DEVELOPMENT AND PRODUCTION PLAN

POINT ARGUELLO FIELD

OFFSHORE SANTA BARBARA COUNTY, CALIFORNIA

Chevron U.S.A. Inc.

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EXECUTIVE SUMMARY

1. DEVELOPMENT AND PRODUCTION OVERVIEW

Chevron U.S.A. Inc. (Chevron) is the operator and co-lessee of 12 Federal leases south of Point Arguello, California. Ownership of the leases is described in Table 1.1. These leases are depicted in Figure 1.1. Initial development of the leases is planned to begin in 1985 with the installation of Platform Hermosa on Lease OCS P-0316, as well as support facilities to accommodate Hermosa and additional platforms. Figure 1.2 shows the location of the platform, pipelines, and onshore facilities.

Platform Hermosa will be a central platform for the Pt. Arguello Field. Risers will be installed on the platform to accommodate pipeline hookups from up to three additional platforms on nearby leases as those leases are developed. In addition, both the oil and gas lines from Hermosa to shore will be sized to accommodate potential production from the entire Arguello Field. Further, the onshore facilities including the onshore pipelines are being designed to accommodate production as it is presently estimated from the Arguello Field. Therefore, no unnecessary duplication of facilities is expected, which is both an economically and environmentally sound development practice.

This Development and Production Plan, accompanied by an Environmental Report, has been prepared to comply with 30 CFR Section 250.34-2. It is anticipated that supplements to this plan will be submitted as additional exploration and evaluation data become available and additional platforms are planned. These supplements will include site specific engineering and environmental data for additional platform(s) located on other Arguello Field leases operated by Chevron. Any supplement will also include site specific data on the smaller pipelines that will hookup to Hermosa, the central platform for the Arguello Field.

A complete schedule for the installation of Platform Hermosa and its associated facilities is shown in Figure 1.3. It is expected that the platform will be installed starting in May, 1985 and that the first oil will be produced in January, 1986. Production is expected to peak in 1989 at 27,000 barrels per day. The project is briefly summarized below:

Platform Hermosa

Platform Hermosa will be a three deck, eight leg drilling/production facility installed by conventional methods in approximately 183m (602 ft) of water. Forty-eight well slots will be provided and it is anticipated that 40 production wells will be drilled.

Two cantilever type drilling rigs will be used to drill the wells. Three risers will be installed on the platform to accommodate production from other (future) platforms in the area, including Texaco's proposed Hueso platform to be located on Lease OCS P-0315.

When production begins, free water will be separated from the oil. An oil emulsion will be delivered to the pipeline after metering. Water will also be removed from the gas before delivery to the pipeline to prevent pipeline deterioration or corrosion or other operational problems. Hydrocarbon condensate will be commingled with the oil and sent to shore.

Cogeneration will be used on the platform to minimize air emissions. Electrical power will be produced on the platform wtih gas fired turbines equipped with water injection to reduce NO_x emissions. Burners and motors on the platform will be of low NO_x design. To further reduce emissions, a fugitive emission inspection and maintenance program will be instituted.

To minimize disturbance of the marine environment, all cuttings will be cleaned prior to discharge, and any cuttings from hydrocarbon bearing formations will be taken to shore. Further, all discharges will be in strict compliance with the National Pollution Discharge Elimination System (NPDES) Permit issued by the EPA.

Extensive geological, biological, archaeological and other environmental surveys have been carried out to assure that the platform and pipelines (discussed below) will result in a minimum impact to the environment.

Results of the surveys show that all significant ocean features have been avoided, including rocky outcrops and cultural resources such as shipwrecks.

Pipelines

It is currently expected that a 22 inch gas line and an oil line as large as 30 inches will be installed to transport oil and gas to shore. These lines will originate at the platform and will run approximately ten (10) miles to the east to a landfall north of Pt. Conception. The pipeline route has been chosen to avoid sub-surface features and is shown in detail on Figure 1.1.

As mentioned above, the lines will be sized to accommodate production expected from the entire Arguello area in line with the commitment by Chevron to consolidated facilities. The lines will be protected from corrosion and will be equipped with high and low pressure shutdowns to prevent any spillage of oil in the event of an emergency.

From the landfall, the pipeline will run an additional sixteen (16) miles to the processing plant located at Gaviota. Environmental surveys have been run in the area of the pipeline route to eliminate or minimize geologic and environmental impacts, including fault zones, sensitive biological habitats and significant cultural resources. Additional specific surveys will be run when the pipeline route is finalized.

Oil and Gas Processing

Oil dehydration, gas sweetening, oil pumping, and gas compression facilities will be installed at the site of the existing Gaviota gas plant. The plant is currently expected to handle approximately 148,000 barrels per day of oil and 98 million standard cubic feet per day of gas. However, Chevron is surveying other potential users of this consolidated processing facility and if necessary, will refine its design values based on this survey.

Oil will be dehydrated with heat and coalescers. Gas will be processed first in a sulfur recovery unit. Additional dehydration and separation of gas liquids will then take place.

Power will be generated at the Gaviota plant with cogeneration units. It is currently anticipated that up to six, 2.8 megawatt units will be installed. Waste heat from the units will be used to heat incoming oil. Sweet gas will be burned in these units and water injection will be installed to reduce emissions of NO_x.

To further reduce emissions from the facility, all tanks and vessels will be equipped with vapor recovery. In addition, electric motor compressors and pumps will be used. Finally, a fugitive emission inspection and maintenance program will be instituted to provide additional reductions in hydrocarbon emissions.

Transportation

A marine terminal for petroleum transportation is not a part of this plan, however it is anticipated that Chevron will use the proposed expanded Getty marine terminal at Gaviota (where Arguello crude will be processed) or the proposed Exxon marine terminal to be located approximately twelve miles east of Gaviota at Las Flores. Regardless of the marine terminal that Chevron will use, it is essential that at least one terminal is available for industry use to provide the required flexibility essential for crude transportation to refineries. Pipelining a portion of the crude may be feasible and studies are being conducted now to determine the technical and economic feasibility of using an onshore line to a refining facility for a portion of Arguello crude. However, neither a pipeline from the Gaviota processing facility to a refining facility nor a marine terminal is a part of this project. Chevron plans to use whichever marine terminal is onstream by the first quarter of 1986. If neither the Getty expansion nor new Exxon terminal is completed, then we will use the existing Getty terminal on an interim basis only.

This plan describes the following project areas in detail:

1. Geology
2. Reservoir Evaluation
3. Platform Site and Construction

4. Drilling Facilities
5. Platform Facilities
6. Pipelines
7. Onshore Facilities
8. Crude Transportation

TABLES

FIGURES

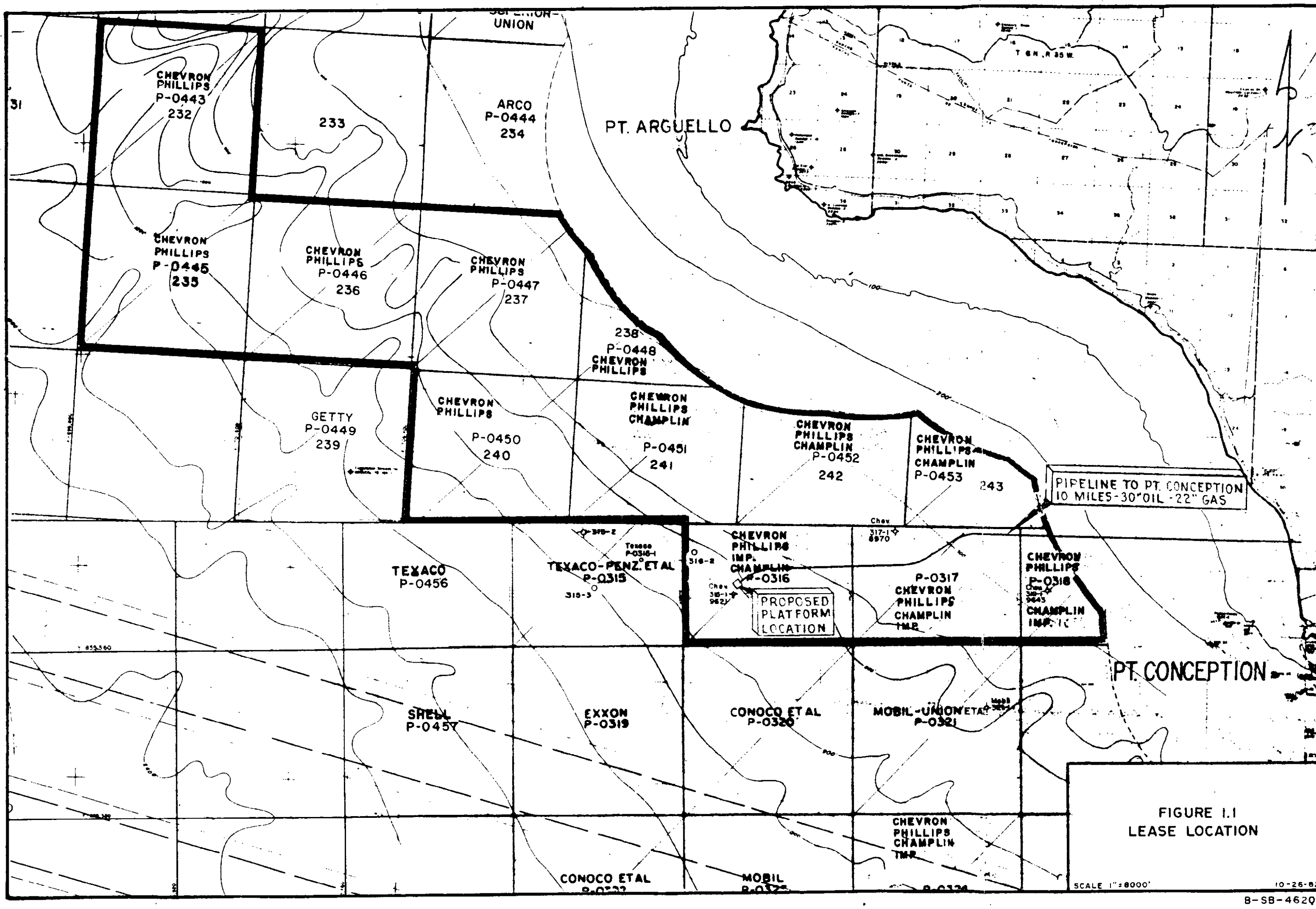

FIGURE 1.1
LEASE LOCATION

SCALE 1"=8000'

10-26-82

B-SB-4620

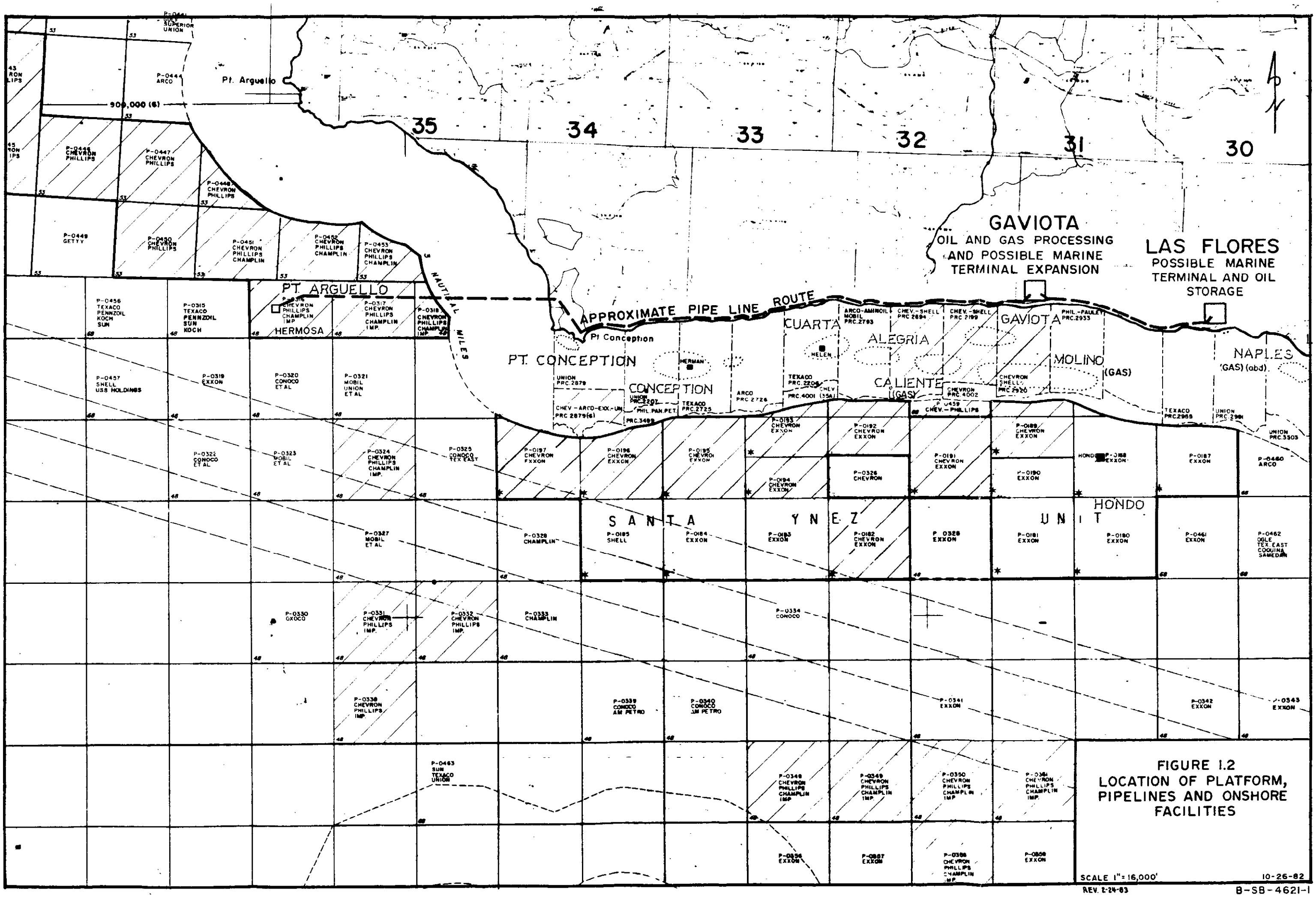

FIGURE 1.2
LOCATION OF PLATFORM,
PIPELINES AND ONSHORE
FACILITIES

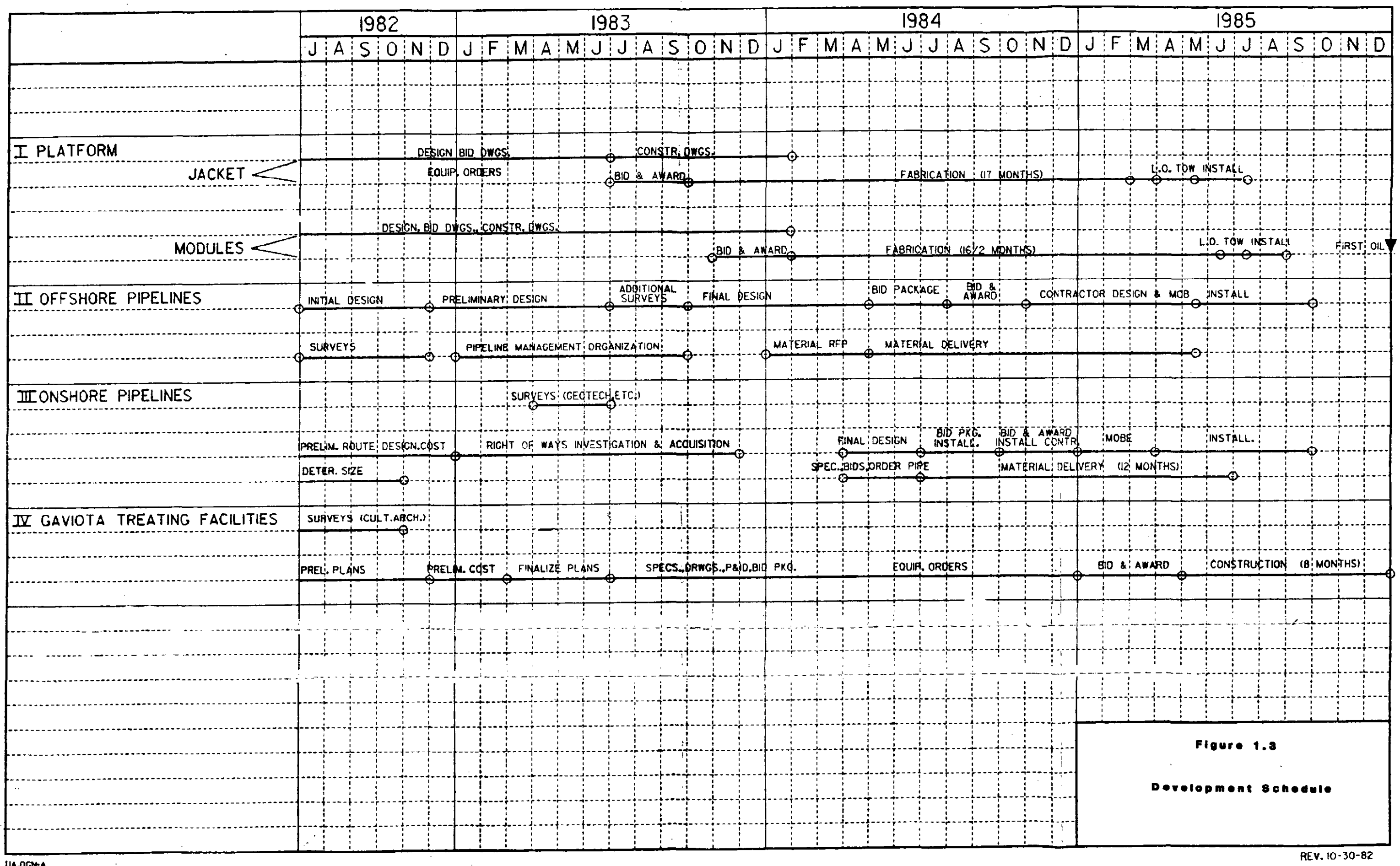

Figure 1.3

Development Schedule

REV. 10-30-82

TABLE 1.1

OWNERSHIP OF LEASES

LEASE	OWNERSHIP*	
OCS-P 0443	CHEVRON U.S.A. INC.	50%
	PHILLIPS PETROLEUM CO.	50%
OCS-P 0445	CHEVRON U.S.A. INC.	50%
	PHILLIPS PETROLEUM CO.	50%
OCS-P 0446	CHEVRON U.S.A. INC.	50%
	PHILLIPS PETROLEUM CO.	50%
OCS-P 0447	CHEVRON U.S.A. INC.	50%
	PHILLIPS PETROLEUM CO.	50%
OCS-P 0448	CHEVRON U.S.A. INC.	50%
	PHILLIPS PETROLEUM CO.	50%
OCS-P 0450	CHEVRON U.S.A. INC.	50%
	PHILLIPS PETROLEUM CO.	50%
OCS-P 0451	CHEVRON U.S.A. INC.	44.444%
	PHILLIPS PETROLEUM CO.	44.444%
	CHAMPLIN PETROLEUM CO.	11.112%
OCS-P 0452	CHEVRON U.S.A. INC.	44.444%
	PHILLIPS PETROLEUM CO.	44.444%
	CHAMPLIN PETROLEUM CO.	11.112%
OCS-P 0453	CHEVRON U.S.A. INC.	44.444%
	PHILLIPS PETROLEUM CO.	44.444%
	CHAMPLIN PETROLEUM CO.	11.112%

OWNERSHIP OF LEASES (CONTINUED)

LEASE	OWNERSHIP*	
OCS-P 0316	CHEVRON U.S.A. INC.	40%
	PHILLIPS PETROLEUM CO.	40%
	CHAMPLIN PETROLEUM CO.	10%
	IMPKEMIX INC.	10%
OCS-P 0317	CHEVRON U.S.A. INC.	40%
	PHILLIPS PETROLEUM CO.	40%
	CHAMPLIN PETROLEUM CO.	10%
	IMPKEMIX INC.	10%
OCS-P 0318	CHEVRON U.S.A. INC.	40%
	PHILLIPS PETROLEUM CO.	40%
	CHAMPLIN PETROLEUM CO.	10%
	IMPKEMIX INC.	10%

*CHEVRON IS THE OPERATOR OF ALL THE ABOVE LEASES

SECTION 2

GEOLOGY

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FIGURES

Geology Section

Pursuant to the Freedom of Information Act (5 U.S.C. 552) and its implementing regulations (43 CFR Part 2) and as provided in 30 CFR 550.199(b), the information contained in this section is deleted from the public information copy of this submission.

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minor amounts of sand. The Miocene rest uncomformably on the Upper and Lower Cretaceous in the field area. These older sediments where penetrated to date consist of interbedded conglomerates, sands and shales.

2.4.2 Pipeline Routes

Discussions covering the geologic and geotechnical conditions along the proposed pipeline route between Platform Hermosa and the Las Flores Canyon are covered in Section 7.3.

2.5 Refèrences

2.5.1 Bureau of Land Management (1979), Final Environmental Statement, OCS Sale No. 48, U.S. Department of the Interior, Washington D.C. 5 Volumes.

2.5.2 Ibid (1980) Final Environmental Impact Statement, OCS Sale No. 53, U.S. Department of the Interior, Washington D.C. 2 Volumes.

2.5.3 W. C. Richmond, et al. (1981) Regional Geology, Seismicity, and Potential Geologic Hazards and Constraints, OCS Oil and Gas Lease Sale 53, Northern and Central California, U.S. Geological Survey Open-file Report 81-318, 38 p, 6 plates.

2.5.4 McCulloch, D.S., et al. (1980), A Summary Report of the Geology and Geologic Hazards in Proposed Lease Sale 53, Central California Outer

Continental Shelf, U.S. Geological Survey Open File Report 80-1095.

2.5.5 Yerkes, et al. (1981) Maps Showing Seismotechtonic Setting of the Santa Barbara Channel Area, California, U.S. Geological Survey Miscellaneous Field Studies, Map MF-1169.

2.5.6 Vedder, J.G., et al. (1969), Geologic Framework of the Santa Barbara Channel Region, U.S. Geological Survey Professional Paper 679-A.

2.5.7 Yerkes, R.F., et al (1980) Seismotectonic Setting of Santa Barbara Channel Area, Southern California, U.S. Geological Survey Open File Report 80-299, 24 p. 2 plates, 16 figures.

2.5.8 California State Lands Commission, (1982) Program Environmental Impact Report Leasing, Exploration and Development of Oil and Gas Resources on State Tide and Submerged Lands, Point Conception to Point Arguello, Santa Barbara County, California. California State Lands Commission, 2 Volumes.

2.5.9 McClelland Engineers (1982) Site and Foundation Investigation Platform Hermosa Point Arguello Field OCS Lease P-0316 Offshore California. Report to Chevron U.S.A. Inc.

2.5.10 Fairfield Industries (1978) Offshore California FA-12 Program Geological Coring Geophysical Survey Point Conception. 4 Volumes.

2.5.11 McClelland Engineers (1979) Final Report of Field Operations High Resolution Geophysical Survey, Offshore Southern California. Report to U.S. Geological Survey. U.S.G.S. Contract No. 14-08-0001-17200.

2.5.12 Intersea Research Corp. (1979) Hazards and Cultural Resource Survey of Channel Islands Area Tract 48-004, OCS Lease No. P-0316. Report to Chevron U.S.A. Inc.

2.5.13 Dames & Moore (1982) Hazard and Cultural Resource Investigation Proposed Platform Hermosa Site OCS Lease P-0316 Offshore Santa Barbara County, California. Report prepared for Chevron U.S.A. Inc.

2.5.14 Ibid (1982) Hazard and Cultural Resource Investigation Proposed Marine Pipeline Route Platform Hermosa to Government Point Area Offshore Santa Barbara County, California. Report prepared for Chevron U.S.A. Inc.

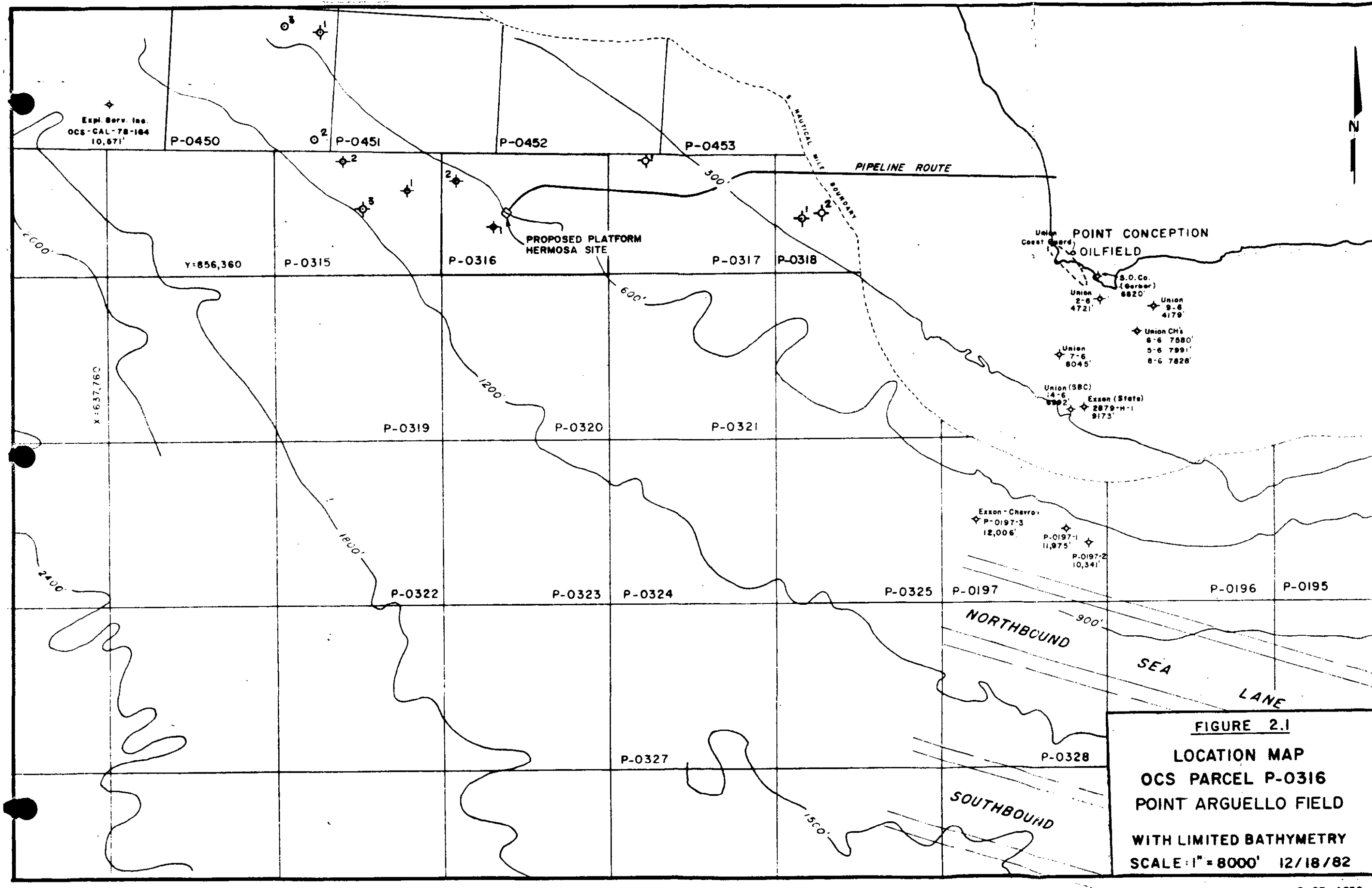
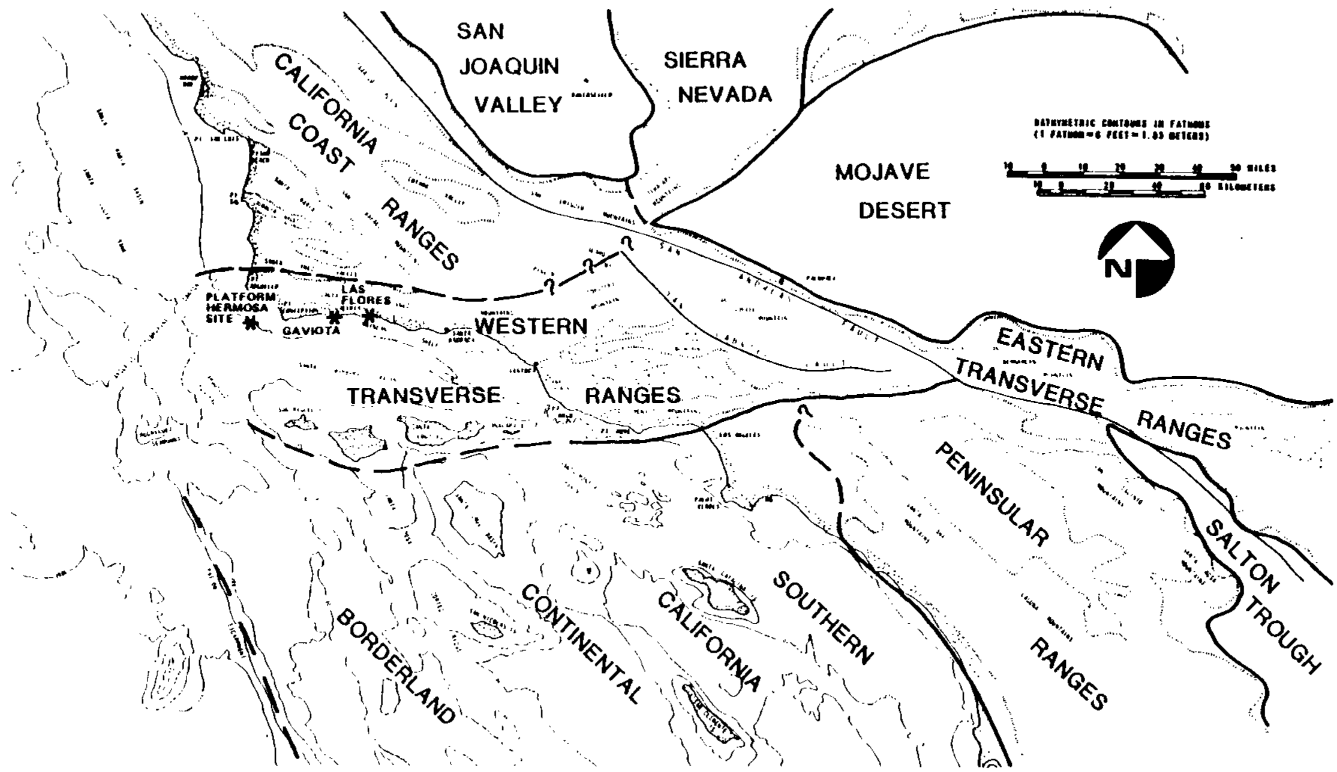


FIGURE 2.1

LOCATION MAP
OCS PARCEL P-0316
POINT ARGUELLO FIELD

WITH LIMITED BATHYMETRY
SCALE: 1" = 8000' 12/18/82

B-SB-4656



REGIONAL GEOMORPHIC PROVINCES IN SOUTHERN CALIFORNIA

FIGURE 2.2

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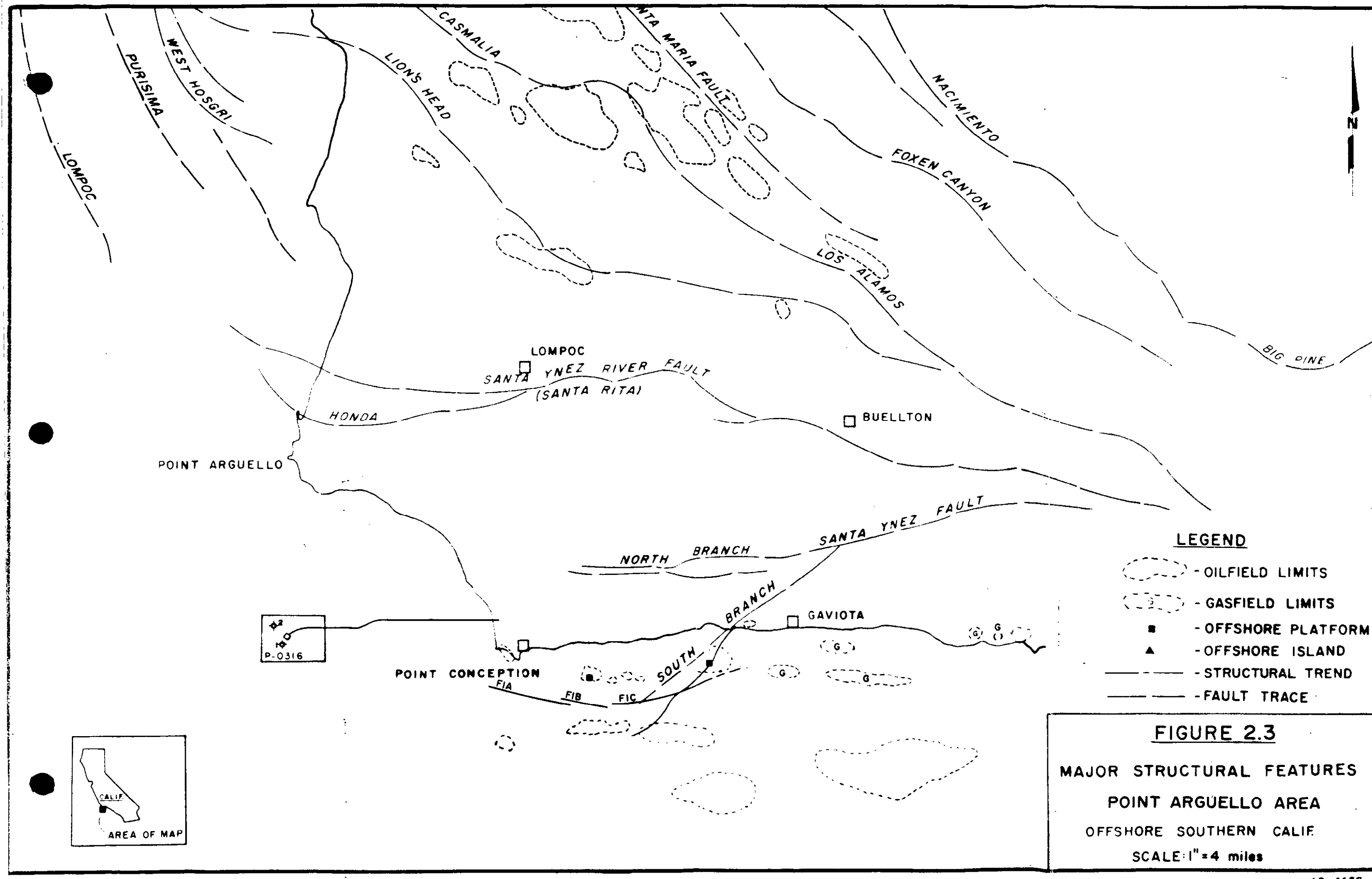


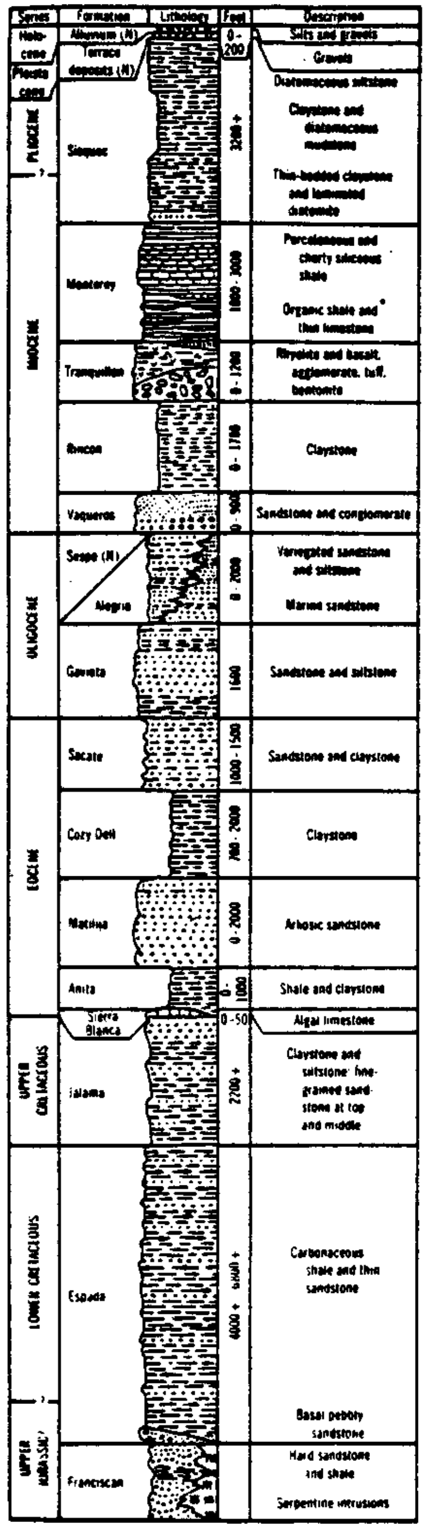
FIGURE 2.3

MAJOR STRUCTURAL FEATURES

POINT ARGUELLO AREA

OFFSHORE SOUTHERN CALIF.

SCALE: 1" = 4 miles



N - Non-Marine

Source: Vedder et al., 1969
WESTEC SERVICES, INC.

Stratigraphic Section for Western Santa Ynez Mountains and Vicinity

FIGURE 2.4

Forecast Data

Pursuant to the Freedom of Information Act (5 U.S.C. 552) and its implementing regulations (43 CFR Part 2) and as provided in 30 CFR 550.199(b), the information contained in this section is deleted from the public information copy of this submission.

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SECTION 3

PROPRIETARY

RESERVOIR EVALUATION

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Reservoir Evaluation Section

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SECTION 4

PLATFORM SITE AND CONSTRUCTION

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4. PLATFORM SITE AND CONSTRUCTION

4.1. Introduction

Platform Hermosa will be designed to withstand site specific environmental, installation and operational loads. The water depth and geology of the area has been evaluated extensively and will not present problems for setting, design or installation. This section describes the methodology that was used to develop the geological, geotechnical, oceanographic and seismic design criteria. A description of the platform design and installation is also included. Detailed design data will be reviewed under the platform verification program in accordance with OCS Order 8. Design work is being performed by Fluor Ocean Services.

4.2 Onsite Geology

The Platform Hermosa location was initially selected on the basis of geologic data that was obtained from geophysical records and the drilling of two exploratory wells. This data defined a commercial hydrocarbon accumulation which trends northwesterly across the western portion of the lease (Figure 2.5). In order to adequately develop this accumulation, by directional drilling from the shallowest possible water depth, with good foundation conditions, the site shown on Figure 2.5 was selected. Following this initial selection, regional and site-specific geologic studies were conducted by McClelland Engineers (Reference 2.5.9) and Dames & Moore (References 2.5.13 and 2.5.14) at the proposed platform site and along the proposed pipeline route (Figure 1.2). These studies were conducted to assess geologic conditions and to develop geologic and geotechnical design criteria for the platform and pipeline. The conclusion of these studies is that the choosen platform location and pipeline route present no geologic problems to their design. Site-specific findings by the consulting firms for the platform are summarized in the following paragraphs. The pipeline site-specific findings are covered in Section 7.3.

4.2.1 Bathymetry

Ocean floor water depths and sea floor topography at the proposed platform site are shown on Figure 4.1 of this report and Map 2 of Dames & Moore's report (Reference 2.5.13) and Plate 2 of McClelland Engineer's report (Reference 2.5.11). A northeast-southwest trending rectangular area, 9,000' by 6,000' centered on the platform site, was surveyed in detailed. This area and the platform site area are located on a slope with water depths that range from 400' (122 meters) to 880' (268 meters). At the proposed platform site, the water depth is 603' (183 meters).

At the platform site the ocean floor is generally smooth, and slopes southwesterly at a grade of 5% (gradient of 1:20, dip of 2.9°. The sea floor in the surrounding area also slopes to the southwest with grades from 5% (1: 20 or 2.9°) to 7.8% (1: 13 or 4.5°). There are local depressions in this slope which disrupt the bottom and have been described as swales and channels by Dames & Moore (Reference 2.5.13) and McClelland Engineers (Reference 2.5.9). These minor sea floor depressions, range up to 1400' in length, 800' in width, and penetrate .from 5 to 40' (1½ to 12 meters) below the mudline. The side slopes of these depressions grade up to 10% (i.e. 1: 10 or 5.7°).

4.2.2 Ocean Bottom Conditions

The Dames & Moore report (Reference 2.5.13) and the McClelland report (Reference 2.5.9) both identify sea floor features in the survey area that include small outcrops of stiffer sediments which form an irregular bottom topography, occasional natural gas seeps, anchor scars, a previous drill site and two unidentified sonar targets. The area selected for the platform site is generally smooth and undisturbed by any of the above-mentioned features.

4.2.3 Shallow Gas and Hydrocarbon Seeps

There are occasional gas seepages in the area of parcel P-0316. These seeps have been noted in the records from the high resolution geophysical surveys. Generally, the gas seeps show up as plumes in the water column which start at the mudline. No seeps were noted in the platform area.

4.2.4 Shallow Overburden Sediments

An analysis of site specific soil borings and high resolution geophysical surveys indicates that the proposed construction site is underlain by Holocene and Pleistocene sediments to a depth of 450' below the mud line (Reference 2.5.13 and 2.5.9). McClelland Engineers (Reference 2.5.9) have described four separate stratum (Table 4.1). The uppermost strata (A) is a very soft silty clay to clay silt of possible Holocene age. This strata is about 14' thick and dips 3° to the southwest. The next three lower stratum (B, C and D) vary from sandy silts to stiff clay silts and probably are of Pleistocene age. These sediments also dip 3° to 4° to the southwest. All of the strata contain shells and shell fragments indicating that they were probably deposited in a marine environment. For the purpose of determining geotechnical characteristics, McClelland Engineers (Reference 2.5.9) made extensive laboratory tests on soil samples recovered from two deep soil borings taken at and near the proposed platform site. Their report should be referred to for geotechnical details and laboratory results. The Pleistocene sediments are slightly gasified in this area. Evidence of the presence of this finely dispersed gas is based on relative amplitude anomalies noted on geophysical records obtained from running high resolution profiles across the site. Most of these anomalies are located in the northeast portion of the lease where the ocean floor becomes part of the Arguello shelf. No free gas was reported or noted in any of the soil samples taken from the soil borings at the platform site. Woodward-Clyde Consultants (Reference 4.1) reported that the methane content was generally less than 10,000 ppm in the samples. All of the methane present was dissolved in the pore water, and was not found in the bubble phase. This further indicates that the gas is too finely dispersed within the Pleistocene sediments to cause any reduction in their shear strength.

4.2.5 Shallow Structural Geology

The Dames & Moore report (Reference 2.5.13) should be referred to for a detailed description of the shallow geologic structure in the area of the proposed construction. Generally, both the Holocene and Pleistocene sediments dip 3° to 4° to the southwest. The shallowest sediments have approximately the same dip as the mudline slope. With depth, the dip within the Plio-Pleistocene sedimentary section increases to over 5°. In the area of the platform, the Plio-Pleistocene section is about 4000' thick, has relatively uniform bedding, contains a few minor unconformities and is not cut by any significant faults. At the platform site, no shallow faulting was found.

4.2.6 Deep Drilling Hazards

The usual deep drilling hazards encountered while penetrating hydrocarbon bearing formations are expected during the drilling of the proposed wells. As part of the blowout and oil spill prevention plan, Chevron's drilling program will contain a casing program that will be in accordance with OCS Order #2 - Drilling Procedures. The deepest hole drilled in the area, Chevron's OCS-P-0316 #2, was drilled to a measured vertical depth of 11,416 feet (3480 meters). Similar to Chevron's other exploratory well OCS P-0316 #1, no abnormal formation pressures were encountered. No loss of circulation occurred during the drilling of these wells. Consequently, since the reservoir fluids contain a low gas saturation, there is probably a very low potential for a blowout while drilling.

4.2.7 Earthquake Activity

The Santa Barbara coastal area from Ventura to Santa Maria is located within a seismically active portion of Southern California. Earthquake activity within this area, which might impact the platform, was investigated by McClelland Engineering (Reference 2.5.9). Their study, which includes a probabilistic seismic risk analysis, recommended a strength level design response spectrum that has a 0.15g peak horizontal ground acceleration for a 200-year return period. The corresponding peak velocity is approximately 9 in./sec. Similarly, a response spectrum for ground motions from "a rare, intense" or extreme" event in rock/stiff sand was developed. Their analysis concluded that the potential accelerations from such an event would be 0.3 g for the rock spectrum and 0.25 g for the mudline spectrum within a 200-year return period.

McClelland Engineering used a phased interdisciplinary approach to determine the potential earthquake ground motion at the proposed platform site. This procedure required, 1) the determination of geotechnical soil properties from site specific soilforings; 2) seismotecanic modeling of the Santa Barbara channel and Santa Maria Basin areas; 3) the determination of seismic risk, and probable ground acceleration during both "extreme" and "strength" level seismic events; and 4) the development of both an "extreme" and "strength" level responespectra for Platform Hermosa. Their procedure, described in McClelland Engineering's report to Chevron (Reference 2.5.9), follows:

1. Determination of subsurface soil characteristics (Reference 2.5.9).

2. Faults believed to be active or potentially active were mapped using compiled geologic and seismic information (Figure 4.2 and Table 4.2).

3. A source model for the generation of significant earthquakes was constructed. Table 4.3 lists these faults, along with their distances from the proposed platform site and their estimated limiting maximum earthquakes (i.e. Extreme event).

4. A seismic risk analysis was conducted by combining the source model with acceleration levels at the site (plate C-6 McClelland report for attenuation relationships) and with seismic activity (plate C-5 McClelland report). In addition, background seismicity, not associated with a specific source, was also specified.

5. A 200-year mean recurrence interval was used to select a zero period acceleration for the design response spectrum (plate C-11 McClelland report). An extreme response spectra (plate C-14 McClelland report) was also constructed. On Table 4.3, the limiting magnitude earthquakes are also the extreme level events.

As part of Federal requirement OCS Order #8, Chevron will determine the proposed platforms structural response to earthquake loads. A Certified Verification Agent (CVA) will also verify the earthquake design for platform Hermosa.

The intent of the Federal requirements is to insure that structures subjected to earthquake loading have adequate energy absorption capacity to prevent collapse under a rare, intense earthquake. This ductility check must demonstrate that the structure-foundation system is capable of absorbing at least four times the amount of energy associated with the level of structural response determined in the strength analysis with the structure remaining stable.

Studies by both Dames & Moore (Reference 2.5.13) and McClelland Engineers, Inc. (Reference 2.5.9) conclude that the platform site will not be effected by sudden fault displacements, ground failure or tsunamis. They also present the following conclusions concerning the possible failure modes of the near surface sediments from earthquake activity.

1. Ground Rupture

A review of the published literature and an analysis of the test borings and high resolution geophysical surveys indicates that there are no fault traces beneath the proposed site. Therefore, ground rupturing from fault movement is not anticipated during any nearby earthquakes.

2. Ground Failure

(a) Liquefaction

The subsurface soils at the proposed site can safely support the proposed drilling and production equipment. The studies to evaluate soil properties and liquefaction potential indicate that the potential for liquefaction at the proposed site is extremely low (Reference 2.5.9).

(b) Slumping

The ocean bottom in the immediate area has a slope that varies from 5% to 7%. McClelland (Reference 2.5.9 page D-4) concludes that the very soft Recent material on this slope may tend to slip and creep downslope under static and/or seismic loading. The pockmarked characteristic of this slope may have resulted from such movements. Chevron plans to design the platform so that this thin 14 ft. layer does not support the platform.

4.2.8 Tsunami Hazards

Based on published records and the location of the platform site in open water, tsunami damage will not be a factor to be considered at the proposed platform location. Tsunamis or seismic waves are large oceanic waves that are generated by earthquakes, submarine volcanic eruptions or large submarine landslides. The waves are formed in groups having great wave length and a long period. In deep water, wave heights (crest to trough) may be a few meters or less, wave lengths may be a hundred miles or more and with velocities greater than 400 knots (460 mph). However, as a tsunami enters shallower waters, the wave velocity diminishes and their heights increase. Waves can crest at heights of more than 30m (100 feet) and strike with devastating force. Tsunami waves do not impact vessels or structures in open water because of their low amplitude and great breadth.

The largest tsunami ever reported in California followed the 1812 earthquake in the Santa Barbara Channel. This wave may have reached land elevations of 50 feet (15.2m) at Gaviota and 30-35 feet (9.1-10.7m) at Santa Barbara. The most recent tsunami to impact the California coast line occurred following the 1964 Alaskan earthquake. Only minor damage was sustained by small craft in some of the coastal harbors.

4.2.9 Subsidence

Surface subsidence due to reservoir fluid withdrawal is not expected to be a problem at the Pt. Arguello field. It is expected to be neligible for the following reasons:

1) The region has been in compression since the end of Miocene time.

2) The trapping structure, at the reservoir depth, has a good arch supporting structure with associated thrust faulting.

3) The depth of burial of the oil producing section is over 6000 feet below the ocean floor. This thick section of overburden will furnish additional support.

4) The characteristic of the reservoir rock lends additional support because of its hard siliceous nature.

4.2.10 Hydrology

In the Pt. Arguello oil field area, no fresh water bearing formations, of any significance, are encountered below 1100 feet (335.3m). Above this depth, there is no electric log record. However, soil borings showed the sediments to consist mostly of tight clayey silts and silty clays with occasional thin interbeds of fine silty sand. This upper section contains interstitial saline water. Chevron has not encountered any fresh water bearing sands in any of the wells drilled to date.

4.2.11 Other Mineral Deposits

Other than hydrocarbons, there are no other known mineral deposits of either commercial or noncommercial value on or adjacent to Lease OCS P-0316.

4.3 Cultural Resources

The area around proposed Platform Hermosa and along the route of the proposed pipeline from Platform Hermosa to Pt. Conception was evaluated for cultural and archaeological resources. Dames & Moore (Reference 2.5.13, Appendix E) retained the services of Dr. Stephen P. Horne to make this evaluation. Their report was done in accordance Mineral Management Service's order NTL 77-3 dated March 1, 1977. This order only requires a cultured survey be made in waters of less than 394 feet (120 meters) in depth. Since the 394 feet water depth was only a short distance from the platform site their survey was continued out to water depth of 750 feet (230m).

They concluded from this review that there are no identifiable prehistoric cultural resources in the area of the proposed projects. Side scan sonar showed three anomalies that have been interpreted as possible shipwrecks. These areas will be avoided during anchoring activities connected with platform and pipeline construction.

4.4 Platform Structure

4.4.1. Geotechnical Design Criteria

Platform foundation design criteria for Platform Hermosa will be based on geotechnical information obtained from extensive state-of-the-art investigations conducted in late 1981 by McClelland Engineers, Inc. The information was obtained from pushed sample recovery, downhole cone penetrometer testing, in-situ remote vane testing, and gamma ray logging in deep boreholes. Additionally single, shallow, continuous cone penetrometer soundings were done. Results from the offshore boring program indicate that soil conditions at the platform site is favorable for the proposed construction and that potential liquefacation and slumping in subsurface soils will not be a hazard.

The static and dynamic laboratory program consisted of both conventional (classification, consolidation, triaxial, and simple shear strength) and special (cyclic triaxial, cyclic simple shear, and resonant column) testing. The testing and analyses defined soil shear strength characteristics, lateral pile responses, axial pile responses, potential for scour, and the potential for soil liquefacation. All associated boring logs, laboratory test results, and engineering reports will be included in the detailed platform design submittal to the Minerals Management Services (MMS) in accordance with the Platform Verification Program (MMS OCS Order No. 8). Platform foundation design criteria will utilize API-RP2A guidelines for establishing minimum design criteria.

4.4.2 Design Standards

The platform structure will be designed in compliance with the MMS OCS Order NO. 8, API RP2A "Recommended Practices for Planning, Designing and Constructing Offshore Platforms", and applicable American Institute of Steel Construction (AISC) guidelines. Additionally, the platform will meet or exceed all the elements of the MMS's "Requirements for Verifying the Structural Integrity of OCS Platforms".

4.4.3 Environmental Design Criteria

4.4.3.1 Earthquake Design Criteria

The earthquake design criterion is based on a detailed evaluation of earthquake potential in the western portion of the Santa Barbara Channel. It specifically accounts for the regional and local geologic structure, local active faulting, and local soil conditions. The design criterion is site specific. The platform design will meet both strength and ductility requirements for earthquake loading (i.e. paragraph 4.2.7).

The strength requirement assures resistance to those ground motions most likely to occur during the platform's life without the platform sustaining any significant sructural damage. The strength level design site motion is expressed in terms of a smoothed response spectra. The response spectrum method of analysis is used to evaluate the platform's dynamic elastic response to earthquake ground motion.

The ductility requirement provides a platform-foundation system that has sufficient energy absorption capacity such that the platform will not collapse in the event of rare intense ground shaking. Careful joint detailing and fabrication will ensure that the structures perform as designed under earthquake loadings. The seismic environment does not present any problems that preclude the safe design, installation and operation of the offshore structure.

4.4.3.2 Oceanographic Design Criteria

The oceanographic design criteria provide for waves, currents, tides, and winds which may occur during the expected life of the structure. A review of existing oceanographic data has been made to develop estimates of these values. Hindcasting models were made to provide required site specific information. An analysis of the oceanographic data and hindcast models indicate that oceanographic conditions offer no problems for the safe design, installation and operation of the offshore structure.

a. Waves

A sophisticated wave hindcast model which develops the directional wave spectrum was used to determine design waves at the platform site during selected west coast storm events. The model was developed by Ocean Weather, Inc. and verified with site specific measurements. This state-of-the-art technology was used to determine design wave heights.

b. Currents

Extreme ocean current velocities were based on an analysis by Intersea Research Corporation combining tidal wind driven and general background currents as a function of depth. The Intersea study was based on on-site measurements, historical data and theoretical considerations.

c. Wind

Ocean Weather, Inc. will build a state-of-the-art wind model of the offshore Santa Barbara Channel region that will be used to determine the gusts which the platform will be designed to withstand. This model will be calibrated to an extensive meteorological data set obtained offshore during past significant storms to provide the most accurate wind design criteria available.

d. Marine Growth

An extensive study of marine growth on other Santa Barbara Channel platforms will provide the basis for the marine growth design criteria.

4.4.4 Platform Design

The design work is being performed by Fluor Ocean Services and verified by a Certified Verification Agent according to OCS Order No. 8. The design will consist primarily of stress analyses using established site specific design criteria to evaluate structural responses to extreme oceanographic, installation, operational, fatigue, and earthquake loading conditions. A comprehensive detailing of design criteria, site conditions, design analyses, and structural design will be provided as part of the Verification Documentation. A conceptual description of the proposed platform follows:

The platform will be a single piece, eight leg conventional jacket type platform installed in 602 ft. (183 meters) of water. The jacket will support a three-level deck including well conductors. Preliminary elevation views of the platform jacket are shown in Fig. 4-3. The jacket configuration will be similar to that of conventional jacket platforms. The deck structure will provide space and load carrying capability for two drilling rigs and oil and gas production facilities. Layout arrangements of the drilling and production decks are shown in Figure 4.4, 4.5, 4.6, 4.7, 4.8 and 4.9.

4.5 Platform Installation

Fabrication and installation will follow conventional procedures for such structures. Complete details for the platform will be provided as part of the Verification Documentation pursuant to OCS Order No. 8. Installation of the platform and commissioning of the facilities will require four to six months. Major marine equipment required for installation of the platform will include a derrick barge or ship, the jacket launch barge, cargo barges, tug boats, supply boats, and crewboats.

Generalized procedures applicable to the platform are as follows:

4.5.1 Fabrication - The principal components of the platform; the jacket, piling, and deck modules will be fabricated and assembled in onshore yards. Sites for construction and assembly will be determined when contracts are awarded.

4.5.2 Jacket Tow and Launch - Upon completion of fabrication, the jacket structure will be loaded onto a transportation/launch barge and secured for tow. The jacket will be towed from its fabrication site to the Santa Barbara Channel where it will be launched from its transport barge and floated horizontally in the water.

4.5.3 Jacket Upending - Following launch, the jacket will be towed to its installation site and upended by the flooding of selected leg compartments. Final positioning will be made with the derrick barge and further flooding will set the jacket on the sea floor.

4.5.4 Pile and Conductor Installation - The main piles will be installed through the jacket legs in approximately 100 foot long welded sections. The skirt piles will be installed through pile sleeves and driven to their design penetration with the aid of a retrievable follower. Design penetration is estimated to be 330 feet below the mudline. Both main and skirt piles will be grouted to the jacket structure. The well conductors will be installed with the drilling rig at the time each well is spudded.

4.5.5 Deck Setting - Jacket captruss units will be set and welded to the jacket for support of the deck structure. The decks, composed of four to six modules with production equipment preinstalled, will be transported by barge from the assembly site to the offshore installation site. The modules will be lifted by the derrick barge, set on the jacket captruss and welded into place. The flare boom and other miscelleously miscellaneous components will then be attached to the deck structure.

4.5.6 Hookup and Commissioning - Following setting of deck modules, offshore crews will make structural, piping, electrical and instrumentation interconnections between modules, and will test and commission all systems.

4.6 Platform Removal

Platform Hermosa is currently expected to be a central platform for the Pt. Arguello area. Therefore, it may be used beyond the time of reservoir from which it produces is depleted. The platform may serve as a central pumping station, storage station and/or may produce power for other platforms. When these functions can no longer be served, the platform will be removed in accordance with the applicable MMS regulations. The structure will be disposed of or used as an artificial reef as dictated by the applicable environmental engineering and economic restraints at the time. Ultimate disposition of the platform (i.e. salvage for scrap, salvage for placement as an artificial reef, etc.) will depend on various factors which must be addressed at that time.

4.7 References

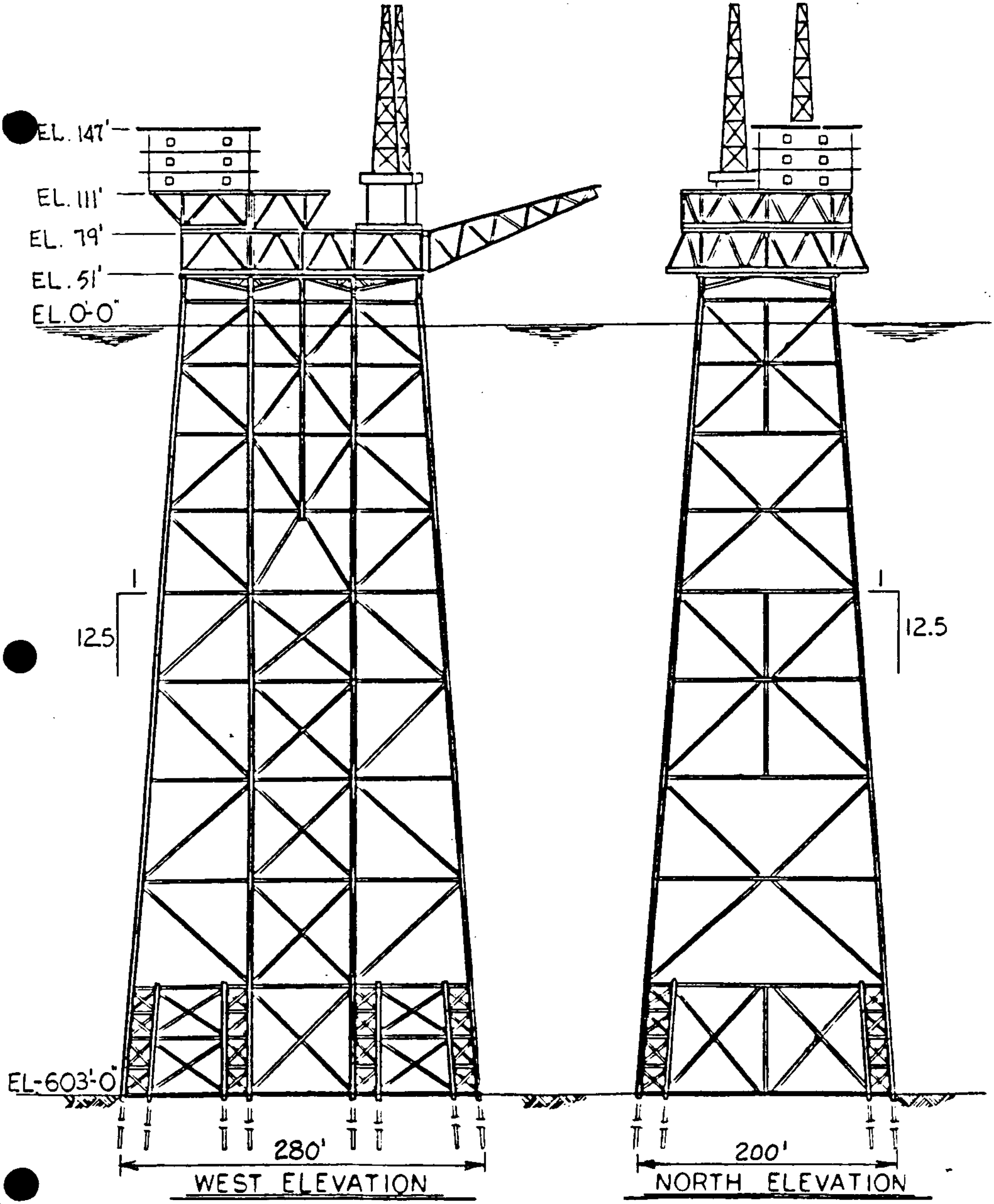
4.7.1 Woodward-Clyde Consultants (1982). Geochemical Investigation of 6 Foundation Borings, Offshore California Interpretative Report. Prepare for McClelland, Inc. 12 p.

Bathymetry Data

Pursuant to the Freedom of Information Act (5 U.S.C. 552) and its implementing regulations (43 CFR Part 2) and as provided in 30 CFR 550.199(b), the information contained in this section is deleted from the public information copy of this submission.

Proprietary

Not for Public Release



Chevron U.S.A. Inc.
Platform Hermosa

Fluor Ocean Services, Inc.
Job No. 409801

FIGURE 4-3

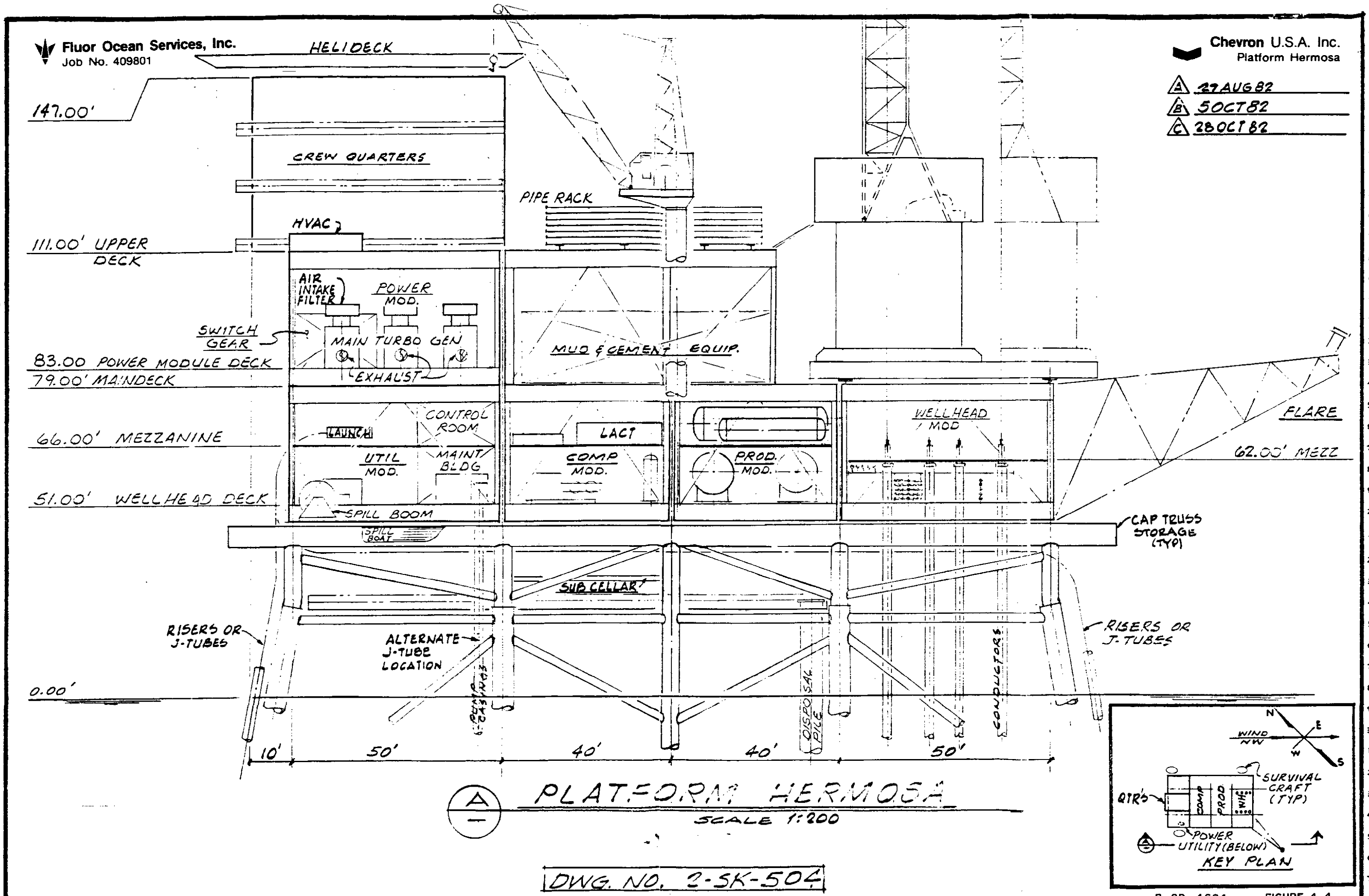

Fluor Ocean Services, Inc.
Job No. 409801
Chevron U.S.A. Inc.
Platform Hermosa
A 27AUG82
B 5OCT82
C 28OCT82
HELIDECK
147.00'
CREW QUARTERS
PIPE RACK
HVAC
111.00' UPPER DECK
AIR INTAKE FILTER
POWER MOD.
SWITCH GEAR
MAIN TURBO GEN
MUD & CEMENT EQUIP.
83.00 POWER MODULE DECK
79.00' MAINDECK
EXHAUST
LAUNCH
CONTROL ROOM
LACT
WELLHEAD MOD
FLARE
66.00' MEZZANINE
UTIL MOD.
MAINT BLDG
COMP MOD.
PROD. MOD.
62.00' MEZZ
51.00' WELLHEAD DECK
SPILL BOOM
SPILL BOAT
CAP TRUSS STORAGE (TYP)
SUB CELLAR
RISERS OR J-TUBES
ALTERNATE J-TUBE LOCATION
CONDUCTORS
DISPOSAL PILE
0.00'
10'
50'
40'
40'
50'
WIND
NW
N
E
W
S
QTR'S
COMP
PROD
WHD
SURVIVAL CRAFT (TYP)
POWER UTILITY (BELOW)
KEY PLAN
PLATFORM HERMOSA
SCALE 1:200
DWG. NO. 2-SK-504
B-SB-4624

FIGURE 4-4

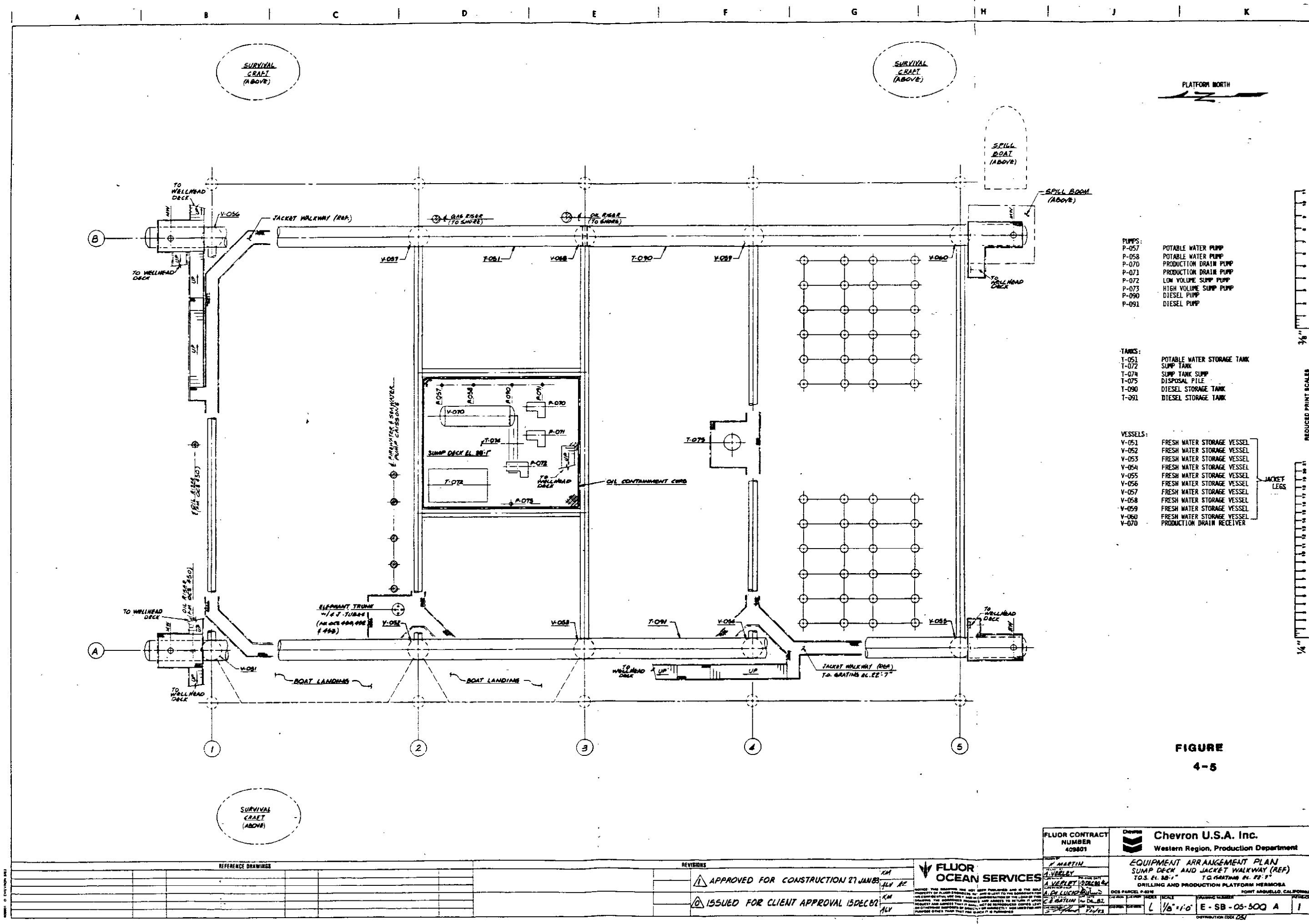
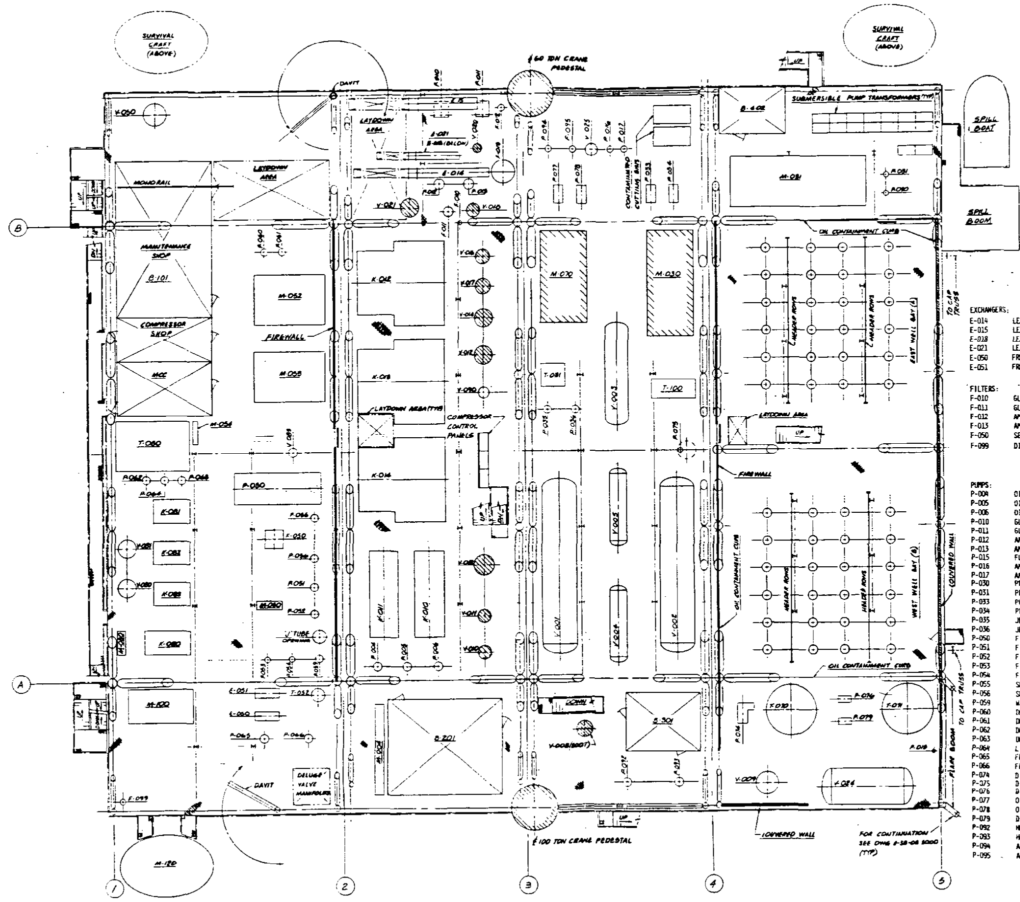

PLATFORM NORTH
SURVIVAL CRAFT (ABOVE)
SPILL BOAT (ABOVE)
SPILL BOOM (ABOVE)
JACKET WALKWAY (REF)
GAS RISER (TO SHORE)
OIL RISER (TO SHORE)
TO WELLHEAD DECK
OIL CONTAINMENT CURB
SUMP DECK EL 38'-1"
ELEPHANT TRUNK
BOAT LANDING
PUMPS:
P-057 POTABLE WATER PUMP
P-058 POTABLE WATER PUMP
P-070 PRODUCTION DRAIN PUMP
P-071 PRODUCTION DRAIN PUMP
P-072 LOW VOLUME SUMP PUMP
P-073 HIGH VOLUME SUMP PUMP
P-090 DIESEL PUMP
P-091 DIESEL PUMP
TANKS:
T-051 POTABLE WATER STORAGE TANK
T-072 SUMP TANK
T-074 SUMP TANK SUMP
T-075 DISPOSAL PILE
T-090 DIESEL STORAGE TANK
T-091 DIESEL STORAGE TANK
VESSELS:
V-051 FRESH WATER STORAGE VESSEL
V-052 FRESH WATER STORAGE VESSEL
V-053 FRESH WATER STORAGE VESSEL
V-054 FRESH WATER STORAGE VESSEL
V-055 FRESH WATER STORAGE VESSEL
V-056 FRESH WATER STORAGE VESSEL
V-057 FRESH WATER STORAGE VESSEL
V-058 FRESH WATER STORAGE VESSEL
V-059 FRESH WATER STORAGE VESSEL
V-060 FRESH WATER STORAGE VESSEL
V-070 PRODUCTION DRAIN RECEIVER
JACKET LEGS
REDUCED PRINT SCALES
REFERENCE DRAWINGS
REVISIONS
APPROVED FOR CONSTRUCTION 27 JAN 83
ISSUED FOR CLIENT APPROVAL 15 DEC 82
FLUOR OCEAN SERVICES
FLUOR CONTRACT NUMBER 409801
Chevron U.S.A. Inc.
Western Region, Production Department
EQUIPMENT ARRANGEMENT PLAN
SUMP DECK AND JACKET WALKWAY (REF)
DRILLING AND PRODUCTION PLATFORM HERMOSA
POINT ARGUELLO, CALIFORNIA
1/8" = 1'-0"
E-SB-05-500 A
1

FIGURE 4-5



PLATFORM NORTH

VESSELS:	
V-001	PRODUCTION SEPARATOR
V-002	PRODUCTION SEPARATOR
V-003	LARGE TEST SEPARATOR
V-004	BAY A SMALL TEST SEPARATOR
V-005	BAY B SMALL TEST SEPARATOR
V-009	WELL CLEANUP SEPARATOR
V-010	FIRST STAGE VAPOR RECOVERY SUCT SCRUBBER
V-011	MGC FIRST STAGE SUCTION SCRUBBER
V-012	MGC SECOND STAGE SUCTION SCRUBBER
V-013	MGC THIRD STAGE SUCTION SCRUBBER
V-014	MGC THIRD STAGE DISCHARGE SCRUBBER
V-016	GLYCOL CONTACTOR
V-017	DRY GAS SCRUBBER
V-018	GLYCOL FLASH TANK
V-020	AMINE CONTACTOR
V-021	AMINE SURGE TANK
V-024	FLARE CONDENSATE K.O. DRUM
V-025	AMINE REFLUX DRUM
V-050	POTABLE WATER PRESSURE VESSEL
V-061	FRESH WATER EXPANSION TANK
V-080	INSTRUMENT AIR RECEIVER
V-081	UTILITY AIR RECEIVER
V-083	STARTING AIR VOLUME BOTTLE
V-090	FUEL GAS SCRUBBER

EXCHANGERS:	
E-014	LEAN GLYCOL COOLER
E-015	LEAN/RICH GLYCOL EXCHANGER
E-018	LEAN AMINE COOLER
E-021	LEAN/RICH AMINE EXCHANGER
E-050	FRESH WATER PLATE EXCHANGER
E-051	FRESH WATER PLATE EXCHANGER

FILTERS:	
F-010	GLYCOL CARTRIDGE FILTER
F-011	GLYCOL ACTIVATED CARBON FILTER
F-012	AMINE FILTER
F-013	AMINE FILTER
F-050	SEAWATER STRAINER
F-099	DIESEL FUEL COALESCER

TANKS:	
T-031	PRODUCED WATER SURGE TANK
T-050	DEMINERALIZED WATER STORAGE TANK
T-070	DIRTY OIL TANK
T-071	DIRTY OIL TANK
T-100	DEMULSIFIER STORAGE TANK

PUMPS:	
P-004	OIL CHARGE PUMP
P-005	OIL CHARGE PUMP
P-006	OIL CHARGE PUMP
P-010	GLYCOL CIRCULATION PUMP
P-011	GLYCOL CIRCULATION PUMP
P-012	AMINE CIRCULATION PUMP
P-013	AMINE CIRCULATION PUMP
P-015	FLARE CONDENSATE PUMP
P-016	AMINE REFLUX PUMP
P-017	AMINE REFLUX PUMP
P-030	PRODUCED WATER RECIRCULATION PUMP
P-031	PRODUCED WATER RECIRCULATION PUMP
P-033	PRODUCED WATER SAND PUMP
P-034	PRODUCED WATER SAND PUMP
P-035	JET WATER PUMP
P-036	JET WATER PUMP
P-050	FIREWATER PUMP (DIESEL)
P-051	FIREWATER PUMP
P-052	FIREWATER PUMP
P-053	FIREWATER JOCKEY PUMP
P-054	FIREWATER JOCKEY PUMP
P-055	SEAWATER PUMP
P-056	SEAWATER PUMP
P-059	WASHDOWN BOOSTER PUMP
P-060	DESALINATED WATER PUMP
P-061	DESALINATED WATER PUMP
P-062	DEMINERALIZED WATER PUMP
P-063	DEMINERALIZED WATER PUMP
P-064	L.P. DEMINERALIZED WATER PUMP
P-065	FRESH WATER CIRCULATION PUMP
P-066	FRESH WATER CIRCULATION PUMP
P-074	DIRTY OIL
P-075	DISPOSAL PILE PUMP
P-076	DIRTY OIL TANK DRAIN PUMP
P-077	OILY WATER SAND PUMP
P-078	OILY WATER SAND PUMP
P-079	DIRTY OIL TANK DRAIN PUMP
P-092	HEAT MEDIUM CIRCULATION PUMP
P-093	HEAT MEDIUM CIRCULATION PUMP
P-094	AUXILIARY HEAT MEDIUM CIRC PUMP
P-095	AUXILIARY HEAT MEDIUM CIRC PUMP

BUILDINGS:	
B-101	MCC/COMPRESSOR SHOP/MAINTENANCE SHOP
B-201	MCC (COMPRESSOR)
B-301	MCC (PRODUCTION)
B-402	CUT LAB

MISCELLANEOUS	
M-004	METER PROVER
M-030	PRODUCED WATER C.P.I. SEPARATOR
M-031	AIR FLOTATION CELL
M-050	HYPOCHLORITE GENERATOR
M-052	DESALINATOR
M-053	DESALINATOR
M-054	DEMINERALIZER
M-070	OILY WATER C.P.I. SEPARATOR
M-080	INSTRUMENT AIR DRYER
M-100	SEWAGE TREATMENT UNIT
M-120	SURVIVAL CRAFT

COMPRESSORS:	
K-010	VAPOR RECOVERY COMPRESSOR
K-011	VAPOR RECOVERY COMPRESSOR
K-012	MAIN GAS COMPRESSOR
K-013	MAIN GAS COMPRESSOR
K-014	MAIN GAS COMPRESSOR
K-080	INSTRUMENT AIR COMPRESSOR
K-081	UTILITY AIR COMPRESSOR
K-082	UTILITY AIR COMPRESSOR
K-083	UTILITY AIR COMPRESSOR

REDUCED PRINT SCALES 3/8" 1/4"

FIGURE 4-6

REFERENCE DRAWINGS

REVISIONS

1 APPROVED FOR CONSTRUCTION 27JAN83 KM

0 ISSUED FOR CLIENT APPROVAL 15DEC82 KM

FLUOR OCEAN SERVICES

FLUOR CONTRACT NUMBER 409801

Chevron U.S.A. Inc.
Western Region, Production Department

EQUIPMENT ARRANGEMENT PLAN
WELLHEAD DECK EL 51'-0"

DRILLING AND PRODUCTION PLATFORM HERMOSA
POINT ARGUELLO, CALIFORNIA

OCS PARCEL P-0316

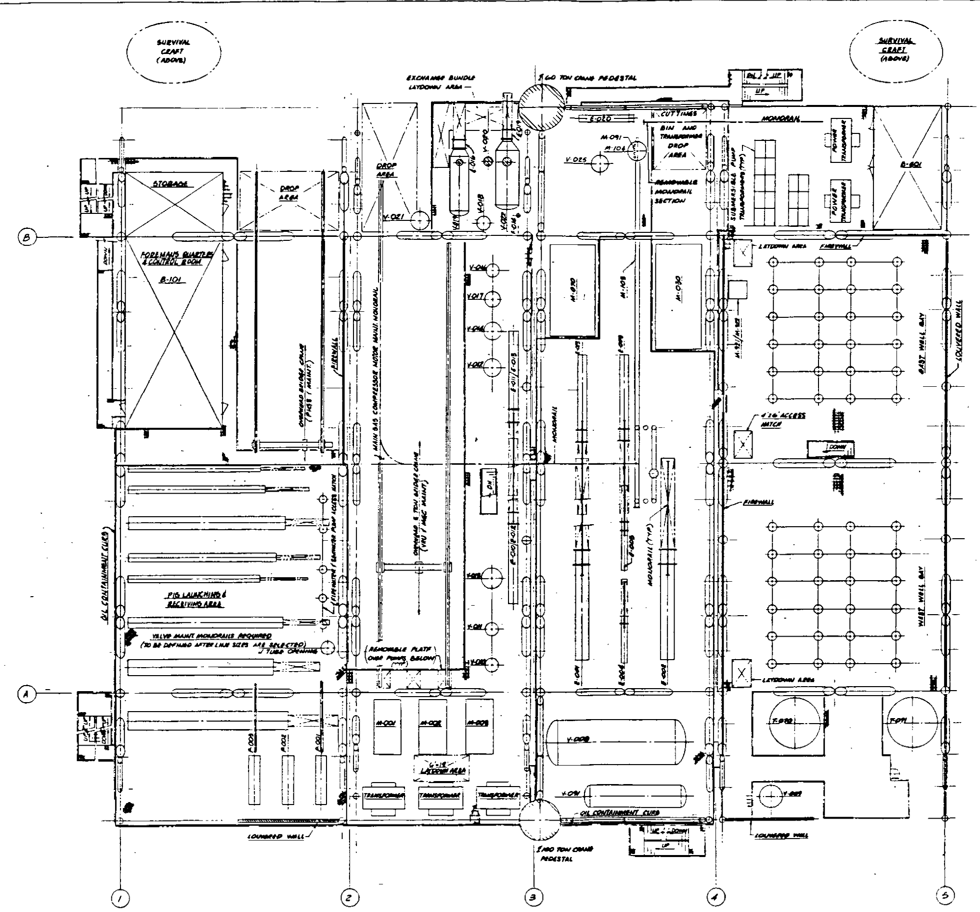
K. MARTIN
J. VERLEY
J. VERLEY
A. DeLUCIO
E. E. GATLIN

SCALE 1/8"=1'-0"

DRAWING NUMBER E-SB-05-500 B

REVISION 1

DISTRIBUTION CODE 051



PLATFORM NORTH

EXCHANGERS:

E-001	PRODUCTION PREHEATER
E-002	PRODUCTION PREHEATER
E-003	LARGE TEST PREHEATER
E-004	BAY A TEST PREHEATER
E-005	BAY B TEST PREHEATER
E-010	VAPOR RECOVERY DISCHARGE COOLER
E-011	MGC FIRST STAGE DISCHARGE COOLER
E-012	MGC SECOND STAGE DISCHARGE COOLER
E-013	L.P. OVERHEAD VAPOR COOLER
E-016	GLYCOL REGENERATOR REBOILER
E-019	AMINE REGENERATOR REBOILER
E-020	AMINE REGENERATOR CONDENSER
E-023	VAPOR RECOVERY COMPRESSOR SUCTION COOLER

FILTERS:

F-014	RICH GLYCOL CARTRIDGE FILTER

PUMPS:

P-001	OIL SHIPPING PUMP
P-002	OIL SHIPPING PUMP
P-003	OIL SHIPPING PUMP

TANKS:

T-070	DIRTY OIL TANK
T-071	DIRTY OIL TANK

VESSELS:

V-008	WET OIL SURGE TANK
V-009	WELL CLEANUP SEPARATOR
V-010	FIRST STAGE VAPOR RECOVERY SUCTION SCRUBBER
V-011	MGC FIRST STAGE SUCTION SCRUBBER
V-012	MGC SECOND STAGE SUCTION SCRUBBER
V-013	MGC THIRD STAGE SUCTION SCRUBBER
V-014	MGC THIRD STAGE DISCHARGE SCRUBBER
V-016	GLYCOL CONTACTOR
V-017	DRY GAS SCRUBBER
V-018	GLYCOL FLASH TANK
V-019	GLYCOL REGENERATOR
V-020	AMINE CONTACTOR
V-021	AMINE FLASH TANK
V-022	AMINE REGENERATOR
V-025	AMINE REFLUX DRUM
V-091	HEAT MEDIUM EXPANSION TANK

BUILDINGS:

B-101	STORAGE/CONTROL
B-401	MCC (WELLHEAD)

MISCELLANEOUS:

M-001	LACT UNIT
M-002	LACT UNIT
M-003	LACT UNIT
M-030	PRODUCED WATER C.P.I. SEPARATOR
M-070	OILY WATER C.P.I. SEPARATOR
M-091	CYCLONE SAND SEPARATORS
M-103	CONTAMINATED CUTTINGS SCREW CONVEYOR
M-104	CUTTINGS DEWATERING SHAKER
M-921	HYDRAULIC UNIT
M-922	HYDRAULIC CONTROL

FIGURE

4-7

REFERENCE DRAWINGS

REVISIONS

1	APPROVED FOR CONSTRUCTION 27 JAN 83	KM / ALV
0	ISSUED FOR CLIENT APPROVAL 15 DEC 82	KM / ALV

FLUOR OCEAN SERVICES

FLUOR CONTRACT NUMBER 409801

Chevron U.S.A. Inc.
Western Region, Production Department

EQUIPMENT ARRANGEMENT PLAN
WELLHEAD DECK MEZZANINE EL. 63'-11"

DRILLING AND PRODUCTION PLATFORM HERMOSA

OCS PARCEL P-0316 — POINT ARGUELLO, CALIFORNIA

K. MARTIN · A. VERLEY · A. VERLEY · A. DeLUCIO · C. B. GATLIN

L · 1/8" = 1'-0" · E-SB-05-500 C · 1

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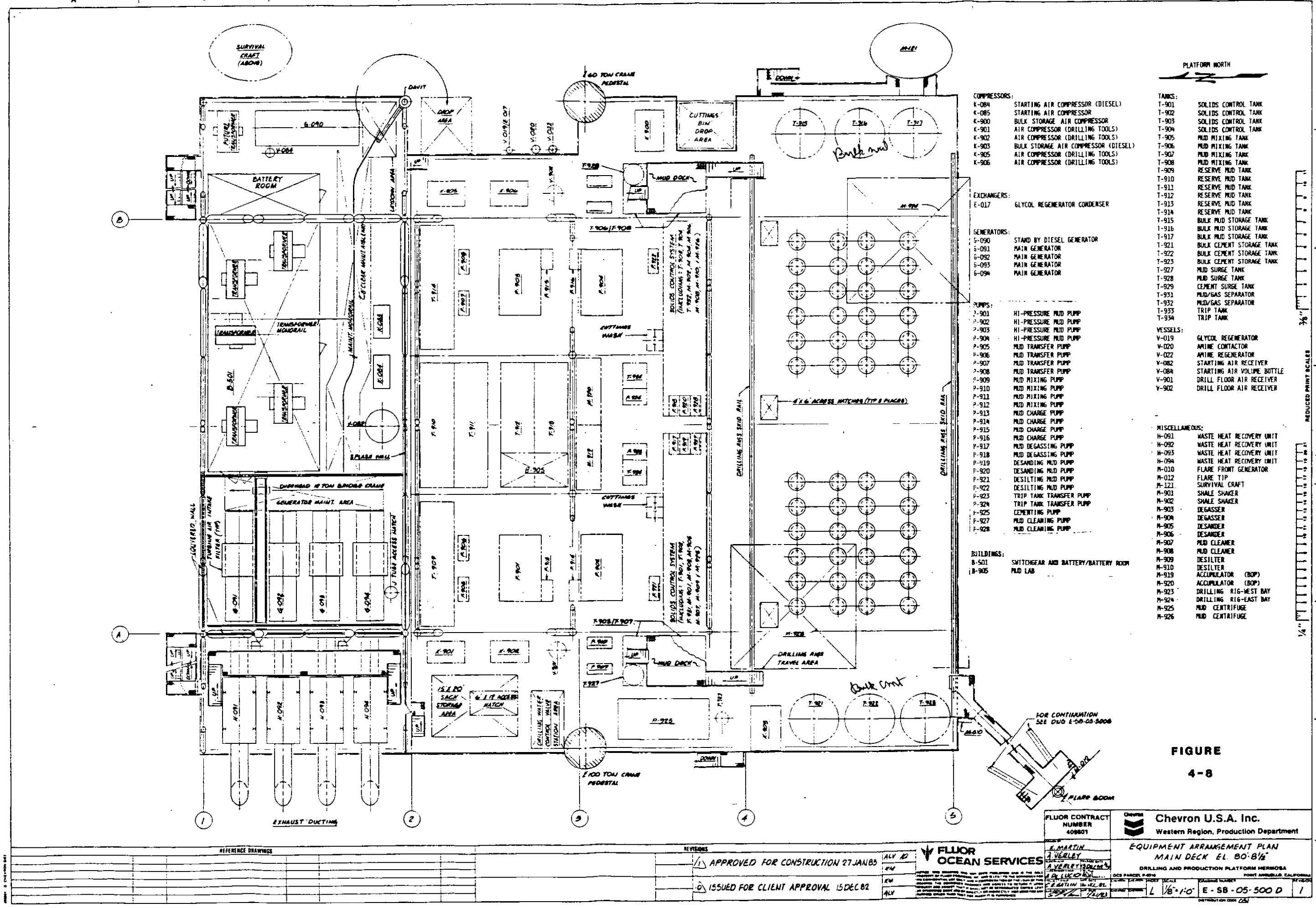

PLATFORM NORTH
COMPRESSORS:
K-084 STARTING AIR COMPRESSOR (DIESEL)
K-085 STARTING AIR COMPRESSOR
K-900 BULK STORAGE AIR COMPRESSOR
K-901 AIR COMPRESSOR (DRILLING TOOLS)
K-902 AIR COMPRESSOR (DRILLING TOOLS)
K-903 BULK STORAGE AIR COMPRESSOR (DIESEL)
K-905 AIR COMPRESSOR (DRILLING TOOLS)
K-906 AIR COMPRESSOR (DRILLING TOOLS)
EXCHANGERS:
E-017 GLYCOL REGENERATOR CONDENSER
GENERATORS:
G-090 STAND BY DIESEL GENERATOR
G-091 MAIN GENERATOR
G-092 MAIN GENERATOR
G-093 MAIN GENERATOR
G-094 MAIN GENERATOR
PUMPS:
P-901 HI-PRESSURE MUD PUMP
P-902 HI-PRESSURE MUD PUMP
P-903 HI-PRESSURE MUD PUMP
P-904 HI-PRESSURE MUD PUMP
P-905 MUD TRANSFER PUMP
P-906 MUD TRANSFER PUMP
P-907 MUD TRANSFER PUMP
P-908 MUD TRANSFER PUMP
P-909 MUD MIXING PUMP
P-910 MUD MIXING PUMP
P-911 MUD MIXING PUMP
P-912 MUD MIXING PUMP
P-913 MUD CHARGE PUMP
P-914 MUD CHARGE PUMP
P-915 MUD CHARGE PUMP
P-916 MUD CHARGE PUMP
P-917 MUD DEGASSING PUMP
P-918 MUD DEGASSING PUMP
P-919 DESANDING MUD PUMP
P-920 DESANDING MUD PUMP
P-921 DESILTING MUD PUMP
P-922 DESILTING MUD PUMP
P-923 TRIP TANK TRANSFER PUMP
P-924 TRIP TANK TRANSFER PUMP
P-925 CEMENTING PUMP
P-927 MUD CLEANING PUMP
P-928 MUD CLEANING PUMP
BUILDINGS:
B-501 SWITCHGEAR AND BATTERY/BATTERY ROOM
B-905 MUD LAB
TANKS:
T-901 SOLIDS CONTROL TANK
T-902 SOLIDS CONTROL TANK
T-903 SOLIDS CONTROL TANK
T-904 SOLIDS CONTROL TANK
T-905 MUD MIXING TANK
T-906 MUD MIXING TANK
T-907 MUD MIXING TANK
T-908 MUD MIXING TANK
T-909 RESERVE MUD TANK
T-910 RESERVE MUD TANK
T-911 RESERVE MUD TANK
T-912 RESERVE MUD TANK
T-913 RESERVE MUD TANK
T-914 RESERVE MUD TANK
T-915 BULK MUD STORAGE TANK
T-916 BULK MUD STORAGE TANK
T-917 BULK MUD STORAGE TANK
T-921 BULK CEMENT STORAGE TANK
T-922 BULK CEMENT STORAGE TANK
T-923 BULK CEMENT STORAGE TANK
T-927 MUD SURGE TANK
T-928 MUD SURGE TANK
T-929 CEMENT SURGE TANK
T-931 MUD/GAS SEPARATOR
T-932 MUD/GAS SEPARATOR
T-933 TRIP TANK
T-934 TRIP TANK
VESSELS:
V-019 GLYCOL REGENERATOR
V-020 AMINE CONTACTOR
V-022 AMINE REGENERATOR
V-082 STARTING AIR RECEIVER
V-084 STARTING AIR VOLUME BOTTLE
V-901 DRILL FLOOR AIR RECEIVER
V-902 DRILL FLOOR AIR RECEIVER
MISCELLANEOUS:
H-091 WASTE HEAT RECOVERY UNIT
H-092 WASTE HEAT RECOVERY UNIT
H-093 WASTE HEAT RECOVERY UNIT
H-094 WASTE HEAT RECOVERY UNIT
M-010 FLARE FRONT GENERATOR
M-012 FLARE TIP
M-121 SURVIVAL CRAFT
M-901 SHALE SHAKER
M-902 SHALE SHAKER
M-903 DEGASSER
M-904 DEGASSER
M-905 DESANDER
M-906 DESANDER
M-907 MUD CLEANER
M-908 MUD CLEANER
M-909 DESILTER
M-910 DESILTER
M-919 ACCUMULATOR (BOP)
M-920 ACCUMULATOR (BOP)
M-923 DRILLING RIG-WEST BAY
M-924 DRILLING RIG-EAST BAY
M-925 MUD CENTRIFUGE
M-926 MUD CENTRIFUGE
REDUCED PRINT SCALES
SURVIVAL CRAFT (ABOVE)
BATTERY ROOM
60 TON CRANE PEDESTAL
100 TON CRANE PEDESTAL
DROP AREA
CUTTINGS BIN DROP AREA
MUD DOCK
CUTTINGS WASH
SOLIDS CONTROL SYSTEM
6'x 6' ACCESS HATCHES (TYP 8 PLACES)
DRILLING RIGS SKID RAIL
DRILLING RIGS TRAVEL AREA
GENERATOR MAINT. AREA
OVERHEAD 10 TON BRIDGE CRANE
LOUVERED WALL
EXHAUST DUCTING
15 X 20 SACK STORAGE AREA
FOR CONTINUATION SEE DWG E-SB-05-500B
FLARE BOOM
Bulk mud
Bulk Cmt
REFERENCE DRAWINGS
REVISIONS
1 APPROVED FOR CONSTRUCTION 27 JAN 83
0 ISSUED FOR CLIENT APPROVAL 15 DEC 82
FLUOR OCEAN SERVICES
FLUOR CONTRACT NUMBER 409801
Chevron U.S.A. Inc.
Western Region, Production Department
EQUIPMENT ARRANGEMENT PLAN
MAIN DECK EL 80'-8½"
DRILLING AND PRODUCTION PLATFORM HERMOSA
OCS PARCEL P-0316
POINT ARGUELLO, CALIFORNIA
K. MARTIN
J. VERLEY
A. VERLEY
C.E. GATLIN
L
1/8" = 1'-0"
E-SB-05-500 D
1

FIGURE 4-8

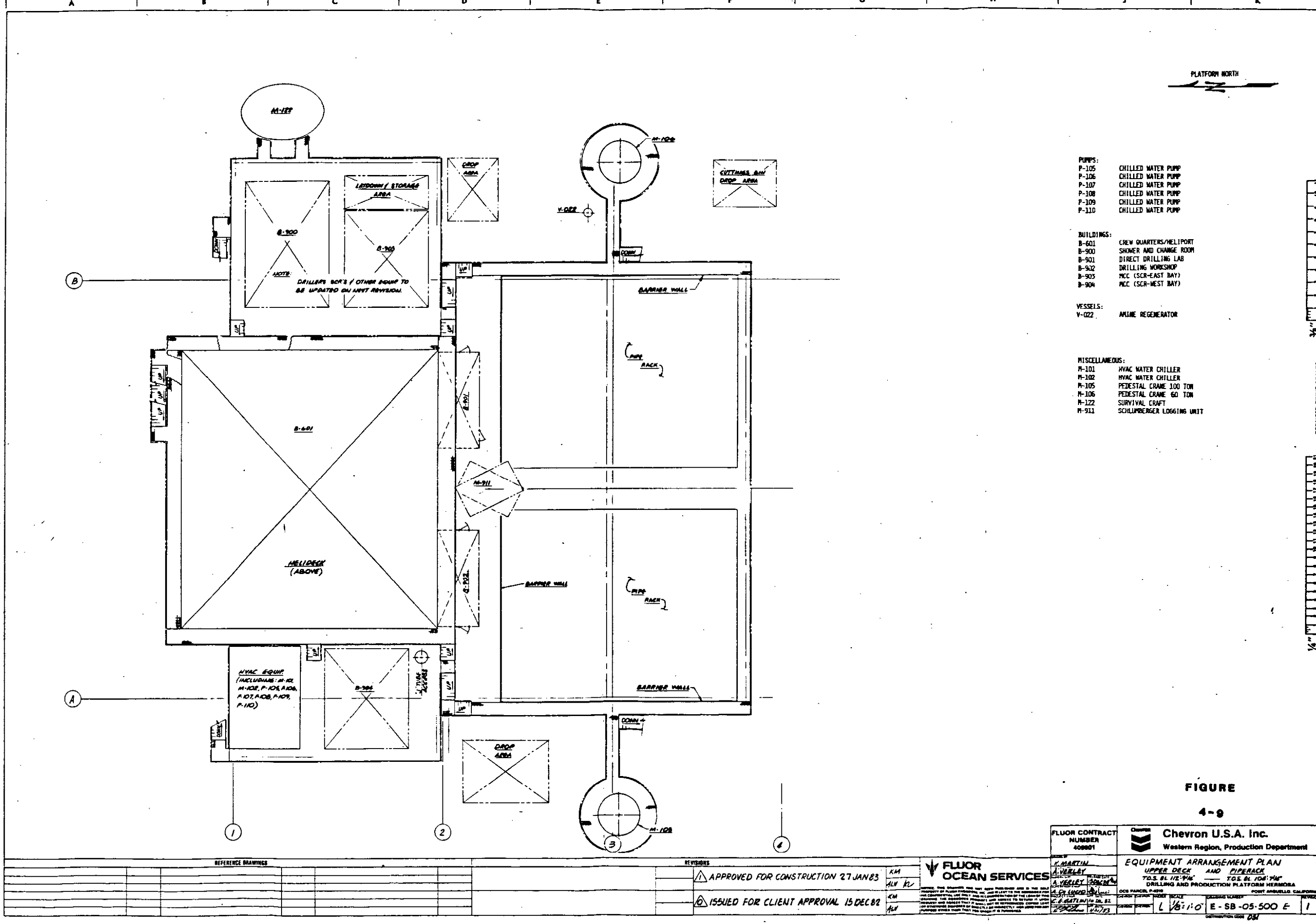

PLATFORM NORTH
PUMPS:
P-105 CHILLED WATER PUMP
P-106 CHILLED WATER PUMP
P-107 CHILLED WATER PUMP
P-108 CHILLED WATER PUMP
P-109 CHILLED WATER PUMP
P-110 CHILLED WATER PUMP
BUILDINGS:
B-601 CREW QUARTERS/HELIPORT
B-900 SHOWER AND CHANGE ROOM
B-901 DIRECT DRILLING LAB
B-902 DRILLING WORKSHOP
B-903 MCC (SCR-EAST BAY)
B-904 MCC (SCR-WEST BAY)
VESSELS:
V-022 AMINE REGENERATOR
MISCELLANEOUS:
M-101 HVAC WATER CHILLER
M-102 HVAC WATER CHILLER
M-105 PEDESTAL CRANE 100 TON
M-106 PEDESTAL CRANE 60 TON
M-122 SURVIVAL CRAFT
M-911 SCHLUMBERGER LOGGING UNIT
M-122
LAYDOWN / STORAGE AREA
DROP AREA
CUTTINGS BIN DROP AREA
B-900
B-903
NOTE: DRILLERS SCR'S / OTHER EQUIP TO BE UPDATED ON NEXT REVISION.
B-601
HELIDECK (ABOVE)
M-911
BARRIER WALL
PIPE RACK
HVAC EQUIP (INCLUDING: M-101, M-102, P-105, P-106, P-107, P-108, P-109, P-110)
B-904
DROP AREA
M-105
M-106
V-022
REFERENCE DRAWINGS
REVISIONS
1 APPROVED FOR CONSTRUCTION 27 JAN 83
0 ISSUED FOR CLIENT APPROVAL 15 DEC 82
FLUOR OCEAN SERVICES
FLUOR CONTRACT NUMBER 408801
Chevron U.S.A. Inc.
Western Region, Production Department
K. MARTIN
A. VERLEY
A. VERLEY
A. DE LUCIO
C. E. GATLIN
EQUIPMENT ARRANGEMENT PLAN
UPPER DECK AND PIPERACK
T.O.S. EL. 112'-9 1/16" — T.O.S. EL. 108'-7 1/16"
DRILLING AND PRODUCTION PLATFORM HERMOSA
OCS PARCEL P-0316
POINT ARGUELLO, CALIFORNIA
1/8" = 1'-0"
E - SB - 05 - 500 E
1
DISTRIBUTION CODE 051

FIGURE 4-9

TABLE 4.2
HISTORIC SEISMICITY

Event No.	Date	Earthquake(1) Magnitude (Richter)	Approximate Distance Of Epicenter From Site KM (MI)
1	22 Nov 1937	4.5	8 (5)
2	18 Nov 1936	4.5	11 (7)
3	01 Oct 1959	4.5	11 (7)
4	26 Aug 1949	4.2	14 (9)
5	27 Aug 1949	4.9	14 (9)
6	12 Dec 1902	VII	14 (9)
7	24 Dec 1937	4.0	15 (9)
8	19 Mar 1935	4.0	16 (10)
9	29 Sep 1938	4.0	16 (10)
10	17 Oct 1939	4.0	16 (10)
11	16 Jun 1940	4.0	16 (10)
12	09 Sep 1936	4.0	17 (11)
13	12 Jun 1969	4.3	22 (14)
14	30 Oct 1969	4.2	25 (16)
15 (2)	01 Nov 1936	4.0	25 (16)
16	04 Nov 1927	7.5	28 (17) to 50 (31)
17	13 Jun 1944	4.4	28 (17)
18	17 Dec 1934	4.5	33 (20)
19	18 Dec 1934	4.0	33 (20)
20	30 Nov 1944	4.1	36 (22)
21	28 Jul 1902	VIII	43 (27)
22	12 Jan 1915	VIII	43 (27)
23	16 Oct 1936	4.0	43 (27)
24	16 Feb 1937	4.0	45 (28)
25	21 Dec 1966	7.5	47 (29)
26	21 Jun 1966	4.1	48 (30)
27	01 Feb 1962	4.5	48 (30)
28	29 Mar 1928	V	54 (34)
29	29 May 1980	5.1	54 (34)
30	28 Jul 1945	4.2	57 (35)
31	03 Dec 1937	4.0	35 (35)
32	26 Jun 1933	4.3	59 (37)
33	13 Aug 1967	3.8	60 (37)
34	01 May 1973	3.7	63 (39)
35	24 Apr 1965	4.1	69 (43)
36	1830	VII	69 (43)
37	17 Dec 1852	VIII	69 (43)
38	01 Dec 1916	VII	69 (43)
39	27 Mar 1947	4.2	69 (43)
40	01 Apr 1945	5.4	75 (47)
41	26 Jun 1933	4.3	76 (47)
42	29 Jun 1925	6.25	79 (49)
43 thru 66	23 Feb 1969 thru 26 Dec 1971	4.0 to 5.9	63 (39)
67	27 Aug 1949	4.0	79 (49)
68	10 Nov 1940	4.0	84 (51)
69	16 Nov 1958	4.0	83 (52)
70	09 Aug 1956	4.0	85 (53)
71	29 Mar 1973	4.4	86 (53)
72	29 May 1854	6.0	88 (55)
73	09 Jan 1857	VII	88 (55)
74	13 Aug 1978	5.7	89 (55)
75	21 Oct 1953	4.0	89 (55)
76	16 Sep 1962	4.0	89 (55)
77 thru 107	26 Jun 1968 thru 31 Jul 1968	4.0 to 5.7	90 (56) to 105 (65)
108	13 Aug 1965	4.3	95 (59)
109	01 Jul 1941	6.0	98 (61)
110 thru 130	02 Oct 1938 thru 21 Nov 1941	4.0 to 4.5	98 (61)
131	07 Dec 1906	VI	98 (61)
132	21 May 1940	4.0	98 (61)
133	09 Jul 1917	VI	98 (61)

(1) Maximum Modified Mercalli Intensity is given for events lacking an assigned Richter magnitude. All earthquakes with V or greater intensity are included.

(2) This event has been recently assigned three separate eqicentral locations by difference researchers.

NOTE: Data obtained from N.O.A.A. Earthquake File Print, December 15 1981.

After McClelland Engineers - 1982

TABLE 4.3
SIGNIFICANT FAULTS

Fault(s) or Fault Zone	Nearest Distance To Site KM (MI)	Approx. Length KM (MI)	Maximum(1) Probable Earthquake	Limiting(2) Magnitude Earthquake	Relative(3) Activity Number
Point Arguello A	3 (2)	7 (4)	5¼	6¼	2
Point Arguello B	10 (6)	5 (3)	5	6¼	1
FIC	16 (10)	20 (13)	5¼	6¼	3
Honda	17 (11)	24 (15)	4½	5-3/4	1
Santa Ynez River	21 (13)	80 (50)	6¼	7	5
Pacifico	23 (14)	18 (11)	4¼	5½	1
Santa Cruz Island	24 (15)	120 (75)	5½	6-3/4	1
S. Branch Santa Ynez	27 (17)	23 (14	5½	6½	2
Hosgri	30 (19)	145 (91)	6¼	7	4
Lompoc	32 (20)	25 (16)	6¼	7	4
Purisima	37 (23)	26 (16)	5	6	2
Lions Head	37 (23)	60 (38)	5½	6-3/4	1
Main Santa Ynez	40 (25)	100 (63)	6	6-3/4	5
Pezzoni-Casmalia-Alamos-Baseline	47 (20)	80 (50)	6	6-3/4	5
Santa Rosa Island	50 (31)	60 (38)	5½	6-3/4	1
Santa Luica Bank	50 (31)	100 (63)	6¼	7	4
Santa Maria	55 (34)	38 (24)	6	6-3/4	5
Little Pine	58 (36)	60 (38)	5½	6-3/4	1
Arroyo-Parida	60 (38)	75 (47)	5-3/4	6-3/4	3
Suey	65 (41)	25 (16)	5¼	6½	1
Nacimiento	67 (31)	192 (120)	6	7¼	1
Big Pine	70 (44)	70 (44)	6	6-3/4	4
Red Mountain	87 (54)	55 (34)	6	7	3
Pitas Point	87 (54)	50 (31)	6	7	3
Oak Ridge	93 (58)	100 (63)	6¼	7¼	2
San Andreas	108 (68)	965 (603)	7½	8¼	5

1 Estimated Maximum Earthquake for a 250-year return period.

2 Estimated Maximum Earthquake for a 1,000-year return period (based on estimated maximum of 30 percent surface rupture of fault length during period) (computed from Slemmons, 1977).

3 Estimated relative activity rating on a scale of 1 (low) to 5 (high):

Minimum Age of Activity

5 Definite Historic Activity
4 Possible Historic Activity
3 Definite Holocene Activity
2 Possible Holocene Activity
1 Late Quaternary Activity

After McClelland Engineers 1982

Forecast Data

Pursuant to the Freedom of Information Act (5 U.S.C. 552) and its implementing regulations (43 CFR Part 2) and as provided in 30 CFR 550.199(b), the information contained in this section is deleted from the public information copy of this submission.

Proprietary

Not for Public Release

SECTION 5

DRILLING FACILITIES

TABLE OF CONTENTS

FIGURES

5. DRILLING FACILITIES

5.1 Introduction

Platform Hermosa will have slots for a maximum of 48 wells. Two electric drilling rigs and associated crews and services will be contracted to drill the 40 wells presently planned.

All operations will be conducted with safety to personnel and the environment as the primary consideration. Drilling operations, pollution prevention systems, and safety systems will be in accordance with Minerals Management Service Pacific Region OCS Orders No. 2 and No. 5, EPA NPDES permit conditions and API Standards. Complementing this section are "Critical Operations and Curtailment Plan" and "Oil Spill and Emergency Contingency Plan" for Platform Hermosa.

5.2 Drilling Equipment

All drilling equipment and services will be handled on a contract basis. Preliminary drilling equipment layouts are shown on Figure 4-4. Major drilling equipment will include:

5.2.1 Rig Components

Two land-type cantilever masts, 142 feet (43m) high with 16,500 foot drilling and 1,000,000 pound hook-load capacities, will be required. The masts will be designed in accordance with A.P.I. Standard 4D for freestanding masts.

The drawworks will be electrically powered (rated at 1000 HP) and be complete with sandreel and rotary table drive. The hook, traveling block, and crown block will be of 500 ton load rated capacity to match the mast. The drill string will be 4-1/2" or 5" (11.4 cm or 12.7 cm), grade E and grade G drill pipe.

5.2.2 Substructures

The substructure of each rig will be capable of supporting the derrick and setback loads. It will be designed to provide unobstructed clearance for the blowout prevention equipment.

Each substructure will be supported on a skidbase, resting on elevated skidbeams. The skidbase will be equipped with a hydraulic jacking system to allow transition along the direction of the well rows. The subbase will also be equipped with hydraulic jacks to allow lateral skidding over the desired well. Mechanical restraint equipment will be provided to prevent substructure movement once positioned over the desired location.

5.2.3 Drilling Mud System

A separate mud system will be provided for each drilling rig. Each mud system will be equipped with two mud pumps (approximately 1000 HP each), and approximately 1450 bbls. of active and reserve mud tank capacity. The system would include a mud mixing tank, trip tank and a sand trap tank below the shale shaker.

Return mud will be treated with separate high speed shale shakers, mud cleaner, desilters, and degassers for each rig. The shale shaker units will be equipped with a cuttings washing system to clean any oil-contaminated cuttings before ocean disposal. No discharge of free oil resulting from the discharge of muds and cuttings will take place. Cuttings that cannot be adequately cleaned by washing will be diverted to a waste cuttings holding tank, to be hauled ashore for disposal in an appropriate Disposal Site.

Mud volumes will be closely monitored using a pit volume totalizer system, an incremental flowrate indicator, and a precision fill-up measurement system. These warning systems will have visual and audible alarm signals at the driller's console. A common bulk material handling system will be provided with 3000 cu. ft. (85 cu. m.) storage capacity for clay and barite materials. Sacks of mud additives (chemicals, lost circulation material, etc.), needed on the platform will be stored on pallets.

5.2.4 Cementing Unit

One diesel powered dual cementing unit and three 1000 cubic foot (28 cu. m.) bulk storage tanks will be provided for well cementing operations.

5.2.5 Power Generation

Rig power will be provided by dual fuel turbine generator packages.

These generators also provide power requirements for platform and producing facilities. It is anticipated that three 2500 KW generators will be required for total platform requirements.

Each rig will utilize a silicon controlled rectifier (SCR) system to convert alternating current to the direct current required by the drawworks, rotary table, mud pumps, and cementing unit motors. Transformers will convert the generated AC power to lower voltages, as necessary, for the AC equipment on the rig.

5.2.6 General Layout

The drilling mud system equipment, cementing unit and completion tank will be located on the upper deck. Above the mud package will be the pipe rack. Outboard of the pipe rack, on each side of the platform, will be the platform cranes. The Rig power control package and transformers will be located in close proximity to the platform power package. The masts, subbases, drawworks, and associated equipment will be installed on the skidbase at the upper deck level. Contractors living quarters and offices will be located in a central quarters building.

5.3. Drilling Operations

5.3.1 Casing Program

Depending on individual well completions, two different casing programs are anticipated. When wells are completed with 4" production tubing, the planned casing program consists of 24" conductor, 18-5/8" intermediate and 13-3/8" production casing with a 9-5/8" liner hung below the 13-3/8" casing set at the top of the production interval as shown in Figure 5-1. For wells completed with 2-7/8" production tubing, the planned casing program consists of 24" conductor, 13-3/8" intermediate and 9-5/8" production casing with a 7" liner hung below the 9-5/8" casing set at the top of the production interval as shown in Figure 5-2.

This casing program assumes the issuance of a field rule precluding the installation of structural casing. The casing setting depths and cementing will be in accordance with MMS Pacific Order No. 2 and/or field rules.

All casing will be designed to exceed anticipated burst and collapse pressures and tensile loads. Casing designs will include appropriate safety factors. Production casing, liner, and tubing subjected to sour service will be made of controlled hardness quenched and tempered steel.

5.3.2. Well Completions

Cemented and perforated liner will be used where it is necessary to selectively produce in locations subject to gas or water intrusion. When gas or water intrusion is not anticipated, slotted casing may be used. The completion tubing string will be designed for natural flow but will allow for conversion to electric downhole submersible pumps in the future.

5.3.3 Wellhead Equipment

All wellhead components will meet API specifications. The working pressure of each wellhead section will exceed the maximum anticipated pressure imposed on that section. The wellhead will provide fluid circulation passage between each set of casing and each succeeding smaller casing or tubing.

5.3.4 Blowout Preventer Equipment (BOPE)

Each rig will have separate mud and blowout prevention equipment (BOPE) systems.

Blowout preventer systems will be operated and tested in accordance with OCS Order No. 2 and/or field rules. These systems will be hydraulically operated with control stations at the driller's console on the rig floor, at the accumulator unit, and at a remote platform location.

Since two different completions are anticipated, two different BOPE stacks are proposed:

For the casing program as shown on Figure 5-1, the low pressure system will consist of a 29-1/2" 500 psi annular-type blowout preventer with diverter system (see Figure 5.4 for Diverter System Schematic) installed for drilling below the 24" conductor pipe. After 18-5/8" surface casing is landed and cemented, the low pressure BOPE stack will be removed. A 3000 psi 20" Class III BOPE stack will then be nippled up to the surface casing head with a riser. The BOP equipment will include an annular preventer, one pipe ram, and a blind ram. After the above BOPE and the 13-3/8" casing is landed and cemented, the Class III BOPE stack will be removed. A 5000 psi 13-5/8" Class IV BOPE stack will then be nippled up to the 13-3/8" casing head with a riser. The BOPE will include an annular preventer, two pipe rams and a blind ram. For the casing program as shown on Figure 5-2, the low pressure system will be the same as previously described. After the 13-3/8" casing is landed and cemented, the low pressure BOPE stack will be removed. A 5000 psi 13-5/8" Class IV BOPE stack will then be nippled up on the surface casing head with a riser. The BOPE will include an annular preventer, two pipe rams and a blind ram. All the above BOPE will be actuated by pressure provided by a hydraulic accumulator unit located at a remote platform location. Control stations will be located both on the drill rig floor and in a remote location (such as near the drilling superintendent's office). In addition, the BOPE can be actuated manually by controls located on the accumulator unit itself (see Figure 5-3). Each rig will have its own accumulator unit.

Below the BOPE a drilling spool will be provided with side outlets for separate choke and kill lines. The kill line will have two valves located adjacent to the BOPE; a master and a control valve. The choke line will be in accordance with "API Recommended Practice for Blowout-

Prevention Equipment Systems".

Chevron is currently working with various manufacturers of BOP equipment to determine the feasibility of fabricating an 18-3/4" bore 5000 psi Class IV BOP stack. Successful fabrication of such a stack would eliminate the need for the two stack system as now proposed.

5.3.5 Typical Drilling Procedure

Typical drilling programs for the different development wells are given here. Each well will be drilled using these general procedures supplemented as necessary for the particular well program and anticipated drilling conditions.

A typical Monterey well with 4" tubing completions will follow this general procedure:

1. Move and rig-up. Lower 24" conductor pipe to ocean floor.

2. Drill 22" hole to 450' B.O.F. (V.D.). Under-ream hole to 30" and cement 24" conductor pipe.

3. Install diverter and low pressure BOPE stack on 24" conductor and test.

4. Directionally drill 17" hole to 2300' B.O.F. (V.D.). Under-ream hole to 22".

5. Run and cement 18-5/8" casing at 2300' B.O.F. (V.D.).

6. Install Class III BOPE stack and test.

7. Directionally drill 17" hole to the proper depth for setting 13-3/8" casing. Run logs.

8. Run and cement 13-3/8" casing. Install Class IV BOPE stack and test.

9. Drill 12¼" hole to proper depth below 13-3/8" casing. Run logs.

10. Run and cement 9-5/8" liner.

11. Run logs.

12. Perforate the production interval.

13. Install completion tubing.

14. Remove BOPE stack and install Christmas tree.

A typical Monterey well with 2-7/8" tubing completions will follow this general procedure:

1. Move and rig-up. Lower 24" conductor pipe to ocean floor.

2. Drill 22" hole to 450' B.O.F. (V.D.). Under-ream hole to 30" and cement 24" conductor pipe.

3. Install diverter and low pressure BOPE stack on 24" conductor and test.

4. Directionally drill 17" hole to 2300' B.O.F. (V.D.).

5. Run and cement 13-3/8" casing at 2300' B.O.F. (V.D.).

6. Install Class IV BOPE stack and test.

7. Directionally drill 12¼" hole to the proper depth. Run logs.

8. Run and cement 9-5/8" casing.

9. Directionally drill 8½ or 8-3/4 hole to proper depth. Run logs.

10. Run and cement 7" liner.

11. Run logs.

12. Perforate the production interval.

13. Run completion tubing.

14. Remove BOPE stack and install Christmas tree.

5.3.6 Pollution Prevention

To prevent pollution due to drilling operations, all runoff from drilling equipment will go to the deck drainage system. Oil will be removed to levels specified in NPDES permit conditions before the runoff is discharged to the ocean. Collection of any runoff will be facilitated by the inclusion of 6" (15 cm) high kick boards extending around the perimeter of the platform on all decks.

To prevent pollution due to drill cuttings, a cleaning and handling system will be installed for each drilling rig below the shale shakers. Cuttings produced by drilling operations will be washed by this equipment prior to their disposal into the ocean through the disposal caisson. No discharge of free oil will result from the disposal of muds and cuttings. Oil-soaked cuttings obtained when penetrating a hydrocarbon bearing zone will be conveyed to metal bins for storage until they can be taken to shore for disposal in an appropriate disposal site.

5.3.7 Safety Features

The safety system includes the following:

5.3.7.1 Fire Suppression

a. A saltwater pumping system.

b. 1-1/2" (3.8 cm) hard rubber hose reels to provide coverage at any point on the platform with two hoses.

c. Fixed fog suppression with automatic area controls capable of wetting critical surfaces with a water density of not less than 0.25 gpm (gallons per minute) per square foot.

d. Two 250 gpm monitors on the main deck to cover the BOP stacks and the upper well bay area.

e. Dry chemical and Halon fire extinguishers.

f. Standpipe connections on both boat landings for fireboat use.

5.3.7.2 Fire Detection and Alarm

a. Ultraviolet "fire eyes".

b. Smoke detectors.

c. Fusible plugs in the process and drilling areas.

5.3.7.3 H_2S and SO_2 Contingency Plan

The Oil Spill and Emergency Contingency Plan for Platform

Hermosa contains a detailed emergency plan to be followed when encountering formations that contain hydrogen sulfide while drilling wells. See the Chevron Oil Spill and Emergency Contingency Plan for Platform Hermosa.

5.3.7.4 Critical Operations and Curtailment Plan

In compliance with OCS Order No. 2, a Critical Operations and Curtailment Plan for Platform Hermosa has been submitted as part of the Oil Spill and Emergency Contingency Plan for Platform Hermosa. This plan describes the critical operations that are likely to be conducted and in what circumstances or conditions the critical operations are to be curtailed.

5.3.7.5 Deck Drainage/Sump System

Platform Hermosa will be divided into two drainage systems for separate handling. Drainage from the upper decks, from drip pans in the rig substructure and from rig floor will gravitate to a waste tank located on the lower deck. Drainage from the lower deck areas will drain to a sump tank below the lower deck, from which the liquids will be pumped into the waste tank. Oily waste water from the waste tank will be sent to the production train for treating. Washed cuttings and oil free sediments from the waste tank will gravitate to the skim pile for ocean disposal.

5.3.7.6 Safety and Escape Equipment

The escape system provided on Platform Hermosa will include life jackets and three survival capsules accommodating 35 persons each. From time of arrival of helicopter to Platform Hermosa, injured personnel can be delivered to Goleta Valley Hospital in approximately 25 minutes.

5.3.7.7 Safety Control Systems

Safety, anti-pollution and control systems will be installed on all piping headers, machinery, and vessels pursuant to OCS Order No. 5. The system will be a combination of electric and pneumatic controls. All automatic control valves will be designed to be fail-safe. Control devices will include the following:

1. High-low pressure alarm and shutdown sensors.

2. High-low liquid level alarm and shutdown sensors.

3. Flow safety valves.

4. Pressure safety valves.

5. Vibration sensors.

6. High-low temperature alarm and shutdown sensors.

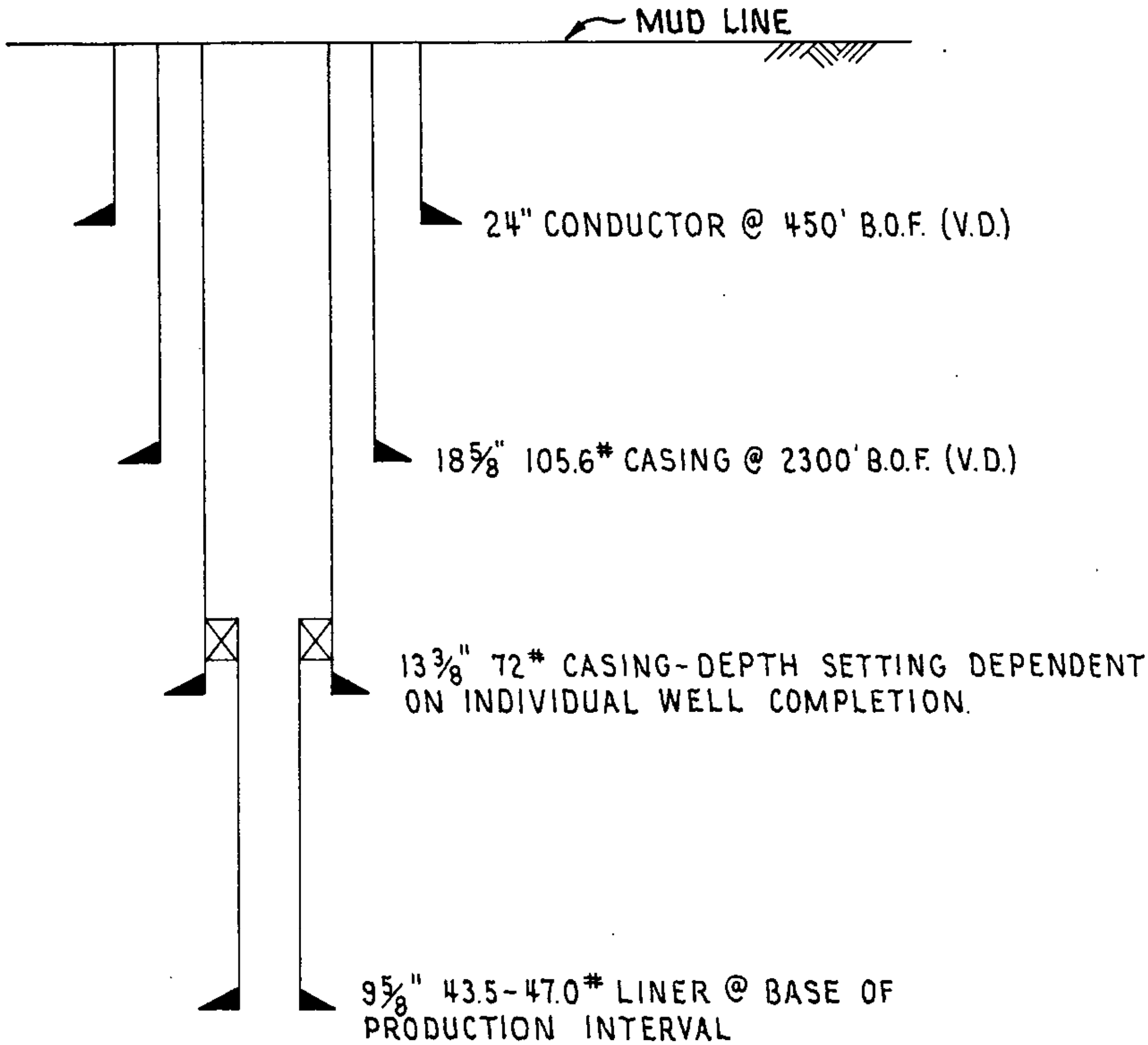
All of the above items will be designed and installed to facilitate testing. The devices will be tested for accurate operation on a schedule to be approved by the MMS.

All of the above safety devices will be interconnected through a central control panel. When a malfunction occurs, an alarm will be sounded; and if the condition is not immediately corrected, the platform will shut down. Shut-downs will be accomplished by automatically closing the surface controlled subsurface saftey valves and the surface controlled surface safety valves. Produced fluid will continue to move off the platform through the pipeline until the equipment is automatically shut down by either low levels or low pressure. If the malfunction is pipeline related, liquids would not be pumped off the platform, but instead the vessels would automatically shut-in and contain the production.

5.3.8 Crew and Supply Transport

Drilling crews will work regular 12-hour shifts, and will be quartered on the platform. Day shifts are expected to contain 18 persons and night shifts 17 persons. Supply boats will transport supplies as required.

Weather should have little effect on crew and supply boat operations, but emergency facilities and supplies will be provided at the platform to allow at least one week of normal operations if supplies delivery is interrupted.



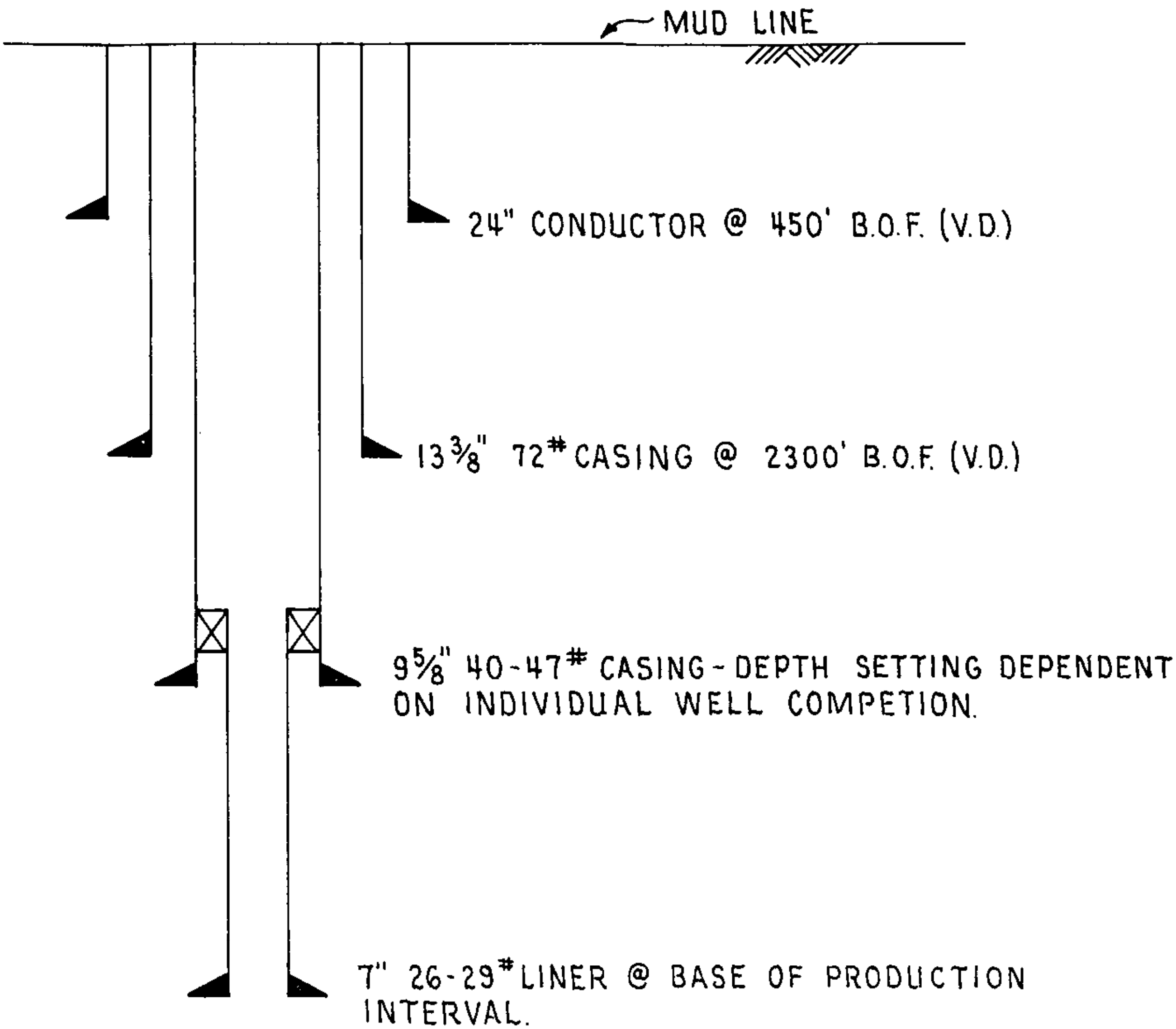
NOTE: B.O.F. (V.D.) BELOW OCEAN FLOOR (VERTICAL DEPTH)

PLATFORM HERMOSA
PROPOSED CASING PROGRAM
TYPICAL WELL SKETCH
4" PRODUCTION TUBING COMPLETION

NO SCALE

FIGURE 5-1

A-SB-4629



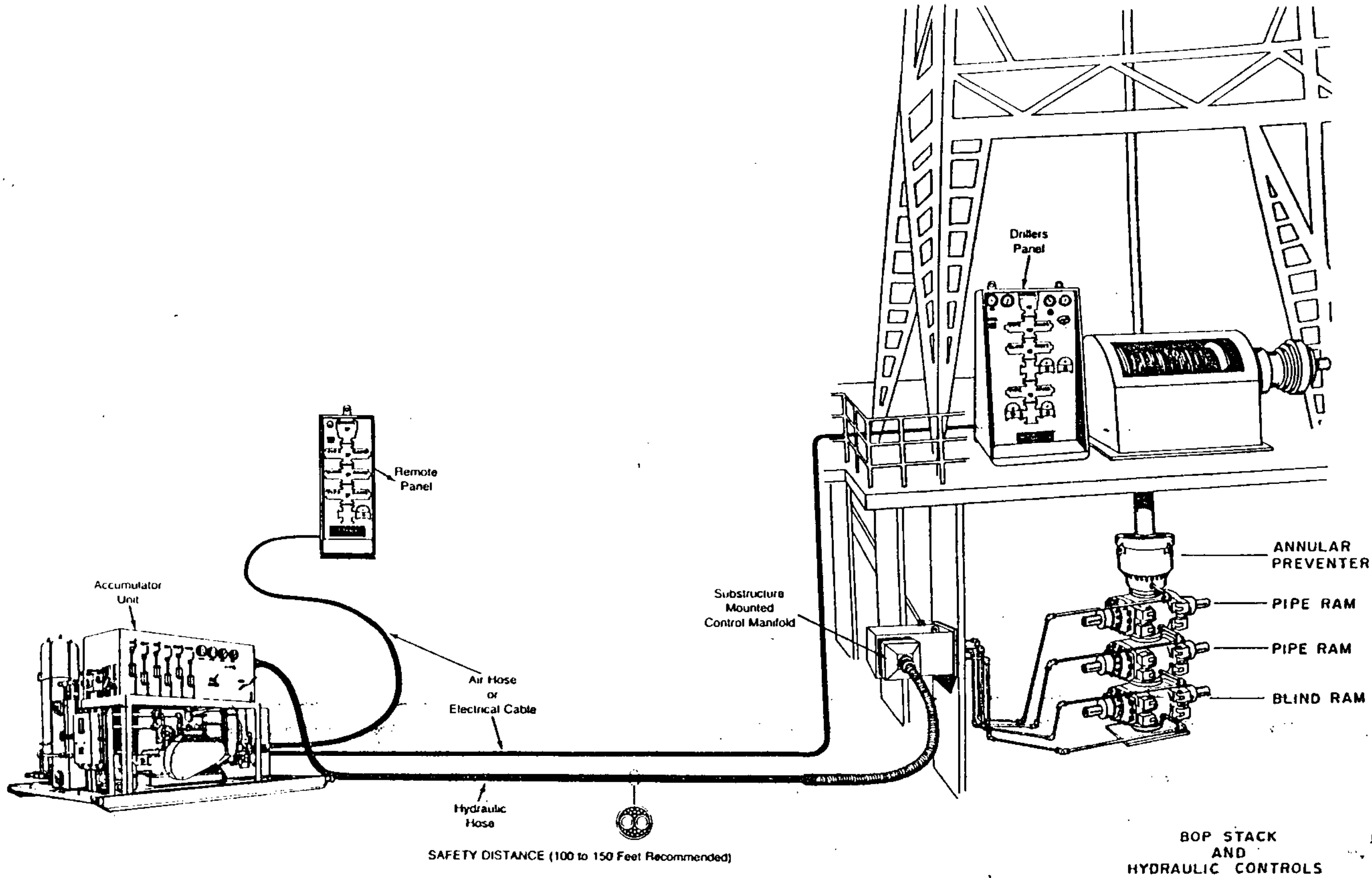
NOTE: B.O.F. (V.D.) BELOW OCEAN FLOOR (VERTICAL DEPTH)

PLATFORM HERMOSA
PROPOSED CASING PROGRAM
TYPICAL WELL SKETCH
2 7/8" PRODUCTION TUBING COMPLETION

NO SCALE

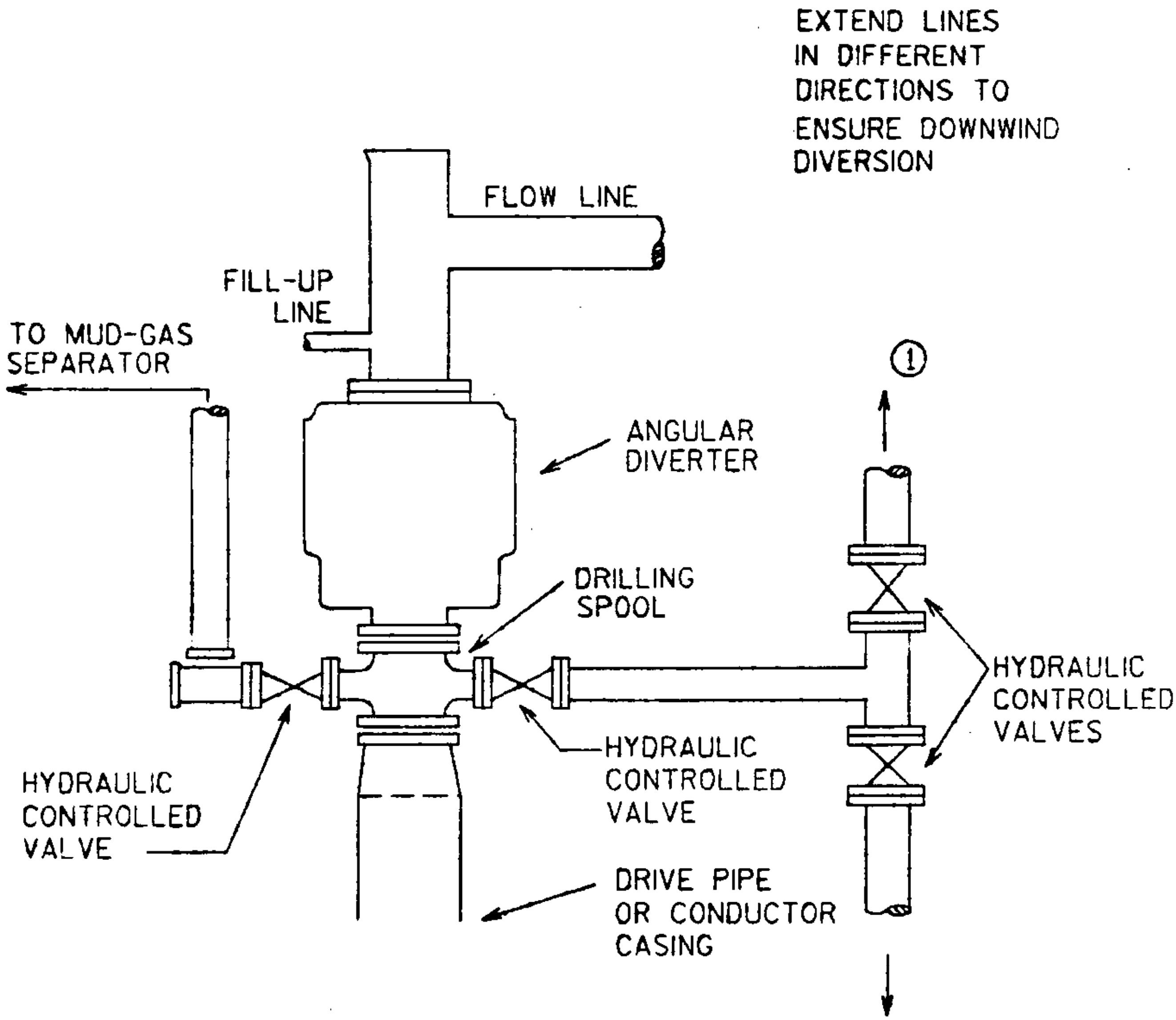
FIGURE 5-2

A-SB-4630



BOP STACK
AND
HYDRAULIC CONTROLS
FIGURE 5-3

DIVERTER-PREVENTER HOOKUP



DIVERTER-PREVENTER HOOKUP
FIGURE 5-4
A-SB-4681

DATE: 3-7-83

SECTION 6

PLATFORM FACILITIES

TABLE OF CONTENTS

FIGURES

FIGURE 6.1. PROCESS FLOW SCHEME

6. PLATFORM FACILITIES

6.1 Introduction

This section describes all production equipment and related facilities to be installed on the platform and is divided into the following four parts (1) Production Process Facilities; (2) Utility System; (3) Support Facilities; and (4) Environmental Impact Mitigation Measures.

The platform will contain production facilities for the initial separation of the produced oil, gas, and free water. An oil emulsion will be sent to onshore facilities for crude stabilization and water removal. Gas will be dehydrated and will also be sent to shore hydrocarbon we and water dry. Equipment, controls, monitors, safety devices, etc., will be installed in accordance with applicable O.C.S. Orders and industry standards.

All initial production will be from the Monterey. Drill stem production tests made in this area indicate that the reservoir consists of zones with varying hydrocarbon properties (G.O.R. and gravity). All tests indicated the presence of sulfur with average level of 3 percent by weight in the oil. The API gravity averaged 20°. Figure 6.1. provides an overview of the proposed producing facilities. Primary gas and emulsion separation occurs on the platform with the bulk of the gas going to an onshore gas treating plant for liquids removal and sweetening. A small portion of the gas will be utilized on the platform as fuel for the power generation equipment. H_2S will be removed from fuel gas before use with an amine unit. Anticipated maximum

H_2S concentration in associated gas is approximately 6000 ppm. Separated produced water and deck drainage and other discharges will be treated and cleaned in compliance with EPA NPDES permit conditons for discharge into the ocean.

Utility systems and support facilities will be provided to allow the platform to be as self-reliant as possible. Provisions for power supply, potable water production, standby power, and safety systems, etc., have been made to allow operations to continue safely even though platform resupply may be interrupted for several days.

6.2 Production Process Facilities

6.2.1 Design Criteria

1. Reservoir Data: Reservoir data utilized in the design of platform facilities have been obtained from two wells drilled on Lease OCS P-0316 and additional information obtained from a data exchange of two wells drilled on OCS P-0315.

6.2.2 General Layout

As shown on Figures 4.4 to 4.8, process equipment has been located to minimize the length of interconnecting piping and to segregate this equipment from personnel occupied areas. Fire walls and doors on the well deck effectively divide the well deck into hazardous (wellhead area) and non-hazardous (process) areas.

6.2.3 Wellheads and Flow Manifolds

Forty-eight well slots will be provided; forty producing wells are presently planned, with eight spare slots provided for future reservoir evaluation drilling. The wells will be arranged in four rows, with short flowlines connecting each well to a manifold system.

The manifold system will allow production to be switched between pool and test separators. Lines for future casing gas recovery, hydraulic and pneumatic controls, etc., will also be provided. All wells will be equipped with downhole hydraulically controlled safety valves in accordance with OCS Order No. 5.

6.2.4 Artificial Lift

It is anticipated that artificial lift will eventually be required for all wells. It may be necessary for producing some weaker wells immediately upon completion. Therefore, initial provisions for submersible electric pumps will be provided.

6.2.5 Production/Separation

The crude oil to be produced will be of relatively low API gravity and relatively high viscosity. It is planned to produce to three-phase separators for primary oil/gas/free water separation. Wells are to be manifolded in such a manner as to be able to isolate wells for individual testing and gauging and to place the remaining wells into the "pool" three phase separator(s). The wet-oil and gas stream to the separators is to be heated to 150°F to assist in water removal. An oil emulsion will then flow to the production surge tank. The production surge tank will operate at about 2 psig to further assist in degassing the emulsion.

Three test separators and heaters will be provided. One of the three separators will be sized to handle high volume wells. These separators will be three phase equipped with free water draw-offs. Each well will be tested at least once a month in order to facilitate reservoir evaluation.

A well cleanup separator will be provided for the initial unloading of wells to remove mud and water until the well is flowing sufficiently to be turned into the normal production separators.

6.2.6 Oil Cleaning

All crude stabilization and final dewatering will be provided for at the onshore treating facility. A detailed description is provided in Section VIII.

6.2.7 Oil Shipping

Emulsion collected in the wet oil surge tank will be boosted to a pressure of 100 psig to maintain bubble point depression. Metering of the emulsion and gas is discussed in Section 6.2.9. Since the oil pipeline to shore has capacity for additional platforms, the shipping pumps discharge pressure will vary depending on the amount of oil tendered to the line and the temperature. The maximum operating pressure for the pumps is not expected to exceed ANSI 600 design pressure (1480 psig at 100°F).

6.2.8 Gas Processing/Compression

Produced gas from the three-phase production and test separators will be compressed to pipeline shipping pressure by electric motor-driven reciprocating compressors. Provisions will be made to recover low pressure gas such as that available from the casing annulus, wet oil surge tank and blanketing gas from utility tanks and vessels. Since the gas pipeline to shore has capacity for additional platforms, the compressor discharge pressure will vary with throughput. However, the maximum compressor discharge is not expected to exceed ANSI 600 design pressure.

Each stage of compression will be equipped with suction scrubbers, discharge coolers, and various unloaders and clearance pockets to allow for handling of varying gas production rates. Dehydration facilities shall be provided on the platform to avoid hydrate formation formation and corrosion in the pipeline. Sufficient gas compression capacity will be provided to prevent the need for flaring in the event of a compressor failure.

6.2.9 Oil and Gas Metering

All oil and gas leaving the platform will be metered. Oil, and water that has not been removed in a three phase separator, will leave the platform as an emulsion. This will require measurement of volume and quality with enough accuracy and repeatibility to allocate the total dry oil from the treating plant onshore back to each platform. Custody transfer will be at the platform or at the net oil sales meter at the onshore treating plant based on allocation procedures detailed in the transportation system tariff.

The platform emulsion will be metered by double case positive displacement type meters equipped with a mechanical prover. In order to achieve the best measurement accuracy, there will be no water existing as a separate phase. This is accomplished by the installation of one or more inline static mixers. This mixer assures uniform distribution of water and oil in an emulsion.

To assist in the allocation of commingled platform oil production, each emulsion meter system will have a proportional-to-flow composite sampling device, with the sampling point immediately upstream of the meters. The sample accumulated in the storage container will be representative of all the crude oil delivered to the gathering system from the platform and will be the basis of the gravity and basic sediment and water (BS&W) measurments necessary to allocate treated oil back to the appropriate platform. For details of the proposed metering plans, please refer to Appendix A-1. Additional details on the proposed metering plan is covered in our transmittal "Point Arguello Area Oil and Gas Production, Measurement, Transportation and Accounting" submitted to the MMS dated October 28, 1982 and referenced Appendix 1.

Gas volumes consumed as fuel and and those delivered to the offshore gas gathering pipeline system will be metered with orifice type metering instruments operated in accordance with the specifications contained in the American Gas Association publication "Orifice Metering of Natural Gas, Gas Measurement Report Number 3."

For well-test purposes, each of the platform test separators will be outfitted with orifice type gas metering instruments, a digital readout oil meter with a capacitance type water cut sensor, and a digital readout turbine type water meter.

6.2.10 Condensate Handling

Condensate collected from the gas scrubbers will flow, depending on scrubber operating pressures, to the wet oil surge tank or to the production preheater upstream of the three phase separators. Ultimate destination of all condensate collected on the platform will be to the wet oil surge tank for commingling with the emulsion for shipment to shore.

6.2.11 Relief and Vent Systems

All high pressure balanced relief valves on vessels and gas compressors, as well as stack regulators on the gas collection systems, will be manifolded together to a high pressure stack scrubber and flare. Low pressure relief valves from the vapor recovery system, tanks, compressor spacer block vents, etc., will be manifolded together to a vapor stack scrubber and flare.

Both the high pressure and vapor stack flares will be incorporated into a single flare boom. Liquids collected in the stack scrubbers will be drained into a waste oil tank and pumped back to the wet oil surge tank.

6.2.12 Produced Water Treatment and Disposal

Produced free water resulting from the oil separation process on the platform will be discharged to the ocean through a disposal caisson. This water is discharged primarily from the two production separators with a smaller volume discharged from the test separators. To meet the requirements of 40 CFR 435, Effluent Limitations for the Offshore Subcategory of the Oil and Gas Extraction Point Source Category, the water will be treated by passing it through a corrugated plate interceptor followed by a flotation cell to remove suspended oil from the water. The oil content of the discharge water will be less than 72 ppm (instantaneous average). Oily solids resulting from this treating process will be pumped to a waste tank for disposal on shore. All discharges will be in accordance with the general NPDES permit (No. CAO-110516).

6.3 Utility Systems

The platform design will include the following utilities:

6.3.1 Power

It is anticipated electrical power will be generated at 4160 volts by three 2500 KW turbine generators. The turbines will have diesel alternate fuel capability to allow for early drilling and facility production startup until fuel gas becomes available when the first well is completed (45 to 60 days). Electric motors for oil shipping pumps and the main gas compressors will operate at 600V. Stepdown transformers and motor control centers will operate general process and utility loads at 480V.

The power system design will provide for the possibility of standby capacity via a submarine cable tie-in from future platforms. All electrical wiring and equipment on the platform will conform to National Electrical Code requirements.

It is planned that water will be injected into the turbines to reduce NO_x emissions. It is expected that a 50% or better reduction in NO_x emissions can be achieved.

6.3.2 Standby Power Generation

Standby power generation will be supplied by a diesel powered generator. This unit will provide electric power under standby conditions for critical services such as Blow-Out-Prevention accumulators, lights, air pressuring systems, sump pumps, etc. The diesel generator will have an air starter and a separate air reservoir tank.

6.3.3 Diesel Fuel

Diesel fuel will be utilized for the turbine generators until fuel gas becomes available from producing wells. Other diesel fuel usage will include the intermittent use of the cementing pumps, cranes, standby generator and diesel fire pump.

Permanent diesel storage will be provided in one crane pedestal (300 bbls.). Transfer pumps, filters, distribution piping, and day tanks at each engine will be included. Connections at the boatlanding level will be provided for the transfer of the diesel fuel from work boats to the pedestal storage tanks.

6.3.4 Fuel Gas

The primary use of fuel gas on the platform is for the turbine generators. Once the initial wells have gone on production, turbines will be switched from diesel or buy back fuel gas (see 6.3.3 above) to produced fuel gas. Other potential uses for fuel gas on the platform include the flotation unit, vapor recovery makeup system, and blanket gas.

The absence of sweet gas for fuel use on the platform will require an H_2S removal system. Gas will be sweetened with an Amine unit. Gas will be cleaned to 50 ppm H_2S or better.

6.3.5 Water Maker/Demineralized Water System

Two 100% vapor compression desalination units (one stand-by) will be utilized to produce fresh water from sea water for the potable and demineralized water systems. The capacity of the unit will be based on estimated potable (5000 gal/day) and demineralized water requirements. The system will keep the potable water system and mixed bed demineralizer supplied with 4 PPM TDS water, while any surplus will go to fresh water storage.

Demineralized water requirements will be based on the fuel-rate of the turbines, an estimated 1 pound of water per pound of fuel injected into the combustion chamber. Water from the vapor compression unit will enter a mixed bed cartridge type demineralizer where the total disolved solids will be reduced from 4 PPM to less than 0.5 PPM. A demineralized water holding tank with an 18 hour capacity will be provided between the demineralizer and the turbine generators.

6.3.6 Potable Water System

Freshwater produced from the desalination unit will continually resupply the 300 bbl. potable water storage tank. This water will be utilized in the quarters building. Potable water fountains are also to be installed in operating areas.

6.3.7 Fresh Drill Water System

Fresh drill water storage capacity will be provided in the jacket legs. The water will be removed from the legs by means of compressed utility air. This water will be used primarily for mixing drilling muds and cement. Makeup into the system will be from the desalinator with the balance as required transported by work boat from shore.

6.3.8 Process Heating System

A circulating heating media system will be used to provide heat for production and test separator heat exchangers, wet oil surge tank, glycol regeneration, and fuel gas heating. Cogeneration will be used on the platform, that is, the heat source for the heating media will be waste heat recovered from the turbine drivers on the electrical generators.

The system consists of a heating fluid surge tank, circulating pumps, supply and return headers and a heat source (i.e. turbine drivers for generators).

6.3.9 Utility Air

Three rotary screw air compressors will be provided to distribute a supply of 125 psi air throughout the platform for such uses as air tools and hoists, moving drill water, air-powered hydraulic pumps, sewage treatment air scour, DC motor purge, etc.

6.3.10 Instrument Air

An instrument air system will be provided to compress, dry, store and distribute an adequate supply of 100 psi instrument air throughout the platform process area.

6.3.11 Starting Air System

Two high pressure reciprocating compressors (one diesel, one electric) will be used to provided starting air for the turbines, the standby generator, and the diesel firewater pump. Enough air storage capacity will be provided for black starting.

6.3.12 Saltwater System

Two saltwater systems will be provided for fire suppression, washdown, flushing water for cleaning cuttings, process cooling, and the desalinator. The fire suppression system will be designed for approximately 2500 gallons per minute. An additional system will be incorporated to provide 3000 gallons per minute capacity for the process cooling systems, the desalinator, and other miscellaneous systems.

6.3.13 Sewage Treatment

A packaged sewage treatment unit will be incorporated to process the sewage from the quarters building. The effluent from this unit will comply with U.S. Coast Guard requirements found in 33 CFR 159.53(b) and will be discharged to the ocean through the disposal caisson.

6.3.14 Chemical Injection

Numerous small storage tanks and metering pumps will be provided for injection of corrosion inhibitors, antifoam agents, etc.

The platform will include a hypochlorite generator for supplying chlorine to the saltwater intake system and sewage treatment unit as required.

6.3.15 Lighting

Platform lighting will meet or exceed the API RP14F recommended levels of illumination. Indoor lighting will consist of fluorescent fixtures and outdoor lighting will consist of high pressure sodium vapor fixtures. Critical lighting circuits will be connected to a battery backup system to provide emergency lighting in the event of a power failure.

6.3.16 Deck Drainage

All drainage from the decks will go to a waste tank where any solids entrained will drop out and any oil will float to the surface. Water from this tank, together with any oil, will then flow into a corrugated plate separator where oil will be separated and returned to a hydrocarbon sump tank. This oil is then pumped into the emulsion system or into a holding tank at the operator's option. Clean water from the corrugated plate interceptor is discharged to the ocean through a disposal caisson.

All drains that may contain oil will be piped directly to the hydrocarbon sump tank mentioned above.

All decks will be solid steel plate and have a 6" (15cm) high curb around the perimeter to prevent any run-off overflow into the ocean. Spray shields will be included where necessary to prevent liquid hydrocarbon spray from reaching the ocean.

6.4 Support Facilities

6.4.1 Hydraulic Control System

A hydraulic pressure system will be provided for downhole subsurface safety control valves. The system will include pneumatic-powered pumps, reservoir tanks, filters and a distribution system. This is a closed loop system with spent fluid returning to a pump suction reservoir.

6.4.2 Control and Monitoring Systems

The general process and associated equipment will be monitored and controlled from the central control room. All monitoring and control functions such as process temperatures, pressures, flow rates, and liquid levels will be by a programmable controller system.

In the event that normal process controls are unable to maintain the process within prescribed operating limits, alarms will be triggered in the control room to warn the operators of impending upset conditions. These alarms will cause a horn to sound and a flashing light to indicate the precise nature of the trouble.

Should the operator fail to clear up an alarm condition before it reaches unsafe limits, the following types of safety equipment are provided to protect the process and equipment

- o High/Low Pressure Sensors (Shutdowns)
- o High Temperature Sensors (Shutdowns)
- o High/Low Liquid Level Sensors (Shutdowns)
- o Pressure Safety Valves (Relief)
- o High/Low Flow Sensors (Shutdown)
- o Automatic Emergency Shutdown (ESD) System
- o Manual Emergency Shutdown (ESD) System
- o Surface and Subsurface Well Safety Valves
- o Equipment Isolation Shutdown Valves (SDV's)

This safety shutdown equipment is applied in accordance with USGS Pacific Region OCS Order 5 and API Recommended Practice RP-14C.

6.4.3 Personnel Quarters

Personnel quarters are to be sized for normal drilling and production activities. Facilities include sleeping accommodations for 90 persons with restroom facilities, locker room, wash room, galley, and a recreation/training room. The quarters building will be designed to minimize transmission of vibration and noise. A heliport will be situated on top of the quarters building.

6.4.4 Fire Suppression

Primary fire protection will be by sighting and manual (push buttons at each hose reel) initiation by platform personnel. Secondary protection will be by automatic detection using U.V. fire detectors, fusible plug loops, and low firewater header pressure switches. Both manual and automatic initiation signals are sent to the a controller which in turn initiates an alarm and starts at least one electric fire pump. Should the controller not maintain continuous communications with either the electric or the diesel control system, the respective pump(s) will automatically start.

The deluge system will be arranged in a loop routed around the periphery of the platform to increase reliability and reduce operating friction loss. Automatic valves for the deluge systems shall be placed in safe areas where a fire zone header branches off the main loop.

Firewater pumps shall be specified to meet pump curves which ensure constant flow at constant line pressure as required for fire fighting. Pumps will furnish not less than 150 percent of the rated capacity at 65 percent of the total rated head.

The following is a brief description of the system components:

(a) Two electric submersible fire pumps to provide firewater (2000 gpm minimum) at 100 psi residual pressure to the platforms deluge system, hose reels, and fire monitors. Each pump will start automatically by a signal from its low pressure switch on the firewater header.

(b) One standby diesel-powered right angle drive verticle turbine fire pump to provide firewater (2000 gpm minimum) at 100 psi residual pressure to the platform's deluge system, fire monitors, and hose reels. The pump will start (air start) automatically by a signal from its low pressure switch on the firewater header. The pressure setting will be lower than that of the two electric fire pump start settings.

(c) Two 50 gpm (maximum) centrifugal jockey water pumps (one operating, one standby) to maintain the firewater header at 150 psi. The pumps will get their suction from the cooling water header and will prevent automatic starting of the main fire pumps due to system leaks or small firewater demands.

(d) Adequate 1" hard rubber hose reels to provide water/foam coverage at any point on the platform with two 100 ft. hoses equipped with constant flow nozzles.

(e) Deluge system with automatic area controls capable of wetting critical deck areas not occupied by major equipment with water density of not less than 0.25 gpm/ft^2. The system will also protect the wellhead area and process equipment with the following design densities:

1)	pipe racks and manifold area	0.25 gpm/ft^2
2)	hydrocarbon pumps	0.50 gpm/ft^2
3)	flare knock-out drum	0.25 gpm/ft^2

4)	immediate wellhead area	0.50 gpm/ft^2
5)	surrounding wellhead area	0.30 gpm/ft^2
6)	top half of separator vessels	0.30 gpm/ft^2
7)	inlet coolers	0.30 gpm/ft^2
8)	process deck area	0.25 gpm/ft^2

(f) Two 250 gpm monitors on the main deck to cover the BOP stacks and the upper well bay area.

(g) Portable fire extinguishers of the appropriate size and class for the anticipated hazard will be provided and located to permit coverage of the entire platform deck areas and buildings. Different types used are dry chemical, CO_2, and halon.

(h) Automatic Halon 1301 flooding protection system will be provided in each turbine generator enclosure.

(i) Manual fire alarm pull stations will be provided in the Generator Room and Quarters Buildings.

(j) Firehose connections at both boat landings for fire boat use will be piped to the platforms deluge loop.

(k) Automatic dry chemical spray over stove and grill in the quarters building.

6.4.5 Escape and Lifesaving Equipment

The platform will be equipped with U.S. Coast Guard approved escape capsules or lifeboats, plus an adequate number of life preservers, life floats, ring life buoys, first aid kits, litters, and other lifesaving appliances as required by 33 CFR 144.

6.4.6 Corrosion Control

Corrosion is to be controlled by using corrosion-resistant coatings on the top-side structures and equipment, an underwater sacrificial anode system, and internal coating for selected piping, vessels and tanks. Corrosion inhibitors may also be added during operations.

6.4.7 Aids to Navigation

Aids to navigation will consist of four quick-flashing, Coast Guard approved, five-mile white lights (one light at each corner of the platform), and a Coast Guard approved 2-mile fog horn. All aids to navigation will meet Coast Guard Regulation for Class A Structures (33 CFR 67.20). The platform will be painted white to assure high visibility to passing vessels.

The flare boom and each drilling rig derrick will be illuminated for aviation safety with a combination of steady and flashing red lights.

The heliport perimeter is outlined with lights plus one flashing amber beacon. The heliport lights are illuminated only when needed.

6.4.8 Communication Facilities

Intra-platform communication will utilize hardwired speakers and handsets. Additionally, these will be hand-held portable radios for operational communication.

For external communication with crew boats, supply boats, helicopters, shore bases, etc., there will be a wide-area radio system. A Company-owned microwave system will provide telephone service and circuits for the pipeline leak detection system and onshore emergency shut-down system.

6.5 Environmental Impact Mitigation Measures

6.5.1 Turbine Water Injection

Although not required by regulation, turbines on the platform will be equipped with water injection to reduce emissions of NOx. Reductions of 50% or more are currently expected.

The system will inject demineralized water (approximately 5 ppm or less solids content) into the turbine. Injection of water will lower combustion temperatures and low combustion temperatures result in lower rates of NOx production.

Injection rates of 0.5 to 1.0 pounds of water per pound of fuel are expected. At these injection rates reduction of 50% or greater have been demonstrated.

Sola~~s~~r, Rustin and Allison turbines are currently being considered for use on the platform. Significant operating experience with these and other turbines has demonstrated the feasibility of water injection. For example, several months of successful operations have taken place in applications in Irvine, California. These turbines have operated successfully for a total of over 6000 hours without significant operational problems. These turbines were throughly examined in March, 1983 and no internal damage was noted. Additional examples of the successful application of water injection on small turbines have also shown it to be a feasible technology. Information regarding water injection is available in "Standards for Support and Environmental Impact Statement, Volume 1, Proposal Standards of Performance for Stationary Gas Turbines", EPA, September, 1977, Chevron is continuing to follow the progress of water injection technology.

6.5.2 Gas Blanketing and Vapor Recovery

All pressure vessels, surge tanks and other process equipment operating at or near atmospheric pressure, are connected to a gas blanketing and vapor recovery header system which maintains a slight positive pressure on the system. As gas is released from process fluids or forced out of vessels and tanks as they are filled, it is compressed by vapor recovery compressors and flows into the sales gas system. As fluids are withdrawn from vessels or tanks, blanket gas is made up from the platform fuel gas system. This type of gas blanketing and vapor recovery reduces explosion hazards by eliminating oxygen, eliminates VOC (volatile organic compounds) emissions normally associated with atmospheric tanks and vessels, and recovers energy that would otherwise be lost.

6.5.3 Waste Heat Recovery

A significant amount of heat is required on the platform for process heating and to assist in degassing the emulsion before shipment. Heat is also required to regenerate glycol used in the gas dehydration system. Since gas turbines are used for power generation waste heat will be recovered from the turbine exhaust to the extent required to satisfy platform heat requirements. This measure conserves fuel and reduces emissions by reducing or eliminating the need for fired heaters. It also lowers the temperature of the turbine exhaust entering the atmosphere. Lowering the emulsion viscosity with recovered waste heat also results in less shipping pump horsepower and its associated emissions.

6.5.4 Spill Prevention and Containment

All platform facilities are designed to prevent the occurrence of an oil spill. The platform decks are enclosed with a toe plate to prevent spillage on the decks from going overboard. Deck drains gather up fluids and route them to sumps where the solids and liquids are separated. The liquids are pumped back into the emulsion system; solids are stored for intermittent transportation to shore for disposal. All process bleed valves and drains are also routed to a sump from which fluids are pumped back into the emulsion system. All gas and liquid relief valves are piped into closed systems. Gas is routed to the flare; liquids flow to a surge tank from which they are pumped back into the emulsion system.

In the unlikely event that an overboard spill occurs, the offshore facilities are equipped with a spill containment boom and boom deployment boat that can be used to minimize the impact of such an occurrence.

For a very detailed discussion of such a possibility as well as the proposed actions in case of occurrence, please refer to the Environmental Report for the Point Arguello Field and the Oil Spill and Emergency Contingency Plan for Platform Hermosa.

6.5.5 Emergency Flare

All vapor safety relief valves exhaust into a closed flare header system which gathers the emergency releases and routes them through a scrubber to a flare burner. The burner is of a smokeless design.

6.5.6 Common Grid Electrical Power Generation and Distribution

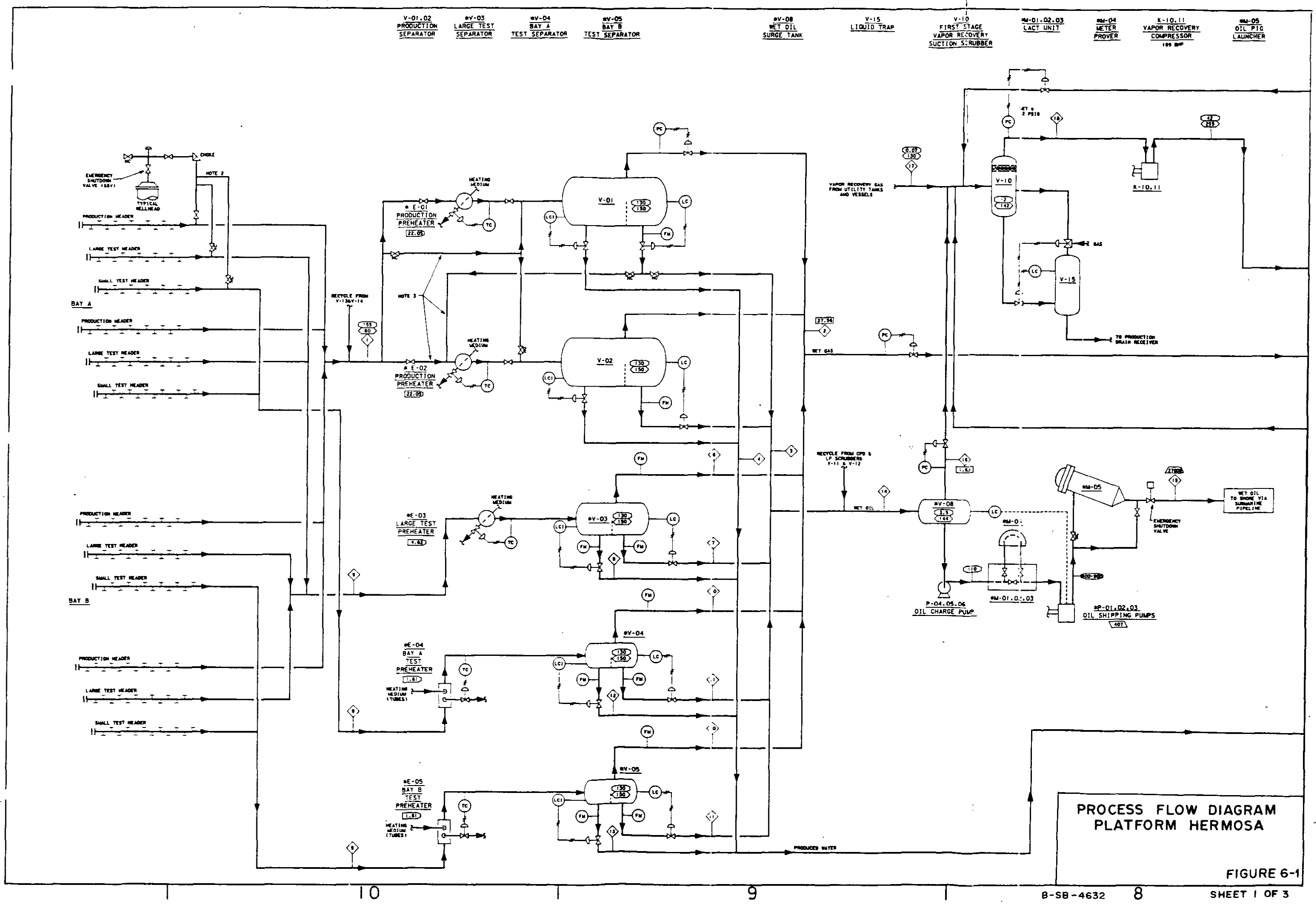
In order to minimize the amount of installed electric generating capacity, future platforms may be interconnected with a submarine power cable. Each platform could then draw upon the spare capacity of the overall system during generator maintenance rather than having to install spare generating capacity on each individual platform.

By reducing the overall amount of generating horsepower installed, the per unit percent load is increased. This results in an increased thermal efficiency of each unit and thus reduces overall fuel consumption and emissions.

6.5.7 Fugitive Emission Inspection Program

Fugitive Emissions are those which result from leaks around pump seals, valve stems, hatches, connections and other process components.

To reduce hydrocarbon emissions from Platform Hermosa, Chevron will institute a fugitive emission inspection and maintenance plan on the platform. This will substantially reduce fugitive emissions from process components.

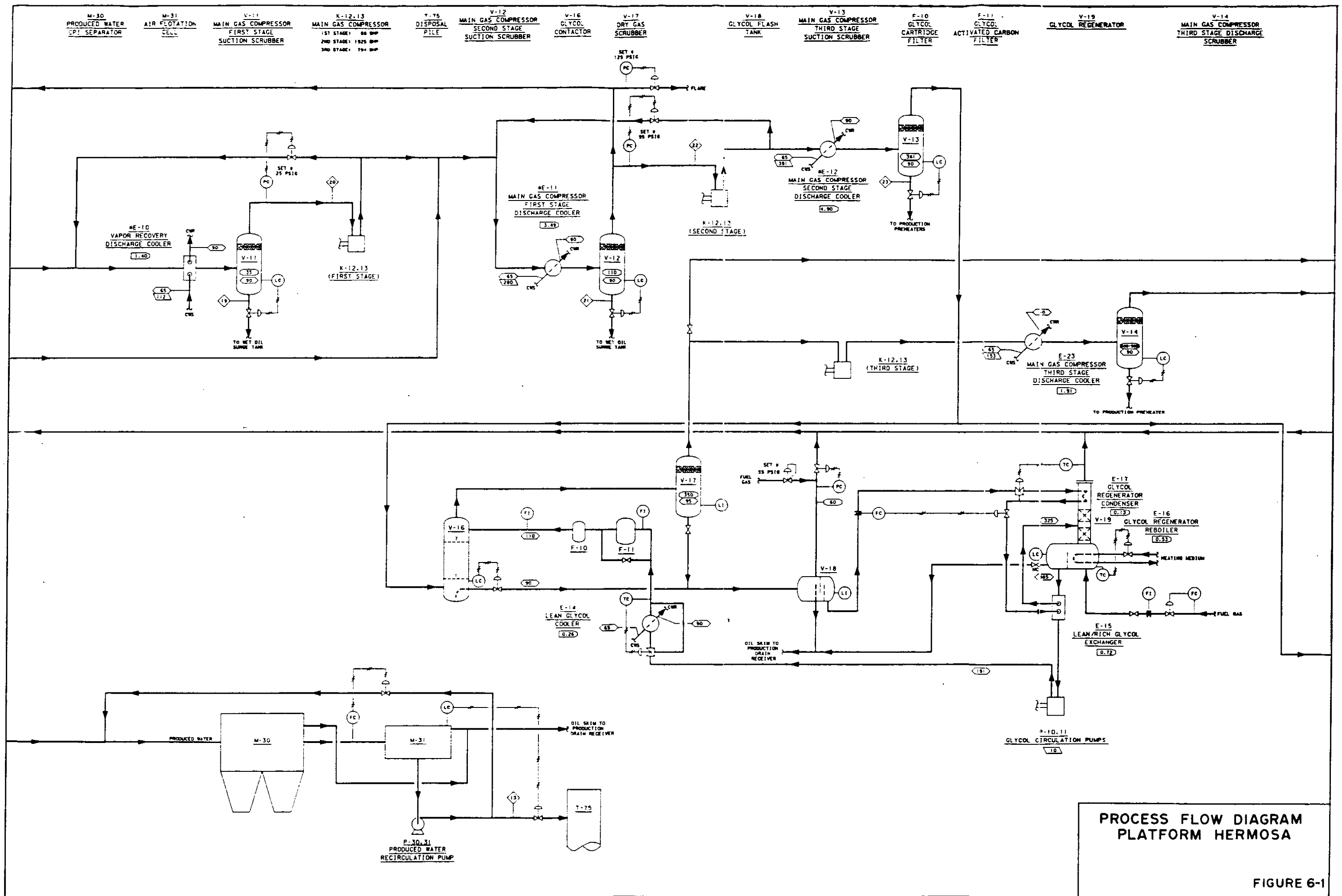


PROCESS FLOW DIAGRAM
PLATFORM HERMOSA

FIGURE 6-1

B-SB-4632

SHEET 1 OF 3

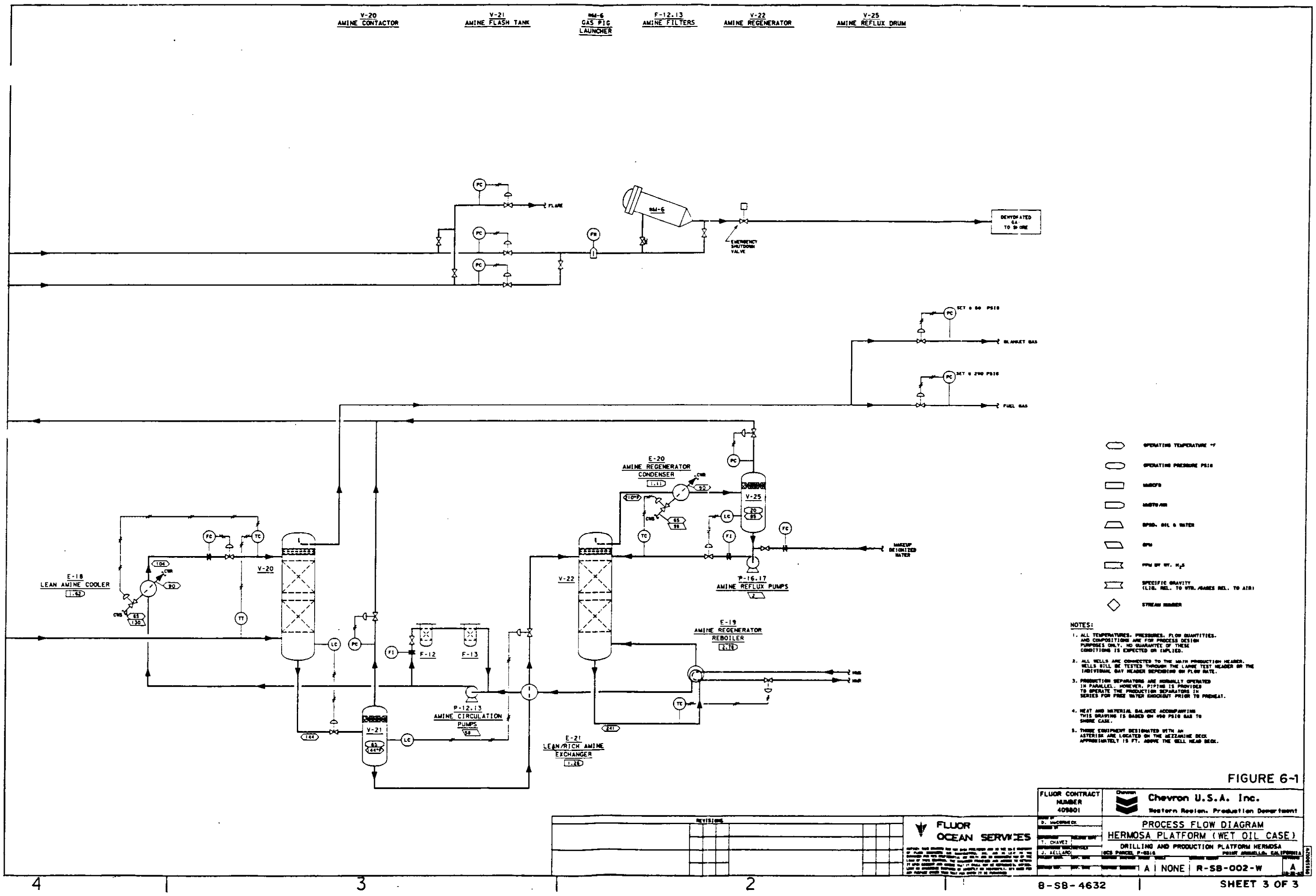


PROCESS FLOW DIAGRAM
PLATFORM HERMOSA

FIGURE 6-1

B-SB-4632

SHEET 2 OF 3



V-20 AMINE CONTACTOR
V-21 AMINE FLASH TANK
NM-6 GAS PIG LAUNCHER
F-12,13 AMINE FILTERS
V-22 AMINE REGENERATOR
V-25 AMINE REFLUX DRUM
FLARE
EMERGENCY SHUTDOWN VALVE
DEHYDRATED GAS TO SHORE
BLANKET GAS
FUEL GAS
E-20 AMINE REGENERATOR CONDENSER
E-18 LEAN AMINE COOLER
P-16,17 AMINE REFLUX PUMPS
MAKEUP DEIONIZED WATER
E-19 AMINE REGENERATOR REBOILER
P-12,13 AMINE CIRCULATION PUMPS
E-21 LEAN/RICH AMINE EXCHANGER
SPECIFIC GRAVITY (LIQ. REL. TO WTR./GASES REL. TO AIR)
STREAM NUMBER
NOTES:
1. ALL TEMPERATURES, PRESSURES, FLOW QUANTITIES, AND COMPOSITIONS ARE FOR PROCESS DESIGN PURPOSES ONLY. NO GUARANTEE OF THESE CONDITIONS IS EXPECTED OR IMPLIED.
2. ALL WELLS ARE CONNECTED TO THE MAIN PRODUCTION HEADER. WELLS WILL BE TESTED THROUGH THE LARGE TEST HEADER OR THE INDIVIDUAL BAY HEADER DEPENDING ON FLOW RATE.
3. PRODUCTION SEPARATORS ARE NORMALLY OPERATED IN PARALLEL. HOWEVER, PIPING IS PROVIDED TO OPERATE THE PRODUCTION SEPARATORS IN SERIES FOR FREE WATER KNOCKOUT PRIOR TO PREHEAT.
4. HEAT AND MATERIAL BALANCE ACCOMPANYING THIS DRAWING IS BASED ON 490 PSIG GAS TO SHORE CASE.
5. THOSE EQUIPMENT DESIGNATED WITH AN ASTERISK ARE LOCATED ON THE MEZZANINE DECK APPROXIMATELY 15 FT. ABOVE THE WELL HEAD DECK.
FLUOR CONTRACT NUMBER 409801
Chevron U.S.A. Inc.
Western Region, Production Department
FLUOR OCEAN SERVICES
D. McCORMICK
T. CHAVEZ
J. KELLARD
PROCESS FLOW DIAGRAM
HERMOSA PLATFORM (WET OIL CASE)
DRILLING AND PRODUCTION PLATFORM HERMOSA
A
NONE
R-SB-002-W
8-SB-4632
SHEET 3 OF 3

FIGURE 6-1

SECTION 7

PIPELINE SYSTEM

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FIGURES

7. PIPELINE SYSTEM

7.1 Introduction

Current analysis indicates that as large as a 30" oil line and a 22" gas line will be installed in conjunction with Platform Hermosa. They have been sized to accommodate anticipated production from the Pt. Arguello Field of 200,000 BPD of emulsion (160,000 BOPD and 40,000 BWPD) and 160 MMSCFD of gas. The pipelines will carry emulsified oil and hydrocarbon wet sour gas from Platform Hermosa in 602' of water to a landfall near Pt. Conception. These lines will then continue onshore to Gaviota where the oil will be dehydrated and stablized and the gas will be processed and sold. An onshore dry oil line may be required from Gaviota to a marine terminal at Las Flores if the terminal expansion proposed by Getty is unsuccessful.

Organization of an industry "Pt. Arguello Transportation System" (PATS) is being coordinated by Chevron. The objective is to provide consolidated common facilities for the transportation and processing of oil and gas from the Point Arguello area. The pipelines proposed for Hermosa would become part of PATS. A regulated common carrier oil line and a common gas line are currently envisioned. In an effort to establish throughput quantity and quality data, an industry confidential survey has been initiated. It is being coordinated by Price-Waterhouse and consolidated information will be presented to the potential participants. Pipeline system design criteria will be reviewed and amended as necessary when these production estimates are available.

The following sections will present the current status of the pipeline route selection, corridor details, design codes, design basis, and expected operations. Finally, other considerations will be discussed.

7.2 Pipeline Route

The proposed pipeline route is shown in Figure 1.2. It is composed of three segments:

A. Offshore Line (10 miles, 16 km) - from Platform Hermosa to the Point Conception landfall. The line profile will include a relatively steep gradient from Hermosa to the Arguello Shelf and a gradual slope to the landfall at Point Conception.

B. Onshore Line (approximately 16 miles, 26 km) - from Point Conception to the oil and gas processing facilities at Gaviota. The line profile will be relatively constant. However, at stream and canyon crossings if the lines follow the topography allowing them to be buried, significant low spots will be developed.

C. Possible Onshore Extension (approximately 10 miles, 16 km) - from the oil dehydration facilities at Gaviota to the oil marine terminal at Las Flores. The line profile will be similar to the Point Conception to Gaviota segment.

7.3 Pipeline Corridors

7.3.1 Offshore (Platform Hermosa to Point Conception)

The lines will be laid over the route depicted in Figure 1.2. Surveys recently completed by Dames and Moore indicate the following features:

7.3.1.1 Geology/Hazards

A detailed geological evaluation was made along the offshore pipeline route from Platform Hermosa to Point Conception by Dames & Moore (Reference 2.5.14). The corridor surveyed for this portion of the pipeline varied from 5000 ft. to 7000 ft. in width and 53,000 ft. (10 miles) in length. Based on this survey work, the final route for the pipeline was selected to avoid most seafloor anomalies (Maps 2 & 3, Reference 2.5.14). The resulting alignment avoids three seafloor anomalies which have been identified as possible cultural resources. The route does not cross any clearly threatening faults. Further, the seafloor sediments along the route will adequately support the pipeline under normal static (non-earthquake) conditions.

The geological conditions along the proposed pipeline route are favorable for the laying and maintaining of the line. No serious geologic hazards were found. The shallow subsurface geology reflects a complex series of folds and faults, near the eastern landfall, that becomes simpler toward the western end. Most of these variations are buried beneath a nearly flat lying layer of young sediments that are considered to be Holocene in age. These shallow sediments along the pipeline route have been categorized into five zones by Dames & Moore (Reference 2.5.14, page 3-25). Each zone is characterized by a typical soil type with varying thicknesses. Additional details on these geologic conditions along the pipeline route are described in Sections 2.3.2 and 2.3.3 of this report and by Dames & Moore in their 1982 report on the shallow geology along the pipeline route (Reference 2.5.14).

7.3.1.2 Geotechnical

Dames and Moore (Reference 2.5.14) concluded in their report that the construction and maintenance of a pipeline along the proposed route from Platform Hermosa to Pt. Conception is feasible. Their report (Reference 2.5.14, Section 3.2.4, page 3-23) should be referred to for a detailed discussion of geotechnical conditions. In summary, they concluded that in the portion of the pipeline route between the landfall and shelfbreak, the ocean floor sands are sufficiently silty (Zone 3) to withstand any large movements during the design earthquake. Where the ocean floor sands are less silty (Zone 4), the pipeline can be supported boyantly during such an earthqake if the soils liquify. Between the shelfbreak and the platform (Zone 1), the upper three feet of these sediments are silty clays which are subject to some possible downslope movement during the extreme earthquake. McClelland Engineers (Reference 2.5.9, Section D) concluded from their studies of this material, at the platform site, that the downslope movement might be in the order of 6 inches at the seafloor to zero movement at a depth of 10 feet.

7.3.1.3 Cultural

Dames and Moore (References 2.5.14, Appendix E) utilized the services of Dr. Stephen P. Horne to review the route of the proposed pipeline for cultural and archaeological resources. Based on his findings and the geological hazards assessment, the final route for the pipeline was selected so that it avoids all of the anomalies noted. Three anomalies, thought to be shipwrecks, were identified in his report. These areas will also be avoided during anchoring activities connected with the platform and pipeline construction.

7.3.2 Onshore (Point Conception to Gaviota)

The lines could be installed across the Chevron Gerber Fee property, through a proposed Bixby Ranch Right-of-Way (ROW) parallel to the Southern Pacific railroad and then over a Texaco ROW to Gaviota. Other routes are also being investigated including the Southern Pacific railroad and Pacific Lightings LNG property. Surveys are scheduled for Spring, 1983 and only literature searches, map reconnaissance and field reconnaissance have been undertaken to date for geological/geotechnical data. An intensive archaeological survey was completed over the general route by WESTEC Services, (Reference 7.7.3).

7.3.2.1 Geology/Hazards

The geologic conditions along this portion of the pipeline route have been described by Dibblee in 1950 & 1966 (References 7.7.1 & 7.7.2). Most of this coastal area from Point Conception to Gaviota is characterized by rocky headlands which separate sandy beaches at the ocean from the high ground inland. The geologic conditions which control this coastline area consist of southerly dipping strata that have been exposed by erosion on the southflank of the Santa Ynez mountain range. The youngest strata, Upper Miocene silts and shales, are exposed in a narrow belt along the coastline. A coastal terrace that has been cut into these sediments contains unconsolidated deposits of gravel, sand, silt and clay which cap these Miocene sediments in most areas. Streams have deeply incised into these sediments at numerous locations.

There appear to be very few geologic hazards along this part of the coastline. The most significant ones are: 1) local landsliding of the Miocene sediments from the bluff toward the ocean, 2) the South Branch of the Santa Ynez fault where it crosses the pipeline route just west of Canada de Alegria and, 3) occasional erosion along the north-south stream channels. All of there features can be designed for on the basis of a proposed detailed geological survey.

7.3.2.2 Geotechnical

The geotechnical characteristics of the soils and sediments along the pipeline route will be determined when the final onshore route has been selected. The findings from this study will be used in the design of the pipeline and preparation of a report on geologic conditions along the proposed route.

7.3.2.3 Cultural

Between September 22 and 29, 1982, and October 18 and 23, 1982, WESTEC Services (Reference 7.7.3) made an intensive on-foot archaeological survey along the proposed pipeline route shown on Figure 1.2. The findings from this survey are reported in Appendices 4 & 5 of Reference 7.7.3. Should changes be made in the preliminary pipeline route, additional surveys will be conducted where required. In the Pt. Conception to Gaviota area, WESTEC encountered a total of 10 archaeological sites. The final pipeline alignment and construction right-of-way will be selected to avoid disturbing these areas unless sound engineering would prevent rerouting.

7.3.3 Possible Onshore (Gaviota to Las Flores)

The line would be installed in or near the Southern Pacific railroad or Pacific Gas and Lighting Rights Of Way. The following features are indicated:

7.3.3.1 Geology/Hazards

Geologic conditions along this onshore portion of the pipeline are very similar to those described in Section7.3.2.1. Therefore, similar detailed geological and geotechnical studies will be made along the final route in order to design the pipeline.

7.3.3.2 Geotechnical

The same or similar geotechnical studies as those planned for the Point Conception to Gaviota portion of the pipeline will be made along this portion of the line. The findings from this study will be used in the design of the pipeline and preparation of a report on geologic conditions along the proposed route.

7.3.3.3 Cultural

WESTEC completed a literature search for known archaeological sites between Gaviota and Las Flores Canyon (Reference 7.7.3, Appendix 5). In addition, an on-foot survey was carried out. They found 18 sites that have been recorded and 12 of these may be encountered during construction of the pipeline. The final pipeline alignment and construction right-of-way will be selected to avoid disturbing these areas unless sound engineering would preclude rerouting.

7.4 Design Codes

Oil and gas pipelines (offshore and onshore) will be designed, constructed, tested, operated, and inspected in accordance with the latest edition of the following applicable design standards:

- o Liquid Petroleum Transportation Piping Systems, American National Standards Institute (ANSI) B31.4.

- o Gas Transmission and Distribution Piping Systems, American National Standards Institute (ANSI) B31.8.

- o Transportation of Liquids by Pipeline: Minimum Federal Safety Standards, Department of Transportation Regulation 49, Part 195.

- o Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards, Department of Transportation Regulation 49, Part 192.

- o Recommended Practice for Liquid Petroleum Crossing Railroads and Highways, American Petroleum Institute Publication API-RP 1102.

- o Recommended Practice for Design, Construction, Operation and Maintenance of Offshore Hydrocarbon Pipelines, American Petroleum Institute Publication API-RP 1111.

- o OCS Order No. 9.

- Applicable portions of California State Lands Commission "Regulations for Oil and Gas Drilling on State Tide and Submerged Lands," Section 2132(h).

7.5 Pipeline Design Basis

A schematic of the pipeline system from Platform Hermosa to Gaviota is included as Figure 7.1. On deck tie-ins for Texaco's proposed Hueso platform and two possible Chevron platforms are now provided. Other production could join into the pipelines originating at Hermosa via the Texaco and possible Chevron platforms. Adding risers to Hermosa in the field is also a possibility but viability is contingent on there being deck space available, and no specific allocations have been made in the design to date. Should the situation dictate, access could be managed by making subsea tie-ins or by running a line to Pt. Conception. Values will be included for this purpose.

The oil characteristics used in sizing studies to date are:

Gravity: 20° API

Oil Viscosity: 1401 cp at 52°F
501 cp at 72°F
48 cp at 140°F

Based on laboratory tests, there is a 20% variation of viscosity with pressure, and this has been included in the flow calculations. The percent water cut has also been shown to affect capacity and the optimum is 10%. Temperatures at Hermosa have been predicted using a network analysis. The required pressure at Hermosa is affected by all of the noted variables. Using a 20% cut Gaviota inlet pressure of 100 psig and predicted temperatures, the maximum pressure required at Hermosa for the design flow of 200,000 BFPD is about 700 psi.

The gas will be dehydrated and at its hydrocarbon dewpoint when leaving individual platforms. As the temperature drops, liquids will condense. An average of 25B/MM SCF has been estimated for use in calculating pressure drops. The discharge pressure at Hermosa and the inlet pressure at Gaviota will also affect the system capacity. Assuming a 700 psi discharge at Hermosa and a 500 psi inlet at Gaviota, and using pigging spheres to control the affects of liquids, the 22" line will handle 160MMSCFD.

The pipelines will also be capable of operating successfully at offpeak capacity. For the oil line, calculations show a restart can be accomplished with the line contents at 50°F if there is an extended shutdown. The line also has the ability to handle flows at 50°F in excess of that required. For the gas line, low flows will cause excessive pressure drops if condensed liquids are allowed to accumulate. Pigging will be scheduled to avoid this situation.

7.5.1 Offshore (Platform Hermosa to Point Conception)

The proposed offshore pipelines will be designed to ensure that they can be safely installed and operated in an environmentally acceptable manner. Specific design data will be supplied in compliance with M.M.S. OCS Order No. 9 and California State Lands Commission Offshore Pipeline Right-of-Way requirements.

7.5.1.1 Design/Operating Conditions

Maximum design pressure of both the oil and gas pipelines to shore will probably be determined by the wall thickness required to withstand laying stresses. However, an ANSI 600 (1480 psig) system will be the minimum design pressure. Maximum operating pressures are expected to be less than 1200 psig in the crude line and less than 1000 psig in the gas line.

By adjusting the discharge pressures and temperatures, the pipelines will be capable of handling the range of expected flows at maximum efficiency. At a minimum, the oil line size will be sufficient to transport up to 200 MBPD of crude oil emulsion. The gas pipeline will be sized to have a capacity of 160 MMSCFD.

Temperature of crude in the oil pipeline is expected to range from 50°F to 150°F. Temperature of the gas line is expected to range from 50°F to 90°F. The pipelines will be designed to accommodate thermal effects without damage.

7.5.1.2 Mechanical Design

Pipeline materials specifications will be developed to satisfy requirements of both operating and installation modes. Pipe buckle arrestors will be installed where diameter to wall thickness ratios are insufficient to protect the pipe from propogating buckles.

Pipelines will be designed to resist predicted recurring environmental loads resulting from steady-state and wave induced currents, seabed soil liquification, slumping and mud slides and seismic activity. The magnitude and direction of loads will be determined through ocean data measurements and review of existing data. A current survey to provide site specific data has been completed and a report is being prepared.

7.5.1.3 Corrosion Protection

Pipelines will be protected from external corrosion by coating and cathodic protection (impressed current and/or sacrificial anodes).

Internal corrosion will be controlled through the use of corrosion inhibitors and through proper selection of pipeline materials.

7.5.1.4 Construction

Construction equipment, methods and procedures will be selected to insure that the pipelines are not overstressed during installation. Pipeline installation will most likely be by the conventional pipe lay barge/stinger method, but other methods will also be investigated. The near shore section of each pipeline may be installed using a state-of-the-art towing technique.

Pipeline risers and their connections to pipelines will be made using methods selected on the basis of technical and economic analysis. Risers will be pre-installed on the jacket. Connection to the pipeline will most likely be made using flanges or mechanical connectors. J-tubes will be provided for the smaller diameter gathering lines tying into Hermosa.

Prior to construction, all pipe and coatings will be inspected for defects. Pipeline welding procedures and welders will be prequalified. During construction, all girth welds will be 100 percent radiographically inspected. Full time qualified inspectors will monitor all phases of construction. Pipelines will be gauged and will be pressure tested with inhibited water to 1.25 times the maximum design pressure. Test water will remain in the pipelines until production begins. Test water will be treated in accordance with applicable regulations prior to disposal.

Pipelines will be trenched and buried through the surf zone. Additional trenching without backfill will place the top of each pipeline below the sea floor out to a water depth to be determined by engineering analysis of pipeline stability.

7.5.2 Onshore (Point Conception to Gaviota)

7.5.2.1 Design/Operating Conditions

The emulsified oil and hydrocarbon wet sour gas pipelines between Point Conception and Gaviota will be designed for ANSI 600 (1480 psig) working pressure. The oil pipeline design flow rate will be 200,000 BFPD (160,000 BOPD and 40,000 BWPD). Crude oil temperatures will be 50°-100°F. The gas pipeline will have a design flowrate of 160 MMSCFD and is expected to operate at near ambient temperature of 50°F.

In addition to internal pressure, the effects of thermal expansion, seismic loading and installation stresses will be considered during pipeline design. The pipeline will include relief valves located at the Gaviota Facility to prevent overpressure due to thermal expansion of static liquid or excessive pump pressure. Block values will be installed to isolate segments. Adequate facilities will be installed at Gaviota to handle the predicted gas line liquid volumes and rates.

7.5.2.2 Corrosion Protection

Pipelines will be coated and wrapped in accordance with sound engineering practices and industry standards for buried pipelines. Additional corrosion protection will be achieved through use of galvanic or impressed current systems. Insulating flanges will be used as necessary.

7.5.2.3 Construction

These pipelines will be installed using conventional land pipelaying methods and equipment. They will be buried with a minimum 3' of cover over the entire route, except for stream and canyon crossings where the alternatives of using existing railroad bridges, constructing new pipe bridges, or following the land contour to allow burial will be considered.

Chevron or its third party inspectors will inspect all pipeline materials for defects prior to installation using accepted industry standards. Pipe girth welds will be radiographically inspected per applicable codes at a minimum. After installation, the pipeline will be pigged and hydrostatically tested to 1.25 times the design working pressure. Test water will most likely be disposed of through the Gaviota outfall.

7.5.3 Possible Onshore (Gaviota to Las Flores)

7.5.3.1 Design/Operating Conditions

The dry oil pipeline between Gaviota and Las Flores will be designed for ANSI 600 (1480 psi) working pressure. The pipeline design flow rate will be 160,000 barrels of oil per day. Crude oil temperatures will vary from 100° to 160°F.

In addition to internal pressure, the effects of thermal expansion, seismic loading, and installation stresses will be considered during pipeline design. The pipeline will include relief valves located at Gaviota to prevent damage due to thermal expansion of static liquid or excessive pump pressure. Block valves will be installed to isolate segments.

7.5.3.2 Corrosion Protection

This pipeline will be coated and wrapped in accordance with industry standards for buried pipelines. Additional corrosion protection will be achieved through the use of galvanic or impressed current systems. Insulating flanges will be used as necessary.

7.5.3.3 Construction

This pipeline will be installed using conventional land pipelaying methods and equipment. They will be buried with a minimum 3' of cover over the entire route, except for stream and canyon crossings where the alternatives of using existing railroad bridges, constructing new pipe bridges, or following the land contour to allow burial will be considered.

Chevron will inspect all pipeline materials for defects prior to installation using accepted industry standards. Pipe girth welds will be radio graphically inspected per applicable codes at a minimum. After installation, the pipeline will be pigged and hydrostatically tested to 1.25 times the design working pressure.

7.5.4 Produced Water Outfall Line

The produced water outfall line at Gaviota will be designed to accommodate up to 50,000 barrels per day. Getty will also use this line for water disposal from their proposed expanded marine terminal. Present plans are to install this line from the Gaviota processing facilities to a suitable point offshore in State waters.

7.6 Pipeline Operations

The leak detection, pigging, and shutdown systems are schematically shown in Figure 7.1. Additional details on the operations are prescuted in the following sections. The communicating between facilities will be designed to meet all code and operating requirements.

7.6.1 Offshore (Platform Hermosa to Point Conception)

The oil/water emulsion entering offshore pipelines will be metered on each platform using positive displacement meters. Meter provers will be installed on each platform. Metered offshore volumes will be continuously compared to metered volumes delivered at the Gaviota process facility. System alarms will be activated if significant differences between input and output volumes are measured, as required by OCS Order No. 9. Appropriate measures will be taken to assess the validity of alarms when they occur and to shut in the affected pipeline. The leak detection system will be designed in accordance with OCS Order

No. 9.

Gas entering offshore pipelines will also be metered and deliveries to Gaviota will be measured. A continuous comparison is not feasible due to the 2-phase nature of the flow.

High and low pressure shut-down devices will automatically shut-in offshore production and shut down pipeline(s) if changes in pressure (high or low) exceed preset limits. Pipelines coming onto and leaving platforms will have automatic shut-in valves operated in accordance with OCS Order No. 9.

Corrosion inhibitors, pipeline pigs and instrumented pigs will be used as needed to assure that pipelines remain free of potentially harmful deposits, corrosion products and defects. For the gas line, pigging will be used to control the pressure drops and Gaviota handling problems associated with condensed liquids.

All offshore pipelines will be operated in accordance with OCS Order No. 9 and California State Lands Commission Regulations for Oil and Gas Production, Section 2132(h). This will include external inspections of the lines, testing of safety devices, and actuation of isolating valves on the prescribed schedule.

7.6.2 Onshore (Point Conception to Gaviota)

Wet crude oil in the pipeline segment between Point Conception and Gaviota will be volumetrically compared using the system described in

Section 7.6.1. That is, no additional facilities are planned for this segment. Significant changes in volume will result in alarms. As with the offshore pipeline, appropriate steps will be taken to assess the nature of the problem and shut down the pipeline if necessary, in compliance with the Onshore Oil Spill Plan. High and low pressure sensors will shut down pipelines if pressures reach preset limits. Corrosion inhibitor, pipeline pigs, and instrumented pigs will be used as necessary to assure the pipelines remain free of potentially harmful deposits, corrosion products, and defects. For the gas line, pigging will be used to control the pressure drops and Gaviota handling problems associated with condensed liquids.

Internal and external inspection of the lines, testing of safety devices, and actuation of isolating valves will be undertaken on the prescribed schedule.

7.6.3 Possible Onshore (Gaviota to Las Flores) - Optional

Dry oil in this pipeline segment will be metered at both Gaviota and Las Flores and continuously compared. Significant differences in volumes will result in alarms and appropriate steps will be taken to assess the nature of the problem and shut down the pipeline if necessary. High and low pressure sensors will initiate shutdowns if preset limits are exceeded. Pigging will be used routinely to keep the line free of potentially harmful deposits and corrosion products.

Internal and external inspections of the lines, testing of safety devices and actuation of isolating valves will be undertaken on the prescribed schedule.

7.7 Other Considerations

7.7.1 Capacity Increases

The lines are currently sized to handle the peak Chevron et al and Texaco et al estimated volumes from the Pt. Arguello Field. As previously noted, these volumes will be amended as necessary based on the results of the Price-Waterhouse confidential industry survey and line sizes and operating conditions subsequently revised. Should greater throughout be required in the future, additional measures are available to increase capacity.

For the oil line, the water cut can be optimized at 10%, or the line temperature can be increased to reduce viscosity. Higher pumping pressure would also increase capacity. The use of friction reducing chemicals would also be a possibility. In an extreme case, a pumping/heating station could be installed at Point Conception on Chevron's Gerber Fee property or a parallel pipeline could be installed over all or a portion of the route (looping).

For the gas line, additional capacity can easily be obtained by reducing the Gaviota plant inlet pressure. This would increase the allowable pressure drop, assuming Hermosa continued to operate at the same pressure. Removing hydrocarbon liquids on each platform and transporting dry gas would also increase the system capacity. In an extreme case, looping the system pipelines (partially or totally) would be possible.

7.7.2 Fishing/Marine Line Compatibility

The pipelines are expected to lay on the seabed except at the shore crossing where they will be trenched and appurtenances for subsea tie-ins will most likely be provided.

To ensure compatibility with fishing equipment, and preclude damage to the pipeline system, smooth profiled protective devices will be installed. This may take the form of attachment to the line itself for small items to a cover which rests on the scabed for complete subrea tie ins. Spanning of the pipeline will also be monitored and corrected as necessary. The large diameter, concrete coated pipelines will withstand trawl board impacts and damage therefore is not expected to be a problem.

7.7.3 Seabed Topographic Alterations

The use of anchored vessels for pipeline installation could result in marking the seabed. At this time, we are uncertain whether these disturbances would be permanent and what constitutes a compromise to fishing or other involved parties interests. We plan to develop additional information by studying the seabed soils, currents, etc. and meeting with involved parties per past similar projects.

With the background data in hand, various alternates to mitigate the situation will be explored. These could include use of installation techniques which minimize seabed topography changes or post installation treatment of the problem. The overall economics and technical feasibility of the options will be determined and the most feasible approach recommended. An acceptable solution to all parties will be pursued: the goal.

7.8 References

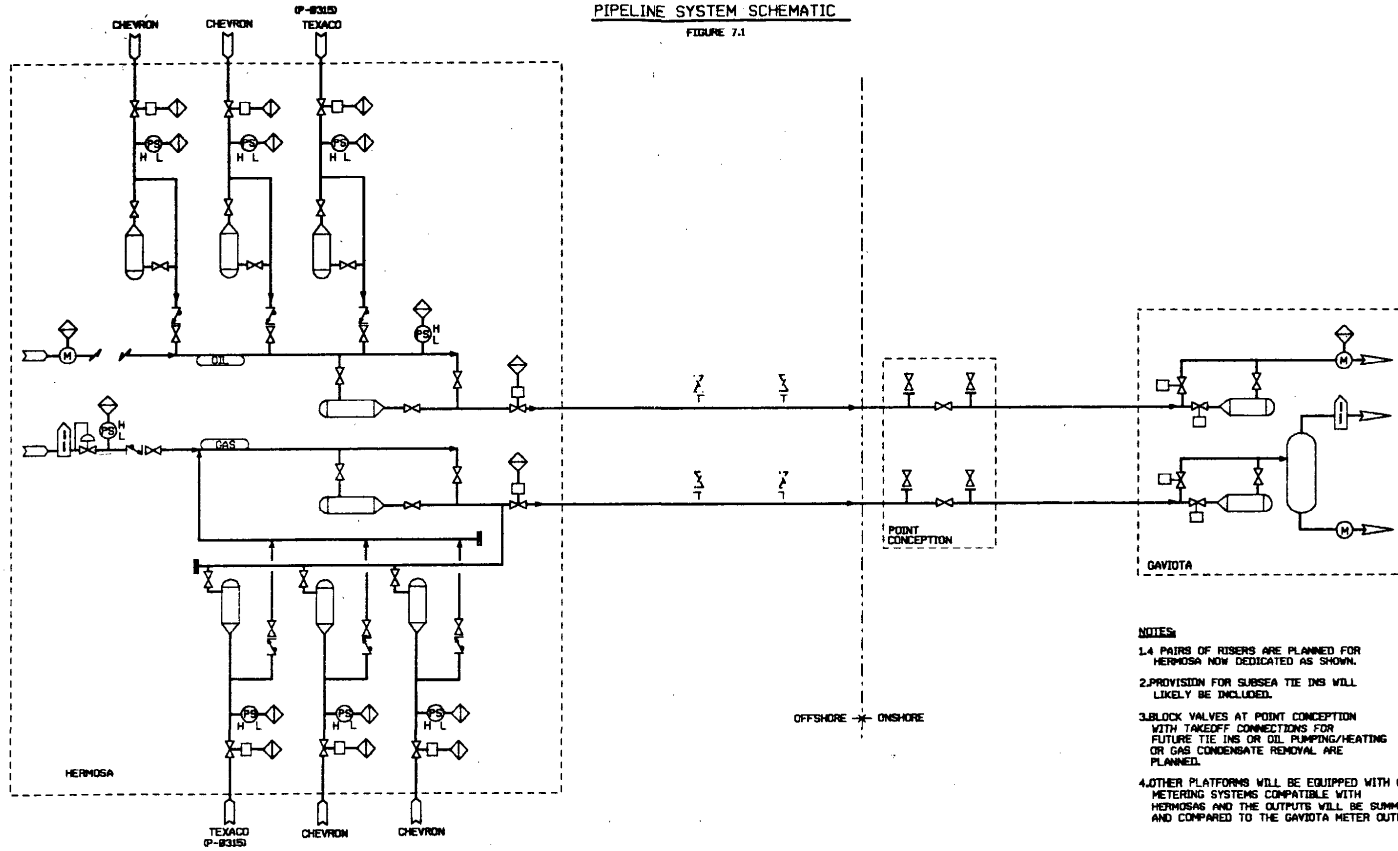
7.8.1 Dibblee, T. W., Jr. (1950), Geology of Southwestern Santa Barbara County; Point Arguello, Lompoc, Point Conception, Los Olivos, and Gaviota Quadrangles, California Division of Mines and Geology Bulletin 150, June.

7.8.2 Dibblee, T. W., Jr. (1966), Geology of the Central Santa Ynez Mountains, Santa Barbara County, California, California Division Mines and Geology Bulletin 186, 99 p.

7.8.3 WESTEC (1982) Environmental Report for the Point Arguello Field. Prepared for Chevron U.S.A.

POINT ARGUELLO FIELD
PIPELINE SYSTEM SCHEMATIC

FIGURE 7.1



NOTES:

1.4 PAIRS OF RISERS ARE PLANNED FOR HERMOSA NOW DEDICATED AS SHOWN.

2.PROVISION FOR SUBSEA TIE INS WILL LIKELY BE INCLUDED.

3.BLOCK VALVES AT POINT CONCEPTION WITH TAKEOFF CONNECTIONS FOR FUTURE TIE INS OR OIL PUMPING/HEATING OR GAS CONDENSATE REMOVAL ARE PLANNED.

4.OTHER PLATFORMS WILL BE EQUIPPED WITH OIL METERING SYSTEMS COMPATIBLE WITH HERMOSAS AND THE OUTPUTS WILL BE SUMMED AND COMPARED TO THE GAVIOTA METER OUTPUT

FIG 7.1

NONE

PIPELINE SYSTEM SCHEMATIC

POINT ARGUELLO FIELD

SECTION 8

POINT ARGUELLO GAVIOTA

PROCESSING FACILITIES

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FIGURES

8. PROCESSING FACILITIES

8.1 Introduction

Oil dehydration, gas sweetening and dehydration, oil pumping and gas compression facilities are proposed for installation at the existing gas plant site located at Gaviota. Additional areas will be reserved to expand facilities at the site as required to handle production that might be discovered and require processing at Gaviota. If needed for an industry pipeline, land will be made available for a crude pumping station. Initially, gas may be processed for commercial sale at the existing Chevron gas plant at Gaviota which has a capacity of 30 MMCF/D. Depending on the reservoir data developed with additional drilling, this plant may be either expanded or replaced with a new plant.

8.2 Production Handling Facilities

Preliminary process flow diagrams and facility plot plans for the Gaviota facility are shown in Figures 8.1 through 8.5. The facility will be built in phases and will be designed to permit expansion with minimum disruption to existing equipment when plant additions are required. Plot plans for this facility are shown in Figures 8.4 and 8.5. Expansions are expected to occur over a period of nine years. The facilities shown are designed to heat and dehydrate approximately 148,000 BPD of oil in an emulsion (185,000 barrels of fluid per day) and to sweeten 98 million standard cubic feet per day (98 MMSCF/D) of sour gas and 37,000 BPD of waste water will be cleaned for disposal through a new ocean outfall line. Space will be provided and the design will allow expansion to accommodate future increases in volumes that may occur. Chevron is surveying industry to refine their production estimates.

8.2.1 Oil Dehydration and Shipping

8.2.1.1 Inlet

Crude oil emulsion and free water will enter the Gaviota facility from the pipeline at a pressure of 100 psig. It will first pass through an inlet metering station. The volume of fluid reaching Gaviota will be continuously compared to the platform shipping meters. Differences exceeding preset limits will result in alarms and appropriate measures will be taken to assess the validity of the alarm and shut-in the pipeline.

Fluid leaving the meter enters a free water knock out (FWKO) vessel where water that has separated out in the pipeline is removed and sent to the water cleaning plant. A pressure control valve located between the inlet and FWKO will direct a portion of the incoming production to the re-run tank if vessel pressure exceeds a preset value. Crude from the re-run tank will then be pumped into the system downstream of the control valve when operating conditions permit.

8.2.1.2 Oil Dehydration

Oil dehydration is a process of removing water from the oil emulsion using a combination of heat, settling time, emulsion breaking chemicals and an electrostatic field. This process is started within the FWKO vessels and continues within the treating vessels.

Emulsion heating will occur in heat exchangers that utilize waste heat from a cogeneration power plant (supplying electricial power to the onshore facility) (see Section 8.3.1). The emulsion will flow through another bank of heat exchangers using a heating medium from boilers or fired heaters. In addition, excess heat from oil and water streams leaving the treaters will be transferred to the incoming emulsion stream. The oil/water mix then flows to the dehydration vessel, one of three electrostatic coalescers.

Electrostatic grids located in the processing section of each vessel causes droplets of water suspended in the oil stream to be attracted to each other (coalesce). These larger drops of water then settle to the bottom of the treater more rapidly than they would without this coalescing section. Dehydrated oil will pass through a dry oil/wet oil heat exchanger to preheat the incoming crude.

Produced water extracted during dehydration will be mixed with the stream from the free water knock out (FWKO) after flowing through crude oil heat exchangers to conserve energy. The water from the FWKO and dehydrators will flow to the produced water facility.

8.2.1.3 Oil Shipping

Dehydrated oil will leave the dehydration system with a water content of less than one percent. Actual cut will vary depending upon the difficulty in breaking the emulsion and the percent water in the emulsion when it reaches the Gaviota facility. Before entering the shipping pump surge tanks, the crude stream will pass through a monitor to insure that it meets pipeline specifications; crude that does not will be sent to the 40,000 reject tank. Off-specification crude (i.e. greater than one percent) will be pumped through the treating vessels again.

Two 10,000 barrel insulated tanks will provide about 2.6 hours surge capacity at peak flow rates; the reject tank about 4.8 hours.

8.2.2 Waste Water Handling

Waste water removed during oil and gas dehydration, and water from the sump tank will be stored in a 5,000 barrel oily water tank. From this tank, waste water will be processed through a flotation cell and/or other equipment to clean water to meet current California Ocean Plan requirements for disposal in the ocean through a proposed new 4000' ocean outfall line.

Liquids and suspended solids removed during water treating will be collected in the sump tank. Oil from the sump tank will be pumped to the dirty oil tank and water will be pumped to the oily water tank. Solids will be hauled away and disposed of at an appropriate dump site.

8.2.3 Blanket Gas System

Sweet gas from the sulfur recovery unit will provide blanket gas for all atmospheric tanks, the flotation unit, and sumps.

8.2.4 Relief and Vent Systems

All vessels and tanks will be equipped with pressure relieving devices. Tanks will vent to a low pressure knock out drum and flare, while pressure vessels will relieve to a common high pressure knock out drum and flare. Liquids from the knock out drums will be pumped to the dirty oil tank. Relieved gas will be burned by a flare equipped with an automatic ignition system. Pilot gas will be sweet.

8.2.5 Gas Handling

8.2.5.1 General Process

Gas will be dehydrated offshore prior to entering submarine pipelines. Upon reaching Gaviota, the gas stream will pass through liquid slug catchers, low temperature liquid separation and to a sulfur recovery unit. Gas from the process will supply sweet fuel to the heaters and turbine generator sets.

Gas from the acid gas removal process will go through the sulfur recovery unit. After natural gas liquids are removed, it will then be compressed and enter the utility gas line. Natural gas liquids will be placed in storage tanks for transportation by tanker trucks.

The sulfur recovery unit will produce sulfur as a by-product. It is anticipated that approximately 33 tons of sulfur will be generated daily at peak production. This material will be sold or taken to an appropriate disposal periodically by rail and/or truck. Processed gas will be the source of blanket gas for the atmospheric tanks, fuel for the turbine generators and supplemental boilers and/or heaters. Tail gas from the sulfur recovery unit will be incinerated and scrubbed.

8.2.5.2 Facilities

The gas plant will condition the gas for fuel use and for delivery to the local utility line. Hydrocarbon liquids from the gas will be stored in tanks and removed in trucks.

8.3 Utilities

8.3.1 Electrical

At peak production, the onshore facility will require approximately 13,000 KW. The electric power for the Gaviota facility will be provided by gas turbine driven generators.

Cogeneration facilities will be used. Waste heat from the turbine exhaust will be used to preheat crude going to the oil dehydrators and thus reduce the amount of energy generated with fired heaters. Power will be purchased from the utility company in the event of a turbine failure.

8.3.2 Fuel

Produced gas will be the primary fuel source for electric power generation and fired heaters. Arrangements will be made with the gas companies to purchase gas when produced gas is not available.

8.3.3 Water

Water source wells will be drilled to provide fresh water for facility needs. Approximately 20 acre feet of water will be used annually. Water will be stored in a 2000 barrel tank. Initial studies indicate that adequate fresh water sources are available.

8.4 Safety

8.4.1 Monitoring and Control

All facilities will be monitored and controlled (if appropriate) from a central location on the site. Critical parameters will be continuously monitored on each pressure vessel, tank, pump and compressor in the facility in compliance with industry standards and applicable codes. Alarms will be activated when abnormal conditions occur.

Combustible gas and hydrogen sulfide monitors will be located in areas where gas handling equipment is installed. Abnormal levels of either will cause an alarm to sound in the control room and automatically shut down equipment if appropriate.

Continuous monitoring fire sensors will be placed throughout the facility. Fire detection will result in an alarm in the control room and, in critical areas, activation of automatic fire extinguishing equipment.

Certain alarms will result in partial or total shutdown of facility equipment. In most cases an alarm will preceed a shutdown action, giving an operator time to correct the alarmed condition.

8.4.2 Fire Protection

Fire protection will be furnished by the local fire protection agencies. In critical areas, automatic fire extinguishing equipment will be installed. Hand held dry chemical extinguishers will be located throughout the plant. Seawater will be used to supply water to a fire hydrant system for local fire protection agencies' pumping equipment. Other fire prevention measures include the separation of fired equipment from process equipment, remote impounding for tank leakage, storage of AFFF foam, vessel and support fine-proofing, and others.

8.4.3 Emergency Shutdown

The shutdown system will provide for orderly shutdown and facility isolation in the event of an emergency.

8.5 Environmental Considerations

8.5.1 Water

Chevron will construct an outfall to dispose of up to 50,000 barrels per day of produced water. This water will be cleaned and cooled so that environmental impacts will be minimized. All effluent will be continously monitored for oil content. All discharges will be made in compliance with a permit that will be obtained from the Regional Water Quality Control Board.

8.5.2 Air

All facilities at the Gaviota facility will be designed to minimize the impact on air quality. Emission sources will include:

a. Cogeneration Turbines
b. Supplemental Heaters
c. Fugitive Emissions

Cogeneration facilities are inherently more efficient than separate electrical generation and heating facilities and this will result in a substantial reduction in emissions. To further reduce the emission from these turbines, Chevron will equip them with water injection. This will further reduce the amount of NOx emissions by approximately 70%.

Heaters will be equipped with burners of low NOx design and will burn sweet natural gas. To reduce fugitive emissions, Chevron will institute a fugitive emission inspection and maintenance program at the Gaviota Facility. All fixed roof tanks will be designed to reduce hydrocarbon emissions with vapor recovery.

Emergency relief valves on all systems will be routed to a flare knock-out drum. All liquids will be removed from the gas stream at this point. The remaining gas will then go to flares with smokeless tip designs.

For a detailed description of the air emissions from the Gaviota, please refer to the Environmental Report.

8.5.3 Solid Waste

All solid wastes generated at the Gaviota facility will be hauled to an appropriate disposal site by rail or truck. Sanitary waste will be placed in septic tanks.

8.5.4 Oil Spills

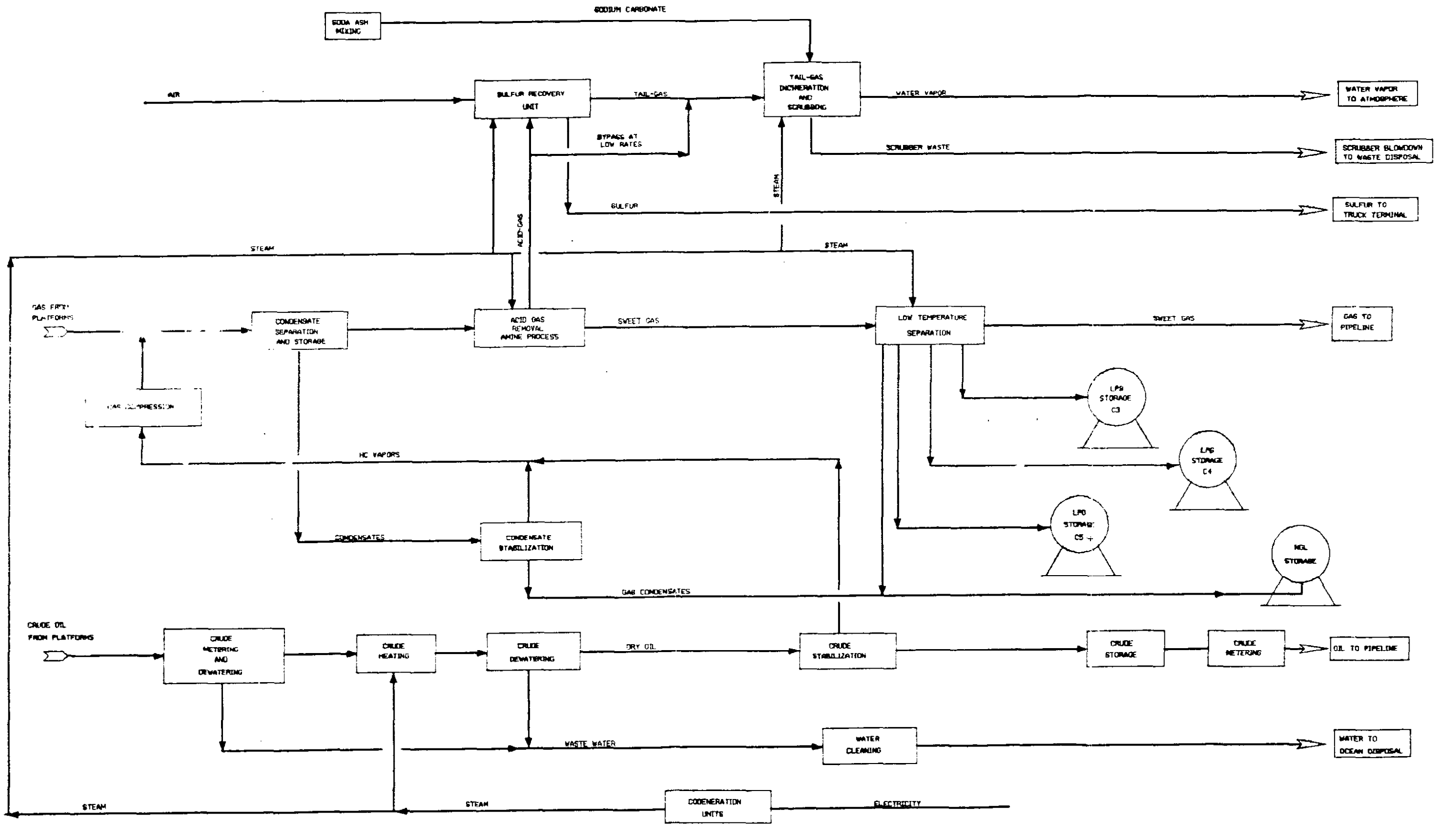
Chevron will construct remote impounding on containment berms for all tankage, and will be in compliance with the requirements stated in 40 CFR Part 112. All operating personnel will be trained to react quickly and effectively in the unlikely event of an oil spill.

If a spill threatens navigable waters, equipment stored onsite (containment booms, skimmers, Sorbento, etc.) will be used to quickly remove any oil that does reaches the water. If the volume of oil is large or if the oil spill threatens to enter the ocean, additional onshore and offshore equipment from Clean Seas, or contractors, will be utilized.

A complete description of the measures that will be taken, and equipment to be located on site in the event of an onshore oil spill will be provided in an Oilspill Prevention, Control and Countermeasure Plan (SPCC Plan). This plan will be filed within six months of the time the facility begins to operate (as required by 40 CFR Part 112).

8.5.5 Other

Chevron will provide vegetation to screen all facilities to the maximum extent possible. Vegetation will also be provided to minimize run-off from graded areas. Facilities will be designed to minimize noise levels. Construction activities creating substantial noise levels will be carried out only during daylight hours. Lights will be shielded and directed to prevent excessive glare. Fences will be placed around all facilities to prevent public access to the process area.



FIGURE

8-1

ONSHORE GAS AND OIL PROCESS BLOCK DIAGRAM

GAVIOTA, CALIFORNIA

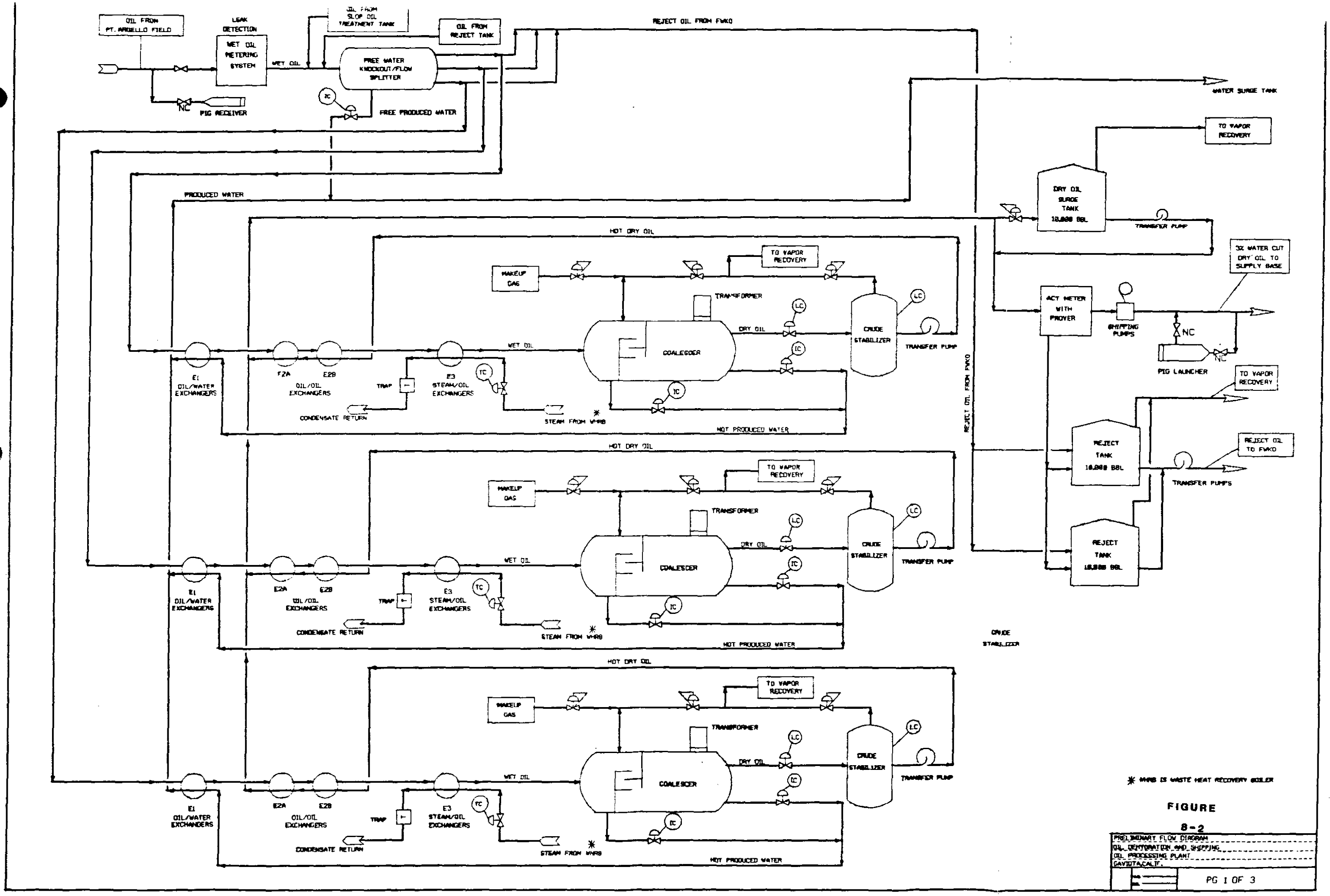
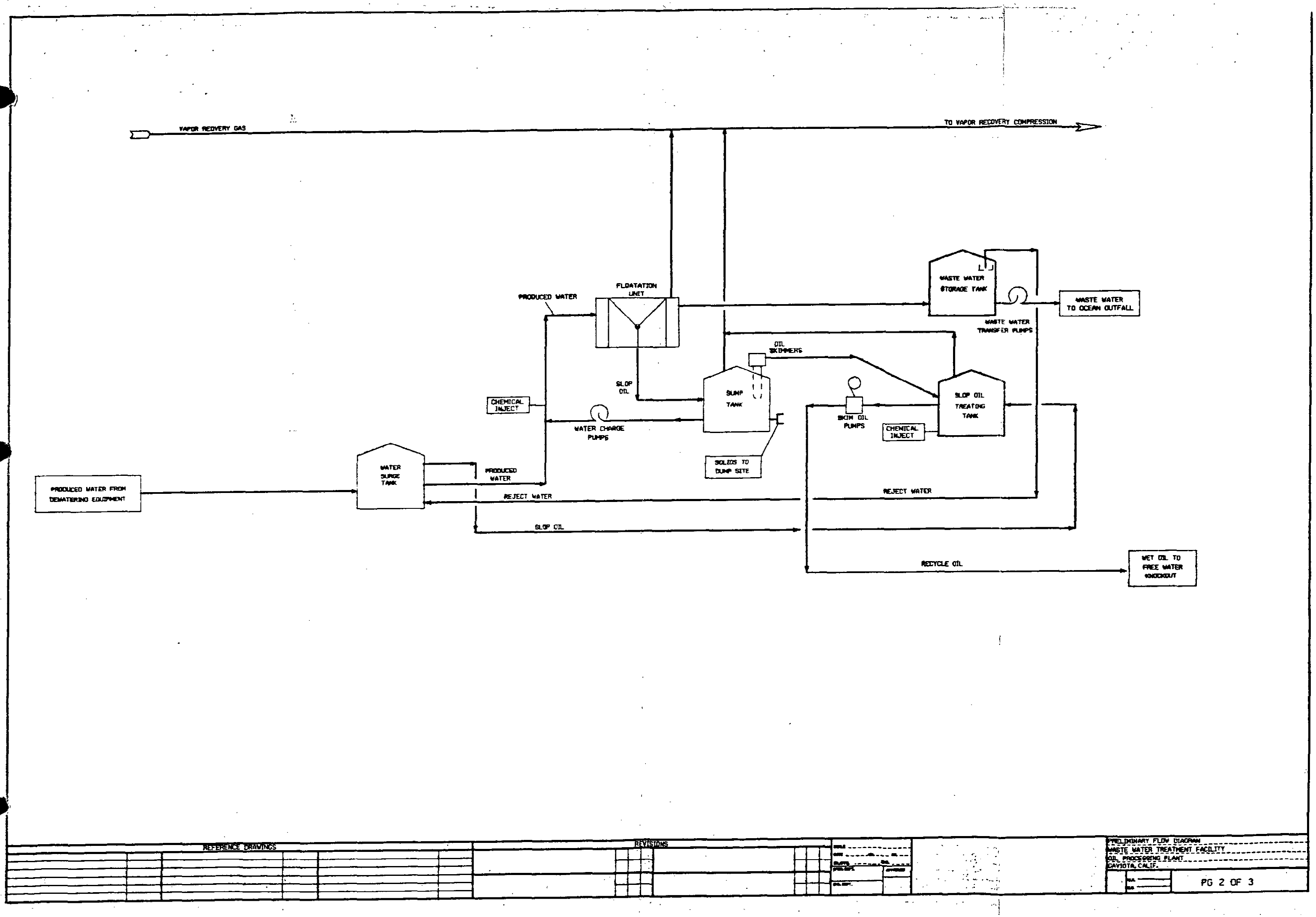
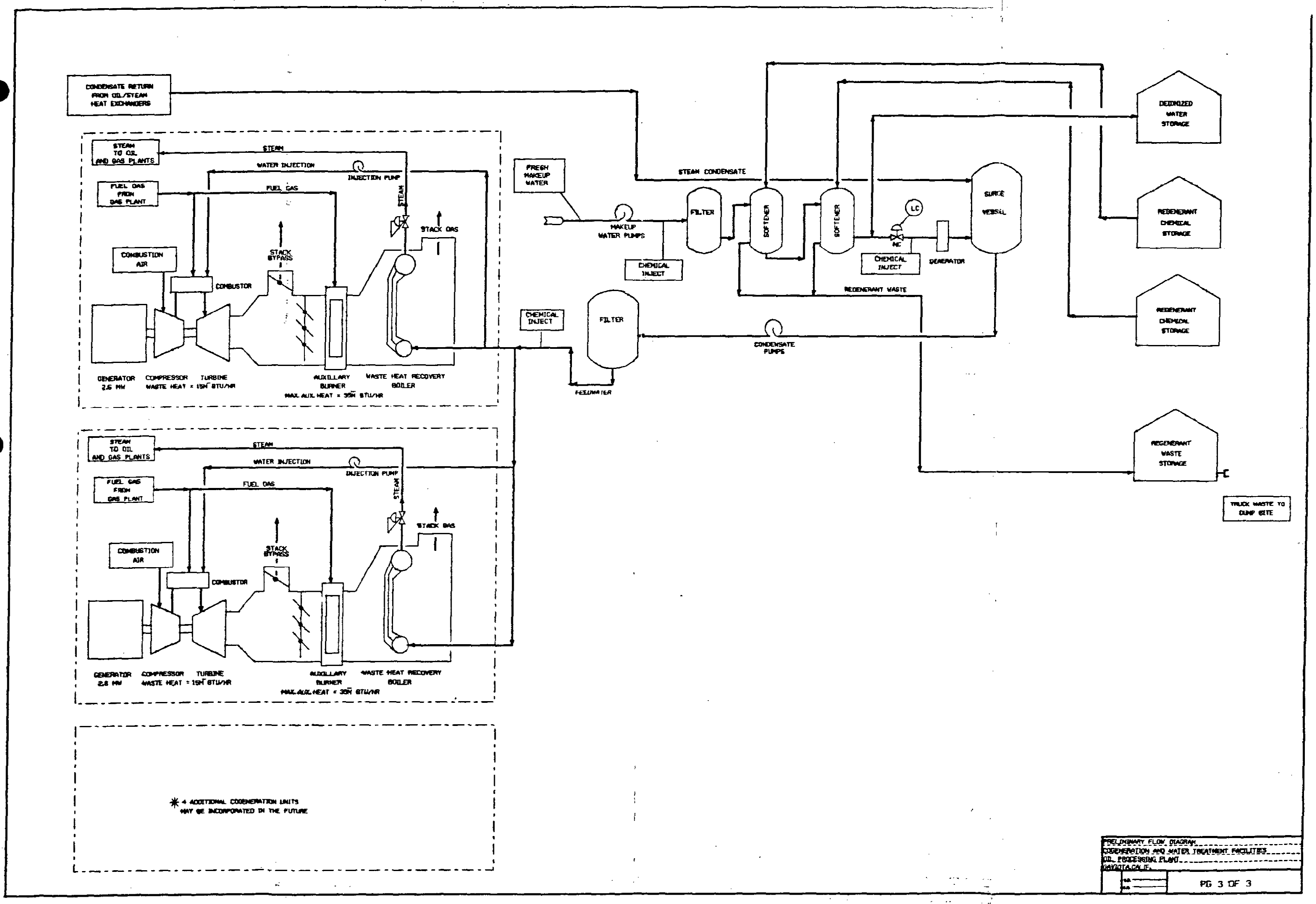


FIGURE 8-2

PRELIMINARY FLOW DIAGRAM
OIL DEHYDRATION AND SHIPPING
OIL PROCESSING PLANT
GAVIOTA,CALIF.


VAPOR RECOVERY GAS
TO VAPOR RECOVERY COMPRESSION
FLOATATION UNIT
PRODUCED WATER
WASTE WATER STORAGE TANK
WASTE WATER TO OCEAN OUTFALL
WASTE WATER TRANSFER PUMPS
OIL SKIMMERS
SLOP OIL
SUMP TANK
CHEMICAL INJECT
WATER CHARGE PUMPS
SKIM OIL PUMPS
SLOP OIL TREATING TANK
CHEMICAL INJECT
SOLIDS TO DUMP SITE
WATER SURGE TANK
PRODUCED WATER FROM DEWATERING EQUIPMENT
PRODUCED WATER
REJECT WATER
REJECT WATER
SLOP OIL
RECYCLE OIL
WET OIL TO FREE WATER KNOCKOUT
REFERENCE DRAWINGS
REVISIONS
PRELIMINARY FLOW DIAGRAM
WASTE WATER TREATMENT FACILITY
OIL PROCESSING PLANT
GAVIOTA, CALIF.
PG 2 OF 3


CONDENSATE RETURN FROM OIL/STEAM HEAT EXCHANGERS
STEAM TO OIL AND GAS PLANTS
STEAM
WATER INJECTION
INJECTION PUMP
FUEL GAS FROM GAS PLANT
FUEL GAS
COMBUSTION AIR
COMBUSTOR
STACK BYPASS
STACK GAS
GENERATOR 2.6 MW
COMPRESSOR
TURBINE
WASTE HEAT = 15M BTU/HR
AUXILLARY BURNER
MAX AUX HEAT = 35M BTU/HR
WASTE HEAT RECOVERY BOILER
4 ADDITIONAL COGENERATION UNITS MAY BE INCORPORATED IN THE FUTURE
FRESH MAKEUP WATER
MAKEUP WATER PUMPS
CHEMICAL INJECT
FILTER
SOFTENER
STEAM CONDENSATE
SURGE VESSEL
LC
REGENERATOR
REGENERANT WASTE
CONDENSATE PUMPS
FEEDWATER
DEIONIZED WATER STORAGE
REGENERANT CHEMICAL STORAGE
REGENERANT WASTE STORAGE
TRUCK WASTE TO DUMP SITE
PRELIMINARY FLOW DIAGRAM
COGENERATION AND WATER TREATMENT FACILITIES
OIL PROCESSING PLANT
GAVIOTA, CALIF.
PG 3 OF 3

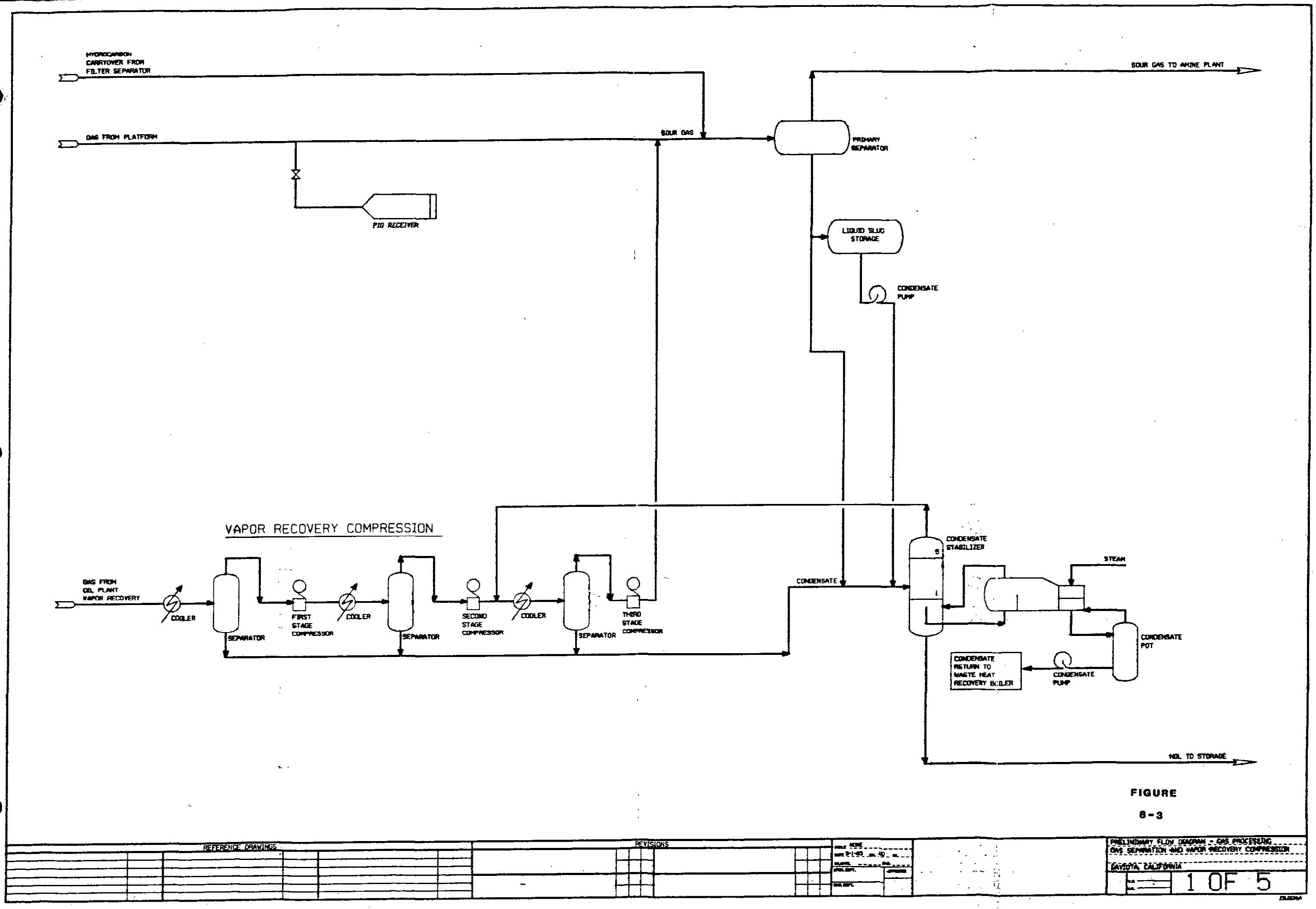
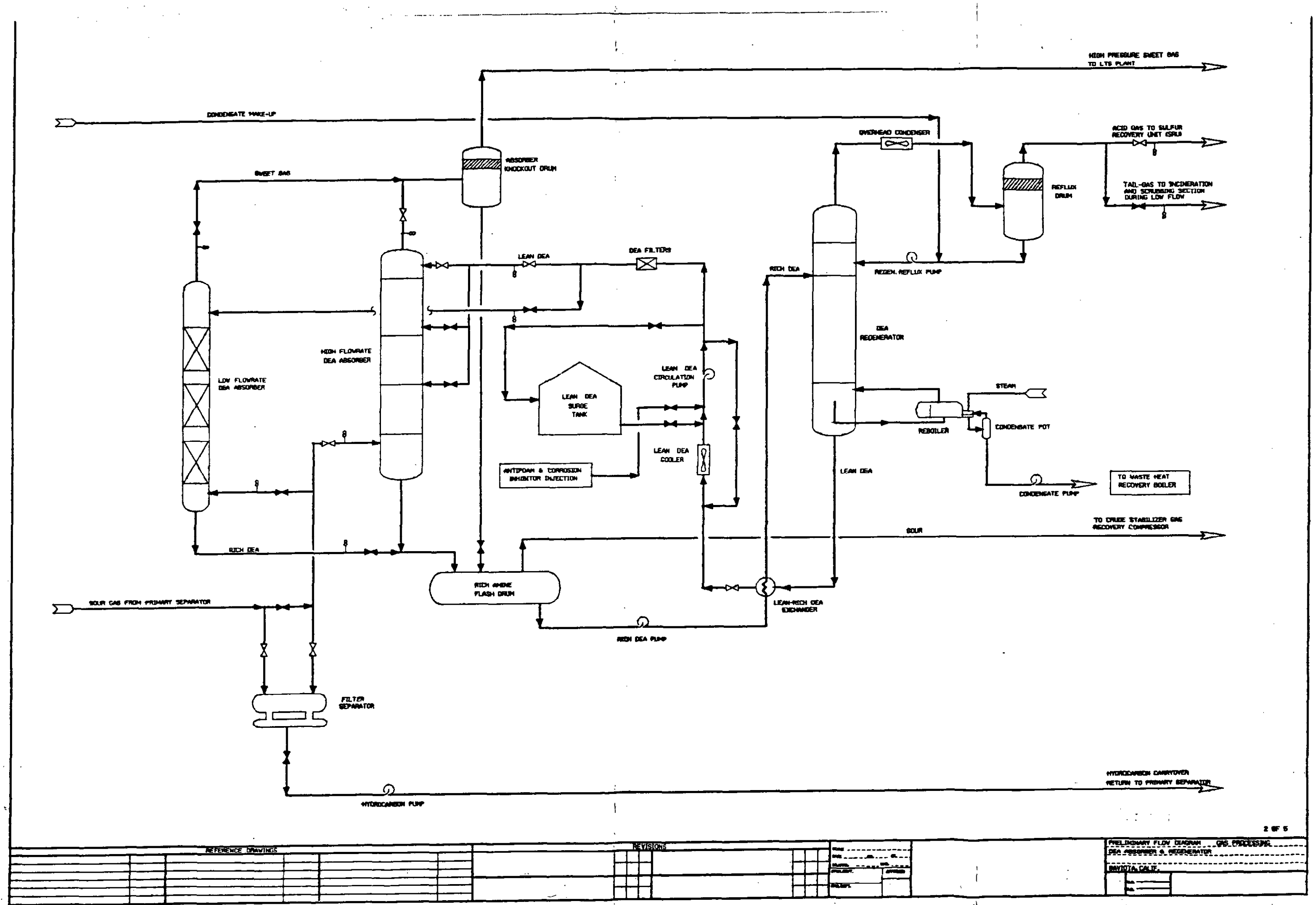
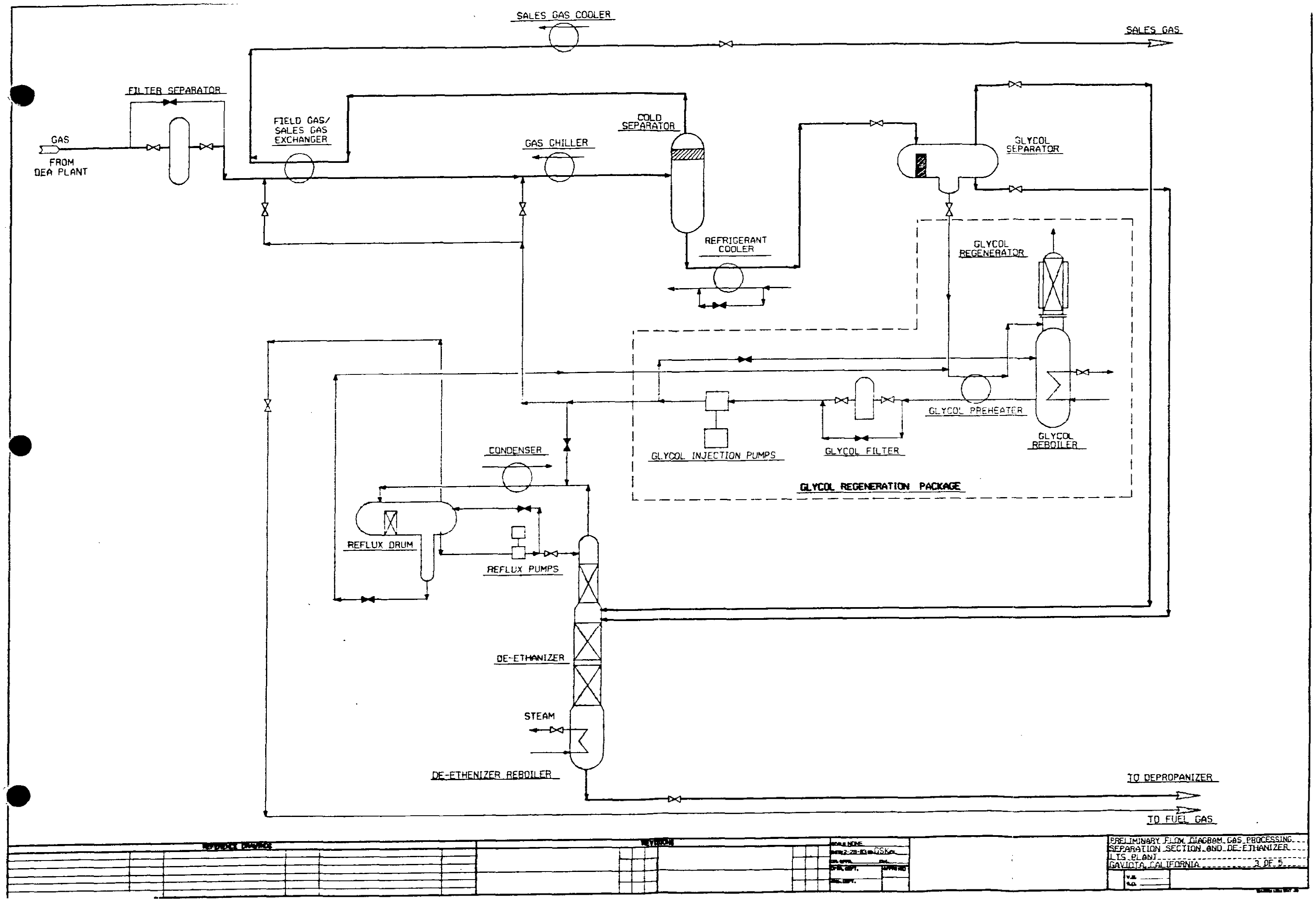
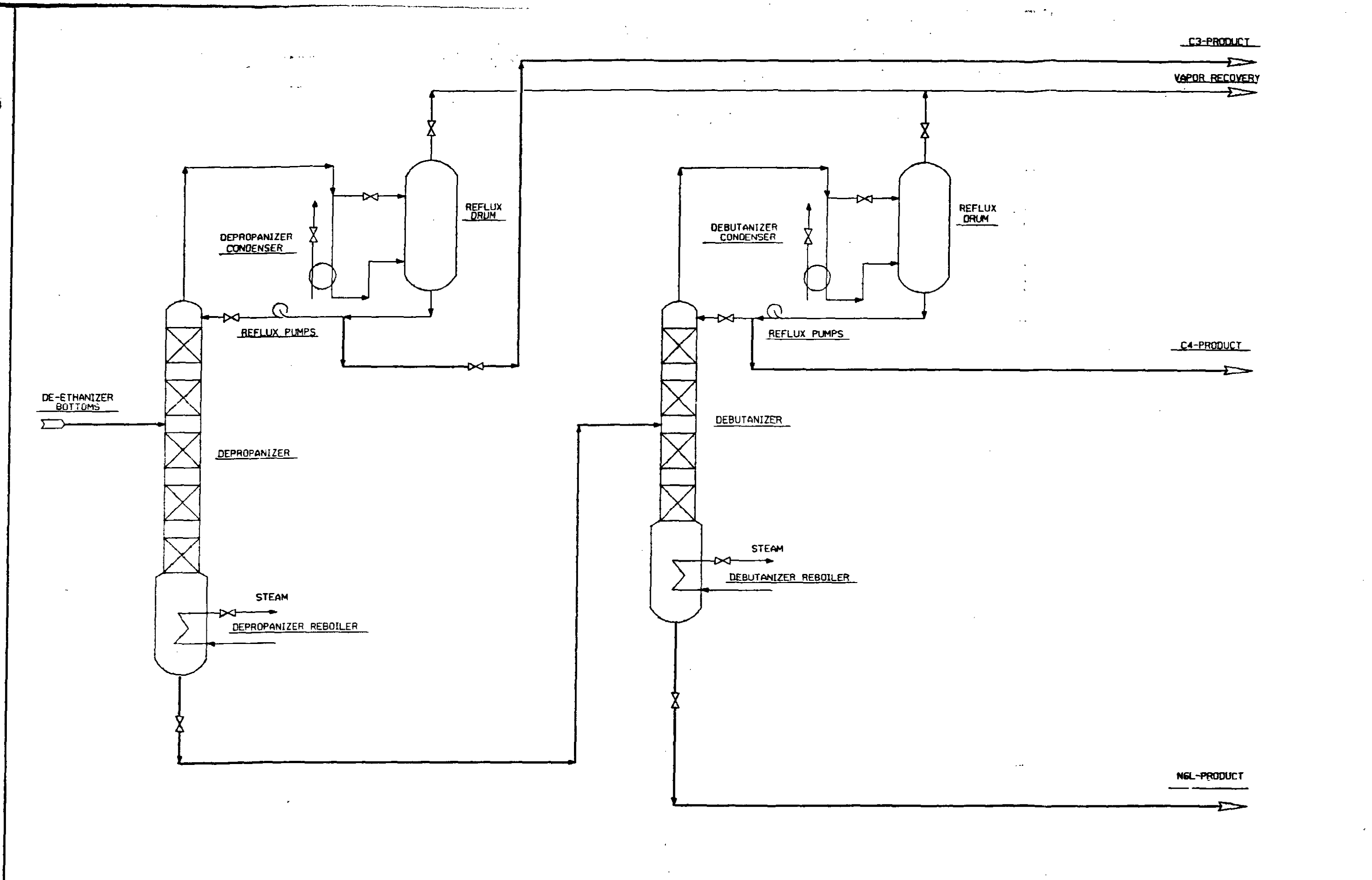

HYDROCARBON CARRYOVER FROM FILTER SEPARATOR
GAS FROM PLATFORM
PIG RECEIVER
SOUR GAS
PRIMARY SEPARATOR
SOUR GAS TO AMINE PLANT
LIQUID SLUG STORAGE
CONDENSATE PUMP
VAPOR RECOVERY COMPRESSION
GAS FROM OIL PLANT VAPOR RECOVERY
COOLER
SEPARATOR
FIRST STAGE COMPRESSOR
COOLER
SEPARATOR
SECOND STAGE COMPRESSOR
COOLER
SEPARATOR
THIRD STAGE COMPRESSOR
CONDENSATE
CONDENSATE STABILIZER
STEAM
CONDENSATE POT
CONDENSATE RETURN TO WASTE HEAT RECOVERY BOILER
CONDENSATE PUMP
NGL TO STORAGE
REFERENCE DRAWINGS
REVISIONS
SCALE NONE
PRELIMINARY FLOW DIAGRAM - GAS PROCESSING
GAS SEPARATION AND VAPOR RECOVERY COMPRESSION
GAVIOTA, CALIFORNIA
1 OF 5

FIGURE 8-3


HIGH PRESSURE SWEET GAS
TO LTS PLANT
CONDENSATE MAKE-UP
ABSORBER KNOCKOUT DRUM
SWEET GAS
OVERHEAD CONDENSER
ACID GAS TO SULFUR
RECOVERY UNIT (SRU)
REFLUX DRUM
TAIL-GAS TO INCINERATION
AND SCRUBBING SECTION
DURING LOW FLOW
LEAN DEA
DEA FILTERS
RICH DEA
REGEN. REFLUX PUMP
HIGH FLOWRATE
DEA ABSORBER
DEA
REGENERATOR
LOW FLOWRATE
DEA ABSORBER
LEAN DEA
CIRCULATION
PUMP
LEAN DEA
SURGE
TANK
STEAM
REBOILER
CONDENSATE POT
LEAN DEA
COOLER
ANTIFOAM & CORROSION
INHIBITOR INJECTION
LEAN DEA
CONDENSATE PUMP
TO WASTE HEAT
RECOVERY BOILER
TO CRUDE STABILIZER GAS
RECOVERY COMPRESSOR
SOUR
RICH DEA
RICH AMINE
FLASH DRUM
SOUR GAS FROM PRIMARY SEPARATOR
LEAN-RICH DEA
EXCHANGER
RICH DEA PUMP
FILTER
SEPARATOR
HYDROCARBON CARRYOVER
RETURN TO PRIMARY SEPARATOR
HYDROCARBON PUMP
2 OF 5
REFERENCE DRAWINGS
REVISIONS
PRELIMINARY FLOW DIAGRAM GAS PROCESSING
DEA ABSORBER & REGENERATOR
GAVIOTA, CALIF.

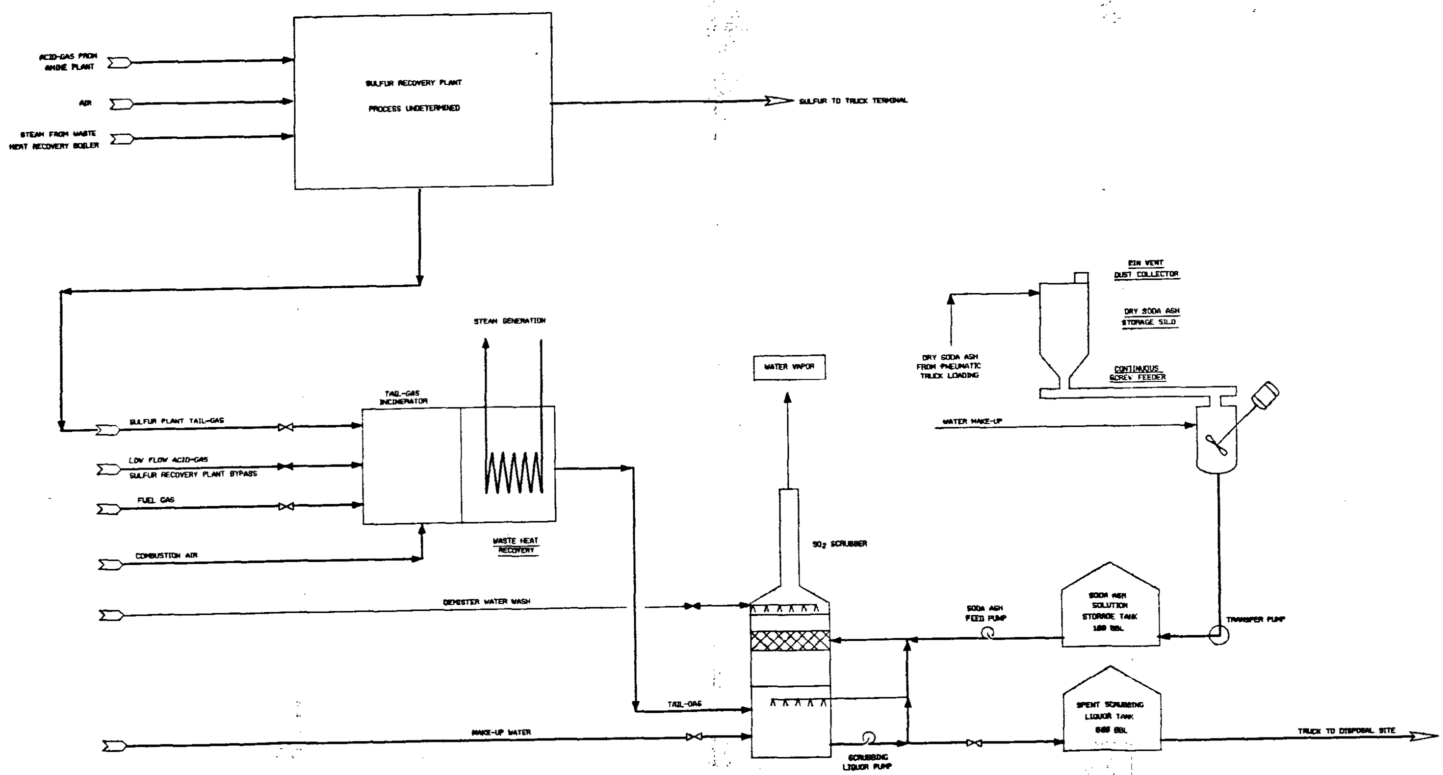

SALES GAS COOLER
SALES GAS
FILTER SEPARATOR
GAS
FROM DEA PLANT
FIELD GAS/ SALES GAS EXCHANGER
GAS CHILLER
COLD SEPARATOR
GLYCOL SEPARATOR
REFRIGERANT COOLER
GLYCOL REGENERATOR
GLYCOL PREHEATER
GLYCOL REBOILER
GLYCOL INJECTION PUMPS
GLYCOL FILTER
GLYCOL REGENERATION PACKAGE
CONDENSER
REFLUX DRUM
REFLUX PUMPS
DE-ETHANIZER
STEAM
DE-ETHANIZER REBOILER
TO DEPROPANIZER
TO FUEL GAS
REFERENCE DRAWINGS
REVISIONS
SCALE NONE
DATE 2-28-83
GSK
PRELIMINARY FLOW DIAGRAM GAS PROCESSING
SEPARATION SECTION AND DE-ETHANIZER
LTS PLANT
GAVIOTA, CALIFORNIA
3 OF 5



SCALE NONE

12-21-83 GSK

PRELIMINARY FLOW DIAGRAM GAS PROCESSING
FRACTIONATION SECTION
LTS PLANT
GAVIOTA, CALIFORNIA 4 OF 5



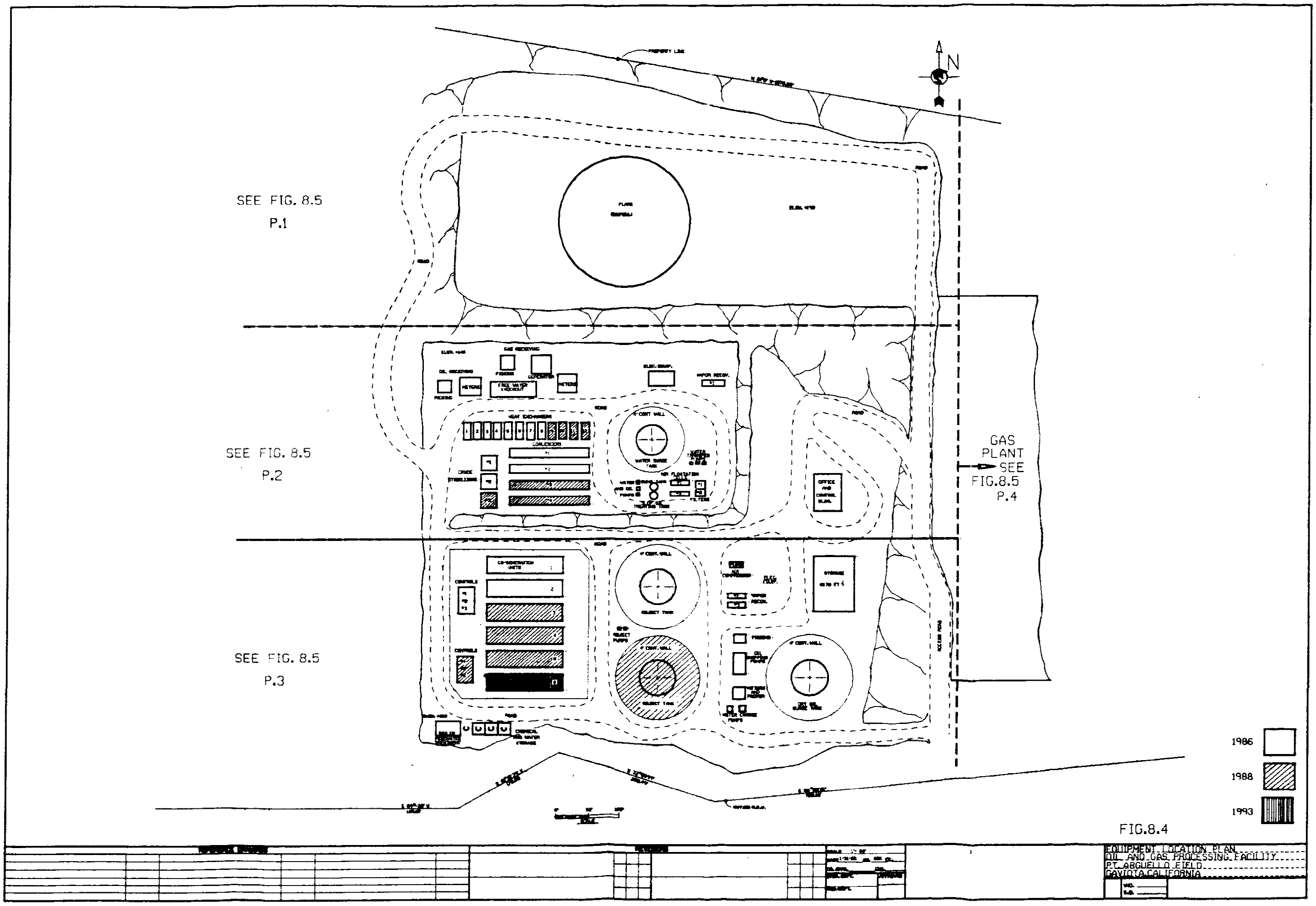
6 of 6

REFERENCE DRAWINGS

REVISIONS

PRELIMINARY FLOW DIAGRAM GAS PROCESSING
INCINERATION AND SO_2 SCRUBBING

GAVIOTA, CALIF.


SEE FIG. 8.5
P.1
SEE FIG. 8.5
P.2
SEE FIG. 8.5
P.3
GAS
PLANT
SEE
FIG.8.5
P.4
N
1986
1988
1993
FIG.8.4
EQUIPMENT LOCATION PLAN
OIL AND GAS PROCESSING FACILITY
PT. ARGUELLO FIELD
GAVIOTA, CALIFORNIA

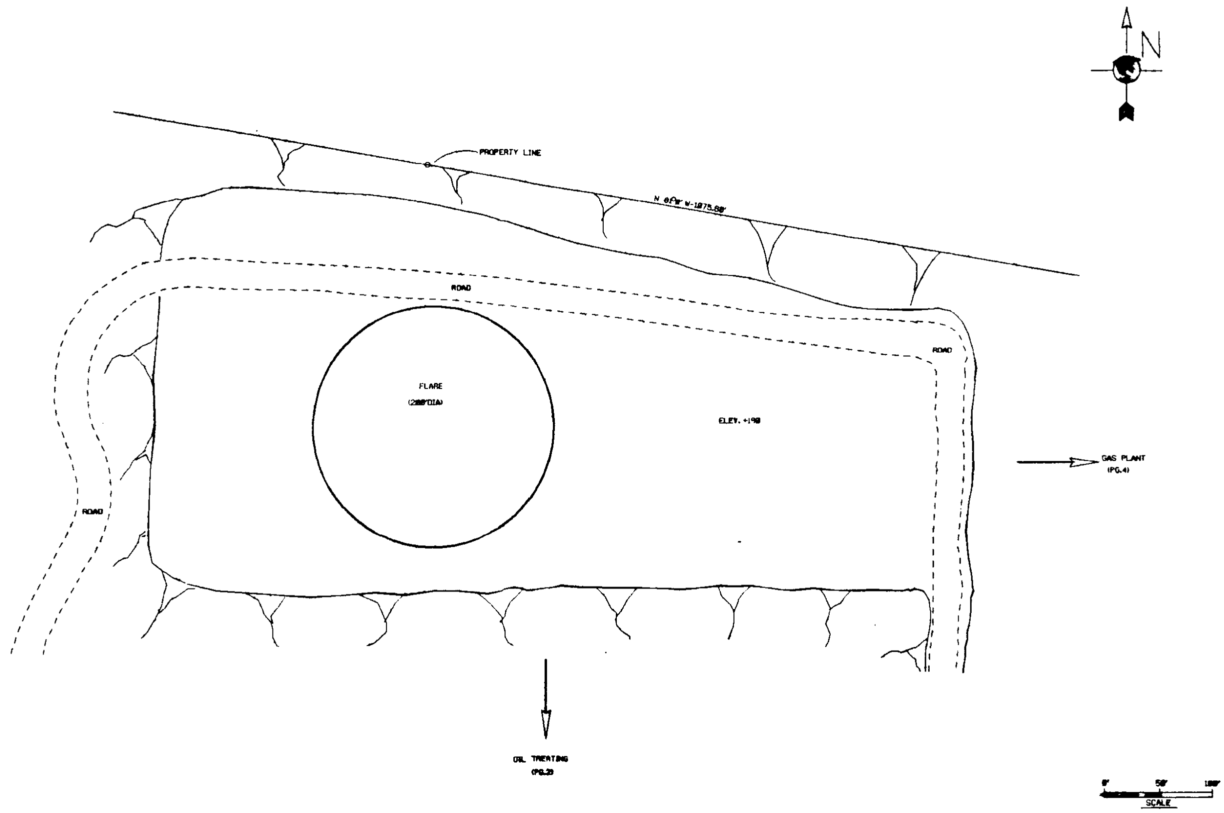


FIG.8.5 PG.1 OF 4

NONE
3-1-93 GSK

EQUIPMENT LOCATION PLAN
OIL AND GAS PROCESSING FACILITY
PT. ARGUELLO FIELD
GAVIOTA, CALIFORNIA

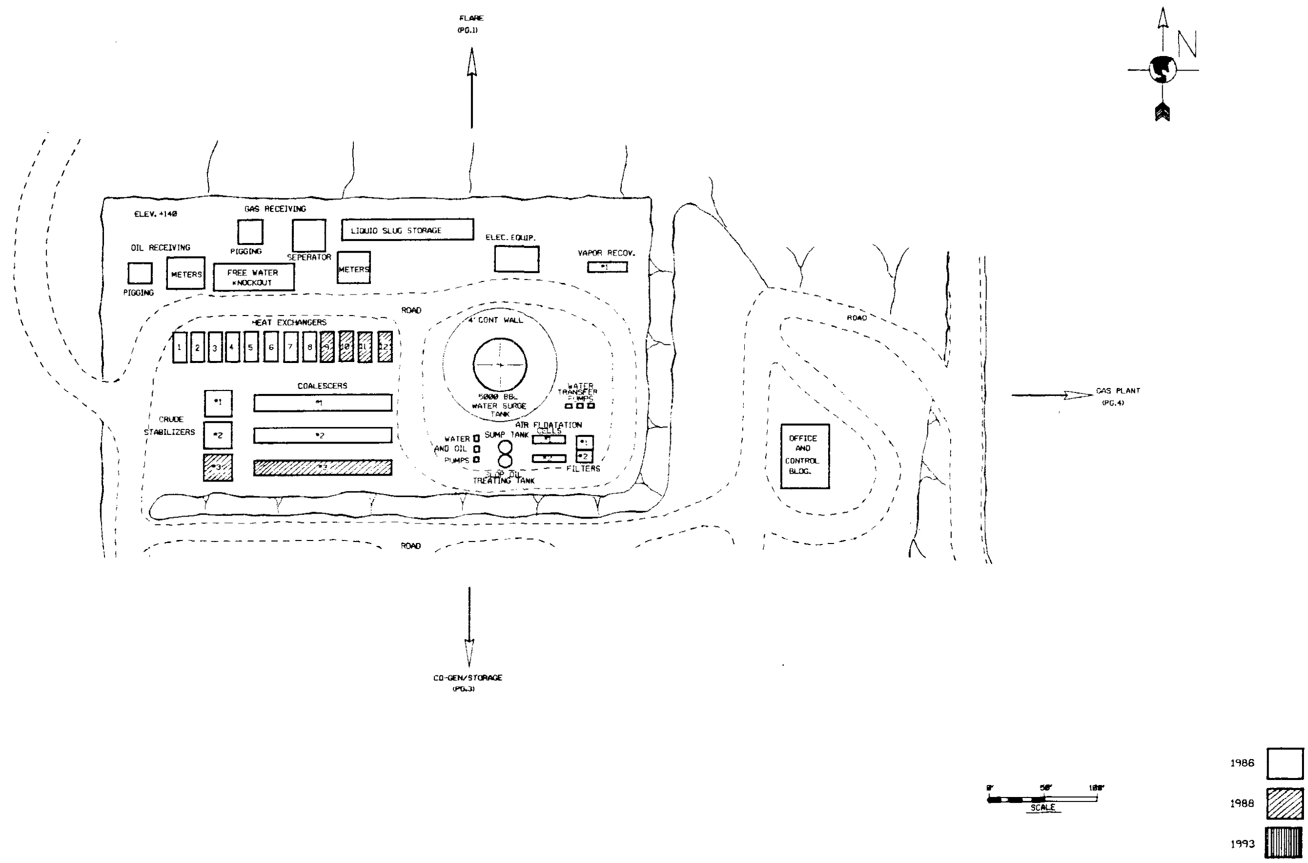


FIG.8.5 PG.2 OF 4

SCALE	NONE
DATE	3-1-83
BY	GSK

EQUIPMENT LOCATION PLAN
OIL AND GAS PROCESSING FACILITY
PT. ARGUELLO FIELD
GAVIOTA, CALIFORNIA

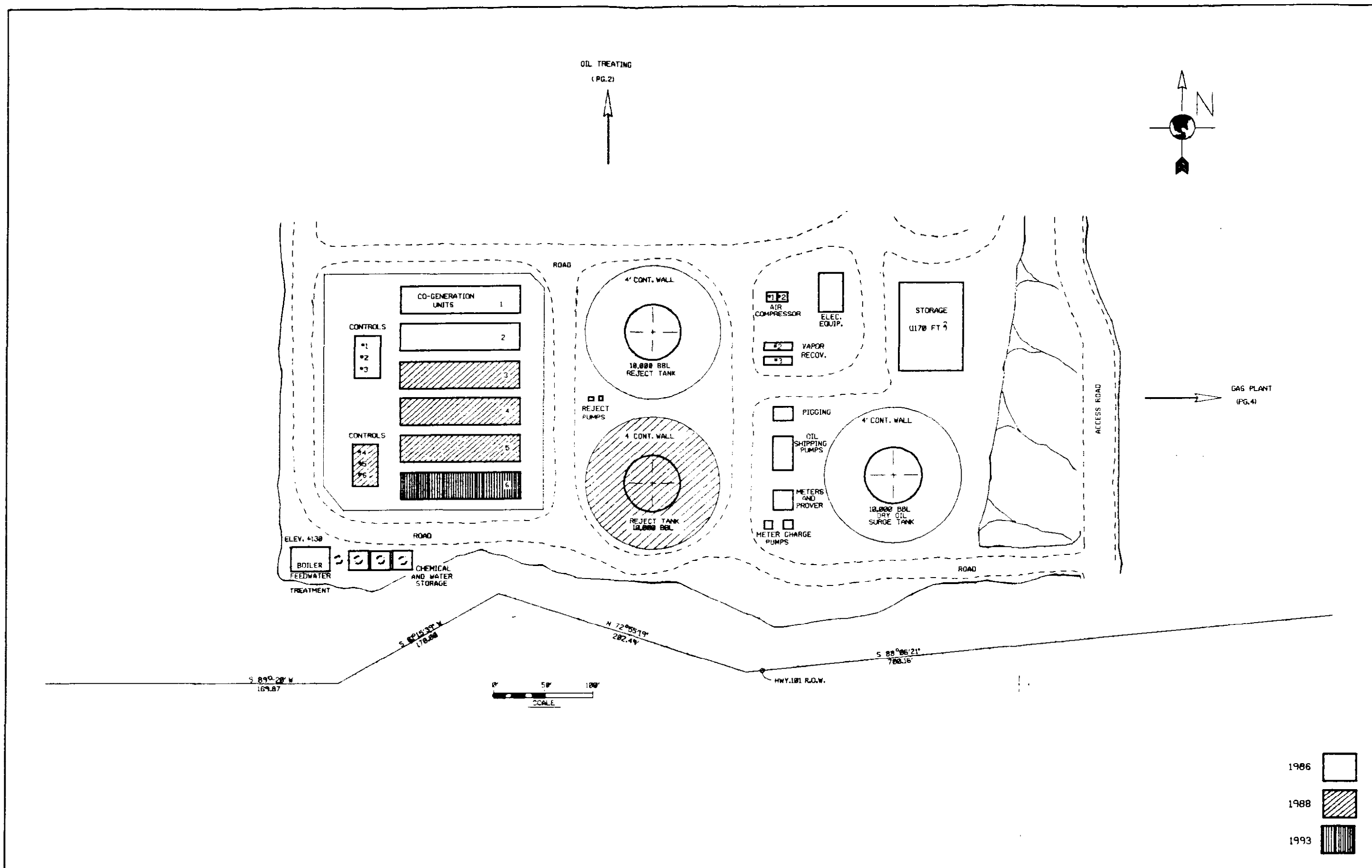
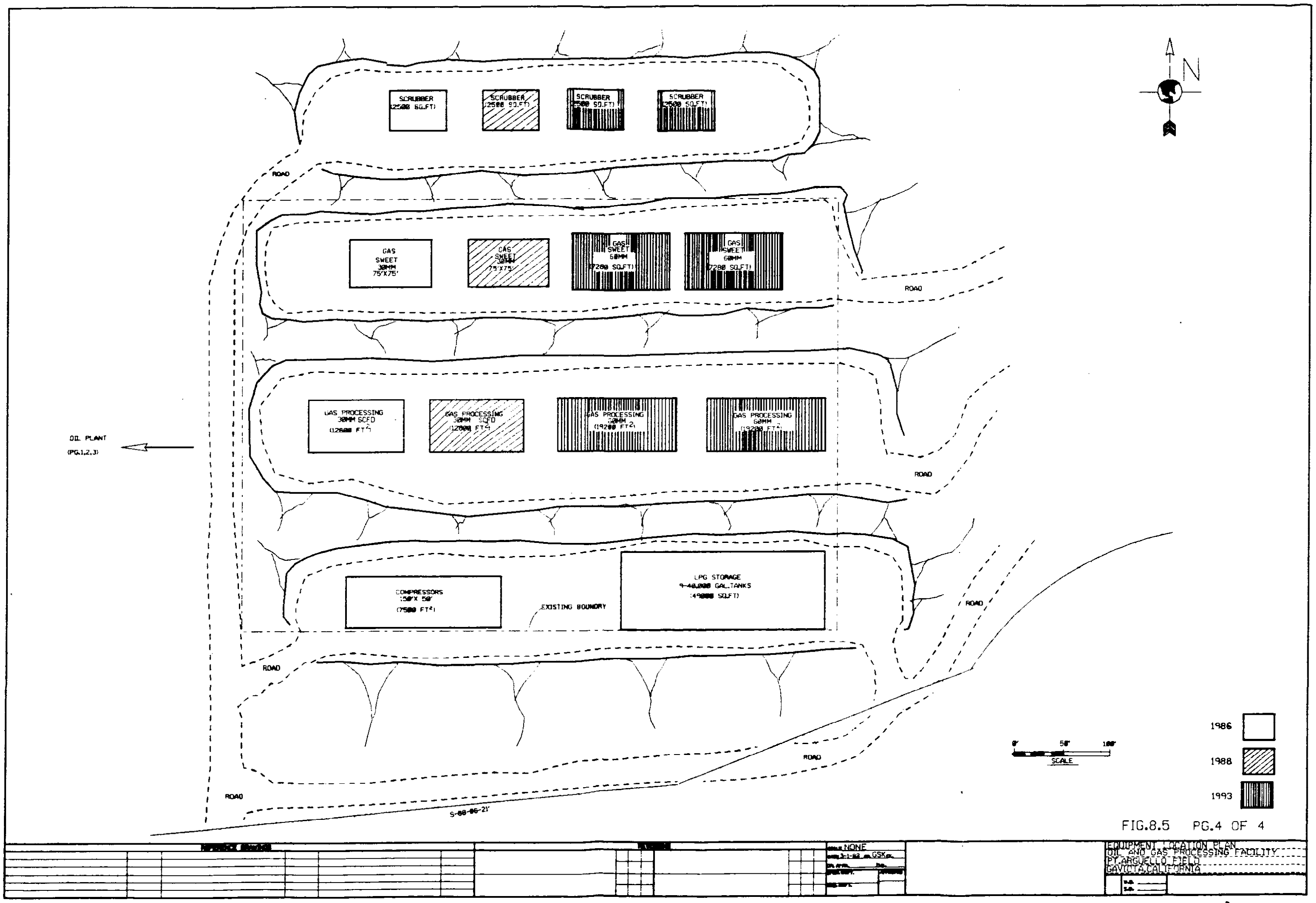


FIG.8.5 PG.3 OF 4

SCALE NONE

EQUIPMENT LOCATION PLAN
OIL AND GAS PROCESSING FACILITY
PT. ARGUELLO FIELD
GAVIOTA, CALIFORNIA


SCRUBBER (2500 SQ.FT)
SCRUBBER (2500 SQ.FT)
SCRUBBER (2500 SQ.FT)
SCRUBBER (2500 SQ.FT)
ROAD
GAS SWEET 30MM 75'X75'
GAS SWEET 30MM 75'X75'
GAS SWEET 50MM (7200 SQ.FT)
GAS SWEET 60MM (7200 SQ.FT)
ROAD
OIL PLANT (PG.1,2,3)
GAS PROCESSING 30MM SCFD (12000 FT²)
GAS PROCESSING 30MM SCFD (12000 FT²)
GAS PROCESSING 50MM (19200 FT²)
GAS PROCESSING 60MM (19200 FT²)
ROAD
COMPRESSORS 150'X 50' (7500 FT²)
EXISTING BOUNDRY
LPG STORAGE 9-40,000 GAL.TANKS (49000 SQ.FT)
ROAD
ROAD
ROAD
ROAD
S-88-06-21'
N
0' 50' 100'
SCALE
1986
1988
1993
FIG.8.5 PG.4 OF 4
NONE
3-1-93 GSK
EQUIPMENT LOCATION PLAN
OIL AND GAS PROCESSING FACILITY
PT.ARGUELLO FIELD
GAVIOTA,CALIFORNIA

SECTION 9

CRUDE TRANSPORATION

TABLE OF CONTENTS

9. CRUDE TRANSPORTATION

9.1 Introduction

This section describes the potential crude transportation systems associated with the development of the Point Arguello Field. The use of the proposed Las Flores marine terminal or a modified marine terminal at Gaviota will be considered. Pipelines to Los Angeles or the San Joaquin Valley to transport crude are also discussed. At this time, a marine terminal is considered essential to provide the required flexibility for crude transportation. Pipelining may be feasible and installation and/or use would be a function of the prevailing technical and economic situation.

Permitting and construction of the Las Flores or Gaviota marine terminals or dry oil pipelines out of the area are not a part of this Point Arguello Field project. Chevron will initially use either of the above terminals based on a committment to use consolidated industry facilities. If neither terminal is "on stream" by first quarter 1986, then Chevron plans to temporarily tanker out of the existing terminal at Gaviota.

9.2 Las Flores Marine Terminal

9.2.1 Present Situation

Exxon Company, U.S.A. has submitted a Development and Production Plan for the Santa Ynez Unit which includes a new marine terminal at Las Flores. The proposed terminal is currently designed to handle only the production from the Santa Ynez Unit. However, engineering work is in progress to increase the capacity so it can operate as an industry terminal. It has also been indicated that initial facilities could be installed on the schedule required to accommodate the Point Arguello Field Development, which is several years sooner than required for the Santa Ynez Unit Option B development.

Based on the above discussion, expansion of the proposed Las Flores marine terminal and its use to handle Point Arguello crude is possible. Additional details are presented below:

9.2.2 Crude Characteristics

Dry 20^{o} gravity crude from the Gaviota oil dehydration and stabilizing plant would flow through an onshore pipeline to the Las Flores marine terminal onshore facilities (refer to Section 7). Pressures would be sufficient to enter the system and inlet temperatures of 50 to 150^{o}F are anticipated.

9.2.3 Additional Facilities Required

An inlet pig trap, a basic sediment and water monitor and meters would be installed. A pressure control valve would be used as required. Tankage would be provided as necessary. Additional pumps may be required to achieve the design loading rate of 50,000 BPH. A second Single Anchor Leg Mooring (SALM) may be necessary to handle the maximum production through the facility.

The use of the proposed ACT, loading lines, and single point mooring is envisioned. The vapor recovery system, circulating hot oil system , and water treating facilities would all be integrated into the design and be completely compatible with the original plan for handling Santa Ynez Unit production at Las Flores.

9.2.4 Operations

The planned marine terminal would be operated by a separate company as an "Industry" facility. As a first step, an organization has been established with several participants to coordinate a conceptual design study and prepare all necessary permits.

Operations would be as outlined in the Santa Ynez Unit Development and Production Plan. There is the potential to segregate the Santa Ynez Unit and Point Arguello Field crudes in separate tankage but commingling is also possible. The optimum approach would be determined after further analysis.

9.3 Gaviota Marine Terminal

9.3.1 Present Situation

Getty Trading and Transportation Company has presented a plan for developing their existing Gaviota property as an "Industry" facility including a modified marine terminal. Production from the Point Arguello area as well as the Santa Barbara Channel, including the Santa Ynez Unit, would be potential throughput. Getty has indicated it can meet an installation schedule compatible with Chevron and other Point Arguello operations, and they are presently engaged in engineering and environmental studies.

Based on the above, modifying the existing Getty marine terminal and using it to load Point Arguello crude is viable. Additional details are presented below:

9.3.2 Crude Characteristics and Inlet

Dry 20° gravity crude from the adjacent Gaviota oil dehydration and stabilizing plant will be fed to the modified marine terminal tankage.

9.3.3 Existing Facility Modifications

Onshore, crude oil storage with a capacity of 2,000,000 barrels would be provided for. Pumps will be installed to load at a design rate of about 50,000 BPH. An ACT and meters will also be incorporated. Vapor control procedures will be used while loading ships. Interfaces will be established between the adjacent oil and gas processing facilities for services required. For instance, blanket gas will be supplied from the gas plant and treated waste water from the marine terminal will be discharged through the oil plant outfall line.

Offshore, the existing tanker loading and mooring facilities will be phased out and replaced. Alternates being investigated include SPM(s), a rubble island, or a pier. Necessary pipelines and control lines will be installed as required.

9.3.4 Operations

Getty has indicated they would completely finance a terminal for the industry or entertain joint venture proposal. They are now soliciting industry support.

Operations will be controlled from the Gaviota onshore facility. Instrumentation and communications will be provided to ensure the safety of the ship and terminal facilities. Flows and pressures will be monitored and appropriate action will be taken by the operator to shut down the system should a malfunction occur.

Getty's plan for their Gaviota property incorporates a supply base and associated pier. If the base and pier are marine terminal operations including mooring assistance and the oil spill containment equipment storage and deployment would be enhanced.

9.4 Pipelines

9.4.1 Present Situation - Coastal Route

The use of a pipeline from Gaviota to Los Angeles to transport Santa Barbara Channel and Santa Maria Basin crude has been investigated as an alternate to tankering. It has been investigated and generally by a joint Government-Industry Petroleum Transportation Committee who commissioned Bechtel to develop preliminary designs and costs. Bechtel's report (Reference 9.7.1) details the results. While there has been a considerable amount of data generated, there are still numerous questions to be answered. The greatest is how much oil could eventually be used as feed stock to Los Angeles refineries and can the appropriate permits be obtained to retrofit the refineries? Investigations are continuing and will provide the data to make an informed decision on this approach.

9.4.2 Present Situation - Gaviota to San Joaquin Valley Route

Getty has proposed to construct and operate a pipeline from Gaviota to the San Joaquin Valley. It would tie into an existing pipeline network extending north to the San Francisco area and south to Los Angeles. This would be an option to move the oil out of Gaviota but the economics of such a plan, existing pipeline capacities, and end location refinery capabilities to handle the crude are still to be determined.

9.5 Immediate Approach

As part of Chevron's Point Arguello project, a pipeline would be installed from Point Conception to Gaviota or Las Flores. This line is be oversized to handle the existing estimates of maximum production from the Point Arguello Field. This would be the first leg of a pipeline system which could be extended to move crude to refining locations out of the area. Tankering is initially proposed to permit earliest development of the fields and to obtain the required additional information on crude characteristics and volumes. This permits flexibility in efficiently transporting the crude.

9.6 Long Term Approach

Based on historical crude characteristics, produced volumes, and crude movement data and the detailed review of pipeline design and cost parameters, a decision would be made on the installation and/or use of a pipeline extension to Los Angeles or some other location. For flexibility, the final crude transportation options must include a marine terminal. The proportion of crude moved by ship or pipeline would be a function of the technical and economic situation prevailing at the time.

9.7 References

9.7.1 Bechtel Corporation (1981), Feasibility Study Phase I - Part A.2 Southern California Coastal Pipeline Draft report to Chevron Pipeline Company et al and California Energy Commission.

Information Redaction Statement

Pursuant to the Freedom of Information Act (5 U.S.C. 552) and its implementing regulations (43 CFR Part 2) and as provided in 30 CFR 550.199(b), some information has been redacted from this document and was deleted from the public information copy of this submission.

Proprietary Information Redacted

Not for Public Release