the existing equipment.	*New Operations Increased Throughput Extension of Life*	*Class III*

The proposed Tranquillon Ridge Project would increase demand for electricity. The current power usage for Platform Irene and the LO~~PG~~GP is about 6.1 MW (4.85 MW plus 1.25 MW, see Section 5.16.1.2). Power usage is expected to increase by 8.5 MW to almost 14.6 MW due to increased throughput and new equipment. Currently only one heater treater is being used at LOGP. With the proposed project it will be necessary to operate two additional heater treaters. Although they have capacity to burn more, natural gas consumption will likely increase by about 21,000 cfh (100 percent of current consumption per ~~Section 5.1.16.4~~ Table 2.3) to run these two additional heater treaters.

The new pumps at Valve Site #2 would consume electricity in the amount of approximately 1.9 MW or 44.7 MWh/day, when only two pumps are operating and the third is on standby, as proposed. At the LOGP, the existing equipment is expected to consume approximately 30 percent more electricity due to increased throughput and subsequent higher loads. The total potential electricity usage is shown in Table 5.16.3.

Table 5.16.3 Expected Electricity Usage Due to the Proposed Tranquillon Ridge Project

Project Location	Current Facility Usage, MWh/day	Due to Increase in Operations, MWh/day	Due to New Equipment, MWh/day	Total Facility Increase, MWh/day, (%)	Usage with Project, MWh/day
Platform Irene	116.3	5.3	130.6	135.9 (116.9%)	252.2
LOGP, Valve Site #2	30.2	8.1	60	68.1 (225.5%)	98.3
TOTAL	146.5	13.4	190.6	204.0 (139.2%)	350.5
Totals may not add up due to rounding.					

Three alternative sources of energy have been evaluated for their potential to offset the required increase in electricity and natural gas consumption, and for feasibility of application to the proposed project. These methods are photovoltaic cells, wind turbines, and combined cycle gas turbine (cogeneration). Each of these methods is discussed below.

Photovoltaic Cells

Photovoltaic cells convert sunlight into electrical energy. Most solar cells are made of silicon although other materials are sometimes used; however, the process of how these other materials convert sunlight to electricity is the same as for the silicon cell. Silicon has the properties of metal and an insulator. Atoms in a metal have loosely bound electrons that flow easily when a voltage or electrical pressure is applied. Atoms in insulators have tightly bound electrons that cannot flow until a strong voltage is applied.

At the atomic level, light is composed of energy particles called photons that flow from the sun and strike a solar cell. As each photon strikes a silicon atom, it ionizes the atom by transferring its energy to an electron, allowing the electron to break free of the atom. The energy of the photon has been converted into electron energy called electric current. This electric current flows through the cell by an electrostatic field and ends up with a one–half volt potential. This is the voltage of a solar cell. Solar cells are wired in series of 36 solar cells which results in a voltage of 18 volts of direct current. More solar modules can be connected in series to provide higher voltage and make a solar array suitable for the planned task.

The production of 4 kW of electricity requires an array area of 377 square feet of photovoltaic cells. To supply the 8.5 MW of incremental electrical power would require 18.4 acres of photovoltaic cells. This does not include the additional generating capacity and corresponding land area that would have to be provided to take into account power loss for converting the direct current (DC) to alternating current (AC). There is no power generated at night and during cloudy days, so power would only be generated when there is sufficient solar radiation. Power generation would also vary during the day as the angle of the sun changes.

The information in Table 5.16.4 was developed using data from the DOE Energy Information Agency Report on Energy Consumption and Power Generation for the period January to May 2006 and focused on generation units located in California using natural gas as the fuel.

When generating 8.5 MW, the solar panels would eliminate about 90,200 cfh (8.5 MW x 10.614 Mcf/MW) of natural gas that would be consumed by the local electrical utility to generate the same amount of power.

Table 5.16.4 Power Plant Energy Usage for Electricity Production Using Natural Gas in California, January to May 2006

Facility ID	Gas Usage, Mcf	MW of Power Produced	Mcf Gas per MW Power
259	496,581	51,183	9.702
260a	7,780,873	657,084	11.842
260b	2,365,092	231,240	10.227
271	1,478,860	136,838	10.800
273b	2,784,882	264,001	10.500
Average			10.614

This alternative has some major drawbacks for application to the proposed project. First, the power production is highly variable depending on daily weather conditions as well as the time of day and time of year. Solar energy would not always provide a dependable source of power most of the time and would require drawing power from the grid when power is not being generated. Second, the land requirements for installation of the panels are large. These two factors make this option infeasible for the Tranquillon Ridge Project.

Wind Power

The California wind map from the National Renewable Energy Laboratory (NREL), Figure 5.16-1, shows that the coast of Santa Barbara County has wind resources that are classified as Good to Excellent. “Good” winds have a speed of 15.7 to 16.8 mph and “excellent” winds are 16.8 to

17.9 mph. These wind speeds are based on historical weather data and are measured at 164 feet above grade.

For this analysis, a GE Power 1.5 MW unit was selected. The turbine has a hub height of 177 to 328 feet above grade. The cut-in speed (i.e., minimum air speed to start the model turbine turning) is 7.8 to 8.9 mph. The rated wind speed for maximum power output is 29.1 to 31.3 mph.

The power curve for this model wind turbine from GE Power literature is shown in Figure 5.16-2. At the lower range of the "Good" wind speed (15.7 mph or 7.0 meters per second), the turbine's output would be 500 kW or 33 percent of its rated capacity. This output takes into account the intermittent nature of wind power generation. At the upper range of the "Excellent" wind speed (17.9 mph or 8.0 meters per second), the power output would be 600 kW or 40 percent of rated capacity. Therefore, assuming that each wind turbine generates 500 kW of power on average when it is running, 18 GE Power 1.5 MW units would be needed to generate 8.5 MW. ~~However, wind turbines only generate electricity 65-80 percent of the time (Wind Energy Facts and Myths, August 2006).~~ When generating power at 8.5 MW, the wind turbines would displace about 90,200 cfh of natural gas that would be required to be consumed by the local electrical utility to produce the same amount of power. However, the LOGP would still need to be tied into the grid to compensate for the intermittent wind power generation and minimize power supply interruptions.

In Santa Barbara County, the Lompoc Wind Energy Project has been proposed. This project would be located ~~north of~~ near southern Vandenberg Air Force Base and would generate 80 to 120 MW of electricity. Sixty to 80 wind turbines would be located on approximately 3,000 acres of land. The spacing of these turbines is from 37.5 to 50 acres per turbine. At this spacing, supplying the additional electrical load to the LOGP facility would require an area about 675 to 900 acres in size, assuming similar wind regime and terrain as for the Lompoc Wind Energy Project site. This area requirement would make~~s~~ this option infeasible for the Tranquillon Ridge Project. Further, this alternative also has some other major drawbacks. First, the power production is variable depending on daily wind conditions and would not provide a dependable source of power since the units would only be operational between 65 to 80 percent of the time and would need to draw power from the grid during those down periods. Second, the potential environmental impacts (e.g., wildlife and aesthetics) would be likely more severe if wind power was included as part of the proposed project. Third, confirming the feasibility of a site to produce wind power is a lengthy process, requiring several years of meteorological data collection and analysis. Fourth, although other areas within the County with potential for wind energy development exist, many of them have major constraints or impediments to development. Examples include federally controlled lands on Vandenberg AFB and in the Los Padres National Forest, and areas within the County's coastal zone, where wind energy development projects currently are not allowed.

Cogeneration Power

This option involves the use of a gas turbine to drive an electric generator, which will use natural gas for fuel and then recover the heat from the exhaust gas. This heat is then used to heat the emulsion in the heater treaters. This option is only economical if the combustion turbine waste heat is fully utilized, so the combustion turbine would need to provide between 16 to 32 million

BTU/hr of heat ~~the limit would be the entire heat load of the three heater treaters or about 31,000 cfh of natural gas~~.

In this case, a Solar Centaur 40 unit has been used as an example. This unit will produce 3.5 MW of electricity. The major characteristics of the unit are shown in Table 5.16.5.

Table 5.16.5 Typical Small Gas Turbine Characteristics

Solar Centaur 40	Capacity
Electrical Capacity, MW	3.5
Fuel Requirement, Mcfh Gas	41
Turbine Exhaust Temperature, °F	835
Exhaust Mass flow, lbs/hr	149,600

Source: Solar Centaur 40 literature.

For heat recovery to supply the needs of the heater treaters, a heat exchanger using Therminol as the heat transfer fluid would be installed in the turbine exhaust flow in place of the usual steam generation system. Figure 5.16-3 is a simple flow diagram for the heat recovery process.

With the system as shown in Figure 5.16-3, it is possible to recover 22 million BTU/hr of heat from the exhaust gases which would result in a decrease in natural gas usage of about 26,000 cfh. This would completely offset the 21,000 cfh of additional gas use of the proposed project, plus about 5,000 cfh of existing natural gas consumption in the heater treaters.

In addition to the heat recovered from the exhaust gases, the turbine would generate 3.5 MW of electrical power. The incremental increase needed for the project is 8.5 MW. The additional power output can be utilized on the site, resulting in a reduction in demand for power from the grid by LOGP of 3.5 MW.

The total natural gas saving using a gas turbine with heat recovery is 26,000 cfh from the heater treaters and 37,000 cfh for power generation on site or a gross saving of about 63,000 cfh. Since the Centaur 40 Turbine requires 41,000 cfh for operation, the net natural gas saving would be 22,000 cfh when the cogeneration unit is running.

As this unit has a small foot print of 262 square feet, it could be accommodated on the LOGP site. To address operability/reliability considerations, natural gas could be used as the heat source in the heater treaters when maintenance of the cogeneration unit is required. The typical availability of a gas turbine cogeneration unit is about 95 percent, making it a dependable alternative.

Mitigation Measures

In accordance with County policies, in order to mitigate the consumption of electricity and natural gas during operations to the maximum extent feasible, the following mitigation measure would apply:

Energy-1 PXP ~~The applicant~~ shall prepare energy efficiency Study to be reviewed and approved by SBC and then implemented by PXP. The Study shall address future energy consumption by function (i.e., heater treaters, etc.) and assess available options to optimize energy efficiency utilizing existing equipment and operations.

The Study shall also include a cost-benefit analysis for cogeneration~~.~~ The Study shall be submitted to SBC for review and approval prior to land use clearance for the Tranquillon Ridge Project modifications at the LOGP facility. Energy efficiency measures deemed feasible by the County shall be incorporated into the LOGP modifications.

Residual Impact

The consumption of electricity and natural gas during operation of the proposed project is considered to be an *adverse but not significant (Class III) impact*.

5.16.5 Impact Analysis for the Alternatives

Detailed descriptions of the various alternatives have been provided in Chapter 3. This section provides a discussion of the energy/mineral resource impacts of the various alternatives.

5.16.5.1 No Project Alternative

Scenarios 2 and 3. As discussed in Section 3.2, under the No Project Alternative Scenarios 2 and 3, production of the federal portion of the Tranquillon Ridge field would and would not occur, respectively. However, no extension of life of Point Pedernales facilities (Platform Irene, pipelines, and LOGP) is assumed under either scenario.

Impact Energy.1 - Construction Energy Use: This impact would be eliminated, since there would be no energy or mineral resources consumed due to construction.

Impact Energy.2 - Operational Electrical and Natural Gas Energy Use: This impact would be substantially reduced since no new facilities would be built and therefore there would be no new equipment to operate. Further, as presented in Section 3.2, it is unlikely that ~~no~~ additional wells would be drilled from Platform Irene into the Federal portion of the Tranquillon Ridge Field.

Options for Meeting California Fuel Demand. The relative energy and mineral resources impacts associated with the various options for meeting California fuel demand are summarized in Table 5.16.6.

Table 5.16.6 No Project Alternative Comparison to Options for Meeting California Fuel Demand, Energy and Mineral Resources

Source of Energy		Impacts
Other Conventional Oil & Gas		
	Domestic onshore crude oil and gas	Could increase energy consumption due to longer transportation routes. Likely to displace, rather than eliminate, mineral resource impacts. Development of new production could have increased energy and mineral resource impacts.
	Increased marine tanker imports of crude oil	Would increase energy consumption due to longer transportation routes. Likely to displace, rather than eliminate, mineral resource impacts.
	Increased gasoline imports[1]	Would increase energy consumption due to longer transportation routes. Likely to displace, rather than eliminate, mineral resource impacts.
	Increased natural gas imports (LNG)	Would increase energy consumption due to longer

Table 5.16.6 No Project Alternative Comparison to Options for Meeting California Fuel Demand, Energy and Mineral Resources

Source of Energy		Impacts
		transportation routes. Likely to displace, rather than eliminate, mineral resource impacts. Development of new offshore LNG facilities could have increased energy and mineral resource impacts.
Alternatives to Oil and Gas		
	Fuel Demand Reduction: increased fuel efficiencies, conservation, electrification[2]	
	Alternative transportation modes	Proposed project impacts would be eliminated.
	Implementation of regulatory measures	Proposed project impacts would be eliminated.
	Coal, Nuclear, Hydroelectric	Proposed project impacts would be eliminated. All power facilities would produce and consume energy. Coal and nuclear would consume different nonrenewable mineral resources; whereas, hydroelectric would not consume nonrenewables.
	Alternative Transportation Fuels	
	Ethanol/Biodiesel[3]	Proposed project impacts could be reduced. Ethanol/biodiesel facility construction would consume energy. Facility operation would produce and consume energy.
	Hydrogen[2]	Proposed project impacts would be eliminated. Hydrogen delivery infrastructure construction would consume energy.
	Other Energy Resources[2]	
	Solar[2,4]	Solar facility construction would consume energy. Facility operation would produce energy.
	Wind[2,4]	Wind facility construction would consume energy. Facility operation would produce energy.
	Wave[2,4]	Wave facility construction would consume energy. Facility operation would produce energy.

Footnotes:
1. Pipeline and tanker truck import from out-of-State assumed.
2. Assumes that Tranquillon Ridge production would not be replaced with other petroleum-based energy supply.
3. Assumes ethanol and biodiesel used as blends only and therefore would reduce, but not eliminate Tranquillon Ridge or equivalent production.
4. Assumes, large centralized facilities.

5.16.5.2 VAFB Onshore Alternative

The VAFB Onshore Alternative would require the construction of a new drilling/production facility, 10 miles of emulsion and gas pipelines, and 6 miles of transmission line (alternatively a cogeneration facility could be constructed as part of the processing facility as discussed in Section 3.3.3). In addition, pipeline tie-in facilities and two electrical substations would be required. The energy consumption associated with this alternative is discussed below.

Impact Energy.1 - Construction Energy Use: The construction energy use would be substantially higher than for the proposed project due to the need to construct new onshore drilling and production facilities, pipelines, transmission lines, pipeline tie-in facilities, and electrical substations. However, diesel usage for supply boats would be less than the proposed project since construction at Platform Irene would not be necessary, eliminating the need for additional supply boat trips to transport construction materials to the platform. ~~Gasoline~~ Jet fuel use due to additional helicopter trips to support the proposed project construction activities at Platform Irene would be eliminated as well. Gasoline and diesel would be consumed due to the alternative construction workers commute and construction equipment operation. However, the construction would be short-term and is not expected to require unusually high amounts of energy resources, or result in the use of energy in a wasteful or inefficient manner. Also, the energy used by the alternative construction activities would not conflict with energy conservation plans. Therefore, the construction impacts on energy are considered to be *adverse but not significant (Class III)*.

Impact Energy.2 - Operational Electrical and Natural Gas Energy Use: The electrical energy use would be about the same as that for the proposed project. Total electrical consumption would remain at approximately 0.02 percent of the State demand; however, if a cogeneration facility was constructed as part of the drilling/production facility, this electrical demand would be minimized. Therefore, the impact is considered *adverse but not significant (Class III)*.

5.16.5.3 Casmalia East Oil Field Processing Location

Impact Energy.1 - Construction Energy Use: The construction energy use would be substantially higher than for the proposed project due to the need to construct new pipelines and a processing facility. Construction energy use would also increase due to the need to decommission and remove the majority of the LOGP facility. However, the construction would be short-term and is not expected to require unusually high amounts of energy resources, or result in the use of energy in a wasteful or inefficient manner. Also, the energy used by the construction activities would not conflict with energy conservation plans. Therefore, the construction impacts on energy are considered to be *adverse but not significant (Class III)*.

Impact Energy.2 - Operational Electrical and Natural Gas Energy Use: The electrical energy use would be greater than that for the proposed project because the oil and gas production would need to be transported for a longer distance for processing (e.g., from the constructed LOGP compressor/pump station to the Casmalia Site). However, this is not expected to substantially increase electrical consumption. Most of the onshore electrical demand would shift from the LOGP to the new Casmalia site. The total electrical consumption would remain at approximately 0.02 percent of the State demand; however, if a cogeneration facility was constructed as part of the ~~drilling/production~~ processing facility, this electrical demand would be minimized. Therefore, the impact is considered *adverse but not significant (Class III)*.

5.16.5.4 Alternative Power Line Routes to Valve Site #2

Impact Energy.2 would be the same as for the proposed project.

Impact Energy.1 - Construction Energy Use: Construction of the power lines using routes other than the proposed project could slightly differ in consumption of fuels. Undergrounding the power line along Terra Road or across Santa Ynez River would increase energy use only marginally. The proposed alternative power line routes are approximately the same in length. Therefore, Impact Energy.1 would stay the same as for the proposed project, adverse but *not significant (Class III).*

5.16.5.5 Replacement of Oil Emulsion Pipeline from Platform Irene to LOGP

Impact Energy.2 would be the same as for the proposed project.

Impact Energy.1 - Construction Energy Use: The construction energy use would be greater than for the proposed project due to the need to construct the new pipeline. However, the construction would be short-term and is not expected to require unusually high amounts of energy resources, or result in the use of energy in a wasteful or inefficient manner. Therefore, the construction impacts on energy are considered to be *adverse but not significant (Class III)*.

5.16.5.6 Alternative Drill Muds and Cuttings Disposal

Impacts Energy.1 and Energy.2 would be the same for the two drilling mud disposal alternatives as for the proposed project.

5.16.6 Cumulative Impacts

Cumulative projects that could impact the current analysis include the potential offshore oil and gas projects discussed in Sections 4.2 and 4.3, and the onshore development projects outlined in Section 4.4. The cumulative impacts of these potential off- and onshore development projects are discussed separately below.

5.16.6.1 Oil and Gas Projects

There are several oil and gas development projects being proposed in the vicinity of the proposed project. Some of these potential development projects would use existing platforms, pipelines and onshore facilities, while others (the Santa Maria, Lion Rock, Point Sal and Purisima Point Units and Lease OCS-P 0409) would require new off- and onshore facilities.

The cumulative offshore oil and gas projects that may potentially occur in the proposed project area would be expected to utilize efficient technologies for drilling and production, and some of them may use existing facilities to develop new oil and gas fields. Use of existing facilities would substantially reduce the overall energy consumption per barrel of oil produced by avoiding construction-related energy use and taking advantage of underutilized transportation and processing capacity. Therefore, the cumulative impact on energy resources, including the incremental contribution of the proposed project, would not be considered significant.

5.16.6.2 Onshore Projects

Potential onshore development projects in ~~northern Santa Barbara County~~ the proposed project area are discussed in Section 4.4 and summarized in Table 4.2. The majority of these potential development projects are residential and commercial in nature~~, although~~; however, several other types of development and redevelopment projects are either in review or have been approved for construction and one proposed project, the proposed Lompoc Wind Energy Project, would generate up to 80 to 120 megawatts of commercially available power, if approved.

As referenced in Section 5.14.6.2, it has been projected that the City of Lompoc's population may increase by 21,000 by the year 2030. Consequently, the potential onshore development projects listed in Section 4.4, including future residential developments, would be expected to require more energy as a natural result of population growth. While significant growth is expected to occur in the proposed project area, this growth is not expected to affect available power supply or distribution. Therefore, the cumulative energy impacts of the potential onshore development projects, including the proposed project's incremental contribution to them, would not be considered significant.

5.16.7 Mitigation Monitoring Plan

Mitigation Measure	Mitigation Requirements and Timing	Method of Verification	Timing of Verification	Party Responsible For Verification
Energy-1	PXP ~~The applicant~~ shall prepare energy efficiency Study to be reviewed and approved by SBC and then implemented by PXP. The Study shall address future energy consumption by function (i.e., heater treaters, etc.) and assess available options to optimize energy efficiency utilizing existing equipment and operations. The Study shall also include a cost-benefit analysis for cogeneration. The Study shall be submitted to SBC for review and approval prior to land use clearance for the Tranquillon Ridge Project modifications at the LOGP facility. Energy efficiency measures deemed feasible by the County shall be incorporated into the LOGP modifications.	Plan review and approval. Inspection of facility modifications and operations.	Plan review prior to land use clearance. Facility & operation modifications during operations.	SBC

5.16.8 References

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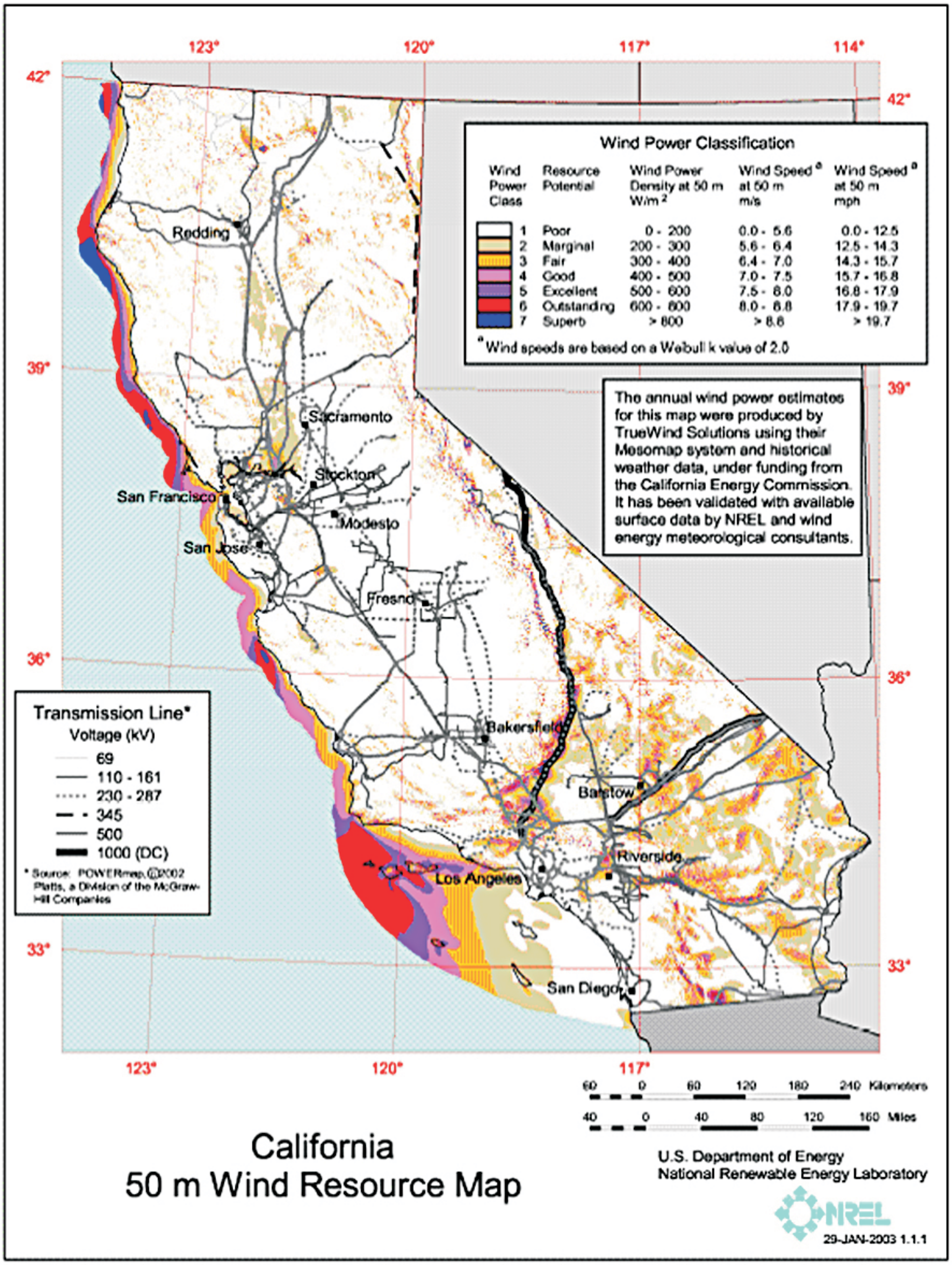

Source: NREL, 2003.

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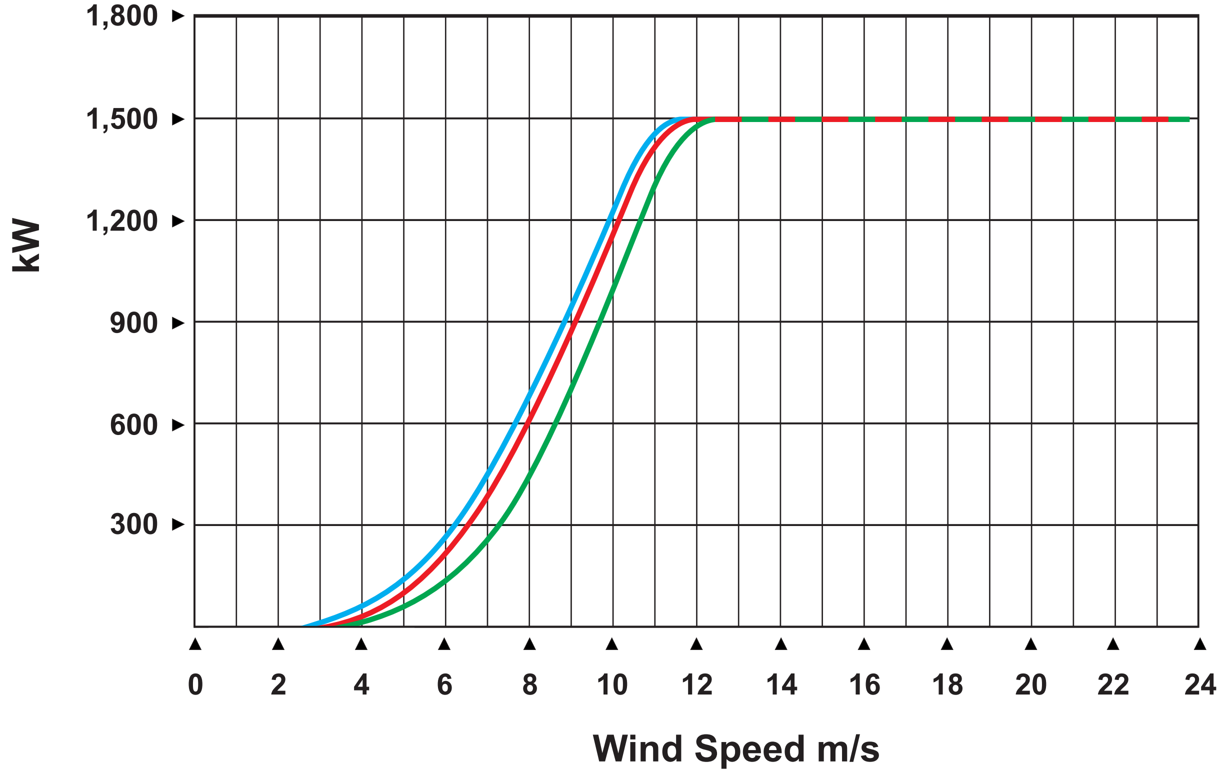
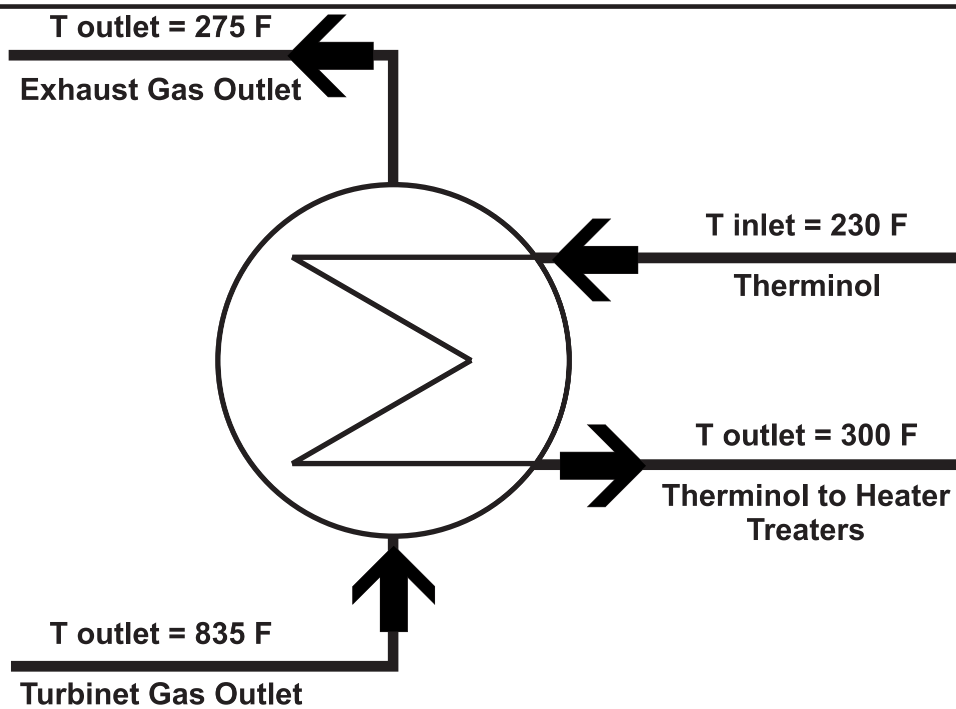
Figures 5.16-1
California 50 m Wind Resources Map (NREL, DOE)



Source: GE Power literature.

Figures 5.16-2
Power Curve for the GE 1.5 MW Series of Wind Turbines



Source: GE Power literature.

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Figures 5.16-3
Flow Diagram for Heat Recovery from Exhaust Gases for use in Heater

6.0 ENVIRONMENTALLY SUPERIOR ALTERNATIVE

This section summarizes the environmental advantages and disadvantages associated with the proposed project and the alternatives evaluated in this Environmental Impact Report (EIR). This comparison is based on the assessment of environmental impacts of the proposed project and each alternative, as identified in Sections 5.1 through 5.16. Section 3.0 introduces and describes the alternatives considered in this EIR and those alternatives eliminated from further consideration. The Tranquillon Ridge Project alternatives that were evaluated in Section 5.0 included the following:

- No Project Alternative,
- Vandenberg Air Force Base (VAFB) Onshore Alternative,
- New Oil and Gas Processing Facility at Casmalia East Site,
- New Oil Pipeline from Platform Irene to the Lompoc Oil and Gas Plant (LOGP),
- Alternative Power Line Routes to Valve Site #2, and
- Muds and Cuttings Handling – Injection and Onshore Disposal.

This section is organized as follows:

Section 6.1 describes the methodology used for comparing alternatives to the proposed project. Section 6.2 compares the No Project Alternative to the proposed project. Section 6.3 compares the other alternatives to the proposed project and Section 6.4 discusses the identification of an environmentally superior alternative.

6.1 Comparison Methodology

The California Environmental Quality Act (CEQA) does not provide specific direction regarding the methodology of comparing alternatives. Each project must be evaluated for the issues and impacts that are most important; this will vary depending on the project type and the environmental setting. Issue areas that are generally given more weight in comparing alternatives are those with long-term impacts (e.g., visual impacts or permanent loss of habitat). Impacts that are short-term (e.g., construction-related impacts) or those that are easily mitigable to less than significant levels are generally considered to be less important.

This comparison is designed to satisfy the requirements of CEQA Guidelines Section 15126.6(d), Evaluation of Alternatives, which states that:

> *"The EIR shall include sufficient information about each alternative to allow meaningful evaluation, analysis, and comparison with the proposed project. A*

> *matrix displaying the major characteristics and significant environmental effects of each alternative may be used to summarize the comparison. If an alternative would cause one or more significant effects in addition to those that would be caused by the project as proposed, the significant effects of the alternative shall be discussed, but in less detail than the significant effects of the project as proposed."*

In accordance with CEQA Guidelines Section 15126.6(d) as presented above, this EIR provides sufficient information about each alternative to allow meaningful evaluation, analysis, and comparison with the proposed project. It should be noted that assumptions made regarding the alternatives' descriptions could differ from actual proposals and the analyses are not presented to a project level of detail. Different alternative project configurations and a project-level environmental analysis could result in different conclusions from those presented herein.

If the environmentally superior alternative is the No Project Alternative, CEQA requires identification of an environmentally superior alternative from among the other alternatives [CEQA Guidelines Section 15126.6(e)(2)].

The following methodology was used to compare alternatives in this EIR:

- **Step 1: Identification of Alternatives**. An alternatives screening process (described in Section 3) was used to identify a number of alternatives to the proposed project. That screening analysis resulted in one project~~ level~~ alternative (VAFB Onshore Alternative), one oil and gas processing plant alternative (Casmalia Alternative), one pipeline replacement alternative (Emulsion Pipeline Replacement Alternative), three alternative power line routing alternatives, and two alternatives for drilling muds and cuttings disposal. The No Project Alternative was also identified. No other feasible alternatives meeting most of the project objectives were identified that would lessen or alleviate significant impacts.
- **Step 2: Determination of Environmental Impacts**. The environmental impacts of the proposed project and alternatives were identified in Sections 5.1 through 5.16.
- **Step 3: Comparison of Proposed Project with Alternatives**. Sections 6.2 through 6.3 summarize the significant and unmitigable (Class I) impacts that could occur with the proposed project and the alternatives and Section 6.4 discusses the relative importance of each issue area and whether the alternatives or the proposed project are environmentally preferred.

6.2 Comparison of the Proposed Project to the No Project Alternative

~~With the No Project Alternative, no~~ As discussed in Section 3.2, no extension of life of Point Pedernales facilities (Platform Irene, pipelines, and LOGP) is assumed under either No Project Alternative Scenarios 2 or 3. Scenario 2 considers further development of the Federal portion of the Tranquillon Ridge Field; however, it is unlikely that new wells would be drilled. ~~into the Tranquillon Ridge Field to develop~~ Further, under Scenario 3, no wells would be drilled into the Federal portion of the field. ~~Further~~ Finally, no development wells would be drilled from Platform Irene into the State Tidelands portion of the Tranquillon Ridge Field under the No Project Alternative, whereas under the proposed project, 22 to 30 wells would be drilled. Peak production for the No Project Alternative Scenarios 2 and 3 is estimated to be about 7,000 bpd, which is close to the 2005 average production from Platform Irene. Moreover, production from the Tranquillon Ridge Field would end within the lifetime of the Point Pedernales Field (estimated 2017). The No Project Alternative Scenarios 2 and 3 would have the same impacts as existing operations, since Platform Irene would continue producing from the Point Pedernales Field, and the existing pipelines and Lompoc Oil and Gas Plant (LOGP) would be used to transport and process, respectively, the produced oil emulsion and gas. Under the No Project Alternative, ~~would eliminate~~the following Class I impacts ~~associated with the proposed project~~ would not continue as they would with the proposed project through 2037, but instead would be eliminated at the time the Point Pedernales Project is decommissioned (approximately 2017):

- ***Impact Risk.3*:** Increased risk to public due to additional NGL/LPG transport.
- ***Impact TB.6*:** Oil spill impact to upland, riparian, and aquatic habitats, and wildlife.
- ***Impact TB.7:*** Oil spill impact to state-or federally-listed plant species.
- ***Impact TB.8:*** Oil spill impact to state-or federally-listed wildlife species.
- ***Impact OWR.2***: Oil spill impacts to surface and ground waters.
- ***Impact MB.1***: Oil spill impacts to marine organisms.
- ***Impact MWQ.1***: Oil spill impacts to marine water quality.
- ***Impact CRF/KH.2***: Oil spill impacts to fisheries.
- ***Impact T.4:*** Oil spill impacts to transportation corridors.
- ***Impact CR.3***: Oil spill clean up impacts to cultural resources.
- ***Impact Visual.1***: Long term presence of Platform Irene & Surf substation
- ***Impact Visual 4***: Long term presence of LOGP nighttime glare.
- ***Impact Rec.1***: Oil spill impacts to recreational resources.

The No Project Alternative Scenarios 2 and 3 would eliminate the significant impacts identified for the proposed project due to oil spills because of increased throughput and extension of life of the platform and oil pipeline for terrestrial biology, onshore water resources, marine water quality, marine biology, commercial and recreational fishing, cultural resources, and recreation. All of these significant oil spill impacts were identified for the current operations as part of the 1985 Point Pedernales EIR/EIS. This alternative would also reduce the duration of the significant visual impacts due to the nighttime glare associated with the LOGP, and the visual impacts associated with Platform Irene and the Surf substation that would result from extending the life of the facilities; under the No Project Alternative these facilities would be removed in approximately 10 years instead of 30 years. In addition, this alternative would reduce the duration over which the public would be exposed to an existing significant public health risk associated with truck transportation of natural gas liquids/liquefied petroleum gas (NGL/LPG) from the LOGP; 30 years for the proposed project and 10 years for the No Project Alternative.

It should be noted that there is a possibility the Tranquillon Ridge Field could be developed by others from an onshore location, should the proposed project not be implemented. The discussions of the potential effects of the No Project Alternative do not address this situation; rather, the potential environmental impacts that could result from such development are considered under the VAFB Onshore Alternative, but only at a conceptual level. The conceptual VAFB Onshore Alternative evaluated in this EIR was developed based on certain assumptions regarding potential project components, as described in Section 3.0, and may not reflect all details of an actual proposal. In addition, some impacts ascribed to the VAFB Onshore Alternative herein may or may not be expected to occur for a differently configured onshore drilling and production proposal. Detailed analysis of a specific proposed onshore drilling and production project would occur through a separate environmental review process for that project.

In summary, the No Project Alternative Scenarios 2 and 3 ~~(not including Tranquillon Ridge development by others)~~ would offer significant environmental advantages over the proposed project; however, this alternative would not meet the major objective of the project, which is full development of the Tranquillon Ridge oil and gas reserves to meet demand primarily for fuels. ~~This alternative~~ Scenario 2 is estimated to extract a small percentage of the recoverable oil and gas reserves when compared to the proposed project since only one well, currently located in Federal waters, would be used to produce the Tranquillon Ridge Field. Section 3.0 provides a discussion of the basis for the amount of recoverable reserves for the No Project Alternative.

As previously stated, if the environmentally superior alternative is the No Project Alternative, CEQA requires identification of an environmentally superior alternative from among the other alternatives. Section 6.3 provides a comparison of the proposed project with the other alternatives carried forward for consideration and analyzed in Sections 5.1 through 5.16. Section 6.4 summarizes the comparison of the proposed project to the various alternatives and discusses the environmentally preferred options.

6.3 Comparison of Proposed Project to Other Alternatives

The comparison begins with a summary of the significant impacts that cannot be mitigated to insignificance (Class I). Highlighting these areas of significant impacts identifies which alternative would be capable of eliminating significant adverse environmental effects of the proposed project. This helps identify the environmentally superior alternative while considering all issue areas equally. Tables 6.1a through 6.1c show a summary of significant unmitigable (Class I) impacts of the proposed project and each alternative, and a determination of whether the proposed project or an alternative is considered to be environmentally "preferred" for each Class I impact. In most cases, the classification of "preferred" for either the proposed project or alternative for each impact is an assessment of severity of the Class I impact; the Class I impact occurs for both the proposed project and alternative, but the "preferred" option would minimize the effects of the Class I impact. In a few cases, the impact classification of either the proposed project or alternative is Class II (significant but mitigable to insignificance) or III (adverse but not significant); therefore, the Class II or III impacts would be much less severe than a Class I impact. The Class II and Class III impacts identified for the proposed project and the alternatives are also compared in ~~Tables 6.1a through 6.1c~~ the Executive Summary tables.

6.3.1 VAFB Onshore Alternative

The Vandenberg Air Force Base (VAFB) Onshore Alternative was the only project-level alternative carried forward for analysis in this EIR. This alternative would involve the development of a new oil and gas drilling and production facility on southern VAFB. In addition, 10 miles of emulsion and gas pipelines would be constructed in a common corridor from the new drilling/production site to the existing PXP pipelines just north of the Santa Ynez River and west of 13th Street. To provide power to the drilling/production facility, a six-mile transmission line would be constructed from the existing Surf substation south to the drilling/production site. The VAFB Onshore Alternative would use the existing PXP pipelines from a tie-in point just west of

13th Street to the LOGP. In addition, the LOGP would be used to process the emulsion and gas production, the same as the proposed project. Produced water would either be treated and re-injected at the VAFB drilling/production site or sent from LOGP to Platform Irene for re-injection or ocean discharge. Over the short-term, a portion of the produced water may be re-injected into the onshore Lompoc Field.

Table 6.1a provides a comparison of the Class I impacts between the proposed project and the VAFB Onshore Alternative. Use of this alternative (assuming eventual onshore produced water disposal at the drilling/production site) would eliminate one significant impact associated with the proposed Tranquillon Ridge Project (Impact Visual.1 - long-term continued presence of Platform Irene); however, Surf substation would remain under this alternative. The presence of Surf substation within the coastal zone is also considered a Class I visual impact. Although the VAFB drilling/production site would be located in the coastal zone, given its remote location, proximity to VAFB space launch facilities, and limited public access to the area, the visual impact would not be significant *(Class III).*

Class I oil spill impacts for marine biology (Impact MB.1), marine water quality (Impact MWQ.1), and commercial/recreational fishing (Impact CRF/KH.2) would be reduced, but not eliminated with the VAFB Onshore Alternative, since there is still a small chance that an oil spill from a rupture at the new drilling/production site or along the new pipeline route could reach ocean waters, particularly if a leak should occur beneath the Santa Ynez River. In addition, the Class I oil spill impact to recreational facilities (Impact Rec.1) would be reduced, but not eliminated under the VAFB Onshore Alternative, since there is a small probability that oil could reach Surf Beach or Ocean Beach County Park as a result of a pipeline rupture along the pipeline route near these recreational areas. In addition, under the VAFB Onshore Alternative, extension of life of Platform Irene and the offshore pipelines would not occur. This would eliminate impacts associated with Platform Irene and offshore pipeline oil or produced water spills, and resultant clean up to marine environments and aquatic resources after 2017 when baseline project operations are anticipated to cease.

The VAFB Onshore Alternative could result in a number of new Class I significant impacts that would not occur with the proposed Tranquillon Ridge Project. Construction of the new drilling/production facilities and associated pipelines from the drilling/production site to the tie-in to the existing PXP pipelines could result in significant impacts to onshore biological resources (Impacts TB.9 and TB.10) and cultural resources (Impact CR.6). While rerouting of the pipeline corridor could avoid some of the identified sensitive biological and cultural resources, given the abundance and density of biological and cultural resources within southern VAFB and technical limitations to pipeline design/routing, it is unlikely that all sensitive biological and cultural resources could be avoided. If cultural resource impacts are to be mitigated through data recovery, additional impacts to biological resources could occur from excavation activities. The VAFB Onshore Alternative would also increase the likelihood of an onshore oil spill due to the 10 miles of new pipeline through sensitive resources required to connect the alternative drilling/production facility to the existing PXP pipelines. Although a new pipeline could have a slightly lower spill frequency, the reduced spill frequency would not be enough to offset the increase in the length of new pipeline in comparison to the existing PXP pipelines. After 2017, the approximate 4.5 miles of existing (baseline) PXP onshore pipelines

Table 6.1a: Comparison of <u>Class I Impacts for</u> the Proposed Project ~~to the~~ <u>and</u> VAFB Onshore Alternative

Impact #	Description of Impact	Proposed Project	VAFB Onshore Alternative
Risk.3	The proposed project could generate risks to public safety by exposing the public to transportation hazards.	The project would increase the transportation of gas liquids along roadways over the current operations. By increasing the number of trips, and therefore the risks to the public, this existing significant impact is exacerbated (more truck trips and a longer period over which truck trips would occur). **No Preference**	The severity of the impact for the VAFB Onshore Alternative would be the same as the proposed project since production levels would be the same, thereby resulting in the same number of gas liquid truck trips. **No Preference**
<u>Risk.4</u>	<u>The alternative project could generate additional risks to public safety by exposing the public to produced gas releases from the new drilling/production/processing facilities, additional length of sour gas pipeline and new metering/pigging facilities at the PXP pipeline tie-in station that could leak gas.</u>	<u>Impact Risk.4 would not occur under the proposed project.</u> **<u>Preferred</u>**	<u>Hazards associated with the VAFB Onshore Alternative could affect the Base operations of SLC-5 and/or Coast Road and Surf Road, in addition to exposing the public and Base personnel to produced gas releases.</u>
TB.6	A pipeline leak or rupture on land could result in an oil spill and subsequent degradation of upland, riparian and freshwater aquatic habitats and injury to plants and terrestrial and aquatic wildlife through direct toxicity, smothering, and entrapment as well as through resultant cleanup efforts. It is possible but ~~very~~ unlikely that an offshore oil spill would directly affect terrestrial and freshwater (or brackish/estuarine) environments, as this would only occur if oil were driven ashore above the high tide line by wind and high tides, and similarly driven upstream at an open tidal inlet during flood tide and low-outflow conditions. The oil would be highly dispersed by the time it reached the shore, leading to the deposition of relatively small amounts of oil at a given location, but over potentially large areas. Terrestrial or freshwater habitats could be indirectly affected by containment and cleanup efforts in response to an offshore oil spill that approaches the shore. The modeled trajectories for offshore oil spills (Appendix G) indicate that a large oil spill from Platform Irene or the pipeline would be most likely to reach shore between Point Arguello and Point Sal, or on the north-facing coastline of San Miguel Island. Oil could be dispersed as far north	While the risk of an oil spill and/or pipeline rupture is a risk already associated with the existing oil pipeline, the proposed increase in throughput and oil percentages would increase the combined lifetime probability of oil leaks, ruptures, blowouts, and spills from Platform Irene and the offshore portion of the emulsion pipeline from <u>5.4</u>~~10.5~~% to 22.1% over the life of the project (see Table 5.1.28). In addition, assuming that the pumps are installed at Valve Site #2, the lifetime probability for a rupture along the onshore emulsion pipeline would increase from 0.9% to 11.2% and for a leak would increase from 3.6% to 100% (see Table 5.1.24). <u>The pumps at Valve Site #2 would only be required if the existing emulsion pipeline MAOP is derated below 1000 psig. Current MAOP of the line is 1,194 psig. Also, leaks from pumps would likely be contained within the pump station and not produce onshore biological impacts.</u> Upland Habitats: Several sensitive upland habitat areas are crossed by the pipeline corridor or lie close to and down slope of the corridor. These include foredunes, coastal dune scrub, coastal sage scrub, Burton Mesa chaparral, Bishop pine forest, and	For the VAFB Onshore Alternative, the oil spill related impacts to aquatic, upland, and riparian habitats, and wildlife would be the same as the proposed project from the tie-in point to the existing PXP pipelines just west of 13th Street to the LOGP. Vegetation and wildlife resources that could be impacted along this portion of pipeline include riparian habitats near Oak Canyon and Santa Lucia Canyon; upland plant communities (Burton Mesa chaparral, Bishop pine forest); riparian reptiles and amphibians; terrestrial mammals; and invertebrates. If an onshore spill from the pipeline reaches the Santa Ynez River, riparian and aquatic habitats downstream, probably extending to the lagoon and estuarine habitat at the mouth of the river, would be affected. Oil would drift downstream at the surface and tend to strand along the shore and in wetland vegetation, potentially causing injury or mortality to, and degrading the habitats of, a wide variety of fish and wildlife species, including threatened and endangered species. Sensitive bird species that forage and rest on the beach or in the open waters of the river mouth would be affected. Shore- and waterbirds in such areas would experience toxicity

Table 6.1a: Comparison of Class I Impacts for the Proposed Project ~~to the~~ and VAFB Onshore Alternative			
Impact #	**Description of Impact**	**Proposed Project**	**VAFB Onshore Alternative**
	as Piedras Blancas or southward to other shores of the Channel Islands.	coast buckwheat populations, which may support El Segundo blue butterfly. Upland habitats that could be directly affected by an offshore spill under certain conditions (Appendix G) include sandy beaches and fringing coastal strand vegetation, as well as rocky shores, just above the high tide line. Oil could be widely dispersed, but in relatively small amounts at any particular location. Containment and cleanup activities could also affect upland habitats if off-road access is necessary to reach the affected shoreline; these impacts would be temporary. Areas with the greatest possibility of impact are the beaches and rocky shorelines from Point Arguello to Point Sal, and on the north side of San Miguel Island. Aquatic Habitats: Salt or freshwater marshes would be most sensitive because the biological activity of these communities is concentrated near the soil or water surface, where oil would be stranded. Direct effects of an offshore oil spill on freshwater or brackish-estuarine habitats at a coastal inlet could occur under an unlikely combination of winds, tides, and low-outflow conditions that would drive oil ashore and then upstream at a particular location. Oil could be widely dispersed, but in relatively small amounts at any particular location. Some oil would strand or sink, while the rest would be carried back out to sea during the outgoing tide. Direct impacts may include toxicity and smothering of wetland plants and contamination of rooting substrate. Containment and cleanup activities could also have indirect effects on aquatic habitats due to vehicle access, foot traffic, and sediment excavation. Tidal inlets to aquatic and wetland habitats within the area potentially reached by an oil spill may occur at the mouths of Pismo Creek, San Luis Obispo Creek, Arroyo Grande Creek, the Santa Maria River, Shuman Creek, San Antonio Creek, Santa Ynez River, La Honda Creek, and Jalama Creek	due to oil ingestion, and difficulties foraging, swimming, flying, and body temperature regulation due to oiled feathers. While an onshore spill would not directly affect foredunes or dune scrub habitat, resulting clean-up activities may require access through the dunes to contain the spill before reaching the ocean. This may result in disturbance to coast buckwheat and the dune community as a whole. The VAFB Onshore Alternative would include approximately 10 miles of new emulsion pipeline from the alternative drilling/production site on south VAFB to the tie-in point to the existing PXP pipelines just west of 13th Street. The VAFB Onshore Alternative would involve the risk of an onshore spill along this new pipeline corridor. Aquatic, upland, and riparian habitats, and wildlife that could be affected by a spill along this new pipeline include coastal scrub and grassland; semi-disturbed/ruderal vegetation; coast buckwheat; riparian and wetland habitat in several drainages; aquatic habitats associated with the Santa Ynez River and Bear Creek; drainage swale and wetlands near Highway 246; aquatic reptiles and amphibians; fish; wetland wildlife and bird species; terrestrial mammals, and invertebrates. In the event of a spill, containment and cleanup activities would be likely to impact sensitive dune habitats, riparian areas, and aquatic habitats. The VAFB Onshore Alternative would not involve a change in offshore operations through 2017, at which time Platform Irene and offshore pipeline operations would cease. The impacts associated with an offshore spill would be equivalent to the No Action Alternative since oil production levels and resultant spill probabilities, volumes, and clean up activities would be similar to current operations (i.e., the baseline).

Table 6.1a: Comparison of <u>Class I Impacts for</u> the Proposed Project ~~to the~~ <u>and</u> VAFB Onshore Alternative

Impact #	Description of Impact	Proposed Project	VAFB Onshore Alternative
		(Appendix G), although the probability of a spill reaching any particular site is small. The modeling results include many different event scenarios and shoreline sites within the trajectory would not be affected to the same extent or degree by an actual spill. Riparian Habitats: Riparian woodland communities may be somewhat less sensitive to an oil spill because leaves in the canopy would not be susceptible to oiling. Effects of an oil spill on plant root systems would include reductions in the availability of soil water, nutrients, and oxygen to plant root systems; and toxicity. All of these would lead to reduced growth and reproduction, and possible mortality in plants exposed to oil. Riparian habitats crossed by the pipeline corridor ~~are limited to~~<u>include</u> the Santa Ynez River corridor, drainage tributaries, and small riparian habitats in Oak Canyon and Santa Lucia Canyon. Oil could enter riparian habitats through direct entry, runoff from upland areas within the watershed (especially during storm runoff), and contamination of groundwater feeding streams. Oil could also enter drainages and riparian areas through overland flow; however, under dry conditions, overland flow of oil would be relatively slow due to the viscous nature of the crude oil. The rate of spread would slow as the oil cools and becomes more viscous. As the water fraction of the oil-water emulsion increases over the life of the project the emulsion would have different behaviors when spilled. Indirect effects of containment or cleanup efforts could occur. Since riparian habitats do not extend downstream into tidal inlets, no impacts due to offshore oil spills would occur.	A direct comparison of oil spill impacts between the Proposed Action and VAFB Onshore Alternative is problematic because of differences and inherent unpredictability in the points of origin, subsequent dispersion, and locations potentially affected. The VAFB Onshore Alternative would expose sensitive coastal habitats, especially coastal dunes and the Santa Ynez River, to the risk of severe damage from an oil spill. A spill into the river would spread downstream to the lagoon and subsequently into the ocean, depending on tidal and river flow conditions, affecting a large area of sensitive coastal wetland and open-water habitat that supports large aggregations of shore- and waterbirds. A spill along the pipeline route into Honda Creek or other coastal drainages could flow rapidly downslope due to steep terrain and either reach the ocean or accumulate where drainage is impeded (in which case the impacts would be less severe). Once in the ocean, oil from an onshore spill would be dispersed to adjacent shoreline areas. Under the Proposed Action, the geographic range of potential impacts is widely dispersed and diffuse due to seasonal and climatic variables (Appendix G). The extent of potential impact to terrestrial and freshwater resources is more widespread, but likely to be less severe at any particular location than would be the case for the VAFB Onshore Alternative. Containment and cleanup activities for spills under either alternative may also impact terrestrial vegetation and wildlife, but these impacts would diminish with time. Overall, given the proximity of sensitive terrestrial and freshwater resources to the VAFB Onshore Alternative pipeline, the severity of spill-related impacts is considered to be greater under the VAFB Onshore Alternative than under the Proposed

Table 6.1a: Comparison of Class I Impacts for the Proposed Project ~~to the~~ and VAFB Onshore Alternative

Impact #	Description of Impact	Proposed Project	VAFB Onshore Alternative
		Freshwater aquatic wildlife would be affected by an onshore spill that reaches drainages or by an offshore spill that reaches the shoreline and is driven upstream by wind and tidal action. The latter would affect only brackish-estuarine habitats. Aquatic reptiles, amphibians, fish, and waterbirds would be vulnerable to an onshore spill and clean up efforts. Impacts would include toxicity, degradation of habitat and breeding areas, and sediment excavation during containment or cleanup. Species that occur in brackish-estuarine habitats at the mouths of tidal inlets would be similarly affected if oil were dispersed upstream into these areas. Shore- and waterbirds in such areas would experience toxicity due to oil ingestion, and difficulties foraging, swimming, flying, and body temperature regulation due to oiled feathers. Terrestrial Wildlife: Oil spills and their clean-up are expected to directly affect wildlife species such as Pacific chorus frogs, western toads, a wide range of invertebrates and sensitive species such as western pond turtles and two-striped garter snakes. Depending on the size and areal extent of the spill, an unknown number of birds, reptiles and land mammals could be sickened, injured, or killed by direct contact with the oil. An offshore spill would not be expected to have substantial direct effects terrestrial wildlife, but containment or cleanup activities may have a minor effect on terrestrial species if off-road access is necessary to reach the affected shoreline. **Preferred**	Project. Impacts associated with crude oil spills would be similar to the proposed project, with an increase in severity as the length of onshore pipeline that could spill crude oil would be increased, and the addition of the thermal radiation hazard due to potential fires during the initial years of operation due to oil content of the emulsion being in the range of 88 to 90 percent. While rerouting of the pipeline corridor could avoid sensitive biological resources, given the diversity of biological resources of considerable importance within southern VAFB and technical limitations to pipeline design/routing, it is unlikely that all sensitive biological resources could be avoided.
TB.7	A spill and/or subsequent cleanup efforts may directly or indirectly cause the loss of habitat and individuals or colonies of state-or federally-listed plant species including seaside bird's beak, Surf thistle, beach spectacle pod, La Graciosa thistle,	Individuals of the following state- or federally-listed plant species may be removed or damaged by activities associated with an onshore oil spill and cleanup. These species are typically found above the beach and tidal zone and are not found close to	For the VAFB Onshore Alternative, the oil spill related impacts to state-or federally-listed plant species would be the same as the proposed project from the tie-in point to the existing PXP pipelines just west of 13th Street to the LOGP. Plant species

Table 6.1a: Comparison of <u>Class I Impacts for</u> the Proposed Project ~~to the~~ <u>and</u> VAFB Onshore Alternative

Impact #	Description of Impact	Proposed Project	VAFB Onshore Alternative
	beach layia, and possibly Pismo clarkia or degrade designated critical habitat for the Lompoc yerba santa and the La Graciosa thistle. It is possible but ~~very~~ unlikely that an offshore oil spill would directly <u>affect</u> terrestrial vegetation and listed plant species, as this would only occur if oil were driven ashore above the high tide line by wind and high tides, and similarly driven upstream at an open tidal inlet during flood tide and low-outflow conditions. The oil would be highly dispersed by the time it reached the shore, leading to the deposition of relatively small amounts of oil at a given location, but over potentially large areas. Listed plant species in coastal dunes and foredune habitats could be indirectly affected by containment and cleanup efforts in response to an offshore oil spill that approaches the shore. The modeled trajectories for offshore oil spills (Appendix G) indicate that a large oil spill from Platform Irene or the pipeline would be most likely to reach shore between Point Arguello and Point Sal, or on the north-facing coastline of San Miguel Island. Oil could be dispersed as far north as Piedras Blancas or southward to other shores of the Channel Islands.	the Santa Ynez River, thus are unlikely to be directly affected by an offshore spill, but could be affected by subsequent cleanup efforts. • La Graciosa thistle, a federally listed endangered species and state-listed threatened species, has the potential to be impacted by an onshore oil spill or cleanup activities if a spill reaches its habitat. The species it has not been observed on VAFB in recent years, but the existing pipeline overlaps a small portion of designated critical habitat south of Orcutt and north of the intersection of Highway 1 and Highway 135. La Graciosa thistle may be affected by an offshore spill or cleanup activities in coastal dunes and swales near its habitat near Oso Creek, Santa Ynez River and Santa Maria River mouths. These sites are within the trajectory range described in Appendix G, although the probability of a spill reaching any particular site is small. Oil from an offshore spill could be widely dispersed, but in relatively small amounts at any particular location. • Gaviota tarplant, a federal and state listed endangered species, have been observed along the pipeline corridor and adjacent habitat in grassland, scrub, and semi-disturbed areas on the coastal terrace. These habitats could be affected by an onshore spill. An offshore spill would not migrate onshore to areas inhabited by Gaviota tarplant. Containment and cleanup activities could affect upland habitats if off-road access is necessary to reach the affected area; these impacts would be temporary. • Surf thistle and beach spectacle pod, both state-listed as threatened, have been recorded in the foredunes crossed by the pipeline corridor. These habitats could be affected by an onshore spill. Containment or cleanup activities for an offshore spill may impact occupied coastal dune	that could be impacted along this portion of pipeline include the Gaviota tarplant and seaside bird's beak. La Graciosa thistle, Lompoc yerba santa, and Pismo clarkia are not likely to be present in or near the area affected by the VAFB Onshore Alternative due to lack of habitat. If an onshore spill occurs near the Santa Ynez River, downstream habitats may be affected. A spill of sufficient volume could be transported to the Santa Ynez River mouth. While an onshore spill would not directly affect foredunes or dune scrub habitat, resulting clean-up activities may require access through the coastal zone to contain the spill before reaching the ocean. This may result in disturbance to surf thistle and/or beach spectacle pod in the foredune habitat. In addition, the VAFB Onshore Alternative would include approximately 10 miles of new emulsion pipeline from the alternative drilling/production site on south VAFB to the tie-in point to the existing PXP pipelines just west of 13th Street. The VAFB Onshore Alternative would involve the risk of an onshore spill along this new pipeline corridor. State-or federally-listed plant species that could be affected by a spill along this new pipeline include the following: • Gaviota tarplant is likely to be present along the pipeline corridor running north from the onshore drilling site. • Beach layia, a federal and state-listed endangered species has been observed in stabilized dune system habitat to west of Surf Road. • <u>Surf thistle, state-listed as threatened, recorded in foredunes along VAFB.</u>

Table 6.1a: Comparison of <u>Class I Impacts for</u> the Proposed Project ~~to the~~ <u>and</u> VAFB Onshore Alternative

Impact #	Description of Impact	Proposed Project	VAFB Onshore Alternative
		habitat near Oso Creek, Pismo Beach, and Oceano dunes. These sites are within the trajectory range described in Appendix G, although the probability of a spill reaching any particular site is small. • Seaside bird's-beak, state-listed endangered, is known to occur within or directly adjacent to the pipeline corridor north of the Federal Penitentiary and west of the LOGP An offshore spill and any associated containment or cleanup would not be likely to impact habitats occupied by this species. • Beach layia, a federal and state-listed endangered species, is a foredune species that is not known or suspected to occur in the area that may be affected by an onshore spill. An offshore spill would not reach the coastal dune habitat preferred by this species, but containment or cleanup activities may affect occupied habitat along the coastline west of Surf Road. Lompoc yerba santa, federally-listed as endangered, is known in a few locations in the project area, all of which are upslope from the oil pipeline and not likely to be affected by impacts associated with an oil spill or cleanup activities. Pismo clarkia, federally-listed endangered and state-listed rare, is also unlikely to be affected by spills or clean up since suitable habitat for this species is upslope of the pipeline in the vicinity of Summit Pump Station. Neither of these species would be affected by an offshore spill. **Preferred**	The VAFB Onshore Alternative would not involve a change in offshore operations through 2017, at which time Platform Irene and offshore pipeline operations would cease. The impacts associated with an offshore spill would be equivalent to the No <u>Project</u> ~~Action~~ Alternative since oil production levels and resultant spill probabilities, volumes, and clean up activities would be similar to current operations (i.e., the baseline). A direct comparison of oil spill impacts between the Proposed Action and VAFB Onshore Alternative is problematic because of differences and inherent unpredictability in the points of origin, subsequent dispersion, and locations potentially affected. An onshore spill associated with the VAFB Onshore Alternative could impact known populations of listed plant species through direct or indirect effects. Under the Proposed Action, the geographic range of potential impacts is widely dispersed and diffuse due to seasonal and climatic variables (Appendix G). The extent of potential impact to terrestrial and freshwater resources is more widespread, but likely to be less severe at any particular location than would be the case for the VAFB Onshore Alternative. Containment and cleanup activities for spills under either alternative may also impact listed plant species, but these impacts would diminish with time. Overall, given the proximity of sensitive plant species to the VAFB Onshore Alternative pipeline, the severity of spill-related impacts is considered to be greater under the VAFB Onshore Alternative than under the Proposed Project.
TB.8	An oil spill and/or subsequent cleanup effort may directly or indirectly cause the loss of individual state or federally-listed wildlife species or cause the loss or degradation of sensitive species habitat. An	El Segundo blue butterfly may be adversely affected if an oil spill or subsequent clean up activities result in destruction of its host plant, coast buckwheat.	For the VAFB Onshore Alternative, the oil spill related impacts to state-or federally-listed wildlife species would be the same as the proposed project from the tie-in point to the existing PXP pipelines

Table 6.1a: Comparison of <u>Class I Impacts for</u> the Proposed Project ~~to the~~ <u>and</u> VAFB Onshore Alternative			
Impact #	**Description of Impact**	**Proposed Project**	**VAFB Onshore Alternative**
	oil spill and/or subsequent cleanup effort may impact designated critical habitat for steelhead, western snowy plover, <u>California tiger salamander,</u> and California red-legged frog. It is possible but very unlikely that an offshore oil spill would directly affect terrestrial and freshwater (or brackish/estuarine) environments, as this would only occur if oil were driven ashore above the high tide line by wind and high tides, and similarly driven upstream at an open tidal inlet during flood tide and low-outflow conditions. The oil would be highly dispersed by the time it reached the shore, leading to the deposition of relatively small amounts of oil at a given location, but over potentially large areas. An offshore spill may affect listed fish and wildlife that inhabit shorelines, beaches, lagoons, estuaries, and river mouths. Terrestrial or freshwater habitats could be indirectly affected by containment and cleanup efforts in response to an offshore oil spill that approaches the shore. The modeled trajectories for offshore oil spills (Appendix G) indicate that a large oil spill from Platform Irene or the pipeline would be most likely to reach shore between Point Arguello and Point Sal, or on the north -facing coastline of San Miguel Island. Oil could be dispersed as far north as Piedras Blancas or southward to other shores of the Channel Islands.	Spills from the pipeline between the shoreline and LOGP could enter the Santa Ynez River and affect the species listed below. In addition, depending on the time of the year, weather conditions, and tidal action, these species could also be affected by an offshore oil spill. • Steelhead trout could be affected by an offshore spill that reaches river mouths and lagoons along the shoreline. Potentially inhabited streams in the area worst-case spill trajectory area (Appendix G) include San Luis Obispo Creek, Pismo Creek, Arroyo Grande Creek, Santa Maria River, Shuman Creek, Santa Ynez River, Jalama Creek, and small coastal drainages from Point Conception to Gaviota Creek. These sites are within the trajectory range described in Appendix G, although the probability of a spill reaching any particular site is small Effects on steelhead would depend on the time of year and size of the spill. Impacts would be greatest if the spill occurred during adult or juvenile migration to or from spawning and rearing areas upstream of the project (January to June). • Spills could affect tidewater gobies, because they reside in lower river segments and lagoons all year. Tidewater gobies have the potential to occur in San Luis Obispo Creek, Pismo Creek, Santa Maria River, Shuman Creek, San Antonio Creek, Santa Ynez River, Jalama Creek, and small coastal drainages from Point Conception to Gaviota Creek. These sites are within the trajectory range described in Appendix G, although the probability of a spill reaching any particular site is small. • <u>Unarmored threespine sticklebacks could be affected by offshore spills that disperse into San Antonio Creek or Honda Creek.</u> • California least tern and California brown	just west of 13th Street to the LOGP<u>, and from the LOGP to Summit Pump Station</u>. Terrestrial <u>and aquatic</u> wildlife species could be impacted along this portion of pipeline. El Segundo blue butterfly may be affected if the spill affects its host plant, coast buckwheat. If an onshore spill occurs near the Santa Ynez River, riparian and aquatic habitats may be affected. Oil would strand in the stream bank and riparian margin, potentially impacting California red-legged frogs and steelhead trout in the River. A spill of sufficient volume could be transported to the Santa Ynez River mouth, which may affect birds that forage or dive in the lagoon, including California least terns and California brown pelicans. Tidewater gobies and migrating steelhead may also be affected by oiled sediments in the lower Santa Ynez River and lagoon. <u>California tiger salamander would not be directly affected by the proposed project (see Section 5.2.4.3).</u> While an onshore spill would not directly affect foredunes or dune scrub habitat, resulting clean-up activities may require access through the coastal zone to contain the spill before reaching the ocean. This may result in disturbance to nesting and foraging habitat for western snowy plovers. In addition, the VAFB Onshore Alternative would include approximately 10 miles of new emulsion pipeline from the alternative drilling/production site on south VAFB to the tie-in point to the existing PXP pipelines just west of 13th Street. The VAFB Onshore Alternative would involve the risk of an onshore spill along this new pipeline corridor. A spill from the pipeline could flow to the beach below, affecting relatively remote and undisturbed coastal strand habitats. State-or federally-listed wildlife species could be affected by

Table 6.1a: Comparison of Class I Impacts for the Proposed Project ~~to the~~ and VAFB Onshore Alternative

Impact #	Description of Impact	Proposed Project	VAFB Onshore Alternative
		pelican could be affected if spills encounter foredune habitat near the river mouth where these species reside for portions of the year. California least terns forage in estuaries and would be affected be an offshore spill that reaches the coastline near river mouths or lagoons. Coastal areas inhabited by California least tern include the Santa Maria River mouth and Santa Ynez River mouth. These sites are within the trajectory range described in Appendix G, although the probability of a spill reaching any particular site is small. The western snowy plover would be adversely affected by an oil spill that occurred on the beach where plovers nest or forage. An offshore spill would adversely affect this species if oil migrated to the beach habitat. Western snowy plovers breed, nest, and forage near the tide line and within the kelp wrack. Oiling of beach sediments and kelp litter would adversely affect this species feeding and nesting success. Cleanup efforts could also significantly impact breeding success of this species if cleanup efforts were to occur in the foredunes and beach habitat near the Santa Ynez River or San Antonio Creek river mouths. Several other beaches along the shoreline on San Luis Obispo and Santa Barbara County, and beaches at San Miguel and Santa Rosa Islands are used by western snowy plovers and may be impacted by a large offshore spill (Appendix G). These sites are within the trajectory range described in Appendix G, although the probability of a spill reaching any particular site is small. The greatest potential for impacts would occur during this species' breeding season from March 1 through September 30. <u>California tiger salamander would not be directly affected by the proposed project (see Section 5.2.4.3).</u>	a spill along this new pipeline. The California red-legged frog may be present in Bear Creek and other drainages crossed by the coastal pipeline corridor. Suitable habitat for coast buckwheat is present along this additional segment of pipeline. An oil spill could adversely affect El Segundo blue butterfly by damaging or killing its host plant. Containment and cleanup impacts could also impact habitat for listed wildlife species. The VAFB Onshore Alternative would not involve a change in offshore operations through 2017, at which time Platform Irene and offshore pipeline operations would cease. The impacts associated with an offshore spill would be equivalent to the No Action Alternative since oil production levels and resultant spill probabilities, volumes, and clean up activities would be similar to current operations (i.e., the baseline). A direct comparison of oil spill impacts between the Proposed Action and VAFB Onshore Alternative is problematic because of differences and inherent unpredictability in the points of origin, subsequent dispersion, and locations potentially affected. An onshore spill associated with the VAFB Onshore Alternative would affect sensitive coastal habitats and could affect listed wildlife species along the pipeline corridor. Under the Proposed Action, the geographic range of potential impacts is widely dispersed and diffuse due to seasonal and climatic variables (Appendix G). The extent of potential impact to terrestrial and freshwater resources is more widespread, but likely to be less severe at any particular location than would be the case for the VAFB Onshore Alternative. Containment and cleanup activities for spills under either alternative may also impact listed wildlife species or their habitat, but these impacts

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Impact #	Description of Impact	Proposed Project	VAFB Onshore Alternative
		California red-legged frogs, federally listed as threatened, could also be impacted if an onshore oil spill entered the Santa Ynez River. An offshore spill would not be likely to migrate upstream to occupied California red-legged frog habitat within the river channel. **Preferred**	would diminish with time. Overall, given the proximity of potential wildlife habitat to the VAFB Onshore Alternative pipeline, the severity of spill-related impacts is considered to be greater under the VAFB Onshore Alternative than under the Proposed Project.
TB.9	Under Alternative Power Line Route (Option 2b) or the VAFB Offshore Alternative, a directionally drilled bore hole would be routed under the Santa Ynez River. Drilling noise, construction, and accidental release of boring materials (“frac-outs”) during construction activities could impact one or more sensitive wildlife species.	This impact would not occur under the proposed project unless Alternative Power Line Route – Option 2b was chosen. **Preferred**	For the VAFB Onshore Alternative, directional drilling under the Santa Ynez River would be utilized to install pipelines from the onshore drilling/production site. Drilling has the potential to indirectly impact sensitive biological resources in the Santa Ynez River if a frac-out occurs (inadvertent release of bentonite drilling muds through natural fractures). Bentonite slurry released into the Santa Ynez River would increase turbidity and sedimentation, potentially impacting the California red-legged frog, tidewater goby, and steelhead by covering egg masses and breeding habitat. Some mortality of invertebrates and possibly amphibians and fish would be expected. Other than during migration (January through June), steelhead are not likely to spawn or be present in the lower reaches of the Santa Ynez River. This impact would be greater for the VAFB Onshore Alternative than the proposed project because the larger bore diameter would increase the risk of frac-out and the amount of bentonite slurry that may be released into the Santa Ynez River.
TB.10	Installation of the new pipelines and associated facilities has the potential to remove or damage extensive acres of native vegetation, wildlife habitat including sensitive plant species, and previously disturbed natural areas.	Vegetation removal associated with the proposed project is limited to power line installation. Assuming 45 power poles total, the disturbance would be approximately 0.33 acre of vegetation and wildlife habitat. Construction of the proposed transformer station would result in temporary impacts to 4,200 square feet and permanent loss of 150 square feet of vegetation or wildlife habitat	The new VAFB Onshore Alternative pipeline installation would impact an additional 61 acres of vegetation and wildlife habitat adjacent to existing roadways. In addition, six miles of transmission line would be installed. Assuming 90 poles total, the disturbance would be approximately 0.65 acre of vegetation and wildlife habitat along portions of Coast Road, Bear Creek Road, and Surf Road.

Table 6.1a: Comparison of <u>Class I Impacts for</u> the Proposed Project ~~to the~~ <u>and</u> VAFB Onshore Alternative

Impact #	Description of Impact	Proposed Project	VAFB Onshore Alternative
		(depending on location), for a total of less than 0.1 acre of impact. Given the nominal total acreage (0.43 acres) and that the acreage is dispersed by pole and substation site, the impact is *considered Class II, significant but mitigable*, for the proposed project (see Impact TB.1 in Section 5.2.4.1). **Preferred**	Loss of individuals of sensitive plant species, such as Gaviota tarplant, would be substantially larger under the onshore alternative due to the additional area of terrestrial ground disturbance. If the pipeline were to be installed along the west side of Surf Road, it may impact a population of beach layia (a federally listed species) due to ground disturbance. Isolated occurrences of coast buckwheat may be present in the dune vegetation to the west of Coast Road. Installation of pipelines and power lines may trample or remove patches of coast buckwheat, and therefore negatively affect the El Segundo blue butterfly. Loss of individuals of wildlife species would be greater under the onshore alternative compared to the proposed action. Vernal pool fairy shrimp could be present along the onshore alternative pipeline route. Further, protected species in or near the willow riparian habitats along Highway 246 could be impacted by pipeline installation. A large drainage swale running parallel to and south of the Highway 246 road shoulder contains wetland plants, riparian birds, and aquatic wildlife. The wetland and riparian habitats are likely to support sensitive and/or protected species. Pipeline installation in this area could result in disturbance or mortality to southwestern pond turtles, California red-legged frogs, and adverse effects on eggs and breeding habitat. Unlike the southern border of Highway 246, the corridor north of the road shoulder does not support an extensive wetland. However, wildlife that inhabits the coastal scrub and coastal terrace would be disturbed and displaced during installation of the pipeline. Wildlife near the Santa Ynez River crossing could be impacted by pipeline installation. Installation of the new drilling/production facility would result in the permanent loss of 25 acres of

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Impact #	**Description of Impact**	**Proposed Project**	**VAFB Onshore Alternative**
			vegetation and wildlife habitat. Disturbed areas in the stabilized dune habitat are prone to invasion by weedy species such as veldt grass, beach grass, and iceplant. Restoration efforts along the pipeline corridor are unlikely to be 100% successful for all native plant communities. The severity of impacts to vegetation would be greater under the VAFB Onshore Alternative than under the proposed project because of the additional miles of ground disturbance required for the onshore pipeline. While rerouting of the pipeline corridor could avoid some of the identified biological resources, given the density of biological resources within southern VAFB and technical limitations to pipeline design/routing, it is unlikely that all biological resources could be avoided.
OWR.2	A rupture or leak from the emulsion, produced water or dry oil pipelines could substantially degrade surface and groundwater quality	Both produced water and oil emulsion spills could affect surface and ground waters depending on the location and size of the spill. Although the proposed project would treat produced water to achieve compliance with offshore receiving water criteria (if ocean discharge is used instead of re-injection), onshore spills still may contain some soluble hydrocarbons with the potential for affecting surface and/or groundwater quality. The worst-case onshore oil spill for the proposed project is estimated to be 7,006 bbls, an increase of 688 bbls in comparison to existing operations (see Table 5.1.25). If a spill reached the Santa Ynez River, it could have significant, long-term and widespread impacts to water quality and, consequently, sensitive biological resources. Similarly, subsurface (i.e., underground) spills, or surface spills in areas with porous surface soils and a shallow aquifer, could result in significant, long-term contamination of groundwater.	The severity of the impact for the VAFB Onshore Alternative would be greater than the proposed project because of the additional miles of onshore pipeline associated with this alternative. Impacts associated with crude oil spills would be similar to the proposed project, with an increase in severity as the length of onshore pipeline that could spill crude oil would be increased, and the addition of the thermal radiation hazard due to potential fires during the initial years of operation due to oil content of the emulsion being in the range of 88 to 90 percent.

Table 6.1a: Comparison of Class I Impacts for the Proposed Project ~~to the~~ and VAFB Onshore Alternative			
Impact #	**Description of Impact**	**Proposed Project**	**VAFB Onshore Alternative**
		An offshore oil spill could also enter the waters of the Santa Ynez River mouth/estuary creating significant water quality impacts and consequently affecting biological resources. **Preferred**	
MB.1	Oil spills from the project may impact benthic and intertidal organisms, fish, marine mammals, marine birds, and marine turtles. Oil spills from the project may impact plankton.	The degree of impacts to marine biota from an oil spill will depend on several factors, including location, volume, rate, and type of oil that is spilled; amount of weathering, evaporation, and dispersion of oil in the water column and shoreline; and the amount of oil that is contained and cleaned immediately after the spill. Oil effects to marine biota include mortality or can be sublethal by inhibiting growth and reproduction. Oil can also bioaccumulate in certain marine species and can also cause histological damage, alter physiology and metabolism, and decrease reproductive capacity. The maximum offshore oil spill estimated for the proposed project is 7,929 bbls for the offshore pipeline and 4,500 bbls for a Platform Irene well blowout (see Table 5.1.29). Oil spills are far more likely to travel due south from the site of the spill to important seabird and shorebird areas at the Santa Ynez River mouth, Point Pedernales, Point Arguello and Rocky Point as well as areas frequented by sea otters and harbor seals. Spills could potentially extend substantial distances and impact ocean areas south of the Channel Islands. There is a tangible probability that they would impact the Channel Islands Marine Sanctuary. To the north, only open-ocean areas south of Point Sal were likely to be impacted by oil spills resulting from the proposed project. Clean up of oil spills could also impact the marine environment. In addition, even with the most prudent spill clean up efforts, the majority of spilled	For the VAFB Onshore Alternative, the risk of an oil spill from Platform Irene or associated offshore pipelines would be reduced to the baseline conditions. There is a small chance that an oil spill from the rupture of the new pipeline or upset conditions at the drilling/production site could reach ocean waters. The chances of oil from the onshore pipeline or drilling/production sites reaching the ocean are nominal because the alternative facilities would be landward of the railroad tracks. The railroad tracks run along a berm that forms a partial barrier to flows. However, under high flow conditions, spilled oil might reach ocean waters via one of the drainages crossed by the pipeline. Spilled oil that did reach the ocean from this alternative would be close to important seabird and shorebird areas at the Santa Ynez River mouth, Point Pedernales, Point Arguello and Rocky Point as well as areas frequented by sea otters and harbor seals. **Preferred**

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Impact #	**Description of Impact**	**Proposed Project**	**VAFB Onshore Alternative**
		oil is not recovered.	
MWQ.1	Accidental discharge of petroleum hydrocarbons into marine waters would adversely affect marine water quality.	The combined probability of oil leaks, ruptures, blowouts, and spills from Platform Irene and the offshore portion of the emulsion pipeline would approximately ~~double~~ quadruple under the proposed project (5.4~~10.5~~% to 22.1% - see Table 5.1.28). In addition, the expanded new production would increase the concentration of crude in the oil emulsion transported to shore. Because of increased crude concentrations, offshore oil spills associated with a rupture of the transmission line would induce greater deleterious effects within marine waters. Finally, the frequency and duration of trips made by offshore support vessels would increase under the proposed project. The increased vessel traffic would increase the risk of a vessel accident and an attendant spill although its volume would be limited compared to other oil-spill scenarios.	For the VAFB Onshore Alternative, the risk of an oil spill from Platform Irene or associated offshore pipelines would be reduced to the baseline conditions. There is a small chance that an oil spill from the rupture of the new pipeline or upset conditions at the drilling/production site could reach ocean waters. The chances of oil from the onshore pipeline or drilling/production sites reaching the ocean are nominal because the alternative facilities would be landward of the railroad tracks. The railroad tracks run along a berm that forms a partial barrier to flows. However, under high flow conditions, spilled oil might reach ocean waters via one of the drainages crossed by the pipeline. Spilled oil that did reach the ocean from this alternative would have the potential to result in significant degradation of marine water quality. **Preferred**
CRF/KH.2	Oil spills may potentially impact commercial and recreational fishing in the proposed project area.	A wide variety of fish and shellfish species are commercially harvested in the project area. Biota residing in the intertidal and shallow subtidal habitat are vulnerable to oil spills. Although abalone is not presently harvested in the project area, both sea urchins and lobsters are high value species that are harvested both commercially and recreationally in the area. In the event of an oil spill, there could be impacts to abalone, sea urchins, and lobster. Smothering is the most common cause of mortality and would be limited to direct contact with weathered tar balls from the oil spill. Although not high value species, other intertidal or shallow subtidal organisms that are harvested include sea cucumbers and whelks. While the probability for oil contacting and fouling the shoreline or shallow subtidal areas where commercial or recreational species are harvested is	For the VAFB Onshore Alternative, the risk of an oil spill from Platform Irene or associated offshore pipelines would be reduced to the baseline conditions. There is a small chance that an oil spill from the rupture of the new pipeline or upset conditions at the drilling/production site could reach ocean waters. The chances of oil from the onshore pipeline or drilling/production sites reaching the ocean are nominal because the alternative facilities would be landward of the railroad tracks. The railroad tracks run along a berm that forms a partial barrier to flows. However, under high flow conditions, spilled oil might reach ocean waters via one of the drainages crossed by the pipeline ~~If spilled oil from the new onshore pipeline did reach the ocean, it might be more likely to reach kelp beds than a spill from Platform Irene because the oil would enter the ocean close to shore and the nearshore kelp beds.~~. Oil entering the ocean from onshore might have a greater chance to impact

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Impact #	Description of Impact	Proposed Project	VAFB Onshore Alternative
		low, it nevertheless can occur. While contaminated shorelines may be cleaned, in some instances, depending on substrate type, oil may persist in sediments for several years. Adult fish, due to their mobility, may be able to avoid or minimize exposure to spilled oil. However, there is no conclusive evidence that fish will avoid spilled oil. Egg and larval stages would also not be able to avoid exposure to spilled oil. Fish harvested from contaminated areas may also be reduced in value and fishing gear can be damaged due to oil fouling.	<u>nearshore areas frequented by fishermen than a spill from Platform Irene. Therefore, although the chance of a spill would be greatly reduced compared to the proposed project, if substantial amounts of oil did enter the ocean, impacts on nearshore fishing areas might be greater.</u> **Preferred**
T.4	An oil spill from the proposed Tranquillon Ridge project could result in the disruption of commercial shipping, fishing, and recreational marine traffic, and onshore transportation infrastructure.	An oil spill could result in the closure of the Coast Guard's recommended marine traffic corridors through the Santa Barbara Channel and restrict boating along up to 70 miles of coastline and San Miguel, Santa Rosa, and western Santa Cruz Islands. The event of an oil spill could disrupt marine traffic for a number of days, due to clean-up activities. Depending on the location of the spill, marine traffic might have to use routes outside of the Coast Guard's recommended marine traffic corridors. Also, commercial/recreational fishing boat traffic could be precluded from areas around the spill during the cleanup activities. **No Preference**	For the VAFB Onshore Alternative, the potential to impact marine transportation would be less than the proposed project because of the lower likelihood of a spill reaching the marine environment. However, an oil spill within VAFB could temporarily close mission critical transportation infrastructure on VAFB. If a spill were to occur within southern VAFB or come onshore along southern VAFB, oil spill clean up response times could be hindered if mission critical operations were underway. **No Preference**
CR.3	Containment and cleanup activities associated with an accidental oil spill would result in ground disturbance and potential impacts on cultural resources.	Oil spill containment activities that would potentially affect cultural resources include the use of heavy earth moving equipment (e.g., graders, scrapers, front-end loaders) or manual excavation to remove oil-contaminated material. Soil removal by manual or mechanized means poses potential significant impacts on any cultural resource in the affected areas. Water flooding is another cleanup method whereby subsurface oil is forced to the surface by water pumped into the groundwater table. Although drilling holes for water flooding would potentially impact sites, flooding (in most cases)	The risk and severity of the impact for the VAFB Onshore Alternative would be greater than the proposed project due to additional length of new pipeline and the proximity of the new pipelines to numerous NRHP eligible cultural resources.

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Impact #	**Description of Impact**	**Proposed Project**	**VAFB Onshore Alternative**
		would be preferable to soil removal because it is likely that drilling would result in relatively low levels of subsurface disturbance. **Preferred**	
CR.5	Disturbance or destruction of cultural sites that may contain significant or potentially significant cultural materials by the construction of new drilling/ production/processing facilities, and pipelines.	Impact CR.5~~6~~ does not apply to the proposed project. **Preferred**	Construction of the VAFB Onshore Alternative may permanently remove or destroy 44 sites that may contain significant or potentially significant cultural materials, and would alter the spatial relationships and context of those materials. Because of the extent of grading and excavation required to construct the new facilities, there would be a high potential for the destruction of cultural materials and alteration of their context, which may not be fully mitigable by measures implemented after the fact. Given prevailing substrates of unconsolidated sand on old dunes, in close proximity to the coastline, as well as sources of fresh water, the potential for undiscovered, buried cultural materials to exist is high. Sedimentary deposits containing paleontological materials are also likely to be encountered. While rerouting of the pipeline corridor could avoid some of the identified sites, given the density of cultural site within southern VAFB and technical limitations to pipeline design/routing, it is unlikely that all cultural sites could be avoided.
Visual.1	Visual impacts due to long-term continued presence of the project facilities visible from coastal zone (Platform Irene and Surf substation).	The presence of Platform Irene, which is visible from the public beach to marine recreational users and from the Union Pacific Railroad, creates a negative aesthetic impact. The proposed project would continue, but not worsen, this impact by extending the life of Platform Irene from approximately 10 years to 30 years. The Surf Substation provides power to Platform Irene. The substation, which is visible from several public areas, such as the Ocean County Park, Surf Beach, and portions of the Union Pacific Railroad	This impact would be eliminated with the VAFB Onshore Alternative (assuming onshore produced water disposal), since there would be no extension of life of Platform Irene. However, under the VAFB Onshore Alternative, Surf Substation would remain for the projected 30-year project life. Although the VAFB drilling/production site would be located in the coastal zone, given its remote location, proximity to VAFB space launch facilities, and limited public access to the area, the impact would not be significant.

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Impact #	Description of Impact	Proposed Project	VAFB Onshore Alternative
		and Ocean Avenue, creates a negative aesthetic impact. The life of the substation under the proposed project would also be extended from approximately 10 years to 30 years.	**Preferred**
Visual.4	Visual impacts due to long-term continued presence of the LOGP.	The LOGP creates nighttime glare from the light of the facility that can be seen through most of the Lompoc area, (including public viewsheds), and as far away as Highway 101 north of Los Alamos. This glare reduces the darkness of the night sky and could obscure the stars and other astronomical phenomena. The glare degrades the public's enjoyment of viewing the nighttime sky from many public areas, and therefore adversely impacts visual resources of several visually important areas. The glare is also incompatible with the mostly dark nighttime sky of the undeveloped areas near Lompoc that are in the public viewshed. The lights at the LOGP are needed to allow for the safe operation of the facility at night and to comply with OSHA regulations. Under the proposed project, the nighttime glare associated with LOGP would be extended from approximately 10 years to 30 years. **No Preference**	Nighttime glare associated with the LOGP would be the same for the VAFB Onshore Alternative since the LOGP would remain in operation for the projected 30 year project life. Although nighttime glare would also occur at the VAFB drilling/production site, given the remote location of the site, the impact would not be significant. **No Preference**
Visual.5	New oil and gas facilities due to their tall structures and glare from lighting could impact visual resources in the area.	Impact Visual.5 would not occur under the proposed project. **Preferred**	The VAFB Onshore Alternative would require construction and operation of a new drilling and production facility. The facility would include up to 30 well slots, production well heads, piping and well test facilities, an oil dehydration facility including a Wet Lease Automatic Custody Transfer (LACT), and a gas compression and dew point control plant. These facilities would require approximately 25 acres of land. It is assumed that the drilling rig would be approximately 180 to 200 feet high. At least one tank up to approximately 50 feet in height could also be needed. In addition, pipeline tie-in facilities would be constructed west of 13th Street at approximate Milepost 4.5 of the existing PXP pipeline right-of-way.

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Impact #	Description of Impact	Proposed Project	VAFB Onshore Alternative
Rec.1	The proposed project would increase the likelihood and volume of an oil spill, which could result in public access restrictions to coastal and inland recreational resources.	An offshore spill caused by an accident or failure at Platform Irene or in the offshore pipeline could lead to beach closures and boating restrictions during spill response and cleanup, as well as a lingering public perception that recreational resources are polluted, even after the cleanup period. The duration and extent of beach closures would depend on the volume of the spill and prevailing ocean and local weather conditions. A worst-case scenario oil spill could reach recreational resources as far north as Montana de Oro State Park near Morro Bay and as far south as the Santa Barbara Channel Islands. The coastline east of Point Conception, including Gaviota and Refugio State Beaches would likely avoid direct spill impacts. The area from Point Sal to Point Arguello is at greatest risk from a spill due to its proximity to the Point Pedernales Project facilities; therefore Ocean Beach County Park, Point Sal Beach State Park, and Jalama Beach County Park would be more likely impacted than other recreation areas An onshore spill near the pipeline landfall could pose a similarly adverse effect on the recreational utilization of Ocean Beach Park. An onshore spill further inland could adversely affect recreational resources such as the Burton Mesa Ecological Reserve, the Santa Ynez River, and Ocean Beach Park (via a spill into the river).	The severity of this impact for the VAFB Onshore Alternative would be less than the proposed project due to the reduced likelihood of an oil spill reaching coastal recreational facilities/areas. The e~~a~~ffect of an onshore spill east of the tie-in point to the PXP pipelines would be the same as the proposed project. **Preferred**

west of 13th Street would no longer be in operation. In the event of an onshore oil spill and resultant clean up, there could be significant impacts to onshore biological (Impacts TB.6, TB.7, and TB.8), cultural (CR.3) and water (Impact OWR.2) resources, and mission-critical transportation infrastructure within VAFB (Impact T.4). The proposed project could also result in impacts to onshore biological resources in the event of an offshore release that finds its way onto beaches and into the Santa Ynez River mouth and/or other coastal estuaries.

Under the VAFB Onshore Alternative, the LOGP would remain in operation as with the proposed project. Therefore, the Class I impact associated with LOGP nighttime glare (Impact Visual.4) would be the same for the alternative as the proposed project. In addition, the Class I impact associated with public safety due to the truck transport of NGL/LPGs (Impact Risk.3) would be the same for the alternative as the proposed project.

In summary, the VAFB Onshore Alternative would eliminate the Class I visual impact due to the long-term continued presence of Platform Irene, assuming that produced water is re-injected onshore. <u>However, the additional nighttime lighting the alternative would add to the existing lighted features at VAFB could result in a Class I or Class II impact, depending on VAFB's final lighting requirements (see Section 5.13.5.2).</u> The alternative would also reduce the severity, but not eliminate, the Class I impacts associated with an oil spill on the marine environment and to recreational facilities. However, the VAFB Onshore Alternative poses environmental disadvantages in the issue areas of: (1) onshore biology, (2) onshore water resources, and (3) cultural resources.

6.3.2 New Oil and Gas Processing Facility at Casmalia

The Casmalia Alternative would involve the development of a new oil and gas processing facility at the Casmalia East oil field along with the decommissioning of the majority of the LOGP. With this alternative, the pipelines from Platform Irene to the LOGP would remain in service. A pumping and compressor station would be constructed at the LOGP along with <u>approximately 10 to 15 miles of</u> new emulsion, sour gas, and produced water pipelines from the LOGP to the Casmalia site. In addition, a dry oil pipeline would be constructed from the Casmalia site to the ConocoPhillips Orcutt Pump Station.

Table 6.1b provides a comparison of the Class I impacts between the proposed project and the Casmalia Processing Site Alternative. Use of this alternative would not result in the elimination of any significant impacts associated with the proposed Tranquillon Ridge Project. The only significant impact identified for the LOGP was nighttime glare of the facility, which was considered significant due to extension of life of the LOGP. With the Casmalia alternative site, a new pumping and compressor station would need to be constructed at the LOGP to move the emulsion, sour gas, and produced water to the Casmalia site from the LOGP. This new facility at the LOGP site would still require nighttime lighting that would still cause a significant visual impact, but it would be less severe than the existing LOGP facility glare. In addition, the new site at Casmalia would create a new Class I visual impact by generating nighttime glare along portions of Highway 101 and possibly the southern portions of Orcutt. This would be particularly true during foggy periods.

Table 6.1b: Comparison of Class I Impacts for the Proposed Project ~~to the~~ and Casmalia East Processing Site Alternative

Impact #	Description of Impact	Proposed Project	Casmalia East Processing Site Alternative
Risk.3	The proposed project could generate risks to public safety by exposing the public to transportation hazards.	The project would increase the transportation of gas liquids along roadways over the current operations. By increasing the number of trips, and therefore the risks to the public, this existing significant impact is exacerbated (more truck trips and a longer period over which truck trips would occur). **No Preference**	The severity of the impact for the Casmalia Alternative would be the same as the proposed project since production levels would be the same, thereby resulting in the same number of gas liquid truck trips. For the Casmalia site, the location of the transportation risk would shift from the LOGP to Casmalia. **No Preference**
TB.6	A pipeline leak or rupture could result in an oil spill and subsequent degradation of upland, riparian and freshwater aquatic habitats and injury to plants and terrestrial and aquatic wildlife through direct toxicity, smothering, and entrapment as well as through resultant cleanup efforts. An offshore spill may affect the terrestrial environment if oil is transported to the shoreline. Oil could be transported up creeks and rivers that are open to tidal influence. The modeled trajectory for a worst-case offshore oil spill (Appendix G) indicates that shorelines, lagoons, estuaries, and river mouths may be directly affected. Surrounding terrestrial areas may be affected by cleanup efforts.	While the risk of an oil spill and/or pipeline rupture is a risk already associated with the existing oil pipeline, the proposed increase in throughput and oil percentages would increase the combined lifetime probability of oil leaks, ruptures, blowouts, and spills from Platform Irene and the offshore portion of the emulsion pipeline from 5.4~~10.5~~% to 22.1% over the life of the project (see Table 5.1.28). In addition, assuming that the pumps are installed at Valve Site #2, the lifetime probability for a rupture along the onshore emulsion pipeline would increase from 0.9% to 11.2% and for a leak would increase from 3.6% to 100% (see Table 5.1.24) Upland Habitats: Several sensitive upland habitat areas are crossed by the pipeline corridor or lie close to and down slope of the corridor. These include foredunes, coastal dune scrub, coastal sage scrub, Burton Mesa chaparral, Bishop pine forest, and coast buckwheat populations, which may support El Segundo blue butterfly. Upland habitats would not be directly affected by an offshore spill, but containment and cleanup activities may affect upland habitats if off-road access is necessary to reach the affected shoreline. Aquatic Habitats: Salt or freshwater marshes would be most sensitive because the biological activity of these communities is concentrated near the soil or water surface, where oil would be stranded. Aquatic habitats would be affected by an offshore spill if oil	For the Casmalia Alternative, the oil spill related impacts to upland, riparian, and aquatic habitats, and wildlife would be the same as the proposed project from pipeline landfall at Wall/Surf Beach to the LOGP. The risk and impacts from an offshore spill would also be the same as the proposed project. Under the Casmalia Alternative, new emulsion and gas pipelines would need to be constructed from LOGP to the Casmalia site. In addition, a new dry oil pipeline would be constructed from Casmalia to the ConocoPhillips Orcutt Pump Station. The habitats that would be impacted by a spill along these new pipelines include the following: grasslands, oak woodland, agricultural fields; chaparral and evergreen forest in the Purisima Hills, riparian woodlands and aquatic habitats along San Antonio Creek and in unnamed tributaries in Graciosa Canyon, Orcutt Creek and Pine Canyon Creek near the Orcutt Pump Station; and recovering/revegetated areas along the existing pipeline corridor. Wildlife that would be impacted includes terrestrial mammals, aquatic reptiles and amphibians, fish, and invertebrates. The severity of spill-related impacts to vegetation and wildlife would be greater under the Casmalia East Processing Site Alternative than under the Proposed Project due to the additional length of pipeline that would be installed in currently undisturbed and sensitive habitat.

Table 6.1b: Comparison of Class I Impacts for the Proposed Project ~~to the~~ and Casmalia East Processing Site Alternative			
Impact #	Description of Impact	Proposed Project	Casmalia East Processing Site Alternative
		were to reach the shoreline and be dispersed upstream by tidal flow. Tidally influenced aquatic and wetland habitats within the area potentially affected by oil spills occur at the mouths of Pismo Creek, San Luis Obispo Creek, Arroyo Grande Creek, Santa Maria River, Shuman Creek, San Antonio Creek, Santa Ynez River, La Honda Creek, Jalama Creek, Gaviota Creek, and several small drainages between Point Conception and Gaviota. Discharged oil could reach the shoreline in solid or liquid form. Direct impacts may include toxicity and smothering of wetland plants and contamination of rooting substrate. Containment and cleanup activities may have indirect effects on aquatic habitats due to vehicle access, foot traffic, and sediment excavation. Riparian Habitats: Riparian woodland communities may be somewhat less sensitive to an oil spill because leaves in the canopy would not be susceptible to oiling. Effects of an oil spill on plant root systems would include reductions in the availability of soil water, nutrients, and oxygen to plant root systems; and toxicity. All of these would lead to reduced growth and reproduction, and possible mortality in plants exposed to oil. Riparian habitats crossed by the pipeline corridor are limited to the Santa Ynez River corridor, drainage tributaries, and small riparian habitats in Oak Canyon and Santa Lucia Canyon. Oil could enter riparian habitats through direct entry, runoff from upland areas within the watershed (especially during storm runoff), and contamination of groundwater feeding streams. Oil could also enter drainages and riparian areas through overland flow; however, under dry conditions, overland flow of oil would be relatively slow due to the viscous nature of the crude oil. The rate of spread would slow as the oil cools and becomes more viscous. As	

Table 6.1b: Comparison of Class I Impacts for the Proposed Project ~~to the~~ and Casmalia East Processing Site Alternative			
Impact #	Description of Impact	Proposed Project	Casmalia East Processing Site Alternative
		the water fraction of the oil-water emulsion increases over the life of the project the emulsion would have different behaviors when spilled. Riparian habitat is scarce in the coastal area that may be affected by an offshore spill. Oil discharged offshore may reach the shoreline, but would not be transported inland above the extent of tidally influenced waters near river mouths, sloughs, and lagoons. Riparian habitat along tidal waters exists in small amounts at large drainages including the , Santa Maria River, San Antonio Creek, and Santa Ynez River. Potential impacts to riparian habitats would be minor, but may include direct toxicity to riparian vegetation and indirect damage due to containment and cleanup activities. Aquatic Wildlife: Aquatic wildlife would most likely be affected by an offshore spill and cleanup activities. Shorebirds that forage in wetlands and estuaries would be affected if an offshore spill reached the shoreline. Birds would be unable to fly if their feathers are oiled. Similarly, a large offshore spill may affect fish in brackish water lagoons. Freshwater aquatic wildlife would be affected by an onshore spill that reaches drainages or by an offshore spills that reaches the shoreline. Aquatic reptiles, amphibians, fish, and birds would be vulnerable to an onshore spill and clean up efforts. Impacts would include toxicity, degradation of habitat and breeding areas, and sediment excavation during containment or cleanup. Terrestrial Wildlife: Oil spills and their clean-up are expected to directly affect wildlife species such as Pacific chorus frogs, western toads, a wide range of invertebrates and sensitive species such as western pond turtles and two-striped garter snakes. Depending on the size and areal extent of the spill,	

Table 6.1b: Comparison of Class I Impacts for the Proposed Project ~~to the~~ and Casmalia East Processing Site Alternative

Impact #	Description of Impact	Proposed Project	Casmalia East Processing Site Alternative
		an unknown number of birds, reptiles and land mammals could be killed if they come in direct contact with the oil. An offshore spill would not directly affect terrestrial wildlife, but containment or cleanup activities may have a minor effect on terrestrial species if off-road access is necessary to reach the affected shoreline. **Preferred**	
TB.7	A spill and/or subsequent cleanup efforts may directly or indirectly cause the loss of habitat and individuals or colonies of state-or federally-listed plant species including seaside bird's beak, Surf thistle, beach spectacle pod, La Graciosa thistle, beach layia, and possibly Pismo clarkia or degrade designated critical habitat for the Lompoc yerba santa and the La Graciosa thistle. An offshore spill may affect listed plant species in coastal dunes and foredune habitat due to resultant containment or cleanup efforts.	Individuals of the following state- or federally-listed plant species may be removed or damaged by activities associated with an onshore oil spill and cleanup. These species are typically found above the beach and tidal zone and are not found close to the Santa Ynez River, thus are unlikely to be directly affected by an offshore spill, but could be affected by subsequent cleanup efforts. • La Graciosa thistle, a federally listed endangered species and state-listed threatened species, has the potential to be impacted by an oil spill or cleanup activities if a spill reaches its habitat. The species it has not been observed on VAFB in recent years, but the existing pipeline overlaps a small portion of designated critical habitat south of Orcutt and north of the intersection of Highway 1 and Highway 135. La Graciosa thistle may be affected by an offshore spill that reaches its habitat near Oso Creek, Santa Ynez River and Santa Maria River mouths. Cleanup activities may affect the coastal dunes and swales occupied by this species. • Gaviota tarplant, a federal and state listed endangered species, have been observed along the pipeline corridor and adjacent habitat in grassland, scrub, and semi-disturbed areas on the coastal terrace. • Surf thistle and beach spectacle pod, both state-listed as threatened, have been recorded in the	For the Casmalia Alternative, the oil spill related impacts to state-or federally-listed plant species would be the same as the proposed project from pipeline landfall at Wall/Surf Beach to the LOGP. . The risk and impacts from an offshore spill would also be the same as the proposed project. Under the Casmalia Alternative, new emulsion and gas pipelines would need to be constructed from LOGP to the Casmalia. In addition, a new dry oil pipeline would be constructed from Casmalia to the ConocoPhillips Orcutt Pump Station. The state-or federal-listed plant species that would be impacted by a spill along these new pipelines includes the following: • La Graciosa thistle, a federally listed endangered species and state-listed threatened species, has the potential to be impacted by an oil spill or cleanup activities if a spill reaches its habitat. The pipeline overlaps designated critical habitat south of Orcutt and north of the intersection of Highway 1 and Highway 135. • Lompoc yerba santa, federally listed as endangered, occurs in maritime chaparral communities. This species may be present in suitable habitat along the pipeline corridor between LOGP and Orcutt. The severity of spill-related impacts to listed plant species would be greater under the Casmalia East

Table 6.1b: Comparison of <u>Class I Impacts for</u> the Proposed Project ~~to the~~ <u>and</u> Casmalia East Processing Site Alternative

Impact #	Description of Impact	Proposed Project	Casmalia East Processing Site Alternative
		foredunes crossed by the pipeline corridor. Containment or cleanup activities for an offshore spill may impact occupied coastal dune habitat near Oso Creek, Pismo Beach, and Oceano dunes. • Seaside bird's-beak, state-listed endangered, is known to occur within or directly adjacent to the pipeline corridor north of the Federal Penitentiary and west of the LOGP An offshore spill and associated containment or cleanup would not be likely to impact habitats occupied by this species. • Beach layia, a federal and state-listed endangered species, is a foredune species that is not known or suspected to occur in the area that may be affected by an onshore spill. An offshore spill would not reach the coastal dune habitat preferred by this species, but containment or cleanup activities may affect occupied habitat along the coastline west of Surf Road. Lompoc yerba santa, federally-listed as endangered, is known in a few locations in the project area, all of which are upslope from the oil pipeline and not likely to be affected by impacts associated with an oil spill or cleanup activities. Pismo clarkia, federally-listed endangered and state-listed rare, is also unlikely to be affected by spills or clean up since suitable habitat for this species is upslope of the pipeline in the vicinity of Summit Pump Station. Neither of these species would be affected by an offshore spill. **Preferred**	Processing Site Alternative than under the Proposed Project due to the greater length of pipeline that would be installed through undisturbed habitat that may support listed plant species.
TB.8	An oil spill and/or subsequent cleanup effort may directly or indirectly cause the loss of individual state or federally-listed wildlife species or cause the loss or degradation of sensitive species habitat. An	El Segundo blue butterfly may be adversely affected if an oil spill or subsequent clean up activities result in destruction of its host plant, coast buckwheat.	For the Casmalia Alternative, the oil spill related impacts to state-or federally-listed wildlife species would be the same as the proposed project from pipeline landfall at Wall/Surf Beach to the LOGP. .

Table 6.1b: Comparison of Class I Impacts for the Proposed Project ~~to the~~ and Casmalia East Processing Site Alternative

Impact #	Description of Impact	Proposed Project	Casmalia East Processing Site Alternative
	oil spill and/or subsequent cleanup effort may impact designated critical habitat for steelhead, western snowy plover, California tiger salamander, and California red-legged frog. An offshore spill may affect listed fish and wildlife that inhabit shorelines, beaches, lagoons, estuaries, and river mouths.	Spills from the pipeline between the shoreline and LOGP could enter the Santa Ynez River and affect the species listed below. In addition, depending on the time of the year, weather conditions, and tidal action, these species could also be affected by an offshore oil spill. • Steelhead trout could be affected by an offshore spill that reaches river mouths and lagoons along the shoreline. Potentially inhabited streams in the area worst-case spill trajectory area (Appendix G) include San Luis Obispo Creek, Pismo Creek, Arroyo Grande Creek, Santa Maria River, Shuman Creek, Santa Ynez River, Jalama Creek, and small coastal drainages from Point Conception to Gaviota Creek. Effects on steelhead would depend on the time of year and size of the spill. Impacts would be greatest if the spill occurred during adult or juvenile migration to or from spawning and rearing areas upstream of the project (January to June). • Spills could affect tidewater gobies, because they reside in lower river segments and lagoons all year. Tidewater gobies have the potential to occur in San Luis Obispo Creek, Pismo Creek, Santa Maria River, Shuman Creek, San Antonio Creek, Santa Ynez River, Jalama Creek, and small coastal drainages from Point Conception to Gaviota Creek. • California least tern and California brown pelican could be affected if spills encounter foredune habitat near the river mouth where these species reside for portions of the year. California least terns forage in estuaries and would be affected be an offshore spill that reaches the coastline near river mouths or lagoons. Coastal areas inhabited by California least tern include the Santa Maria River mouth and Santa Ynez River mouth.	The risk and impacts from an offshore spill would also be the same as the proposed project. Under the Casmalia Alternative, new emulsion and gas pipelines would need to be constructed from LOGP to the Casmalia. In addition, a new dry oil pipeline would be constructed from Casmalia to the ConocoPhillips Orcutt Pump Station. The state-or federal-listed wildlife species that would be impacted by a spill along these new pipelines includes the following: • The California tiger salamander would be affected if spills occur on or near breeding pools or adjacent upland habitat. California tiger salamanders are known to occur along the pipeline corridor north. Impacts may include toxicity, smothering of adults or eggs, and habitat loss. • The unarmored threespike stickleback and California red-legged frog may be affected if a spill reaches San Antonio Creek. The creek and several of its drainage tributaries are located along the pipeline corridor north of LOGP. The severity of spill-related impacts to listed wildlife species would be greater under the Casmalia East Processing Site Alternative than under the Proposed Project due to the additional area of disturbance and additional listed species that may be affected in the onshore habitat.

Table 6.1b: Comparison of Class I Impacts for the Proposed Project ~~to the~~ and Casmalia East Processing Site Alternative

Impact #	Description of Impact	Proposed Project	Casmalia East Processing Site Alternative
		The western snowy plover would be adversely affected by an oil spill that occurred on the beach where plovers nest or forage. An offshore spill would adversely affect this species if oil migrated to the beach habitat. Western snowy plovers breed, nest, and forage near the tide line and within the kelp wrack. Oiling of beach sediments and kelp litter would adversely affect this species feeding and nesting success. Cleanup efforts could also significantly impact breeding success of this species if cleanup efforts were to occur in the foredunes and beach habitat near the Santa Ynez River or San Antonio Creek river mouths. Several other beaches along the shoreline on San Luis Obispo and Santa Barbara County, and beaches at San Miguel and Santa Rosa Islands are used by western snowy plovers and may be impacted by a large offshore spill (Appendix G). The greatest potential for impacts would occur during this species' breeding season from March 1 through September 30. California red-legged frogs, federally listed as threatened, could also be impacted if an onshore oil spill entered the Santa Ynez River. An offshore spill would not be likely to migrate upstream to occupied California red-legged frog habitat within the river channel. **Preferred**	
TB.9	Under Alternative Power Line Route (Option 2b) or the VAFB Offshore Alternative, a directionally drilled bore hole would be routed under the Santa Ynez River. Drilling noise, construction, and accidental release of boring materials ("frac-outs") during construction activities could impact one or more sensitive wildlife species.	This impact would not occur under the proposed project unless Alternative Power Line Route – Option 2b was chosen.	This impact would not occur under the Casmalia Alternative.

Table 6.1b: Comparison of <u>Class I Impacts for</u> the Proposed Project ~~to the~~ <u>and</u> Casmalia East Processing Site Alternative

Impact #	Description of Impact	Proposed Project	Casmalia East Processing Site Alternative
TB.10	Installation of the new pipelines and associated facilities has the potential to remove or damage extensive acres of native vegetation, wildlife habitat including sensitive plant species, and previously disturbed natural areas.	Vegetation removal associated with the proposed project is limited to power line installation. Assuming 45 power poles total, the disturbance would be approximately 0.33 acre of vegetation and wildlife habitat. Construction of the proposed transformer station, would result in the temporary impacts to 4,200 square feet and permanent loss of 150 square feet of vegetation or wildlife habitat (depending on location), for a total of less than 0.1 acre of impact. Given the nominal total acreage (0.43 acres) and that the acreage is dispersed by pole and substation site, the impact is considered *Class II, significant but mitigable,* for the proposed project. **Preferred**	The construction activities associated with the Casmalia Alternative would result in approximately 55 acres of disturbance, in primarily natural habitats, from installation of a pipeline corridor from the LOGP to the Casmalia East facility. In addition, installing a new dry oil pipeline along the existing pipeline corridor from Casmalia to the Orcutt Pump Station has the potential to disturb 97 acres, including agricultural fields and previously disturbed natural areas (especially in the Purisima Hills), many of which have recovered from installing the existing pipeline array. The new facility would be placed in the existing Casmalia Oil Field, which although disturbed by oil well pads and roads, provides habitat for plants and wildlife. Installation of the new facility would result in the permanent loss of vegetation and wildlife habitat. Revegetation efforts along the pipeline corridor would require intensive management to restore the impacted plant communities. Oak woodland, Bishop pine, and chaparral communities would take many years to reach maturity.
OWR.2	A rupture or leak from the emulsion, produced water or dry oil pipelines could substantially degrade surface and groundwater quality	Both produced water and oil emulsion spills could affect surface and ground waters depending on the location and size of the spill. Although the proposed project would treat produced water to achieve compliance with offshore receiving water criteria (if ocean discharge is used instead of re-injection), onshore spills still may contain some soluble hydrocarbons with the potential for affecting surface and/or groundwater quality. The worst-case onshore oil spill for the proposed project is estimated to be 7,006 bbls, an increase of 688 bbls in comparison to existing operations (see Table 5.1.25). If a spills reached the Santa Ynez River, it could have significant, long-term and widespread impacts to water quality and, consequently, sensitive	The severity of the impact for the Casmalia Alternative would be greater than the proposed project because of the additional miles of pipeline associated with this alternative.

Table 6.1b: Comparison of Class I Impacts for the Proposed Project ~~to the~~ and Casmalia East Processing Site Alternative

Impact #	Description of Impact	Proposed Project	Casmalia East Processing Site Alternative
		biological resources. Similarly, subsurface (i.e., underground) spills, or surface spills in areas with porous surface soils and a shallow aquifer, could result in significant, long-term contamination of groundwater. An offshore oil spill could also enter the waters of the Santa Ynez River mouth/estuary creating significant water quality impacts and consequently affecting biological resources. **Preferred**	
MB.1	Oil spills from the project may impact benthic and intertidal organisms, fish, marine mammals, marine birds, and marine turtles. Oil spills from the project may impact plankton.	The degree of impacts to marine biota from an oil spill will depend on several factors, including location, volume, rate, and type of oil that is spilled; amount of weathering, evaporation, and dispersion of oil in the water column and shoreline; and the amount of oil that is contained and cleaned immediately after the spill. Oil effects to marine biota include mortality or can be sublethal by inhibiting growth and reproduction. Oil can also bioaccumulate in certain marine species and can also cause histological damage, alter physiology and metabolism, and decrease reproductive capacity. The maximum offshore oil spill estimated for the proposed project is 7,929 bbls for the offshore pipeline and 4,500 bbls for a Platform Irene well blowout (see Table 5.1.29). Oil spills are far more likely to travel due south from the site of the spill. Spills could potentially extend substantial distances and impact ocean areas south of the Channel Islands. There is a tangible probability that they would impact the Channel Islands Marine Sanctuary. To the north, only open-ocean areas south of Point Sal were likely to be impacted by oil spills resulting from the proposed project. Clean up of oil spills could also impact the marine environment. In addition, even with the most	The severity of this impact for the Casmalia Alternative would be the same as the proposed project since the probability of a spill and associated spill volumes would the same for offshore facilities.

Table 6.1b: Comparison of Class I Impacts for the Proposed Project ~~to the~~ and Casmalia East Processing Site Alternative

Impact #	Description of Impact	Proposed Project	Casmalia East Processing Site Alternative
		prudent spill clean up efforts, the majority of spilled oil is not recovered. **No Preference**	**No Preference**
MWQ.1	Accidental discharge of petroleum hydrocarbons into marine waters would adversely affect marine water quality.	The combined probability of oil leaks, ruptures, blowouts, and spills from Platform Irene and the offshore portion of the emulsion pipeline would approximately ~~double~~ quadruple under the proposed project (5.4~~10.5~~% to 22.1% - see Table 5.1.28). In addition, the expanded new production would increase the concentration of crude in the oil emulsion transported to shore. Because of increased crude concentrations, offshore oil spills associated with a rupture of the transmission line would induce greater deleterious effects within marine waters. Finally, the frequency and duration of trips made by offshore support vessels would increase under the proposed project. The increased vessel traffic would increase the risk of a vessel accident and an attendant spill although its volume would be limited compared to other oil-spill scenarios. **No Preference**	The severity of this impact for the Casmalia Alternative would be the same as the proposed project since the probability of a spill and associated spill volumes would the same for offshore facilities. **No Preference**
CRF/KH.2	Oil spills may potentially impact commercial and recreational fishing in the proposed project area.	A wide variety of fish and shellfish species are commercially harvested in the project area. Biota residing in the intertidal and shallow subtidal habitat are vulnerable to oil spills. Although abalone is not presently harvested in the project area, both sea urchins and lobsters are high value species that are harvested both commercially and recreationally in the area. In the event of an oil spill, there could be impacts to abalone, sea urchins, and lobster. Smothering is the most common cause of mortality and would be limited to direct contact with weathered tar balls from the oil spill. Although not high value species, other intertidal or shallow subtidal organisms that are harvested include sea cucumbers and whelks.	The severity of this impact for the Casmalia Alternative would be the same as the proposed project since the probability of a spill and associated spill volumes would the same for offshore facilities.

Table 6.1b: Comparison of <u>Class I Impacts for</u> the Proposed Project ~~to the~~ <u>and</u> Casmalia East Processing Site Alternative

Impact #	Description of Impact	Proposed Project	Casmalia East Processing Site Alternative
		While the probability for oil contacting and fouling the shoreline or shallow subtidal areas where commercial or recreational species are harvested is low, it nevertheless can occur. While contaminated shorelines may be cleaned, in some instances, depending on substrate type, oil may persist in sediments for several years. Adult fish, due to their mobility, may be able to avoid or minimize exposure to spilled oil. However, there is no conclusive evidence that fish will avoid spilled oil. Egg and larval stages would also not be able to avoid exposure to spilled oil. Fish harvested from contaminated areas may also be reduced in value and fishing gear can be damaged due to oil fouling. **No Preference**	**No Preference**
T.4	An oil spill from the proposed Tranquillon Ridge project could result in the disruption of commercial shipping, fishing, and recreational marine traffic, and onshore transportation infrastructure.	An oil spill could result in the closure of the Coast Guard's recommended marine traffic corridors through the Santa Barbara Channel and restrict boating along up to 70 miles of coastline and San Miguel, Santa Rosa, and western Santa Cruz Islands. The event of an oil spill could disrupt marine traffic for a number of days, due to clean-up activities. Depending on the location of the spill, marine traffic might have to use routes outside of the Coast Guard's recommended marine traffic corridors. Also, commercial/recreational fishing boat traffic could be precluded from areas around the spill during the cleanup activities. **No Preference**	The severity of this impact for the Casmalia Alternative would be the same as the proposed project since the probability of a spill and associated spill volumes would the same for offshore facilities. **No Preference**
CR.3	Containment and cleanup activities associated with an accidental oil spill would result in ground disturbance and potential impacts on cultural resources.	Oil spill containment activities that would potentially affect cultural resources include the use of heavy earth moving equipment (e.g., graders, scrapers, front-end loaders) or manual excavation to remove oil-contaminated material. Soil removal by manual or mechanized means poses potential significant impacts on any cultural resource in the	For the Casmalia Alternative, the oil spill related impacts to cultural resources would be the same as the proposed project from pipeline landfall at Wall/Surf Beach to the LOGP. The risk and severity of the impact for the Casmalia Alternative would be greater than the proposed project due to additional length of new pipeline from the LOGP to

Table 6.1b: Comparison of Class I Impacts for the Proposed Project ~~to the~~ and Casmalia East Processing Site Alternative

Impact #	Description of Impact	Proposed Project	Casmalia East Processing Site Alternative
		affected areas. Water flooding is another cleanup method whereby subsurface oil is forced to the surface by water pumped into the groundwater table. Although drilling holes for water flooding would potentially impact sites, flooding (in most cases) would be preferable to soil removal because it is likely that drilling would result in relatively low levels of subsurface disturbance. **Preferred**	Casmalia and from Casmalia to the Orcutt Pump Station.
CR.5	Disturbance or destruction of cultural sites that may contain significant or potentially significant cultural materials by the construction of new drilling/ production/processing facilities, and pipelines.	Impact CR.~~6~~5 does not apply to the proposed project. **Preferred**	Four recorded archaeological sites are located within 200 feet of the alternative pipeline route; however, there are potentially unrecorded sites because approximately 7 miles of the pipeline corridor and the new processing site have never been surveyed for cultural resources. Because of the expected low density of cultural sites, the pipeline corridor could be designed to avoid known cultural resources. Therefore, this impact is considered to be significant but mitigable.
Visual.1	Visual impacts due to long-term continued presence of the project facilities visible from coastal zone (Platform Irene and Surf substation).	The presence of Platform Irene, which is visible from the public beach by marine recreational users and from the Union Pacific Railroad, creates a negative aesthetic impact. The proposed project would continue, but not worsen, this impact by extending the life of Platform Irene from approximately 10 years to 30 years. The Surf Substation provides power to Platform Irene. The substation, which is visible from several public areas, such as the Ocean County Park, Surf Beach, and portions of the Union Pacific Railroad and Ocean Avenue, creates a negative aesthetic impact. The life of the substation under the proposed project would also be extended from approximately 10 years to 30 years. **No Preference**	The severity of this impact for the Casmalia Alternative would be the same as the proposed project since Platform Irene and Surf Substation would remain for the projected 30-year project life. **No Preference**

Table 6.1b: Comparison of <u>Class I Impacts for</u> the Proposed Project ~~to the~~ <u>and</u> Casmalia East Processing Site Alternative

Impact #	Description of Impact	Proposed Project	Casmalia East Processing Site Alternative
Visual.4	Visual impacts due to long-term continued presence of the LOGP.	The LOGP creates nighttime glare from the light of the facility that can be seen through most of the Lompoc area, (including public viewsheds), and as far away as Highway 101 north of Los Alamos. This glare reduces the darkness of the night sky and could obscure the stars and other astronomical phenomena. The glare degrades the public's enjoyment of viewing the nighttime sky from many public areas, and therefore adversely impacts visual resources of several visually important areas. The glare is also incompatible with the mostly dark nighttime sky of the undeveloped areas near Lompoc that are in the public viewshed. The lights at the LOGP are needed to allow for the safe operation of the facility at night and to comply with OSHA regulations. Under the proposed project, the nighttime glare associated with LOGP would be extended from approximately10 years to 30 years. **Preferred**	Nighttime glare associated with the LOGP would be less for the Casmalia Alternative since much of the LOGP processing equipment would be removed; however, the facility would remain in operation for the projected 30 year project life as a pumping facility for the Casmalia pipelines. As a result, nighttime glare would be reduced, but not eliminated. In addition, there would also be a Class I impact associated with nighttime glare at the new Casmalia processing facility. Given that nighttime glare would occur at both the Casmalia and LOGP sites under the Casmalia Alternative, this impact would be greater than for the proposed project.
Rec.1	The proposed project would increase the likelihood and volume of an oil spill, which could result in public access restrictions to coastal and inland recreational resources.	An offshore spill caused by an accident or failure at Platform Irene or in the offshore pipeline could lead to beach closures and boating restrictions during spill response and cleanup, as well as a lingering public perception that recreational resources are polluted, even after the cleanup period. The duration and extent of beach closures would depend on the volume of the spill and prevailing ocean and local weather conditions. A worst-case scenario oil spill could reach recreational resources as far north as Montana de Oro State Park near Morro Bay and as far south as the Santa Barbara Channel Islands. The coastline east of Point Conception, including Gaviota and Refugio State Beaches would likely avoid direct spill impacts. The area from Point Sal to Point Arguello is at greatest risk from a spill due to its proximity to the Point Pedernales Project facilities; therefore Ocean Beach County Park, Point Sal Beach State Park, and	For the Casmalia Alternative, the oil spill related impacts to coastal and inland recreational resources would be the same as the proposed project given the absence of any recreational resources between LOGP and the Casmalia site.

Table 6.1b: Comparison of Class I Impacts for the Proposed Project ~~to the~~ and Casmalia East Processing Site Alternative

Impact #	Description of Impact	Proposed Project	Casmalia East Processing Site Alternative
		Jalama Beach County Park would be more likely impacted than other recreation areas An onshore spill near the pipeline landfall could pose a similarly adverse effect on the recreational utilization of Ocean Beach Park. An onshore spill further inland could adversely affect recreational resources such as the Burton Mesa Ecological Reserve, the Santa Ynez River, and Ocean Beach Park (via a spill into the river). **No Preference**	**No Preference**

The alternative processing site at Casmalia would result in a number of new significant impacts that would not occur with the proposed Tranquillon Ridge Project. Construction of the new processing facilities and associated pipelines from the LOGP to Casmalia would result in significant impacts to biological resources (Impact TB.10). This alternative would also increase the likelihood of an onshore oil spill due to the additional ~~13.5~~ 10 to 15 miles of pipelines required to connect the Casmalia site to the LOGP. In the event of an oil spill from these pipelines, there could be significant impacts to onshore biological resources (Impact TB.6, TB.7, and TB.8), cultural resources (Impact CR.3), and onshore water resources (Impact OWR.2).

Use of the Casmalia site would not eliminate any of the significant impacts to the marine environment associated with Platform Irene and the pipelines from Platform Irene to the LOGP that result from increased throughput or extension of life (Impacts MB.1, MWQ.1, and CRF/ KH.2).

In summary, the alternative site at Casmalia would offer one environmental advantage over the proposed project (reduced night lighting at the LOGP); however, the alternative would create a new Class I visual impact due to the nighttime glare associated with the alternative processing site. Further, the Casmalia Alternative poses environmental disadvantages in the issue areas of: (1) onshore biology; (2) onshore water resources; (3) risk of upset; (4) visual resources, and (5) cultural resources.

6.3.3 New Oil Emulsion Pipeline from Platform Irene to the LOGP

This alternative would not eliminate any of the significant (Class I) impacts associated with the proposed project. The new oil pipeline alternative would generate a new Class II terrestrial biology impact (Impact TB.10) that would not occur with the proposed project. All of the Tranquillon Ridge Project significant (Class I) impacts associated with increased throughput and extension of life would remain the same as for the proposed project. While the new pipeline would have a lower spill probability than the existing pipeline, the reduction in spill frequency was determined to be approximately 10 percent, resulting in a reduction of the spill probability due to rupture from 11.2 percent for the proposed project to approximately 10.1 percent for the onshore portion of the emulsion pipeline, and from 9.7 percent to approximately 8.7 percent for the offshore portion. The new pipeline would have the same oil spill volumes as the proposed project. It is also likely that the new pipeline would require fewer repairs and less maintenance over the life of the project, reducing the need to mobilize work crews along the pipeline right-of-way.

In summary, this alternative would offer environmental advantages over the proposed project of a slight reduction in the oil spill probability. Due to construction impacts, this alternative would have a number of environmental disadvantages in the issue areas of: (1) onshore biology; (2) onshore water resources; and (3) cultural resources.

Table 6.1c: Comparison of Class I Impacts for the Proposed Project and ~~to the~~ Emulsion Pipeline Replacement Alternative

Impact #	Description of Impact	Proposed Project	Emulsion Pipeline Replacement Alternative
Risk.3	The proposed project could generate risks to public safety by exposing the public to transportation hazards.	The project would increase the transportation of gas liquids along roadways over the current operations. By increasing the number of trips, and therefore the risks to the public, this existing significant impact is exacerbated (more truck trips and a longer period over which truck trips would occur). **No Preference**	The severity of the impact for the Emulsion Pipeline Replacement Alternative would be the same as the proposed project since production levels would be the same; thereby, resulting in the same number of gas liquid truck trips. **No Preference**
TB.6	A pipeline leak or rupture could result in an oil spill and subsequent degradation of upland, riparian and freshwater aquatic habitats and injury to plants and terrestrial and aquatic wildlife through direct toxicity, smothering, and entrapment as well as through resultant cleanup efforts. An offshore spill may affect the terrestrial environment if oil is transported to the shoreline. Oil could be transported up creeks and rivers that are open to tidal influence. The modeled trajectory for a worst-case offshore oil spill (Appendix G) indicates that shorelines, lagoons, estuaries, and river mouths may be directly affected. Surrounding terrestrial areas may be affected by cleanup efforts.	While the risk of an oil spill and/or pipeline rupture is a risk already associated with the existing oil pipeline, the proposed increase in throughput and oil percentages would increase the combined lifetime probability of oil leaks, ruptures, blowouts, and spills from Platform Irene and the offshore portion of the emulsion pipeline from 5.4~~10.5~~% to 22.1% over the life of the project (see Table 5.1.28). In addition, assuming that the pumps are installed at Valve Site #2, the lifetime probability for a rupture along the onshore emulsion pipeline would increase from 0.9% to 11.2% and for a leak would increase from 3.6% to 100% (see Table 5.1.24) Upland Habitats: Several sensitive upland habitat areas are crossed by the pipeline corridor or lie close to and down slope of the corridor. These include foredunes, coastal dune scrub, coastal sage scrub, Burton Mesa chaparral, Bishop pine forest, and coast buckwheat populations, which may support El Segundo blue butterfly. Upland habitats would not be directly affected by an offshore spill, but containment and cleanup activities may affect upland habitats if off-road access is necessary to reach the affected shoreline. Aquatic Habitats: Salt or freshwater marshes would be most sensitive because the biological activity of these communities is concentrated near the soil or water surface, where oil would be stranded. Aquatic habitats would be affected by an offshore spill if oil were to reach the shoreline and be dispersed upstream	For the Emulsion Pipeline Replacement Alternative, the oil spill related impacts to upland, riparian, and aquatic habitats, and wildlife would be the same as the proposed project from pipeline landfall at Wall/Surf Beach to the LOGP. However, the probability of a spill along the new emulsion line would be approximately 10% less than for the existing emulsion line associated with the proposed project. **Slightly Preferred**

Table 6.1c: Comparison of Class I Impacts for the Proposed Project and ~~to the~~ Emulsion Pipeline Replacement Alternative			
Impact #	Description of Impact	Proposed Project	Emulsion Pipeline Replacement Alternative
		by tidal flow. Tidally influenced aquatic and wetland habitats within the area potentially affected by oil spills occur at the mouths of Pismo Creek, San Luis Obispo Creek, Arroyo Grande Creek, Santa Maria River, Shuman Creek, San Antonio Creek, Santa Ynez River, La Honda Creek, Jalama Creek, Gaviota Creek, and several small drainages between Point Conception and Gaviota. Discharged oil could reach the shoreline in solid or liquid form. Direct impacts may include toxicity and smothering of wetland plants and contamination of rooting substrate. Containment and cleanup activities may have indirect effects on aquatic habitats due to vehicle access, foot traffic, and sediment excavation. Riparian Habitats: Riparian woodland communities may be somewhat less sensitive to an oil spill because leaves in the canopy would not be susceptible to oiling. Effects of an oil spill on plant root systems would include reductions in the availability of soil water, nutrients, and oxygen to plant root systems; and toxicity. All of these would lead to reduced growth and reproduction, and possible mortality in plants exposed to oil. Riparian habitats crossed by the pipeline corridor are limited to the Santa Ynez River corridor, drainage tributaries, and small riparian habitats in Oak Canyon and Santa Lucia Canyon. Oil could enter riparian habitats through direct entry, runoff from upland areas within the watershed (especially during storm runoff), and contamination of groundwater feeding streams. Oil could also enter drainages and riparian areas through overland flow; however, under dry conditions, overland flow of oil would be relatively slow due to the viscous nature of the crude oil. The rate of spread would slow as the oil cools and becomes more viscous. As the water fraction of the oil-water emulsion	

Table 6.1c: Comparison of <u>Class I Impacts for</u> the Proposed Project <u>and</u> ~~to the~~ Emulsion Pipeline Replacement Alternative

Impact #	Description of Impact	Proposed Project	Emulsion Pipeline Replacement Alternative
		increases over the life of the project the emulsion would have different behaviors when spilled. Riparian habitat is scarce in the coastal area that may be affected by an offshore spill. Oil discharged offshore may reach the shoreline, but would not be transported inland above the extent of tidally influenced waters near river mouths, sloughs, and lagoons. Riparian habitat along tidal waters exists in small amounts at large drainages including the Santa Maria River, San Antonio Creek, and Santa Ynez River. Potential impacts to riparian habitats would be minor, but may include direct toxicity to riparian vegetation and indirect damage due to containment and cleanup activities. Aquatic Wildlife: Aquatic wildlife would most likely be affected by an offshore spill and cleanup activities. Shorebirds that forage in wetlands and estuaries would be affected if an offshore spill reached the shoreline. Birds would be unable to fly if their feathers are oiled. Similarly, a large offshore spill may affect fish in brackish water lagoons. Freshwater aquatic wildlife would be affected by an onshore spill that reaches drainages or by an offshore spills that reaches the shoreline. Aquatic reptiles, amphibians, fish, and birds would be vulnerable to an onshore spill and clean up efforts. Impacts would include toxicity, degradation of habitat and breeding areas, and sediment excavation during containment or cleanup. Terrestrial Wildlife: Oil spills and their clean-up are expected to directly affect wildlife species such as Pacific chorus frogs, western toads, a wide range of invertebrates and sensitive species such as western pond turtles and two-striped garter snakes. Depending on the size and areal extent of the spill, an unknown number of birds, reptiles and land	

Table 6.1c: Comparison of Class I Impacts for the Proposed Project and ~~to the~~ Emulsion Pipeline Replacement Alternative

Impact #	Description of Impact	Proposed Project	Emulsion Pipeline Replacement Alternative
		mammals could be killed if they come in direct contact with the oil. An offshore spill would not directly affect terrestrial wildlife, but containment or cleanup activities may have a minor effect on terrestrial species if off-road access is necessary to reach the affected shoreline.	
TB.7	A spill and/or subsequent cleanup efforts may directly or indirectly cause the loss of habitat and individuals or colonies of state-or federally-listed plant species including seaside bird's beak, Surf thistle, beach spectacle pod, La Graciosa thistle, beach layia, and possibly Pismo clarkia or degrade designated critical habitat for the Lompoc yerba santa and the La Graciosa thistle. An offshore spill may affect listed plant species in coastal dunes and foredune habitat due to resultant containment or cleanup efforts.	Individuals of the following state- or federally-listed plant species may be removed or damaged by activities associated with an onshore oil spill and cleanup. These species are typically found above the beach and tidal zone and are not found close to the Santa Ynez River, thus are unlikely to be directly affected by an offshore spill, but could be affected by subsequent cleanup efforts. • La Graciosa thistle, a federally listed endangered species and state-listed threatened species, has the potential to be impacted by an oil spill or cleanup activities if a spill reaches its habitat. The species it has not been observed on VAFB in recent years, but the existing pipeline overlaps a small portion of designated critical habitat south of Orcutt and north of the intersection of Highway 1 and Highway 135. La Graciosa thistle may be affected by an offshore spill that reaches its habitat near Oso Creek, Santa Ynez River and Santa Maria River mouths. Cleanup activities may affect the coastal dunes and swales occupied by this species. • Gaviota tarplant, a federal and state listed endangered species, have been observed along the pipeline corridor and adjacent habitat in grassland, scrub, and semi-disturbed areas on the coastal terrace. • Surf thistle and beach spectacle pod, both state-listed as threatened, have been recorded in the foredunes crossed by the pipeline corridor. Containment or cleanup activities for an offshore spill may impact occupied coastal dune	For the Emulsion Pipeline Replacement Alternative, the oil spill related impacts to state-or federally-listed plant species would be the same as the proposed project from pipeline landfall at Wall/Surf Beach to the LOGP. However, the probability of a spill along the new emulsion line would be approximately 10% less than for the existing emulsion line associated with the proposed project. **Slightly Preferred**

Table 6.1c: Comparison of Class I Impacts for the Proposed Project and ~~to the~~ Emulsion Pipeline Replacement Alternative			
Impact #	**Description of Impact**	**Proposed Project**	**Emulsion Pipeline Replacement Alternative**
		habitat near Oso Creek, Pismo Beach, and Oceano dunes. • Seaside bird's-beak, state-listed endangered, is known to occur within or directly adjacent to the pipeline corridor north of the Federal Penitentiary and west of the LOGP An offshore spill and associated containment or cleanup would not be likely to impact habitats occupied by this species. • Beach layia, a federal and state-listed endangered species, is a foredune species that is not known or suspected to occur in the area that may be affected by an onshore spill. An offshore spill would not reach the coastal dune habitat preferred by this species, but containment or cleanup activities may affect occupied habitat along the coastline west of Surf Road. Lompoc yerba santa, federally-listed as endangered, is known in a few locations in the project area, all of which are upslope from the oil pipeline and not likely to be affected by impacts associated with an oil spill or cleanup activities. Pismo clarkia, federally-listed endangered and state-listed rare, is also unlikely to be affected by spills or clean up since suitable habitat for this species is upslope of the pipeline in the vicinity of Summit Pump Station. Neither of these species would be affected by an offshore spill.	
TB.8	An oil spill and/or subsequent cleanup effort may directly or indirectly cause the loss of individual state or federally-listed wildlife species or cause the loss or degradation of sensitive species habitat. An oil spill and/or subsequent cleanup effort may impact designated critical habitat for steelhead, western snowy plover, and California red-legged frog. An offshore spill may affect listed fish and wildlife that inhabit shorelines, beaches, lagoons, estuaries, and river mouths.	El Segundo blue butterfly may be adversely affected if an oil spill or subsequent clean up activities result in destruction of its host plant, coast buckwheat. Spills from the pipeline between the shoreline and LOGP could enter the Santa Ynez River and affect the species listed below. In addition, depending on the time of the year, weather conditions, and tidal action, these species could also be affected by an offshore oil spill.	For the Emulsion Pipeline Replacement Alternative, the oil spill related impacts to state-or federally-listed wildlife species would be the same as the proposed project from pipeline landfall at Wall/Surf Beach to the LOGP. However, the probability of a spill along the new emulsion line would be approximately 10% less than for the existing emulsion line associated with the proposed project. **Slightly Preferred**

Table 6.1c: Comparison of Class I Impacts for the Proposed Project and ~~to the~~ Emulsion Pipeline Replacement Alternative

Impact #	Description of Impact	Proposed Project	Emulsion Pipeline Replacement Alternative
		• Steelhead trout could be affected by an offshore spill that reaches river mouths and lagoons along the shoreline. Potentially inhabited streams in the ~~area~~ worst-case spill trajectory area (Appendix G) include San Luis Obispo Creek, Pismo Creek, Arroyo Grande Creek, Santa Maria River, Shuman Creek, Santa Ynez River, Jalama Creek, and small coastal drainages from Point Conception to Gaviota Creek. Effects on steelhead would depend on the time of year and size of the spill. Impacts would be greatest if the spill occurred during adult or juvenile migration to or from spawning and rearing areas upstream of the project (January to June). • Spills could affect tidewater gobies, because they reside in lower river segments and lagoons all year. Tidewater gobies have the potential to occur in San Luis Obispo Creek, Pismo Creek, Santa Maria River, Shuman Creek, San Antonio Creek, Santa Ynez River, Jalama Creek, and small coastal drainages from Point Conception to Gaviota Creek. • California least tern and California brown pelican could be affected if spills encounter foredune habitat near the river mouth where these species reside for portions of the year. California least terns forage in estuaries and would be affected by an offshore spill that reaches the coastline near river mouths or lagoons. Coastal areas inhabited by California least tern include the Santa Maria River mouth and Santa Ynez River mouth. The western snowy plover would be adversely affected by an oil spill that occurred on the beach where plovers nest or forage. An offshore spill would adversely affect this species if oil migrated to the beach habitat. Western snowy plovers breed, nest, and forage near the tide line and within the	

Table 6.1c: Comparison of <u>Class I Impacts for</u> the Proposed Project <u>and</u> ~~to the~~ Emulsion Pipeline Replacement Alternative			
Impact #	**Description of Impact**	**Proposed Project**	**Emulsion Pipeline Replacement Alternative**
		kelp wrack. Oiling of beach sediments and kelp litter would adversely affect this species feeding and nesting success. Cleanup efforts could also significantly impact breeding success of this species if cleanup efforts were to occur in the foredunes and beach habitat near the Santa Ynez River or San Antonio Creek river mouths. Several other beaches along the shoreline on San Luis Obispo and Santa Barbara County, and beaches at San Miguel and Santa Rosa Islands are used by western snowy plovers and may be impacted by a large offshore spill (Appendix G). The greatest potential for impacts would occur during this species' breeding season from March 1 through September 30. California red-legged frogs, federally listed as threatened, could also be impacted if an onshore oil spill entered the Santa Ynez River. An offshore spill would not be likely to migrate upstream to occupied California red-legged frog habitat within the river channel.	
TB.9	Under Alternative Power Line Route (Option 2b) or the VAFB Onshore Alternative, a directionally drilled bore hole would be routed under the Santa Ynez River. Drilling noise, construction, and accidental release of boring materials ("frac-outs") during construction activities could impact one or more sensitive wildlife species.	This impact would not occur under the proposed project unless Alternative Power Line Route – Option 2b was chosen.	This impact would not occur under the Emulsion Pipeline Replacement Alternative.
~~TB.10~~	~~Installation of the new pipelines and associated facilities has the potential to remove or damage extensive acres of native vegetation, wildlife habitat including sensitive plant species, and previously disturbed natural areas.~~	~~Vegetation removal associated with the proposed project is limited to power line installation. Assuming 45 power poles total, the disturbance would be approximately 0.33 acre of vegetation and wildlife habitat. Construction of the proposed transformer station, would result in the temporary impacts to 4,200 square feet and permanent loss of 150 square feet of vegetation or wildlife habitat (depending on location), for a total of less than 0.1 acre of impact. Given the nominal total acreage (0.43 acres) and that the acreage is dispersed by pole and substation site, the impact is considered *Class*~~	~~For the Emulsion Pipeline Replacement Alternative, removal of up to 88.6 acres of native vegetation and wildlife habitat would occur, including the loss of individuals of sensitive plant species that may be present in the disturbance corridor, such as sand mesa manzanita, La Purisima manzanita, and black-flowered figwort, as well as oak trees and coast buckwheat,~~ ~~For the Emulsion Pipeline Replacement Alternative, the residual impact on sensitive plant species is expected to be significant but mitigable because of~~

Table 6.1c: Comparison of Class I Impacts for the Proposed Project and ~~to the~~ Emulsion Pipeline Replacement Alternative			
Impact #	**Description of Impact**	**Proposed Project**	**Emulsion Pipeline Replacement Alternative**
		~~*II, significant but mitigable*, for the proposed project.~~ ~~**Preferred**~~	~~the previously disturbed nature of the corridor and the small number of individuals present in the adjacent habitat that would be impacted.~~
OWR.2	A rupture or leak from the emulsion, produced water or dry oil pipelines could substantially degrade surface and groundwater quality	Both produced water and oil emulsion spills could affect surface and ground waters depending on the location and size of the spill. Although the proposed project would treat produced water to achieve compliance with offshore receiving water criteria (if ocean discharge is used instead of re-injection), onshore spills still may contain some soluble hydrocarbons with the potential for affecting surface and/or groundwater quality. The worst-case onshore oil spill for the proposed project is estimated to be 7,006 bbls, an increase of 688 bbls in comparison to existing operations (see Table 5.1.25). If a spills reached the Santa Ynez River, it could have significant, long-term and widespread impacts to water quality and, consequently, sensitive biological resources. Similarly, subsurface (i.e., underground) spills, or surface spills in areas with porous surface soils and a shallow aquifer, could result in significant, long-term contamination of groundwater. An offshore oil spill could also enter the waters of the Santa Ynez River mouth/estuary creating significant water quality impacts and consequently affecting biological resources. ~~**No Preference**~~	The severity of the impact for the Emulsion Pipeline Replacement Alternative would be the same as the proposed project since production levels and resultant spill volumes would be the same<ins>; however, the probability of a spill would be reduced by 10%</ins>. ~~**No Preference**~~ <ins>**Slightly Preferred**</ins>
MB.1	Oil spills from the project may impact benthic and intertidal organisms, fish, marine mammals, marine birds, and marine turtles. Oil spills from the project may impact plankton.	The degree of impacts to marine biota from an oil spill will depend on several factors, including location, volume, rate, and type of oil that is spilled; amount of weathering, evaporation, and dispersion of oil in the water column and shoreline; and the amount of oil that is contained and cleaned immediately after the spill. Oil effects to marine biota include mortality or can be sublethal by inhibiting growth and reproduction. Oil can also	The severity of this impact for the Emulsion Pipeline Replace Alternative would be the same as the proposed project <ins>since production levels and resultant spill volumes would be the same; however, the probability of a spill would be reduced by 10%.</ins>~~since the probability of a spill and associated spill volumes would the same for offshore facilities.~~

Table 6.1c: Comparison of Class I Impacts for the Proposed Project and ~~to the~~ Emulsion Pipeline Replacement Alternative			
Impact #	**Description of Impact**	**Proposed Project**	**Emulsion Pipeline Replacement Alternative**
		bioaccumulate in certain marine species and can also cause histological damage, alter physiology and metabolism, and decrease reproductive capacity. The maximum offshore oil spill estimated for the proposed project is 7,929 bbls for the offshore pipeline and 4,500 bbls for a Platform Irene well blowout (see Table 5.1.29). Oil spills are far more likely to travel due south from the site of the spill. Spills could potentially extend substantial distances and impact ocean areas south of the Channel Islands. There is a tangible probability that they would impact the Channel Islands Marine Sanctuary. To the north, only open-ocean areas south of Point Sal were likely to be impacted by oil spills resulting from the proposed project. Clean up of oil spills could also impact the marine environment. In addition, even with the most prudent spill clean up efforts, the majority of spilled oil is not recovered. **~~No Preference~~**	**~~No Preference~~** **Slightly Preferred**
MWQ.1	Accidental discharge of petroleum hydrocarbons into marine waters would adversely affect marine water quality.	The combined probability of oil leaks, ruptures, blowouts, and spills from Platform Irene and the offshore portion of the emulsion pipeline would approximately ~~double~~ quadruple under the proposed project (~~10.5~~5.4% to 22.1% - see Table 5.1.28). In addition, the expanded new production would increase the concentration of crude in the oil emulsion transported to shore. Because of increased crude concentrations, offshore oil spills associated with a rupture of the transmission line would induce greater deleterious effects within marine waters. Finally, the frequency and duration of trips made by offshore support vessels would increase under the proposed project. The increased vessel traffic would increase the risk of a vessel accident and an attendant spill although its volume would be limited compared to other oil-spill scenarios. **~~No Preference~~**	The severity of this impact for the Emulsion Pipeline Replace Alternative would be the same as the proposed project since production levels and resultant spill volumes would be the same; however, the probability of a spill would be reduced by 10%.~~since the probability of a spill and associated spill volumes would the same for offshore facilities.~~ **~~No Preference~~** **Slightly Preferred**

Table 6.1c: Comparison of Class I Impacts for the Proposed Project and ~~to the~~ Emulsion Pipeline Replacement Alternative			
Impact #	**Description of Impact**	**Proposed Project**	**Emulsion Pipeline Replacement Alternative**
CRF/KH.2	Oil spills may potentially impact commercial and recreational fishing in the proposed project area.	A wide variety of fish and shellfish species are commercially harvested in the project area. Biota residing in the intertidal and shallow subtidal habitat are vulnerable to oil spills. Although abalone is not presently harvested in the project area, both sea urchins and lobsters are high value species that are harvested both commercially and recreationally in the area. In the event of an oil spill, there could be impacts to abalone, sea urchins, and lobster. Smothering is the most common cause of mortality and would be limited to direct contact with weathered tar balls from the oil spill. Although not high value species, other intertidal or shallow subtidal organisms that are harvested include sea cucumbers and whelks. While the probability for oil contacting and fouling the shoreline or shallow subtidal areas where commercial or recreational species are harvested is low, it nevertheless can occur. While contaminated shorelines may be cleaned, in some instances, depending on substrate type, oil may persist in sediments for several years. Adult fish, due to their mobility, may be able to avoid or minimize exposure to spilled oil. However, there is no conclusive evidence that fish will avoid spilled oil. Egg and larval stages would also not be able to avoid exposure to spilled oil. Fish harvested from contaminated areas may also be reduced in value and fishing gear can be damaged due to oil fouling. ~~**No Preference**~~	The severity of this impact for the Emulsion Pipeline Replace Alternative would be the same as the proposed project since production levels and resultant spill volumes would be the same; however, the probability of a spill would be reduced by 10%.~~since the probability of a spill and associated spill volumes would the same for offshore facilities.~~ ~~**No Preference**~~ **Slightly Preferred**

Table 6.1c: Comparison of Class I Impacts for the Proposed Project and ~~to the~~ Emulsion Pipeline Replacement Alternative

Impact #	Description of Impact	Proposed Project	Emulsion Pipeline Replacement Alternative
T.4	An oil spill from the proposed Tranquillon Ridge project could result in the disruption of commercial shipping, fishing, and recreational marine traffic, and onshore transportation infrastructure.	An oil spill could result in the closure of the Coast Guard's recommended marine traffic corridors through the Santa Barbara Channel and restrict boating along up to 70 miles of coastline and San Miguel, Santa Rosa, and western Santa Cruz Islands. The event of an oil spill could disrupt marine traffic for a number of days, due to clean-up activities. Depending on the location of the spill, marine traffic might have to use routes outside of the Coast Guard's recommended marine traffic corridors. Also, commercial/recreational fishing boat traffic could be precluded from areas around the spill during the cleanup activities. **No Preference**	The severity of this impact for the offshore portion of the Emulsion Pipeline Replace Alternative would be the same as the proposed project since the probability of a spill and associated spill volumes would the same for offshore facilities. However, the probability of a spill along the onshore portion of the alternative would be approximately 10% less than for the existing emulsion line associated with the proposed project. **No Preference**
CR.3	Containment and cleanup activities associated with an accidental oil spill would result in ground disturbance and potential impacts on cultural resources.	Oil spill containment activities that would potentially affect cultural resources include the use of heavy earth moving equipment (e.g., graders, scrapers, front-end loaders) or manual excavation to remove oil-contaminated material. Soil removal by manual or mechanized means poses potential significant impacts on any cultural resource in the affected areas. Water flooding is another cleanup method whereby subsurface oil is forced to the surface by water pumped into the groundwater table. Although drilling holes for water flooding would potentially impact sites, flooding (in most cases) would be preferable to soil removal because it is likely that drilling would result in relatively low levels of subsurface disturbance.	The severity of this impact for the Emulsion Pipeline Replace Alternative would be the same as the proposed project since the probability of a spill and associated spill volumes would the same for the onshore pipeline. However, the probability of a spill along the new emulsion line would be approximately 10% less than for the existing emulsion line associated with the proposed project. **Slightly Preferred**
CR.5	Disturbance or destruction of cultural sites that may contain significant or potentially significant cultural materials by the construction of new drilling/ production/processing facilities, and pipelines.	Impact CR.5~~6~~ does not apply to the proposed project. **Preferred**	There are 29 recorded sites within a ½-mile of the pipeline corridor. However, because the new emulsion line would be placed within the same corridor of the existing PXP pipelines and this corridor has been previously disturbed by construction activities associated with the existing pipelines, it is unlikely that any new cultural sites would be disturbed and therefore this impact would be significant but mitigable.

Table 6.1c: Comparison of <u>Class I Impacts for</u> the Proposed Project <u>and</u> ~~to the~~ Emulsion Pipeline Replacement Alternative

Impact #	Description of Impact	Proposed Project	Emulsion Pipeline Replacement Alternative
Visual.1	Visual impacts due to long-term continued presence of the project facilities visible from coastal zone (Platform Irene and Surf substation).	The presence of Platform Irene, which is visible from the public beach by marine recreational users and from the Union Pacific Railroad, creates a negative aesthetic impact. The proposed project would continue, but not worsen, this impact by extending the life of Platform Irene from approximately 10 years to 30 years. The Surf Substation provides power to Platform Irene. The substation, which is visible from several public areas, such as the Ocean County Park, Surf Beach, and portions of the Union Pacific Railroad and Ocean Avenue, creates a negative aesthetic impact. The life of the substation under the proposed project would also be extended from approximately 10 years to 30 years. **No Preference**	The severity of this impact for the Emulsion Pipeline Replacement Alternative would be the same as the proposed project since Platform Irene and Surf Substation would remain for the projected 30 year project life. **No Preference**
Visual.4	Visual impacts due to long-term continued presence of the LOGP.	The LOGP creates nighttime glare from the light of the facility that can be seen through most of the Lompoc area, (including public viewsheds), and as far away as Highway 101 north of Los Alamos. This glare reduces the darkness of the night sky and could obscure the stars and other astronomical phenomena. The glare degrades the public's enjoyment of viewing the nighttime sky from many public areas, and therefore adversely impacts visual resources of several visually important areas. The glare is also incompatible with the mostly dark nighttime sky of the undeveloped areas near Lompoc that are in the public viewshed. The lights at the LOGP are needed to allow for the safe operation of the facility at night and to comply with OSHA regulations. Under the proposed project, the nighttime glare associated with LOGP would be extended from approximately10 years to 30 years. **No Preference**	Nighttime glare associated with the LOGP would be the same for the Emulsion Pipeline Replacement Alternative since the LOGP would remain in operation for the projected 30 year project life. **No Preference**

Table 6.1c: Comparison of <u>Class I Impacts for</u> the Proposed Project <u>and</u> ~~to the~~ Emulsion Pipeline Replacement Alternative

Impact #	Description of Impact	Proposed Project	Emulsion Pipeline Replacement Alternative
Rec.1	The proposed project would increase the likelihood and volume of an oil spill, which could result in public access restrictions to coastal and inland recreational resources.	An offshore spill caused by an accident or failure at Platform Irene or in the offshore pipeline could lead to beach closures and boating restrictions during spill response and cleanup, as well as a lingering public perception that recreational resources are polluted, even after the cleanup period. The duration and extent of beach closures would depend on the volume of the spill and prevailing ocean and local weather conditions. A worst-case scenario oil spill could reach recreational resources as far north as Montana de Oro State Park near Morro Bay and as far south as the Santa Barbara Channel Islands. The coastline east of Point Conception, including Gaviota and Refugio State Beaches would likely avoid direct spill impacts. The area from Point Sal to Point Arguello is at greatest risk from a spill due to its proximity to the Point Pedernales Project facilities; therefore Ocean Beach County Park, Point Sal Beach State Park, and Jalama Beach County Park would be more likely impacted than other recreation areas An onshore spill near the pipeline landfall could pose a similarly adverse effect on the recreational utilization of Ocean Beach Park. An onshore spill further inland could adversely affect recreational resources such as the Burton Mesa Ecological Reserve, the Santa Ynez River, and Ocean Beach Park (via a spill into the river).	For the Emulsion Pipeline Replacement Alternative, the oil spill related impacts to coastal and inland recreational resources would be the same as the proposed project. However, the probability of a spill along the new emulsion line would be approximately 10% less than for the existing emulsion line associated with the proposed project. **Slightly Preferred**

6.3.4 Alternative Power Lines Routes to Valve Site #2

The installation of power lines in any of the three identified configurations would not affect the severity of any Class I impacts for the proposed project. All impacts associated with the proposed power line route were found to be Class II or III. Table 6.2 provides a comparison of the proposed project power line impacts with each of the alternatives.

The proposed project impacts would be greater in severity than those for some of the power line alternatives, such as impacts to terrestrial biology and air quality for the Terra Road undergrounding or Option 2b alternative. The Terra Road undergrounding alternative was found to reduce the severity of the visual impacts of the proposed project (power line on poles) along some portions of the power line route where the addition of power poles in the area would result in a reduction of visual quality of the highly scenic coastal area. Along other portions of the route, where there are existing power poles, visual impacts would be minimally affected.

In summary, Option 2a would have the same impacts as the proposed project. Option 2b would have a number of environmental disadvantages in the issue areas of: (1) onshore biology; (2) onshore water resources; (3) air quality; and (4) traffic. Undergrounding along Terra Road would offer an environmental advantage in the area of: (1) visual resources and (2) fire protection, but would have a number of environmental disadvantages in the issue areas of: (1) onshore biology; (2) air quality; and (3) cultural resources.

6.3.5 Alternative Muds and Cuttings Handling - Injection and Onshore Disposal

With the proposed project, muds and cuttings that meet EPA discharge standards would be discharged into the ocean in accordance with the current NPDES permit. Under the muds disposal alternatives, drilling muds and cuttings would either be injected offshore or transported to shore for disposal in an appropriately classified disposal facility. The muds and cuttings handling alternatives would not change or affect the severity of any Class I impacts identified for the proposed project. Impacts associated with the discharge of muds to the ocean for the proposed project due to potential smothering of biota and effects on marine water quality were determined to be significant but mitigable with implementation of NPDES permit requirements (Class II). Table 6.3 provides a comparison of the proposed project drill muds and cuttings impacts with the two alternatives.

Injection or onshore disposal of muds and cuttings would reduce in severity or eliminate this Class II impact. However, the potential for a contaminated muds and cuttings spill during transportation, or for the seepage of mud-contaminated waters into the marine environment would still be considered a Class III impact but lower in severity than the ocean discharge of the muds and cuttings (i.e., the proposed project). The muds and cuttings alternatives would increase the severity of the air quality impacts due to the increased emissions from injection equipment or the boats and trucks used to transport the muds and cuttings to the disposal site. These air quality impacts were found to be adverse but not significant (Class III), which is the same as the proposed project. Transportation of the muds and cuttings to shore for disposal or recycling would result in increased boat and truck traffic, a Class III impact.

TABLE 6.2 COMPARISON OF IMPACTS FOR THE PROPOSED TRANQUILLON RIDGE PROJECT WITH THE POWER LINE ROUTES TO VALVE SITE #2 ALTERNATIVES[1]

Impact #	Description of Impact	Option 2a	Option 2b	Underground along Terra Road	Comments
TB.9	Accidental release of boring materials ("frac-outs") during construction activities related to boring could impact one or more sensitive wildlife species **(Class I)**.	NA	+	NA	This impact would only occur as a result of boring the Santa Ynez River. This impact would not occur with the proposed project.
CR.2 and CR.6	Installation of power poles would result in ground disturbance and potential impacts on cultural resources **(Class II).**	Same	Same	+	The severity of the impact would be greater for undergrounding along Terra Road as a result of the increase in ground disturbance due to trenching.
Visual.2	Visual impacts due to the power lines to Valve Site #2 **(Class II).**	Same	Same	-	The severity of the impact would be less with the Terra Road undergrounding alternative since a portion of the route would not have power poles. However, the impact would still be Class II since some power poles would still be needed.
TB.1	Installation of power poles would result in disturbance or loss of less than one acre of native vegetation and wildlife habitat and possible injury to wildlife **(Class III).**	Same	Same	+	The severity of the impact would be greater for undergrounding along Terra Road as a result of the increase in ground disturbance due to trenching.
TB.2	Installation of power poles have the potential to increase erosion and sedimentation in aquatic habitats **(Class III).**	Same	Same	+	The severity of the impact would be greater for undergrounding along Terra Road as a result of the increase in ground disturbance due to trenching.
Air.1	Construction activities would generate air emissions **(Class III).**	Same	+	+	The severity of the impact would be greater for undergrounding along Terra Road as a result of the increase in ground disturbance due to trenching. The severity would be greater for Option 2b due to the increased equipment needed to bore the Santa Ynez River.
T.1	Onshore construction associated with the project would temporarily add to local road traffic **(Class III)**.	Same	+	Same	The severity would be greater for Option 2b due to the increase equipment needed to bore the Santa Ynez River.
N.2	Construction noise would temporarily increase ambient daytime noise levels (**Class III**).	Same	+	Same	The severity would be greater for Option 2b due to the increase equipment need to bore the Santa Ynez River, and the fact that the boring machine has a higher noise level.
AG.1	Addition of power poles to Valve Site #2 could disturb farm operations **(Class III).**	Same	+	Same	The work areas needed for boring the Santa Ynez River would both be located on agricultural lands. This would preclude the use of the land during the boring operations.

TABLE 6.2 COMPARISON OF IMPACTS FOR THE PROPOSED TRANQUILLON RIDGE PROJECT WITH THE POWER LINE ROUTES TO VALVE SITE #2 ALTERNATIVES[1]

Impact #	Description of Impact	Option 2a	Option 2b	Underground along Terra Road	Comments
~~TB.9~~	~~Accidental release of boring materials ("frac-outs") during construction activities related to boring could impact one or more sensitive wildlife species (Class I).~~	~~NA~~	~~+~~	~~NA~~	~~This impact would only occur as a result of boring the Santa Ynez River. This impact would not occur with the proposed project.~~
OWR.7	Potential "frac-out" of boring muds could cause siltation and degrade surface water quality **(Class III**).	NA	+	NA	This impact would only occur as a result of boring the Santa Ynez River. This impact would not occur with the proposed project.
Fire.2	Operation of the new power line to Valve Site #2 could result in impacts to fire protection and emergency response resources due to addition of an ignition source into a high fire hazard area **(Class III**).	Same	Same	-	The severity of the impact would be less for the Terra Road undergrounding alternative since less of the power line would be aboveground. However, it would still be considered a Class III impact since portions of the power line would still be aboveground.

[1] NA = Impact does not apply to this alternative.
+ = Severity of the impact is greater than the proposed project.
- = Severity of the impact is less than the proposed project.

TABLE 6.3 COMPARISON OF IMPACTS FOR THE PROPOSED TRANQUILLON RIDGE PROJECT WITH THE MUDS AND CUTTINGS DISPOSAL ALTERNATIVES[1]

Impact #	Description of Impact	Injection	Transportation to Shore	Comments
MB.2	The discharge of drilling muds and cuttings from Platform Irene may potentially impact marine organisms in the project area **(Class III).**	NA	-	The injection alternative would eliminate this impact. The transportation to shore alternative would reduce the severity of the impact as compared to the proposed project. However, it would not be eliminated since there is still the possibility of accidentally spilling the muds and cutting into the ocean during transport to shore.
MWQ.2 and MWQ.7	Reduced marine water and sediment quality would result from increased oceanic discharge of drilling fluids **(Class III).**	NA	-	The injection alternative would eliminate this impact. The transportation to shore alternative would reduce the severity of the impact as compared to the proposed project. However, it would not be eliminated since there is still the possibility of accidentally spilling the muds and cutting into the ocean during transport to shore.
CRF/ KH.3	The discharge of drilling muds and drill cuttings from Platform Irene may potentially impact kelp communities in the project area **(Class III).**	NA	-	The injection alternative would eliminate this impact. The transportation to shore alternative would reduce the severity of the impact as compared to the proposed project. However, it would not be eliminated since there is still the possibility of accidentally spilling the muds and cutting into the ocean during transport to shore.
CRF/ KH.5	The deposition of shells, or shell mounds, could prevent commercial trawling activities beneath Platform Irene **(Class III).**	-	-	The severity of the impact would be reduced, but not eliminated since shells would still deposit on the sea floor from the platform. The contribution of the cuttings to the shell mounds would be eliminated for both alternatives.
Rec.3	Muds and cuttings spilled near the shore could disrupt recreational activities such as SCUBA diving **(Class III).**	NA	+	This impact only applies to the transportation to shore alternative. This impact could occur in the unlikely event that muds and cuttings are spilled into the ocean during transport to shore. This impact would not occur for the proposed project.
T.2	Transportation of drilling muds and cuttings would increase truck traffic on local roads **(Class III).**	NA	+	This impact only applies to the transportation to shore alternative. This impact would not occur for the proposed project.

[1] NA = Impact does not apply to this alternative.
+ = Severity of the impact is greater than the proposed project.
- = Severity of the impact is less than the proposed project.

In summary, the injection or the disposal of muds and cuttings would eliminate or substantially reduce the severity of Class II and III impacts to marine water quality and marine biology associated with ocean discharge, but would increase air emissions (both injection and onshore disposal) and truck traffic (onshore disposal only), both Class III impacts.

6.4 Environmentally Superior Alternative

Tables 6.1a through 6.1c provide detailed comparisons of the likely impacts of the proposed project to the VAFB Onshore Alternative and the major project component alternatives (Casmalia East Processing Site and Emulsion Line Replacement) evaluated in this EIR. Tables 6.2 and 6.3 compare the impacts of the proposed power line routing alternatives, and drilling mud/cuttings disposal alternatives to one another. As stated earlier, the only feasible project-level alternative to the proposed project evaluated in this EIR is the VAFB Onshore Alternative. Because there are no other feasible project-level alternatives to the proposed project, the VAFB Onshore Alternative is considered to be the de facto "environmentally superior alternative" for purposes of CEQA Guidelines Section 15125~~5~~6.6(e)(2). ~~The~~ This defacto ESA determination does not, however, suggest that this alternative is environmentally superior to the proposed project. Rather, by default, this alternative is the only identified project-level alternative that is feasible and meets most of the project objectives and therefore merits further detailed ~~consideration~~ comparison to the proposed project.

The final step in the alternatives analysis is to compare the impacts of the examined alternatives to the impacts identified for the proposed project. The remainder of this section summarizes the comparison of the proposed project to the VAFB Onshore Alternative and the other three major component alternatives evaluated in the EIR and discusses the environmental preferability of these alternatives relative to the proposed project.

Although this comparison presents the significant Class I impacts identified for the proposed project and alternatives across all issue areas, determining environmental preference is challenging because of the many important factors that must be balanced. For example, one alternative may result in significant construction impacts, but greatly reduces operational impacts when compared to the proposed project. Where an alternative is identified as preferable to the proposed project based on the analyses in this EIR, it would still be necessary to provide additional, more detailed environmental analysis to identify specific impacts and mitigation measures before a fully informed decision could be made to permit that alternative.

In addition, it is possible that the final decision-makers could balance the importance of each impact area differently and reach a different conclusion than that presented herein. Moreover, only the proposed project has been evaluated to a project-level of detail, while the alternatives have been reviewed at a reasonable but much more general level of detail. In this EIR, the impacts identified for the alternatives are presented in terms of what could happen under worst-case scenarios, while the impacts of the proposed project are typically described in more definitive terms, based on the greater detail available about it.

6.4.1 Tranquillon Ridge Project

As discussed in Section 6.2, the No Project Alternative is the environmentally superior alternative; however, this alternative would not meet the major objective of the project, which is the full development of the Tranquillon Ridge Field. If the environmentally superior alternative is the No Project Alternative, CEQA requires identification of an environmentally superior alternative from among the other alternatives. As noted earlier, since there are no other feasible project-level alternatives, the VAFB Onshore Alternative could be considered the de facto environmentally superior alternative. This does not, however, speak to how the VAFB Onshore Alternative compares to the proposed project; that comparison is presented here. Table 6.4 summarizes the Class I impact comparison conducted for the proposed project, VAFB Onshore Alternative, Casmalia Alternative, and Emulsion Pipeline Replacement Alternative presented in Section 6.3.

Table 6.4 Comparison of Class I Impacts for the Proposed Project ~~Compared to~~ and Major Alternatives

Class I Impacts	Proposed Project	VAFB Onshore Alternative	Casmalia Alternative	Emulsion Pipeline Replacement Alternative
Risk.3: Increased risk to public due to NGL/LPG transport.[1]	Extension of life of LOGP would continue risk. *No preference.*	Same as proposed project. *No preference.*	*No preference*, but from Casmalia site instead of LOGP.	Same as proposed project. *No preference.*
Risk.4: Increased risk to VAFB operations and personnel.[1]	Impact would not occur under proposed project. **Preferred**	Additional hazards within VAFB due to drilling/production facilities and pipelines.[4]	Same as proposed project.	Same as proposed project.
TB.6: Oil spill impact to upland, riparian, and aquatic habitats, and wildlife.[1]	Increased throughput increases oil spill risk and volumes above baseline conditions.	Higher risk than proposed project because of new pipeline through sensitive resources and thermal radiation hazards in the initial years of operation.	Higher risk than proposed project because of new pipeline through sensitive resources.	Throughput same as proposed project. **Slightly preferred** due to 10% decrease in spill probability, compared to proposed project.
TB.7: Oil spill impact to state-or federally-listed plant species.[1]	Increased throughput increases oil spill risk and volumes above baseline conditions.	Higher risk than proposed project because of new pipeline through sensitive resources.	Higher risk than proposed project because of new pipeline through sensitive resources.	Throughput same as proposed project. **Slightly preferred** due to 10% decrease in spill probability.
TB.8: Oil spill impact to state-or federally-listed wildlife species.[1]	Increased throughput increases oil spill risk and volumes above baseline conditions.	Higher risk than proposed project because of new pipeline through sensitive resources.	Higher risk than proposed project because of new pipeline through sensitive resources.	Throughput same as proposed project. **Slightly preferred** due to 10% decrease in spill probability.
TB.9: Directionally drilling impacts to Santa Ynez River.[2]	Impact would not occur under proposed project.[3] **Preferred** ~~Would only occur if Alternative Power Line Route – Option 2b was chosen.~~ ~~**Preferred** because of smaller diameter bore~~	Frac-out could cause Class I impacts to aquatic resources and water quality.	Same as proposed project.	Same as proposed project.
TB.10: New pipeline construction impacts.[2]	Construction would result in 0.43 acres of vegetation removal *(Class II)*. **Preferred**	Construction would result in 61 acres of vegetation removal.	Construction would result in 152 acres of vegetation removal.	Construction would result in 88.6 acres of vegetation removal, but within previously disturbed right-of-way *(Class II)*.

Class I Impacts	Proposed Project	VAFB Onshore Alternative	Casmalia Alternative	Emulsion Pipeline Replacement Alternative
OWR.2: Oil spill impacts to surface and ground waters.[1]	Increased throughput increases oil spill risk and volumes above baseline conditions.	Higher risk than proposed project because of additional pipeline length.	Higher risk than proposed project because of additional pipeline length.	Throughput same as proposed project. **Slightly preferred** due to 10% decrease in spill probability.
MB.1: Oil spill impacts to marine organisms.[1]	Extension of life of platform and offshore pipeline would continue oil spill risk to marine organisms an additional 20 years.	No extension of life. Risk to marine organisms reduced since alternative facilities are inland. **Preferred**.	Same as proposed project.	Throughput same as proposed project; however 10% decrease in spill probability.
MWQ.1: Oil spill impacts to marine water quality.[1]	Extension of life of platform and offshore pipeline would continue oil spill risk to marine water quality an additional 20 years.	No extension of life. Risk to marine water quality reduced since alternative facilities are inland. **Preferred**.	Same as proposed project.	Throughput same as proposed project; however 10% decrease in spill probability.
CRF/KH.2: Oil spill impacts to fisheries.[1]	Extension of life of platform and offshore pipeline would continue oil spill risk to fisheries an additional 20 years.	No extension of life. Risk to fisheries reduced since alternative facilities are inland. **Preferred**.	Same as proposed project.	Throughput same as proposed project; however 10% decrease in spill probability.
T.4: Oil spill impacts to marine transportation corridors.[1]	Spill could temporarily close Coast Guard recommended marine traffic corridors. *No preference.*	Spill could close mission critical VAFB transportation corridors. *No preference.*	Same as proposed project. *No preference.*	Throughput same as proposed project; however 10% decrease in spill probability. *No preference.*
CR.3: Oil spill clean up impacts to cultural resources.[1]	Increased throughput increases oil spill risk and volumes above baseline conditions.	Higher risk than proposed project because of additional pipeline length and proximity to NRHP sites.	Higher risk than proposed project because of additional pipeline length through sensitive resources.	Throughput same as proposed project. **Slightly preferred** due to 10% decrease in spill risk compared to proposed project.
CR.5~~6~~: New pipeline construction impacts to cultural resources.[2]	Impact would not occur under proposed project. **Preferred.**	44 significant or potentially significant cultural sites could be destroyed as part of construction.[4]	4 recorded sites located within 200 ft of pipeline corridor; 7 miles of corridor have not been surveyed.	29 recorded sites within ½ mile of previously disturbed pipeline corridor.
Visual.1: Long term presence of Platform Irene & Surf substation.[1]	Extension of life would continue platform and substation presence an additional 20 years.	No extension of life; platform removed in 10 years. Substation to remain an additional 20 years. **Preferred.**	Same as proposed project.	Same as proposed project.
Visual 4: Long term presence of LOGP nighttime glare.[1]	Extension of life would continue LOGP nighttime glare an additional 20 years. *No preference.*	Same as proposed project. *No preference.*	More severe than proposed project because of new Casmalia facility.	Same as proposed project. *No preference.*
Visual 5: Presence of tall structures (180-200 foot drilling rig and 50 foot tall tank).[1]	Impact would not occur under proposed project. **Preferred.**	Addition of tall structures within VAFB due to drilling/production facilities.[4]	Same as proposed project.	Same as proposed project.

Class I Impacts	Proposed Project	VAFB Onshore Alternative	Casmalia Alternative	Emulsion Pipeline Replacement Alternative
Rec.1: Oil spill impacts to recreational resources.[1]	Extension of life would continue oil spill risk to coastal recreational resources an additional 20 years.	No extension of life. Risk to coastal recreational resources reduced since alternative facilities are inland. **Preferred**.	Same as proposed project.	Throughput same as proposed project; however 10% decrease in spill probability.

1. Operational impact.
2. Construction impact.
3. Proposed project preferred even if Option 2b is implemented for providing power to Valve Site #2.
4. Potential Class I, significant and unavoidable, or Class II, significant but mitigable, impact.

The comparison information presented in Table 6.4 is summarized as follows:

- ***Proposed Project***: The proposed project would use existing facilities, including Platform Irene, the offshore and onshore pipelines, and LOGP. The increased throughput associated with the proposed project would increase the oil spill risk and volumes above baseline conditions. For the existing Point Pedernales Project, PXP has implemented a comprehensive corrosion monitoring and control program for the oil, gas and produced water pipelines that does reduce the potential risks for releases into the marine and terrestrial environments. However, even with these and other operational safeguards, the extension of life of Platform Irene and offshore oil pipeline resulting from the proposed project would continue significant oil spill risks and associated impacts to marine biology, marine water quality, commercial fisheries, terrestrial biology, cultural resources, onshore water resources, and recreational resources beyond the lifetime of the original Point Pedernales Project. In addition, long-term visual impacts regarding the continued presence of Platform Irene and Surf substation within the coastal zone, and LOGP nighttime glare would continue through 2037, instead of 2017 as estimated for current operations. Construction activities associated with the proposed project, however, are nominal, requiring only an estimated 0.43 acres of vegetation removal.
- ***VAFB Onshore Alternative***: The VAFB Onshore Alternative would eliminate the extension of life of Platform Irene, the offshore pipeline, and onshore pipeline from landfall at Wall/Surf Beach to 13th Street (approximately 4.5 miles of pipeline) after 2017. By eliminating the extension of life for these offshore facilities, the alternative oil spill risk and associated impacts would be greatly reduced for marine and coastal biology, marine water quality, commercial fisheries, and coastal recreational resources. Installation and operation of approximately 10 miles of new onshore pipeline could result in significant oil spill risk and associated impacts to terrestrial biology, cultural resources, onshore water resources, and potential estuarine resources. In addition, construction and operation of the VAFB Onshore Alternative drilling/production site, pipelines, and power line could create new significant impacts to terrestrial biology,~~and~~ cultural, and visual resources, and VAFB operations and personnel.

  ~~Conclusion:~~ The proposed project and VAFB Onshore Alternative both would result in significant Class I impacts, but these impacts would occur in different issue areas as summarized below:

  Proposed Project:

  - The proposed increase in throughput and oil percentages would increase the combined lifetime probability of oil leaks, ruptures, blowouts, and spills from Platform Irene and the offshore portion of the emulsion pipeline from 5.4~~10.5~~ percent to 22.1 percent over the life of the project. In addition, assuming that the pumps are installed at Valve Site #2, the lifetime probability for a rupture along the onshore emulsion pipeline would increase from 0.9 percent to 11.2 percent and for a leak would increase from 3.6 percent to 100 percent. These increased oil spill risks would continue through 2037, instead of 2017. As presented above, an oil spill could present significant Class I impacts to marine and terrestrial biology, marine and onshore water quality, commercial fisheries, and cultural and recreational resources.

- The presence of Platform Irene, which is visible from the public beach to marine recreational users and to Amtrak users, would increase from approximately 10 years to 30 years; Surf substation would remain for 30 years under either the proposed project or VAFB Onshore Alternative.
- Under the proposed project, existing facilities (Platform Irene, offshore and onshore pipelines and LOGP) would be used. As a result, construction activities associated with the proposed project are nominal, requiring only an estimated 0.43 acres of vegetation removal, and therefore, are considered Class II, significant but mitigable.

VAFB Onshore Alternative:

- Installation of the new drilling/production facility would result in the permanent loss of approximately 25 acres of vegetation and wildlife habitat. In addition, construction of the VAFB Onshore Alternative pipelines, tie-in station, ~~and transmission~~ power lines, and substation could require the removal of approximately 61 acres of vegetation and wildlife habitat. Restoration efforts along the pipeline corridor are unlikely to be 100 percent successful for all native plant communities.
- Construction of the VAFB Onshore Alternative may permanently remove or destroy 44 sites that may contain significant or potentially significant cultural materials, and would alter the spatial relationships and context of those materials.
- For the VAFB Onshore Alternative, directional drilling under the Santa Ynez River would be used to install pipelines from the onshore drilling/production site. Drilling has the potential to indirectly impact sensitive biological resources in the Santa Ynez River if a frac-out occurs (inadvertent release of bentonite drilling muds through natural fractures). Bentonite slurry released into the Santa Ynez River would increase turbidity and sedimentation, potentially impacting listed species and their habitats.
- Platform Irene, the offshore pipeline, and approximate 4.5 miles of onshore pipeline (landfall to west of 13th Street) would not be used by the VAFB Onshore Alternative. As a result, these facilities could be decommissioned in 2017 and their associated oil spill risk would be eliminated. However, prior to decommissioning, the spill risk to the marine environment would remain and would be slightly increased over baseline conditions because of the VAFB Onshore Alternative. Subsequent to decommissioning, the alternative would ~~also~~ reduce the severity, but not eliminate, the Class I impacts associated with an onshore oil spill on the marine environment and to recreational facilities through 2037.
- Operation of the drilling/production facility and gas pipelines could present a significant risk to VAFB operations and personnel. Further, the long-term presence of the drilling/production facility and new Surf substation within the coastal zone could present a significant visual impact.

The VAFB Onshore Alternative would eliminate the long-term extension of life impacts of the proposed project associated with Platform Irene and the offshore pipelines after 2017. However, this alternative would require construction of new onshore drilling and production facilities, pipelines and various onshore support facilities that would not be required for the proposed project. This new construction could result in extensive and possibly significant impacts, particularly to biological and cultural resources that lie along the new pipeline route, although it may be possible to reroute a pipeline to lessen those impacts. Both the VAFB Onshore Alternative and proposed project could result in significant onshore and offshore operational impacts, as described below.

The VAFB Onshore Alternative could result in significant impacts to marine resources resulting from an onshore pipeline spill that enters ravines, coastal estuaries or other conduits leading to the ocean. Such a spill could impact benthic and intertidal organisms, fish, marine mammals, marine birds and marine turtles. However, the likelihood of an onshore spill reaching the marine environment from the drilling/production facility or pipeline is low, due to the natural and artificial barriers onshore between these facilities and the marine environment. Oil could reach open ocean waters during high flow periods, particularly if the spill would occur under or within close proximity to the Santa Ynez River or other estuary. In comparison, a spill from the offshore pipeline would immediately affect the marine environment and result in more severe impacts to marine resources due to its location directly in the ocean. An offshore oil spill would also have greater potential and consequences of impacting shoreline recreational resources in the spill zone. In either an offshore or onshore release scenario, factors such as spill origin, spill volume, spill rate, type of oil spilled and tidal and weather conditions would greatly influence the ultimate degree of impact to sensitive resources.

The VAFB Onshore Alternative would increase the onshore pipeline spill risks because of the additional length of emulsion pipeline in operation through 2037. However, after 2017, approximately 4.5 miles of the existing onshore pipeline would be decommissioned, lessening the onshore spill potential for this alternative. Oil spills from the new onshore pipeline could result in impacts to terrestrial biological resources including endangered and/or threatened plant and animal species and sensitive habitat areas such as creeks and other coastal estuaries. This is due to the fact that a new onshore pipeline would be directly beneath or in close proximity to these types of sensitive resources. Conversely, a spill from the offshore pipeline would have a more remote chance of reaching those same resources due to limited coastal pathways leading inland. Examples of upland sensitive areas that could be directly impacted by an offshore spill (under certain conditions) include sandy beaches, rocky shorelines and estuaries, as well as those plant and animal species that occupy those environments. Impacts to both terrestrial and marine resources resulting from clean up of oil spills would occur under both the VAFB Onshore Alternative and the proposed project, and the severity of such impacts would be a result of the size and extent of such a spill. Oil spill impacts could also occur to cultural resource sites near the onshore drilling/production facility and along the pipeline route resulting from spill remediation efforts.

Both the VAFB Onshore Alternative and the proposed project would increase and extend the significant risks to the public due to truck transportation of gas liquids from the Lompoc Oil and Gas Processing Facility. Further, both the VAFB Onshore Alternative and proposed project would result in the long-term presence of industrial facilities within the coastal zone, resulting in a significant visual impact.

The VAFB Onshore Alternative could present a significant risk to VAFB operations and personnel as a result of the drilling/production facility and gas pipeline operations.

Conclusion: To determine whether a proposed project or an alternative would be environmentally preferred, the process normally is to compare the significant Class I impacts of the proposed project to those of the alternative(s), and to identify the option with the fewest significant impacts that meets the primary project objectives. Guidance for this comparison is also sought from the relevant regulatory policies for each issue area, as necessary. However, such policies do not always provide explicit direction on relative importance when weighing one issue area over another (e.g., biological resources versus cultural resources). As a result, this analysis relies on a comparison of the nature, extent, permanence and probability of each Class I impact in order to identify the environmentally preferred option.

Table 6.1a compares each of the proposed project's impacts to those that could be expected to result from the VAFB Onshore Alternative. Implementation of the onshore alternative would substantially reduce the likelihood of an offshore oil spill and its related impacts after 2017, when Platform Irene, the offshore pipeline, and the existing onshore pipeline to the 13th Street tie-in would be decommissioned. Through 2017, the existing offshore pipeline would carry a diminishing amount of crude oil which would lead to diminishing impact from an oil spill from the Point Pedernales project. Offshore impacts due to an onshore oil spill could still occur, though the likelihood and severity of such impacts would be expected to be less~~small~~.

Implementation of the onshore alternative also would result in substantially more significant impacts to onshore biological and cultural resources than the proposed project. Several threatened and/or endangered species, both plant and animal, occur at the drillsite and along the likely pipeline corridor and would be affected by facility construction of the alternative and by operational impacts, such as an onshore oil spill, safety risks to VAFB operations and personnel, and long-term presence of industrial facilities within the coastal zone. There is a potential that many of these impacts could be mitigated, but there is no assurance they could be mitigated to insignificance.

Table 6.1a shows that both the proposed project and VAFB Onshore Alternative would result in permanent and significant impacts, with varying probabilities, and in varying issue areas. As such, and because of their uniquely different locations (offshore versus onshore) and resulting disparate impact issue areas, and partly because the proposed and alternative onshore projects are described and analyzed to different levels of detail, it is extremely difficult to determine that one is environmentally preferable over the other.

- ***Casmalia Alternative***: The Casmalia Alternative would not eliminate any of the Class I impacts associated with the proposed project regarding extension of life for oil spill risks and volumes, and continued presence of Platform Irene, Surf substation, and LOGP. In addition, because of the installation of approximately 10 to 15~~3~~ miles of new onshore pipeline, the alternative oil spill risk and associated impacts would be greater than the proposed project for terrestrial biology, cultural resources, and onshore water resources. In addition, construction of the Casmalia Alternative processing facility and pipelines would create new significant impacts for the issue areas of terrestrial biology and cultural resources.

  Conclusion: Since the Casmalia Alternative offers no environmental benefit to the proposed project, the proposed project component of processing at LOGP is considered to be environmentally preferable to this alternative.

- ***Emulsion Pipeline Replacement Alternative***: The Emulsion Pipeline Replacement Alternative would be similar to the proposed project with regards to extension of life and associated oil spill risks and impacts to marine biology, marine water quality, commercial fisheries, terrestrial biology, cultural resources, onshore water resources, and recreational resources. The oil spill risk for the new emulsion pipeline would be approximately 10 percent less than for the existing pipeline to be used by the proposed project. However, regardless of spill risk, the volumes of spill would be the same. In addition, construction of the new emulsion pipeline within the previously disturbed right-of-way would create intensified Class II impacts for the issue areas of terrestrial biology and cultural resources.

  Conclusion: Because a 10 percent reduction in spill risk is considered nominal (reduced from 11.2 percent for the proposed project to 10.1 percent for the onshore portion of the emulsion line and 9.7 to 8.7 percent for the offshore portion), and would not lead to reduced spill volumes and associated impacts, and construction efforts would intensify several Class II impacts in comparison to the proposed project, the proposed project's use of the existing pipelines is considered to be environmentally preferable to the Emulsion Pipeline Replacement Project.

6.4.2 Power Line Routing Alternatives

For the most part, all of the power line alternatives have similar impacts. The proposed project, with mitigation, was found to be the environmentally preferred alternative. The proposed project, with mitigation, would eliminate the need to install poles or bore under the Santa Ynez River since the power line would be placed on existing VAFB poles, and the portion from the intersection of Terra Road and Pipeline Dirt Road would be placed underground. If and when this power line is built the applicant and the County would need to work with VAFB to gain permission to use the existing poles. By using the existing poles, a number of Class III impacts would be avoided.

For the power line alternatives to Valve Site #2, burying the power line along Terra Road from its intersection with 13th Street to Valve Site #2 was identified as the environmentally superior alternative from among the power line options evaluated because trenching activities would eliminate significant visual impacts associated with the installation of new power lines. Impacts to biological resources associated with trenching could be effectively mitigated if this alternative is implemented.

6.4.3 Mud/Cuttings Disposal Alternatives

With regard to the handling of muds and cuttings, injection at the platform was selected as the environmentally superior alternative for muds and cuttings disposal. However, in order for this alternative to be implemented, a suitable underground formation would need to be found that could handle all of the muds and cuttings and would require MMS approval. Although the CSLC prohibits ocean disposal of drill muds and cuttings in State waters (where well completions would be located), disposal would take place in Federal waters at Platform Irene (where the muds and cuttings are collected) – a currently approved practice. If a suitable formation can not be found, or MMS does not approve the injection of muds and cuttings from Platform Irene, then the onshore disposal of muds and cuttings would be considered the second environmentally superior option. In summary, both the injection of muds and cuttings at the platform or their transport to shore for disposal would be environmentally preferred to discharging into the water column at the platform as proposed ~~but there may be other factors that affect the feasibility of implementing these disposal option~~; however, as previously noted, for the reinjection alternative, a suitable formation would be required and MMS approval would need to be secured.

7.0 GROWTH INDUCING IMPACTS

Section 15126.2(d) of the California Environmental Quality Act (CEQA) Guidelines states that growth-inducing impacts of the proposed project must be discussed in the EIR. In general terms, a project may induce spatial, economic or population growth in a geographic area if it meets any one of the four criteria identified below:

1. Removal of an impediment to growth (e.g., establishment of an essential public service or the provisions of new access to an area).
2. Economic expansion or growth (e.g., changes in revenue base, employment expansion, etc.).
3. Establishment of a precedent setting action (e.g., an innovation, a change in zoning or general plan amendment approval).
4. Development or encroachment in an isolated area or one adjacent to open space (being different from an "infill" type of project).

Should a project meet any one of the above listed criteria, it can be considered growth inducing. The impacts of the proposed project are evaluated below with regard to these four growth-inducing criteria.

7.1 Removal of an Impediment to Growth

The proposed project involves the drilling of oil and gas development wells from an existing platform and the installation of new equipment at existing oil and gas processing facilities. The project would increase the volume of oil being handled by the facilities from what is occurring today and would increase the life of these facilities. However, the increased volumes would not exceed the volumes permitted for the Point Pedernales Project under the existing Final Development Plan (FDP) and would require minimal new infrastructure.

The proposed project would not result in the establishment of an essential public service, and would not provide new access to an area previously inaccessible. As a result, the project is not considered to cause significant growth inducement under this criterion.

7.2 Economic Growth

Short-term economic growth could occur in the Lompoc area during the construction phase of the proposed project because of construction workers and associated support services. Long-term project employment is extremely limited and would only occur offshore during the drilling phase of the Tranquillon Ridge Project. Therefore, there would be no new significant operational employment associated with the proposed project. The construction activities would result in some short-term increase to the SBC's existing revenue base. The operational activities would result in an increase to the revenue base for the State of California. Economic growth associated with the proposed project is not considered to be significant.

7.3 Precedent Setting Action

The proposed project involves development of oil and gas reserves from an existing offshore platform using extended reach drilling techniques. This type of development maximizes the use of existing infrastructure, and avoids the need to build new offshore platforms. The development of State oil and gas reserves using extended reach drilling from Federal Waters may be viewed as a precedent setting action by some. However, other offshore oil and gas development projects in the Santa Barbara Channel have been using directional drilling to develop Federal leases. Therefore, the proposed project is not considered a precedent setting action that would result in significant growth inducing impacts.

7.4 Development of Open Space

Development of open space is considered growth inducing when it encroaches upon urban-rural interfaces or in isolated localities. Construction associated with the proposed project would occur at existing facilities. No development is proposed in open spaces. Therefore, the proposed project is not considered to be growth inducing under this criterion.

7.5 Conclusion

The proposed project does not meet any of the four growth inducing criteria specified in this section. As a result, the proposed project is not considered to be growth inducing.

8.0 SIGNIFICANT IRREVERSIBLE ENVIRONMENTAL CHANGES

Section 15126.2(c) of the California Environmental Quality Act (CEQA) Guidelines states that significant irreversible environmental changes, which would be involved with a proposed project, may include the following:

- Uses of non-renewable resources during the initial and continued phases of the project which would be irreversible because a large commitment of such resources makes removal or non-use thereafter unlikely;
- Primary impacts and, particularly, secondary impacts which commit future generations to similar uses; and
- Irreversible damage, which may result from environmental accidents, associated with the project.

The purpose of the Tranquillon Ridge Project is to produce approximately 170 to 200 million barrels of oil and 40 to 50 billion standard cubic feet of gas for markets in California. Thus, the project by definition involves use of non-renewable resources. Development of the proposed project would involve the consumption of some non-renewable and locally limited natural resources (i.e., fossil fuels and water) associated with construction activities. The proposed project would also require an increase in consumption of non-renewable resources during operation (i.e., natural gas and fossil fuels). However, the main goal of the proposed project is to develop the non-renewable oil and gas resources while the infrastructure exists to support the development. Therefore, the non-renewable resources demand by the proposed project are not considered to be significant.

The proposed project would directly increase the volume of oil and gas extracted and produced locally, but would not overall increase the consumption of oil or gas. The production from the Tranquillon Ridge Project would be used to satisfy existing demand.

The proposed project could result in environmental accidents (e.g., oil spills) that have the potential to create irreversible impacts to biological, cultural, and hydrological resources. Potential impacts can be reduced through use of adequate design and operating procedures, and effective emergency response plans specifying staffing and equipment needs. However, the potential remains for irreversible damage as a result of an unlikely upset associated with the operation of the proposed project.

9.0 COMMENTS RECEIVED ON THE PUBLIC DRAFT EIR AND RESPONSES

This chapter of the Final EIR presents copies of all of the comment letters received on the Public Draft EIR. The comments have been numbered and given written responses. In addition, the transcript from the December 11, 2006 public hearing on the Draft EIR has been similarly annotated to identify comments and is presented, along with responses to comments made at the hearing, in Section 9.4.

This chapter consists of four sections:

The comment letters and the hearing transcript are presented in their entirety (each letter page shrunk to approximately 50 percent). An alpha-numeric identification code was given to each letter and comment to provide the reader with an easy indicator of which comment is being responded to for each letter. For example, the first letter from Plains Exploration and Production Company is designated PXP2 and the first comment of that letter is PXP2-1. The identification code appears in the left margin of the letter page and is accompanied with enlarged brackets surrounding the comment. Each letter is closely followed by its written response. The letters and their responses are organized alphabetically according to each comment letter's alpha-numeric identification code.

The following table of contents lists each comment letter, its identification code, and location in this section.

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PXP2

RECEIVED
COUNTY OF SANTA BARBARA
JAN 16 2007
PLANNING AND DEVELOPMENT
DEPARTMENT - ENERGY DIVISION

H&B
ESTABLISHED 1966

JOHN S. POUCHER
RICHARD C. MONK
STEVEN EVANS KIRBY
BRADFORD F. GINDER
JOHN G. BUSBY
SUSAN H. McCOLLUM
ROBERT L. BRACE
MARCUS S. BIRD
PETER L. CANDY
MICHAEL P. DENVER

JOHN B. GALVIN
Of Counsel

HOLLISTER & BRACE
A PROFESSIONAL CORPORATION
ATTORNEYS AT LAW

SANTA BARBARA OFFICE
1126 SANTA BARBARA STREET
P.O. BOX 630
SANTA BARBARA, CA 93102
805.963.6711
FAX: 805.965.0329

SANTA YNEZ VALLEY OFFICE
2933 SAN MARCOS AVENUE
SUITE 201
P.O. BOX 206
LOS OLIVOS, CA 93441
805.688.6711
FAX: 805.688.3587

www.hbsb.com

January 12, 2007

HAND DELIVERED

Mr. Doug Anthony, Deputy Director
SANTA BARBARA COUNTY
PLANNING & DEVELOPMENT, ENERGY DIVISION
123 East Anapamu Street
Santa Barbara, CA 93101

Re: Additional Comments on Behalf of Applicant
Tranquillon Ridge Oil & Gas Development Project DEIR
County EIR: 06-EIR-00000-00005
State Clearinghouse No. 2006021055

Dear Mr. Anthony:

These comments are submitted on behalf of our client Plains Exploration & Production Company (PXP), and are in addition to those set forth in our letter of January 11, 2007. The following comments focus on the DEIR's analysis of the VAFB Onshore Alternative. In our view, the DEIR should be revised i) to delete characterization of this alternative as necessarily *feasible*, and ii) to include a reasonably thorough land use policy consistency analysis of this alternative.

Discussion

1. The DEIR Should Not Characterize the VAFB Onshore Alternative As Necessarily "Feasible."

PXP2-1

The DEIR describes the VAFB Onshore Alternative as the only "*feasible* project–level alternative to the proposed project." pp. ES - 14 & 15; Section 3.3.3, pp. 3-7 thru 11; emphasis added. In fact, as explained below, this alternative may not even qualify as a "feasible alternative" within the meaning of CEQA jurisprudence so as to mandate that it be analyzed as such in the EIR. However, under the circumstances, we believe it is wise to thoroughly evaluate this project alternative, since it is apparently being pursued by a

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Mr. Doug Anthony, Deputy Director
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PXP2-1 Cont'd

third party and no other project-level alternatives exist. Nonetheless, the DEIR should be revised to clarify that the VAFB Onshore Alternative is not necessarily *feasible*.

CEQA requires that public agencies "not approve projects as proposed if there are feasible alternatives or feasible mitigation measures available which would substantially lessen the significant environmental effects of such projects…." Pub. Res. C. § 21002; *Mountain Lion Foundation v. Fish & Game Commission* (1997) 16 Cal. 4th 105, 134. Public agencies must consider a range of reasonable alternatives "which would feasibly obtain most of the basic objectives of the project but would avoid or substantially lessen any of the significant effects of the project, and evaluate the comparative merits of the alternatives." Guidelines § 15126.6(a). An alternative is considered "feasible" only if it is "capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, social and technological factors." Pub. Res. C. § 21061.1; Guidelines § 15364.

An analysis of alternatives is to be grounded in reality. With respect to the application of the "rule of reason" to an EIR's evaluation of alternative project sites, Guidelines § 15126.6(f) requires that if the lead agency concludes that there is no feasible alternative location, the agency must disclose the reason for this conclusion and the EIR should not consider an alternative whose effects cannot be reasonably ascertained and whose implementation is remote and speculative. Citing, *Residents Ad Hoc Stadium Committee v. Board of Trustees* (1979) 89 Cal. App. 3rd 274.[1] As the California Supreme Court explained in *Citizens of Goleta Valley v. Board of Supervisors* (1990) 52 Cal. 3rd 553, 574:

> "Surely whether a property is owned or can reasonably be acquired by the project proponent has a strong bearing on the likelihood of a project's ultimate cost and the chances for an expeditious and 'successful accomplishment.'" See also, Guidelines § 15126.6(f)(1).

In this case, whether an onshore project location at VAFB can be acquired privately and then actually developed at such a location within the Coastal Zone is uncertain, at best. As the DEIR correctly observes at p. 3-7: "The VAFB Onshore Alternative was considered in the 2002 Torch EIR but eliminated from further consideration because VAFB considered such a commercial project unfeasible at the time because it might interfere with Base operations." The DEIR goes on to explain that VAFB has now agreed to review the onshore alternative to determine if the project will conflict with current or future Base

[1] Indeed, the Guidelines recognize that for some types of projects, such as natural resources projects, location is critical and there may be no feasible alternative sites. Guidelines § 15126.6(f)(2)(B); *Save Our Residential Environment v. City of West Hollywood* (1992) 9 Cal. App. 4th 1745. The Tranquillon Ridge Project appears to be just such a project.

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Mr. Doug Anthony, Deputy Director
January 12, 2007
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PXP2-1 Cont'd

operations. Having rejected the concept as recently as 2002, it is difficult to envision that VAFB would now find a similar project compatible with the Base's operations and mission. In short, it is speculative whether the VAFB site can be acquired at any price. And, as explained more fully below, it is doubtful that new oil and gas facilities at VAFB in the Coastal Zone could satisfy a number of applicable land use policies, including those set forth in Pub. Res. C. § 30260. The EIR should therefore not characterize the VAFB Onshore Alternative as necessarily "feasible."

2. <u>The DEIR Should Include a Reasonably Thorough Land Use Policy Consistency Analysis of the VAFB Onshore Alternative.</u>

The DEIR includes a detailed analysis of the consistency of the proposed project with the Coastal Act, as well as Local Coastal and Comprehensive Plan policies. Section 5.14. No such analysis is provided with respect to the VAFB Onshore Alternative. Compare the Recreation/Land Use discussion of the VAFB Onshore Alternative at Section 5.14.5.2, pp. 5.14-13 thru 15. While not mandatory, the CEQA Guidelines and case law encourage such an analysis in assessing the feasibility of alternatives. Guidelines § 15126.6(f)(1) provides as follows:

> "Among the factors that may be taken into account when addressing the feasibility of alternatives are site feasibility, economic viability, availability of infrastructure, <u>general plan consistency, other plans or regulatory limitations,</u> jurisdictional boundaries (projects with a regionally significant impact should consider the regional context), and whether the proponent can reasonably acquire, control or otherwise have access to the alternative site." Emphasis added.

P

See also, the California Supreme Court's opinion in *Citizens of Goleta Valley v. Board of Supervisors* (1990) 52 Cal. 3rd 553, 573 ("Conversely, an EIR may properly consider an *inconsistent* land-use designation in the general plan or coastal element in assessing the feasibility of a project alternative.") Emphasis in original. A land use policy consistency analysis is particularly appropriate in a case such as this, where the only project-level alternative presented is of such doubtful feasibility and it becomes all the more imperative that the public and decision makers not be misled about its viability.[2]

[2] The possibility of a third party successfully pursuing the VAFB Onshore Alternative is even more remote. Any such onshore project will inevitably need to rely upon the use of Pt. Pedernales processing and transportation facilities. If the Pt. Pedernales Field were to cease production before the Tranquillon Ridge Field ceases production, and if the owner/operator of the Pt. Pedernales facilities had no interest in Tranquillon Ridge, the owner/operator could elect to abandon the Pt. Pedernales facilities *before* Tranquillon Ridge production is complete. This suggests that, as a practical matter, Tranquillon Ridge may not be able to be developed by any one other than an owner/operator of the Pt. Pedernales Project.

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Mr. Doug Anthony, Deputy Director
January 12, 2007
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PXP2-2 Cont'd

The DEIR's analysis of the VAFB Onshore Alternative should therefore be expanded to include a land use policy consistency analysis. While not necessarily as exhaustive as that with respect to the project itself, the consistency analysis should be sufficient to disclose any significant land use policy consistency issues, including those arising under the Coastal Act and the County's Local Coastal and Comprehensive Plans.[3]

A list of policies that should be considered in such an analysis is attached as Attachment "A" hereto. Of particular importance is an assessment of the consistency of the onshore alternative with Pub. Res. C. § 30260, which encourages coastal-dependent industrial facilities, such as oil and gas facilities, "to locate or expand within *existing sites*...." Emphasis added. It is difficult to see how the operator of the VAFB Onshore Alternative could locate new drilling, production, processing and transportation facilities on Coastal Zone lands at VAFB in light of this policy and the presence of the existing Pt. Pedernales Project facilities. This policy and others go to the heart of the feasibility of the VAFB Onshore Alternative.

Thank you once again for the opportunity to submit these comments

Very truly yours,

HOLLISTER & BRACE

By ______________________
Steven Evans Kirby

SEK/sgt
Attachment

[3] The United States Supreme Court has upheld applicability of the California Coastal Commission's permit requirements with respect to federal lands within the Coastal Zone, such as VAFB. The Court held that the state's coastal environmental permit scheme was not preempted by federal law. *Calif. Coastal Commission v. Granite Rock Co.* (1987) 480 v.s. 572.

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Attachment "A"
VAFB Onshore Alternative
Land Use Policy Consistency Analysis

The following Coastal Act and Coastal Plan Policies should be addressed:

Pub. Res. C. §§ 30250 & 30260 (location of industrial developments); Coastal Plan Policy 2-11 (environmentally sensitive habitat areas); Coastal Plan Policy 3-9 (pipeline geohazards); PRC § 30251 (scenic and visual resources); Coastal Plan Policies 3-13 and 3-14 (soils and topography); Coastal Plan Policy 3-19 (water quality): Coastal Plan Policy 4-3 (height and scale); Coastal Plan Policy 6-6B (processing facilities); Coastal Plan Policy 6-14A (new pipelines); Coastal Plan Policy 6-19 (pipeline routing); PRC § 30231 (biological productivity); PRC § 30240 (environmentally sensitive habitat areas); Coastal Plan Policy 9-14 (wetlands); Coastal Plan Policy 9-15 (oak trees); Coastal Plan Policies 10-2, 10-3 and 10-5 (archaeological).

The following Comprehensive Plan Policies should be addressed:

Land Use Element

- LUD Policies 4 (availability of services and resources); 10 (pipeline impacts); and 11a (NCCPA policies).
- Hillside and Watershed Protection Policies 1 and 2 (soils and topography); and 7 (water quality).
- Historical and Archaeological Sites Policies 2, 3 and 4.
- Visual Resources Policy 2 (compatibility).

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- Lompoc Area Land Use.
- Lompoc Area Environment.

Circulation Element

- B. Roadway Standards

Energy Element

- Policy 5.3 Cogeneration.

Agricultural Element

- Goal I
- Policy I.A.
- Goal II
- Policy II.D.

Seismic Safety and Safety Element (Supplement)

- Policy I-A. Risk Estimates

Conservation Element

- Mineral Resources

Ecological Systems

F:\MATTER\WK5\6267.006\Attachment A.doc 2

Response to Comment Set PXP2

PXP2-1: **The DEIR should not characterize the VAFB Onshore Alternative as necessarily "feasible."**

This comment suggests that because the Air Force has not yet made a final determination that the onshore alternative may be considered for permitting, this alternative is not feasible. Further, the comment states that the 2002 EIR for the previous application for Tranquillon Ridge eliminated the onshore alternative from consideration because the Air Force concluded such a commercial project might interfere with Base operations. The comment concludes that this alternative is "speculative" and need not be considered.

This EIR gives the onshore alternative much more consideration because the Air Force tentatively indicated in a July 8, 2005 letter[1] that it would consider allowing Sunset Exploration Company to use 40 to 70 acres on Vandenberg Air Force Base "to directionally drill to other areas, both onshore and offshore, provided [certain] conditions are met and we successfully conclude a binding agreement." This letter states it was intended to open a continuing dialogue on this issue and was not by any means an approval of the proposal.

Given the change in position by the Air Force to consider allowing an onshore project on the Base, County had an obligation under CEQA to review this alternative in the PXP Tranquillon Ridge EIR. The Air Force may ultimately conclude that the onshore proposal unacceptably interferes with the Base mission and therefore will not be allowed. County does not have the luxury of time to wait for a final Air Force decision and, therefore, based on the best available evidence, has concluded that the onshore alternative was at least potentially feasible.

In light of the Air Force letter of July 8, 2005, it is not appropriate to dismiss this alternative as "speculative." Indeed, ExxonMobil has since partnered with Sunset on this project and a development application has been submitted to the County for consideration. County has not deemed this application complete because the Air Force has not yet reached a decision on whether it will authorize formal consideration of the Sunset/ExxonMobil project. But, given these developments, this alternative is a much more concrete proposal than was the case in 2002 when the previous Tranquillon Ridge EIR was prepared.

PXP2-2: **The DEIR should include a reasonably thorough land use policy consistency analysis for the VAFB onshore alternative.**

Public Resources Code Section 30260 "Coastal-dependent facilities" provides as follows:

> Coastal-dependent industrial facilities shall be encouraged to locate or expand within existing sites and shall be permitted reasonable long-term growth where consistent with this division. However, where new or expanded coastal-dependent industrial facilities cannot feasibly be accommodated consistent with other policies of this division, they may nonetheless be permitted in accordance with this section and Sections 30261 and 30262 if (1) alternative locations are infeasible or more environmentally damaging; (2) to do otherwise would adversely affect the public welfare; and (3) adverse environmental effects are mitigated to the maximum extent feasible.

[1] July 8, 2005 letter from Paul R. Klock, Chief of Plans and Programs, VAFB, to Robert Nunn, Sunset Exploration Company, in Appendix B, Sunset/ExxonMobil Development Plan application to SBC, March 2006; available for review at SBC P&D Energy Division.

Expansion or extension of the life of Platform Irene may or may not be found consistent with the policies of the State Coastal Zone Management Program. In particular, as discussed in detail in the DEIR and summarized in Table 6.1a, the proposal to extend the life of Platform Irene would cause several Class I environmental impacts. Further, Platform Irene is not designated in any federal, state or local plan as a consolidated facility for the production or transportation of oil and gas.

The onshore alternative at VAFB may be considered under Section 30260. New or expanded facilities may be permitted if 1) alternative locations are infeasible or more environmentally damaging; 2) to do otherwise would adversely affect the public welfare; and 3) adverse environmental effects are mitigated to the maximum extent feasible. Table 6.1a provides a summary of the DEIR's substantive analysis of whether the onshore alterative at VAFB is environmentally superior to the proposed project. As discussed in the EIR, the VAFB Onshore Alternative could result in a number of Class I significant adverse impacts that would not occur with the proposed Tranquillon Ridge Project. The same is true of the proposed project. The problem of comparing the two alternatives is that while both result in significant Class I impacts, many of these impacts would occur in different issue areas and, in addition, cannot be evaluated to the same level of detail, given the conceptual nature of the onshore alternative and the greater level of detail available for the proposed project (see EIR Section 6.4). Ultimately, it is for the decision-makers to weigh these two alternatives and decide which is environmentally preferable. If that decision is ultimately that the proposed Tranquillon Ridge Project is more environmentally damaging, then the VAFB Onshore Alternative could be considered for permitting consistent with the requirements of Section 30260, and a project-specific environmental analysis would need to be conducted to fully analyze the impacts.

This comment also suggests that if the VAFB Onshore Alternative is permitted, then the owner/operator of the Point Pedernales Project would have no interest in operating the Lompoc Oil and Gas Plant and could elect to abandon this facility before Tranquillon Ridge production is complete. This comment ignores that several factors could weigh in on such a proposal to abandon, included the Point Pedernales FDP Condition Q-9 which requires the owner/operator to operate the LOGP as a consolidated oil and gas facility, "with access for use available on a nondiscriminatory and equitable basis." Further, before PXP could abandon its facilities, it would be required to submit an application to abandon pursuant to Chapter 35, Section 35.56.010 et seq. of the Santa Barbara County Land Use & Development Code. Under Section 35.56.070, one factor the Director "shall consider" prior to approving such an application is whether "there are no other existing offshore leases that may reasonably be expected to use the consolidated facility or site in the next 10 years." If production from Tranquillon Ridge is still being produced and processed at the LOGP, the Director would presumably consider denying the application to abandon. Alternatively, an economic arrangement could be worked out between the owner of the LOPG and the owner/operator of the Tranquillon Ridge onshore project.

PXP3

PXP

Steven P. Rusch, P.E.
Vice President Environmental, Health,
Safety & Governmental Affairs
Direct 323.298.2223 Fax: 323.296.9375

January 16, 2007

Mr. Doug Anthony, Deputy Director
Santa Barbara County
Planning & Development, Energy Division
123 East Anapamu Street
Santa Barbara, CA 93101

Re: Plains Exploration and Production Company (PXP) Comments on Tranquillon Ridge Oil & Gas Development Project DEIR
County EIR: 06-EIR-00000-00005
State Clearinghouse No. 2006021055

Dear Mr. Anthony:

Plains Exploration and Production Company (PXP) is pleased to submit these comments on the Tranquillon Ridge Oil & Gas Development Project DEIR. In general, the DEIR's analysis is thorough and complies with CEQA. The comments offered here and in letters submitted by Hollister and Brace on our behalf are intended to lead to an even better final document for use by the public and decision makers.

The majority of our comments focus on how to improve the analysis of the VAFB onshore alternative. While PXP questions the feasibility of this alternative (see letter from Hollister and Brace), the alternative needs to be thoroughly and accurately evaluated since it is the only project specific alternative in the DEIR, and is apparently being pursued by a third party operator.

Once the comments presented below are addressed in the Tranquillon Ridge Oil & Gas Development Project DEIR it will be clear to the public and the decision makers that the proposed project is environmentally superior to the VAFB onshore alternative.

A. Executive Summary

PXP3-1

1. ***Page ES-5, Second paragraph*** – The document states that PXP has stated that "no additional wells will be drilled from Platform Irene to develop the Federal portions of the field" (Tranquillon Ridge Field). While it is true that PXP does not currently have plans to drill any more wells, this could change based upon ongoing review of the reservoir geology and economics. The text should be changed to reflect this position.

PXP3-2

2. ***Page ES-5, VAFB Alternative*** – The text should state that the pipelines would have to cross a number of streams and the Santa Yenz River. Also, as stated in the alternatives section, a new substation would have to be built near Surf Beach to

PXP3-2 Cont'd

provide power to the drilling and processing site. The existing substation at Surf Beach does not have sufficient capacity to provide power to Platform Irene and the VAFB drilling and processing site.

PXP3-3

3. ***Page ES-9, first paragraph*** – The ConocoPhillips pipeline does not provide access to other crude oil pipelines that move crude oil to the Bay Area. These pipelines are intermediate product pipelines that move material from the ConocoPhillips Refinery to their Rodeo Refinery Contra Costa County. The text should be changed to reflect this point.

PXP3-4

4. ***Page ES-9, first paragraph*** –Only the section of the ConocoPhillips' 300 pipeline system from LOGP to Suey Junction will see an increase in flow due to Tranquillon Ridge. The remainder of the line from Suey Junction to the Santa Maria Refinery will remain at its present levels since the throughput is limited by the capacity of the Santa Maria Refinery. This change would make the text consistent with what is presented on page 2-10 of the project description.

PXP3-5

5. ***Page ES-9, first paragraph*** – The document states "Since this pipeline primarily ships oil only from the LOGP…." This pipeline also ships oil from the Orcutt and Lompoc fields. Therefore the word "only" should be removed from the sentence.

PXP3-6

6. ***Page ES-45: Item T.3*** – This item is for offshore traffic impacts and would not apply to the VAFB alternative as stated on page 5.9-13 of the DEIR. Therefore, this impact should be deleted from the table.

B. Introduction

PXP3-7

7. ***Page 1-5, Minerals Management Service*** – PXP did not submit a DPP revision to MMS in March of 2000. This document was submitted by Nuevo. PXP did submit a DPP revision document to MMS in May of 2005. In November of 2005, PXP received a letter from MMS stating that a DPP revision of the Point Pedernales Field would be required for the development of Tranquillon Ridge. The text in this section should be revised to reflect the updated facts.

C. Chapter 2-Project Description

PXP3-8

8. ***Page 2-10, last paragraph, 2nd line*** – "form" should be "from"

PXP3-9

9. ***Page 2-11, Section 2.2.5, Schedule*** – The installation of the shipping pumps on Irene and modifications at LOGP should take nine weeks not nine months. This was an error in our application submittal. The timing also affects the construction emissions. The nine months was for the installation that included the water treatment system,

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PXP3-9 Cont'd
which is unrelated to the Tranquillon Ridge Project. The water treatment system has already been approved by the County.

PXP3-10
10. ***Page 2-24, PXP Sales Gas Pipeline, next to last line*** – The Righetti valve site is not in the Lompoc Oil Field. It is in, or near, the Orcutt Hill Oil Field.

D. Chapter 3-Alternatives

11. ***Page 3-5, Table 3.1*** – The following comments are made on the table.
    - The aesthetics for drilling from shore should be a "+" and noted that the drilling and production facility would be visible from the coastal zone as well as boaters in the area. The new substation would be visible from Surf Beach. The top of the drill rig would be visible from Surf Beach (see our comments under F.10 - Aesthetic Impacts - below).
    - The note for air quality should state that operational emissions would increase for all of these alternatives.
    - The note for biological resources should state that the onshore alternative would result in the loss of habitat due to facility and pipeline construction. The pipeline will require crossing a number of water bodies including the Santa Ynez River.
    - The note for marine biology needs to be modified since Platform Irene and the offshore pipelines would not be decommissioned as per the 1985 EIR/EIS. Also, the marine biology impact analysis in the DEIR states that the onshore alternative would still have Class I impacts to marine biology from an oil spill. Therefore, oil spill impacts to marine biota would not be eliminated with the onshore alternative.
    - The note for marine water quality needs to be modified since Platform Irene and the offshore pipelines would not be decommissioned as per the 1985 EIR/EIS.
    - Marine water quality impact analysis in the DEIR states that the onshore alternative would still have Class I impacts to marine water quality from an oil spill. Therefore, oil spill impacts to marine water quality would not be eliminated with the onshore alternative.
12. ***Page 3-8, Third Paragraph*** – Water is injected at the Lompoc Oil Field not the LOGP.

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PXP3-13
13. ***Page 3-8, VAFB Alternative Description*** – With the addition of 10-mile of new oil emulsion pipeline, it is possible that proposed pumps would still need to be installed at Valve Site #2 if the portion of the emulsion pipeline needs to be derated to less than 1,000 psig in the future. This would be particularly true if water was removed from the oil at the VAFB processing site prior to shipment to the LOGP since higher pressures would be needed to move the more viscous material. The pumping and pressure requirement for various oil/water cuts was detailed in the Fluor study, which was extensively discussed in the 2002 Tranquillon Ridge EIR. Therefore, the EIR should include the possible installation of the Valve Site #2 pumping station as part of the VAFB alternative. ***This comment should be addressed in all of the applicable issue areas.***
14. ***Page 3-8, VAFB Alternative Description*** – The description of the VAFB pipeline tie-in just west of 13th Street is incomplete. The connection of the two pipelines would require a valve station, and a pig receiver for both the oil emulsion pipeline and the gas pipeline. In addition, there will need to be additional equipment to allow for the collection of liquids from the pigging operations for both pipelines. Specifically, there will need to be a method of collecting the gas liquids from the gas pipeline and then transporting these to the LOGP for processing. The alternative description needs to be expanded to address this pipeline interconnect facility. What is the size of the facility? What are the construction impacts? What are the public safety impacts of the pigging operations and transportation of the gas liquids? ***This comment should be addressed in all of the applicable issue areas.***
15. ***Page 3-9, Second Bullet*** – Water is injected at the Lompoc Oil Field not the LOGP.
16. ***Page 3-10, First Bullet*** – The EIR should specify where the produced water would be reinjected. The EIR needs to evaluate the impacts of this reinjection in the applicable issue areas.
17. ***Page 3- 10, 6th Paragraph*** – The document states that a new substation would have to be built near Surf Beach to provide power to the VAFB drilling and production site. This is a true statement since the existing substation at Surf Beach does not have sufficient capacity to provide power to Platform Irene and the VAFB drilling and processing site. The document should provide an estimate of the size of this site and the type and height of equipment that would be needed at this new substation. In addition, for most of the issue areas, it has been assumed that the existing substation at Surf Beach would be used. ***This needs to be corrected in almost all of the issue areas.***

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PXP3-18

18. ***Page 3-11, First Paragraph, Last Sentence*** – The DEIR states that, "For the purposes analysis of this alternative, it is assumed that cogeneration would be incorporated into the 25-acre facility footprint." None of the issue areas discuss the impacts associated with a cogeneration facility. All of the impact analyses for this alternative are based upon electric power being supplied via the grid. We would suggest this cogeneration alternative be dropped from further consideration, since the use of grid power would result in fewer environmental impacts. If cogeneration is not dropped from further consideration then the appropriate issues areas must discuss the impacts.

PXP3-19

19. ***Page 3-11, Second Paragraph*** – The DEIR needs to make it clear that it is uncertain that VAFB can or will provide natural gas and potable water for the alternative. If VAFB can not provide natural gas and potable water, then new pipelines would have to be constructed to the site.

20. ***Page 3-18, Section 3.5.1.1, 4th paragraph*** – The Pt Pedernales pipelines were not installed using a lay barge. They were welded on the beach and then pulled into position using a barge and tugs.

21. ***Page 3-29, Figure 3-1*** – The figure states that Platform Irene is a "new oil dehydration and gas processing platform". This text should be eliminated because it is not true.

22. ***Page 3-33, Figure 3-5*** – The figure does not show the pipeline route from the intersection of Surf Road and Bear Creek Road to the intersection of Arguello Road and SR 246.

E. Chapter 4-Cumulative Projects

23. ***Page 4-4, Section 4.1.4.2*** – This section should be 4.2.4.2. Also the last sentence in this section should refer to Section 4.2.5.2

24. ***Page 4-8, Table 4.2, Purisima Hills Development*** – The proposed residential development west of the LOGP on PXP property is being evaluated by Cook Hill Properties. The proposed Purisima Hills Development is in the early stages of planning, and would involve an annexation of property to the City of Lompoc. A number of people raised this development as part of the hearings on the Public Draft EIR and said this should be included as part of the project. No application has been filed for this project and the project is not in anyway related to the Tranquillon Ridge project. Clearly, this project meets the definition of cumulative project under CEQA and therefore should only be discussed and evaluated in the cumulative analysis

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portions of the EIR.

As the project currently stands, it would involve the development of approximately 804 acres and would include 1,308 residential units along with a number of open spaces and parks. Approximately 339 acres would be for residential development, 51 acres would be for streets, and 413 acres would be open space (294 acres of natural open space and 119 acres of parks and trails). The area of the development shown in Figure 4-3 is fairly close to the footprint currently envisioned by Cook Hills Property.

The proposed development would occur within the existing pipeline corridor for the pipelines from Platform Irene to the LOGP. PXP has committed to Cook Hill Properties that the pipelines would be relocated if the residential development moves forward, is approved, and is built. The pipelines would be moved to another location on PXP property that would assure risk associated with the pipelines would be insignificant based upon the County of Santa Barbara significance criteria. The exact route that the pipelines would take has not been developed. PXP continues to work with Cook Hill Properties to assure that the realignment of the pipelines will not have a significant impact on public safety.

F. Issue Area Specific Comments

The following provides comments on the specific issues areas in Chapter 5 of the DEIR.

F.1 Risk of Upset/System Safety

25. ***Page 5.1-13, Third Paragraph, Second Sentence*** – This sentence should be deleted since it is not relevant to the emulsion pipeline smart pig results. The sentence is stated again on page 5.1-29, last paragraph, under the onshore pipeline. The sentence is more appropriate in this later section.

26. ***Page 5.1-14, First Paragraph, Last Sentence*** – The word "not" in the sentence should be deleted since there is a statistical correlation between failure rates and pipe stresses.

27. ***Page 5.1-51, Impact Risk.1*** – The EIR states that "increased throughput of crude oil between Platform Irene and the LOGP is not expected to generate increased public risk due to the high levels of water in the process stream". This is further confirmed by the fact that the risk profiles do not contain any curve for fire risk to the public from a crude oil spill from oil emulsion pipeline. In fact, the EIR acknowledges that the fire risk from an oil spill does not exist with the current operations due to the high level of water in the emulsion mixture. The finding of the EIR is that fire risk would

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not change from the baseline. Since there is no increase in risk (the risk remains the same as baseline) there is no nexus for mitigation measure Risk-1. This mitigation measures should be eliminated. The County can always use the B-2 review process to address these issues.

PXP3-28

28. ***Page 5.1-51, Impact Risk.1*** –In addition, mitigation measure Risk-1 discusses the need for a new SCADA system on the gas pipeline; however Impact Risk.1 has nothing to do with public risk from a sour gas pipeline release. Therefore, mitigation measure Risk-1 should be deleted from Impact Risk.1.

PXP3-29

29. ***Page 5.1-51, Impact Risk.2*** – This section states "the risks to the public are considered to be the same as the current operations." This statement is confirmed by comparing the baseline and project FN curves for the sour gas pipeline. Since there is no increase in risk (the risk remains the same as baseline) there is no nexus for mitigation measure Risk-2. The mitigation measure should be eliminated. Furthermore, the limit of 600 psig is part of the project description and the 8,000 ppm H_2S is already a permit condition.

30. ***Page 5.1-54, VAFB Alternative*** – This section should also discuss potential impacts to Amtrak passengers as well as impacts to other rail traffic. Rail traffic could also serve as an ignition source for the drilling and production facility.

31. ***Page 5.1-56, Impact Risk.4*** – The determination that this is a Class II impact is not supported by the evidence in the document. The County significance criterion for public safety uses FN curves to determine the level of significance. No analysis was done to show that the proposed mitigation measures would be effective in reducing risk to an insignificant level. While CEQA does not require the same level of detail for analysis of alternatives, the EIR should not assume that the proposed mitigation measures would reduce the significant impact to insignificant without some analysis. As such, it should be assumed that this is a Class I impact even with the proposed mitigation measures unless some analysis is done to support the reduction to Class II. The other option is to use the methodology used in Cultural Resources Impact CR.5, where the impacts are Class I or Class II.

32. ***General Risk of Upset Comment for VAFB Alternative*** – No discussion or impact analysis is done on the potential for base operations (e.g., rocket fueling, military or commercial launches, etc.) to impact the onshore drilling and production activities. Given the proximity of the site to SLC-5 and SLC-6 there is a possibility that an aborted launch or a mishap during fuel loading could impact the drilling and production facility. The alternative site is within the hazard zones for fueling.

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Bixby Ranch has use and development restrictions that were placed on the property due to concerns related to launches. They also have occupancy limits during some base operations. It is likely that a drilling and processing facility at this site would also have substantial restrictions associated with drilling and production during selected base operations. This should be discussed in the document and included as an impact for the VAFB alternative.

F.2 Biological Resources

PXP3-33

33. ***Page 5.2-62, Impact TB.10*** – The new Surf Beach substation should be included in this impact. Page 5.2-63, 1st paragraph talks about the installation of the new power poles but does not discuss the loss of vegetation that would occur with the installation of the new substation at Surf Beach. Depending upon its location there could be impacts to listed or threatened species.

34. ***Noise Impacts to Snowy Plovers for VAFB Alternative*** – Drilling and production operations can generate noise levels as high as 85dBA. Given the close proximity of the drilling and production site to the beach, the EIR should discuss the impacts of noise from the drilling and production operations on the Snowy Plover. Noise from the drilling and production facility could also affect other wildlife species.

F.3 Geological Resources

35. ***Page 5.3-15, Impact GR.2*** – The impacts associated with the construction of the new substation near Surf Beach are not discussed as part of this impact.

36. ***Page 5.3-11, Impact GR.3*** – The EIR contains no substantial evidence to support the claim that the minor upgrades and modifications at the LOGP will result in continued or accelerated ground settlement. The upgrades at the LOGP will not require the installation of any heavy equipment. The majority of the equipment is in place and only minor loads will be added by introducing new production. The analysis does not acknowledge the extensive injection grouting that has been done at the site and the fact that the site is surveyed twice per year and reviewed by the SSRRC.

The EIR needs to provide additional supporting evidence to support the claim that this significant settlement would occur with the improvements prior to applying the mitigation. Otherwise, the impact should be made insignificant (Class III), and mitigation measure GR-2 deleted.

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F.4 Onshore Water Resources

PXP3-37
37. ***Page 5.4-20, Impact OWR.6 and page 5.4-21, Impact OWR.8*** – These seem to be the same impact. Please explain in the text or delete one of the impacts from the alternative discussion.

F.5 Marine Resources

PXP3-38
38. ***Page 5.5-43, Mitigation Measure MB-1b*** – This mitigation measure should have a time limit on it. The fingerprint and variability of the tar normally present in the intertidal zone would not be expected to change significantly on an annual basis. It is more appropriate to require that this baseline analysis be conducted once every five years. Conducting this baseline assessment annually is excessive.

39. ***Page 5.5-56, Mitigation Measure MB-5*** - This mitigation measure should only apply during the drilling phase of the project since the impact is tied to drilling. Application of this measure beyond the drilling phase has no nexus since the impact is limited to drilling only.

40. ***Page 5.5-57, Mitigation Measure MB-6*** – This mitigation measure should only apply during the drilling phase of the project since the impact is tied to drilling. Application of this measure beyond the drilling phase has no nexus since the impact is limited to drilling only.

F.6 Air Quality

41. ***Page 5.8-13 Table 5.8.7 and Related Emissions Table on Appendix C, page C-3*** - The construction emissions for the Valve Site #2 equipment modifications are significantly overstated. Use of the equipment (Backhoe, A-frame Truck, Service Truck, 15-ton Crane, Concrete Truck, and Welding Machine) should be approximately 20 percent of the duration indicated. The actual construction will not last nine months (see comment #9). The estimated emissions would correspond to approximately 20 percent of those identified in the DEIR (Table 5.8.7).

42. ***Page 5.8-17, second paragraph and corresponding table in Appendix C page C-23*** - The text identifies seven tons of NOx and two tons of SOx emissions increases in the context of increases in green house gases (GHGs). Although NOx is a precursor to ozone, neither NOx nor SOx are GHG constituents.

43. ***Page 5.8-20, Impact Air.2*** – The discussion states that operational emissions would be similar to that for the proposed project and refers to Table 5.8.8. This is an

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incorrect statement. The operational emissions would be much greater for the alternative since it would include both drilling and production. The EIR should make some attempt at quantifying these emissions. The processing facility would have increased ROC and NOx emissions due to the processing equipment, tanks, a flare, etc. Clearly, these emissions would be substantially greater than for the proposed project. An estimate of operational emissions is needed in order to determine if the mitigation measure of offsets if feasible. Offsets in North County are in very short supply. CEQA requires that mitigation measures be feasible. The EIR needs to determine if offsets for the estimated operational emissions are available. If they are not then the impact must be Class I.

F.7 Noise

44. ***Page 5.10-1, Section 5.10.2*** – This section only discusses noise impacts to marine wildlife. The Terrestrial and Freshwater Biology wildlife should also be referenced and noise impact associated with construction and operation should be discussed for both the proposed project as well as for the various alternatives.

F.8 Traffic

45. ***Page 5.9-10, First Paragraph under Impact T.3*** – The DEIR states that "Existing marine traffic (project-and non-project-related) between Platform Irene and the shoreline is estimated at five vessels per day." What is the basis for this number? What data source was used to develop this estimate? The only marine traffic that goes to Platform Irene is the supply boats.

46. ***Page 5.9-12 – Impact T.2*** – This impact states "Workers traveling to the VAFB drilling and production facility would increase road traffic, but would not change the level of service of any roadways." This statement is not supported by the evidence in the document. The impact discussion does not address the large volume of materials that must be moved to and from the site on a daily basis to support the drilling operations. There is no analysis of impacts to the VAFB roads. What is the LOS of these roads? What would be the impact of traffic on these roads? These issues must be addressed before a determination can be made that the impact is insignificant (Class III).

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F.9 Fire Protection and Emergency Response

PXP3-47

47. ***Page 5.11-18, VAFB Onshore Alternative*** – This section of the EIR contains no discussion of the fire and emergency response impacts associated with the operation of the onshore drilling and production facility (Impact Fire.4 for the proposed project). Given the very remote location of the alternative facility this should be carefully addressed. Clearly this project site is more than 10 miles from a public emergency response location with both hazmat (spill response) for fire fighting and emergency response capabilities. While, there is a VAFB fire station on the south base (about 4-5 miles from the facility), it is not clear that VAFB is equipped or would be willing to be the primary responder for emergency response. In addition, accessibility to the site by County fire could be difficult or limited given that it is on a secured military base. Therefore, based upon the significance criteria in the DEIR, the fire and emergency response impact for the drilling and production facility would be significant (Class I).

F.10 Aesthetics/Visual Resource

PXP3-48

48. ***Page 5.13-10, VAFB Onshore Alternative*** – The text in the first paragraph states "The site is located west and north of Surf Road, east of Coast Road, and south of Delphy Road. The area is located on a hill sloping upwards to the east, which blocks most views of the site from Coast Road." If the site slopes upward to the east and Coast Road is to the west, then how can the statement in the DEIR be correct? Based upon detailed topographical data the site has an elevation of approximately 55 meters on the western edge and 60 meters on the eastern edge. Coast Road and the railroad tracks have an elevation of approximately 50 meters. Therefore, the drill rig and the processing facility will be highly visible along Coast Road and for passengers on Amtrak for a number of miles in both directions. In addition, the facilities would be visible for mariners in the area.

The figure below shows a viewshed analysis for the VAFB onshore alternative site. The analysis looked at where a 200 foot drill rig would be visible as well as a 50 foot high tank at the processing facility. The 50 foot high tank would be visible in the immediate vicinity of the facility, including the railroad tracks and the two roads, and about ½ mile north and 1 mile south of the facility. It would also be clearly viewable from the ocean.

The 200 foot drilling rig would be visible intermittently north of the facility due to the undulating hills, to a point about 1.5 miles north of the facility. At this point, there is a ridge of about 290 feet high which would block views of the drilling rig until the

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beach areas near Surf. Based upon the viewshed analysis, the top of the drill rig would be visible to the public on potions of Surf Beach as well as to mariners.

49. ***Page 5.13-11, Impact Visual.1*** – This section needs to be re-written based upon the information provided above. Clearly, the onshore drilling and production facility will be a significant Class I impact since it would impact visual resources of the coastal zone (second significance criteria listed on page 5.13-6). Also, the discussion needs to address the installation of a new substation near Surf Beach to support the project, which also would be visible from the Coastal Zone and would be a significant Class I impact. The visual impacts of the pipeline tie-in facility, discussed in the comments for Chapter 3, need to be evaluated in the visual impact section. This facility may be visible from Highway 246.

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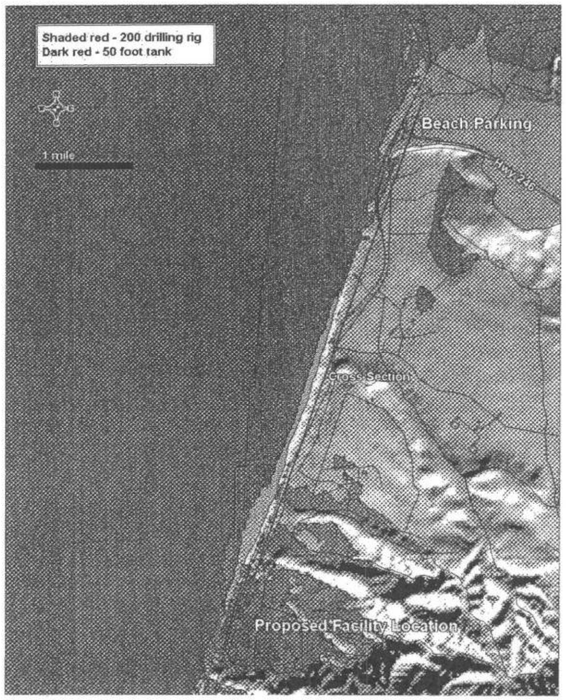
Viewshed Analysis for VAFB Onshore Alternative



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PXP3-50
50. ***Page 5.13-11, Impact Visual.2*** – The statement that there will be no new equipment at Valve Site #2 and LOGP is incorrect. The EIR in the Alternatives section makes it clear that the modifications to the LOGP would still be needed for this alternative. Based upon the comments for the VAFB alternative description (Chapter 3 comments) the modification to Valve Site #2 may still be needed with this alternative. The text for this impact needs to be re-written.

PXP3-51
51. ***Page 5.13-11, Impact Visual.3*** – The statement that no new transformer and powerlines for Valve Site #2 would be needed for this alternative is incorrect. Based upon the comments for the VAFB alternative description (Chapter 3 comments) the modification to Valve Site #2 may still be needed with this alternative. The text for this impact needs to be re-written.

PXP3-52
52. ***Page 5.13-12, Impact Visual.5 nighttime*** - Based upon the comment provided above, the text for this impact need to be re-written. The FAA will require that the top of the drill rig be equipped with a flashing red light. Given the data presented in the comments above, this light will be visible from Surf Beach and very western portions of Highway 246. Clearly, the nighttime glare would be a significant Class I impact since it would impact visual resources of the coastal zone (second significance criteria listed on page 5.13-6).

F.11 Energy and Mineral Resources

PXP3-53
53. ***Page 5.16-3, second paragraph*** – The helicopters do not use gasoline, they use jet fuel

PXP3-54
54. ***Page 5.16-5, Section 5.16.3, first sentence*** – There is a 1 inside the parentheses which should not be there i.e. Manual (1 as revised

PXP3-55
55. ***Page 5.16-6, second paragraph*** - The helicopters do not use gasoline, they use jet fuel

PXP3-56
56. ***Page 5.16-10, last paragraph*** – Although diesel use for the supply boats will be eliminated, the materials will still need to be trucked to the alternate site so the amount of diesel used will probably be greater since the amount of materials, pipe, vessels, etc. will be greater. The helicopter uses jet fuel, not gasoline.

PXP3-57
57. ***General Comment on Energy and Mineral Resources*** – The document should have a beneficial (Class IV) impact for oil production since the proposed project would result in a reduction in tankering of foreign oil to California. The California crude oil supply comes from three sources, California, Alaska, and foreign imports. The California Energy Commission has estimated that foreign imports are expected to

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reach 465 MM barrels by 2015 and 530 MM barrels by 2025. In 2004, 390 MM barrels of crude oil came from foreign imports. Given these numbers, any increase in domestic crude oil production would offset foreign imports. If one assumes 200 MM barrels of crude oil would be produced from the Tranquillon Ridge Project, then this would reduce foreign imports via tankering by 200 MM barrels or about 133 tanker trips assuming 1.5 MM barrels per tanker. This represents a reduction of four tanker trips per year averaged over the 30 year life of the project. This would reduce the air emissions and spill risk associated with tankering.

G. Environmentally Superior Alternative

PXP3-58

58. ***Page 6-4, Section 6.3, Last Sentence*** – The Class II and III impacts identified for the proposed project and the alternatives are not compared in Table 6.1a through 6.1c. This sentence should be deleted or reworded.

PXP3-59

59. ***Table 6.1a*** – Based upon the discussion in comment # 31 a new Class I impact should be added for risk that addresses the potential for the VAFB onshore alternative to generate public safety risk by exposing Vandenberg personnel, their contractors and the public to processing and pipeline hazards. With the addition of this Class I impact, the proposed project would clearly be preferred over the VAFB onshore alternative.

PXP3-60

60. ***Table 6.1a*** – Based upon the discussion in comment # 47 a new Class I impact should be added for Fire Protection and Emergency Response. With the addition of this Class I impact, the proposed project would clearly be preferred over the VAFB onshore alternative.

PXP3-61

61. ***Table 6.1a*** – Based upon the discussion in comments # 48 and 49 a new Class I impact should be added for visual resources that address the addition of new facilities (drilling and production facilities, new substation at Surf Beach, and pipeline tie-in facility) that are visible from the coastal zone for the VAFB onshore alternative. With the addition of this Class I impact, the proposed project would clearly be preferred over the VAFB onshore alternative.

PXP3-62

62. ***Table 6.1a*** – If the EIR preparers can not determine the feasibility of offsets for the operational emissions associated with the VAFB onshore alternative, then operational emissions should be added to the table as a Class I impact for the VAFB alternative. With the addition of this Class I impact, the proposed project would clearly be preferred over the VAFB onshore alternative.

PXP3-63

63. ***Page 6-57, First Paragraph – Page 6-57, First Paragraph*** – The DEIR states the following "Because there is no other feasible project-level alternative to the proposed

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project, the VAFB Onshore Alternative is considered to be the de facto "environmentally superior alternative" for purposes of CEQA Guidelines Section 15125.6(e)(2)." There are two problems with this statement. The first is that it cites the wrong section of the CEQA Guidelines. The CEQA section that should be cited is 15126.6(e)(2).

The second problem is explained as follows: In Section 6.2 of the DEIR, the proposed project is compared to the No Project Alternative. This comparison is properly used to make the determination that the No Project Alternative is the "environmentally superior alternative". This same comparison approach should be used to determine the next "environmentally superior alterative". In other words, the VAFB Onshore Alternative should be compared to the proposed project to determine which one of these two scenarios would be the "environmentally superior alternative". Only after this comparison can one make a definitive statement as to the "environmentally superior alternative". Indeed, this analysis is provided in Section 6.4.1 of the DEIR, and neither the VAFB Onshore Alternative nor proposed project is found to be preferred. As such, the statement in the first paragraph of page 6-57 that the VAFB Onshore Alternative is considered to be the de facto "environmentally superior alternative" should be deleted.

PXP3-64

64. ***Page 6-57, First Paragraph*** – The statement that "…the VAFB Onshore Alternative could be considered the de facto environmentally superior alternative." should be deleted based upon the comment above.

PXP3-65

65. ***Page 6-60, First Bullet*** – The increase in spill probability for the onshore pipeline from tie-in to the LOGP would be similar for both the proposed project and the VAFB alternative. This point is not made clear in the comparison of the two alternatives.

PXP3-66

66. ***Page 6-60, Third Bullet under Proposed Project*** – This vegetation removal is not a Class I impact for the proposed project and therefore should be deleted. The vegetation removal is a Class II impact (TB.1).

PXP3-67

67. ***General Comment on Comparison of Proposed Project and VAFB Onshore Alternative*** – Page 6-62, second paragraph states that "As a result, this analysis relies on a comparison of the nature, extent, permanence and probability of each Class I impact in order to identify the environmentally preferred option." However, it does not appear that any weight was given to permanence or probability in making the determination of what is the preferred project.

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PXP3-67 Cont'd

The only major Class I impact from the proposed project is the increase in probability of an oil spill to the marine environment. The DEIR acknowledges that there is 22.1 percent probability of an offshore spill over the lifetime of the proposed project, which means a spill would not be expected to occur during the lifetime of the project. When this is compared to the number of Class I impact that are guaranteed to occur with the VAFB alternative, and will be permanent (TB.9, TB.10, CR.5) it is clear that the proposed project is preferred.

In addition, the comparison of the proposed project and the VAFB onshore alternative should discuss the following.

- The VAFB alternative would increase the overall spill probabilities and volumes for the onshore pipelines since approximately 10 miles of new pipelines would be added.
- During the years that both Platform Irene and the VAFB onshore facility are operating, the VAFB alternative would increase the probability of a spill to the marine environment due to the operation of 10 miles of new pipeline that could result in spills to the marine environment.
- As discussed in the visual comments, the VAFB alternative would result in significant new structures within the coastal zone that would not occur with the proposed project.
- The VAFB alternative would result in a substantial new source of air emissions for which offsets may not be feasible. Even if offsets are available, the VAFB alternative would consume a large number of offsets that are in very short supply in the North County, which could restrict future development.

When all of these factors are fully addressed in the EIR, it will be clear that the proposed project is preferred over the VAFB Onshore Alternative.

H. Appendices

68. ***Appendix B-5*** – The Sisquoc to Santa Maria Pump Station pipeline is not shown on the map even though it is labeled.

69. ***Appendix B-6*** – The 8" Orcutt pipeline is not shown on the map even though it is labeled

70. ***Appendix C*** – The emissions relating to LOGP construction activities should be recalculated based on 9 weeks of activity instead on 9 months. There is an error in our project application.

January 16, 2007

Mr. Doug Anthony, Deputy Director
Santa Barbara County
Planning & Development, Energy Division

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I. Other General Comment

PXP3-71

71. The mitigation monitoring plans need to be reviewed to assure that the timing of verification is tied to the project activity for which it applies. For example, mitigation measures for Valve Site #2 should be timed to occur prior to installation or operation of the additional equipment at Valve Site #2.

Should you have any questions about our comments, please contact me at 323-298-2223.

Sincerely,

Steven P. Rusch

cc: Paul Mount, California State Lands Commission

Response to Comment Set PXP3

PXP3-1: The noted paragraph has been clarified to reflect that while PXP currently has no plans to drill additional wells into the Federal portion of Tranquillon Ridge Field, reservoir geology and future economics could warrant otherwise.

PXP3-2: The description of the VAFB Onshore Alternative provided in the Executive Summary is a brief overview. Specific Class I, II, and III impacts are summarized in the tables provided at the end of the Executive Summary, including impacts related to the waterway crossings associated with the VAFB Onshore Alternative. A complete description of the conceptual VAFB Onshore Alternative is provided in EIR Section 3.3.3 and impacts associated with this alternative are evaluated throughout the EIR.

PXP3-3: The EIR text has been revised as follows:

Implementation of the Tranquillon Ridge Project would also result in an increased throughput of crude oil through the ConocoPhillips Line 300 pipeline system, which moves dry oil from the LOGP, ~~to the ConocoPhillips Santa Maria Refinery or connects to additional pipelines for transport to Bay Area refineries. Point Pedernales projection has historically been processed at the Santa Maria Refinery.~~ as well as Santa Ynez Unit, Point Arguello, Lompoc Field, and Orcutt Field production, to the ConocoPhillips Santa Maria Refinery in San Luis Obispo County. From the Santa Maria Refinery, partially refined products are transported to Bay Area refineries via existing pipelines. The Line 300 pipeline system is a regulated common carrier and is operated by ConocoPhillips under a separate SBC permit. The portion of the system that moves dry oil from LOGP to the Santa Maria Refinery has a permitted capacity of 36,000 barrels per day (bpd). The average Point Pedernales production throughput through the subject portion of the pipeline in 2005 was 7,000 bpd. Since this pipeline primarily ships oil ~~only~~ from LOGP (with some production from the Lompoc and Orcutt Fields), the throughput in the pipeline segment from LOGP to Suey Junction has been diminishing along with the production from the Point Pedernales Field. At Suey Junction, Santa Ynez Unit and Point Arguello production make up the required throughput rate (limited by the Santa Maria Refinery capacity) via the Sisquoc portion of the Line 300 pipeline system. As such, the baseline for this pipeline segment from LOGP to Suey Junction was assumed to be the throughput at the time the NOP was issued (7,000 bpd).

PXP3-4: Please refer to Response PXP3-3.

PXP3-5: Please refer to Response PXP3-3.

PXP3-6: The Executive Summary table entitled *Class I Impacts of the VAFB Onshore Alternative* as been corrected to reflect Impact T.4, disruption of onshore transportation infrastructure resulting from an oil spill, rather than Impact T.3.

PXP3-7: The description of the regulatory role of MMS in Section 1.3 has been corrected to reflect the May 2005 submittal of the PXP revisions to the DPP.

PXP3-8: The noted correction has been made.

PXP3-9: Thank you for the clarification; the text has been corrected. It should also be noted that the construction emission calculations in Appendix C reflect the shorter duration (nine weeks) of work expected by PXP as a result of earlier permitting and construction of the water treatment system. Emissions from the produced water treatment system are identified in the December 2006 Permit to Operate and Part 70 Operating Permit (No. 6708) for LOGP. See also Response to Comment PXP3-41.

PXP3-10: The noted correction has been made.

PXP3-11: Regarding the first bullet in Comment PXP3-11, Table 3.1 has been revised to reflect the EIR's assessment that drilling from shore would have, overall, about the same visual impacts as the proposed project. Table 3.1 also has been revised to reflect the information in the remaining bullets in Comment PXP3-11.

PXP3-12: The noted correction has been made.

PXP3-13: The referenced Fluor Study indicates that the pumping pressure requirement is the highest at about 50% water cut with 40%-60% water cut range representing the high pumping pressure requirement range. This is due to the higher viscosity of the emulsion in this 40-60% water cut range. The pumping (discharge) pressure at Platform Irene for the emulsion with water cuts greater than or equal to 70% is 473 psig for flow rates up to 100,000 barrels per day. This is well below the MAOP of 1,194 psig for the emulsion pipeline.

The existing production rate from Platform Irene is 57,000 barrels per day of oil/water emulsion with 88% water cut (2005 average), or 7,000 barrels per day oil production. In the future, the water cut would increase with a corresponding decrease in oil production.

The VAFB Onshore Alternative peak production would be the same as the proposed project, i.e., 27,000 barrels per day of oil. Under Produced Water Scenarios 2 or 3 (see EIR Section 3.3.3), produced water would be removed at the alternative production/processing site and dry oil would be sent to the alternative tie-in station at the existing PXP pipelines. Assuming peak production for the VAFB Onshore Alternative, the production from Platform Irene would be 3,000 barrels of oil providing a combined total production of 30,000 barrels per day of oil, same as the peak production for the proposed project.

The peak production rate of 27,000 barrels per day dry oil from the VAFB Onshore Alternative combined with 57,000 barrels per day of oil/water emulsion with 3,000 barrels per day of oil would provide 84,000 barrels per day of oil/water emulsion with 64% water cut. This combined emulsion rate of 84,000 barrels per day with 64% water cut would represent the lowest anticipated water cut for the Point Pedernales Project life. Based upon the Fluor Study, for the 84,000 barrels per day emulsion with 64% water cut, booster pumps may not be necessary since the Platform Irene discharge pressure would be less than 900 psig, below the emulsion pipeline MAOP of 1,194 psig.

However, due to crude oil composition changes (i.e., higher viscosity than anticipated), higher combined production flow rates, de-rating of the emulsion pipeline or any other reason, a higher pipeline pressure could be required. In this case, booster pumps could be installed at the tie-in station to boost the pressure for the PXP stream. The tie-in station would be the ideal location for the booster pumps for operations, as well as for maintenance. The pumps at the VAFB Onshore Alternative drilling and production site would be designed to provide sufficient discharge pressure for the tie-in to the PXP pipeline.

The description of the VAFB Onshore Alternative, Section 3.3.3, has been clarified to reflect that if the existing PXP pipelines require additional pumping capacity to accommodate the dry oil volumes associated with the alternative, then the pumps would be installed at the tie-in station and power would be provided to the area. The issue area analyses have been updated to reflect this potential, additional alternative requirement.

PXP3-14: EIR Section 3.3.3 has been revised to provide the necessary details for the VAFB Onshore Alternative tie-in station. The emulsion and gas-liquids could be pumped back in to the respective pipelines or could be transported by vacuum trucks to the LOGP for processing.

Section 5.1.5.2 has been revised to include a more detailed analysis of the tie-in station risks. In addition, the issue area analyses have been updated to reflect this potential, additional alternative requirement.

PXP3-15: The noted correction has been made.

PXP3-16: As presented under Produced Water Scenario 2, the water cleaning and injection plant would be located within the alternative drilling and production site. As described earlier, the alternative drilling and production site would be approximately 25 acres is size and would be located with the 75-acre area bounded by Coast Road to the west and south, Surf Road to the east, and Delphy Road to the north (see Figure 3-2).

PXP3-17: Further details have been incorporated into Section 3.3.3 regarding the electrical substation required for the VAFB Onshore Alternative.

PXP3-18: The VAFB Onshore Alternative is conceptual but, in accordance with CEQA, provides sufficient detail to conduct a qualitative analysis of potential impacts. As stated in Section 3.3.3, the cogeneration facility, if used, would be located within the 25-acre drilling and production site. Construction and operational impacts associated with the 25-acre drilling and production site were considered throughout the EIR. If and when an application for a specific onshore drilling/production project were to be submitted, an air quality analysis would be conducted to assess the emissions associated with cogeneration versus tying into the grid.

PXP3-19: The conceptual alternative was designed to minimize impacts, as discussed throughout Section 3.3.3, so water and gas utility tie-ins were assumed to be close to the drilling/ production site. Availability of water and gas utility hook-ups (and locations) would need to be negotiated with the Base should the Air Force allow an onshore development project to move forward. If utility and gas hook-up locations were not near the drilling/production site, it is true that additional construction impacts would occur.

PXP3-20: The noted correction has been made.

PXP3-21: The noted correction has been made.

PXP3-22: As noted on Figure 3-5, the yellow shading represents the area where the alternative pipeline would travel cross-country from the approximate intersection of Surf Road and Bear Creek Road to the approximate intersection of Highway 246 and 13th Street. As noted in Section 3.3.3, a cross-country route through this area was eliminated from further consideration due to the high density of cultural and biological resources that, based on consultations with VAFB personnel, are known to occur in this area.

PXP3-23: The noted corrections have been made.

PXP3-24: The summary descriptions for the proposed residential development in DEIR Table 4.2, Relevant Cumulative Projects, and Section 4.4.1, Development Projects in Lompoc Area, have been revised to reflect the information provided in Comment PXP3-24. As reflected in Response to Comment CPA-4, it is noted that with implementation of Santa Barbara County Safety Element Policies 2A, 3A, 3B, and Planned Development Policy 3(c), no new large-scale residential development would be allowed within the respective hazard footprints of the proposed project's off- to onshore oil emulsion and natural gas pipelines; therefore, the impacts associated with introducing a greater number of people to the risks of a pipeline rupture and leak would be minimized if the housing project were in County jurisdiction. The discussion contained within the text of DEIR Table ES.2 and Section 5.1.6, Risk of Upset, Cumulative Impacts, has been revised to reflect that with implementation of County safety policies and the mitigation measures identified in DEIR Section 5.1.4, impacts would be less than significant. Please also see Responses to Comments JP-1 and CPA-4.

PXP3-25: The sentence, "In addition as a result of the 1997 offshore failure, the emulsion pipeline would have been considered a 'high-risk' pipeline by CSFM" is relevant here because the smart pig survey results over the last several years indicated that the internal corrosion program has been effective at substantially reducing the rate of corrosion in the onshore portion of the pipeline. The smart pig survey results for the internal as well as external corrosion justify that the emulsion pipeline is no longer a "high-risk" pipeline.

PXP3-26: The CSFM report does indicate that there is no statistical correlation between the failure rates and operating pressure or pipe stresses. The operating pressures have been below the established MAOP (Maximum Allowable Operating Pressure) of the pipelines. The MAOP of a pipeline is required to be lowered (de-rated) if there is any significant metal wall loss. This de-rating restricts the pipeline operating pressure. As a result, the operating pressure is not a contributing factor for the failure rates like other factors such as temperature and coating.

PXP3-27: Increased throughput of crude oil between Platform Irene and the LOGP is not expected to generate increased public risk due to the high water content in the emulsion. However, the current leak detection system should be upgraded to a current state-of-the-art leak detection system due to the increased throughput and the extension of life of the emulsion pipeline if the Tranquillon Ridge project is approved and implemented. These enhancements would improve the leak detection and the response time reducing the crude oil spill volumes in case of leaks or ruptures. Other significant impacts associated with oil spills would occur (for example, Impacts OWR.2, MB.1, MWQ.1, CRF/KH.2, and T.4). Early detection of pipeline leaks would help minimize the extent of a spill and the resulting impacts in these issue areas. In addition, installation of state-of-the-art leak detection, especially on a pipeline that experienced a significant oil spill in 1997, would render the project more consistent with State and County policies that require maximum feasible mitigation of project impacts. An upgraded leak detection system on the sour gas pipeline would reduce the likelihood of public exposures for toxic and flammable gas releases due to leaks or ruptures. Mitigation Measure Risk-1 has been modified to read as follows:

Risk-1 The applicant shall install an upgraded state-of-the-art leak detection system on the existing emulsion line and on the sour gas line. The upgraded system shall use the Best Available Technology (BAT) for detection of small leaks in the emulsion pipeline. The applicant shall provide the County with a comparative analysis of available technologies that have been used in applications similar to this project and the demonstrated effectiveness and reliability of those systems. The County shall review and approve of the leak detection technology prior to its installation. Review and approval of the comparative analysis and installation of the approved leak detection system shall occur prior to land use permit approval.

PXP3-28: The leak detection on the gas pipeline is included in Mitigation Measure Risk-1 to keep the leak detection mitigations for the emulsion line and the sour gas line together. Impact Risk.2 requires leak detection mitigation on the gas pipeline. This mitigation is discussed under Impact Risk.2, Mitigation Measures.

PXP3-29: Although limits of 600 psig pressure and 8,000 ppm H_2S are part of the project description and permit condition respectively, administrative controls need to be in place to ensure that the pressure and/or H_2S limits are not exceeded. Mitigation Measure Risk-2 delineates this requirement.

PXP3-30: The impact discussion for the VAFB Onshore Alternative, Section 5.1.5.2, has been revised to include impacts due to the drilling and production facility and its surroundings. Specifically, the fatality hazard footprint from a sour gas release at the production site would encompass the nearby Coast and Surf roads and the Union Pacific Railroad, requiring road and rail closures for a period of time. These cars and trains could also be potential ignition sources. This would temporarily isolate approximately 140 personnel at South Vandenberg facilities and could interfere with launch operations at SLC-6. Also, individuals traveling in cars and on the railroad could be exposed to toxic or flammable vapors.

PXP3-31: The comment is correct. Though experience has shown it may be possible to reduce the impacts of a produced gas release through measures such as optimum siting of facilities and pipelines that handle sour gas and/or reduced pipeline operating pressures to limit the extent of a release, reliance on such measures in the absence of a quantitative risk analysis (QRA) to reduce the potential impacts to less than significant levels is not appropriate. A QRA will produce the FN curves that will indicate whether a risk is significant (Class I) or not significant (Class III) regardless of the application of mitigation measures, or less than significant only with application of mitigation measures (Class II). A QRA cannot be prepared for the conceptual VAFB Onshore Alternative as sufficient project description detail is not available and cannot be assumed in order to generate the FN curves for this conceptual alternative. Therefore, the discussion of the residual impact for Impact Risk.4 in the EIR has been revised to acknowledge that this impact would be "Class I or Class II," similar to the classification of potentially significant impacts to cultural resources for the VAFB Onshore Alternative.

PXP3-32: VAFB operations would affect the operations of the VAFB Onshore Alternative drilling and production facilities. For example, during launches all personnel at the VAFB Onshore Alternative would need to evacuate the site as specified by launch operations protocols. It is likely that during production, the VAFB Onshore Alternative could operate in an unmanned automated state. However, for drilling operations, it could be necessary to shutdown drilling operations. Evacuation of drilling and production site personnel, and potential shutdown of drilling operations could also occur during Base rocket fueling operations. The implementation of rocket fueling evacuation protocols are dependent upon weather conditions, so their implementation might not be necessary for all fueling operations.

As discussed at the end of EIR Section 3.3.3, VAFB would review an onshore project through the Air Force's Base Unit Beddown Program. The purpose of this review is to determine the potential impacts of the project on the present and future Air Force operations at VAFB. This process and the necessary CEQA and NEPA reviews could result in a project description that mitigates potential operations and safety conflicts.

PXP3-33: The text for Impact TB.10 has been clarified to reflect substation construction. Impacts of a new substation are included within Impact TB.10, and corresponding mitigation measures would also apply to a new substation. The exact design, location and ground disturbance footprint of a new substation are currently unknown and hence cannot be assessed with precision at this level of analysis. Construction and operation of a new substation would incrementally increase the magnitude of Impact TB.10, which is already recognized as a Class I impact.

PXP3-34: Drilling and production operations at the onshore location would be more than 500-800 feet from the beach, and separated from it by topography and vegetation, Coast Road, and the railroad. Existing noise sources include car and rail traffic, missile launches, and background wind and surf noise. Given typical sound attenuation with distance (6 dBA per doubling of distance from the source) and the absorption of sound energy by intervening topography and vegetation, it is unlikely that noise associated with drilling and production would adversely affect snowy plovers on the beach or other wildlife in the general vicinity. The beach below the VAFB Onshore Alternative drilling and production site is narrow and is not known or likely to support snowy plover nesting, although the birds may temporarily rest and forage along this stretch of coast.

PXP3-35: The referenced text has been revised to incorporate possible erosion and sedimentation impacts associated with grading of the electrical substations and pipeline tie-in locations.

PXP3-36: Table 2.3 (Summary of Changes to the LOGP with the Tranquillon Ridge Project) includes the additional equipment and equipment modifications required at the LOGP for the proposed project. The status of equipment addition/modification with respect to the LOGP foundation subsidence issue is summarized below:

a. Return to service of two heat exchangers.

These heat exchangers are existing exchangers, currently out of service. No modifications to the foundation are required. These exchangers will be brought back in service. This area was grout injected in 2005.

b. Addition of Duplex Filters.

These filters may require small foundations. These filters will be installed in the heat exchanger area discussed above in a. This heat exchanger area was grout injected in 2005.

c. Addition of internal coalescing assemblies inside the existing free-water knockout vessel and insulation of its interior.

These modifications would add minimal weight to the existing vessel. The coalescing assemblies are internal to the vessel. The free water knock out vessel area is scheduled for injection grouting this year (2007). The injection is currently underway at the facility.

d. Addition of internal coalescing assemblies and four (4) externally adjustable baffles on the three existing Heater Treaters.

These modifications should add minimal weight to the existing vessels (Heater Treaters). The Heater Treater area is scheduled for injection grouting this year (2007). The injection is currently underway at the facility.

PXP is required to survey the facility semiannually and submit the subsidence survey reports and analyses to the county. PXP coordinates the survey and grouting plans with the County. PXP has recently submitted the survey results and currently is implementing a substantial grout injection program this year. The semiannual subsidence surveys track all past subsidence results. Subsidence is monitored and addressed as necessary. Mitigation Measure GR-2 has been revised to reflect the requirements of this program and ensure that the program is implemented through the future.

PXP3-37: Impact OWR.8 has been deleted.

PXP3-38: Mitigation Measure MB-1b specifies the development of a program in order to provide a baseline for shoreline clean-up efforts in the event of a spill. At the time the program is established, the frequency for sampling shall be specified. Further, as specified by Mitigation Measure MB-1b, the agencies shall evaluate the program on an annual basis and "if new information indicates that changes to the methodology or protocol would improve the efficiency or accuracy of determining baseline oiling conditions, the County shall revise the program."

PXP3-39: Impact MB.5 has been clarified to reflect that it is addressing increased vessel traffic for all phases of the proposed project, including drilling, production, and spill response clean up.

PXP3-40: Please see Response to Comment PXP3-39.

PXP3-41: PXP expects that a shorter duration (nine weeks instead of nine months) of construction activity would be needed since only construction at LOGP and Valve Site #2 would be required; as discussed under Response to Comment PXP3-9, the water treatment system has already been permitted by SBC and constructed, and the LOGP Permit to Operate was revised accordingly. Table 5.8.7 and Appendix C include revisions to the emissions summary and onsite construction equipment emissions for LOGP and Valve Site #2. The recalculation for the proposed project also affects Tables 5.8.12, 5.8.13, and 5.8.14.

PXP3-42: NOx and SOx are criteria pollutants that are relatively short-lived in the atmosphere. Because they can contribute to forming particles and atmospheric haze, these criteria pollutants probably play an indirect role in global climate change. However, since there is no scientific consensus on characterizing the global warming effects of these criteria pollutants and since SBCAPCD and other permitting agencies do not have specific policies or criteria regarding the contribution of these pollutants to global warming, they have been removed from the GHG discussion in Section 5.8.4.2. Methane has been added to the list of GHG pollutants because it is approximately 20 times more effective as CO_2 at trapping heat in the atmosphere, and it can be released during natural gas and petroleum exploration and production processes.

PXP3-43: The comment requests quantification of emissions for drilling and production under the VAFB Onshore Alternative. Quantification of emissions from new sources related to drilling and production is not necessary to characterize the permitting requirements and potential impacts. Section 5.8.5.2 has been revised to reflect the relative operational emissions that would be generated by the VAFB Onshore Alternative and that these operational emissions would likely trigger the need for offsets under SBCAPCD rules. Although offsets in northern Santa Barbara County are in short supply, emissions related to the VAFB Onshore Alternative could be offset with notable quantities of emission reduction credits (ERCs) that are currently held by PXP or the U.S. Air Force VAFB (see: http://www.sbcapcd.org/eng/nsr/srledgr.htm). See also Response to Comment S&EM-80.

PXP3-44: Text has been added to the impact descriptions (e.g., Impact TB.1, TB.3, and EIR Section 5.2.5.2) to clarify that noise disturbance to wildlife is a component of impacts related to construction and maintenance and repair activities, although the noise effect by itself is generally not significant because of its localized, temporary nature. Continuing operational noise from established facilities is not expected to have a significant adverse effect on wildlife in surrounding areas due to the continuous (as opposed to impulsive) nature of such sounds and their attenuation to relatively low levels by distance, intervening structures, and vegetation.

PXP3-45: The referenced discussion has been revised to reflect that there was an average of 3.3 boat trips to Platform Irene per week during 2006.

PXP3-46: With the existing and future traffic on West Ocean Avenue, roadways accessing the VAFB Onshore Alternative are shown to be Level of Service (LOS) A in Tables 5.9.1 and 5.9.3. Section 5.9.5.2 indicates that traffic within VAFB would need to conform to Base operations, which would coordinate existing VAFB activity with traffic caused by the VAFB Onshore Alternative in a way that would mitigate impacts to VAFB roadways. Given the classification of affected roads at LOS A, Section 5.9.5.2 includes clarification to indicate that any change in LOS due to the VAFB Onshore Alternative is not expected to be significant.

PXP3-47: As provided by VAFB personnel, Base fire stations are first responders for incidents on the Base. The fire station located on Coast Road, a few miles from the alternative drilling and production site, is the first responder for incidents at SLC-3, SLC-4, and SLC-6 (note that the alternative drilling/production site is located between SLC-4 and SLC-6). While the Base is the primary responder for its fire-fighting needs, VAFB and Santa Barbara County have an executed Mutual Aid Agreement for fire prevention, rescue, and hazardous materials response. If and when an application for a specific onshore drilling/production project were to be submitted, exact emergency/fire response capabilities would need to be negotiated with the Base if the Base were to allow the project to move forward. If the Base needed County Fire to respond to incidents at the alternative facilities, it is likely that the County would serve as a secondary or backup responder in support of VAFB fire-fighting capabilities.

PXP3-48: The VAFB Onshore Alternative would be placed on a coastal bench above (to the east of) Coast Road. Although the drilling rig and tank would be visible from several locations, the extent of visibility is unclear without a detailed viewshed analysis, which is beyond the scope of this Environmental Impact Report (please note that per Section 15126[d] of the California Environmental Quality Act Guidelines, the impact evaluation for alternatives is not required to be as detailed as the impact evaluation for a proposed project). Although the commenter has provided its own assessment of potential visual impacts, its accuracy has not been verified. Consequently, the visual resources impacts of this alternative cannot be established with certainty. Due to this uncertainty, DEIR Section 5.13.5.2 (Visual Resources, VAFB Onshore Alternative), Impact Visual.5, has been revised to reflect that impacts could be potentially *significant and unavoidable* (*Class I*) or *significant but mitigable (Class II)*, although further evaluation of this impact would be needed as part of this alternative's environmental review, if undertaken.

PXP3-49: The additional features associated with the VAFB Onshore Alternative noted in Comment PXP3-49 have been added to the impact discussion of DEIR Section 5.13.5.2, Visual Resources - VAFB Onshore Alternative, Impact Visual.1. It is noted that the DEIR analysis concludes that this alternative would result in *significant and unavoidable* (*Class I*) visual impacts within the Coastal Zone; therefore, the overall impact conclusion for Impact Visual.1 has not been changed.

PXP3-50: For the purposes of the EIR, the description of the conceptual VAFB Onshore Alternative assumes that no new features would be required at Valve Site #2. Required pumps and electrical connections would be installed at this alternative's pipeline tie-in location. However, under this alternative, the same LOGP upgrades would be required as described for the proposed project. The impact discussion for DEIR Section 5.13.5.2 (Visual Resources, VAFB Onshore Alternative), Impact Visual.2, has been revised to clarify the above.

PXP3-51: As noted under Response to Comment PXP3-50, it is assumed that no new features would be required at Valve Site #2. The text of Section 5.13.5.2 (Visual Resources, VAFB Onshore Alternative), Impact Visual.3, has been revised to clarify this assumption.

PXP3-52: The U.S. Department of Transportation, Federal Aviation Administration's (FAA's) standards for twilight and nighttime obstruction lighting have been reviewed, as have the specifications for obstruction lighting utilized by the U.S. Department of the Air Force (Air Force). Although the Air Force generally does follow the FAA's obstruction lighting standards, it retains the right to stipulate its own standards when the FAA standards conflict with Air Force operations and requirements. VAFB has been contacted and has confirmed that if this alternative is carried forward for review and approval, VAFB would require its own lighting specifications through an Obstruction Evaluation/Airport Airspace Analysis (OEAAA) process. Consequently, the specific lighting requirements and plans for the VAFB Onshore Alternative's drilling rig cannot be predicted or evaluated in detail at this level of analysis. However, the assessment of DEIR Section 5.13.5.2 (Visual Resources, VAFB Onshore Alternative), Impact Visual.5, has been revised to indicate that depending on VAFB's lighting requirements, visual impacts from public viewing locations could be *significant and unavoidable* (*Class I*) or *mitigable to a level of less than significant* (*Class II*).

PXP3-53: The noted correction has been made.

PXP3-54: The noted correction has been made.

PXP3-55: The noted correction has been made.

PXP3-56: As stated in Section 5.16.5.2, *Impact Energy.1 – Construction Energy Use*, for the VAFB Onshore Alternative "construction energy use would be substantially higher than for the proposed project." The referenced section also notes that the alternative would eliminate "the need for additional supply boat trips to transport construction materials to the platform." However, this energy offset is negligible since required construction at Platform Irene to accommodate the proposed project is limited (see Table 2.2). The correction regarding jet fuel has been made.

PXP3-57: Firstly, the comment correctly notes that California refiners receive crude oil from three producing sources: California (both offshore and onshore), Alaska, and foreign imports. However, it incorrectly implies that 2004 imports of foreign crude oil to California refiners was 390 million barrels, whereas, the California Energy Commission reports foreign imports by California refiners at 238.4 million barrels and the Energy Information Agency of the U.S. Department of Energy reports about 234.2 million barrels.

Secondly, the comment is likely correct in noting that "any increase in domestic crude oil production would offset foreign imports," assuming that domestic production includes the combined volume of crude oil from both Alaska and California that is sent to California refiners, and that increased domestic production is not exported to foreign countries.[1] However, the comment incorrectly assumes that Tranquillon Ridge oil production automatically offsets foreign imports. The west-coast crude oil market is much too complex and unpredictable to base such a statement on anything but speculation. What we can say is, while Tranquillon Ridge oil may displace foreign oil (partially or fully), it may also displace California onshore production, as offshore oil production did during the 1990s, and it may offset Alaskan production that may legally be exported to foreign countries on the Pacific Rim. Pursuant to CEQA Guidelines Section 15145, this document concludes that it is too speculative and unpredictable to state with any degree of certainty that Tranquillon Ridge oil will offset foreign imports rather than other domestic production in the blend-stocks of California refineries over the life of the proposed project.

Several factors support this conclusion, including those summarized below.

- Trends in the price differential between light and heavy crude oils greatly influence whether predominantly lighter (and lower sulfur content) foreign crude-oil imports hold a competitive edge

[1] In 1996, the U.S. Department of Commerce lifted the export ban imposed on Alaska's North Slope production, and bans on export of California production can be (and have been) lifted on a case-by-case basis.

over heavier (and higher sulfur content) domestic crude-oil production. Between 1992 and 2004, 91% of foreign crude imported to California ranged between 21-40 degrees API gravity (medium to light crude), with 45% of that amount ranging between 31-35 degrees API gravity (light crude). A predominately narrow price differential favored the lighter crude oils, even in California refineries like Chevron's that have been retrofitted to handle both light and heavy crude oils. In short, foreign crude oil imports to California refiners have been predominantly higher quality, yielding more gasoline per barrel than domestic production overall.

- The historic competition between major, vertically integrated companies, major independents, and smaller independents over access to California refiners is important. There is much documentation that smaller independents lack the competitive access that majors enjoy. One may reasonably assume that the long-term and relatively large volume of estimated Tranquillon Ridge oil gives the owner a greater competitive advantage in negotiating long-term contracts with buyers.

- Observations over the last 10-15 years indicate that increased oil production offshore California, which qualifies as heavy crude oil, did not decrease foreign imports. Rather, offshore production successfully competed against onshore production, having better access to the west-coast market during a period of low crude oil prices. The ratio of producing-to-shut-in oil wells in California was 7:1 in 1978, but has hovered around 2:1 since 1987, despite a large number of wells being permanently plugged and abandoned over the years. Generally speaking, around half of California's producing wells remain idle, while foreign imports continue to increase. The table below suggests that California producers, by and large, have not competed well with foreign imports, and that any substantial increase in California production could as easily force other California producers to become idle as it could offset foreign imports.

SOURCES OF OIL SUPPLIED TO CALIFORNIA REFINERIES

Year	*Alaska*	*California*	*Foreign*	*TOTAL*	*% Alaska*	*% California*	*% Foreign*
1982	196.5	366.0	33.6	596	33	61	6
1983	189.5	377.0	48.0	615	31	61	8
1984	210.5	369.2	53.3	633	33	58	8
1985	210.6	398.3	35.4	644	33	62	5
1986	237.5	403.5	36.9	678	35	60	5
1987	260.8	386.7	33.4	681	38	57	5
1988	306.2	365.4	37.2	709	43	52	5
1989	328.4	337.5	46.7	713	46	47	7
1990	320.9	336.1	39.5	697	46	48	6
1991	316.1	336.6	30.7	683	46	49	4
1992	299.7	331.6	33.1	664	45	50	5
1993	285.6	342.8	43.4	672	43	51	6
1994	297.0	319.2	49.2	665	45	48	7
1995	264.5	320.8	56.9	642	41	50	9
1996	268.8	316.2	64.0	649	41	49	10
1997	244.4	322.2	78.1	645	38	50	12
1998	222.0	317.8	104.7	645	35	49	16
1999	188.7	306.9	140.6	636	29.7	48.2	22.1
2000	163.2	326.4	169.1	659	24.8	49.6	25.7
2001	139.9	323.6	191.8	655	21.3	49.4	29.3
2002	143.7	317.3	200.0	661	21.7	48	30.3
2003	160.2	289.4	232.5	682	23.5	42.5	34.0
2004	142.0	274.4	238.5	655	21.7	41.9	36.4
2005	135.9	266.1	272.3	674	20	39.5	40.4

Source (millions of barrels) reported by California Energy Commission

- Alaskan production is estimated to increase, perhaps substantially, over the foreseeable future, as more areas onshore, in State Tidelands, and the OCS are opened or leased for development. ConocoPhillips, who is the anticipated buyer of Tranquillon Ridge oil and is expected to refine it at its Rodeo Refinery in the Bay Area, has recently commissioned five new, double-hulled tankers to transport future Alaskan production to Hawaii and the U.S. West Coast. Meanwhile its Rodeo Refinery has imported as much as 8,852,000 barrels of oil from foreign countries in 2000, declining to 7,342,000 barrels in 2004. The quality of that imported oil to the Rodeo Refinery in 2004 averaged around 45 degrees API gravity (light crude). Compare this to estimated peak annual production from Tranquillon Ridge at 10,000,000 barrels (30,000 daily) with an estimated 18 degrees API gravity prior to initial refining at the ConocoPhillips upgrader refinery in San Luis Obispo County.

Lastly, it remains uncertain whether or not Tranquillon Ridge oil, itself, would end up to some extent being shipped by marine tanker. The oil industry has long fought against County and State efforts to prohibit shipment of crude oil produced offshore California via marine vessel. In 2002, California revised its law to prohibit shipment of new oil production offshore California via marine vessel (i.e., tankers or barges). The oil industry strongly opposed this revision during its drafting, and continues to challenge its implementation, as exemplified in a February 18, 2004, letter to John King of the National Oceanic and Atmospheric Administration from the Western States Petroleum Association (WSPA), to challenge inclusion of the 2002 revision into the California Coastal Management Program. The following excerpts characterize the oil industry’s contention that prohibiting shipment via marine vessels of oil produced offshore California would adversely impact such production.

> “AB 16 [the 2002 revision prohibiting shipment of offshore oil via marine vessel] will adversely impact OCS oil development by eliminating transportation options for moving the crude to refineries. Currently, the majority of crude produced offshore California is transported to refineries by pipeline. However, other modes of transportation are also used, and there is a growing need for transportation flexibility in order to assure that offshore crude can be delivered to the refining locations at which it will be most needed. This need for flexibility has increased over the last several decades as the available refining capacity in California has come under increasing strain. Refining capacity in California has become increasingly constrained as regulation of refining emissions have continued to tighten, the manufacture of ever cleaner fuels has required major equipment modifications at California refineries, and the substantial costs of these changes have become too great for some companies to bear, resulting in the shut down of more financially marginal refineries. …
>
> In contrast, pipeline transportation has limited flexibility. If a producer does not have supply contracts with a refinery that is easily accessible by pipeline, the crude would have to be moved via other modes of transportation. …
>
> AB 16’s restrictions on transportation flexibility would have several corollary consequences impacting national interest. Concerns regarding the lack of transportation options may deter further development of existing oil leases, even where such development was envisioned in the original permits and approvals. Such unreasonable restrictions on transportation could even be considered a material breach of contract, with attendant governmental liabilities, to the extent that these restrictions impede the development of oil and gas leases entered into at a time when no such restrictions existed.

> Moreover, AB 16 will impede interstate commerce. At the current time, there is not a single crude pipeline that leaves the State of California for other refining destinations. Transporting crude for long distances via truck or train is inefficient and very costly. Therefore, by mandating pipeline transportation, California has effectively mandated that all crude produced offshore California must be refined within the state. AB 16 would allow California to interfere in markets and activities which take place far from its shores, since the prohibition on marine transport would follow the crude all the way to the ultimate refining destination, whether that be in California or in another state."

The foregoing excerpts are not presented herein as factual or objective, but rather to present different views within the oil industry regarding both the modes of transporting California crude oil in the future and its ultimate refining destination. They also indicate that current California law restricting the shipment of oil produced offshore California may be challenged. Therefore, as noted earlier, there is no certainty that the Tranquillon Ridge production would offset tankering of foreign oil to California. A beneficial impact cannot be assigned to the proposed project for a speculative assertion.

PXP3-58: The noted correction has been made.

PXP3-59: Table 6.1a has been modified to include a discussion of Impact Risk.4; see also Response to Comment PXP3-31.

PXP3-60: Please see Response to Comment PXP3-47.

PXP3-61: Table 6.1a has been modified to include a discussion of Impact Visual.5; see also Responses to Comments PXP3-48 and PXP3-49.

PXP3-62: Please see Response to Comment PXP3-43.

PXP3-63: The correct CEQA Guidelines citation is Section 15126.6(e)(2), as noted. The statement that the VAFB Onshore Alternative could be considered a "de facto" environmentally superior alternative does not mean it is environmentally superior to the proposed Tranquillon Ridge Project. As further stated in the referenced paragraph, "The ESA determination does not, however, suggest that this alternative is environmentally superior to the proposed project. Rather, by default, this alternative is the only identified project-level alternative that is feasible and meets most of the project objectives and therefore merits further detailed consideration." Table 6.1a compares the significant and unavoidable impacts of the proposed project to those for the VAFB Onshore Alternative. As noted in the discussion on page 6-62 of the Draft EIR, both the proposed project and the VAFB Onshore Alternative would result in permanent and significant impacts, in varying issue areas. For these and other reasons, the EIR states that it is difficult to determine that one is environmentally preferred over the other.

PXP3-64: See Response to Comment PXP3-63.

PXP3-65: The commenter's statement is true; however, the referenced discussion focuses on the differences, not the similarities, of the proposed project versus the VAFB Onshore Alternative.

PXP3-66: The referenced bullet has been clarified to reflect that the construction vegetation removal impacts are considered Class II given the nominal acreage of vegetation removal. Tables 6.1a and 6.1b note that Impact TB.10 for the proposed project is Class II, significant but mitigable. Impact TB.10 has been deleted from Table 6.1c because it is a Class II impact for both the proposed project and the emulsion pipeline replacement alternative.

PXP3-67: Regarding the first bullet in Comment PXP3-67, the DEIR states in the last paragraph on page 6-61 that the "VAFB Onshore Alternative would increase the onshore pipeline spill risks because of the additional length of emulsion pipeline in operation through 2037."

Regarding the second bullet in Comment PXP3-67, the VAFB Onshore Alternative discussions in the EIR has been clarified to reflect that the baseline spill risk to the marine environment would remain and would be slightly increased because of the VAFB Onshore Alternative until 2017 or until such time that Platform Irene, offshore pipeline, and approximately 4.5 miles of onshore pipeline (landfall to west of 13th Street) are decommissioned.

Regarding the third bullet in Comment PXP3-67, see Responses to Comments PXP3-48 and PXP3-49.

Regarding the fourth bullet in Comment PXP3-67, see Response to Comment PXP3-43.

PXP3-68: The noted correction has been made.

PXP3-69: The noted correction has been made.

PXP3-70: See Responses to Comments PXP3-9 and PXP3-41.

PXP3-71: The mitigation monitoring plans presented in the EIR include the mitigation measures only. Should the Tranquillon Ridge project be approved, the impacts and mitigation measures would be correlated and combined with existing Point Pedernales FDP conditions, as appropriate, to clarify the exact timing of mitigation implementation.

RWQCB

9.2 Governmental Agency Comment Letters and Responses

California Regional Water Quality Control Board
Central Coast Region

Internet Address: http://www.waterboards.ca.gov/centralcoast
895 Aerovista Place, Suite 101, San Luis Obispo, California 93401
Phone (805) 549-3147 • FAX (805) 543-0397

Linda Adams
Secretary for Environmental Protection

Arnold Schwarzenegger
Governor

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COUNTY OF SANTA BARBARA
JAN 08 2007
PLANNING AND DEVELOPMENT
DEPARTMENT - ENERGY DIVISION

January 4, 2007

Mr. Kevin Drude
County of Santa Barbara County
Department of Planning and Development, Energy Division
123 E. Anapamu Street
Santa Barbara, CA 93101

Dear Mr. Drude:

ENVIRONMENTAL IMPACT REPORT, TRANQUILLON RIDGE OIL AND GAS DEVELOPMENT PROJECT, COUNTY EIR #06-EIR-000000-00005

We have reviewed the *Environmental Impact Report, Tranquillon Ridge Oil and Gas Development Project*, County EIR #06-EIR-000000-00005 (the EIR). The County of Santa Barbara, Department of Planning and Development, submitted the subject document to the Central Coast Regional Water Quality Control Board to solicit comments.

RWQCB-1 The EIR indicates that the proposed project could have significant impacts on the waters of the State of California; however, if mitigation measures are utililized and all appropriate permits are obtained, the Central Coast Water Board will not object to the proposed project.

If you have any questions, please call **Rich Chandler at (805) 542-4627** or Sheila Soderberg at (805) 549-3592.

Sincerely,

Sheila Soderberg for

Roger W. Briggs
Executive Officer

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California Environmental Protection Agency

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Response to Comment Set RWQCB

RWQCB-1: Comment noted.

Tranquillion Ridge Oil and Gas Development Project Comment
City of Lompoc 1/16/07

The proposed project would increase the life of the natural gas and crude oil pipeline from off-shore for an additional 30 years to 2037. The project also includes an increase of 15 years to the life of the Lompoc Oil and Gas Plant (LOGP). (If its estimated life was through 2022.) The project includes installation of an above-ground power line, equipment modification, and increased production. A related increase in risk of upset and wildland fire is projected. This could include fire, oil spill, hazardous substance release, or emergency event resulting from an earthquake, traffic accident or pipeline rupture. The EIR also notes on page 5.1-12 that significant corrosion on segments of the existing pipeline, the use of which is proposed to be extended to 2037 years, was identified in 1995 and 1996. The EIR states that through the City / County mutual aid agreement, the City of Lompoc's Fire Department (Station 1 or 2) could respond during an emergency along the pipeline route, or at the LOGP.

Concern

The City of Lompoc's Fire Department is identified in the EIR as a primary emergency responder, operating two of the three fire stations located within a fifteen-minute response time of the LOGP site.

Fire Impact #2 – Operation of the new power line to valve site #2 could result in impacts to fire protection and emergency response resources, due to addition of an ignition source (New overhead power line) into a high fire hazard area.

Fire Impact #3 – Increased risk of upset due to increased oil flow rates through the project pipelines and pipeline facilities could create impacts to fire protection and emergency response resources.

Fire Impact #4 – Increased likelihood of upset conditions due to equipment modifications at the LOGP and potential increase of wet oil and sour gas quantities processed at the facility could create impacts to fire protection and emergency response. The proposed project would result in increased flow rates and related increased spill rates of 114 barrels (bbls), with a worst-case increase in flow rates of 688 bbls over current operations.

- The EIR argues that the change in spill volumes is relatively small 3.6 – 10.9 percent and response capabilities are currently available to address these increased spill volumes.
- The EIR also argues that while the need to maintain the required fire protection and emergency response capabilities for these facilities would be extended, the pipeline facilities represent only a very small portion of the local response services' scope of work. The EIR states that the response services are funded by PXP to provide the services and this funding would continue if the facilities life term is extended.
- The EIR argues that combined with resources onsite, County Station 51, and Lompoc Stations 1 and 2 have sufficient fire-fighting and emergency response capabilities (page 5.11-16 and 17).

Response – The City of Lompoc does not believe that the on-site resources, in combination with those of Station 51 and Lompoc Stations 1 and 2, would be sufficient to fight a fire on the pipeline, as well as provide fire protection to the citizens of Lompoc. Currently, PXP does not fund any portion of the City of Lompoc's Fire Department Operations. If this growing City is to be expected to provide 1/3 equipment and 2/5 personnel resources of the initial response to an emergency at the LOGP, or along the pipeline / power line, then mitigation fees should be assessed to address the need for additional personnel, equipment and/or facilities generated by the increased risk associated with the expanded production and extended operational life of the pipeline and LOGP.

Response to Comment Set COL1

COL1-1: Impacts Fire.1 through Fire.4 in Section 5.11.4 discuss the impacts to fire protection and emergency responders associated with the proposed project, including the emulsion and sour gas pipelines, LOGP, and power line. As concluded in the EIR, Impacts Fire.1 through Fire.4 are considered to be adverse but not significant (Class III). However, to ensure that these impacts are mitigated to the maximum extent feasible, in accordance with County policies, Mitigation Measures Fire-1 and Fire-2 are proposed to ensure that the facility Fire Protection Plans, Emergency Response Plan, and Oil Spill Response Plan are updated to reflect the proposed project and submitted to the Santa Barbara County Fire Department for review and approval.

According to Santa Barbara County Fire Department (Diane Sauer, personal communication, 2/16/07) PXP currently funds a "Partial Position" for County Fire Station #51. In addition, there is a Mutual Aid Agreement between Santa Barbara County and the City of Lompoc. Under the Mutual Aid Agreement, the County and City fire stations operate under what is called "Closest Resource" which means that if there is an incident, the agency closest to the site should respond. Therefore, even though there could be an incident under the jurisdiction of the City of Lompoc, if a County fire station or crew were closer to the incident site, the County fire station/crew would respond. With the Mutual Aid Agreement in place, this response assistance is provided free of charge between Santa Barbara County and the City of Lompoc. As result, some of the money the County Fire receives from PXP is distributed indirectly to the City of Lompoc under the terms of the Mutual Aid Agreement.

COL2

COL2-1 Hello: After looking the DEIR over a bit more, it would be nice to see a map showing the impact area of a hydrogen sulfide gas leak, along the length of the nearshore and onshore pipeline, assuming the worst case scenario of 600 psig. Please let me know if I have missed this in the DEIR. Thanks, Stacy Lawson

Stacy L. Lawson
Senior Environmental Coordinator
City of Lompoc
(805) 875-8275 phone
(805) 875-8375 fax

Response to Comment Set COL2

COL2-1: Figure 5.1-2 has been revised to reflect the fatality and injury zones associated with the existing sour gas pipeline and the LOGP.

APCD

Our Vision Clean Air

Santa Barbara County
Air Pollution Control District

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PLANNING AND DEVELOPMENT
DEPARTMENT - ENERGY DIVISION

January 16, 2007

Nancy Minick, Project Manager
Energy Division
Planning and Development Department
123 East Anapamu Street
Santa Barbara, CA 93101

RE: PXP Tranquillon Ridge Project: Draft EIR

Dear Nancy:

Air Pollution Control District staff appreciates the opportunity to review and comment on the DEIR.

APCD-1

1. **Page 5.8-5, Table 5.8.3.** The Table appears to state that, for the Federal standards, Santa Barbara County is Unclassified (U) for PM10 and in Attainment (A) for PM2.5. Please switch the order of the letters in the Table to clarify that PM10 is "A" and PM2.5 is "U".
2. **Page 5.8-9, Section 5.8.1.5, 1st Paragraph.** The last sentence should state that, "subsequent modifications triggered offset requirements for *ROC only* under SBCAPCD rules", i.e., please delete *NOx* and *NAROC*.
3. **Page 5.8-9, Section 5.8.1.5, last Paragraph.** The last sentence should be revised to state "Any new *ROC* emissions as a result..." so the there is no contradiction with the above revision to the first paragraph of this section.
4. **Page 5.8-12, 1st paragraph.** Please note in the FEIR that Santa Barbara County has been in attainment of the state CO standard for many years and ambient CO levels have declined significantly. Therefore, the APCD no longer requires analysis of traffic-related CO "hotspots" emissions at intersections.
5. **Page 5.8-15, Criteria Pollutants.** This section addresses both CEQA significance thresholds and APCD requirements and triggers within the same paragraph. The terminology and definitions for each are different, thus the entire section is confusing and inaccurate. For clarity, we suggest that the DEIR break it up into two subsections; one for APCD requirements and one for CEQA thresholds and mitigation. The APCD section could reiterate the statement in Section 5.8.1.5, that ROC offsets will be required for any ROC emissions generated by this new project since the Point Pedernales project has triggered the APCD ROC offset

Terence E. Dressler · Air Pollution Control Officer
260 North San Antonio Road, Suite A · Santa Barbara, CA · 93110 · www.sbcapcd.org · 805 961 8800 · 805 961 8801 (fax)

APCD-5
Cont'd

threshold prior to this proposed project. With regard to NOx, for the proposed project, the APCD has determined that since the heater treaters are currently permitted at their maximum operational capacity, there are effectively no new NOx emissions from this project and thus no offsets are necessary. This needs to be stated. References to the FDP are confusing and should be deleted or clarified.

Thank you for the opportunity to comment. Please contact me at bratzb@sbcapcd.org or 961.8890 if you need additional information.

Sincerely,

Bobbie Bratz

Bobbie Bratz
Public Information Officer and Community Programs Supervisor

cc: Brian Shaftriz, APCD Santa Barbara County
Jim Menno, APCD Santa Barbara County
TEA Chron File
PXP Tranquillon Ridge Project File

\\sbcapcd.org\shares\groups\pca\wp\pcacom\pxp tranquillon ridge deir.doc

Response to Comment Set APCD

APCD-1: Table 5.8.3 has been revised to clarify that Santa Barbara County is "unclassified" for the federal PM2.5 standard.

APCD-2: The requested revision is included in Section 5.8.1.5.

APCD-3: The requested revision is included in Section 5.8.1.5.

APCD-4: Section 5.8.3.2 has been clarified to reflect that certain circumstances can trigger an analysis of traffic-related CO under the SBC P&D guidelines, although the SBCAPCD does not require it.

APCD-5 Section 5.8.4.2 has been clarified to reflect how offset credits provide sufficient reductions to mitigate current plus project emissions.

CDPR

01/04/2007 13:48 8055851857 CHANNEL COAST DISTRICT

State of California • The Resources Agency Arnold Schwarzenegger, Governor

DEPARTMENT OF PARKS AND RECREATION Ruth Coleman, Director
Channel Coast District
911 San Pedro Street
Ventura CA 93001
(805) 585-1847

December 28, 2006

Kevin Drude, Energy Specialist
County of Santa Barbara
123 E. Anapamu Street
Santa Barbara CA 91301

RE: EIR – Tranquillon Ridge Oil and Gas Development Project – SCH#20006021055

Dear Mr. Drude:

CDPR-1 The proposed Tranquillon Ridge Oil and Gas Development Project preferred alternative's potential Class 1 impacts to recreation, marine and biological resources in the case of an oil spill appear fairly significant to the near pristine coastal resources between Point Sal and Point Arguello. The 49 acre Point Sal State Beach has 1,463 meters of ocean frontage of which 1,000 meters is sandy beach and the remainder is rocky shoreline. Because of its outstanding scenic and natural character this park unit is included in the San Luis Obispo State Seashore (Public Resource Code 5001.6). In addition, the unit is eligible for registration as a National Natural Landmarks (NPS) and is within the Inventory of California Natural Area by the California Natural Area Coordinating Council.

The marine environment off Point Sal is considered outstanding from several standpoints, most significantly it contains both exposed and protected outer coast and contains examples of marine organisms from both Central and Southern California seascape provinces. Any potential impacts to these resources should be given serious review and evaluation.

Further, adverse potential impacts to extremely popular Gaviota State Park and Refugio and El Capitan State Beaches are identified as likely given a "worst case scenario." These properties and the unique coastal resources they contain acquired by the State of California and stewarded by California State Parks are mentioned only in passing within the discussion and impact sections of the Recreation/ Land Use section of the Draft EIR. The resource values they contain and their existence as a prime destination location for 100's of thousands of visitors each year is not adequately addressed or evaluated. The Draft EIR is inadequate in this regard.

In addition, possible impacts to the Burton Mesa Reserve - the habitat and the wildlife - and thus to surrounding properties, if clean-up would be required, also appear to be inadequately addressed. A major clean-up would have ramifications beyond the zone of impact.

While there is an understanding of the need, State Parks believes the Draft EIR falls short of fully addressing and mitigating the "increased impacts" of this project over current conditions.

Sincerely,

Richard A. Rojas
District Superintendent, Channel Coast

Response to Comment Set CDPR

CDPR-1: The text of DEIR Section 5.14.1.1, Recreation/Land Use/Policy Consistency Analysis, Environmental Setting, has been revised to include the additional information regarding Point Sal State Beach that is referenced in Comment CDPR-1. It is noted that DEIR Section 5.14.4.1, Impact Analysis for the Proposed Project, Recreation, Impact Rec.1, states that Point Sal State Beach would be one of the recreational areas at greatest risk if there was a shoreline failure of the oil emulsion pipeline. This impact is identified as being *significant and unavoidable* (*Class I*) in the DEIR.

Regarding the marine environmental off Point Sal, the DEIR acknowledges and describes the diversity of marine resources in the project area. Impacts of an oil spill on those resources are described in detail, classified as Class I, significant and unavoidable, and mitigation measures are identified to help protect those resources.

CDPR-2: The text of DEIR Section 5.14.1.1, Recreation/Land Use/Policy Consistency Analysis, Environmental Setting for Recreation, has been revised to include additional information regarding El Capitan and Refugio State Beaches and Gaviota State Park. DEIR Section 5.14.4.1, Impact Analysis for the Proposed Project, Recreation, Impact Rec.1, concludes that these recreational areas would likely avoid direct spill impacts on the basis of the oil spill trajectory modeling provided in DEIR Appendix G. However, under a "worst case" oil spill scenario these recreational areas could be affected and related impacts would be considered potentially *significant and unavoidable* (*Class I*). The text of DEIR Section 5.14.4.1, Impact Analysis for the Proposed Project, Recreation, Impact Rec.1, has been augmented to re-iterate this impact conclusion.

CDPR-3: The Burton Mesa Reserve was called out in the introductory second paragraph of the Terrestrial and Freshwater Biological Resources section of the DEIR and elsewhere, and its importance is recognized. Figures in Appendix A illustrate the location of Burton Mesa chaparral along the pipeline route. Burton Mesa chaparral in particular is recognized in the document as a sensitive habitat, and impacts to Burton Mesa chaparral and other sensitive habitats are considered significant under Impact TB.6, Spill Impacts to Vegetation and Wildlife. Mitigation Measures TB-10 through TB-14 require the inclusion of specific measures to protect, restore, and rehabilitate sensitive habitats and wildlife in the event of an oil spill. These measures would apply in the event of a spill affecting Burton Mesa chaparral and the Reserve. Reference to the Draft Land Management Plan for the Burton Mesa Ecological Reserve has been added to Section 5.2.

CDT

STATE OF CALIFORNIA—BUSINESS, TRANSPORTATION AND HOUSING AGENCY ARNOLD SCHWARZENEGGER, Governor

DEPARTMENT OF TRANSPORTATION
50 HIGUERA STREET
SAN LUIS OBISPO, CA 93401-5415
PHONE (805) 549-3101
FAX (805) 549-3077
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December 5, 2006

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SCH# 2006021055

Kevin Drude
Santa Barbara County
123 E. Anapamu Street
Santa Barbara, CA 93101

COMMENTS TO: **Draft EIR – Tranquillon Ridge Project**

Dear Mr. Drude:

The California Department of Transportation (Caltrans), District 5, Development Review, has reviewed the above-referenced document and offers the following comments:

CDT-1

1. The Draft EIR does not provide specific visual, biological, or cultural resource impact information with regards to potential impacts within the State Highway Right of Way as requested in our comments on the projects Notice of Preparation. Prior to submitting an encroachment permit application, the applicant should provide visual, biological, and cultural resource impact information specific to the State Highway Right of Way and identify appropriate mitigation measures for those impacts.

CDT-2

2. Due to the preliminary nature of the information describing this project some items may not have been identified in this review. Significant mitigation measures while not identified at this point may be required as a condition of the encroachment permit for any work within the State Highway System. Detailed information such as complete engineering drawings, traffic studies, hydraulic calculations and environmental reports outlining impacts to environmental resources (biological, cultural, visual, etc.) within the state R/W may need to be identified, quantified and submitted for the Encroachment Permit review. These as well as other documents may need to be submitted and reviewed as part of the encroachment permit application before Caltrans can make a final determination as to the appropriateness of the mitigation measures within the State Highway System. The recommendations made in this review should be considered preliminary and subject to change based on more detailed review of the applicants final engineered construction level plans, final engineered traffic studies and actual field review of the proposed project site. In all cases, any deviation from Caltrans Design standards should not be considered to be a viable option until the applicant has been issued an approved exception to Design Standards.

"Caltrans improves mobility across California"

Draft EIR - Tranquillon Ridge Project – Drude
December 5, 2006
Page 2

If you have any questions, or need further clarification on items discussed above, please don't hesitate to call Joseph Londono at (805) 549-3615

Sincerely,

Joseph Londono

Joseph Londono
District 5 Development Review Coordinator

"Caltrans improves mobility across California"

Response to Comment Set CDT

CDT-1: For purposes of this EIR and in accordance with CEQA, the VAFB Onshore Alternative is conceptual at this time. However, if in the future a specific application is received, detailed visual, biological, and cultural resource impact information specific to the State Highway Right of Way will need to be provided, as required, to the Department of Transportation with any encroachment permit application.

CDT-2: For purposes of this EIR and in accordance with CEQA, the VAFB Onshore Alternative is conceptual at this time. However, if in the future a specific application is received, complete engineering drawings, traffic studies, hydraulic calculations, and environmental reports specific to the State Highway System will need to be provided, as required, to the Department of Transportation with any encroachment permit application. Please also see Response to Comment CDT-1.

CPA

CITIZENS PLANNING ASSOCIATION OF SANTA BARBARA COUNTY, INC.
916 Anacapa Street, Santa Barbara, CA 93101
phone (805) 966-3979 • toll free (877) 966-3979 • fax (805) 966-3970
www.citizensplanning.org • info@citizensplanning.org

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DEPARTMENT - ENERGY DIVISION

December 12, 2006

Kevin Drude, Energy Specialist
County Planning & Development Department
123 E. Anapamu St.
Santa Barbara, CA 93101

RE: Tranquillon Ridge Oil & Gas Development Project - DEIR

Dear Mr. Drude,

The members of the North County Land Use Committee of the Citizens Planning Association have studied the DEIR for the Tranquillon Ridge Project and appreciate this opportunity to provide the following input for the County's consideration.

Prolonging the lifetime of the pipelines and the onshore oil and gas processing facility

CPA-1 The existing pipelines and the LOGP have already outlived their original design. One of these pipelines leaked over 6,000 gallons of oil in 1997, killing hundreds of seabirds and spoiling 40 miles of pristine coastline. The DEIR quotes statistics about the very slim likelihood of such an event happening, but this event was caused by human error and it did happen.

CPA-2 By extending the life of the existing operations, the residential communities near the LOGP will be exposed to increased risks of air and noise pollution, fire, hydrogen sulfide releases, and oil spills. Residents were promised in 1983 that the original separation plant would be decommissioned in 2000. Then this permit was extended and changed in 1997, with additional processing and storage allowed. Now, if Tranquillon Ridge Project is approved, our communities are looking at new and increased risks until at least 2037. The EIR should reflect more of this history from the perspective of the community residents.

Fire Risk

CPA-3 Since the LOPG was built, there have been two significant fires in the immediate area of LOGP. The plant was saved from involvement in the first 5000 acre fire, started by children playing with matches in the chaparral, a situation not listed in any EIR, only because of favorable winds. In the second fire, which burned 11,000 acres in a matter of hours, the fire started on oil company property due to brush not cleared from power line areas. Again, both the plant and homes were spared only because of favorable winds. The one fatality was caused by smoke coming from a bog, a very unpredictable situation never included in an EIR. Burton Mesa Reserve is a valuable endangered habitat but a highly flammable one. To situate

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CPA-3 Cont'd a processing plant adjacent to a highly flammable. These fires should be mentioned and described in the EIR and a more detailed analysis of fire risk because of the surrounding chaparral should also be included.

Hazardous Materials/Risks of Upset

CPA-4 In the Executive Summary on Page 69, it states: "onshore impacts include increasing the traffic on roadways. Consequences of a NGL/LNG truck accident would increase in severity for this already significant impact." It goes on to say, "Construction of residential developments within the hazard footprints of the proposed project existing onshore pipeline would put more people in harm's way in the event of a pipeline accident." Then it says it is an insignificant impact.

A pipeline accident is hardly insignificant to the thousands of residents and the 1,800 students and staff at CHS who live and work near the existing footprint.

CPA-5 Since the plant was built, there have been numerous leaks of H_2S and oil that have been reported in the local newspaper. Residents have asked for a specific evacuation plan but are always told that is the county responsibility. A reverse 911 system was set in place by a previous owner but when tested, many nearby residents were not notified. Now that the plant has changed ownership for the third time, is this system in place? The DEIR mentions repeatedly that the project includes working with the County Fire on plans, etc. Yet the residents living close to this plant have no idea what those plans are. The DEIR mentions worker safety but does not include the safety of the residential neighborhoods which pre-date the LOGP. The EIR should include details of the evacuation plan in case of a catastrophic event.

CPA-6 The existing pipelines are too near schools and homes. Cabrillo High School is almost twice the size than it was when the LOGP was built. Parents now want to build a stadium behind its campus. This would bring the students even closer to the hazardous footprint. There is actually one private home within the footprint as shown on your maps. There should be some section of the EIR to consider the human activity in the vicinity of the pipelines and the plant.

CPA-7 Several years ago, the County did a study of seven potential sites for a consolidated oil facility. The Lompoc Plant ranked last due to its proximity to residential areas. The results of this study should be included in the Tranquillon Ridge Project DEIR.

Traffic

CPA-8 Harris Grade Road has not been properly improved since the LOGP was built. What we have now is tankering on substandard roads. Residents often see trucks parked overnight at Harris Grade and Burton Mesa Rd. on a dirt surface along the side of the road. It is not known why those trucks are in the vicinity, but there has been some speculation that they are related to oil field clearing/plant operations.

Neither the County nor the City has funds to maintain Harris Grade Road, as publicly stated as recently as Spring '06 during the hearings for annexation of the Burton Ranch property at the Wye. Harris Grade Road, where these tankers must travel, has also been the site of numerous fatal accidents, often involving speeding and alcohol. It runs through the Burton Mesa Reserve, posing an even greater risk because of flammability.

Any increase in plant output will result in more tankering. There are now three new developments with more than 300 new homes and a proposed development of 485 homes at the Wye where these tankers must travel. Tankers then turn onto Purisima Road, which is hardly wide enough for two cars, let alone

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CPA-8 Cont'd

tankers carrying dangerous byproducts. An accurate description of the poor condition of these roads should be included in an EIR.

Aesthetics

CPA-9

The lights from the existing plant still are visible for miles and, at close range, there is a very bright glow in the evening. Since the mid-80s, residents have asked for lights to be capped, but this has not happened. The DEIR does say that the project would "change the visual character of affected local areas from semi-rural to urban' and "the proposed project's incremental contribution to these impacts would also be significant due to the prolonged lifetime of the LOGP". Anyone who sees the lights from miles away and residents who live under the glow will agree. Residents chose to live in a semi-rural area long before this plant was built. Now, having this plant with its bright lights does indeed make it seem like living in a pocket of urban 'light' blight in an otherwise dark, quiet rural surrounding. The EIR should include a specific timeline for the capping and/or the reduction of lights.

Noise

CPA-10

Although previous LOGP owners did respond to neighbors' complaints about noise, especially in the night time hours, noise still does travel into the residential areas, depending on topography, orientation of homes, and weather conditions. Noise emanating from low-flying helicopters taking clients/public on tours of the on shore facilities is also disturbing in a semi-rural community. The EIR should include a discussion of the number of flights allowed over the residential communities.

Jurisdiction

CPA-11

Nowhere in the DEIR does it mention the application of PXP to build a housing development after a possible City annexation. This brings into question jurisdictional confusion. Will the City eventually annex the plant? What assurances do the neighbors who live in the existing unincorporated areas have of the higher standards imposed by the County? Will this EIR become obsolete if the City of Lompoc has jurisdiction of this plant and the proposed housing development across the road? These annexation and project proposals should be included in this EIR as they have been advertised and promoted for the past two years. Claiming there has been no formal application does not mean it will not become a reality. PXP, the development company that has spent thousands of dollars on a public relations campaign, and City of Lompoc staff working on the annexation application see this development as a very good possibility.

Sincerely,

Marell Brooks

Marell Brooks
Chair, CPA's North County Land Use Committee

MEB

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Response to Comment Set CPA

CPA-1: Because PXP has proposed using the existing Point Pedernales pipelines for transporting Tranquillon Ridge production to shore, the EIR evaluated the capability of these pipelines to accept the Tranquillon Ridge production, given their design features, age and operating protocols and requirements. The risk analysis presented in Section 5.1 concludes that if the pipelines are operated as they are required to operate today, this continued operation of the oil and gas pipelines for the Tranquillon Ridge project would not significantly increase the risk of an oil spill, though volumes would potentially be larger due to the greater volume of oil present in the emulsion pipeline. The EIR acknowledges the 1997 Torch oil spill from the Point Pedernales emulsion pipeline and notes that the cause of that spill was not related to age of the pipeline, but to an installation defect that was exacerbated by operator error. The EIR recognizes that, even with sound design and engineering, proper pipeline inspection and maintenance, and safe operational protocols, an oil spill could occur, would be difficult to contain and clean up, and would result in significant damage to sensitive resources. For these reasons, the impacts of an oil spill are designated Class I, significant and unavoidable. Please see also Responses to Comments S&EM-5 and S&EM-36 regarding the pipeline inspection requirements and S&EM-95 regarding the risk assessment for the pipelines.

CPA-2: In accordance with CEQA, the EIR addresses the impacts of the proposed project in comparison to the existing baseline. Because PXP has filed applications to extend the life of the Point Pedernales project, the operational history of that project is relevant to an evaluation of the proposed project and is incorporated into the baseline and impact analyses for this EIR. A detailed presentation of the permitting history of the LOGP is more appropriate in the staff report to be prepared for the County Planning Commission for consideration by the public and decision-makers in conjunction with the environmental impact analyses in the EIR.

CPA-3: Information regarding the Harris Grade fire was included in the DEIR; however, more information regarding the fire history of the project area and recognition that the LOGP and pipeline route are located in a high fire hazard area have been added as requested (see Section 5.11.1.2 and Impact Fire.2). As discussed in the EIR, it is recognized that the facility and power lines pose a fire risk. However, these impacts are Class III (adverse but not significant) due to the low likelihood of a fire and adequate response capabilities. Implementation of Mitigation Measures Fire-1 and Fire-2 would require that the Tranquillon Ridge project, including the power lines if installed, be incorporated into the existing Fire Protection Plan for the PXP facilities.

CPA-4: PXP's transportation of liquid gases is required to follow the strict requirements stated in Condition P-23 of the Point Pedernales FDP (94-DP-027; see Appendix M), which include being in accordance with the Board of Supervisors Resolution No. 93-480 and the Transportation Risk Management and Prevention Program.

The comment references the cumulative impact summary discussion for hazardous materials and risk of upset contained in the Draft EIR's Executive Summary (Table ES.2). From a cumulative impacts perspective, potential public safety impacts include: oil spills and related fires; natural gas releases; and, exposure to hazardous materials (including NGL/LPG truck transportation risks). The discussion contained within Executive Summary Table ES.2 notes that public risks associated with natural gas liquids/liquid petroleum gases (NGLs/LPGs) truck transport along Harris Grade Road are significant, and would remain significant under the cumulative projects scenario.

The location of new residences within the hazard footprints of the Point Pedernales facilities (LOGP and pipelines) would result in potentially significant public safety impacts. Within County jurisdiction, Santa Barbara County's Safety Element Supplement Policies 2-A, 3-A, and 3-B, safety threshold C.12 and Land Use Element Planned Development Policy 3(c) would require that the siting and design of new residential development avoid hazardous areas, including the hazard footprints of oil and gas pipelines. It may be possible to avoid the hazard footprints through pipeline operational changes that reduce the footprints, pipeline relocation, and/or housing project redesign. With implementation of these County policies and thresholds, no new large-scale residential development would be allowed within the hazard footprints of the proposed project's off- to onshore oil and gas pipelines; therefore, potential impacts associated with introducing a greater number of people to the risks of a pipeline leak or rupture would be avoided. The discussion contained within the text of Table ES.2 and Section 5.1.6 (Risk of Upset, Cumulative Impacts) has been revised to note these County requirements.

CPA-5: See Response to Comment EDC-18 for a list of reportable releases pertaining to the LOGP and Point Pedernales pipelines. Section 5.11.1.5 of the EIR has been updated to include a discussion of the Santa Barbara County Hazardous Materials Emergency Response Area Plan.

PXP utilizes the Community Alert Network (CAN) system as an emergency notification system to select lists of people that may require notification in the event of an emergency at LOGP or along the pipeline right-of-way. CAN purchases telephone numbers (from a private vendor) in the Lompoc zip code area (93436). They then focus these phone numbers to three specific areas: Area # 1 – Vandenberg Village; Area # 2 - Mission Hills; Area # 3 - Mesa Oaks. CAN tailors the phone numbers to these specific areas by street name and street ranges (i.e., 100-199 block; 200-299 block, etc.). Unlisted phone numbers are not included in the overall numbers that have been purchased. These telephone numbers are updated once a year upon renewal of the contract with CAN.

Tests of the CAN system are conducted semiannually. The test procedure usually calls for 100 phone numbers to be drawn randomly from the overall roster of telephone numbers. Generally, the same number is not called during the second test of the year to avoid calling that number too frequently. A pre-recorded message is used for the tests. Phone numbers are called a total of three times if 1) a person does not answer or 2) a voice machine does not pick up. If after the third attempt a connection is not made, it is reported back to PXP as a non-connect. Immediately after the test is complete, a CAN test report is faxed back to PXP with a summary report of contacts made.

The last test of the CAN system (200 numbers) was completed on September 9, 2006, and showed a total of 187 messages being delivered, 10 calls not being answered, 2 calls received an intercept tone, and 1 call received a busy tone. CAN utilized 128 phone lines to complete 230 attempted phone calls in 4 minutes.

CPA-6: PXP is aware that a parent group associated with Cabrillo High School is in the early stages of planning for development of a stadium and that concern has been expressed that the injury flammable hazard zone associated with the gas pipeline currently intersects the western side of the high school property, which could limit the ability to develop in this area. When and if the stadium project or other expansion of the high school proceeds, PXP has stated that it is committed to working with Cabrillo High School and Santa Barbara County to assure that the injury flammable hazard zone does not interfere with the development plans. Measures that could be undertaken by PXP would include relocating the portion of the pipeline that is currently in the vicinity of the high school or reducing the maximum allowable operating pressure of the pipeline, which would have the effect of shrinking the hazard zone toward the pipeline and away from the school property.

A review of development within and near the injury flammable hazard zone for PXP's gas pipeline indicates that no residences are located within that zone.

CPA-7: The North County Siting Study referred to in this comment concludes that the Lompoc Oil and Gas Plant (LOGP) should not be considered as a processing location for northern offshore leases contained in the Lion Rock, Point Sal, Purisima Point and Santa Maria Units, as well as the non-unitized lease OCS-P 0409 since this would require significant physical expansion as well as extension of the life of the facility. However, this same study draws no conclusion as to the preferability of processing oil and gas produced from the Tranquillon Ridge Field at the LOGP or at a new location. Instead, it defers such a determination to the detailed analysis of an EIR (page 7.0-3, recommendation 3).

This EIR includes a Quantitative Risk Assessment (QRA) to assess the risk of extending the life of LOGP to process oil and gas produced from the Tranquillon Ridge field, which is summarized in Section 5.1. Actual QRA risks were modeled as part of the Point Pedernales 1985 EIR, 1993 SEIR, 1996 Addendum, and the 2002 DEIR prepared for a previous proposal to develop the Tranquillon Ridge field and process oil and gas at LOGP. The QRA addresses risk of existing facilities; for LOGP it examines releases of flammable and toxic materials that have the potential of resulting in impacts beyond the boundaries of the plant (DEIR page 5.1-23). Table 5.1.10 lists these scenarios with regard to LOGP. The risk calculation for LOGP, combined with the risk of the sour gas pipeline from Platform Irene to LOGP, registers as insignificant (see DEIR pp. 5.1-36, 5.1-71, and 5.1-72), and risk of NGL transportation registers as significant. Qualitatively, the EIR finds that the risk of processing Tranquillon Ridge production at Casmalia East Oil Field would result in comparable impacts; that is, Class III for oil and gas processing and pipeline transport, and Class I for NGL truck transportation. However, construction and operation of new facilities at Casmalia East, including a 10- to 15-mile long pipeline corridor, would likely result in significant impacts to biological resources and, perhaps, cultural and other resources. Therefore, it would appear that, with regard to risk, the proposed LOGP and the alternative Casmalia East site are comparable, but the LOGP site is favored for the proposed project when other types of impacts are taken into consideration.

CPA-8: The two-lane Harris Grade Road is described in Section 5.9.1.1 and Tables 5.9.1 and 5.9.3, and future Level of Service (LOS) C conditions are expected due to the cumulative contributions of new development in the area. Further, Section 5.9.1.1 discusses how truck traffic affects the LOS of a roadway by affecting traffic flow. Table 5.9.4 presents the percentage of truck traffic on area roadways, including Harris Grade Road. As presented in Section 5.9.4, NGL/LPG truck trips would increase from 2.9 per week to 5 per week. This impact to traffic represents an increase of less than 0.1 percent in daily vehicle trips on Harris Grade Road, which would not change the LOS; 2006 daily vehicle trips on Harris Grade Road north of Highway 1 averaged 8,233 (see Table 5.9.3). Therefore, this impact is considered adverse but not significant. Safety impacts related to traffic associated with the proposed project are discussed in Section 5.1, Risk of Upset/Hazardous Materials of this EIR (see Impact Risk.3).

There is no need for trucks hauling product from the LOGP facility to park at the noted intersection; the LOGP is located approximately 2.5 miles north of that intersection. If the drivers need to rest due to being out of hours (DOT regulations), they can park on PXP property adjacent to the LOGP facility.

The risks and traffic/transportation impacts due to cumulative development in the project area, including potential impacts associated with PXP's Purisima Hills residential development proposal, are discussed in Sections 5.1.6.2 and 5.9.6.2, respectively. Existing pavement conditions along Harris Grade Road vary from poor to very good depending on the location along the roadway. Given potential cumulative development in the area (see Section 4.4), roadway conditions could be further degraded. PXP's contribution of up to 5 truck trips per week would be small in comparison to the expected increase in average daily vehicle trips along Harris Grade Road of approximately 3,800 over the next 10 years (see Table 5.9.3).

A discussion of the flammability of the Burton Mesa Reserve has been added to Section 5.11.

CPA-9: Nighttime lighting and related glare associated with the LOGP has been an on-going community concern. In response to this concern, Conditions L-2 (Lighting Plan) and L-3 (Glare or Other Radiation) of the Point Pedernales Project's Final Development Plan (FDP) were evaluated in detail in 2000 as part of the existing project's "Condition Effectiveness Review" (Santa Barbara County, 2000). These analyses note that lighting at the LOGP is set at the lowest foot-candle (brightness) level acceptable to the Occupational Safety and Health Administration, and that light fixtures are tilted to 45 degrees above horizontal to minimize visibility from offsite. The analyses conclude that lighting at the LOGP is compliant with the existing project's approved Lighting Plan, that a certain amount of facility lighting is necessary for safety and security reasons, and that complete elimination of offsite glare did not appear to be feasible. Consequently, no changes to these existing FDP conditions were recommended as part of the 2000 Condition Effectiveness Review, although it was recommended that the operator should continue to investigate new lighting technologies that could potentially reduce offsite visual impacts.

Extending the life of the LOGP would result in continued nighttime lighting effects, including glare, in the project area. The EIR identifies these impacts as significant and unavoidable, Class 1 (Impact Visual.4, Section 5.13.4). These nighttime effects would not be intensified by the proposed project; existing (e.g. "baseline") conditions would remain the same, although the existing significant impact would occur over a longer period of time. Continued operation of the LOGP would be required to comply with the existing project's FDP, including Conditions L-2, L-3, and the findings of the 2000 Condition Effectiveness Review.

CPA-10: Section 5.10.4 describes the project-related helicopter noise for Platform Irene. Flights related to tours of onshore LOGP and pipeline facilities are rare and not expected to increase with the proposed project; since PXP has owned the Point Pedernales facilities, there has been less than one helicopter trip per year on average related to tours of LOGP (helicopter tours of Platform Irene are more frequent but follow a different route that avoids onshore urbanized areas). As required by the project Safety, Inspection, Maintenance, Quality

Assurance Plan (SIMQAP), the pipeline is inspected via fixed wing aircraft twice weekly, generally on Tuesday and Thursday, weather permitting. If weather does not permit on those days, it is performed on another day of the week, generally on Wednesday and Friday. Please see Response to Comment S&EM-1 for an overview of the project SIMQAP.

CPA-11: Mention of PXP's application: PXP's proposal to build approximately 1,300 homes on 800 acres was addressed in the following locations in the DEIR:

- It is the twelfth cumulative project listed in Table 4.2 and is further identified in the text of the paragraph following Table 4.2 (pages 4-8 and 4-9 of the Draft EIR).
- Cumulative impacts associated with new residential and commercial developments, either under construction or review, are discussed in the following sections: 5.1.6.2, 5.2.6.2, 5.4.6.2, 5.8.6.2, 5.9.6.2, 5.10.6.2, 5.11.6.2, 5.12.6.2, 5.13.6.2, 5.14.6.2, 5.15.6.2, and 5.16.6.2.

Annexation of plant by the City of Lompoc: The current area under consideration for annexation does not include the Lompoc Oil and Gas Plant (LOGP), but does abut this facility at its southwest corner. A segment of the pipelines that connect LOGP to Platform Irene is located within the area proposed for annexation.

Assurances to Neighbors: Standards are subject to change, whether or not an area is annexed from one jurisdiction into another. With respect to significance thresholds for CEQA review, the public is assured by law that adoption of, or changes in, these thresholds are subject to due process and public hearing. Neighbors have assurances by law that changes in standards are afforded due process and public hearings.

Obsolete EIR: This EIR remains active for the currently proposed Tranquillon Ridge project. This proposed project is much further along in the permitting process than the conceptual annexation, and County decision-makers would render a decision on the Tranquillon Ridge project substantially earlier than LAFCO and the City of Lompoc would be ready to finalize a decision on the conceptual annexation.

Inclusion of annexation in EIR: This EIR addresses the proposed annexation and development in the cumulative impacts sections throughout the EIR, as noted above, and discussions of cumulative impacts in relevant issue areas have been enhanced with additional information related to this housing proposal.

Please also see Response to Comment JP-1.

EDC

January 16, 2007

EDC ENVIRONMENTAL DEFENSE CENTER

Mr. Kevin Drude, Energy Specialist
Energy Division
Santa Barbara County Planning and Development Department
123 East Anapamu Street
Santa Barbara, CA 93101

Re: Draft Environmental Impact Report for the Tranquillon Ridge Project
County EIR #06EIR-00000-00005; State Clearinghouse #2006021055

Dear Mr. Drude:

The following comments are submitted by the Environmental Defense Center (EDC) on behalf of Get Oil Out! (GOO!) and Citizens Planning Association of Santa Barbara County (CPA) in response to the Draft Environmental Impact Report (DEIR) for the proposed Tranquillon Ridge Project. The EDC is a public interest non-profit law firm that represents community groups in environmental matters, including offshore oil and gas development, affecting the tri-counties region of Santa Barbara, Ventura and San Luis Obispo Counties. GOO! is a non-profit corporation whose mission is to protect the natural environment and beauty of the Santa Barbara Channel from the adverse effects of oil development. EDC represented GOO! in 2002, when the Santa Barbara County Board of Supervisors voted unanimously to deny the prior Tranquillon Ridge development proposal. CPA is a non-profit corporation formed in 1960 dedicated to defending the County's natural resources and upholding the County's planning policies and objectives. For over two decades CPA has been involved with Santa Barbara County oil and gas development issues and has monitored oil development proposals in and around the County. Both GOO! and CPA have submitted additional comment letters, which are incorporated herein by reference.

EDC and GOO! urge the Board to continue its opposition to the current proposal because it will result in the same Class I impacts and create unacceptable environmental and safety risks due to the 30-year (or possibly longer) extension of the current facilities and operations. It is now being predicted that the existing project, which was supposed to be completed by 2007, will last until at least 2017. That project was also predicted to have a 30 year life and yet is now projected to last up to 40 years, a 33% increase in lifetime not considered by the original EIR. This same operation has already resulted in

Environmental Defense Center, 906 Garden Street, Santa Barbara, CA 93101, (805) 963-1622
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one devastating oil spill, in 1997; increasing the throughput and life of the existing project will only increase the likelihood of another devastating leak or spill.

The following comments address the Project Objective, Project Description, Alternatives, and Impact Analyses.

1.0 INTRODUCTION

EDC-1

The EIR should disclose the fact that PXP's predecessor, Torch, applied to the County and State in 2000 for permission to slant drill from Platform Irene into a new state lease – virtually the same proposal that has been submitted by PXP. The EIR should discuss the reasons why the County denied the Tranquillon Ridge project in October 2002. This information will be useful for the current decision-makers and public to consider in their review of PXP's proposal.

1.2 PROJECT OBJECTIVE

EDC-2

CEQA Guidelines §15124(b) requires that the statement of objectives "should include the underlying purpose of the project" and provides that "[a] clearly written statement of objectives will help the lead agency develop a reasonable range of alternatives to evaluate in the EIR…" Under CEQA, a project objective cannot be so narrow as to unduly restrict the range of alternatives. *Kings County Farm Bureau v. City of Hanford* (1990) 221 Cal.App.3d 692, 735-737 [270 Cal.Rptr. 650].[1]

The DEIR sets forth the following objectives:

> The main objective of the proposed Tranquillon Ridge Project is to efficiently and effectively develop oil and gas reserves from the Tranquillon Ridge Field, and to sell the oil and gas production to help meet the energy demands of the State of California. If implemented, the proposed project would provide an additional supply of crude oil and natural gas to California. It is also PXP's objective to develop the State portion of the Tranquillon Ridge Field from an existing platform in Federal waters using extended reach drilling to maximize the development of the field, since PXP has expressed concern that the current method of developing the Tranquillon Ridge Field (utilizing bottomhole locations on Federal lands to drain reserves from the State Tidelands) could result in a loss of the reserves and State resources. Further, PXP has stated that it would be in the best interests of the State to grant the lease, allowing for the proper development of the reservoir. PXP has also stated that one of

[1] / NEPA cases are also instructive on this point. See, for example, *Save the Niobara River Association, Inc. v. Andrus*, 483 F.Supp. 844 (D.Neb. 1977) (court rejected action by federal agency in defining project objective for a dam and reservoir too narrowly, and refusing to consider water conservation as an alternative); see also *City of Carmel-by-the-Sea v. Dept. of Transportation*, 123 F.3d 1142, 1155 (9th Cir. 1997).

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EDC-2
Cont'd

the objectives of the project is to provide increased royalty and tax revenue to the State and local community, and to provide a reasonable rate of return to investors. [DEIR, p. 1-3.]

In other words, the applicant's objective is to produce oil and gas from the portion of the Tranquillon Ridge Field that is in State waters, by drilling from an existing platform in Federal waters. Other objectives are more general in nature, including the provision of an energy supply for the State of California, and increased funds to the State, local community, and investors.

The applicant's objective is overly narrow and precludes the consideration of a "reasonable" range of alternatives. In fact, it is so narrow that only the proposed project can meet this objective. Accordingly, this objective should be stricken from the EIR. The objective of supplying energy to the State of California is a proper objective and would open the door to a reasonable range of alternatives as required by CEQA. These additional energy alternatives are set forth in the discussion below regarding Section 3.0 – Alternatives.

2.0 PROJECT DESCRIPTION

2.1.2 Tranquillon Ridge Field Exploration

Section 2.1.2 points out that PXP may be draining oil and gas from lands owned by the State of California. The DEIR states that "[a]s a prerequisite to leasing, the CSLC must make a finding that drainage of state resources is occurring. The CSLC had an independent study prepared to aid the Commission in making its determination." (DEIR, p. 2-3.)

The drainage study must be included in the DEIR to provide full disclosure and afford the public and decision-making agencies an opportunity to review and comment on the study.

Point Pedernales Development and Production Plan (DPP)

The project description should disclose whether the Point Pedernales DPP needs to be revised to accommodate the proposed project.

Potential Relocation of Onshore Pipeline

PXP has also submitted a proposal to the City of Lompoc to annex approximately 800 acres to the City for the Purisima Hills project, which would include development of 1300 homes and a school. As shown in Figure 4-3, the development site directly overlaps the current pipeline route. PXP has stated that the existing pipeline would have to be moved to accommodate the new development. (Lompoc Record, 12/12/06.) Since the developer is the same entity as the project applicant, the DEIR should be revised to identify the proposed new pipeline route.

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Decommissioning

The DEIR does not mention anything about the end of the production cycle and decommissioning. While we are aware that additional discretionary review may be required at that point of time, decommissioning is an inherent part of any oil and gas development project and must be subject to review in the DEIR.

We know from experience that although oil companies know at the beginning of a given project that they will be required to remove their facilities (and thus they must factor these costs into their design and economic analyses), when it comes time to actually remove the facilities, they try to avoid their responsibilities to save money. As mitigation for the possibility that PXP, or a successor in interest, may try to avoid its obligation to remove the platform and other associated facilities, the DEIR should include a condition requiring posting of a bond that will adequately cover future decommissioning expenses. The bond should be posted prior to commencement of any development activities.

3.0 ALTERNATIVES

As stated above, the DEIR includes an impermissibly narrow objective that restricts the range of alternatives in the report. Although the objective set forth in section 1.2 includes broader objectives, such as providing energy to the State of California, in this section the DEIR states that "[i]f an alternative is found to not obtain the basic objective (*to efficiently and effectively develop oil and gas reserves from the Tranquillon Ridge Field* to help meet California's energy demand), then it was also eliminated." (DEIR, p. 3-2, emphasis added.) If the objective is to help meet California's energy demand, there are many alternatives that can feasibly meet that objective and avoid the adverse impacts of the proposed project. However, if the objective is to produce oil and gas from the Tranquillon Ridge Field, there is apparently only one alternative that can be considered - the VAFB Onshore Alternative.[2] Limiting the discussion to one alternative fails to meet the requirements and intentions of CEQA, which is to provide decision-makers with a "*range* of reasonable alternatives" to the project. (CEQA Guidelines §15126.6, emphasis added.)

The alternatives analysis is essential to ensure compliance with the substantive requirement of CEQA, which is to avoid or lessen the environmental impacts of a proposed project. "The core of an EIR is the mitigation and alternatives sections"; alternatives should "offer substantial environmental advantages over the project proposal." *Citizens of Goleta Valley v. Board of Supervisors* (1990) 52 Cal.3d 553, 564, 566 [276 Cal.Rptr. 410]. The DEIR offers only one alternative, and that alternative would increase impacts to onshore biology, onshore water resources, and cultural

[2] / In fact, one of the project objectives stated in section 1.2 of the DEIR is to allow PXP to develop the Tranquillon Ridge Field from Platform Irene; this objective is much too narrow and would not provide for consideration of *any* alternatives.

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resources. (DEIR, pp. 6-4 – 6-6.) As such, the decision-makers are left with both an inadequate range of alternatives, and may not have any alternatives that offer "substantial environmental advantages over the project proposal," unless they decide that the reduced risk of an offshore oil spill constitutes a "substantial environmental advantage."[3]

The DEIR should be modified to include other alternatives that will provide similar energy to the State of California, but without the same level of environmental impact. Some examples are set forth below.

3.2 NO PROJECT ALTERNATIVE

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The DEIR identifies the onshore development project as a component of the "No Project Alternative," pursuant to CEQA Guidelines §15126.6(e)(3)(B). (DEIR, p. 3-4.) As noted in the DEIR, section 15126.6(e)(3)(B) provides that "[i]f disapproval of the project under consideration would result in predictable actions by others, such as the proposal of some other project, this "no project" consequence should be discussed." However, §15126.6(e)(3)(C) goes on to state that the lead agency "should proceed to analyze the impacts of the no project alternative by projecting what would reasonably be expected to occur in the foreseeable future if the project were not approved, *based on current plans and consistent with available infrastructure and community services*." (Emphasis added.) Because "current plans" do not allow drilling into the target area (due to lack of a State lease), the Sunset/Exxon alternative project should not be included within the "No Project Alternative." Instead this alternative should only be analyzed as a stand-alone alternative.

3.3 ALTERNATIVE DRILLING/PRODUCTION LOCATIONS

3.3.3 VAFB Onshore Alternative

The VAFB Onshore Alternative provides an alternate method for extracting the same oil and gas from the same oil and gas field. This alternative would eliminate the impacts associated with the extended life of Platform Irene and the offshore pipelines. However, according to the DEIR, this alternative would also generate some new impacts due to the construction and operation of a new drilling and production facility and new pipelines. While this alternative is appropriately considered, given the submittal from Sunset/Exxon, the DEIR should also consider other or additional alternatives that would provide a "*substantial environmental advantage*" over the proposed project.

The DEIR also finds that because an oil spill from an onshore facility could reach ocean waters, the alternative would still result in Class I oil spill impacts to marine biology. While it may be true that the VAFB Onshore Alternative will still pose a risk of an oil spill, which may affect both terrestrial and marine resources, the DEIR should analyze the relative magnitude of the consequences of an oil spill from the onshore alternative as compared to the proposed project. An oil spill from an offshore platform or

[3] / See comments below under Section 6 - Environmentally Superior Alternative.

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pipeline will generally be larger in scale, and much more difficult to respond to and clean up, as was demonstrated during the 1997 Torch oil spill. Therefore, the DEIR should find that oil spill impacts from an onshore alternative would be less than from the proposed project.

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In addition, the DEIR states that the VAFB Onshore Alternative *"could"* result in significant impacts to onshore biological resources and cultural resources. (DEIR, p. 6-5, emphasis added.) The DEIR then states that rerouting the pipeline corridor "could avoid some of the identified sensitive biological and cultural resources." (*Id.*) The DEIR should provide more detailed information about the impacts that would result from this alternative, so that a more informed comparison can be made between this alternative and the proposed project.

Other Energy Alternatives Not Considered

As stated above, the range of alternatives should be expanded to address the objective of providing a supply of energy to the State. These alternatives should include conservation, energy efficiency and renewable sources of energy. The following alternatives would provide the same or more energy compared to the expected production of 170-200 million barrels of oil and 40-50 billion standard cubic feet of gas.

Alternatives to Oil

In order to adequately propose alternatives, we need to know how much of the oil would be used as a fuel source. Even if all of the 170-200 million standard barrels were to be used as a fuel supply, there are other, cleaner alternatives that can match that supply without *any* of the impacts from the proposed project. For example, this oil supply could be replaced with an increase in vehicle mileage performance. Considering a 30-year life for this project, and an increase in U.S. consumption levels from the current 20 million barrels per day to a projected 30 million barrels per day in 2030, ***an increase in less than .01% in fuel efficiency*** for vehicles would match the supply of oil that would be produced from these leases. Policy experts anticipate a *1.0 mile per gallon increase* for light-duty vehicles over the next few years under "business-as-usual" conditions (i.e. without any particularly proactive efforts to switch to more fuel efficient and renewable-based energy plan), more than *100 times* the benefit from development of these leases.[4]

More aggressive strengthening of CAFÉ standards, as recommended by the National Commission on Energy Policy's (NCEP) 2005 report, would go even further in replacing this oil supply. According to the NCEP report, ***increasing fuel economy standards by 10 mpg*** across all vehicle classes between 2010 and 2015 would decrease projected total US energy demand by 6% of "business-as-usual" levels. This option

[4] / NCEP, "Ending the Energy Stalemate; A Bipartisan Strategy to Meet America's Energy Challenges. Economic Analysis of Commission Proposals." December, 2004. (See www.energycommission.org.) All references cited in this letter are hereby incorporated by reference.

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would dramatically increase the marketability and demand for hybrid technology. Hybrid vehicles are typically $2,500-$3,000 more expensive that their non-hybrid counterpart models, because of the added cost to the producer of the hybrid technology. However, this increased vehicle purchase price is fully offset within four years of a vehicle's 12-year life, so the consumer enjoys net savings via the significantly higher fuel economy of his/her vehicle.[5] (With state or federal rebates, the increased cost of a hybrid may be paid off even quicker. For example, there is a current tax credit of up to $3,400 available for hybrid purchases.)

Strengthening tire and lubricating oil standards are other means to increase vehicle fuel economy (by reducing friction). Already, in some states, legislation is being passed to institute new standards requiring drivers to retrofit their vehicles with better tires and oil. These changes would increase vehicle mileage results by more than the .01% required to offset the oil from these leases.

Other alternatives can also provide an additional fuel supply without the same environmental costs. ***Ethanol and bio-diesel*** are feasible alternatives to using oil as a vehicle fuel. The DEIR should analyze the potential availability of these alternative fuels to satisfy the alleged need for the proposed project. For example, American Ethanol, Inc. has submitted a proposal to build an ethanol plant in Santa Maria.

A gradually integrated pump tax or a tax on vehicle emissions would also create incentives for conserving fuel and promoting more fuel-efficient vehicles.

The fall 2004 edition of "Yes" Magazine (titled *Can We Live Without Oil*) provides a myriad of options for replacing our dependence on oil with other, clean alternatives. In one of the articles, authored by Guy Dauncey, co-author of *Stormy Weather: 101 Solutions to Global Climate Change* (New Society Publishers, 2001), a combination of telecommuting, walking, cycling, ride-sharing, mass transit, electric vehicles, hybrid cars, smart cars, and biofuels could eliminate our need for oil transport fuel.[6] As pointed in this and other articles in the magazine, our state and nation have many options for fueling our demand without resorting to additional oil development.

Alternatives to Gas

Regarding gas supply, the project is expected to provide 40-50 billion standard cubic feet of gas. This estimate translates to approximately 1.67 billion cubic feet of gas per year, or 5 million standard cubic feet per day. This amount of energy can easily be matched through minor advancements in energy conservation and efficiency. Here are a few examples of efficiency opportunities that would more than offset the amount of gas to be produced from the Tranquillon Ridge project:

[5] / *Id.*
[6] / Guy Dauncey, *Getting There on Less*. Yes Magazine: Can We Live Without Oil, Fall 2004.

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Industrial Sector
A recent study conducted by the American Council for an Energy Efficient Economy ("ACEEE") shows that California can save a substantial amount of energy in its industrial sector. By increasing efficiency in such energy expenditures as space heating, water heating, refrigeration, lighting, ventilation, cooking and office equipment, industries can use 5.19% less natural gas and 5.41% less electricity within the next five years.[7] These estimates are based on already available technologies that have been proven to be cost effective.

Residential Sector
Additional measures need to be taken to increase energy efficiency in California homes. Over the next 5 years, by making energy-conscious decisions and using energy efficient technologies to heat water, heat space, ventilate and cook, Californians can use 5.1% less natural gas and 5.7% less electricity in their homes.[8]

Commercial Sector
Similar to the residential sector, lighting holds the largest margin for improvement in the commercial sector. Refrigeration and space cooling also represent significantly large shares of the potential for energy efficiency savings from existing commercial buildings. The total potential annual savings is 6.8% of electricity and 4.8% of natural gas in California's Commercial Sector.

In addition, renewable energy sources can provide as much or more energy without the significant environmental impacts that would result from the proposed project. For example, the proposed Tehachapi wind project will produce the equivalent of 116 billion cubic feet of gas/year, almost 70 times the energy that would be provided from the Tranquillon Ridge project. As another example, the Salton Sea geothermal project will produce the equivalent of 133 billion cubic feet of gas/year, approximately 80 times as much energy as would be provided by the proposed project.

3.4 ALTERNATIVE PROCESSING LOCATIONS

3.4.3 Casmalia Canyon/Oil Field

The DEIR concludes that the Casmalia Alternative processing facility site offers no environmental benefits compared to the Lompoc Oil and Gas Plant ("LOGP") and considers the LOGP the environmentally preferred alternative. (DEIR, p. 6-63.) However, the DEIR's analysis of the Casmalia East site as an alternative processing facility is incomplete and requires further evaluation of potential risks from extending the

[7] / Elliot, R. Neal et al., *Natural Gas Price Effects of Energy Efficiency and Renewable Energy Practices and Policies*. American Council for an Energy Efficient Economy, Report number E032, December 2003.
[8] / *Id.*

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life of the LOGP compared to the potential safety benefits of locating a facility at the Casmalia East site.

According to the DEIR, an oil and gas processing facility at the Casmalia East site would require an entirely new facility on approximately 20 acres. Most of the LOGP would be dismantled and a new gas compressor station and wet oil pump station would be built at the LOGP site, along with new pipelines from the LOGP to the Casmalia East site. (DEIR, p. 3-16.) The new gas compressor station and wet oil/produced water pump station would move wet oil and sour gas to the Casmalia site and move produced water to Platform Irene for disposal. (DEIR, p. 3-16.)

The DEIR describes new Class I impacts of siting a facility in Casmalia, including potential impacts to biological resources from construction and visual impacts from nighttime glare. Further, the DEIR states that Class I impacts would be increased over the proposed project for terrestrial biology, onshore water quality, recreation/land use and cultural resources resulting from the additional 13 miles of new onshore pipeline construction and spill risk. (DEIR, p. 6-23.)

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The DEIR lists two major benefits of locating a processing facility at the Casmalia East site: early abandonment of the LOGP and reduction of visual impacts from the nighttime glare of extending the life of the LOGP. (DEIR, p. 6-23.) However, the DEIR fails to elaborate on these benefits and fails to explain other important safety benefits of locating a new facility at the Casmalia East site that are identified in the Santa Barbara County North County Siting Study. (North County Siting Study, October 2000, County of Santa Barbara Planning and Development Department Energy Division, incorporated herein by reference.)

First, the DEIR fails to adequately discuss impacts from extending the life of the LOGP and increasing plant throughput for 20 additional years, from 2017 to 2037. (DEIR, p. 6-60.) According to the North County Siting Study, any new production added to an existing facility is a key factor to consider when determining what site is environmentally preferred. (Siting Study, p. 6-12.) Extending the life of the LOGP will require equipment modifications, including the return of two heat exchangers back into service, installing additional piping for water heat outlets, creating more oil emulsion processing capacity and other equipment additions. (DEIR, p. 2-7.) Environmental impacts of these proposed modifications were not thoroughly explained in the DEIR.

The only Class I impacts described in the DEIR from extending the life of the LOGP facility are visual impacts. (DEIR, 6-23.) Class III impacts from continued use of LOGP described in the DEIR include possible groundwater overdraft, a thirty percent increase in electricity consumption and a 100% increase in fuel consumption, potential risks to public safety from gas releases and oil spills, and an increased likelihood of upset conditions due to equipment modifications and increased processing at the LOGP facility. (DEIS, Impact Summary Table.) These impacts demand further environmental analysis. For example, the DEIR concluded that there is an increased likelihood of upset conditions, but no mitigation measures were proposed to ensure that long-term

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environmental response capabilities will be sufficient. Further extending the life of the LOGP (beyond the already predicted 10-year extension) will result in additional safety impacts that could be avoided by considering other alternatives. These potentially harmful impacts should be further analyzed to ensure the feasibility and safety of prolonging the life of the LOGP, and to compare such impacts to alternatives such as the Casmalia East site.

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Finally, the DEIR fails to adequately analyze the respective safety impacts associated with the LOGP and the Casmalia East site. The North County Siting Study identified the Casmalia East site as one of the preferred oil and gas processing sites for public safety reasons because of its rural location. While the DEIR states that sites in the Casmalia oil field and Casmalia Canyon "are more rural and would potentially result in lower impacts than the LOGP facility," there is no safety analysis comparing the risks of extending the life of the LOGP with constructing an up-to-date facility at the Casmalia East site. (DEIR, p. 3-16.) The North County Siting Study states that potential new production having a life of 25 or more years "could presumably [have] a net environmental benefit [by] building a new facility in a better location and pursuing abandonment of existing facilities as production declines." (Siting Study, p. 3.0-10.) The North County Siting Study noted that a new facility that can use state of the art pollution control equipment should be a consideration. (Siting Study, p. 6-12.) These potential benefits should be analyzed, along with other benefits of the Casmalia East site described in the Siting Study, including easy railroad access, prior oil extraction disturbance, proximity to landfall, and low potential for noise impacts. (Siting Study, p. 6-5.)

The DEIR also fails to adequately analyze safety issues when determining the environmentally superior processing facility location. As the North County Siting Study explains, the LOGP may have more potential safety risks than the Casmalia East site. (Siting Study, p.3.0-10.) The LOGP processing facility is located about 3 miles northeast of Lompoc and less than one mile from Vandenberg Village and 8,000 feet north of the Mission Hills community. (DEIR, p. 5.1-34, Siting Study, p. 4.0-3.) These areas encompass populated residential communities that include several schools. (Siting Study, p. 5.7-3.) In contrast, the Casmalia East site is located in a sparsely populated rural area. According to the North County Siting Study, "the simplest and most powerful siting measure to minimize risk is to avoid potential public exposure to hazards by siting a facility in a remote, unpopulated area." (Siting Study, p. 5.1-7.) Given that many hazards are associated with oil and gas processing facilities, the DEIR should have evaluated the risks to the communities from extending the life of the LOGP. Hazards associated with oil and gas processing facilities include oil spills, fires, explosions, toxic substance releases and soil contamination. (Siting Study, p.5.1-1.) Sulfur dioxide releases from the processing facility could be fatal, hydrogen sulfide emissions from structural or mechanical defects could ignite or form a fatal vapor cloud, and ruptures in a storage or loading vessel from an earthquake or otherwise could result in a leak or fire. (Siting Study, p.5.1-3.) These risks should be analyzed further given the close proximity of residential communities to the LOGP.

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3.7 ALTERNATIVE DRILL MUDS AND CUTTINGS DISPOSAL

During drilling operations, PXP proposes to discharge uncontaminated muds and cuttings into the ocean according to limitations set forth in the National Pollutant Discharge Elimination System ("NPDES") General Permit for Offshore Oil and Gas Facilities ("General Permit"), Permit No. CAG280000. (DEIR, p.2-6.) An alternative to discharging into the ocean would involve collecting and re-injecting the muds and cuttings into an underground reservoir for disposal. (DEIR, p. 3-25.) This alternative depends on the availability of suitable underground formations. Another alternative described in the DEIR involves transporting all muds and cuttings via boat for onshore disposal at an appropriate waste or recycling facility. (DEIR, p. 3-26.) The proposed project requires all contaminated muds and cuttings to be transported to shore or injected as required by the General Permit. (DEIR, p.5.6-42.)

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Injection at the platform was chosen as the environmentally superior alternative because it would eliminate Class II impacts to marine biology and water quality and it would eliminate Class III impacts to traffic and air emissions associated with onshore disposal. (DEIR, p. 6-63.) Onshore disposal was selected as the second environmentally superior alternative. (DEIR, p. 6-63.) The DEIR also states that there may be other factors that affect the feasibility of implementing these disposal options, but it does not discuss them. (DEIR, p. 6-64.) Other factors affecting the feasibility of alternative disposal methods should be analyzed.

Under the General Permit, discharges of cuttings are limited to 30,000 bbls/yr, drilling fluids are limited to 105,000 bbls/yr, and cement discharges are limited to 2,500 bbls/yr. (General Permit, p.13.) From 2008-2010, the DEIR states that PXP estimates that annual muds discharges will be 48,000 bbls and cuttings discharges will be 5,700 bbls. (DEIR, p. 2-7.) Although these projected amounts would be below the permitted limits, there is no analysis in the DEIR of the total amount of muds and cuttings that would be generated for the 15 years new well drilling is expected to continue, and whether total amounts would meet the limits in the General Permit. (DEIR, p. 2-11.)

4.0 CUMULATIVE PROJECTS DESCRIPTION

The DEIR lists the proposed PXP Residential Development Annexation to the City of Lompoc. (DEIR, p. 4-8.) This project would involve the construction of 1300 homes on 800 acres that overlaps the existing PXP pipeline route. (See Figure 4-3.) The DEIR should analyze potential impacts and conflicts between the proposed continued use of the existing pipeline and PXP's other proposal to develop 1,300 homes.

The DEIR also fails to include projects that may impact the Santa Ynez River and associated biological resources, such as the Bee Rock Quarry Project and the State Water Resources Control Board review of Cachuma operations. (See discussion under section 5.2 below.)

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5.0 ANALYSIS OF ENVIRONMENTAL ISSUES

The DEIR describes the baseline for environmental review as the existing physical environmental conditions, along with consideration of the historic operations of the existing project. We agree that the current operations (as opposed to the permitted levels of production) represent the most accurate environmental baseline. These existing levels of production are represented as 7,000 bpd of oil and 2.6 mmscfd of gas.

According to the DEIR, the proposed project would result in an extension of the life of existing facilities (30 years for the platform and 15 years for the processing facility). The proposed project would also increase the throughput beyond existing levels.

An accurate assessment of the life of the project is critical to ensuring an adequate analysis of potential environmental impacts and comparison to other alternatives. We are concerned that the projected 30-year life for the project may not be reliable, given the fact that the Point Pedernales project is already expected to exceed its original projected life by approximately 10 years. Accordingly, the DEIR should analyze a *range of at least 30-40 years* for the projected life of the project, and base the analysis of impacts on such a range.

5.1 RISK OF UPSET/HAZARDOUS MATERIALS

Public Safety Impacts from the LOGP and Pipelines

As discussed in section 3.4.3 above, the DEIR must analyze the impacts associated with extending the life of the LOGP. This facility, located in close proximity to residential areas, was never intended to operate as long as currently proposed. Originally, the LOGP was intended to be operated as a separation plant only, due to its close proximity to residential areas. Other functions were subsequently added. However, the plant was never intended to be operational for an additional 30-40 years.

The DEIR should be revised to fully analyze the potential impacts to the surrounding communities, from both the LOGP and the associated pipelines. The DEIR should also be revised to include a list of all incidents that have occurred at these facilities.

Moreover, the DEIR should analyze impacts to PXP's proposal to develop 1300 new homes next to the plant and adjacent to the onshore pipelines.

Impacts from Oil Spills

We also appreciate the fact that the DEIR includes a "worst case" oil spill scenario in which the automatic valve shut downs do not operate properly or are overridden by operator error. The 1997 oil spill from a Platform Irene pipeline should have been prevented because the automatic shut-down system functioned properly.

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Unfortunately, an operator on the platform restarted production, causing a major oil spill that impacted 40 miles of pristine coastline. As a result of that spill, the California Coastal Commission determined that it is infeasible to adequately prevent or respond to an offshore oil spill.[9]

The risk of an oil spill is one of most significant and alarming threats posed by the Tranquillon Ridge application. As noted in *Safety at Bay: A Review of Oil Spill Prevention and Cleanup in U.S. Waters* (NRDC, December 1992), oil spills "can cause widespread and long-lasting environmental injury. Oil contains highly toxic and carcinogenic substances that are lethal to fish, wildlife, and plant life."[10] Studies following the Exxon Valdez oil spill confirmed not only the difficulties cleaning up an oil spill, but also the unexpected long-term environmental and human health impacts that result from oil spills.[11]

An oil spill from the proposed project would be especially devastating given the ecological significance of this area. Tranquillon Ridge is located in the middle of the "transition zone" between cooler northern Pacific waters and warmer southern Pacific waters. This confluence results in an incredibly high level of biodiversity and the presence of many several endangered and threatened species, including blue, humpback and sei whales, the southern sea otter, southern Steelhead, western snowy plover, and the California brown pelican. In fact, according to the southern sea otter Recovery Plan, oil spills constitute the primary threat to the survival and recovery of the otter.

Risk Assessment

Risk assessment includes both probability and consequence. With respect to probability, the DEIR relies on historic data of oil spills from OCS facilities. (DEIR, p. 5.1-25 *et seq.*) However, because the facilities in this case would be operational long after their initial expected lifetime, the DEIR should consider how the extended life and aging of the facilities may increase the likelihood of an oil spill.

With respect to the potential consequences of an oil spill, the DEIR should utilize the Ecological Risk Assessment ("ERA") approach that has been used by the United States Coast Guard and various partners in industry and government since 1998.[12] ERAs focus on ecological risk and recovery. They evaluate a spill scenario, the natural resources that may be affected, and various oil spill response options.[13] The first step of the analysis is to develop a scenario and trajectory model. Scenario parameters include

[9] / *Adopted Findings*, California Coastal Commission, November 18, 1997, File No. E-97-23 regarding Torch Operating Company; see attached copy of report.
[10] / *Safety at Bay: A Review of Oil Spill Prevention and Cleanup in U.S. Waters*, p. 10.
[11] / *Id.*; see also *Sound Truth and Corporate Myth$*, Dr. Riki Ott, 2005, and studies cited therein.
[12] / *United States Environmental Protection Agency's Ecological Risk Assessment (ERA) Guidelines*, USEPA 1998.
[13] / J. Kraly, et al., *Ecological Risk Assessment principles Applied to Oil Spill Response Planning* (2005).

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spill location, oil type, spill size, weather, seasonality and established assessment objectives. Trajectory models predict the distribution and quantity of the spilled oil throughout the environment. The next step is to identify habitats and natural resources of concern. The third step requires an identification of stressors, or response options. Stressors can include natural recovery, on-water mechanical recovery, shoreline cleanup, dispersant application, and on-water in situ burning. For each stressor, parameters must be identified that address use (the stressor's role in mitigating the impacts of a spill), logistics (the actions necessary to effectively employ the stressor in response), limitations (the conditions which inhibit effective employment in response) and effectiveness (estimation of the percentage of oil volume spilled that the stressor is likely to remove from the environment). Each stressor is then evaluated for links to resources, such as through air pollution, aquatic toxicity, physical trauma (mechanical impact from people, boats, etc.), oiling or smothering, thermal (heat exposure from in situ burning), waste, and indirect (a secondary effect such as ingestion of contaminated food). After all of this information is collected, the next step involves the analysis. The analysis provides an examination of the degree of exposure of each response option, followed by a comparative analysis of the different response option impacts. Finally, the risk characterization involves an interpretation of the data and analysis results.

D. Aurand, et al. describe an application of this approach to several areas, including the Santa Barbara Channel.[14] Of all scenarios and locations considered, Santa Barbara Channel had the highest number of habitats and subhabitats that would be affected by a spill. The analysis shows that even a small spill (5 - 20% coverage) would create a "high concern" due to the sensitivity of the affected resources.

This type of analysis is certainly possible. The Shoreline Inventory and other biological studies are available to identify the species and habitats that may be impacted by a spill. Production from Platform Irene, including alleged drainage from the Tranquillon Ridge, provides useful information regarding the characteristics of the oil that would be produced from this project.[15] Modeling can predict the consequences of various scenarios and sizes of spills. This information should be sufficient to estimate the environmental impacts for each location and each spill size assuming certain environmental conditions.

Oil spills happen. They even happen from the Point Pedernales project. The 1997 Torch oil spill, which occurred from a pipeline transporting oil from Platform Irene to shore, is reported to have spilled 163 barrels, affecting over 40 miles of shoreline (including the Santa Ynez River, San Antonio Creek and Honda Creek), and killing or injuring between 635 and 815 seabirds and shorebirds (including endangered California Brown Pelicans and threatened Western Snowy Plovers).[16] Dead oiled wildlife was

[14] / D. Aurand, et al., *The Use of Consensus Ecological Risk Assessments to Evaluate Oil Spill Response Options: Lessons Learned from Workshops in Nine Different Locations* (2005).
[15] / See also "*A Catalogue of Crude Oil and Oil Product Properties,*" Environment Canada.
[16] / *Santa Barbara County Board Agenda Letter re: 1997 Torch Oil Spill NRDA – Request to Governor Davis for Trustee*, prepared on May 7, 2003; and "*Torch/Platform Irene Oil Spill:*

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recovered as far south as Honda Cove, just north of Pt. Pedernales, and as far north as Morro Bay. Live oiled wildlife were observed as far south east as Santa Barbara Harbor and as far north as Morro Bay.[17] This spill impacted ecologically intact sandy and rocky intertidal shoreline communities, killing spiny sand crabs, Pismo clams, black abalone, mussels.[18] Torch was required to pay $4 million for natural resource damages and penalties to county, state and federal agencies.[19]

More recently, on June 15, 2005, a 15-barrel platform spill near New Orleans killed at least 400 brown pelicans and oiled 1,000 more.[20]

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Operator Error: The DEIR correctly considers a scenario in which the leak detection system is not operational or is overridden by an operator. (DEIR, p. 5.1-5.) The DEIR assumes that pumping would continue for 30 minutes before a spill would be detected and a response would be initiated. (*Id.*) However, during the 1997 Torch oil spill, from this very facility, an operator overrode the system and the spill was not detected for 3 hours, and the response took even longer. This fact demonstrates that continued pumping will result in additional spillage (and impacts therefrom), but also that delayed detection of the spill will defer response and cleanup, further exacerbating the impacts.

The Torch oil spill demonstrated that the effectiveness of oil spill response and cleanup may be impaired by operator error, in addition to decisions and actions taken by response teams. In fact, in the case of the Torch oil spill, practically the entire spill could have been avoided had the operator not bypassed the automatic shutdown system on the pipeline.[21] This system (referred to as the supervisory control and data acquisition (SCADA) system) was required pursuant to Torch's permit and caused the automatic shutdown of the pipeline *three seconds after the rupture.*[22] Very little, if any, oil would have spilled during this period of time. However, the operator bypassed this system and

Scoping Document for Restoration Planning," prepared by Platform Irene Trustee Council, October 20, 2004.

[17] / *Final Report: Bird Injury Assessment for the Torch/Platform Irene Pipeline Oil Spill, September 1997,* prepared for Office of Spill Prevention and Response, California Department of Fish and Game, by R.G. Ford Consulting Company, July 1998.

[18] / *Id.*

[19] / *Id.*

[20] / "Coast Guard Sees 1,400 Dead, Soiled Birds After Oil Spill," 6/15/05, "Cleanup launched after deadly oil spill 400 pelicans killed in Breton Sound; 1,000+ oiled," Times Picayune, 6/15/05; "Dirty Birds: Oil spill soaks pelican refuge," Sun Herald, 6/16/05; "Collision of Louisiana icons, pelicans and oil, sets rescuers in motion," Times-Picayune, 6/16/05.

[21] / *County of Santa Barbara Planning and Development* Memorandum from Alice McCurdy to Jerry Lulejian, dated December 8, 1998, re: "Torch Override of Emergency Shutdown on September 28, 1997." The County of Santa Barbara did not find out until December 17, 1997, *almost two months later,* that the operator had overridden the emergency shutdown system.

[22] / The People of the State of California v. Torch Operating Company, *Complaint for Civil Penalties and Injunction,* Superior Court of the State of California for the County of Santa Barbara, Case No. 232684, filed September 14, 1999.

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brought the platform back on-line. To do so, the operator had to (1) set systems on bypass, (2) open valves, (3) restart the shipping pump, and (4) restart the wells. The platform resumed production for approximately 45 minutes, during which time oil spilled into the ocean undetected. Finally, two hours later, oil was discovered on the surface of the Pacific Ocean. Accordingly, it took almost three hours before the spill was noticed. During that time, the spill had spread.[23]

In addition, late reporting allowed the spill to spread and decreased the ability of the operator and response agencies to effectively clean up the spill. The initial spill occurred at 10:17 p.m. The automatic shutdown occurred approximately three seconds later. At 10:18 p.m., the operator began the bypass process and resumed pumping at approximately 10:46 p.m. The platform was manually shut down again at 11:10 p.m. The oil spill was not noticed until approximately 1:30 a.m., over three hours after production was resumed and oil began spilling.[24] Platform operators reported the spill to MMS at 2:32 a.m., almost four hours after the spill occurred.[25] ***The Emergency Operations Center ("EOC") at County Fire Headquarters was not activated until 6:00 a.m., over seven hours after the spill.***[26] ***The oil spill lasted for 36 hours.***[27] What this experience demonstrates is that oil will spread (and weather) for many hours before the initial response and cleanup efforts begin. This lapse of time will hinder the effectiveness of oil spill response efforts.

Finally, oil spill response was further diminished due to the decisions that were made by responders. The Unified Incident Command Team ("UICT") for the Torch oil spill failed to implement the measures requested by the County of Santa Barbara, resulting in increased impacts. For example, requests by County employees to protect the Santa Ynez River mouth and the San Antonio Creek lagoon with sand berms were not followed, resulting in oil contamination in these sensitive coastal wetland areas.[28] This is particularly important because the DEIR predicts a 1 in 3 chance of a spill also reaching the Channel Islands. In addition, other sensitive areas were not cleaned because they could not be accessed or were difficult to access, including Purisima Point and approximately five miles of beach south of La Honda Creek.[29]

[23] / *Id.*

[24] / *Id.*; *County of Santa Barbara Planning and Development Memorandum* from Alice McCurdy to Jerry Lulejian, dated December 8, 1998. The Minerals Management Service Incident Report notes that the incident was discovered at 2:00 a.m., almost four hours after the spill began. See *Minerals Management Service Pacific OCS Region Spill Notification,* dated September 29, 1997.

[25] / *Adopted Findings,* California Coastal Commission, File No. E-97-23, filed November 18, 1997.

[26] / *Santa Barbara County Board Agenda Letter,* prepared on October 6, 1997.

[27] / *Id.*

[28] / *Santa Barbara County Board Agenda Letter,* prepared on October 6, 1997; *Santa Barbara County Board Agenda Letter.* prepared on November 25, 1997 – La Honda Creek mouth was also contaminated.

[29] / *Santa Barbara County Board Agenda Letter,* prepared on November 25, 1997.

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Consequences: The above information shows that if an oil spill of as little as 163 barrels is to occur, it will still reach the shoreline and create significant environmental damage due to the inability of response teams to recover local oil quickly and efficiently.

EDC-24

The DEIR should also consider impacts of an oil spill on fishing, recreation and tourism. For example, as a result of the 1997 Torch oil spill, several fishermen filed claims for damages related to the spill and cleanup operations. Steve Dunn, representing the Santa Barbara Trappers, complained that response, cleanup and repair vessels violated Vessel Traffic Corridor restrictions, resulting in lost or destroyed gear. Other fishermen similarly sought damages from loss of nets resulting from the spill and cleanup activities.[30] The 1969 oil spill in Santa Barbara resulted in tremendous economic impacts to the community.

Worst case scenario: A worst case analysis is crucial for evaluation of possible environmental impacts and estimation of the response equipment required for minimization of environmental damage.

EDC-25

The DEIR should consider the scenario of a ***subsurface spill***, which might have a greater impact than a surface spill. Depending upon the depth of the spill and the water column, the process by which the oil may surface, and the water temperature and weather conditions, the spill may create a plume effect and distribute oil over a much greater area than a surface spill. In general, subsurface spills result in greater damage to marine life because they spread further and affect more of the water column. In addition, subsurface spills are harder to recover because they spread over a greater area, creating a thinner slick, and because much of the oil is dispersed underwater. Subsurface spills also take longer to appear, such as in the case of the Torch pipeline oil spill, wherein it took over three hours for the oil to be detected. By that time, the oil spill had spread widely.[31]

Mitigation

While we appreciate that measures have been required to counter corrosion in the pipelines, we are concerned that the extended life of these facilities may lead to increased erosion in the future. The EIR should identify whether any additional mitigation measures (e.g., increased inspections and treatment) over time will be necessary in the future to ensure that the pipelines do not corrode again.

Oil Spill Response

The effectiveness of any recovery effort depends on the characteristics of the oil, the location of the spill (e.g., how far from cleanup vessels, equipment and trained

[30] / *County of Santa Barbara Planning and Development Memorandum re: Update on Torch Oil Spill for January 20, 1998 Hearing*, from John Patton, Director, to Board of Supervisors, dated January 13, 1998.
[31] / *Complaint for Civil Penalties and Injunction*, The People of the State of California, et al. v. Torch Operating Company, Santa Barbara County Superior Court Case No. 232684.

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personnel), and weather and sea conditions. In addition, human error can intensify a spill, such as the situation that occurred during the 1997 Torch oil spill, when an operator bypassed the pressure safety high/low sensor and restarted flow through a broken pipeline.[32] The DEIR fails to analyze how effective a cleanup effort will be in response to a spill from these leases.

In general, only 10 to 15% of spilled oil is typically recovered. (*Safety at Bay: A Review of Oil Spill Prevention and Cleanup in U.S. Waters*, NRDC, December 1992, citing a report by the Office of Technology Assessment in 1990; *No Safe Harbor: Tanker Safety in America's Ports* (NRDC, 1990).)[33] As noted in *No Safe Harbor: Tanker Safety in America's Ports*, "severe weather conditions off northern and central California reduce the effectiveness of cleanup equipment."

EDC-28

The California Coastal Commission has found that clean-up equipment has limited effectiveness and hence that oil and gas projects are inconsistent with section

[32] / *Id.*
[33] / According to *No Safe Harbor: Tanker Safety in America's Ports*:

> "The record of oil spill containment and cleanup is nothing less than dismal. Only 10 to 15 percent of spilled oil is typically recovered….On the technology side, current spill-containment and cleanup equipment quickly become inoperative in anything other than calm weather and seas. For example, most booms – floating barriers intended to prevent oil from spreading – lose effectiveness when wave heights reach three to four feet and currents exceed one knot….Skimmers – devices that skim oil off the water's surface – also lose effectiveness with increasing wave height, with one to five feet the operational limit for most. Dispersants have demonstrated low effectiveness in actual spill situations, and some of them are toxic to marine life. When they work, they merely shift the location of spill impacts from the surface to the water column – the water between the surface and the bottom – and the ocean bottom." (Page 3.) Natural sorbents are also problematic because they "soak up water along with oil and sink to the bottom, complicating the cleanup and transporting oil to bottom-dwellers. Synthetic sorbents are not biodegradable and create a disposal problem. Mineral-based sorbents tend to be very lightweight and are difficult to distribute in windy weather." (Page 31.) Burning has many disadvantages as well. "First and foremost, combustion of oil releases toxic compounds into the atmosphere….Second, combustion of oil is never complete. Third, burning is usually most effective if it takes place within a stable and fireproof boom. Because stability of the boom is dependent on weather conditions, use of burning as a cleanup method is limited to predictable periods of calm waters. Fourth, burning after a tanker spill is limited by the potential for fire damage to the tanker, explosions and further spillage. Finally, burning is problematic because it is often difficult to raise the temperature of a thin sheet of oil floating on a generally cold body of water high enough to cause ignition. (Pages 31-32.) Sinking agents are problematic because they "simply contaminate[] bottom-dwelling marine organisms." (Page 32.)

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30232 of the Act.[34] Several response technologies might not be effective in recovering or cleaning an oil spill from these leases. For example, information presented in "*A Catalogue of Crude Oil and Oil Product Properties*" demonstrates that dispersant efficiency on local crude oil is less than 5% (***0% for most of them***). The reason for this low response effectiveness is the high viscosity of the oil, which only increases during the weathering process.[35]

In addition, oil spill response groups cannot apply dispersants without governmental approval. If government approval is required, it will take more than 24 hours to obtain such approval, which will render dispersants ineffective because weathering will cause high oil viscosity. It also must be noted that dispersants can be efficiently used only in the presence of breaking waves (wind speeds more than 5 m/s). Dispersant application in the Channel might have reduced effectiveness in times of calm conditions.

Burning oil also may not be effective. First, there is no evidence that there would be an adequate quantity of fireproof booms to collect the oil. Second, as cited in the Nuevo Energy Company *Oil Spill Response Plan* (Revised March 2002, Appendix E), California does not permit the burning of oil within state waters. Burning may be applied only in waters beyond 3 miles off the shore, which are under federal jurisdiction. Even there, EPA approval is required which might take some time to obtain. By then, burning might become ineffective as it is recommended to burn oil within the first 24 hours following a spill. Also, it might not be feasible to delay the oil spill cleanup as an oil slick might get out of control.

So, the only response option left is mechanical recovery. The DEIR must analyze whether existing mechanical recovery equipment is capable of handling a worst-case discharge of local highly viscous oil. Changes of oil properties due to weathering can be calculated manually or predicted using various numerical models (ADIOS for example). This model will determine oil properties over time, so one can predict the efficiency of recovery equipment. If oil becomes too viscous, mechanical recovery will also become inefficient.

The DEIR should identify which Clean Seas vessels and equipment would be utilized and what the response times would be to reach an oil spill from the proposed project. The DEIR should analyze how weather and sea conditions in the area may affect the response time. As mentioned above, delays in responding to a spill result in a less effective cleanup, both due to spreading or sinking of oil, as well as weathering effects on the oil.

The 1997 Torch oil spill provides relevant and recent information regarding the problems with oil spill response and cleanup. First, as a result of this spill, the California

[34] / Platforms Heritage/Harmony, CC-7-83, filed 1/5/83.
[35] / See also B.K. Trudel and R.C. Belore, et al., *Determining the Viscosity Limits for Effective Chemical Dispersion: Relating Ohmsett Results to Those from Tests At-Sea* (2005).

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Cont'd

Coastal Commission found that "the state-of-the-art is such that no equipment currently available has the capability to recover all oil from large spills and often even small spills in the open ocean."[36] The Commission noted that effective containment and cleanup of oil spills does not currently exist, as required by Coastal Act Section 30232. Second, some of the impacted sandy beaches and rocky areas were determined to be inaccessible and could not be cleaned for worker safety reasons.[37] As of November 13, 1997, oil remained on the beaches.[38]

The Torch spill also confirmed the fact that only a fraction of the oil spilled is typically recovered. In the Torch spill, an estimated 163 bbl were spilled,[39] but only 56 barrels were collected both offshore and onshore.[40] Thus, the majority of the oil reached shore. Once oil reaches the shore, it damages the environment, mixes with sediments and makes it very hard to recover and even harder to estimate the recovery efficiency. Onshore cleanup is a restoration, rather than preventive, measure. The inability of the response groups to prevent the oil slick from reaching shore and avoid consequent environmental damage proved true the data presented in literature showing that efficiency of mechanical recovery is very low in an open ocean environment.

Finally, response and cleanup operations themselves can cause significant additional impacts to the environment. The physical introduction of vessels, equipment and people in sensitive areas such as beach and rocky intertidal habitats can damage resources and wildlife. Chemical dispersants, hot water beach washes, and burning also cause environmental damage. According to Al Mearns of NOAA's Hazardous Materials Response and Assessment Division, the cleanup of the Exxon Valdez oil spill killed as many plants and animals as the original spill.[41]

The DEIR must consider the impacts of oil spill response on the environment. The DEIR must analyze the toxicity of the dispersants (see *Sound Truth & Corporate Myth$*), and the impacts to marine life that will occur when the oil is dispersed through the water column. For example, the Coastal Commission has previously recognized that Corexit, which has been consistently used to clean-up the oil spills, is more toxic than the

[36] / *Adopted Finding*, Application File No. E-97-23, filed November 18, 1997, p. 12.
[37] / Letter from Sean Morton, Planner, County of Santa Barbara Planning and Development, to Mr. David Rose, Torch Operating Company, dated October 22, 1997.
[38] / Letter from Sean Morton, Planner, and Roy Alexander, Hazardous Materials Specialist, County of Santa Barbara Planning and Development, to Mr. David Rose, Torch Operating Company, dated November 13, 1997.
[39] / In fact, as many as 1,250 barrels of crude oil may have spilled, meaning that less than 5% of the oil would have been recovered. (See *Complaint for Civil Penalties and Injunctive Relief; Santa Barbara County Board Agenda Letter re: 1997 Torch Oil Spill NRDA – Request to Governor Davis for Trustee*, prepared on May 7, 2003.)
[40] / *Complaint for Civil Penalties and Injunction*, supra; see also "*More than a year later, negotiators are left to clean up Torch oil spill,*" Lompoc Record, Dec. 27, 1998.
[41] / A.J. Mearns, *Exxon Valdez Shoreline Treatment and Operations: Implications for Response, Assessment, Monitoring, and Research, AFSS* 18:309-328, 1996, cited in *Sound Truth and Corporate Myth$*, supra.

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oil alone.[42] So, not only would the animals be injured by an oil spill, but the dispersant used to scour the spilt residue could be even more detrimental.

The DEIR should also consider the impacts of hot water washes. Current oil spill response plans continue to include these methods despite their demonstrated fatal impacts to shoreline wildlife.[43] Follow-up studies from the Exxon Valdez spill revealed the devastating environmental damage caused by hot water washes.[44]

EDC-32

Finally, *Sound Truth & Corporate MythS* points out the immediate and long-term public health impacts caused by oil spill response efforts.[45] Exxon Valdez oil spill response workers were injured by exposure to chemical dispersants, oil mists from pressurized hot water washes, fertilizers (for bioremediation), excessive diesel fumes, and toxic cleaning solvents (including Simple Green). During and immediately following the cleanup, workers suffered from headaches, nausea, dizziness, skin blisters and rashes. To this day, cleanup workers suffer from asthma, chemical sensitivities, recurrent headaches, respiratory problems, adrenal system damage, exhaustion, chronic sinus problems, pain, blood and kidney damage, and even cancer.

Inspections

EDC-33

The DEIR should analyze the effect that terminating MMS's Santa Maria inspection office may have on safety and environmental operations from the Tranquillon Ridge project. How have the frequency and scope of inspections changed as a result of the transfer of inspection responsibilities from the nearby Santa Maria office to offices in southern California?

Alternatives

The DEIR states that public safety impacts relating to the Casmalia processing site would be equal to or greater than for the proposed project. (DEIR, p. 5.1-58.) This determination appears inconsistent with the information presented in the North County Siting Study and fails to adequately analyze the benefits of siting gas processing in a rural location. (See comments above.)

[42] / Platform Harvest, CC-27-83, received 9/28/83, p. 26, citing *Acute Lethal Toxic of Prudhoe Bay Crude Oil and Corexit 9527 to Arctic Marine Fish and Invertebrates*, 1982; see also, e.g., *Nuevo Energy Company Oil Spill Response Plan for Platforms in the Santa Barbara Channel*, revised January 2002, Appendix D: Dispersant Use Plan.
[43] / See, e.g., *Nuevo Energy Company Oil Spill Response Plan for Platforms in the Santa Barbara Channel*, revised January 2002, Section 2.7.7.
[44] / *Sound Truth and Corporate MythS*, *supra*, and studies cited therein.
[45] / *Id.*, see *Part I: Sick Workers*.

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Cumulative Impacts

EDC-35

The DEIR states that it is too speculative to ascertain the cumulative safety impacts associated with development of the federal undeveloped leases. (DEIR, pp. 5.1-61, 62.) This cursory dismissal of a proper cumulative impact analysis is unacceptable for two reasons. First, contrary to the statement in the DEIR that development potential and impacts are not known, the MMS-commissioned COOGER Study provides a thorough list of all potential development activities, including the amount of oil and gas to be produced, over what period of time, and from which facilities. A cumulative impact analysis can certainly be developed from this information.[46]

EDC-36

Second, the DEIR fails to consider cumulative impacts from existing development projects. For example, the Point Arguello platforms and associated facilities are just to the south of the proposed project. In addition, there are other existing on- and off-shore oil and gas development projects within the affected region.

EDC-37

Finally, this section deals only with public safety impacts; however, a discussion of the cumulative impacts from oil spills on the environment must also be included.

5.2 TERRESTRIAL AND FRESHWATER BIOLOGY

The following comments set forth CEQA's requirements and identify specific areas where the DEIR fails to meet those requirements.

Environmental Setting

One of the major flaws of the DEIR is its failure to describe the terrestrial and freshwater biology environmental setting with enough detail to ensure an understanding of the significant environmental impacts of the project and alternatives as discussed throughout Section 5.2. As stated in the CEQA Guidelines, "[t]he environmental setting will normally constitute the baseline physical condition by which a lead agency determines whether an impact is significant." (Guidelines §15125(a).) An EIR must include a description of the physical environmental conditions in the vicinity of the project, as they exist at the time the notice of preparation is published. (*Id.*)

When the environmental baseline is not properly understood, environmental impacts cannot be properly assessed. As a result, there is no basis to determine whether avoidance is feasible or what mitigation measures are necessary to reduce significant impacts to the extent possible before a project can be approved, as required pursuant to CEQA Guidelines §§ 15002(a)(3) and 15021(a)(2). (See also Pub. Res. Code §21081(a)(3) and *Mountain Lion Foundation v. Fish and Game Commission* (1997) 16 Cal.App.4th 105, 134 [65 Cal.Rptr.2d 580].)

[46] / The COOGER Study is incorporated herein by reference.

EDC-38
Cont'd

As noted below, the DEIR fails to adequately portray the location and existence of sensitive species and native habitats due to a lack of habitat mapping and deferral of biological surveys.

Proposed pipeline and power line routes and other facilities are mapped in the DEIR. However, without maps identifying the locations of biological resources potentially impacted by the project, it is impossible for the public and decision-makers to understand where and to what degree species and habitats will be impacted. As one example, there is no information in the DEIR regarding surveying and mapping of native grasslands pursuant to the County Thresholds and Guidelines Manual definition of native grasslands (i.e., areas where native grassland species exceed 10% relative cover).

The DEIR defers surveys for sensitive species until after EIR certification and project approval. (See e.g., Mitigation TB-8.) Biological surveys to establish the environmental baseline consistent with standards set forth in the County's Environmental Thresholds and Guidelines Manual must be conducted prior to release of the DEIR in order to form the basis of the DEIR's environmental impact analysis. Absent an accurate description of the biological baseline environment, the DEIR and its impact analyses are deficient.

The DEIR also fails to identify all environmentally sensitive habitats as defined by the Santa Barbara County Local Coastal Plan and the California Coastal Act. The numerous native habitats described in Section 5.2 qualify as Environmentally Sensitive Habitat Areas (ESHA) as defined by Coastal Act Section 30107.5[47] and by the Local Coastal Plan. Specifically, Burton Mesa Chaparral, coastal scrub, chaparral, native grasslands (including the alkali rye grassland referenced on page 5.2-11), sandy beaches supporting rare species (e.g., western snowy plover and California least tern), foredune, oak woodland and oak savanna, native forests, wetlands and riparian habitats qualify as ESHA. These are areas where plant and animal life are rare and easily damaged by human uses and developments. The DEIR's description of the baseline setting should clarify that the aforementioned habitats are ESHA.

Specific Comments regarding Environmental Setting

Tidewater goby – proposed critical habitat in Santa Maria River

Page 5.2-3 of the DEIR should be updated to identify critical habitat for the tidewater goby recently proposed by the US Fish and Wildlife Service (e.g., the Santa Maria River).

[47] / The Coastal Act defines Environmentally Sensitive Area as "any area in which plant or animal life is either rare or especially valuable because of their special role or nature in an ecosystem and which could be easily disturbed or degraded by human activities and developments."

EDC-40

Steelhead – documented in Santa Maria River

Table 5.2-1 states that steelhead "may" use the Santa Maria River. The DEIR notes that NOAA designated critical habitat for steelhead within the Santa Maria River. NOAA only designated critical habitat for steelhead in waterways occupied by steelhead. For internal consistency and accuracy, Table 5.2-1 of the DEIR should clarify that steelhead occupy the Santa Maria River.

EDC-41

Failure to Describe all Rare, Threatened and Endangered Plant Species

Section 5.2.1.3 "Rare, Threatened and Endangered Species" describes seven plant species on pages 5.2-21 through 5.2-24. However, Table 5.2-1 lists 23 species that are Rare, Threatened or Endangered as defined in the DEIR. Table 5.2-1 lists "sources" including the California Native Plant Society's (CNPS) List "1B" species. Table 5.2-1 defines the "1B" species as "rare, threatened or endangered in California and elsewhere." All 23 plant species in Table 5.2-1, including CNPS List 1B species, are rare, threatened and endangered plant species pursuant to CEQA and should be described in Section 5.2.1.3 of the DEIR.

EDC-42

Failure to Describe all Rare, Threatened and Endangered Wildlife Species

Section 5.2.1.3 of the DEIR describes only eleven "Rare, Threatened and Endangered" wildlife species. However, Table 5.2-1 lists 26 Sensitive Wildlife Species, including 14 that are not state or federally listed but are (a) State Species of Concern or (b) on the Special Animals List tracked by the state of California Natural Diversity Database. County practice under CEQA has been to include State Species of Concern within the definition of "rare, threatened or endangered." Section 5.2.1.3 should therefore be amended to describe all potentially affected wildlife species considered under CEQA to be rare, threatened or endangered, including state Species of Concern.

Consideration and Discussion of Environmental Impacts

As stated above, impacts should be measured against the existing environmental setting. In many instances, the Tranquillon Ridge DEIR fails to measure the impacts against the existing environmental setting because the setting is inadequately documented or described.

In addition, the DEIR fails to analyze impacts to all affected rare, threatened and endangered plant and wildlife species, as stated above.

The DEIR also misclassifies some impacts by improperly concluding that they can be mitigated to less than significant.

The following discussion addresses specific deficiencies in the DEIR's analysis of project impacts.

Impact TB.3 – Impacts of Pipeline Repair and Maintenance on Vegetation and Wildlife

The DEIR finds that the impacts of pipeline maintenance and repair on native vegetation, wildlife habitat, and erosion and sedimentation can be mitigated to below a

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level of significance (Class II). These impacts would be extended over time due to the longer project life proposed. The DEIR states that "long segments of the corridor have become colonized with non-native species or remain unvegetated as fuel breaks." However, page 5.2-12 of the DEIR notes that the environmental baseline is changing and some portions of the pipeline corridor are being recolonized by native habitats and plants. Given the changing baseline and deferral of sensitive species surveys until after project approval, it is impossible to determine whether impacts from pipeline maintenance and repair can be mitigated to less than significant. These surveys must occur prior to the DEIR's impact analysis in order for the DEIR to identify the locations of - and impacts to - rare, threatened and endangered species and habitats.

EDC-44

Impact TB.4 – Impacts of Pipeline Repair on Sensitive Plant Species

Biological surveys and mapping of habitats and sensitive species along the pipeline corridors must be completed to adequately describe the existing environmental setting. Only then can the DEIR analyze impacts to rare, threatened and endangered plant and wildlife species. Mitigation TB-8 requires pre-construction (i.e., post-EIR certification) surveys for rare plant species. However, these surveys are needed to define the DEIR's environmental setting and cannot be deferred until after EIR certification and project approval as currently proposed.

Impact TB.4 is limited to impacts to "state or federally listed plant species." As noted in the DEIR on page 5.2-20, CEQA recognizes the possibility that some species which are not yet federally or state listed may also be rare, threatened or endangered. The DEIR recognizes and lists in Table 5.2-1 species which are considered rare under CEQA but which are not state or federally listed. The DEIR fails, however, to analyze impacts to species which are not state or federally listed, but which are rare as defined under CEQA. The DEIR's analysis of impacts to rare, threatened and endangered plant species is therefore incomplete and flawed.

Impact TB.5 – Impacts of Pipeline Repair and Maintenance on Sensitive Wildlife Habitat

The DEIR analyzes impacts to the aquatic habitat of the endangered California Tiger Salamander (CTS) but excludes an analysis of impacts to the CTS' terrestrial habitat. The CTS spends virtually all of its life in terrestrial burrows created by ground squirrels and other burrowing species. Only briefly during the rainy season do CTS leave the burrows to breed in aquatic habitats. The DEIR is inadequate for analyzing impacts to the aquatic habitats of the CTS while not analyzing impacts (e.g., from power poles and the pipelines) to the CTS terrestrial habitats.

Section 5.2.4 – Recolonization of Pipeline Corridor by Native Plants

The first statement in Section 5.2.4 of the DEIR indicates that "only installing the power line to Valve Site #2 and constructing the new transformer station would include disturbances outside of an existing pad or disturbed area." However, DEIR pages 5.2-11 and 5.2-12 describe how formerly disturbed areas where existing project-related pipelines were installed are being recolonized by native plants. The DEIR states that the pipeline corridor within the oil field is "largely vegetated." The DEIR also notes that the area in the corridor is "slowly recovering and cover of non-native species is very low."

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EDC-46 Cont'd

Therefore, the DEIR should be amended to note that in addition to the power line to Valve Site #2 and constructing the new transformer, some of the project's future pipeline replacement associated with the extended project life would occur in areas of natural habitat.

EDC-47

Section 5.2.4.1 – Avoidance of Cultural Resources and Habitats outside Work Area

Page 5.2-37 of the DEIR states that if cultural resources sites are discovered during the proposed project, ground disturbance and excavation could occur outside the construction right-of-way and beyond the project boundaries. Excavation beyond the project boundaries appears to unnecessarily cause impacts to terrestrial and freshwater biological resources. Why would excavation need to occur outside the project boundaries if cultural resource sites in areas outside the project boundaries are discovered during the project? If cultural resources are located outside the project boundaries, cultural resources can (and should) be avoided.

EDC-48

Power Pole Treatment

The DEIR does not describe whether the power poles will be treated with any materials to make them more resistant to weathering and decomposition. Some power pole treatments may have the potential to result in impacts to biological resources. The DEIR should clarify whether the poles will be treated, and if so, what potential biological effects, if any, may result from such treatment.

Impact TB.6 – Spill Impacts to Vegetation and Wildlife

Page 5.2-49 of the DEIR contains the following statements which are unsupported: (1) "The oil would be highly dispersed by the time it reached shore, leading to the deposition of relatively small amounts of oil at any given location, but over large areas;" and (2) it is "very unlikely that an offshore oil spill would directly impact freshwater (or brackish/estuarine) aquatic habitats, as this would only occur if oil were driven ashore above the high tide line by wind and high tides, and similarly driven upstream at an open tidal inlet during flood tide and low-outflow conditions." …" In the project area, dominant west winds would push the oil directly to shore and into tidally influenced bays and estuaries. The statement in the DEIR is at odds with the fact that the 1997 oil spill from the Platform Irene offshore pipeline reached shore and damaged not only the beach at VAFB, but also the Santa Ynez River, San Antonio Creek and Honda Creek estuaries.[48]

Impact TB.6 should include an analysis of how an onshore or offshore oil spill and subsequent cleanup may impact the seed bank at an impacted location. Such analysis should include an assessment of whether such areas may be subject to invasion by non-native plants as an indirect result of the spill and cleanup efforts.

[48] *Santa Barbara County Board Agenda Letter, prepared on 11/25/97 regarding "Update on the Torch Oil Spill;" Santa Barbara County Board Agenda Letter, prepared on 5/7/03 regarding "1997 Torch Oil Sppill NRDA – Request to Governor Davis for Trustee."*

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EDC-51

Finally, the residual Impact TB.6 described on page 5.2-53 is described too narrowly. The discussion includes reference to the impacts of oil spills to "riparian, wetland, and aquatic habitats." However, other native habitats including native grasslands, oak woodlands and savannas, chaparral, and coastal scrub habitats are also significantly impacted by oil spills and cleanups.

EDC-52

Section 5.2.6 Cumulative Impacts and Mitigation Measures

The DEIR's cumulative impact analysis fails to include all projects impacting the terrestrial and freshwater biological resources of the project area. For instance, the cumulative project list presented in Section 4.4 fails to include the Bee Rock Quarry Expansion currently undergoing Santa Barbara County Planning Commission review. The DEIR also fails to consider the significant impacts of the State Water Resources Control Board's Cachuma EIR, currently being revised by the state. The Bee Rock Quarry and the Cachuma Project impact terrestrial and freshwater biological resources which will also be impacted by Tranquillon Ridge, including species in and along the Santa Ynez River.

Consideration and Discussion of Mitigation Measures Proposed to Minimize Significant Effects

EDC-53

The DEIR for the Tranquillon Ridge Project fails to include substantial evidence demonstrating that the proposed mitigation measures are sufficient to lessen certain terrestrial and freshwater biological resource impacts to less than significant. Moreover, the DEIR improperly defers preparation of specific mitigation plans and lacks performance standards to ensure successful mitigation. As a matter of law, an agency cannot defer consideration or adoption of mitigation measures to a later date. (CEQA Guidelines §15126.4(a)(1)(B); *Kings County Bureau v. City of Hanford* (1990) 221 Cal.App.3d 692 [270 Cal.Rptr. 650]; *Sundstrom v. County of Mendocino* (1988) 202 Cal.App.3d 296 [248 Cal.Rptr. 352].) Deferral may be allowed in limited instances, provided there is a reasonable expectation of effectiveness and compliance based on a requirement that the measure meet specific performance standards that are identified in the EIR. (*Endangered Habitats League, Inc. v. County of Orange* (2005) 131 Cal. App.4th 777 [32 Cal. Rptr.3d 177].)

As stated below, the DEIR's Terrestrial and Freshwater Biology section fails to comply with the mandates for CEQA with respect to the proposed mitigation measures for the Tranquillon Ridge Project.

Specific Comments Regarding Terrestrial and Freshwater Biology Mitigation Measures

Measure TB-1 – Improperly Defers Baseline Surveys

As noted above, specific locations of sensitive plant species have not been surveyed and documented in the DEIR. Mitigation Measure TB-1 includes a requirement for pre-construction surveys for some sensitive plant species. However, surveys must be undertaken prior to release of the DEIR in order to inform the DEIR's analysis of impacts

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EDC-53 Cont'd

and mitigation measures. Biological surveys must not be deferred until after project approval as proposed in the DEIR.

EDC-54

Measure TB-2 – Improperly Defers Power Pole Impact and Mitigation Analysis

Measure TB-2 is intended to reduce impacts to raptors by using "raptor-safe" pole designs and implementing other precautionary measures. The last provision of this measure on page 5.2-39 defers determining whether "the pole lines are of a type that raptors might nest on." The pole type should be described as part of the project description so that impacts can be analyzed and so that mitigation measures can be assigned in the DEIR to reduce significant impacts. The analysis of the power pole type and impacts must be undertaken in the context of the DEIR so that "the feasibility of fitting the poles with 3 ft. by 3 ft. nesting platforms a minimum of 4 feet above the tops of the poles as recommended by the California Department of Fish and Game" can be ascertained during the environmental review for this project and not after EIR certification and project approval.

EDC-55

Measure TB-3 – Fails to Identify Schedule for Pre-Construction Surveys

Mitigation Measure TB-3 requires pre-construction surveys to identify wildlife species that may be present in the work area for the purposes of removing them prior to construction. These surveys, while important to lessen project impacts, are not a substitute for surveys needed to adequately define the environmental baseline in the DEIR. Additionally, Measure TB-3 fails to specify how long prior to construction these surveys must occur. If this time period is too long, the mitigation will be ineffective because animals would have time to reenter the work area and be impacted by project activities. Pre-construction surveys must occur immediately prior to construction in each particular work area. Pre-construction surveys pursuant to this mitigation measure should be explicitly required to occur the morning of the day of construction to minimize the possibility that additional (or the same) wildlife individuals may enter (or reenter) the project site prior to construction and be impacted by construction.

EDC-56

Measure TB-4 – Fails to Feasibly Avoid Potentially Significant Erosion and Sedimentation Impact

Mitigation Measure TB-4 fails to mitigate significant Impacts TB.2 and TB.5 to the maximum extent feasible because Measure TB-4 allows construction to occur during the rainy season if a County-approved erosion and sediment control plan is in place.[49] The erosion and sediment control plan is not included in the DEIR as a mitigation measure for public scrutiny, and is instead improperly deferred without performance standards until after EIR certification and project approval. The DEIR states that construction of power lines to Valve Site #2 is expected to take 14 weeks. Construction of power lines to Valve Site #2 can therefore feasibly be scheduled to avoid the rainy season and thus to avoid impacts of erosion and sedimentation of nearby creeks and

[49] / Page 5.2-46 mischaracterizes Measure TB-4 as "scheduling the work during the dry season." However, Measure TB-4 inadvisably allows work during the rainy season despite the fact that work could be feasibly accomplished during the dry season to avoid impacts related to erosion and sedimentation.

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EDC-56 Cont'd

rivers. Similarly, pipeline replacement can be scheduled to avoid the rainy season. Therefore, Measure TB-4 should require that "All ground disturbances for power pole and power line installation and for pipeline maintenance and repair shall occur during the dry season (April 1 through November 1)."

EDC-57

Measure TB-5 – Improperly Defers Erosion and Sediment Control Plan and Lacks Performance Standards

Mitigation Measure TB-5 improperly defers preparation of erosion and sediment control plans until after EIR certification and project approval. Mitigation Measure TB-5 should be amended to include the erosion and sediment control plan or at least specific performance standards to ensure success of the measure.

EDC-58

Measure TB-6 – Improperly Defers Standard Maintenance and Repair Plan without Performance Standards

The DEIR defers mitigation plans for restricting work areas to avoid areas of biological significance. Mitigation Measure TB-6 requires a Standard Maintenance and Repair Plan including biological surveys, identification of work areas, and identification of areas to avoid, and identification of ways to minimize biological impacts, including scheduling of work – all after the EIR has been certified and the project has been approved. In order to adequately and reliably mitigate impacts to below a level of significance, Measure TB-6 should itself identify work areas, avoidance areas, means to minimize biological impacts and scheduling of work. Absent requirements to mitigate Impact TB.3 below a level of significance (i.e., identification of specific work areas and avoidance areas, and identification of measures to reduce impacts including scheduling), Mitigation Measure TB-6 is inadequate and does not justify finding Impact TB.3 less than significant (Class II).

EDC-59

Measure TB-7 – Improperly Defers Habitat Revegetation, Restoration and Monitoring Plan and Lacks Performance Standards to Ensure Success of Mitigation

Mitigation Measure TB-7 defers development of a Habitat Revegetation, Restoration, and Monitoring Plan until after EIR certification and project approval. Measure TB-7 lists elements to be included in the Habitat Revegetation, Restoration, and Monitoring Plan but lacks performance standards to ensure success of Mitigation Measure TB-7. In fact, the sixth bullet point on page 5.2-43 notes that no "minimum performance criteria" have yet been developed for this mitigation measure and defers identification of performance criteria for Mitigation Measure TB-7 until after EIR certification and project approval, in violation of CEQA.

EDC-60

Mitigation Measure TB-7 also fails to include a requirement that every native habitat potentially impacted (i.e., described on pages 5.2-10 through 5.2-17) be addressed by the Habitat Revegetation, Restoration, and Monitoring Plan. Measure TB-7 is therefore inadequate under CEQA and similarly unreliable to lessen Impact TB.3 to a level below significant.

EDC-61

In addition, Measure TB-7 does not include or require a propagation, planting and maintenance plan for every rare, threatened or endangered plant species potentially

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EDC-61 Cont'd

impacted (i.e., in Table 5.2-1). As a result, Measure TB-7 lacks requirements that would potentially lessen impact TB.3 to a level below significant.

EDC-62

The fourth bullet point on page 5.2-43 requires the deferred Habitat Revegetation, Restoration, and Monitoring Plan to include "procedures for timely" "restoration of native communities and native plant species," and "replacement of trees at the appropriate rate." However, Measure TB-7 does not specify what ratios impacted habitats and trees must be replaced at (a standard performance criteria for habitat restoration mitigation measures). In many EIRs, mitigation measures for habitats and trees specify the replacement ratio (i.e., 3:1 for habitat acres and 10:1 for trees). By failing to specify these performance standards, Measure TB-7's inadequacy under CEQA is heightened.

EDC-63

Measure TB-7's fifth bullet point requires the Habitat Revegetation, Restoration, and Monitoring Plan to identify procedures for restoration of riparian corridor stream banks and streambed substrates but improperly defers (without performance standards) identification of these procedures until after EIR certification and project approval.

EDC-64

Measure TB-7's first bullet point (second sentence) uses the word "should" instead of "shall." As a result, the procedures for stockpiling and replacing soil and "provisions for recontouring to approximate the original topography" are not required. Furthermore, the first bullet point under Measure TB-7 on page 5.2-43 fails to identify areas for stockpiling topsoil for later reuse. If stockpiles are located in areas of biological value, stockpiling topsoil would further degrade the biological environment. Measure TB-7 must therefore identify locations for stockpiling and correct the aforementioned shortcomings. Absent these corrections, Measure TB-7 does not reduce Impact TB.3 to a level below significant.

EDC-65

Measure TB-9 – Improper Deferral of Seed Collection and Plant Salvage Scheduling

In addition to Mitigation Measure TB-8's deferral of surveys needed to define the environmental baseline (described under *Impact TB.4 – Impacts of Pipeline Repair on Sensitive Plant Species* above), Mitigation Measure TB-9 (the other mitigation measure intended to reduce Impact TB.4) fails to ensure Impact TB.4 will be reduced to a level below significant. Specifically, Measure TB-9 requires utilization of seed and salvaged plants to perpetuate the genetic lines represented on the impacted sites. While an important goal that should be required, nothing in Measure TB-9 requires that pre-construction surveys will identify areas of rare, threatened or endangered plants in time to collect seeds and to salvage plants. Seed collection is seasonal. If the pre-construction surveys for rare, threatened and endangered plants occur at a time when plants are not seeding and construction is imminent, there will not be adequate time for the plants to produce seed and for workers to collect seeds from the plants prior to construction. Similarly, plant salvage is best done in the fall for most perennial species. Measures TB-7, TB-8 and TB-9 fail to require pre-construction surveys scheduled long enough ahead of construction to identify rare, threatened and endangered plant species and to subsequently collect seeds and salvage plants prior to construction.

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EDC-65

Measure TB-9 also fails to include performance criteria to ensure success of the measure. The description of Measure TB-9 on pages 5.2-44 and -45 explicitly defers identification of performance standards until after EIR certification and project approval. Moreover, Measure TB-9 improperly defers approval of the propagation and revegetation plans to the USFWS and CDFG – neither of which are the CEQA lead agency for this project.

EDC-66

Measure TB-10 – Failure to Schedule Work to Avoid Breeding Season of all Sensitive Species

Measure TB-10 limits work to avoid the breeding season of the western snowy plover and California least tern (March 1 through September 30). While we support Measure TB-10, this mitigation measure lacks limits to avoid the breeding seasons of other rare, threatened and endangered species potentially impacted by pipeline repair and maintenance, including for example the CTS and steelhead (Impact TB.5).

EDC-67

Core Oil Spill Response Plan (OSPR)

Page 5.2-52 of the DEIR notes that PXP has prepared a Core Oil Spill Response Plan (OSRP). The DEIR augments this plan with Measures TB-11, TB-12 and TB-13. The OSRP should be included in this draft ERIR as part of the mitigation plan.

The DEIR notes on page 5.2-52 that "these mitigation measures apply to the proposed project pipeline sections only." There is some level of ambiguity regarding whether existing lines which will convey project oil are considered part of the proposed project analyzed in the DEIR. Do the "proposed project pipeline sections" include all sections of pipeline described in Section 2.2.4 and all sections of pipeline that Tranquillon Ridge oil would flow through?

Measure TB-11 – Deferral of Update to Oil Spill Response Plan and 2005 Supplement

Mitigation Measure TB-11 requires that the OSRP and the July 2005 Supplement be revised and updated to address increased potential spill volumes and updated procedures for spill response beneath ground and in rivers and streams. Measure TB-11 requires only that this updated plan be approved by Santa Barbara County P&D prior to construction. Since this measure is so important for lessening the Class I oil spill impacts, it must not be deferred until after EIR certification. The updated OSRP (or at least the specific measures for spill containment along watercourses and the specific measures to avoid impacts to threatened and endangered[50]) must be included in Measure TB-11 to ensure effectiveness of the mitigation measure as required under CEQA.

[50] / Measure TB-11 is limited to mitigating impacts to state and federally-listed species. In order to mitigate the significant Class I Impact TB.6 further, Measure TB-11 must be revised to include measures to avoid all rare, threatened and endangered species as defined under CEQA and in this DEIR.

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EDC-70

Measure TB-12 – Improperly and Ambiguously Limits Mitigation to a Subset of Sensitive Wildlife Species and to a Subset of Plant Communities

Measure TB-12 lacks verbiage to ensure mitigation of impacts to all native plant communities and all sensitive wildlife species. In failing to specify that impacts to all sensitive species and to all plant communities would be mitigated, Measure TB-12 improperly defers mitigation without including performance standards to ensure successful mitigation of all sensitive wildlife species and plant communities. In order to ensure that the significant impacts from oil spills are mitigated to the maximum extent feasible, Mitigation Measure TB-12 should be amended in the following way:

> Where disturbance to any native habitats ~~disturbance~~ cannot be avoided as determined by a P&D approved biologist, the November 2003 Core Oil Spill Response Plan and July 2005 Supplement shall be updated to provide stipulations for development and implementation of site-specific measures appropriate for mitigating impacts on local populations of all sensitive wildlife species and to restore all native plant and animal communities to prespill conditions. Access and egress points, staging areas, and material stockpile areas that avoid sensitive habitats shall be identified. The Core Oil Spill Response Plan and its Supplement shall include species- and site-specific procedures for collection, transportation, and treatment of ~~oiled~~ all potentially affected native wildlife ~~particularly~~ including sensitive species. The plan shall be reviewed by federal, state and local agencies identified in Measure TB-11 prior to certification of the final EIR and approval by the lead agencies.

Measure TB-13 – Improperly Defers Low-Impact Site Clean Up Measures

The DEIR's Mitigation Measure TB-13 should also be amended to "develop low-impact site-specific clean up procedures" *before* certification of the final EIR. Deferring development of such clean up procedures (and performance standards) until after EIR certification and project approval as proposed violates the spirit and law of CEQA.

In addition, to ensure the Class I impact of oil spills to native habitats (Impact TB.6) is mitigated to the maximum extent feasible, Measure TB-13's requirement to evaluate the "non-clean up option" should apply to all native habitats, not merely those considered "ecologically vulnerable habitats such as estuaries."

Measure TB-14 – Proposed Oil Spill Response Drills are too Infrequent to be Effective

Mitigation Measure TB-14 requires that the applicant develop and implement a spill response training program. Measure TB-14 requires that drills be conducted at least annually. However, to be effective mitigation, drills should be undertaken at least twice per year so personnel are familiar with the equipment and the project area, including habitats.

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Proposed Mitigation TB-14.5 – Requirement to Clean, Rehabilitate and Release Oiled Wildlife

EDC-74

Currently, no proposed mitigation measure requires that all oiled wildlife is cleaned and released. The DEIR should require that "All oiled wildlife shall be treated, cleaned, rehabilitated as necessary, and released."

Impact Analysis for Alternatives

EDC-75

The DEIR states that the VAFB Onshore Alternative would increase significant impacts to terrestrial and aquatic habitats associated with onshore oil spills and oil spill clean ups. These impacts should be compared to those caused by offshore *and* onshore spills that may result from the proposed project.

EDC-76

The DEIR states that oil spill impacts from operations (TB.6, 7 and 8) would be similar for the proposed project and the onshore alternative. (DEIR, p. 5.2-59.) However, the DEIR fails to acknowledge that offshore oil spills tend to be larger and much more difficult to respond to. Hence, the damage is usually greater. For example, even though the 1997 Torch pipeline spill occurred offshore, it affected 40 miles of coastal habitats and resources.

EDC-77

The relative environmental impacts of drilling under the Santa Ynez River and other watercourses, of trenching to underground power lines, and of power poles across the river and other watercourses should be explored in more detail in the DEIR.

5.5 MARINE BIOLOGY

5.5.4 Impact Analysis

Oil Spill

Abalone Species

EDC-78

The DEIR states that oil spill modeling demonstrated an estimated 30 percent chance that San Miguel and Santa Rosa Islands could be affected by an oil spill at the proposed Project. (DEIR, p. 5.5-34.) On the next page, apparently ignoring this remarkably plausible if nightmarish scenario, the DEIR acknowledges that an oil spill could impact abalone species, but suggests that red abalone would be "the only benthic species" that would likely occur in the area "to be impacted in the event of an oil spill." (DEIR, p.5.5-35.) Despite discussing the presence of the highly critically imperiled black and white abalone species at the Channel Islands, the latter of which is federally listed under the Endangered Species Act (DEIR, pp. 5.5-21 and 5.5-24, respectively), the DEIR omits discussion of how these species would be impacted by a Tranquillon Ridge oil spill that reaches the Channel Islands. Given the tenuous survival of these species, the nearly 1 in 3 chance that an oil spill reaches black and white abalone habitat at the Channel Islands represents unacceptable risk that must be fully disclosed and mitigated.

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Sea Otters

EDC-79

Oil spills are the primary threat to the survival and recovery of the southern sea otter. The southern sea otter is listed as "threatened" under the Endangered Species Act ("ESA"), and is therefore also recognized as depleted under the Marine Mammal Protection Act ("MMPA").[51] The southern sea otter is also listed as a "Fully Protected Species" in California.[52]

The southern sea otter population was listed as threatened in 1977 because of (1) its small size and limited distribution, and (2) potential jeopardy to the remaining habitat and population by oil spills.[53] Both the original (1982) and the Revised (2003) Southern Sea Otter Recovery Plans consider a potential oil spill to be the primary threat to sea otter recovery.[54] As stated in the Final Recovery Plan, "Oil spills, which could occur at any time, could decimate the sea otter population."[55] The Recovery Plan concludes that (a) an oil spill is likely to occur over the next 30 years (the same period during which the Tranquillon Ridge Field would be developed)[56]; (b) the probability of death in sea otters as a result of contact with oil following an oil spill is likely to be no less than 50 percent[57]; and (c) rehabilitation of oiled sea otters following a major spill is expensive, may be detrimental to some individuals and is of questionable benefit to the population.[58] The Recovery Plan notes that after the Exxon Valdez spill, most oiled otters were not captured and saved.[59]

Major factors contributing to the mortality of oiled sea otters appear to be 1) hypothermia, 2) shock and secondary organ dysfunction, 3) interstitial emphysema, 4) gastrointestinal ulceration, and 5) stress during captivity.[60] Sea otters are incredibly susceptible to oil pollution. They can be killed outright when their fur is fouled by oil. Otters have no blubber; their fur is their only insulation, thus when crude oil penetrates

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[51] / *Final Revised Recovery Plan for the Southern Sea Otter*, U.S. Fish and Wildlife Service, 2003, hereinafter referred to as "Recovery Plan," attached hereto.
[52] / CA Fish and Game Code §4700(b)(8).
[53] / 42 FR 2965, 1/14/1977.
[54] / Recovery Plan, pp. vi, 10.
[55] / Recovery Plan, p. viii.
[56] / Recovery Plan, p. 10.
[57] / Recovery Plan, Appendix C: "*Using Information About the Impact of the Exxon Valdez Oil Spill on Sea Otters in South-Central Alaska to Assess the Risk of Oil Spills to the Threatened Southern Sea Otter Population*," Allan J. Brody for U.S. Fish and Wildlife Service Southern Sea Otter Recovery Team, Ventura, California, September 1, 1992.
[58] / Recovery Plan, pp. 10, 20 – 26, Appendix B: "*Potential Impacts of Oil Spills on the Southern Sea Otter Population*," Final Report prepared for U.S. Fish and Wildlife Service, R. Glenn Ford and Michael L. Bonnell, January 1995.
[59] / *Id.*
[60] / T.M. Williams et al, *Emerging Care and Rehabilitation of Oiled Sea Otters: A guide for Oil Spills Involving Fur-Bearing Marine Mammals, Chapter 1 – The Effects of Oil on Sea Otters: Histopathology, Toxicology, and Clinical History* (1995).

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the fur and destroys its water repellency,[61] oiled sea otters can become mortally hypothermic. Sea otters can also die from ingesting the oil. This may happen in two ways: they lick the oil off their fur, and/or they eat contaminated prey animals.

Recommendations to limit oil and gas development are key to the Recovery Plan (see, e.g., "Actions Needed" in the Executive Summary: "Protect the population and reduce or eliminate the identified potential limiting factors related to human activities, including: managing petroleum exploration, extraction, and tankering to reduce the likelihood of a spill along the California coast to insignificant levels."[62])

New research from the Exxon Valdez spill reveals not only the short-term, but also the long-term effects of oil spills on sea otters.[63] Modeling suggests that an oil spill the size of the Exxon Valdez could impact 90% of the current southern sea otter population with a minimum (immediate) range-wide mortality of 50 percent.[64] Past efforts to minimize potential effects of an oil spill by relocating otters to San Nicolas Island have proven unsuccessful.[65]

In addition to being protected under the ESA, the otter is listed as depleted under the MMPA. Depleted species and their habitat are afforded extra legal protection. To be de-listed under the MMPA the population needs to be at the "optimum sustainable population," defined in the MMPA as "the number of animals which will result in the maximum productivity of the population or the species, keeping in mind the carrying capacity of the habitat and the health of the ecosystem of which they form a constituent element."[66] According to the otter Recovery Plan, the lower limit of the optimum sustainable population is estimated to be approximately 8,400 individuals.[67] As identified in the DEIR, the current population level of the Southern sea otter is estimated at 2692 as of May, 2006. Critically, otters appear to be declining offshore California — the 2004 otter census counted 2825 individuals. (DEIR, p.5.5-12.) Because the otter population appears to be in decline, and because the current population is still at a fraction of the lower estimate for optimum sustainable population, recovery of this

[61] / See T.M. Williams, *supra,* Chapter 5.
[62] / Recovery Plan, page x.
[63] / C.H. Peterson et al, *Long-Term Ecosystem Response to the Exxon Valdez Oil Spill*, Science 302: 2082-2086 (2003); B. Ballachey et al, *Correlates to survival of juvenile sea otters in Prince William Sound, Alaska, 1992–1993*, Can.J. Zool. 81: 1494–1510, 2003; J.L. Bodkin et al, *Sea Otter population status and the process of recovery from the 1989 'Exxon Valdez' oil spill,* Mar Ecol Prog Ser. 241:237-253, 2002; R.A. Garrott et al, *Mortality of sea otters in Prince William Sound following the Exxon Valdez oil spill,* Marine Mammal Science 9:343-359, 1993; D.H. Monson et al, *Long-term impacts of the Exxon Valdez oil spill on sea otters assessed through age-dependent mortality patterns*, Proc. Natl. Acad. Sci. U.S.A. 97: 6562-6567, 2000.
[64] / Recovery Plan, pp. 20, C-2; A.J. Brody, et al, *Potential impacts of oil spills on California sea otters: Implications of the Exxon Valdez in Alaska,* Marine Mammal Science 12:38-53, 1996.
[65] / Recovery Plan, pp. 13–14, 20–22.
[66]/ 16 U.S.C. §1362(9).
[67] / Recovery Plan, p. vi.

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keystone species remains far from assured. Major protections are still needed and required by law.

The Recovery Plan for the Sea Otter identified two approaches that were intended to lead to the delisting of the otter under the ESA: (1) increasing the range of the sea otters in California to lessen the risk of a single oil spill event reducing the otter population below a viable level, and (2) decreasing the likelihood of a major oil spill event within the sea otter's range.[68] Range expansion into the Southern California Bight and the Santa Barbara Channel is critical to the recovery of the Southern sea otter. According to the July 2000 final Biological Opinion, *Reinitiation of Formal Consultation on the Containment Program for the Southern Sea Otter,* 1-8-99-FW-81, "the best available information indicates that continued, passive expansion of the range of the southern sea otter is necessary for its survival and recovery" (page 31). The literature suggests that colonization in the Channel and at the Channel Islands is critical to the survival and recovery of the sea otter.[69]

New demographic and radio tagging research also emphasizes the importance of southward expansion range. Sea otters have been observed south/east of Point Conception, in substantial numbers, since 1998.[70] Unfortunately, because the population actually appears to be dropping at present, their increased dispersal into the Point Arguello/Platform Irene project area may suggest that the remaining population face an increased threat of extinction due to oil spill should the proposed Project be allowed to proceed for its estimated 30 years. In other words, if a greater percentage of the southern sea otter population is tending to inhabit the project area, the identified threat of oil spill from the Tranquillon Ridge project represents an increasingly dangerous threat to southern sea otter recovery, or even survival.

In sum, the area containing the Tranquillon Ridge Field is critical to the recovery of the southern sea otter. The only solution that will adequately protect the sea otter, and ensure its recovery, is to facilitate the restoration of the southern extent of the sea otter species' historical range and prohibit any further oil development in this area.

Pinnipeds

Table 5.5.5 presents "Pinnipeds of the Eastern North Pacific and Their Status Off California (adapted from Bonnel and Daily, 1993)" and states: Northern fur seal (*Callorhinus ursinus*), "Common, year-round resident." (DEIR, p. 5.5-11.) Just below this table, the body text appears to contradict this, strangely describing the population dynamics of the project area's northern fur seals as reaching "their peak in winter and spring, as migrants from the Bering Sea" [sic]. (*Id.*).

[68] / Recovery Plan at pp. vi, 28, Appendix D-11, 12.
[69] / See, for example, K. Laidre, et al, *An Estimation of Carrying Capacity for Sea Otters Along the California Coast*, Marine Mammal Science 17(2):294-309, April 2001.
[70] / Recovery Plan, p. 3; California Department of Fish and Game, and US Fish and Wildlife Service, unpublished data; The Otter Project, personal communication.

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In fact, according to NOAA's Office of Protected Resources, "the population of northern fur seals on San Miguel Island originated from the Pribilof Islands (Bering Sea) population during the late 1950s or early 1960s," while today, "two separate stocks of northern fur seals are recognized within U.S. waters: an Eastern Pacific stock [centered around the Pribilof Islands] and a San Miguel Island stock."[71]

Given that the Northern fur seals of San Miguel Island are classified by NOAA Fisheries as a distinct stock in relation to the total species population, the EIR should not equivocate on the fact that this stock centers at San Miguel Island, and locates its reproductive activity there alone. Given the acute threat that oil spills from the proposed Project pose to pinnipeds in the project area and breeding at the Channel Islands, it is vital that the DEIR accurately describe the populations and the population dynamics of these animals.

EDC-80
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This data has important implications for the DEIR and the proposed Project. First, the geographic exclusivity of the San Miguel Island stock of Northern fur seals leaves it particularly vulnerable to impact from Tranquillon Ridge oil spills, and the DEIR must face the ecological and legal implications of this reality head-on. NOAA Fisheries calculated the 2006 potential biological removal (PBR) of Northern fur seals of the San Miguel stock as 219.[72] The Exxon Valdez oil spill in 1989 resulted in the loss of an estimated 302 harbor seals from Prince William Sound, demonstrating that relatively large scale die-offs of pinnipeds (at numbers exceeding the current PBR for Northern fur seals) can be caused by oil spills, especially if they occur in areas that feature breeding and haul out sites.[73]

The DEIR admits that a Tranquillon Ridge oil spill has a nearly 1 in 3 chance of reaching San Miguel Island (DEIR, p.5.5-34), a site that is of critical importance to reproduction for Northern fur seals and other pinnipeds.

The DEIR also makes several other important disclosures with respect to how pinnipeds are documented to interact with— and be adversely affected by— oil spills. For example, the DEIR states:

> *Although seals apparently have the ability to detect and avoid oil slicks, Cowell reported that breeding seals swam through oil to reach rookery beaches during the breeding season.* [DEIR, p. 5.5-38.]

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[71]/ Carretta, J.V., K.A. Forney, M.M. Muto, J. Barlow, J. Baker, Brad Hanson, and M. Lowry. 2006. *U.S. Pacific Marine Mammal Stock Assessments: 2005.* U.S. Department of Commerce, NOAA Technical Memorandum NMFS-TM-SWFSC-388. 317p.
[72]/ *Id.*
[73]/ Loughlin, T.R., B.E. Ballachey and B.A. Wright. 1996. "Overview of studies to determine injury caused by the Exxon Valdez oil spill to marine mammals." In: S.D. Rice, R.B. Spies, D.A. Wolfe, B.A. Wright (eds.). *Proceedings of the Exxon Valdez oil spill symposium.* American Fisheries Society, Bethesda, MD.

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Regarding how pinnipeds were affected by the 1997 Tranquillon Ridge spill, it continues:

> *With respect to pinnipeds, it was concluded that pinnipeds were exposed to oil from the spill and that one female California sea lion likely died as a result of oil exposure (CDFG et al., 1998). The conclusion for the death from oil exposure was based on oil in the mouth and coat of the dead animal, the oil on the dead animal was a positive match with the spilled source oil, and the animal had distended pulmonary alveoli and edema that is often associated with exposure to petroleum hydrocarbons (CDFG et al., 1998). CDFG et al. (1998) concluded that pinnipeds in the proximity of the spill most likely were exposed to oil and suffered sub-lethal injuries.* [DEIR, p. 5.5-39.]

These important data are vital to a discussion of the potential impacts of a project oil spill on the region's pinnipeds. The DEIR states:

> *... oil spill trajectory analyses indicated that oil released from a spill the project area can come ashore exposing adults and subadults to potentially long term lethal and sublethal effects.* [DEIR, p. 5.5-39.]

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Apparently, by "come ashore" the DEIR is referring to San Miguel Island, and by "adults and subadults" the DEIR is referring to the adults and their offspring inhabiting the breeding colonies on San Miguel. If this is actually the case, the DEIR must elaborate on this conclusion, and clearly disclose both these specifics and the full breadth of impact uncovered in impact analysis. As suggested by earlier discussion in the DEIR, landfall of a Tranquillon Ridge oil spill at San Miguel Island could have profound consequences for pinnipeds species there, including Northern fur seals. This event would also have profound adverse impacts to resource management and restoration efforts at and around San Miguel Island that are being carried out by the National Park Service and the National Marine Sanctuary Program, with both legal and ecological ramifications.

The DEIR also points out that oil spill cleanup activities themselves could result in additional take of pinnipeds, resulting in additional significant impact on these animals:

> *Onshore cleanup activities would be extremely disruptive to pinnipeds populations. DeLong (1975) reported that seals disturbed on San Miguel Island retreated into the sea and did not return for several days. Such impacts could result in significant* ***behavior impacts*** *should a spill occur during the breeding season (Davis and Anderson, 1976)* [DEIR, p. 5.5-39; emphasis added.]

It is questionable, however, that the impacts of a major oil spill cleanup operation could be limited to "behavior" impacts to San Miguel pinnipeds. For example, walrus in rookery sites are known to 'stampede' in response to human disturbances, sometimes resulting in the death of calves.[74] Additionally, the "behavior impacts" of abandonment "for several days" of rookery sites could significantly impinge on biologically critical functions for affected pinnipeds, such as calving, nursing, and mating. Should cleanup activities at San Miguel result in habitat avoidance that affects these behaviors, *population level* impacts are not implausible for certain pinnipeds species there.

In summary, the EIR identifies that oil spills may reach San Miguel Island, a major breeding area for multiple pinnipeds species. It then reports evidence that pinnipeds tend to swim through oil slicks to reach breeding areas even though they have the ability to avoid them (apparently due to the biologically critical instinct to pursue reproductive activities), and even though such exposure to petroleum hydrocarbons is known to cause sublethal and lethal effects (like those that killed the one documented pinniped mortality during the 1997 spill, and that killed harbor seals after the *Exxon Valdez* oil spill (as reported in the DEIR, p. 5.5-40.)). In the event of an oil spill that reaches San Miguel Island, cleanup activities themselves could result in further profoundly significant impacts to breeding and juvenile pinnipeds there, both to the behavior and survival of individuals and the sustainability of certain populations.

EDC-80
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Collectively, this information strongly suggests that the Tranquillon Ridge Project proposal represents an unacceptable level of risk for these protected marine species, and to the Federal and State-protected terrestrial and marine habitats of the Channel Islands region, and should thus be disallowed. At the very least, the data indicates that the DEIR must specify a much more robust and comprehensive set of mitigation measures to the threat of significant impacts to the Channel Islands resources from oil spills; given the stakes for the area's marine biology, a 1 in 3 chance of harm to this ecosystem in the event of a Tranquillon Ridge spill is simply unacceptable.

Acoustics

EDC-81

The DEIR correctly identifies the noise emissions from all offshore activities associated with the Tranquillon Ridge Project including drilling, vessel and aircraft traffic, and ongoing hydrocarbon production—as potentially causing adverse impacts to marine wildlife. However, the DEIR fails to disclose in sufficient detail the extent of noise emissions associated with the Project, presents inadequate analysis of the potential for impacts from these emissions, and thus presents highly questionable, unsupported conclusions. Overall, the *Underwater Noise* section discussion following Impact #MB.4 is devoid of any project-specific information. This is unacceptable given the growing body of data indicating that underwater noise emissions, such as those associated with the Project, fundamentally alter the marine environment and adversely impact the biological communities therein.

To begin its discussion of underwater noise emissions expected from Platform Irene during drilling and production activities, the DEIR references NOAA Fisheries'

[74]/ National Research Council (NRC). 2003. *Ocean Noise and Marine Mammals*. National Academy Press, Washington, D.C. 204 pages.

upper threshold of 160 dB of impulsive noise for the acceptability of anthropogenic underwater noise emissions. The DEIR then offers a speculative comparison.

> *Marine mammals may be disturbed by drilling noises as well as the noise of increased vessel operations. NOAA Fisheries has adopted 160dB as an acceptable level of impulsive underwater sounds. Based on available scientific evidence, acoustic harassment of marine mammals would not be expected to occur below this conservative level. Drilling rigs may produce noise up to 174 dB. However, drilling from platforms has been found to generate considerably less noise than drilling from mobile vessels (Richardson et al 1995). Gals (1982) measured noises of 119 to 127 near platforms and man-made islands off California where drilling or production were occurring. He found that platform noise was so weak that it was nearly undetectable even alongside the platform during sea states of 3 or greater.* [DEIR (p. 5.5-53)]

As a basis for the DEIR's discussion, this passage is problematic for several reasons:

1. The DEIR Fails to Adequately Describe the Character or Magnitude of Acoustic Emissions from Platform Irene

EDC-81
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The DEIR offers no explanation as to why drilling noise from Platform Irene should be considered relative to NOAA Fisheries' threshold for *impulsive* underwater sounds alone. Table 2.1 of the DEIR enumerates drilling times for the 22 wells "currently proposed" for drilling (though the Tranquillon Ridge development plan calls for 30 wells), with durations between 60 and 120 days required for each of them. (DEIR, p. 2-4.) Because wells will be drilled one at a time (DEIR, p. 2-3), sustained drilling, and, intuitively, *continuous* drilling noise will extend for approximately 2000 days (about five and a half years), either in place of, or in addition to the suggested but undisclosed impulsive drilling noise mentioned in the DEIR.

This ambiguity and vagueness must be rectified with increased clarity and detailed elaboration. Scientists often distinguish between impulsive, or temporally isolated sounds, and those that are continuous, because emissions and animal exposure to one type or the other can result in distinct impacts to marine species.[75] On one hand, temporally discrete, impulsive sounds sources such as air gun blasts during a seismic survey, or tones from a high-intensity active sonar system, are documented to cause severe physiological harm to animals exposed to them (for example in fish[76], in the former case, and in beaked whales[77], in the latter).

[75]/ National Research Council (NRC). 2003. *Ocean Noise and Marine Mammals*. National Academy Press, Washington, D.C. 204 pages.
[76]/ Popper, Arthur N. 2003. "Effects of Anthropogenic Sounds on Fishes." *Fisheries* 28(10): 24-31.
[77]/ Evans, D.L., and G.R. England. 2001. *Joint interim report: Bahamas marine mammal stranding event of 15-16 March 2000*. National Oceanic and Atmospheric Administration.

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In contrast, scientists and resource managers identify a very different set of impacts associated with *continuous* noise, sustained emissions that alter the ambient acoustics of a given area over the long term. For example, according to NOAA Fisheries, relative to the intentionally produced sounds mentioned above,

> [m]*ore subtle, though likely more widespread, effects may result from overall elevation in ambient noise levels due to human activities. Such changes in the local acoustic environment may result in reduced communication ranges for breeding marine mammals using sounds in reproductive interactions, interference with predator/prey detection relying on active or passive biosonar (the use of sound for biological purposes), or, in extreme cases, habitat avoidance. While relatively few empirical data on demonstrated communication ranges are available, calculations of detection zones in various conditions for some marine mammals demonstrate the potential for masking to substantially limit acoustic communication (e.g., Janik, 2000; Southall et al., 2003; Au et al., 2004).*[78]

EDC-81 Cont'd

There is no question that noise from drilling operations alters the local acoustic environment in the area surrounding the facility at which drilling activities occur. For example, in BP Exploration Inc.'s application to NOAA Fisheries for an Incidental Take Permit as required under the Marine Mammal Protection Act for operations at its *Northstar* offshore artificial drilling island, the corporation reported that underwater noise from the facility operations persisted above the ambient, background noise level for a 5-10 kilometer (km) radius beyond the drill site.[79]

Existing data on anthropogenic underwater noise demonstrate both that scientific understanding of the issue of underwater noise is more sophisticated and nuanced than presented in the DEIR, and that anthropogenic noise emissions from facilities like Platform Irene can significantly impact the marine environment in multiple ways.

Unfortunately, the DEIR denies both these facts, first failing to describe *any* Project-specific details with respect to noise emissions from Platform Irene, and

Available at: http://www.nmfs.noaa.gov/prot_res/PR2/Health_and_Stranding_Response_Program/Interim_Bahamas_Report.pdf

[78]/ Southall, B.L., NOAA Fisheries Acoustics Program. 2005. *Final Report of the National Oceanic and Atmospheric Administration (NOAA) International Symposium: "Shipping Noise and Marine Mammals: A Forum for Science, Management, and Technology"* 18-19 May 2004. Arlington, Virginia, U.S.A.

[79] BP Exploration (Alaska) Inc., LGL Alaska Research Associates, Inc., and LGL Limited, environmental research associates. 2004. "Request for a letter of authorization pursuant to Section 101(a)(5) of the Marine Mammal Protection Act covering Taking of Marine Mammals Incidental to Operation of Northstar Facility in the U.S. Beaufort Sea (50 C.F.R. Part 216. Subpart R)." Submitted to NOAA Fisheries Service, 30 August 2004. Available at: http://www.nmfs.noaa.gov/pr/pdfs/permits/northstar_loa_app.pdf

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consequently failing to provide any credible analysis of the project's potential acoustic impacts to the surrounding marine environment.

2. The DEIR Relies on Irrelevant, Contradictory Data to Support a Finding of No Significant Impact to Marine Mammals from Drilling Noise

As cited above, the DEIR first states that some drill rigs produce noise of 174dB (p. 5.5-54). Importantly, this level exceeds the NOAA Fisheries threshold for marine mammal take due to behavioral harassment.[80] Incidentally, based on the DEIR's Significance Criteria for Marine Biology (DEIR, p.5.5-32) if such emissions were produced by Platform Irene, they must be treated as "take" and classified as causing significant impact to marine biological resources.

Apparently to frame its argument, the DEIR then compares this possibility with 1982 data from a researcher that:

> *... measured noises of 119 to 127 near platforms and man-made islands off California where drilling or production were occurring. He found that platform noise was so weak that it was nearly undetectable even alongside the platform during sea states of 3 or greater... Studies of the reaction of cetaceans to drilling noise suggest that cetaceans may avoid stationary industrial activities such as dredging, drilling, and production when the received sounds are strong but not when the sounds are barely detectable.* [DEIR, p. 5.5-53.]

EDC-81 Cont'd

The overarching problem with this passage is the outright failure to disclose the actual noise levels that will be emitted from Platform Irene during either drilling or production. Given that the applicant proposes to vastly increase the scale of drilling and production capacity on Platform Irene, including a doubling of shipping pump horsepower, 15 new 500 horsepower electrical submersible pumps, and a new 1,600 horsepower electric pump for mud handling (DEIR, p. 2-6), this is an unacceptable omission. In place of accurate disclosure of this key information, the DEIR essentially suggests that noise levels from Platform Irene will be somewhere between 119 and 174 dB.

First, this potential range is so broad and vague as to be meaningless: because the decibel scale is logarithmic, the 55dB range represents a difference in sound intensity of more than 5 *orders of magnitude*. In other words, 174dB is more than 10,000 times more intense than 119dB. Without actual data on where Platform Irene's emissions sit on such a spectrum, actual impact analysis is basically impossible.

Second, the use of 1982 data summarizing measurements "near platforms and man made islands" off California, where "drilling or production were occurring" is

[80] California Coastal Commission (CCC). 2006. Revised Staff Recommendation for Consistency Determination: U.S. Navy Onshore and offshore U.S. Pacific Fleet military training exercises. Consistency determination No. CD-086-06. 30 October 2006.

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similarly unacceptable. No mention of which platforms were actually measured is offered, whether or not any platforms were actually included in the measurements, how far from the facilities the measurements were taken, or how the measurements varied with respect to whether the facilities were drilling or pumping oil. Given the proposed horsepower increases for Platform Irene (relative to 1982 drilling and production technology), as well as the diversity of facilities in operation in California's OCS, it is highly questionable whether the comparison is valid at all. Even if it is, the Gales data is presented with so many qualifying conditions as to be essentially meaningless. The DEIR must instead provide acoustic data specific to Platform Irene, so that meaningful impact analysis can be conducted and credible findings disclosed to the public.

As it stands, the DEIR follows this inadequate representation of project-related acoustic emissions with four sentences of discussion regarding impacts to cetaceans from drilling noise, basically stating that because drilling noise will be continuous and stationary, whales and dolphins will either not be bothered, or will habituate to the noise. (DEIR, p.5.5-54.) This argument is supported by one cited resource (Richardson et al. 1995), which, as discussed below, presents a more complex position on the matter than the DEIR, and has been subsequently built upon by important new studies.

This grossly inadequate review culminates in the DEIR's two spurious conclusions with respect to underwater noise impacts from drilling operations. First:

> *The literature indicates that while marine mammals hear man-made noises and sounds generated by construction activities, there is no indication that they are affected deleteriously by the noise (Richardson et al. 1995).* [DEIR, p.5.5-53.]

EDC-81
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And second, without a single quantitative data point in support of it:

> *These data suggest that drilling sounds from Platform Irene will be below the level determined to constitute acoustic harassment and are unlikely to have a significant adverse impact on marine mammals.* [DEIR, p.5.5-54.]

Even a brief review of current syntheses of data provides a clear counterpoint to the simplistic approach and hollow findings of the DEIR.

For example, in its comprehensive review of anthropogenic sound and marine mammals published in 2003, the National Research Council reported specifically on the types of activities and noise typically associated with oil drilling and production, and how locally pervasive that noise can be.

> [Underwater] *noise is generated during oil production activities, which can include borehole logging, casing, cementing, perforating, pumping, pipe laying, pile driving, ship and helicopter support, and others to support rig and platform work. Impulsive hammering sounds created by installation of conductor pipe resulted in received sound levels of 131-135 dB re 1 μPa recorded 1 km from the source (see Richardson et al., 1995). Assuming transmission loss resulting from spherical spreading, this will translate to 195 dB re 1 μPa at 1 m, with the peak amplitudes occurring at around 40 and 100 Hz.*[81]

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NRC's discussion demonstrates a more appropriate level of detail with respect to acoustics data from Platform Irene, one from which functional analysis can proceed. Note the tight range of noise levels measured 1km from the investigated platform, and the calculated source level for drilling noise which significantly exceeds NOAA's behavioral harassment standards. These points add the particular gravity of the proposed Tranquillon Ridge Project to discussion elsewhere in the NRC report regarding impacts from drilling noise to whale migrations:

> *Migrating bowhead and gray whales divert around sources of noise, whether actual industrial activities or playbacks of industrial activities (Richardson et al., 1995) with almost all bowheads reacting at received levels of 114 dB re 1 μPa. However, if no other option is available, migrating bowhead whales will pass through an ensonified field to continue their migration. During spring migration, when the only available lead was within 200 m of a projector playing sounds associated with a drilling platform, the bowheads continued through a sound field with received levels of 131 dB re 1 μPa (Richardson et al., 1991).*[82]

EDC-81
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Yet a simple diversion of migration routes may not be the only adverse impacts to the region's gray whales, or any other of the multitude of cetacean species in the project area, that the drilling and production noise from Platform Irene may cause. Further data relayed by the National Research Council directly addresses the argument put forth in the DEIR that habituation indicates an absence of adverse impact:

> *Animals will tolerate a stimulus they might otherwise avoid if the benefits in terms of feeding, mating, migrating to traditional habitat, or other factors outweigh the negative aspects of the stimulus. Already noted is the case of bowhead whales on spring migration, where they needed to use the one available lead in the ice cover to continue on their eastward migration and passed through a sound field with projected drilling ship sounds at levels of 131 dB re 1 μPa (Richardson et al., 1991). Bowheads also return to the same areas of the Canadian Beaufort Sea year after year even though seismic surveys occurring at the same time are an annual feature of these areas (Richardson et al., 1987). Whether there are particularly dense concentrations of prey in these areas or whether the bowheads' response is simply historical philopatry is unknown.*
>
> *In at least one case, a source that did not elicit a fleeing response turned out to be capable of causing damage. Humpback whales in Newfoundland remained in a feeding area near where seafloor blasting was occurring. The humpbacks showed no behavioral reaction in terms of general behavior, movements, or residency time. In fact, residency time was greater in the bay*

[81]/ NRC. 2003. *Ocean Noise and Marine Mammals.* National Academy Press, Washington, D.C. 204 pages.
[82]/ *Id.*

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> *closest to the blast site than it was in other bays of equivalent size and productivity nearby. Estimated peak received levels during blasting were approximately 153 dB re 1 µPa with most of the sound energy below 1,000 Hz (Todd et al., 1996). Two humpback whales found dead in fishing nets in the area had experienced significant blast trauma to the temporal bones (Ketten et al., 1993).*[83]

Finally, given the array of other sources of industrial anthropogenic noise the animals must endure offshore California, including more than 20 other OCS facilities, extensive commercial ship traffic, and military activities, the NRC's review of impacts from chronic stress is also quite relevant to the applicant's proposal for new drilling and extended production:

EDC-81 Cont'd

> *Sounds resulting in one-time acute responses are less likely to have population-level effects than are sounds to which animals are exposed repeatedly over extended periods of time....*
>
> *Long-term effects of ocean sounds can include the transformation of TTS* [temporary threshold shift, i.e. hearing loss] *to permanent threshold shift and an increase in occurrence of pathological stress. Stress can be defined as a perturbation to homeostasis. So long as the perturbation is within the range the physiological system is capable of handling, is of short duration, and is not continually encountered, homeostasis is restored through an adaptive stress response. However, when the perturbation is frequent, outside the normal physiological response range, or persistent, the stress response can be pathological.*
>
> *Stress can induce secretion of corticotrophin releasing factor (CRF) from the hypothalamus. CRF promotes the release of glucocorticoids and catecholamines, which modulate the immune response and can lead to changes in the response to infectious, neoplastic, allergic, inflammatory, and autoimmune diseases (Webster et al., 1977). Chronic stress can also* ***suppress reproduction*** *(Rabin et al., 1988),* ***inhibit growth*** *(Diegez et al., 1988),* ***and alter metabolism*** *(Mizrock, 1995)*[84] [emphasis added].

This compilation of excerpts from the NRC report provides both a summary of key acoustic impacts that may be associated with the Tranquillon Ridge Project proposal, and an example of the degree of detail that should be included in the DEIR's disclosure and discussion of the project. The DEIR must be revised to address the possibility of these impacts, and provide this fundamental information about the project.

[83] / *Id.*
[84] *Id.*

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EDC-82

3. Helicopter Flights should be Required to Fly at 2500 Feet Except for Take-Off and Landing

"The current Marine Biology Impact Reduction Plan for the Point Pedernales Project requires a minimum flight altitude of 1000 feet as well as avoidance of sensitive habitat areas." (DEIR, p. 5.5-53.) In order to reduce impacts to marine mammals as well as marine birds in the project area over the approximately 30 (or greater) years of additional extended project lifespan, as well as to reduce the project's contribution to cumulative effects on regional wildlife, the minimum altitude for helicopter flights associated with the project should be increased to 2500 feet. The USCG has proposed to apply this standard as a measure to mitigate the additional marine wildlife impacts from helicopter flights associated with the Cabrillo Port LNG project proposal.[85] The applicant should be required to match this regional standard.

5.6 OCEANOGRAPHIC AND MARINE WATER QUALITY

Please see comments in section 3.7 above.

5.8 AIR QUALITY

5.8.2.2 Regulatory Setting

EDC-83

The DEIR should include a description and analysis of AB 32, which was enacted into law in California in 2006, and which requires reductions in greenhouse gas emissions as a means to reduce global warming.

5.8.4.2 Operational Impacts

EDC-84

The DEIR states that electricity consumption at the LOGP could increase by approximately 30% due to the increased operations of the existing equipment. (DEIR, p. 2-8.) In addition, the project would require an increase in truck, boat and helicopter trips. (DEIR, pp. 2-7, 2-8.) Additional pumps would be required at Valve Site #2. (DEIR, p. 2-10.)

Please explain why operational emissions impacts are Class II. (See table at top of page on DEIR, p. 5.8-15.) The extended life of the project, combined with the additional emissions set forth above, would appear to result in new significant impacts. If the DEIR assumes that impacts will be mitigated through offsets, please analyze and disclose whether such offsets are available for the life of the project.

[85] Prescott, M.A. Deepwater Ports Standards Division, U.S. Coast Guard. "Cabrillo Port LNG Project: Response to NMFS letter of July 14, 2006." December 21, 2006.

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Criteria Pollutants

EDC-85

The analysis in the DEIR is confusing. On the one hand, the DEIR states that "If the proposed project estimated emissions are added to the current Point Pedernales Project emissions, the resulting total emissions are still within the previous offset credit provided for NOx and ROC according to the FDP requirement. The proposed project emissions would also be within the allowable PTO emissions." (DEIR, p. 5.8-17.) However, a few paragraphs later, the DEIR states that emissions reductions credits would be required for NOx and ROC emissions (*Id*). Please clarify whether new emissions reductions credits are required and, if so, analyze whether such credits are available.

Greenhouse Gas Emissions

The DEIR evaluates greenhouse gas ("GHG") emissions from the project in comparison to the U.S. inventory, rather than the existing project operations. (DEIR, p. 5.8-17.) *Any* increase in GHG emissions should be considered significant, due to the fact that we need to *reduce* GHG emissions to avoid global warming impacts. AB 32 (2006) requires that GHG emissions in California must be reduced to 1990 levels by 2020. In fact, we need to reduce GHG emissions to *below 1990 levels*, as recommended in the Kyoto Treaty, to avoid disastrous consequences. Thus, any increase in GHG emissions should be considered significant.

In addition, the DEIR appears to understate the GHG emissions from the project by focusing solely on emissions from fuel combustion due to *production-related transportation activities*. The DEIR should quantify all direct *and indirect* global warming impacts from the project, including not just project-specific emissions but also impacts from refining and combustion of the end products.

The DEIR should also discuss how the GHG emissions from the proposed project contribute to global warming, and what the impacts of global warming may be.

Finally, the DEIR should analyze the cumulative impacts of increased GHG emissions on the environment from global warming.

Mitigation Measures

Mitigation Measures Air-2 states that "PXP shall ensure that emission reductions are provided to fully mitigate increases in operational emissions associated with the proposed project consistent with SBCAPCD Rules and Regulations. The documentation supporting the available emission mitigations for operations shall be submitted to the SBCAPCD prior to land use clearance. No operations shall occur until the applicable project Permits to Operate are modified." (DEIR, p. 5.8-18.) Based upon this mitigation measure, the DEIR finds the impact to be Class II ("significant but mitigable," DEIR, p. 5.8-18.)

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EDC-87
Cont'd

This mitigation measure improperly defers an analysis of the feasibility and effectiveness of mitigation, in violation of CEQA. Mitigation measures must be known, effective and feasible. *Kings County Farm Bureau v. City of Hanford* (1990) 221 Cal.App.3d 692; *Federation of Hillside and Canyon Assns v. City of Los Angeles* (2000) 83 Cal.App.4th 1252, 1260-1262. The DEIR must be revised to provide an analysis of the availability of emission reductions in order to determine whether the project's impacts will in fact be mitigated to a less than significant level.

5.9 TRAFFIC

Please refer to the December 11, 2006 comment letter submitted by the North County Land Use Committee of CPA.

5.10 NOISE

Please refer to the December 11, 2006 comment letter submitted by the North County Land Use Committee of CPA.

5.11 FIRE PROTECTION AND EMERGENCY SERVICES

Please refer to the December 11, 2006 comment letter submitted by the North County Land Use Committee of CPA.

5.13 AESTHETICS/VISUAL

Please refer to the December 11, 2006 comment letter submitted by the North County Land Use Committee of CPA.

5.16 ENERGY AND MINERAL RESOURCES

5.16.2 Regulatory Setting

AB 32 was passed into law in the State of California in 2006. This law mandates a *reduction* in greenhouse gas emissions in the State. As stated above, this project would increase production and extend the life of the existing operations, thereby increasing greenhouse gas emissions substantially over the status quo. The DEIR should analyze the project's consistency with AB 32.

Please also include a discussion of the state's Renewable Portfolio Standards requirements, as enacted by SB 1038 (2002), SB 1250 (2006), SB 1078 (2002) and SB 107 (2006).

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6.0 ENVIRONMENTALLY SUPERIOR ALTERNATIVE

EDC-90

6.2 COMPARISON OF THE PROPOSED PROJECT TO THE NO PROJECT ALTERNATIVE

The DEIR states that the No Project Alternative "would offer significant environmental advantages over the proposed project; however, this alternative would not meet the major objective of the project, which is development of the Tranquillon Ridge oil and gas reserves to meet demand primarily for fuels." (DEIR, pp. 6-4, 6-57.) As stated above, the project objective of developing Tranquillon Ridge oil and gas reserves is overly narrow and precludes the consideration of other alternatives that are capable of meeting the same energy needs. In fact, the No Project Alternative is not only environmentally superior, but it would allow for development of clean energy alternatives capable of meeting the state's needs.

6.3 COMPARISON OF PROPOSED PROJECT TO OTHER ALTERNATIVES

6.3.1 VAFB Onshore Alternative

Because of the potentially devastating impacts of an offshore oil spill, the DEIR needs to analyze an onshore project that would avoid or lessen project impacts to the maximum extent feasible. Although the DEIR notes the reduction in spill impacts for marine biology, marine water quality, and commercial/recreational fishing, the DEIR finds that the impacts of a spill from the onshore alternative would still be Class I. (DEIR, p. 6-5.) While this conclusion may be correct, the DEIR must provide the decision-makers with a clear comparison between the different impacts that would be expected from an offshore oil spill versus an onshore spill. Offshore oil spills tend to be much larger and much more difficult to clean up. As such, the impacts from an oil spill from the proposed project would be much greater than for an onshore alternative.

In addition, the impact analysis for the onshore alternative is so vague as to prevent an adequate comparison. The DEIR should be revised to provide more detailed information about the onshore options so that an adequate comparative analysis can be made.

6.3.2 New Oil and Gas Processing Facility at Casmalia

The DEIR states that the Casmalia site would offer only one environmental advantage over the proposed project: reduced night lighting at the LOGP. (DEIR, p. 6-23.) The DEIR then points out the increased impacts that would be associated with this alternative: onshore biology, onshore water resources, risk of upset, visual resources, and cultural resources. (*Id.*) The DEIR concludes that "Since the Casmalia Alternative offers no environmental benefit to the proposed project, the proposed project component of processing at LOGP is considered to be environmentally preferable to this alternative." (DEIR, p. 6-63.)

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EDC-93
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As stated above, the DEIR fails to identify the increased safety benefits of locating the processing facility in a rural setting and utilizing state-of-the-art safety technology, as discussed in the North County Siting Study. The DEIR therefore needs to be revised to more fully analyze and compare the relative safety impacts of the proposed project versus the East Casmalia site.

6.3.5 Alternative Muds and Cuttings Handling – Injection and Onshore Disposal

EDC-94

We agree with the conclusion in the DEIR that injection of muds and cuttings at the platform or their transport to shore would be environmentally preferable to discharging into the water column at the platform as proposed. (DEIR, p. 6-64.)

Conclusion

In conclusion, we support the DEIR's focus on the impacts of increased throughput and extended life of the project. We urge the County to revise and complete its analysis of impacts, mitigation measures and alternatives as discussed in these comments.

Sincerely,

Linda Krop
Chief Counsel

Atts: *Adopted Findings,* California Coastal Commission, File No. E-97-23, November 18, 1997, regarding Torch Operating Company
Final Revised Recovery Plan for the Southern Sea Otter, U.S. Fish and Wildlife Service, 2003,

Cc: Get Oil Out!
Citizens Planning Association of Santa Barbara County
California State Lands Commission
California Coastal Commission

Note to Reader: Attachments to the EDC letter are provided as Appendix P of this EIR.

Response to Comment Set EDC

EDC-1: The text of EIR Section 1.0, Introduction, has been augmented as suggested in the comment. See also Response to Comment CPA-2 regarding the permit history of the Point Pedernales project.

EDC-2: CEQA Guidelines Section 15124(b) requires "a statement of the objectives sought by the proposed project. A clearly written statement of project objectives will help the Lead Agency develop a reasonable range of alternatives to evaluate in the EIR." Under CEQA Guidelines Section 15126.6(b), the analysis in an EIR should focus on alternatives that can eliminate or reduce significant environmental impacts even if they would impede attainment of project objectives to some degree or be more costly. Generally, the EIR need not present project alternatives that are inconsistent with the fundamental project objectives. A project sponsor may not define a project in a way, however, that artificially confines the range of available alternatives.

The project objectives for Tranquillon Ridge are to efficiently and effectively develop oil and gas reserves from the Tranquillon Ridge Field and sell this production to help meet energy demands in California. This is proposed by using an existing platform. These project objectives are not unreasonable. Private developers routinely seek to produce oil and gas for profit. Production from Platform Irene would also use existing infrastructure to develop Tranquillon Ridge, which could be considered consistent with Santa Barbara County and Coastal Act policies for use of existing infrastructure and consolidation of oil and gas production, transportation, and processing facilities.

There are other general policy concerns, including AB 32, which is the new state law addressing global warming. At this time, AB 32 does not require that new production of oil and gas be foregone. Also, requirements for alternative fuels are not such that new oil and gas production is prohibited or discouraged. (Indeed, the use of natural gas as a fuel is generally considered environmentally superior to many other fuels.) Further, before State policy could prohibit the exploration and production of oil and gas or require the exclusive use of alternative fuels, significant changes in governmental policy and legislation would be necessary. CEQA recognizes that where potential project alternatives require significant changes in governmental policy and legislation, such alternatives may be found infeasible. Other project alternatives, such as improving Corporate Average Fuel Economy (CAFE) standards, strengthening tire and lubricating oil standards, and alternative fuels are all important public policy and societal issues; but these also require new policy and legislative actions that are beyond the scope of this proposed project EIR. Therefore, these alternatives are not discussed in detail in the EIR because they do not achieve any of the project objectives and also require major changes in policy and legislation before they could be implemented. However, a brief, qualitative comparison of several potential options for meeting fuel demand if the Tranquillon Ridge reserves were not developed has been added to each issue area under the No Project Alternative discussion. Please see also Response to Comment EDC-11.

EDC-3: The non-confidential portions of the Drainage Study were released to the public during review of the previously proposed Tranquillon Ridge project and continue to be available for review at the Santa Barbara County Energy Division, as are several other documents referenced but not included in the EIR.

EDC-4: Please see revisions to EIR Section 1.3 regarding the MMS's role and Response to Comment PXP3-7.

EDC-5: Please see Response to Comment JP-1.

EDC-6: The baseline conditions for decommissioning activities could be different than the baseline today and, therefore, a detailed assessment of the impacts associated with decommissioning would be somewhat speculative at this time. Recognizing that decommissioning and reclamation of major oil and gas facilities in the County could create significant environmental impacts, in some cases very similar to impacts from construction of the facilities, the County requires that a project owner obtain a Demolition and Reclamation permit prior to initiating removal of its oil and gas facilities. Section 35.56 of the County's Land Use and Development Code requires, among other things, that the decommissioning and reclamation efforts undergo environmental review prior to approval of this permit and initiation of the activities. This approach will assure that decommissioning and restoration activities are mitigated to the maximum extent feasible based upon the environmental conditions at the time of decommissioning. For the Point Pedernales project, including the proposed Tranquillon Ridge project (if approved), the requirement to obtain either a Demolition and Reclamation permit or County approval of an Application to Defer Abandonment, would be triggered if the operator/owner intentionally abandons its operation or, potentially, when the "oil or gas throughput is reduced to three percent (3%) or less of permitted capacity" (pursuant to FDP Condition R-1). Similarly, the Coastal Commission, State Lands Commission, and the Minerals Management Service must review and oversee decommissioning efforts. The County is currently developing financial assurance rules for decommissioning of oil and gas facilities and expects these rules will be adopted this calendar year. The County could require provision of interim financial assurance for decommissioning before these rules are adopted

EDC-7: See Response to Comment EDC-2.

EDC-8: The FEIR clarifies that the VAFB Onshore Alternative is one scenario (Scenario 1) that could occur under the No Project Alternative and is discussed separately from the other No Project Alternative scenarios. The EIR points out that if the Tranquillon Ridge project is denied, there is still a potential that the State Lands Commission could determine that drainage of the state resource is occurring and that, if allowed by the Air Force and other permitting agencies, development of the oil and gas resources from an onshore location on Vandenberg Air Force Base could go forward. This is not a given for the No Project Alternative, but is a possibility, and is discussed in the EIR as required by CEQA, under the conceptual VAFB Onshore Alternative. If the Air Force determines that the Sunset/ ExxonMobil project is not compatible with Base operations, development of the Tranquillon Ridge Field from an onshore location would be unlikely. Another remaining scenario for Tranquillon Ridge Field development would be a new platform or a drill ship using subsea completions that would be connected to Platform Irene or the shore using subsea flow lines. However, with Platform Irene in place, approval of a new platform would be unlikely due to the associated construction impacts (see Section EIR 3.3.1 for a discussion of a new offshore platform alternative) coupled with the presence of suitable existing infrastructure (Platform Irene and associated pipelines). In addition, the use of a drill ship is unlikely given the environmental impacts associated with installation of flow lines along the sea floor from each subsea location to Platform Irene or from each subsea location to shore (see Section 3.3.2). Further, given the nature of the Tranquillon Ridge reservoir, this alternative is not technically feasible because down-hole submersible pumps and gas lift would need to be used as a means of recovery to enhance oil and gas production. This type of recovery is critical to the full development of Monterey type formation reservoirs.

EDC-9: The EIR identifies and examines a reasonable range of alternatives. Section 6, Table 6.1a, concludes that a spill in the marine environment would be more detrimental for the proposed project than the VAFB Onshore Alternative. However, Table 6.1a also concludes that an onshore spill could be more detrimental for the VAFB Onshore Alternative than the proposed project because of the additional length of pipeline and more sensitive biological environment traversed by the alternative.

EDC-10: The VAFB Onshore Alternative is a conceptual project and, as such, does not include the same level of detailed project description information available for the proposed project. The EIR qualitatively discusses the types of impacts that could occur if the VAFB Onshore Alternative were to be implemented instead of the proposed project. Regarding impacts to biological and cultural resources from construction and operation of pipelines associated with the VAFB Onshore Alternative, review of available environmental information and discussions with Base personnel indicated that there are significant resources within the areas the pipeline could traverse and that the potential exists to mitigate some of these impacts, primarily by careful and localized routing of the pipeline trench. Considering this information and based on previous experience with oil and gas pipeline projects in Santa Barbara County, the EIR states that significant impacts to these resources could occur but that it may possible to mitigate many of them. The precise degree to which mitigation measures could avoid or reduce such impacts cannot be established for this conceptual alternative. As noted in Section 6.4 of the EIR, an overall preference between the proposed project and the VAFB Onshore alternative is difficult to determine because significant impacts would occur for either project, but in many cases, these impacts would occur in different issue areas. With respect to onshore biological and cultural resource impacts, however, the proposed project would be preferred, as stated in Table 6.1a of the EIR, because the proposed project does not include construction of new onshore pipelines and thus would not cause construction-related impacts to the same degree as the VAFB Onshore Alternative.

EDC-11: Standards for increased vehicle fuel mileage and use of improved tire and lubricating oils would help to decrease fossil-fuel dependency. (For example, see California Energy Commission at http://www.energy.ca.gov/transportation/tire_efficiency/documents/index.html.). Text has been added to the EIR in Section 3.0, Alternatives, that discusses alternatives to oil that potentially could replace the oil developed from the proposed project, if it is approved. In addition, a table that briefly compares the impacts of potential options for meeting fuel demand has been added to each issue area impact discussion, under the No Project Alternative. Please also see Response to Comment EDC-2.

EDC-12: Please see Response to Comment EDC-2 and text added to Section 3.0, Alternatives, of the EIR regarding alternatives to natural gas that potentially could replace the gas developed from the proposed project, if it is approved.

EDC-13: This Tranquillon Ridge EIR considered an alternative location for the oil and gas processing plant (Casmalia East site) and concluded that such relocation would create more significant impacts in several issue areas than continued use of the existing LOGP and would increase public exposure to sour gas releases because of the additional sour gas pipeline between LOGP and new Casmalia processing facility. See also Response to Comment CPA-7.

EDC-14: The referenced discussion in EIR Section 6.0 has been clarified to reflect that a suitable geologic formation would be required and MMS approval secured for the muds and cutting reinjection alternative to move forward. The NPDES establishes annual limits for discharge at Platform Irene; no limits are established for longer time periods. As a result, there are no significance criteria for total discharges to compare to the proposed project's total discharge volumes.

EDC-15: Please see Responses to Comments CPA-11 and JP-1.

EDC-16: DEIR Section 4.0, Cumulative Projects Description, has been revised to reflect the current status of approved and pending development projects within the incorporated and unincorporated areas of Lompoc, as well as known potential projects that may occur adjacent to or within the Santa Ynez River that could affect terrestrial and freshwater biological resources. The onshore cumulative impact analyses for biological resources contained in DEIR Section 5.2.6.2 have also been modified to reflect these projects. However, it is noted that the impact conclusion of this cumulative impact analysis has not been changed; cumulative impacts to biological resources could be unavoidable and significant (Class I).

EDC-17: The proposed project life of 30 years is based on the economics of the project and does not reflect the useful life of the equipment. There is a possibility that the project life could be longer or shorter than 30 years. However, any change in the project life would not affect the FN curves generated for this EIR, or the risk-of-upset impact classifications, because these curves reflect annual risks. As described in the EIR (Section 5.1.3), the County's significance thresholds are based on these curves. The only spill probabilities that are sensitive to project life are the lifetime spill probabilities, which would vary proportionately to variances in project life. That is, the longer the project life, the higher the lifetime spill probability, and vice versa.

EDC-18: The EIR does analyze public safety impacts associated with extending the operational life of the PXP facilities (Section 5.1). Please also see Response to Comment EDC-17. In 2006, there were six reportable incidents at LOGP. Four of the six incidents involved activation of tank latches, resulting in releases of vapors that exceeded APCD emission control standards. These releases were the result of safety equipment functioning properly, did not result in any offsite impacts, and were remedied immediately. One of the six incidents involved a vacuum truck operator overfilling his truck resulting in less than a barrel of oil spilling onto the ground within the LOGP fence line. This spill was immediately contained and cleaned up. In this case of operator error, current mitigation required and implemented for the Point Pedernales project (containment and response measures) was effective in limiting the volume spilled and preventing more significant impacts from occurring. The last of the six incidents involved no release but was reported in accordance with County requirements. In this case, a level of 4.09 ppm of hydrogen sulfide registered at the Gas Company meter, 0.09 ppm over the limit for acceptance by the Gas Company, although the gas measured 4.0 ppm H_2S at the PXP meter. The gas was routed back to the LOGP and the meters checked and calibrated.

The four vapor releases required a Deviation Report to be filed with the APCD. The oil spill onto the ground within the LOGP fence line required filing a Hazardous Materials Minor

Spill and Release Incident Report Form, also referred to as the Community Awareness & Emergency Response (CAER) form which was faxed to the County Fire Department as required. The 4.09 ppm of H2S in the sales gas line required a call to 911 because it occurred in a pipeline labeled "sales gas line;" however, no gas was released from the pipeline. None of these incidents created a public emergency.

In 2005, there were seven reportable releases and in 2004, there were five reportable releases. These incidents involved primarily releases of oil or other combustible liquid within LOGP, one release of vapors that exceeded APCD emission control standards, one heat-related incident with no ignition, one unintentional detector activation, and two non-LOGP related incidents (one vehicle accident and one outside fire).

There were no pipeline incidents in 2006 and one in 2005: A vacuum truck was being used to depressure the 20-inch oil line for maintenance when a gas bubble entered the truck and caused approximately 5 gallons of crude oil to spray out of the truck's vent scrubber onto the ground. The area affected by the release was approximately 15' x 6' and was cleaned up immediately.

These incidents demonstrate that continued compliance with safety requirements, including inspections and training, is necessary for hazardous facility operations.

EDC-19: Please see Response to Comment JP-1.

EDC-20: The EIR includes an assessment of the potential impacts that could occur in the event of an oil spill and concludes that they would be significant and unavoidable (Class I), due in part to the many sensitive resources that could be affected and the difficulties of containing and cleaning up an oil spill in the ocean and nearshore environment, in particular.

EDC-21: For purposes of CEQA, the EIR accurately identifies the resources present and the potential impacts associated with both offshore and onshore oil spills associated with the proposed project. The risk analysis takes into account appropriate parameters of the facilities and their use for another 30 years, as noted in Section 5.1. The approach used to estimate future oil spills from offshore equipment includes a provision for the extended life of the facilities in terms of the lifetime spill probability. The MMS methodology used is based on historical spill data from 1964-1992. This data covers the period when the offshore equipment was first installed in 1987 and includes much older facilities which would be expected to have higher incident rates. The data are conservative as they do not factor in advancements in corrosion control, piping inspection, and leak detection which are currently used on the offshore pipelines. See also Responses to Comments S&EM-2 and S&EM-95 regarding pipeline spill probability.

The EIR states in Sections 5.2, 5.5, 5.6, and 5.7 that oil spills to the marine and terrestrial environments are considered Class I, significant and unavoidable impacts. Further, mitigation measures are proposed to mitigate oil spill impacts to the maximum extent feasible. The PXP Core Oil Spill Response Plan (OSRP) and its Santa Barbara County Supplement identify existing resources and oil spill response resources and methods applicable to the project area. As required by Mitigation Measure MB-1a, these documents will be updated to include these measures, if the proposed Tranquillon Ridge project is approved. The Core OSRP and County Supplement are available for review at the Santa Barbara County Energy Division. See also Response to Comment EDC-17.

EDC-22: Throughout the EIR, the 1997 oil spill is discussed, including its impacts to the marine and terrestrial environments. In addition, the EIR acknowledges that the Torch 1997 oil spill was exacerbated by operator error.

EDC-23: Please see Responses to Comments EDC-21 and EDC-22. EIR Section 5.1.1.4.1 *(Crude or Emulsion Pipeline Scenarios)* has been revised to include the following text:

> Following the 1997 incident, Nuevo Energy (the operator at the time) developed a new training document: *Response Procedures for Unintended Shutdown of Platform Irene and the 20" Oil Emulsion Pipeline from Platform Irene to the LOGP*. This document outlines the specific steps that must be taken to verify the reason for pump shutdown before the pumps can be restarted. If the cause is a leak, the Oil Spill Response Plan would be implemented. PXP continues to implement these procedures. Effectiveness of oil spill response techniques is discussed in Section 5.5, Marine Biology.

EDC-24: The discussion of Impact CRF/KH.2, under Section 5.7.4, has been modified to elaborate on the impacts of oil spill clean up efforts on fishing gear. In addition, FDP Condition M-8, Cooperation with Santa Barbara Channel Vessel Traffic Corridor Program (see Appendix M), was modified during the 1998-2000 Condition Effectiveness Review to improve implementation of mitigation measures, including, at minimum, annual meetings to educate vessel operators on compliance with the Santa Barbara Channel Vessel Traffic Corridor Program. Further, PXP's FDP Condition M-3 requires that it participate in the Local Fishermen's Contingency Fund (LFCF) "through the life of the project or until the utility of the program is no longer deemed valid by the County." The LFCF is a loan program designed to provide quick relief for equipment losses attributable to the offshore oil and gas projects, including PXP's operations, while waiting for payments from the federal Fishermen's Contingency Fund or for damage not covered under the federal program. This requirement would continue with the proposed project, if it is approved.

DEIR Section 5.14.4.1, Impact Analysis for the Proposed Project, Recreation, addresses the potential recreational impacts associated with a "worst-case" scenario oil spill, as provided for in DEIR Appendix G (Oil Spill Trajectory Modeling). A worst-case scenario oil spill would result in significant and unavoidable (Class I) impacts to recreation; therefore, it would be expected to have a corresponding effect on coastal-dependent tourism within the area affected, which, as noted in DEIR Section 5.14.4.1, could reach recreational resources as far north as Montana de Oro State Park near Morro Bay and as far south as the Santa Barbara Channel Islands. The text of EIR Section 5.14.4.1 has been revised to more clearly reflect these potential impacts on tourism.

EDC-25: Subsurface spills do not necessarily have greater impacts than surface spills. The amount of oil released, the type of oil, and the wind and sea conditions at the time of the spill have a far greater influence on the amount of damage caused by an oil spill than whether the spill originates at or below the water surface. In the case of a spill related to the Tranquillon Ridge project, because the potential water depth of a subsurface spill is relatively shallow (pipeline depth ranges from about 240 feet near Platform Irene to zero feet at landfall), the residence time between the release of oil at the pipeline and the emergence of the oil at the surface would be short and the extent of initial spreading of the plume between the bottom and the surface would have little impact on the final fate and landfall of the oil. Secondly, the EIR estimates a worst-case release volume of 4,244 barrels at the offshore emulsion pipeline midpoint (see Table 5.1.29). Because of the ocean depth and ocean water hydrostatic head, a pipeline rupture at the pipeline midpoint at 120-foot depth was estimated by POSVCM as 259 barrels. Therefore, the EIR addresses a worst-case analysis.

Finally, it is noted that the 1997 Torch oil spill was a subsurface spill. The EIR discusses potential impacts to the marine and terrestrial environments resulting from an offshore spill (see Sections 5.2, 5.5, 5.6, and 5.7), including a summary of the documented impacts of the Torch pipeline spill. As required by Mitigation Measure MB-1a, "lessons learned from the cleanup of the 1997 oil spill shall be in incorporated into" PXP's Core Oil Spill Response Plan and its Santa Barbara County Supplement.

EDC-26: EIR Section 5.1.1.4.2, Emulsion Pipeline Smart Pigging Results, has been revised to include the following text:

> The Point Pedernales Safety Inspection, Maintenance, and Quality Assurance Program (SIMQAP) defines when repair and maintenance of the pipelines is required. Smart pig runs are done on an annual basis as required by the SIMQAP. As part of the SIMQAP, Santa Barbara County staff review the annual inspection results and require repairs where necessary, in coordination with the appropriate State and Federal agencies.

See also Response to Comment S&EM-1 for detail on the SIMQAP and Response to Comment S&EM-36 for a complete list of inspections currently required for the existing PXP facilities.

EDC-27: The EIR acknowledges that oil spill clean up methods are not 100% effective and this fact contributes to the classification of oil spill impacts into the marine and terrestrial environments as Class I, significant and unavoidable impacts. The potential impacts associated with various types of oil spill clean up methods are discussed in detail in Appendix E of the EIR. In addition, PXP's Core Oil Spill Response Plan and its Santa Barbara County Supplement present the various oil spill clean up methods that could be implemented in the event of a spill (for example, see Appendix N, pp. 9-130 to 9-137, Site Strategy Sheets). The OSRP and County Supplement are available for review at the County Planning and Development Department, Energy Division office.

EDC-28: The consistency analysis contained in DEIR Section 5.14.8, Policy Consistency Analysis, for California Coastal Act Section 30232 included review of a summary of the California Coastal Commission's assessment of the effectiveness of oil spill clean-up techniques (cited as "California Coastal Commission, 2006" in DEIR Section 5.14.8). It is recognized that the effectiveness of existing oil spill containment and clean-up techniques is limited, and the DEIR consistency analysis for California Coastal Act Section 30232 concludes that the proposed project may be found inconsistent with this section's second sentence, which states: "Effective containment and clean up facilities and procedures shall be provided for accidental spills that do occur." However, the consistency analysis additionally recognizes that inconsistency with Section 30232 of the California Coastal Act would not necessarily preclude approval of the proposed project. As noted in the subject analysis, the California Coastal Commission may still permit the proposed project under the provisions of California Coastal Act Section 30260, which states that (in conjunction with California Coastal Act Sections 30261 and 30262) approval may be granted if: "(1) alternative locations are infeasible or more environmentally damaging; (2) to do otherwise would adversely affect the public welfare; and (3) adverse environmental effects are mitigated to the maximum extent feasible."

EDC-29: Please see Response to Comment EDC-27.

EDC-30: Please see Response to Comment EDC-27.

EDC-31: Please see Response to Comment EDC-27. Further, as required by Mitigation Measure MB-1a, "lessons learned from the cleanup of the 1997 oil spill shall be incorporated into" PXP's Core Oil Spill Response Plan and its Santa Barbara County Supplement. PXP's Oil Spill Response Plan, Appendix F (Dispersant Use Plan) describes the process for evaluating whether dispersant use is appropriate and includes checklists for requesting EPA and Coast Guard authorization to use dispersant on a spill. One of the questions that must be answered prior to requesting authorization to use a dispersant is whether dispersion of spilled petroleum to the water column would pose less of an environmental risk than leaving the petroleum on the sea surface. The list of potential dispersants in PXP's OSRP includes Corexit 9527. PXP's OSRP advises caution and requires site-specific wildlife agency approval (e.g., CDFG, USFWS) prior to use of high-pressure flushing or steam cleaning as a spill cleanup technique (November 2004 PXP OSRP, Table 5-8). Language has been added to Mitigation Measure MB-1a to specifically require that the toxicity of Corexit 9527 and its inclusion as a potential dispersant for the Tranquillon Ridge project be re-evaluated based on current information. Finally, the impacts associated with spill clean up activities are assessed in the relevant issue areas throughout the EIR. See, for example, EIR Section 5.2.4 (Impacts TB.6, TB.7, and TB.8), Section 5.3.4 (Impact GR.1), Section 5.4.4 (Impact OWR.1), and Section 5.12.4 (Impact CR.3).

EDC-32: Impact Air.3 discusses the "increased health risks from the increased air emissions due to the expected increase in equipment operation and oil volumes processed for the proposed project." Regarding oil spill clean up, there could be potential health effects; however, size and dispersion of a spill will determine spill response methods and the necessary workforce required. PXP requires that all responders to spills be trained in accordance with Hazardous Waste Operations and Emergency Response (HAZWOPER) standards, which include education on the potential health risks associated with oil spill clean up. For safety reasons, volunteers are not used for oil spill cleanup. Some spill response organizations, such as the Wildlife Care Network, use volunteers, but conduct their own training.

EDC-33: The MMS has stated that the frequency and scope of the MMS inspection program for Platform Irene has not changed as a result of the closure of the MMS Santa Maria office. See Responses to Comments S&EM-1 and S&EM-36 regarding project monitoring and inspection programs, respectively.

EDC-34: Please see Response to Comment CPA-7.

EDC-35: The set of reasonably foreseeable federal offshore oil and gas energy projects outlined in DEIR Section 4.0, Cumulative Projects Description, and assessed in DEIR Section 5.1.6, Risk of Upset, Cumulative Impacts, is based upon information contained within the U.S. Department of the Interior, Minerals Management Service's 2001 Draft Environmental Impact Statement for Delineation Drilling in Federal Waters Offshore Santa Barbara County, California (MMS 2001-046;[1] "DEIS") which supersedes the potential offshore oil

[1] Available at http://www.mms.gov/itd/pubs/2001/2001-046/TableofContents.pdf

and gas development scenarios contained in the 2000 “California Offshore Oil and Gas Energy Resources Study” (“COOGER” Study).

The future development scenarios contained within the DEIS for the undeveloped federal offshore oil and gas leases are hypothetical because no formal proposals (applications) for any lease- or Unit-specific development and production had been submitted to the MMS at the time that the DEIS was prepared. As part of the proposed project’s environmental review process, the MMS was contacted to determine if any applications for future oil and gas development had been submitted since publication of the DEIS. No such proposals have been submitted to the MMS, and the MMS does not anticipate any such proposals in the reasonably foreseeable future. As such, there are no known preliminary, draft or final development and production plans for any of the federal undeveloped leases (or Units) to base a cumulative risk of upset analysis on.

Although assumptions for a cumulative risk analysis could be extrapolated from the information contained within the DEIS, the results of this type of analysis would be speculative. This conclusion is not considered a cursory dismissal of potential cumulative risk of upset impacts, but rather the reality of applying a suite of heavily premised assumptions to an analysis that is highly quantitative in nature and dependent on the specific engineering and operational parameters of each project considered. Modeling risk of upset conditions on the basis of conjectures derived from hypothetical development scenarios that may or may not occur in the future could grossly over- or underestimate potential impacts, which would not strengthen the EIR’s Risk of Upset cumulative impacts analysis or provide the public and decision-makers with a reasonable prediction of probable environmental effects. CEQA Guidelines Section 15130 (b) specifies that the assessment of cumulative impacts should be guided by standards of practicality and reasonableness. Therefore, without having the factual data needed to accurately estimate specific cumulative risk of upset impacts, the cumulative impacts analysis provided in the DEIR is considered to be the most reasonable prediction of what may likely occur in the future.

EDC-36: Existing off- and onshore oil and gas development and production projects, including the Point Arguello platforms, within the study area are considered part of the proposed project’s existing (or “baseline”) conditions, although the Tranquillon Ridge project would add, cumulatively, to impacts associated with these baseline projects. The proposed project’s relationship and proximity to these existing projects, as well as potential future projects, are illustrated in DEIR Figures 4-1 and 4-2. The DEIR’s Risk of Upset cumulative impacts analysis (DEIR Section 5.1.6) considered the continued operation of these existing projects, as well as potential future activities that may be associated with them (such as the drilling of new wells within existing leases from an existing platform) and decommissioning.

EDC-37: Cumulative oil spill impacts to the environment are addressed within each issue area throughout the EIR, specifically in Sections 5.2.6 (Terrestrial and Freshwater Biology), 5.4.6 (Onshore Water Resources), 5.5.6 (Marine Biology), 5.6.6 (Oceanography and Marine Water Quality), 5.7.6 (Commercial and Recreational Fishing), 5.12.6 (Cultural Resources), 5.14.6 (Recreation/Land Use/Policy Consistency Analysis), and 5.15 (Agricultural Resources).

EDC-38: The previous Tranquillon Ridge Draft EIR was a primary source for the description of existing conditions, and since that document was prepared in 2002, conditions have not significantly changed in ways that would affect conclusions on impact significance or mitigation design and effectiveness. Other sources of site-specific information used for this analysis include PXP's Core Oil Spill Response Plan and the Santa Barbara County Supplement to that Plan, site visits, and communications with VAFB environmental staff. This information was reviewed during EIR preparation and is incorporated into the description of existing conditions presented in the document. As part of PXP's required compliance with the approved FDP (see Appendix M to the FEIR for reference), resource information along the pipeline right-of-way is updated and must be reflected in maintenance, repair, and spill response planning. In the EIR, impacts have been broadly characterized, but not underestimated. Although the EIR did not call out the ESHA status of each particular habitat, the sensitivities of those habitats to impacts, and the corresponding significance of those impacts, are recognized in the document. The mitigation measures anticipate the need for site-specific evaluation and protection when and where pipeline inspections/repairs are needed. For the VAFB Onshore Alternative, areas subject to new ground disturbance on Vandenberg Air Force Base were reviewed with VAFB and County staff, and information on sensitive species was updated for the EIR. Project-level detail is not available for the alternatives and is not necessary to develop an understanding of the potential for and significance of impacts resulting from the alternatives.

Sensitive species surveys, as described in Mitigation Measure TB-8, are intended to determine current distribution of special status plants and animals in the event that repair or maintenance of facilities is required during the operation phase of the project. Site-specific mitigation measures for avoidance or protection of these resources can then be identified and employed. This process can entail multi-agency review (e.g., SBC, CCC, VAFB, and CDFG) to evaluate the need for implementation of specific mitigation measures available to avoid impacts to sensitive species. These surveys are not intended to define baseline conditions for purposes of impact analysis.

EDC-39: Critical habitat for the tidewater goby had not been proposed at the time of DEIR preparation, but was proposed November 28, 2006. The FEIR text has been updated with this information.

EDC-40: To avoid confusion, the language "may use" in Table 5.2.1 has been replaced with the phrase "occur in".

EDC-41: Text has been added to Section 5.2.1.3 to clarify that CNPS-1B species may be considered rare, threatened, or endangered under CEQA, and that impacts on these species have generally been considered significant in that context. Information on these species that is provided in Table 5.2.1 and the text discussions under *Habitats and Biota* is sufficient for an understanding of the impacts.

EDC-42: Text has been added to Section 5.2.1.3 to clarify that California wildlife Species of Concern may be considered rare, threatened, or endangered under CEQA, and that impacts on these species have generally been considered significant in that context. Information on these species that is provided in Table 5.2.1 and the text discussions under *Habitats and Biota* is sufficient for an understanding of the impacts.

EDC-43: The description of existing conditions as presented in the DEIR is sufficient to determine the nature and significance of potential impacts due to pipeline maintenance and repair activities. The exact time and locations of pipeline repair and maintenance cannot be predicted in advance, and the occurrence of individuals of sensitive species at specific locations along the pipeline corridor is subject to some variation over time. The FEIR clarifies that under the existing PXP FDP (see Appendix M), prior to approving maintenance and repair activities, the County, Coastal Commission and VAFB environmental staff review baseline information for the specific location of the repair/maintenance activity to assess the potential for erosion and sedimentation and the occurrence of sensitive resources in affected areas. The procedure for review of specific proposed repair/maintenance work efforts is intended to provide for additional regulatory scrutiny for these efforts as they arise and as a means of applying site-specific resource protection and avoidance measures. Compliance with the existing permits requires these localized pre-construction surveys prior to initiation of ground-disturbing activities associated with the proposed repair work to ensure that protection and restoration measures consistent with existing permits are applied. If the repair or maintenance action and/or its effects have not been previously addressed and authorized under existing permits, a new permit is required. For example, an inspection of the pipeline tie-in near Wall Beach was recently reviewed and approved based on site-specific supplemental surveys and application of certain mitigation measures with a Coastal Development Permit from the Coastal Commission, and County and VAFB approvals. The DEIR recognizes the potential for significant impacts and provides appropriate mechanisms to verify site-specific biological and geological information and develop appropriate procedures for maintenance and repair that can be applied when and where these actions are needed; see Mitigation Measures TB-6 and TB-7. Based on the permitting agencies' experience with maintenance and repair activities along the existing pipeline route, with proper planning, as required by these measures, impacts would be successfully mitigated. The EIR discussion of Impact TB.3 has been augmented consistent with the foregoing discussion. Also see Response to Comment EDC-38.

EDC-44: Please see Response to Comment EDC-43. Impact TB.4 draws attention to listed plant species because they have different statutory protections than non-listed species, and due to the necessary involvement of the U.S. Fish and Wildlife Service and/or California Dept. of Fish and Game in the protection of these species. Impacts to non-listed species are addressed under Impact TB.3 and corresponding mitigation measures. These non-listed species have been treated as significant resources, which is a conservative approach and is based on the fact that they may be considered rare, threatened, or endangered under CEQA.

EDC-45: California tiger salamander (CTS) does not occur in project areas on VAFB and there are no CTS terrestrial or aquatic habitats in areas of potential new construction for the proposed project (at Valve Site #2) or the VAFB Onshore Alternative. Section 5.2.1.3 describes the use of terrestrial habitats by CTS. Additional information has been added to the EIR to clarify where the CTS occurs with respect to proposed and alternative project activities. The proximity of CTS habitat along the existing ConocoPhillips pipeline route was recognized under Impact TB.5 and has been added to Impact TB.8; however, this habitat would not be directly affected by the proposed project given its geographic distance from the PXP pipelines and LOGP.

EDC-46: The discussion of Impact TB.3 in EIR Section 5.2.4.2 reflects the occurrence of native vegetation and habitat along the pipeline corridor and addresses the potential impact referred to in the comment.

EDC-47: In order to properly investigate and, if necessary, mitigate for disturbance to cultural resources that are discovered within the project's work area, archaeological investigations may be required, including full recovery of a site that may necessitate extending cultural site excavation beyond the existing project boundaries.

EDC-48: PXP plans on using wood poles treated in accordance with utility company (PG&E) requirements. The majority of the wood poles used by PG&E are treated with pentachlorophenal. Less frequently used treatments include a copper naphthenate wrap at the base of the pole only and creosote. The poles are treated by the manufacturer prior to installation. Pentachlorophenol is a restricted-use pesticide and is used industrially as a wood preservative. A discussion of the potential effects of pentachlorophenol on biological resources has been added to Section 5.2.4, Impact TB.1.

EDC-49: The referenced Statement (1) was based on the fact that patches of oil tend to be broken up and become more widely dispersed as they move from a point of origin in the ocean. This occurred during the 1997 Torch oil spill, reference to which has been added to the *Aquatic Biota* discussion in Section 5.2.4.3 of the EIR. Regarding Statement (2), the DEIR goes on to add that modeling results showed the potential for oil spills to reach and affect freshwater and brackish/estuarine habitats at the locations mentioned and at others. Reference to the 1997 Torch oil spill has been added to further support the conclusion that there is a potential for spilled oil to impact these areas. Recognizing this potential, Statement (2) has been revised to delete references to spill probability.

EDC-50: The removal of vegetation and soil is included in Impact TB.6. It is true there could be additional secondary effects such as the loss of buried seeds or the spread of non-native weeds. This has been added to the description of the impact. Mitigation for these impacts would occur via implementation of the Core Oil Spill Response Plan and Santa Barbara County Supplement, which requires the use of native, locally collected seed mix to restore areas affected by a spill. Weed abatement measures are also required to prevent colonization of spill-affected areas by invasive exotic species (see Section 9.3 of the OSRP Supplement Excerpt, FEIR Appendix N).

EDC-51: The referenced habitats have been added to the residual impact discussion.

EDC-52: Please see Response to Comment EDC-16.

EDC-53: As required by the existing PXP Final Development Plan (FDP) conditions (see FEIR Appendix M), mitigation plans have been in place for the Point Pedernales project since it was approved by the County in 1986. These plans include the Restoration, Erosion Control and Revegetation Plan (RECRP) required by FDP Condition H-1 which is relevant to terrestrial biological impacts in particular. This plan was prepared by the project owner at the time (Unocal) and approved by the County prior to construction of the Point Pedernales facilities. Since that time, this plan has been in effect and has been implemented by each subsequent project owner, including PXP. The approved RECRP includes species-specific planting plans, performance criteria, and monitoring requirements. Over the years, this plan has been revised as needed, to include, for example, certain planting schemes or additional or updated performance criteria, based on the experience with specific revegetation and restoration efforts. In addition to its applicability to the initial construction of the Point Pedernales pipelines, the requirements of this plan also apply to all pipeline repair and maintenance projects associated with the Point Pedernales project.

The potential for biological resource impacts due to pipeline maintenance and repair, including those affecting sensitive species and their habitats, was contemplated in the original EIR/EIS for the Point Pedernales project. The procedure for supplemental review of proposed repair and/or maintenance work is intended to determine site-specific resource protection and avoidance measures that are consistent with FDP and Coastal Development

Permit (CDP) conditions of approval and related mitigation plans. All restoration efforts have been monitored by the County's Onsite Environmental Coordinator (OEC) through the Environmental Quality Assurance Program (EQAP; see FDP Condition C-1) and adjustments in the revegetation efforts to respond to conditions on the ground have been made per the recommendations of the OEC. Work within VAFB is also authorized and monitored by Base personnel and work within the coastal zone is reviewed and authorized by Coastal Commission staff.

The July 2000 Condition Effectiveness Study (CES) Final Analysis for the Point Pedernales project (prepared by the County in accordance with FDP Condition B-2) included review of the effectiveness of the RECRP required by Condition H-1 and the Landscaping Plan required by Condition H-5. This report noted that although "substantial progress" had been made toward satisfaction of the RECRP requirements, additional work was necessary to meet the requirements for oak tree restoration along the pipeline corridor and black-flowered figwort restoration (near the LOGP). Deficiencies in the planting efforts were noted and recommendations made to improve the effectiveness of revegetation and landscaping efforts. These recommendations were adopted by PXP and additional progress has been made, especially since 2003, toward oak tree and black-flowered figwort restoration in specific locations.

The 2000 CES report also noted that landscaping at the Surf substation was not meeting the intent of Condition H-5, which was to screen the substation from public views. More recent communications and on-going monitoring efforts have noted that recurring localized erosion from storm runoff through a culvert associated with Highway 246 that drains toward the substation may be contributing to the lack of success of some plantings. Potential mitigation of the erosion and alternative landscape efforts are under discussion. Although efforts have been and continue to be made to implement effective screening at the substation, performance criteria have not yet been fully achieved. In this EIR, Mitigation Measure Visual-1 requires PXP to prepare and implement a visual mitigation plan for the Surf Substation that provides for better screening of the facility. The visual impact of the substation was and continues to be classified as a significant and unavoidable impact (Class I).

The County has several years of experience in the implementation of these RECRP measures, for the same types of impacts in the same locations that are of concern for the proposed project and alternatives reviewed in the EIR. The DEIR determinations as to whether effective mitigation exists for an impact are based in part on this experience. As noted above, baseline information for the mitigation measures identified in the DEIR already exists and additional site-specific information has been required and accumulated by the County over the life of the Point Pedernales Project, in accordance with existing FDP Conditions. The pre-construction surveys referred to in the recommended mitigation measures in the Terrestrial and Freshwater Biology section of the DEIR are not intended, nor are they necessary, to provide baseline information for impact assessment. Rather, they are meant to explicitly require that this baseline information continue to be augmented as needed to ensure effective mitigation for specific activities associated with operation of the Tranquillon Ridge project, if it is approved. For example, the sensitive species surveys, as described in Mitigation Measure TB-8, are intended to determine current distribution of special status plants and animals in the event that repair or maintenance of facilities is required during the operation phase of the project. Site-specific mitigation measures for avoidance or protection of these resources can then be identified and employed. This process entails multi-agency review (e.g., SBC, CCC, VAFB, and CDFG) to evaluate whether additional permitting is necessary. The surveys are not intended to define baseline conditions for purposes of impact analysis. Thus, the DEIR mitigation measures build on the measures that were previously identified in the certified EIR/EIS for the Point Pedernales Project and adopted as conditions of approval.

The pre-construction survey identified in Mitigation Measure TB-1 is recommended in order to verify the precise locations of sensitive plant resources known today to occur within the potential power line routes. The power line component of the Tranquillon Ridge is associated with a possible need in the future to provide additional pumping capacity if the offshore pipeline is required to operate at lower pressure. Since it is not known today if or when this may occur, the mitigation measure TB-1 is intended to identify locations of specific plant species individuals that could be affected by installation of the power line, if this component is implemented in the future. This requirement will ensure that individuals of sensitive plant species that occur at locations subject to construction disturbance will be identified and appropriate restoration measures and performance criteria implemented at the time of that disturbance, pursuant to PXP's RECRP, Coastal Development Permit, and VAFB authorizations, as applicable.

EDC-54: PXP plans on using wood poles. As the DEIR states on page 2-10, they will be 60 feet high and 350 to 400 feet apart. The requirements of the mitigation measure for raptor-safe poles, line spacing and visibility are sufficient to conclude that the impact would be mitigated to less than significant. Raptor-safe poles, by definition, would not be conducive to nesting unless they incorporated platforms similar to what is described in the mitigation measure in order to protect the birds. The measure has been clarified in the FEIR to state that the poles will either be constructed so that they are not conducive to raptor nesting, or that the nesting platforms will be incorporated. Review and approval of the final pole designs by CDFG and USFWS at the time the power line to Valve Site #2 is deemed necessary has been added to Mitigation Measure TB-2 to ensure that the most current regulatory requirements are implemented.

EDC-55: Please see Responses to Comments EDC-38 and EDC-53. The variety of wildlife species that could be present at the time of construction is known from existing baseline information. The requirement for a pre-construction wildlife survey is to confirm whether sensitive species are present within the work area at the time the work is to be done so that they can be avoided (e.g., work areas adjusted if possible or individuals of sensitive species moved out of the construction area). Performance of such pre-construction surveys is a requirement of the FDP which has been implemented for Point Pedernales repair and maintenance efforts in the past. The language of Mitigation Measure TB-3 has been clarified accordingly.

EDC-56: Mitigation Measure TB.4 is consistent with County standard conditions and mitigation measures in requiring dry season construction unless that is not feasible, in which case wet season construction can occur subject to prior County review and approval of specific, detailed erosion and sedimentation control measures. Rather than instituting a blanket prohibition on construction during certain months of the year, the provision for wet season construction allows some construction activity to proceed where adequate precautions are taken. Other temporal constraints on construction often required by permitting agencies (e.g., avoidance of nesting birds, flowering season for annual plants) can place additional limitations on the construction "window." When combined with a blanket prohibition on rainy season construction, they could make construction extremely difficult if not infeasible. Some construction efforts will be relatively small, not in wetlands, and short-term. If conducted with certain precautions, they will not result in impacts due to erosion and sedimentation even if they are conducted in the wet season. This approach allows those activities that can be conducted during the wet season without creating significant biological impacts to proceed, with approval and under certain conditions. Site-specific erosion and sedimentation control measures have been identified and implemented successfully for specific pipeline and LOGP repair and maintenance efforts in the past and have included placement of jute netting, installation of water bars, re-seeding, and restoration with salvaged topsoil. These measures, and others, are identified in the RECRP and are easily adapted to specific topography, drainage, and vegetative characteristics.

EDC-57: Please see Responses to Comments EDC-43 and EDC-56. Prescriptions for erosion and sedimentation control are contained in the RECRP. These measures are currently required for repair and maintenance activities at the LOGP and along the pipeline right-of-way, where they are adapted to site-specific conditions. These measures are similar to those identified in Mitigation Measure TB-5, and this mitigation measure has been clarified to reflect the RECRP measures. As required by existing FDP Conditions, the County's requirement for, and monitoring of, implementation of erosion and sedimentation control measures will continue to be tailored for each work site, based on specific circumstances for each work effort, if the Tranquillon Ridge project is approved.

EDC-58: Mitigation Measure TB-6 describes the type of information that should be provided immediately prior to repair and maintenance work in sensitive resource areas when and where such activities occur during long-term operation of the Tranquillon Ridge project. Further, the RECRP describes methods of revegetation, sediment containment, and erosion control. The plan also identifies performance criteria for measuring the effectiveness and ultimate success of individual plan components. As discussed in Response to Comment EDC-53, there is sufficient knowledge of the project area and of the effectiveness of similar mitigation measures to make a determination that such impacts are mitigable. Also see Response to Comment EDC-43.

EDC-59: Important parameters of the Restoration, Erosion Control and Revegetation Plan required by Condition H-1 are presented in Mitigation Measure TB-7 to clearly identify the substantive requirements of the Plan and to ensure that all relevant requirements are included in any approval of the proposed Tranquillon Ridge project. The plan called for in Mitigation Measure TB-7 currently exists for the Point Pedernales project; the intent of measure TB-7 is to make it clear that any necessary habitat restoration efforts associated with the Tranquillon Ridge project must be implemented, as they are for the Point Pedernales project. Adherence to the existing FDP, including the Condition H-1 Plan, would continue to be required if the Point Pedernales project is modified to include production from the Tranquillon Ridge. The County's Condition Effectiveness Study (per FDP Condition B-2) of the Point Pedernales Project affirmed the effectiveness of Condition H-1 in mitigating impacts. The fact that details of site- and resource-specific performance criteria are required to be specified, and subject to multi-agency review, under Mitigation Measure TB-7 provides greater assurance of effective mitigation. It would be unreasonable to require this level of detail and multi-agency review prior to completing the EIR. See also Response to Comment EDC-58.

EDC-60: Mitigation Measure TB-7 does apply to all native habitats.

EDC-61: Mitigation Measure TB-7 does include requirements to mitigate impacts on all sensitive plant species. The fourth bullet of this measure requires "…restoration of native communities and native plant species propagated from locally-acquired existing plant species, including any sensitive species (such as sand mesa manzanita, La Purisima manzanita, and black-flowered figwort); and replacement of trees at the appropriate rate." See also Response to Comment EDC-62.

EDC-62: Mitigation Measure TB-7 has been revised to reference the required monitoring procedures and performance criteria established in Table 5 of PXP's Point Pedernales Revegetation, Erosion Control, and Restoration Plan (RECRP), required by FDP Condition H-1. This Table has been added to Section 5.2.4 of the EIR for reference (see Table 5.2.2). The monitoring criteria include: pre-construction meetings with the environmental monitor and construction crews to acquaint project personnel with the specific mitigation measures being implemented for the work effort; onsite presence of an environmental monitor before, during, and after construction to ensure specific measures are properly implemented and the site is restored to pre-construction conditions; post-construction plantings at specified ratios, and long-term monitoring of the success of the plantings (or other restoration effort, such as erosion control measures). The performance criteria include refinements based on experience with previous restoration efforts along the pipeline corridor and at the LOGP that have proved successful, as well as lessons learned from unsuccessful restoration efforts. Regular monitoring of the restoration efforts associated with the Point Pedernales project since it was constructed has enhanced the information available regarding the likely success of specific restoration measures at specific locations in the project area and has allowed for an adaptive restoration approach, particularly with respect to mitigating disturbed plant species near the LOGP and within the pipeline corridor to achieve the performance criteria. Previous project owners' and PXP's restoration efforts to date have generally been successful, with the exception of oak tree replacement at some locations and some of the landscape plantings at the Surf substation. In part due to the failure of some of the larger landscape species to establish at the substation site, the visual impact of the substation is considered to be Class I, significant and unavoidable. The proposed Tranquillon Ridge project would not affect existing oak trees nor would it impair ongoing oak tree restoration efforts associated with the Point Pedernales project.

EDC-63: Please see Responses to Comments EDC-58, EDC-59, and EDC-62.

EDC-64: The referenced word "should" has been changed to "shall." Language also has been inserted to state that "stockpiles shall not be placed in biologically sensitive areas."

EDC-65: Emergency actions associated with oil spills are addressed under Impacts TB.6, TB.7, and TB.8. Routine maintenance and repair actions do have longer lead times than emergency actions, which is sufficient to allow pre-construction site-specific assessment of the presence of sensitive plant species (from pre-existing data as well as new site-specific surveys), avoidance where possible (as required by Mitigation Measure TB-8), and potentially salvage or collection and propagation if needed for the mitigation. If onsite seed collection is not possible at the time of the pre-construction survey, PXP is required to use seed mixes previously developed from locally collected seeds to restore the site. This approach, including topsoil salvage and replacement, has been implemented successfully to date along the Point Pedernales pipeline right-of-way by the permitting agencies and the different owners of the pipelines. The topsoil salvage and replacement requirements and performance criteria from the RECRP have been added to the EIR text (see Table 5.2.2 in Section 5.4.2).

The performance criteria for mitigating the impact to less than significant (Class II) are either avoidance through Mitigation Measure TB-8, or reestablishment of individuals of the impacted species within the impacted area through Mitigation Measure TB-9. These measures would be implemented in conjunction with Mitigation Measures TB-6 and TB-7, which also specify restoration for native communities and sensitive species populations. The performance criteria for these species are identified in Table 5.2.2 which has been included in Section 5.2.4 of the EIR and reference to the RECRP has been added to Mitigation Measure TB-9. These standards are sufficient for determining the nature of the impact and whether it can feasibly be mitigated.

It is appropriate to include the requirement for approvals by other agencies with jurisdiction over resources addressed in detailed site-specific mitigation plans prepared after discretionary approvals have been issued. County approval has been added to the language of Mitigation Measure TB-9.

EDC-66: As noted in Responses to Comments EDC-53 and EDC-57, the County's construction mitigation conditions are part of the PXP FDP and apply to maintenance and repair activities. Mitigation Measure TB-10 also would apply to specific maintenance or repair activities. Supplemental review and authorization are normally required for such activities, as described in the discussion under "*Mitigation Measures*" prior to TB-10. Furthermore, the site-specific plans required under Mitigation Measures TB-6 and TB-7 will contain scheduling measures to avoid/minimize impacts. Other than the snowy plover and least tern, requirements to avoid species' breeding seasons are not necessary for successful mitigation. In the case of fishes, reptiles, and amphibians, individuals of sensitive species could reside in or pass through the areas of concern during non-breeding periods, in which case the impact would not be mitigated by avoiding the breeding season. However, the site-specific pre-project survey and protection measures that are currently part of the County's, State's and VAFB's processes, in conjunction with Mitigation Measures TB-6 and TB-7, would ensure adequate mitigation. Mitigation Measure TB-10 reinforces the need to avoid activity during certain seasons in specific locations due to the presence of federally listed species. See also Response to Comment EDC-43.

EDC-67: The Core OSRP and County Supplement are components of the overall mitigation program for the Point Pedernales project that would continue if Tranquillon Ridge production is added to the Point Pedernales project, as is proposed. These plans are publicly available for review through the County and do not need to be physically incorporated into the EIR. However, certain sections of the County Supplement have been included in the Final EIR for reference (see Appendix N).

EDC-68: As stated in EIR Section 2.0, the proposed Tranquillon Ridge Project includes use of PXP's existing oil emulsion, gas, and produced water return pipelines that currently serve the Point Pedernales Project. The referenced sentence is unclear and has been deleted.

EDC-69: In the paragraphs preceding Mitigation Measure TB-11, the EIR provides an overview of the biological resource elements of the existing OSRP. This plan in its current form satisfies the existing PXP FDP Conditions related to oil spill response planning and the protection of biological resources to the maximum extent feasible. Excerpts from the OSRP and County Supplement are provided in FEIR Appendix N and the complete documents are available for review at the County. These documents provide specific measures for spill containment and avoidance of impacts to resources along each segment of the pipeline corridor. Residual Class I impacts were recognized by the County and other regulatory agencies in approving the Point Pedernales project. This EIR specifies which elements of the existing Plan need to be updated to refer to the Tranquillon Ridge Project, if it is approved. It is not appropriate to require the Plan be updated before the CEQA process has been completed, the EIR certified and the project approved. If a proposed project is not approved by all the permitting entities, which can only occur after the CEQA process is completed, there would be no need to update the oil spill plans specifically for that project.

EDC-70: Mitigation Measure TB-12 has been revised to incorporate the suggested revisions, except with respect to the timing of the updated plan. Updating the plan is a mitigation measure to be implemented if the proposed project is approved; it is not appropriate, nor is it necessary, to require an applicant to implement such measures prior to completing the CEQA review and permitting processes.

EDC-71: Mitigation Measure TB-13 has been revised to require that specific low-impact clean-up procedures from the updated OSRP be identified prior to ground disturbance. It is not necessary or appropriate to require that the OSRP be updated before the CEQA and permitting processes are completed.

EDC-72: The OSRP County Supplement includes potential response techniques for selected habitats, including "natural recovery, no action" for each habitat type. Mitigation Measure TB-13 has been revised to specify the non-clean up option shall be considered for all native habitats.

EDC-73: The baseline requirement is that drills are to be conducted at least annually, as stated in the measure, to ensure effective response. Mitigation Measure TB-14 allows more frequent drills to be required as needed. As part of agency permitting requirements, in addition to Santa Barbara County, the following Federal and State agencies may conduct or participate in drills for the Point Pedernales facilities: MMS, Coast Guard, U.S. Environmental Protection Agency, U.S. National Park Service, and the State Office of Spill Prevention and Response/CDFG. Additionally, the State Office of Emergency Services is contacted for required notification of drills and the California Coastal Commission is involved in reviewing and approving the federal spill contingency plan as part of its consistency certification process. The following table provides a summary of drills conducted for the Point Pedernales Project in the last two years.

Table 9.3-1 Point Pedernales Related Drills/Exercises

Drill/Exercise	Date/Scenario
2005	
Notification Exercises	LOGP: March 17, June 1, August 3, October 18 Platform Irene: August 23
LOGP Emergency Response Plan Drill	December 29, Scenario: As the operator is checking the level of Gas/Oil Separator V-140, the half-inch nipple above the sample cock valve breaks off. As a result, oil and gas are spraying downward and the operator is overcome by H2S. The H2S detector (H2S-3) alarms. The oil leak contributes to a 10 -barrel oil spill and a man is down with a H2S gas leak in the inlet area of the facility.
Platform Irene Equipment Deployment Exercises	August 23, Scenario: A simulated blowout on well A-14 during well work led to the release of approximately 2.5 barrels of oil being released onto the ocean. The initial impacted area measured approximately 400' long by 150' wide near the south side on the platform. The Clean Seas OSRV (Oil Spill Response Vessel) "Mr. Clean"

Drill/Exercise	Date/Scenario
	responded to the simulated release drill and deployed 500' of Oil Stop boom along with their 21' Sea Ark boom handling boat.
	September 21, Scenario: A simulated rupture of the 20" oil pipeline from Platform Irene. The initial scenario included a low pressure shutdown of the 20" oil pipeline at the platform and an oil slick approximately 100 feet by 50 feet and growing. The oil slick was reported to be approximately one quarter mile north of Platform Irene directly above the 20" oil pipeline. The Clean Seas OSRV "Mr. Clean" responded to the simulated release site near Platform Irene and deployed a 21' fast response vessel, 1500' of 60" open ocean boom and a GT-185 skimmer. *This equipment deployment exercise was in conjunction the MMS Major Unannounced Oil Spill Drill.*
Spill Management Team Tabletop Exercise	September 21, Scenario: A simulated rupture of the 20" oil pipeline from Platform Irene. The initial scenario included a low pressure shutdown of the 20" oil pipeline at the platform and an oil slick approximately 100 feet by 50 feet and growing. The oil slick was reported to be approximately one quarter mile north of Platform Irene directly above the 20" oil pipeline. *This exercise was unscheduled/unannounced and was initiated by MMS as their "2005 Major Unannounced Oil Spill Drill"*
2006	
Notification Exercises	LOGP: February 16, April 25, September 8, December 12 Platform Irene: June 9
LOGP Emergency Response Plan Drill	June 8, Scenario: As the operator is checking the level of the Gas/Oil Separator V-140, the half-inch nipple above the sample cock valve breaks off. As a result, oil & gas are spraying downward and the operator is overcome by H2S. The H2S detector (H2S-3) alarms. The oil leak contributes to a 10 barrel oil spill and a man is down with a H2S gas leak in the inlet area of the facility.
Platform Irene Equipment Deployment Exercises	August 15, Scenario: A simulated release of 1 barrel crude of oil into the ocean. The release originated from the platform pig launcher 2" blow down line and resulted in a simulated sheen measuring approximately 10 feet by 25 feet, light brown in color. The Clean Seas OSRV "Mr. Clean III" responded to the simulated release site and deployed a rigid hull inflatable boat (RHIB), 500' of Oil Stop boom and a GT-185 skimmer.
	September 25, Scenario: MMS initiated unannounced oil spill drill. The scenario included the release of 3 barrels of crude oil caused by the simulated failure of the pressure drain piping from V-150 to V-910. The Clean Seas OSRV "Mr. Clean III" responded to the simulated release site and deployed a rigid hull inflatable boat (RHIB), 500' of Oil Stop boom and a GT-185 skimmer.
Spill Management Team Tabletop Exercise	October 25, Scenario: A simulated rupture of 24" PAPCO oil pipeline from Platform Hermosa. The initial scenario included Platform Hermosa operators experiencing an automatic low pressure shutdown of the 24" oil pipeline, followed by a call from fisherman who relayed that he had seen oil approximately ¼ mile east of Platform Hermosa. The simulated release was a worst case release amount of approximately 2,100 barrels of crude oil. The oil slick was estimated to be 1.17 miles long by 0.27 miles wide. *This exercise tested the Spill Management Team's organization, communication and decision-making in managing a spill response to an unannounced scenario and includes all covered platforms in the Oil Spill Response Plan. It was scheduled in advance with the team and the agencies, but the scenario was not announced until the exercise began.*
2007 (as of March 21, 2007)	
Notification Exercises	LOGP: February 22
Platform Irene Equipment Deployment Exercises	March 5, Scenario: The simulated break of a sample petcock valve on

Drill/Exercise	Date/Scenario
	V-130 led to the simulated release of 5 barrels of produced fluid into the ocean. The Clean Seas OSRV "Mr. Clean III" responded to the simulated release site and deployed a rigid hull inflatable boat (RHIB), and the starboard side Lori-5 brush advancing skimming unit with outrigger boom arm.

EDC-74: Provision for the treatment and release of all oiled wildlife is discussed in Section 5.7.3 of PXP's Core OSRP, which is a public document available for review at the County. Mitigation Measure TB-12 reinforces that this element of the OSRP is required and is subject to further review and approval in conjunction with the proposed project, if it is approved.

EDC-75: Offshore and onshore oil spill impacts are compared in Section 6.0 of the EIR, subject to the limitations of evaluating the conceptual VAFB Onshore Alternative. See also Response to Comment S&EM-4.

EDC-76: The descriptions of Impacts TB.6, TB.7, TB.8, OWR.2, MB.1, MWQ.1, and CRF/KH.2 in Table 6.1a acknowledge that an offshore oil spill can affect large areas. As noted in Response to Comment EDC-75, impacts of the proposed project are compared in Section 6.0 of the EIR to those of the VAFB Onshore Alternative, subject to the limitations of evaluating the conceptual onshore alternative. In particular, the EIR discussion in Section 6.3.1 notes that impacts of an oil spill to marine resources, commercial/recreational fishing, and recreational resources would be less for the onshore alternative than for the proposed project.

EDC-77: Impacts of drilling under the Santa Ynez River are discussed under Impact TB.9 in EIR Section 5.2.5.2. These impacts apply to the VAFB Onshore Alternative and Alternative Power Line Route – Option 2b. Bear Canyon is very steep and narrow, and drilling was not considered a feasible option for purposes of the conceptual VAFB Onshore Alternative. The option of burying the power lines along Terra Road is described in EIR Section 3.3.3 and analyzed throughout the EIR. Power line installation impacts, including spanning watercourses, are described in Section 5.2.4.1 under Impact TB.1. Section 6.3 and Table 6.1a provide a sufficiently detailed comparison of impacts of the proposed project to those for the alternatives.

EDC-78: Observations of white abalone San Miguel or Santa Rosa Islands have not been recorded where a project-related spill could reach (Hobday and Tegner, 2000). However, suitable habitat does occur there. The text has been revised to state this fact. Potential impacts to black abalone are discussed under "Intertidal." Text has been added to the EIR to indicate that oil could reach black abalone populations on the northern Channel Islands.

EDC-79: The EIR discusses the vulnerability of sea otters to spilled oil and acknowledges the fact that a project-related oil spill has the potential to impact a high number of sea otters in the project region. The EIR also discusses the impacts of the *Exxon Valdez* spill on sea otters and the fact that only 53 percent of otters processed at oiling centers were rehabilitated (EIR Section 5.5.4, Impact MB.1, *Marine Mammals*, DEIR p. 5.5-39). The U.S. Fish and Wildlife Service's Southern Sea Otter Recovery Plan recommends using a three-year running average of sea otter counts to reduce the influence of anomalously high or low counts from any particular year. Although the sea otter population remains vulnerable, according to USGS, the 3-year running average for total sea otters was up 2.3% in 2006 and is representative of a general increasing trend in the southern sea otter population that has been observed since 2002. Nevertheless, the southern sea otter population remains a threatened species and is at risk of significant impact from an oil spill, as described in the EIR (Impact MB.1 – Class I).

The Final Revised Recovery Plan for the Southern Sea Otter (USFWS 2003) does not suggest that oil development in the project area be prohibited, but that plans be implemented to reduce the probability of an oil spill occurring in the sea otter range and to minimize the effects of an oil spill on the otter population, in the event that one occurs. Specific measures suggested to reduce the probability of an oil spill include the implementation of vessel management plans and vessel routing to minimize the risk of vessel accidents. To reduce impacts to sea otters should a spill occur, the Recovery Plan suggests implementation of an oil spill contingency plan that includes a sea otter response plan. Language has been added to Mitigation Measure MB-1a to specify that the updated OSRP specifically include measures to reduce potential oil spill impacts to sea otters.

EDC-80: The EIR states on DEIR p. 5.5-11 that a fur seal rookery exists on San Miguel Island. The text has been amended to clarify that migrants from the Bering Sea add to the number of fur seals in the area in winter and spring, and that the San Miguel Island breeding population is a separate stock of northern fur seals. Text also has been added to the impacts section to identify that the San Miguel Island fur seal population would be especially vulnerable to an oil spill and to clarify that startle responses of breeding pinnipeds to clean up activities could result in mortality of pups. Language has been added to Mitigation Measure MB-1a to require that the updated OSRP include measures to reduce potential oil spill impacts to breeding pinnipeds. Based on the potential consequences of an oil spill for marine biota, including the Northern fur seal, the EIR classifies oil spill impacts to marine biota as Class I, significant and unavoidable (Impact MB.1).

EDC-81: Drilling noises are very strongly related to the type of drilling platform, e.g., mobile vessel or permanent platform (Richardson et al 1995). The highest noises, as stated in the EIR text, are from “mobile drilling vessels” where sounds as high as 174 dB have been recorded. Drilling noise from conventional metal-legged platforms is not very intense and is strongest at low frequencies (Richardson et al 1995). As noted in the EIR, Gales (1982) measured noises of 119 to 127 dB near platforms and man-made islands off California where drilling or production were occurring. Further, drilling and/or operational noises resulting from a permanent platform are continuous in nature versus impulsive or intermittent as in seismic testing. NOAA Fisheries has adopted 160 dB as an acceptable level of “impulsive” underwater sound.

Observed responses of whales to mobile drill vessels appears to be limited to a distance within about a 100 meter radius of the drill vessel (MMS 2005). Because the noise of drilling from a fixed platform would be less than from a semi-submersible drill vessel, it is unlikely that marine mammals would exhibit any response unless they were very close to the platform. This observation would be consistent with the observation of Gales (1982) that the noise from conventional drilling platforms was so weak that it was nearly undetectable even alongside platforms at sea states of 3 feet or greater.

In addition, the proposed project would not substantially change the existing noise environment (baseline) of Platform Irene. For example, in 2006 there were 231 days of drilling and 89 days of work-over activity on the platform.

EDC-82: Based on fourth-quarter 2006 flight data, average monthly trips to Irene were 150. These all originated at the airport in Santa Maria (SMX) via Arctic Air Service. Flying distance from SMX to Platform Irene is approximately 23 miles. It would not be practical to fly at 2,500 feet for several reasons. This would require fairly sharp ascents and descents meaning extra fuel to climb, then descend quickly for landing at Platform Irene. Since more fuel may need to be added to reach 2,500 feet, this may require fewer passengers per trip (due to weight) and thus more trips. Also, because the distance covered is fairly short, the time spent at the 2,500-foot altitude would be only a few minutes before descent to Irene.

The airspace over VAFB is restricted. Each flight to Platform Irene (over any part of the Base) must be cleared by VAFB. VAFB requires PXP to be below their traffic pattern altitude of 1,500 feet so that they are not in conflict with any potential VAFB traffic, including helicopters and large cargo aircraft. Once an aircraft reaches 2,200 feet, it is considered to have entered "Santa Barbara Approach" controlled airspace (which means less flexibility and competing aircraft, etc.). A minimum flight altitude of 1,000 feet should be sufficient to prevent significant impacts since PXP's Marine Biology Impact Reduction Plan also requires that PXP first avoid flying over sensitive habitat areas at all.

The 2,500-foot minimum altitude restriction for helicopters is not an established regional standard and, for the Cabrillo Port LNG Project proposal, was only to be applied during emergency situations, since, as stated in the Cabrillo Port LNG Project Revised DEIR, page 60, although the project vessel "would be equipped with a helicopter landing pad, helicopters would not be used as part of regular operations. Helicopters may be used as appropriate in the rare case of an emergency." As a result, this altitude restriction is much more practical for the Cabrillo Port LNG Project than for the proposed project.

EDC-83: A description of Assembly Bill 32 (The California Global Warming Solutions Act of 2006) has been added to Section 5.8.2.2.

EDC-84: Section 5.8.4.2 and Table 5.8.8 show that operational emissions of NOx would exceed the SBC P&D guideline level for a significant impact, but as shown in Table 5.8.9, previous offset credits provide sufficient reductions to mitigate project impacts. Offset requirements for ROC would also apply before the SBCAPCD can issue a PTO. According to the SBCAPCD website Emission Reduction Credits, Source Register Ledger Report (accessed February 19, 2007), Plains Exploration & Production Company holds emission reduction credit certificates for over ten tons per quarter of ROC (see: http://www.sbcapcd.org/eng/nsr/srledgr.htm).

EDC-85: Clarification has been added to Sections 5.8.1.5 and 5.8.4.2 to illustrate that although project emissions would be below the level of previous offset credits (see Table 5.8.9a), any new ROC emissions as a result of the project would be subject to offset requirements per APCD rules. Thus, offsets would be required for any new ROC emissions as a result of equipment changes and higher throughputs. Response to Comment EDC-84 identifies the availability of ERCs.

EDC-86: Sections 5.8.2.2 and 5.8.4.2 include revisions to identify the plans and subsequent regulations that the California Air Resources Board is developing for reducing greenhouse gases (GHG). The GHG emissions resulting from the proposed project are summarized in Section 5.8.4.2. However, at this time, neither the SBAPCD nor SBC P&D have thresholds for GHGs. In the future, the project could be subject to the rules and regulations being developed by CARB for managing GHG emissions.

EDC-87: Section 5.8.4.2 includes revisions to clarify that the APCD will not issue any PTO for the project without the required ROC offsets, which are emission reductions certified by the SBCAPCD (i.e., an effective and feasible form of mitigation). Response to Comment EDC-84 identifies the availability of ERCs.

EDC-88: Because the rules and regulations to achieve GHG reductions called for in AB 32 have not yet been promulgated, a detailed consistency analysis cannot be conducted at this time. However, a qualitative discussion of the proposed project's potential consistency with the goals of AB 32 has been added to EIR Section 5.14.8.3.

EDC-89: A discussion of the State's Renewables Portfolio Standards requirements as enacted by Senate Bills 1038, 1250, 1078, and 107 has been included in Section 5.16, Energy and Mineral Resources.

EDC-90: Please see Response to Comment EDC-2. Development of the Tranquillon Ridge petroleum resources would not preclude development of alternative energy resources.

EDC-91: EIR Table 6.1a indicates the environmental preference for the VAFB Onshore Alternative with respect to offshore oil spills. See also Response to Comment EDC-9.

EDC-92: The VAFB Onshore Alternative presented in the EIR is conceptual and was developed in such a manner as to meet the basic objectives of the proposed project while minimizing potential impacts. Because the alternative was conceptual, a quantitative comparison could not be conducted; however, Section 6.0, Table 6.1a, provides an extensive qualitative comparison of the Class I impacts identified for the proposed project and VAFB Onshore Alternative. As concluded in Section 6.0, the proposed project would continue the existing oil spill risk to marine and terrestrial environments through 2037 (22% probability over the life of the project) and possibly longer or shorter, depending on the economic life of the project. On the other hand, the VAFB Onshore Alternative would result in permanent impacts to terrestrial and cultural resources as a result of construction, and present a lesser potential for an oil spill into the marine environment. Quantifying these relative oil spill and construction impacts would not change the conclusions drawn regarding the proposed project and VAFB Onshore Alternative impacts on the resources identified. Further, no policy direction is available on the relative importance of one resource over another. As a result, the EIR concluded that when comparing the proposed project to the onshore alternative, "it is extremely difficult to determine that one is environmentally preferable over the other."

EDC-93: Please see Response to Comment CPA-7.

EDC-94: Comment noted.

GFT

Mr. GEORGE F. TISE, II
1901 ELMWOOD DRIVE
SANTA MARIA, CA 93455-2820

12/12/06

Dear Mr. Kevin Drude

GFT-1 As we were unable to attend the public meeting to add our support to the energy exploration project please accept this written comment.

We as a country, state or county can not deny efforts to be self supporting and allow these projects. So we agree with Mr. Thomas Gibbons and echo his words. "I don't think given the energy constraints of today we can take away from this project." he said and we say it also.

The HS&P along hiway over Harris Grade is well able to handle increased production and should be extended.

Thank you

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DEC 15 2006
PLANNING AND DEVELOPMENT
DEPARTMENT - ENERGY DIVISION

Response to Comment Set GFT

GFT-1: The comment does not address the adequacy or content of the EIR. Comments in support or opposition to the proposed project should be submitted to the decision-makers prior to public hearings on the proposed project.

GOO

Get Oil Out!

PO Box 23625
Santa Barbara, CA 93121

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JAN 16 2007
PLANNING AND DEVELOPMENT
DEPARTMENT - ENERGY DIVISION

January 16, 2007

Kevin Drude, Energy Specialist
Santa Barbara County Energy Division
123 East Anapamu Street
Santa Barbara, CA 93101

Re: Draft Environmental Impact Report (DEIR) for the Tranquillon Ridge Project

Dear Mr. Drude:

In less than two weeks, Get Oil Out! (GOO!), which was founded shortly after the tragic oil spill that hit the Santa Barbara Channel on January 28 1969, will celebrate 38 years of working on oil and gas issues off our coast. Given the number of new oil and gas projects that continue to be proposed, GOO! will diligently continue reviewing and monitoring those proposals in hopes that we will never again suffer an oil spill like the one in 1969.

In that light, GOO! offers the following comments on the DEIR for the Tranquillon Ridge project being proposed off the coast of Lompoc. As you may know, GOO! is also being represented by the Environmental Defense Center (EDC) in this matter, so it will not be necessary to reiterate all of the comments submitted by EDC in this letter. However, there are some issues that GOO! feels are worth emphasizing, in addition to making some of our own separate comments.

GOO-1

As an overall comment, GOO! agrees with the County's establishment of the baseline as current production from the existing facilities. It is important to remember that, as originally proposed, these facilities would be winding down at this time but, as stated in the DEIR, are still 10-15 years from completion, even without the proposed project. GOO! also agrees that the two most critical issues are the extension of the project's life for an additional 20 plus years and the increase in production to a level roughly four times that of today's production. It is these two issues that drive virtually all of the impacts associated with the proposal, especially given the age of the facilities involved.

Project Objective and Description

GOO-2

The document begins by saying that "the main objective of the proposed Tranquillon Ridge project is to efficiently and effectively develop oil and gas reserves from the Tranquillon Ridge Field and to sell the oil and gas production to help meet the energy needs of the state of California". From there, the project objective becomes narrower, not broader. This section should contain language which broadens, not narrows, the Project Objective so that a greater variety of Alternatives to the proposed project can be examined. Narrowing the project objective so that the only project that can meet that objective is the one being proposed is unacceptable.

Kevin Drude
January 16, 2007
Page Two

GOO-2
Cont'd

The description of the proposed project should be amended to include the likelihood that the current onshore pipeline, which is in conflict with a proposal that this same applicant has submitted to the City of Lompoc for annexation of land and residential development, will need to be moved. The new pipeline route or alternative routes should be identified in the project description and analyzed in the document. Finally, the least environmentally damaging pipeline route should be identified in the document so that if and when the residential project goes forward, the location of the new pipeline route will have already been established.

Onshore Alternative

GOO-3

GOO!'s biggest concern about the review of this alternative is that the level of detail is not adequate for decision-makers to be able to compare it with the proposed project. As currently proposed and reviewed, both the proposed project and the onshore alternative would use most of the same onshore facilities. Therefore, the main difference between these projects is where the oil is produced and how it ties into the existing onshore pipeline that goes to the Lompoc Oil and Gas Plant (LOGP). The proposed project involves the use of Platform Irene and the existing offshore to onshore pipeline and the onshore alternative involves the abandonment of the offshore facilities and the construction of a new drilling and production facility and a new onshore pipeline that would tie into the existing onshore pipeline to the LOGP.

The key impacts that must be compared between the two options are related to 1) the offshore oil production and pipeline, which carries a significant risk of an offshore oil spill and 2) the construction of new facilities, their maintenance and the risk of onshore oil spill. It is very difficult for the public, as well as decision-makers, to assess these scenarios when the level of detail and of analyses are not equal, a bit like trying to compare apples with oranges. With a project level of detail, the document could review a variety of alternative pipeline routes and mitigation measures so that the least environmentally damaging route could be chosen. This document does not provide enough information to select that route. Without the identification of the least environmentally damaging route for the new pipeline, the comparison between that route, as part of the onshore alternative, and the existing project cannot truly be made.

GOO-4

A comparison of the long term and short term impacts of these differences must also be included. In other words, are most of the impacts related to the proposed project short term or long term, with the same question being posed with regards to the impacts of the onshore alternative. This could be done easily by creating a chart with this information.

Lifetime of the Proposed Project

GOO-5

One of the most overarching issues affecting the impacts of the proposed project is related to the expected lifetime of the facilities. The applicant proposes to use Platform Irene and associated pipelines and the LOGP for an (estimated) 30 years, commencing in 2007. When the original (existing) project was approved, it was also estimated that that it would be completed in 30 years, however, the DEIR tells us that this project is now expected to continue for at least another ten years (until 2017). As a result, we are already entering a phase of oil and gas development on Platform Irene which was not considered in the original environmental document.

Kevin Drude
January 16, 2007
Page Three

GOO-5 Cont'd

In light of this experience and the comment on page 2-5 of the DEIR which states "the oil production estimates for the Tranquillon Ridge Field are base on limited data…" and page 2-13 which states "it is possible that due to changes in the technology and oil prices that the production from the Tranquillon Ridge Field could extend beyond the 30 year estimate…", it is critical that the DEIR review a greater range of the predicted lifetime. In order to accomplish this, the document should refer to the lifetime of the project as 30 (or greater) years. Since the probability of an oil spill has a direct correlation to the lifetime of the project, increasing with time, Tables 5.1.24, 27 and 28 in the Risk of Upset section should include both 30 year and 40 year lifetime columns for the prediction of spill probabilities. Other parts of the document that analyze impacts based on the 30 year lifetime should be similarly altered, including the public safety risks associated with the LOGP, which is in close proximity to residential areas, and the estimates for additional truck trips of LPG/NGL's leaving that facility.

GOO-6

Finally, the document indicates that the proposed project, if approved, would start in 2007. Given where this project is in the process, this is a highly unlikely possibility. The expected start date should be changed to 2008.

Environmental Impacts

GOO-7

GOO! agrees with the statement on page 5.5-40 that "The endangered brown pelican and the California least tern could be severely impacted by an oil spill." and believes that the same language should be applied to the sea otter on page 5.5-39 in lieu of the much weaker language indicating that the potential exists for a spill to impact a high number of sea otters in this region. Given that the sea otters' current range and numbers are relatively small, and that they are extremely susceptible to the effects of oil, the DEIR needs to revise this language to accurately reflect the danger an oil spill poses to sea otters, especially given the information on page 5.5-42 which indicates that "a major spill from the Point Pedernales offshore facilities would likely result in shoreline contamination…. due to the proximity of land and the prevailing winds and currents in the area."

GOO-8

GOO! also believes that the potential impacts to the pinnipeds at San Miguel Island are understated in the DEIR. The DEIR indicates that under certain weather and ocean conditions, portions of the Western Channel Islands could be affected by an offshore oil spill. While the percentage that this could happen is less than 30%, the DEIR needs to recognize that should an oil spill reach these islands, the impacts to the marine mammals that live there would be devastating, especially if the spill occurred during the breeding season. The EDC's letter discusses both of these issues in greater detail.

GOO-9

GOO! has always been concerned about the impacts that dumping muds and cuttings can have on benthic and other organisms and has consistently opposed dumping them into the ocean. As briefly discussed in the DEIR, the State is having severe problems dealing with the muds, cuttings and shell mounds associated with the four "H" platforms off Carpinteria's coast. There is absolutely no reason to allow the dumping of these materials when alternative means of disposal are available. The California State Lands Commission does not allow the disposal of drill muds and cuttings in state waters. While the document indicates that drill mud plumes are not likely to enter into state waters, it is possible that they could, based on the information in the DEIR that currents are strong in the project area (page 5.5-44). GOO!, therefore, strongly supports a requirement that these waste materials be either injected into a reservoir or be taken to shore for disposal. GOO! also takes exception to the language on page 5.5-64 regarding the cumulative impacts of discharging drill muds

Kevin Drude
January 16, 2007
Page Four

GOO-9 Cont'd

and cuttings that states "Because of the dilution and localized dispersion of each discharge, drilling muds or cutting depositions would not be expected to compound or accumulate in any specific area." This is reverting to the old worn-out adage that dilution is the solution to pollution. We can no longer take the stance with our environment that pollution will just "disperse" or "disappear".

GOO-10

GOO! disagrees with the statement on page 5.2-49 that "it is very unlikely that an offshore oil spill would directly affect freshwater or brackish/estuarine aquatic environments" since these environments *were* affected in the 1997 spill which involved only 163 barrels of oil. Recognizing the likelihood of these estuarine impacts from offshore oil spills increases the environmental impacts from the proposed project. A clear understanding of such impacts will be critical when decision-makers and the public begin to evaluate whether or not an onshore alternative exists that would have less impacts than the currently proposed offshore project.

GOO-11

In conclusion, GOO! wishes to commend County staff and the consultants for providing a lot of detailed information about the existing conditions in the area, as well as the potential impacts of the proposed project. It is equally, if not more important, however, for this and other EIR's for oil and gas projects to include the more global impacts of oil development, global warming in particular.

GOO-12

Ultimately, the environmental costs of taking this oil out of the ground, for processing it and for using it must be analyzed and compared with just leaving the oil there and pursuing more environmentally friendly alternatives, such as conservation, solar, wind, etc. Until we begin to look at these issues in that light, we may just be moving the deck chairs on the Titanic instead of trying to steer our boat out of the iceberg's way, thus avoiding a disastrous collision.

Thank you for this opportunity to comment on this DEIR. GOO! looks forward to receiving a copy of the Final EIR.

Sincerely,

Abe Powell

Abe Powell, President
AP:cdf

Response to Comment Set GOO

GOO-1: Comment noted.

GOO-2: Please see Response to Comment EDC-2.

GOO-3: Please see Response to Comment EDC-92.

GOO-4: Impacts in Section 6 are discussed in terms of construction (short-term) and operational (long-term) impacts. Table 6.4 has been clarified to reflect this.

GOO-5: Please see Response to Comment EDC-17. Impact Risk.3 discusses that the existing Class I impact as a result of NGL/LPG truck trips would be exacerbated (more truck trips and a longer period over which truck trips would occur). The classification of this existing impact as Class I (significant and unavoidable) would not change with a 40-year versus 30-year project life.

GOO-6: At the time PXP filed the applications for the Tranquillon Ridge Project, 2007 was the proposed start of the operations timeframe. The emphasis of the analyses of the proposed project presented in the EIR is the projected economic life of the project (approximately 30 years). Therefore, whether the EIR addressed the operations timeframe of 2007 to 2037 versus 2008 to 2038 would have no effect on the analyses presented in the EIR.

GOO-7: Please see Response to Comment EDC-79. The EIR acknowledges the vulnerability of sea otters to oil and has identified the impact of oil spills to marine mammals as Class I. Language has been added to Mitigation Measure MB-1a to specify that the updated Core OSRP must specifically include measures to reduce potential oil spill impacts to sea otters.

GOO-8: Please see the Response to Comment EDC-80. Language has been added to Mitigation Measure MB-1a to specify that the updated Core OSRP must specifically include measures to reduce potential oil spill impacts to breeding pinnipeds.

GOO-9: The EIR acknowledges that the disposal of drilling muds and cuttings via reinjection or onshore disposal would be environmentally preferable to ocean discharge. However, as discussed in the EIR, because of the shunt depth, most of the heavier muds aggregates would be deposited on the seafloor directly below and within 500 meters of the discharge. Appendix D to this EIR presents site-specific modeling of drill-muds dispersion that was conducted as part of the analysis for this EIR. Results indicate that the deposition of drilling flocs (lightweight drilling particles) far from Platform Irene would be negligible. Because of the along-shore alignment of prevailing currents, tangible deposition would not occur in State Waters.

GOO-10: The significance thresholds and resultant impact analysis presented in the EIR for oil spill impacts do not address likelihood, but rather address consequences of an oil spill. As documented throughout the EIR, impacts from an oil spill are considered to be Class I, significant and unavoidable. See also Response to Comment EDC-49.

GOO-11: EIR Sections 5.8.2.2 and 5.8.4.2 include revisions to identify the plans that the California Air Resources Board is developing for reducing greenhouse gas emissions as required by AB 32. See also Response to Comment EDC-86.

GOO-12: Please see Responses to Comments EDC-2, EDC-11, and EDC-12.

JP

Jon Picciuolo
445 Oak Hill Terrace
Lompoc, CA 93436
(805) 733-1217

RECEIVED
COUNTY OF SANTA BARBARA
NOV 27 2006
PLANNING AND DEVELOPMENT
DEPARTMENT - ENERGY DIVISION

November 17, 2006

Kevin Drude, Energy Specialist
Santa Barbara County P & D
Energy Division
123 E. Anapamu St.
Santa Barbara, CA 93101

Re: <u>Draft EIR for the Proposed Tranquillon Ridge Project</u>

Dear Mr. Drude,

I reviewed the draft EIR for the subject project and attended the workshop at Lompoc City Hall on Wednesday, November 15th. I have a major concern with a critical aspect of the analysis contained in the draft EIR.

JP-1

Table 4.2 and Figure 4-3 clearly and correctly identify the "PXP Residential Development Annexation to the City of Lompoc" (Fig. 4-3 Key Site #12) as a Relevant Cumulative Project. This PXP proposed development is for 1300 homes on 800 acres. PXP's land development representatives have repeatedly asserted in multiple venues that PXP intends to build a residential development on Key Site #12.

As I understand California's guidelines for preparing an EIR, projects which are reasonably foreseeable must be considered in the environmental analysis. As I further understand the guidelines, foreseeable projects must be included in the Risk of Upset analysis.

Representatives of PXP (the applicant for the Tranquillon Ridge Project) have made it absolutely clear that PXP considers the proposed residential development of Key Site #12 to be foreseeable. The proposed PXP residential development is undoubtedly a foreseeable project.

In the "Sensitive Populations" part of Section 5.1 (Risk of Upset/Hazardous Materials), on page 5.1-34 of the draft EIR, it is implied that the following assumptions are used in the risk analysis calculations:

- An average of three persons are located in the hills around the LOGP for 24 hours per day, 365 days per year, and
- Less than four persons per mile would be present on Harris Grade Road.

-- page 1 of 2 --

JD-1
Cont'd

Those assumptions most certainly do not agree with the circumstances expected for the Relevant Cumulative Project identified for Key Site # 12. A 1300-home development on Key Site #12 will place many additional Lompoc Valley residents and many more passenger vehicles in proximity to the LOGP. Therefore, the risk analysis assumptions are incorrect. If the assumptions are incorrect, the risk analysis itself cannot be correct.

The EIR for the Tranquillon Ridge Project must include a risk analysis for the PXP residential development which is a foreseeable project proposed for Key Site #12. Omission of this analysis would be a serious and major flaw of the EIR.

It is not prudent to delay an analysis of the Tranquillon Ridge Project's risk to the proposed PXP residential development until that development gets into an environmental impact study stage. The underlying purpose of doing a risk analysis now, while the Tranquillon Ridge Project is still in a formative state, is to ensure that necessary mitigations are formulated and made an integral part of the Tranquillon Ridge Project's design.

Thank you for this opportunity to comment.

Sincerely,

Jon Picciuolo

-- page 2 of 2 --

Response to Comment Set JP

JP-1: The commenter is correct that both the project-specific and cumulative impacts, including risk of upset, associated with the proposed project must be evaluated in the EIR. Project-specific impacts are assessed against the existing baseline environment. The cumulative impacts assessment addresses the potential changes in the environment that could result from the proposed project in combination with other proposed, pending, and reasonably foreseeable projects in the area. The commenter is also correct that the PXP housing proposal is a reasonably foreseeable project. This proposal is included in the cumulative impacts assessment in the EIR. However, as explained below, the assessment of the cumulative risk-of-upset impacts does not include the quantitative component that is part of the project-specific impact assessment.

The potential risks created by the proposed project are quantified and discussed in the EIR (Section 5.1). This project-specific, quantitative risk assessment can only consider how the proposed project would affect the baseline environment, that is, what exists today in the way of surrounding land uses and the risks those land uses would be exposed to as a result of the proposed project. This quantitative assessment uses detailed, known information about the environment (density of homes, schools, hospitals, etc. within the area) and compares that information to the hazards that would be created by the proposed project in order to understand the risks to the public if the project is implemented.

A quantitative risk assessment is based upon specific detailed input about both the proposed project and the existing environment in order to estimate the frequency and consequences (risk) of potential events (e.g., accidents, upset conditions) associated with a proposed project. Risk is a compound measure of the probability and the consequences of an adverse effect and thus the County's safety thresholds of significance are based on both the probability and the consequences of an accident or upset condition. The County thresholds identify three zones – green, amber, and red – on graphs of frequency of an event vs. the consequence to society if the event occurs for guiding the determination of impact significance. The quantitative risk assessment takes into account the effect of mitigation on the risk and results in a curve that is plotted on the graphs of frequency vs. consequence (see, for example, Figures 5.1-3, -4, -5, and -6 in Section 5.1 of the EIR). If the curve falls entirely within the red zone or amber zone, the risk is a Class I impact (significant even with mitigation). If the curve falls entirely within the green zone only if mitigation is applied, the impact is Class II (not significant with mitigation). Risks with curves that fall entirely within the green zone even without mitigation are Class III (not significant). These thresholds, which were adopted by the County in 1999, are used in the County's environmental analysis of a proposed project that would result in risks to society, and also in the analysis of a development proposed in proximity to an existing hazardous operation. Again, the quantitative risk assessment is necessary to apply the County's thresholds and can only be prepared with specific detailed information about the proposed project and the existing environment. The County thresholds cannot be applied without the curves generated by a quantitative risk assessment.

The cumulative impact assessments throughout the EIR address the potential cumulative impacts associated with the proposed project in combination with other reasonably foreseeable projects in the area and region. By its nature, this cumulative analysis is qualitative because these projects do not yet exist on the ground and are not yet part of the baseline; thus, the details needed for a reliable quantitative assessment are not, and cannot be, known at this time. For risk, this analysis must examine the cumulative risks created by the proposed project and other projects with similar impacts that would occur over time if the proposed and these other projects were to be implemented. This analysis is presented in Section 5.1.6.2 of the EIR.

The cumulative risk analysis is not intended to assess the potential risks of the proposed project to future projects. A quantitative risk assessment can and should be performed when the PXP housing project, or any other future project, undergoes environmental review and would be the responsibility of the future project applicant and permitting authority. At that time, the risk to future residents of the housing development from the PXP oil and gas facilities can be quantified and, potentially, mitigation measures designed to eliminate or reduce significant risks. Such measures could include redesign of the housing configuration to avoid the hazard footprints of the PXP facilities, or reduction or relocation of the hazard footprint of the sour gas pipeline (e.g., reduced operating pressure or relocation of the sour gas pipeline and the LOGP). On the other hand, the risk analysis could determine that the risks of the existing hazardous operations to the proposed housing development cannot be mitigated to less than significant levels. In any event, the cumulative risk analysis for the proposed Tranquillon Ridge project cannot presume the outcome of the quantitative risk assessment that would need to be conducted for the future residential project.

Section 4.4.1 of the EIR has been revised to include additional information regarding the current status of the PXP housing proposal. Based on the information available to date, there is a potential for the existing PXP oil and gas facilities (and future operations if the Tranquillon Ridge project is implemented) to pose a significant risk to new residents if this housing proposal were to be implemented as currently configured. It is noted that PXP has stated it would relocate the sour gas pipeline to avoid some of the risk associated with the sour gas pipeline. This potential mitigation measure would need to be analyzed in the environmental review for the housing proposal. In addition, any modifications to the PXP oil and gas facilities, including relocation and/or changed operating parameters of the sour gas pipeline, changes to the NGL/LPG transportation management plan, or other operational changes, required to accommodate the housing proposal would necessitate a modification of PXP's Point Pedernales Final Development Plan, including environmental review. Such review would be conducted by the City of Lompoc as part of the annexation/rezoning proposal associated with the housing development proposal. If the annexation proposal to the City of Lompoc did not go forward and the housing development was proposed to the County, analysis of the risk to the housing development posed by the existing oil and gas facilities (whether or not they include the proposed Tranquillon Ridge project) would be part of the environmental review conducted by the County for the housing project. Part of this review would identify potential mitigation measures and evaluate their effectiveness in eliminating or reducing public risks. If there are significant and unavoidable impacts associated with a project that is approved, a statement of overriding considerations must be adopted by the decision-makers, pursuant to §15093 of the State CEQA Guidelines, to support such approval. However, under the County's Safety Element Supplement Policies 2A, 3A, and 3B, certain kinds of development (high density and/or highly sensitive uses) may not be approved where an unacceptable risk exists.

MEB

Dear Staff:

I am unable to attend tonight's Workshop on the DEIR Tranquillon Ridge. I would like to express my concerns about the project, especially the inclusion of the LOGP in any expansion or new project.

MEB-1

LOGP is now located one mile from two populated areas. Residents voiced concern when the separation plant was first proposed in the early 80s. We voiced concern when the plant became an actual processing plant.

The life of the existing plant and pipelines was supposed to be 15 years. The County allowed an extension in 2000 when the first time limit expired. Residents are concerned about the viability and safety of the now outdated pipes and equipment, not to mention concern about the numerous leaks/human errors, and emergency shutdowns over the years.

MEB-2

Now PXP is planning to build 1300 homes on land that it owns which is even closer to the plant. This will create even more hazardous conditions, not to mention additional traffic leading to and from the plant. Mixing humans with chaparral across the road from a gas facility which is surrounded by H2S pipelines seems foolhardy.

MEB-3

Please give the residents of this area as much consideration as the marine life that will be endangered with this project.

Sincerely,

Mary Ellen Brooks
resident
718 St. Andrews Way
Lompoc, CA 93436

Response to Comment Set MEB

MEB-1: Please see Responses to Comments S&EM-1, S&EM-5, and EDC-18.

MEB-2: Please see Response to Comment JP-1.

MEB-3: The EIR addresses the full range of issue areas, in addition to impacts to the marine environment, including risk of upset, terrestrial biology, geological resources, onshore water resources, air quality, traffic, noise, fire protection and emergency services, cultural resources, aesthetics/visual, recreation/land use, agricultural resources, and energy and mineral resources. Further, one of the findings the County decision-makers would need to make in order to approve the proposed project is that it would not be detrimental to the comfort, convenience, general welfare, health and safety of the neighborhood (SBC Land Use & Development Code Section 35.82.080.E.1.e).

RCN

Richard and Carol Nash
432 St. Andrews Way
Vandenberg Village
January 16, 2007

Kevin Drude, Energy
County of Santa Barbara Planning & Development
Re: Tranquillon Ridge Oil and Gas Development Project
06-EIR -000000-00005, October 2006
FAX: 568-2522

Dear Mr. Drude,

We have lived in Vandenberg Village since January 1961. We have followed the development of the Lompoc Oil & Gas Plant (LOGP) with all its trials, tribulations and some downright scary incidents which have posed threats to our homes and indeed the lives of the thousands of residents in this community.

RCN-1

From the get-go the plant was a colossal error in land use planning. Oil development on a hill atop a residential community is certainly a glaring case of incompatible land use. When the plant was proposed, industry personnel filled the room and lined the walls promising that this site would be used only for the separation of oil and water. There was to be NO processing or refining. We would never have to be concerned about end products moving through our residential neighborhoods. Processing would take place at Battles.

BUT, after the "camel got his nose in the tent", the situation began to change. And, the conditions at the plant were becoming more unsafe. With the preliminary planning of Point Pedernales Project (1985), it seemed the concern for human life, homes and habitat were overshadowed by the oil and gas industry's "state of the art" posturing. There were promises of lots of jobs and money for the County of Santa Barbara. Then, the County had to shut down the Battles processing plant.

In 1994 Unocal was allowed to construct and operate a gas plant at the Lompoc Separation Plant via a Substantial Conformity Determination. Beautiful new maps began to appear with no indication of the residential areas at risk or the Burton Mesa Chaparral Reserve that surrounds the plant, the houses and the La Purisima Mission State Historic Park.

The Final Development Plan 94-DP-027 (July 24,2000) for Torch Point Pedernales Project indicates the Director's Amendments, the modifications to the project, the Supplemental EIR, the EIR Addenda etc. (See 3 attached pages.) The public was hard put to follow and understand the risks to health, safety and general well being. The bog fire alone (that took about a year to finally extinguish) could have wiped out many homes had the wind been blowing in this direction. Instead, it caused miserable pollution problems, the evacuation of another town, and the loss of one human life. The spills and other problems connected with the pipelines and other aspects of the operation seemed to be covered in the document and public testimony.

RCN-1
Cont'd

The County is certainly aware of the dangers the Lompoc O&GP presents. Even if the company's plans were perfect, the risk of human error or an act of nature could cause an incident of catastrophic proportions. The North County Siting Study (January 2000), lists the environmentally preferable location(s) for such a plant - #1 choice, Casmalia East (Conclusion page attached). Certainly this location is less risky for human life. The PXP current proposal for over 1300 homes across the road from the plant indicates how cavalier PXP and the industry regard the threat posed to human life.

The proposed extension for the life of the present Lompoc Oil and Gas Plant should not be permitted. The EIR Alternatives should include moving the plant. The County of Santa Barbara should require PXP, and any other of the parties involved, to move this plant to a safer location. If last year's profit for the oil industry is any indication, this move should be a breeze and probably more economical in the long run. The County must be concerned for the heath, safety and general welfare of the community.

Thank you for this opportunity to comment.

Sincerely,

Richard Nash Carol Nash
Richard and Carol Nash

Attachments: 4 pages

(2)

TORCH POINT PEDERNALES PROJECT

1.0 INTRODUCTION

On August 5, 1985, the County Board of Supervisors approved the Preliminary Development Plan for the Point Pedernales Project. On April 17, 1986, the County's Planning Commission approved the project's Final Development Plan (FDP). The purpose of the FDP is to permit the construction and operation of the Point Pedernales facilities, while mitigating environmental impacts and land use conflicts caused by the project to the maximum extent feasible. Currently, there are 193 conditions listed in the FDP, 12 of which have been previously deleted. The requirements of the remaining 181 conditions collectively span every phase of the project's lifetime, from pre-construction to abandonment.

Condition B-2 of the project's FDP provides the County with the authority to periodically evaluate the effectiveness of the project's conditions of approval. The condition, titled "Condition Effectiveness Review," reads as follows:

> *"If at any time County determines that these permit conditions are inadequate to effectively mitigate significant environmental impacts caused by the project, or that recent proven technological advances could provide substantial additional mitigation, then additional reasonable conditions shall be imposed to further mitigate these impacts. Imposition of such conditions shall only be considered and imposed as part of the County's comprehensive review of project conditions. County shall conduct a comprehensive review of the project conditions and consider adding reasonable conditions which incorporate proven technological advances three years after permit issuance and at appropriate intervals thereafter. A comprehensive review of conditions that are not effectively mitigating impacts may be conducted at any appropriate time. Upon written request, the Board of Supervisors shall determine whether the new condition required is reasonable considering the economic burdens imposed and environmental benefits to be derived."*

2.0 PROJECT BACKGROUND

2.1 Project Description

The Point Pedernales Project (project), as originally approved by Santa Barbara County (County), included Platform Irene located within the Pacific Outer Continental Shelf (POCS) Point Pedernales Unit, an electrical substation located at Surf Beach, and a Heating Separating and Pumping (HS&P) facility located on Harris Grade Road north of the City of Lompoc. The project additionally included a subsea power cable connecting the platform to the Surf Beach substation, three connecting pipelines between Platform Irene and the HS&P facility, and connecting pipelines between the HS&P and the Orcutt Pump Station and Battles Gas Plant. The three pipelines originally proposed for connection between Platform Irene and the HS&P included one 20-inch diameter wet crude oil line, one 10-inch produced water line, and one 10-inch natural gas line. Modifications to the Orcutt Pump Station and Santa Maria Refinery were additionally proposed and approved.

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NASH letter attachment (page 1)

As constructed and initially operated by the Union Oil Company of California (Unocal), the project included all of the above components with the exception that final engineering and design plans replaced the two 10-inch off- to onshore pipelines with 8-inch pipelines.

Since project construction, several physical and administrative modifications have been made. Primary changes have included, in chronological order:

- Planning Commission approval for Unocal to construct and operate a gas plant at the Lompoc HS&P site to replace operations of the Battles Gas Plant (1994);
- Approval, via a Substantial Conformity Determination with the project's FDP, of the purchase and operation of the Point Pedernales Project by Torch Operating Company (on behalf of Nuevo Energy Company) (1994);
- Approval, via Director's Amendment to the project's FDP, of splitting the Point Pedernales Project into three separate projects. Torch Operating Company (on behalf of Nuevo Energy Company) retains Platform Irene, the off- to onshore pipeline bundle connecting Platform Irene to the Lompoc HS&P, the Surf Beach substation and offshore connecting power cable, and the Lompoc HS&P facility. The rest of the original Point Pedernales facilities were retained by Unocal (the Battles Gas Plant) and Unocap (now the Tosco Point Pedernales Project) (1995);
- Approval (via Director's Amendment) of onshore re-injection of natural gas produced from Platform Irene during the period between abandonment of the Battles Gas Plant and construction of the Lompoc Gas Plant (1995);
- Planning Commission approval of the above-referenced Lompoc Gas Plant with modified design and increased capacity, as well as the addition of an approximate seven-mile ("sweet") natural gas sales pipeline to a Southern California Gas Company (SoCal Gas) distribution pipeline (1996); and,
- Approval (via Director's Amendment) to allow an increase in the hydrogen sulfide (H_2S) concentration within the off- to onshore natural gas pipeline from 4,000 parts per million (ppm) to 8,000 ppm (1999).

In addition to the above, several minor facility modifications, such as the replacement of water pumps, have been approved and installed via non-discretionary permit approvals. Figure 1 displays the project's location and components.

2.2 Summary of Project Environmental Reviews

To date, six environmental documents have been prepared for the project pursuant to the California Environmental Quality Act (CEQA). They include reviews for:

(1) the originally proposed project (an Environmental Impact Statement/Environmental Impact Report (EIS/EIR) finalized in 1985);

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NASH letter attachment (page 2)

(2) construction and operation of a gas plant at the Lompoc facility to replace the Battles Gas Plant (a Supplemental EIR finalized in 1993);
(3) transportation of natural gas liquids (NGLs) from the Lompoc facility (an EIR Addendum finalized in 1993);
(4) temporary onshore re-injection of the natural gas produced offshore during the period between closure of the Battles Gas Plant and commissioning and operation of the Lompoc Gas Plant (an EIR Addendum finalized in 1995);
(5) process design and capacity modifications to the originally proposed Lompoc Gas Plant (an EIR Addendum finalized in 1996); and
(6) an increase in the H_2S concentration of the off- to onshore natural gas pipeline from 4,000 ppm to 8,000 ppm (an EIR Addendum finalized in February 1999).

The original suite of FDP conditions for the project were developed, in part, in response to the Class I through Class III impacts and recommended mitigations measures of the original EIS/EIR. Subsequent revisions to the FDP conditions have been made in response to the findings of the project's subsequent Supplemental EIR and EIR Addenda.

2.3 Origin of This Condition Effectiveness Review

As prescribed by Condition B-2, the project underwent its first condition effectiveness review between 1990 and 1992. Of the FDP's original 169 conditions, 73 were evaluated in-depth. The in-depth analysis determined that 40 conditions required some type of modification to enhance mitigation effectiveness. This current condition effectiveness review is the first Condition B-2 report since the 1990-1992 analysis.

On September 28, 1997, the project's off- to onshore wet crude oil line ruptured approximately 2.5 miles from shore. The rupture occurred at the weld of a flange during a routine internal cleaning ("pigging") of the line. The physical integrity of the flange had been compromised during the project's original construction due to a lack of preheating during pipeline welding. This caused the metal in the flange's "heat-affected zone" to become hard and brittle. Following extensive pipeline investigations, repairs, and testing, the County, California Coastal Commission, U.S. Minerals Management Service and State Lands Commission allowed production to resume on December 11, 1997. Estimates of the total crude oil spilled due to the rupture currently range from 163 barrels to in excess of 1,242 barrels.

Torch's omissions and/or acts of non-compliance with conditions relating to leak detection and emergency shutdowns substantially increased the spill volume during the pipeline rupture event and raise significant concerns. Specifically, Torch overrode pipeline safety devices and turned the platform's oil shipping pumps back on following the low pressure automatic shutdown, without inspecting the pipeline corridor to ascertain the cause of the low pressure condition. As a result of restarting the flow of oil into the pipeline, Torch pumped oil out of the rupture into the ocean. These actions constitute violations of FDP Conditions P-16 (Supervisory Control and Data Acquisition System), P-13 (Oil Spill Contingency Plan), and P-2 (Safety Inspection, Maintenance and Quality Assurance Program). The Planning and Development Department, the County Counsel, and the District Attorney's Office completed an investigation of the facts and

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NASH letter attachment (page 3)

North County Oil and Gas Facility Siting and Planning Analysis
Section 1.0 Executive Summary

1.3 CONCLUSIONS

The study addresses different scenarios of how offshore production could be processed onshore. The scenarios incorporate different assumptions regarding which leases would be processed at existing facilities on the County's South Coast. The preferred scenario identified in the study directs production from federal leases in the southern Santa Maria Basin (including Sword and Bonito) to the County's South Coast. Referencing the Chevron R-1 EIR, the study concludes that the existing facility and consolidation site in Las Flores Canyon appears to be environmentally preferred for processing production from these leases.

The study utilizes information from the Minerals Management Service regarding the physical properties of the crude oil in the Santa Maria Basin. This information suggests that either a new facility would have to be constructed, or the Lompoc Oil and Gas Plant would have to undergo substantial modification to process the oil from the northern fields, due to the heavy nature and high metal content of the oil. This study analyzes the potential for expansion of the Lompoc Oil and Gas Plant versus siting a new facility in a less constrained location.

The Site Analysis section of the document compares the merits and flaws of both the existing and the candidate oil and gas sites. Due to the potential for new offshore production to occur for a period that could exceed 25 years, the study concludes that the benefits of siting a new facility in a less constrained location outweigh the negative aspects of constructing a new facility. The five potential sites identified in the study, listed in order of environmental preference, are Casmalia East, Casmalia West, Cat Canyon North, Cat Canyon South, and Miguelito.

Draft Study 1.0-2

NASH letter attachment (page 4)

FAX TRANSMITTAL

To KEVIN DRUDE
ENERGY DIVISION - P&D

Date JAN. 16, 2007

At: FAX No. 568-2522

Phone

RECEIVED
COUNTY OF SANTA BARBARA
JAN 16 2007
PLANNING AND DEVELOPMENT
DEPARTMENT - ENERGY DIVISION

Transmitting the following:

Sheets	Dated	Title/Description
2	1-16-07	letter - NASH
3		on POINT PEDERNALES PROJECT
1		on NORTH COUNTY OIL + GAS FACILITY SITING

Number of pages, including this page: 7

From: RICHARD and CAROL NASH
VANDENBERG VILLAGE

Phone: 733-2483

Fax: (Same)

Comments:

Response to Comment Set RCN

RCN-1: Regarding the Battles plant, the land use decision was made by the County that it would be better overall to relocate gas processing to the LOGP location than to retrofit the Battles plant to bring it up to then-current safety standards. This led to decommissioning and abandonment of the Battles plant. The HS&P was permitted by the County with a Development Plan (91-DP-017) which allowed construction and operation of gas processing facilities at the LOGP location. This permitting process included preparation, public review, and certification of a Supplemental EIR (SCH#92021083, SBC # 92-EIR-13) and County approval at a public hearing in January 1994. The 1994 Supplemental EIR risk evaluation addressed potential risks of hydrogen sulfide exposure, flammable vapor hazards, thermal radiation exposure, and explosion overpressure exposure to people in Vandenberg Village, among other potentially affected areas near the HS&P/LOGP site.

This Tranquillon Ridge EIR considered an alternative location for the oil and gas processing plant (Casmalia East site) and concluded that such relocation would create more significant impacts in several issue areas than continued use of the existing LOGP and would increase public exposure to sour gas releases because of the additional sour gas pipeline between LOGP and new Casmalia processing facility. See also Responses to Comments CPA-2, JP-1, S&EM-1 and S&EM-5.

S&EM

January 12, 2007

Mr. Kevin Drude
Energy Specialist
Santa Barbara County P&D, Energy Division
123 E. Anapamu Street
Santa Barbara, CA 93101

RE: Comments on Tranquillon Ridge Project Draft EIR

Dear Mr. Drude:

Sunset Exploration, Inc. (Sunset) and Exxon Mobil Corporation (ExxonMobil) are hereby submitting the enclosed comments on the adequacy of analysis of the Tranquillon Ridge Draft Environmental Impact Report (SCH # 2006021055, County EIR #06EIR-00000-00005) published and submitted for public comment on October 30, 2006.

The technical analysis of the Draft EIR (DEIR) was prepared by subject matter experts from Sunset, ExxonMobil and several consultant organizations. The analysis determined inadequacies in the DEIR on the proposed project and the identified alternatives.

Specific comments on the DEIR are provided in the enclosure. The comments are organized by DEIR section for ease of review. Each comment within a section is individually numbered and contains the DEIR Section reference, the Section title, a paraphrase of the DEIR statement, an indication of the portion of the project referenced, and the specifics of the concern or request for revision of the document.

Our evaluation indicates that the major inadequacy of the DEIR is the incomplete, and therefore inaccurate description of the VAFB Onshore Alternative. The Sunset/ExxonMobil Vahevala Project is specifically referenced in defining the VAFB Onshore Alternative, and is discussed as the primary project alternative throughout the document. However, the DEIR does not include a number of optimizations that have been made to the Vahevala Project to mitigate potential impacts to environmental and cultural resources.

Additionally, our analysis indicates that the DEIR does not adequately address multiple potential environmental impacts of the PXP-proposed offshore project. The primary areas of concern relate to the risks associated with extending the life of the 20 year old Platform Irene and it's pipelines to shore by an additional 30 years. In particular, our evaluation indicates that the DEIR lacks a realistic assessment of the probability of an additional leak from the PXP Irene pipelines to shore, as occurred in 1997. Our analysis also indicates that there may be several Platform Irene and related infrastructure upgrades required to implement the PXP-proposed offshore project such as potential modifications to or replacement of the drilling rig, new pipelines to shore and a new power cable to shore. Each of these activities as well as other maintenance required to safely extend the life of Platform Irene and related equipment have environmental impacts that are not adequately evaluated in this DEIR.

In order to accurately compare the environmental impacts of the Proposed Project (PXP offshore) with the various alternatives, the jurisdictional agency is required by CEQA Guidelines (Section 15126.6 [d]) to prepare an environmental document that includes sufficient information about each alternative to allow meaningful evaluation, analysis, and comparison to the Proposed Project. As such, we request that the VAFB Onshore Alternative be revised to include the key optimizations identified in our comments and the full impacts of the PXP-proposed offshore project be incorporated. Once this has occurred, the comparison of the projects and the determination of impacts will need to be reanalyzed and the DEIR recirculated for public review and comment, as we believe is required by Section 21092.1 of CEQA and Section 15088.5 of the CEQA Guidelines.

Should you have questions or require additional information, please do not hesitate to call Mr. Robert Nunn of Sunset Exploration, Inc. at (925) 634-2148 or Mr. David Kasper of ExxonMobil Exploration Company, a Division of Exxon Mobil Corporation, at (281) 654-7067.

Sincerely,

Robert E. Nunn
President
Sunset Exploration, Inc.

William T. Drennen III
Vice President Americas
ExxonMobil Exploration Company

Enclosure

Tranquillon Ridge DEIR Comments from Sunset and ExxonMobil - January 2007

TRANQUILLON RIDGE DEIR COMMENTS

	Comment No.	DEIR SECTION	DEIR Section Title	DEIR Statement	T-Ridge Project	Onshore Alternative	Both T-Ridge & Onshore Alt.	Tranquillon Ridge DEIR Comments (Concern/Request)
	DEIR Executive Summary							
S&EM-1	1	ES.1	Introduction	Section indicates that expected Tranquillon Ridge project life is 30 years.	X			Request that the DEIR be revised to explain and demonstrate how the proposed project will ensure safe operation of Platform Irene and its associated pipelines and power cable to shore and existing onshore pipelines for a life extension of 30 years, particularly given past oil spill history. Reference comments provided in the specific issue areas of the DEIR.
S&EM-2	2	ES.2	Proposed Project	Section indicates that the applicants use of existing platform and facilities to develop the oil "which serves to minimize environmental impacts".	X			Request that the DEIR be revised to explain the conclusion that the project will minimize potential negative impacts of extending the life by another 30 years of currently 19 year old marine infrastructure (Irene and pipeline to shore) as well as 19 year old onshore pipelines to LOGP given potential for future spills from this aging infrastructure. Reference comments provided in the specific issue areas of the DEIR.
S&EM-3	3	ES.2	Proposed Project	Section indicates that a single lease in the state tidelands has been applied for, which is approximately 14,760 acres (Fig. ES-1).	X			Request that the DEIR be revised to indicate how PXP will comply with State code which limits a single lease in state tidelands to no greater than 5760 acres.
S&EM-4	4	ES.3	Description of Project Alternatives	Section indicates in the 'No Project Alternative' that there is the possibility that the Tranquillon Ridge Field could be developed from an onshore site, as currently proposed by Sunset/ExxonMobil, in the event the PXP proposed project is not implemented. Further the DEIR addresses the onshore drilling alternative as the VAFB Onshore Alternative.			X	Request that the DEIR incorporate a revised onshore alternative description based on the information provided to Santa Barbara County and other agencies concerning the proposed Sunset/ExxonMobil Vahevala project. As discussed further below in comments to Section 3.3.3 and in specific issue area comments, the present design configuration is favorable from both an environmental and operational standpoint, as compared to the DEIR's VAFB Onshore Alternative. In order to accurately compare the onshore and offshore projects with respect to environmental impacts and advantages, the currently proposed Vahevala project configuration should be used in the alternatives analysis. Refer to comments below in Section 3.3.3 for more information regarding the VAFB Onshore Alternative description as it relates to the proposed Vahevala Project.
S&EM-5	5	ES.3	Description of Project Alternatives	Section indicates in 'VAFB Onshore Alternative' that the project would use the existing PXP pipelines from the tie-in point, just west of 13th street, to the LOGP.		X		Request that the DEIR be revised to document how PXP will maintain the integrity of this existing 19 year old pipeline over a 30 year extended project life regarding the potential for future spills. As indicated in Figure 5.13-8 and 5.4-1, these existing lines cross drainages above ground using exposed spans in some areas.
S&EM-6	6	ES.3	Description of Project Alternatives	Section indicates in 'VAFB Onshore Alternative' that project produced water would either be treated and reinjected at the VAFB drilling/production site or sent to Platform Irene for re-injection or ocean discharge.		X		Request that the DEIR be revised to reanalyze this statement that produced waters from a State Tidelands lease would be disposed of at a Federal OCS platform. This statement appears to be in disagreement with Federal MMS rules. The proposed Vahevala project would utilize no offshore discharge, instead it would handle all produced water disposal through injection at the onshore VAFB drill site.
S&	7	ES.3	Description of Project Alternatives	Section indicates in 'VAFB Onshore Alternative' (Figure 3-3) the proposed routing for the new pipeline (Pipeline Scenario 1).			X	Request that the DEIR be revised to reanalyze the pipeline route described in the VAFB Onshore Alternative (Pipeline Scenario 1) since it is not optimized in several areas including the the approach for crossing Bear Creek and proximity to the Santa Ynez River estuary. The Vahevala project utilizes an environmentally favorable pipeline route (based upon extensive field evaluations and discussions with VAFB personnel) which includes a horizontal directional drill (HDD) under Bear Creek and Bear Creek Road and a route with further setback away from the Santa Ynez River estuary. This route also is optimized with respect to minimizing impact on cultural resources, again based on consultation with VAFB personnel. Additionally, as per Figures 3-4, 3-5, 3-6, 3-7 and 3-8, the VAFB Onshore Alternative Pipeline Scenarios 2 through 6 are all suboptimal with respect to environmental, cultural and VAFB infrastructure impacts as compared to the Vahevala proposal. Reference comments provided in the specific issue areas of the DEIR.
S&	8	ES.5.1	Significant Impacts Associated with the Proposed Project - Extension of Life	Section indicates the significant impacts associated with increased throughput of the facilities, as well as the extended life of Platform Irene, the Surf substation and the LOGP facility.	X			Request that the DEIR be revised to consider the risks as well as the repairs and modifications that will need to be made due to the extension of life of the existing facilities. In addition, include the significant impact of the extension of life of the existing pipelines which are not specifically mentioned. Significant impacts have been associated with offshore pipeline leaks from the very pipelines proposed for this significant extension of life.
S&	9	ES.5.2	Significant Impacts Associated with the Alternatives - VAFB Onshore Alternative	Section states "In addition, construction of the VAFB Onshore Alternative drilling/production site, pipelines and transmission lines would create new significant impacts for the issue areas of terrestrial biology and cultural resources."		X		Request the summary acknowledge that these risks can be mitigated through a variety of means to minimize impacts on environmentally or culturally sensitive areas including installation of new pipelines (rather than reuse of existing pipelines) and installation of advanced pipeline monitoring systems.

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Tranquillon Ridge DEIR Comments from Sunset and ExxonMobil - January 2007

	Comment No.	DEIR SECTION	DEIR Section Title	DEIR Statement	T-Ridge Project	Onshore Alternative	Both T-Ridge & Onshore Alt.	Tranquillon Ridge DEIR Comments (Concern/Request)
S&EM-10	10	ES.5.2	Significant Impacts Associated with the Alternatives - New Emulsion Pipeline from Platform Irene to LOGP Alternative	Section states "the reduction in spill frequency was determined to be 10%" for the installation of a new pipeline over the proposed project use of the existing pipeline.	X			Request further explanation and documentation regarding the statement that a new oil emulsion pipeline would provide a 10% reduction in spill frequency over the existing oil emulsion pipeline. If statistics compiled by the CSFM were used for the 10% reduction in spill frequency, provide the background for these statistics and show that they are being properly applied to this case. Using new construction technologies and monitoring systems should have a greater impact on potential chance for a release than overall reduction of 10%.
S&EM-11	11	ES.5.2 & ES Table Class III, MB.2	Significant Impacts Associated with the Alternatives - Alternative Muds and Cuttings Disposal Options	Section 5.5.4 and the 'Impact Summary Table' state "Impacts associated with muds and cuttings discharge to the ocean in the proposed project were determined to be a Class III impact."	X			Request clarification on how Class III determination was made. It appears to commenter that direct discharge to the ocean of drilling mud is, at best, a Class II (Significant, but mitigable adverse impact) in that without mitigation steps, such as use of water based, non-toxic drilling fluids, such disposal would be significantly adverse to the marine environment.
S&EM-12	12	ES.6	Environmentally Superior Alternative - VAFB Onshore Alternative	Section states "By eliminating the extension of life for these offshore facilities, the alternative oil spill risk and associated impacts would be **greatly reduced** for marine and coastal biology..." (emphasis added).		X		Request DEIR be revised to more accurately reflect that risk to marine and coastal environments will be effectively eliminated by the Revised VAFB Onshore Alternative as all onshore facilities can be located sufficiently inland as to pose no realistic risk to marine and coastal environments. Reference comments provided in specific issue areas of the DEIR.
S&EM-13	13	ES.6, Footnote 1	Environmentally Superior Alternative - VAFB Onshore Alternative	Similar to Section 5.2, Section states that the Tranquillon Ridge Field could be developed from an onshore site, as currently proposed by Sunset/ExxonMobil, in the event the PXP proposed project is not implemented, and that "this onshore drilling option has been considered in the EIR as the VAFB Onshore Alternative."		X		Request that the DEIR be revised to base the VAFB Onshore alternative on the information provided to SBC and others concerning the proposed Sunset/ExxonMobil Vahevala project. It is clear that the Vahevala project has been optimized in a favorable environmental manner in several respects as compared to the DEIR's VAFB Onshore Alternative. In order to accurately weigh these projects with respect to environmental impacts and advantages, the currently proposed Vahevala project configuration should be used in the alternatives analysis. Request that the VAFB Onshore Alternative be revised to incorporate the improvements included in the Vahevala project. Reference comments provided in the specific issue areas of the DEIR.
S&EM-14	14	ES.6	Environmentally Superior Alternative - VAFB Onshore Alternative	Paragraph 3 of Section discusses, under the VAFB onshore alternative, the impacts associated with the continuing use of the offshore pipeline from Platform Irene until current operations at Platform Irene conclude.			X	The continued use of the pipeline from Platform Irene for Point Pedernales oil is part of the 'No Project Alternative'. Request that the DEIR be revised to eliminate the statements regarding "risk to the marine environment" under the Revised VAFB Onshore Alternative and that paragraph (3rd in this section) be revised to reflect the effective elimination of risk to the marine environment from the Revised VAFB Onshore Alternative as compared to the increased risk due to higher volume and water-oil mixture through that pipeline from the proposed project.
S&EM-15	15	ES.6	Environmentally Superior Alternative - VAFB Onshore Alternative	Paragraph 4 of Section discusses the impact of the VAFB onshore alternative on onshore biological and cultural resources and states "Several threatened and/or endangered species, both plant and animal, occur at the drillsite and along the likely pipeline corridor."		X		Request that this paragraph in the DEIR be revised to acknowledge that these risks can be mitigated through a variety of means. Reference comments provided in the specific issue areas of the DEIR.
S&EM-16	16	ES Tables	Impact Summary Tables - Alternatives (Impact of Proposed Project that also apply to Alternatives)	Table in Section shows that "No Project" Alternative has very few checkmarks for specific impacts.			X	Request that the DEIR be revised to reflect that base case operations at Platform Irene and LOGP have many of the same risks as the proposed project and the various alternatives during the next ten years until production from Platform Irene is currently scheduled to cease. (Eg., Risk.1, Risk.2, Risk.3, TB.3-8, GR.1, GR.3-6, OWR.2-6, CR.1, CR.3-4)

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Tranquillon Ridge DEIR Comments from Sunset and ExxonMobil - January 2007

	Comment No.	DEIR SECTION	DEIR Section Title	DEIR Statement	T-Ridge Project	Onshore Alternative	Both T-Ridge & Onshore Alt.	Tranquillon Ridge DEIR Comments (Concern/Request)
S&EM-17	17	ES Tables	Impact Summary Tables - Alternatives (Impact of Proposed Project that also apply to Alternatives)	Impact # TB.6 states that a pipeline leak or rupture could result in an oil spill and subsequent degradation of upland, riparian and aquatic habitats and injury to plants and terrestrial and aquatic wildlife through direct toxicity, smothering, and entrapment as wells as through resultant cleanup efforts (Class I).		X		Request that the DEIR be revised to reanalyze the statement that this is a valid impact for the Revised VAFB Onshore Alternative. For the Revised VAFB Onshore Alternative, all of the infrastructure including the drill site, facilities and pipeline are over 1000 feet from the coastline. Additionally, topography formed by the coastal dune complex present natural barriers between the VAFB site infrastructure and the shoreline. Hence it is highly unlikely that any spill could reach the marine environment. The horizontal directional drill approach used by the Revised VAFB Onshore Alternative to cross under the Santa Ynez river approximately 2.5 miles inland from the coastline also makes it highly unlikely that a spill would occur into the Santa Ynez river.
S&EM-18	18	ES Tables	Impact Summary Tables - Alternatives (Impact of Proposed Project that also apply to Alternatives)	Impact # MB.1 states that oil spills from the project may impact benthic and intertidal organisms, fish, marine mammals, marine birds and marine turtles (Class I).		X		Request that the DEIR be revised to reanalyze the statement that this is a valid impact for the Revised VAFB Onshore Alternative. As stated in the comments to the specific issue areas of the DEIR, it is highly unlikely that this impact would occur from the Revised VAFB Onshore Alternative.
S&EM-19	19	ES Tables	Impact Summary Tables - Alternatives (Impact of Proposed Project that also apply to Alternatives)	Impact # MB.3 states that a discharge of produced water from Platform Irene may potentially impact marine organisms in the project area (Class III).		X		Request that the DEIR be revised to reflect the fact that this does not apply to the Revised VAFB Onshore Alternative, given that there will be no utilization of Platform Irene infrastructure and there will be no offshore discharge of produced waters.
S&EM-20	20	ES Tables	Impact Summary Tables - Alternatives (Impact of Proposed Project that also apply to Alternatives)	Impact # MWQ.1 states that an accidental discharge of petroleum hydrocarbons into marine waters would adversely affect marine water quality (Class I).		X		Request that the DEIR be revised to reanalyze the statement that this is a valid impact for the Revised VAFB Onshore Alternative. As stated in the comments to the specific issue areas of the DEIR, it is highly unlikely that this impact would occur from the Revised VAFB Onshore Alternative.
S&EM-21	21	ES Tables	Impact Summary Tables - Alternatives (Impact of Proposed Project that also apply to Alternatives)	Impact # MWQ.2 states that reduced marine water and sediment quality would result from oceanic discharge of drilling fluids (Class II).		X		Request that the DEIR be revised to reanalyze the statement that this is a valid impact for the Revised VAFB Onshore Alternative. As stated in the comments to the specific issue areas of the DEIR, it is highly unlikely that this impact would occur from the Revised VAFB Onshore Alternative.
S&EM-22	22	ES Tables	Impact Summary Tables - Alternatives (Impact of Proposed Project that also apply to Alternatives)	Impact # MWQ.3 states that reduced marine water quality would result from oceanic discharge of produced water (Class II).		X		Request that the DEIR be revised to reflect the fact that this does not apply to the Revised VAFB Onshore Alternative, given that there will be no utilization of Platform Irene infrastructure and there will be no offshore discharge of produced waters.

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Tranquillon Ridge DEIR Comments from Sunset and ExxonMobil - January 2007

	Comment No.	DEIR SECTION	DEIR Section Title	DEIR Statement	T-Ridge Project	Onshore Alternative	Both T-Ridge & Onshore Alt.	Tranquillon Ridge DEIR Comments (Concern/Request)
S&EM-23	23	ES Tables	Impact Summary Tables - Alternatives (Impact of Proposed Project that also apply to Alternatives)	Impact # MWQ.4 states that reduced marine water quality would result from additional discharge of sanitary wastes, desalination brine, and other materials from Platform Irene (Class II).		X		Request that the DEIR be revised to reflect the fact that this does not apply to the Revised VAFB Onshore Alternative, given that there will be no utilization of Platform Irene infrastructure and there will be no offshore discharge.
S&EM-24	24	ES Tables	Impact Summary Tables - Alternatives (Impact of Proposed Project that also apply to Alternatives)	Impact # CRF/KH.1 states that oil spills may potentially impact commercial and recreational kelp harvests in the proposed project area (Class III).		X		Request that the DEIR be revised to reanalyze the statement that this is a valid impact for the Revised VAFB Onshore Alternative. As stated in the comments to the specific issue areas of the DEIR, it is highly unlikely that this impact would occur from the Revised VAFB Onshore Alternative.
S&EM-25	25	ES Tables	Impact Summary Tables - Alternatives (Impact of Proposed Project that also apply to Alternatives)	Impact # CRF/KH.2 states that oil spills may potentially impact commercial and recreational fishing in the proposed project area (Class I).		X		Request that the DEIR be revised to reanalyze the statement that this is a valid impact for the Revised VAFB Onshore Alternative. As stated in the comments to the specific issue areas of the DEIR, it is highly unlikely that this impact would occur from the Revised VAFB Onshore Alternative.
S&EM-26	26	ES Tables	Impact Summary Tables - Alternatives (Impact of Proposed Project that also apply to Alternatives)	Impact # CRF/KH.4 states that marine traffic to and from Platform Irene could cause loss or damage to commercial fishing gear in the proposed project area (Class III).		X		Request that the DEIR be revised to reflect the fact that this does not apply to the Revised VAFB Onshore Alternative, given that there will be no utilization of Platform Irene infrastructure and thereby no resulting marine traffic.
S&EM-27	27	ES Tables	Impact Summary Tables - Alternatives (Impact of Proposed Project that also apply to Alternatives)	Impact # CRF/KH.5 states that deposition of shells or shell mounds could prevent commercial trawling activities beneath Platform Irene (Class III).		X		Request that the DEIR be revised to reflect the fact that this does not apply to the Revised VAFB Onshore Alternative, given that there will be no utilization of Platform Irene infrastructure.
S&EM-28	28	ES Tables	Impact Summary Tables - Alternatives (Impact of Proposed Project that also apply to Alternatives)	Impact # T.3 states that increased offshore drilling activity would increase offshore traffic (Class III).		X		Request that the DEIR be revised to reflect the fact that this does not apply to the Revised VAFB Onshore Alternative, given that there will be no utilization of Platform Irene infrastructure.

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Tranquillon Ridge DEIR Comments from Sunset and ExxonMobil - January 2007

	Comment No.	DEIR SECTION	DEIR Section Title	DEIR Statement	T-Ridge Project	Onshore Alternative	Both T-Ridge & Onshore Alt.	Tranquillon Ridge DEIR Comments (Concern/Request)
S&EM-29	29	ES Tables	Impact Summary Tables - Alternatives (Impact of Proposed Project that also apply to Alternatives)	Impact # T.4 states that an oil spill from the proposed Tranquillon Ridge Project could result in the disruption of commercial shipping, fishing, and recreational marine traffic (Class I).		X		Request that the DEIR be revised to reanalyze the statement that this is a valid impact for the Revised VAFB Onshore Alternative. As stated in the comments to the specific issue areas of the DEIR, it is highly unlikely that this impact would occur from the Revised VAFB Onshore Alternative.
S&EM-30	30	ES Tables	Class I impacts of VAFB Onshore Alternative	Item T.3 addresses offshore traffic and is shown as applicable to the VAFB Onshore Alternative.			X	Request that the DEIR be revised to remove this item as an impact of Revised VAFB Onshore Alternative as there will be no offshore traffic associated with the Revised VAFB Onshore Alternative and onshore traffic issues are addressed separately under T.1 (Class II impact).
	DEIR Section 2							
S&EM-31	1	Sect. 2.2.1	Well Development and Production	States that new wells for T-Ridge will be drilled from "unused well-slot locations currently available on Platform Irene"	X			Request that the DEIR be revised to indicate the weight loading constraints of the platform, the current loading and expected loading with project equipment installed. Indicate if any additional structural supports will have to be modified or added. If platform modifications are required, the DEIR should discuss potential impacts associated with offshore construction.
S&EM-32	2	2.2.2	Platform Irene Modifications	Section indicates that the existing drilling rig on platform would be used to drill extended reach wells.	X			Request that the DEIR be revised to include justification that the existing drilling rig will be able to drill extended reach wells which require large power requirements and weight handling capabilities or indicate the activities and impacts associated with the replacement with a larger rig including higher HP emergency generators.
S&EM-33	3	2.2.2	Platform Irene Modifications	Section indicates that oil based muds, if used, would be stored and transported to shore or injected offshore.	X			Request that the DEIR be revised to include an indication of when and how much oil based mud would be used. Other locations have used oil based muds when drilling extended reach wells to reduce friction and improve flow characteristics. Consider replacing water based mud for oil based mud as the base case.
S&EM-34	4	2.2.2	Platform Irene Modifications	Section indicates that produced water from LOGP could be discharged to ocean under existing NPDES permit.	X			Request that the DEIR be revised to include documentation from appropriate agencies to demonstrate that the existing NPDES permit can be used for discharge of water from state leases. Discuss any required amendments.
S&EM-35	5	2.2.2	Platform Irene Modifications	Table 2.2 indicates that additional electric power of about 117% will be required during drilling.	X			Request that the DEIR assess the capability of the existing electric power system to the platform to meet the project requirements, and discuss potential limitations of the sub sea power cable system and delivery to platform.
S&EM-36	6	2.2.2	Platform Irene Modifications	Table 2.6 indicates that Platform Irene's life will be extended 30 years (original life was 20 years)	X			Request that the DEIR be revised to provide details of the platform inspection program conducted to ensure that the platform structure is capable of the extended life. Include results of the most recent inspections. Include consideration of replacement of anode systems and repair of fatigue cracking.
S&EM-37	7	2.3.1.1	Platform Irene	Section indicates that electric power is supplied to platform by a sub sea cable.	X			Request that the DEIR be revised to indicate the design, capacity, water seal barriers and any redundancy in the sub sea power cable to platform. Provide results of recent testing and inspection of the cable. Provide substantiation that the power cable life can be extended past the project life without repairs.
S&	8	2.3.1.1	Platform Irene	Section indicates that electric power is supplied to platform by a sub sea cable.	X			Based on other facilities that have had sub sea power cable failures, it appears that there is a strong likelihood that the sub sea power cable could require replacement. Request that the DEIR be revised to include an alternative for replacing the sub sea power cable that includes the associated impacts.
S&	9	2.3.1.3	Other Point Pedernales Facilities	Pipeline descriptions indicate that both the emulsion and the produced water pipeline from Irene to LOGP have had sections replaced due to corrosion in the last 10 years	X			Given the history of the pipelines from Irene to LOGP, request that the DEIR be revised to include, at a minimum, the repair and/or replacement of several sections of the pipelines over the life of the proposed project. Include impacts for these activities.
S&	10	2.3.1.3	Other Point Pedernales Facilities- Oil Emulsion Pipeline	Section indicates that the pipeline is coated with PRITEC 70/15 for entire length.	X			Request that the DEIR be revised to indicate that the emulsion pipeline was not coated with concrete for damage protection in nearshore areas as is current practice. Also indicate that no rip rap was placed over pipeline in surf zone for protection during storms, and discuss the potential risks of pipeline accidents in this critical area of the pipeline. To the extent that these measures should be incorporated as mitigation measures, the DEIR should also identify the potential construction impacts of this work, and any potential long-term shoreline morphology impacts.

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Tranquillon Ridge DEIR Comments from Sunset and ExxonMobil - January 2007

	Comment No.	DEIR SECTION	DEIR Section Title	DEIR Statement	T-Ridge Project	Onshore Alternative	Both T-Ridge & Onshore Alt.	Tranquillon Ridge DEIR Comments (Concern/Request)
S&EM-41	11	2.3.1.3	Other Point Pedernales Facilities- Oil Emulsion, Produced Water and Sour Gas Pipeline	Section indicates that these pipelines are inspected with a smart pig.	X			Request that the DEIR be revised to indicate the analysis of the smart pig results. The DEIR needs to elaborate on the implication of the results and whether the corrosion program is adequate to assure that no failures will occur or whether replacement of selected sections will be required.
	DEIR Section 3							
S&EM-42	1	3.3.3	Description of the VAFB Onshore Alternative	Section 3.3.3 describes the VAFB Onshore Alternative as based to some extent on the March 2006 Sunset/ExxonMobil Vahevala application (information available at the time of the project scoping) and an independent analysis of alternative features.		X		Request that the DEIR be revised to base the VAFB Onshore Alternative description on the current information provided to Santa Barbara County and other agencies concerning the proposed Sunset/ExxonMobil Vahevala project. The Vahevala project has been optimized based on field investigations, engineering analyses, and discussions with VAFB operations and environmental staff. As discussed further in comments below, the key differences between the proposed Vahevala project and the DEIR VAFB Onshore Alternative include alignment of the pipeline corridor in an area that is topographically remote from the Santa Ynez River estuary; reduced diameter pipelines and avoidance of existing older pipelines to the LOGP; use of current technology pipeline leak detection; placement of numerous block and check valves at strategic locations to minimize potential spill volumes; onsite water disposal and avoidance of offshore disposal and other offshore infrastructure; and siting of new electrical infrastructure out of public view.
S&EM-43	2	3.5.1	New Oil Emulsion Pipeline Alternative	Section indicates that the existing offshore pipeline would be decommissioned in place when a new pipeline is installed.	X			Request that the DEIR be revised to include the removal of the existing pipeline after it is taken out of service in concurrence with the SBC policy to remove all abandoned facilities. Discuss potential impacts associated with pipeline removal in the relevant resource issue areas.
S&EM-44	3	3.5.1.1	Offshore Pipeline Installation	Section does not describe the surf zone installation.	X			Request that the DEIR be revised to include the details of installing the pipeline from the offshore connection point through the surf zone to the onshore connection point.
S&EM-45	4	3.5.1.1	Offshore Pipeline Installation	Section indicates that the pipeline would be buried to a depth of 5-15 feet through surf zone using air jets.	X			Request that the DEIR be revised to include environmentally beneficial alternatives to use of air jets due to turbidity generated by this type of operation.
S&EM-46	5	3.5.1.1	Offshore Pipeline Installation	Section indicates that the pipeline would be buried to a depth of 5-15 feet through surf zone using air jets.	X			Request that the DEIR be revised to include the use of rip rap on top of the pipeline in the surf zone to provide protection during storms. Provide description of how this work would be accomplished including access to beach site.
S&EM-47	6	3.5.1.1	Offshore Pipeline Installation	Section indicates that the pipeline would be connected to the platform pipe using a template approach.	X			Request that the DEIR be revised to consider other methods that do not have additional risk of leaks such as the alternative of pulling the pipeline up the J-tube to eliminate joints on sea bottom.
S&EM-48	7	3.5.1.1	Offshore Pipeline Installation	Table 3.3 indicates a Lay Vessel with 3000 HP.	X			Request that DEIR be revised to utilize more realistic equipment requirements and HP ratings. Recent projects using DP vessels indicated a total of 8,000 to 10,000 HP; projects also required ROV and associated generators.
	DEIR Section 5.1							
S&	1	Section 5.1.1.4.2	Existing LOGP Facility and Sales Gas Pipeline: Scenarios and failure Rates	Table 5.1.4. Current Operations Gas Pipeline Release Scenario Impacts	X			The information used to generate the results should be included in this DEIR rather than referring to past documents and results. Revise the DEIR to include a description of the methodology used to develop the information presented in Table 5.1.4. Estimated volumes of sour gas, H_2S mass, and duration for each release scenario should be shown in the table.
S&	2	Section 5.1.1.4.2	Existing LOGP Facility and Sales Gas Pipeline: Scenarios and failure Rates	Table 5.1.10 Current Operations LOGP Release Scenarios Impacting Offsite and Base Frequencies	X			The information used to generate the results should be included in this DEIR rather than referring to past documents and results. Revise the DEIR to include a description of the methodology used to develop the information presented in Table 5.1.10. Estimated volumes of sour gas, H_2S mass, and duration for each release scenario should be shown in the table.
S&	3	5.1.5.2	Impact Analysis for the VAFB Onshore Alternative	Table 5.1.30 Potential Spill Volumes from VAFB Onshore Production Site to PXP Emulsion Pipeline		X		Except for the 1.3 mile Santa Ynez River to the PXP Emulsion Line segment, the cited table and associated text does not take into account, but does acknowledge, the planned use of block valves at regular intervals (i.e., approximately one mile segments) along both the oil and gas pipelines. Thus, the estimated spill volumes shown in the table are overestimated for the remaining 8.5 miles of pipeline by a factor of 3 to 5. This table should be revised to include consideration of block valves at several key locations along the proposed Vahevala pipeline alignment, as depicted on the Vahevala Project application drawings and tabulated on Drawing SK-06485-07.

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Tranquillon Ridge DEIR Comments from Sunset and ExxonMobil - January 2007

	Comment No.	DEIR SECTION	DEIR Section Title	DEIR Statement	T-Ridge Project	Onshore Alternative	Both T-Ridge & Onshore Alt.	Tranquillon Ridge DEIR Comments (Concern/Request)
	DEIR Section 5.2							
S&EM-52	1	Section 5.2 and (throughout EIR)	Description of Alternatives/ Significant Impacts of Project Alternatives	The VAFB Onshore Alternative is described as including approximately 10 miles of additional pipeline.		X		Request that the assessment of the VAFB Onshore Alternative pipeline route (Pipeline Scenario 1) in the DEIR be revised to reflect the Vahevala Project proposed pipeline route which is optimized in several areas including the approach for crossing Bear Creek and avoidance of the Santa Ynez River estuary area. In addition, the Vahevala Project proposed pipeline route between the drilling and production site and the point of intersection with PXP pipeline right-of-way is less than 10 miles (8.4 mi). Therefore the stated impacts in this portion of the pipeline alignment are overstated. In addition, the Vahevala oil pipeline contains dry oil not more corrosive emulsion as in the proposed project.
S&EM-53	2	Section 5.2.1.3	Terrestrial Habitats and Biota: Rare Threatened and Endangered Species	The proposed rule was withdrawn in 2002, and the tidewater goby remains on the endangered species list throughout its range (USFWS, 2005). Critical habitat has not been proposed or designated north of Orange County, California.			X	Request that the DEIR be revised to reflect current status of the Tidewater Goby. USFWS issued proposed critical habitat for the tidewater goby on Nov. 28, 2006 (Federal Register 50 CFR Part 17: Endangered and Threatened Wildlife and Plants; Revised Critical Habitat for the Tidewater Goby (*Eucyclogobius newberryi*); Proposed Rule) which includes the Santa Maria River.
S&EM-54	3	Section 5.2.1.3	Terrestrial Habitats and Biota: Rare Threatened and Endangered Species	This species [unarmored threespine stickleback] is known to inhabit San Antonio Creek primarily downstream of Barka Slough on VAFB (Irwin and Soltz, 1982), and unidentified threespine sticklebacks have been observed as far upstream as Los Alamos in the 1980s (R. Thompson field notes).			X	Federally and state listed endangered unarmored threespine stickleback (*Gasterosteus aculeatus williamsoni*) have been documented in Honda Creek (reference Camm Swift personal observation - 9/2006). Request that the DEIR be revised to add this stream to the discussion.
S&EM-55	4	Section 5.2.5.2	Class I Impacts of Onshore Alternative	Impact TB.9: Drilling noise, construction, and accidental release of boring materials ("frac-outs") during construction activities related to boring could impact one or more sensitive wildlife species.		X		Request that the DEIR be revised to re-analyze the magnitude of this effect. A Class II impact classification is more appropriate because impacts from horizontal drilling can be reduced to less than significant levels by various mitigations, including scheduling construction outside critical breeding and migration periods of target species. Implementation of a Frac-Out Contingency Plan would address several measures to avoid impacts resulting from a frac-out.
S&EM-56	5	Section 5.2.5.2	Class I Impacts of Onshore Alternative	Impact TB.10: Replacement of the existing pipeline from landfall to the LOGP has the potential to remove or damage up to 88.6 acres of native vegetation and wildlife habitat including sensitive plant species.		X		Request that the DEIR be revised to re-analyze the magnitude of this effect. A Class I impact is assigned to the Onshore Alternative (76.65 acres of native vegetation), but a Class II impact is assigned to the Oil Emulsion Line Replacement Alternative (88.6 acres of native vegetation). The analysis should reflect conclusions in Impact TB. 13, Impacts to Listed Plants - Onshore Alternative (significant but mitigable).
S&EM-57	6	Section 5.2.5.2	Terrestrial Habitats and Biota: VAFB Onshore Alternative Impact Analysis	Impacts TB.6, TB.7, TB.8: The pipeline segment along Highway 246 is directly adjacent to the Santa Ynez River. In the event of a spill or rupture, impacts on aquatic habitats would be more severe under the VAFB Onshore Alternative compared to the proposed project. The Santa Ynez River and adjacent riparian areas support sensitive aquatic species such as the tidewater goby, red-legged frog, and steelhead. A spill into the Santa Ynez River could result in oil flow to the river mouth and beach, which is proposed critical habitat for the western snowy plover.		X		This discussion assumes that the VAFB Onshore Alternative pipeline route would be located north of Highway 246 near the Santa Ynez River estuary. Request that the DEIR be revised to reflect the proposed Vahevala Project pipeline route, which avoids placement of new pipelines in this area by using a cross-country route that is substantially south of Highway 246 and topographically remote from the estuary. The resulting analysis of impacts to terrestrial biota and habitats are thus overstated, particularly with respect to aquatic resources. The assessment should also be revised to reflect the fact that the existing PXP pipelines, which have a history of corrosion, will continue to operate in close proximity to the estuary. Therefore, in the event of a spill or rupture, impacts on aquatic habitats would be less severe under the Revised VAFB Onshore Alternative compared to the proposed project.
S&EM58	7	Section 5.2.5.2	Terrestrial Habitats and Biota: VAFB Onshore Alternative Impact Analysis	Impacts TB.6, TB.7, TB.8: The pipeline would be installed along Surf Road, Bear Creek Road, and Coast Road, all of which are in close proximity to the shoreline.		X		Revise the DEIR to include details from the proposed Vahevala Project for the VAFB Onshore Alternative so that impacts for this alternative are more accurately assessed. The pipeline route for the proposed Vahevala Project, which has been optimized to mitigate environmental impacts with input from VAFB staff, is located greater than 1000 feet inland from the coastline. Additionally, the drainage patterns within the drilling and production area for the proposed Vahevala Project would prevent spilled oil from reaching Honda Creek watershed (located to the south of the drilling area). Topography along the pipeline corridor on South VAFB is formed by the coastal dune complex and UPRR tracks which present natural and man-made barriers between the VAFB Onshore Alternative infrastructure and the shoreline. The proposed Vahevala Project's pipeline crossing under the Santa Ynez River would be located approximately 2.5 miles inland from the coastline, making it unlikely that a spill into the Santa Ynez River would reach the coastline.

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Tranquillon Ridge DEIR Comments from Sunset and ExxonMobil - January 2007

	Comment No.	DEIR SECTION	DEIR Section Title	DEIR Statement	T-Ridge Project	Onshore Alternative	Both T-Ridge & Onshore Alt.	Tranquillon Ridge DEIR Comments (Concern/Request)
S&EM-59	8	Section 5.2.5.2	Terrestrial Habitats and Biota: VAFB Onshore Alternative Impact Analysis	Known threatened and endangered species present along the proposed onshore pipeline route include Gaviota tarplant, beach layia (Layia carnosa), and vernal pool fairy shrimp (Branchinecta lynchi).		X		Request that the DEIR be revised to review validity of the statement that vernal pool habitat occurs along the 8.4 mile section of pipeline between the VAFB Onshore Alternative drilling and production site and the intersection with the PXP pipeline right-of-way. During the analysis for the proposed Vahevala Project no vernal pool habitat along the proposed pipeline route was found.
	DEIR Section 5.3							
S&EM-60	1	5.3.5.2	Geological Resources	Impact GR.4 Ground Disturbance during Maintenance Activities. This discussion states in part "...Given the crossing of the Santa Ynez River, this impact is considered more severe for the VAFB Onshore Alternative than the proposed project..."			X	Request that this impact for the Revised VAFB Onshore Alternative be revised to more closely match the Replacement of Oil Emulsion Pipeline Alternative. This impact is referring to impacts during maintenance activities (and not oil spill clean up activities) and pipeline maintenance would be less than the proposed project due to the less frequent maintenance requirements associated with a new pipeline. Furthermore, geotechnical data would be used to design and install the new pipeline so no long-term geological impacts associated with the pipeline would be expected.
S&EM-61	2	5.3.5.2	Geological Resources	Impact GR.5 Scour. This discussion states in part "...However, given the crossing of the Santa Ynez River, this impact is considered more severe for the VAFB Onshore Alternative than the proposed project..."			X	Request that the DEIR be amended to reflect the proposed Vahevala Project pipeline route which is substantially south of Highway 246 and topographically remote from the estuary. Avoidance of this area in addition to pipeline design and installation techniques based on sound geotechnical data would reduce scour impacts from crossing the Santa Ynez River.
S&EM-62	3	5.3.5.2	Geological Resources	Impact GR.7 Liquefaction could jeopardize the integrity of the VAFB Onshore Alternative pipelines at the Santa Ynez River valley and Bear Creek crossings.		X		Request that the DEIR be amended to reflect the proposed Vahevala Project pipeline route which is substantially south of Highway 246 and topographically remote from the estuary and therefore remote from soil conditions favorable to liquefaction. Avoidance of these areas in addition to pipeline design and installation techniques based on sound geotechnical data would reduce this impact to less than significant.
	DEIR Section 5.5							
S&EM-63	1	Section 5.5.5.2	Marine Biology: VAFB Onshore Alternative Impact Analysis	Impact MB.6 Impingement and Entrainment. Impingement and entrainment from seawater uptake at Platform Irene would be the same as existing baseline conditions.		X		Request that the DEIR be revised to state that the Revised VAFB Onshore Alternative would not require use of Platform Irene. Therefore, there is no impact related to impingement and entrainment.
	DEIR Section 5.6							
S&EM-64	1	Section 5.6.5.2	Impacts of the Proposed Project that also Apply to the Alternatives	MWQ.2 Reduced marine water and sediment quality would result from increased oceanic discharge of drilling fluids. The impacts of discharging drilling fluids and other wastes would be considered adverse but not significant (Class III).		X		Oceanic discharge of drilling fluids is associated with the "No Project" alternative and is not proposed under the Revised VAFB Onshore Alternative. Therefore the DEIR should be revised to state that there is no impact to marine water and sediment quality from these discharges for the Revised VAFB Onshore Alternative.
S&EM-65	2	Section 5.6.5.2	Impacts of the Proposed Project that also Apply to the Alternatives	MWQ.3: Reduced marine water quality would result from the oceanic discharge of produced water (Class II).		X		Oceanic discharge of produced water is associated with the "No Project" alternative and is not proposed under the Revised VAFB Onshore Alternative. Therefore the DEIR should be revised to state that there is no impact to marine water and sediment quality from these discharges for the Revised VAFB Onshore Alternative.
S&EM-66	3	Section 5.6.5.2	Impacts of the Proposed Project that also Apply to the Alternatives	MWQ.4: Reduced marine water quality would result from additional discharges of sanitary wastes, desalinization brine, and other materials from Platform Irene (Class III).		X		Oceanic discharges of sanitary waste, desalinization brine, and other materials is associated with the "No Project" alternative and is not proposed under the Revised VAFB Onshore Alternative. Therefore the DEIR should be revised to state that there is no impact to marine water and sediment quality from these discharges for the Revised VAFB Onshore Alternative.
	DEIR Section 5.7							
S&EM-67	1	Section 5.7.5.2	Impacts of the Proposed Project that also Apply to the Alternatives	CRF/KH.1: Oil spills may potentially impact commercial and recreational kelp harvests in the proposed project area (Class III).		X		Request that the DEIR be revised to re-analyze the statement that this is a valid impact for the Revised VAFB Onshore Alternative. As stated, it is highly unlikely that a spill from this infrastructure would impact the marine environment.

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	Comment No.	DEIR SECTION	DEIR Section Title	DEIR Statement	T-Ridge Project	Onshore Alternative	Both T-Ridge & Onshore Alt.	Tranquillon Ridge DEIR Comments (Concern/Request)
S&EM-68	2	Section 5.7.5.2	Impacts of the Proposed Project that also Apply to the Alternatives	CRF/KH.2: Oil spills may potentially impact commercial and recreational fishing in the proposed project area (Class I).		X		Request that the DEIR be revised to re-analyze the statement that this is a valid impact for the Revised VAFB Onshore Alternative. Commercial/recreational fishing is not permitted in the Santa Ynez River or estuary due to the presence of endangered steelhead and tidewater goby.
S&EM-69	3	Section 5.7.5.2	Impacts of the Proposed Project that also Apply to the Alternatives	Impact CRF/KH.4: Marine Vessel traffic to and from Platform Irene could cause loss or damage to commercial fishing gear in the project area (Class III).		X		Marine Vessel traffic to and from Platform Irene is associated with the "No Project" alternative and is not proposed under the Revised VAFB Onshore Alternative. Therefore the DEIR should be revised to state that there is no impact to commercial fishing gear from the Revised VAFB Onshore Alternative.
S&EM-70	4	Section 5.7.5.2	Impacts of the Proposed Project that also Apply to the Alternatives	Impact CRF/KH.5: The deposition of shells, or shell mounds, could prevent commercial trawling activities beneath Platform Irene (Class III).		X		Deposition of shells, or shell mounds is associated with the "No Project" alternative and is not proposed under the Revised VAFB Onshore Alternative . Therefore the DEIR should be revised to state that there is no impact to commercial trawling activities from the Revised VAFB Onshore Alternative.
S&EM-71	5	Section 5.7.5.2	Commercial and Recreational Fishing/Kelp Harvesting (for the onshore alternative)	Impact CRF/KH.1 Spill Impacts to Kelp. This discussion states in part "...If spilled oil from the new onshore oil pipeline did reach the ocean, it could be more likely to reach kelp beds than a spill from Platform Irene because the oil would enter the ocean close to shore and the near shore kelp beds..."			X	Request that the DEIR be revised to include the Proposed Project's continued use of existing onshore pipelines which are located immediately upland of the Santa Ynez River estuary. In other words, although a spill from Platform Irene may not reach the kelp beds depending on wind and current directions at the time, a spill from the proposed project's existing onshore pipelines would have a higher probability of reaching the ocean and near shore kelp beds than the proposed Vahevala Project's new onshore oil pipeline. As previously noted, it is highly unlikely that any spill from the Vahevala infrastructure could reach the shoreline given the optimized route and distance from coastline.
S&EM-72	6	Section 5.7.5.2	Commercial and Recreational Fishing/Kelp Harvesting (for the onshore alternative)	Impact CRF/KH.2 Spill Impacts to Fish. This discussion states in part "...although the chance of a spill would be greatly reduced compared to the proposed project, if substantial oil did enter the ocean, impacts on near shore fishing areas might be greater..."			X	Request that the DEIR be revised to include a discussion of the Proposed Project's continued use of existing onshore pipelines which are located immediately upland of the Santa Ynez estuary. Once the onshore pipelines for the Proposed Project are included in the impact analysis, then the comparison of impacts would most likely conclude that the overall potential for impacts to fisheries due to an oil spill from the onshore alternative would be less than for the Proposed Project.
	DEIR Section 5.8							
S&EM-73	1	5.8	Regulatory Setting	The DEIR does not discuss new regulatory requirements potentially affecting the project. This includes the California Air Resources Board (CARB) Air Toxic Control Measures for portable and stationary diesel-fired engines and the APCD rules affecting stationary engines.	X			Request that the DEIR be revised to include an analysis of the new CARB and APCD rules affecting stationary and portable diesel PM. CARB and APCD consider diesel PM as a significant air toxic. In addition, the APCD has required others to include contractual language reducing diesel PM and criteria pollutants during the construction and operations processes. Include discussion of applicable mitigation measures in the DEIR.
S&EM-74	[illegible]	[illegible]	Study Area [illegible]	Table 5.8.5 lists current emissions from [illegible]	X			Request that the DEIR be revised to include the emissions from the emergency generator and firewater [illegible]

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Tranquillon Ridge DEIR Comments from Sunset and ExxonMobil - January 2007

	Comment No.	DEIR SECTION	DEIR Section Title	DEIR Statement	T-Ridge Project	Onshore Alternative	Both T-Ridge & Onshore Alt.	Tranquillon Ridge DEIR Comments (Concern/Request)
S&EM-80	8	5.8.5.2	VAFB Onshore Alternative- Residual Impact Impact Air.2	In fourth sentence, indicate that operational emissions from Platform Irene would be less than proposed project.		X		Request that the DEIR be revised to correct an apparent error in fourth sentence. Operational emissions from Platform Irene would be greater than the Revised VAFB Onshore Alternative because helicopter and boat activity would not be required for the Revised VAFB Onshore alternative.
S&EM-81	9	5.8.5.5	Replacement of Oil Emulsion Pipeline from Platform Irene to LOGP	Table 5.8.14 lists construction emissions for replacement of pipeline from Platform Irene to LOGP.	X			Request that the DEIR be revised to indicate that the existing offshore emulsion pipeline would have to be removed as part of construction project as per SBC policy on decommissioned equipment. Include associated impacts for removal.
S&EM-82	10	5.8.5.5	Replacement of Oil Emulsion Pipeline from Platform Irene to LOGP	Table 5.8.14 lists construction emissions for replacement of pipeline from Platform Irene to LOGP.	X			Request that the DEIR be revised to include a more realistic estimate of the operations and associated equipment required to install the offshore portion of the emulsion pipeline using a dynamic positioning (DP) vessel. Consider pre and post surveys, ROV use, divers, support barges and work vessels.
S&EM-83	11	5.8.5.5	Replacement of Oil Emulsion Pipeline from Platform Irene to LOGP	Table 5.8.14 lists construction emissions for replacement of pipeline from Platform Irene to LOGP.	X			Request that the DEIR be revised to provide a more realistic estimate of emissions for Offshore Equipment. Appendix C (page C-3) references use of lay vessel for 56 days. Previous projects have determined an emission rate of approximately 1 ton/day of NOx or 56 ton for only lay vessel operation.
	DEIR Section 5.9							
S&EM-84	1	5.9.5.2	Traffic (for the onshore alternative)	Impact T.3 - Marine Traffic. The impact statement concludes that marine traffic would be the same as for the No Project Alternative, and is considered adverse but not significant (Class III).		X		Marine traffic is associated with the "No Project" alternative and is not proposed under the Revised VAFB Onshore Alternative. Request that the DEIR be revised so that the conclusion states that there isno impact related to marine traffic.
S&EM-85	2	5.9.5.2	Traffic (for the onshore alternative)	Impact T.4. This impact concludes that a accidental oil spill or gas release would have significant adverse impacts to Base operations that cannot be mitigated to less than significant (Class I).		X		As part of the proposed Vahevala Project review process VAFB is conducting a Site Survey (review page 3-11 of the DEIR for more detail on the Site Survey process) to evaluate the potential impacts of the Vahevala project on Base operations. The Site Survey will include an evaluation of impacts from an accidental release and the related impacts to Base operations. Although it is too soon to conclude that an accidental release would not disrupt Base operations to a Class I level, without input from VAFB, it is also too soon to conclude that it would. The Vahevala Project team is collaborating with VAFB to ensure impacts to Base operations would be minimal and of short duration. The results of the Site Survey process will include VAFB's analysis on whether or not an accidental release from the Vahevla Project would have significant adverse impacts to Base Operations. This information can then be used when evaluating the Revised VAFB Onshore Alternative.
	DEIR Section 5.10							
S&EM-86	1	5.10.5.2	Noise (for the onshore alternative)	Impact Noise.1 - Offshore Noise. The impact statement concludes that offshore noise is adverse but not significant (Class III) for the onshore alternative.		X		Offshore activities are associated with the "No Project" alternative and is not proposed under the Revised VAFB Onshore Alternative. Request that the conclusion be revised to state that there isno impact related to offshore noise.
	DEIR Section 5.12							
S&EM-87	1	5.12.5.2, page 5.12-19	Cultural Resources (for the onshore alternative)	Impact CR.1 - Pipeline Maintenance Ground Disturbance. The discussion concludes that impacts to cultural resources from maintenance and repair of the pipelines constructed for the onshore alternative would be "substantially greater" than for the proposed project.		X		Request that the DEIR be revised to reflect that the proposed Vahevala project would not rely on the existing PXP pipelines, which have a history of corrosion. Therefore, although the Revised VAFB Onshore Alternative will be overall more miles of onshore pipeline than the Proposed Project (12.1 miles for the proposed project compared to 17.7 miles for the Vahevala Project), the maintenance-related ground disturbances associated with the new pipelines would be <u>reduced</u> over those of the proposed project because the integrity of the pipeline would be improved over the existing pipeline, and there will be fewer pipelines that require maintenance (i.e., no water pipeline). The proposed Vahevala Project pipeline routes have been optimized with VAFB staff input to mitigate impacts to cultural resources.
S&EM-88	2	5.12.5.2	Cultural Resources (for the onshore alternative)	Impact CR.4 - Produced Water Spill assumes that the onshore alternative will construct a produced water pipeline, which could result in impacts to cultural resources in the event of a spill cleanup.		X		Request that the DEIR be revised to reflect that the Revised VAFB Onshore Alternative does not include a produced water pipeline. The Revised VAFB Onshore Alternative would dispose of water via new water injection at the drilling and production area.
	DEIR Section 5.13							

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Tranquillon Ridge DEIR Comments from Sunset and ExxonMobil - January 2007

	Comment No.	DEIR SECTION	DEIR Section Title	DEIR Statement	T-Ridge Project	Onshore Alternative	Both T-Ridge & Onshore Alt.	Tranquillon Ridge DEIR Comments (Concern/Request)
S&EM-89	1	5.13.5.2	Visual Resources for the onshore alternative	Impact Visual.1 Long Term Presence of Facilities Visible from the Coastal Zone. This impact is classified as significant and unavoidable (Class 1) for the onshore alternative because it is assumed that the existing Surf Substation, which is visible from public viewing areas, would also support the onshore alternative project		X		Request that the DEIR be amended to reflect the Revised VAFB Onshore Alternative, which includes construction of a separate substation to be located on VAFB and out of view from public vantage points. Specific location and site information for the new substation is provided in the December 29, 2006 Response to Comment package submitted to SBC.
	DEIR Section 5.14							
S&EM-90	1	5.14.5.2	Recreations/Land Use (for the onshore alternative)	Impact REC.1 - Oil Spill. The discussion states that "...there is a small potential for spilled oil to reach Ocean Beach County Park and/or Surf Beach if the pipelines are placed on the northern side of Highway 246 or if high flow conditions result in the breach of the UPRR created berm. Therefore this impact [to recreation] is still considered significant and unavoidable (Class 1).		X		Request that the DEIR be revised to reflect the Revised VAFB Onshore Alternative pipeline route, which avoids placement of new pipelines in this area by using a cross-country route that is substantially south of Highway 246 and topographically remote from the estuary.
	DEIR Section 6							
S&EM-91	1	6.2	Comparison of Proposed Project to No Project Alternative	The "No Project Alternative" states it would eliminate several Class I impacts, including Impacts TB.6, TB.7, TB.8, OWR.2, MB.1, MWQ.1, CRF/KH.2, T.4, CR.3 and Impact Rec.1"			X	Request that the DEIR be revised to state that these impacts would not increase above current levels, rather than state that they would be eliminated. As acknowledged in the Point Pedernales EIR/EIS, these risks exist in the base case and will continue to exist even if no project goes forward.
S&EM-92	2	6.3.1	Comparison of Proposed Project to Other Alternatives - VAFB Onshore Alternative	This section states that the Class I oil spill impacts for marine biology, marine water quality and commercial/recreational fishing would be reduced but not eliminated with the VAFB onshore alternative.		X		Request that the DEIR be revised to acknowledge that any risk to marine and coastal environments will be far less significant than characterized in the DEIR. The Revised VAFB Onshore Alternative facilities are located sufficiently inland as to pose no realistic risk to marine and coastal environments. At a minimum, the risk should be reduced to Class II given the remoteness of this contingency and the various mitigation steps that can be taken.
S&EM-93	3	6.3.1	Comparison of Proposed Project to Other Alternatives - VAFB Onshore Alternative	The third (3rd) paragraph of this section states that the pipelines associated with the VAFB onshore alternative will be located in a pipeline route near Surf Beach or Ocean Beach County Park and a release there from could impact beaches, the Santa Ynez River Mouth and other coastal estuaries.		X		The Revised VAFB Onshore Alternative should address more advantageous potential pipeline routes available from the proposed drill site to LOGP. The proposed Vahevala project has identified other pipeline routes that will minimize the risk to marine and coastal environments by locating the pipeline further from those areas. As such, commentor requests that the DEIR be revised to incorporate the pipeline route from the Revised VAFB Onshore Alternative, in order to portray a more accurate "environmentally superior alternative" than is currently portrayed. When such a pipeline route is incorporated, commentor suggests that mitigation would reduce this impact to a Class II impact.
S&EM-94	4	6.3.1	Comparison of Proposed Project to Other Alternatives - VAFB Onshore Alternative	The fourth paragraph of this section states that the VAFB onshore alternative could result in significant (Class I) impacts to onshore biological and cultural resources due to the onshore drilling area and pipelines.		X		Request that the DEIR (fourth (4th) paragraph) be revised to acknowledge that these risks can be mitigated through a variety of means to minimize impacts to environmentally or culturally sensitive areas including installation of new pipelines primarily along existing pipeline right-of-ways and roads.
S&EM-95	5	6.3.1	Comparison of Proposed Project to Other Alternatives - VAFB Onshore Alternative	The fourth paragraph of this section states that the VAFB onshore alternative would increase the likelihood of an onshore oil spill due to the 10 miles of new pipeline from the VAFB drill site.		X		Request that the DEIR be revised to re-evaluate the basis for this statement as commentor would suggest that the use of a new pipeline as detailed in the Revised VAFB Onshore Alternative and installed with better isolation capabilities and a current pipeline monitoring/shutdown system, rather than continued use of the existing onshore pipeline, actually reduces the likelihood of an onshore release from pipelines, when compared to extending the use of the existing 20 year old pipeline for an additional 30 years at higher flowrates than its current service.
S&EM-96	6	Table 6.1a	Comparison of Proposed Project to Other Alternatives - VAFB Onshore Alternative	Table 6.1a lists a selection of impacts and compares the Proposed Project to the VAFB Onshore Alternative.			X	Request that the DEIR be revised to state this is a comparison of Class I impacts only, as currently it is unclear that this is the case until the reader compares this Table to the table in the Executive Summary.

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Tranquillon Ridge DEIR Comments from Sunset and ExxonMobil - January 2007

	Comment No.	DEIR SECTION	DEIR Section Title	DEIR Statement	T-Ridge Project	Onshore Alternative	Both T-Ridge & Onshore Alt.	Tranquillon Ridge DEIR Comments (Concern/Request)
S&EM-97	7	Table 6.1a	Comparison of Proposed Project to Other Alternatives - VAFB Onshore Alternative	Table 6.1a lists a selection of impacts and compares the Proposed Project to the VAFB Onshore Alternative.			X	Request that the DEIR be revised to also compare the Class II impacts of the proposed project to the Revised VAFB Onshore Alternative as this onshore alternative is the only project level alternative and such a comparison is necessary to determine which alternative is the preferred alternative. Further, suggest the organization of the table be modified, particularly in long sections (multiple pages), to be a point/counterpoint discussion to make comparison of the alternatives easier.
S&EM-98	8	Table 6.1a	Comparison of Proposed Project to Other Alternatives - VAFB Onshore Alternative	TB.6 addresses effects of a pipeline leak on upland, riparian and freshwater aquatic habitats.			X	While the DEIR is correct in its discussion that the length of onshore pipeline associated with the Revised VAFB Onshore Alternative is greater than associated with the proposed project and thus potentially impacts more onshore acreage than the Proposed Project, commentor is concerned that the DEIR does not take into consideration the fact that the proposed Vahevala Project pipelines will be new, and thus will have a longer expected life and much lower likelihood of failure than the 20 year old pipelines associated with the proposed project. Request that the DEIR be revised to incorporate the comments later discussed under TB.6 in Table 6.1c, which indicates the new pipeline from Platform Irene is slightly preferable to use of the existing pipeline due to reduced likelihood of spills.
S&EM-99	9	Table 6.1a	Comparison of Proposed Project to Other Alternatives - VAFB Onshore Alternative	TB.6 addresses effects of a pipeline leak on upland, riparian and freshwater aquatic habitats.		X		Request that the DEIR be revised to evaluate the impact of a pipeline installed with better isolation capabilities and a current pipeline monitoring/shutdown system for all new pipelines associated with the Revised VAFB Onshore Alternative. Installation of a pipeline with automatic isolation capabilities and secondary containment in sensitive areas (i.e., the Santa Ynez river crossing) would greatly minimize the potential for any release to the environment. Given that installation of such "modem" technologies are not proposed on the existing pipelines, this could impact the determination that the proposed project is preferred for this impact.
S&EM-100	10	Table 6.1a	Comparison of Proposed Project to Other Alternatives - VAFB Onshore Alternative	TB.6 addresses effects of a pipeline leak on upland, riparian and freshwater aquatic habitats.		X		Request that the DEIR be revised to add explanation regarding conclusion that the Revised VAFB Onshore Alternative poses a greater risk to coastal areas than the proposed project when the pipelines associated with the proposed project actually cross the coastal area while the Revised VAFB Onshore Alternative pipelines are located some distance from and do not cross the coastal areas.
S&EM-101	11	Table 6.1a	Comparison of Proposed Project to Other Alternatives - VAFB Onshore Alternative	TB.6 addresses effects of a pipeline leak on upland, riparian and freshwater aquatic habitats.		X		Concern that potential impacts of the Revised VAFB Onshore Alternative on the Santa Ynez River are viewed as significant and subjecting the river and estuaries to "severe damage" while the proposed project pipelines which also run through the Santa Ynez River corridor, actually cross the coastal areas, and also run through the Oak Canyon and Santa Lucia Canyon are described as "limited." Request that the DEIR be revised to address this issue.
S&EM-102	12	Table 6.1a	Comparison of Proposed Project to Other Alternatives - VAFB Onshore Alternative	TB.6 addresses effects of a pipeline leak on upland, riparian and freshwater aquatic habitats.		X		Concern that potential impacts of an onshore spill from the Proposed Project pipeline are downplayed because "under dry conditions, overland flow of oil would be relatively slow due to the viscous nature of crude oil." Yet these same mitigating factors are not acknowledged for a VAFB Onshore Alternative spill, but rather oil from a VAFB onshore spill is consistently described as reaching the river or other drainage feature and impacting coastal and estuarian habitats. Further, alternative pipeline routes from VAFB to LOGP that minimize the distance which the pipeline runs along the Santa Ynez River are not discussed at all. Request that the DEIR be revised to evaluate such a pipeline route as part of the Revised VAFB Onshore Alternative.
S&EM-103	13	Table 6.1a	Comparison of Proposed Project to Other Alternatives - VAFB Onshore Alternative	TB.6 addresses effects of a pipeline leak on upland, riparian and freshwater aquatic habitats.		X		Concern that the conclusion that the proposed project is preferred with respect to onshore oil spills (TB.6) fails to consider the optimum pipeline construction, routing and engineered mitigation steps for the new pipelines associated with the Revised VAFB Onshore Alternative. Request that the DEIR be revised so that further evaluations can be performed to verify the feasibility of alternative routes and engineered mitigation steps and the subsequent reduction in likelihood and impacts of spills from the new pipeline.
S&EM-104	14	Section 6.3.1; Table 6-1a	Comparison of the Proposed Project to the VAFB Onshore Alternative	TB.6: A spill along the pipeline route into Honda Creek or other coastal drainages could flow rapidly downslope due to steep terrain and either reach the ocean or accumulate where drainage is impeded (in which case the impacts would be less severe). Once in the ocean, oil from an onshore spill would be dispersed to adjacent shoreline areas.		X		Request that the DEIR be revised to reflect the proposed Vahevala Project, which includes measures to reduce the likelihood of an oil spill from the facilities and pipeline, and provides measures to minimize and contain onsite spilled oil in the event of an accident.

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	Comment No.	DEIR SECTION	DEIR Section Title	DEIR Statement	T-Ridge Project	Onshore Alternative	Both T-Ridge & Onshore Alt.	Tranquillon Ridge DEIR Comments (Concern/Request)
S&EM-105	15	Section 6.3.1; Table 6-1a	Comparison of the Proposed Project to the VAFB Onshore Alternative	Impact TB.6: Under the Proposed Action, the geographic range of potential impacts is widely dispersed and diffuse due to seasonal and climatic variables (Appendix G). The extent of potential impact to terrestrial and freshwater resources is more widespread, but **likely to be less severe at any particular location than would be the case for the VAFB Onshore Alternative. Overall, given the proximity of sensitive terrestrial and freshwater resources to the VAFB Onshore Alternative pipeline, the severity of spill-related impacts is considered to be greater under the VAFB Onshore Alternative than under the Proposed Project.**		X		Request that the DEIR be revised to include the following points: the proposed project would include continued use of existing onshore pipelines which have a history of corrosion; the onshore pipeline for the proposed project is located immediately upland of the Santa Ynez River estuary; spill frequency and subsequent oil spill impacts would be less from a new pipeline; the Revised VAFB Onshore Alternative pipeline route crosses primarily coastal sage scrub habitat and fallow agricultural fields as compared to the proposed project pipeline route which includes 4.5 miles parallel to the Santa Ynez River Estuary, sensitive marsh habitat and riparian corridor from landfall to the point of intersection with the VAFB Onshore Alternative pipeline route.
S&EM-106	16	Table 6.1a	Comparison of Proposed Project to Other Alternatives - VAFB Onshore Alternative	TB.7 addresses effects of a pipeline leak on state or federally listed plant species.		X		While the DEIR is correct in it's discussion that the length of onshore pipeline associated with the Revised VAFB Onshore Alternative is greater than with the proposed project and thus potentially impacts more onshore acreage than the Proposed Project, commentor is concerned thatthe DEIR does not take into consideration the fact that the Vahevala pipelines will be new, and thus will have a longer expected life and much lower likelihood of failure than the 20 year old pipelines associated with the proposed project. Request that the DEIR be revised to incorporate the comments later discussed under TB.6 in Table 6.1c, which indicates the new pipeline from Platform Irene is slightly preferable to use of the existing pipeline due to reduced likelihood of spills
S&EM-107	17	Table 6.1a	Comparison of Proposed Project to Other Alternatives - VAFB Onshore Alternative	TB.7 addresses effects of a pipeline leak on state or federally listed plant species.		X		Request that the DEIR be revised to evaluate the impact of a pipeline installed with better isolation capabilities and a current pipeline monitoring/shutdown system for all new pipelines associated with the Revised VAFB Onshore Alternative. Installation of a pipeline with automatic isolation capabilities and secondary containment in sensitive areas (i.e., the Santa Ynez river crossing) would greatly minimize the potential for any release to the environment. Given that installation of such "modern" technologies are not proposed on the existing pipelines, this could impact the determination that the proposed project is preferred for this impact
S&EM-108	18	Table 6.1a	Comparison of Proposed Project to Other Alternatives - VAFB Onshore Alternative	TB.7 addresses effects of a pipeline leak on state or federally listed plant species.		X		Request that the DEIR be revised to provide additional explanation regarding conclusion that the Revised VAFB Onshore Alternative poses a greater risk to coastal areas and the sensitive plant species with habitat there than the proposed project when the pipelines associated with the proposed project actually cross the coastal area while the Revised VAFB Onshore Alternative pipelines are located some distance from and do not cross the coastal areas.
S&EM-109	19	Table 6.1a	Comparison of Proposed Project to Other Alternatives - VAFB Onshore Alternative	TB.7 addresses effects of a pipeline leak on state or federally listed plant species.		X		Concern that Revised VAFB Onshore Alternative discusses the "new" impact of the 10 miles of new pipeline, but does not acknowledge this new length of pipeline reduces pressure and flowrate requirement of the existing offshore pipeline, thus significantly reducing the risk of a rupture compared to this older section of line, which runs through the coastal zone and dunes and sensitive plant habitats. Further, conclusion does not appear consistent with the DEIR's acknowledgement that the probability of an onshore oil leak increases to 100% with the installation of the pumps at Valve station #2 associated with the Proposed project. Request that the DEIR be revised to address this issue.
S&EM-110	20	Table 6.1a	Comparison of Proposed Project to Other Alternatives - VAFB Onshore Alternative	TB.7 addresses effects of a pipeline leak on state or federally listed plant species.		X		Concern that potential impacts of the Proposed Project are tempered by the "probability of a spill reaching any particular site is small" while no such probability or likelihood is included in the discussion of potential impacts of the Revised VAFB Onshore Alternative spills. Request that the DEIR be revised to include likelihood or probability of all potential spills.
S&EM-111	21	Table 6.1a	Comparison of Proposed Project to Other Alternatives - VAFB Onshore Alternative	TB.7 addresses effects of a pipeline leak on state or federally listed plant species.		X		Request that the DEIR be revised to evaluate the pipeline route included as part of the Revised VAFB Onshore Alternative. This route minimizes the distance which the pipeline runs along the Santa Ynez River.

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	Comment No.	DEIR SECTION	DEIR Section Title	DEIR Statement	T-Ridge Project	Onshore Alternative	Both T-Ridge & Onshore Alt.	Tranquillon Ridge DEIR Comments (Concern/Request)
S&EM-112	22	Table 6.1a	Comparison of Proposed Project to Other Alternatives - VAFB Onshore Alternative	TB.7 addresses effects of a pipeline leak on state or federally listed plant species.		X		Concern that the conclusion that the proposed project is preferred with respect to impacts on sensitive plant species (TB.7) fails to consider the optimum pipeline construction, routing and engineered mitigation steps for the new pipelines associated with the Revised VAFB Onshore Alternative. Request that the DEIR be revised to include the amended alternative routes and engineered mitigation steps and the subsequent reduction in likelihood and impacts of spills from the new pipeline, as opposed to the existing 20 year old pipeline. Request that the DEIR be revised to incorporate comments later discussed under TB.6 in Table 6.1c, which indicates the new pipeline from Platform Irene is slightly preferable to use of the existing pipeline due to reduced likelihood of spills.
S&EM-113	23	Table 6.1a	Comparison of Proposed Project to Other Alternatives - VAFB Onshore Alternative	TB.7 addresses effects of a pipeline leak on state or federally listed plant species.		X		Concern that the discussion in the "impact" column regarding impact to coastal dunes of remediation efforts due to offshore spill are not included in the proposed project discussion. Such impacts are likely in the event of an offshore spill, yet remote in the event of any onshore spill. Since the Revised VAFB Onshore Alternative has no reasonable mechanism for an offshore spill, these impacts are solely associated with the proposed project, yet do not appear to be acknowledged in the conclusion. Request that the DEIR be revised to address this issue.
S&EM-114	24	Table 6.1a	Comparison of Proposed Project to Other Alternatives - VAFB Onshore Alternative	TB.7 addresses effects of a pipeline leak on state or federally listed plant species.		X		Request that the DEIR be revised to provide additional justification for the conclusion that "given the proximity of sensitive plant species to the VAFB Onshore Alternative pipeline, the severity of spill-related impacts is considered to be greater under the VAFB Onshore Alternative" as the Proposed Project discussion acknowledges that an onshore spill from the proposed project and cleanup efforts from an offshore spill could impact any of the discussed plant species. Further offshore spills would require cleanup impacting coastal areas and dunes while the majority of spills from Revised VAFB Onshore Alternative site or pipelines could be cleaned up from the site or from the roads adjacent to the pipeline right of ways without any impact to the dunes or coastal zone.
S&EM-115	25	Table 6.1a	Comparison of Proposed Project to Other Alternatives - VAFB Onshore Alternative	TB.8 addresses effects of a pipeline leak on state or federally listed wildlife species.		X		Request that the DEIR be revised to delete the Platform Irene impacts associated with the Revised VAFB Onshore Alternative, as those impacts are associated with the "No Project" alternative, not the Revised VAFB alternative.
S&EM-116	26	Table 6.1a	Comparison of Proposed Project to Other Alternatives - VAFB Onshore Alternative	TB.8 addresses effects of a pipeline leak on state or federally listed wildlife species.		X		While the DEIR is correct in it's discussion that the length of onshore pipeline associated with the Revised VAFB Onshore Alternative is greater than associated with the proposed project and thus potentially impacts more onshore acreage than the proposed project, commentor is concerned that the DEIR does not take into consideration the fact that the Vahevala pipelines will be new, and thus will have a longer expected life and much lower likelihood of failure than the 20 year old pipelines associated with the proposed project. Request that the DEIR be revised to incorporate the comments later discussed under TB.6 in Table 6.1c, which indicates the new pipeline from Platform Irene is slightly preferable to use of the existing pipeline due to reduced likelihood of spills.
S&EM-117	27	Table 6.1a	Comparison of Proposed Project to Other Alternatives - VAFB Onshore Alternative	TB.8 addresses effects of a pipeline leak on state or federally listed wildlife species.		X		Request that the DEIR be revised to evaluate the impact of a pipeline installed with better isolation capabilities and a current pipeline monitoring/shutdown system for all new pipelines associated with the Revised VAFB Onshore Alternative. Installation of a pipeline with automatic isolation capabilities and secondary containment in sensitive areas (i.e., the Santa Ynez river crossing) would greatly minimize the potential for any release to the environment. Given that installation of such "modern" technologies are not proposed on the existing pipelines, this could impact the determination that the proposed project is preferred for this impact.
S&EM-118	28	Table 6.1a	Comparison of Proposed Project to Other Alternatives - VAFB Onshore Alternative	TB.8 addresses effects of a pipeline leak on state or federally listed wildlife species.		X		Request that the DEIR be revised to evaluate the pipeline route included as part of the Revised VAFB Onshore Alternative. This route minimizes the distance which the pipeline runs along the Santa Ynez River.
S&EM-119	29	Table 6.1a	Comparison of Proposed Project to Other Alternatives - VAFB Onshore Alternative	TB.8 addresses effects of a pipeline leak on state or federally listed wildlife species.		X		Concern that the conclusion that the proposed project is preferred with respect to impacts on wildlife (TB.8) fails to consider the optimum pipeline construction, routing and engineered mitigation steps for the new pipelines associated with the Revised VAFB Onshore Alternative. Request that the DEIR be revised to include alternative route and engineered mitigation steps and the subsequent reduction in likelihood and impacts of spills from the new Vahevala pipeline, as opposed to the existing 20 year old pipeline. Request that the DEIR be revised to incorporate the comments later discussed under TB.6 in Table 6.1c, which indicates the new pipeline from Platform Irene is slightly preferrable to use of the existing pipeline due to reduced likelihood of spills and previous acknowledgement that likelihood of an onshore oil leak associated with the proposed project increases to 100% with the installation of the pumps at Valve station #2

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	Comment No.	DEIR SECTION	DEIR Section Title	DEIR Statement	T-Ridge Project	Onshore Alternative	Both T-Ridge & Onshore Alt.	Tranquillon Ridge DEIR Comments (Concern/Request)
S&EM-120	30	Section 6.3.1; Table 6-1a	Comparison of the Proposed Project to the VAFB Onshore Alternative	TB.8: An oil spill and/or subsequent cleanup effort may directly or indirectly cause the loss of individual state or federally-listed wildlife species or cause the loss or degradation of sensitive species habitat. An oil spill and/or subsequent cleanup effort may impact designated critical habitat for steelhead,western snowy plover, and California red-legged frog.	X			Federally and state listed endangered unarmored threespine stickleback (*Gasterosteus aculeatus williamsoni*) have been documented in San Antonio Creek and Honda Creek. Request that the DEIR be revised to add this species to the list of federally and state species potentially impacted by an offshore oil spill. (Note: included in text in Section 5.2.1.1)
S&EM-121	31	Section 6.3.1; Table 6-1a	Comparison of the Proposed Project to the VAFB Onshore Alternative	Impact TB.8: Under the Proposed Action, the geographic range of potential impacts is widely dispersed and diffuse due to seasonal and climatic variables (Appendix G). The extent of potential impact to terrestrial and freshwater resources is more widespread, but likely to be less severe at any particular location than would be the case for the VAFB Onshore Alternative. Overall, given the proximity of potential wildlife habitat to the VAFB Onshore Alternative pipeline, the severity of spill-related impacts is considered to be greater under the VAFB Onshore Alternative than under the Proposed Project.		X		The VAFB Onshore Alternative pipeline route as per this DEIR is located north of Highway 246 near the Santa Ynez River estuary, and is described as having only minimal pipeline control measures (i.e., the analysis assumes that the oil from entire segment would spill into the River or estuary). Request that the DEIR be amended to reflect the proposed Vahevala Project, which includes a smaller diameter oil pipeline, multiple, strategically located block and check valves along the pipeline route, and avoids placement of new pipelines in the estuary area by using a cross-country route that is south of Highway 246 and topographically remote from the estuary. The DEIR analysis of impacts to terrestrial biota and habitats from the Onshore Alternative are thus overstated, particularly with respect to aquatic resources. The assessment should reflect the fact that the existing PXP pipelines, which have a history of corrosion, will continue to operate in close proximity to the estuary, including an exposed pipeline span over a drainage that flows directly into the estuary.
S&EM-122	32	Table 6.1a	Comparison of Proposed Project to Other Alternatives - VAFB Onshore Alternative	TB.10 addresses effects of a construction of the VAFB onshore facilities on state or federally listed plant and wildlife species.		X		Concern that this discussion does not include identified mitigation steps and portrays worst-case unmitigated impacts rather than reasonably mitigated impacts. Request that the DEIR be revised to reflect a fully mitigated case that properly characterize the impacts of Revised VAFB Onshore Alternative.
S&EM-123	33	Table 6.1a	Comparison of Proposed Project to Other Alternatives - VAFB Onshore Alternative	OWR.2 addresses effects on surface or groundwater quality.			X	Concern that Revised VAFB Onshore Alternative is not preferred solely due to the length of the onshore pipeline and evaluation does not consider that this new length of pipeline reduces pressure and flowrate requirement compared to the existing offshore pipeline, thus significantly reducing the risk of a rupture compared to the older section of line, which runs through the coastal zone and dunes and sensitive plant habitats. Concern that this discussion fails to evaluate the reduced likelihood of spills from a new pipeline installed with better isolation capabilities and a current pipeline monitoring/shutdown system as opposed to a 20 year old pipeline. Request that the DEIR be revised to quantify the reduced risk of the new pipeline vs. the old pipeline as well as further reductions in likelihood of release associated with the installation of the new pipeline with automatic isolation capabilities and avoidance of sensitive areas, significantly reducing the potential of any release to the environment.
S&EM-124	34	Table 6.1a	Comparison of Proposed Project to Other Alternatives - VAFB Onshore Alternative	MB.1 addresses impacts to marine organisms			X	Request that the DEIR be revised to remove oil spill impacts for the Revised VAFB Onshore Alternative reaching the ocean as too remote to be considered feasible. If not removed, request inclusion of shoreline impacts in discussion of Proposed Project as well since shoreline impacts are much more likely to occur from an offshore pipeline leak than from an onshore release.
S&EM-125	35	Table 6.1a	Comparison of Proposed Project to Other Alternatives - VAFB Onshore Alternative	MB.1 addresses impacts to marine organisms	X			Request that the DEIR be revised to include marine species that could be impacted by offshore spill in Proposed Project discussion. (To discuss impacted marine species only in VAFB Onshore Alternative, which is acknowledged in the DEIR to be extremely remote scenario, is misleading as such species are much more likely to be impacted by an offshore spill than by an onshore spill.)
S&EM-126	36	Table 6.1a	Comparison of Proposed Project to Other Alternatives - VAFB Onshore Alternative	MWQ.1 addresses impacts to marine water quality		X		Request that the DEIR be revised to remove discussion of oil spill impacts for the Revised VAFB Onshore Alternative reaching the ocean as too remote to be considered feasible. If not removed, request revision of last sentence, removing the word "significant".

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Tranquillon Ridge DEIR Comments from Sunset and ExxonMobil - January 2007

	Comment No.	DEIR SECTION	DEIR Section Title	DEIR Statement	T-Ridge Project	Onshore Alternative	Both T-Ridge & Onshore Alt.	Tranquillon Ridge DEIR Comments (Concern/Request)
S&EM-127	37	Table 6.1a	Comparison of Proposed Project to Other Alternatives - VAFB Onshore Alternative	CRF/KH.2 addresses impacts to commercial and recreational fishing			X	Request the discussion of oil spill impacts for the Revised VAFB Onshore Alternative reaching the ocean be removed as too remote to be considered as a realistic scenario. Further, since it is such a remote possibility that oil could reach marine waters from Revised VAFB Onshore operations, a release from Platform Irene should be considered more likely to reach the kelp beds. In addition, a release from the offshore pipeline would be much more likely to impact the kelp beds than a release from Revised VAFB onshore operations. Request that the DEIR be revised to include an offshore pipeline leak scenario and the associated nearshore and shoreline impacts from such a release in the Proposed Project discussion.
S&EM-128	38	Table 6.1a	Comparison of Proposed Project to Other Alternatives - VAFB Onshore Alternative	T.4 addresses potential disruption of commercial fishing, shipping, and recreational marine traffic as well as onshore transportation infrastructure.		X		Disagree with and request that the DEIR be revised to re-evaluate the conclusion that there is no preference between the Proposed project and the Revised VAFB Onshore Alternative with respect to this issue. The Revised VAFB Onshore Alternative will have no realistic impact on any type of marine traffic. Further, because "under dry conditions, overland flow of oil would be relatively slow due to the viscous nature of crude oil" (as noted earlier) the spatial extent of any onshore release would be greatly limited. As such, commentor suggests that the Revised VAFB Onshore Alternative is preferable with respect to disruptions of marine traffic and onshore transportation infrastructure.
S&EM-129	39	Table 6.1a	Comparison of Proposed Project to Other Alternatives - VAFB Onshore Alternative	CR.3 addresses the impacts from an oil spill on cultural resources		X		Concern that Revised VAFB Onshore Alternative is not preferred solely due to the length of the onshore pipeline and evaluation does not consider this new length of pipeline reduces pressure and flowrate requirement compared to the existing offshore pipeline, thus significantly reducing the risk of a rupture compared to the older section of line, which runs through the coastal zone and dunes and sensitive plant habitats. Concern that this discussion fails to evaluate the reduced likelihood of spills from a new pipeline installed with better isolation capabilities and a current pipeline monitoring/shutdown system as opposed to a 20 year old pipeline. Request that the DEIR be revised to quantify the reduced risk of the new pipeline vs. the old pipeline as well as further reductions in likelihood of release associated with the installation of the new pipeline with automatic isolation capabilities and secondary containment in sensitive areas (i.e., the Santa Ynez river crossing), significantly reducing the potential of any releases.
S&EM-130	40	Table 6.1a	Comparison of Proposed Project to Other Alternatives - VAFB Onshore Alternative	CR.5 addresses the impacts from construction on cultural resources		X		Request that the DEIR be revised since impacts on cultural resources due to construction can be mitigated through a variety of means prior to construction and project facilities can be relocated / rerouted based upon these results. As such, there should be no preference between the proposed project and the Revised VAFB Onshore Alternative.
S&EM-131	41	Table 6.4	Proposed Project Compared to Major Alternatives	TB.6 row		X		Request that the DEIR be revised to use a more accurate statement for the Revised VAFB Onshore Alternative such as- "Risk of onshore oil spill increased due to more onshore pipeline, but risk is offset by use of new pipeline with new monitoring and shutdown systems."
S&EM-132	42	Table 6.4	Proposed Project Compared to Major Alternatives	TB.7 row		X		Request that the DEIR be revised to use a more accurate statement for the Revised VAFB Onshore Alternative such as- "Risk of onshore oil spill increased due to more onshore pipeline, but risk is offset by use of new pipeline with new monitoring and shutdown systems."
S&EM-133	43	Table 6.4	Proposed Project Compared to Major Alternatives	TB.8 row		X		Request that the DEIR be revised to use a more accurate statement for the Revised VAFB Onshore Alternative such as- "Risk of onshore oil spill increased due to more onshore pipeline, but risk is offset by use of new pipeline with new monitoring and shutdown systems."
S&EM-134	44	Table 6.4	Proposed Project Compared to Major Alternatives	TB.9 row	X			Request that the DEIR be revised to use a more accurate statement for Proposed Project such as- "Slightly preferred because of smaller diameter bore."
S&EM-135	45	Table 6.4	Proposed Project Compared to Major Alternatives	OWR.2 row		X		Request that the DEIR be revised to use a more accurate statement for the Revised VAFB Onshore Alternative such as- "Risk of onshore oil spill increased due to more onshore pipeline, but risk is offset by use of new pipeline with new monitoring and shutdown systems."

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S&EM-136	46	Table 6.4	Proposed Project Compared to Major Alternatives	T.4 row			X	Request that the DEIR be revised to show that the Revised VAFB Onshore Alternative should be preferred. Potential traffic corridor impacts under Revised VAFB Onshore Alternative are limited to VAFB, one entity through which various response scenarios will be developed in advance, and have no impact on marine traffic. Alternatively, an offshore spill has the potential to impact numerous third parties and will require extensive Coast Guard involvement and coordination with all marine traffic. In addition, if shipping lanes are impacted, delays and demurrages could result.
S&EM-137	47	Table 6.4	Proposed Project Compared to Major Alternatives	CR.3 row		X		Request that the DEIR be revised to use a more accurate statement for the Revised VAFB Onshore Alternative such as- "Risk of onshore oil spill increased due to more onshore pipeline, but risk is offset by use of new pipeline with new monitoring and shutdown systems."
S&EM-138	48	Table 6.4	Proposed Project Compared to Major Alternatives	CR.6 row		X		Request that the DEIR be revised to reflect mitigated case where cultural site survey is performed in advance of construction to minimize the potential to impact culturally significant sites. Current wording is misleading. Suggest wording such as- "Potential to impact 44 culturally significant sites will be mitigated to the extent possible through initial survey and cultural resource plan." Suggest "No preference" is proper conclusion due to mitigation.
S&EM-139	49	Section 6.4	Environmentally Superior Alternative	The discussion of the environmentally superior alternative states, in part: "...only the proposed project has been evaluated to a project-level of detail, while the alternatives have been reviewed at a reasonable but much more general level of detail. In this DEIR, the impacts identified for the alternatives are presented in terms of what could happen under worst case scenarios, while the impacts of the proposed project are typically described in more definitive terms, based on the greater detail available about		X		The commenter understands that the VAFB Onshore Alternative was developed by Santa Barbara County with limited information, and that the comparative analysis is qualitative. It is further understood that the comparison of the proposed project with the VAFB Onshore Alternative reflects a 'worst-case' scenario, not a 'likely scenario' with respect to biological and water quality impacts. Request that the DEIR be amended to describe the VAFB Onshore Alternative in the DEIR using the currently proposed Vahevala Project configuration in order to allow for a more reasonable comparison. CEQA Guidelines (Section 15126.6 [d]) require that an environmental document include sufficient information about each alternative to allow meaningful evaluation, analysis, and comparison to the Proposed Project.
S&EM-140	50	6.4.1	Environmentally Superior Alternative - Tranquillon Ridge Project	First bullet (Proposed Project) on page 6-60 states "the extension of life of Platform Irene and offshore oil pipeline resulting from the proposed project would continue significant oil spill risks and associated impacts...beyond the lifetime of the original Point Pedernales Project."	X			Suggest the statement fails to acknowledge the increased risk to those resources in the interim due to higher production rates at Platform Irene and higher flowrates through the aging, existing pipelines, as well as the increased risk (to 100%) of a release associated with the new pumps at Valve Station #2. Request that the DEIR be revised to acknowledge the significant increased risk during the initial years of the project, as well as the risk associated with extension of life.
S&EM-141	51	6.4.1	Environmentally Superior Alternative - Tranquillon Ridge Project	Second bullet (VAFB Onshore Alternative) on page 6-60 states "installation and operation of approximately 10 miles of new onshore pipeline could result in significant oil spill risk and associated impacts to terrestrial biology,..."		X		Concern that Revised VAFB Onshore Alternative discusses the "new" impact of the 10 miles of new pipeline, but does not acknowledge this new length of pipeline reduces pressure and flowrate requirement of the existing offshore pipeline, thus significantly reducing the risk of a rupture compared to this older section of line, which runs through the coastal zone and dunes and sensitive plant habitats. Further, conclusion does not appear consistent with applicant's acknowledgement that the probability of an onshore oil leak increases to 100% with the installation of the pumps at Valve station #2 associated with the Proposed project. Request that the DEIR be revised to address this issue.
S&EM-142	52	6.4.1	Environmentally Superior Alternative - Tranquillon Ridge Project	Second bullet under VAFB Onshore Alternative on page 6-61 states "Construction of the VAFB Onshore Alternative may permanently remove or destroy 44 sites that may contain significant or potentially significant cultural materials and would alter the spatial relationships and context of those materials."		X		Request that the DEIR be revised to reflect mitigated case where cultural site survey is performed in advance of construction to minimize the potential to impact culturally significant sites. Current wording is misleading. Suggest wording as such "Potential to impact 44 culturally significant sites will be mitigated to the extent possible through initial survey and cultural resource plan."
S&EM-143	53	6.4.1	Environmentally Superior Alternative - Tranquillon Ridge Project	Third bullet under VAFB Onshore Alternative on page 6-61 discusses the risk associated with directional drilling under the Santa Ynez River.		X		Request that the DEIR be revised to include the very small probability associated with such risk to reflect the fully mitigated case under which all practicable precautions are taken during directional drilling to ensure that a "frac out" does not occur. Mitigations include drilling only during dry season. Further request the DEIR quantify the risk of a frac out and revise this paragraph accordingly.

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	Comment No.	DEIR SECTION	DEIR Section Title	DEIR Statement	T-Ridge Project	Onshore Alternative	Both T-Ridge & Onshore Alt.	Tranquillon Ridge DEIR Comments (Concern/Request)
S&EM-144	54	6.4.1	Environmentally Superior Alternative - Tranquillon Ridge Project	Fourth bullet under VAFB Onshore Alternative on page 6-61 discusses Platform Irene, the offshore pipeline and 4.5 miles of the onshore pipeline and decommissioning.			X	Suggest this discussion is part of the base case and not a Class I impact of the Revised VAFB Onshore Alternative. Request that the DEIR be revised to remove this paragraph under this discussion of Class I impacts of Revised VAFB Onshore Alternative.
S&EM-145	55	6.4.1	Environmentally Superior Alternative - Tranquillon Ridge Project	Text on pgs 6-61-62 discusses the oil spill impacts from VAFB alternative and the proposed project. Potential impact from proposed project to shoreline, river estuaries and other onshore resources is described as "remote" while potential impact from VAFB onshore release to marine environment is described as "could result in significant impacts"			X	Request that the DEIR be revised to recharacterize several statements. If probability and remoteness are being considered for the risk of proposed project offshore releases reaching the shoreline and other onshore resources, it also should be considered for the Revised VAFB Onshore Alternative releases reaching the marine environment. Further, request that the DEIR be revised to separate these risks into separate paragraphs for each alternative to make it easier for readers and decision makers to compare.
S&EM-146	56	6.4.1	Environmentally Superior Alternative - Tranquillon Ridge Project	Text on p. 6-62 states "this analysis relies on a comparison of the nature, extent, permanence and probability of each Class I impact in order to identify the environmentally preferred option."		X		Request that the DEIR be revised to re-analyze all aspects of the Revised VAFB Onshore Alternative. Analysis to account for **extent** of impact, **permanence** of impact, and **probability** of impact, as well as the effect of **mitigation steps** that can be implemented to minimize the extent, permanence and probability of such impacts.
S&EM-147	57	6.4.2	Environmentally Superior Alternative - Power Line Routing Alternatives	This section acknowledges "impacts to biological resources associated with trenching (for a new underground power line) could be effectively mitigated"		X		Request that the DEIR be revised to acknowledge that this condition is also applicable to the pipeline construction activities that would also involve trenching as part of the Revised VAFB Onshore Alternative, and all discussions regarding terrestrial and biologic impacts of pipeline construction should be revised accordingly.
	DEIR Section Appendix C							
S&EM-148	1	Appendix C	Air Emissions- Tranquillon Ridge Development Project	The DEIR calculations use the EMFAC 7G model.	X			Request that the DEIR be revised to utilize the most recent model requirements (SBC Burden Emission Factors from EMFAC 2002, version 2.2). In addition, the EMFAC 2002 model (or URBEMIS 8.7) should be applied for on-road vehicles.
S&EM-149	2	Appendix C	Air Emissions- Tranquillon Ridge Development Project	Emission tables in Appendix C apply emission factors but do not site the source of the factors.	X			Request that the DEIR be revised to provide references to identify the source and justify the emission factor applied.
S&EM-150	3	Appendix C	Air Emissions- Tranquillon Ridge Development Project	For construction and operational on-road emissions, the DEIR uses SCAQMD emission factors.	X			Request that the DEIR be revised to utilize the SBC APCD Form 24 emission factors or other SBC APCD approved emission factors for these calculations.
S&EM-151	4	Appendix C	Air Emissions- Tranquillon Ridge Development Project	Emission tables in Appendix C footnotes are not clearly described. In addition, the tables in Appendix C are not numbered.	X			Request that the DEIR be revised to identify the specific item for each reference. Also include a number convention to each table identified in Appendix C.
S&EM-152	5	Appendix C	Air Emissions- Tranquillon Ridge Development Project	Permit exempt emission tables include the emergency generator and firewater pump.	X			Request that the DEIR be revised to update the permit exempt emission tables to remove the emergency generator and firewater pump since they are no longer exempt from APCD permit.
S&EM-153	6	Appendix C	Air Emissions- Tranquillon Ridge Development Project	In Appendix C, the commenter could not determine if the health screening reviewed the implications of diesel PM.	X			Request that the DEIR be revised to specify or include the implication of diesel PM in the health screening.
S&EM-154	7	Appendix C	Air Emissions- Tranquillon Ridge Development Project	Appendix does not provide any discussion regarding an increase in utilization. e.g., actual versus permitted potential over the past five years.	X			Request that the DEIR be revised to include a discussion regarding an increase in utilization. e.g., actual versus permitted potential over the past five years.

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Comment No.	DEIR SECTION	DEIR Section Title	DEIR Statement	T-Ridge Project	Onshore Alternative	Both T-Ridge & Onshore Alt.	Tranquillon Ridge DEIR Comments (Concern/Request)
8	Appendix C	Air Emissions-Tranquillon Ridge Development Project	Appendix indicates that diesel fueled combustion equipment operates using diesel fuel with a sulfur content of 500 ppm.	X			Request that the DEIR be revised to specify that all onshore diesel fueled equipment will combust diesel fuel with a sulfur content of <15 ppm.

Response to Comment Set S&EM

S&EM-1: The existing Point Pedernales facilities are maintained according to the project Safety, Inspection, Maintenance, Quality Assurance Plan (SIMQAP). Current pipeline operations include performing ongoing routine internal and external pipeline surveys. Pipeline surveys include, but are not limited to, smart pigging, corrosion checks, pressure tests, air and ground patrols, visual surveys using a video camera, and cathodic protection surveys. Table 5.1.2a of Section 5.1, Risk of Upset/Hazardous Materials, summarizes the PXP pipeline corrosion control and monitoring program. As noted on Page 5.1-13 of the Draft EIR, "since the 1997 release, smart-pig survey results have indicated that the internal corrosion program has been effective at substantially reducing the rate of corrosion in the onshore portion of the pipeline. In addition, smart-pig results indicated that external corrosion, the primary cause of the difference between "high risk" and "non-high risk" pipelines in the CSFM report, is non-existent for the emulsion pipeline." Further, "although internal corrosion has been experienced on the existing emulsion pipeline, adhering to DOT de-rating requirements reduces the failure rates associated with the internal corrosion to levels similar to pipelines that do not exhibit internal corrosion problems," as has been done for the existing PXP pipelines. PXP and the County evaluate the pipeline integrity program twice per year and adjustments to the program are made for improvements. The County Systems Safety Reliability Review Committee (SSRRC) conducts an annual SIMQAP audit and approves all facility/operation plans and future modifications as required by Final Development Plan Condition P-2, which will continue throughout the project lifetime, including the Tranquillon Ridge project, if it is approved.

Periodic internal and external pipeline inspections are also performed on a schedule specified by Minerals Management Service (MMS), SBC, and Santa Barbara County Air Pollution Control District (SBCAPCD) permits, and PXP policy. These inspections also satisfy the requirements of the Department of Transportation (DOT) and the California State Fire Marshal (CFSM) for the onshore portions of the pipelines. Response to Comment S&EM-36 details the specifics of the noted agency inspection programs. As with SIMQAP implementation, noted agency inspections and SSRRC review would continue for the life of the Tranquillon Ridge project, if it is approved.

Response to Comment S&EM-35 addresses the existing Point Pedernales power cable.

S&EM-2: A risk assessment was conducted to compare the existing baseline facilities (which are 19 years old) to the proposed project which is projected to have a 30-year life. Leak frequencies for pipelines were based on historical data from the MMS and the CSFM. The potential consequences of leaks were then evaluated using dispersion modeling and historical weather data. Finally, the population that could potentially be impacted by toxic and flammable vapor clouds was determined. These results were presented in the form of FN curves that depict the frequency (F) of events that could produce a given number (N) of fatalities or injuries. These curves were plotted against the Santa Barbara County established Public Safety Thresholds for CEQA documents that establish areas on a FN curve that are considered acceptable (or not significant) and those areas which are unacceptable (or significant). A full discussion of the risk assessment methodology is provided in Section 5.1.1.4.4. The only significant risk was associated with the truck transportation of liquid petroleum gases from the LOGP, which is significant in the baseline and becomes more significant with the project due to more truck shipments. The impacts to the environment resulting from an oil spill are discussed throughout the EIR. Finally, the proposed project would not require new pipeline construction or crossing of the Santa Ynez River. As a result, these construction impacts would not be incurred by the proposed project.

S&EM-3: Public Resources Code Section 6871.4 provides as follows: "The [State Lands] commission may divide the lands within the area proposed to be leased into parcels of convenient size and shape and shall prepare a form of lease *or leases* therefor embracing not to exceed 5,760 acres in any one lease." (emphasis added) Therefore, the State Lands Commission has the authority to approve multiple leases covering the premises sought to be leased by PXP.

S&EM-4: The VAFB Onshore Alternative developed for the EIR is a conceptual alternative that addresses potential development of the Tranquillon Ridge Field from an onshore location. The intent in developing the VAFB Onshore Alternative was to describe an alternative that would minimize potential impacts through appropriate siting and pipeline routing based on the environmental resources present and Base constraints (i.e., subsurface communications and utility infrastructure in roadways, unexploded ordnance areas, etc.). Biological and cultural resource information was provided by the Base, in addition to roadway and fire fighting/emergency response capabilities. Further, minimum regulatory requirements, such as block valve placement, were assumed, but not mitigated further. It is conceivable that alternative routing and/or site-specific mitigation such as additional block valves could further mitigate potential impacts of a proposed onshore development proposal, but for purposes of the analysis was not assumed.

The description for the VAFB Onshore Alternative was fixed at the time of publication of the Draft EIR. The environmental review process typically identifies specific proposed project redesigns that could reduce, and sometimes avoid, specific impacts. However, it is not appropriate to revise the components of a conceptual development alternative, nor is such revision necessary to provide for a qualitative evaluation of likely impacts of an onshore development scenario, including classification of potential impacts in the EIR. EIR Section 6.3.1 acknowledges that "while rerouting of the pipeline corridor could avoid some of the identified sensitive biological and cultural resources, given the abundance and density of biological and cultural resources within southern VAFB and technical limitations to pipeline design/routing, it is unlikely that all sensitive biological and cultural resources could be avoided." When and if an application is deemed complete for an onshore development project, it will receive specific project review in accordance with CEQA. See also Response to Comment EDC-10.

S&EM-5: PXP is maintaining the existing pipeline(s) integrity through implementation of its Pipeline Integrity Program. The Program would continue to be implemented for the proposed Tranquillon Ridge project, if it is approved and is summarized below for each pipeline.

20-inch Emulsion Pipeline

Internal Corrosion Control

- Continuous Corrosion Inhibitor: 12-15 ppm average residual at LOGP
- Brush Pig Cleaning: Weekly intervals
- Batch Corrosion Inhibitors with every pig run

Corrosion Monitoring
- Smart Pig Surveys: Annually
- Weight Loss Corrosion Coupons
- Hydrogen Permeation Measurements: Beta Foil
- Continuous Corrosion Monitoring Probes
- Microbiological Cultures (SRB)
- Ultrasonic Thickness Measurements
- Chemical Analysis
- Corrosion Inhibitor Residuals
- Visual Inspections: Brush Pig Returns; Removable Pipe Spools

Cathodic Protection (External)
- Offshore-Zinc Bracelet Sacrificial Anodes
- Onshore-Impressed Current
- Smart Pig Surveys identify external anomalies

8-inch Gas Pipeline

Internal Corrosion Control
- Gas Dehydration: Prevents Condensed Water forming
- Brush Pig Cleaning: Monthly
- Batch Corrosion Inhibitor: Every Pig Run

Corrosion Monitoring
- Gas Dew Point Temperature
- Smart Pig Surveys: Annually
- Weight Loss Corrosion Coupons
- Ultrasonic Thickness Measurements
- Chemical Analysis
- Visual Inspections: Brush Pig Returns; Removable Pipe Spools

Cathodic Protection (External)
- Offshore-Zinc Bracelet Sacrificial Anodes
- Onshore-Impressed Current
- Smart Pig Surveys identify external anomalies

8-inch Produced Water Pipeline

Internal Corrosion Control
- Continuous Corrosion Inhibitor at LOGP: 17 ppm residual at Platform
- Brush Pig Cleaning: Weekly
- Batch Corrosion Inhibitor with every pig run

Corrosion Monitoring
- Smart Pig Surveys: Annually
- Weight Loss Corrosion Coupons
- Continuous Monitoring: Hydrogen Permeation Measurements: Beta Foil; Electrochemical Monitoring: LPR or ECN
- Microbiological Cultures (SRB)
- Ultrasonic Thickness Measurements
- Chemical Analysis
- Visual Inspections: Brush Pig Returns; Removable Pipe Spools

Cathodic Protection (External)
- Offshore-Zinc Bracelet Sacrificial Anodes
- Onshore-Impressed Current
- Smart Pig Surveys identify external anomalies

PXP and the County evaluate the pipeline integrity program twice per year and make adjustments to improve it as appropriate. The County conducts its oversight of pipeline operations and maintenance through the Safety Inspection, Maintenance and Quality Assurance Program (SIMQAP) required by Final Development Plan Condition P-2, which includes the annual safety audits for the Point Pedernales Project, and which will continue throughout the project lifetime, including the Tranquillon Ridge project, if it is approved.

The exposed pipeline spans referred to in the comment are over Drainage Area #1, where the emulsion, sour gas, and produced water pipelines cross the drainage. At this location, each pipeline is encased with concrete as follows:

- 20-inch Emulsion Pipeline is encased with a 26-inch outer dimension (OD), 460-foot long casing.
- 8-inch Gas and Produced Water Pipelines are encased with 22-inch OD, 460-foot long casing each.

The casings are anchored, supported by pipe supports at each end and within the drainage area, and sealed at each end. In case of a leak or rupture in a pipeline, vents (drains) are provided at each end of each casing. The west-end vents drain to Catch Basin #4 and the east-end vents drain to Catch Basin #5. Corrosion monitoring of the pipelines over Drainage Area #1 has not revealed significant corrosion problems at this location.

Response to Comment S&EM-36 discusses the various agency inspection programs conducted for the existing Point Pedernales facilities.

S&EM-6: As presented in Section 5.6.5.2, under the discussion of Impact MWQ.3, "under current regulations/permits, discharges at Platform Irene of produced water from the Tranquillon Ridge Field would be prohibited unless that produced water was produced from wells drilled from Platform Irene. To discharge produced water at Platform Irene from wells drilled onshore, the existing discharge permit would need to be modified or a new discharge permit would need to be obtained (E. Bromley, USEPA, personal communication, 2006). Modifying the existing permit or obtaining a new discharge permit is feasible, but could be a lengthy process and would require the approval of the California Coastal Commission in addition to approval of USEPA." As a result, the EIR addressed the offshore discharge scenario, in addition to initial re-injection of produced water at the Lompoc Oil Field and construction of a water cleaning and injection plant within the VAFB Onshore Alternative drilling and production site.

S&EM-7: EIR Section 6.3, Table 6.1a, Impact CR.5, acknowledges that "While rerouting of the pipeline corridor could avoid some of the identified sites, given the density of cultural sites within southern VAFB and technical limitations to pipeline design/routing, it is unlikely that all cultural sites could be avoided." A similar clarification has been added to Impact TB.10 in Table 6.1a. However, for purposes of comparing the VAFB Onshore Alternative to the proposed project, exact pipeline routing for the alternative is irrelevant since for the proposed project no new pipeline construction would occur. Further, for the proposed project the (existing) pipeline does not cross the Santa Ynez River. See also Response to Comment S&EM-4.

S&EM-8: The impacts of repair and maintenance are discussed throughout the EIR. See Responses to Comments S&EM-5 and S&EM-36 for a description of the Santa Barbara County and

MMS pipeline monitoring programs, respectively. It should be noted that these monitoring programs are also implemented on pipelines throughout the region (e.g., Pt. Arguello, Santa Ynez Unit, etc.). Further, Response to Comment S&EM-1 discusses the County's pipeline leak detection requirements, and maintenance and repair programs as defined by the SIMQAP and enforced by the County SSRRC. If need for a repair is identified, the County would review the repair project in accordance with CEQA; for the coastal zone or repairs in Federal waters, the CCC and MMS would also be involved, respectively. Finally, the 1997 Torch oil spill resulted from mechanical failure most likely due to faulty installation and was exacerbated by operator error. The age of the pipeline was not a contributing factor to that oil spill.

S&EM-9: See Response to Comment S&EM-7.

S&EM-10: Although the data from the CSFM report is somewhat outdated to extrapolate to a new pipeline, more recent data supports the conclusion. A 2002 report from CONCAWE Western European Cross-Country Oil Pipelines 30-year Performance Statistics states that there is no evidence to show that ageing (up to 45 years old at least) is affecting environmental security. Inspection methods are now available to monitor pipeline condition such that any upturn in age-related spillages is likely to be prevented or delayed for many years. Section 5.3.1 from the report, in particular Figure 21, shows that spills due to corrosion have not changed significantly for pipelines with average age between 5 to 35 years.

S&EM-11: As presented in Section 5.5.4, Impact MB.2, "drilling muds discharged from Platform Irene would dilute rapidly and the dispersion would be limited to a few kilometers (km) from the platform. The majority of drill cuttings would be deposited in the immediate vicinity of the platform. The impacts to marine organisms caused by the discharge of drilling muds and cuttings are considered to be adverse but not significant (Class III)." The analysis for Impact MB.2 provides an extensive discussion of mud and cuttings-related impacts by marine resource. Please refer to this discussion.

S&EM-12: The EIR notes that the potential risk of an oil spill that reaches the marine environment from the VAFB Onshore Alternative would be greatly reduced compared to the proposed project; however, this risk would not be reduced to zero. As discussed in EIR Sections 5.5, 5.6, and 5.7, and summarized in EIR Section 6, Table 6.1a, Impacts MB.1, MWQ.1, and CRF/KS.2, the oil spill impacts to the marine environment as a result of the VAFB Onshore Alternative are based on consequence rather than probability of occurrence. EIR Sections 5.5.5.2, 5.6.5.2, and 5.7.5.2 discuss how an onshore oil spill could reach the marine environment.

S&EM-13: Please see Response to Comment S&EM-4.

S&EM-14: Please see Response to Comment S&EM-12.

S&EM-15: Please see Response to Comment S&EM-7.

S&EM-16: The referenced table in the Executive Summary attempted to summarize all of the impacts of the proposed project and alternatives. This table has been deleted and the Executive Summary has been reorganized to include Tables 6.2, 6.3, and 6.4 (as Tables ES.9, ES.10 and ES.11) so that the relative comparison amongst the alternatives is clearer to the reader.

S&EM-17: Please see Response to Comment S&EM-12. With respect to impacts to the Santa Ynez River, Section 5.2.5.2 discusses the oil spill impacts to the terrestrial environment. This discussion is summarized in Section 6, Table 6.1a, Impacts TB.6, TB.7, and TB.8.

S&EM-18: Please see Responses to Comments S&EM-12 and S&EM-16.

S&EM-19: Please see Responses to Comments S&EM-6 and S&EM-16.

S&EM-20: Please see Responses to Comments S&EM-12 and S&EM-16.

S&EM-21: Please see Responses to Comments S&EM-6 and S&EM-16.

S&EM-22: Please see Responses to Comments S&EM-6 and S&EM-16.

S&EM-23: Please see Responses to Comments S&EM-6 and S&EM-16.

S&EM-24: Please see Responses to Comments S&EM-12 and S&EM-16.

S&EM-25: Please see Responses to Comments S&EM-12 and S&EM-16.

S&EM-26: Please see Response to Comment S&EM-16.

S&EM-27: Please see Response to Comment S&EM-16.

S&EM-28: Please see Response to Comment S&EM-16.

S&EM-29: Please see Responses to Comments S&EM-12 and S&EM-16.

S&EM-30: The Executive Summary table entitled Class I Impacts of the VAFB Onshore Alternative has been corrected to reflect Impact T.4, not Impact T.3. Under Impact T.4, an oil spill could result in the disruption of "onshore" transportation infrastructure. Note that this impact considers both offshore shipping corridors and onshore transportation infrastructure. This impact is considered to be Class I as discussed in Section 5.9.5.2.

S&EM-31: PXP has stated the following: Third-party structural engineering contractors reviewed and evaluated Platform Irene's jacket structure and piles and concluded they have sufficient strength to support the added equipment loads required to develop the Tranquillon Ridge Field. The load conditions reviewed in the evaluations were storm and seismic loads combined with operating condition gravity loads. The jacket and the foundation were found to have a significant margin of safety for all of these conditions. The pile foundation capacities were assessed using information gathered during platform installation. A conservative pile penetration approach which considers soil conditions was also used. The pile capacity evaluation demonstrated that the platform foundation desired factors of safety would be maintained at all eight platform pile locations.

Prior to any drilling, the MMS will conduct at least two inspections of all major drilling rig components, including safety and environmental protection devices such as blowout prevention and gas detection systems. Once activities are underway, the activities and platform operations will be subject to ongoing inspections and reviews by the MMS.

S&EM-32: PXP has stated that they have no plans to exchange the drilling rig currently on Platform Irene: PXP Rig 104. K & M Technology Group conducted both an Offset Well Review and Feasibility Study and Preliminary Design for drilling extended reach wells to Tranquillon Ridge field using the existing PXP Rig 104. The results of the studies indicate that the existing PXP Rig 104 is suitable for drilling the initial Tranquillon Ridge wells.

As noted in the project description, PXP plans to replace the two (1300 HP) mud pumps with two 1600 HP mud pumps after the first several wells are drilled. Torque and Drag Analysis modeling conducted by PXP indicates that the existing 500-ton mast is capable of supporting the most severe loads generated by the highest departure well case evaluated. Existing well A-21 (16,714' measured depth and 14,671' horizontal distance) was drilled using the existing PXP Rig 104, but with much older down-hole directional drilling technology than is currently available and this well is longer than seven of the proposed Tranquillon Ridge wells and more deviated than 17 of the proposed Tranquillon Ridge wells.

Should a different rig be required for the drilling project, PXP would be required to submit rig load and structural changes to the MMS for structural evaluation per MMS regulations at 30 CFR 250 Subpart I. The use of a larger rig with heavier loads than previously evaluated could trigger analysis for re-assessment of the structure.

The existing electrical power distribution system and electrical components associated with the drilling rig and ancillary equipment are adequate to safely drill all of the proposed wells. The existing emergency generators (two Caterpillar D-399 with 800 KW generators) on Platform Irene are for the purpose of providing electrical power during an unscheduled outage event such as an interruption of electrical power supplied by PG&E. In such an event, drilling would be suspended and power supplied to the hoisting system, mud pumps or top drive to safely secure the well until normal electrical power is restored. Please see Response to Comment S&EM-37 for a complete discussion of the power cable for Platform Irene.

S&EM-33: PXP has stated that they have no plans to use oil-based drilling fluids for the Tranquillon Ridge drilling effort. PXP plans to use an acceptable water-based drilling fluid that exhibits similar properties in terms of both lubricity and inhibition to that of an oil-based drilling fluid. As stated in EIR Section 2.2.2, if oil-based muds are required to be used (for example, on longer-reach drills), the excess muds would be stored in bins and transported to shore, or possibly reinjected at the platform.

S&EM-34: As presented throughout the EIR, any muds and cuttings discharge would be in accordance with National Pollutant Discharge Elimination System (NPDES) General Permit No. CA280000, which is included in the DEIR as Appendix L. EIR Table 5.6.4 presents the current and proposed discharges from Platform Irene. As provided by Eugene Bromley, EPA (personal communications, February 28, 2007), if drilling occurs from Platform Irene then discharges can occur from the platform under the existing NPDES General Permit regardless of how far PXP extends the reach of the drilling. Therefore, PXP could tap into State oil reserves and discharge from the platform under the existing NPDES permit so long as the standards set in that permit are met.

S&EM-35: According to PXP, the existing power cable to Platform Irene is rated for 28,000 kVA at 34.5 kV and PXP is currently using 5600 kVA. The power cable was originally designed to support three platforms in the area. As stated in the DEIR, in Table 5.16.3, the anticipated total load for full Tranquillon Ridge Field development is 12,300 kVA. The power cable manufacturer (Kerite) has reported that the cable is rated for a 40-year life. This life rating assumes worst case operating conditions. However, because the existing power cable is oversized for its current application, and thus has been underused since its installation, its expected functional life may be greater than the economic life of the proposed project. This is supported by the fact that the power cables installed in the 1960s along the California coast for many other platforms are still in service. If a failure were to occur, the procedure would be to locate the specific failure point through testing; the repair plan would involve splicing in a new section of cable to replace the bad section. Such repair and maintenance activities are assessed throughout the EIR.

S&EM-36: The Minerals Management Service (MMS) regulations at 30 CFR 250.919(a) require all OCS platforms be inspected in accordance with the provisions of American Petroleum Institute (API), Recommended Practice (RP) 2A for Planning, Designing, and Constructing Fixed Offshore Platforms, Section 14 (Surveys). The regulation at 30 CFR 250.912(b) requires lessees to submit an annual report to the MMS that lists the platforms inspected during the preceding 12 months with a description of the extent, area, and type of each inspection.

Per the API RP 2A, the MMS requires lessees to perform the following surveys:

Level I: A Level I survey consists of a below-water verification of performance of the cathodic protection system, an above-water visual survey, and a general examination of all structural members in the splash zone and above water. This survey is performed every year.

Level II: A Level II survey consists of an underwater inspection by divers or a Remotely Operated Vehicle to look for excessive corrosion, overloading, seal instability, fatigue, construction deficiencies, debris and excessive marine growth. This survey is performed every 3 to 5 years.

Level III: A Level III survey consists of an underwater visual inspection of pre-selected areas that an engineering evaluation determines are particularly susceptible to structural damage, pre-selected areas where repeated inspections are desirable to monitor their integrity over time, and areas where a Level II survey has indicated damage or suspected damage. This survey is performed every 6 to 10 years or as needed based on the results of a Level II survey.

Past surveys on Platform Irene and any subsequent corrective actions have met regulatory requirements. Level II and Level III surveys were conducted on Platform Irene in 2007.

The following table summarizes other inspection programs implemented for LOGP, the existing PXP pipelines, and Platform Irene:

Table 9.3.2. Point Pedernales Facility Inspections/Consultations

Facility	Inspection	Frequency	Agency
LOGP	SIMQAP Audit	Annual	SSRRC
LOGP	SSRRC Review of Operations	Monthly	SSRRC
LOGP	Equipment Modifications	Before changes are made	Building & Safety
LOGP	Fugitive Emissions Monitoring	Oil Plant - Quarterly Gas Plant - Monthly	APCD requirement
LOGP	APCD Inspection	Quarterly	APCD
LOGP	Fire Department Inspection	Random	County Fire Department
LOGP	Emergency Response Drills	Annual	County Fire Department/OES

Facility	Inspection	Frequency	Agency
LOGP	Vessel Cleaning /Internal Inspection	Per schedule depending on service	Results reviewed by Building and Safety
LOGP	Erosion/Corrosion Testing	Per schedule depending on service	Results reviewed by Building and Safety
LOGP	BAST Audit	5 year	Results reviewed by SSRRC
LOGP	OSHA Audit	Random	Cal OSHA
LOGP	CERCLA Audit	Random	EPA/County PSD
LOGP	SPCC Plan Audit	Random	EPA
LOGP	Safety System Audit	Annual	OES
LOGP	Environmental Quality Assurance Program	Monthly	Planning and Development
Pipelines	Smart Pig	Annual	SSRRC/MMS/CSLC
Pipelines	Pipeline Integrity Meeting	6 month	Meet with Building and Safety
Pipelines	Corrosion Coupons	6 month	Results reviewed by Building and Safety/MMS
Pipelines	Corrosion Chemical Residual	6 month	Results reviewed by Building and Safety/MMS
Pipelines	Cathodic Protection Survey	Annual	Results reviewed by Building and Safety/MMS/CSLC/DOT
Pipeline	Fugitive Emission Monitoring	Quarterly	APCD Requirement
Pipelines	Emergency Response Drills	Annual	County Fire Department/OES
Pipelines	ROV Inspection	2 year	Results reviewed by Building and Safety/MMS
Pipelines	Right of Way Patrols	1 by air and 1 by land per week	MMS
Pipelines	Flame Ionization Detection	Annual	DOT
Pipelines	Valves and PSVs	Annual	DOT
Pipelines	Rectifier Readings	Monthly	DOT
Pipelines	Atmospheric Corrosion	Annual	DOT
Pipelines	UT at Valve Boxes	Annual	Results are reviewed by Building and Safety
Pipelines/Irene	Spill Drill	Random (1 per year at one of the California Facilities)	MMS/Coast Guard/State and County Agencies
Pipelines/Irene	Spill Drill	Annual	PXP
Irene	Spill Drill Deployment Exercise	2 per year (1 unannounced, 1 scheduled)	MMS
Irene	Annual Inspection	Annual	MMS
Irene	Unannounced Inspections	Periodic	MMS
Irene	APCD Inspection	Quarterly	APCD
Irene	Fugitive Emissions Monitoring	Quarterly	APCD requirement
Irene	Cathodic Protection Survey	Annual	Results reviewed by MMS
Irene	Marine Growth	Annual	Results reviewed by MMS
Irene	Level 1 Survey	Annual	Results reviewed by MMS
Irene	Level 2 Survey	5 year	Results reviewed by MMS
Irene	Level 3 Survey	10 year	Results reviewed by MMS

The most recent inspection data shows that the platform structure is fully protected subsea by the cathodic protection system, and that the splash zone and topside coatings are in acceptable condition and no fatigue cracking has been noted.

The repair and replacement history of the platform structure does not indicate any major concerns with its continued use. It is expected that some time within the next 10 years the cathodic protection system will require some replacement anodes or additions to the system. Anode replacement/additions would be conducted by divers off of Platform Irene and is considered a maintenance activity; no permits are required. This system maintenance effort is not related to the Tranquillon Ridge Project and would be conducted with or without implementation of the Tranquillon Ridge Project.

S&EM-37: Because the existing power cable is oversized for its current application, and thus has been underused since its installation, its expected functional life may be greater than the economic life of the proposed project. There is no redundant electrical power cable to Platform Irene. Testing power cables is not normally conducted unless there is an indication that a problem may exist and needs to be investigated because such testing can put undue stress on the cable and may shorten its useful life. PXP periodically conducts visual inspections of the above-water portions of the cable. The PXP power cable has not required any repairs since its installation. See also Response to Comment S&EM-35.

S&EM-38: Please see Responses to Comments S&EM-35 and S&EM-37.

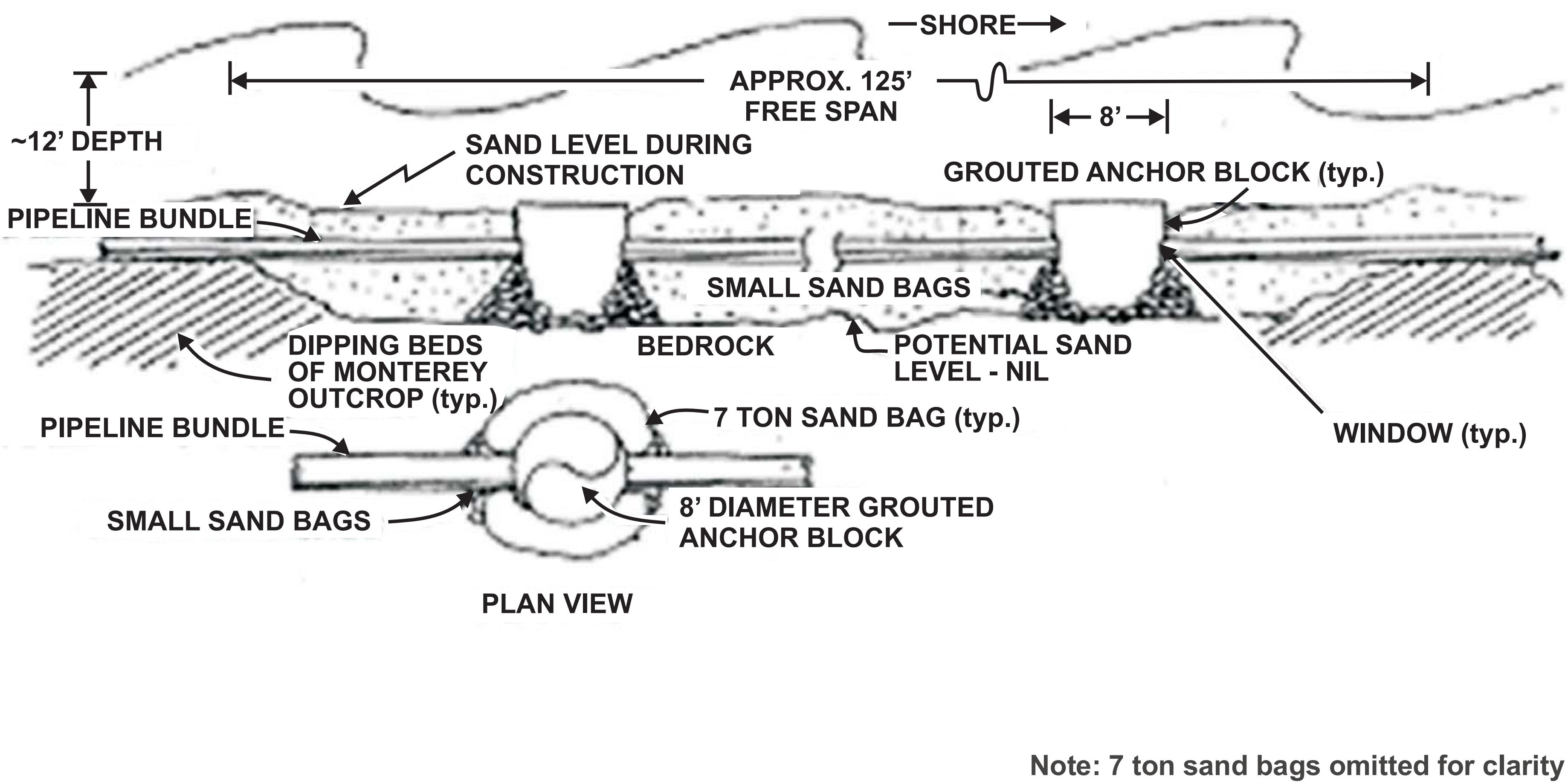
S&EM-39: A table of historic repairs for the existing PXP pipelines has been added to EIR Section 5.1 (Table 5.1.2a). See also Response to Comment S&EM-8.

S&EM-40: Figure 9.3-1 illustrates the installation configuration of the existing PXP pipelines. PXP has provided the following description of pipeline installation in the nearshore area:

> These installation techniques were used to mitigate a free span: Each of two anchors is 8 feet high and 8 feet wide, made from galvanized corrugated culverts standing on end with a slot cut in one side to go over the pipeline bundles. The anchors rest on bedrock. They were put in place, and then filled with construction-grade grout tying the anchor and pipelines to bedrock. The anchors were designed to streamline the shape to allow for breaking waves. The lateral load capacity of one anchor, assuming limited bedrock and pipeline friction, was 35 tons. Two-poly type material sandbags with dimensions of 7 feet by 12 feet and weighing 7 tons each were installed around each anchor, along with smaller sandbags. After the work was completed on the 125-foot span, the resulting spans were 20 feet, 45 feet, and 60 feet from offshore to onshore. The reduction in span length reduced the loads on the pipeline.

In addition, recent (March 2007) inspections indicate that the pipelines are covered and there are no free spans in this area.

The PXP pipelines are inspected regularly (see Responses to Comments S&EM-5 and S&EM-36) and to-date have not required repair in the nearshore area. Impacts associated with pipeline repair and maintenance activities were addressed in the original Point Pedernales project EIR/EIS and would be similar to those described in this EIR for the Emulsion Pipeline Replacement alternative for the nearshore area. Mitigation measures addressing marine and terrestrial impacts associated with pipeline repair are currently required in the Point Pedernales project Final Development Plan and would continue in effect for the Tranquillon Ridge project, if it were approved. For terrestrial biology, these include FDP Conditions H-1, H-3, H-7, H-8, H-10, H-11, H-20, H-21, H-24, H-25, H-26, H-27, H-28. For mitigation of impacts to marine biology, the Marine Biology



Source: PXP, 2007.

PREPARED BY Aspen Environmental Group

Figure 9.3-1
Primary Free Span Schematic Cross Section

Impact Reduction Plan required in FDP Condition G-2 would be updated prior to any pipeline repairs in the nearshore area to identify specific procedures for avoidance and/or mitigation of impacts to marine resources.

S&EM-41: Smart pigging results for the emulsion and produced water pipelines are included in Sections 5.1.1.4.2 and 5.1.1.4.3, respectively. Also see Responses to Comment S&EM-1 and S&EM-8.

S&EM-42: Please see Response to Comment S&EM-4.

S&EM-43: Section 35.56.130.L of the County's Land Use & Development Code specifically states that:

> Subsurface segments of inter-facility pipelines may be abandoned in-place except under the following circumstances:
>
> a. Presence of the pipeline would inhibit future land uses proposed in an active development application.
>
> b. Modeling approved by the U.S. Army Corps of Engineers or U.S. Bureau of Reclamation indicates that segments of the pipeline in erosive locations would become exposed at some time during the next 100 years, and environmental review determines that impacts from exposure and subsequent removal during inclement weather are more significant than removal at the time of abandonment.

Further, FDP Condition R-2 (see EIR Appendix M) states that all unburied portions of the pipeline and those underground pipelines that have the potential to become exposed shall be removed. Neither the County ordinance nor FDP Condition R-2 requires that the entire underground pipeline be removed. Also see Response to Comment EDC-6.

The CCC staff has noted that the Coastal Act does not have any specific policies regarding abandonment of offshore pipelines. CCC considers the issue of abandonment on a project-specific basis under the general Chapter 3 policies of the Coastal Act. In practice, the CCC has supported the SLC's position that pipelines under the beach and in nearshore waters (surf zone) must be removed to prevent hazards. Regarding pipelines in deep water, the CCC has agreed that they may be left in place (as was the case for removal and abandonment of Chevron 4H platforms). Pursuant to 30 CFR 250.1750-1754 and Notice to Lessees No. 2003-P10, the MMS follows a similar approach and determines the preferable means (removal vs. abandon in place) of pipeline abandonment on a case-by-case basis. In addition, offshore pipeline abandonment activities typically require additional CEQA and NEPA review as they occur well into the future and sufficient detail regarding baseline information and up-to-date abandonment techniques cannot be specified with a high degree of certainty at the time of project approval.

S&EM-44: Section 3.5.1.1 discusses installation of the alternative offshore pipeline through the surf zone, including the following: "The pipeline would be buried to a depth of 5 feet to –15 feet below the mean low water level through the surf zone (from shore up to 4,000 feet offshore) by divers using hand held "air jets." These jets pump seawater under the pipeline to displace the sand. This action would bury the line to a depth of 3 to 6 feet." For purposes of a conceptual alternative, this level of detail is adequate.

S&EM-45: Section 3.5.1.1 states that the "exact method used for installing a new offshore pipeline is not known." For purposes of a conceptual alternative, the level of detail provided is adequate to provide a qualitative assessment of the nature and extent of impacts associated with this alternative.

S&EM-46: See Response to Comment S&EM-40 for a description of existing pipeline installation through the surf zone. The ongoing pipeline inspection and monitoring programs have not revealed any necessity to replace the existing PXP pipelines through the surf zone. Mitigation Measure TB.10 addresses protective measures that would need to be implemented for construction within the beach and foredune habitats if the need were to arise.

S&EM-47: As noted in Section 3.5.1.1, "the pipeline barge would set spools to connect the pipelines to the risers as well as replace the "J" tube risers, which would have been previously removed from the existing pipeline." While multiple methods are available for connection of the pipelines to the platform and use of "J" tube risers would eliminate a joint, "J" tube risers present disadvantages in terms of increased erosion potential and reduced visual inspection opportunities. Therefore, the EIR analysis for this alternative is sufficient as written. See also Response to Comment S&EM-45.

S&EM-48: For purposes of the conceptual Emulsion Pipeline Replacement Alternative, a lay barge, versus a dynamic position vessel, was assumed because of the sandy ocean bottom along the existing offshore pipeline corridor. However, if a dynamic position vessel were used, the commenter is correct that this method would require equipment with increased HP ratings over those for the lay barge method.

S&EM-49: Appendix H provides additional details on the release scenarios presented in Table 5.1.4. A reference to Appendix H has been added to Section 5.1.1.4.2.

S&EM-50: Appendix H provides additional details on the release scenarios presented in Table 5.1.10. A reference to Appendix H has been added to Section 5.1.1.4.2.

S&EM-51: Section 5.1.5.2 states the following: "Pipeline design details showing the elevation profile and proposed valve locations are not currently available. The spill volumes presented in Table 5.1.30 would be lower with the installation of additional block and check valves beyond those assumed" (DEIR, p. 5.1-56, first paragraph). See also Response to Comment S&EM-4.

S&EM-52: Please see Response to Comment S&EM-4.

S&EM-53: Information on the current status of the tidewater goby has been incorporated in the EIR; however, this information does not change the conclusions presented in the EIR.

S&EM-54: This information is in the DEIR in Table 5.2-1 and on page 5.2-28.

S&EM-55: The intent of a Frac-out Contingency Plan is to minimize the potential for a frac-out and mitigate the extent of and damage from a frac-out to the maximum extent feasible. However, even with a well thought out Frac-out Contingency Plan, including engineered bore based on geotechnical data, a frac-out may still occur and affect the sensitive habitat in the Santa Ynez River. For example, in 2001, site-specific Frac-out Contingency Plans were prepared for the Level 3 Communications Fiber Optic Project within Santa Barbara County. As documented under the County EQAP, dozens of frac-outs occurred at various locations throughout the County, including the coastal zone. The development of a Frac-out Contingency Plan does not guarantee that a frac-out will not occur, nor that any and all effects of a frac-out can be fully mitigated; therefore, Impact TB.9 is considered to be Class I, significant and unavoidable.

S&EM-56: The baseline for the Emulsion Pipeline Replacement Alternative is the existing, previously disturbed PXP pipeline right-of-way. Since portions of this corridor have been successfully revegetated, it can be concluded that successful revegetation could occur again and therefore the impact is considered to be Class II, significant but mitigable. In contrast, the VAFB Onshore Alternative would involve pipeline construction within an undisturbed corridor that contains sensitive biological resources. As a result, 100% revegetation is not guaranteed and thus the impact has been classified as Class I, significant and unavoidable.

S&EM-57: Section 5.2.5.2 discusses the biological resource impacts of placing the VAFB Onshore Pipeline along both the north and south sides of Highway 246. Further, regardless of the exact location of the alternative pipeline's east-west alignment in this area, the alternative pipeline would still need to cross the Santa Ynez River. The existing PXP pipelines do not cross the Santa Ynez River as do the pipelines for the VAFB Onshore Alternative; therefore, the potential for impacts to aquatic habitats as a result of a pipeline leak or rupture would be greater for the VAFB Onshore Alternative than for the proposed project. See also Response to Comment S&EM-4.

S&EM-58: Please see Response to Comment S&EM-4.

S&EM-59: Information provided by VAFB indicates an occurrence of the vernal pool fairy shrimp near the intersection of Ocean Park Road and West Ocean Avenue, in close proximity to the route of the pipelines for the VAFB Onshore Alternative as analyzed in this document.

S&EM-60: The significance thresholds and impact analyses presented in the EIR for oil spill impacts do not address likelihood of a spill, but rather are related to spill consequences. While the VAFB Onshore Alternative crosses the Santa Ynez River, neither the proposed project nor Emulsion Pipeline Replacement Alternative do and as a result, Impact GR.4 is considered to be more severe for the VAFB Onshore Alternative. The exact crossing location of the VAFB Onshore Alternative is not necessary for the qualitative assessment conducted.

S&EM-61: Please see Response to Comment S&EM-4. Similar to the discussion regarding biological impacts in Response to Comment S&EM-57, the existing PXP pipelines do not cross the Santa Ynez River as do the pipelines for the VAFB Onshore Alternative evaluated in his EIR. Therefore, scour impacts to the Santa Ynez River would be more severe for the VAFB Onshore Alternative than for the proposed project, as stated in the EIR.

S&EM-62: Please see Responses to Comments S&EM-4, S&EM-57, S&EM-60, and S&EM-61. Regardless of the exact river crossing location for the VAFB Onshore Alternative, liquefaction is a concern along the banks and bed of the river.

S&EM-63: The EIR has been clarified as suggested.

S&EM-64: The EIR has been clarified to reflect that Impact MWQ.2 would not occur for the VAFB Onshore Alternative.

S&EM-65: Section 3.3.3 presents the three produced water disposal options considered. Section 5.6.5.2, Impact MWQ-3, acknowledges that under Produced Water Scenarios 2 and 3, treated produced water would be re-injected onshore either at the onshore drilling and production site or the Lompoc Oil Field. Under either of these scenarios, no impacts associated with VAFB Onshore Alternative would occur to marine water quality from produced water discharges. The discussion of Impact MWQ-3 accurately describes the impacts of all three produced water disposal methods. Also see Responses to Comments S&EM-4 and S&EM-6.

S&EM-66: The EIR has been clarified to reflect that Impact MWQ.4 would not occur for the VAFB Onshore Alternative.

S&EM-67: Please see Response to Comment S&EM-12.

S&EM-68: Please see Response to Comment S&EM-12.

S&EM-69: Section 5.7.5.2 states that the "only potential impacts to fishing and kelp harvesting from the VAFB Onshore Alternative would be if oil spilled from a pipeline rupture or due to upset conditions at the drilling/production site reaches ocean waters."

S&EM-70: The EIR has been clarified to reflect that Impact CRF/KH.5 would not occur for the VAFB Onshore Alternative.

S&EM-71: Section 5.7.5.2, Impact CRF/KH.1, acknowledges that "the VAFB Onshore Alternative would reduce the risk of oil spills compared to the proposed project"; however, this comparison includes the proposed project offshore pipeline. The referenced impact discussion notes that a spill from the VAFB Onshore Alternative "would be more likely to reach kelp beds than a spill from Platform Irene because the oil would enter the ocean close to shore and near shore kelp beds. The emulsion pipeline for the VAFB Onshore Alternative would parallel the coastline from Bear Creek Road to near Highway 246 whereas the proposed project onshore pipeline runs perpendicular to the coastline. Therefore, it is less likely that an onshore spill from the proposed project onshore pipeline would reach the shoreline, given that it travels away from shore rather than parallel to the shoreline. Please see Response to Comment S&EM-105 for a discussion of the proximity of the proposed project onshore pipeline to the Santa Ynez River compared to the VAFB Onshore Alternative pipeline. See also Response to Comment S&EM-12.

S&EM-72: Please see Response to Comment S&EM-12.

S&EM-73: EIR Section 5.8.2.2 includes revisions to illustrate the rules affecting portable engines, as they are a source of diesel particulate matter (PM). These programs and APCD permitting requirements obviate the need for additional mitigation. Previously-exempt diesel engines rated at greater than 50 brake-horsepower were required to obtain SBCAPCD permits in 2005. For Platform Irene and LOGP, these sources were considered "exempt" in the 2003 permits, but are now included in APCD Permits to Operate issued December 2006.

S&EM-74: EIR Table 5.8.5 provides a summary of the current emissions, including exempt sources such as emergency generators and firewater pumps based on the Point Pedernales December 2006 PTOs. Further detail has been included as part of Appendix C.

S&EM-75: Activities such as: "sea bottom anode cathodic protection for platform, repair or replacement of power cable and emulsion pipeline, structural modification of platform for load and other potential upgrades to existing systems to safely extend design life" and the related marine vessel trips are examples of activities that could occur in the baseline conditions, with or without the proposed project. In accordance with PXP's Permit to Operate and Final Development Plan, any such modifications to the existing project would undergo SBC and SBCAPCD review, including review and approval by the County Systems Safety Reliability and Review Committee, which includes an SBCAPCD representative. Emissions from project-related activities are described in EIR Section 5.8.4.2, and emissions from helicopters, boats, and trucks servicing Platform Irene, LOGP, or other existing facilities, which occurs in the baseline, are addressed in Section 5.8.1.4.

S&EM-76: A typographical error in the NOx emission calculation for supply boat emissions has been revised to show 4.264 tons per year, instead of 0.305 tons per year in Table 5.8.8. Total project NOx emissions are also revised in Table 5.8.9, and the NOx estimates for alternatives in Tables 5.8.11, 5.8.15, and 5.8.16 reflect the correction. The correction does not change the conclusion of the analysis.

S&EM-77: Lifetime impacts of hazardous air pollutants are identified as Impact Air.3. Emissions of criteria pollutants from the proposed project and alternatives are tabulated in terms of annual (tons per year) or daily (pounds per day) because impacts are characterized on either an annual or daily basis. Compared to the project lifetime, criteria pollutants are relatively short-lived in the atmosphere because they either reactively degrade or are deposited to the earth. As a result, it is unnecessary to quantify lifetime emissions of criteria pollutants for characterizing project impacts.

S&EM-78: Section 5.8.4.2 describes the impacts of increased use of the heaters, and the associated emission increase is described as part of Impact Air.2. The heaters are not new sources, but compliance with SBCAPCD permitting requirements would ensure that any contemporaneous emission increases comply with New Source Review requirements.

S&EM-79: Emissions from project-related activities are described in Section 5.8.4.2. This comment identifies activities that could occur as part of the project baseline conditions for servicing existing facilities, which are addressed in Section 5.8.1.4. No additional drilling rig would be installed with the proposed project. See also Response to Comment S&EM-75.

S&EM-80: Section 5.8.5.2 includes a clarification to illustrate how operational emissions at Platform Irene could be reduced with the VAFB Onshore Alternative because additional helicopter and boat emissions would not occur.

S&EM-81: Please see Response to Comment S&EM-43.

S&EM-82: For purposes of the conceptual Emulsion Pipeline Replacement Alternative, a lay barge, versus a dynamic position vessel, was assumed because of the sandy ocean bottom along the existing offshore pipeline corridor. Section 5.8.5.5 and Table 5.8.14 include emission estimates for the offshore equipment related to replacement of the oil emulsion pipeline, including the positioning vessel (lay barge). Appendix C provides more detail. The supply barge and lay vessel are included, with generators to provide power to divers and the remotely operated vessel (ROV). Surveys and supply or work vessels are included in Table 5.8.14 as "offsite" activities. See also Response to Comment S&EM-48.

S&EM-83: Table 5.8.14 and the calculations in Appendix C include emissions from the engine of a tug boat along with those from two barge generators, one for the lay vessel and one for a supply vessel. Separate lay vessel emissions would not occur.

S&EM-84: Section 5.9.5.2, Impact T.3, clearly states that "the marine traffic impacts associated with the proposed project would not occur under the VAFB Onshore Alternative, but rather would be the same as the No Project Alternative."

S&EM-85: Please see Response to Comment S&EM-4. In addition, as presented in EIR Section 5.9.4, Impact T.4, disruption of marine traffic corridors and onshore transportation infrastructure, also applies to the proposed project and is considered Class I. With respect to onshore transportation infrastructure, both the VAFB Onshore Alternative and proposed project traverse VAFB. In the event of a spill, response and clean up activities could force closure of Base roadways, as addressed in the EIR. In addition, both the proposed project and the VAFB Onshore Alternative would be subject to periodic roadway closures as a result of normal Base operations. Should Base roads be closed when a spill occurs, such closures could also result in the disruption of oil spill clean up response activities. As discussed in EIR Section 1.3, VAFB personnel served in an advisory capacity to the EIR Joint Review Panel and provided input to this document.

S&EM-86: Section 5.10.5.2, Impact Noise.1, clearly states that the "VAFB Onshore Alternative would not generate any offshore noise impacts since all operations would be onshore." The discussion also states that any offshore noise would be associated with the baseline or No Project Alternative.

S&EM-87: The significance thresholds and resultant impact analyses (other than Risk of Upset) presented in the EIR do not address oil spill likelihood, but rather address spill consequences. The greater potential for impacts to cultural resources for the VAFB Onshore Alternative derives in large part from the substantial length of new pipeline that would be constructed through and operated within previously undisturbed archaeologically sensitive areas within VAFB, as compared to the proposed project which would use existing pipelines. See also Responses to Comments S&EM-4 and S&EM-7.

S&EM-88: Please see Response to Comment S&EM-4.

S&EM-89: Please see Response to Comment S&EM-4. The visual resources impact analysis for the VAFB Onshore Alternative substation near Surf Beach was based upon the conceptual alternative description presented in EIR Section 3.3.3. Additional detail regarding the substation configuration has been added to Section 3.3.3.

S&EM-90: Please see Response to Comment S&EM-4.

S&EM-91: Section 6.2 has been clarified to reflect that under the No Project Alternative Class I spill impacts would continue through 2017.

S&EM-92: Please see Response to Comment S&EM-12.

S&EM-93: Please see Response to Comment S&EM-4 and PXP3-63.

S&EM-94: Please see Responses to Comments S&EM-4 and S&EM-7.

S&EM-95: The estimated flow rates for the existing pipelines proposed to be used for the Tranquillon Ridge project are accounted for in the risk analysis presented in EIR Section

5.1.1.4. This analysis is based on California State Fire Marshal (CSFM) data which provides an incident rate of 0.97 for pipelines construction between 1980 and 1989. CSFM does not provide more recent data to support a lower incident rate for a new line. Further, other correction factors such as pipeline diameter, specification, and type, operating temperature, cathodic protection, polyethylene butyl coating, and internal inspection would be the same for the existing emulsion line as a new pipeline, based on the CSFM database. Finally, Mitigation Measure Risk-1 has been modified to require the applicant to install an upgraded state-of-the-art leak detection system on the existing emulsion pipeline. The upgraded system would use the Best Available Technology for detection of small leaks in the emulsion pipeline. As a result, the leak detection system for the existing emulsion pipeline would be the same as for a new pipeline. Therefore, there is little, if any, difference in spill probability for a new pipeline versus the existing emulsion pipeline. If a 10% reduction in spill probability for the new pipeline associated with the VAFB Onshore Alternative was assumed, this reduction would be negated by the additional length of onshore pipeline to the tie-in point for the VAFB Onshore Alternative versus the proposed project (10 miles versus 4.5 miles, respectively). See also Response to Comment S&EM-10.

S&EM-96: The titles for Tables 6.1a, 6.1b, and 6.1c have been revised to reflect that only Class I impacts are being compared in these tables, as is noted in the text preceding the tables.

S&EM-97: The Executive Summary provides Class II and III impact summaries for the proposed project and alternatives addressed in the EIR. Tables 6.1a, 6.1b, and 6.1c present Class I impacts and are organized by impact. For each impact, a direct comparison is made of each alternative to the proposed project. While for some impacts the information presented is lengthy, the intent is to address the full breadth of each impact for the proposed project and each alternative. Table 6.4 provides a very concise summary of the Class I impacts for the proposed project compared to the major alternatives. This table has been added to the Executive Summary as Table ES.9.

S&EM-98: Please see Response to Comment S&EM-95.

S&EM-99: Please see Responses to Comments S&EM-4, S&EM-51, and S&EM-95. As presented in Section 2.3.1.3 and illustrated in EIR Appendix A, the installation of the existing PXP pipelines includes valve sites and catchment basins. The 12 miles of onshore pipelines incorporates ten valve sites between the shoreline and the LOGP. These valve sites consist of valves, either check or block, and Remote Terminal Unit electronic equipment. In addition, the onshore pipeline route is constructed with 12 secondary containment catchment basins located at strategic locations along the route. These basins are designed to catch oil if a pipeline leak or rupture were to occur.

S&EM-100: The VAFB Onshore Alternative would parallel the coastline from Bear Creek Road to near Highway 246, whereas the proposed project onshore pipeline runs perpendicular to the coastline. In addition, the VAFB Onshore Alternative traverses a more sensitive terrestrial environment in comparison to the proposed project's previously disturbed right-of-way.

S&EM-101: In Table 6.1a, the use of "severe damage" is correct in describing the potential impact on the river. To avoid misunderstanding, the phrase "limited to" has been changed to "include."

S&EM-102: Table 6.1a, Impact TB.6, acknowledges that "for the VAFB Onshore Alternative, the oil spill related impacts to aquatic, upland, and riparian habitats, and wildlife would be the same as the proposed project from the tie-in point to the existing PXP pipelines…" A spill during dry conditions would be similar for both the proposed project and VAFB Onshore Alternative with respect to spill dispersion. However, the VAFB Onshore Alternative includes 10 miles of new pipeline to the tie-in location that traverse a terrestrial environment containing sensitive species whereas the proposed project includes 4.5 miles of existing onshore pipeline to the tie-in location. As a result, the proposed project was deemed preferable to the VAFB Onshore Alternative for Impact TB.6.

Section 3.3.3 discusses a reasonable range of VAFB Onshore Alternative pipeline alignments, including several tie-in locations. Based on the analysis presented, the VAFB Onshore Alternative tie-in location west of 13th Street was chosen since it appears to be a reasonable location to tie-in to the existing PXP pipeline system while minimizing potential construction-related environmental impacts.

S&EM-103: The level of detail provided is appropriate for a conceptual alternative. Also see Responses to Comments S&EM-4, S&EM-95, and S&EM-102.

S&EM-104: Please see Response to Comment S&EM-4.

S&EM-105: As illustrated on Figure 3-3, from the landfall location to approximately Milepost 1.5, the proposed project pipeline corridor is within 350 to 1,900 feet of the Santa Ynez River estuary. After this point, the proposed project pipeline is approximately one mile north of the Santa Ynez River to the VAFB Onshore Alternative tie-in point. As a result of proximity to the river, especially from landfall to Milepost 1.5, Impact TB.6 acknowledges that this oil spill impact for the proposed project would be Class I. However, the VAFB Onshore Alternative crosses the Santa Ynez River and runs parallel to the river for approximately 2.75 miles at approximate distances ranging from 1,000 feet to 1,900 feet. See also Responses to Comments S&EM-4 and S&EM-95.

S&EM-106: Please see Response to Comment S&EM-95.

S&EM-107: Please see Responses to Comments S&EM-4, S&EM-5, and S&EM-95.

S&EM-108: Please see Responses to Comments S&EM-4 and S&EM-100.

S&EM-109: As presented in EIR Appendix A, Detail 1, Valve Site #2 is approximately 1,300 feet from the Santa Ynez River. While the leak (<100 barrels) probability over the lifetime of the project is 100% at Valve Site #2 if the new pumps are installed, it is reasonable to assume that leaks would not reach the Santa Ynez River estuary because of the distance to the river. In contrast, a rupture at Valve Site #2 has an 11% probability of occurring over the lifetime of the project and given larger spill volumes, impacts to the Santa Ynez River estuary system could occur. The EIR also acknowledges that the proposed project's oil spill impacts to terrestrial biology are Class I.

S&EM-110: The reference in the comment pertains to surf thistle only. For surf thistle, this species could also be impacted by an onshore spill generated from the VAFB Onshore Alternative. As noted in Table 6.1a, Impact TB.7, "a direct comparison of oil spill impacts between the Proposed Action and VAFB Onshore Alternative is problematic because of differences and inherent unpredictability in the points of origin, subsequent dispersion, and locations potentially affected. An onshore spill associated with the VAFB

Onshore Alternative could impact known populations of listed plant species through direct or indirect effects."

S&EM-111: Please see Response to Comment S&EM-4.

S&EM-112: Please see Responses to Comments S&EM-4 and S&EM-95.

S&EM-113: DEIR Table 6.1a, Impact TB.7, Proposed Project, does include the potential impact of oil spill cleanup activity on sensitive coastal dune species, including surf thistle and beach spectacle pod. There are several mechanisms by which an oil spill associated with the VAFB Onshore Alternative could impact sensitive coastal dune species, as described in Section 5.2.5.2, Impacts TB.6, TB.7, TB.8 – Spill Impacts to Vegetation, Wildlife, and Listed Species; and summarized in Table 6.1a. Also see Response to Comment S&EM-12.

S&EM-114: The justification for the conclusion is as stated, that based on information from VAFB, those plant species, especially beach layia, are in closer proximity to the VAFB Onshore Alternative route as it crosses the coastal terrace of southern VAFB than they are to the existing PXP pipeline right-of-way. Further, topography would determine oil spill dispersion, not the proximity of the pipeline right-of-way to existing roadways. As a result, in some cases, spill clean up activities would need to occur from overland areas. Also see Response to Comment S&EM-4, S&EM-95, and S&EM-113.

S&EM-115: DEIR Table 6.1a, Impact TB.8, specifically states that "the VAFB Onshore Alternative would not involve a change in offshore operations through 2017, at which time Platform Irene and offshore pipeline operations would cease. The impacts associated with an offshore spill would be equivalent to the No Action Alternative since oil production levels and resultant spill probabilities, volumes, and clean up activities would be similar to current operations (i.e., the baseline)."

S&EM-116: Please see Responses to Comments S&EM-4, S&EM-7, and S&EM-95.

S&EM-117: See Response to Comment S&EM-99.

S&EM-118: Please see Response to Comment S&EM-4.

S&EM-119: Please see Response to Comments S&EM-4, S&EM-7, S&EM-95, and S&EM-109.

S&EM-120: As presented in Table 5.2.1, the unarmored threespine stickleback are present in San Antonio Creek, primarily downstream of Barka Slough and a transplanted population has been established in Honda Creek. As a result, this species could only be affected by an offshore oil spill that disperses into the noted waterways. Table 6.1a has been modified accordingly.

S&EM-121: As presented in Tables 5.1.25 and 5.1.26, it is assumed throughout the EIR that maximum spill volumes would equal the volume of oil within each pipeline segment. See also Responses to Comments S&EM-4, S&EM-5, and S&EM-105.

S&EM-122: Please see Response to Comment S&EM-4.

S&EM-123: The VAFB Onshore Alternative pipeline corridor crosses the Santa Ynez River, Bear Creek, and numerous drainages. While the proposed project's pipelines also cross numerous drainages, they do not cross any perennial waterways. See also Response to Comment S&EM-95.

S&EM-124: Shoreline oil spill impacts are discussed in EIR Section 5.2.4 and are summarized in Table 6.1a. See also Response to Comment S&EM-12.

S&EM-125: DEIR Table 6.1a, Impact MB.1, identifies the potentially affected organisms under the "Description of Impact" column. The comparison discussion in Table 6.1a has been clarified.

S&EM-126: The significance thresholds and oil spill impact analyses for biological and natural resources are based on the consequences of a spill, as opposed to the probability or frequency of a spill occurring. The discussion for the VAFB Onshore Alternative does note that there is a "small chance that an oil spill from the rupture of the new pipeline or upset conditions at the drilling/production site could reach ocean waters." Therefore, in accordance with the impact significance criteria, as described in the EIR, a spill that reaches the marine environment is considered Class I, significant and unavoidable. See also Response to Comment S&EM-12.

S&EM-127: Table 6.1a, Impact CRF/KH.2, has been corrected to reflect fisheries, instead of kelp harvesting. See also Response to Comment S&EM-126.

S&EM-128: Impact T.4 addresses oil spill impacts on marine traffic corridors and onshore transportation infrastructure. The VAFB Onshore Alternative is located within the southern VAFB launch complex area, which includes Base-designated mission-critical roadways. Given that Base road closures can be associated with launches, rocket fueling, and other Base operations, access to a spill area could be delayed for hours. As a result, Impact T.4 is considered to be Class I for the VAFB Onshore Alternative.

S&EM-129: Impact CR.3 addresses oil spill impacts to cultural resources, not sensitive plant habitats. See also Responses to Comments S&EM-4, S&EM-7, and S&EM-95.

S&EM-130: New construction associated with the VAFB Onshore Alternative does present a greater likelihood of significant impacts to cultural resources, due to the potential for encountering previously undiscovered resources, and for encountering resources that cannot be avoided due to other constraints such as roads and other VAFB infrastructure. Also see Response to Comment S&EM-7.

S&EM-131: Please see Response to Comment S&EM-95.

S&EM-132: Please see Response to Comment S&EM-95.

S&EM-133: Please see Response to Comment S&EM-95.

S&EM-134: For purposes of the conceptual VAFB Onshore Alternative, multiple bores (or one much larger bore) were assumed for the alternative pipelines. In the case of the proposed project power line to Valve Site #2, if the power line is needed as a result of pump installation and if the bore option (Option 2b) were implemented, only one bore would be required. As a result, the proposed project is deemed preferable for Impact TB.9.

S&EM-135: Please see Response to Comment S&EM-95.

S&EM-136: Please see Response to Comment S&EM-128.

S&EM-137: Please see Response to Comment S&EM-95.

S&EM-138: Please see Response to Comment S&EM-7.

S&EM-139: Please see Responses to Comments EDC-10, EDC-92, S&EM-4, and S&EM-95.

S&EM-140: Section 6.4.1 clearly states that the increased spill risk due to extension of life of proposed project facilities would continue through 2037 and the associated Class I impacts would continue as well. While increased throughput does not affect frequency, increased throughput does affect consequence because of greater spill volumes. See also Responses to Comments S&EM-95 and S&EM-109.

S&EM-141: Please see Responses to Comments S&EM-95 and S&EM-109.

S&EM-142: Please see Response to Comment S&EM-7.

S&EM-143: Experience has shown that even with a fully mitigated bore, there is still the possibility of frac-out. See also Responses to Comments S&EM-4 and S&EM-55.

S&EM-144: As stated in the last sentence of bullet 4, "The alternative would also reduce the severity, but not eliminate, the Class I impacts associated with an onshore oil spill on the marine environment and to recreational facilities through 2037." As discussed throughout the EIR, the VAFB Onshore Alternative would result in Class I impacts to the marine environment. The first sentence of bullet 4 simply states the fact that the baseline associated with the Point Pedernales Project would continue through 2017 and then be eliminated.

S&EM-145: The referenced discussion is a summary. Prior to that, the Class I impacts associated with the proposed project and VAFB Onshore Alternative are discussed separately in bullet format. Further, Table 6.4 provides a comprehensive summary by Class I impact. Additional detail by impact is presented in Table 6.1a. Also, throughout Section 6.0, it is made clear that the probability of an oil spill reaching the marine environment from the VAFB Onshore Alternative is much less than that for the proposed project. See also Responses to Comments EDC-92 and S&EM-12.

S&EM-146: Please see Responses to Comments S&EM-4 and S&EM-7.

S&EM-147: The underground power line alternative would run from the intersection of Terra Road and 13th Street to Valve Site #2, a distance of approximately 2.5 miles. As presented in Section 3.6.5, "the buried power line would follow an existing road, thereby minimizing the potential impacts to cultural and biological resources." In contrast, the VAFB Onshore Alternative would involve the construction of approximately 10 miles of pipeline off of existing Base roadways, since Base infrastructure is located underneath the existing roadways and in some cases the roadways are classified as mission-critical.

S&EM-148: The comment requests revision of on-road mobile source emission factors to those within the CARB's EMFAC2002 model. EMFAC2002 was replaced by EMFAC2007 in November 2006. These models provide the basic calculation terms for mobile source emission forecasts statewide. In response to this comment, the Santa Barbara County emission factors generated by EMFAC2007 were reviewed and compared to those used in the DEIR. For all on-road vehicles, with vehicle model years 1965 to 2007 inclusive, the emission factors provided by EMFAC2007 were lower than those shown in the DEIR, but typographical errors in the spreadsheet cause some values to change and increase. The EMFAC2007 factors are included in revisions to Appendix C and typographical errors in the spreadsheets are corrected with results shown in the tables of Section 5.8. Estimates of current emissions are also revised accordingly.

S&EM-149: The sources of emission factors are shown in Appendix C and additional citations have been included where needed. The guidelines that are followed are from U.S. Environmental Protection Agency (AP-42), California Air Resources Board (including EMFAC), South Coast Air Quality Management District, and Santa Barbara County Air Pollution Control District.

S&EM-150: Comment requests revision of construction emissions using the SBCAPCD's Form-24, which provides a summary of construction equipment emission factors. SBAPCD Form-24 was last updated in 1997, and does not provide factors for the comprehensive list of equipment in Appendix C. SBCAPCD provided comments on the DEIR and did not object to the construction emission factors used in Appendix C. No revision is necessary.

S&EM-151: Please see Response to Comment S&EM-149.

S&EM-152: Appendix C includes revisions to show that the emergency generators and firewater pump engines are no longer exempt from the APCD permits.

S&EM-153: The comment requests revisions to include the "implication of diesel PM in the health screening." Diesel PM and the other toxic air contaminants and hazardous air pollutants are subject to the Air Toxics "Hot Spots" Information and Assessment Act of 1987 described in Section 5.8.2.2, and Table 5.8.10 shows the current estimate of health risks. The risk contribution of diesel PM from testing and intermittent operation of the emergency generator and firewater pumps at LOGP would be negligible. See also Response to Comment S&EM-73.

S&EM-154: Please see Response to Comment S&EM-78.

S&EM-155: In 2006, use of ultra low sulfur diesel fuel (under 15 parts per million sulfur) became mandatory for on-road and off-highway vehicles and equipment in California. As a result, the potential SOx emissions due to diesel fuel use are somewhat overstated in the DEIR.

9.4 Public Hearing Comments and Responses

PH

COUNTY OF SANTA BARBARA PLANNING AND DEVELOPMENT
DRAFT ENVIRONMENTAL IMPACT REPORT
PUBLIC COMMENT HEARING

IN THE MATTER OF:	)	
	)	
TRANQUILLON RIDGE E.I.R.	)	SCH No. 2006021055
	)	County EIR No.
DRAFT ENVIRONMENTAL IMPACT REPORT	)	06OIR-00000-00005
	)	
COMMENT HEARING	)	
	)	

TRANSCRIPT OF PROCEEDINGS, taken at 100 Civic Center Plaza, Lompoc City Council Chambers, Lompoc, California, 93438, commencing at 7:05 P.M. and concluding at 8:20 P.M., on Monday, December 11, 2006, before Lindsey K. Kennedy, Certified Shorthand Reporter in the County of Santa Barbara, State of California.

COPY

OUR FILE NO.: 1-64522
REPORTED BY: Lindsey K. Kennedy, CSR NO. 13021

APPEARANCES:

FOR THE COUNTY
OF SANTA BARBARA: KEVIN J. DRUDE, ENERGY SPECIALIST
-and-
NANCY MINICK, PLANNER
COUNTY OF SANTA BARBARA
PLANNING AND DEVELOPMENT
123 East Anapamu Street
Santa Barbara, California 93101-2058
(805)568-2000

INDEX

SANTA BARBARA SANTA MARIA SAN LUIS OBISPO VENTURA
(805) 966-4562

LOMPOC, CALIFORNIA, MONDAY, DECEMBER 11, 2006

7:05 P.M.

MR. DRUDE: Well, good evening, everybody. Welcome back to a lot of you. This is the Public Comment Hearing for the Draft Tranquillon Ridge E.I.R.

I want to make sure that everyone's in the right room. I understand that there is a Planning Commission hearing down the hallway, and having said that, I'm hoping I don't lose half my crowd, but anyway, I hope you're all in the right room. You are welcome.

The purpose of tonight's meeting is to take your comments on the Draft E.I.R., and I'm going to ask that if you're going to speak tonight, if you could please fill out a speaker slip, we have them over here on this table in the right-hand corner.

Fill it out, please; you can put it here right on this table. All right. Also I have a number of handouts I want to point out. We have copies of the E.I.R. if you don't have one yet. If you don't wish to have the entire document, we also have copies of the Executive Summary. We also have copies of the entire E.I.R., including technical appendices, on discs which are on the table.

Also I have our business cards there, too, the contact information. And I also have this yellow sheet, which has my contact information, Nancy's, how to get a

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hold of us at the Energy Division in terms of talking to us and submitting comments on the Draft E.I.R.

And I'm going to work on this yellow sheet on the slide tonight -- that's right. Nancy noticed that I left out that we have a mailing list sign up here, too. If you're not already on our mailing list and would like to be, please get on there.

That way, we'll mail you notices on future Planning Commission and Board of Supervisors hearings and any other on-goings with this project. Okay. It's not working. I guess I've got to get closer to it.

I'm going to start out this evening with a short presentation. I'm going to talk about the project description. I'm going to discuss the impacts that we identified in the Environmental Impact Report, and I'm going to discuss the project alternatives that we looked at in this E.I.R.

Following that description, we're then going to open up to public comments, and I ask tonight when you come up to speak, please fill out a speaker slip, and when you do come up to the podium, come up to this podium and literally spell your last name for our stenographer. Okay.

When you're making your comments tonight, remember, this is a comment hearing on the adequacy of the E.I.R.

I would like to ask you if you could reserve your comments on whether or not you like the project, the project's merits, when we have hearings before our decision makers, the Planning Commission and the Board of Supervisors.

What I'm going to talk to you also about tonight is where you can and how you can provide comments to the Energy Division on this document after tonight's hearing.

And then I'm going to discuss what is going to happen after January 16, which is the close of public comment on this E.I.R.

And by that I mean what do we do with your comments after tonight; how do we incorporate them into the E.I.R.; when is the Planning Commission going to meet; and when is the Board of Supervisors going to meet, if they need to; and what happens when this project, after this project is considered by the County, what other agencies get to look at it.

Let me acquaint you with the project location. This project is proposed to use the existing infrastructure of the Point Pedernales Project.

There is the -- encircled to the bottom left is the platform Irene, which is in Federal waters off the coast of Vandenberg Air Force Base.

Pipeline system of oil, gas, and producing oil pipelines that come to shore and over a course of about 20 miles, including both on and offshore portions, go into the Lompoc Oil and Gas Processing Facility, which is just north of the City of Lompoc, where the production is processed and then sent north in the pipeline system for processing at the Tasco Santa Maria Refinery.

The project as proposed would drill 30 new wells from Platform Irene. I understand that the platform is currently set up that it could accept 72 wells, but they are proposing to drill 30 wells over an approximately 15-year period.

Twenty two of those wells would be used for production and the others would be used for possibly injection of waste water back down into the formation.

They are proposing to do a combined production of a little over 30,000 barrels a day. That's the existing Point Pedernales production combined with the production they would get for the new drilling.

They are also proposing to do about six million standard cubic feet of gas production per day. Currently, just to give you an idea of what they're doing out there, Plains is producing approximately 7,000 barrels of crude oil per day and about 2.6 million standard cubit feet of gas.

In order to do this, they would have to do some

SANTA BARBARA SANTA MARIA SAN LUIS OBISPO VENTURA
(805) 966-4562

project upgrades on the platform, new subversive pumps on the wells, other modifications for the increased drilling.

Onshore, they would have to bring some existing idle facilities onshore back into operation at the Lompoc Oil and Gas Plant.

There's the possibility they would have to install a new system of transportation pumps at Valve Site II to pump the oil from offshore into the Lompoc oil and gas facility.

The Applicant, PXP, has said that they could produce, permitted, anywhere from 170 to 200 million barrels of oil in the permitted life of the project and anywhere from 40 to 50 billion standard cubic feet of gas.

In order to carry out this project, they also -- PXP needs to acquire under the States Land Commission, a new lease, and they have requested this new lease extension boundary, which would begin at the terminus of the Federal lease and extend inward towards shore, and they would then drill into that new State lease from the existing Federal platform.

So once they leave the County, whether the County approves it or not, if they get to the State, they still need to have the State Lands Commission approve that

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lease.

I'll tell you will a little bit more about Platform Irene. I think -- is that the previous slide, Nancy?

I'll give you a little bit more information about it since I was just on it the other day. It's in 242 feet of water. This platform was set in 1986, began operations in 1987. It's about 4.5 miles offshore.

It's on a Federal lease, and as I said, there's about 72 well slots available, and I think, talking to the engineers this week, I think 12 or 13 of those well slots are currently in use.

It has one drilling rig, and it has living quarters for a crew that's normally about 15 persons. Sometimes they ramp up when they do the drilling to as many as 55 people on the platform, and there is a connection between onshore and the platform of a 20-inch oil emulsion line, that's mixed oil with water.

They have a natural gas pipeline, which is an 8-inch line, and they also have a return line, which is a waste water line.

Once they remove the waste water or the produced water from the oil onshore, it is then sent back out to the platform for disposal by downward projection producing reservoir or the some of that produced water is injected at the Lompoc field onshore.

SANTA BARBARA SANTA MARIA SAN LUIS OBISPO VENTURA
(805) 966-4562

If I could get the slide of the Lompoc Oil and Gas Plant. Thank you.

This plant is about three miles north of Lompoc. It's located on Harris Grade Road, and it occupies about 22.5 acres.

At this plant, the primary functions are dehydration of oil emulsion, meaning they take the water and other impurities out of the oil for transportation of that product to oil refinery destinations and they process the gas.

By that, I mean they take out the gas liquids, and they strip it of other impurities including hydrous sulfide, a poisonous component, and then they sell that produced gas directly to Southern California Gas Company near the site.

The byproduct of producing the gas is they collect the natural gas liquids, and currently they are shipping approximately three truckloads of natural gas liquids off site to destinations a week.

Currently they are producing about 57,000 barrels of oil water emulsion per day at this facility.

This is a cover I hope many of you are familiar with. This is the E.I.R. we are discussing tonight. I have copies of them over here, boxes of them.

If you would like to take one with you tonight,

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please do. If you need an extra copy, I also welcome you to take that with you tonight, as well.

Let's now talk a little bit about the need of the analysis, which is why we prepare the Environmental Impact Report, and that's to take a look at the project and the potential environmental impacts if the project was carried forward.

And I have a slide here where I've identified the issue areas, which you'll find in sections 5.1 through 5.8 of your E.I.R.

These are also summarized in your Impact Summary Tables in the front of the document as well as the Executive Summary, if you just want to quickly look through them and see what the impacts are.

What we did identify -- let me back up a little bit.

In E.I.R.'s, what we try to do during the scoping process is look at the issue areas that we believe could be impacted by a specific project.

In this case, we've identified all of these on the next slide you'll see. These are the areas that could -- in which you could incur impacts.

And what we're trying to do is identify whether the impacts are significant, and you'll hear me use the term "Class I." Those are significant Class I impacts.

Those are impacts that even after you apply

mitigation, they still remain significant.

We're also looking at Class II impacts. Those are impacts that start as significant, but through the application of mitigation measures, we're able to reduce them to a level less than significant.

Then there's Class III impacts, which are less than significant, even without mitigation, and on rare occurrences there are Class IV impacts, which are beneficial impacts that could occur as a result of the project.

And what we did is we identified areas in each one of these risk areas and we tried to identify which one of the impacts that would occur would be significant, Class I, II or III.

For risks, we looked at things such as the transportation of natural gas liquids, transportation of gas, transportation of oil.

There's a lot of impacts associated with this project that we identified, or potential impacts associated with the byproducts of drilling offshore, which are the oil transportation issues, possible leaks, possible gas explosions, possible hydrogen sulfide release from the pipeline.

The oil spill impacts are identified in many of the issue areas that we've looked at for potential impacts,

SANTA BARBARA SANTA MARIA SAN LUIS OBISPO VENTURA
(805) 966-4562

and those would be onshore water resources, in the event that a pipeline could leak onshore during transportation, marine biology, oceanography and marine water quality, also impacts to kelp and kelp harvesting in the event of a spill. You could wind up having impacts on those industries during the clean-up period.

Of course, there's potential for air quality impacts from the continued operation of an oil and gas facility, plus new impacts possibly from drilling offshore.

We looked at traffic both onshore as well as offshore, the new vessel traffic taking crew boats and piping and things to the platform in the drilling phases.

We looked at noise emanating from the Lompoc Gas Facility -- we've heard -- Lompoc Oil and Gas Facility.

We've heard comments from residents in nearby Vandenberg Village and other areas that they can hear a P.A. system or have heard it in the past and they could hear some of the operations on certain days and nights, so we looked at that.

We looked at fire protection. There's always the risk of fire when you're dealing with hydrocarbons. We looked at the risks of cultural resources. Any time you would have to go excavate a pipe in the event of a possible spill onshore, there could be impacts to sensitive cultural resources that were purposely buried

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SANTA BARBARA SANTA MARIA SAN LUIS OBISPO VENTURA
(805) 966-4562

but then would have to be excavated during the cleanup.

Visual resources. There's the existing and long-term potential impact of the platform, the Lompoc Oil and Gas Facility as well as the substation at Surf.

We looked at impacts to recreational and land use. Again, these things would most likely, if it would happen, be affected by an oil spill and subsequent clean up.

We looked at potential agricultural impacts because of the pipeline, the onshore pipeline going through the agricultural areas. And then we looked at the energy and mineral resources and we looked at the use of the facility on the grid and other material's that they need to fuel their operations.

The Impact Summary of the proposed project. Again, this is getting to the Class I, II, and III impacts I discussed.

As you'll see in this analysis so far, I've identified -- you'll see 13 Class I impacts. And again, those are impacts that even though we apply mitigation measures, they remain significant.

We identified ten related to oil spill and possible clean up, two related to visual resource impacts, and one related to risk. Now again, risk is associated also with spill and clean up, but the risk, one that we identified

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in this particular case, had to do with the transportation of natural gas liquids by trucks on public roads.

And can you can see there were far more Class II significant and mitigable, and Class III -- excuse me -- adverse and not significant effects than there were of the Class I impacts, just so you can get a comparison of where this project plays out.

Part of an E.I.R. is that you not only look at the project that's proposed but you try to identify feasible alternatives that could accomplish the goals of the project yet either reduce or limit some of the Class I impacts.

So we looked at an array of alternatives for this project. One that you always look at when you look at an E.I.R. is the "No Project Alternative," and that is what happens if you don't go forward with the project, and that would be the continuation of the existing Point Pedernales Project, and that's estimated to produce the oil and gas from only the Federal reserve. It would not go into the State reserve.

Now that's not to say -- and we made this clear in the E.I.R. -- that the shoreward portion of that field would not be produced some day, and there's a possibility that it could be reached by onshore some day or perhaps

by other methods.

But we wanted to make that clear, that just because this project doesn't go forward, doesn't mean that field would never be developed.

We also looked at an onshore drilling and production alternative on the Vandenberg Air Force Base. We didn't look at this on the first E.I.R. because at that time we were informed by the Base Commander on Vandenberg Air Force Base that they wouldn't consider such a proposal, so we dismissed it.

In this E.I.R., at that time when we began this process, we got the go-ahead from the Wing Commander to at least look at it, so we developed a conceptual project in this E.I.R. which looks at a drilling and production site, a series of pipe lines connecting into the Lompoc Oil and Gas Facility, gas dehydration, some gas processing, some oil processing.

We looked at a number of variations of that onshore project with a number of variable pipeline routes to get there.

What we identified was that there were different impacts associated with this type of onshore project, impacts that you wouldn't get from an offshore project.

With an offshore project, you're more likely to have a potential impact in the marine environment, if there were a spill; whereas onshore you would more likely have onshore oil spill impacts.

So each of the impacts that we identified during this analysis were really either land or water based specific. So it was really a matter of which of those impacts is most important to the County.

And at this point, with no policy guidance, it appeared that -- that there was really no environmental preference of either of the projects, because we tried to balance which of the impacts was most important and we couldn't come to a conclusion on this without further analysis, because we were preparing project for which we had project specific information offshore with a conceptual project that we built onshore.

So at this point, you'll see in the environmental analysis that there is no hard conclusion as to which of those is best, and we did not identify one as an environmentally superior alternative.

We also looked at the Casmalia Processing Site. This is a site that was identified in the County's North County Siting Study as a very responsible site in the future for the development of an additional processing site to accommodate, when we did the study, additional production that might come further from the north.

When we looked at this site for this particular

project, we identified that there would be a significant new construction impact from developing a new pipeline that would have to come from a Lompoc facility to go to Casmalia, as well as constructing a brand new processing facility at the Casmalia site.

All of the existing Class I impacts from the Lompoc project would remain in addition to those that would occur at the Casmalia Processing Site, so there this was not identified as an alternative that would be preferred over the Lompoc Oil and Gas processing operations.

We also looked at a new emulsion pipeline, the oil emulsion pipeline. We identified that there would likely be significant new construction impacts from taking out the old emulsion pipeline all the way from the platform to the Log P(phonetic) and putting in a new one.

You'd have to open up that trench again. There's a lot of areas that have already been re-vegitated extensively, by mitigation programs of other sensitive species, cultural resource sites along this route.

So we identified that those impacts would likely be significant. All the Class I impacts from the existing project would remain and again, this alternative was not identified as one that was preferred over the existing proposed operations.

The E.I.R. also identified a number of power line routes. There's a part of the project that proposes running power poles and lines to Valve Station II, where the Applicant has proposed he may eventually need to put in additional pumps if they have to lower the operating pressure of the pipeline from platform to shore over time.

They would then need to increase its pressure onshore to get it into the Lompoc Oil and Gas Processing Facility.

This is not necessarily something that will happen, but it's a project component that we have looked at in case they eventually have to build that.

So what we did is we looked at a number of ways of running a power line from its -- beginning to the terminus at Pump Station II. And we identified the proposed project as well as a new portion of underground, the line along the road called Carol(phonetic) Road, was the preferred alternative because it followed the existing route, but it under-grounded in certain areas which would eliminate a visual impact of that project component.

We also looked at at the muds and cutting disposal. The muds and cuttings are the byproducts of the drilling of the platform. Mud is used as a lubricant on the drill bit for drilling all the wells, and after a while it gets

used up and they need to dispose of it.

A number ever different options were looked at. Some of them were to put it on boats and to take it back to shore for disposal. The proposed project wanted to dispose of it into the water column at the platform, which is absolutely permissible under waste discharge permit so long as it meets certain specifications.

Another way to get rid of it is to inject it back into the formation, and the formation has to be able to take that much mud injection without ruining its productivity.

We looked at it and identified that the mud injection alternative was slightly preferred over the ocean discharge. And that is, again, if there is suitable underground formation to do that.

So that may take a little more analysis before we can come to that conclusion. But at this time, that's what we identified.

As I said at the beginning, purpose of tonight's meeting is that public can provide comments on the adequacy of our analysis.

By that what I mean is, did we identify the right impacts? Did we identify the right level of that impact? What about our mitigation measures? Did we propose suitable mitigation measures for those impacts, and did

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(805) 966-4562

we identify the correct residual impact?

By that, I mean after we mitigated, what was left over; did we identify that correctly?

We're also looking to see if whether or not we correctly described the project; and did we provide enough alternatives, reasonable alternatives; and did we analyze those or identify the impacts of those adequately so that the public, you, have a good picture of what we are looking at so that you can compare those alternatives and find out why we found what we did.

Again, we're not looking at whether or not you like the project tonight. If you don't, you can call me. We can talk about this at length. A number of you have called me, and I really enjoy your conversations and I know you have some strong feelings about it.

So please call me at my office so we can talk about it or reserve those comments for when we come to the Planning Commission in March, and that's when you can express to your decision makers, based on your knowledge of the project at that time, why you do or do not believe it should go forward.

Tonight is your opportunity to provide me with verbal comments. We have a stenographer who is going to take down your words tonight. This is your chance for verbal comments. I prefer not to take them over the

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phone. I don't want to misquote you.

It's important that we get everything that you have to say accurately. I do accept e-mails and of course written comments. All right. So this is not your last opportunity, I'll make that clear.

This is the comment hearing for verbal comments. You have until January 16 to provide me with either e-mail or other written comments.

Those written comments would be sent to me, my attention, Kevin Drude, at the Energy Division at this address, and again, we have that address on this yellow sheet that you can pick up over at the table.

And the comment period ends on January 16th, that's a Monday -- okay -- Tuesday.

We have extended it. We had a request to extend it because of the holiday, and it was a reasonable request and we agreed to extend that because I know everybody has a busy holiday season and we wanted to make sure, because this is such an extensive, lengthy document with a lot of complicated issues, that you had time to look at it. So January 16, 5:00 P.M.

So what are we going to do after the 16th? We take all of your responses and we amend the E.I.R. and we include a new section, which is "Response To Comments," and we bracket in your letters or your e-mails or your

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text from tonight, each comment that you make, and we assign it a number.

And then we have a response page where we address each and every of one of your comments either with substantive issues or comment noted, or we reference another comment that somebody else made, "See comment six."

So if somebody makes the same comment over and over, we have a response to it. Then we consider all of your comments and responses, and we amend the E.I.R. as appropriate. You may have some good comments.

We have a good audience here, generally gives me a lot of good, informative comments, and we'll make amendments as appropriate. Once we have completed that update including your comments, we're ready to take that E.I.R., which is the proposed E.I.R., to our decision makers, and the first one would be the County Planning Commission.

We have a tentative hearing date scheduled in March. It would be in the North County at the Santa Maria Hearing Office. If the Planning Commission either approves or denies the project, they'll do one or the other, it would then go to the Board of Supervisors upon appeal, if it is appealed.

Following a Board of Supervisors hearing, the

Coastal Commission has to issue its permit. The Coastal Commission has authority on this project from the coastal zone out ward into the State Lands area. They would have to issue a consistency determination with the Federal operations as well as their own coastal development permit.

Following the Coastal Commission action, this project would then have to go to the State Lands Commission wherein a noticed hearing, the State Lands Commission would have to consider the action on the new lease application.

For those of you who don't have an E.I.R. yet, don't want one but would like to read one, we have copies at the Vandenberg Village, Lompoc, Santa Maria, Santa Barbara, and the U.C.S.B. libraries.

We have a number of copies at the Energy Division office in downtown Santa Barbara.

We also have the entire E.I.R. on our website, and this website address is on that yellow piece of paper as well, and I believe I mentioned that we have it on disc here tonight.

If you grab one, make sure you grab both versions. I have the technical appendices on one and the E.I.R. on the other.

If you want to get ahold of staff who is working on

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this, there's our contacts. Again, we're on this yellow piece of paper. I'm Kevin Drude; that's my e-mail address and phone number. Nancy Minick working with me; she's the principal Project Planner on this project.

Our energy division website also has all our energy staff listed on there, if you need to contact any other staff about any other project you're interested in reading about.

Written comments after tonight, Planning and Development, our Energy Division Office, my attention. Going back to this yellow piece of paper again, it's all on here, or just get it on the website and it will give you guidance on how to get comments to me.

And remember, once again, we need to have your comments by 5:00 January 16th, Tuesday. Okay.

Well, that concludes my presentation. At this time I'd like to ask any speakers who are going to talk to us tonight, if you haven't filled out a slip yet, please bring me one. Okay.

And I'm going to call who's first and then I'll say the person who is going to follow. All right. And I would ask you please to come to this podium.

Please say your name and spell your last name. The first speaker tonight is Carla Frisk, followed by Linda Krop.

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MS. FRISK: Good evening, everyone. Thanks for being here where folks can come out and comment on this.

COURT REPORTER: Excuse me. Could you please state and spell your name for the record.

MS. FRISK: Oh, I'm sorry. Carla with a "C," Frisk, F-R-I-S-K, representing Get Oil Out tonight.

Again, thank you for coming out tonight to be in Lompoc where folks can come and have a chance to comment on this document, which as you pointed out, is no small feat.

As I'm sure most of you know, G.O.O. was formed in 1969 after the oil spill in the Santa Barbara Channel and has continued to monitor oil and gas development throughout Santa Barbara County since that time.

PH-1

Well, I've just recently returned from a much-needed vacation. I'm still on G.O.O.'s behalf reviewing the document and will be submitting the comments by the January 16th deadline, but I have some general comments about some items that I think need to be addressed I thought I'd present tonight.

First of all, I'd like to indicate that G.O.O. is in total agreement with the baseline that's used in the document regarding existing production of 7,000 barrels a day in gas to begin with, and to compare the impacts that may occur as a result of this project with that baseline.

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PH-1 Cont'd

Secondly, G.O.O. also agrees that the two largest issues are that of the extension of the project's life, the life of the project, and the increase of output, but it is these two issues that really drive many more important environmental impacts.

PH-2

With regards to the increase in Throup(phonetic) at the proposal, I think it's important to really emphasize that the proposal would increase production by over four times of what is currently happening, and would utilize facilities which are already projected to exist ten years longer than originally anticipated, 1985, and I want to discuss that a little bit later.

So the significant increase in Throup(phonetic) is important, considering the increase in oil spill and public safety at the Lompoc Oil and Gas development project, and also a plant. And also the trucking that was mentioned of the L.P.G.'s.

PH-3

With regards to extending the life of the project by 30 years than what was originally analyzed in 1985, it was interesting to note that this project is already going, at least by estimate in the E.I.R., ten years past that -- those projected the impacts.

So it's interesting that the project is operating more -- is already having more impacts or will soon already have more impacts than was estimated when that

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original E.I.R. was written.

And why that is a concern to us is that based on this analysis in -- this would add up to 2037. But how reliable is that estimate based on our experience already?

The estimate that was given by staff was 170 to 200 million barrels of oil. I don't know if the 170 represents the 30 years or the 200 represents the 30 years, but given the existing project, it's already ten years over a third of the way estimated to be over a third longer than it was originally anticipated.

G.O.O. would like to see the impacts associated with the increase in the lifetime of the project. We'd like to see more of an estimate, not just say, okay, these are the impacts that were estimated at 30 years.

We would like to see a range of 30 to 40 years so we would have an idea, especially as the facilities get older and older, even though the Throup(phonetic) may go down, by the time this project ends, if it goes over ten years, it's going to be twice the age that it was expected it would actually go out of existence.

And that is true also for public safety impacts also associated with the Lompoc Oil and Gas Plant and also with the transportation of the M.P.G.'s and L.P.G.'s.

So we would like to see a chart or some kind of

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PH-3 Cont'd

analysis that would show us, if this does go an additional amount, how steeply would those impacts go up; would it be relatively small or would it be a steep curve?

PH-4

Also, the Draft Environmental Impact Report expects that the additional 30 years would begin in 2007, which was when the 1985 E.I.R. said that the project would be completed, but that's probably wishful thinking.

It's probably unlikely that this project can get through the permitting process and meeting all the conditions and receiving their permits.

So we might want to think about revising that to somewhere around 2008. And again, that's another year that's been pushed out before we even get off the ground.

PH-5

Finally, the Alternative Section. The onshore alternative was not reviewed at the same level as the proposed project.

This makes it very difficult for the public and decision makers to prepare onshore and offshore alternative proposals, and especially this case, when the offshore project, the proposed project, is going to have most of its impacts offshore, and the onshore alternative is going to have different types of impacts onshore.

So you're really trying to compare apples and oranges. And I think what we really need is some kind --

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and it may be in the text and I just missed it because I haven't been through the whole document.

We really need a section to look at all specifics in the project and see it says, Okay. These are these kinds of impacts, and they are more significant than these kinds of impacts or they're not because of the kinds of the impacts that they are; how can we get as close as we can with comparing those apples and oranges and getting them as close as possible.

And one of the ways to do that is long-term versus short-term impacts. And in the alternative we have an alternative, since it hasn't gotten a project level of review, how many of those impacts can be mitigated by changing maybe the project design or by doing significant mitigation.

I just don't think we're quite there on that. Let's see. And I think that may be about it. I think that's it. So those are the basic concerns that we have kind in a large nutshell and we'll try to get you more specific comments later.

MR. DRUDE: Thank you for your comments. Linda Krop followed by Mary Ellen Brooks.

MS. CROP: Thank you and good evening. My name is Linda, L-I-N-D-A, Krop, K-R-O-P.

Thank you for having this community hearing

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creating an opportunity for us to learn more about the project and environmental review process and also provide you with our thoughts so far.

And it is a voluminous document, so I also have just started reading it, but wanted to share some questions and thoughts I have so far.

I'm the Chief Counsel of the Environmental Defense Center. We're a public interest environmental law firm headquartered in Santa Barbara and representing organizations throughout the Santa Barbara, San Luis Obispo, and Ventura counties.

PH-6

Going through the sections of the E.I.R. that I've read so far with respect to the project objective, the project objective is described in various terms.

Some are appropriate, allowing for consideration of a range of alternatives that could meet those project objectives. Other project objectives are described extremely narrowly and are more of a project description, and that's inappropriate under SEQUA(phonetic) because it unduly restricts the range of alternatives that could fulfill those objectives.

So we request that the project objectives be limited to the general statement of providing energy supply for California.

The project description refers to a drainage study

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which is critical to the whole project, because this project requires a new State lease for the first time since the 1969 oil spill.

That can only happen under State law at the direction of the State Lands Commission, and only if there's a finding that oil and gas resources are being drained from State jurisdiction and adjacent Federal facility.

And although the E.I.R. references a drainage study that was conducted by the California State Lands Commission, I wasn't able to find the description or analysis of that study.

And maybe it's in there and I just haven't gotten to it yet, but in the Project Description it would be nice to have a summary of that.

PH-8

The Project Description should also identify any Federal approvals that are required. The E.I.R. references the fact that the Minerals Management Service maybe required to consider revisions or amendment to the final development plan for Platform Irene, but doesn't make a determination that should be part of the project description.

PH-9

With respect to decommissioning, we'd like to have some discussion in the E.I.R., because that is a predictable part of the life of the project.

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PH-9 Cont'd

And even though further discretionary action may be taken at the time of decommissioning, the impacts should be disclosed now, and there should be some kind of mitigation measure in the E.I.R. to make sure that decommissioning activities do take place as intended, whether that be posting of a bond or something like that to cover decommissioning.

PH-10

Also within the project description, we'd like some analysis or discussion on whether or not the onshore pipeline route that currently exists would have to be relocated due to PXP's other proposed project, which is to build a 1,300 unit residential development project right within that pipeline corridor.

PH-11

Regarding alternatives, as I mentioned, it's really important to have a range of alternatives, and that goes back to the project objective. It must be described broad enough that the E.I.R. can include a range of alternatives.

Right now, the E.I.R. basically has one alternative, which is opportunistically presented because there is a competing proposal, but we need a broader range.

We also need to make sure that the alternatives decrease impacts, and they are not in the E.I.R. simply because there is a competing proposal.

And I agree with Carla Frisk that with respect to

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that competing proposal, since there is an application pending, it would be nice to have as much detail of that alternative so that a comparison can be made.

PH-12

With inspect to the Impact Analysis, we agree with the baseline as being based on the current historic production levels.

PH-13

We also agree with the main focus of the E.I.R. On the increase should be put on extending life on the existing facilities. I've only looked at a couple impact sections yet, the risk of upset and air quality.

PH-14

The risk of upset I focused primarily on the risk of oil spills, because we've already had a major oil spill from this very facility in 1997, and it happened as a result of something that probably wasn't really anticipated in that original E.I.R. but that this E.I.R. does refer to, and that is operator error or override of the detection system. So we're happy to see that that's in there.

PH-15

We would like to see an analysis of the full consequences of an oil spill as well as oil spill response and clean up and feasibility of oil response and clean up.

PH-16

I'd also like to see an analysis of impacts from an oil spill to the sea otter and its pending recovery plan.

PH-17

With respect to air quality impacts, my final point,

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PH-17
Cont'd

the E.I.R. -- it's unclear from the E.I.R. whether or not off sets will be required for the Ox and Nox(phonetic) the ozone precursor.

So if that could be clarified, we'd appreciate that. And if they are required to obtain new emission reduction credits, we need an analysis to determine if those offsets are available because mitigation measures must be known and effective.

PH-18

And finally, under Air Quality Analysis, we appreciate the fact that there is a section dealing with greenhouse gas emissions; however, the baseline in the E.I.R. is comparing greenhouse gas emissions from this project to total U.S. emissions as opposed to the baseline of this project, in which case there will be an increase in greenhouse gas emissions and with all that we know about global warming now, any greenhouse gas emissions has to be considered a significant environmental impact.

We'd also like to see the E.I.R. include greenhouse gas emissions not just from production and processing, but also refining and combustion.

And we will be submitting written comments by January 16th. Thank you.

MR. DRUDE: Okay. Thank you. Mary Ellen Brooks followed by Jon Picciuolo.

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MS. BROOKS: Good evening. My name is Mary Ellen Brooks. M-A-R-Y, capital E-L-L-E-N, Brooks, B-R-O-O-K-S.

I live at 718 Saint Andrews Way in Vandenberg Village. I'm speaking tonight as an individual.

I've lived in Vandenberg Village for 28 years and I think I spoke at hearings in the early eighties.

So I'm back. I want to thank the County for including Vandenberg Village and Mission Hills in their new energy maps. We asked for this back in the early eighties, and it arrived this past August, and this is dated August, 2006,

So the communities of Vandenberg Village and Mission Hills, which we're about a mile from the Lompoc Oil and Gas Plant, are now included on the energy map, and we are very thankful that our communities are now shown on the map.

Okay. I'd like to start off with some of my concerns of the E.I.R. about prolonging the life of the pipelines and the onshore oil and gas processing facility.

PH-19

The existing pipelines in the Lompoc -- we'll call it Log-P, I had better get used to saying that -- have outlasted their original design.

One of these pipelines leaked over 6,000 gallons of oil in 1997, killing hundreds of sea birds and spoiling

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PH-19 Cont'd

40 miles of pristine coastline.

The E.I.R. quotes the statistics about a very slim likelihood of such an event happening, but this event was caused by human error and it did happen.

So I'd like to see more details about that incident in the E.I.R., because sometimes we do make mistakes.

PH-20

By extending the life of the existing operations, the residential communities near Log P. would be exposed to increased air pollution, fire, hydrogen sulfide leaks, and oil spills.

Residents were promised in the early eighties that the original separation plant would be decommissioned in the year 2000.

Then this permit was extended and changed in 1997 with additional processing and storage allowed. Now, if Tranquillon Ridge Project is included, our communities are looking at increased risks until at least 2037.

Perhaps the E.I.R. could include some more of the history on how this plant has evolved.

PH-21

And next issue is fire risk. Since the Log P. has been built, there have been two significant fires in the area of Log P. The plant was saved from involvement in the first 5,000 acre fire which was started by children playing with matches in the surrounding chaparral, a situation that was not listed in an original E.I.R. It

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was saved only because of favorable winds.

In the second fire, which burned 11,000 acres in a matter of hours, the fire itself started on the oil company property due to brush not cleared from power lines or power line areas.

Again, the plant and homes were spared only because of good fire protection and favorable winds.

The one fatality that was caused indirectly by this was a vehicle accident that was caused by the obstruction because of the fog/smog coming from the bog area, and again, this was a situation that was never included in the E.I.R. Maybe that needs to be included also.

Burt Mason Reserve is a endangered habitat; it's highly flammable. And I hope these fires are mentioned and described a little built more in the E.I.R.

PH-22

Next area is hazardous materials and risk of upset. In the Executive Summary on page 69 states, "Onshore impacts including increasing the traffic on roadways. Consequences of an L.G.L. or L.N.G. truck accident would increase the severity for this already significant impact."

It goes on to say, quote, "Construction of residential developments within the hazard footprints of the proposed project existing onshore pipeline would put more them harm's way in the event of a pipeline

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accident."

Then it says this would be an insignificant impact. A pipeline accident is it hardly insignificant to the thousands of residents and to the 1,800 students and staff of Cabrillo High School who live and work near the the existing footprint.

PH-23

Since the plant was built, there have been numerous leaks of hydrogen sulfide and oil that have been reported in our local newspaper. Residents have asked for a specific evacuation plan, but we're always told that that is the County's responsibility.

The reverse 911 system was set into place, but when it was tested, many of us that lived near the plant were not notified.

Now that the plant has changed ownership for the third time, is this reverse 911 system in place?

I would like to see the E.I.R. include specific plans for an evacuation route instead of just saying, "Oh, well, the County Fire has those plans."

We have never seen an evacuation plan in Vandenberg Village. It says the E.I.R. mentions worker safety, but it doesn't include the safety of the residential neighborhoods, which predate any plant.

The E.I.R. should include details about an evacuation plan, existing pipelines near schools and

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homes.

Cabrillo High School is almost twice the size now in population than it was when the plant was first built and the pipelines were built right behind it. Parents now want to build a stadium behind the campus.

This would bring students and human beings closer to the hazardous footprint. Next issue is traffic.

PH-24

Harris Grade has not been properly improved since the plant was built, but we now have, as anyone who travels those roads would agree, are substandard roads.

Residents often see trucks parked overnight at the intersection of Harris Grade and Burt Mesa Road on a dirt surface on the side of the road.

It's not known why those trucks are in that vicinity, but there's been speculation that they might be related to oil field clearing or plant operations.

Either the County or the City has funds to maintain Harris Grade Road as publicly stated as recently as Spring '06, during the hearings for the annexation of Burton Ranch Property at the "Y."

Harris Grade Road where these tankers must travel has also been the site of numerous fatal accidents usually involving speed and alcohol. It runs through the Burt Mesa Reserve, posing an even greater risk because of the flammability.

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PH-24 Cont'd

An crease in the planned output results in more tankering. There are three new housing developments with more than 300 homes in the "Y." There is also proposed development for 485 homes in the "Y."

Tankers then turn from Harris Grade Road to Paris Road. That's hardly wide enough for more than two cars, no less tankers carrying dangerous byproducts. I think an accurate description of the impact to these roads should be included in the E.I.R.

PH-25

In the area of aesthetics, the lights from the existing plant are visible for miles, and for those of us who live near the plant, we are under this very bright glow every evening.

Since the mid-eighties we've asked for the lights to be capped, but as far as I know, this has not happened. THe E.I.R. says that the proposed project would change the visual character of the affected areas from semi-rural to urban and quote, "The proposed project's incremental contribution to these impacts would be significant due to the prolonged life of the Lompoc Gas Plant."

Anyone who sees the lights from miles away are residents who live under the glow will also agree with that. We have chosen to live in semi-rural area long before this plant was built, and now, having the plant

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PH-25 Cont'd

with its bright lights does seem like living in a pocket of urban light blight in an otherwise dark, rural setting. The E.I.R. should include a specific time line for the capping or the reduction of these lights.

PH-26

Noise. Previous owners of the plant did respond to neighbor's complaints about noise, especially in the nighttime hours, but depending on topography, the orientation of your home, and weather conditions, noise does still travel.

Noise also emanates from low-flying helicopters which seem to be taking clients or the public on tours above the onshore facilities. This is also disturbing in a semi-rural community. So I'd like to see more details about helicopter flights in the E.I.R.

PH-27

Lastly, the jurisdiction. I don't know where this fits in. It's probably for the whole thing. There is a proposal for a 1,300-unit housing development for the across the street from the plant. Nowhere in the E.I.R. does it mention this application of PXP and it is also -- there's a proposal before the City for annexation to the City of Lompoc.

This brings into question jurisdictional, I would think, confusion. Will the City eventually annex this area? Will the City eventually annex the plant?

What assurances do neighbors who live in the

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PH-27 Cont'd

existing unincorporated areas have of higher standards imposed by the County?

Will this E.I.R. become obsolete if the City has jurisdiction of the plant and of the proposed housing development across the street?

These annexation and project proposals should be included in this E.I.R., as they have been advertised and promoted for the past two years.

Claiming there's been no formal application does not mean it will become a reality. The development company has spent thousands of dollars on a public relations campaign.

The City is presently working on an annexation application, so I would think, you know, the project is quite feasible.

Thank you for this opportunity to express my concerns, and some things that I would like see added added to the E.I.R.

MR. DRUDE: Thank you very much for your comments. John Picciuolo followed by Thomas Gibbons.

MR. PICCIUOLO: Good evening. My name is Jon, J-O-N, Picciuolo. I'll spell that. P-I-C-C-I-U-O-L-O.

I'm a resident of Vandenberg Village, and I believe that the Draft E.I.R. has a major flaw.

PH-28

The analysis of risk to human life is based on two

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PH-28 Cont'd

critical assumptions. The first is that there will be an average of only three persons present in the vicinity of the Lompoc Oil and Gas Plant, and the second is that there will be less than only four persons per mile on vehicles in the adjacent road.

It is a fact that PXP is planning to build housing close to the plant. PXP has submitted preliminary plans to the City of Lompoc, submitted requests for the City to explore the site, taken officials on tour there, reported to the United States Security and Exchange Commission that a multi-million-dollar development consultant is hard at work and a negotiation with State water supply with Carpinteria Valley Water District.

PXP has repeatedly and publicly asserted that the company intends to build as many as 1,300 houses there. The projected time frame of this is within the time frame of the Tranquillon Ridge Project.

So would there be only three persons in the vicinity of the plant, and four persons on the nearby road? I don't think so.

The risk analysis assumptions are incorrect. Therefore, the risk analysis cannot be correct.

I'm talking about the risk to human life, so please listen closely to what I say next.

California's SEQUA(phonetic) guidelines authorize

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PH-28 Cont'd

the County to limit its analysis of probable future projects to those which are planned or have an application made at the time the plans are released for review.

The guidelines go on to say if additional projects are identified later, they be included and they be addressed during completion of the final E.I.R.

I don't know what stage the PXP Housing Project was when the notice of preparation for Tranquillon Ridge was released; however, I'm here tonight to tell you that PXP's housing project is deep into planning right now.

In the E.I.R. under consideration tonight, the County must assess Tranquillon Ridge Project risk to the families who will live in PXP's planned homes. If the County takes the position that this risk analysis can be delayed until the environmental review for the homes is undertaken by Lompoc, the critical window of opportunity will be lost, the window when mitigations to protect human life can be efficiently designed to the Tranquillon Ridge Project.

Thank you for the opportunity to speak.

MR. DRUDE: Thank you for your comments. And the last speaker on this list is Mr. Thomas Gibbons.

MR. GIBBONS: Good evening. My name is Thomas Gibbons, T-H-O-M-A-S, G-I-B-B-O-N-S.

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P.O. Box 2297 Orcutt, or 3840 Foxen Canyon Road in Santa Maria.

PH-29

I support the project. The E.I.R. generally overstates the Class I impacts, as I read them. I'll be doing a detailed analysis, and it's in progress, and I'll be informing you in writing before the due date, and I will submit specific comments.

Many of the stated impacts are just not similar to the Point Pedernales Project, but are the same.

No one needs to review the Tranquillon Ridge Project environmental effects and mitigation unless they do it in parallel to the Point Pedernales Project.

As for any other project requiring a level of mitigation, one has to look at the previous mitigation and the existing mitigation, because in the nature of these projects, mitigation is done in kind of an odd-looking bell curve, and it's all done on the front end.

And generally, we find these projects never reach their full design capacity, much like the existing project.

Using the time management of the effects of mitigation, it is only logical that one can see the project is mitigated to its fullest from the start. Before the project starts production, the mitigation is

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PH-29
Cont'd

at its maximum.

I almost feel this project's already mitigated. The linear progression of impact relative to the true effects is probably where this is today. The existing Point Pedernales Project final development plan permits 36,000 barrels a day of oil. PXP estimates Tranquillon Ridge, Point Pedernales Project together will peak at 30.

Like all other oil and gas projects that never meet the planned goal stated or the designed goals, again, they're over-mitigated.

This is bad form to see this over and over again. I've seen it in this room a couple of times; it should be corrected.

We know when it's well-stated that the Platform Irene is designed for 100,000 barrels a day of emulsion. You can break that down to whatever percentage you want. Right now it seems to be a lot of water.

The pipeline current rate for mellow G.P. to Orcutt is operating at 7,500 barrels a day, way under capacity.

Cumulative impacts. The E.I.R. projections for offshore oil in your document is very, again, generous, almost doesn't fit with reality.

Looking at it, there's a great projection that many of these projects are going to come on very soon and give one a false impression that there's a big pending

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PH-29
Cont'd

offshore oil construction getting ready to happen -- probably not even close to reality.

It's my feeling that the State Lands Commission has a fiduciary duty to manage those resources for me, as a citizen.

They belong to us, and they should collect the taxes on those resources, and distribute them to where they need to go.

The County of Santa Barbara, I feel, has a similar duty to develop resources that will create tax revenue and develop domestic production real close.

I feel this project is a logical extension of the existing project. Onshore oil and gasses operated in those Lompoc fields for almost a hundred years, and I think it's probably been a successful enterprise.

It's employed a lot of people. I mean, it's no secret -- I've probably got a little crude oil on me here and there; made a pretty good living. There's not a credit of value in your document relative to the existing processing infrastructure as it exists today.

If this project was started new, there would be a tremendous requirement for infrastructure. There's no analysis given to the value of the produced oil and gas volume in the future.

You know, we've got little refining capacity in our

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PH-29 Cont'd

area here. Transportation always seems to be a big problem. I consumed my fair sure coming over here tonight, made sure I came by myself so it's a real value.

We want to give the value and the credit where its due. Most of these offshore projects take many years from their inception to production. This project here could probably be kicked in pretty close to its maximum production, say, in five to seven years, because most of the infrastructure's in place.

I don't think, given the energy constraints of the world economy today, that we can back away from even doing this project. Thank you.

MR. DRUDE: Okay. Thank you for your comments. Is there anybody else in the audience who wishes to speak this evening? All right.

MS. NASH: Good evening. Thank you for the opportunity to speak. My name is Carol Nash, C-A-R-O-L, N-A-S-H. I live on Saint Andrews Way in Vandenberg Village.

I wasn't prepared really to speak because I haven't read the document, but I've read portions of it, and I've certainly looked through the Post-its in the Executive Summary.

PH-30

But I've had concerns about the project, and about not only this project, but those in the past regarding

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PH-30 Cont'd

mostly the Lompoc Oil and Gas Plant, and the pipelines that lead to it because of the homes, because of where the existing homes, where they are and where they've been when all of this -- when the separation plant became a production plant and a processing plant.

I think that it's the wrong place, and I think it's a planned area. When you talked earlier about this being a planning issue, it certainly is a bad planning issue, because we have a industrial site right on top of a residential area that was there prior to this production, and we were promised, frankly, by the industry when all of this -- when the separation plant came on line that there would never be any production there, that everything was going to Battles.

And there would be no production and no end-products rolling on these roads, but we have very volatile fuels running on the roads, and this is going to increase it by a considerable measure to have more trucks with more fuels.

It's interesting that the capacity of the plant has been permitted over a long series of addendums and supplements to E.I.R.'s as they went along the way, and there's also been a change of companies, the companies -- one company after another, so that the personnel working at this plant has differed.

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PH-30
Cont'd

And when you think about the probability of the risk of human error, I think it's significant, because there's a lot of things that maybe aren't -- are passed on from one thing -- one company's person-in-charge to the next, and there are a lot of areas where something can happen.

When Battles went down, the County, I guess, decided that Battles was not a safe place to work or a safe plant, and it was aging. Now, this plant is aging, and the pipelines are aging, but what's happening is little patches and fixes, but the integrity of the whole system, I question the integrity of the whole system when the life of the whole system, frankly, from the pipelines to the plant, are really beyond what their life should have been.

I worry about fires and explosions. I worry about the traffic on the road. I'm concerned that the industry, for instance, is ready to turn -- I've been to these hearings for the new PXP development being proposed, and they're really willing to extend the pipeline, absorb the cost of the pipeline to go all around this development.

But it seems when it comes to putting the plant in the place where it would be, you know, it would be less dangerous for the people who are living in the area and propose to be living in the area. This is not even a

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PH-30
Cont'd

consideration. It's caused -- their cost of benefit is apparently something different.

And I wanted to read you something about the alternatives. When I read a while back the alternatives -- alternative sites for the Lompoc Oil and Gas Plant, I thought we were talking about just that, alternative sites for the Lompoc Oil and Gas Plant.

But all the alternatives that are talked about in the Executive Summary that I've read so far talk about alternatives with the pipeline here in this area, in that area or to something else, but not really.

Everything, no matter where it goes, it seems to to come up to this -- goes through the Lompoc Oil and Gas Plant for production, so I wanted to read to you the last sentence of the conclusions on your North County Oil and Gas Plan Siting and Planning Analysis.

It says "Due to its potential of new offshore production to occur for a period that could exceed 25 years" -- yes, we were there -- "the study concludes that the benefits of siting a new facility in a less constrained location outweighs the negative aspect of" -- "negative aspects of constructing a new facility."

The five potential sites identified in the study listed in order of environmental preference are Casmalia East and Casmalia West.

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PH-30
Cont'd

This actually talked about replacing the plant, if you are really going to go on with this, but instead we keep patching the plant and keep bringing it up to what the industry would say is safe.

But I have serious concerns and I think there are other people, if they knew, would have serious concerns, too, because we're dealing with very volatile fuels running through our neighborhoods.

And we're living in the middle of a chaparral preserve, which is a wonderful thing to have, but in terms of fire, it's a tremendous risk, and I think we ought to have this plant in another place. The whole industry should contribute. Thank you.

MR. DRUDE: Okay. Thank you for your comments. Is there anybody else who wishes to speak this evening? No.

Well, that concludes our Public Comment Hearing, and I want to offer each and every one of you the opportunity to contact the Energy Division Office while reviewing this document through the end of January.

If you have any questions, contact us on the means listed on that yellow sheet and we'd be glad to answer any kinds of questions you may have so you can include the most informed comments for us. Thank you very much for coming in tonight.

(HEARING CONCLUDED AT 8:20 P.M.)

Response to Comment Set PH

PH-1: Comment noted.

PH-2: Section 5.1, Risk of Upset, assesses the public risks associated with increased throughput and extended operation of the Pt. Pedernales facilities. As discussed in EIR Section 5.1.4, Impact Analysis for the Proposed Project, the transportation of gas liquids along roadways over current operations would exacerbate an existing Class I impact. Finally, the EIR identifies Class I impacts resulting from an oil spill across issue areas.

PH-3: Please see Response to Comment EDC-17. As discussed under Impact Risk.3, the existing Class I impact as a result of NGL/LPG truck trips would be exacerbated (more truck trips and a longer period over which truck trips would occur). The classification of this existing impact as Class I would not change with a 40-year versus 30-year project life.

PH-4: Please see Response to Comment GOO-6.

PH-5: Please see Responses to Comments EDC-10, EDC-92, and GOO-4.

PH-6: Please see Response to Comment EDC-2.

PH-7: Please see Response to Comment EDC-3.

PH-8: Please see Response to Comment PXP3-7.

PH-9: Please see Response to Comment EDC-6.

PH-10: Please see Response to Comment JP-1.

PH-11: Please see Responses to Comments EDC-2, EDC-10, and EDC-92.

PH-12: Comment noted.

PH-13: Comment noted.

PH-14: Comment noted.

PH-15: Please see Response to Comment EDC-21.

PH-16: Please see Response to Comment EDC-79.

PH-17: Please see Responses to Comments EDC-84, EDC-85, and EDC-87.

PH-18: Please see Response to Comment EDC-86.

PH-19: Please see Response to Comment EDC-23.

PH-20: Please see Responses to Comments CPA-2, S&EM-1, and S&EM-5.

PH-21: Please see Response to Comment CPA-3.

PH-22: Please see Response to Comment CPA-4.

PH-23: Please see Responses to Comments CPA-5 and CPA-6.

PH-24: Please see Response to Comment CPA-8.

PH-25: Please see Response to Comment CPA-9.

PH-26: Please see Response to Comment CPA-10.

PH-27: Please see Response to Comment CPA-11.

PH-28: Please see Response to Comment JP-1.

PH-29: PXP has filed applications to extend the life of the Pt. Pedernales project and increase throughput volumes as a result of producing the Tranquillon Ridge Field. In accordance with CEQA, the EIR addresses the impacts of the proposed project in comparison to the existing baseline (i.e., current operations). Comments in support or opposition to the proposed project should be submitted to the decision-makers prior to public hearings on the proposed project.

PH-30: Please see Responses to Comments CPA-3, CPA-4, CPA-7, CPA-8, JP-1, RCN-1 and PH-2.

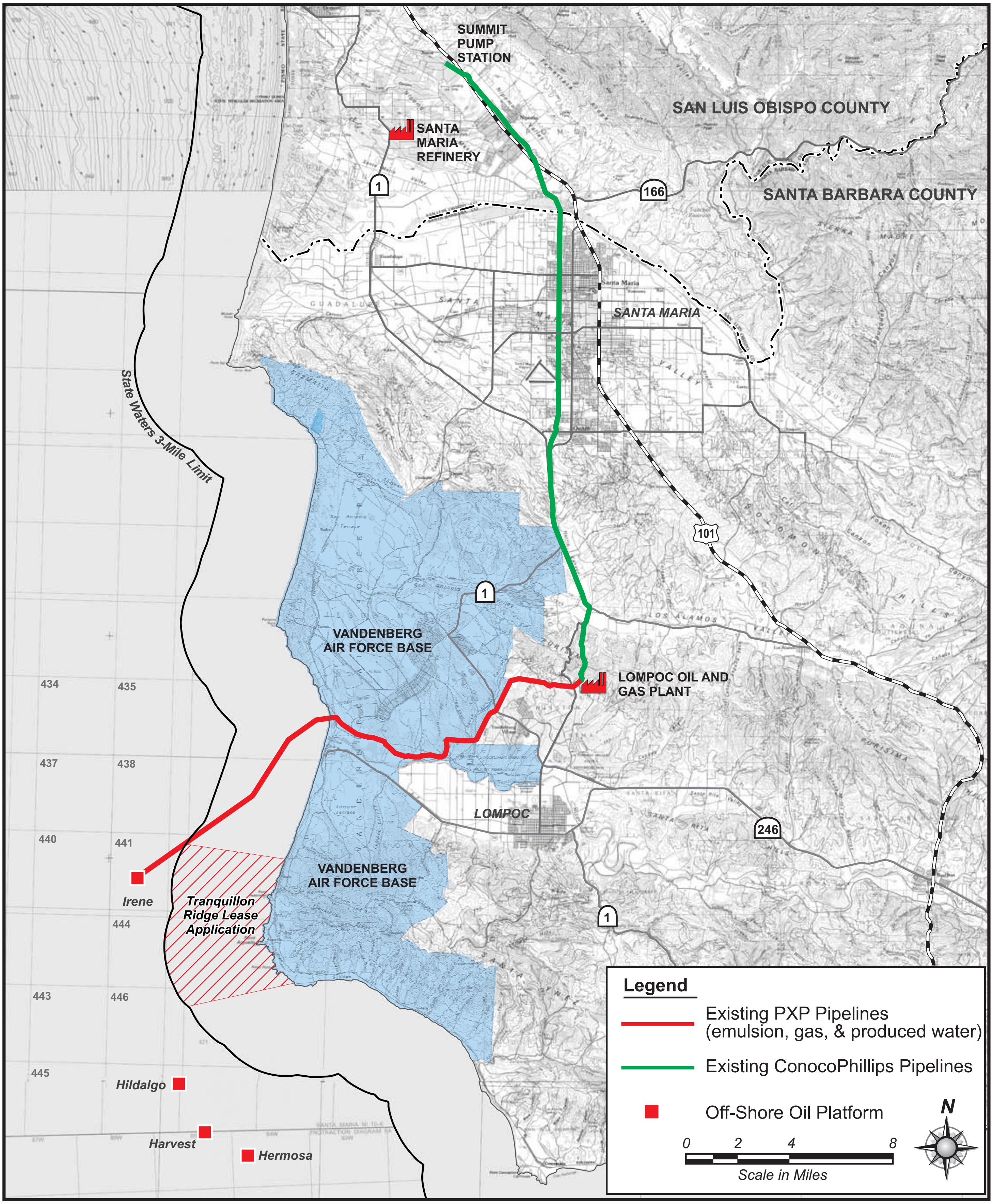

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Figure 1-1

Proposed Project Location

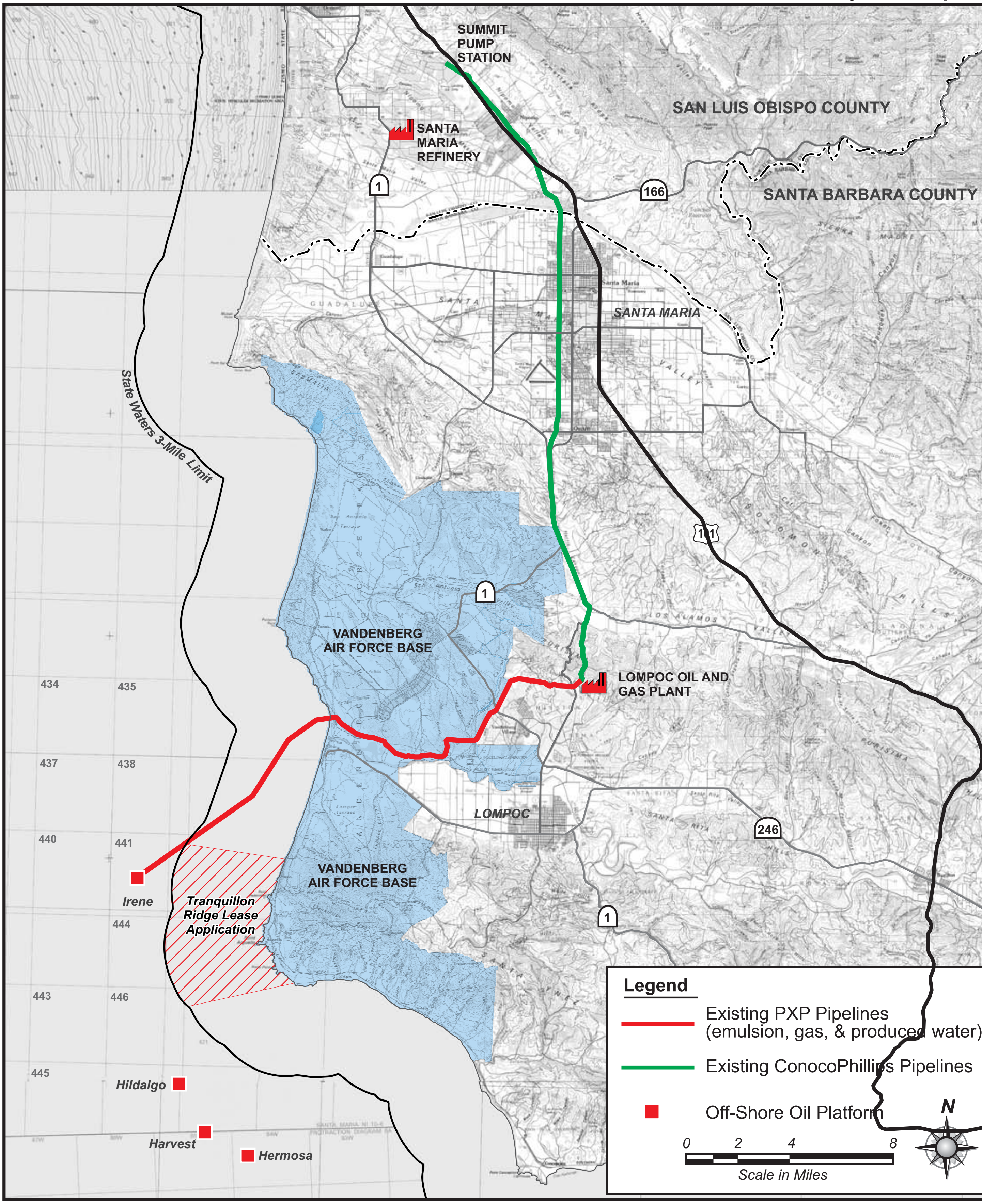

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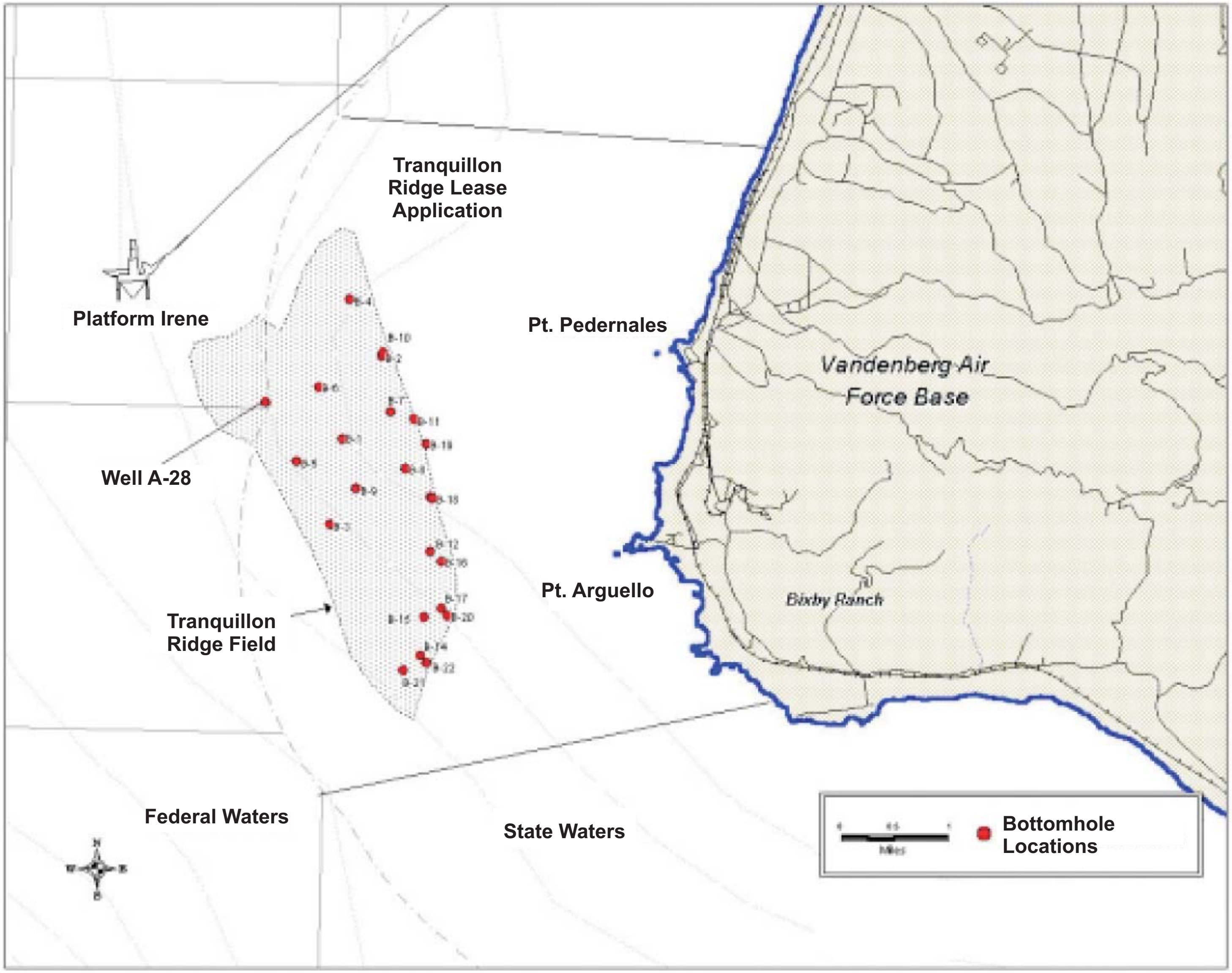
Figure 2-1
Proposed Project Location



Source: MRS, 2002.

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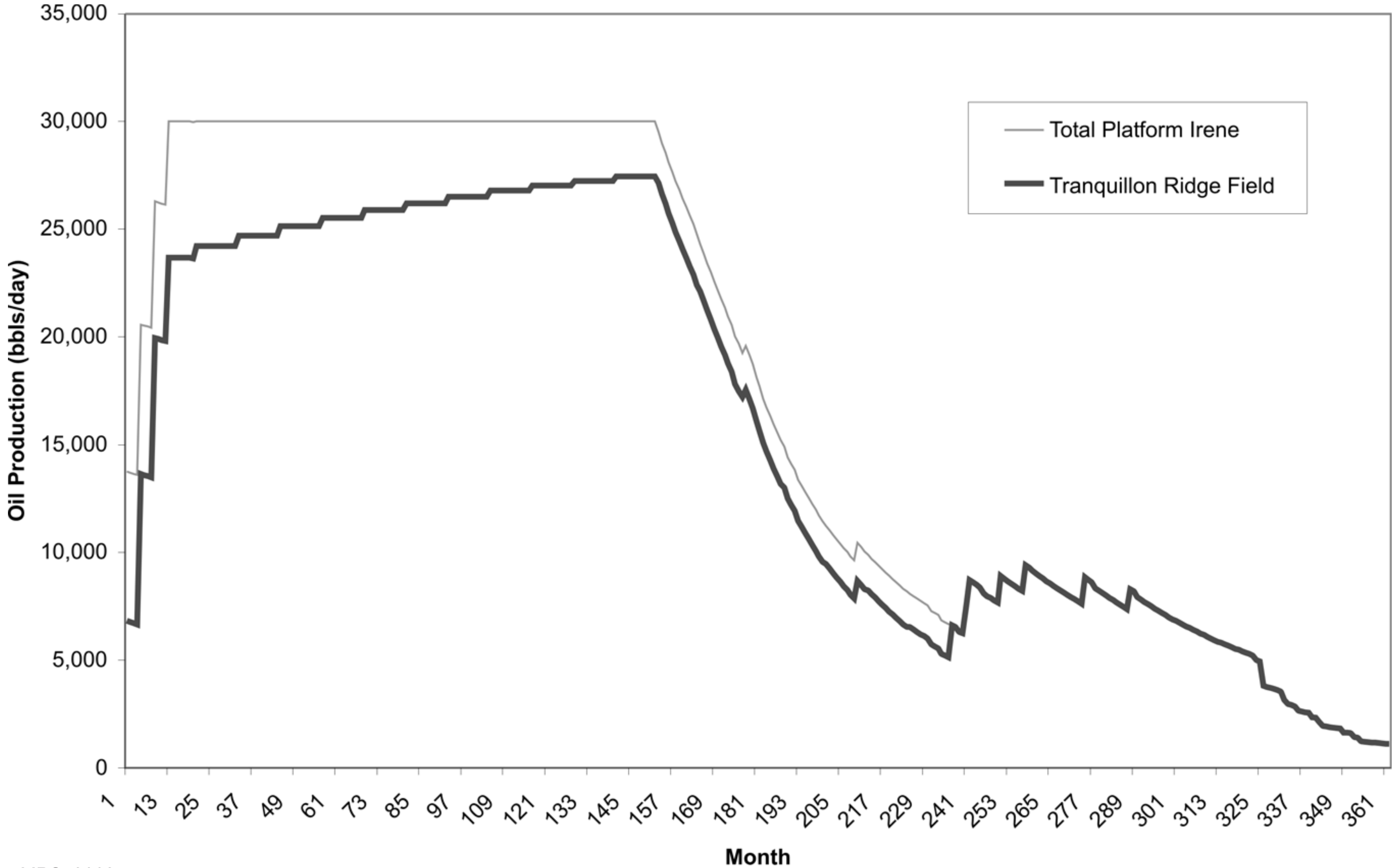
Figure 2-2
Proposed Tranquillon Ridge Drilling Map



Source: MRS, 2002.

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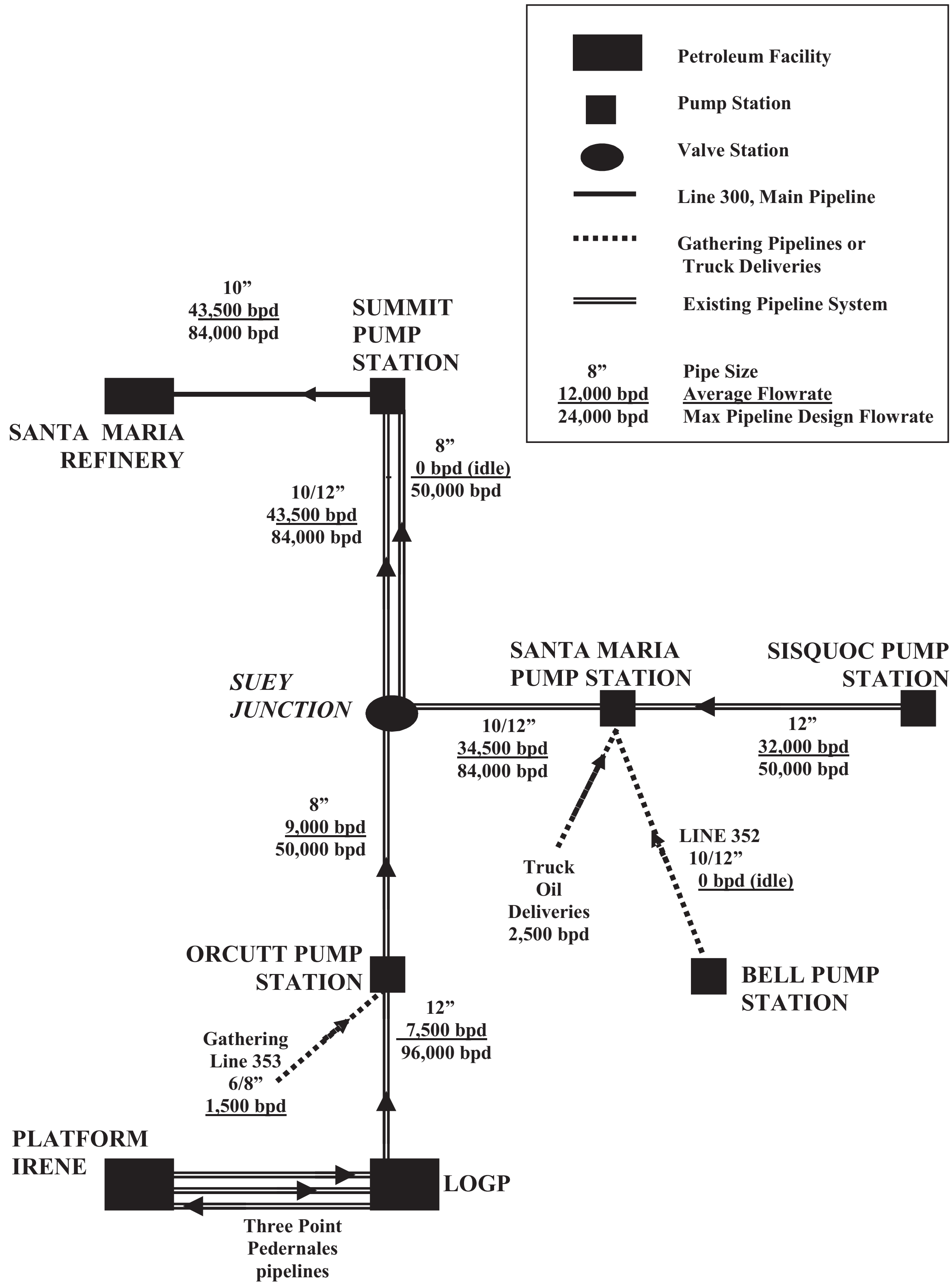
Figure 2-3

Estimated Oil Production for the Tranquillon Ridge Field



Source: PXP, 2006.

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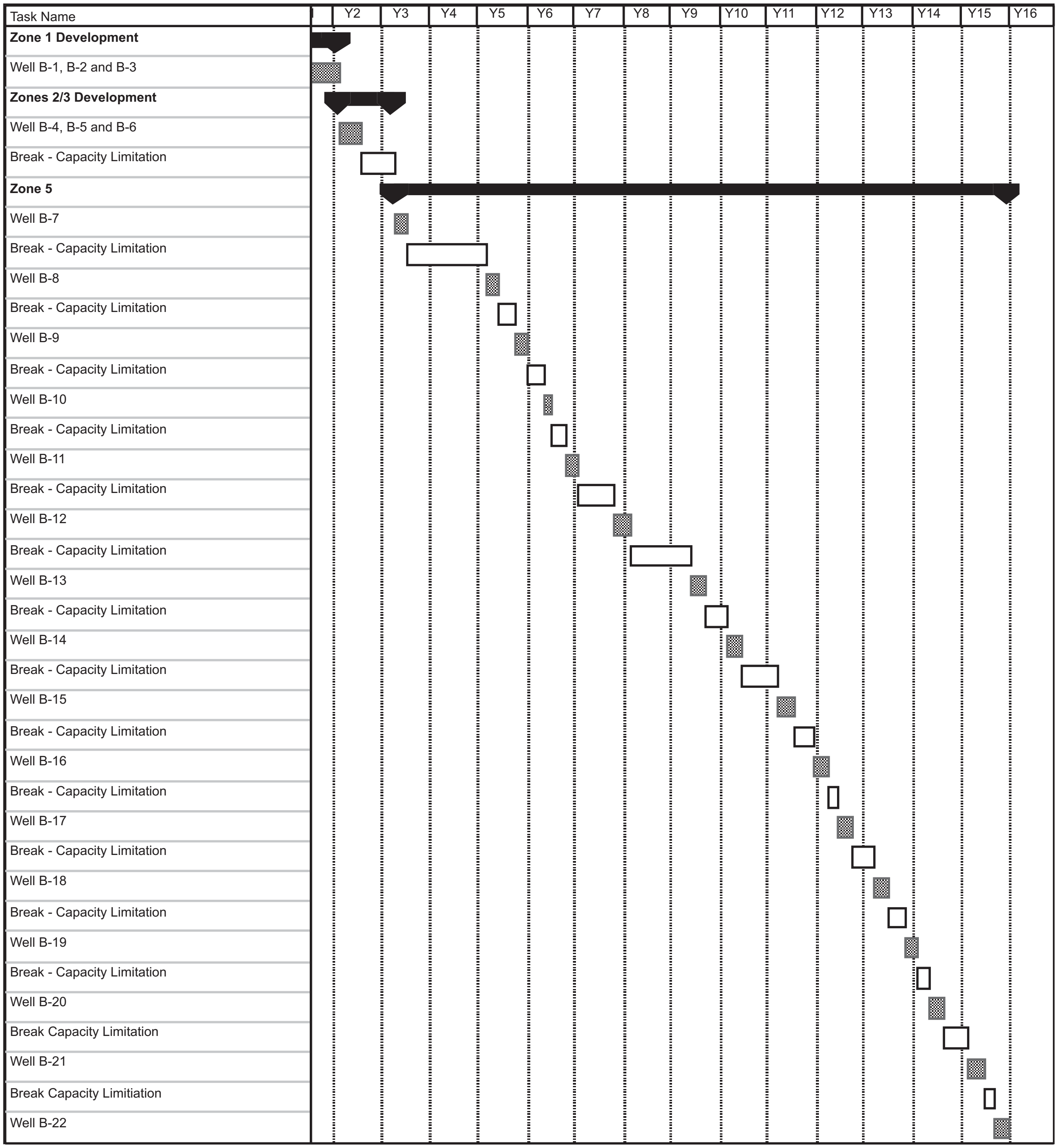
Figure 2-4
ConocoPhillips Pipeline System



Source: MRS, 2002.

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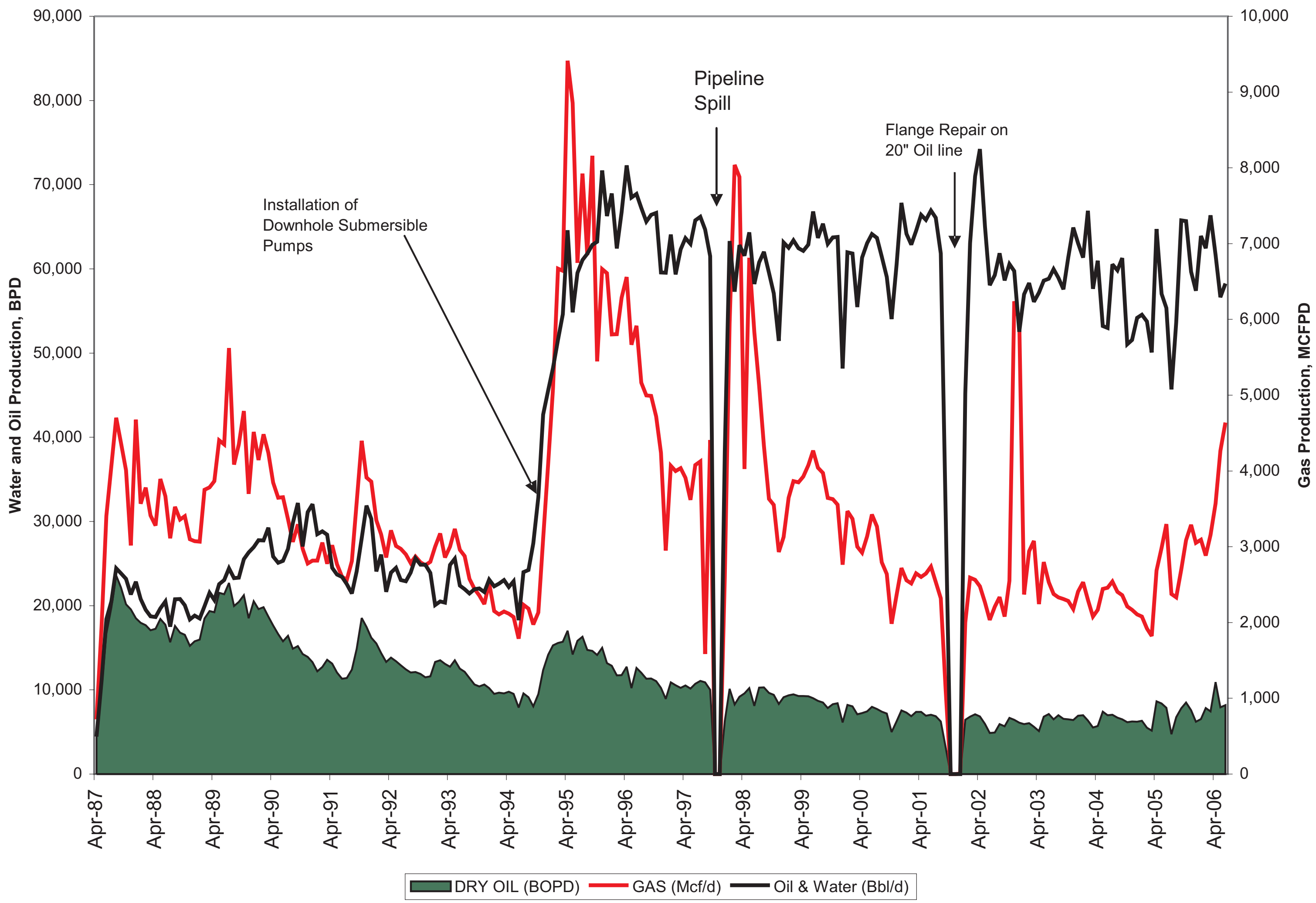
Figure 2-5

Proposed Tranquillon Ridge Field Drilling Schedule



Note: Average daily production data is derived from monthly production data by dividing it by the number of days of production.

Source: PXP, 2006.

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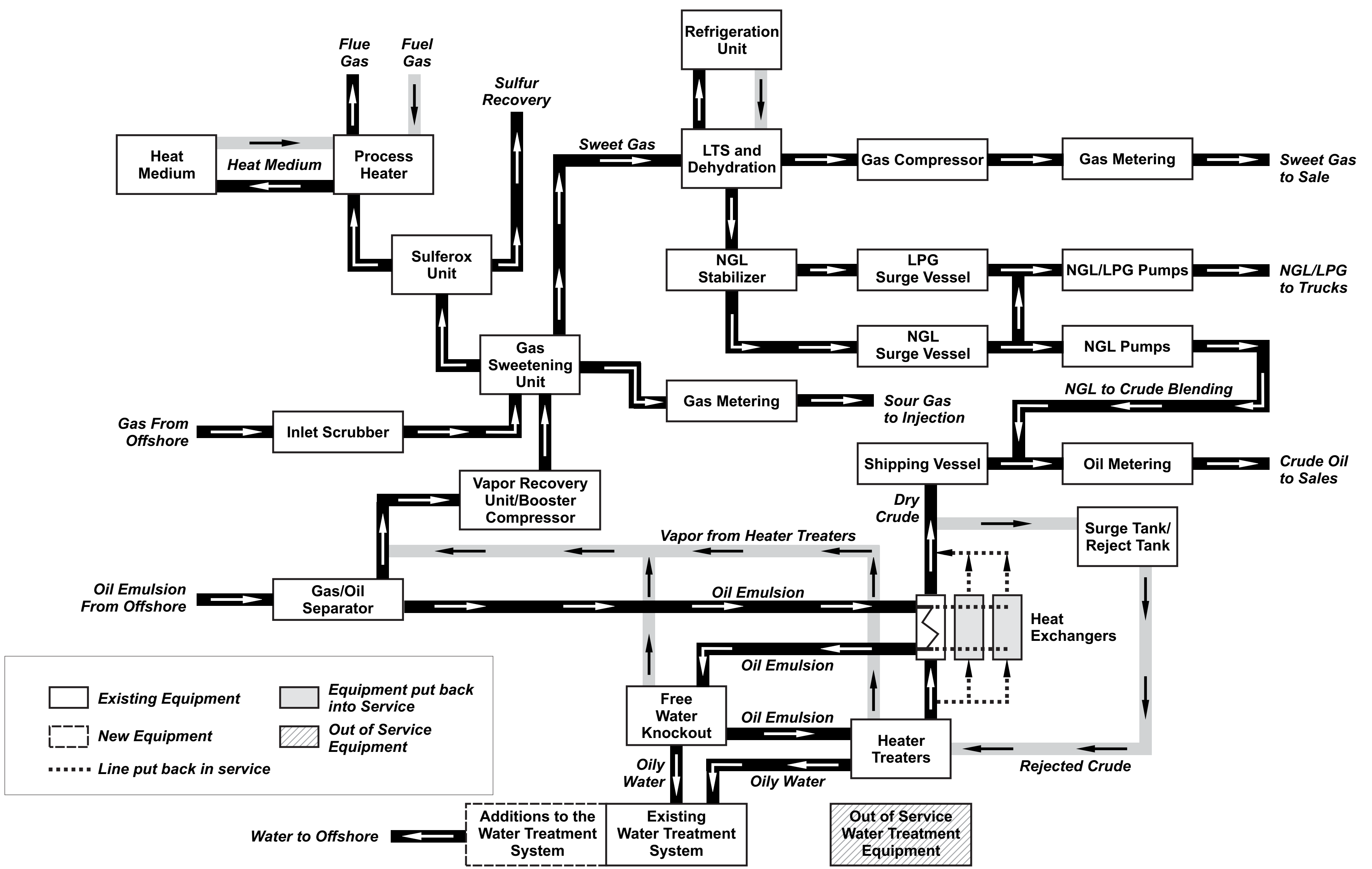
Figure 2-6
Point Pedernales Total Produced Fluids (1987-2006)



Source: PXP, 2006.

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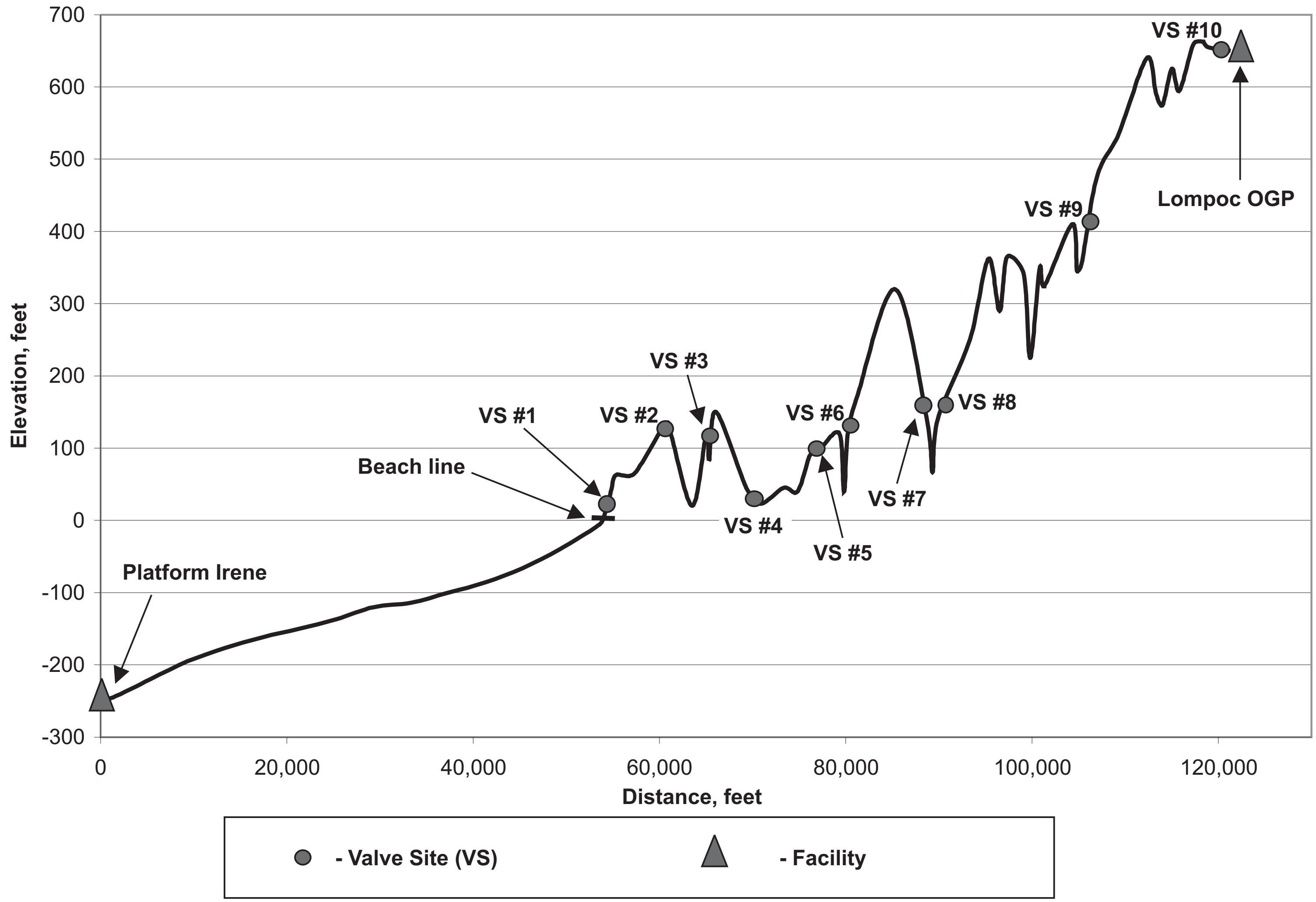
Figure 2-7
LOGP Block Flow Diagram



Source: MRS, 2002.

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Figure 2-8
Platform Irene to LOGP 20-inch Oil Emulsion Pipeline Elevation Profile

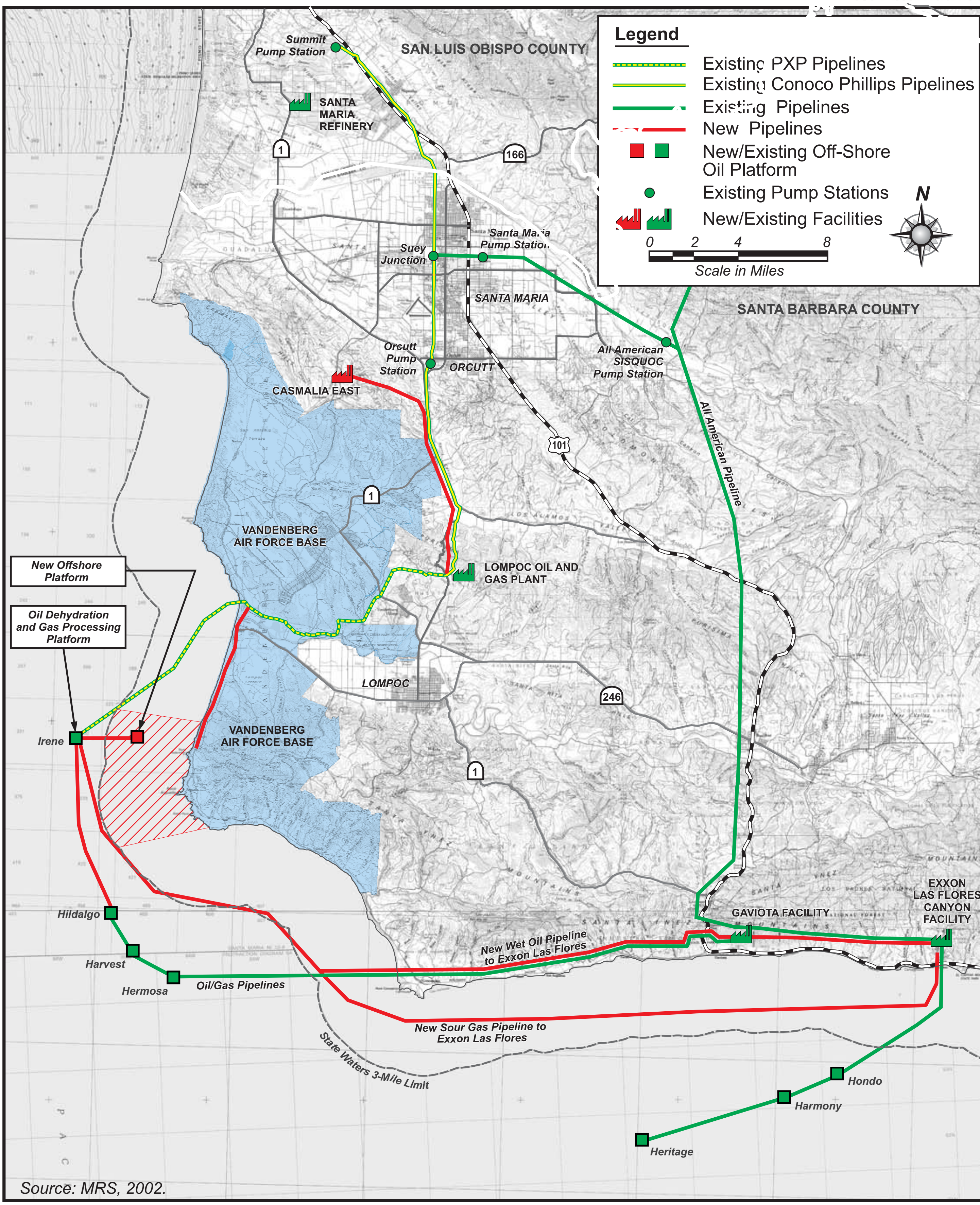

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Figure 3-1
Alternatives Locations

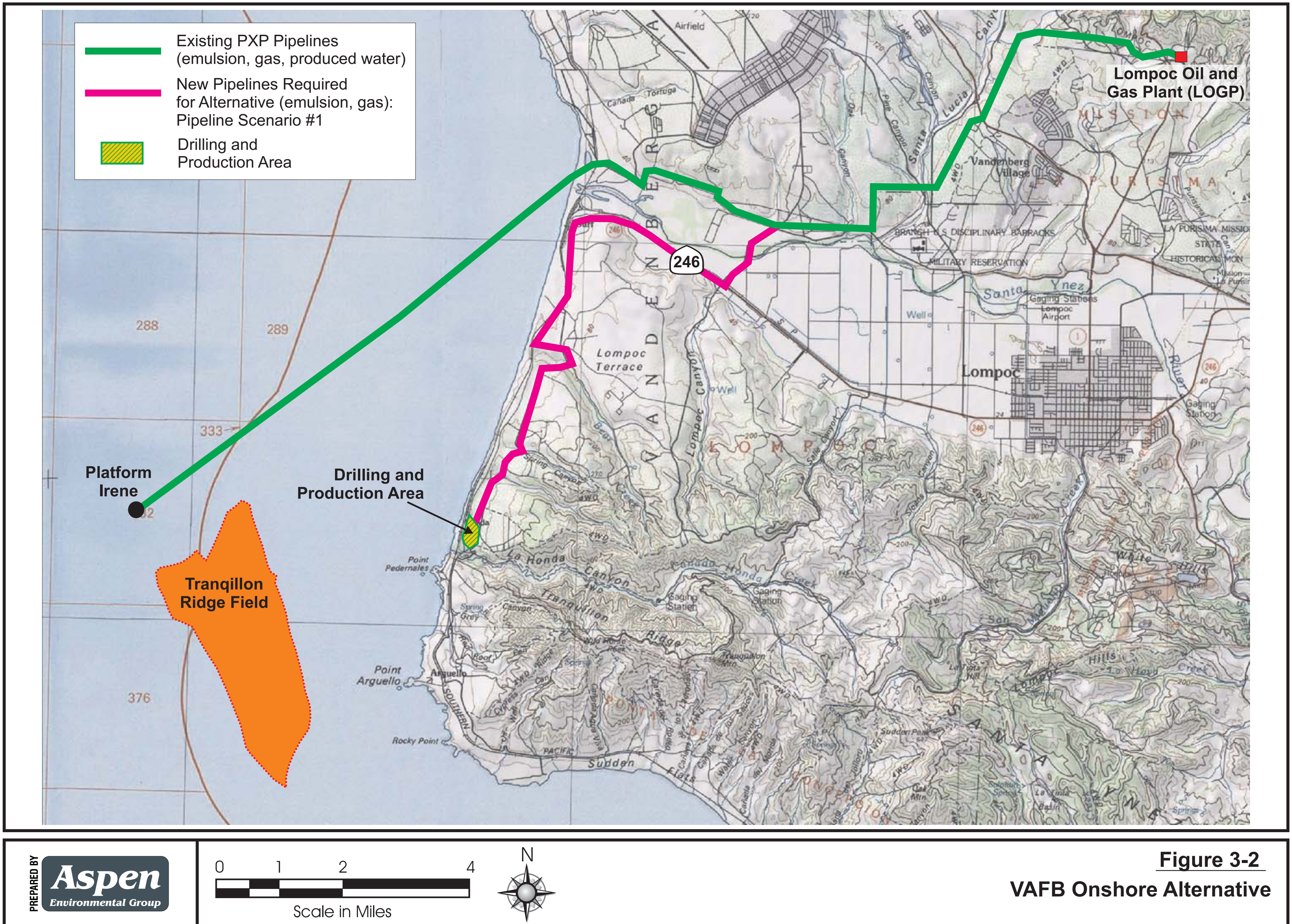

Figure 3-2
VAFB Onshore Alternative

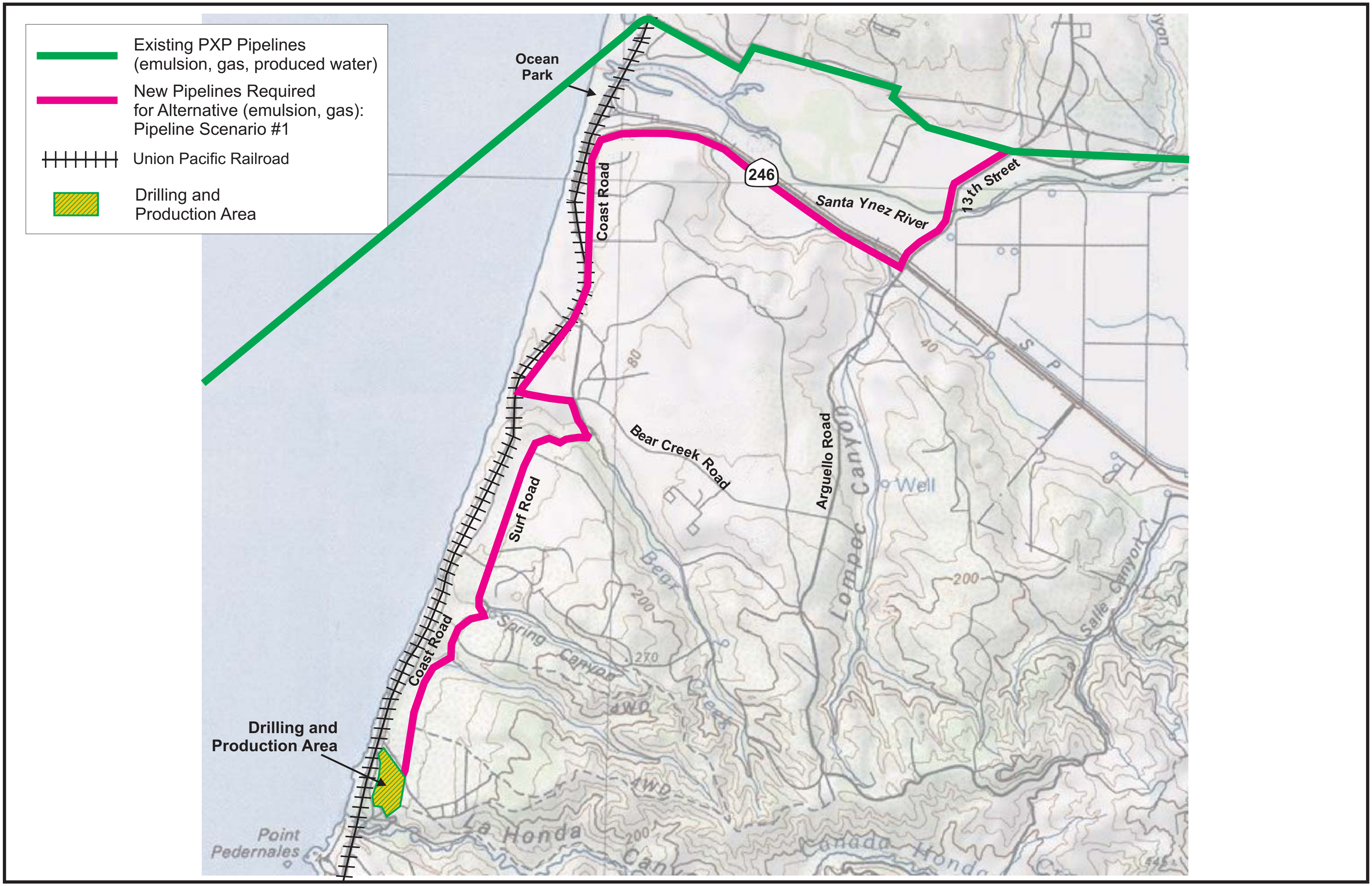

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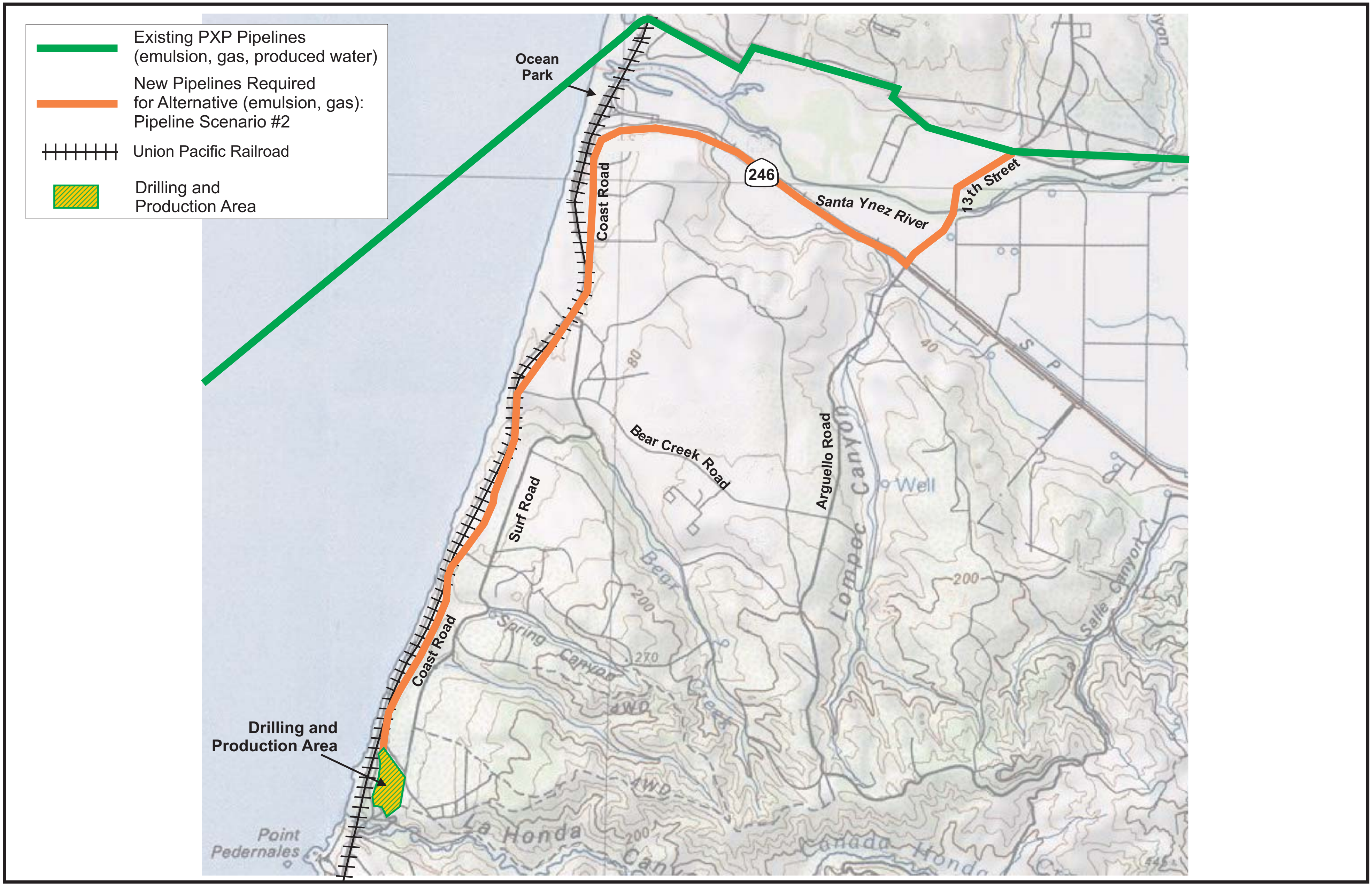
Figure 3-3
VAFB Onshore Alternative Pipeline Scenario 1



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0 1 2 Scale in Miles N

Figure 3-4
VAFB Onshore Alternative Pipeline Scenario 2

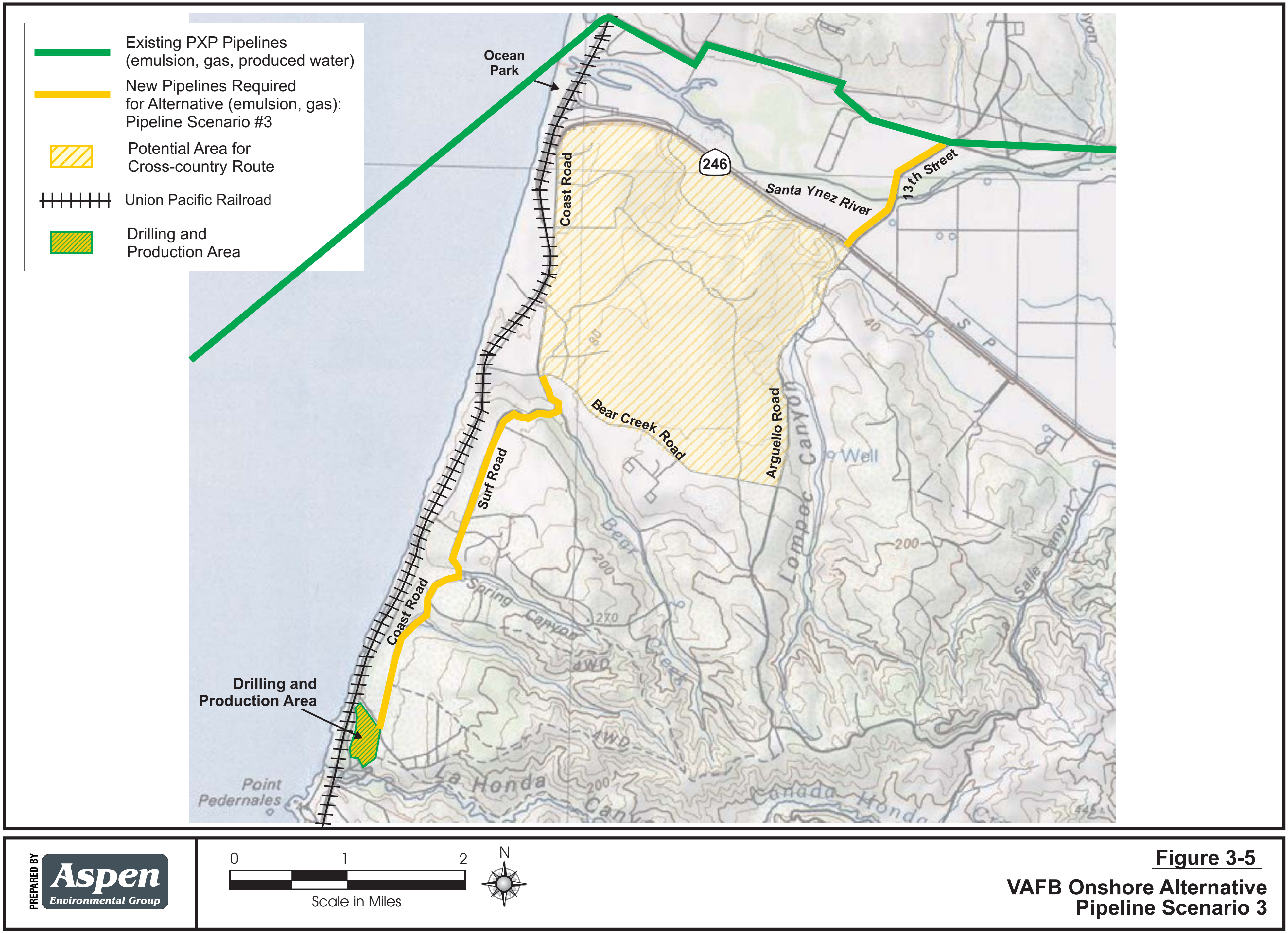

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Figure 3-5
VAFB Onshore Alternative
Pipeline Scenario 3

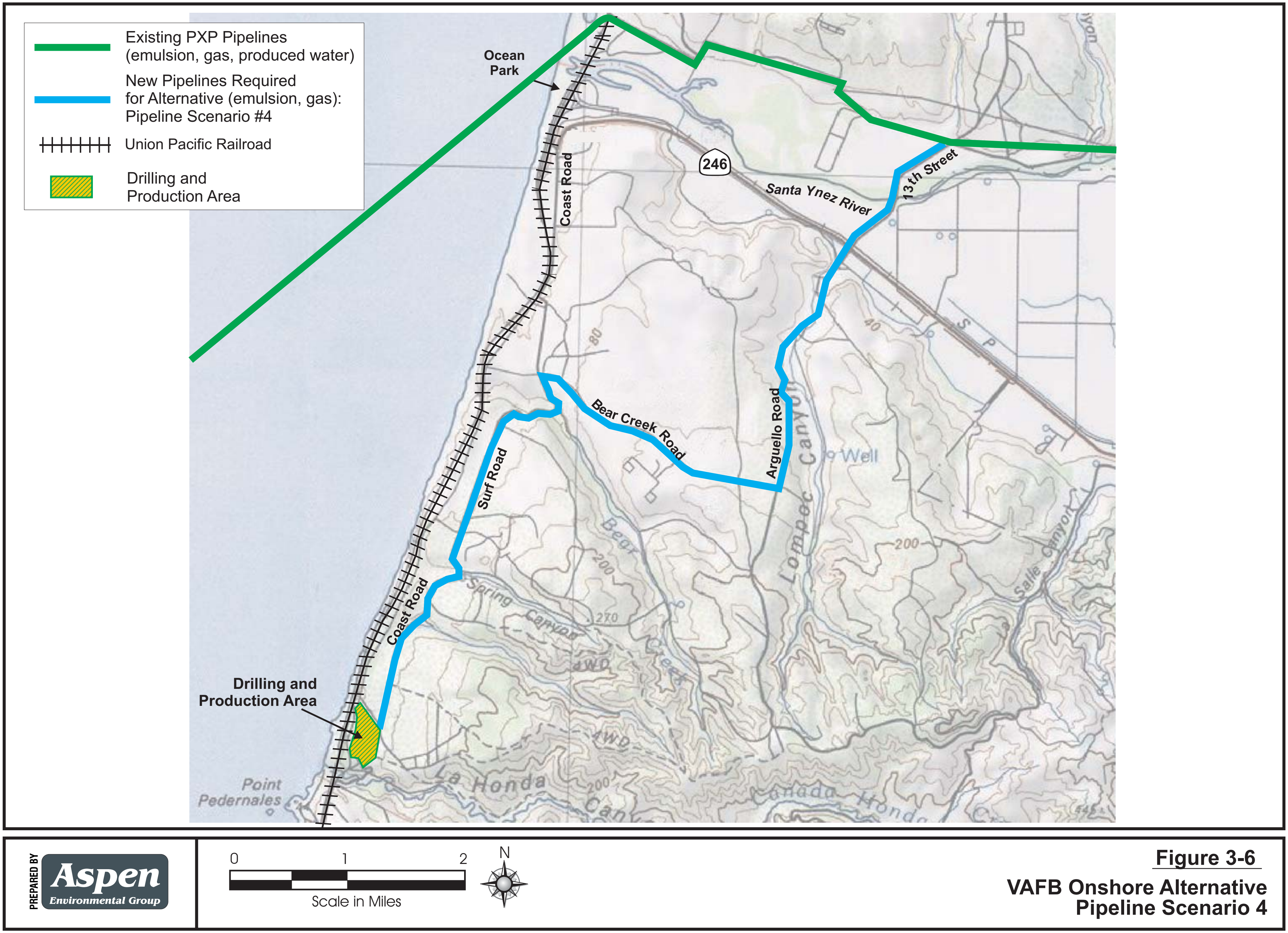

Figure 3-6
VAFB Onshore Alternative Pipeline Scenario 4

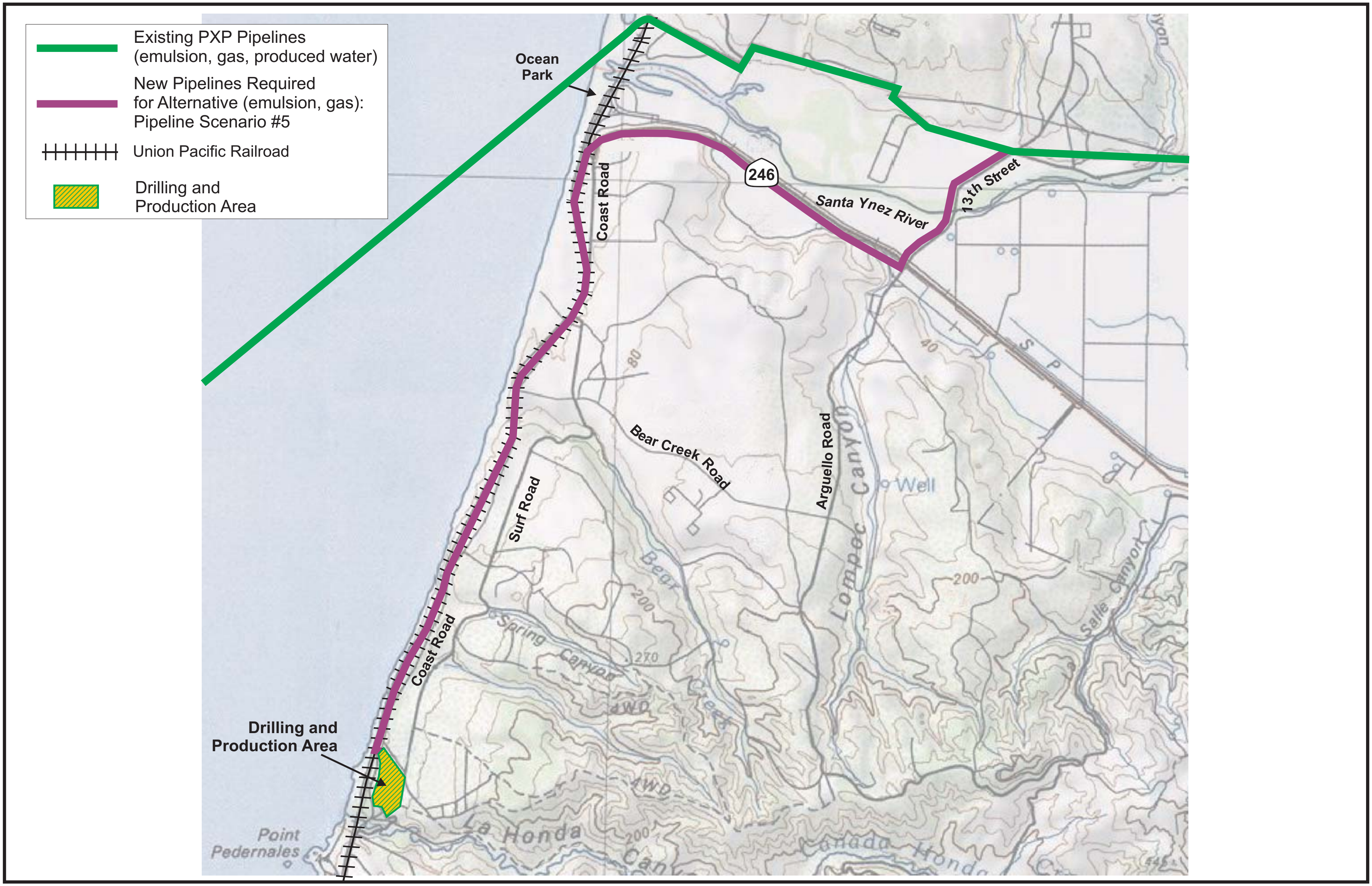

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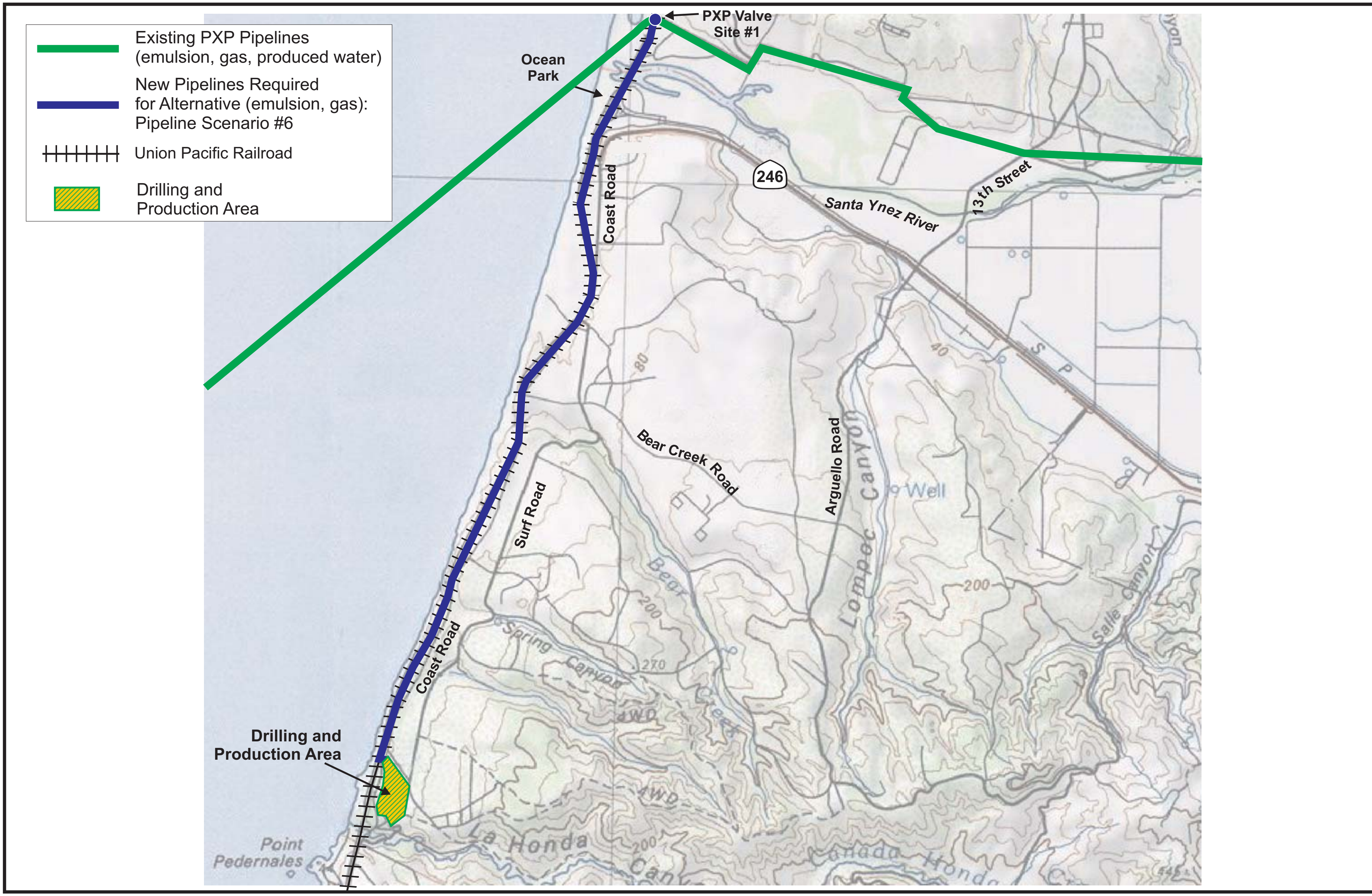
Figure 3-7
VAFB Onshore Alternative Pipeline Scenario 5



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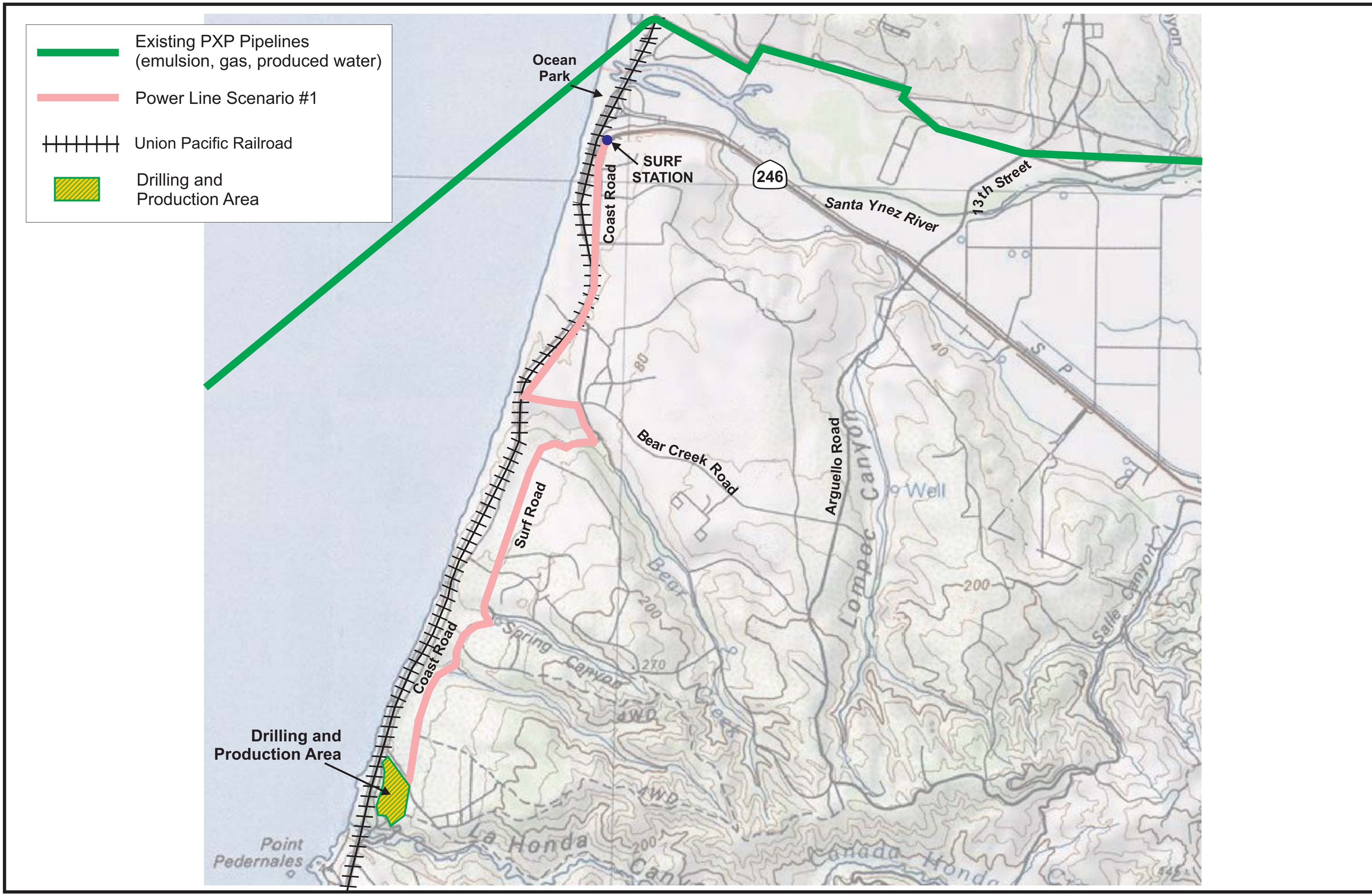
0 1 2
Scale in Miles
N

Figure 3-8
VAFB Onshore Alternative
Pipeline Scenario 6



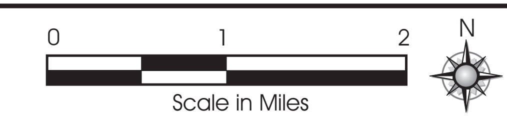
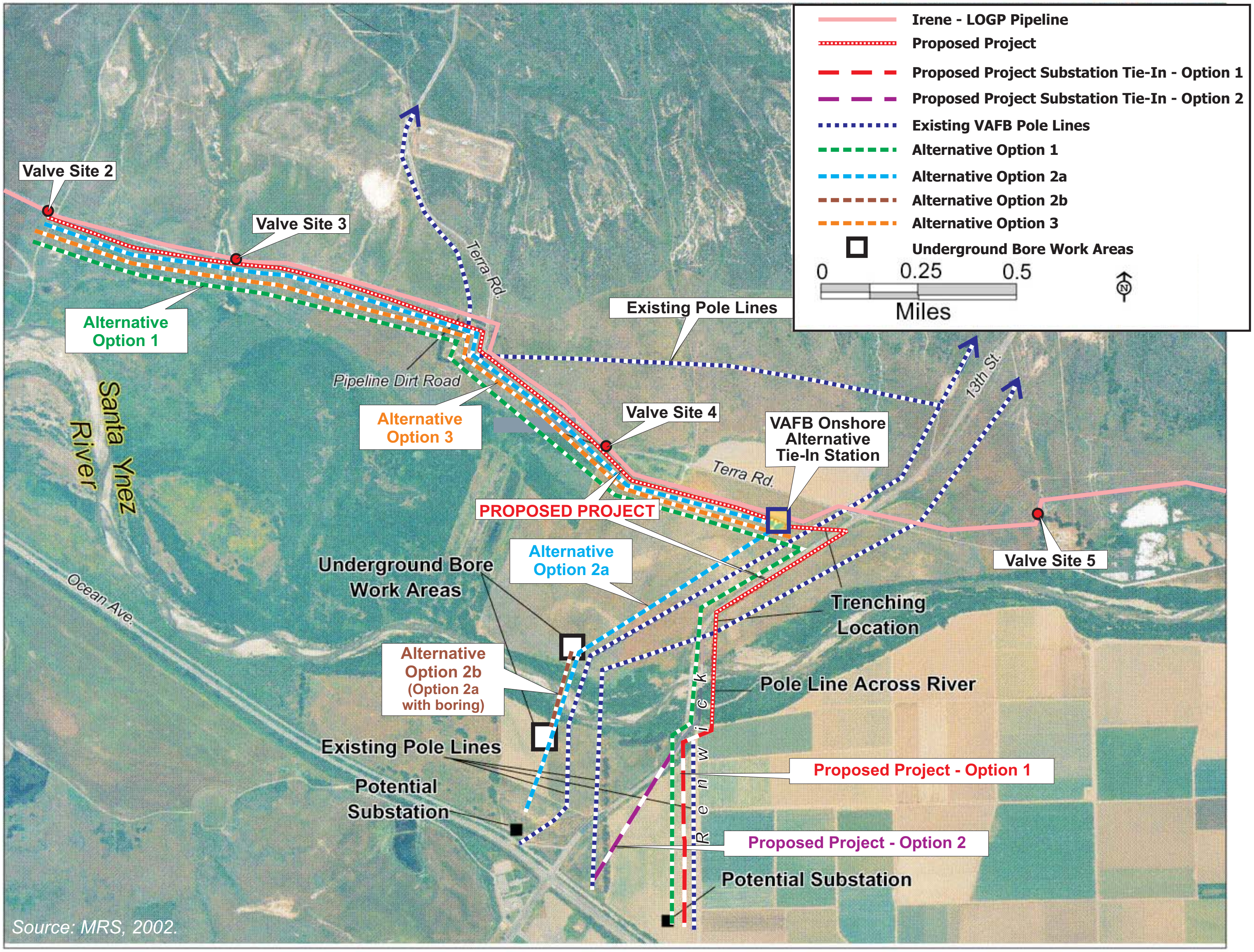


Figure 3-9
VAFB Onshore Alternative
Power Line Scenario 1



PREPARED BY Aspen Environmental Group

Figure 3-10
Alternative Power Line Routes

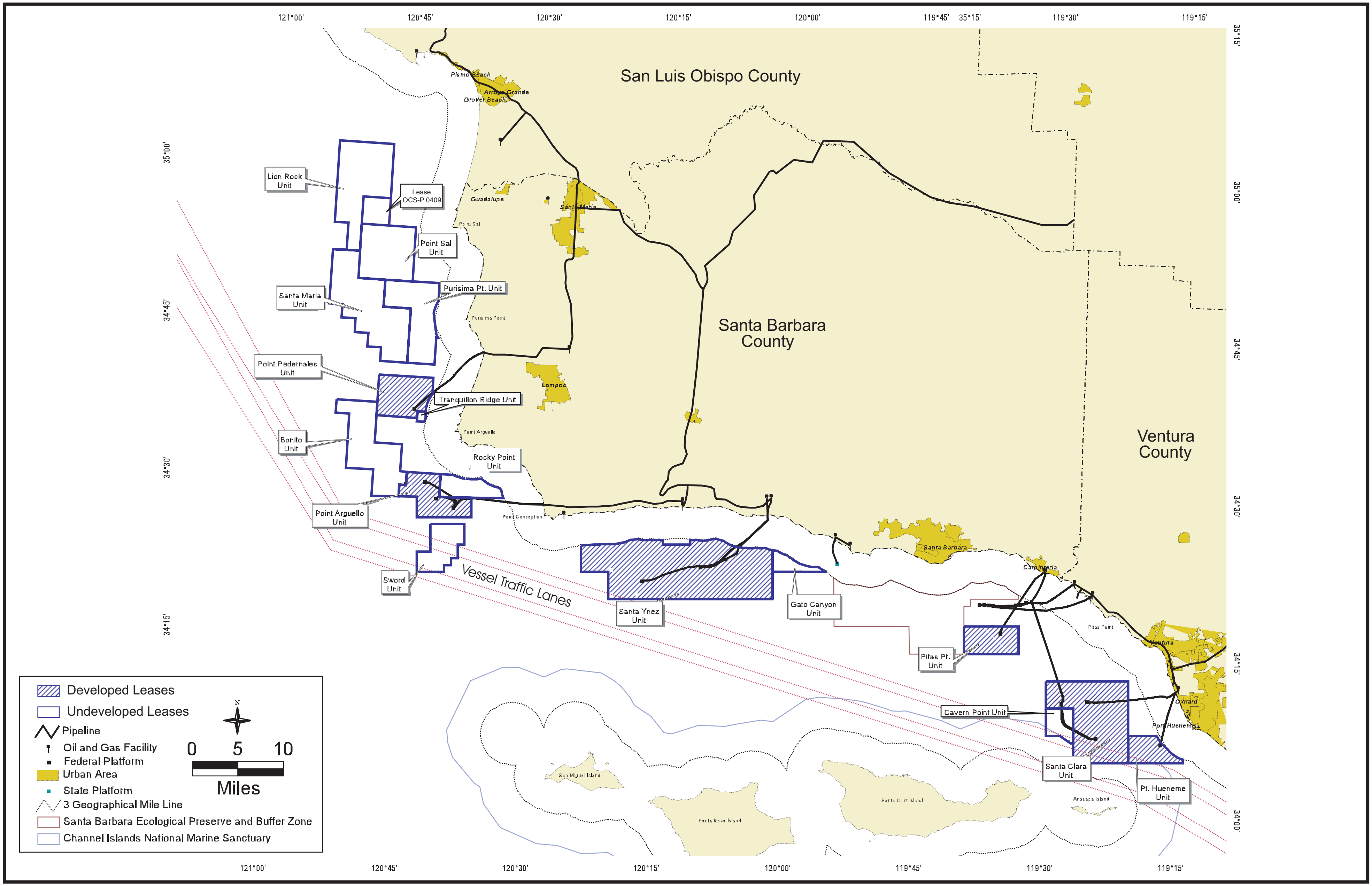


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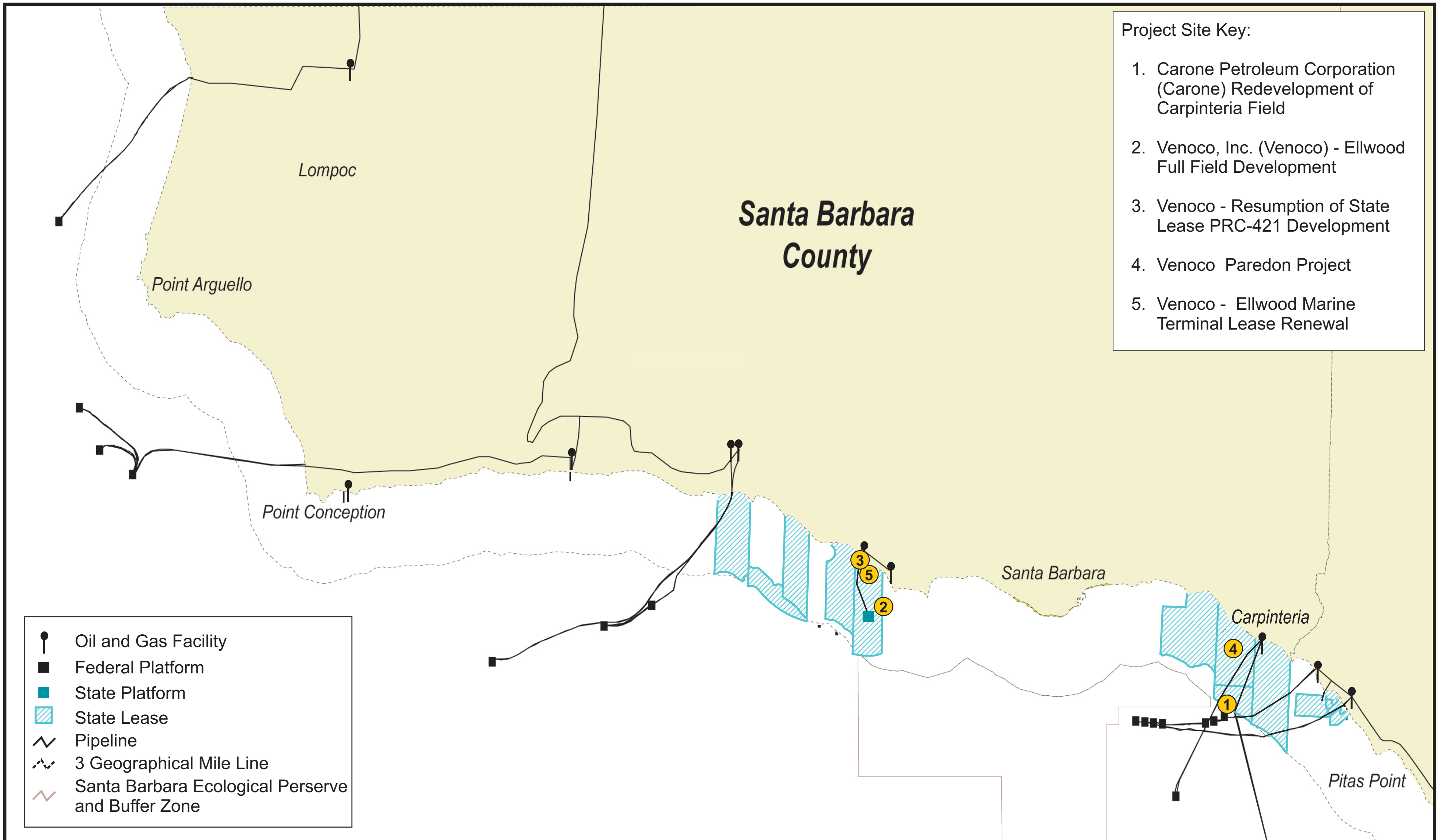
Figure 4-1
Location of Cumulative Federal OCS Oil and Gas Development Projects

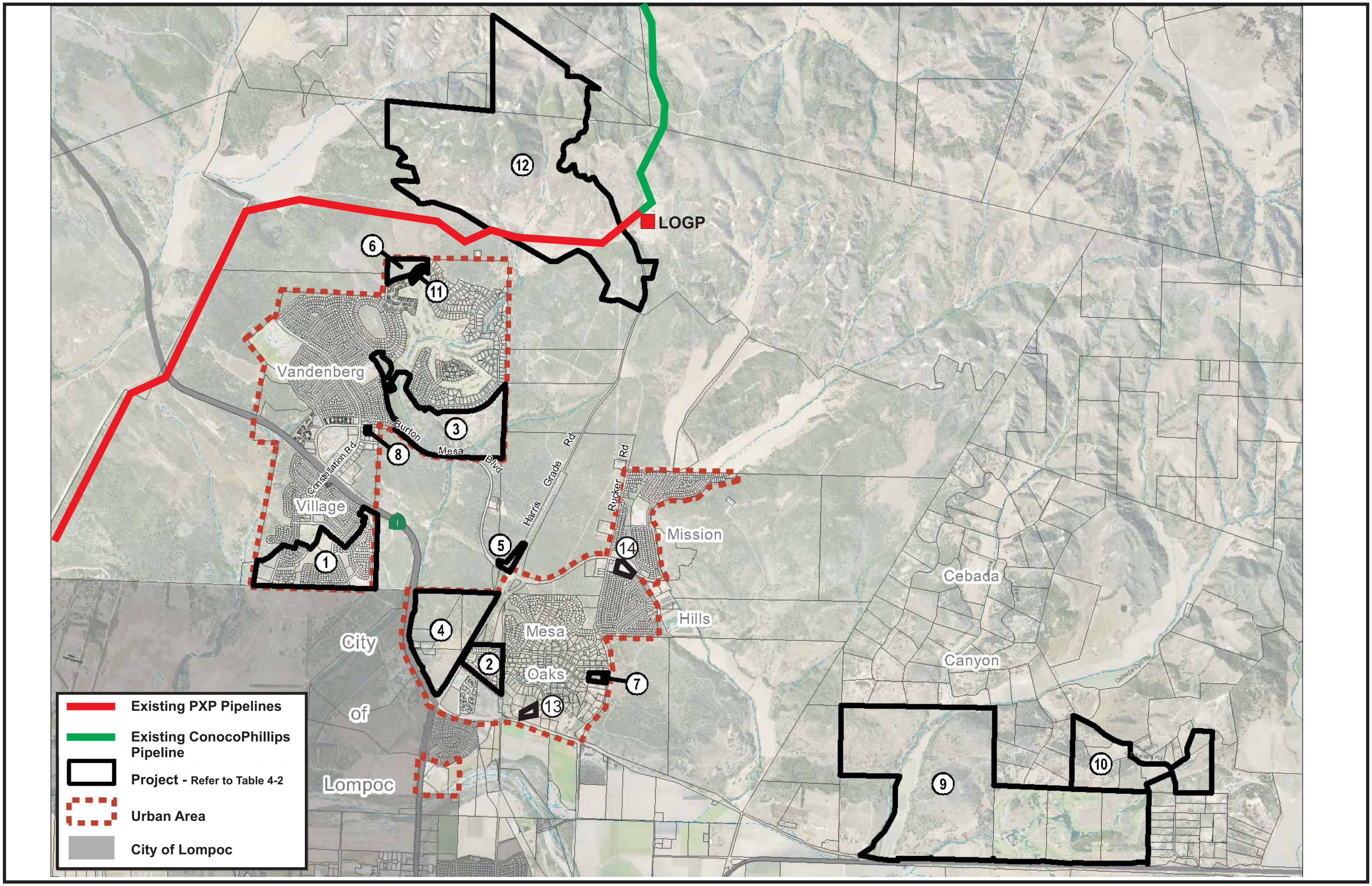


Sources:
MMS DEIS on Delineation Drilling Activities in Federal Waters Offshore Santa Barbara County, CA., 2001; California State Lands Commission. A Report to the California State Lands Commission on Offshore Oil and Gas Leases: Area Maps. 2005. (http://www.slc.ca.gov/Reports/Offshore_Oil_and_Gas.htm).

PREPARED BY Aspen Environmental Group

0 5 10 20
Scale in Miles
N

Figure 4-2
Potential State Offshore Oil and Gas Development Projects



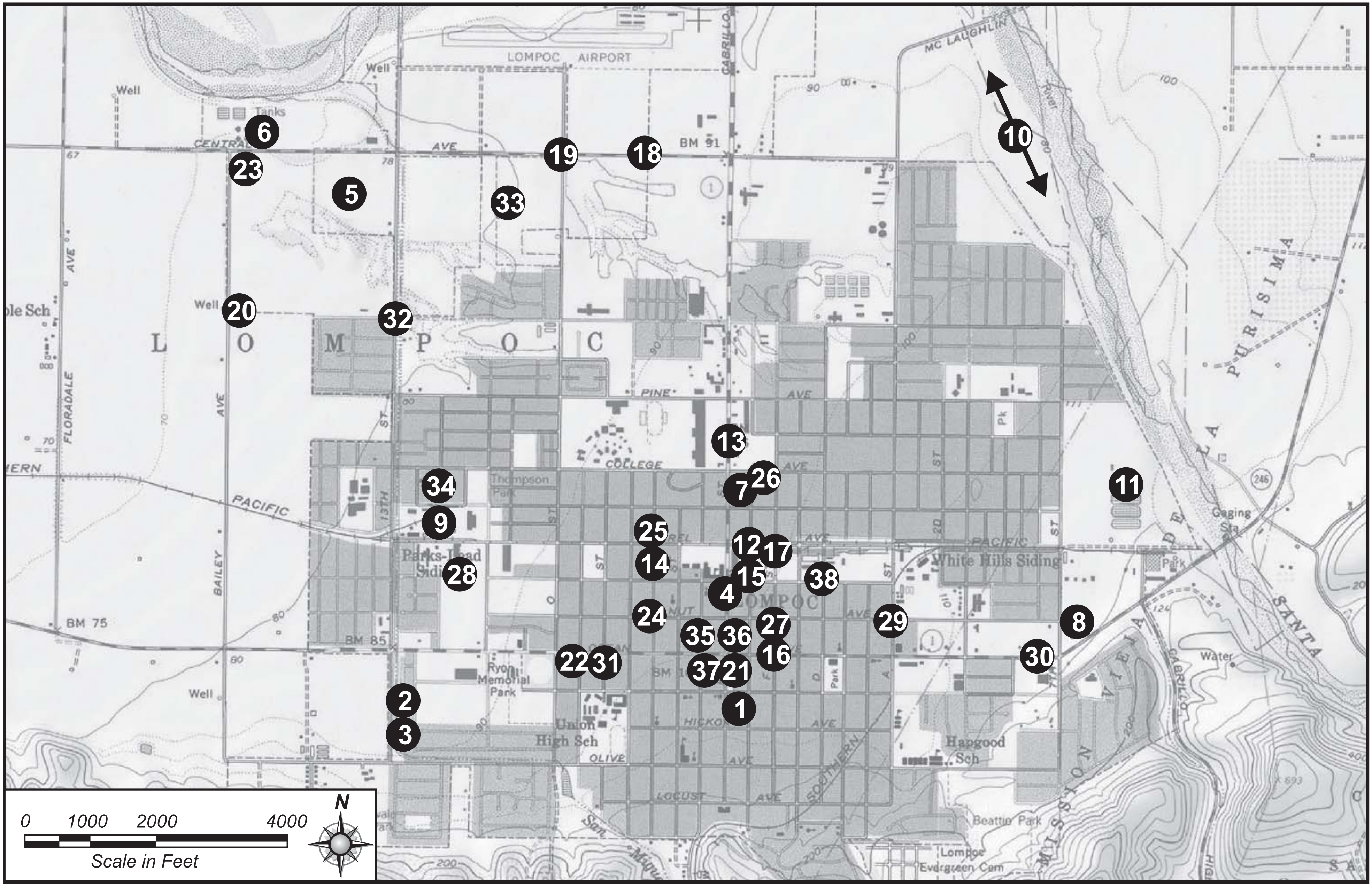
PREPARED BY Aspen Environmental Group

0 ¼ ½ 1 Scale in Miles N

Source: SBC P&D, North County, 2006

Figure 4-3

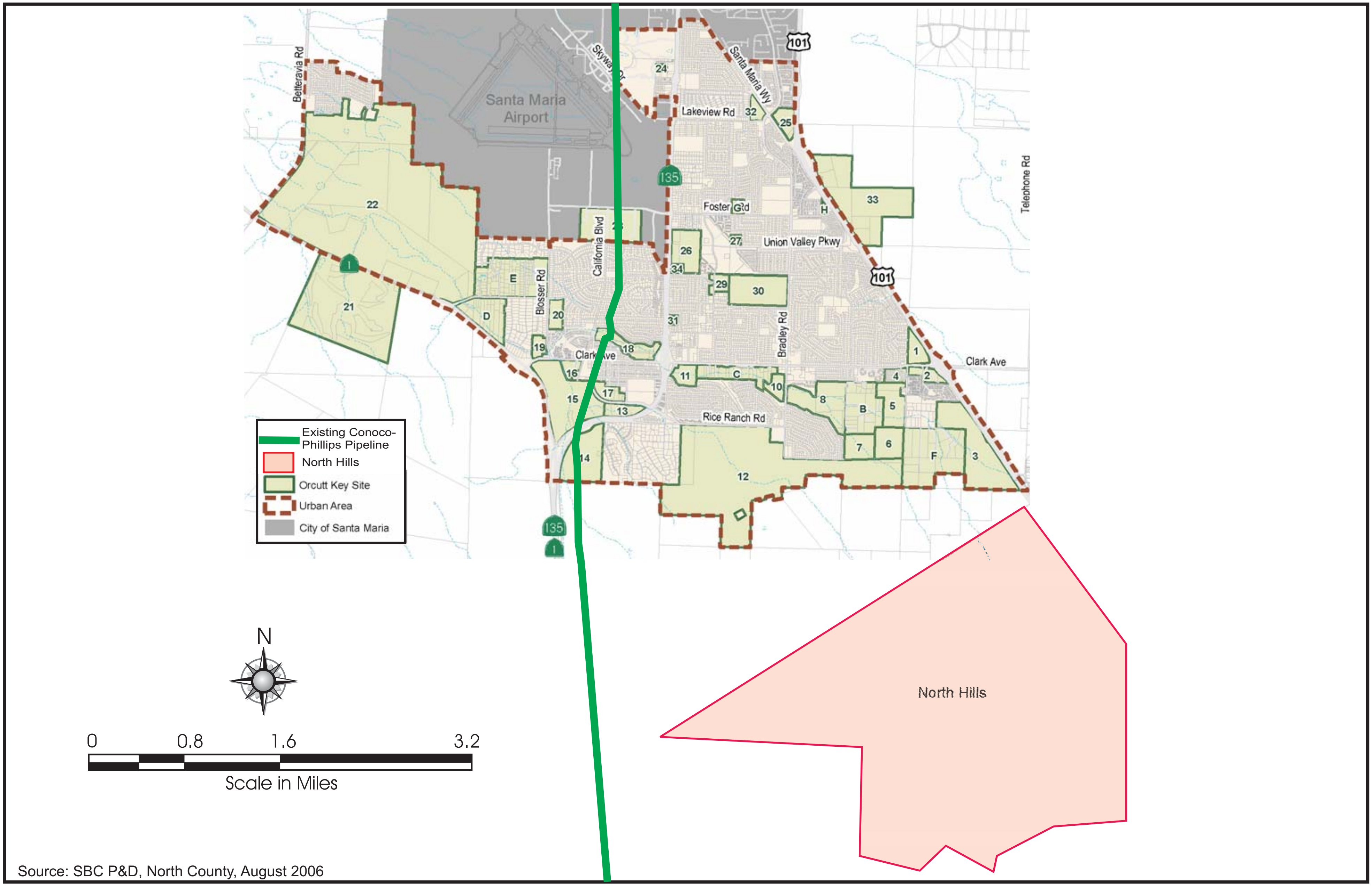
Location of Cumulative Residential, Commercial, and Industrial Projects - Santa Barbara County, North of Lompoc



PREPARED BY Aspen Environmental Group

Figure 4-4

Location of Cumulative, Residential, Commercial, and Industrial Projects - Incorporated City of Lompoc



Source: SBC P&D, North County, August 2006

PREPARED BY Aspen Environmental Group

Figure 4-5

Location of Cumulative Residential, Commercial, and Industrial Projects - Orcutt/Santa Maria Area

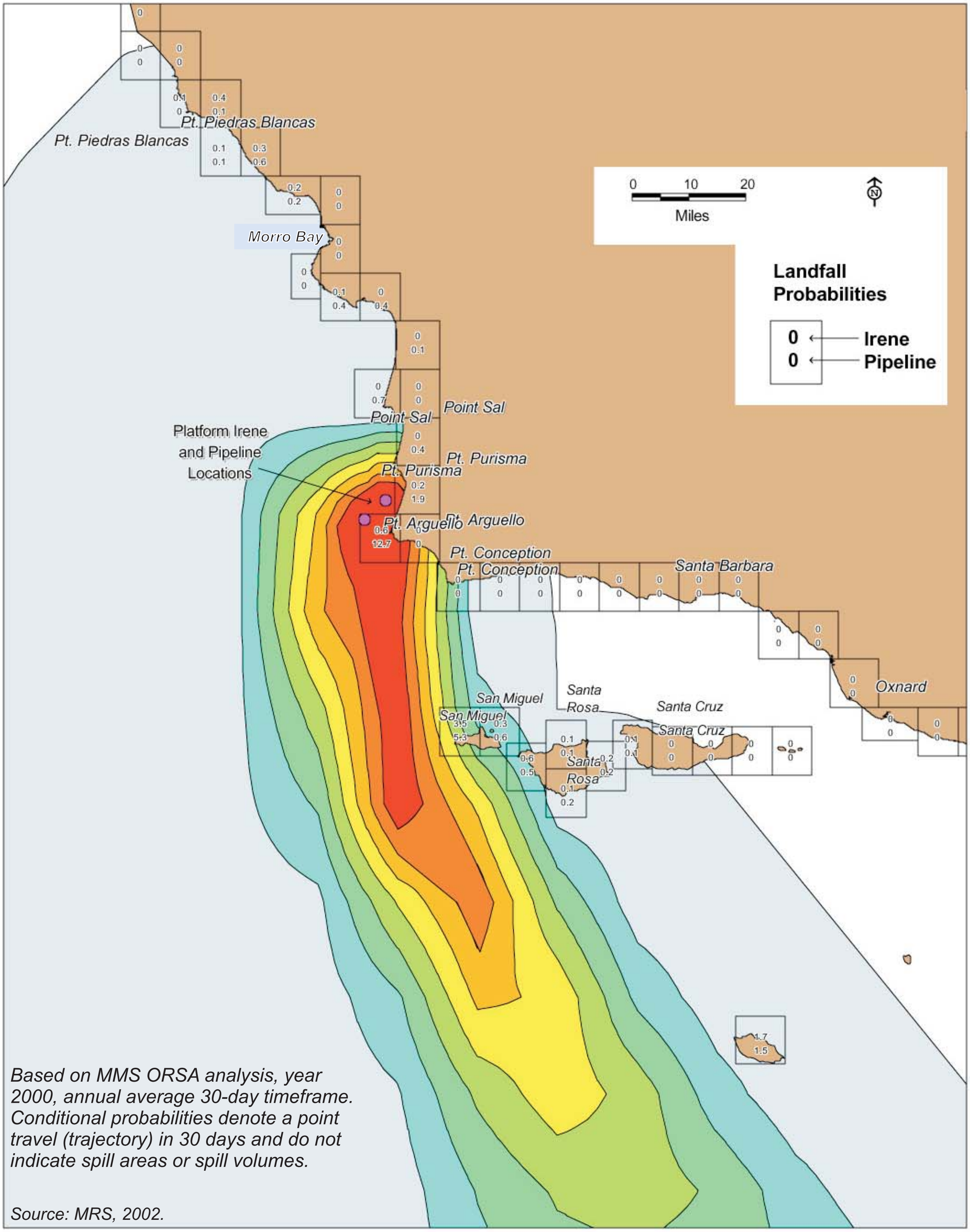


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Figure 5.1-1
MMS OSRA Probabilities (5) of Oil Spill Impact for Platform Irene and Pipeline

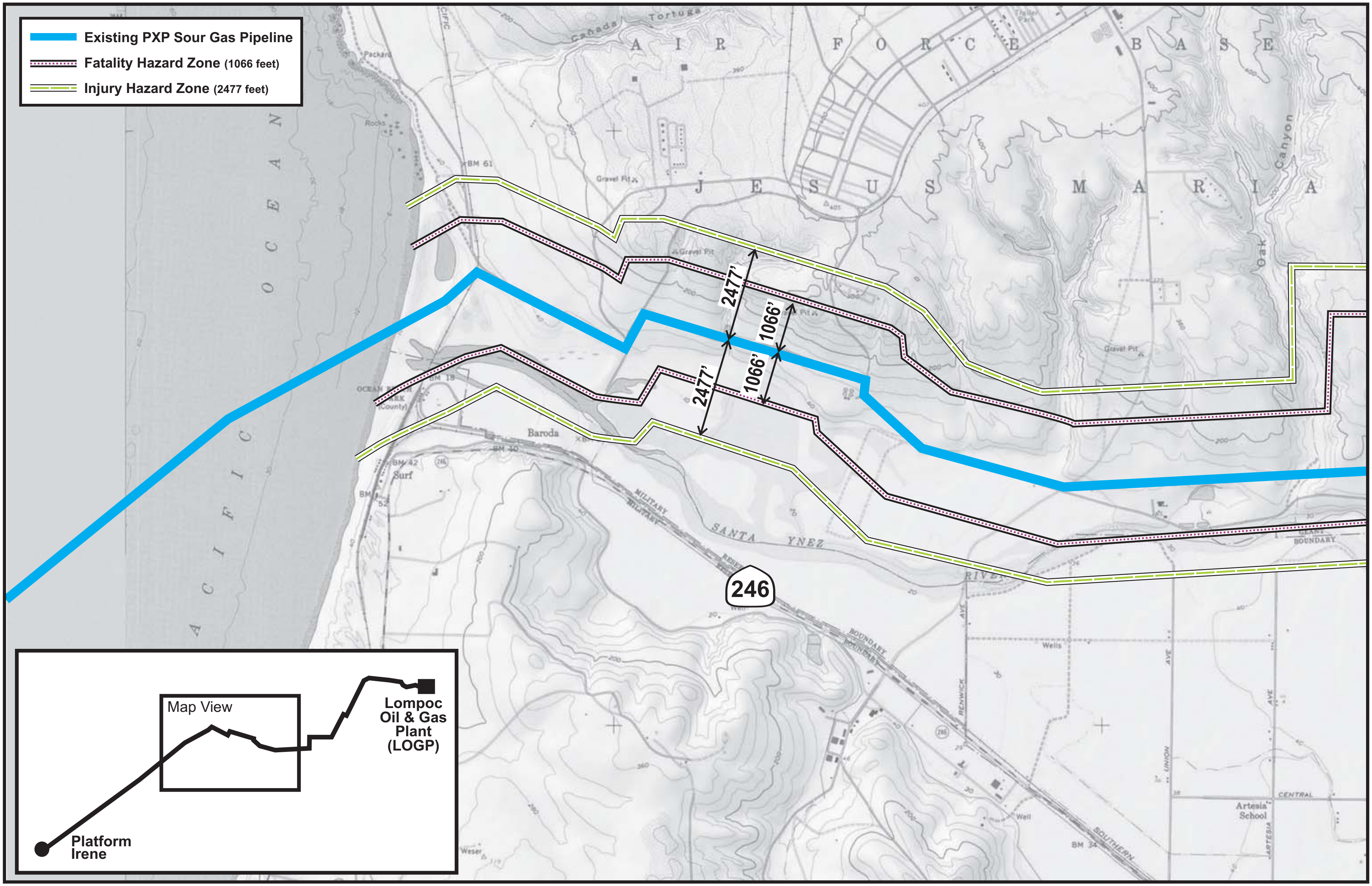
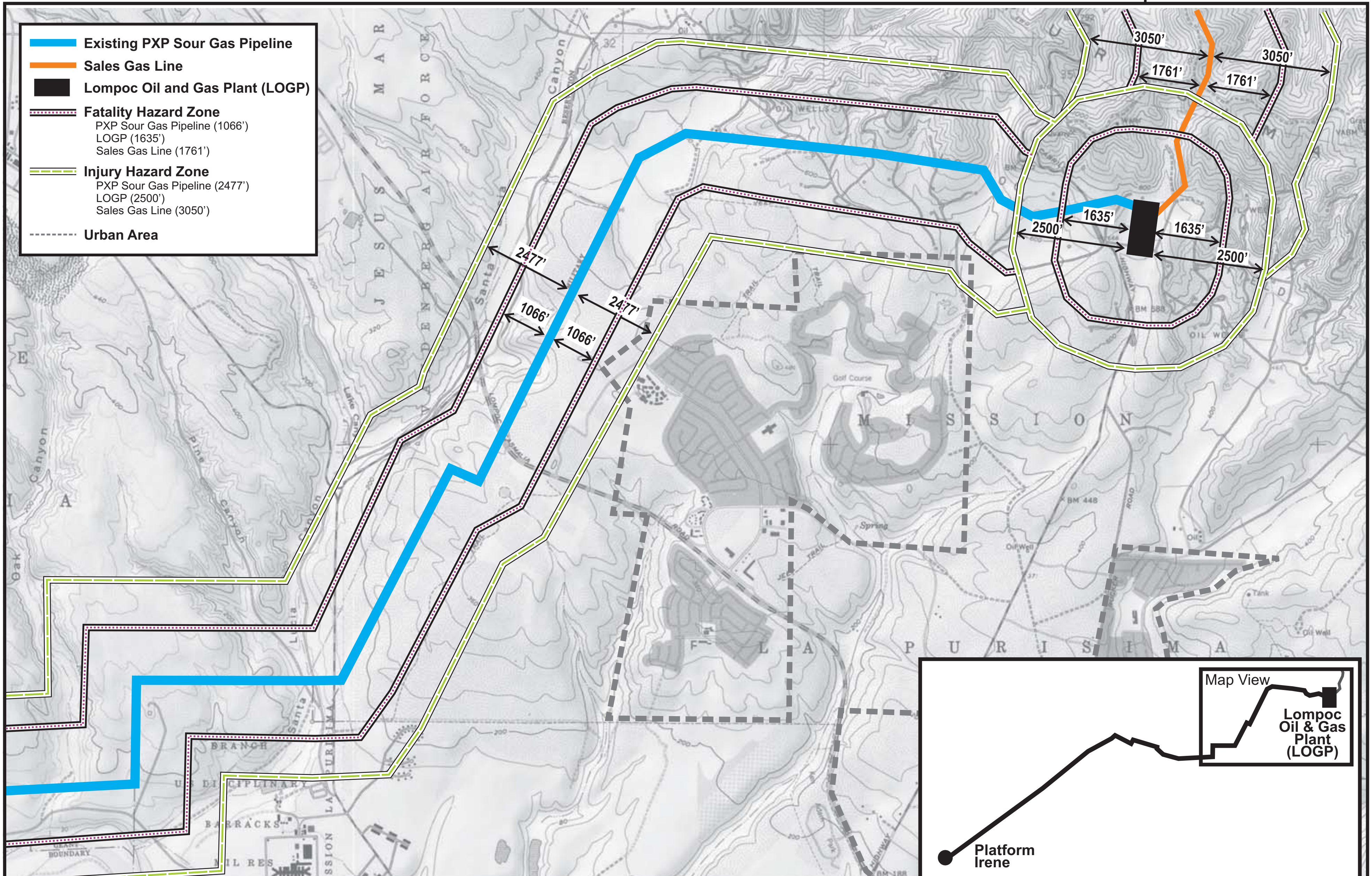


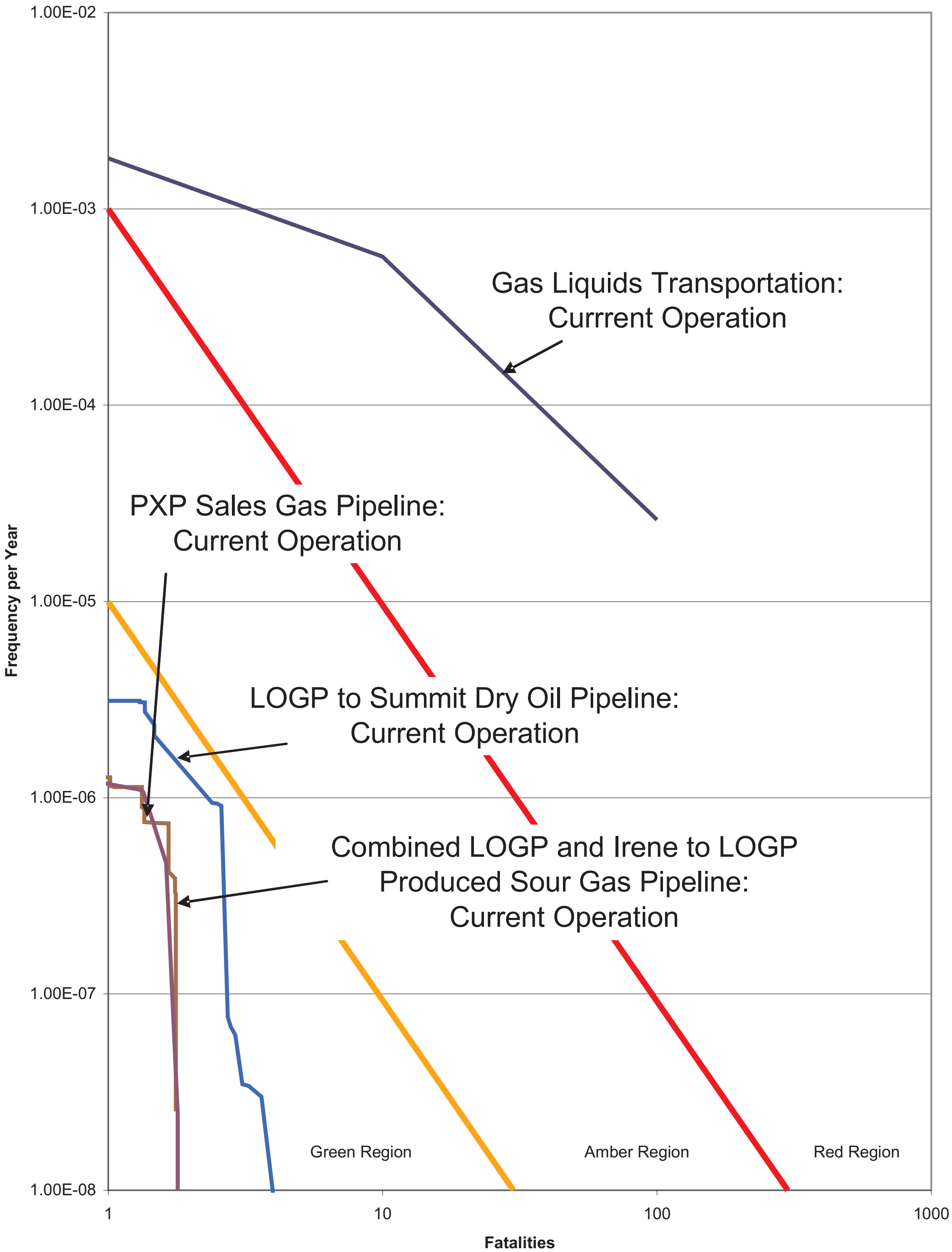
Figure 5.1-2a
Injury and Fatality Hazard Zones for PXP Facilities - (West)



N

0 ¼ ½ 1
Scale in Miles

Figure 5.1-2b
Injury and Fatality Hazard Zones for PXP Facilities - (East)



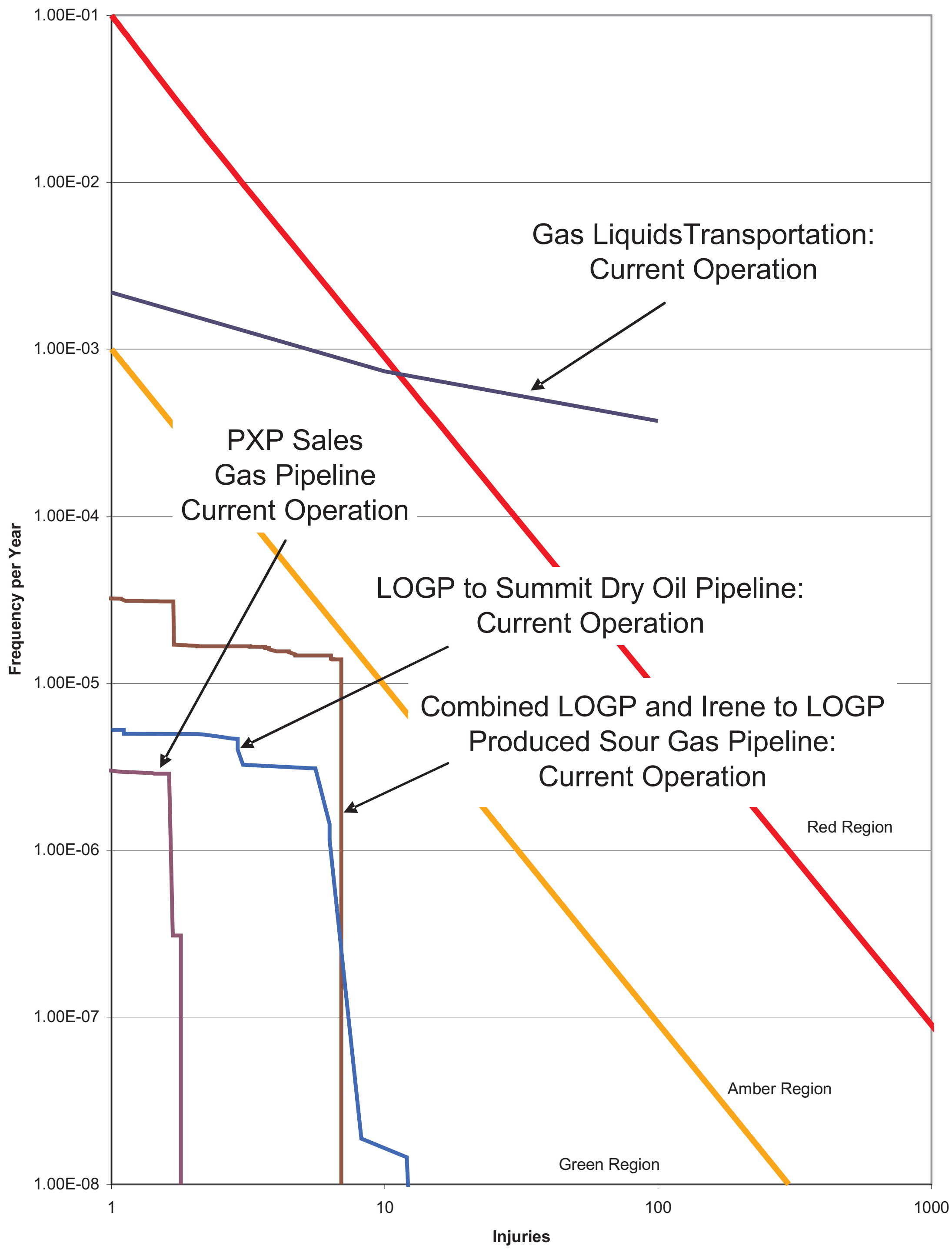
Transportation FN curves are taken from the 1985 Point Pedernales EIR and are scaled to the annual average number of gas liquid truck trips that have been recorded.

Source: ioMosaic, 2006.

PREPARED BY Aspen Environmental Group

Figure 5.1-3

Fatality FN Curves: Current Conditions



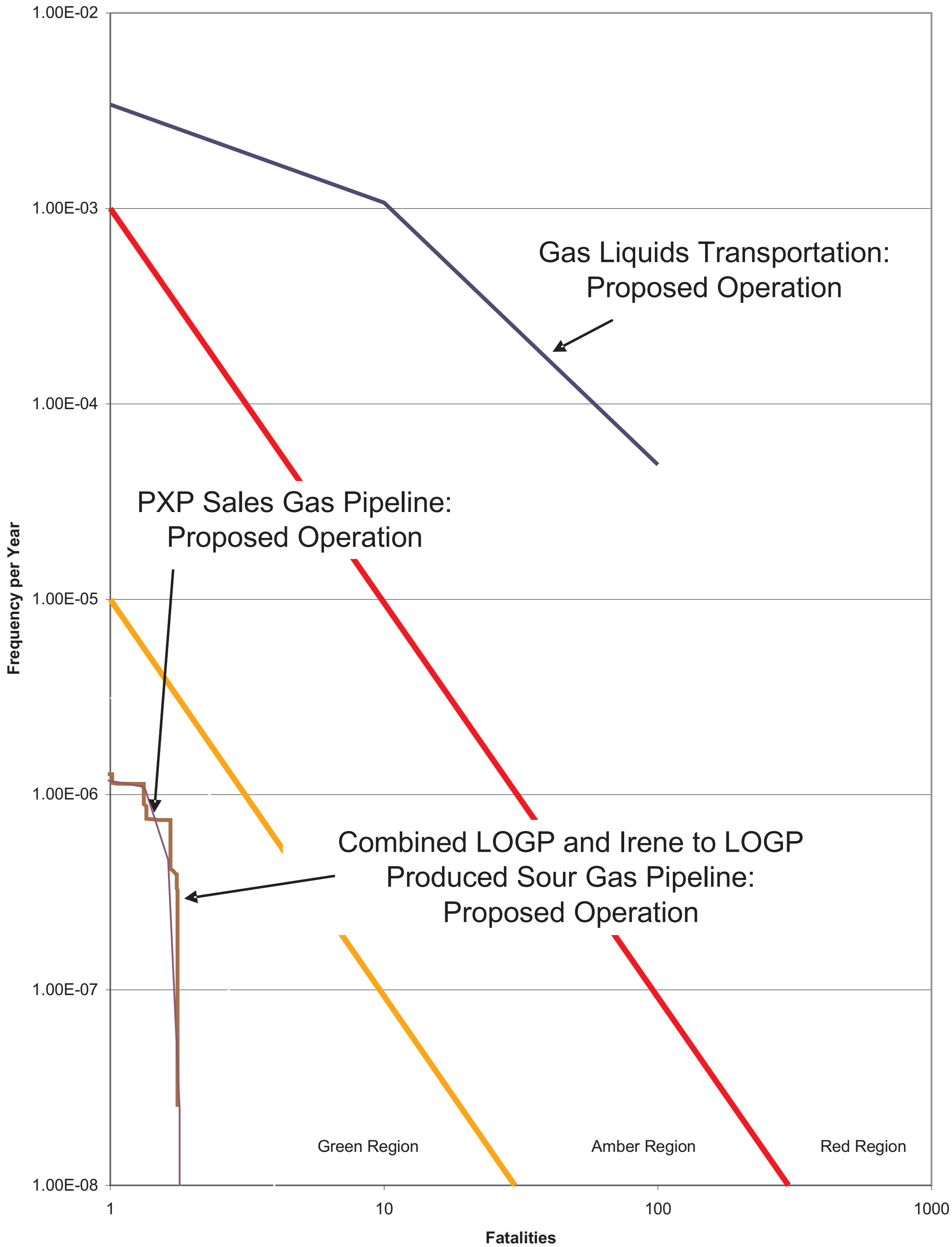
Transportation FN curves are taken from the 1985 Point Pedernales EIR and are scaled to the annual average number of gas liquid truck trips that have been recorded.

Source: ioMosaic, 2006.

PREPARED BY Aspen Environmental Group

Figure 5.1-4

Injury FN Curves: Current Conditions

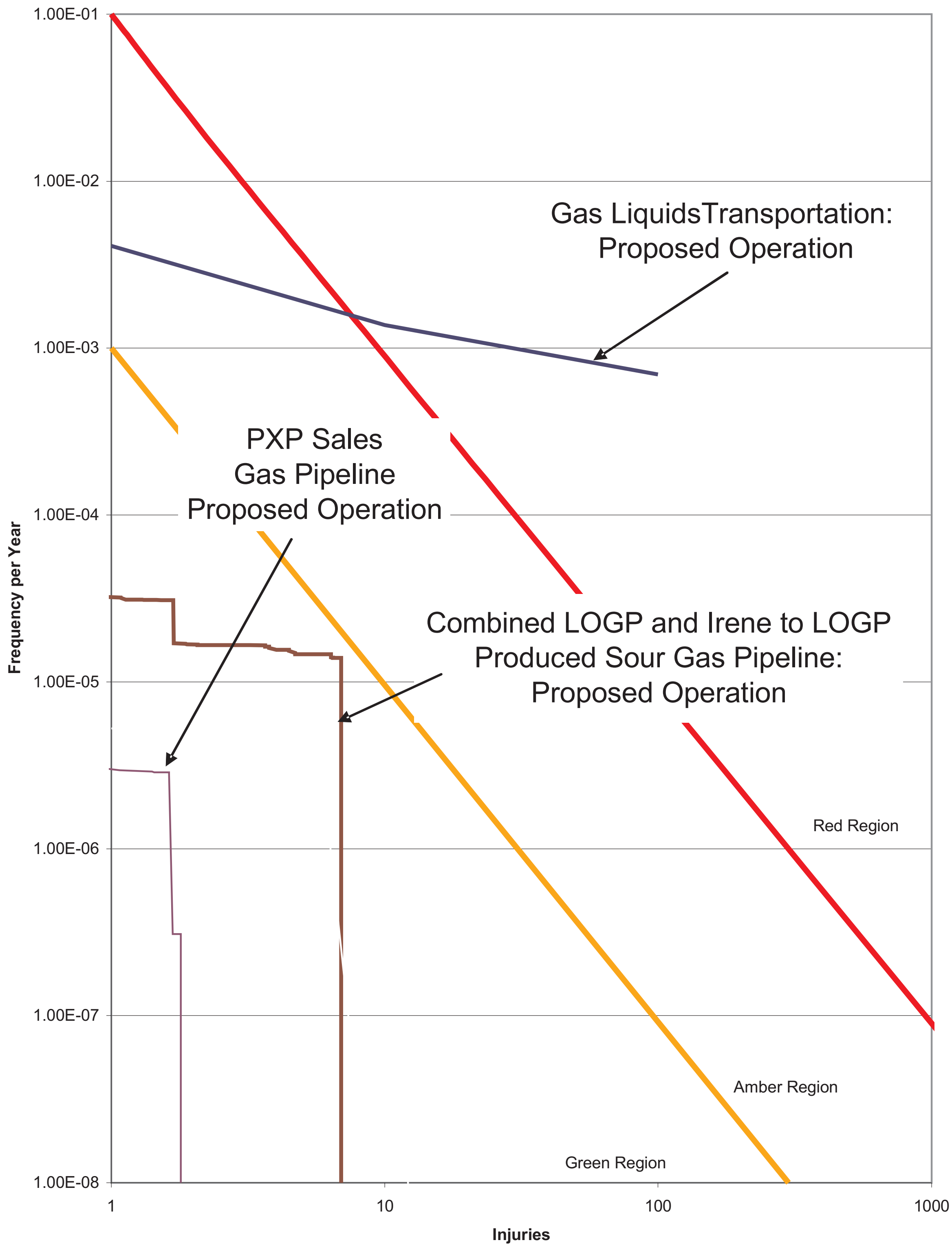


Source: ioMosaic, 2006.

PREPARED BY Aspen Environmental Group

Figure 5.1-5

Fatality FN Curves: Proposed Conditions



Source: ioMosaic, 2006.

PREPARED BY Aspen Environmental Group

Figure 5.1-6

Injury FN Curves: Proposed Conditions

Figures 5.4-1: **Photograph of Pipeline Route Crossing Small Drainage Feature Near Basin 4.**

Figures 5.4-2: **Example of a Catchment Basin (Basin 1) Adjacent to Onshore Portion of the Pipeline Route.** *(A weired Concrete Outlet is Shown Near the Upper Left Corner of the Photograph.)*

Source: MRS, 2002.

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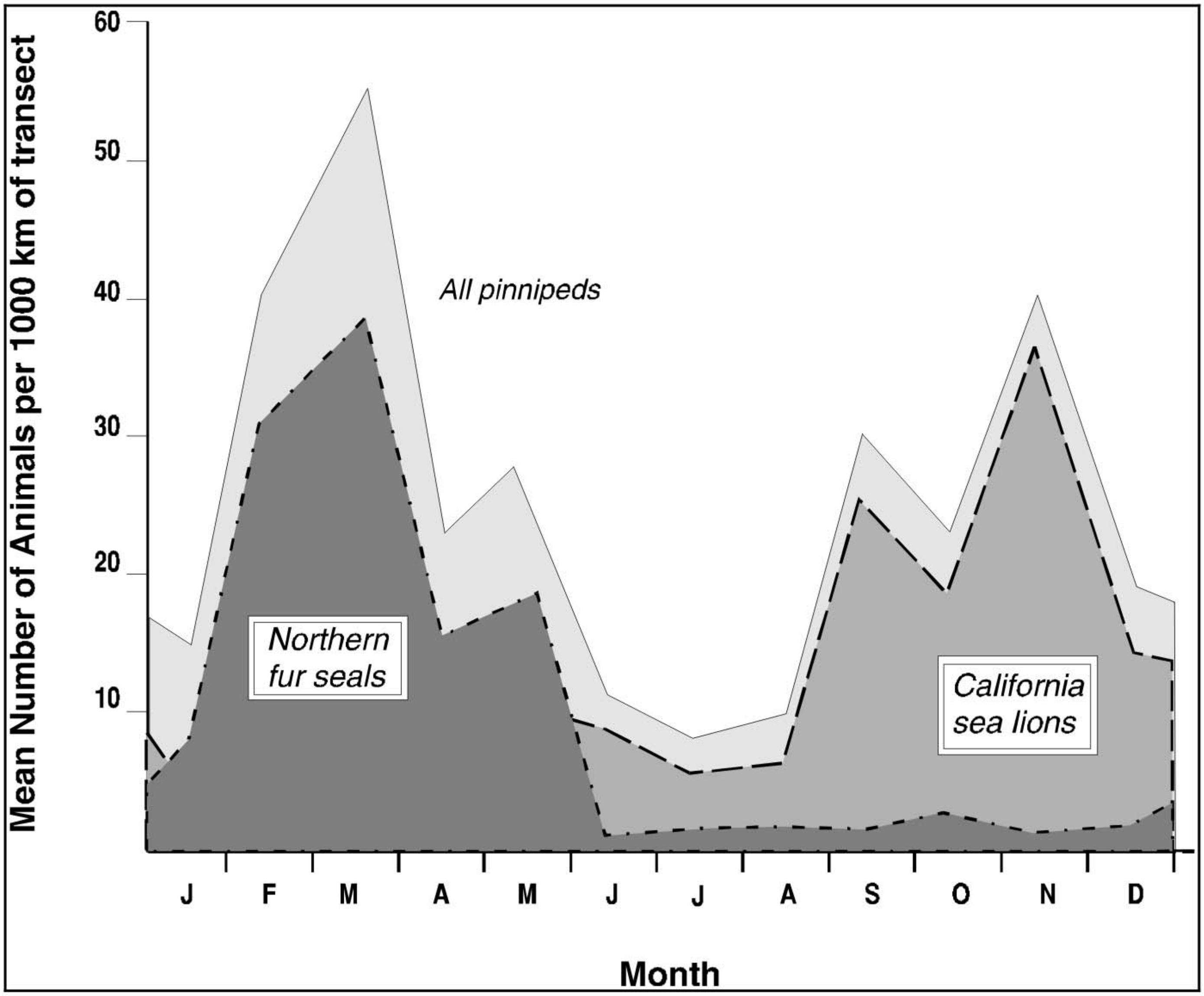
Figures 5.4-1 & 5.4-2
Photographs

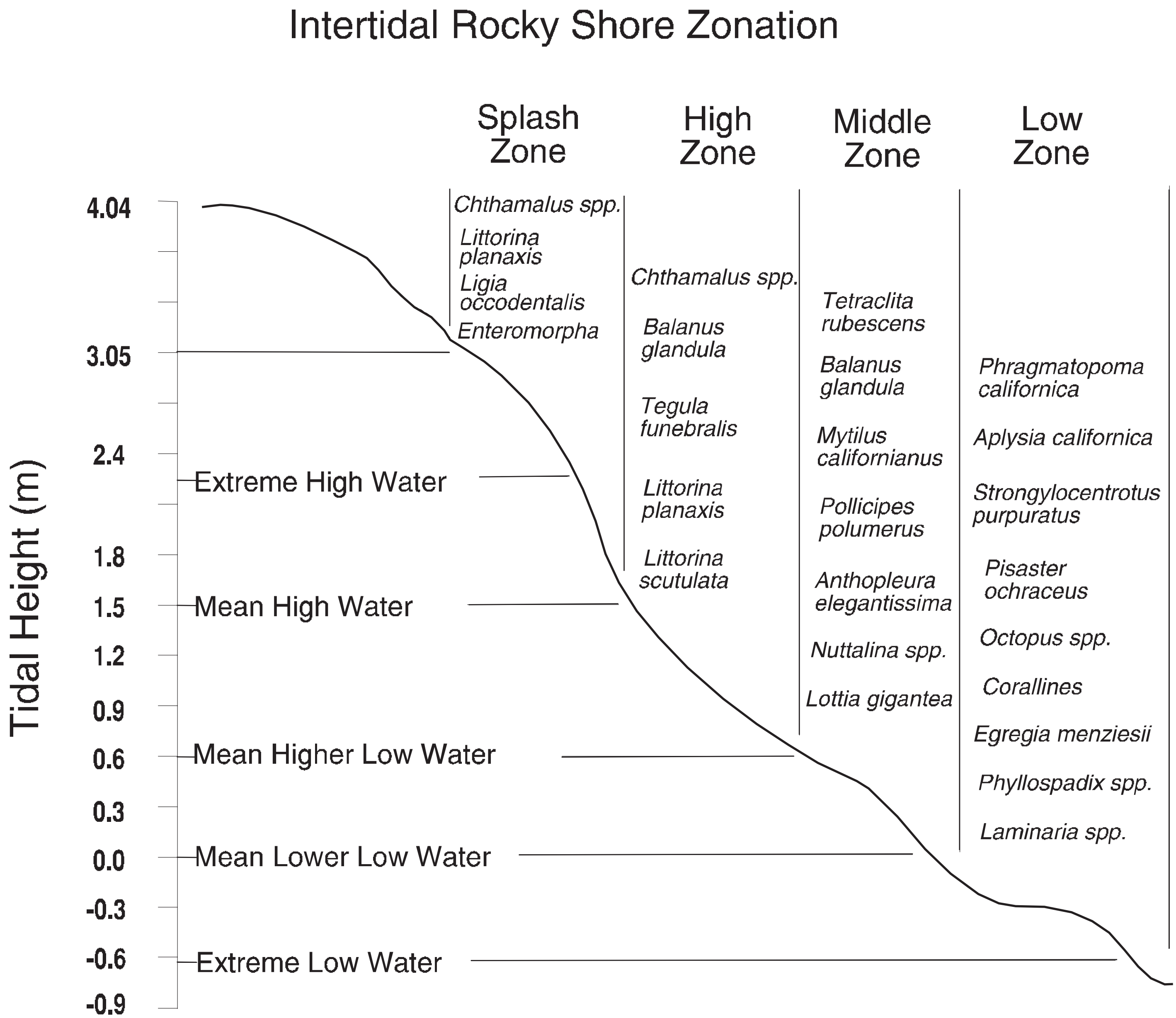


Source: MRS, 2002.

PREPARED BY Aspen Environmental Group

Figures 5.5-1

Seasonal Abundance of Pinnipeds in Waters of Central and Northern California



Source: MRS, 2002.

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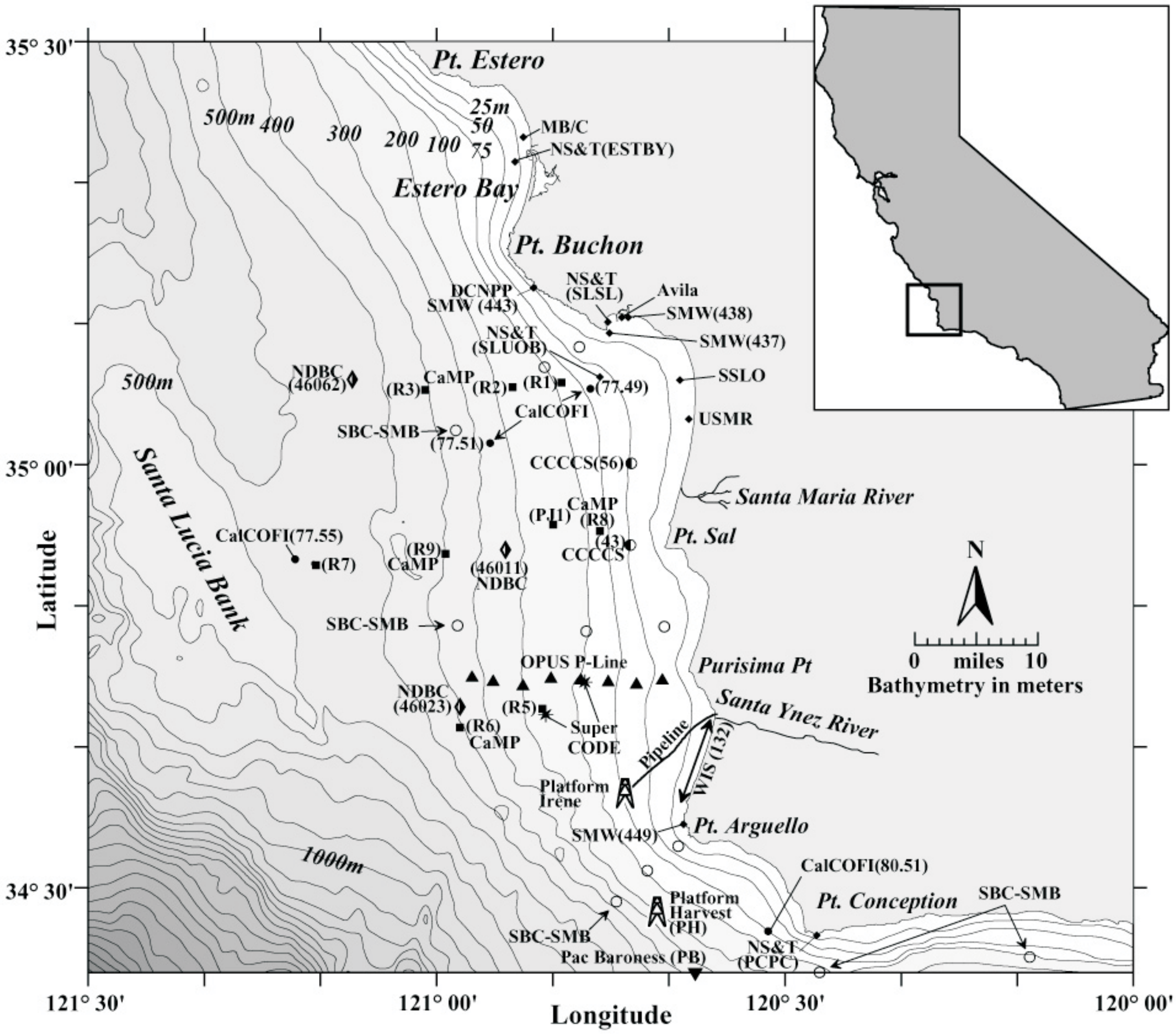
Figures 5.5-2
Intertidal Zonation of a Rocky Shore in Southern Calironia



Acronyms for the studies shown in this Figure are defined in Table 5.6.1.

Source: MRS, 2002.

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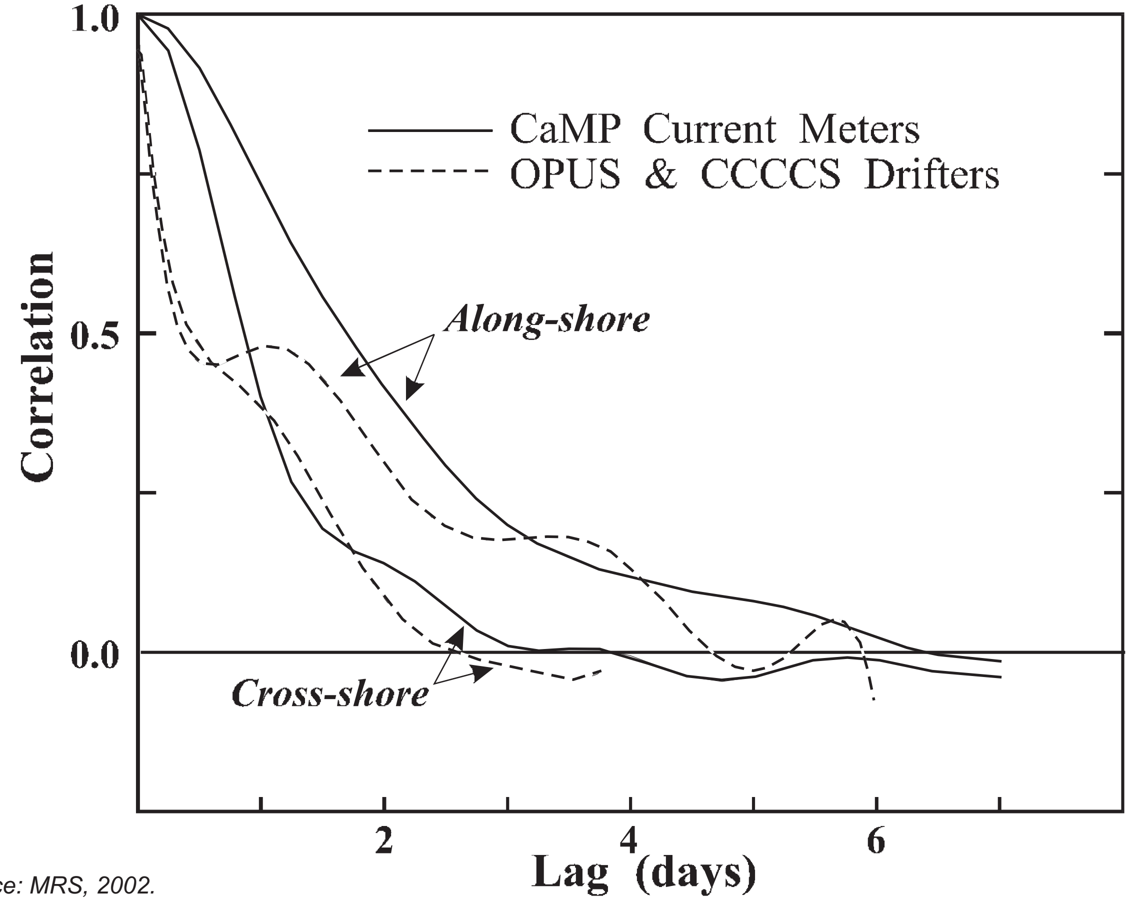
Figures 5.6-1

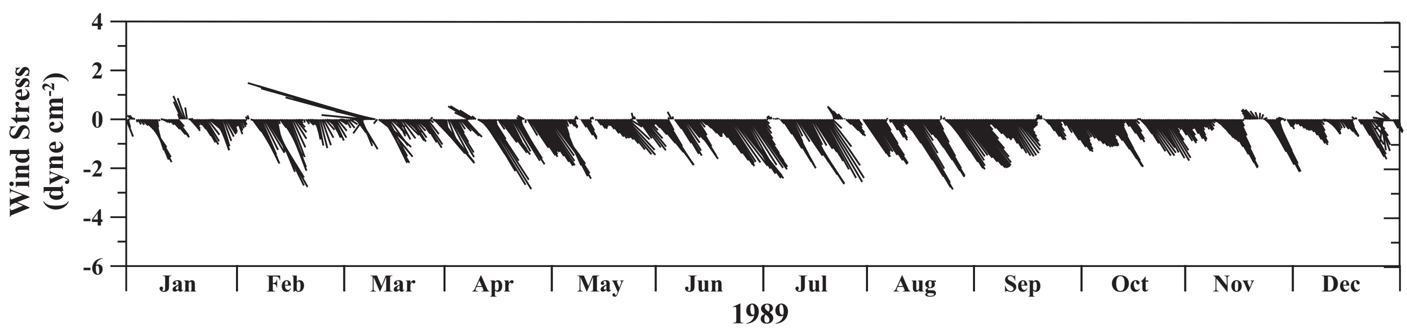
Location of Oceanographic Studies Conducted Near Platform Irene



Source: MRS, 2002.

Figures 5.6-2

Time-lagged Correlation of Velocity from Near-Surface Moored Current Meters and from Surface Drifters along the Central Coast



Source: MRS, 2002.

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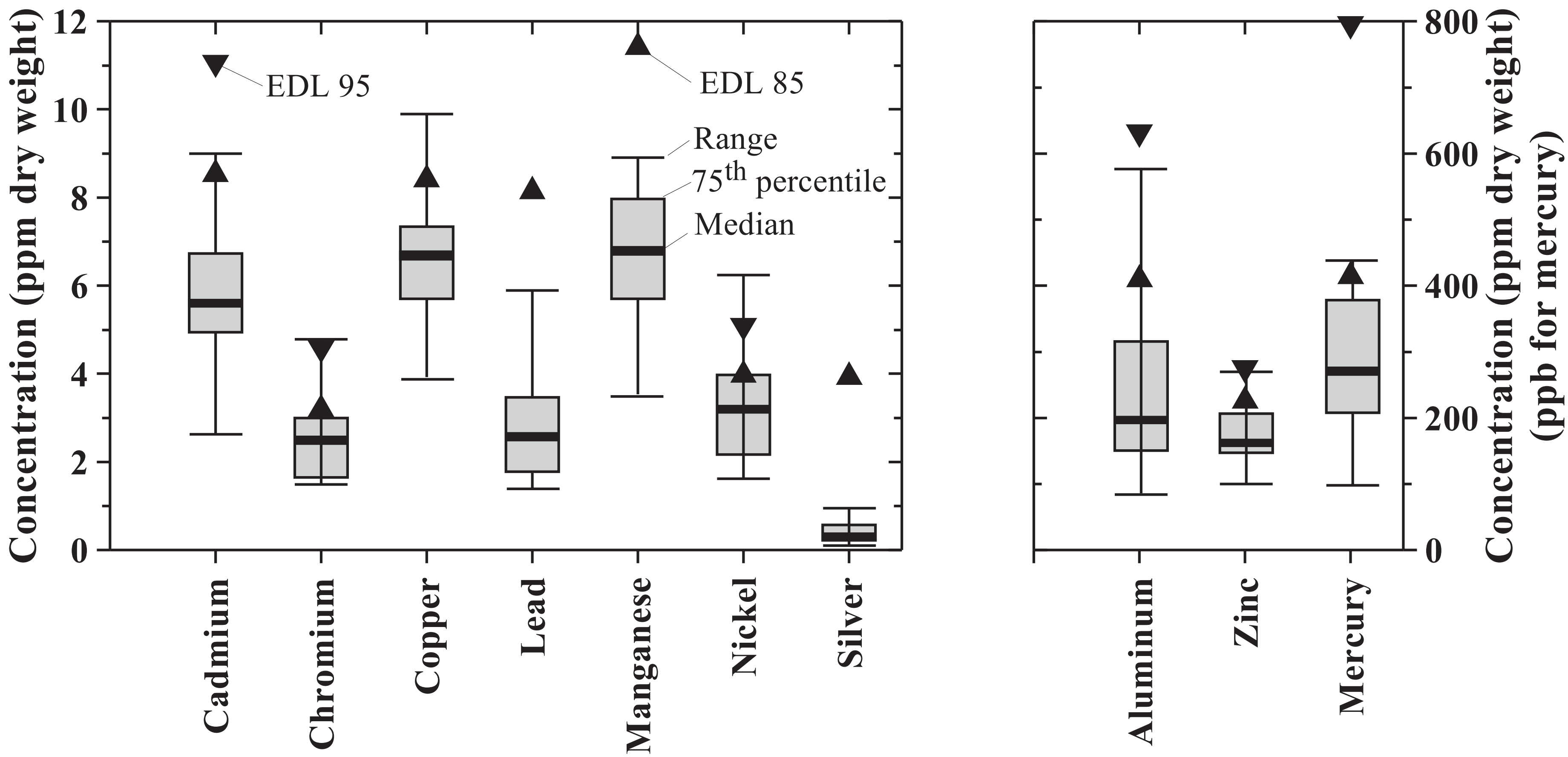
Figures 5.6-3

Wind Stress Recorded at Buoy 46023 near Platform Irene



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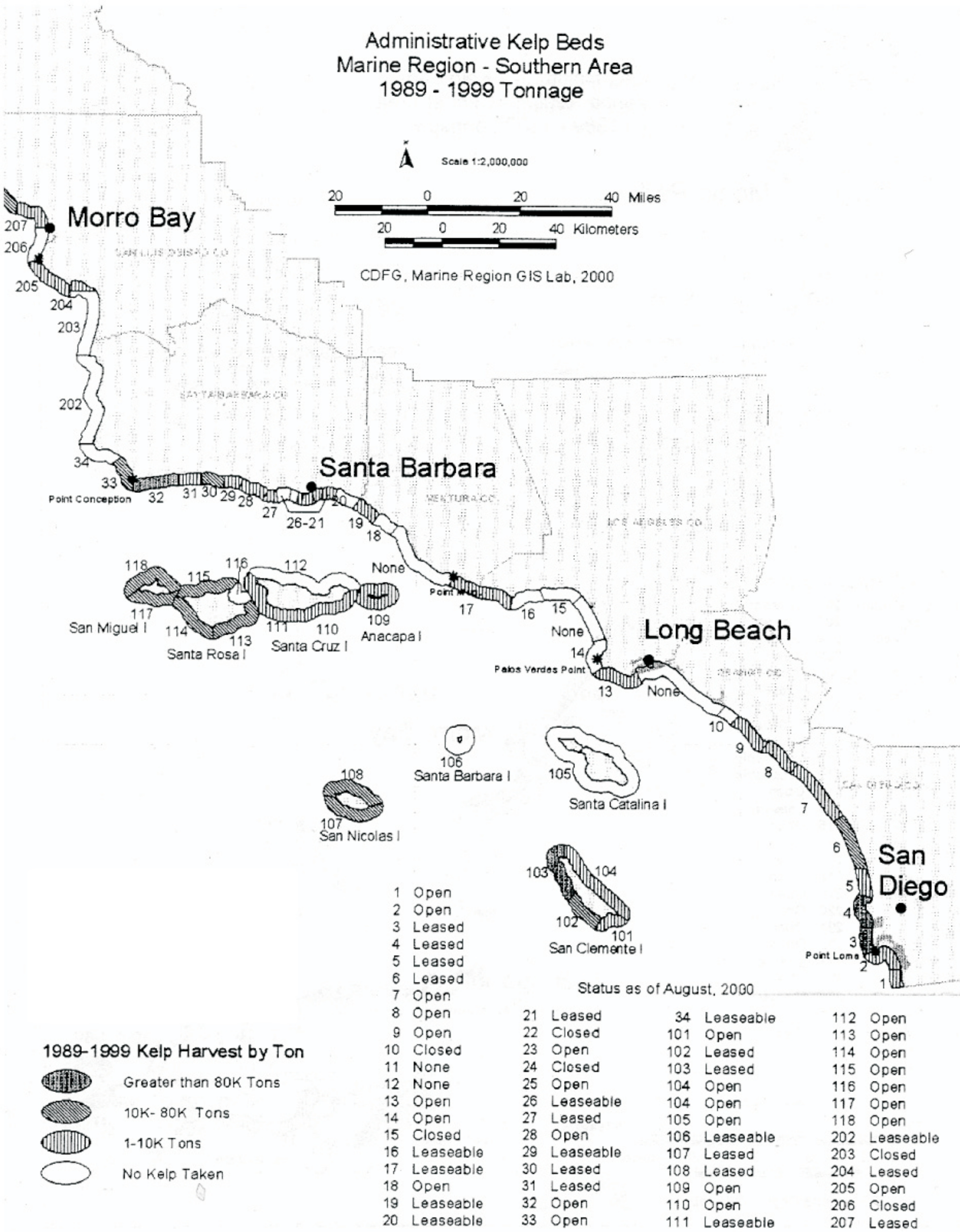
Figures 5.6-4

Distribution of Trace Metal Concentrations in Mussels Collected in the Study Region Compared to Statewide Levels



Source: MRS, 2002.

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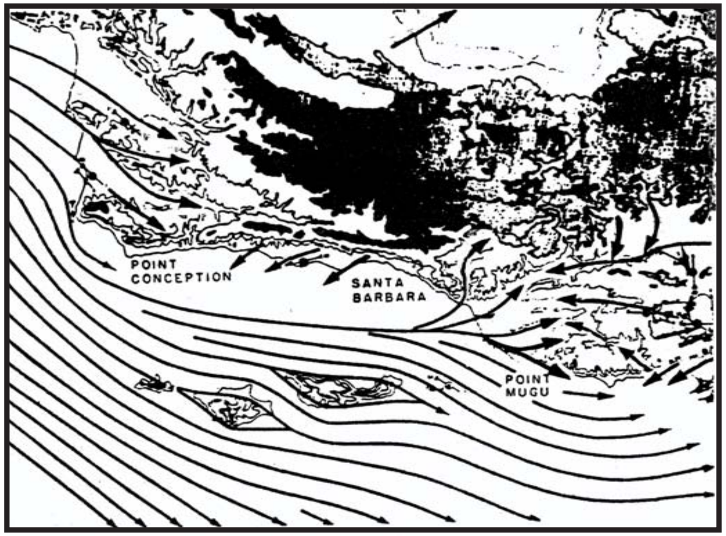
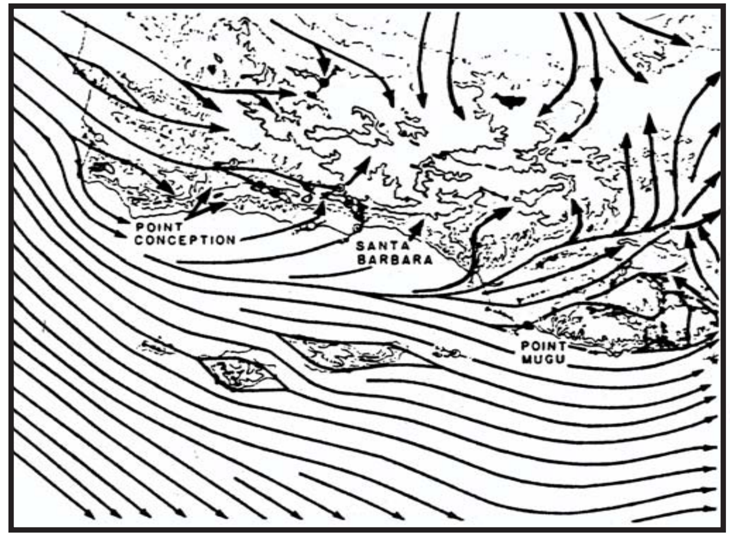
Figures 5.7-1

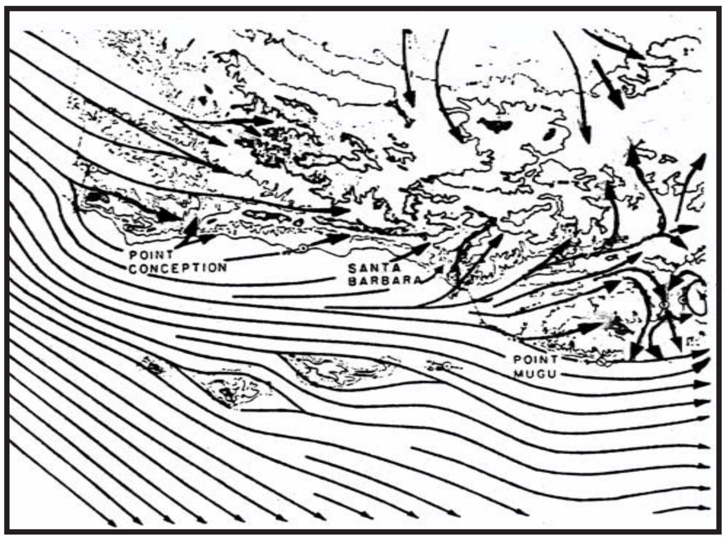
Location and Yield from Kelp Beds in Southern California (CDFG, 2000)



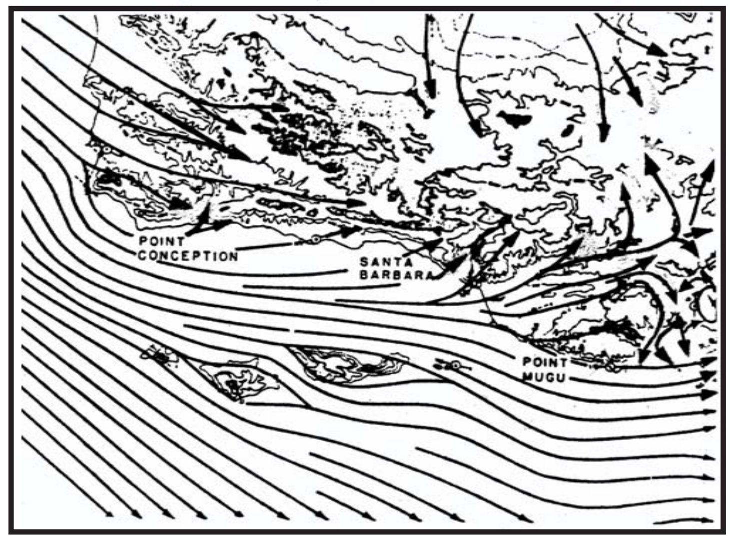
Summer Night



Summer Day



Winter Night

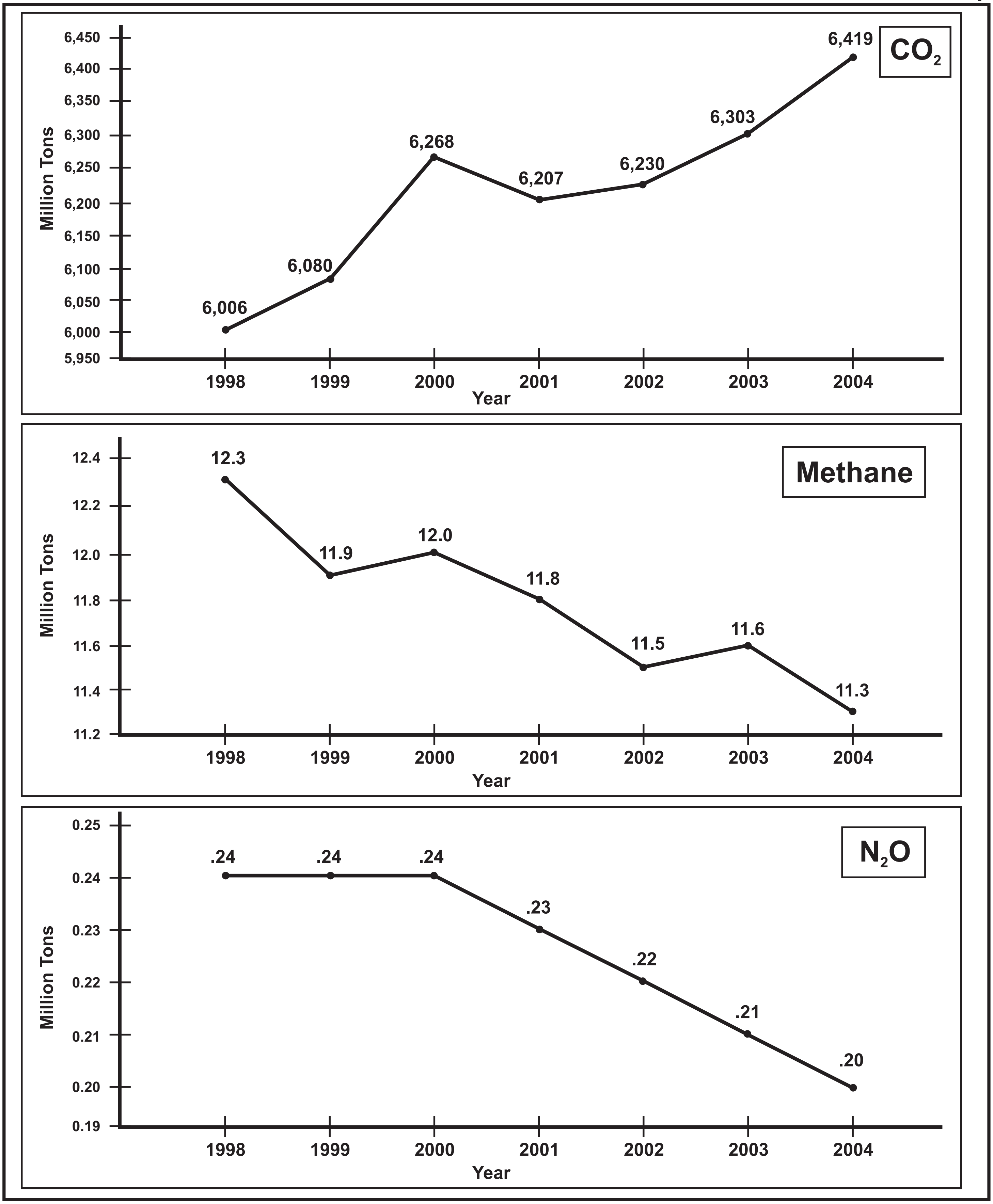


Winter Day

PREPARED BY Aspen Environmental Group

Figure 5.8-1

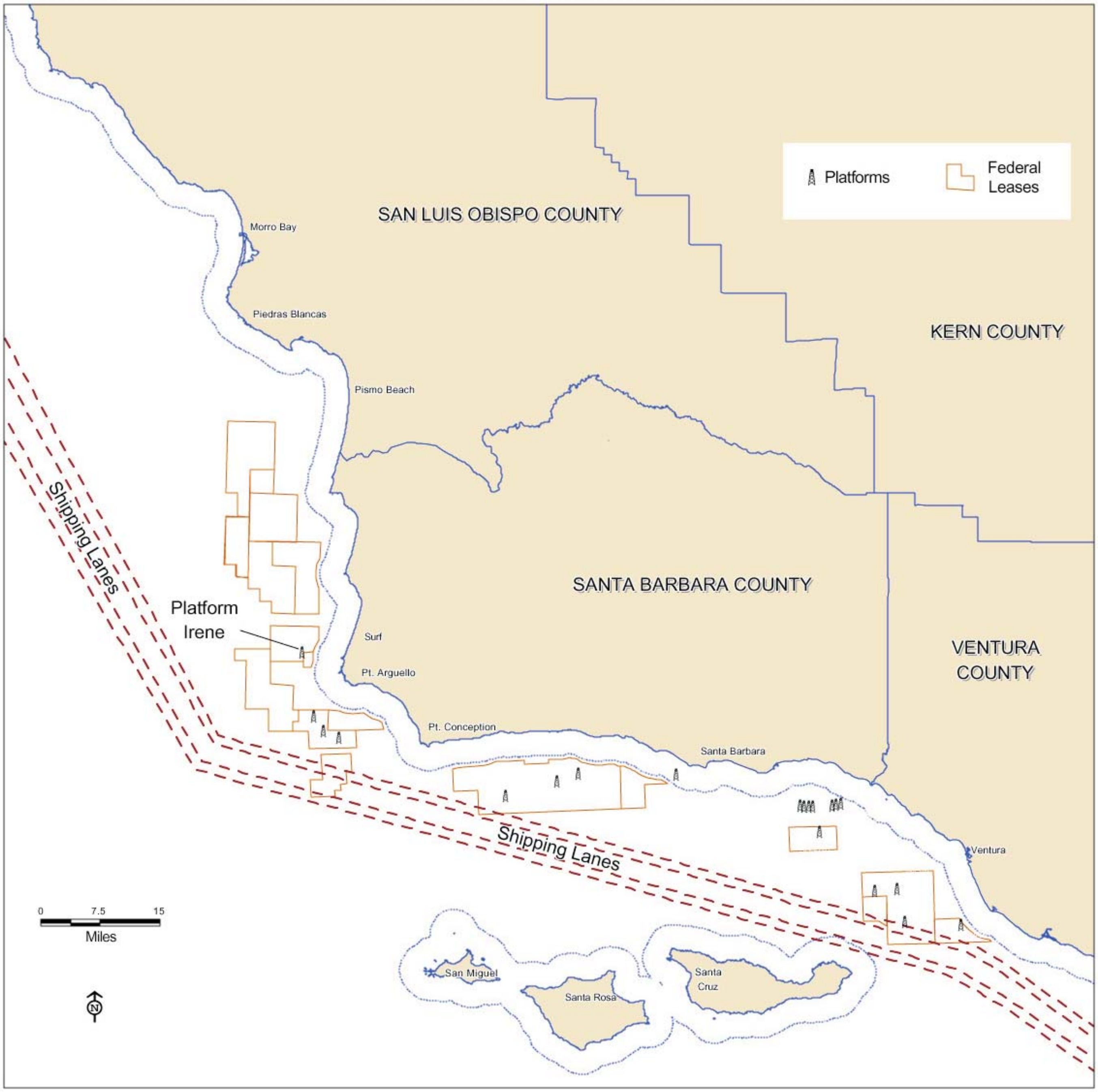
Typical Regional Wind Patterns



PREPARED BY Aspen Environmental Group

Source: US EPA, 2006

Figure 5.8-2
Trend of U.S. GHG Emissions for Energy Related Activities 1998 through 2004



Source: MRS, 2002.

PREPARED BY Aspen Environmental Group

Figures 5.9-1

Shipping Lanes in the Project Area

Common Outdoor Noise Levels	Noise Level (dBA)	Common Indoor Noise Levels
	110	Rock Band
Jet Flyover at 1,000 feet		
	100	
		Inside Subway Train (New York)
Gas Lawnmower at 3 feet		
	90	
Diesel Truck at 50 feet		
Noisy Urban Daytime		Food Blender at 3 feet
		Garbage Disposal at 3 feet
	80	
		Shouting at 3 feet
Gas Lawnmower at 100 feet		
	70	Vacuum Cleaner at 10 feet
Commercial Area		
Heavy Traffic at 300 feet		Normal Speech at 3 feet
	60	
		Large Business Office
Quiet Urban Daytime		
	50	Dishwasher Next Room
Quiet Urban Nighttime		Small Theater, Large Conference
	40	Room (Background)
Quiet Suburban Nighttime		
		Library
	30	Bedroom at Night
Quiet Rural Nighttime		Concert Hall (Background)
	20	
		Broadcast and Recording Studio
	10	
		Threshold of Hearing
	0	

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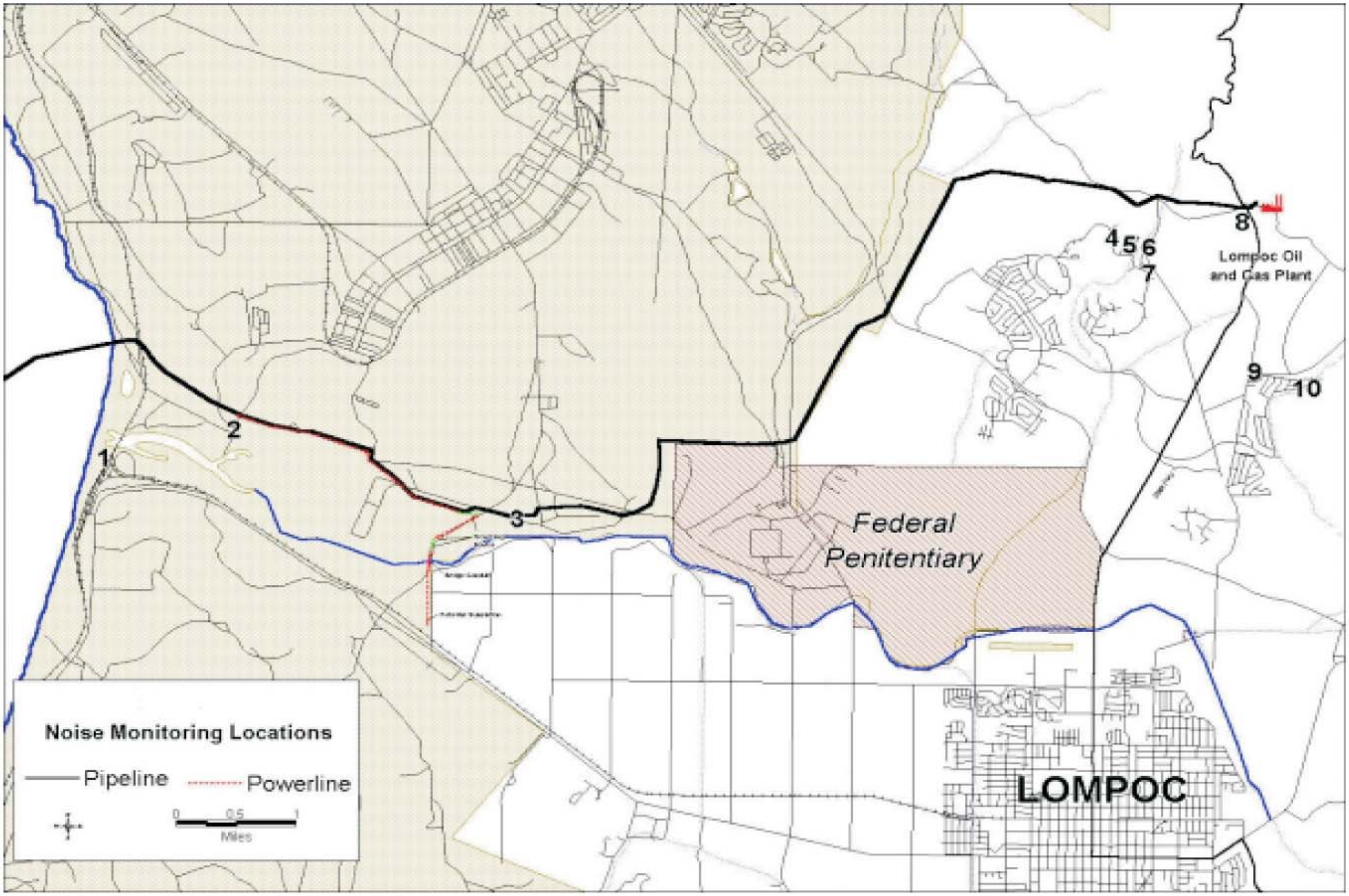
Figure 5.10-1
Common Environmental Noise Levels



Source: MRS, 2002.

PREPARED BY Aspen Environmental Group

Figure 5.10-2
Noise Monitoring Locations

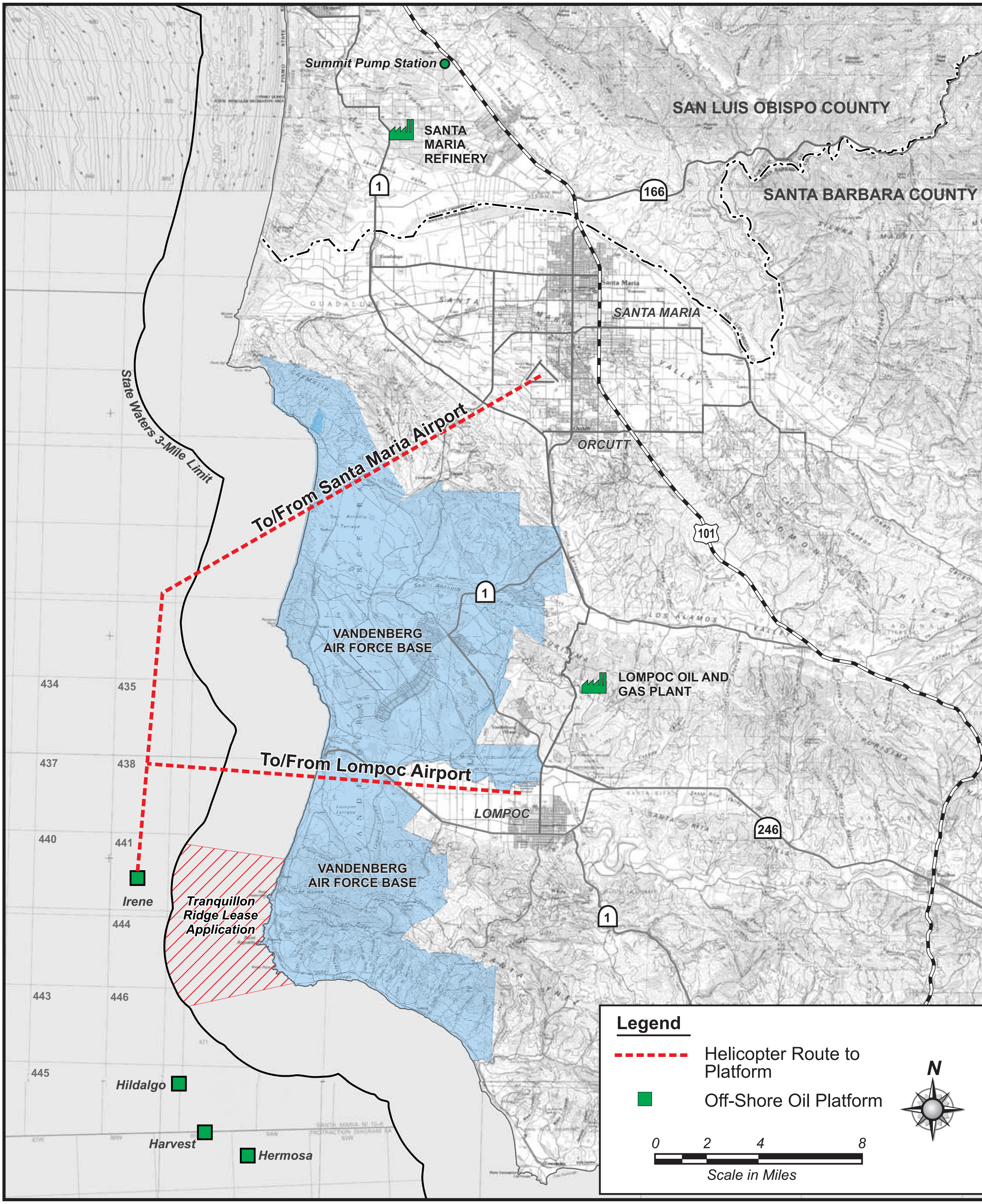


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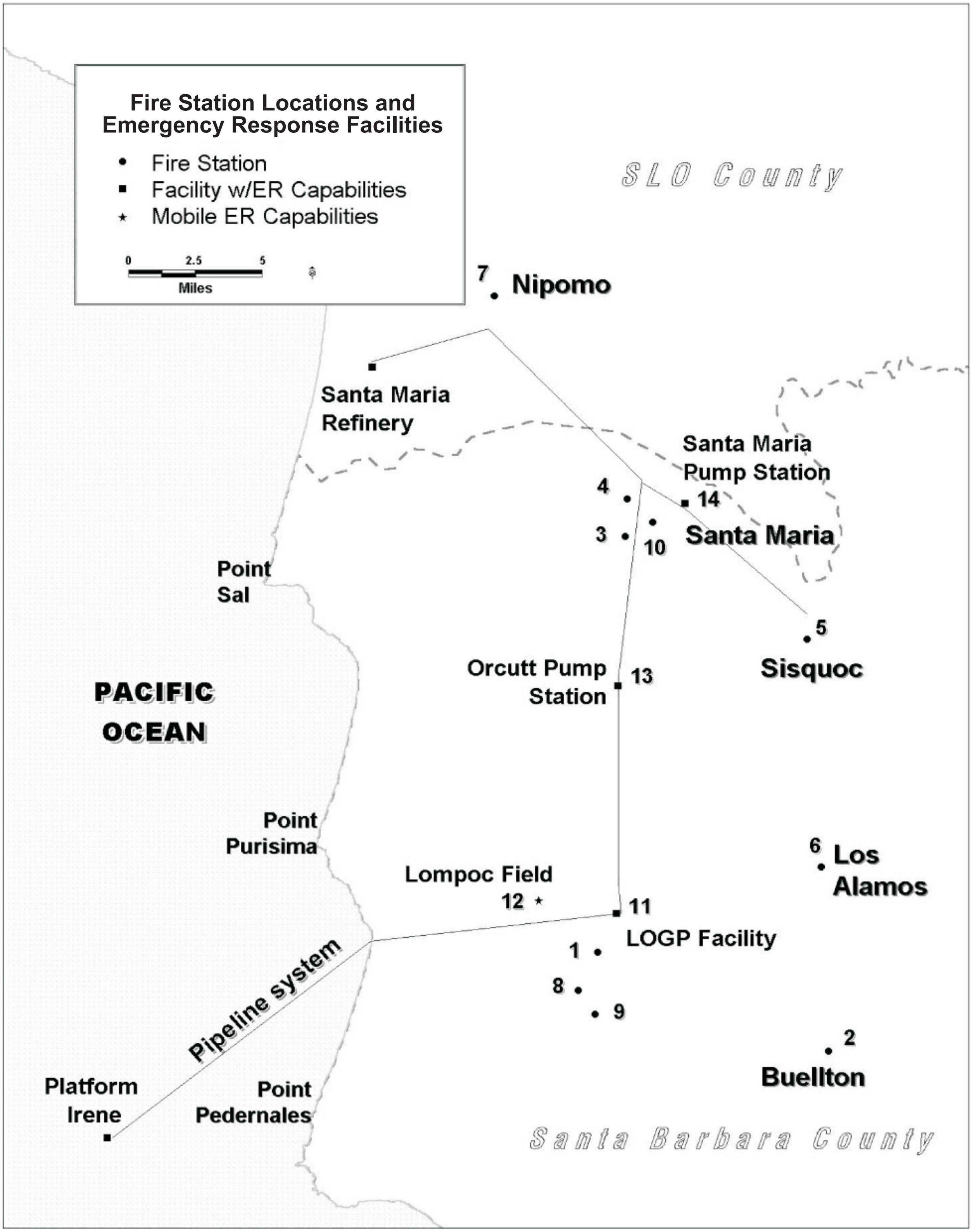
Figure 5.10-3

Helicopter Route to Platform Irene

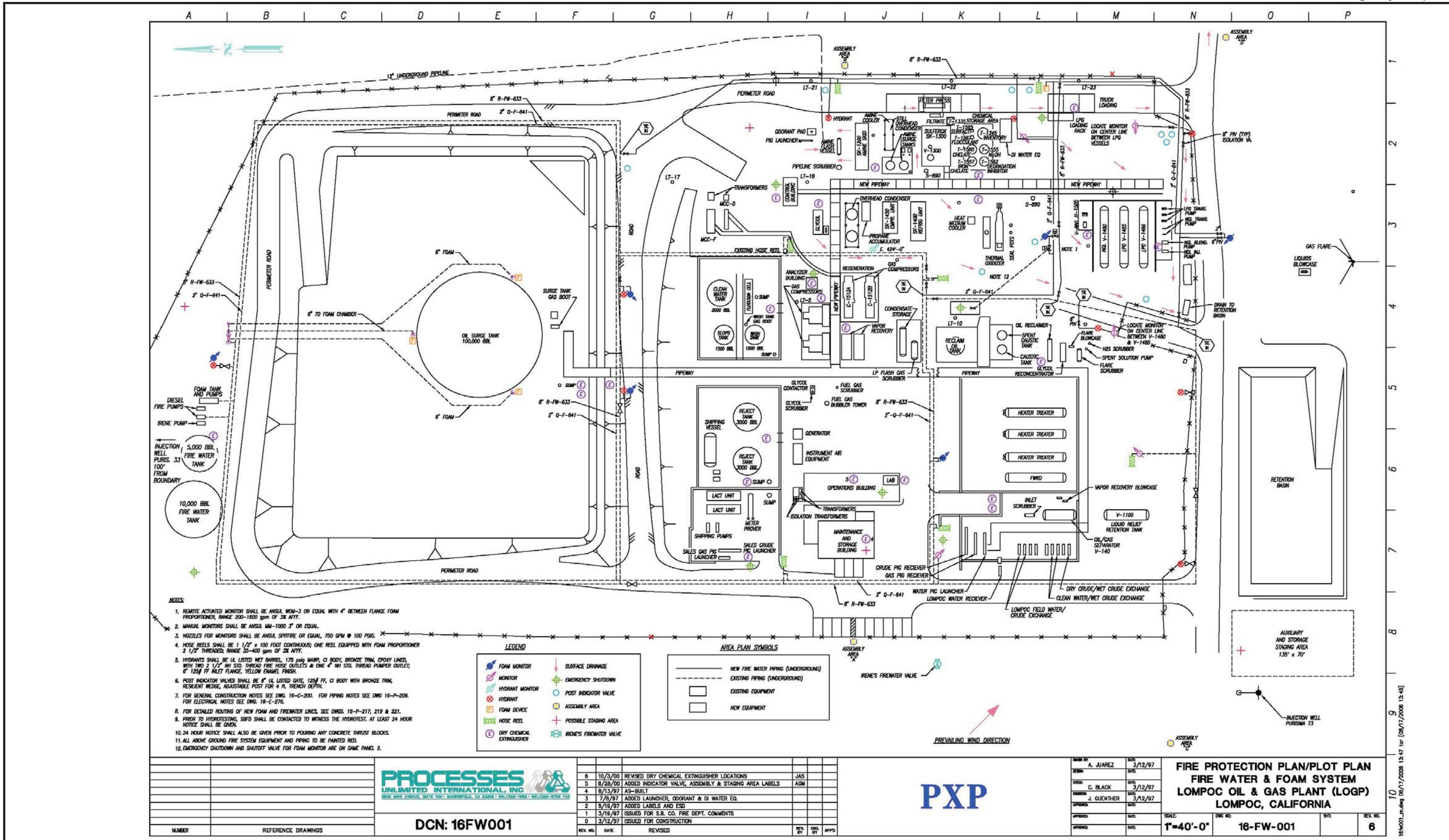


Source: MRS, 2002.

PREPARED BY Aspen Environmental Group

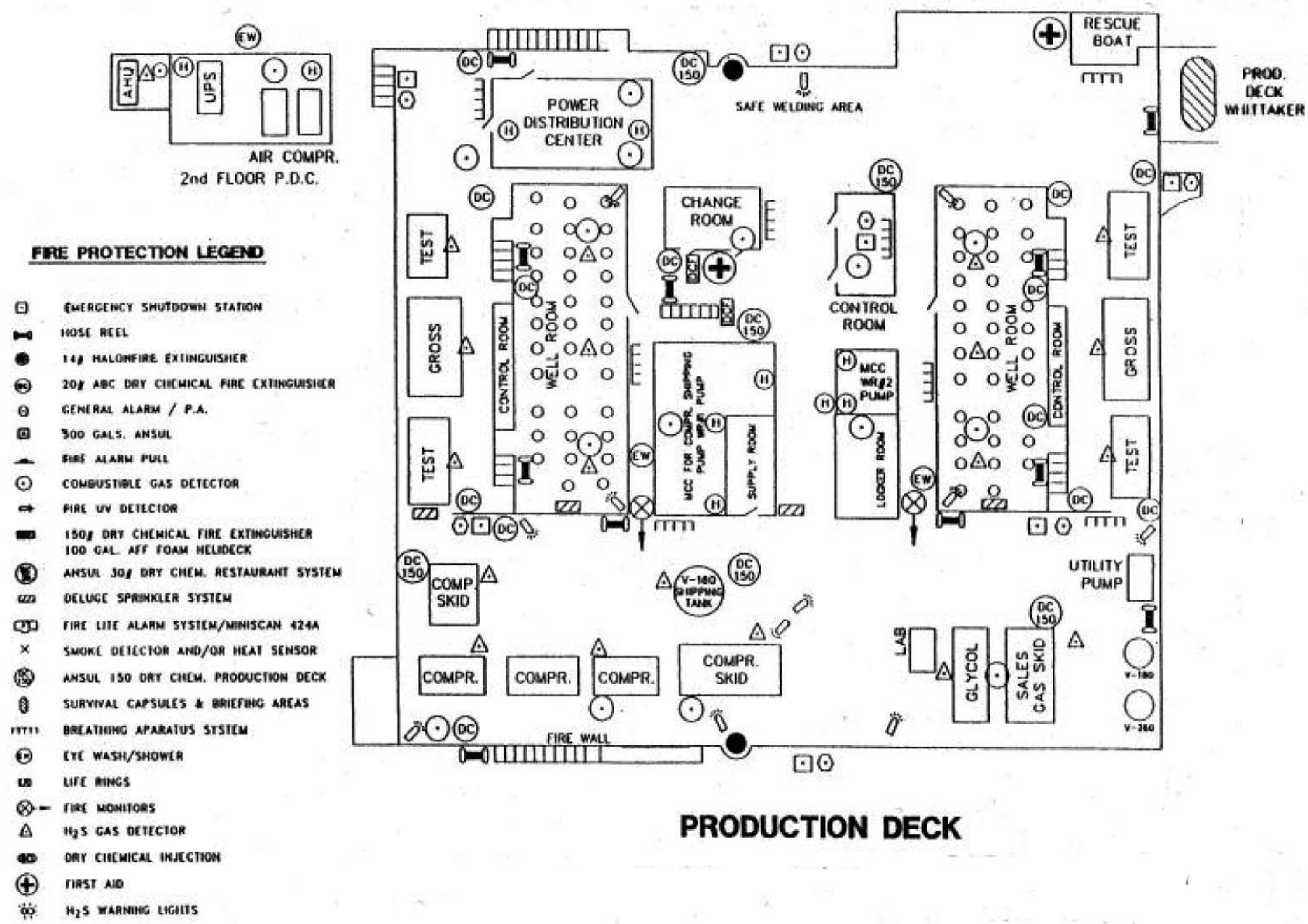
Figures 5.11-1

Fire Station Locations and Emergency Response Facilities



Figures 5.11-2
Fire Protection Equipment - Lompoc Oil and Gas Plant

PREPARED BY Aspen Environmental Group

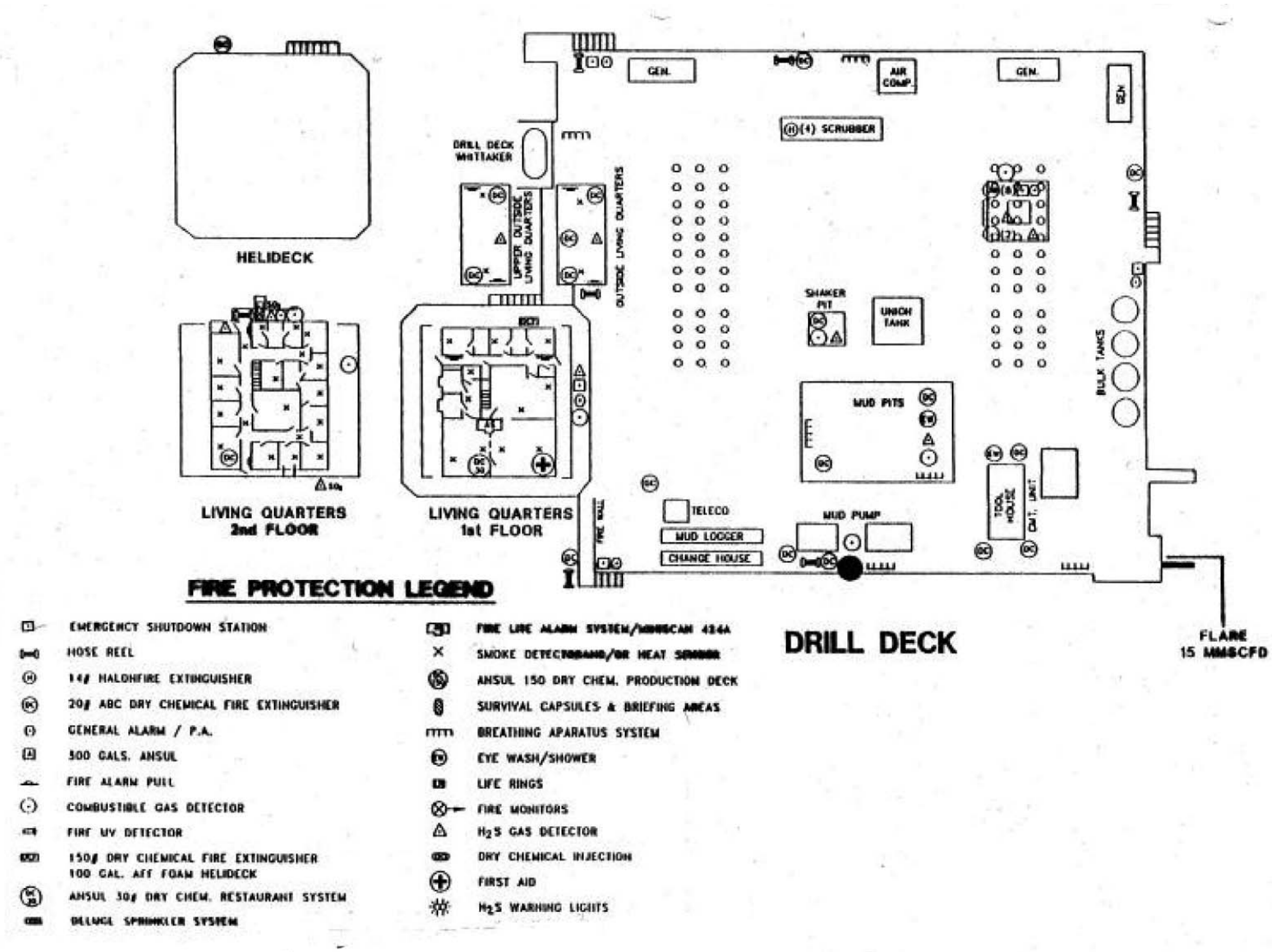


Source: MRS, 2002.

PREPARED BY Aspen Environmental Group

Figure 5.11-3a

Fire Protection Equipment - Platform Irene Production Deck



Source: MRS, 2002.

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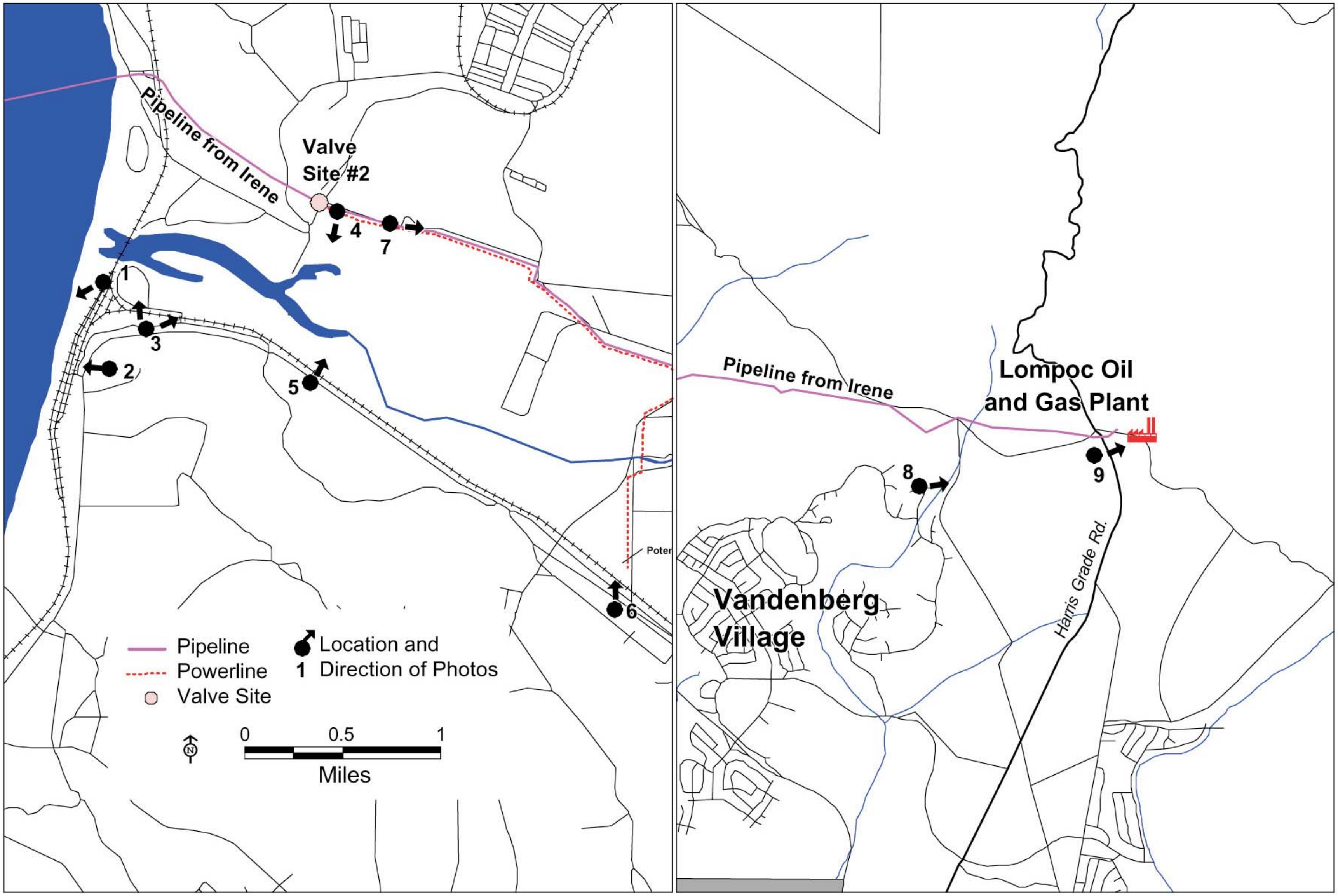
Figure 5.11-3b

Fire Protection Equipment - Platform Irene Drill Deck



Source: MRS, 2002.

PREPARED BY Aspen Environmental Group

Figure 5.13-1
Map of View Positions for the Photos

Figures 5.13-2: Platform Irene and Coastline (View Position 1)
(View west from Surf Beach with dunes in the foreground, Pacific Ocean and Platform Irene n the background)

Figures 5.13-3: View of Surf Substation (View Position 2)
(View of Surf Substation looking west from the west end of Ocean Avenue. The low vegetation is in the foreground, the substation is in the mid-ground and the ocean is in the background.)

Source: MRS, 2002.

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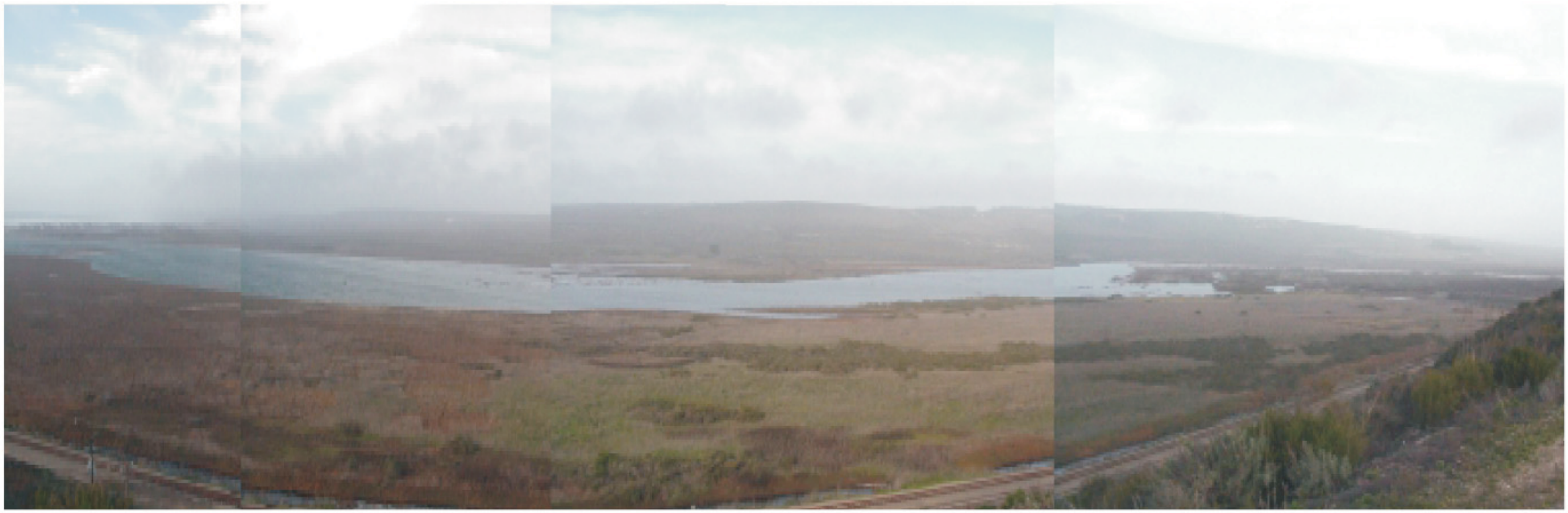
Figures 5.13-2 & 5.13-3
Photographs



(View from Ocean Avenue near Ocean Beach Park looking northeast towards Valve Site #2 and Terra Road. Union Pacific Railroad is in the foreground, the Santa Ynez River estuary is in the mid-ground, and the hills behind Terra Road are in the backgound.)

PREPARED BY Aspen Environmental Group

Figure 5.13-4

View of Santa Ynez River from Ocean Avenue Near Ocean Beach Park (View Position 3)

Figures 5.13-5: View of Santa Ynez River and Hills from Valve Site #2 (View Position 4)
(View south from Valve Site #2)

Figures 5.13-6: Route 246 to Valve Site #2 (View Position 5)
(View of Surf Substation looking west from the west end of Ocean Avenue. The low vegetation is in the foreground, the substation is in the mid-ground and the ocean is in the background.)

Source: MRS, 2002.

PREPARED BY Aspen Environmental Group

Figures 5.13-5 & 5.13-6
Photographs

Figures 5.13-7: View from Ocean Avenue near 13th Street and Renwick Road (View Position 6)
(View north from Ocean Avenue with the road in the foreground, power lines and vegetation along the road in the mid-ground, and the hills north of Terra Road visible in the background.)

Figures 5.13-8: View of Pipeline Bridge Near Catchment Basin 4 (View Position 7)
(Pipelines rack crossing over drainage, view from Terra Road east with the road continuing on the left in the background, three pipelines on the right fore- and mid-ground.)

Source: MRS, 2002.

PREPARED BY Aspen Environmental Group

Figures 5.13-7 & 5.13-8
Photographs

Figures 5.13-9: View with LOGP in Background (View Position 8)
(View from Firestone Road looking northeast with the LOGP in the background.)

Figures 5.13-10: View of LOGP at Night (View Position 8)
(View from Firestone Road looking northeast with the LOGP in the background.)

Source: MRS, 2002.

PREPARED BY Aspen Environmental Group

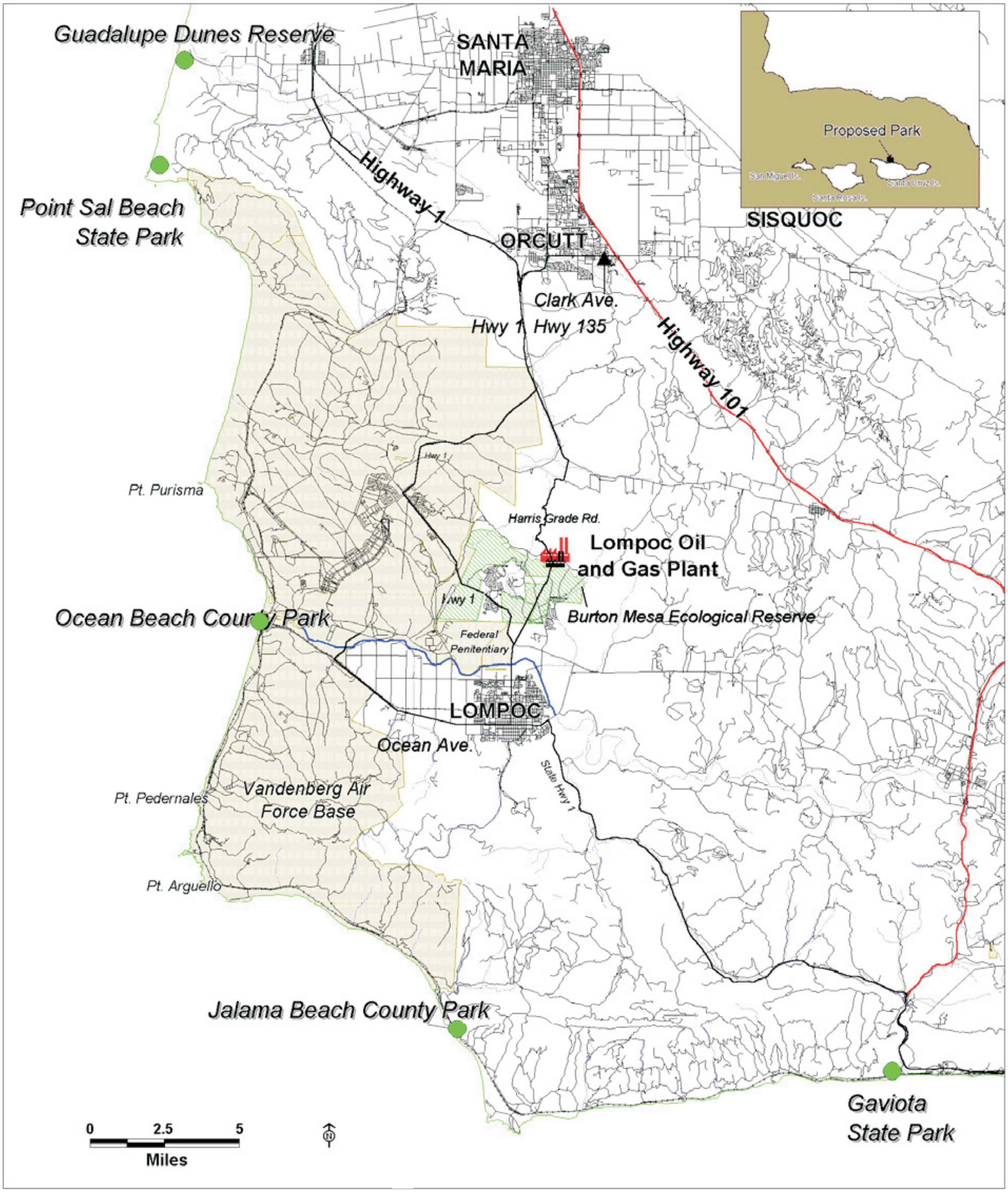
Figures 5.13-9 & 5.13-10
Photographs

Figures 5.13-11: View of LOGP from Harris Grade Road (View Position 9)
(View looking northwest from Harris Grade Road onto the LOGP.)

Source: MRS, 2002.

PREPARED BY Aspen Environmental Group

Figure 5.13-11
Photograph



Source: MRS, 2002.

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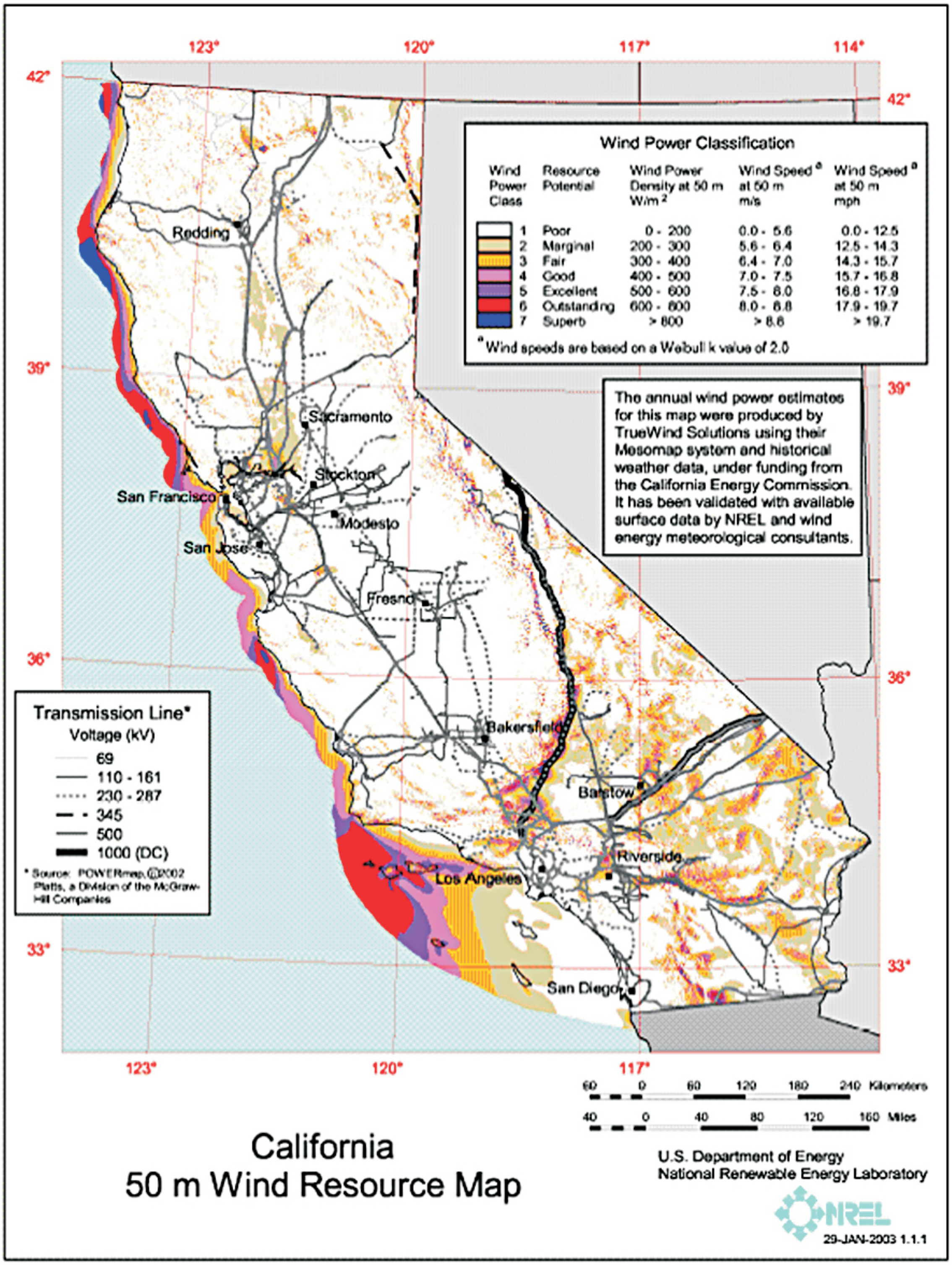
Figure 5.14-1
Coastal Beaches and Parks



Source: NREL, 2003.

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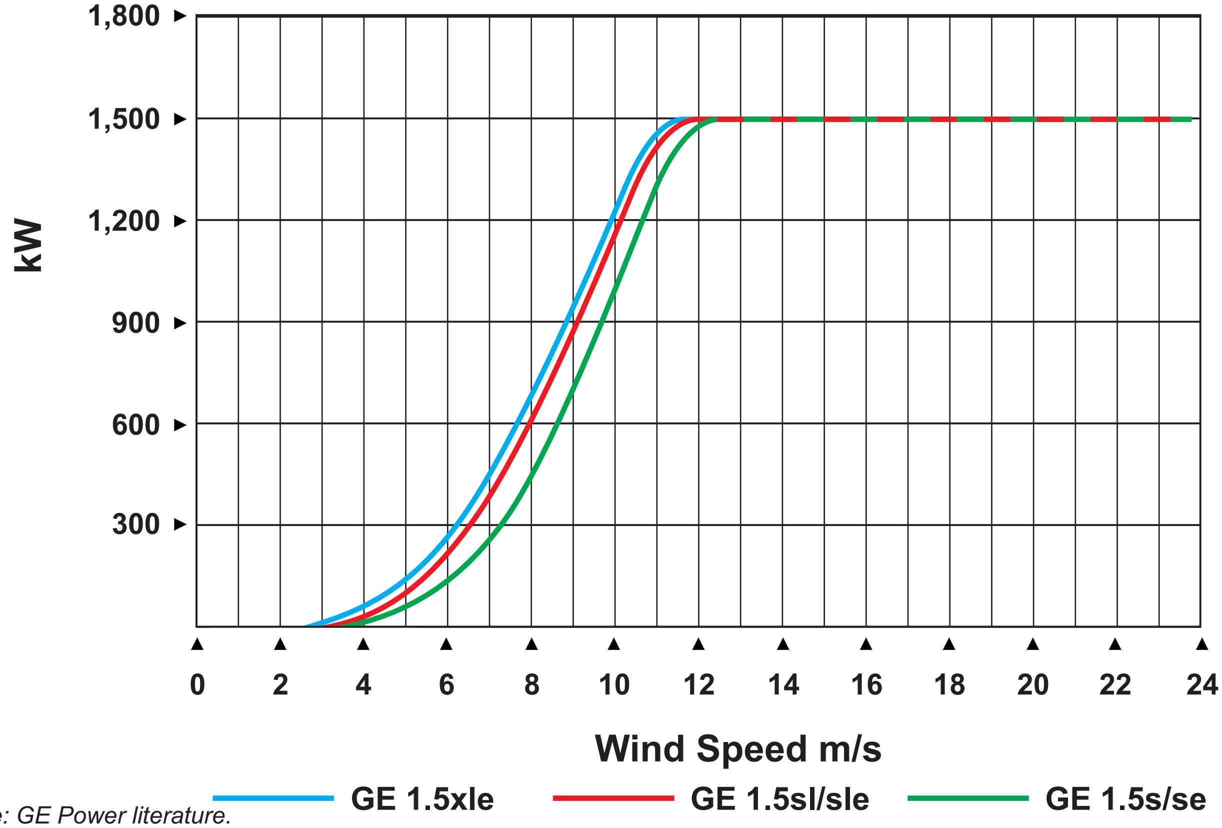
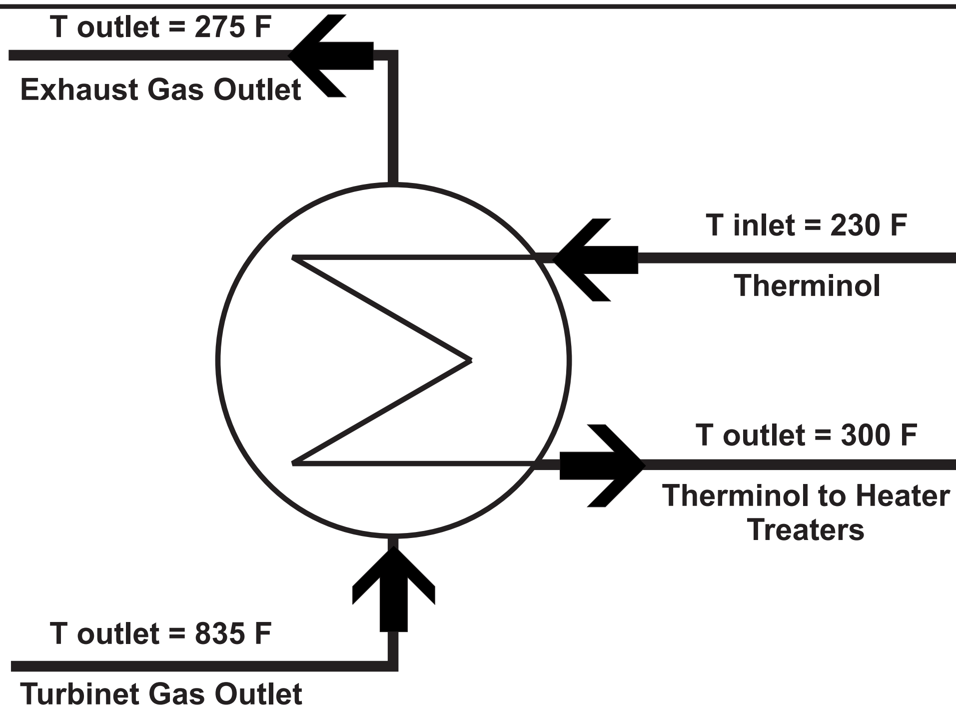
Figures 5.16-1
California 50 m Wind Resources Map (NREL, DOE)



Source: GE Power literature.

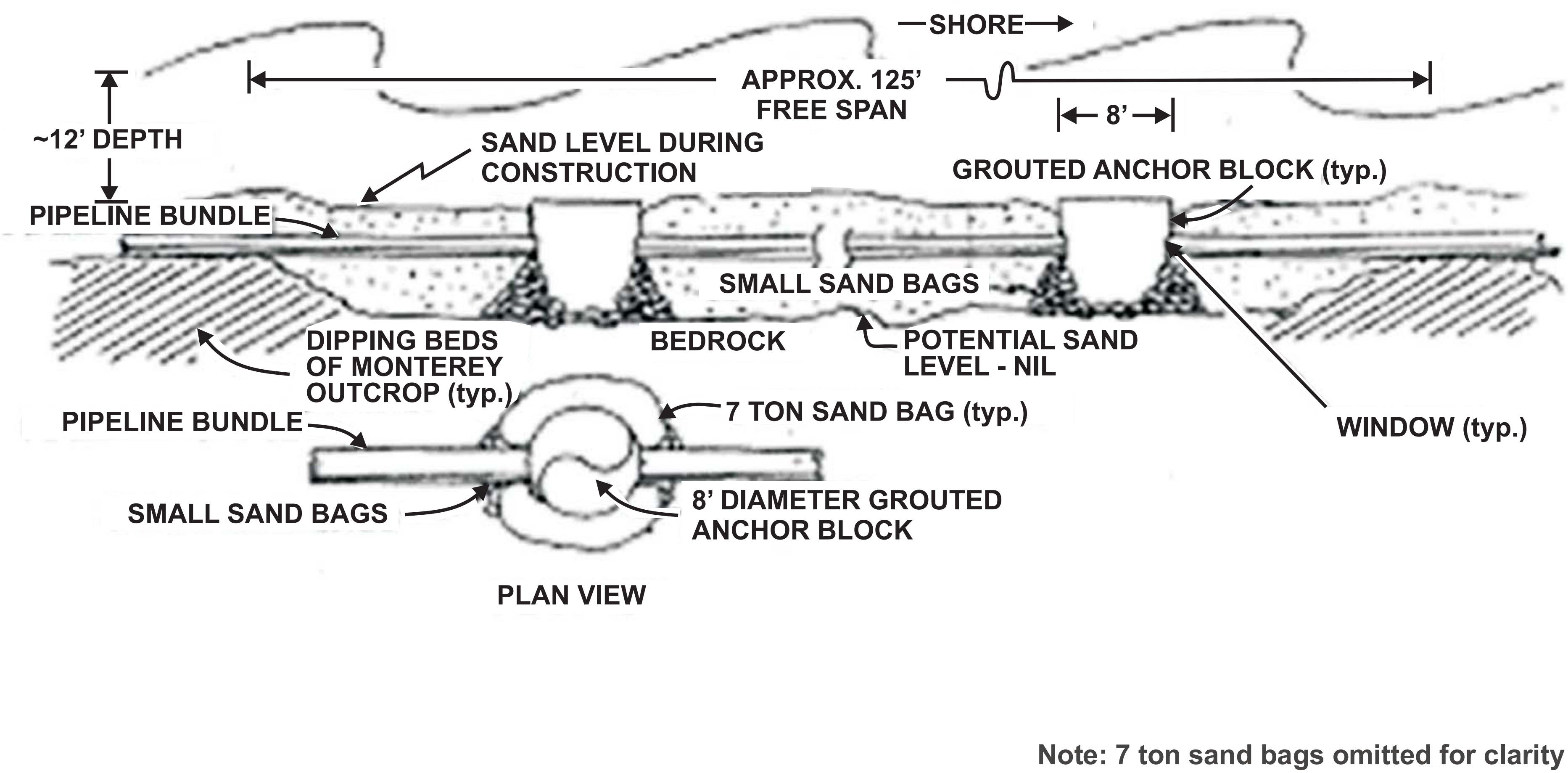
Figures 5.16-2
Power Curve for the GE 1.5 MW Series of Wind Turbines



Source: GE Power literature.

PREPARED BY Aspen Environmental Group

Figures 5.16-3
Flow Diagram for Heat Recovery from Exhaust Gases for use in Heater



Source: PXP, 2007.

PREPARED BY Aspen Environmental Group

Figure 9.3-1
Primary Free Span Schematic Cross Section

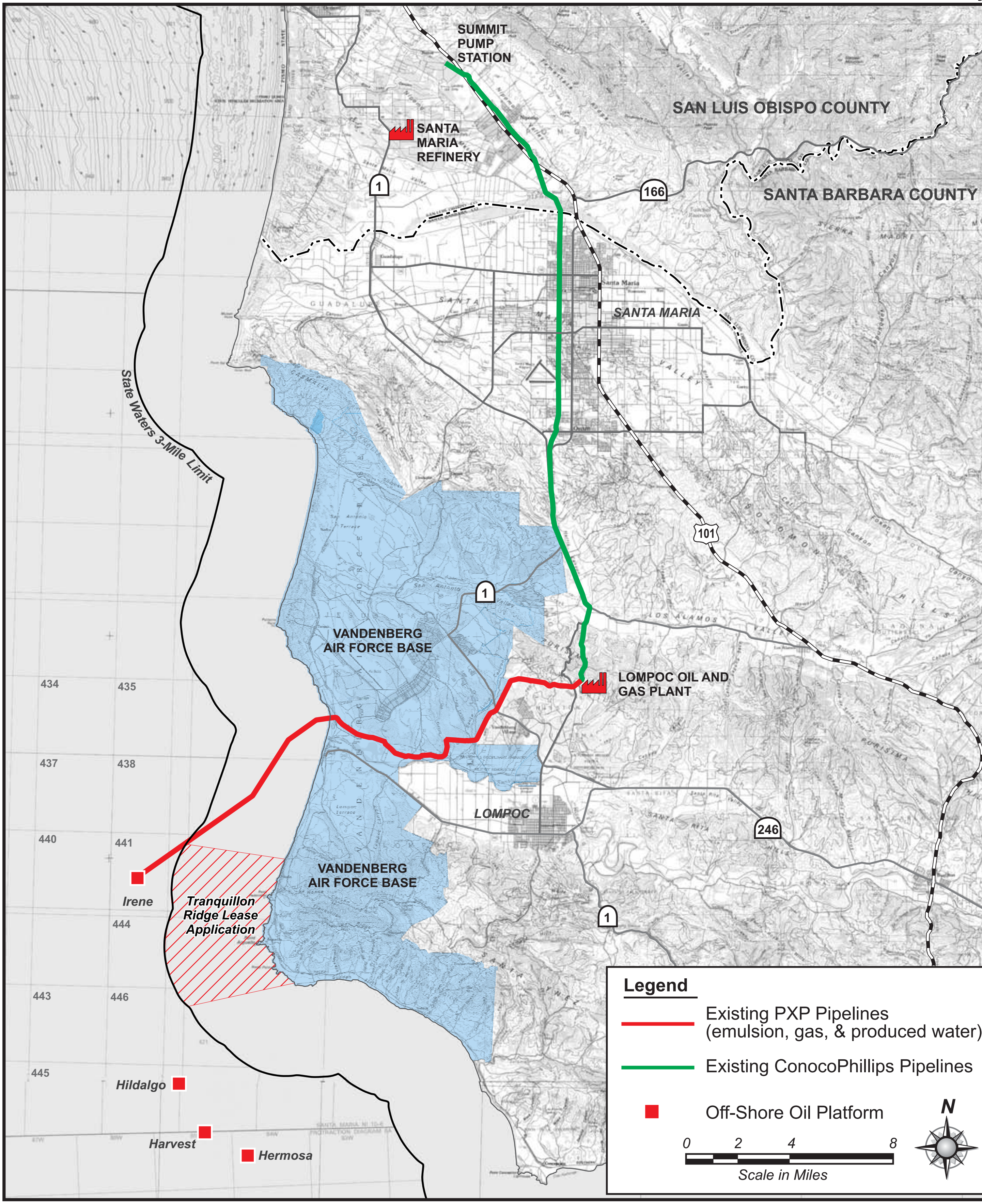


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Figure ES-1

Proposed Project Location