DEVELOPMENT AND PRODUCTION PLAN
(CUMULATIVE UPDATES)
SANTA YNEZ UNIT DEVELOPMENT

PACIFIC OCS AREA

OFFSHORE SANTA BARBARA COUNTY, CALIFORNIA

SANTA YNEZ UNIT

EXXON COMPANY, U.S.A., UNIT OPERATOR

SEPTEMBER, 1987

INQUIRIES SHOULD BE ADDRESSED TO:

MR. T. J. TIBBITTS, REGULATORY AFFAIRS MANAGER

EXXON COMPANY, U.S.A.

P. O. BOX 5025

THOUSAND OAKS, CALIFORNIA 91359-5025

(805) 494-2380

DEVELOPMENT AND PRODUCTION PLAN

(CUMULATIVE UPDATES)

SANTA YNEZ UNIT DEVELOPMENT

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ABBREVIATIONS

ac	acre(s)
AAPL	All American Pipeline
AC	alternating current
ACT	automatic custody transfer
ADS	Atmospheric Diver System
ANSI	American National Standards Institute
APCD	Air Pollution Control District
API	American Petroleum Institute
bbl(s)	barrel(s)
BO	barrels of oil
BML	below mud line
BOD	barrels of oil per day
BOP	blowout preventer
BS&W	basic sediment and water
BTU	British Thermal Unit
BW	barrels of water
BWD	barrels of water per day
CFR	Code of Federal Regulations
cm	centimeter(s)
CO_2	carbon dioxide
COS	carbonyl sulfide
cp	centipoise
CPP	Cogeneration Power Plant
CVA	Certified Verification Agent
DC	direct current
DCS	Distributed Control System
ECB	Emergency Containment Basin
EG	ethylene glycol
EPA	U.S. Environmental Protection Agency
ESD	emergency shutdown
F	Fahrenheit
ft	feet
GOR	gas-to-oil ratio
gpm	gallons per minute
GSCF	billion standard cubic feet
H_2S	hydrogen sulfide
HRSG	Heat Recovery Steam Generator
HVAC	heating, ventilating, and air conditioning
IES	Illuminating Engineering Society
kBD	thousand barrels per day
kBH	thousand barrels per hour
kBOD	thousand barrels of oil per day
kHz	kilohertz
KSCFD	thousand standard cubic feet per day
kV	kilovolt(s)

ABBREVIATIONS (Cont.)

kVA	kilovolt-ampere(s)
kVARh	kilovolt-ampere (reactive) - hour(s)
kW	kilowatt(s)
kWh	kilowatt-hour(s)
LFCCMT	Las Flores Canyon Consolidated Marine Terminal
LPG	Liquified Petroleum Gas
MB	million barrels
MCC	motor control center
md	millidarcies
MD	measured depth
MHz	megahertz
MLLW	mean lower low water
MMS	Minerals Management Service (formerly U.S. Geological Survey)
MSCF	million standard cubic feet
MSCFD	million standard cubic feet per day
MSL	mean sea level
MW	megawatt(s)
MWL	mean water level
NGL	natural gas liquids
NH_3	ammonia
NOC	net oil computer
NO_x	oxides of nitrogen
NPDES	National Pollutant Discharge Elimination System
NPSH	net positive suction head
NTL	Notice to Lessees
OCS	Outer Continental Shelf
OS&T	Offshore Storage and Treating Vessel
OSHA	Office of Safety and Health Administration
OSS	Offshore Substation
OTP	Oil Treating Plant
PF	power factor
PLEM	Pipeline End Manifold
POPCO	Pacific Offshore Pipeline Company
ppm	part(s) per million
psia	pound(s) per square inch (absolute)
psig	pound(s) per square inch (gauge)
ROC	reactive organic compound
ROV	Remote Operated Vehicle
SALM	Single Anchor Leg Mooring
SCE	Southern California Edison Company
SCF	standard cubic feet
SCR	selective catalytic reduction
SDV	shutdown valve
SGTP	Stripping Gas Treating Plant
SO_2	Sulfur Dioxide

ABBREVIATIONS (Cont.)

SOV	Stabilizer Overhead Vapor
SPCC	Spill Prevention Control and Countermeasure
ss	subsea
STB	stock tank barrel
STV	surge tank vapor
SYU	Santa Ynez Unit
TD	total depth
TEG	triethylene glycol
TGCU	Tail Gas Cleanup Unit
TFL	through flowline
TOS	top of steel
TT	Transportation Terminal
UPS	Uninterruptible Power System
USCG	U.S. Coast Guard
USGS	U.S. Geological Survey
VOC	volatile organic compounds

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1.1 Santa Ynez Unit Development

Exxon Company, U.S.A. (hereinafter called Exxon), a division of Exxon Corporation, is the operator for the development of the crude oil and gas reserves in the Santa Ynez Unit. As indicated in Figure 1.1, the Santa Ynez Unit is a consolidation of leases on the Federal Outer Continental Shelf (OCS) in the Santa Barbara Channel. Seventeen leases were acquired in the Bureau of Land Management Lease Sale of 1968. The Santa Ynez Unit Operating Agreement and Unit Agreement were approved by the U.S. Geological Survey in 1970. OCS Leases P-0326 and P-0329 were purchased by Exxon (P-0329) and Chevron U.S.A. (hereinafter called Chevron) (P-0326) in Lease Sale 48 and were added to the Santa Ynez Unit in October, 1982. The Unit was expanded effective July 1, 1987 to include OCS Lease P-0461 which was purchased by Exxon in 1982. Exxon owns nine leases in the Unit, a one-half interest with Chevron in eight others, and has a two-thirds interest with Chevron in OCS Lease P-0191. One lease is held entirely by Chevron and another entirely by Shell Oil Company.

Three major development areas are addressed in this Development and Production Plan; the Harmony Platform Area, the Heritage Platform Area, and the Heather Platform Area. Hydrocarbons have been found in the western portion of the Unit, but the prospects will require additional evaluation to determine commerciality. The location and timing of future Santa Ynez Unit development will become better defined as additional data is gathered and production history is obtained.

Production from the Santa Ynez Unit was initiated on April 1, 1981 from the existing Hondo A platform (hereinafter called Platform Hondo) on OCS Lease P-0188. Platform Hondo will develop only the eastern portion of the Unit. Exxon estimates that primary recovery by the proposed development will amount to approximately 300 to 400 million barrels (MB) of crude oil and 600 to 700 billion standard cubic feet (GSCF) of natural gas. Recovery of these reserves will take place over a period of approximately 25 to 35 years.

The Development and Production Plan originally submitted in 1982 described two development options: Option A (Offshore Oil Treating) and Option B (Onshore Oil Treating). Option A involves pumping crude emulsion to an expansion of the existing Offshore Storage and Treating Vessel (OS&T) and piping the gas to onshore gas treating facilities in Las Flores Canyon. In Option B, both oil and gas production is brought onshore. Only Option B is addressed in this Development and Production Plan reflecting current plans, but Exxon still reserves Option A as an alternative development and production mode, which will be updated if required.

The detailed plans, specifications, and locations of wells and facilities presented in this Development and Production Plan are based on current data and estimates derived from exploratory drilling, development drilling on Platform Hondo, geologic and reservoir studies, and engineering analyses. Changes to the definition of the extent and producing characteristics of the drilling areas may lead to changes in the commerciality of these proposed development opportunities and to a better definition of additional potential reserves with development opportunities. As unit operator, Exxon's primary objective in the proposed SYU Development is to produce oil and natural gas from the Hondo, Harmony, Heritage, and Heather Platform Areas. However, the proposed development, or any part of the development, is dependent on receipt of an acceptable return on invested capital.

Project engineering for the SYU Development is still in a preliminary stage. Specific details concerning equipment types, sizes, and capacities will not be determined until final design has been completed. Consequently, information contained in this document which relates to such detail will be subject to change based on continuing evaluation. Design changes will reflect inputs from engineering and economic analyses to ensure that the SYU Development is conducted in a cost effective and environmentally sound manner.

Present plans for continuing development of the Santa Ynez Unit call for the installation of three new platforms. Platform Harmony will be a conventional jacket with three decks in approximately 1,200 feet of water. It will have provisions for 60 conductors arranged for the simultaneous operation of two drilling rigs. Produced water from onshore water treating facilities will be pumped back to Platform Harmony for ocean disposal via subsea diffusers. Based on the current reservoir assessment, Platform Heritage will be a twin rig, 60-well, three-deck, conventional platform in approximately 1,075 feet of water. Based on current data, Platform Heather will be a three-deck conventional platform in approximately 620 feet of water with 28 conductors and one drilling rig.

The offshore oil and gas gathering system to support this development will consist of pipeline segments connecting platforms Heather, Heritage, Harmony, and Hondo. From Platforms Harmony and Hondo total production will be sent to oil treating facilities.

Figure 1.2 shows the proposed development of the Santa Ynez Unit. Both oil and gas will be brought onshore for processing. The gas processing capacity at the POPCO Gas Plant will be expanded from the current design capacity of 30 MSCFD to 60 MSCFD. Platform Harmony gas production in excess of 30 MSCFD and all Platform Heritage gas production will initially be injected back into the reservoir to maximize oil recovery by maintaining reservoir pressure, thereby keeping the expansion of gas processing facilities to their current permitted capacity. The sales gas will be pipelined to the Southern California Gas Company regional gas transmission line. Oil treating facilities with an initial design capacity of 100 kBOD (ultimate total capacity of 140 kBOD) will be built adjacent to the POPCO Gas Plant to handle the platform production. A stripping gas facility will be constructed to process sour gas into fuel gas for the onshore facilities.

A 49 MW cogeneration power plant will supply the electrical and process heat requirements of the oil and stripping gas treating plants, transportation terminal facilities, and NGL storage and loading facilities. The cogeneration plant will also send electrical power to the platforms through three submarine cables. No gas turbine generators will be installed on any of the new platforms. As such, there will be no power generation on the new platforms other than for emergency use.

Treated crude oil transportation will be via pipeline to refineries, if desirable routing and reasonable tariffs exist, or via marine vessels from the Las Flores Canyon Consolidated Marine Terminal (LFCCMT) located approximately 11,250 feet from shore. A transportation terminal will be built for pipeline transportation in Phase I. Facilities required for tanker loading will be defined as Phase II facilities, incremental to Phase I. The locations of all the proposed platforms and the marine terminal are given in Table 1.1 and shown in Figure 1.3.

The projected schedule is shown in Figure 1.4. Installation of Platforms Harmony and Heritage is scheduled to begin in 1989 with production start-up in 1992. Installation of Platform Heather will be deferred at least until after 1994. Platform Heather timing will depend upon reservoir performance and economic conditions.

This Development and Production Plan is submitted per Minerals Management Service request for a summary of all updates since the approval of the original on December 27, 1982. Exxon has two development options, Option A for offshore oil treating and Option B for onshore oil treating. Option A will be updated if required, while Option B is fully updated as current plans are to treat oil onshore.

This plan includes the following project areas: geology, reservoir evaluation, platform sites and structures, drilling plans and facilities, subsea production systems, offshore platform facilities, pipelines, oil and gas treating facilities, crude transportation and field operations. The Attachments highlight the Critical Operations and Curtailment Plan, the H_2S Contingency Plan, and the Oil Spill Contingency Plan for California Operations.

TABLE 1.1

FACILITY LOCATIONS

Facility	Lambert Coordinates, Zone 6		Polar Coordinates	
	X	Y	Longitude	Latitude
Hondo	832,341	830,947	120° 07' 14" W	34° 23' 27" N
Harmony	817,960	826,503	120° 10' 03" W	34° 22' 37" N
Heritage	784,000	818,560	120° 16' 44" W	34° 21' 06" N
Heather	769,640	834,300	120° 19' 43" W	34° 23' 36" N
Marine Terminal	862,295	843,038	120° 01' 22" W	34° 25' 37" N

NOTE: Facility locations are approximate and may change slightly based on ongoing design studies.

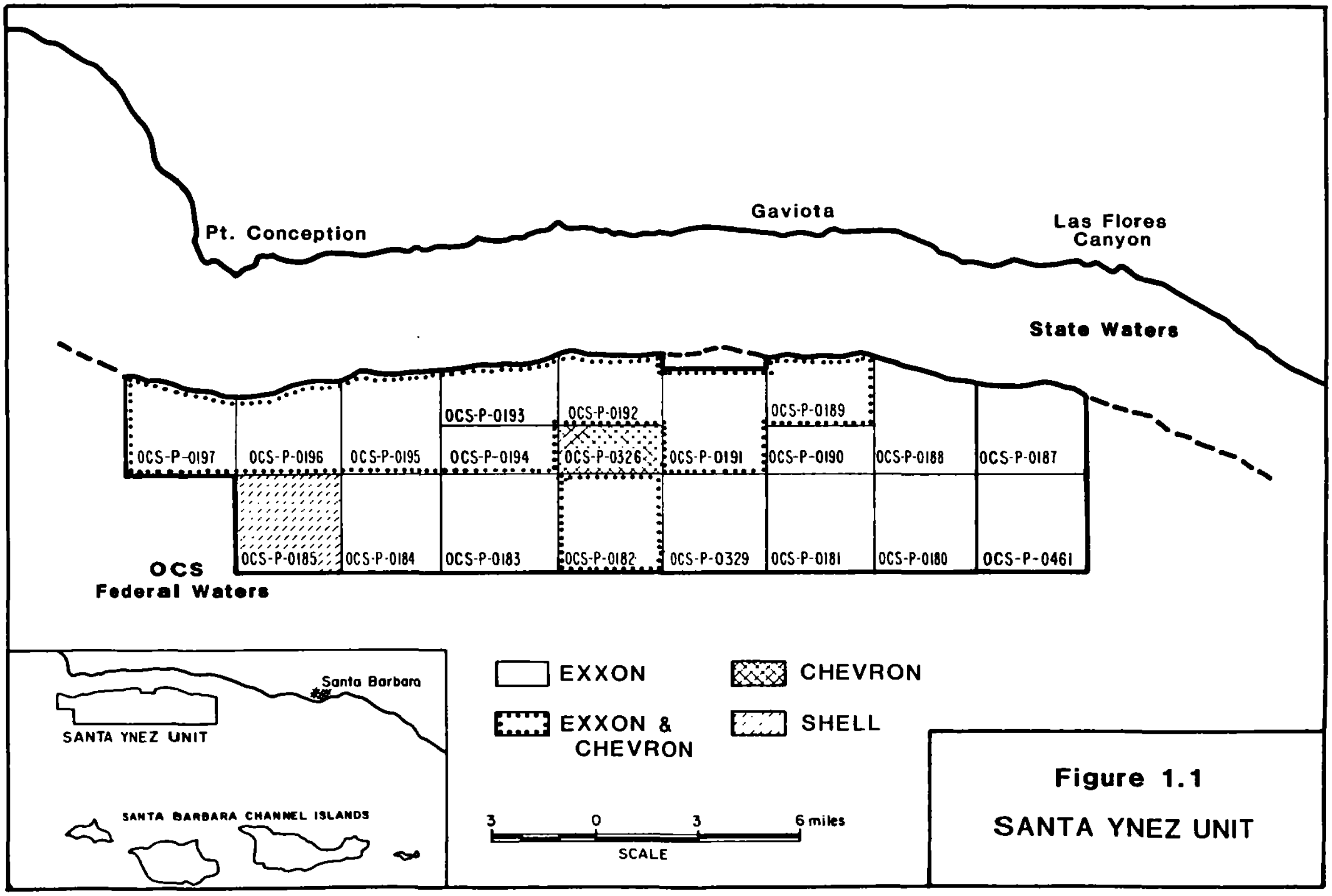


Figure 1.1

SANTA YNEZ UNIT

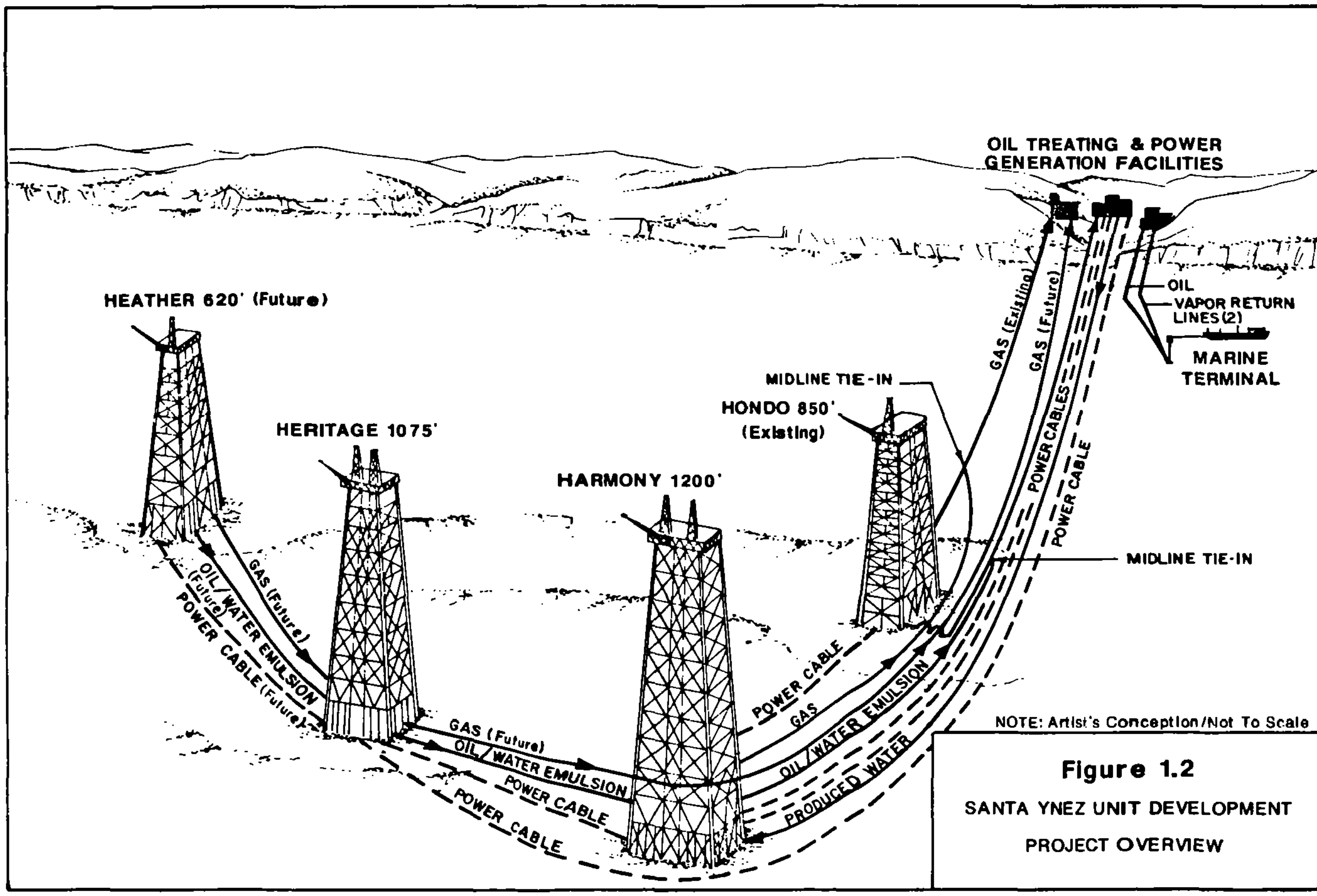


Figure 1.2

SANTA YNEZ UNIT DEVELOPMENT PROJECT OVERVIEW

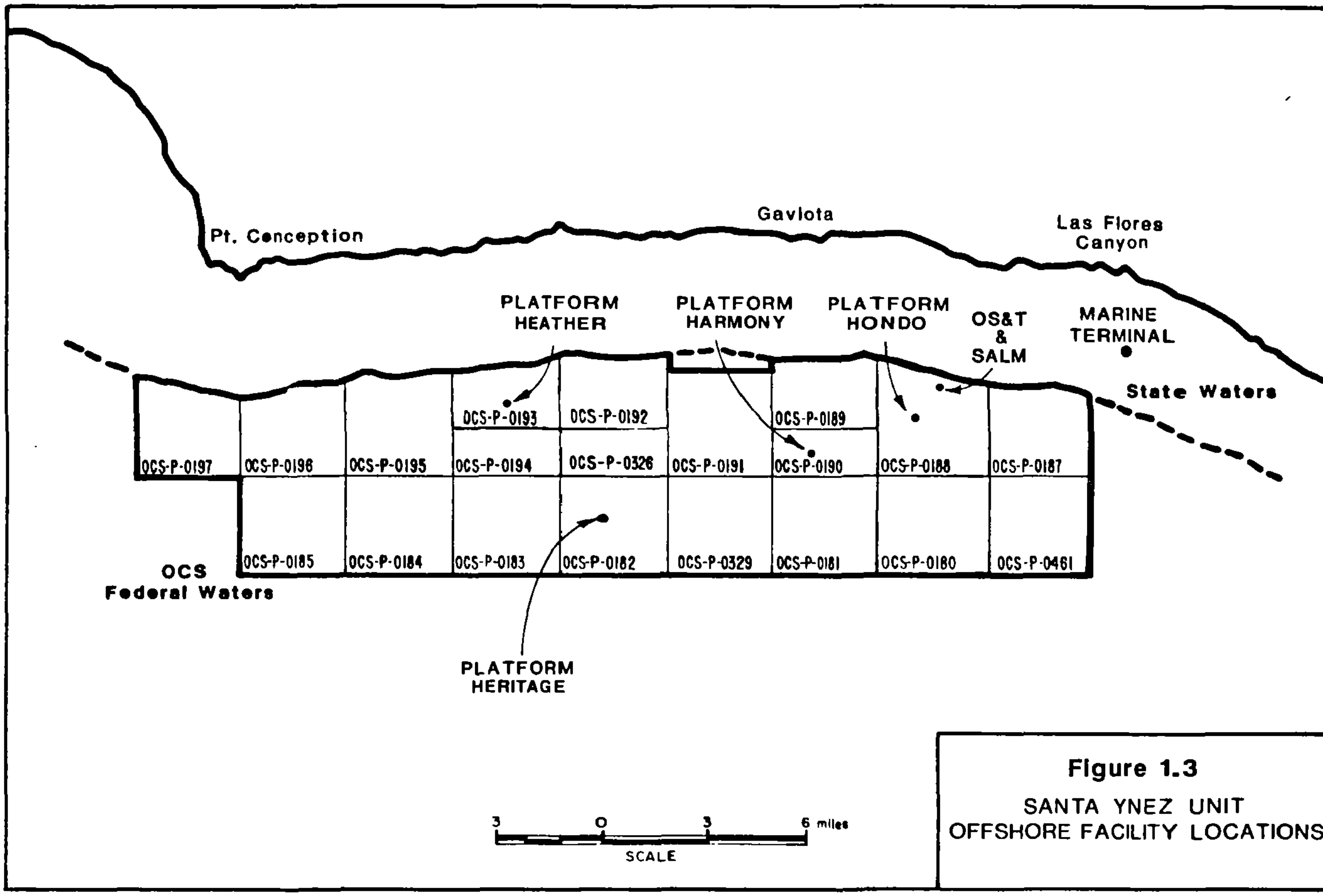
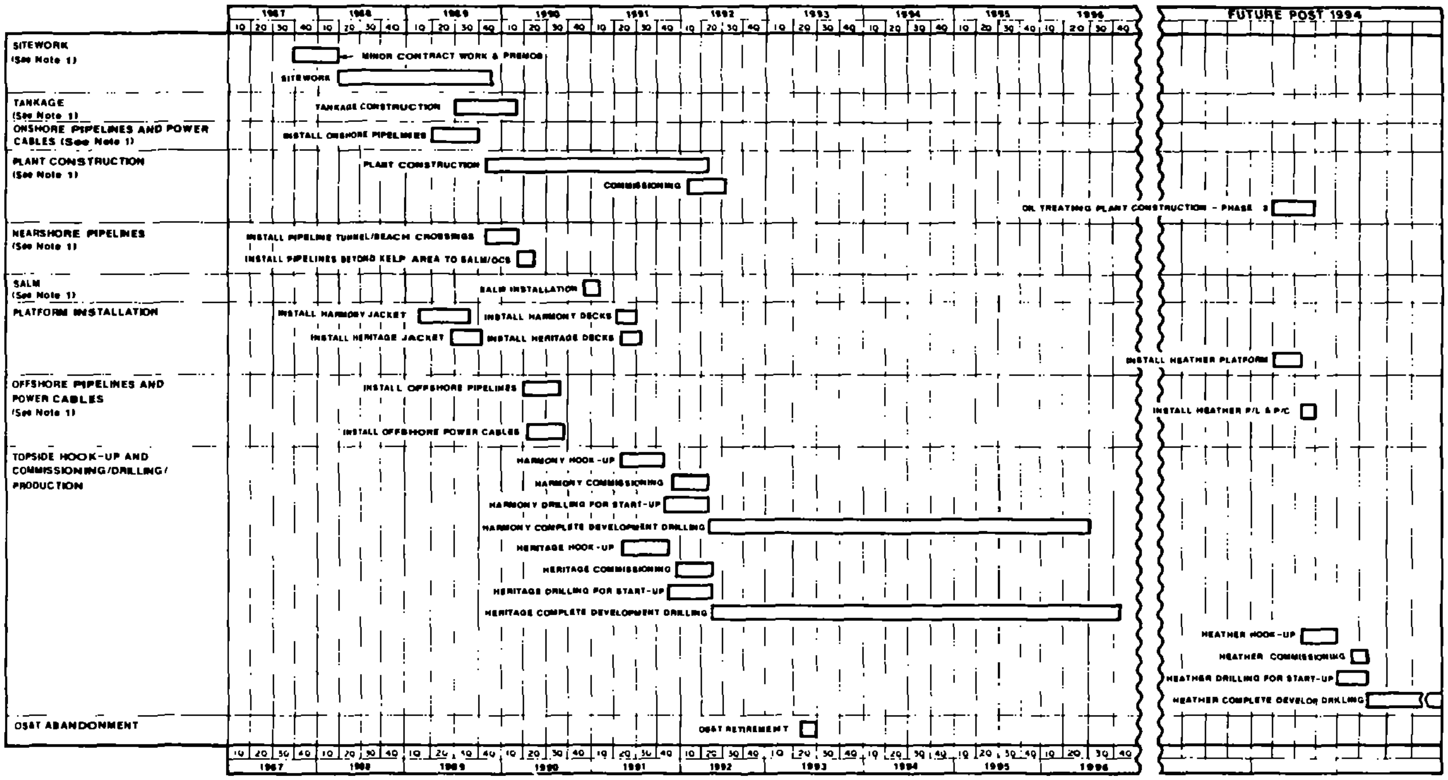


Figure 1.3

SANTA YNEZ UNIT
OFFSHORE FACILITY LOCATIONS



NOTES:

(1) INCLUDES ALL NECESSARY CONSTRUCTION FOR: OIL TREATING PLANT (PHASE 1 FACILITIES), COGENERATION POWER PLANT, STRIPPING GAS TREATING PLANT, NGL/LPG STORAGE AND LOADING FACILITIES, TRANSPORTATION TERMINAL PHASE 1 (PIPELINE TERMINAL), AND TRANSPORTATION TERMINAL PHASE 2 (MARINE TERMINAL)

(2) FOLLOWING ARE THE DATES FOR PLATFORM PRODUCTION
HONDO...... THROUGH 2014
HARMONY .... 1992 - 2020
HERITAGE .... 1992 - 2020
HEATHER .... AFTER 1994

(3) ALL DURATIONS AND SCHEDULE DATES ARE APPROXIMATE

Figure 1.4

SANTA YNEZ UNIT

DEVELOPMENT SCHEDULE

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GEOLOGY

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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.

Proprietary

Not for Public Release

SECTION III

RESERVOIR EVALUATION

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SECTION III

RESERVOIR EVALUATION

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SECTION III

RESERVOIR EVALUATION

NOTE: Tables 3.2 to 3.16 contain detailed reservoir information which is considered EXXON PROPRIETARY and are located in a separate "Appendix A." NO DISCLOSURE OF THESE TABLES BEYOND THE MINERALS MANAGEMENT SERVICE IS ALLOWED WITHOUT PRIOR WRITTEN AUTHORIZATION FROM EXXON.

TABLES

Geology Section

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Proprietary

Not for Public Release

SECTION III

RESERVOIR EVALUATION

NOTE: Figures 3.1 to 3.4 contain detailed reservoir information which is considered EXXON PROPRIETARY and are located in a separate "Appendix A". NO DISCLOSURE OF THESE FIGURES BEYOND THE MINERALS MANAGEMENT SERVICE IS ALLOWED WITHOUT PRIOR WRITTEN AUTHORIZATION FROM EXXON.

FIGURES

Reservoir Evaluation Section

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Proprietary

Not for Public Release

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4.1 Introduction

Platforms Harmony, Heritage, and Heather were designed to withstand site-specific environmental, installation, and operational loads. Design and construction of these platforms will involve siting platforms in water depths as deep as 1,200 feet and in two distinctly different geomorphic provinces: the Slope Province and the Conception Fan. The water depth and geology of these provinces (discussed in detail in Section 2.3) have been evaluated extensively and will not present problems for platform siting, design, or installation. The following sub-sections discuss the methodology and site-specific field investigations that were used to develop the geologic, geotechnical, oceanographic, and seismic design criteria. A description of the platform structures and the approach for platform design and installation are also discussed. Detailed design data will be reviewed under the requirements of the Platform Verification Program in accordance with Pacific Region OCS Order No. 8.

4.2 Design Standards

The platform structures are being designed to satisfy the Pacific Region OCS Order No. 8, API RP2A "Recommended Practices for Planning, Designing, and Constructing Offshore Platforms," and applicable American Institute of Steel Construction guidelines. Additionally, the platforms will meet or exceed all elements of the MMS's "Requirements for Verifying the Structural Integrity of OCS Platforms."

4.3 Geologic Design Criteria

Regional and site-specific geologic studies were conducted to assess geologic conditions and to develop geologic design criteria for the proposed platform sites and pipeline routes. General geologic conditions, discussed in Section 2.3, are consistent with what is known about the Santa Barbara Basin. The geology of the Santa Ynez Unit area and geologic design criteria are detailed in References 6 through 21 of Section 2.5.

Site specific geologic studies were conducted for three platform areas (Figure 4.1): one of the Slope Province (Platform Harmony) and two on the Conception Fan (Platforms Heritage and Heather). The conclusion of the studies is that the chosen platform locations present no geologic problems to platform design. Site-specific geologic conditions will be accounted for in the engineering design of the individual platforms.

Platform Harmony Site

A north-south trending rectangular area, 12,000 feet by 10,000 feet, was studied to evaluate potential sites for Platform Harmony (Figure 4.1). The area is on the Slope Province and is in water depths ranging from 900 feet to 1,500 feet. Slope gradients are fairly uniform and average seven percent. The surface and subsurface sediment is a fairly homogeneous silty clay deposited slowly by both normal marine nepheloid flow and hemipelagic sedimentary processes. Zones of near-surface gas and gas seepage were found in the studied area; however, there are no indications of sediment instability at the platform site location. A topographic bulge with small, crater-shaped depressions (gas vents) occurs about one-half mile north of the site. The bulge is a zone of topographic uplift related to a small anticline that trends across the northern edge of the study area. There are no indications of Holocene seismogenic fault activity in the study area, although there is indication that the anticline is disrupted by minor, discontinuous, shallow-rooted flexural faults. These flexural faults represent minor adjustments of late Quaternary sediment during the slow growth of the anticline.

Platform Heritage

An east-west trending rectangular area, 17,500 feet by 5,000 feet, was studied to evaluate potential sites for Platform Heritage (Figure 4.1). The site is in an interchannel area on the middle part of the Conception Fan and is in water depths ranging from 1,000 feet to 1,200 feet. Slope gradients are relatively gentle and range from two to four percent. Local irregular topography (three to nine feet in relief) is most probably indicative of partially buried, relict features. Surficial sediment, as thick as ten feet, consists of sandy or silty clay probably deposited by normal marine nepheloid flow. Subsurface sediment consists of fine sand with clay interbeds and some gravel lenses. This sediment, about 500 feet thick, was deposited during the Pleistocene epoch as a sequence of sand sheets and nested filled channels when the Conception Fan was active. Possible zones of near-surface gas are present locally but there are no indications of sediment instability. There are no structural features, faults, or folds in the site area.

Platform Heather

An east-west trending rectangular area, 10,000 feet by 4,000 feet, was studied to evaluate the proposed Platform Heather site (Figure 4.1). The site is in an interchannel area on the upper part of the Conception Fan and is in water depths ranging from 600 feet to 750 feet. Slope gradients are relatively gentle and range from three to four percent. Other features are similar to those found at the Platform Heritage site.

4.4 Geotechnical Design Criteria

The platform foundation design criteria is based on soils information obtained from extensive, state-of-the-art geotechnical investigations conducted in 1981 and in 1984 by McClelland Engineers, Inc. at each platform location. Offshore activities included pushed sample recovery, downhole cone penetrometer testing, in-situ remote vane testing, gamma ray logging in deep boreholes, and an offshore pile driving test program at the Platform Heritage site. Additionally, shallow, continuous cone penetrometer soundings were performed. The number, location, and penetration of deep borings and shallow cone tests were determined on the basis of site-specific geophysical findings, local/regional geologic information, and preliminary platform base and foundation designs. Preliminary results from the offshore boring program and pile driving test program indicate that soil conditions at the platform sites are favorable for the proposed installations and that potential liquefaction and slumping in subsurface soils appear unlikely.

The subsequent static and dynamic laboratory testing program includes both conventional (classification, consolidation, triaxial, and simple shear strength) and special (cyclic triaxial, cyclic simple shear, and resonant column) testing techniques. The geotechnical laboratory testing program and the engineering analysis program were aimed at defining soil shear strength characteristics, lateral pile responses, axial pile responses, pile installation responses, and the potential for soil liquefaction. All associated boring logs, laboratory test results, and engineering reports shall be included in the detailed platform design submittal to a Certified Verification Agent (CVA) in accordance with the Platform Verification Program. Platform foundation design criteria will satisfy API RP2A guidelines.

4.5 Environmental Design Criteria

4.5.1 Earthquake Design Criteria

The earthquake design criteria is based on a detailed evaluation of earthquake potential in the western portion of the Santa Barbara Channel and specifically accounts for the regional and local geologic structure, local active faulting and local soil conditions. The design criteria is site-specific for each platform. The platform design meets both strength and ductility requirements for earthquake loading.

The strength requirements assure resistance to ground motions likely to occur during the platform's life without the platform sustaining any significant structural damage. The strength level design site motions are expressed in terms of a smoothed response spectra and a suite of representative three-dimensional ground motion records.

The response spectrum method of analysis will be used to evaluate the platform's dynamic elastic response to earthquake ground motion.

The ductility requirements provide 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 welding are insured to guarantee that the structures perform as designed under earthquake loadings.

Exxon Production Research Company's assessment of the seismic environment in the Santa Barbara Channel indicates that expected earthquake activity does not present any problems that preclude the safe design, installation, and operation of offshore structures in the Santa Ynez Unit.

4.5.2 Oceanographic Design Criteria

The oceanographic design criteria provides for waves, currents, tides, and winds which may occur during the expected life of the structure. Existing oceanographic data have been reviewed to develop estimates of these values and hindcasting studies have been initiated to provide the required site-specific information. Results of the oceanographic study and modeling efforts are the basis for design, installation, and operation of offshore structures in the Santa Ynez Unit.

Waves

A sophisticated numerical wave hindcast model which provides a directional wave spectrum was used to determine design waves at the platform sites during selected storm events. The model, developed by Oceanweather, Inc., includes effects of variation of the storm wind field in time and space; wave generation, propagation, and decay over a large grid extending well into the Pacific; directional spreading; diffraction around headlands and through islands; and island sheltering. It was calibrated with existing data to insure its accuracy. Using this state-of-the-art technology, design wave heights were determined for each of the platform sites.

Currents

Two-dimensional numerical current models developed by the University of California at Santa Barbara and Exxon Production Research Company account for storm wind generated currents during the same storms for which wave conditions were generated. Existing current measurements were used to estimate expected values of background and tidal currents which were combined with the simulated storm currents to develop the maximum expected currents for each of the platform sites.

Wind

Oceanweather, Inc. developed accurate representations of sustained wind fields during severe historical storms based on all available atmospheric pressure and wind velocity measurements. These winds were used with the design waves and currents to determine the maximum combined oceanographic load on the platforms. In addition, extreme gusts (which may not be associated with extreme storm waves) were determined by extrapolating local wind speed statistics. These gusts were used in designing deck facilities to withstand aerodynamic loads.

Marine Growth

An extensive study of marine growth on Platform Hondo and a concurrent analysis of marine growth on nearshore Santa Barbara Channel platforms provided the basis for the marine growth design criteria.

4.6 Platform Design

Platforms Harmony and Heritage jackets were designed by Exxon and verified by a CVA pursuant to Pacific Region OCS Order No. 8. Exxon's design effort consisted 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 designs for each of the platforms will be provided as part of the Verification Documentation. Platform Heather will undergo a similar design and verification process at a later date. A conceptual description of each of the proposed platforms follows.

4.6.1 Platform Harmony

Platform Harmony will be a conventional eight-leg jacket-type platform with a three-level deck and 60 well slots. Fabricated and transported in one piece, the jacket structure will be installed in approximately 1,200 feet of water. There will be two electric SCR drilling rigs on the platform. The Harmony Platform Area will be developed with 48 wells, leaving 12 spare well slots. Additional conductors may be installed using platform drilling rigs if required at a future date. Three of the 12 spare Harmony well slots will be used for diffuser pipes for subsea disposal of treated produced water returned from onshore treating facilities.

Elevation views of the Harmony jacket are shown in Figure 4.2. Preliminary engineering plan views of the platform's decks are shown in Figures 7.5 through 7.10. The jacket structure is comprised of eight main legs framed with diagonal and horizontal bracing. The jacket design assumes one section for transportation to the installation site. The structure will be secured to the ocean floor with main piles driven through its legs and welded and grouted to the jacket. Twenty skirt piles will be installed and connected to the jacket by grouting. The platform decks will provide adequate space and load carrying capability for simultaneous twin rig drilling and oil and gas production operations.

4.6.2 Platform Heritage

Platform Heritage will be a conventional eight-leg jacket-type platform with a three-level deck and 60 well conductors. The jacket will be fabricated and transported as one piece and installed in approximately 1,075 feet of water.

Elevation views of the Heritage jacket are shown in Figure 4.3. Corresponding preliminary engineering deck plan views are shown in Figures 7.17 through 7.22. The Heritage jacket will have a basic configuration similar to the Harmony jacket; eight legs interconnected with diagonal and horizontal bracing, and eight main piles. The Heritage jacket will have a total of 26 skirt piles. The platform decks will provide adequate space and load carrying capability for simultaneous twin rig drilling and oil and gas production operations.

4.6.3 Platform Heather

Platform Heather will be a single piece conventional jacket-type platform installed in approximately 620 feet of water. The jacket will support a three-level deck and 28 well conductors. Preliminary elevation views of the Heather jacket are shown in Figure 4.4 and preliminary deck plan views are shown in Figure 7.29. The jacket configuration will be similar to that of the other platforms; eight legs interconnected with diagonal and horizontal bracing, eight main piles and 16 skirt piles. The deck structure will provide space and load carrying capability for a single drilling rig and oil and gas production operations.

4.7 Platform Installation

Platform installation procedures will be similar for all of the platforms. Complete details on the fabrication and installation of the individual platforms will be provided as part of the Verification Documentation pursuant to Pacific Region OCS Order No. 8. Installation of each platform will require five to seven months. Major marine equipment required for installation of the platforms will include a derrick barge, the jacket launch barge, cargo barges, tug boats, supply boats, and crewboats.

General installation procedures applicable to each platform are as follows:

Marine Spread Mobilization - Prior to arrival of the installation derrick barge, an eight-point spring buoy mooring system will be installed at the platform installation site. Upon arrival, the derrick barge will be moved in and connected to the moorings. A conventional anchoring system may also be used by the barge.

Jacket Tow & 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.

Jacket Upending - Following launch, the jacket will be towed to its installation site and upended to an upright position 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.

Pile and Installation - The eight main piles will be installed through the jacket legs in approximately 100-foot long welded segments. Upon reaching the mudline, the piles will be driven to their design penetration. The skirt piles will be installed through pile sleeves and driven to their design penetration with the aid an underwater hammer on both Platforms Harmony and Heritage. Either an underwater hammer or a retrievable follower will be used on Platform Heather. Both main and skirt piles will be grouted to the jacket structure. The well conductors will be installed through guides in the interior of the jacket structure. Sections approximately 100 feet long will be welded end-to-end with the conductors finally driven to the design penetration.

Deck Setting - A two-piece jacket cap will first be set and welded to the jacket top for support of the deck structure. The decks are composed of eight modules with production equipment pre-installed. The modules will be lifted by the derrick barge, set on top of the jacket cap and then welded into place. The flare boom, boat fenders, quarters, and other miscellaneous components will then be attached to the deck structure.

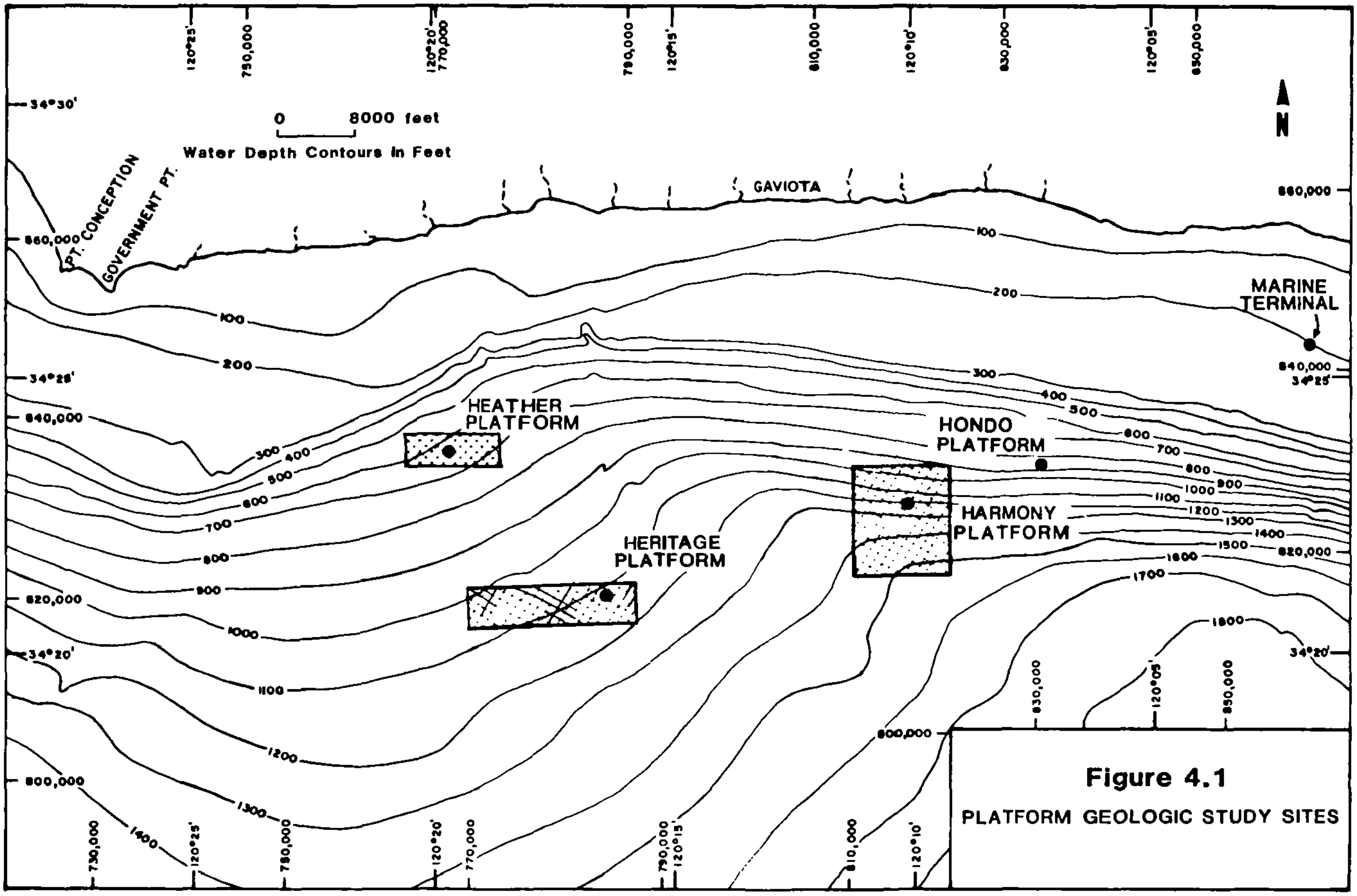

Figure 4.1

PLATFORM GEOLOGIC STUDY SITES

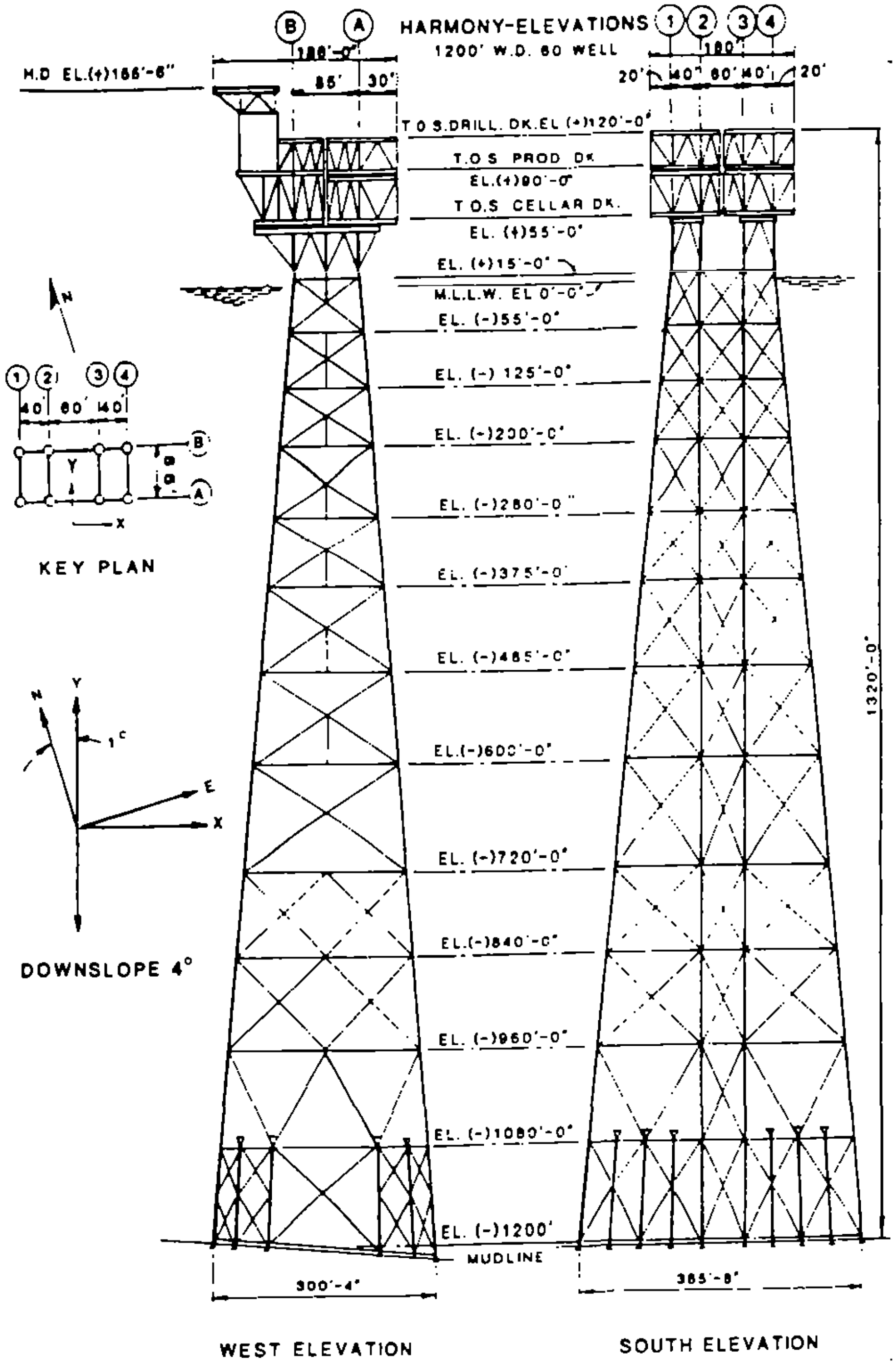

Figure 4.2

PLATFORM HARMONY-ELEVATION

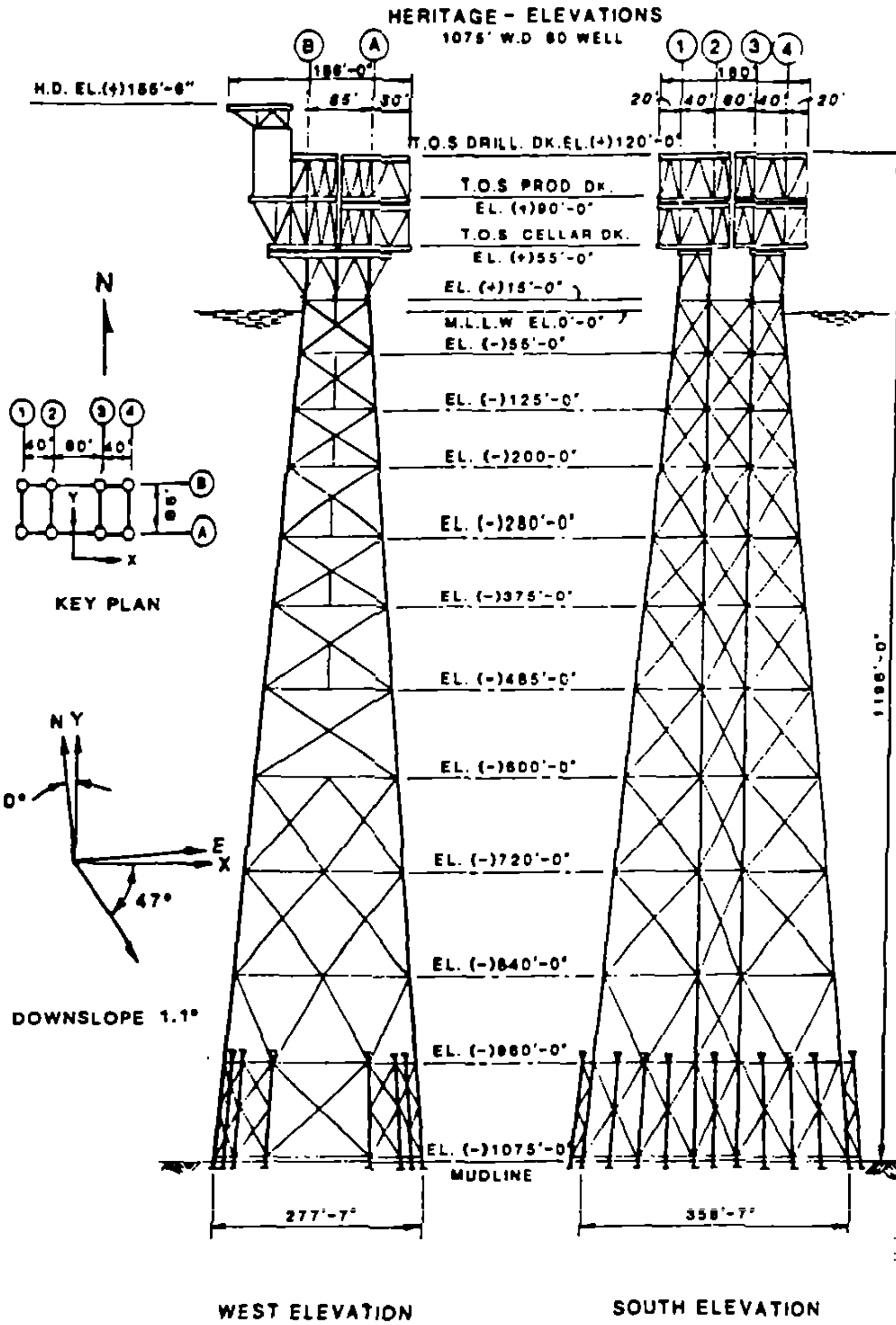

Figure 4.3

PLATFORM HERITAGE-ELEVATIONS

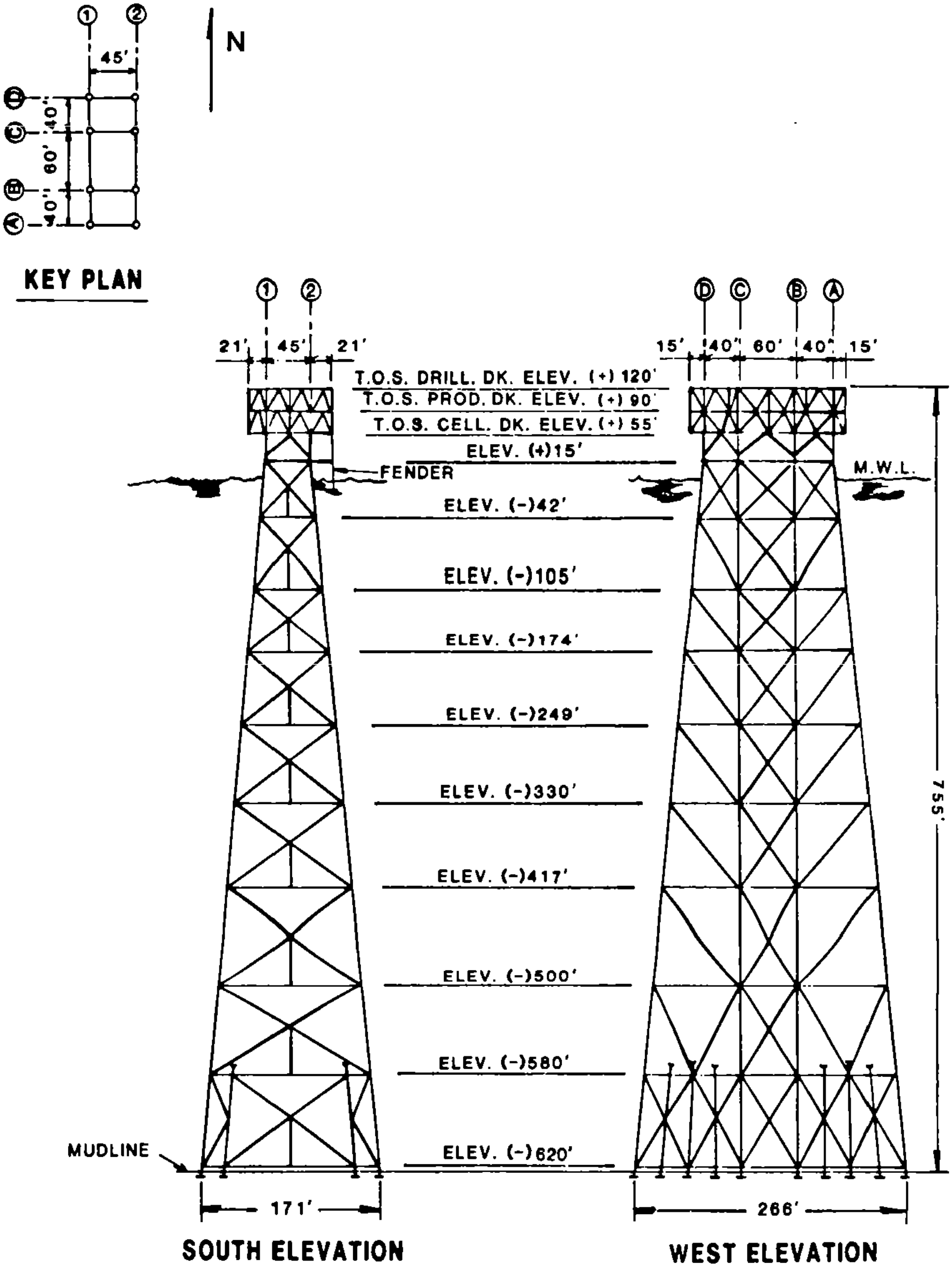

Figure 4.4

PLATFORM HEATHER-ELEVATIONS

SECTION V

DRILLING PLANS AND FACILITIES

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5.1 Introduction

This section discusses the platform drilling deck and well bay plans, the major components of the platform drilling systems and the operational plans and procedures for the Harmony, Heritage, and Heather Platform Areas. Typical drilling programs for the various producing formations are also included.

All operations will be conducted with safety to personnel and the environment as the primary considerations. Operational procedures will be conducted in compliance with all applicable regulatory agency regulations. Complementing this section are Attachments A and B, "Critical Operations, and Curtailment Plan" and "Hydrogen Sulfide Contingency Plan," respectively. These documents describe the safety plans and procedures to be implemented when critical events occur.

5.2 Drilling Deck and Well Bay Layouts

Platforms Harmony, Heritage and Heather will all be conventional steel jacket structures with 60, 60, and 28 well slots, respectively. Platforms Harmony and Heritage will each use two electric drilling rigs. Each rig will be entirely independent of the other but may have interconnection provisions for emergency purposes. Platform Heather will be a one drilling rig operation. All drilling equipment and services will be handled on a contract basis.

Preliminary drilling equipment deck layouts are included on the deck plans shown in Section VII: Platform Harmony (Figure 7.5), Platform Heritage (Figure 7.17), and Platform Heather (Figure 7.29). Preliminary well bay area layouts are shown in Figures 5.1 to 5.3. The drilling rigs will be especially designed and/or adapted for use on offshore platforms. The drilling contractor will have some flexibility in final equipment layouts, but the equipment will require compatibility with the platform deck designs.

5.3 Platform Drilling Equipment

5.3.1 Rig Components

Each drilling rig will have a ±150-foot derrick with a 1,000,000-pound hook load capacity and a drilling depth capability beyond 15,000 feet. The drawworks will be powered by two 1000-horsepower DC motors. The unit will include a sand line reel. The rotary table will be independently driven by a 1000-horsepower DC motor. The hook, traveling block and crown will be of 500-ton capacity to match the derrick. The rig will use up to 5-inch drill pipe of various grades.

5.3.2 Substructure

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

The substructure base will rest on skid beams elevated above the drilling deck. A hydraulic jacking system will be used to move the rig over the desired well slot. Mechanical restraints will be used to prevent movement once the rig is positioned.

5.3.3 Drilling Mud System

Each rig will have a separate mud system equipped with all of the components listed below.

Each mud system will contain two 1,600-horsepower mud pumps and approximately 1,200 barrels of active and reserve mud tank capacity. The system would include a mud mixing tank, a trip tank, and a sand trap tank below the shale shakers.

Up to three 1,000-cubic foot storage tanks will be provided for bulk barite and bentonite. Sacked mud additives will be stored on pallets. Storage for approximately 1,800 barrels of water will be provided.

Mud treating equipment will consist of dual screen shale shakers, a desilter, a desander and a degasser. Oil contaminated cuttings will be caught and hauled to shore for disposal at an approved dump site. Centrifugal pumps will be installed for mixing mud, circulating mud through the desander, desilter, and degasser, and transferring mud, water, and diesel fuel.

Mud volume monitoring equipment will include a pit volume totalizer, an incremental flow rate indicator, and a precision fill-up measurement system. These warning devices will transmit visual and audible signals to the driller's console.

5.3.4 Cementing Unit

Each rig will have separate dual cementing units powered by two 650-horsepower DC motors. Each rig will have up to three 1,000-cubic foot bulk cement storage tanks.

5.3.5 Power Distribution

Electrical power will be supplied from the onshore cogeneration power plant via a submarine cable system.

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

5.4 Drilling Operations

5.4.1 Casing Program

The planned casing program consists of 26-inch conductor, 20-inch or 18-5/8-inch surface, 13-3/8-inch intermediate and 9-5/8-inch production casing, as shown in Figure 5.4 (Monterey and Gaviota [Sandstone] Producer) and Figure 5.5 (Monterey gas injection well). On wells with a slotted casing completion, a 7-inch liner would be hung below the 9-5/8-inch casing, set at the top of the productive interval as in Figure 5.6 (deep Monterey producer) and Figure 5.7 (non-associated [Camino Cielo] gas well). Depending upon individual well conditions, a 7-inch liner might also be used on wells with a measured depth greater than 12,000 feet.

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 Pacific Region OCS Order No. 2 and/or field rules. Exxon plans to install the 26-inch conductor by driving.

Exxon will design all casing to exceed anticipated burst and collapse pressures and tensile loads. Casing designs will include appropriate safety factors. Production casing and tubing subjected to sour oil and gas service will be made of controlled yield strength quenched and tempered steel.

5.4.2 Well Completions

Cemented and perforated casing (Figure 5.8) will be used when it is necessary to selectively produce the interval due to gas or water intrusion. When gas or water intrusion is not present, slotted casing (Figure 5.9) may be used. The completion tubing string will be designed for natural flow but will allow for conversion to gas lift in the future. The proposed well programs are shown in Table 5.1.

All 48 Harmony wells (45 producers and 3 gas injectors) will be completed in the Monterey Formation using tubing inside of either perforated or slotted production casing.

Three types of Heritage wells are tentatively planned: 52 Monterey Formation producers, 4 Sandstone (Gaviota) dual producers, 3 gas injection wells, and 1 Camino Cielo Formation producer. The sandstone dual completion wells and the Camino Cielo well would be produced through tubing inside of perforated production casing. Monterey wells would be produced through tubing inside of either perforated or slotted production casing.

Four types of Heather wells are tentatively planned: 14 Monterey Formation producers, 11 Vaqueros/Alegria formation producers, one Lower Gaviota-Upper Gaviota dual producer, and two Camino Cielo-Vaqueros/Alegria Formations dual producers. The Monterey wells would be produced using tubing inside of either perforated or slotted production casing. The remaining wells would be completed using tubing inside of perforated casing. All depleted wells could be available for recompletion to other producing formations.

5.4.3 Wellhead Equipment

All wellhead components will satisfy API specifications. The working pressure of each wellhead section will exceed the maximum anticipated pressure imposed on that section. The wellhead will provide fluid access to each casing or tubing annulus.

5.4.4 Blowout Preventer Equipment

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

Before drilling below the 26-inch conductor casing, an annular blowout preventer and diverter system will be installed (Figure 5.10).

Before drilling below the 20-inch or 18-5/8-inch surface casing, the blowout prevention system will include four remotely controlled, hydraulically operated blowout preventers (Figure 5.11). Two will be equipped with pipe rams, one with blind rams, and one will be an annular type. The blowout prevention system will have a rated working pressure of 5,000 psig. This pressure exceeds the maximum anticipated surface pressure.

The blowout prevention system will also include:

1. A hydraulic actuating system with sufficient accumulator capacity to operate all functions without the aid of the hydraulic pumps and without reducing the chamber charge pressure below 1,200 psig. Air and electricity will drive independent hydraulic pumps.
2. A drilling spool with side outlets to provide for kill and choke lines.
3. Choke and kill lines, a choke manifold, and a fill-up line.
4. A top kelly cock installed below the swivel, and another at the bottom of the kelly that can be run through the blowout preventers.
5. An inside blowout preventer and a full opening drill string safety valve in the open position which would be maintained on the rig floor at all times while drilling.
6. A pit volume totalizer system, an incremental flow rate indicator, a pit level indicator, and a fill-up measurement system to continuously monitor mud volume. These devices will transmit visual and audible warnings to indicate abnormal conditions.

Control for operating the blowout prevention system will be located on the rig floor, at the accumulator unit, and in a remote platform location. Operation and testing of the BOP equipment will be in accordance with Pacific Region OCS No. 2 and/or field rules.

5.4.5 Typical Drilling Procedures

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

A typical Monterey well will be directionally drilled with the following general procedure:

1. Move and rig up. Install diverter.
2. 17-1/2-inch hole to 1,000 feet below the mud line (BML) through the 26-inch driven conductor. Underream to 26 inches.
3. Run and cement 20-inch or 18-5/8-inch casing at 1,000 feet BML. Install and test BOP stack.
4. 17-1/2-inch hole to 3,500 feet BML. Run logs as needed.
5. Run and cement 13-3/8-inch casing at 3,500 feet BML.
6. Directionally drill 12-1/4-inch hole to the proper depth for setting 9-5/8-inch casing (see Table 5.1). Run logs.
7. Run and cement 9-5/8-inch casing.
8. Run correlation log.
9. Perforate the Monterey interval.
10. Install completion equipment on 4-inch tubing.
11. Remove BOP stack and install Christmas tree.

Note: On wells with measured depths greater than 12,000 feet, the 9-5/8-inch casing would be set at the top of the Monterey interval, an 8-1/2-inch hole would be drilled below the 9-5/8-inch casing to Total Depth (TD), and a 7-inch liner would be set from 300 feet above the base of the 9-5/8-inch casing to TD.

A typical Sandstone (Gaviota) dual completion well will be directionally drilled as follows:

1. Move and rig up. Install diverter.
2. 17-1/2-inch hole to 1,000 feet BML through the 26-inch driven conductor. Underream to 26 inches.
3. Run and cement 20-inch or 18-5/8-inch casing at 1,000 feet BML. Install and test BOP stack.
4. 17-1/2-inch hole to 3,500 feet BML. Run logs as needed.
5. Run and cement 13-3/8-inch casing at 3,500 feet BML.
6. Directionally drill 12-1/4-inch hole to the proper depth for setting 9-5/8-inch casing (see Table 5.1). Run logs.
7. Run and cement 9-5/8-inch casing.
8. Run correlation log.
9. Perforate the Lower and Upper Gaviota intervals.
10. Install completion equipment on dual 2-7/8-inch tubing.
11. Remove BOP stack and install Christmas tree.

Note: After the Sandstone Formation is depleted, this formation would be plugged back, and the well could be recompleted in the Vaqueros/Alegria Formation.

A typical Camino Cielo well will be directionally drilled with the following general procedure:

1. Move and rig up. Install diverter.
2. 17-1/2-inch hole to 1,000 feet BML through the 26-inch driven conductor. Underream to 26 inches.
3. Run and cement 20-inch or 18-5/8-inch casing at 1,000 feet BML. Install and test BOP stack.
4. 17-1/2-inch hole to 3,500 feet BML. Run logs as needed.
5. Run and cement 13-3/8-inch casing at 3,500 feet BML.

6. Directionally drill 12-1/4-inch hole to the proper depth for setting 9 5/8-inch casing (see Table 5.1). Run logs.
7. Run and cement 9-5/8-inch casing.
8. Directionally drill 8-1/2-inch hole to the proper depth for setting 7-inch liner (see Table 5.1). Log.
9. Run and cement 7-inch liner.
10. Run correlation log.
11. Perforate the Camino Cielo interval.
12. Install completion equipment on 3-1/2-inch tubing.
13. Remove BOP stack and install Christmas tree.

Note: After the Camino Cielo Formation is depleted, the formation would be plugged back, and the well could be recompleted to other formations.

A typical Vaqueros/Alegria well will be directionally drilled as follows:

1. Move and rig up. Install diverter.
2. 17-1/2-inch hole to 1,000 feet BML through the 26-inch driven conductor. Underream to 26 inches.
3. Run and cement 20-inch or 18-5/8-inch casing at 1,000 feet BML. Install and test BOP stack.
4. 17-1/2-inch hole to 3,500 feet BML. Run logs as needed.
5. Run and cement 13-3/8-inch casing at 3,500 feet BML.
6. Directionally drill 12-1/4-inch hole to the proper depth for setting 9-5/8-inch casing (see Table 5.1). Run log.
7. Run and cement 9-5/8-inch casing.
8. Run correlation log.
9. Perforate the Vaqueros/Alegria interval.

10. Install completion equipment on 2-7/8-inch tubing.
11. Remove BOP stack and install Christmas tree.

A typical Lower Gaviota-Middle Gaviota dual completion well will be directionally drilled as follows:

1. Move and rig up. Install diverter.
2. 17-1/2-inch hole to 1,000 feet BML through the 26-inch driven conductor. Underream to 26 inches.
3. Run and cement 20-inch or 18-5/8-inch casing at 1,000 feet BML. Install and test BOP stack.
4. 17-1/2-inch hole to 3,500 feet BML. Run logs as needed.
5. Run and cement 13-3/8-inch casing at 3,500 feet BML.
6. Directionally drill 12-1/4-inch hole to the proper depth for setting 9-5/8-inch casing (see Table 5.1). Run logs.
7. Run and cement 9-5/8-inch casing.
8. Run correlation log.
9. Perforate the Lower Gaviota-Middle Gaviota intervals.
10. Install completion equipment on dual 2-7/8-inch tubing.
11. Remove BOP stack and install Christmas tree.

A typical Camino Cielo-Vaqueros/Alegria well will be directionally drilled as follows:

1. Move and rig up. Install diverter.
2. 17-1/2-inch hole to 1,000 feet BML through the 26-inch driven conductor. Underream to 26 inches.
3. Run and cement 20-inch or 18-5/8-inch casing at 1,000 feet BML. Install and test BOP stack.
4. 17-1/2-inch hole to 3,500 feet BML. Run logs as needed.

5. Run and cement 13-3/8-inch casing at 3,500 feet BML.
6. Directionally drill 12-1/4-inch hole to the proper depth for setting 9-5/8-inch casing (see Table 5.1). Run logs.
7. Run and cement 9-5/8-inch casing.
8. Directionally drill 8-1/2-inch hole to the proper depth for setting 7-inch liner (see Table 5.1). Log.
9. Run and cement 7-inch liner.
10. Run correlation log.
11. Perforate the Camino Cielo-Vaqueros/Alegria intervals.
12. Install completion equipment on dual 2-7/8-inch tubing.
13. Remove BOP stack and install Christmas tree.

5.4.6. Pollution Prevention

A cuttings washing device will be used to remove any oil contained in the drill cuttings prior to their disposal into the ocean in accordance with an NPDES permit. All oil effluent from the cuttings washer will be transported to shore for disposal. Exxon will also transport to shore for disposal any cuttings from which the oil cannot be removed. Drilling mud which contains oil will be transported to shore for disposal.

A deck drainage system will collect deck and equipment runoff. Before disposal into the ocean, the oil contained in the deck drainage will be skimmed off. The skimmed oil will be transported to shore for disposal.

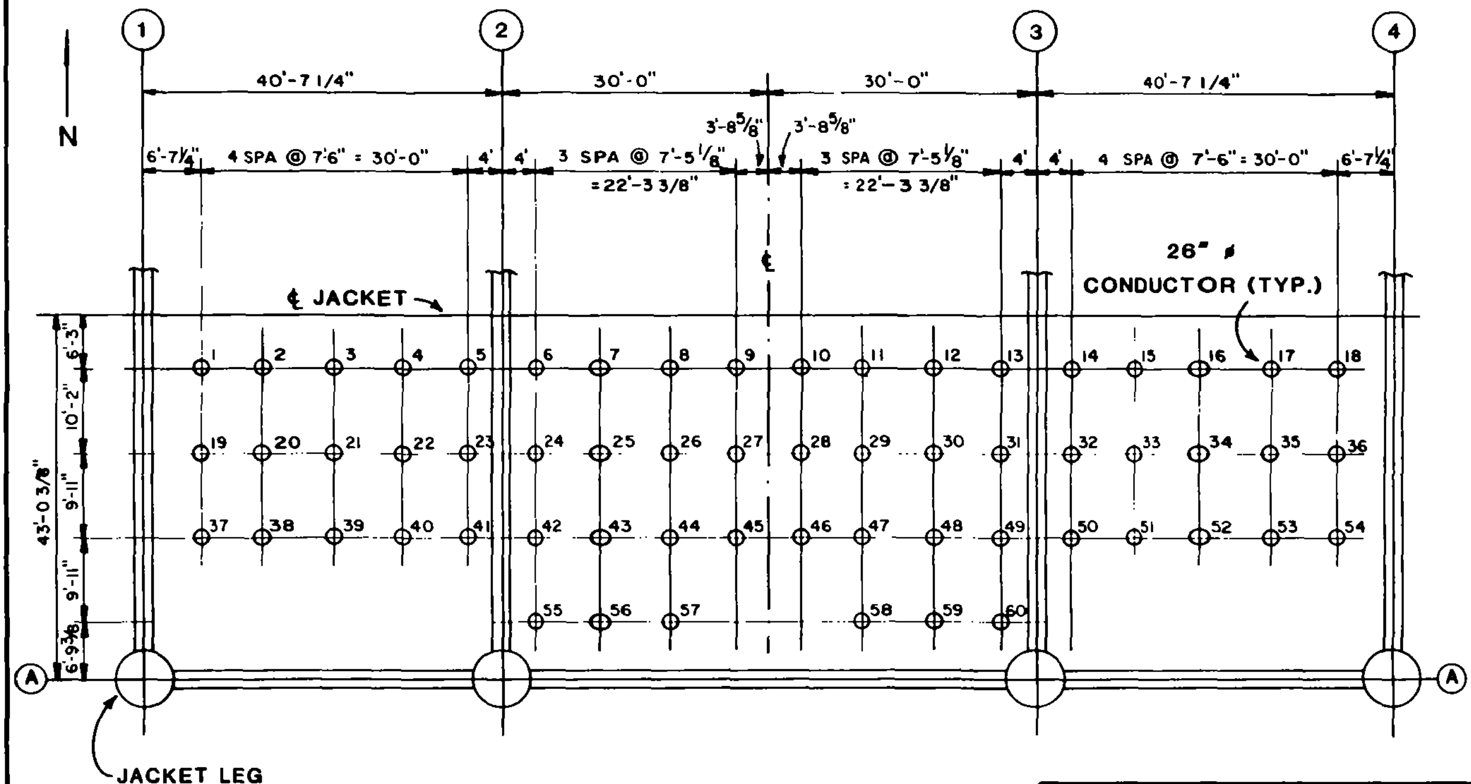
Trash and garbage will be transported to shore for disposal. Containers will be constructed to prevent accidental loss onboard or enroute to the disposal site.

Drilling rigs will be powered by onshore generated electrical power, thereby eliminating a significant amount of air pollutant emissions.

TABLE 5.1

PROPOSED TYPICAL WELL PROGRAMS

Platform	Completion Type	Number of Wells	Producing Formation	9-5/8" Casing Set (Feet Subsea	7" Liner Set (Feet Subsea)	Reference Figure
Harmony	Single	45	Monterey	8,500	-	5.6/5.4
Harmony	Single	3	Gas Injection	7,400		5.5
Heritage	Single	52	Monterey	7,200	-	5.6/5.4
Heritage	Single	3	Gas Injection	6,000		5.5
Heritage	Dual	4	Gaviota (Sandstone)	9,900	-	5.4
Heritage	Single	1	Camino Cielo (Non-Associated Gas)	10,600	10,300-12,500	5.7
Heather	Single	14	Monterey	6,100	-	5.6/5.4
Heather	Single	11	Vaqueros/Alegria	8,800	-	5.4
Heather	Dual	1	Lower Gaviota - Middle Gaviota Gas	9,600	-	5.7
Heather	Dual	2	Camino Cielo - Vaqueros/Alegria Gas	11,000	10,700-11,500	5.7



60-WELL ARRANGEMENT
@ EL.(+)15'-0"

Figure 5.1
HARMONY PLATFORM
WELL BAY AREA PLAN

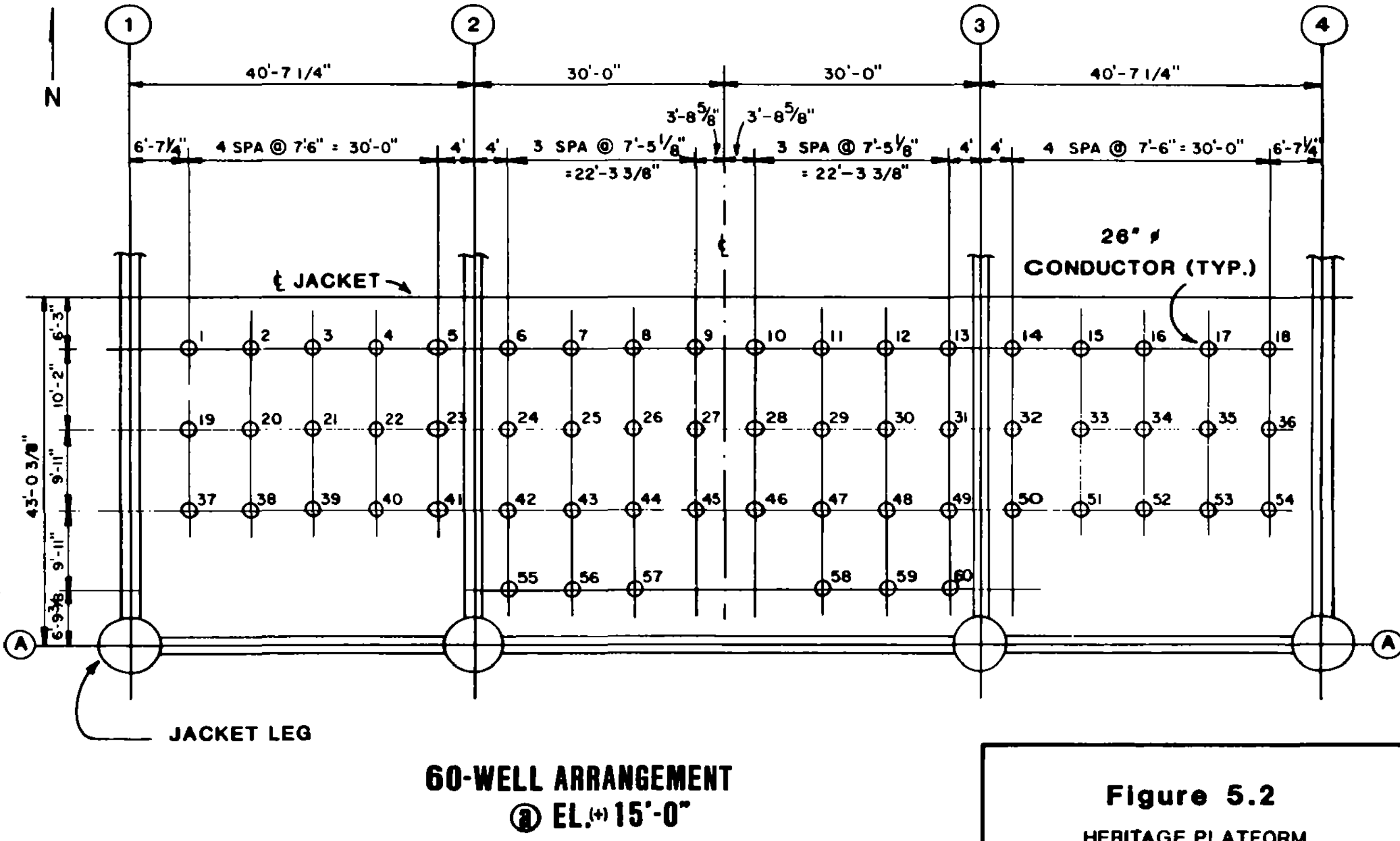


Figure 5.2

HERITAGE PLATFORM
WELL BAY AREA PLAN

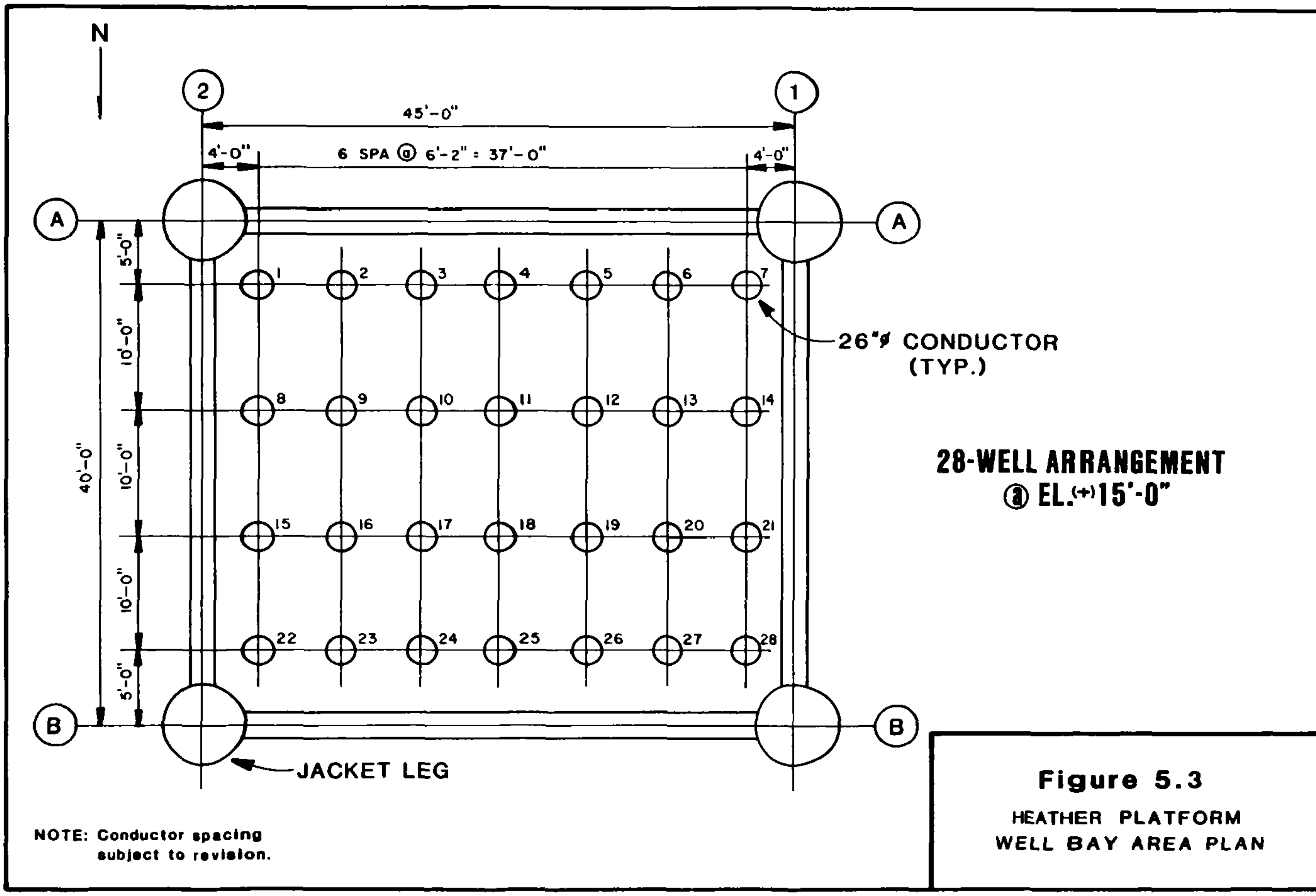
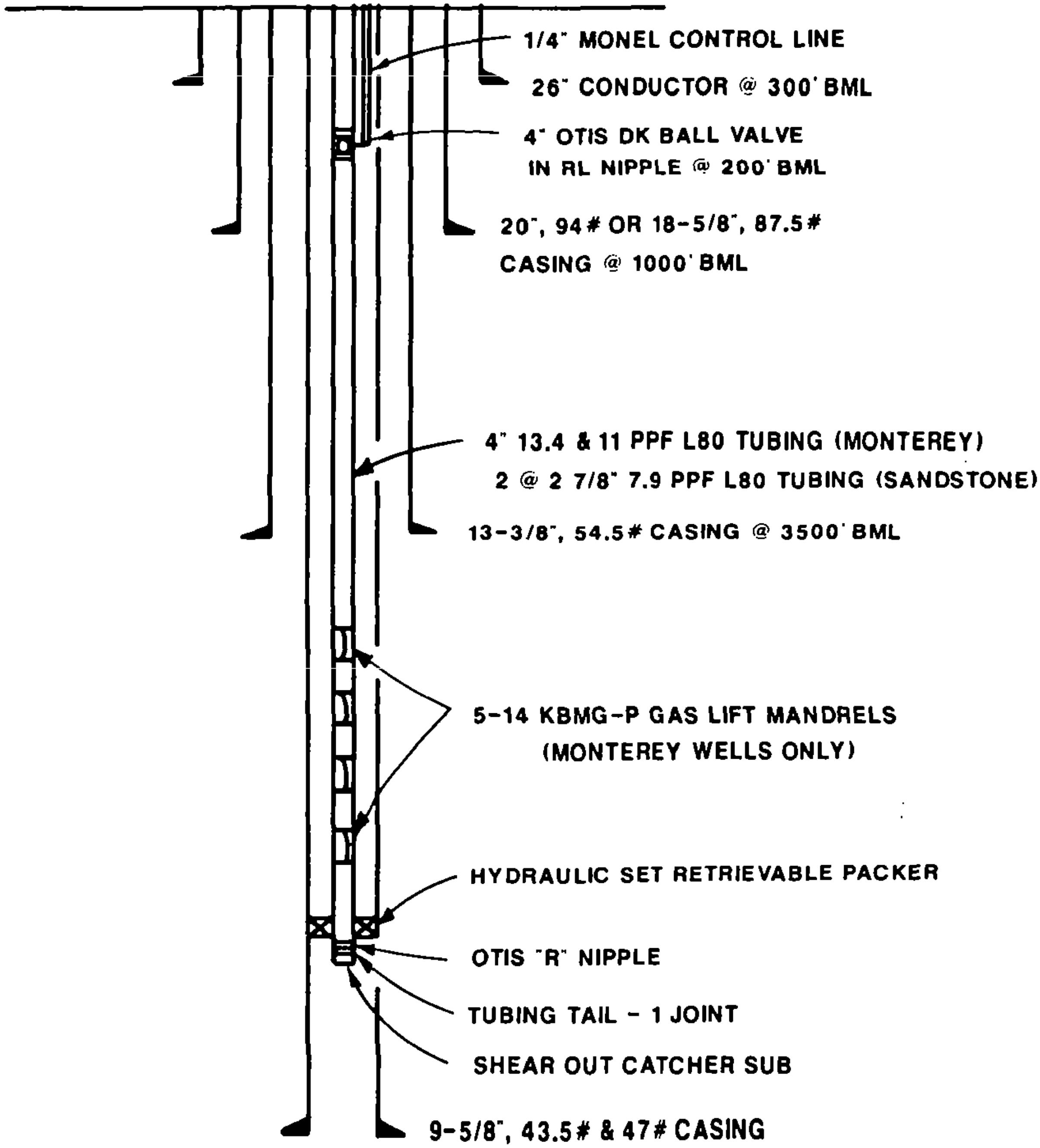


Figure 5.3

HEATHER PLATFORM
WELL BAY AREA PLAN



NOTE: BML - BELOW MUD LINE

NOT SHOWN: BOTTOM HOLE PRESSURE MONITORING VIA CAPILLARY TUBING AND PRESSURE CHAMBER.

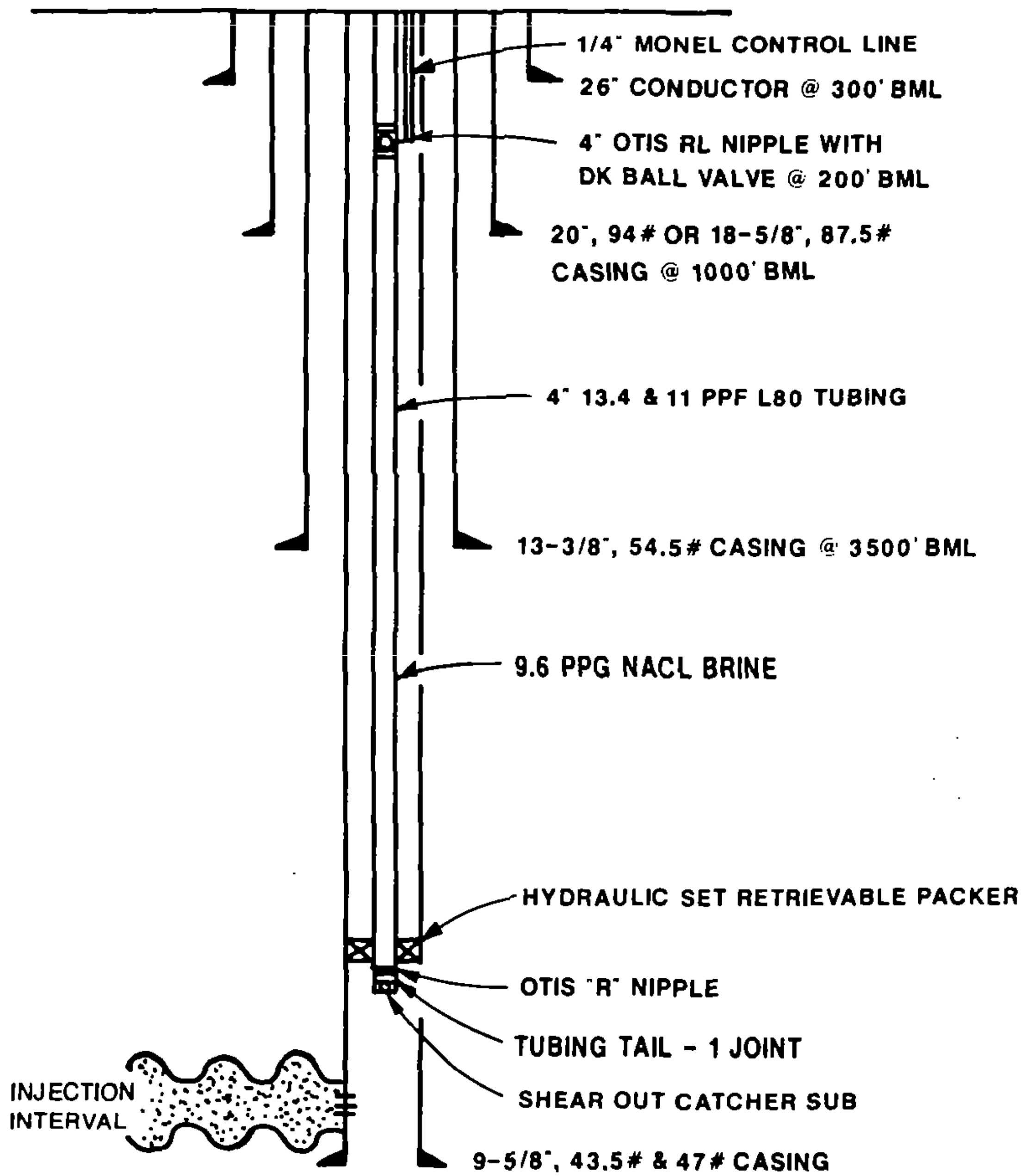
Figure 5.4

MONTEREY & GAVIOTA (SANDSTONE) PRODUCER

PROPOSED CASING PROGRAM

TYPICAL WELL SKETCH

WITHOUT LINER

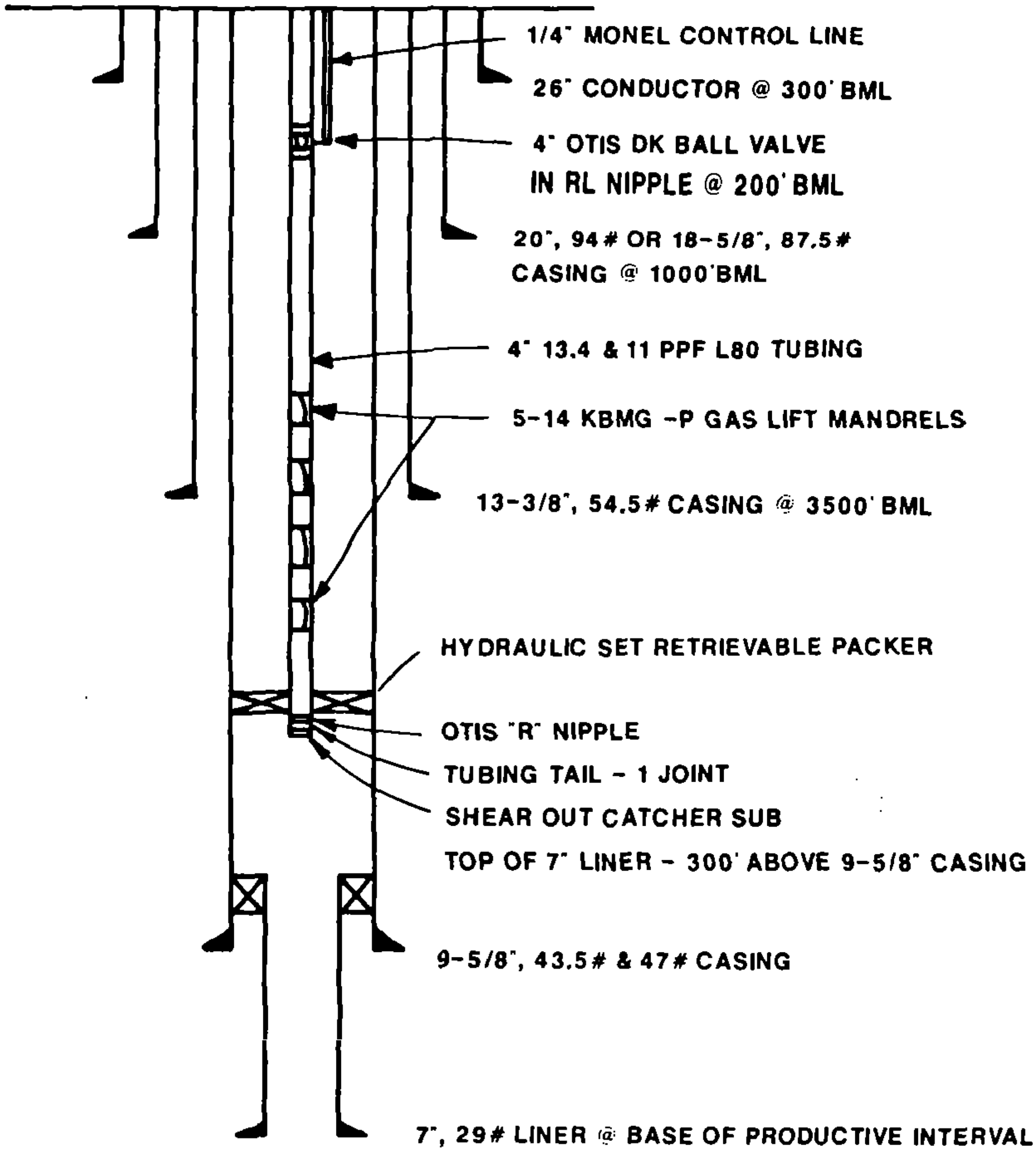


NOTE: BML - BELOW MUD LINE

NOT SHOWN: BOTTOM HOLE PRESSURE MONITORING
VIA CAPILLARY TUBING AND
PRESSURE CHAMBER.

Figure 5.5

MONTEREY GAS INJECTION WELL
PROPOSED CASING PROGRAM
TYPICAL WELL SKETCH
WITHOUT LINER

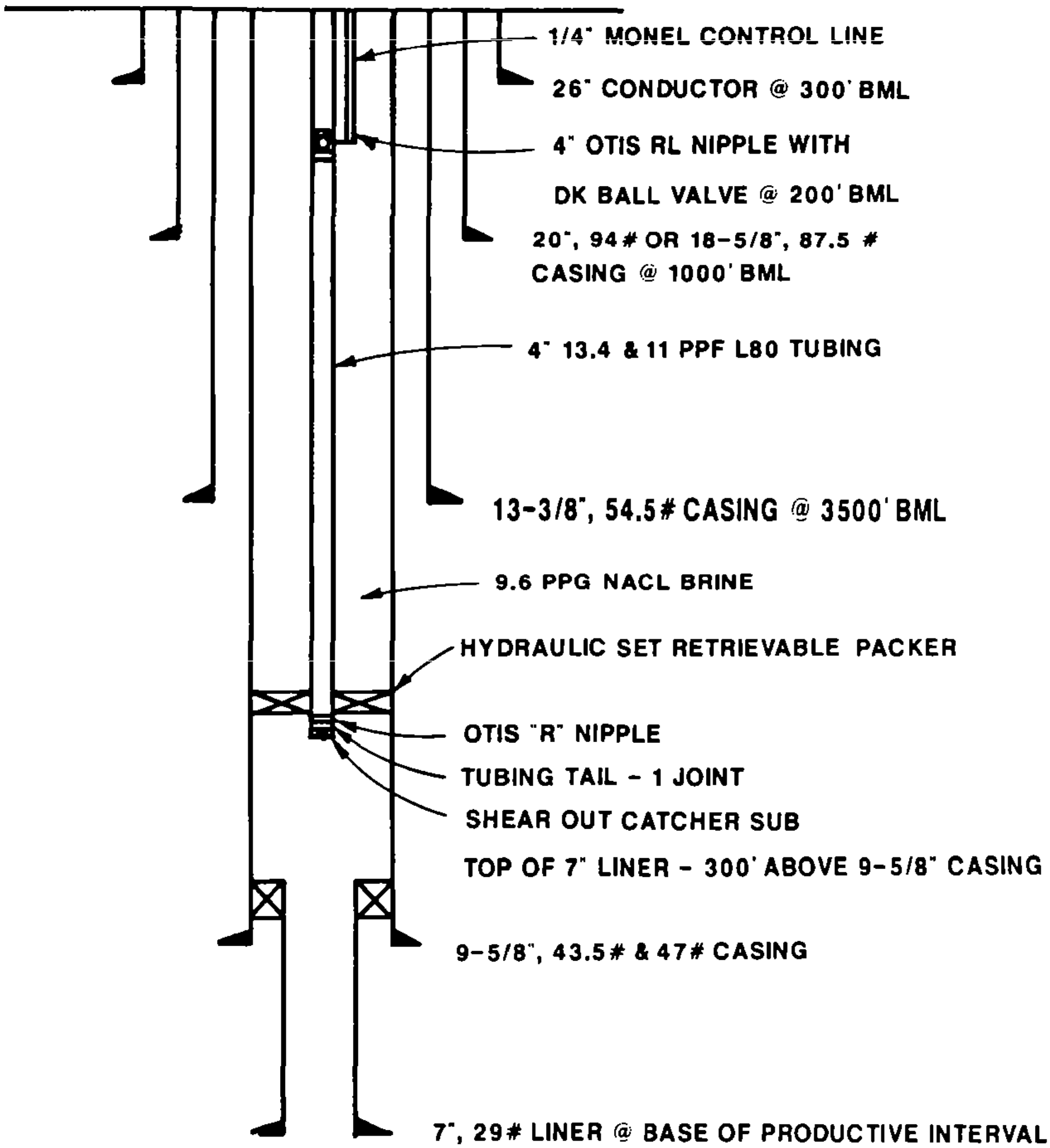


NOTE: BML - BELOW MUD LINE

NOT SHOWN: BOTTOM HOLE PRESSURE MONITORING VIA CAPILLARY TUBING AND PRESSURE CHAMBER.

Figure 5.6

DEEP MONTEREY PRODUCER
PROPOSED CASING PROGRAM
TYPICAL WELL SKETCH
WITH LINER



NOTE: BML - BELOW MUD LINE

NOT SHOWN: BOTTOM HOLE PRESSURE MONITORING VIA CAPILLARY TUBING AND PRESSURE CHAMBER.

Figure 5.7

NON-ASSOCIATED GAS WELL
PROPOSED CASING PROGRAM
TYPICAL WELL SKETCH
WITH LINER

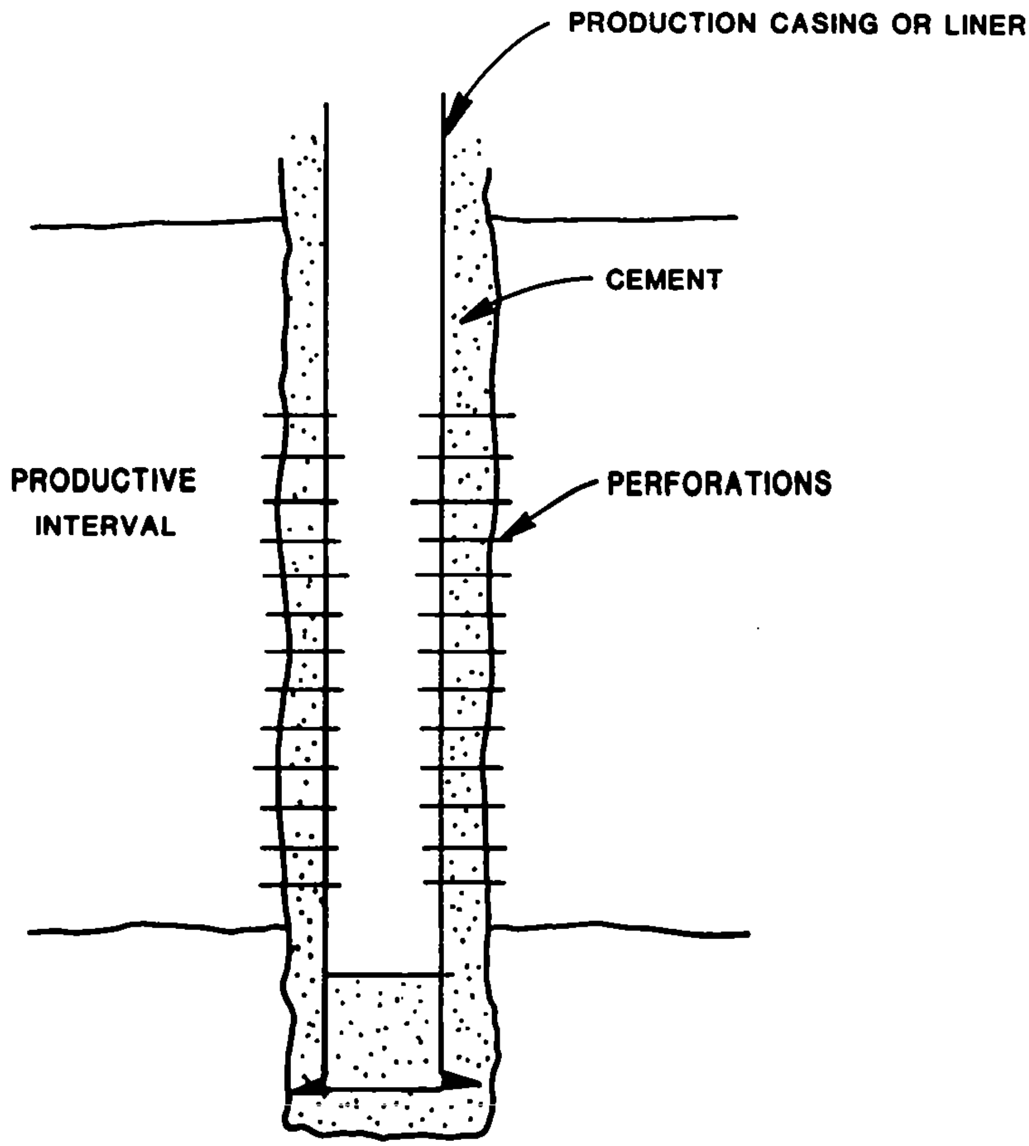


Figure 5.8

PROPOSED WELL COMPLETION
CEMENTED & PERFORATED

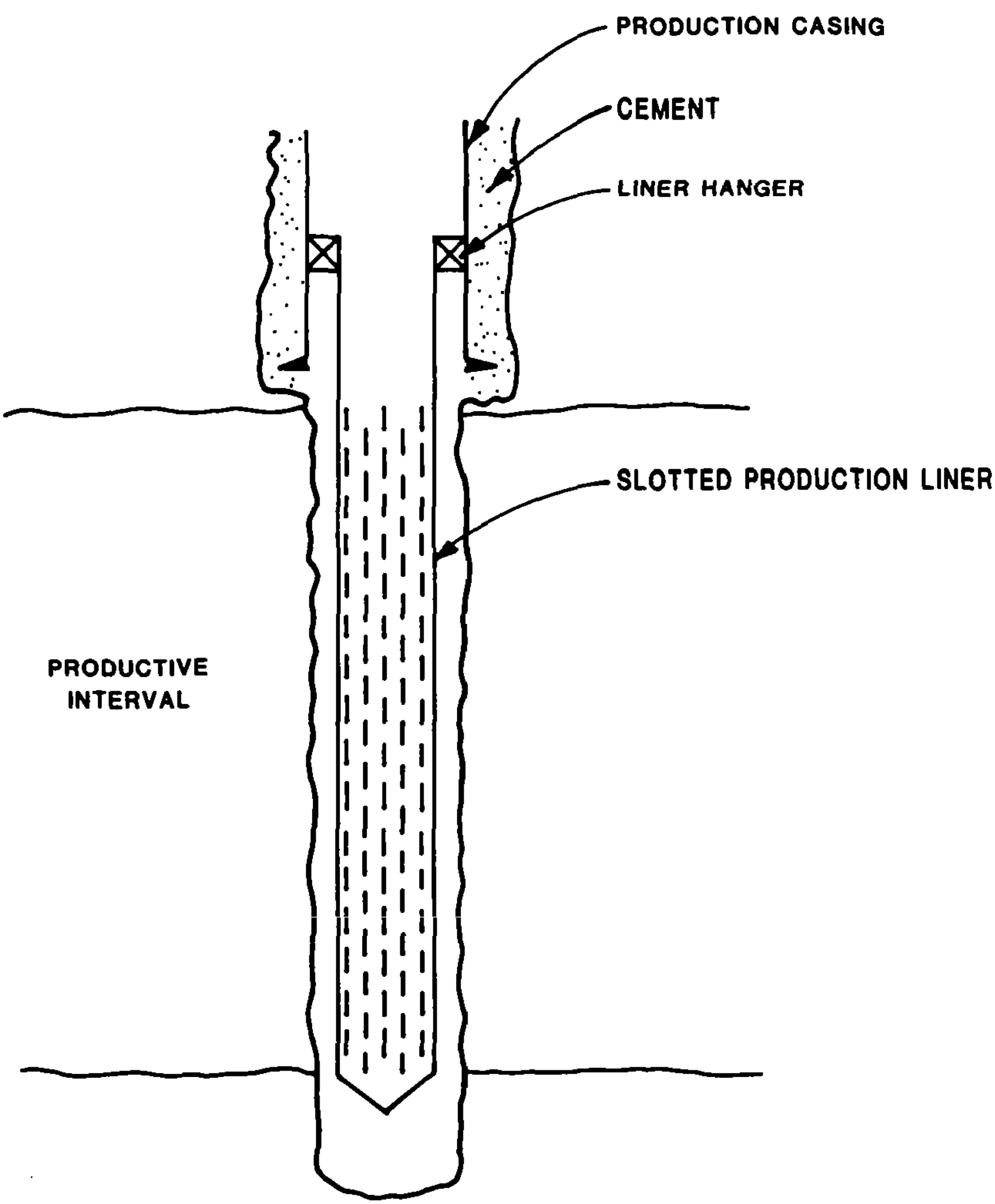
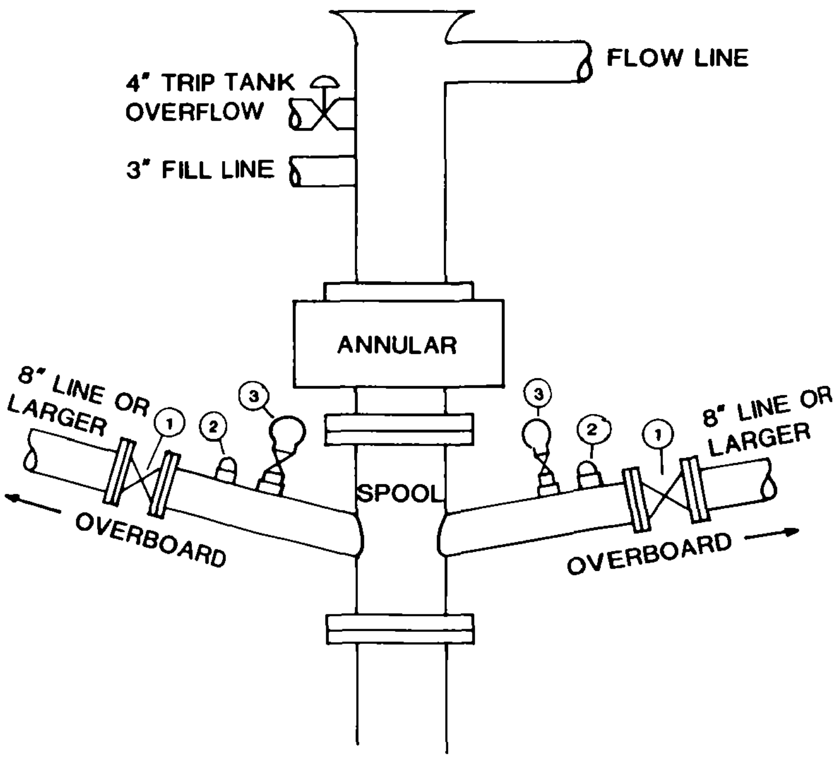


Figure 5.9

PROPOSED WELL COMPLETION
SLOTTED LINER



(1) 8" OR LARGER REMOTE CONTROLLED GATE VALVE
(2) BULL PLUG
(3) TAPPED BULL PLUG, VALVE AND PRESSURE GAUGE

NOTES:

1. DIVERTER LINE,VALVES AND OTHER COMPONENTS WILL HAVE A 300 PSI MINIMUM WORKING PRESSURE.
2. DIVERTER LINE VALVES WILL BE OPERATED SO THAT ONE VALVE IS ALWAYS OPEN BEFORE AND WHILE THE ANNULAR IS CLOSED.
3. AN ALTERNATE ARRANGEMENT MAY BE USED CONSISTING OF A SINGLE DIVERTER LINE EXITING THE SPOOL AND ENTERING A TEE WITH TWO BRANCH LINES GOING OVERBOARD.
4. A KILL LINE (NOT SHOWN) WILL ENTER THE SPOOL.

Figure 5.10

DIVERTER SYSTEM

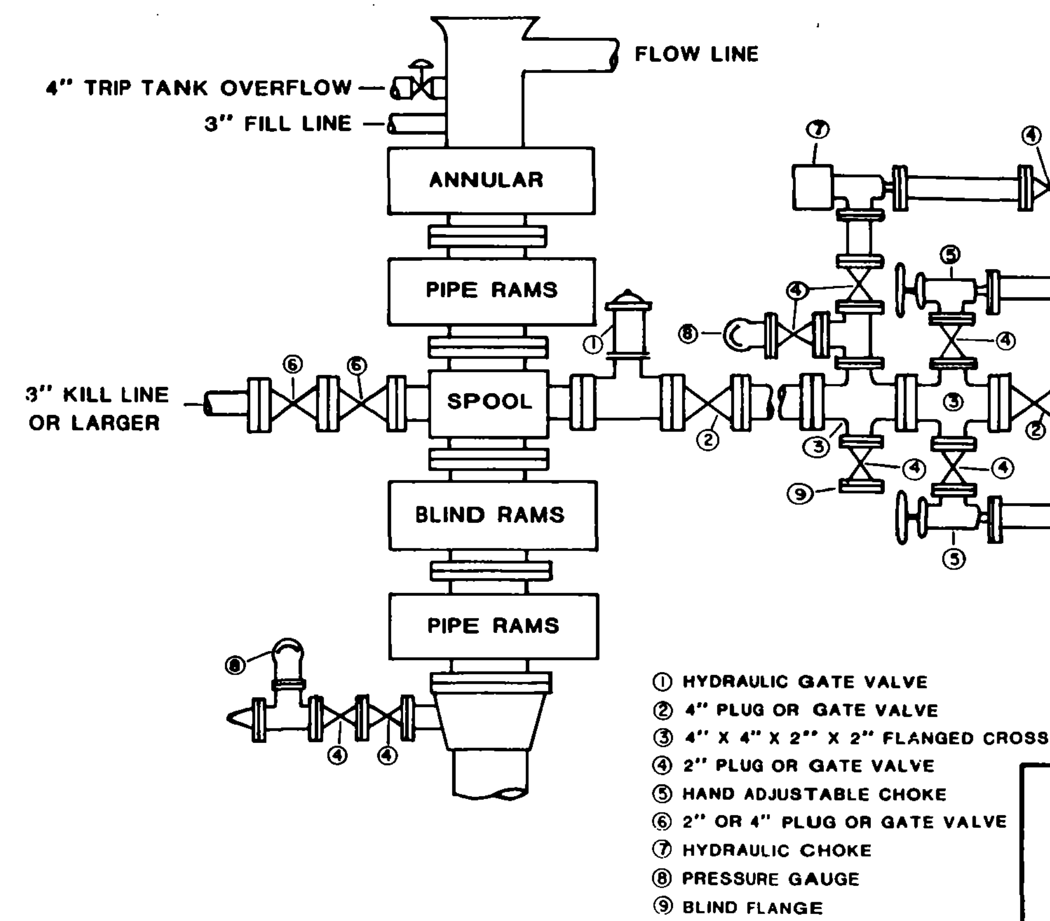


Figure 5.11

BLOWOUT PREVENTER STACK

SECTION VI

SUBSEA PRODUCTION SYSTEMS

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SUBSEA PRODUCTION SYSTEMS

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6.1 Introduction

This section discusses the potential application of subsea production systems to offshore reservoir development in the Santa Ynez Unit. Although no specific sites have been determined, subsea completions may be required for future development of reserves which cannot be produced by wells drilled from the fixed platforms installed in the Unit. The location and number of possible subsea completions will be determined by requirements for effective field development

6.2 Santa Ynez Unit Application

If it is not possible to reach all of the desired drilling locations from a platform, the use of subsea wells can extend the reach of a conventional platform surface production system. Development wells are drilled and completed subsea. Drilling operations would be conducted from a floating drilling vessel just as it is done for exploratory wells.

Three subsea well configurations may be considered to supplement platform development. These configurations include: 1) individual subsea satellite wells connected to the platform with separate flowlines; 2) a small cluster of satellite production wells directionally drilled from a single template; and 3) a group of individual subsea satellite wells with production gathered through a centrally located manifold and the total production routed through a larger line to the platform. These three subsea production configurations are illustrated in Figure 6.1.

With all of the configurations, flowlines and control lines would be installed to, and be operated from, the field production platform. Well fluids would be produced directly to the production platform.

Each system would use technology permitting installation, operation, and maintenance without general diver assistance. Divers may be used to modify existing platform facilities for satellite well flowline installation and to supplement remote operations when appropriate. Satellite wells would have "Through Flowline" (TFL) maintenance capability to permit the servicing of gas lift and subsurface safety valves from the platform. All wellhead functions would be controlled hydraulically from the platform and would consist of fail-safe closed valves.

Research, engineering, and testing have been carried out to develop a 20 to 30 multi-well template which could replace a surface production platform in a production development plan. Studies and field tests performed to date indicate that the use of this type of system is technically feasible for the development and production of only certain types of reservoirs and crudes. However, at this time, it is not technically feasible with available technology to use a multi-well subsea system in place of a Santa Ynez Unit surface platform.

The multi-well template requires a nearby support facility. Heavy viscous crude produced from the Santa Ynez Unit precludes use of long flowlines to take production from several templates to a central facility or ashore. Pressure drop in the long flowlines would cause the reservoir to stop production prematurely. Premature termination of production capability not only has an adverse economic effect, but also would cause loss of reserves relative to those that could be recovered in a platform operation. Some loss of reserves relative to platform recovery always occurs with subsea production systems. The high cost of well re-entry for maintenance from a floating drilling rig causes abandonment of wells at an earlier time than in an equivalent platform operation.

Satellite wells may have applicability to produce reserves that cannot be reached with platform wells in the Santa Ynez Unit. Flowline lengths will be restricted for satellite wells just as they would be for multi-well templates. However, flowline constraints for satellite wells will not unduly restrict applicability. These wells are supplemental to a platform development and hence, are relatively close to the platform. All three configurations shown in Figure 6.1 might be considered.

6.3 Single Subsea Satellite Wells

A typical single satellite well system consists of a well drilled as a straight hole using conventional floating drilling equipment and techniques, a wellhead installed after completion of the well, tubing strings with production gas lift valves and subsurface safety valves, flow control valves, flowlines and control lines installed to the production platform. Control and production facilities are installed on the platform. A schematic diagram of the single satellite well system is shown in Figure 6.2.

6.4 Clustered Satellite Wells

Clustered satellite wells to supplement platform operations would be produced, operated, and maintained similarly to that of the single subsea satellite wells. Clustering is limited to a small number of wells due to the flowline pressure drop constraints mentioned above.

The clustered well system would consist of a structural support frame to provide both the mechanical strength and the foundation for all of the underwater piping and valving and the pre-designated well slots.

This template would be installed prior to drilling the first well. Wells would be directionally drilled through the template instead of vertically as done for single satellite wells.

The gathering and distribution manifold would be similar to the equipment used for a single satellite well, only expanded to handle simultaneous production from several wells. The individual wells would be connected by valving to gathering header and then produced to the production platform through a common flowline bundle.

6.5 Manifold Satellite Wells

Production is gathered from several single subsea satellite wells to a centrally located subsea manifold for routing to the production platform. This subsea production concept is a combination of the satellite well discussed in Section 6.3 and the template and manifold features of the subsea clusters discussed in Section 6.4.

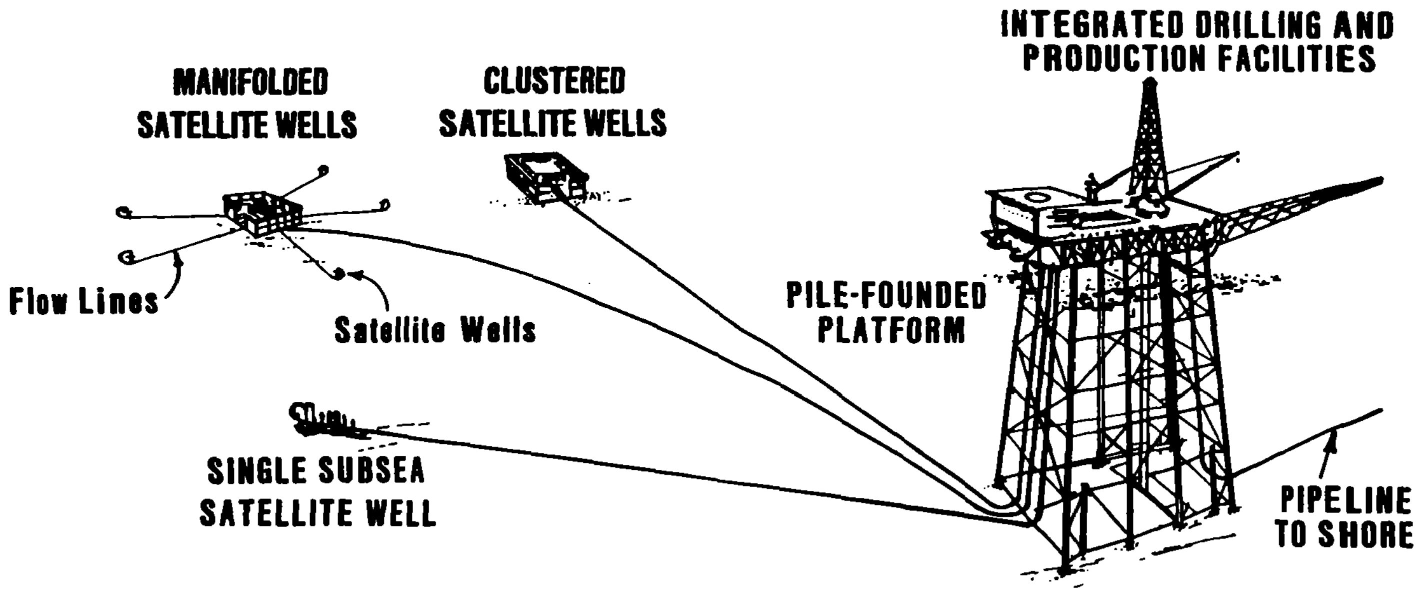

Figure 6.1

SUBSEA PRODUCTION CONFIGURATIONS

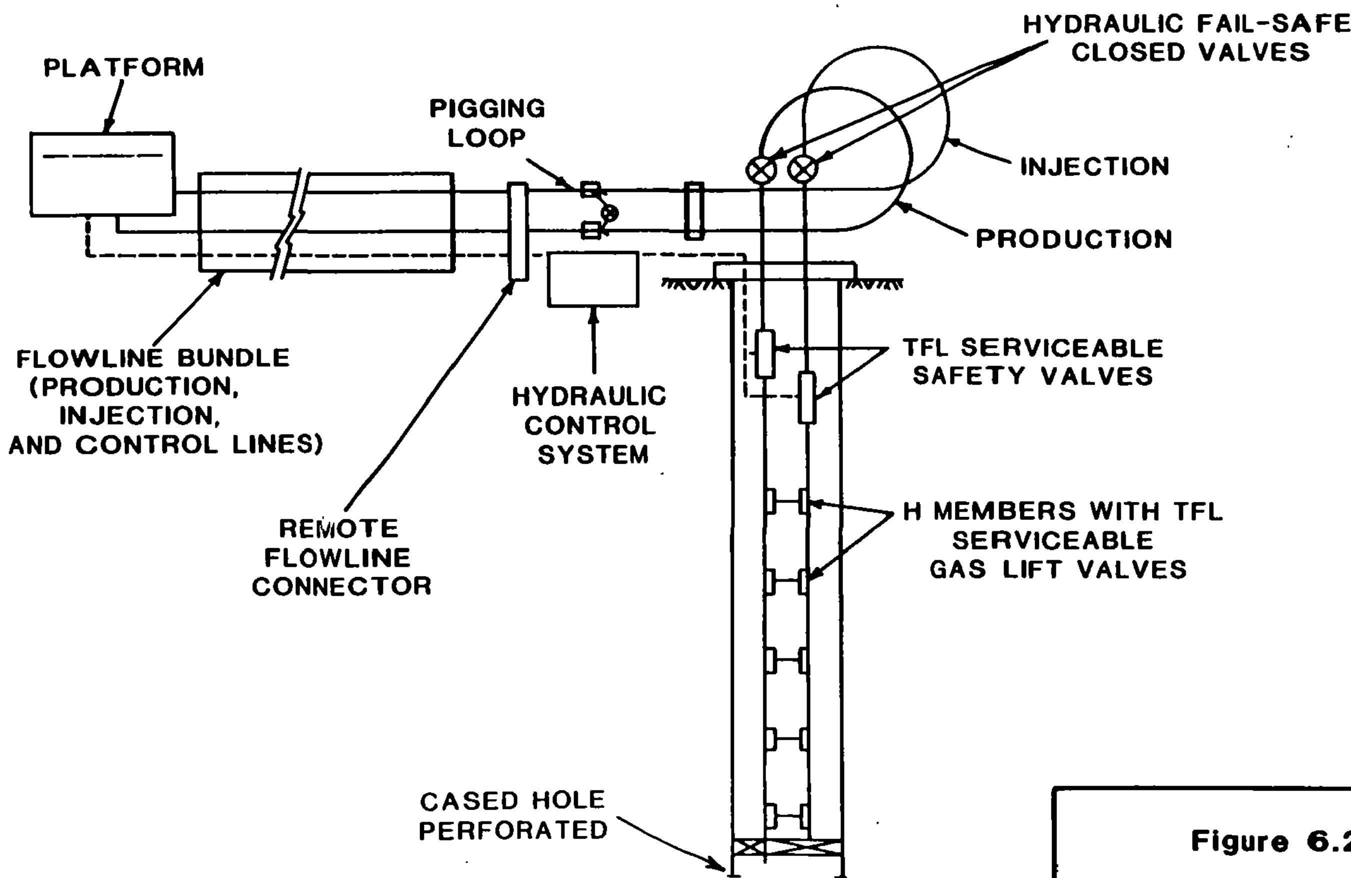

Figure 6.2

SINGLE SATELLITE WELL SYSTEM

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OFFSHORE PLATFORM FACILITIES

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OFFSHORE PLATFORM FACILITIES

FIGURES

NOTE: Figure 7.36 contains information which is considered EXXON PROPRIETARY and is located in a separate "Appendix A". NO DISCLOSURE OF THIS INFORMATION BEYOND THE MINERALS MANAGEMENT SERVICE IS ALLOWED WITHOUT PRIOR WRITTEN AUTHORIZATION FROM EXXON.

SECTION VII

OFFSHORE PLATFORM FACILITIES

FIGURES (continued)

SECTION VII

7.1 Introduction

This section discusses the facilities to be installed on the new offshore platforms and the modifications planned for Platform Hondo as a result of the Santa Ynez Unit expanded development. The production facilities design guidelines that will be used are listed in Section 7.2. Process and utility systems descriptions for the new platforms follow. The legend shown in Figure 7.1 should be referenced when looking at the new platform process flow diagrams. Control and monitoring systems, safety equipment, and environmental impact mitigation measures are described as facilities with a common design basis.

A functional block diagram of the proposed expanded development is shown in Figure 7.2 to aid in understanding the interrelationship between the existing Platform Hondo, the new platforms (Harmony and Heritage), the onshore facilities, and the future Platform Heather. The facilities on the platforms will be designed for separation of the produced fluids into gas and emulsion streams. The emulsion will be pipelined to onshore oil treating facilities for crude dehydration, sweetening, and stabilization prior to disposition by either pipeline or a modernized nearshore Marine Terminal. Up to 75 MSCFD of natural gas will be sent via the existing gas sales pipeline to shore while the remainder will be reinjected at the platforms to maintain reservoir pressure and maximize oil recovery.

Electric power will be generated in an onshore cogeneration power plant and/or purchased from Southern California Edison (SCE) and sent offshore via three submarine cables.

7.2 Standards

Exxon is committed to complying with all applicable regulations which may affect the offshore platform facility designs. The following American Petroleum Institute Recommended Practices will be considered as guidelines for safe and efficient design of facilities on each of the offshore platforms:

API RP 2G — Recommended Practice for Production Facilities on Offshore Structures.

API RP 14C — Recommended Practice for Analysis, Design, Installation, and Testing of Basic Surface Safety Systems on Offshore Production Platforms.

API RP 14E — Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems.

API RP 14F — Recommended Practice for Design and Installation of Electrical Systems for Offshore Production Platforms.

API RP 14G — Recommended Practice for Fire Prevention and Control on Open Type Offshore Production Platforms.

API RP 500B Recommended Practice for Classification of Areas for Electrical Installation at Drilling Rigs and Production Facilities on Land and on Marine Fixed or Mobile Platforms.

In addition, the requirements of the MMS Pacific Region OCS Order 5 will apply to the installation and operation of production safety systems. All designs for mechanical and electrical systems will be certified by registered professional engineers.

7.3 Platform Hondo Facilities

7.3.1 Existing Platform Hondo Facilities

The facilities presently installed and operating on Platform Hondo are designed to handle approximately 48 kBD of total emulsion and to compress 70 MSCFD of gas. A single water injection pump with a 14 kBD capacity disposes of all the produced water returned to the platform from the Offshore Storage and Treating Vessel (OS&T). The process flow schematic is shown on Figure 7.3.

Primary production is sour gas and emulsion (crude oil and water) from completions in the Monterey Formation. Sweet gas for fuel is provided by completions in the Sandstone Formations. Sandstone produced liquids are combined with Monterey liquids for pipeline shipment to the OS&T for dehydration, sweetening, stabilization, and storage.

Produced gas and vapors from the separators are combined and routed to a sour gas scrubber. This scrubber also receives gas from the well clean-up system and the vapor recovery compression system. Outlet gas is fed to the main platform gas compressors.

The main compression system utilizes two parallel two-stage electric motor-driven reciprocating compressors for compression of low pressure production to a pressure sufficient for gas sales and artificial lift. Dehydration of the discharge gas, after cooling and scrubbing, is accomplished by conventional glycol dehydration. All discharge gas, except for 30 MSCFD gas sales to POPCO (initiated December 1983) and fuel gas sent to the OS&T, is then combined with the high pressure gas production and compressed through a single stage electric motor-driven reciprocating compressor for injection into the reservoir.

Water produced with the hydrocarbon fluids from the Monterey and Sandstone formations is transported with the crude oil to the OS&T. The emulsion is broken down on the OS&T and the produced water is separated and treated. The clean produced water is pipelined back to Platform Hondo and received in a surge tank. A multi-stage centrifugal pump takes the water to injection pressure. The water is metered and then injected into subsurface formations.

All rotating equipment (pumps, compressors) on Platform Hondo is driven by electric motors. Part of the power is generated at 4160 volts by three Solar Saturn 720 kW generators, each capable of operating on diesel or gas fuel. Additional power is transmitted to the platform from the OS&T. This additional power is carried by a submarine cable operating at 35 kV and is then transformed down to

4160 volts for supply in parallel with the platform generators. Process heat requirements are supplied by waste heat recovery from the three Saturn turbine drivers. The initial Hondo development is shown in Figure 7.4.

7.3.2 Platform Hondo Modifications

Modifications to existing Platform Hondo facilities consist of the following:

7.3.2.1 Emulsion and Gas Pipelines

The existing 12-inch emulsion pipeline from Platform Hondo to the OS&T will be extended to tie into the shorebound 20-inch emulsion pipeline from Platform Harmony. Platform Hondo gas production will continue to be transported to shore via the existing 12-inch gas pipeline.

7.3.2.2 Electrical Power

The existing submarine power cable between Platform Hondo and the OS&T will be removed and replaced by a new submarine cable from Platform Harmony.

7.4 Platform Harmony, Heritage, and Heather Facilities

7.4.1 General Description

The deck layouts for Platforms Harmony, Heritage, and Heather are given in Figures 7.5 through 7.10 (Harmony), Figures 7.17 through 7.22 (Heritage), and Figure 7.2.9 (Heather). The following process and utility systems descriptions may be assumed applicable for all three platforms unless otherwise noted.

7.4.2 Process Systems

Refer to the Process Flow Diagrams included in this section (Figures 7.11 through 7.16 (Harmony) and Figures 7.23 through 7.28 (Heritage)).

7.4.2.1 Wellhead Manifolds

Harmony will have 60 well slots arranged in three rows of 18 each and one row of six. Harmony development wells will include 45 oil producers and three gas injection wells. All wells will be completed in the Monterey Formation. The production system will be divided into two parallel separation trains. Well manifolds will be provided to flow each well to a Production Separator or divert it to a Test Separator or the Well Cleanup Separator. A gas lift manifold with metering will connect to the production casing of each producing well. An injection manifold with metering will connect to each of the gas reinjection wellheads. High pressure production and test headers will be provided in the wellhead manifold for future tie-in of high GOR wells to handle gas coning of some wells without having to expand the sales gas compression and gas conditioning system. High pressure production facilities, if required, will be a future addition on the drilling deck following completion of drilling. Well manifold piping connections will be provided to divert flow to either Production Separator.

Heritage also will have 60 well slots arranged in three rows of 18 each and one row of six. Of the 60 well slots, approximately 52 will be initially allocated as Monterey producers, four as Sandstone producers (dual completions), and one as a non-associated sweet gas well. The remaining three well slots will be utilized for gas reinjection. The production system is divided into two parallel separation trains for Monterey wells and one for the Sandstone wells. Well manifolds will be provided to flow each well to a Production Separator or divert it to a Test Separator or the Well Cleanup Separator. A gas lift manifold with metering will connect to the production casing of each Monterey producing well. The Sandstone wells will not require gas lift. An injection manifold with metering will connect to each of the reinjection wellheads. As for Harmony, high pressure production and test headers will be provided in the wellhead manifold for future tie-in of high GOR wells. Well manifolds for the Monterey wells will include piping to divert flow to either Production Separator.

Platform Heather will have 28 well slots of which approximately 14 will be initially completed as Monterey producers, 11 as sweet Sandstone oil producers, and three as sweet non-associated gas producers. It is anticipated that the production system for Platform Heather will be very similar to that for Platform Heritage.

7.4.2.2 Well Cleanup

The Well Cleanup system will be a single train, one-stage system for bringing individual wells on-stream after servicing, shutdowns, or completion operations. The Well Cleanup Separator will remove undesirable workover fluids and solids. It can also be operated as a continuous flowing Test Separator. Gas from the Well Cleanup Separator can flow either to flare or to the first stage of compression.

7.4.2.3 Well Testing

Each of the two Monterey production trains will have a two-phase Test Separator. Both the gas and liquid streams exiting the separator will be metered. Connections will be provided for calibration of the meter by means of a portable test meter. Well testing will be controlled automatically. An additional Test Separator will be provided on Heritage and Heather for testing Sandstone and non-associated gas wells.

7.4.2.4 Batch Treatment

A batch treatment header will be provided in the wellhead manifold for downhole chemical treatment of each well. Since tubing corrosion is not expected to be a problem initially, the batch treatment facilities will be deferred. A corrosion monitoring program will be implemented for detection of corrosion and the need for mitigation.

7.4.2.5 Oil/Gas Separation

Monterey wellstreams will flow directly to Monterey Production Separators (one per train) operating at 80 psig. The gas and liquid will be separated. The gas will be routed to the gas compression/conditioning system. The emulsion will be combined with the recycled liquid from the First Stage Suction Scrubber and enter the Emulsion Surge Tank. The Emulsion Surge Tank will operate at 15 psig to "degas" the crude emulsion. The vapor generated will be routed to the Surge Tank Vapor (STV) Compressor system.

The design includes a Monterey Production Heater to ensure adequate NPSH to the Emulsion Shipping Pumps during off design operating cases. Heating of the emulsion is not required for the base design case.

An additional production train will be provided on Heritage and Heather for production from the non-associated gas wells and the Sandstone wells. Produced fluids from the Sandstone and non-associated gas wells will be combined and flashed at 330 psig and 80 psig pressure levels. The separated liquid at 80 psig will be commingled with the Monterey Production Separator liquid upstream of the Emulsion Surge Tank. Part of the gas separated at 330 psig will be used as platform fuel gas and the remaining gas will be routed to the gas compression/conditioning system.

7.4.2.6 Emulsion Shipping

The degassed emulsion will be pumped from the Emulsion Surge Tank to pipeline pressure, mixed with the Natural Gas Liquids (NGL's) from the gas conditioning system, and metered in the Automatic Custody Transfer (ACT) Unit before entering the submarine pipeline. The ACT Unit will be equipped with a meter prover and sampling system. Metering of the emulsion is discussed in Section 7.4.3.17.

7.4.2.7 Surge Tank Vapor (STV) Compressor System

The vapors from the Emulsion Surge Tank and the Vent Recovery Compressor will be routed to the STV Compressor Suction Cooler. The vapor will be cooled and sent to the STV Compressor Suction Scrubber along with the acid gas from the Amine Reflux Accumulator (Harmony only). The water and hydrocarbon liquids from the STV Compressor

Suction Scrubber will be pumped back to the Emulsion Surge Tank. The gas will be compressed by the STV Compressor to 80 psig, combined with the Monterey Production Separator gas and the Sandstone Flash Separator gas (Heritage and Heather), and sent to the gas compression/conditioning system.

7.4.2.8 Gas Compression/Conditioning System

All 80 psig gas from the Monterey Production Separators, Sandstone Flash Separator (Heritage and Heather), and the STV Compressor, as well as vapor from the Glycol Hydrocarbon Separator and the Amine Flash Tank (Harmony only), will be compressed in the Main Gas Compressors to 1115 psig in two stages using electric motor driven reciprocating compressors.

The gas will first be compressed to about 325 psig in the first stage of the Main Gas Compressors and cooled to 70° F. The condensed liquid will be separated in the First Stage Discharge Scrubber and recycled to the First Stage Suction Scrubber. The remaining gas will be filtered and dehydrated to a water dewpoint of -40° F using Triethylene Glycol (TEG).

The dehydrated gas will be cooled in the Gas/Gas Exchanger and combined with the Depropanizer overhead vapor prior to further cooling in the Depropanizer Condenser. The Depropanizer will operate as a conventional reboiled fractionator with a refrigerated partial condenser. Depending upon production rate and product market demand, the Depropanizer can be operated to give in the range of 20 to 60 percent recovery of propane from the feed gas stream. Reflux for the Depropanizer will be generated by chilling the rich gas from the Gas/Gas Exchanger and Depropanizer overhead vapor in the Depropanizer Condenser. A mechanical refrigeration system, using Freon 22 as the refrigerant, will be used to achieve overhead process temperatures ranging from -15° F to -30° F. Refrigerant compressors will be electric motor driven screw compressors. The refrigeration system will be designed for a minimum refrigerant evaporator temperature of -40° F. The Depropanizer bottoms product will be sub-cooled and pumped to emulsion pipeline pressure before commingling with the crude emulsion.

The conditioned gas leaving the Depropanizer Reflux Accumulator will be heat exchanged with the dehydrated rich gas in the Gas/Gas Exchanger and compressed to 1,115 psig in the second stage of the Main Gas Compressors. The compressor discharge will be cooled and routed to the Second Stage Discharge Scrubber. Any liquid condensed (normally none) will be recycled to the First Stage Discharge Cooler.

7.4.2.9 Gas Lift and Gas Injection

The gas from the Second Stage Discharge Scrubber will supply the gas lift requirements as needed with the remainder being compressed to approximately 2,945 psig and sent to the Gas Injection Wells. The gas injection system will utilize electric motor-driven reciprocating compressors with shared coolers. An optional sales gas outlet will be provided for the Harmony Platform at 1,100 psig pressure. Provisions for future gas sales from Heritage and Heather will be incorporated.

4.7.2.10 Fuel Gas Treating (Harmony Only)

During normal operation, a portion of the Depropanizer overhead gas will be routed to the fuel gas treating system to provide fuel for the platform. The fuel gas treating system will be designed to use MDEA to selectively remove H_2S. The acid gas removed will be recycled to the STV compressor system.

For start-up of the platform, either initially or following a platform shut-down, fuel gas will be taken from the sales gas pipeline and routed to the fuel gas treating system for sweetening. Prior to availability of heat from the Central Process Heater, the heat source for amine regeneration will be electrical heaters. Once the Main Gas Compressors are running, the start-up fuel gas from the sales gas pipeline may be shut off.

Fuel gas treating will not be required for Heritage and Heather since sweet gas will be available for fuel use from the non-associated gas wells and/or associated gas from the Sandstone wells. This will require drilling some of the Sandstone wells early in the field life to ensure a reliable secondary source of fuel gas.

7.4.3 Utility Systems

7.4.3.1 Instrument and Utility Air

Air compressors will provide compressed air at 125 psig. A portion of this air will be dehydrated to a water dewpoint of 30° F at 125 psig for use as instrument air. The remainder will be used as utility air for pneumatic tools, air diaphragm pumps, and other utility air requirements.

7.4.3.2 Potable and Utility Water

Seawater will be converted to freshwater in the Freshwater Maker. The freshwater will flow to the utility water storage tank in one of the crane pedestal columns. The Utility Water Pumps maintain a constant pressure on the utility water system. An Ultraviolet Sterilizer will purify a side stream of utility water to provide potable water needs.

7.4.3.3 Diesel Fuel

Diesel fuel will be stored in one of the crane pedestal columns. A pump will transfer fuel as needed to the deck crane, fire water pump, standby generator, and other diesel users. Coalescers will be included to remove water prior to distribution to users. Any water separated will be routed to the Closed Drain Sump.

7.4.3.4 Flare

The platforms will be equipped with a relief header that gathers all gas pressure safety valve discharges, emergency backpressure control valve discharges, and manual blowdowns. The discharges flow through a Flare Scrubber out to a flare burner tip mounted at the end of a cantilevered boom. In order to promote efficient burning and reduce smoke, the burner will be supplied with forced draft air from two 50 percent blowers. Flare design will be such that no greater than than 1500 $BTU/hr/ft^2$ radiation will be experienced at the deck edge during maximum short term relief events, or 500 $BTU/hr/ft^2$ during long term smokeless flaring. The design gas flare rate for smokeless operation will be equal to or greater than the capacity of one Main Gas Compressor Unit. The maximum flare rate for design (short term non-smokeless) will consider a total Main Gas Compressor shutdown.

7.4.3.5 Drains

There will be three main drain systems: Closed Drain, Open Drain, and Wellbay Drain. The Closed Drain Sump will collect hydrocarbons from process drains and pump them to the Emulsion Surge Tank. The Open Drain Sump will gather all deck drainage and non-hydrocarbons from atmospheric drains. From the Open Drain Sump, the hydrocarbon liquids will be skimmed and pumped to the Closed Drain Sump. Water will flow from the Open Drain Sump to the Skim Pile, which also will pump its skim liquids to the Closed Drain Sump. The remaining clean water will be discharged to the ocean. The drilling deck and wellbay area will have a separate Wellbay Drain Sump with a special washout system and pumps to transfer drilling fluids and mud back to the drilling rig tanks to prevent contamination of the oil production system.

In addition to the above main drain systems, local drain systems will be provided for glycol and amine (Harmony only). Liquids collected in the Amine Sump and Glycol Sump will be pumped back to the respective process system. These sumps will also provide reserve storage.

7.4.3.6 Heating Oil

A circulating heating oil system will be employed to provide heat to process heat exchangers. The system is to consist of a heating oil surge tank, circulating pumps, supply and return headers, plus a heat source. The heat source will be a direct fired Central Process Heater. The majority of the heating oil will operate at a temperature of 450° F. A small side stream of hot oil will be temperature controlled at 350° F for amine regeneration (Harmony only).

7.4.3.7 Cooling Medium

Process cooling will be provided by a closed water system utilizing shell and tube or double pipe exchangers and an inhibited freshwater coolant. The system will be designed to provide precooling, intercooling, and aftercooling for the platform compression train, in addition to miscellaneous cooling needs. Cooling water surge capacity will be provided by a surge tank. Makeup water will be drawn from the Utility Water System as required. Cooling water return will be cooled to about 60° F by plate-type Seawater Exchangers. Centrifugal pumps will be used for cooling water circulation.

7.4.3.8 Seawater Cooling

Heat will be removed from the platform cooling water in plate-type Seawater Exchangers. Seawater will be lifted approximately 100 feet by submersible pumps. The seawater will be chlorinated to kill marine growth and strained to remove solid contaminants before entering the plate exchangers. The Seawater Exchangers will be designed to cool the cooling medium from an inlet temperature of approximately 80° F down to an exit temperature of 60° F.

The seawater supply design inlet temperature is 50° F which will be achieved through the use of deep suction caissons. Warm outlet seawater at 70° F will be returned directly to the sea via a disposal caisson. A sidestream of the cool seawater will supply the feed to the Freshwater Maker.

7.4.3.9 Sewage Treatment

Raw sewage from the quarters will flow to a marine sewage treatment unit wherein it will be electrocatalytically treated and chlorinated. The effluent from this unit will comply with USCG and NPDES general permit requirements and will be discharged to the ocean via a separate outfall line.

7.4.3.10 Chemical Injection

Small storage tanks and metering pumps will be provided for injection of corrosion inhibitors, antifoam agents, and methanol into the appropriate process streams. Chemicals will be supplied and stored offshore in "TOTE" tanks which are transported by boat.

7.4.3.11 Cranes

The platforms will be equipped with two pedestal mounted cranes. Each crane will be API certified. Pedestal heights shall be sufficient for all rotating parts of cranes to clear drilling piperacks, piping, and equipment located above the drilling deck. The smaller crane will be powered by a diesel engine and the other will be electric.

7.4.3.12 Solid Waste Disposal

Solid waste from drilling activities, general refuse, and construction activities will be collected in large enclosed metal containers (dumpsters) and hauled to shore for disposal at an approved onshore dump site.

7.4.3.13 Fuel Gas

Sweet fuel gas for the Harmony Platform will be produced from sour, conditioned gas drawn off at the suction to the second stage of the Main Gas Compressor. The gas will be sweetened in an Amine Contactor using MDEA to selectively remove H_2S. The sweetened gas will be scrubbed and heated to 100° F for use as heater fuel, blanket gas, and flare purge and pilot.

Fuel gas for Heritage and Heather will be provided from the sweet gas produced in the Sandstone and non-associated gas production system. The primary source of fuel gas will be the non-associated gas well. Back-up fuel gas supply will be provided by associated gas from the Sandstone oil wells. The fuel gas will be dewpoint controlled to 70° F in the Fuel Gas Cooler. The liquids generated will be separated in the Fuel Gas Scrubber. The remaining fuel gas will then be heated to 100° F in the Fuel Gas Heater prior to distribution.

7.4.3.14 Glycol Dehydration System

A standard TEG Contactor will be used to dehydrate gas from the First Stage Discharge Scrubber down to a water dewpoint of -40° F. A filter upstream of the Contactor will help control carryover of heavy hydrocarbons and particulates into the Contactor. Rich TEG from the Contactor will be regenerated in the Glycol Still by heating the glycol solution to about 400° F with hot oil and stripping with a small amount of stripping gas. Lean TEG from the reboiler will be cooled and pumped to Contactor pressure. A sidestream of lean glycol to the Contactor will be continuously recycled through a charcoal filter.

7.4.3.15 Corrosion Control and Monitoring

Corrosion control is required to ensure the facilities are safe and will meet the design life. Corrosion allowance will be provided. General corrosion, pitting, and stress cracking will be prevented in aggressive systems, such as the sour gas handling systems, by the use of inhibitors, internal coatings, or metallurgy, as appropriate.

After production has begun, a corrosion monitoring program, including the use of coupons, probes, ultrasonics, and radiography, will be implemented to detect corrosion before it has an impact on the facilities.

7.4.3.16 Produced Water Disposal (Harmony Only)

All produced water from the Harmony, Heritage, and Heather Platforms will be transported to onshore facilities in an oil/water emulsion state for separation and treating. The total effluent from onshore water treating facilities will be routed via pipeline to the Harmony Platform for disposal. The disposal facilities at Harmony will consist of three vertical diffusers which discharge between subsea elevations -630 feet to -1100 feet. Water metering and staging valves will ensure adequate discharge velocity for at least a 300:1 worst case dilution ratio. Further details on the produced water ocean outfall are included in Section 7.7.10.

7.4.3.17 Oil and Gas Metering

All oil and gas measurements required to properly ascertain produced volumes and to allocate production to the proper reservoirs will be in accordance with the standard practices, procedures, and specifications generally used by the industry.

Oil volumes measured at the Oil Treating Plant Automatic Custody Transfer (ACT) Meters will be considered absolute and will be the basis for royalty payment and sales.

This volume will then be allocated to the platforms based on net oil measurements and samples taken at each platform's oil and water emulsion metering station. Platform volumes will then be allocated back to each well based on actual well test data multiplied by hours of production. See Figure 7.30 and 7.31

The platform emulsion shipping and metering system, as shown in Figure 7.32, will consist of a surge tank, shipping pumps, positive displacement meters, a meter prover, a net oil computer (NOC) with a BS&W probe, and a rate paced sampler. The water cut signal and the volume pulses from the pipeline meters will be combined in the NOC to produce net oil and water volume accumulations in the emulsion stream. After a set number of barrels of flow passes, the mechanical sampler will take an emulsion sample which will be periodically analyzed to verify NOC operation for allocation purposes and to determine crude characteristics.

Each test separator will have meters for gas, free water, and emulsion. Each separator will have a net oil computer which accepts input from the emulsion and water meters and the BS&W probe to provide total water and net oil volume accumulations and rate data.

All gas measurements will utilize orifice-type meters as shown in Figure 7.33. Each meter will have static, differential, and temperature transmitters tied into a local metering unit. A local mechanical static and differential recorder will be placed on the sales gas meter as a contingency against electronic meter outage. Gas metering will be done in accordance with the specifications contained in the American Gas Association publication "Orifice Metering of Natural Gas, Gas Measurement Report Number 3."

7.5 · 't

7.5.1 Quarters

The permanent Quarters Building will contain sleeping accommodations, offices, a galley, and other support facilities. Temporary quarters will be provided for short-term drilling service personnel during the time that both rigs are operating.

7.5.2 Communications

There will be two intra-platform voice communication systems: a hard-wired page-party system for general use and hand-held FM portable radios for Operations personnel. For external communications with crew boats, supply boats, shore bases, etc., there is a wide area 450 MHz radio system. Telephones will operate on an Exxon-owned microwave system.

7.5.3 Lighting

General platform lighting levels will meet or exceed standards set forth by the Illuminating Engineering Society (IES) for safety and efficiency of visual operations. Outdoor lighting will be high intensity discharge lights and indoor lighting will be fluorescent fixtures.

7.5.4 Heating, Ventilation, and Air Conditioning

Building heating, ventilation, and air conditioning (HVAC) will be accomplished by three types of systems. A central chilled water system will provide cooling to all buildings requiring air conditioning. A central purge/pressurizing air system will supply air makeup to all buildings requiring pressurization or purging. Local air circulation units containing fans, filters, heaters, and cooling coils will be placed in all buildings that contain electric or electronic equipment.

Pressurized Heating, Ventilation, and Air Conditioning:	Electronic/Communication Room
	Control Building
	Mechanical Shop
	Instru./Electrical Shop
	Battery Room
	Laboratory Room
	Quarters Building
Pressurized Ventilation and Air Conditioning:	Switchgear and MCC Buildings
Pressurized Ventilation:	Weld Room

7.6 Safety

Each platform will incorporate safety features and equipment as required by the appropriate authorities and as described in the following subsections.

7.6.1 Hazard Detection

Continuous monitoring fire sensors will be located in all high-hazard areas. The sensors will be ultraviolet, ionization, or thermal types depending on the application. Any fire detection will result in audible and visual alarms in the central control room and audible alarms within the facilities.

Combustible gas and H_2S detectors will be strategically located throughout the platform in areas which are potentially hazardous or have limited natural ventilation. Detection of a low level gas concentration will trigger audible and visual alarms in the control room. Detection of high gas concentration will result in alarm actuation on the control panel, a platform-wide audible alarm, and automatic shutdown and isolation of incoming sources to the affected area.

7.6.2 Fire Protection

The platforms will be equipped with several fire suppression/protection systems as described below:

- A pressurized fire water header will distribute fire water to hose reels, fixed monitors, and deluge systems located throughout the platform. Two fire pumps, one electric motor-driven submersible and one diesel hydraulic-driven, can deliver 2,000 gpm each to the system. System pressure will be maintained by a small continuously operating pressurizing pump which is fed from the seawater cooling system.

- Manually activated deluge systems will cover the wellbay and certain hydrocarbon process equipment.

- Light water stations will be located at each hose reel to provide aqueous film forming foam for fighting liquid fires.

- Numerous hand and cart-mounted dry chemical or CO_2 fire extinguishers will be placed according to 33 CFR 145.

- Manually tripped Halon 1301 extinguishing systems will protect building enclosures housing electric and electronic equipment.

- The Quarters Building will be provided with an integral firewall and with fire water and dry chemical extinguisher systems to meet Exxon's safety requirements and all applicable regulations.

- Additional firewalls will be strategically located to limit the spread of fire and to provide added protection for personnel and critical equipment.

7.6.3 Escape and Lifesaving

The platforms will be equipped with inflatable life rafts having a total capacity at least equal to the maximum number of quartered personnel (permanent plus temporary quarters). Redundant escape capability will be provided in the form of escape capsules to cover the permanent quarters capacity only. Life preservers, life floats, ring life buoys, first aid kits, and other life saving devices as required by 33 CFR 144 will be provided. All life saving devices will be USCG approved. A breathing air system consisting of a compressor, storage tanks, cascade plug-ins, and numerous self-contained work/escape units will also be provided.

7.6.4 Aids to Navigation

USCG-approved Class A obstruction lights and a fog signal designed in accordance with 33 CFR 67 will be provided. For aviation safety, the drilling rig derrick and the flare boom will have a combination of steady and flashing red lights. Each crane boom will have a steady red light at the tip. The heliport perimeter will be outlined by alternating amber and blue lights plus one flashing amber beacon. All navigation aids will be powered by the Uninterruptible Power System (UPS).

7.6.5 Control Systems

The general process and auxiliary systems will be automatically controlled and monitored for safe operation. Process variables will be controlled primarily by closed-loop analog proportional controllers. Those variables requiring continuous operator monitoring will be controlled from the central control room via a microprocessor-based distributed control system (DCS). Less critical variables will have local controllers.

7.6.6 Alarm and Shutdown Systems

Control room alarms will warn operators of abnormal conditions in the various platform systems. The alarm will activate a horn and a flashing annunciator or CRT message identifying the upset condition. Should operator action fail to correct an alarm condition before it exceeds safe limits, the systems will be protected by safety devices applied per the recommendations of API RP 14C and in accordance with MMS OCS Order 5. The safety devices trigger various combinations of equipment isolation valves (SDV's) and partial or complete platform shutdowns (ESD). The alarm and shutdown logic will be contained in a microprocessor-based DCS.

7.6.7 Emergency Power and Lighting

Emergency AC power for lighting, communications equipment, hazard detection systems, quarters, controls, and minor utility systems will be provided by a diesel engine-driven standby generator.

Self-contained, standby, battery-powered emergency lighting units will be installed in several areas of the platform to illuminate critical escape or facility black-start work areas.

Battery chargers and battery systems will be provided for aids to navigation, communications, general alarm systems, generator starting, and electrical switchgear control.

7.7 Environmental Impact Mitigation Measures

7.7.1 Gas Blanketing and Vapor Recovery

All pressure vessels, surge tanks, and other process equipment operating at or near atmospheric pressure will be connected to a gas blanketing and vapor recovery header system, which will maintain 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 will be compressed by vapor recovery compressors and flow into the sales gas system. As fluids are withdrawn from vessels or tanks, blanket gas will be made up from the platform fuel gas system. This type of gas blanketing and vapor recovery will reduce explosion hazards by eliminating oxygen, personnel exposure to H_2S, and VOC (volatile organic compounds) emissions normally associated with atmospheric tanks and vessels.

7.7.2 Spill Prevention and Containment

All platform facilities will be designed to prevent the occurrence of an oil spill during routine operations. The platform decks will be enclosed with a sealed toe plate to prevent spillage on the decks from going overboard. Deck drains will collect fluids and route them to sumps where the oil and water will be separated. The liquid hydrocarbons will be pumped to the emulsion system, and waste water will be pumped to the skim pile. All process bleed valves and drains will also be routed to a sump from which fluids will be pumped back into the emulsion system. All gas and liquid relief valves will be piped into closed systems.

A boom reel with a 1,500-foot spill containment boom and a 32-foot boom assist boat will be provided on the Heritage Platform. Storage of at least 15 bales of oil sorbent pads will be maintained at Harmony, Heritage, and Heather. Exxon's Oil Spill Contingency Plan for California Operations is overviewed in Attachment C.

7.7.3 Emergency Flare

All vapor safety relief valves and back-pressure surge control regulators will exhaust into a closed flare header system. This system will gather the emergency releases and route them through a scrubber to a flare burner. The burner will be designed for smokeless operation up to about 25 percent of the maximum design rate. The design utilizes electric motor-driven air blowers to provide adequate air for complete combustion. This measure will reduce VOC, H_2S, particulate emissions, and smoke.

7.7.4 Fugitive Emissions Program

Fugitive emissions are emissions which result from leaks around pump seals, valve stems, hatches, or connections. Exxon will minimize hydrocarbon pump seal leakage through the use of tandem mechanical seals which include an alarm pressure switch between the inner and outer seals. For pumps handling fluids below the flash point, the pressure switch will trigger an alarm only. If fluids are above the flash point, the switch will shut down the pump and also cause an alarm in the control room. Leaks from valve stems, connections, and hatches will be controlled by a rigorous preventative maintenance plan and operator attention.

7.7.5 Electrical Power

Electrical power for all of the offshore platforms will be generated onshore and fed to the offshore facilities via a submarine cable system. No power generation, other than for emergency use, will be installed on any of the new platforms.

Power from SCE or from the SYU Cogeneration Power Plant will be converted from 66 KV to 34.5 KV in the Offshore Substation located in Las Flores Canyon for distribution offshore. The secondaries of two parallel transformers will feed a ring-bus which, in turn, will feed three submarine cables; two to Harmony and one to Heritage. By the use of a submarine cable between Harmony and Heritage, the second cable between shore and Harmony can be used to supply back-up power to Heritage. Power to Hondo will be supplied through a single submarine cable from Harmony; power to Heather will likewise be supplied through a single submarine cable from Heritage.

For each platform, parallel high voltage transformers will convert the 34.5 KV to 4160 V to power the large horsepower electric motor drivers and the drilling rig(s). Two additional pairs of transformers (four total) will convert 4160 V to 480 V to supply power to the remaining platform loads.

In the event of total loss of power, a diesel engine-driven standby generator will provide sufficient 480 V power to run the quarters, essential utilities, and safety systems. The drilling rig(s) will have their own diesel-powered auxiliary generators to supply subsistence level power during outages. Batteries and UPS systems will provide emergency power for diesel engine starting, alarm systems, switchgear control, communications, emergency lighting, and navigational aids.

7.7.6 Harmony Platform Gas Sweetening

The Harmony Platform will be equipped with a solvent-type gas sweetening facility sized to handle the necessary fuel gas volumes due to the absence of sweet gas production. Acid gas produced from solvent regeneration will be commingled with the vapor recovery gas and compressed into the sales or injection gas. This measure will greatly reduce sulfur dioxide emissions from all fuel burning equipment on this platform.

7.7.7 Pipeline Leak Detection

For pipeline leak detection monitoring purposes, the platform emulsion metering systems will transmit a totalized volume signal to the receiving oil treating facilities. There, a leak detector will provide a continuous volumetric comparison of inputs to the line with deliveries at the treating facilities. The system will include an alarm trigger of adequate sensitivity to detect significant variations between input and output volume. Each end of the line will also have a check valve and an automatic shut-in valve activated by high and low pressure sensors. The line will be shut in if safe operating limits are exceeded.

7.7.8 NOx Control

The central process heater will be equipped with staged low NOx burners. The low NOx burners are proven technology and will give approximately a 50 percent reduction in emissions when compared to standard burners.

7.7.9 Noise Control

The objective in controlling noise is to provide an operating environment such that the sound generated will not interfere with efficient operations or exceed the set guidelines. A preliminary estimate of noise values has been made for different items of equipment. From the equipment estimates, reasonable design sound pressure levels will be established for various platform areas. This will enable problem areas to be identified at an early stage such that practical noise abatement or personnel protection measures can be evaluated and implemented.

7.7.10 Produced Water Ocean Outfall

The onshore produced water treating facilities will continuously treat the water removed from the incoming emulsion in the Oil Treating Plant and waste water streams from the Stripping Gas Treating Plant, Cogeneration Power Plant, and Transportation Terminal. The treated water will be pumped back to Platform Harmony through a 12-inch pipeline for ocean disposal via diffusers (Figure 7.34). See Figure 10.2 for pipeline routing. The platform water disposal facilities will include a pipeline pig receiver and meter and three separate diffusers (Figure 7.35). The pre-discharge treatment procedures (Section 9.6.5 and Figure 9.5) and predicted disposal rates for Hondo, Harmony, and Heritage over the life of the project (Figure 7.36) are considered EXXON PROPRIETARY and are located in Appendix A. Peak disposal rates for Platform Heather will be in the range of 10 to 15 kBD.

A downsized (wall thickness only) conductor will be utilized as a diffuser and lowered through the conductor guides. This would be allowed to run into the soil under its own weight. A plug will be installed to prevent communication between the produced water and the mud. At this point, the diffuser would be free-standing (supported only at the mudline and guided at the various conductor guide levels) with nozzles approximately 100 feet above the mudline. These diffusers would likely be installed at the same time as the conductors.

The ocean outfall diffuser was relocated from the nearshore site to the Harmony Platform to increase initial dilution and to decrease potential impacts to the environment. The outfall diffusers take advantage of the difference in density between produced water being discharged and receiving ambient water. Additionally, the combination of onshore pumping facilities and multiple offshore diffusers allows flexibility to optimize the momentum of the discharged plumes. Based on preliminary computer modeling at the peak produced water rate, a minimum initial dilution ratio of 300:1 is achieved during the worst seasonal conditions (winter) and without an ambient ocean current. Under conditions evaluated in the 1986 SEIR (i.e. with 0.1 knot ambient current), much higher dilutions in the range of 900+:1 are expected.

Exxon's current best assessment of the pre-treatment, post-treatment, pre-dilution concentrations of the major chemical constituents and trace elements of the waste waters expected to be discharged in the ocean are given in Table 7.1. The ambient chemical concentrations of the receiving waters are also indicated. The pre-treatment concentrations and, to a lesser extent the post-treatment concentrations could be somewhat different than those shown due to unforeseen variations in the quality of formation fluids. The numbers indicated represent a reasonable estimate of future operations. Post-treated concentrations will be maintained so as to meet all applicable NPDES limits.

TABLE 7.1

EXXON SANTA YNEZ UNIT PROJECT
ANTICIPATED WASTE WATER CHARACTERISTICS
(ALL VALUES IN µg/l)

Component	Pre-Treatment Concentration		Post-Treatment Concentration		Concentration After Dilution [1]				Ocean Background Concentration[2]
					No Current		0.1 Knot Current		
	Average	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	
Oil & Grease	422,000	985,000	<48,000	<72,000	<160	<240	<50	<75	-
Arsenic	<100	400	<100	400	<3.33	4.33	<3.10	3.41	3
Cadmium	<100	160	<100	160	<0.33	0.53	<0.10	0.17	0
Chromium^{+6}	<100	<400	<100	<400	<0.33	<1.33	<0.10	<0.41	0
Copper	<100	410	<100	410	<2.33	3.37	<2.10	2.42	2
Lead	<400	1,140	<400	1,140	<1.33	3.80	<0.41	1.18	0
Mercury	<10	160	<10	160	<0.09	<0.59	<0.07	<0.23	0.06
Nickel	<200	500	<200	500	<0.67	1.67	<0.21	0.52	0
Silver	<10	<100	<10	<100	<0.19	<0.49	<0.17	<0.26	0.16
Zinc	300	3,260	300	3,260	9.00	10.87	8.31	11.38	8
Cyanides	80	387	80	387	0.27	1.29	0.08	0.40	0
Ammonia	150,000	325,000	70,000	325,000	233	1,083	73	337	0
Phenols	2,930	7,120	<100	<500	<0.33	<1.67	<0.10	<0.52	0
Sulfides	117,000	465,000	<1,000	<1,000	<3.33	<3.33	<1.04	<1.04	-
Suspended Solids	152,000	315,000	<15,000	<50,000	<50	<167	<17	<52	-

[1] Concentrations after dilution are calculated by adding the ocean background concentration to the concentration after initial dilution as predicted by the EPA-approved computer model UDKHDEN.

[2] Ocean Background Concentrations are taken from the 1983 Water Quality Control Plan, Ocean Waters of California, issued by the State of California Water Resource Control Board.

VALVE SYMBOLS

	BLOCK VALVE
	CHECK VALVE
	CHOKE
	3-WAY DIVERTER VALVE
	4-WAY DIVERTER VALVE
 LCV	LEVEL CONTROL VALVE
	PRESSURE CONTROL VALVE (BACKPRESSURE)
	PRESSURE CONTROL VALVE (DOWNSTREAM)
	PISTON OPERATED VALVE
	3-WAY PISTON OPERATED VALVE

MISCELLANEOUS

A.C.T.	AUTOMATIC CUSTODY TRANSFER METER
FR	FLOW RECORDER

MISCELLANEOUS

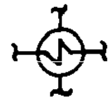
	HEAT EXCHANGER
M	METER
	FILTER
	CENTRIFUGAL PUMP
	POSITIVE DISPLACEMENT PUMP
	ROTARY PUMP
N.O.	NORMALLY OPEN
N.C.	NORMALLY CLOSED
H.O.	HEATING OIL
G	GAS
O	OIL
W	WATER
C	CONDENSATE
------	FACILITIES DRAWN WITH DASH LINES INDICATE POSSIBLE FUTURE ADDITIONS

Figure 7.1

PLATFORM PROCESS FLOW DIAGRAMS LEGEND

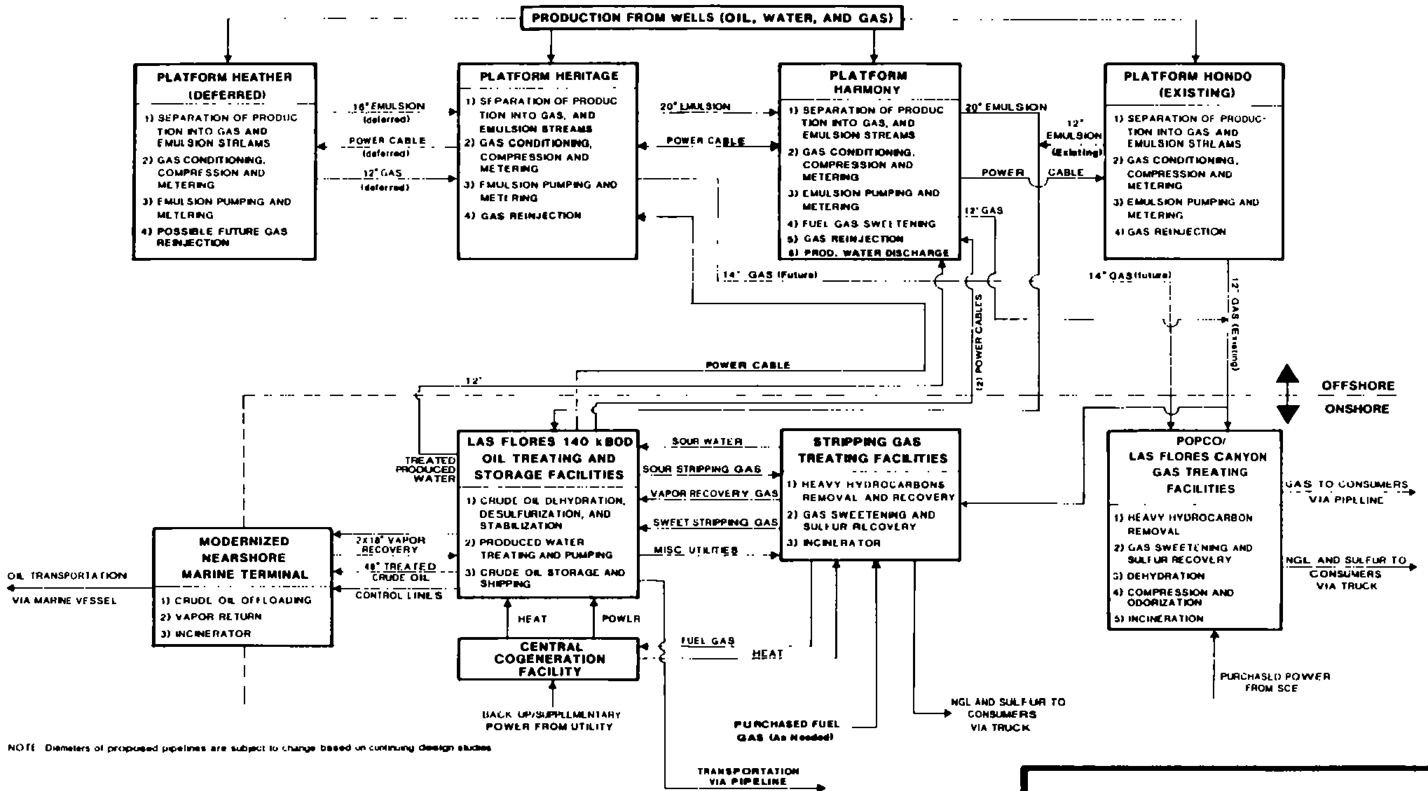


Figure 7.2

FUNCTIONAL BLOCK DIAGRAM

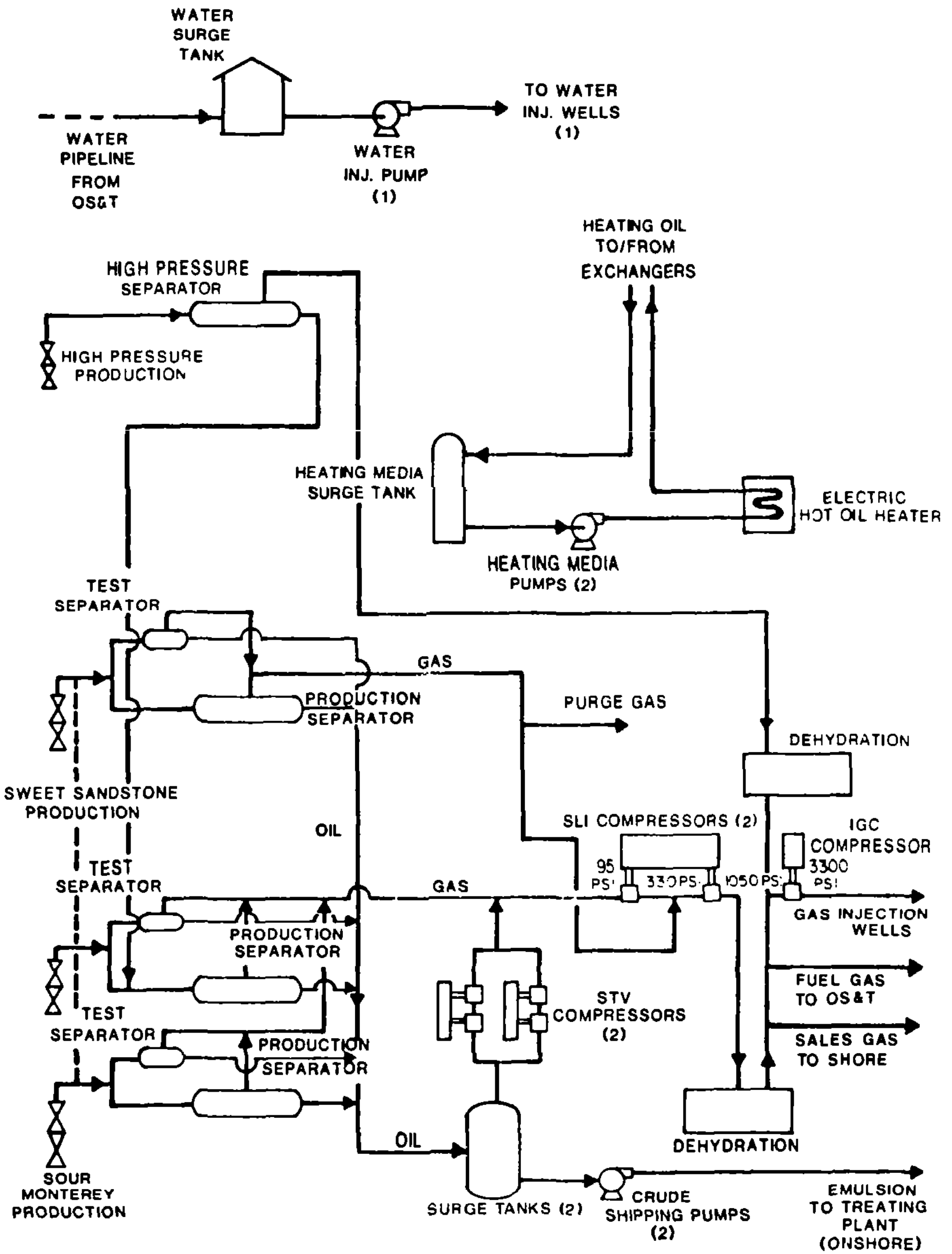


Figure 7.3

HONDO PLATFORM

PROCESS SCHEMATIC

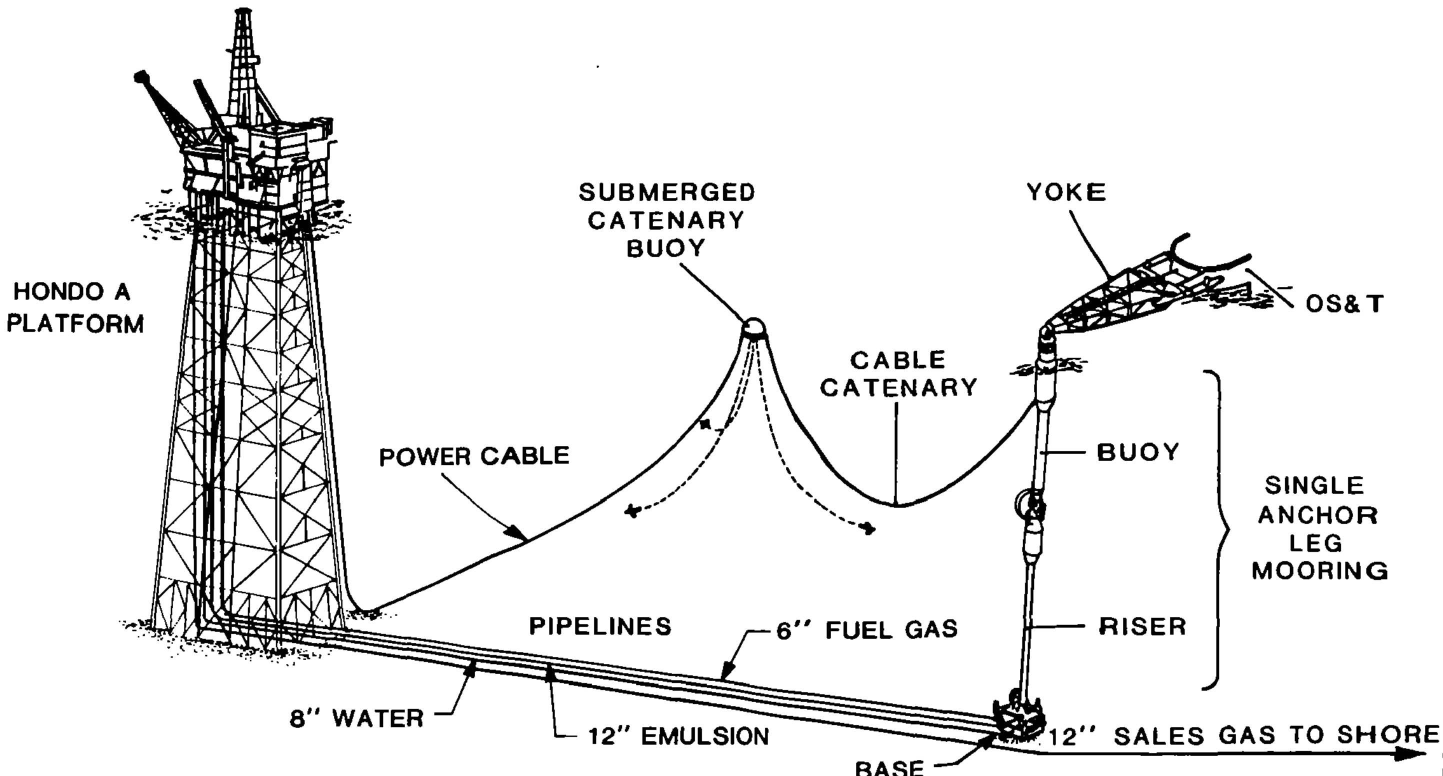


Figure 7.4

INITIAL HONDO DEVELOPMENT

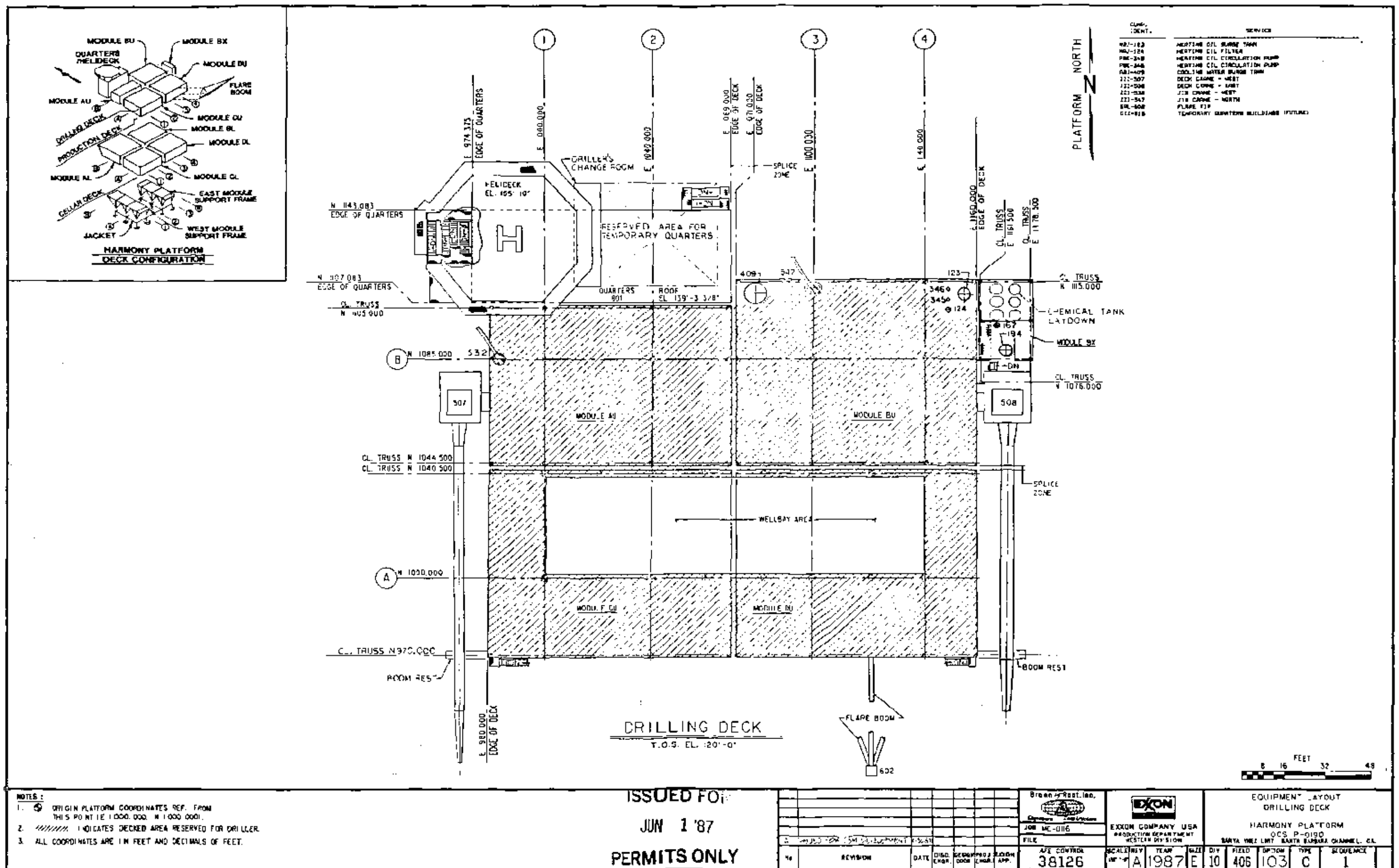

HARMONY PLATFORM DECK CONFIGURATION
MODULE BU
MODULE BX
QUARTERS /HELIDECK
MODULE DU
FLARE BOOM
MODULE AU
DRILLING DECK
MODULE CU
MODULE BL
PRODUCTION DECK
MODULE DL
MODULE AL
MODULE CL
CELLAR DECK
EAST MODULE SUPPORT FRAME
WEST MODULE SUPPORT FRAME
JACKET
PLATFORM NORTH
HELIDECK EL. 155'-10"
DRILLER'S CHANGE ROOM
RESERVED AREA FOR TEMPORARY QUARTERS
SPLICE ZONE
EDGE OF QUARTERS
EDGE OF DECK
QUARTERS 801
ROOF EL. 139'-3 3/8"
CHEMICAL TANK LAYDOWN
MODULE BX
MODULE AU
MODULE BU
WELLBAY AREA
MODULE CU
MODULE DU
BOOM REST
FLARE BOOM
DRILLING DECK
T.O.S. EL. 120'-0"
NOTES :
1. ORIGIN PLATFORM COORDINATES REF. FROM THIS POINT (E 1000.000, N 1000.000).
2. INDICATES DECKED AREA RESERVED FOR DRILLER.
3. ALL COORDINATES ARE IN FEET AND DECIMALS OF FEET.
ISSUED FOR
JUN 1 '87
PERMITS ONLY
EXXON COMPANY USA
EQUIPMENT LAYOUT DRILLING DECK
HARMONY PLATFORM OCS P-0190
38126
1987

Figure 7.5

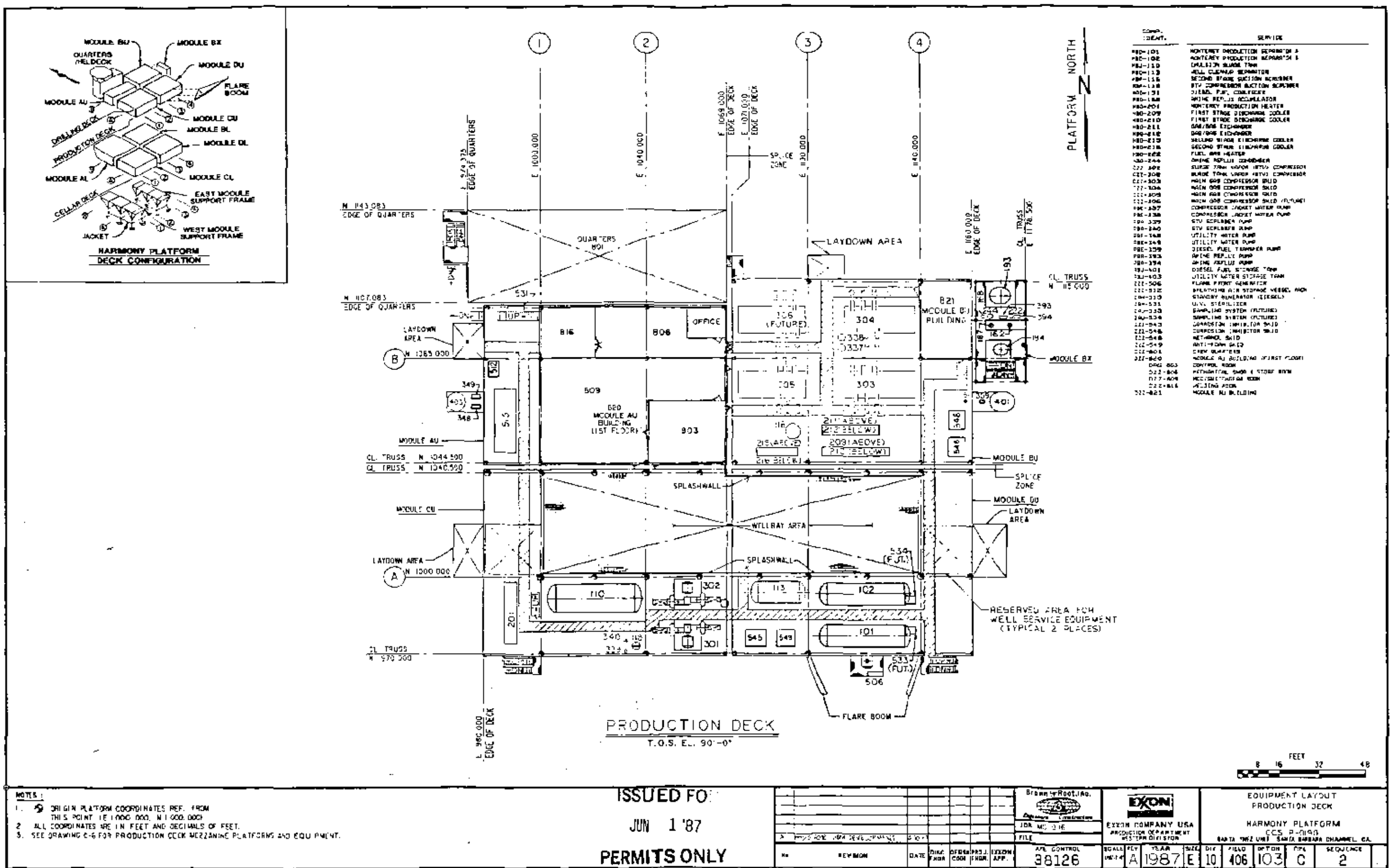
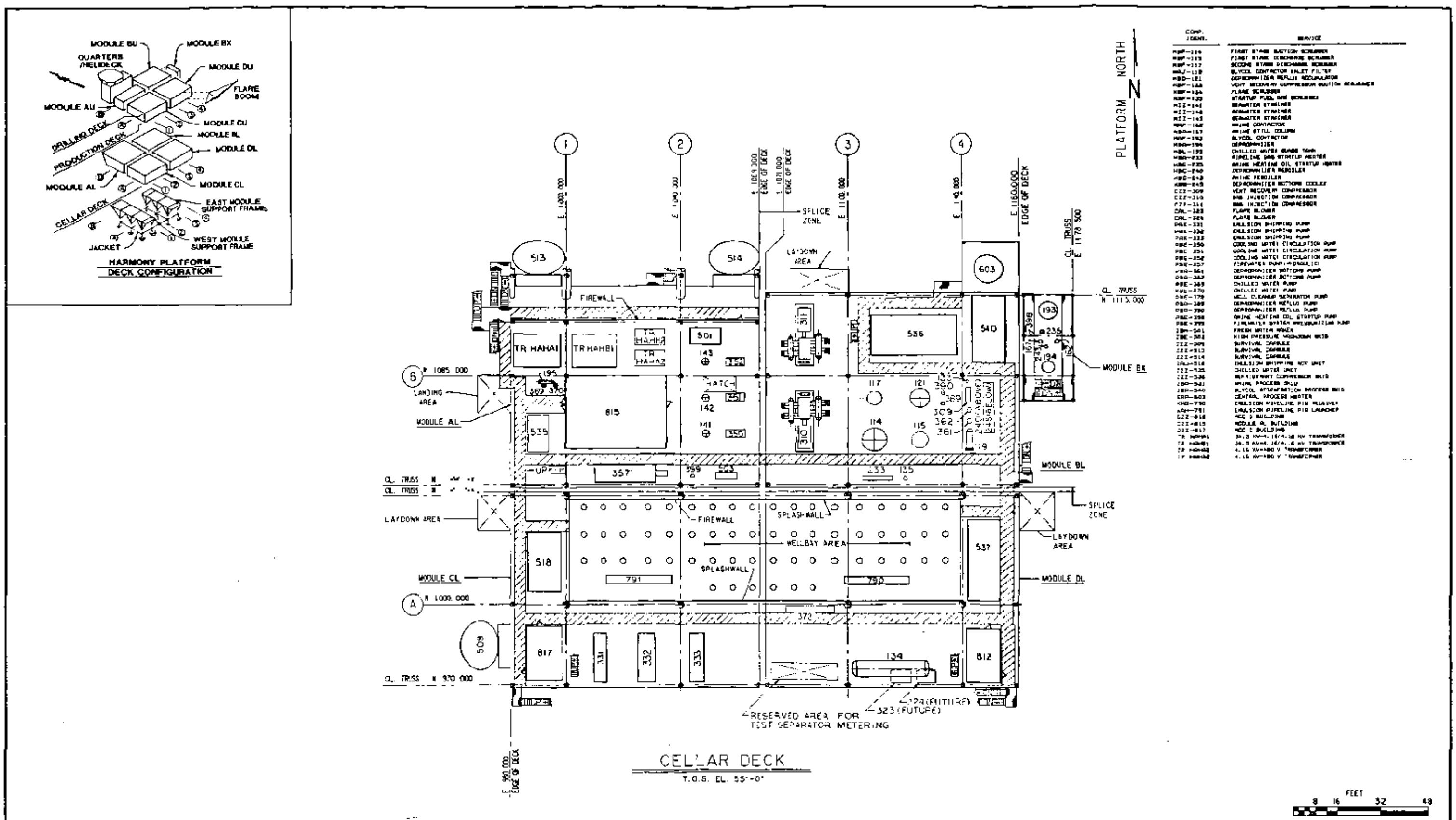

HARMONY PLATFORM
DECK CONFIGURATION
PRODUCTION DECK
T.O.S. EL. 90'-0"
PLATFORM NORTH
LAYDOWN AREA
WELL BAY AREA
SPLASHWALL
FLARE BOOM
RESERVED AREA FOR
WELL SERVICE EQUIPMENT
(TYPICAL 2 PLACES)
NOTES:
ISSUED FOR
JUN 1 '87
PERMITS ONLY
EQUIPMENT LAYOUT
PRODUCTION DECK
HARMONY PLATFORM
EXXON COMPANY USA
38126
1987

Figure 7.6



NOTES:
1. ⊕ ORIGIN PLATFORM COORDINATES REF. FROM THIS POINT: N 1000.000, E 1000.000.
2. ALL COORDINATES ARE IN FEET AND DECIMALS OF FEET.
3. SEE DRAWING C-8 FOR CELLAR DECK MEZZANINE PLATFORMS AND EQUIPMENT.

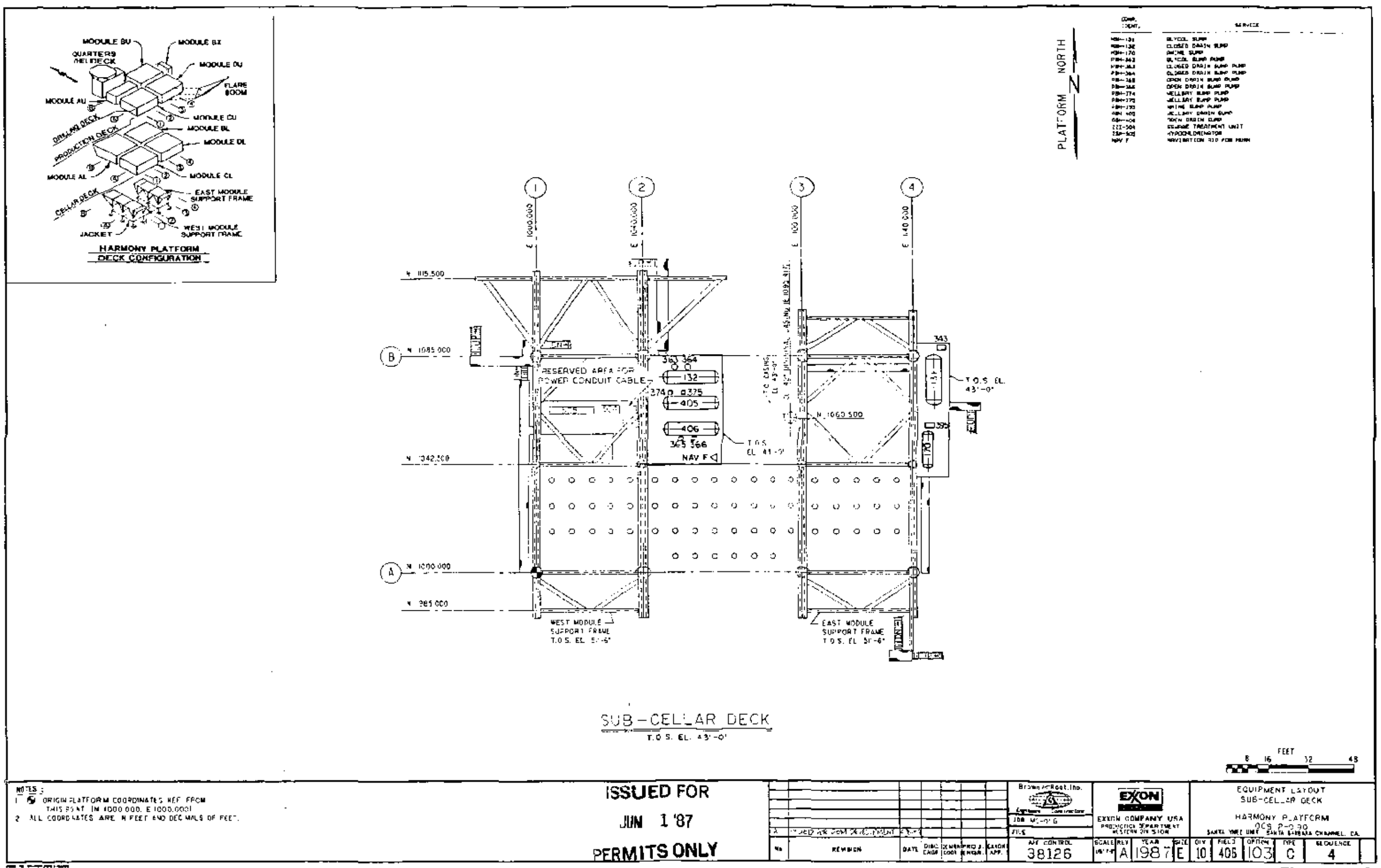
ISSUED FOR
JUN 1 '87
PERMITS ONLY

Brown & Root, Inc.
EXXON COMPANY USA
PRODUCTION DEPARTMENT
WESTERN DIVISION

EQUIPMENT LAYOUT
CELLAR DECK
HARMONY PLATFORM
OCS P-0190
SANTA YNEZ UNIT SANTA BARBARA CHANNEL, CA.

AFE CONTROL	REV	YEAR	SIZE	DIV	FIELD	OPTION	TYPE	SEQUENCE
38126	A	1985	E	10	406	103	C	3

Figure 7.7



HARMONY PLATFORM
DECK CONFIGURATION
MODULE BU
MODULE BX
QUARTERS HELIDECK
MODULE DU
FLARE BOOM
MODULE AU
DRILLING DECK
MODULE CU
PRODUCTION DECK
MODULE BL
MODULE DL
MODULE AL
MODULE CL
CELLAR DECK
EAST MODULE SUPPORT FRAME
WEST MODULE SUPPORT FRAME
JACKET
PLATFORM NORTH
COMP. IDENT.
SERVICE
GLYCOL SUMP
CLOSED DRAIN SUMP
OPEN DRAIN SUMP PUMP
WELLBAY SUMP PUMP
SEWAGE TREATMENT UNIT
HYPOCHLORINATOR
NAV F
RESERVED AREA FOR POWER CONDUIT CABLE
132
405
406
T.O.S. EL. 41'-0"
T.O.S. EL. 43'-0"
N. 1115.500
N. 1085.000
N. 1060.500
N. 1042.000
N. 1000.000
N. 985.000
WEST MODULE SUPPORT FRAME T.O.S. EL. 51'-6"
EAST MODULE SUPPORT FRAME T.O.S. EL. 51'-6"
SUB-CELLAR DECK
T.O.S. EL. 43'-0"
FEET
8 16 32 48
NOTES:
1. ORIGIN PLATFORM COORDINATES REF. FROM THIS POINT (N 1000.000, E 1000.000)
2. ALL COORDINATES ARE IN FEET AND DECIMALS OF FEET.
ISSUED FOR
JUN 1 '87
PERMITS ONLY
REVISION
DATE
Brown & Root, Inc.
EXXON
EXXON COMPANY USA
PRODUCTION DEPARTMENT
WESTERN DIVISION
EQUIPMENT LAYOUT
SUB-CELLAR DECK
HARMONY PLATFORM
OCS P-0190
SANTA YNEZ UNIT - SANTA BARBARA CHANNEL, CA.
AFE CONTROL
38126
SCALE
REV
A
YEAR
1987
SIZE
E
DIV
10
FIELD
406
OPTION
103
TYPE
C
SEQUENCE
4

Figure 7.8

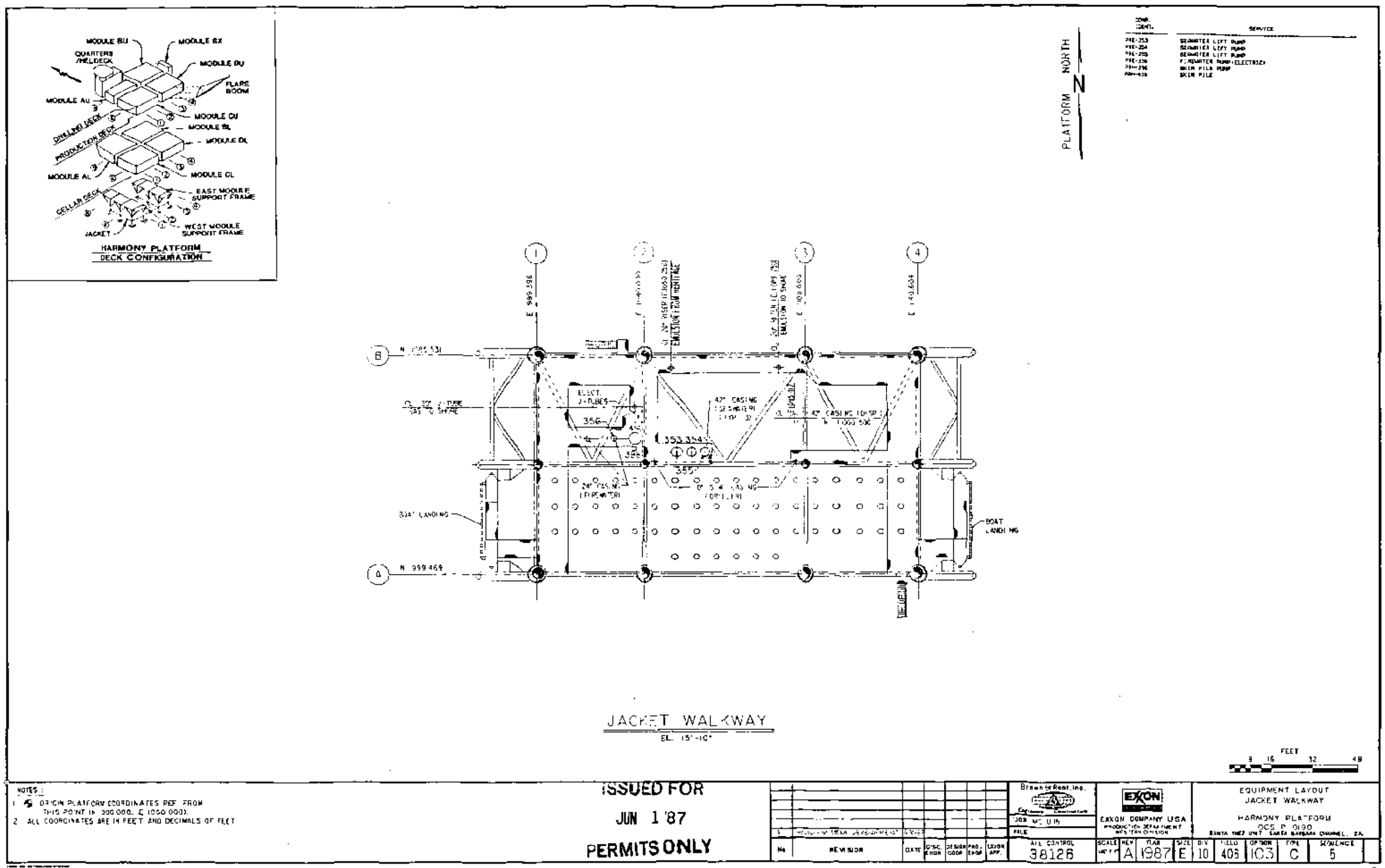

HARMONY PLATFORM
DECK CONFIGURATION
PLATFORM NORTH
N
JACKET WALKWAY
EL. 15'-10"
BOAT LANDING
NOTES:
1. ORIGIN PLATFORM COORDINATES REF. FROM THIS POINT IS 1000.000, E 1000.000.
2. ALL COORDINATES ARE IN FEET AND DECIMALS OF FEET.
ISSUED FOR
JUN 1 '87
PERMITS ONLY
EQUIPMENT LAYOUT
JACKET WALKWAY
HARMONY PLATFORM
OCS P 0190
SANTA YNEZ UNIT SANTA BARBARA CHANNEL, CA.
EXXON COMPANY U.S.A.
38126
A
1987
E
10
406
103
C
5

Figure 7.9

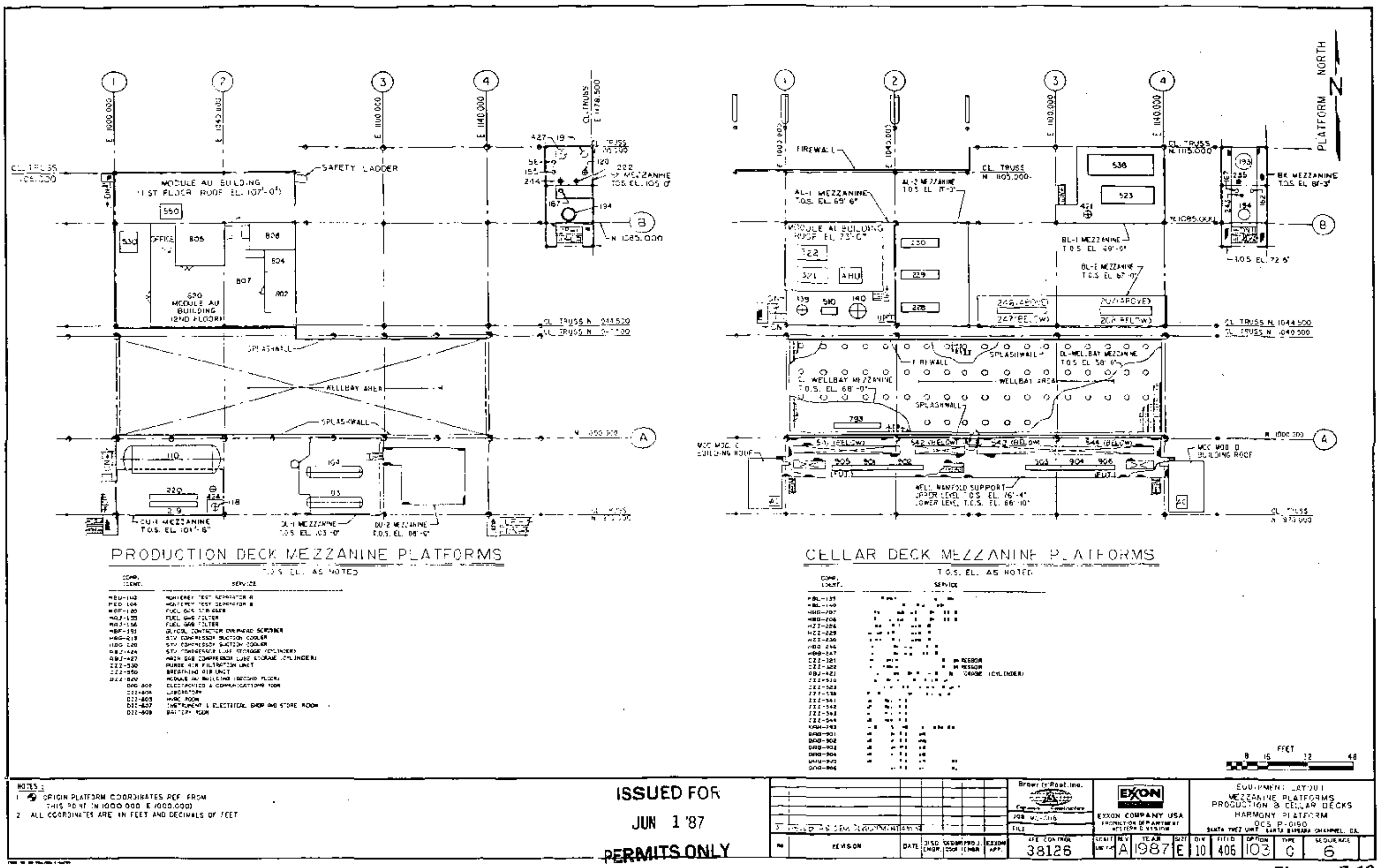

PRODUCTION DECK MEZZANINE PLATFORMS
T.O.S. EL. AS NOTED
CELLAR DECK MEZZANINE PLATFORMS
T.O.S. EL. AS NOTED
MODULE AU BUILDING
SAFETY LADDER
WELLBAY AREA
SPLASHWALL
FIREWALL
MODULE AU BUILDING (2ND FLOOR)
DU-1 MEZZANINE T.O.S. EL. 101'-6"
DU-2 MEZZANINE T.O.S. EL. 98'-0"
AL-1 MEZZANINE T.O.S. EL. 65'-6"
MODULE AL BUILDING
WELL MANIFOLD SUPPORT
PLATFORM NORTH
FEET
NOTES:
1. ORIGIN PLATFORM COORDINATES REF. FROM THIS POINT (N 1000.000 E 1000.000)
2. ALL COORDINATES ARE IN FEET AND DECIMALS OF FEET
ISSUED FOR
JUN 1 '87
PERMITS ONLY
EXXON
EXXON COMPANY USA
EQUIPMENT LAYOUT
MEZZANINE PLATFORMS
PRODUCTION & CELLAR DECKS
HARMONY PLATFORM
OCS P-0190
38126
A 1987 E 10 406 103 C 6

Figure 7.10

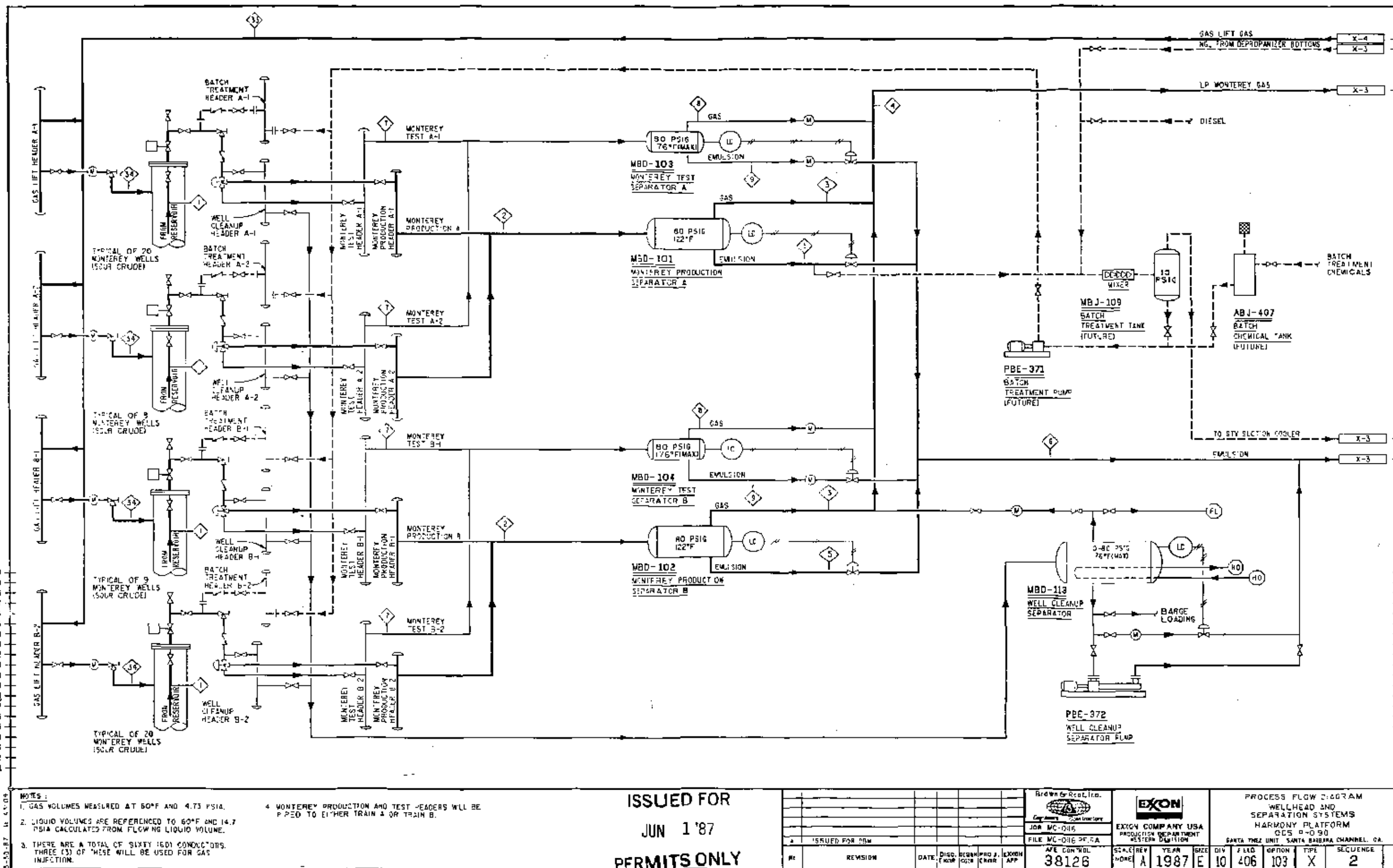

GAS LIFT GAS
NGL FROM DEPROPANIZER BOTTOMS
LP MONTEREY GAS
DIESEL
BATCH TREATMENT HEADER A-1
MONTEREY TEST A-1
MONTEREY PRODUCTION A
MBD-103
MONTEREY TEST SEPARATOR A
MBD-101
MONTEREY PRODUCTION SEPARATOR A
GAS
EMULSION
WELL CLEANUP HEADER A-1
TYPICAL OF 20 MONTEREY WELLS (SOUR CRUDE)
BATCH TREATMENT HEADER A-2
MONTEREY TEST A-2
WELL CLEANUP HEADER A-2
TYPICAL OF 8 MONTEREY WELLS (SOUR CRUDE)
BATCH TREATMENT HEADER B-1
MONTEREY TEST B-1
MBD-104
MONTEREY TEST SEPARATOR B
MONTEREY PRODUCTION B
MBD-102
MONTEREY PRODUCTION SEPARATOR B
WELL CLEANUP HEADER B-1
TYPICAL OF 9 MONTEREY WELLS (SOUR CRUDE)
BATCH TREATMENT HEADER B-2
MONTEREY TEST B-2
WELL CLEANUP HEADER B-2
TYPICAL OF 20 MONTEREY WELLS (SOUR CRUDE)
GAS LIFT HEADER A-1
GAS LIFT HEADER A-2
GAS LIFT HEADER B-1
GAS LIFT HEADER B-2
FROM RESERVOIR
MONTEREY TEST HEADER A-1
MONTEREY PRODUCTION HEADER A-1
MONTEREY TEST HEADER A-2
MONTEREY PRODUCTION HEADER A-2
MONTEREY TEST HEADER B-1
MONTEREY PRODUCTION HEADER B-1
MONTEREY TEST HEADER B-2
MONTEREY PRODUCTION HEADER B-2
MIXER
MBJ-109
BATCH TREATMENT TANK (FUTURE)
PBE-371
BATCH TREATMENT PUMP (FUTURE)
ABJ-407
BATCH CHEMICAL TANK (FUTURE)
BATCH TREATMENT CHEMICALS
TO STV SUCTION COOLER
EMULSION
MBD-113
WELL CLEANUP SEPARATOR
BARGE LOADING
PBE-372
WELL CLEANUP SEPARATOR PUMP
NOTES:
1. GAS VOLUMES MEASURED AT 60°F AND 14.73 PSIA.
2. LIQUID VOLUMES ARE REFERENCED TO 60°F AND 14.7 PSIA CALCULATED FROM FLOWING LIQUID VOLUME.
3. THERE ARE A TOTAL OF SIXTY (60) CONDUCTORS. THREE (3) OF THESE WILL BE USED FOR GAS INJECTION.
4. MONTEREY PRODUCTION AND TEST HEADERS WILL BE PIPED TO EITHER TRAIN A OR TRAIN B.
ISSUED FOR
JUN 1 '87
PERMITS ONLY
EXXON
EXXON COMPANY USA
PRODUCTION DEPARTMENT WESTERN DIVISION
PROCESS FLOW DIAGRAM
WELLHEAD AND SEPARATION SYSTEMS
HARMONY PLATFORM
OCS P-0190
SANTA YNEZ UNIT SANTA BARBARA CHANNEL, CA.
38126
A
1987
E
10
406
103
X
2

Figure 7.11

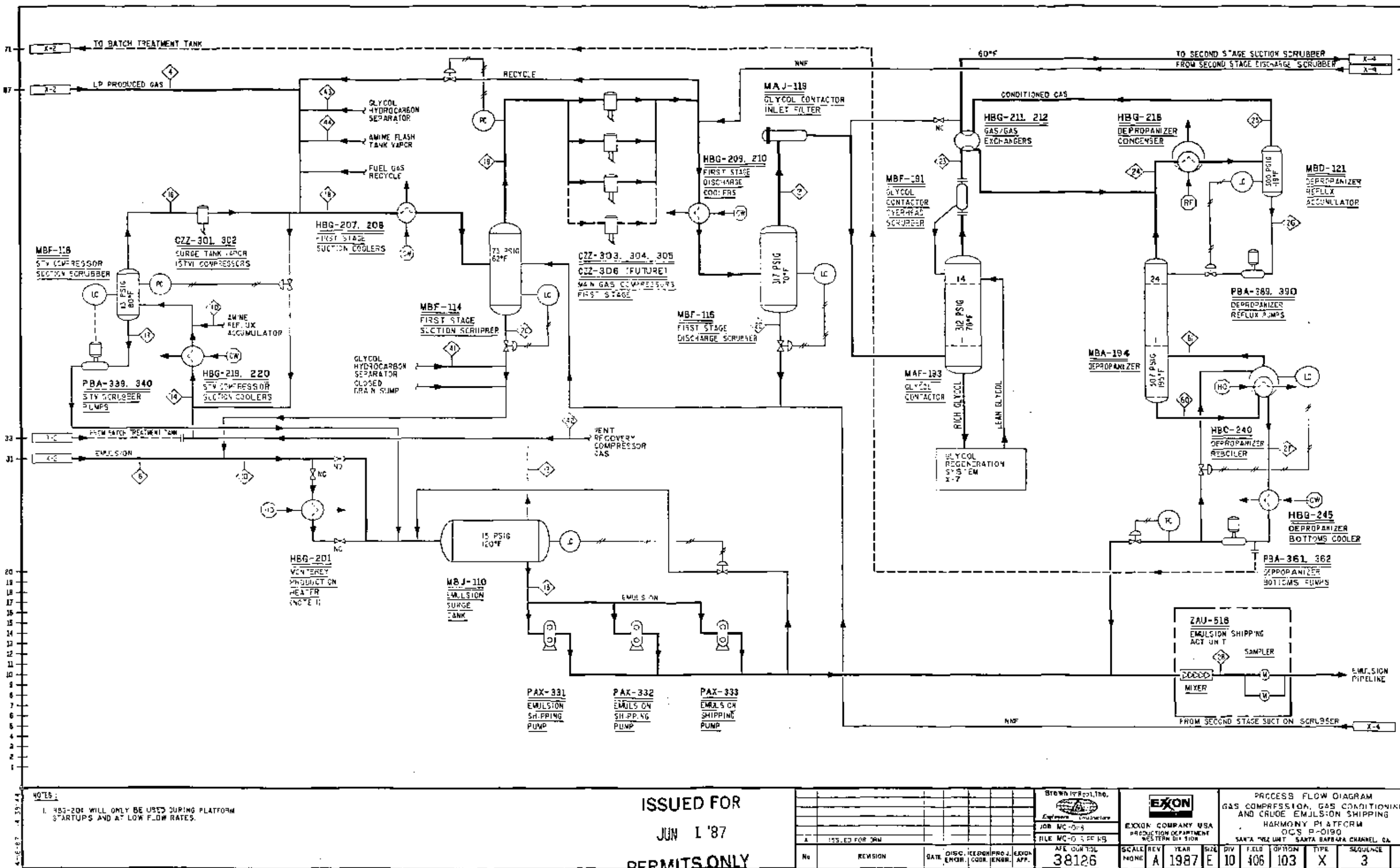

TO BATCH TREATMENT TANK
LP PRODUCED GAS
RECYCLE
GLYCOL HYDROCARBON SEPARATOR
AMINE FLASH TANK VAPOR
FUEL GAS RECYCLE
MAJ-119 GLYCOL CONTACTOR INLET FILTER
HBG-211, 212 GAS/GAS EXCHANGERS
HBG-218 DEPROPANIZER CONDENSER
MBD-121 DEPROPANIZER REFLUX ACCUMULATOR
CONDITIONED GAS
TO SECOND STAGE SUCTION SCRUBBER
FROM SECOND STAGE DISCHARGE SCRUBBER
HBG-209, 210 FIRST STAGE DISCHARGE COOLERS
MBF-191 GLYCOL CONTACTOR OVERHEAD SCRUBBER
MBF-118 STV COMPRESSOR SUCTION SCRUBBER
CZZ-301, 302 SURGE TANK VAPOR (STV) COMPRESSORS
HBG-207, 208 FIRST STAGE SUCTION COOLERS
CZZ-303, 304, 305 CZZ-306 (FUTURE) MAIN GAS COMPRESSORS FIRST STAGE
MBF-114 FIRST STAGE SUCTION SCRUBBER
MBF-116 FIRST STAGE DISCHARGE SCRUBBER
PBA-389, 390 DEPROPANIZER REFLUX PUMPS
AMINE REFLUX ACCUMULATOR
HBG-219, 220 STV COMPRESSOR SUCTION COOLERS
PBA-339, 340 STV SCRUBBER PUMPS
GLYCOL HYDROCARBON SEPARATOR
CLOSED DRAIN SUMP
MAF-193 GLYCOL CONTACTOR
MBA-194 DEPROPANIZER
RICH GLYCOL
LEAN GLYCOL
GLYCOL REGENERATION SYSTEM X-7
HBC-240 DEPROPANIZER REBOILER
VENT RECOVERY COMPRESSOR GAS
FROM BATCH TREATMENT TANK
EMULSION
HBG-245 DEPROPANIZER BOTTOMS COOLER
PBA-361, 362 DEPROPANIZER BOTTOMS PUMPS
HBG-201 MONTEREY PRODUCTION HEATER (NOTE 1)
15 PSIG 120°F
MBJ-110 EMULSION SURGE TANK
ZAU-518 EMULSION SHIPPING ACT UNIT
SAMPLER
MIXER
EMULSION PIPELINE
PAX-331 EMULSION SHIPPING PUMP
PAX-332 EMULSION SHIPPING PUMP
PAX-333 EMULSION SHIPPING PUMP
FROM SECOND STAGE SUCTION SCRUBBER
NOTES:
1. HBG-201 WILL ONLY BE USED DURING PLATFORM STARTUPS AND AT LOW FLOW RATES.
ISSUED FOR
JUN 1 '87
PERMITS ONLY
A ISSUED FOR DRW
REVISION
Brown & Root, Inc.
JOB NC-0-3
EXXON
EXXON COMPANY USA
PRODUCTION DEPARTMENT
WESTERN DIVISION
PROCESS FLOW DIAGRAM
GAS COMPRESSION, GAS CONDITIONING AND CRUDE EMULSION SHIPPING
HARMONY PLATFORM
OCS P-0190
SANTA BARBARA CHANNEL, CA
AFE CONTROL 38126
SCALE NONE
REV A
YEAR 1987
SIZE E
DIV 10
FIELD 406
OPTION 103
TYPE X
SEQUENCE 3

Figure 7.12

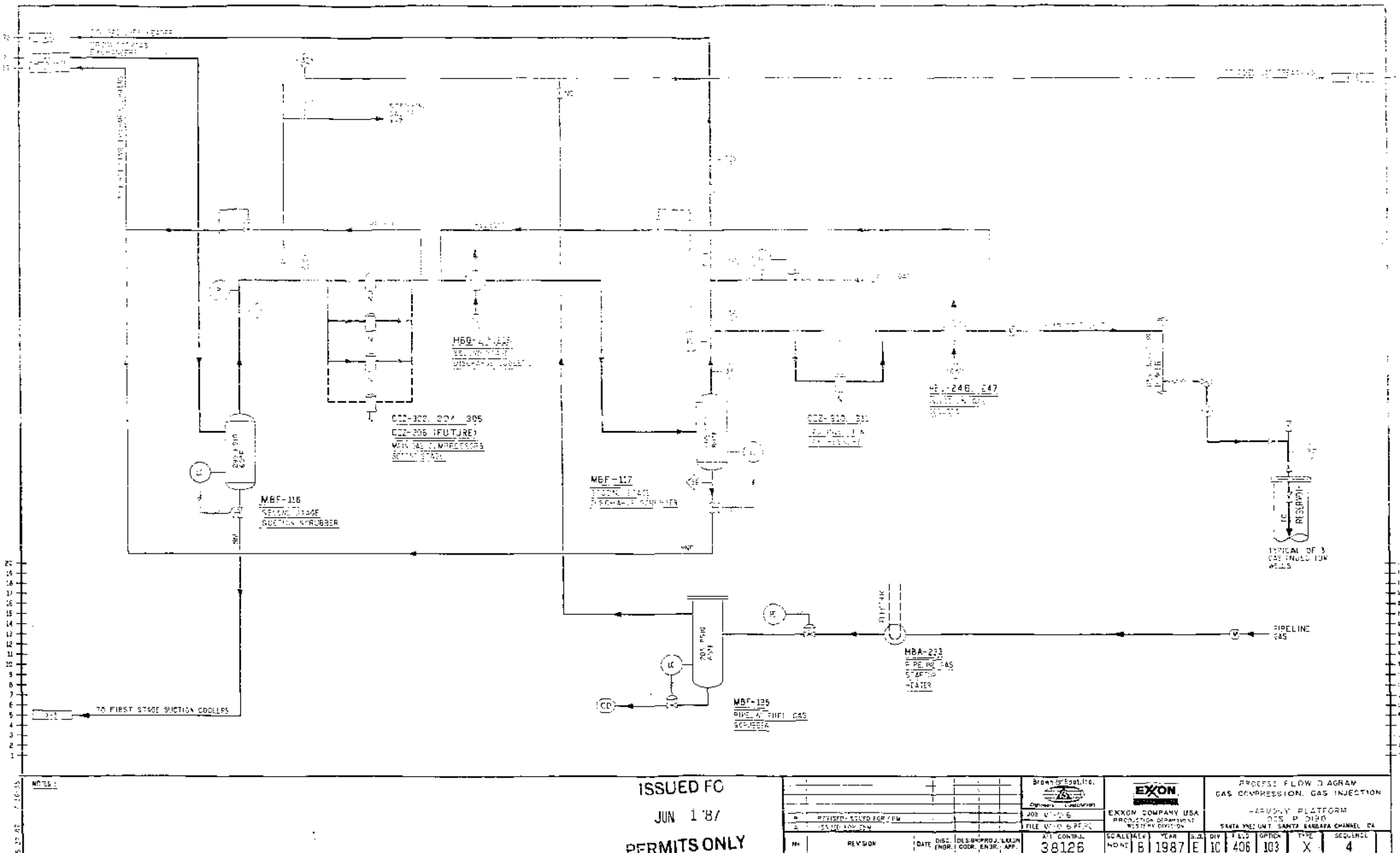
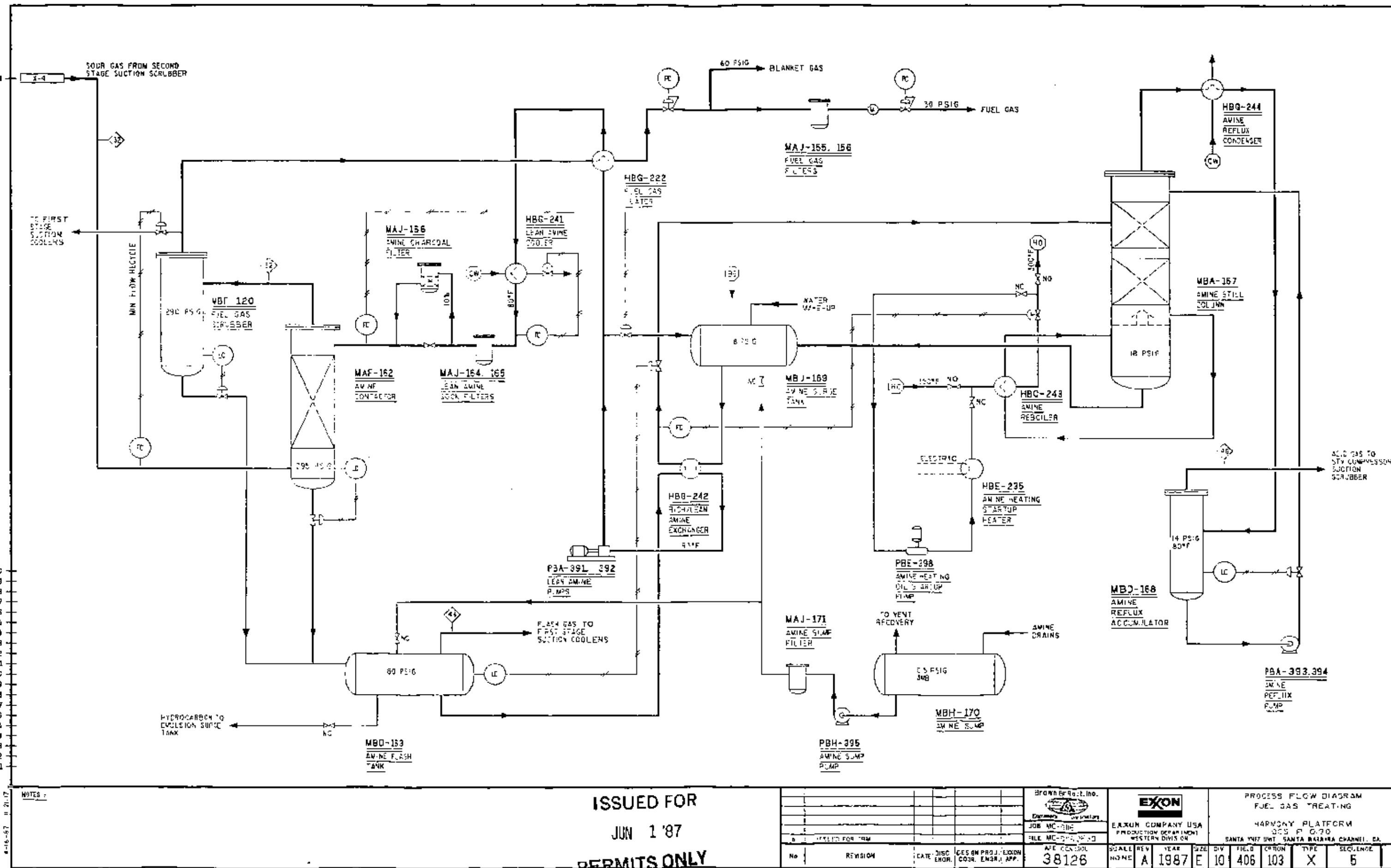

MBF-116
SECOND STAGE
SUCTION SCRUBBER
MBF-117
MBF-135
MBA-233
STARTUP
HEATER
PIPELINE
GAS
TYPICAL OF 3
TO FIRST STAGE SUCTION COOLERS
NOTES:
ISSUED FC
JUN 1 '87
PERMITS ONLY
REVISION
EXXON
EXXON COMPANY USA
GAS COMPRESSION, GAS INJECTION
PLATFORM
SANTA BARBARA CHANNEL
38126
NONE
B
1987
E
406
103
X
4

Figure 7.13


SOUR GAS FROM SECOND STAGE SUCTION SCRUBBER
60 PSIG
BLANKET GAS
30 PSIG
FUEL GAS
MAJ-155, 156
FUEL GAS FILTERS
HBG-244
AMINE REFLUX CONDENSER
HBG-222
FUEL GAS HEATER
TO FIRST STAGE SUCTION COOLERS
MIN FLOW RECYCLE
MAJ-156
AMINE CHARCOAL FILTER
HBG-241
LEAN AMINE COOLER
MBF-120
FUEL GAS SCRUBBER
WATER MAKE-UP
MBA-167
AMINE STILL COLUMN
18 PSIG
MAF-162
AMINE CONTACTOR
MAJ-164, 165
LEAN AMINE SOCK FILTERS
MBJ-169
AMINE SURGE TANK
HBG-243
AMINE REBOILER
ELECTRIC
HBE-235
AMINE HEATING STARTUP HEATER
ACID GAS TO STV COMPRESSOR SUCTION SCRUBBER
14 PSIG
HBG-242
RICH/LEAN AMINE EXCHANGER
PBA-391, 392
LEAN AMINE PUMPS
PBE-398
AMINE HEATING STARTUP PUMP
MBD-168
AMINE REFLUX ACCUMULATOR
FLASH GAS TO FIRST STAGE SUCTION COOLERS
MAJ-171
AMINE SUMP FILTER
TO VENT RECOVERY
AMINE DRAINS
60 PSIG
PBA-393, 394
AMINE REFLUX PUMP
HYDROCARBON TO EMULSION SUMP TANK
MBD-163
AMINE FLASH TANK
PBH-395
AMINE SUMP PUMP
MBH-170
AMINE SUMP
NOTES:
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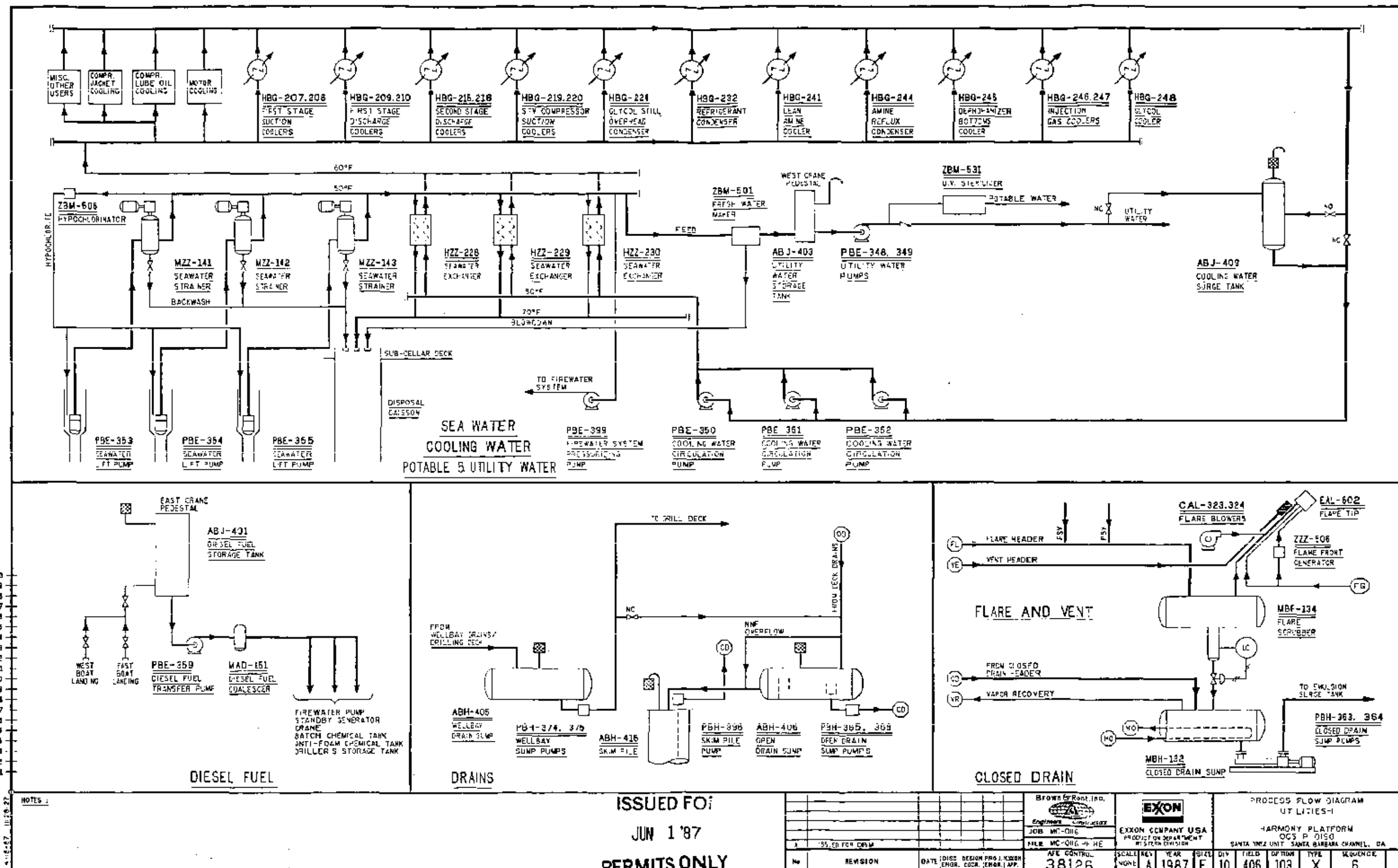
REVISION
DATE
DISC ENGR.
DES GN PROJ. COOR.
EXXON ENGR. APP.
Brown & Root, Inc.
EXXON
EXXON COMPANY USA
PRODUCTION DEPARTMENT
WESTERN DIVISION
PROCESS FLOW DIAGRAM
FUEL GAS TREATING
HARMONY PLATFORM
SANTA YNEZ UNIT SANTA BARBARA CHANNEL, CA
AFE CONTROL
38126
SCALE NONE
REV A
YEAR 1987
SIZE E
DIV 10
FIELD 406
OPTION 103
TYPE X
SEQUENCE 5

Figure 7.14



MISC. OTHER USERS
COMPR. JACKET COOLING
COMPR. LUBE OIL COOLING
MOTOR COOLING
HBG-207,208 FIRST STAGE SUCTION COOLERS
HBG-209,210 FIRST STAGE DISCHARGE COOLERS
HBG-215,216 SECOND STAGE DISCHARGE COOLERS
HBG-219,220 STV COMPRESSOR SUCTION COOLERS
HBG-221 GLYCOL STILL OVERHEAD CONDENSER
HBG-232 REFRIGERANT CONDENSER
HBG-241 LEAN AMINE COOLER
HBG-244 AMINE REFLUX CONDENSER
HBG-245 DEPROPANIZER BOTTOMS COOLER
HBG-246,247 INJECTION GAS COOLERS
HBG-248 GLYCOL COOLER
60°F
50°F
ZBM-606 HYPOCHLORINATOR
HYPOCHLORITE
MZZ-141 SEAWATER STRAINER
MZZ-142 SEAWATER STRAINER
MZZ-143 SEAWATER STRAINER
BACKWASH
HZZ-228 SEAWATER EXCHANGER
HZZ-229 SEAWATER EXCHANGER
HZZ-230 SEAWATER EXCHANGER
90°F
70°F
BLOWDOWN
SUB-CELLAR DECK
ZBM-501 FRESH WATER MAKER
FEED
WEST CRANE PEDESTAL
ABJ-403 UTILITY WATER STORAGE TANK
PBE-348, 349 UTILITY WATER PUMPS
ZBM-531 U.V. STERILIZER
POTABLE WATER
UTILITY WATER
NC
NO
ABJ-409 COOLING WATER SURGE TANK
TO FIREWATER SYSTEM
DISPOSAL CAISSON
PBE-353 SEAWATER LIFT PUMP
PBE-354 SEAWATER LIFT PUMP
PBE-355 SEAWATER LIFT PUMP
SEA WATER
COOLING WATER
POTABLE & UTILITY WATER
PBE-399 FIREWATER SYSTEM PRESSURIZING PUMP
PBE-350 COOLING WATER CIRCULATION PUMP
PBE-351 COOLING WATER CIRCULATION PUMP
PBE-352 COOLING WATER CIRCULATION PUMP
EAST CRANE PEDESTAL
ABJ-401 DIESEL FUEL STORAGE TANK
WEST BOAT LANDING
EAST BOAT LANDING
PBE-359 DIESEL FUEL TRANSFER PUMP
MAD-151 DIESEL FUEL COALESCER
FIREWATER PUMP
STANDBY GENERATOR
CRANE
BATCH CHEMICAL TANK
ANTI-FOAM CHEMICAL TANK
DRILLER'S STORAGE TANK
DIESEL FUEL
TO DRILL DECK
FROM DECK DRAINS
FROM WELLBAY DRAINS/ DRILLING DECK
NNF OVERFLOW
ABH-405 WELLBAY DRAIN SUMP
PBH-374, 375 WELLBAY SUMP PUMPS
ABH-416 SKIM PILE
PBH-396 SKIM PILE PUMP
ABH-406 OPEN DRAIN SUMP
PBH-365, 366 OPEN DRAIN SUMP PUMPS
DRAINS
FLARE HEADER
VENT HEADER
CAL-323,324 FLARE BLOWERS
ZAL-602 FLARE TIP
ZZZ-506 FLAME FRONT GENERATOR
FLARE AND VENT
MBF-134 FLARE SCRUBBER
FROM CLOSED DRAIN HEADER
VAPOR RECOVERY
TO EMULSION SURGE TANK
PBH-363, 364 CLOSED DRAIN SUMP PUMPS
MBH-132 CLOSED DRAIN SUMP
CLOSED DRAIN
NOTES :
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REVISION
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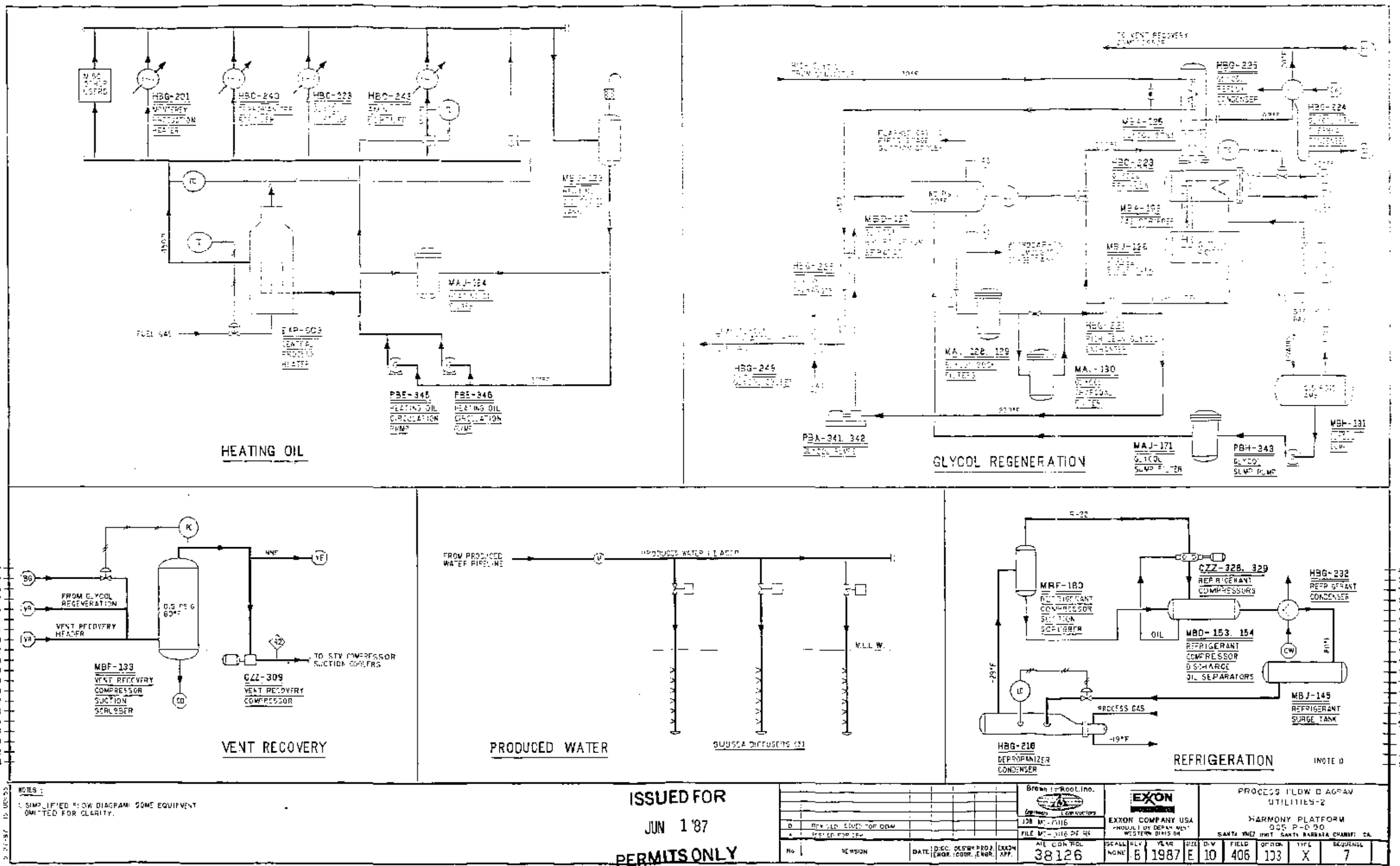
EXXON
EXXON COMPANY USA
PROCESS FLOW DIAGRAM
UTILITIES-I
HARMONY PLATFORM
OCS P 0190
SANTA YNEZ UNIT SANTA BARBARA CHANNEL, CA
38126
A
1987
E
10
406
103
X
6

Figure 7.15


HEATING OIL
HBG-201
HBG-240
HBC-223
HBC-243
MAJ-184
EAP-002
CENTRAL PROCESS HEATER
FUEL GAS
PBE-345
HEATING OIL CIRCULATION PUMP
PBE-346
HEATING OIL CIRCULATION PUMP
GLYCOL REGENERATION
HBG-235
HBG-224
MBJ-125
HBC-223
MBA-193
MBJ-126
MBD-197
HBG-237
HBG-221
MAJ-128, 129
MAJ-130
HBG-245
PBA-341, 342
MAJ-171
GLYCOL SUMP FILTER
PBH-343
GLYCOL SUMP PUMP
MBH-131
VENT RECOVERY
FROM GLYCOL REGENERATION
VENT RECOVERY HEADER
MBF-133
VENT RECOVERY COMPRESSOR SUCTION SCRUBBER
CZZ-309
VENT RECOVERY COMPRESSOR
TO STV COMPRESSOR SUCTION COOLERS
PRODUCED WATER
FROM PRODUCED WATER PIPELINE
M.L.L.W.
REFRIGERATION
R-22
MBF-180
CZZ-328, 329
REFRIGERANT COMPRESSORS
HBG-232
REFRIGERANT CONDENSER
OIL
MBD-153, 154
REFRIGERANT COMPRESSOR DISCHARGE OIL SEPARATORS
MBJ-145
REFRIGERANT SURGE TANK
PROCESS GAS
-29°F
-19°F
HBG-216
DEPROPANIZER CONDENSER
NOTES :
1. SIMPLIFIED FLOW DIAGRAM. SOME EQUIPMENT OMITTED FOR CLARITY.
ISSUED FOR
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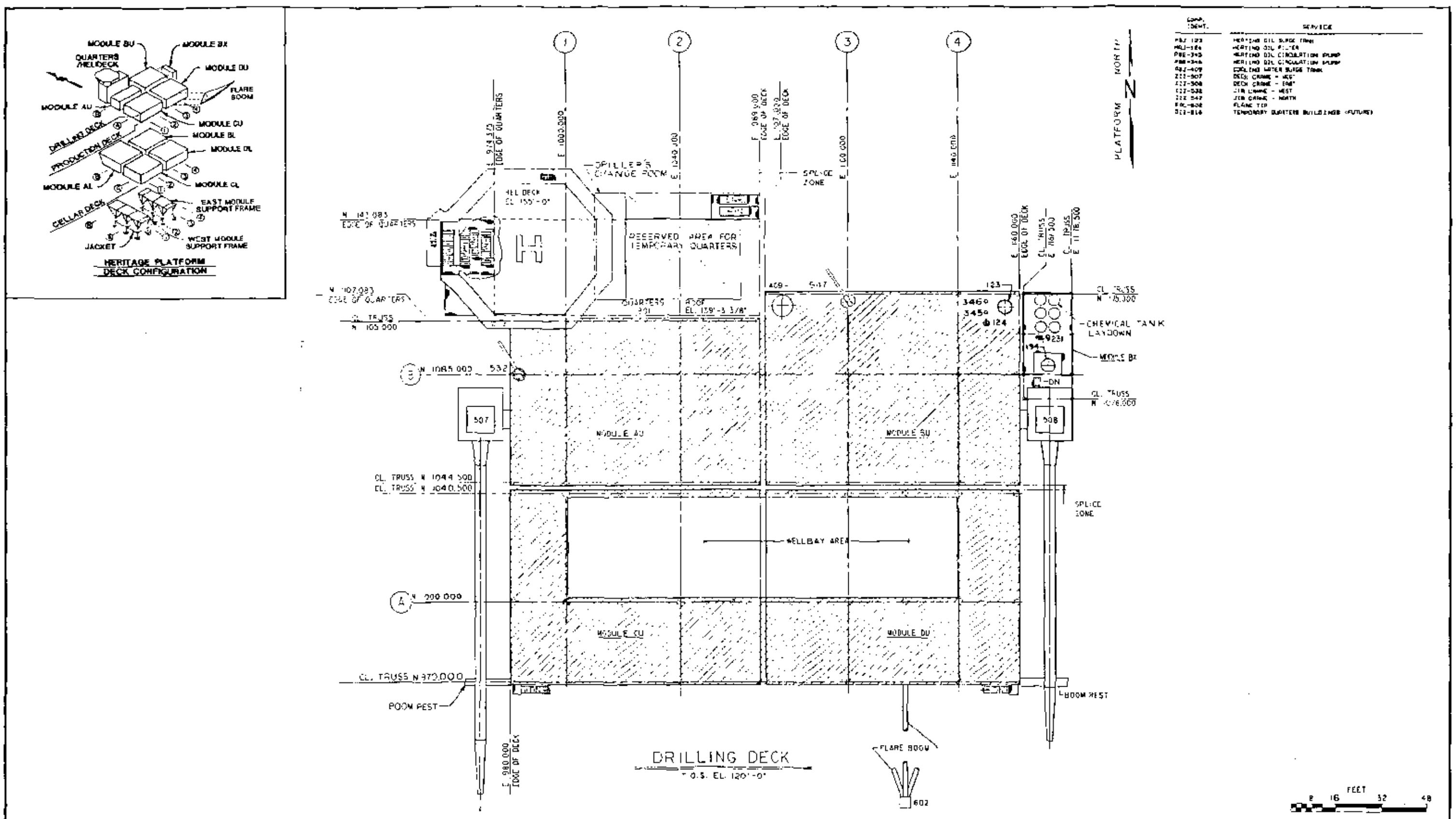
PERMITS ONLY
Brown & Root, Inc.
EXXON
EXXON COMPANY USA
PROCESS FLOW DIAGRAM
UTILITIES-2
HARMONY PLATFORM
38126
1987
406
7

Figure 7.16



NOTES:

1. ORIGIN PLATFORM COORDINATES REF. FROM THIS POINT (E 1 000 000, N 1 000 000).
2. INDICATES DECKED AREA RESERVED FOR DRILLER.
3. ALL COORDINATES ARE IN FEET AND DECIMALS OF FEET.

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JUN 1 '87
PERMITS ONLY

No	REVISION	DATE	DISC. ENGR	DESIGN COOR	PROJ. ENGR	EXXON APP.
A						

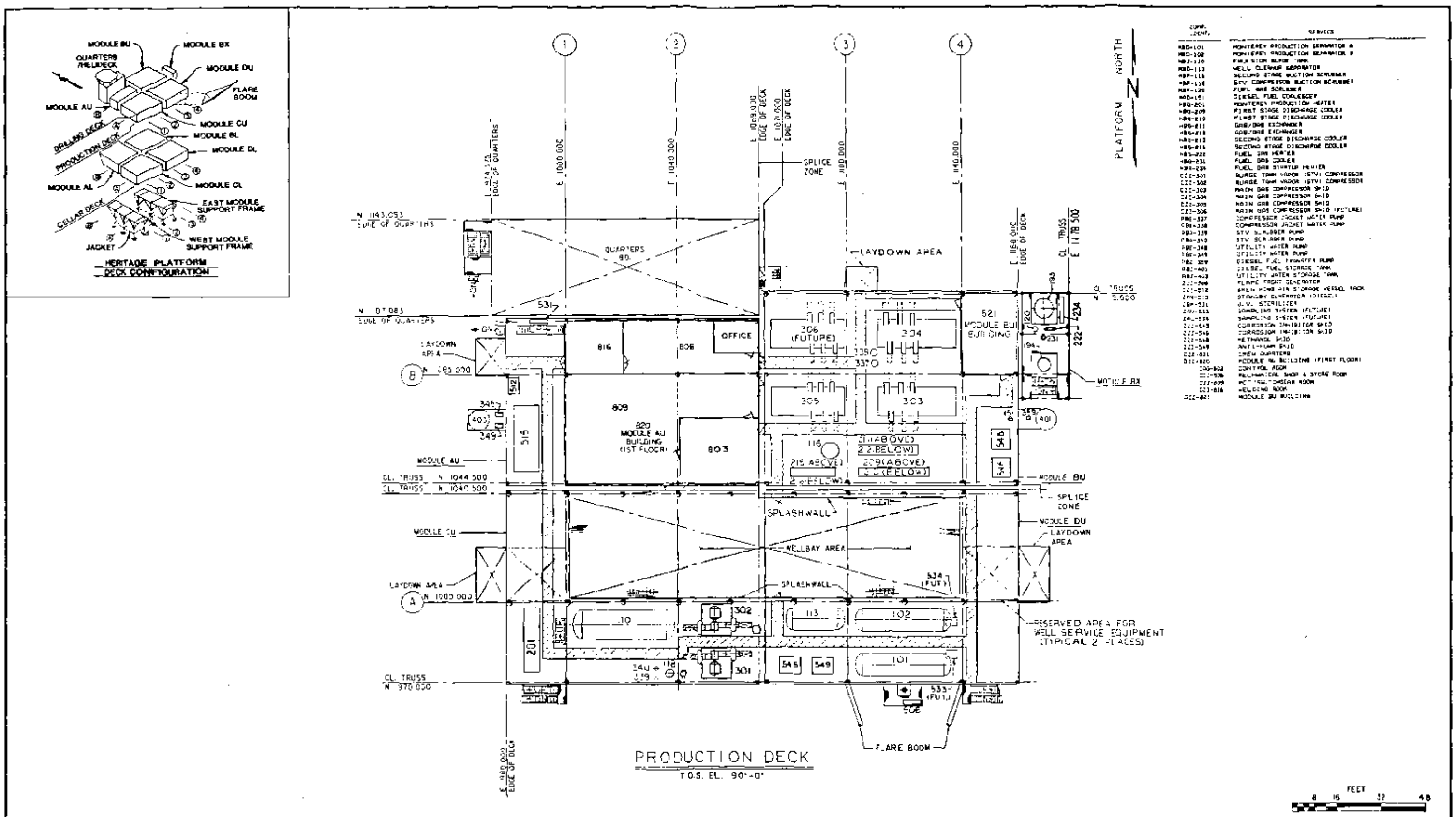
Brown & Root, Inc.
JOB NO.
FILE
AFE CONTROL 38127

EXXON
EXXON COMPANY USA
PRODUCTION DEPARTMENT
WESTERN DIVISION

EQUIPMENT LAYOUT
DRILLING DECK
HERITAGE PLATFORM
OCS P-0182
SANTA YNEZ UNIT SANTA BARBARA CHANNEL, CA.

SCALE	REV	YEAR	SIZE	DIV	FIELD	OPTION	TYPE	SEQUENCE
	A	1967	E	10	407	103	C	1

Figure 7.17



NOTES:
1. ORIGIN PLATFORM COORDINATES REF. FROM THIS POINT. (E 1000.000, N 1000.000)
2. ALL COORDINATES ARE IN FEET AND DECIMALS OF FEET.
3. SEE DRAWING C-7 FOR PRODUCTION DECK MEZZANINE PLATFORMS AND EQUIPMENT.

ISSUED FOR
JUN 1 '87
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EXXON COMPANY USA
PRODUCTION DEPARTMENT

EQUIPMENT LAYOUT
PRODUCTION DECK
HERITAGE PLATFORM
OCS P-0182
SANTA YNEZ UNIT SANTA BARBARA CHANNEL, CA.

AFE CONTROL	REV.	YEAR	SIZE	DIV.	FIELD	OPTION	TYPE	SEQUENCE
38127	A	1987	E	10	407	103	C	2

Figure 7.18

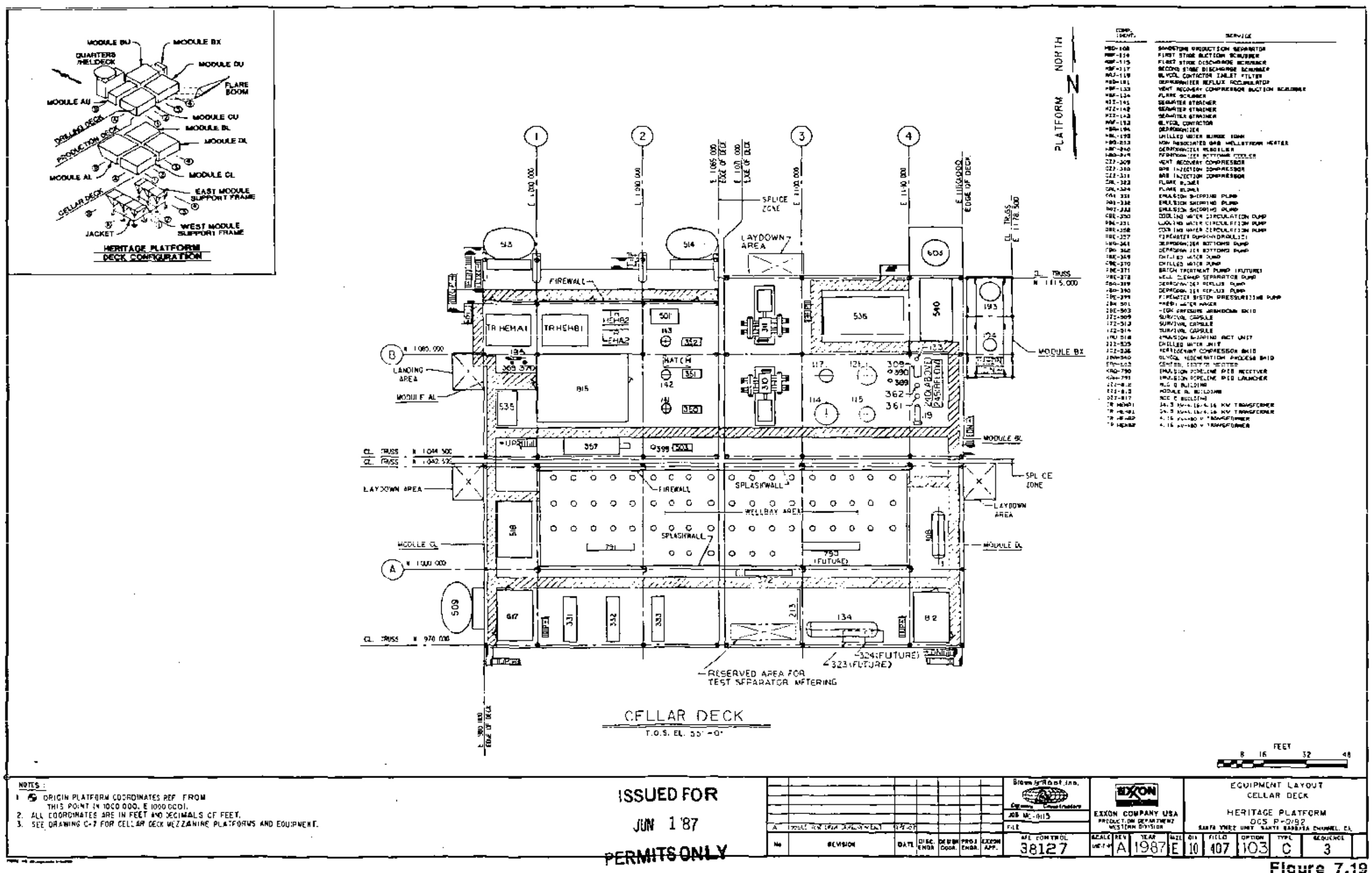

HERITAGE PLATFORM DECK CONFIGURATION
PLATFORM NORTH
FIREWALL
SPLICE ZONE
LAYDOWN AREA
LANDING AREA
MODULE AL
MODULE BX
MODULE BL
MODULE CL
MODULE DL
SPLASHWALL
WELLBAY AREA
RESERVED AREA FOR TEST SEPARATOR METERING
CELLAR DECK
NOTES:
1. ORIGIN PLATFORM COORDINATES REF. FROM THIS POINT N 1000.000, E 1000.000.
2. ALL COORDINATES ARE IN FEET AND DECIMALS OF FEET.
3. SEE DRAWING C-7 FOR CELLAR DECK MEZZANINE PLATFORMS AND EQUIPMENT.
ISSUED FOR
JUN 1 '87
PERMITS ONLY
EXXON COMPANY USA
EQUIPMENT LAYOUT
CELLAR DECK
HERITAGE PLATFORM
38127

Figure 7.19

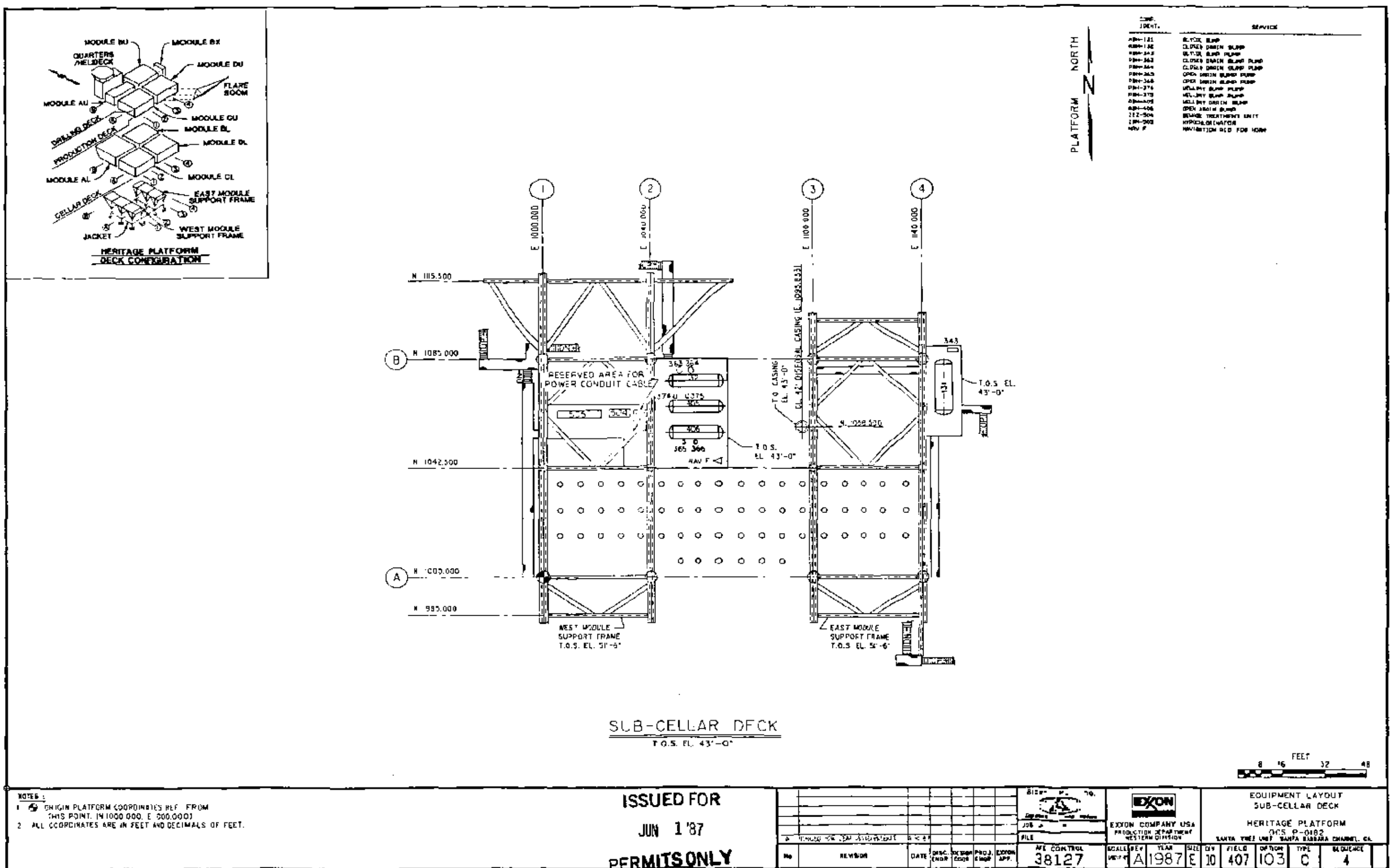

HERITAGE PLATFORM
DECK CONFIGURATION
MODULE BU
MODULE BX
QUARTERS /HELIDECK
MODULE DU
FLARE BOOM
MODULE AU
DRILLING DECK
MODULE CU
PRODUCTION DECK
MODULE BL
MODULE DL
MODULE AL
MODULE CL
CELLAR DECK
EAST MODULE SUPPORT FRAME
WEST MODULE SUPPORT FRAME
JACKET
PLATFORM NORTH
N
N 1115,500
N 1085,000
N 1042,500
N 1000,000
N 985,000
E 1000,000
E 1040,000
E 1100,000
E 1140,000
RESERVED AREA FOR POWER CONDUIT CABLE
T.O. CASING EL. 43'-0"
T.O.S. EL. 43'-0"
NAV F
WEST MODULE SUPPORT FRAME T.O.S. EL. 51'-6"
EAST MODULE SUPPORT FRAME T.O.S. EL. 51'-6"
SUB-CELLAR DECK
T.O.S. EL. 43'-0"
FEET
8 16 32 48
NOTES:
1. ORIGIN PLATFORM COORDINATES REF. FROM THIS POINT. (N 1000,000, E 1000,000)
2. ALL COORDINATES ARE IN FEET AND DECIMALS OF FEET.
ISSUED FOR
JUN 1 '87
PERMITS ONLY
No
REVISION
DATE
DISC. ENGR
DESIGN COOR
PROJ. ENGR
EXXON APP.
AFE CONTROL
38127
EXXON
EXXON COMPANY USA
PRODUCTION DEPARTMENT WESTERN DIVISION
EQUIPMENT LAYOUT
SUB-CELLAR DECK
HERITAGE PLATFORM
OCS P-0182
SANTA YNEZ UNIT SANTA BARBARA CHANNEL, CA.
SCALE
REV
A
YEAR
1987
SIZE
E
DIV
10
FIELD
407
OPTION
103
TYPE
C
SEQUENCE
4

Figure 7.20

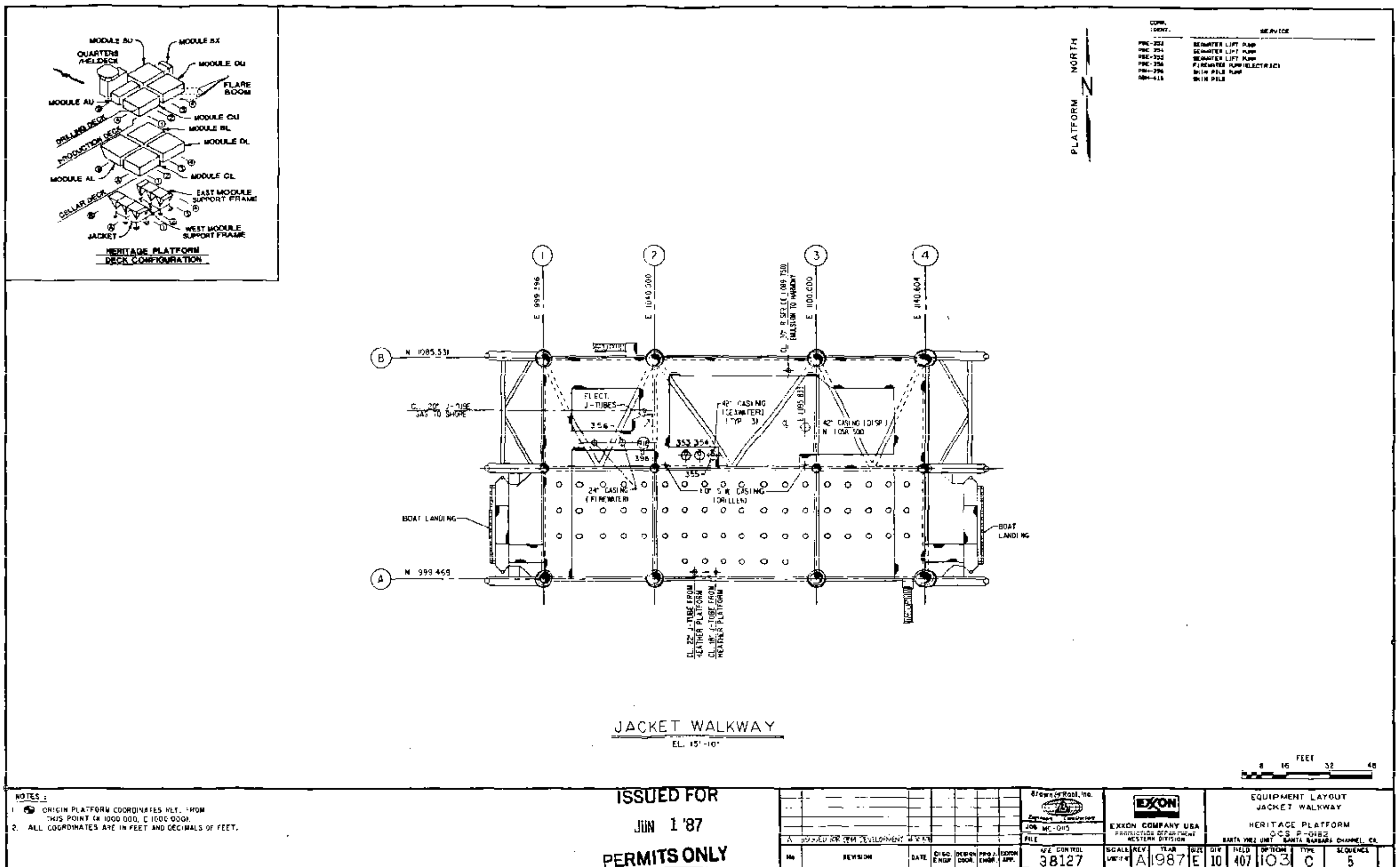
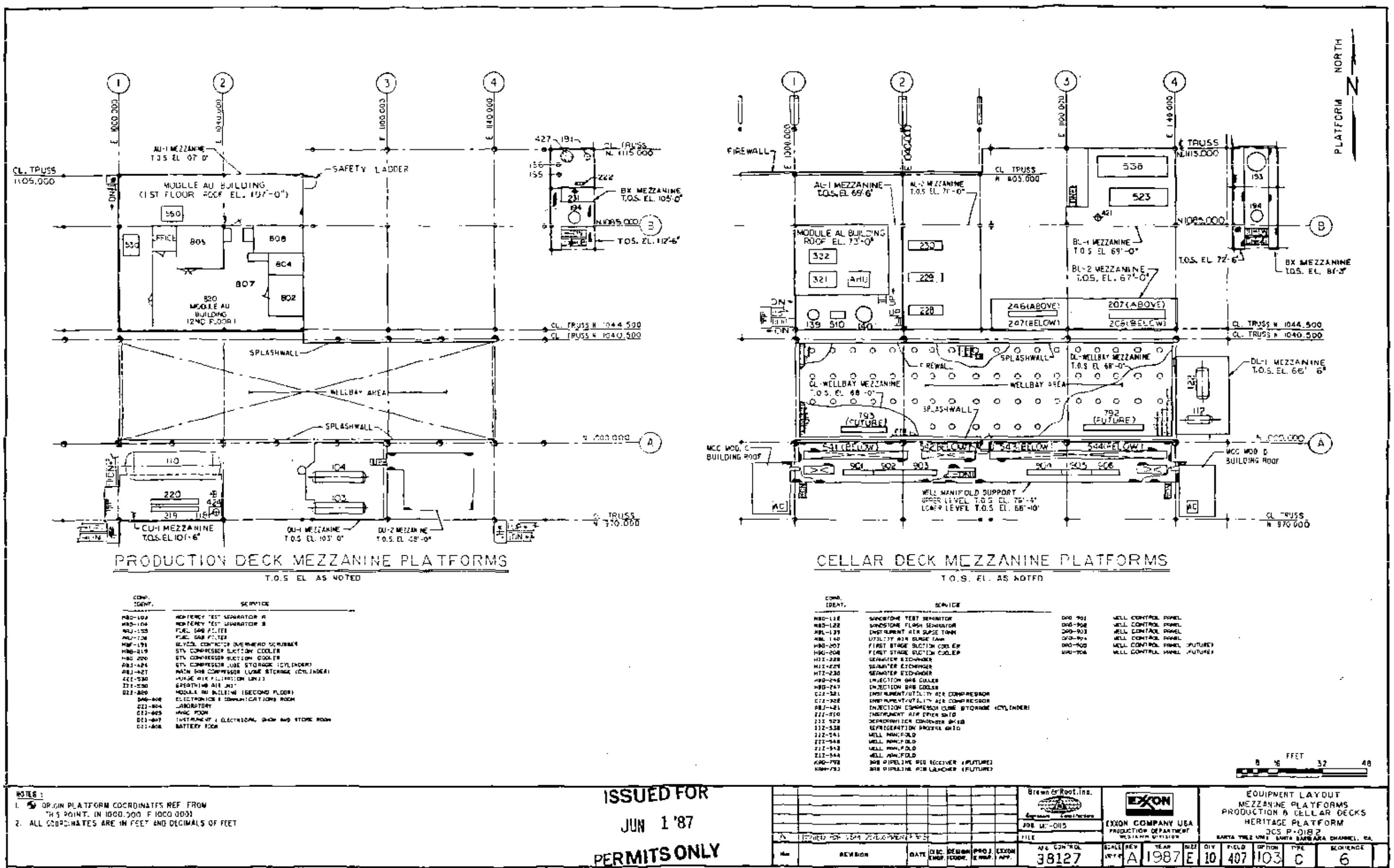

HERITAGE PLATFORM DECK CONFIGURATION
PLATFORM NORTH
JACKET WALKWAY
EL. 15'-10"
BOAT LANDING
FEET
NOTES :
1. ORIGIN PLATFORM COORDINATES REF. FROM THIS POINT (N 1000.000, E 1000.000).
2. ALL COORDINATES ARE IN FEET AND DECIMALS OF FEET.
ISSUED FOR
JUN 1 '87
PERMITS ONLY
EXXON COMPANY USA
EQUIPMENT LAYOUT
JACKET WALKWAY
HERITAGE PLATFORM
OCS P-0182
38127
A
1987
E
10
407
103
C
5

Figure 7.21


PRODUCTION DECK MEZZANINE PLATFORMS
T.O.S EL AS NOTED
CELLAR DECK MEZZANINE PLATFORMS
T.O.S. EL. AS NOTED
PLATFORM NORTH
SAFETY LADDER
SPLASHWALL
WELLBAY AREA
FIREWALL
CU-I MEZZANINE T.O.S.EL 101'-6"
WELL MANIFOLD SUPPORT
UPPER LEVEL T.O.S. EL. 76'-9"
LOWER LEVEL T.O.S. EL. 66'-10"
NOTES:
2. ALL COORDINATES ARE IN FEET AND DECIMALS OF FEET
ISSUED FOR
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PERMITS ONLY
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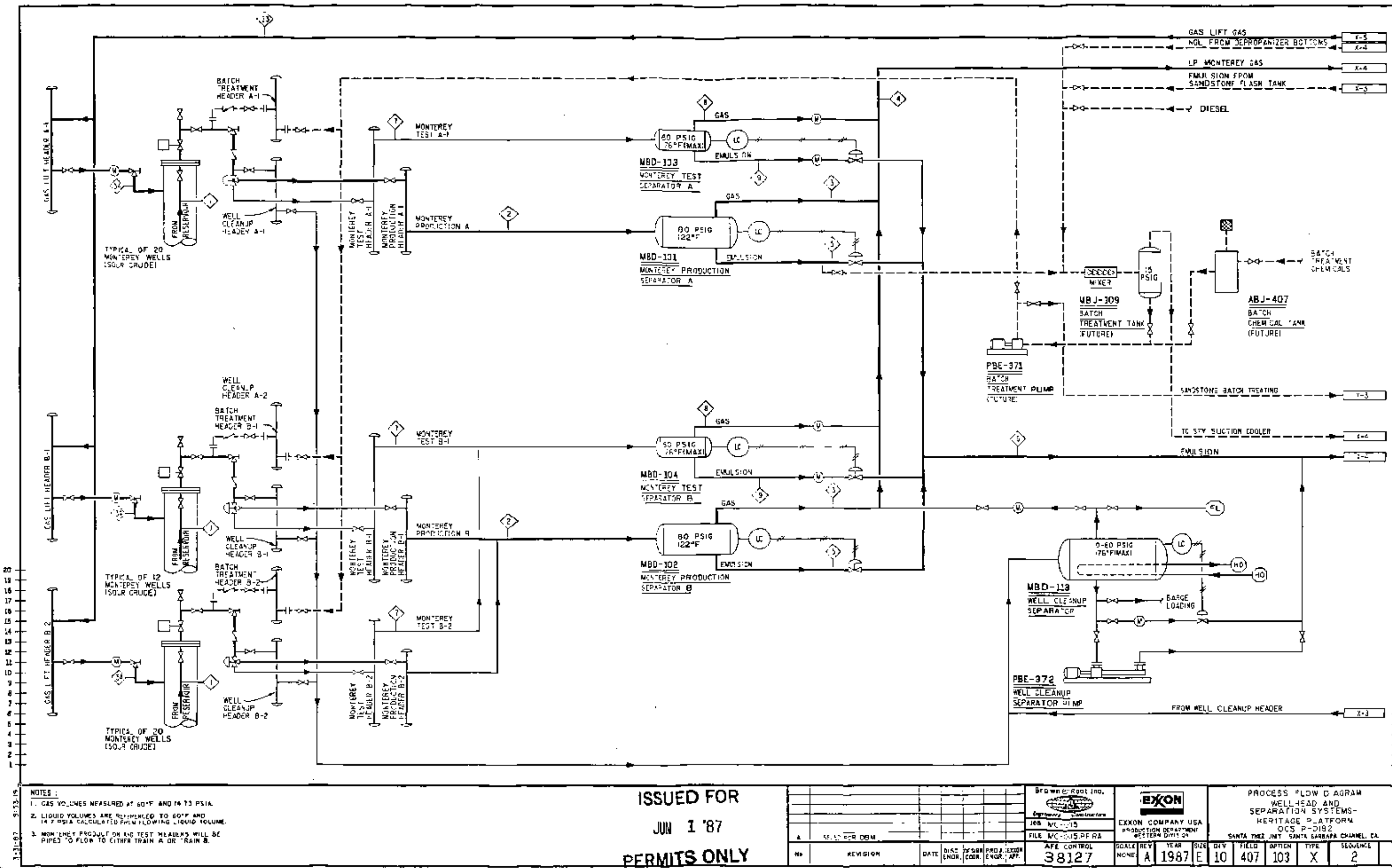
EXXON
EXXON COMPANY USA
PRODUCTION DEPARTMENT
EQUIPMENT LAYOUT
MEZZANINE PLATFORMS
PRODUCTION & CELLAR DECKS
HERITAGE PLATFORM
38127
A
1987
E
10
407
103
C
6

Figure 7.22


GAS LIFT GAS
NGL FROM DEPROPANIZER BOTTOMS
LP MONTEREY GAS
EMULSION FROM SANDSTONE FLASH TANK
DIESEL
BATCH TREATMENT HEADER A-1
MONTEREY TEST A-1
MONTEREY PRODUCTION A
GAS
EMULSION
MBD-103
MONTEREY TEST SEPARATOR A
MBD-101
MONTEREY PRODUCTION SEPARATOR A
80 PSIG 122°F
MIXER
MBJ-109
BATCH TREATMENT TANK (FUTURE)
ABJ-407
BATCH CHEMICAL TANK (FUTURE)
BATCH TREATMENT CHEMICALS
PBE-371
BATCH TREATMENT PUMP
TYPICAL OF 20 MONTEREY WELLS (SOUR CRUDE)
WELL CLEANUP HEADER A-1
WELL CLEANUP HEADER A-2
BATCH TREATMENT HEADER B-1
SANDSTONE BATCH TREATING
TO STV SUCTION COOLER
EMULSION
MONTEREY TEST B-1
MBD-104
MONTEREY TEST SEPARATOR B
MONTEREY PRODUCTION B
MBD-102
MONTEREY PRODUCTION SEPARATOR B
MBD-113
WELL CLEANUP SEPARATOR
BARGE LOADING
TYPICAL OF 12 MONTEREY WELLS (SOUR CRUDE)
WELL CLEANUP HEADER B-1
BATCH TREATMENT HEADER B-2
MONTEREY TEST B-2
PBE-372
WELL CLEANUP SEPARATOR PUMP
FROM WELL CLEANUP HEADER
WELL CLEANUP HEADER B-2
TYPICAL OF 20 MONTEREY WELLS (SOUR CRUDE)
NOTES:
1. GAS VOLUMES MEASURED AT 60°F AND 14.73 PSIA.
2. LIQUID VOLUMES ARE REFERENCED TO 60°F AND 14.7 PSIA CALCULATED FROM FLOWING LIQUID VOLUME.
3. MONTEREY PRODUCTION AND TEST HEADERS WILL BE PIPED TO FLOW TO EITHER TRAIN A OR TRAIN B.
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REVISION
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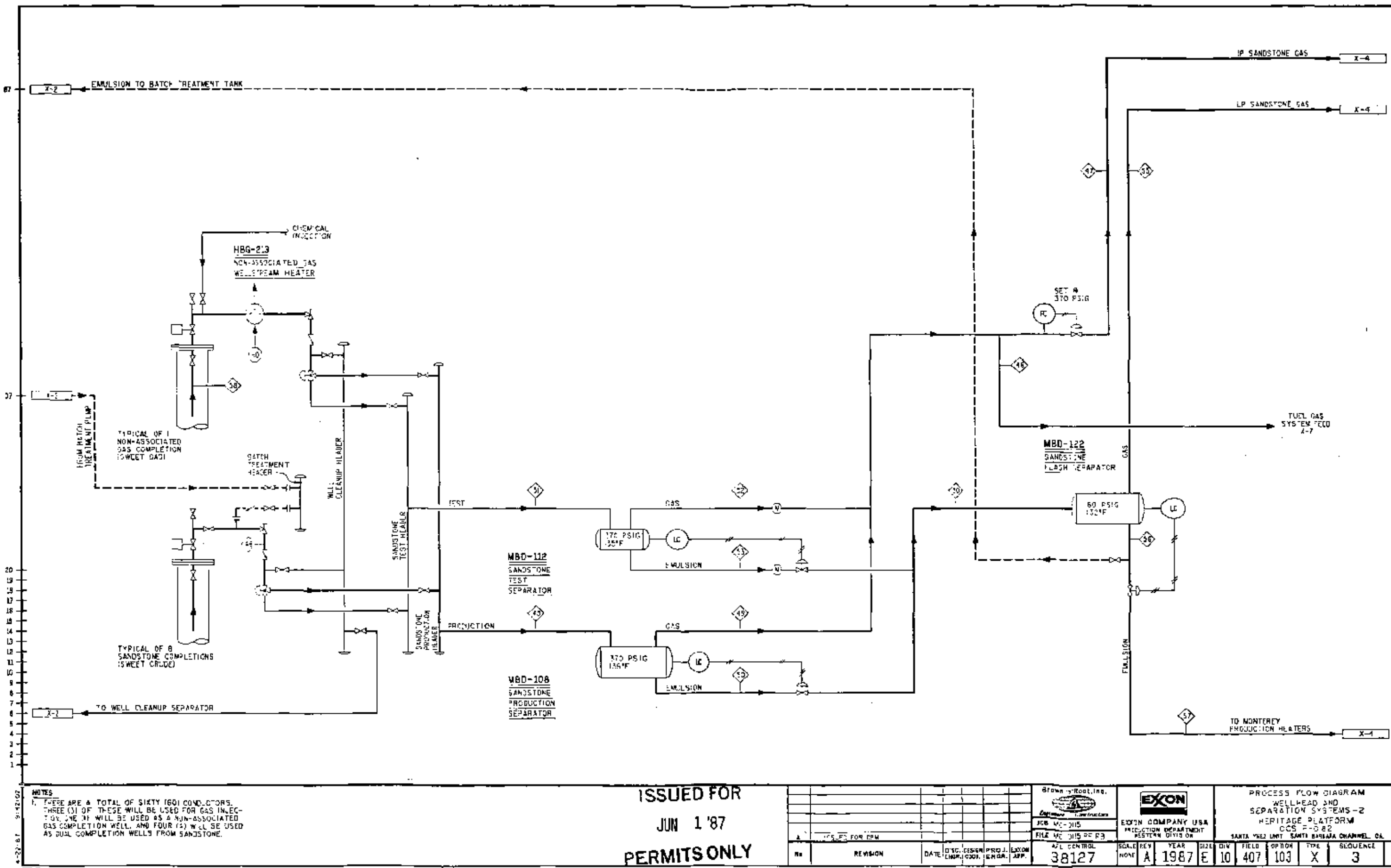
JOB MC-015
FILE MC-015.PF RA
AFE CONTROL 38127
EXXON
EXXON COMPANY USA
PRODUCTION DEPARTMENT
WESTERN DIVISION
PROCESS FLOW DIAGRAM
WELLHEAD AND SEPARATION SYSTEMS-
HERITAGE PLATFORM
OCS P-0182
SANTA YNEZ UNIT SANTA BARBARA CHANNEL, CA
SCALE NONE
REV A
YEAR 1987
SIZE E
DIV 10
FIELD 407
OPTION 103
TYPE X
SEQUENCE 2

Figure 7.23



EMULSION TO BATCH TREATMENT TANK
IP SANDSTONE GAS
LP SANDSTONE GAS
CHEMICAL INJECTION
HBG-213
NON-ASSOCIATED GAS WELLSTREAM HEATER
TYPICAL OF 1 NON-ASSOCIATED GAS COMPLETION (SWEET GAS)
BATCH TREATMENT HEADER
WELL CLEANUP HEADER
SANDSTONE TEST HEADER
SANDSTONE PRODUCTION HEADER
TYPICAL OF 8 SANDSTONE COMPLETIONS (SWEET CRUDE)
TO WELL CLEANUP SEPARATOR
TEST
PRODUCTION
GAS
EMULSION
MBD-112
SANDSTONE TEST SEPARATOR
MBD-108
SANDSTONE PRODUCTION SEPARATOR
370 PSIG
MBD-122
SANDSTONE FLASH SEPARATOR
60 PSIG
FUEL GAS SYSTEM FEED
TO MONTEREY PRODUCTION HEATERS
NOTES
1. THERE ARE A TOTAL OF SIXTY (60) CONDUCTORS. THREE (3) OF THESE WILL BE USED FOR GAS INJECTION, ONE (1) WILL BE USED AS A NON-ASSOCIATED GAS COMPLETION WELL, AND FOUR (4) WILL BE USED AS DUAL COMPLETION WELLS FROM SANDSTONE.
ISSUED FOR
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REVISION
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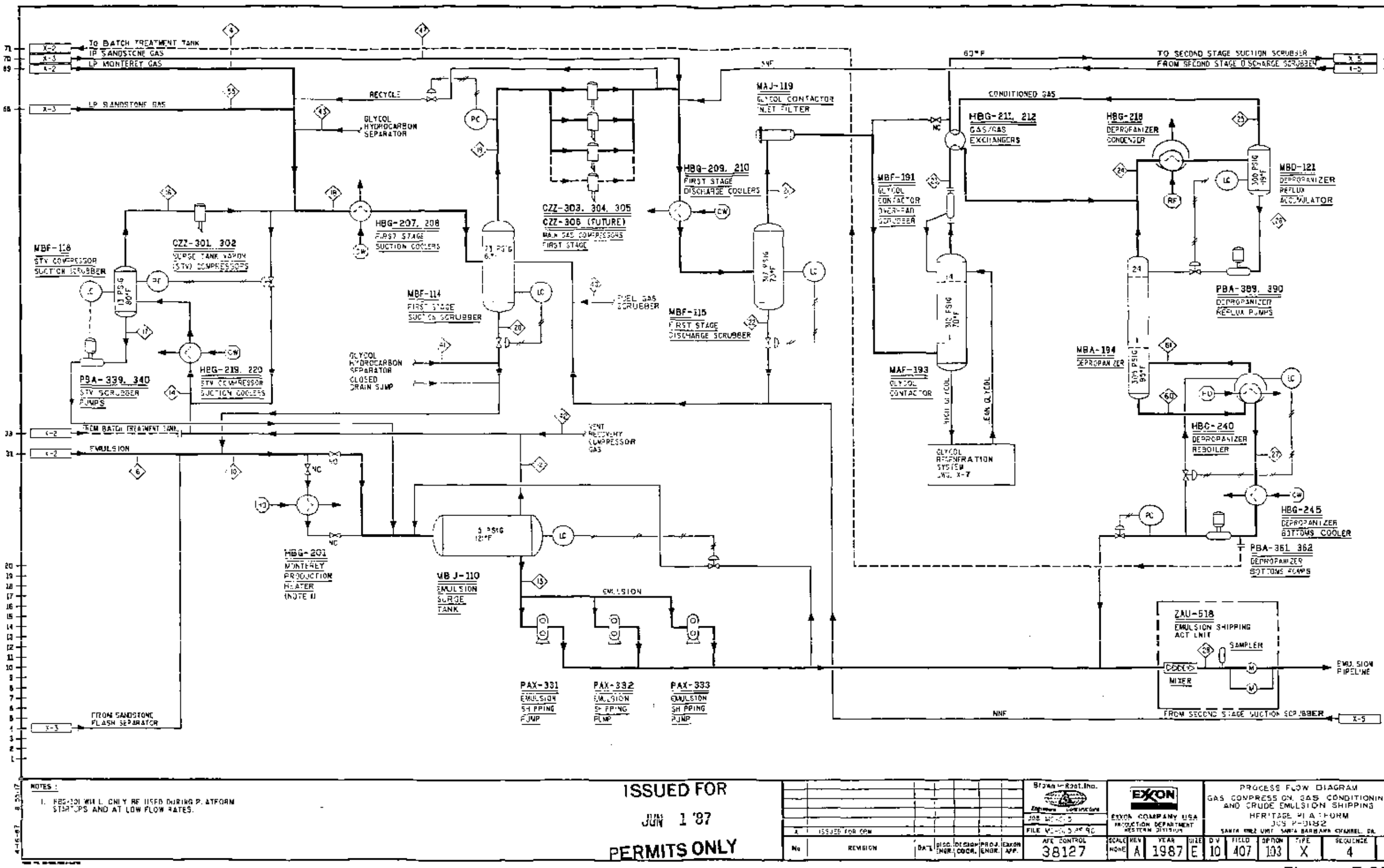
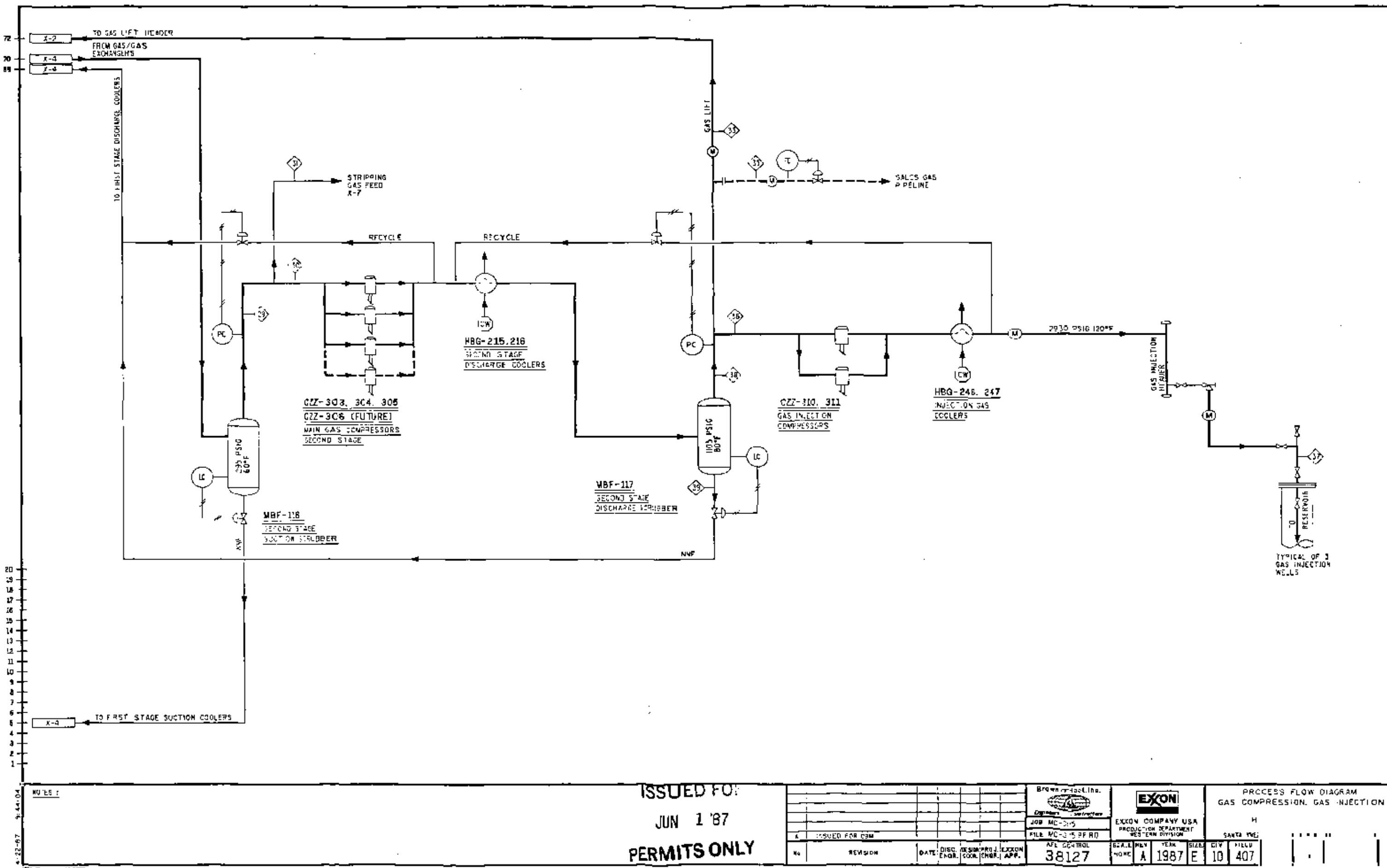
EXXON COMPANY USA
PROCESS FLOW DIAGRAM
WELLHEAD AND SEPARATION SYSTEMS-2
HERITAGE PLATFORM
38127
1987

Figure 7.24



TO BATCH TREATMENT TANK
LP SANDSTONE GAS
LP MONTEREY GAS
RECYCLE
GLYCOL HYDROCARBON SEPARATOR
MAJ-119 GLYCOL CONTACTOR INLET FILTER
TO SECOND STAGE SUCTION SCRUBBER
FROM SECOND STAGE DISCHARGE SCRUBBER
CONDITIONED GAS
HBG-211, 212 GAS/GAS EXCHANGERS
HBG-218 DEPROPANIZER CONDENSER
MBD-121 DEPROPANIZER REFLUX ACCUMULATOR
MBF-118 STV COMPRESSOR SUCTION SCRUBBER
CZZ-301, 302 SURGE TANK VAPOR (STV) COMPRESSORS
HBG-207, 208 FIRST STAGE SUCTION COOLERS
CZZ-303, 304, 305 MAIN GAS COMPRESSORS FIRST STAGE
CZZ-306 (FUTURE)
HBG-209, 210 FIRST STAGE DISCHARGE COOLERS
MBF-191 GLYCOL CONTACTOR OVERHEAD SCRUBBER
MBF-114 FIRST STAGE SUCTION SCRUBBER
FUEL GAS SCRUBBER
MBF-115 FIRST STAGE DISCHARGE SCRUBBER
MAF-193 GLYCOL CONTACTOR
PBA-389, 390 DEPROPANIZER REFLUX PUMPS
MBA-194 DEPROPANIZER
PBA-339, 340 STV SCRUBBER PUMPS
HBG-219, 220 STV COMPRESSOR SUCTION COOLERS
GLYCOL HYDROCARBON SEPARATOR
CLOSED DRAIN SUMP
GLYCOL REGENERATION SYSTEM
HBG-240 DEPROPANIZER REBOILER
FROM BATCH TREATMENT TANK
EMULSION
VENT RECOVERY COMPRESSOR GAS
HBG-245 DEPROPANIZER BOTTOMS COOLER
PBA-361, 362 DEPROPANIZER BOTTOMS PUMPS
HBG-201 MONTEREY PRODUCTION HEATER (NOTE 1)
MBJ-110 EMULSION SURGE TANK
ZAU-518 EMULSION SHIPPING ACT UNIT
SAMPLER
MIXER
EMULSION PIPELINE
PAX-331 EMULSION SHIPPING PUMP
PAX-332 EMULSION SHIPPING PUMP
PAX-333 EMULSION SHIPPING PUMP
FROM SANDSTONE FLASH SEPARATOR
NNF
FROM SECOND STAGE SUCTION SCRUBBER
NOTES:
1. HBG-201 WILL ONLY BE USED DURING PLATFORM STARTUPS AND AT LOW FLOW RATES.
ISSUED FOR
JUN 1 '87
PERMITS ONLY
A ISSUED FOR CPM
No REVISION DATE DISC. ENGR. DESIGN COOR. PROJ. ENGR. EXXON APP.
Brown & Root, Inc.
AFE CONTROL 38127
EXXON
EXXON COMPANY USA
PRODUCTION DEPARTMENT WESTERN DIVISION
PROCESS FLOW DIAGRAM
GAS COMPRESSION, GAS CONDITIONING AND CRUDE EMULSION SHIPPING
HERITAGE PLATFORM
SANTA YNEZ UNIT SANTA BARBARA CHANNEL, CA
SCALE NONE REV A YEAR 1987 SIZE E DIV 10 FIELD 407 OPTION 103 TYPE X SEQUENCE 4

Figure 7.25


TO GAS LIFT HEADER
FROM GAS/GAS EXCHANGERS
TO FIRST STAGE DISCHARGE COOLERS
STRIPPING GAS FEED X-7
SALES GAS PIPELINE
GAS LIFT
RECYCLE
RECYCLE
HBG-215, 216
SECOND STAGE DISCHARGE COOLERS
CZZ-303, 304, 305
CZZ-306 (FUTURE)
MAIN GAS COMPRESSORS SECOND STAGE
MBF-118
SECOND STAGE SUCTION SCRUBBER
MBF-117
SECOND STAGE DISCHARGE SCRUBBER
CZZ-310, 311
GAS INJECTION COMPRESSORS
HBG-246, 247
INJECTION GAS COOLERS
2930 PSIG 120°F
GAS INJECTION HEADER
RESERVOIR
TYPICAL OF 3 GAS INJECTION WELLS
TO FIRST STAGE SUCTION COOLERS
NOTES:
ISSUED FOR
JUN 1 '87
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ISSUED FOR CBM
REVISION
DATE
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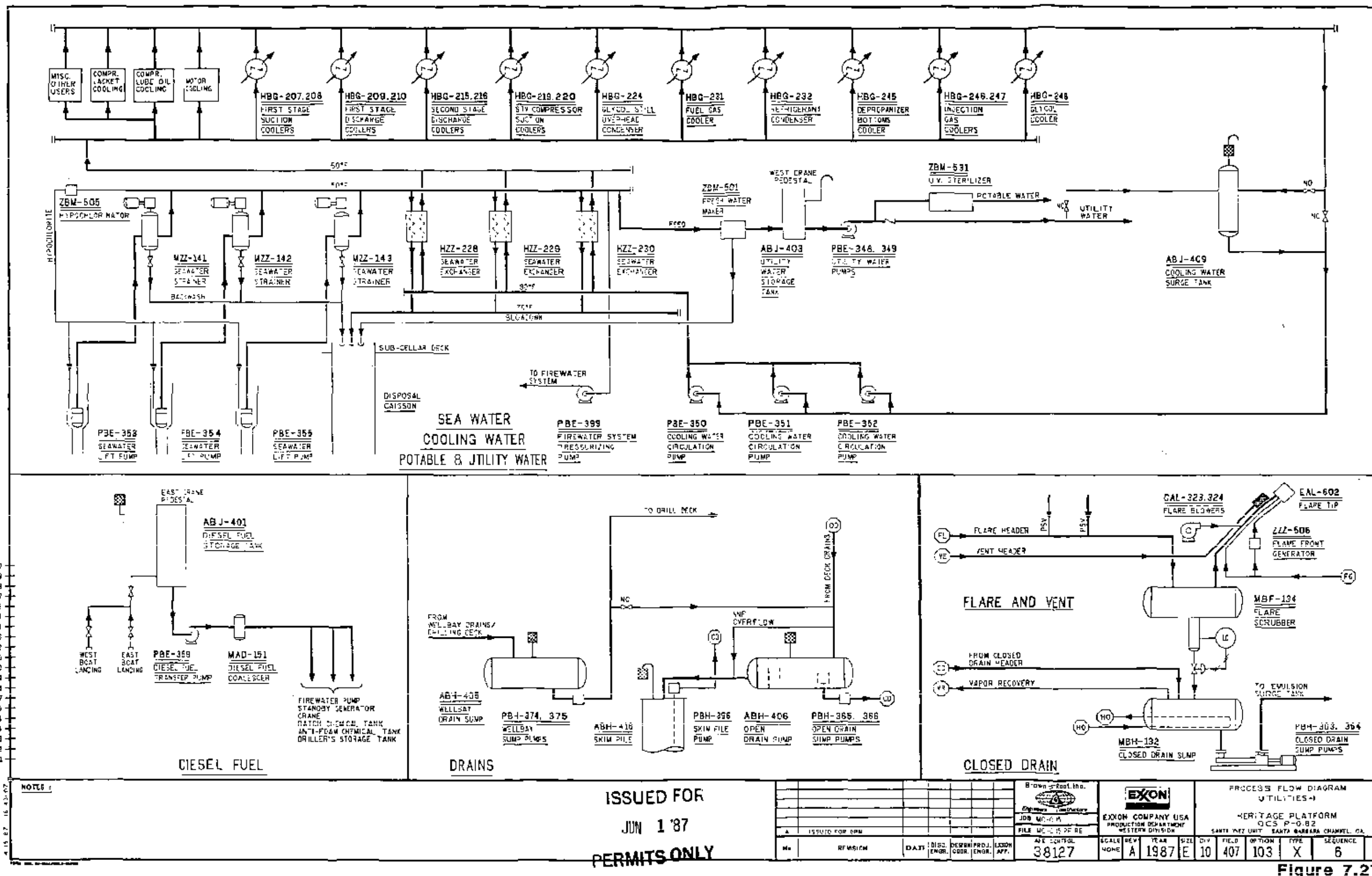
PROJ. ENGR.
EXXON APP.
JOB MC-305
AFE CONTROL
38127
EXXON
EXXON COMPANY USA
PRODUCTION DEPARTMENT
WESTERN DIVISION
PROCESS FLOW DIAGRAM
GAS COMPRESSION, GAS INJECTION
SANTA YNEZ
SCALE NONE
REV A
YEAR 1987
SIZE E
FIELD 407

Figure 7.26



MISC. OTHER USERS
COMPR. JACKET COOLING
COMPR. LUBE OIL COOLING
MOTOR COOLING
HBG-207,208 FIRST STAGE SUCTION COOLERS
HBG-209,210 FIRST STAGE DISCHARGE COOLERS
HBG-215,216 SECOND STAGE DISCHARGE COOLERS
HBG-219,220 STV COMPRESSOR SUCTION COOLERS
HBG-224 GLYCOL STILL OVERHEAD CONDENSER
HBG-231 FUEL GAS COOLER
HBG-232 REFRIGERANT CONDENSER
HBG-245 DEPROPANIZER BOTTOMS COOLER
HBG-246,247 INJECTION GAS COOLERS
HBG-248 GLYCOL COOLER
ZBM-505 HYPOCHLORINATOR
HYPOCHLORITE
MZZ-141 SEAWATER STRAINER
MZZ-142 SEAWATER STRAINER
MZZ-143 SEAWATER STRAINER
BACKWASH
HZZ-228 SEAWATER EXCHANGER
HZZ-229 SEAWATER EXCHANGER
HZZ-230 SEAWATER EXCHANGER
BLOWDOWN
SUB-CELLAR DECK
DISPOSAL CAISSON
TO FIREWATER SYSTEM
PBE-353 SEAWATER LIFT PUMP
PBE-354 SEAWATER LIFT PUMP
PBE-355 SEAWATER LIFT PUMP
SEA WATER
COOLING WATER
POTABLE & UTILITY WATER
PBE-399 FIREWATER SYSTEM PRESSURIZING PUMP
PBE-350 COOLING WATER CIRCULATION PUMP
PBE-351 COOLING WATER CIRCULATION PUMP
PBE-352 COOLING WATER CIRCULATION PUMP
FEED
ZBM-501 FRESH WATER MAKER
WEST CRANE PEDESTAL
ABJ-403 UTILITY WATER STORAGE TANK
PBE-348, 349 UTILITY WATER PUMPS
ZBM-531 U.V. STERILIZER
POTABLE WATER
UTILITY WATER
NO
NC
ABJ-409 COOLING WATER SURGE TANK
EAST CRANE PEDESTAL
ABJ-401 DIESEL FUEL STORAGE TANK
WEST BOAT LANDING
EAST BOAT LANDING
PBE-359 DIESEL FUEL TRANSFER PUMP
MAD-151 DIESEL FUEL COALESCER
FIREWATER PUMP
STANDBY GENERATOR
CRANE
BATCH CHEMICAL TANK
ANTI-FOAM CHEMICAL TANK
DRILLER'S STORAGE TANK
DIESEL FUEL
TO DRILL DECK
FROM DECK DRAINS
FROM WELLBAY DRAINS/ DRILLING DECK
OVERFLOW
ABH-405 WELLBAY DRAIN SUMP
PBH-374, 375 WELLBAY SUMP PUMPS
ABH-416 SKIM PILE
PBH-396 SKIM PILE PUMP
ABH-406 OPEN DRAIN SUMP
PBH-365, 366 OPEN DRAIN SUMP PUMPS
DRAINS
PSV
FLARE HEADER
VENT HEADER
CAL-323,324 FLARE BLOWERS
EAL-602 FLARE TIP
ZZZ-606 FLAME FRONT GENERATOR
FLARE AND VENT
MBF-134 FLARE SCRUBBER
FROM CLOSED DRAIN HEADER
VAPOR RECOVERY
TO EMULSION SURGE TANK
MBH-132 CLOSED DRAIN SUMP
PBH-363, 364 CLOSED DRAIN SUMP PUMPS
CLOSED DRAIN
NOTES:
ISSUED FOR
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PERMITS ONLY
ISSUED FOR EPA
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EXXON
EXXON COMPANY USA
PRODUCTION DEPARTMENT WESTERN DIVISION
PROCESS FLOW DIAGRAM UTILITIES
HERITAGE PLATFORM
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SANTA YNEZ UNIT SANTA BARBARA CHANNEL, CA.
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Figure 7.27

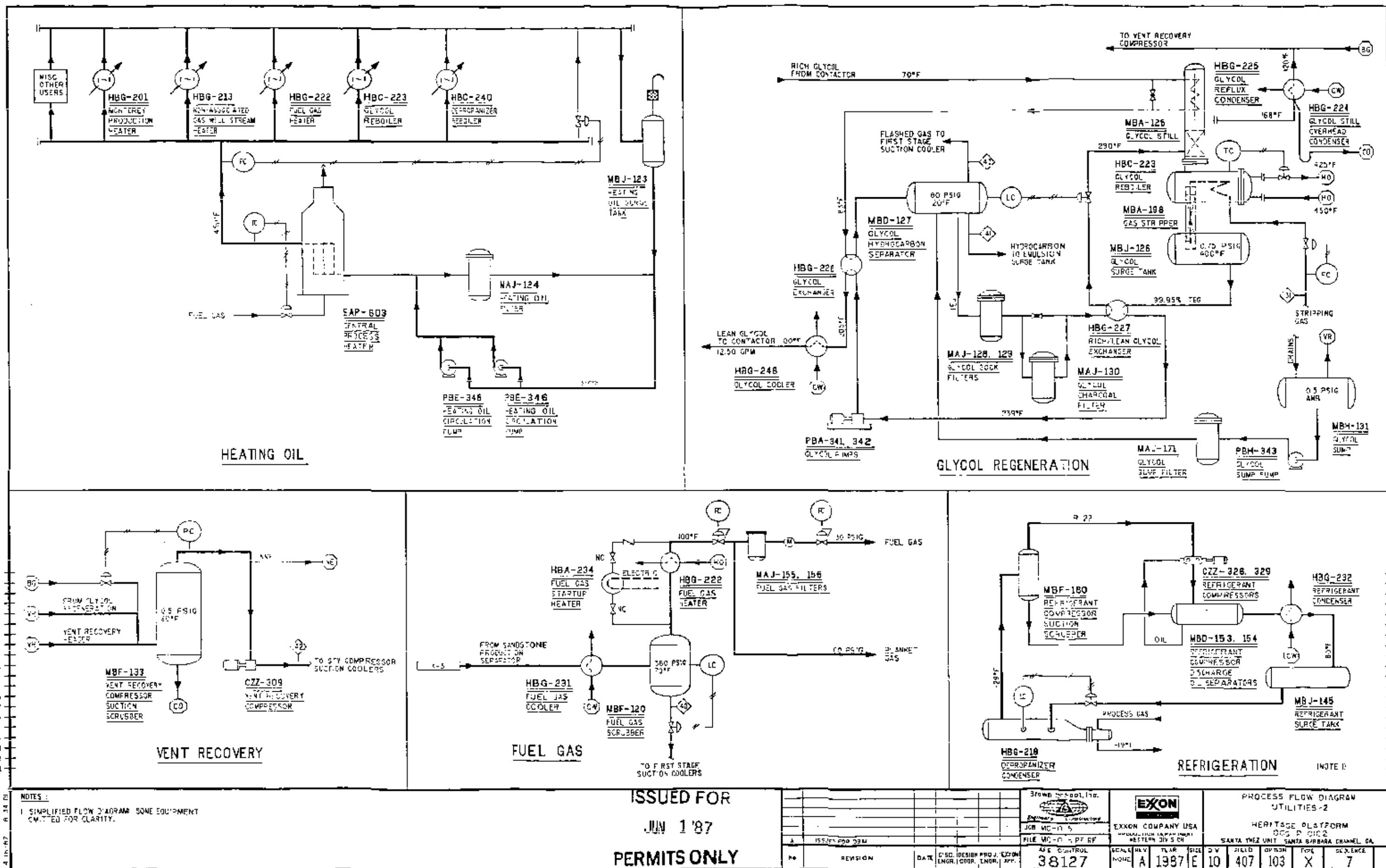
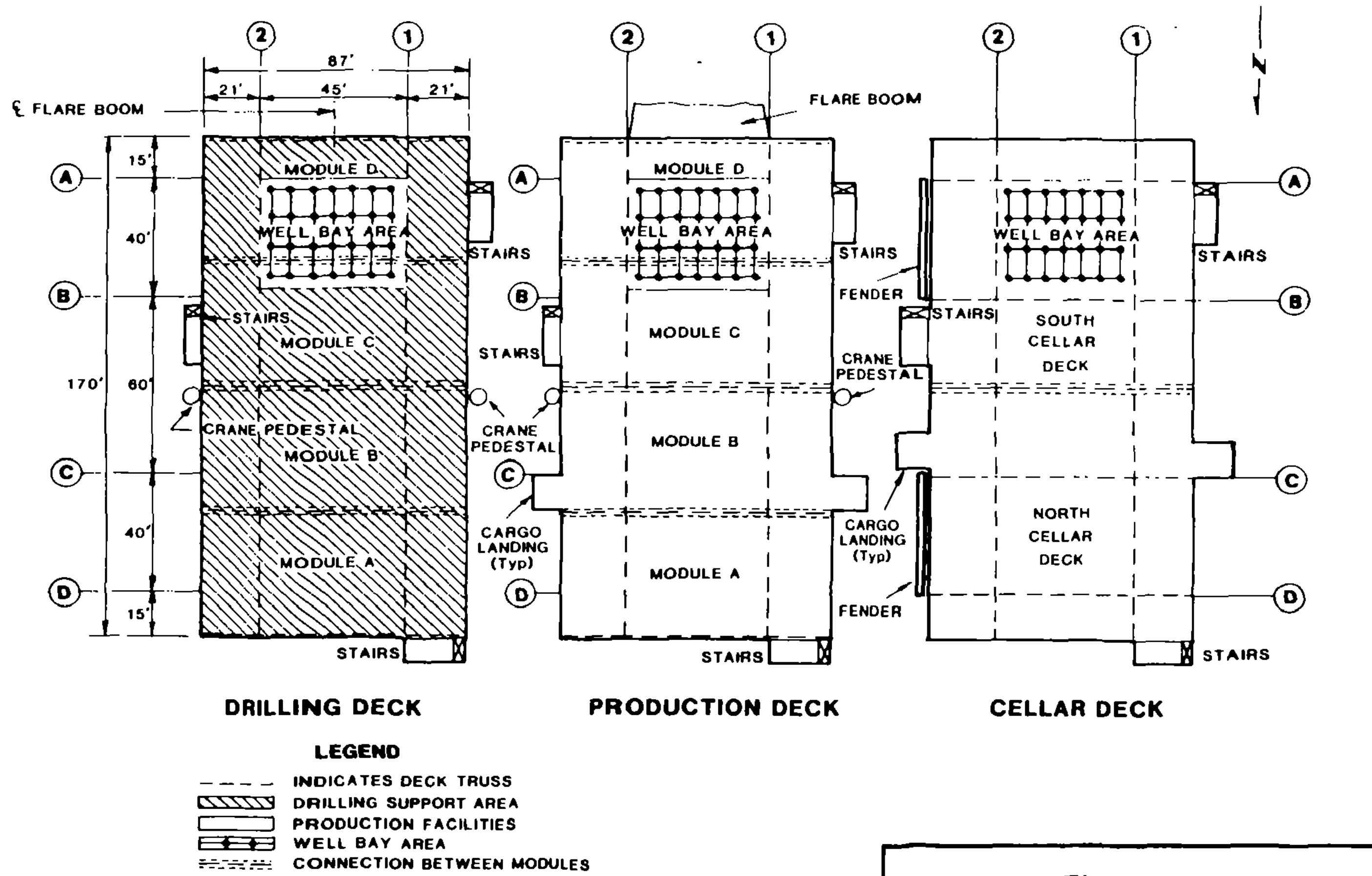

HEATING OIL
HBG-201 MONTEREY PRODUCTION HEATER
HBG-213 NON-ASSOCIATED GAS WELL STREAM HEATER
HBG-222 FUEL GAS HEATER
HBG-223 GLYCOL REBOILER
HBG-240 DEPROPANIZER REBOILER
MISC OTHER USERS
MBJ-123 HEATING OIL SURGE TANK
MAJ-124 HEATING OIL FILTER
EAP-603 CENTRAL PROCESS HEATER
PBE-345 HEATING OIL CIRCULATION PUMP
PBE-346 HEATING OIL CIRCULATION PUMP
FUEL GAS
GLYCOL REGENERATION
RICH GLYCOL FROM CONTACTOR 70°F
TO VENT RECOVERY COMPRESSOR
HBG-225 GLYCOL REFLUX CONDENSER
HBG-224 GLYCOL STILL OVERHEAD CONDENSER
MBA-125 GLYCOL STILL
HBG-223 GLYCOL REBOILER
MBA-198 GAS STRIPPER
MBJ-126 GLYCOL SURGE TANK
FLASHED GAS TO FIRST STAGE SUCTION COOLER
MBD-127 GLYCOL HYDROCARBON SEPARATOR
60 PSIG
HYDROCARBON TO EVOLUTION SURGE TANK
HBG-226 GLYCOL EXCHANGER
HBG-227 RICH/LEAN GLYCOL EXCHANGER
99.95% TEG
STRIPPING GAS
LEAN GLYCOL TO CONTACTOR
HBG-248 GLYCOL COOLER
MAJ-128, 129 GLYCOL SOCK FILTERS
MAJ-130 GLYCOL CHARCOAL FILTER
PBA-341, 342 GLYCOL PUMPS
MAJ-171 GLYCOL SLUG FILTER
PBH-343 GLYCOL SUMP PUMP
MBH-131 GLYCOL SUMP
0.5 PSIG
VENT RECOVERY
FROM GLYCOL REGENERATION
VENT RECOVERY HEATER
0.5 PSIG
MBF-133 VENT RECOVERY COMPRESSOR SUCTION SCRUBBER
CZZ-309 VENT RECOVERY COMPRESSOR
TO 1ST COMPRESSOR SUCTION COOLERS
FUEL GAS
HBA-234 FUEL GAS STARTUP HEATER
HBG-222 FUEL GAS HEATER
MAJ-155, 156 FUEL GAS FILTERS
FROM SANDSTONE PRODUCTION SEPARATOR
HBG-231 FUEL GAS COOLER
MBF-120 FUEL GAS SCRUBBER
TO FIRST STAGE SUCTION COOLERS
BLANKET GAS
REFRIGERATION
MBF-180 REFRIGERANT COMPRESSOR SUCTION SCRUBBER
CZZ-328, 329 REFRIGERANT COMPRESSORS
HBG-232 REFRIGERANT CONDENSER
MBD-153, 154 REFRIGERANT COMPRESSOR DISCHARGE OIL SEPARATORS
MBJ-145 REFRIGERANT SURGE TANK
HBG-218 DEPROPANIZER CONDENSER
PROCESS GAS
NOTE 1
NOTES:
1. SIMPLIFIED FLOW DIAGRAM. SOME EQUIPMENT OMITTED FOR CLARITY.
ISSUED FOR
JUN 1 '87
PERMITS ONLY
EXXON COMPANY USA
PROCESS FLOW DIAGRAM UTILITIES-2
HERITAGE PLATFORM
38127

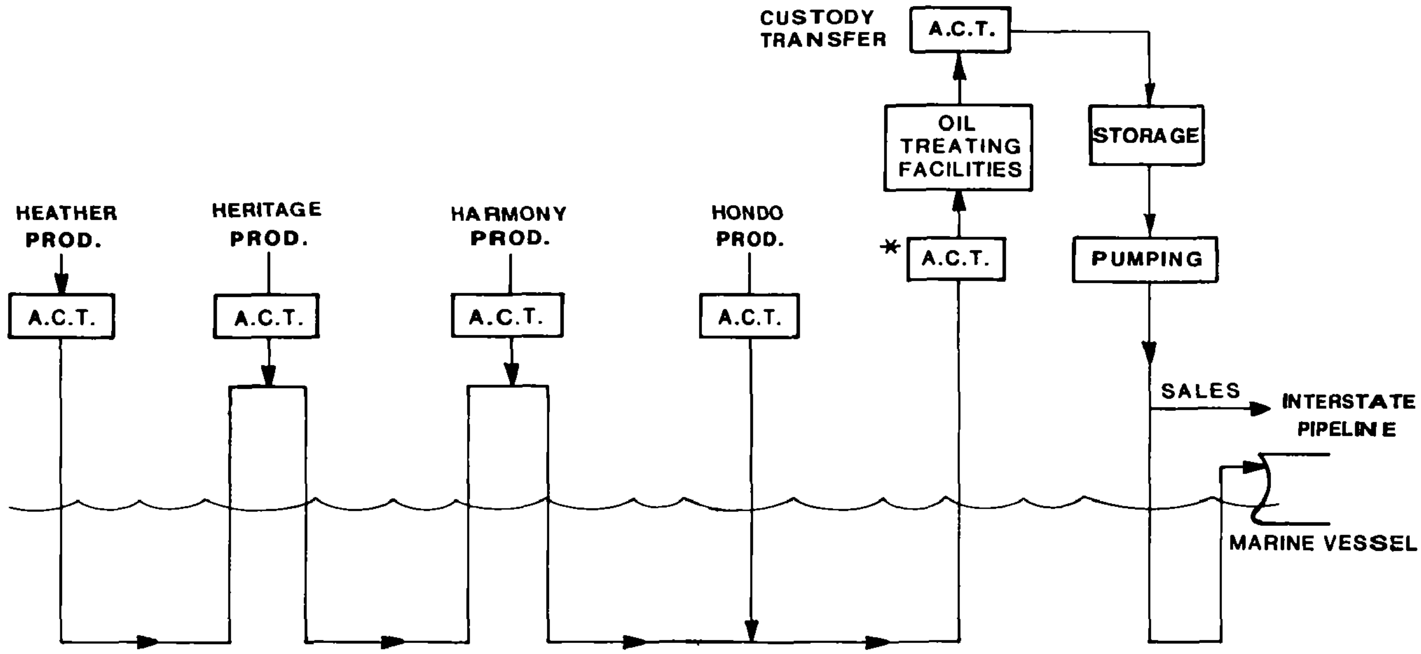
Figure 7.28



HEATHER PLATFORM
DECK ARRANGEMENTS

Figure 7.29

HEATHER PLATFORM
PRELIMINARY DECK ARRANGEMENTS



*A.C.T. Coming in from the gathering system used only for volumetric leak checking and total system operational metering verification. No BS&W measurement made.

Figure 7.30

COMMINGLED EMULSION METERING SYSTEM

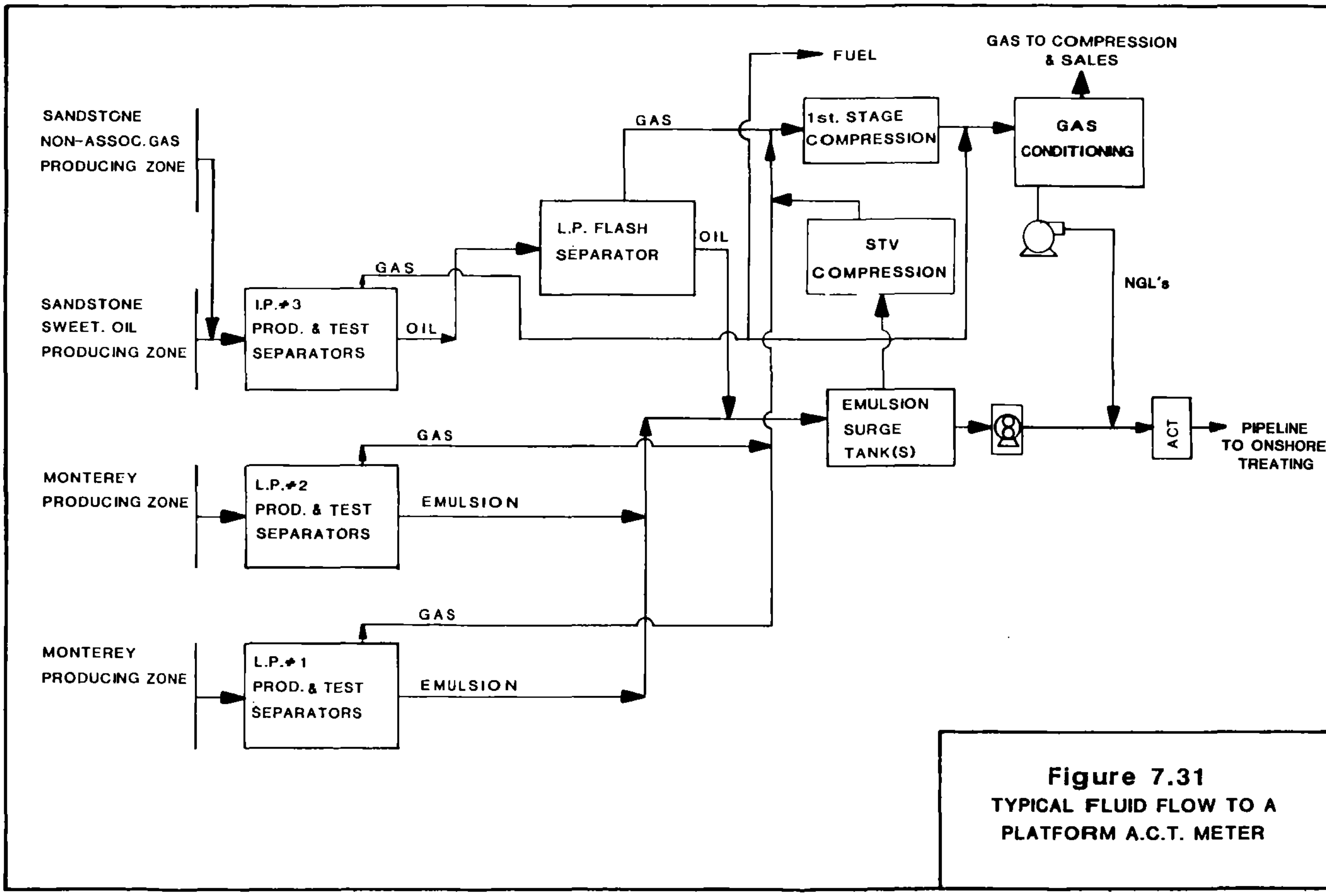


Figure 7.31
TYPICAL FLUID FLOW TO A PLATFORM A.C.T. METER

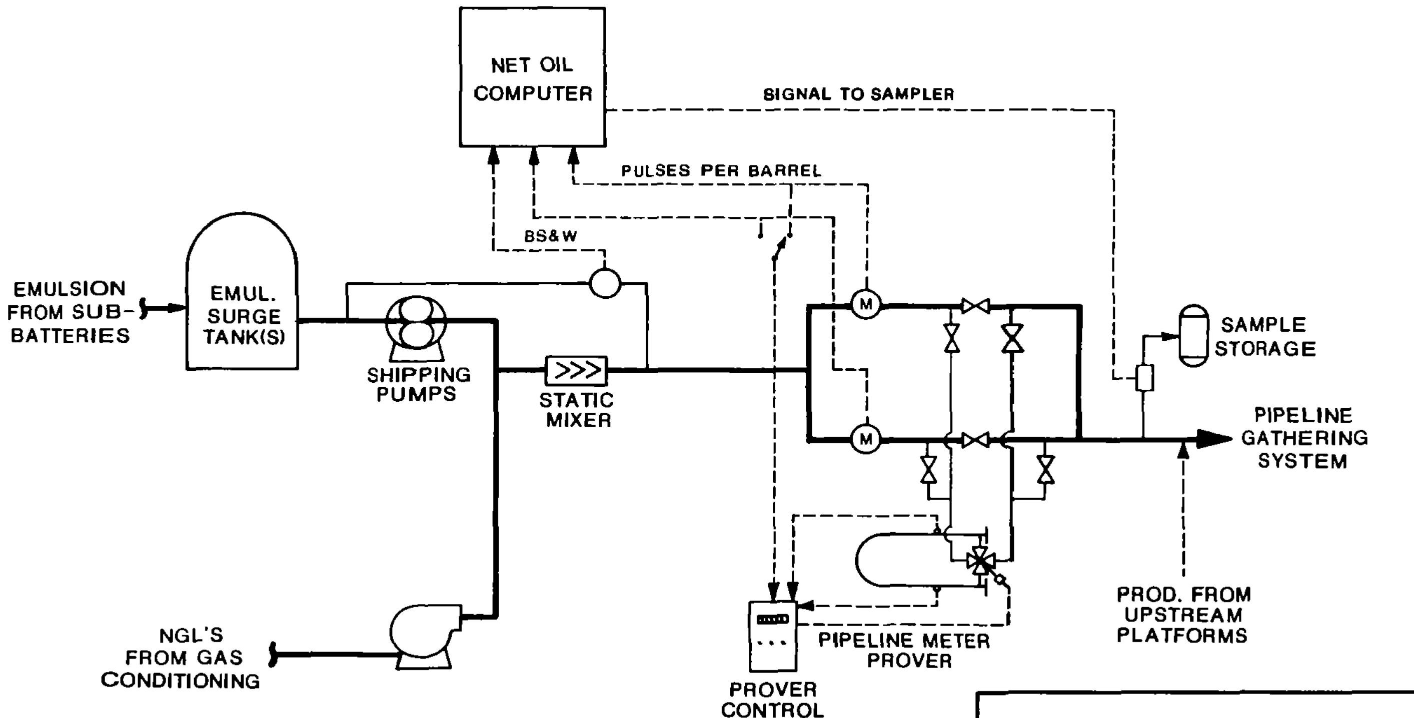


Figure 7.32

TYPICAL PLATFORM

(BATTERY) A.C.T. METER SYSTEM

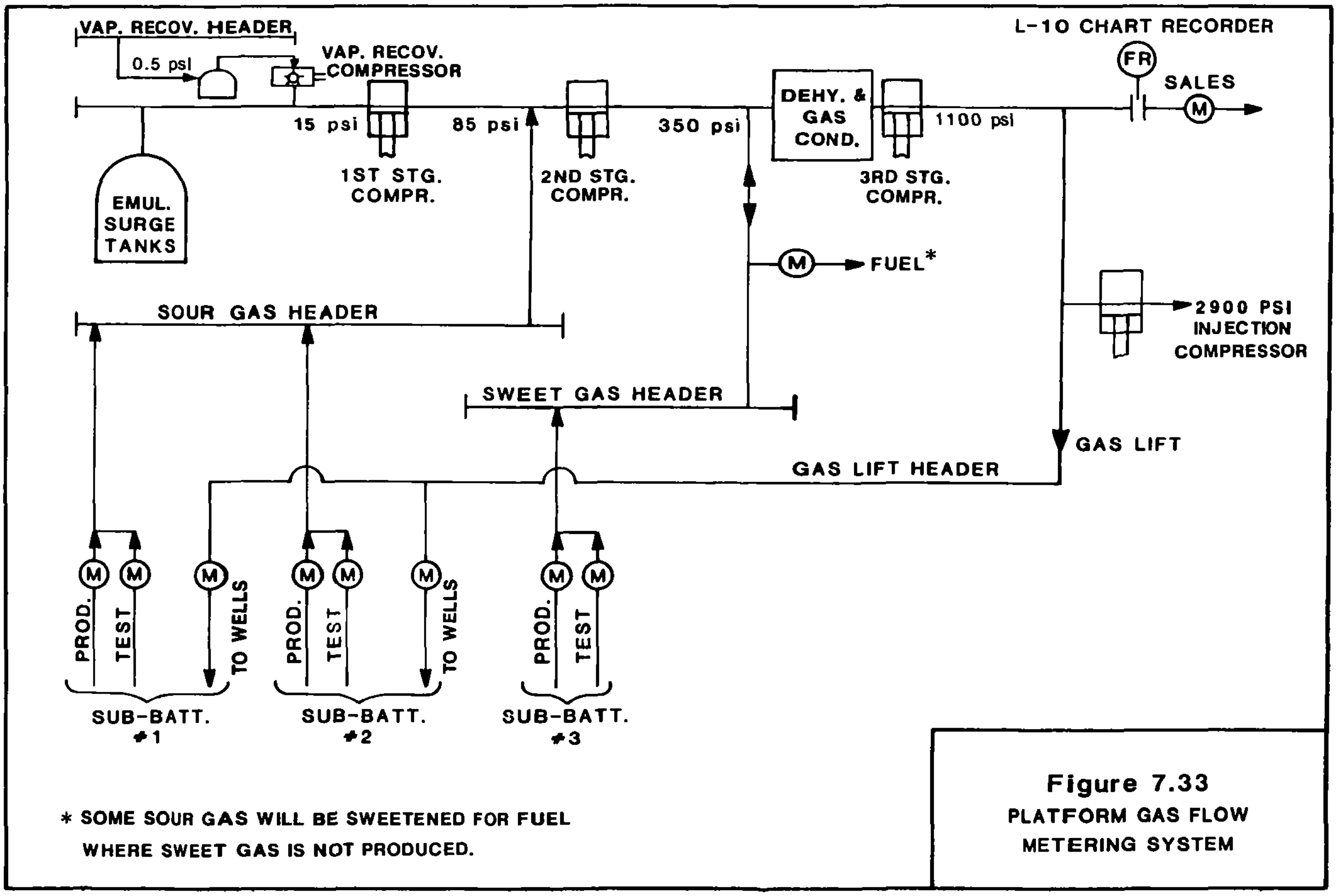


Figure 7.33
PLATFORM GAS FLOW METERING SYSTEM

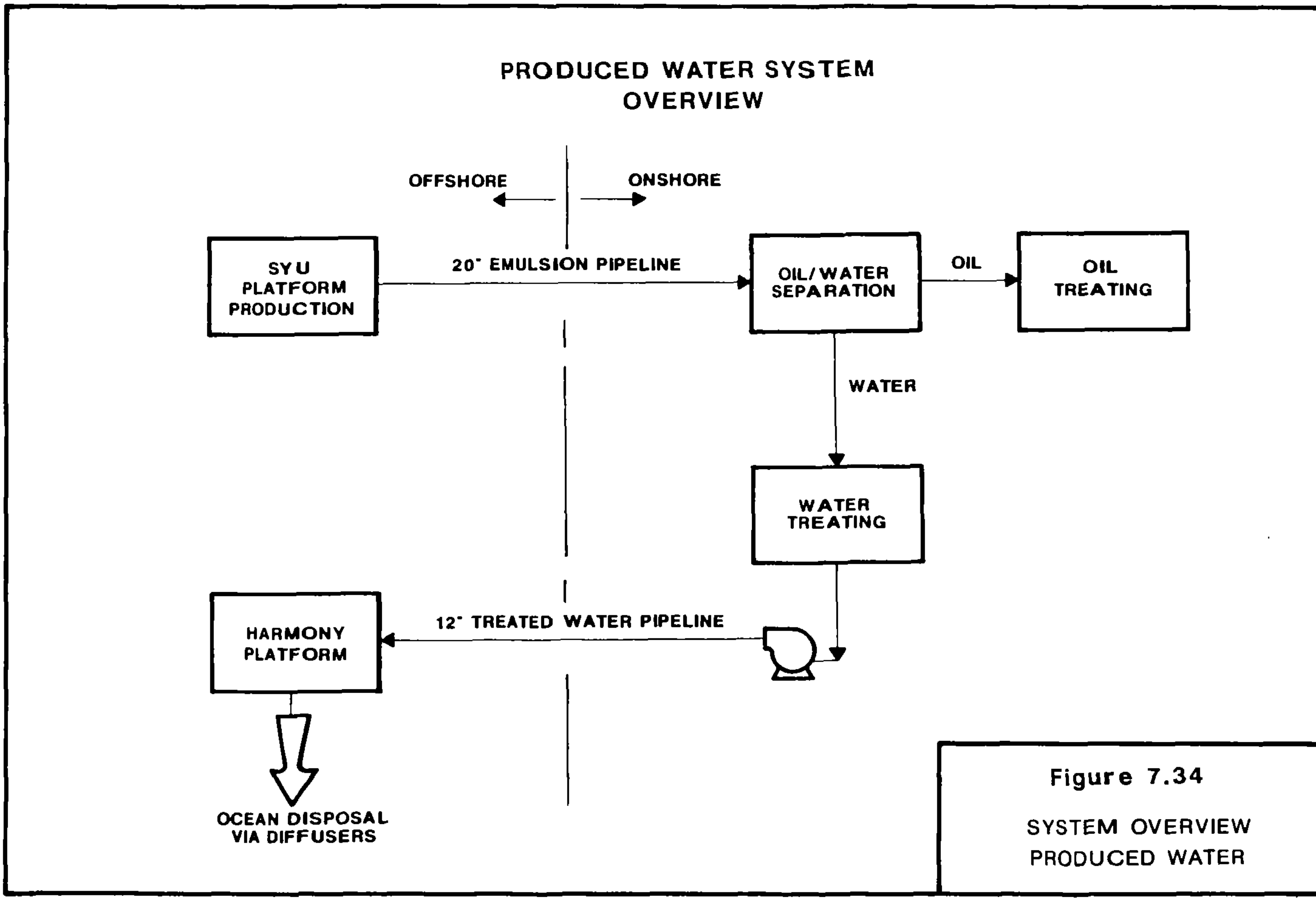


Figure 7.34

SYSTEM OVERVIEW
PRODUCED WATER

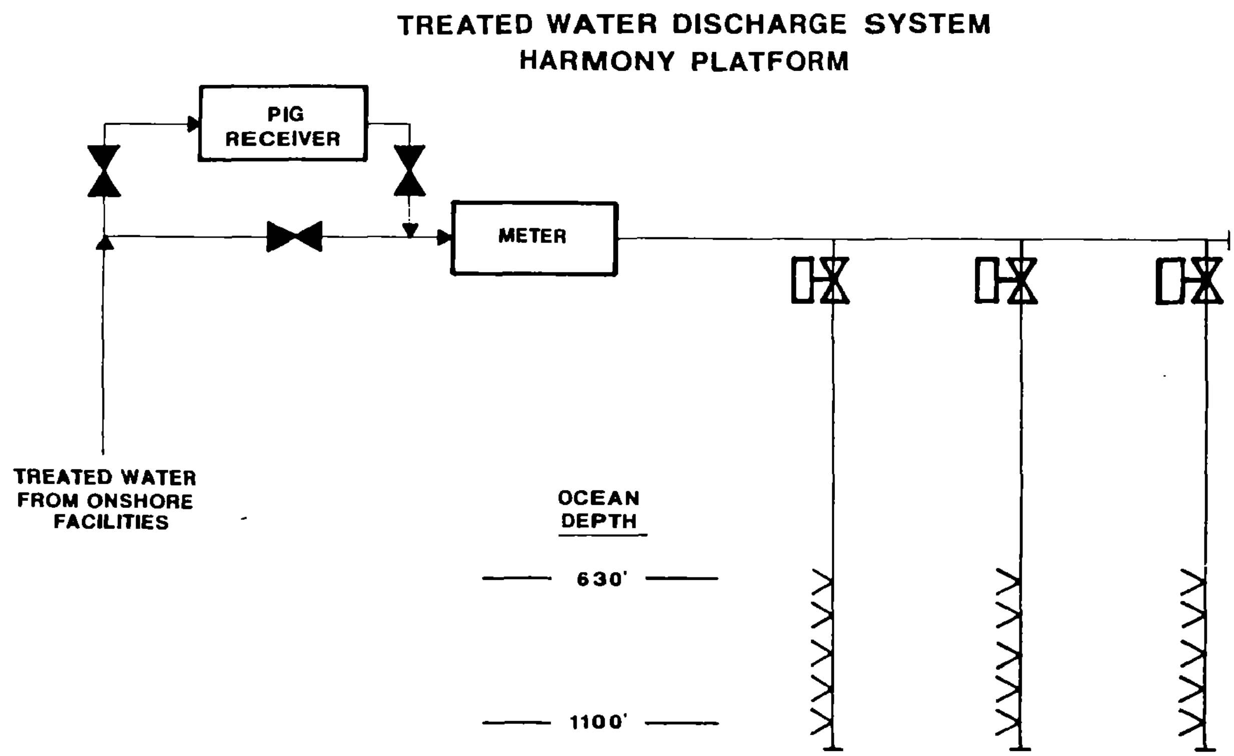


Figure 7.35

TREATED WATER DISCHARGE
SYSTEM-HARMONY PLATFORM

FIGURE 7.36

EXXON COMPANY, U.S.A. PROPRIETARY FIGURE

SYU FACILITY TREATED WATER FLOW RATE

1992 TO 2020

SEE APPENDIX A

SECTION VIII

PIPELINES

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SECTION VIII

PIPELINES

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SECTION VIII

PIPELINES

TABLES

SECTION VIII

PIPELINES

FIGURES

SECTION VIII

8.1 Introduction

This section describes the pipelines associated with the development of the Santa Ynez Unit. The pipeline system is discussed in terms of the safety of the proposed pipeline routes, applicable regulations, pipeline design criteria, and construction and operations procedures. Section 2.3 (Near-Surface Geology) provides additional information which is applicable to the discussions of the pipeline corridors. The pipeline system includes both onshore and offshore pipeline segments. The electrical power cables interconnecting the project elements will be installed in the same corridors as the pipelines.

8.2 Pipeline System

The proposed pipeline system, as allowed by safety and engineering studies, will be routed through the pipeline corridors shown in Figure 8.1. The design flow rates are 210 kBD of emulsion and a combined "to-shore" gas flow rate of 230 MSCFD. Reference Figure 7.2 for the pipeline system schematic and Table 8.1 for pipeline system characteristics. The offshore gas and water pipelines connecting to the OS&T will be purged and abandoned in place.

Interplatform emulsion pipelines will range from 12 to 20 inches. The existing 12-inch emulsion line from Platform Hondo to the OS&T will be disconnected and tied in midline to a new 20-inch emulsion line extending from Platform Harmony to the Las Flores Canyon oil treating facilities. All SYU oil production will be transported to the oil treating facilities via this 20-inch pipeline.

Produced gas will be brought to shore via two pipelines. The first pipeline, the existing 12-inch pipeline originating at Platform Hondo, will continue to bring all Platform Hondo gas onshore to the POPCO Gas Plant. Harmony gas production will be tied into this existing line at a midline subsea interconnect. The second pipeline, a new 14-inch line, will bring Heritage and Heather gas production onshore. Since the current plan initially calls for injection of all Platform Heritage gas and deferral of Platform Heather, installation of this line will also be deferred.

Additionally, a 12-inch pipeline will carry produced water from the oil treating facilities to an offshore outfall discharge point located at Platform Harmony. Power to the offshore platforms will be provided via two cables from onshore to Platform Harmony and one cable from onshore to Platform Heritage. Additional jumper cables will connect to Platforms Hondo and Heritage from Harmony and from Heritage to Heather. The pipelines connecting the Transportation Terminal with the Las Flores Canyon facilities will include: a 48-inch crude oil offloading line, two 18-inch vapor balance lines, and miscellaneous control lines. A 4-inch sewage line will connect the Transportation Terminal with the leach field.

8.3 Pipeline Corridors

8.3.1 Platform Heather to Platform Heritage Corridor

8.3.1.1 Geologic Design Considerations

A geologic evaluation was made of the pipeline corridor between Platform Heather and Platform Heritage. This corridor is 24,000 feet long and approximately 1,000 feet wide (see Figure 8 for details). It lies wholly within the Conception (submarine) Fan Province. The corridor parallels the axial trend of the Western and Pescado Channels and is located on a broad interchannel area. The shallow subsurface geology reflects the complex depositional development of the Conception Fan. The shallow sediment consists of interbedded sand and silt deposited in an area of internested channels and levee deposits. Except for a locally thin veneer of clayey silt to silty sand, the majority of the shallow subsurface sediment is interpreted to be compacted fine sand.

8.3.1.2 Geotechnical Design Considerations

Soils within this pipeline corridor are typically fine-grained sands and sandy silts which present no obvious obstacles or hazards to pipeline construction or operation. The potential for liquefaction or other types of failure mechanisms will be analyzed based on the specific soil properties and loadings from the design environmental conditions such as earthquake and storm waves. The existence and location of any areas of potential instability will be defined by a route analysis survey. If such areas are defined, the pipelines will then either be routed to avoid these areas or be designed to remain stable and/or within allowable stress limits when such areas are traversed.

8.3.2 Platform Heritage to Platform Harmony Corridor

8.3.2.1 Geologic Design Considerations

The pipeline corridor between Platforms Heritage and Harmony is approximately 36,000 feet long and 1,000 feet wide (see Figure 8.1 for details). It lies in both the Conception Fan Province and the Smooth-Slope Province. The corridor crosses several fan channels and then crosses the lower slope area of the Slope Province.

The portion of the corridor within the Conception (submarine) Fan Province crosses a substrate of fine sand with silt and gravel interbedding overlain by a veneer of silty sand to silty clay. On the basis of its characteristic seismic signature, this veneer is designated the "transparent layer." It is thicker in the channels than in the interchannel areas and seems to increase in thickness towards the east.

The modern fan channels are broad features, ranging from less than 1,000 feet to 3,000 feet wide and between 20 feet and 70 feet deep. Slopes along the channel walls, the steepest encountered along the corridor, are generally less than ten degrees. Axial gradients within the channels and downslope gradients in the interchannel area are less than seven degrees.

A geologic hazards analysis indicates that the fan channels are presently dormant and are not acting as conduits for large mass density flows. The channels and fan surface were found to be receiving sediment at a relatively slow rate, probably from weak nepheloid flow and normal hemipelagic sedimentation.

In contrast with the Conception (submarine) Fan Province, the gradients on the Smooth-Slope Province generally do not exceed six percent. The Smooth-Slope represents a region of fairly uniform and steady deposition. The surface and near-surface sediment is predominantly silt to clayey silt with little lateral variability.

8.3.2.2 Geotechnical Design

Soils within this pipeline corridor typically range from silty sands and silts on the western side to silts and muddy silts on the eastern side. No significant geotechnical obstacles or hazards to pipeline construction or operation have been identified within this corridor.

Pipeline routes have been selected within the corridors shown in Figure 8.1 which avoid crossing any known areas of potential soil instability. However, if such areas are subsequenty defined, pipelines will be designed to remain stable and/or within allowable stress limits when such areas are traversed.

8.3.3 Platform Harmony to Shelf Break Corridor

8.3.3.1

The pipeline corridor between Platform Harmony and the boundary between the Smooth-Slope and Shelf Provinces is approximately 24,000 feet long and 5,000 feet wide and lies wholly within the Smooth-Slope Province. The inter-connecting pipelines between Platforms Harmony and Hondo will be installed within this corridor. The surface sediment and shallow subsurface stratigraphy is identical to that of the eastern half of the Platform Heritage to Platform Harmony route. The slope gradient averages six percent.

8.3.3.2 Geotechnical Design Considerations

Soil properties within this corridor are identical to those found at the eastern side of the Platform Heritage to Platform Harmony corridor, and similar routing and design considerations will prevail.

8.3.4. Shelf Break to Corral Canyon Shorefall

8.3.4.1 Geologic Design Considerations

The pipeline route from the Shelf Break is approximately 27,500 feet long and approximately 2,000 feet wide (see Figure 8.1). It extends northeastward across the Shelf Province to shore. Slopes are gentle except for a local area near the shelf break (approximately the 300-foot water depth) where rock is exposed as ridges (one to three feet) and a zone just offshore of the beach where there are low bedrock ridges (three to five feet). Sediment along the route ranges from fine silt offshore to sand onshore.

8.3.4.2 Geotechnical Design Considerations

Soils along this route range typically from medium grained sands to silty sands. In the shelf area, surface sediments are underlain by bedrock which outcrops in a few instances. Gas charged near-surface sediments occur in localized areas on the slope; however, the pipeline will be routed to avoid these areas. The route and construction methods will be selected to assure that the pipeline gradient is not adversely affected by abrupt changes in the sea bottom profile.

8.3.5 Transportation Terminal to Shelf Break/Corral Canyon Corridor Intersection

8.3.5.1 Geologic Design Considerations

This pipeline route lies entirely in the Shelf Province where slopes are nearly flat with a typical 2.4 percent gradient. Sediments in this corridor are generally silty sands overlaying bedrock.

8.3.5.2 Geotechnical Design Considerations

Soils along this route are typically low strength silty sands. Several possible gas seeps and a 500-foot by 1,600-foot zone of gas-charged sediment have been identified within the corridor; however, no related soil instabilities were observed. Surveys have been conducted to cover the SALM location and pipeline route which indicate that no geologic hazards exist along the proposed pipeline routes that preclude safe design, installation, and operation of the pipelines. See Section II, Reference 22 for further information.

8.3.6

8.3.6.1 Geologic and Geotechnical Design Considerations

Studies have indicated that no major hazards exist along the pipeline route. However, soils and geologic investigations in the Las Flores/Corral Canyon have noted the occurrence of large landslide areas in portions of the west side of Corral Creek. If it is necessary to relieve the hydrostatic pressures that cause these slide potentials, the slopes may be dewatered using horizontal slope drains. This will assist in the protection of the road and pipelines from potential slide damage.

A complete review of geologic and geotechnical considerations has been made for the onshore site and pipeline areas of Las Flores/Corral Canyons and is presented in Volume I, Section 2 of the "Final Environmental Impact Report For The Proposed Exxon Oil and Gas Handling At Las Flores Canyon, Santa Barbara County, California" dated October, 1974. No additional studies have been done specifically for the onshore corridor.

8.4 Applicable Design Codes

The oil and gas pipelines will be designed, constructed, tested, operated and inspected in compliance with the following standard specifications, as applicable:

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

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

- Transportation of Liquids by Pipeline, Department of Transportation Regulation 49, Part 195.

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

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

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

Pipeline segments that pass through state waters will also meet or exceed all requirements of applicable state and local agencies.

8.5 Design

8.5.1 Offshore Pipelines

The proposed offshore pipelines will be designed to ensure construction and operation in a technically sound and environmentally acceptable manner. The pipelines will be installed along pipeline routes that have been carefully scrutinized for potential hazards to ensure that the pipelines may be safely installed and operated. Detailed design data will satisfy Pacific Region OCS Order No. 9.

8.5.1.1 Design Criteria

Design criteria will be determined by the external environmental loads and the internal loads that the pipelines may experience over their operating life, including stresses induced during pipeline installation. Pipeline design will ensure that the level of stress imposed by these conditions will not exceed acceptable limits. All pipelines will be designed to withstand their maximum internal design operating pressure in accordance with the applicable standard specifications listed in Section 8.4.

The internal loads are a result of the chemical and physical characteristics of the transported fluid under operating conditions, including fluid composition, density and rheological parameters, flow rates, pressure and temperature. Design flow rates are 210 kBD of emulsion and 230 MSCFD of combined gas production from two pipelines.

External environmental loads result from meteorological and oceanographic phenomena and the geologic and geotechnical characteristics of the sea bottom along the pipeline routes. Environmental forces include waves, currents, earthquake ground motions, and ambient pressure and temperature. Design parameters will account for significant wave height, period and direction, bottom steady current velocity and direction, and earthquake wave velocities and periods. These criteria may vary depending upon the specific location and direction of the pipelines but will be consistent with the values used in the platform designs. Ambient external pressure is a function of water depth over the routes. The maximum water depth that could be encountered in the pipeline system is approximately 1,350 feet (in the Platform Heritage to Platform Harmony corridor). The design minimum ambient temperature will be approximately 40° F.

Stresses induced in the pipeline during installation are a function of construction methods and equipment, as well as the prevailing natural environment at the time and place of construction activities. The construction methods and specific equipment will be selected to ensure that the pipelines are not overstressed during installation.

Criteria for monitoring out-of-bounds operating conditions and shutting off flow in case of such conditions will satisfy MMS Pacific Region OCS Order No. 9.

8.5.1.2 Mechanical Design

The emulsion and gas pipelines will be designed for a maximum allowable net internal working pressure corresponding to an ANSI 600 class (1,480 psig @ 100° F) of valves, flanges and fittings. The produced water pipeline design will correspond to an ANSI 300 class (740 psig @ 100°F). These designs will include appropriate safety factors for the pipelines and pipeline risers. The lines will also be designed to withstand the maximum bending moment and the maximum local external hydrostatic pressure with the pipeline void of fluids. The lines will be equipped with buckle arrestors where required to protect the pipelines from propagation of a buckle during construction.

Thermal, environmental, and other external loads will be analyzed to assure safe stress levels under all possible loading combinations for both pipelines and pipeline risers. Pipe wall thickness and steel properties will be determined based on the above design analyses and on corrosion protection requirements.

8.5.1.3 Stability

The pipelines will be designed to resist significant horizontal and vertical deflection under the action of bottom steady currents, wave induced oscillatory currents and earthquakes. Earthquake motion design criteria will be consistent with the values used in the platform designs. Stability will be accomplished via routing, increased submerged weight, trenching, anchoring, or combinations of these methods.

8.5.1.4 Corrosion Protection

The pipelines will be protected from external corrosion by a protective coating which will be supplemented with sacrificial anode type cathodic protection. The splash zone sections of the platform risers will have additional protection from the more severe mechanical and corrosive attack associated with this area. Design of protection from internal corrosion and other chemical degradation mechanisms will be based on a proper selection of pipe steel chemistry, pipe wall thickness and manufacturing processes.

Internal control of the pipeline system will include the use of inhibitors, either batch or continuous, and the periodic removal of stagnant fluids (water) by pigging. The emulsion and gas pipelines will be designed to allow use of a Linalog inspection tool with two exceptions: 1) the 12-inch gas line from Harmony to the subsea tie-in at the existing Hondo gas pipeline, and 2) the existing emulsion line from Hondo to the proposed mid-line tie-in at the new 20-inch line to shore.

8.5.2 Onshore Pipelines

8.5.2.1 Design Criteria

Design criteria will be determined by the external environmental loads and the internal loads that the pipelines may experience over their operating life, including stresses induced during pipeline installation. Pipeline design will ensure that the levels of stress imposed by these conditions will not exceed acceptable limits.

The SYU emulsion line size was derived from hydraulic and thermal calculations. The water outfall line size is based upon transporting 87,000 barrels per day of treated produced water from the Oil Treating Plant to diffusers at Platform Harmony. Booster pumps in the Transportation Terminal will pump the water offshore.

All pipelines will be designed to withstand their maximum internal design operating pressure in accordance with the applicable standard specifications listed in Section 8.4. The design flow rates for the onshore pipeline segments are given in Table 8.1.

Special consideration will be given to the stresses induced by the heating and cooling of the contents within the pipelines. Dynamic effects such as earthquakes, vibrations, and land subsidence will be evaluated in the design studies. External loads such as pipe coating, backfill material and pipe installation stresses will also be considered in the design of these systems.

8.5.2.2 Mechanical Design and Corrosion Protection

The emulsion and gas pipelines will be designed for a maximum allowable net working pressure corresponding to an ANSI 600 class (1,480 psig @ 100° F) of valves and fittings. Actual onshore operating pressure for the emulsion pipeline will be less than 500 psig. Actual onshore operating pressure for the gas pipeline will be approximately 1,000 psig. The produced water pipeline design will correspond to an ANSI 300 class (740 psig @ 100° F). Actual onshore operating pressure for the produced water pipeline will be approximately 275 psig.

All pipeline systems will include relief valves to prevent the accumulation of pressure resulting from surges and the ambient heating and consequent thermal expansion of static liquid contents.

The onshore pipelines will be equipped with cathodic protection devices for external corrosion protection. Insulating flanges will be installed where needed. The cathodic protection method will incorporate either a rectifier system or an all galvanic system. Design for protection from internal corrosion and other chemical degradation mechanisms will be based on a proper selection of pipe materials, coatings, wall thicknesses, and manufacturing processes. Internal wall thicknesses and manufacturing processes. Internal corrosion control may include the use of inhibitors and pigging.

8.6 Construction

8.6.1 Offshore Pipelines

The primary construction method anticipated for installation of the offshore pipelines is the conventional lay barge method. The most critical part of the installation is the section from Heritage to Harmony where water depths of 1,350 feet may be encountered. Installation can be accomplished by a conventional second generation lay barge with upgraded pipe tensioning and mooring capabilities. Other installation methods, such as pipe tow techniques, will also be evaluated.

Assuming that pipeline construction will be by a lay barge, the equipment will be selected to provide for safe installation within the acceptable pipe stress limits. This will be accomplished by proper pipe ramp and stinger curvature, stinger length, tensioner capacity, abandonment and recovery system capacity, and mooring capability. All relevant parameters associated with pipelaying will be pre-calculated and monitored throughout construction.

Prior to construction, quality assurance will be provided at all states of material manufacture, fabrication, and coating application by qualified inspectors. During construction, quality assurance will again be accomplished by full-time, qualified inspectors. All girth welding procedures and welders will be prequalified. API Standard 1104, "Standard for Welding Pipelines and Related Facilities," will be considered a minimum guideline for welding and weld inspection. All girth welds will be radiographically inspected and recorded prior to acceptance.

The emulsion lines will be connected to pre-installed risers on the platform jackets with hydraulically-operated connectors using diverless procedures. Alignment of pipelines with the risers will be via the controlled pipeline deflection method utilizing platform deck-mounted winches. Subsea rigging and monitoring of deflection, pull-in, and connection operations will be by acoustic measurement and ROV or possibly ADS. Only small vessel support will be required for the tie-in operations.

Twenty-inch J-tubes are provided for the gas lines (owned/operated by others) which are planned to originate at each of the platforms and terminate onshore or tie in to the existing POPCO 12-inch gas line from Hondo. Up to 14-inch gas lines can be accommodated from each platform, although a 12-inch line from Harmony is most likely.

A 20-inch J-tube is provided on the east face of the Harmony Platform for the produced water pipeline. Emulsion from the Hondo Platform will be routed through the existing 12-inch line now connected to the SALM/OS&T by means of a jumper line across to the shorebound 20-inch line from Harmony. Current plans are to lay approximately 2,000 feet of new 12-inch line between a pre-installed connection point on the 20-inch line to the vicinity of the SALM. Divers will be utilized to make subsea tie-ins after first disconnecting a spool piece in the existing 12-inch line to the SALM. This could result in up to two weeks downtime for the Hondo Platform.

Adherence to all applicable regulations regarding discharge of pollutants, as well as the discharge or dumping of any solid materials, will be strictly enforced during the construction period. The construction vessels selected will be equipped with USCG-approved (or equivalent) sewage treatment systems such that the sanitary wastes are treated before disposal. For the major construction activities, including pipeline and diffuser installation, the effluent volume and constituents will be consistent with the toilet, shower/lavatory, laundry, dishwashing and garbage disposal needs of a construction vessel housing up to 250 personnel.

The pipeline systems will be gauged upon completion with a pipeline pig to assure roundness and then hydrostatically pressure tested to at least 1.25 times the maximum design operating pressure. The test duration will be at least eight hours. The test water will be disposed of offshore in compliance with a NPDES permit. Test water will be treated as needed prior to disposal to assure no adverse impact on the environment.

Neither construction nor operation of these pipelines is expected to cause interference with trawling operations or other uses of the sea floor. The smooth, round surface of the pipelines installed without valves or other protrusions will allow trawl boards and nets to pass over them with a minimum of effort. Additionally, any sea floor disturbances caused by the pipeline barge anchors should be short term and therefore are not expected to interfere with trawling. Since the seafloor soils are generally low shear strength granular materials, any soil disturbance should not obstruct trawl boards or fishing nets and in a short time should smooth out to near original contours.

The design, specifications, and construction planning for the pipeline and tie-ins will incorporate considerations for minimizing potential interference with jacket and topsides construction and commissioning activities.

Additionally, consideration will be given for the inclusion of "others" pipelines. Specifically, provisions in the pipeline corridor designs and construction plans will be made to accommodate POPCO's future 14-inch gas line from Heritage, routing of the POPCO

12-inch gas line from the Harmony mid-line tie-in to shore, and ARCO's Coal Oil Point pipelines.

8.6.2 Nearshore Pipelines

The nearshore portion of the pipelines may be made up onshore and pulled offshore by a pull barge located seaward of the kelp beds or may be made up on a lay barge located seaward of the kelp and pulled ashore. The beach crossing portion of the lines includes transit through one or more tunnels approximately 400 feet long under the Southern Pacific railroad, U.S. Highway 101, and Calle Real to a "valve box" containing remotely-operated block valves for the emulsion pipeline, produced water outfall line, and Transportation Terminal crude loading line. The beach crossing and pipeline installation out to a water depth of 80 to 90 feet will include the emulsion and produced water pipelines and three power cable conduits. The power cable conduits terminate south of the tunnel; the cables will be placed in trays through the tunnel and direct buried north of the tunnel.

Trenching will be required across the beach and out to approximately 25-foot water depth which is just shoreward of the kelp beds. Blasting will be minimized but will be required for this section in order to place the lines below potential scour depth. Regulations require backfill out to 12-foot depth contour; the remainder of the trench may be backfilled or allowed to backfill via normal sedimentation. The lines will not be trenched through or beyond the kelp beds. However, plowheads on the leading ends of the lines may be employed to partially embed the lines and prevent bridging on kelp hold-fasts. There is a potential requirement for trestles to enable trenching/backfill operations very near shore and on the beach. This potential is increased with increasing number of lines and with schedule constraints.

Tunnel lay-outs will be designed to utilize the existing tunnel for SYU lines, then for others as feasible. A second tunnel will probably be required if the remaining Marine Terminal pipeline segments are installed.

Nearshore SYU lines will terminate seaward of the kelp beds and approximately one-half mile offshore, at the point where the SYU corridor turns sharply toward the southwest. The Marine Terminal lines may be laid all the way to the SALM at one time or may be terminated at the half-mile point and finished later (probably at the same time as the offshore emulsion line and water outfall line). Design/specifications will provide this flexibility.

8.6.3 Onshore Pipelines

The onshore pipelines are defined to extend from the "valve box" north of the tunnel(s) approximately 4,200 feet northward through Corral Canyon to an area just south of the Offshore Substation/SCE pads.

The main pipeline/cable corridor will be a nominal 55-foot width plus a 25-foot temporary construction zone width (total 80-foot disturbed area) from the valve box to approximately Station 43 + 00 at which point all pipelines (except the future POPCO line) will emerge from the ground and be routed on an overhead pipe rack along the Offshore Substation/SCE pads to the Transportation Terminal and then to the Oil Treating Plant. The SYU power cables will stay underground all the way into the Offshore Substation.

The pipelines will be buried except at stream crossings and in-plant areas. The stream will be spanned at four points in the pipeline corridor by natural pipe bridges designed to clear the 100-year design flood height. SCE power cables are expected to be installed in conduits.

The onshore pipelines will be installed using conventional land pipeline construction methods and equipment. Right-of-way clearing, grading, ditching and backfilling will be performed in such a manner as to cause a minimum disturbance to the existing topography and environment.

The coated and wrapped onshore pipeline will be buried with a minimum three-foot cover on a pad of rock-free fill. The bottom of the trench will be overexcavated a minimum of six inches and a layer of sand or select backfill placed in the bottom. Sand or select backfill will also be used to backfill between pipes and to a height of 6 inches above the top of the pipelines. The remainder of the trench could be backfilled with native soils (no boulders larger than 12 inches in diameter).

All materials will be inspected for defects and for compliance with codes and specifications before installation in the pipelines. All girth welds will be 100 percent inspected by radiography.

Application of pipe coatings will be inspected in coating yards to insure conformance with the specifications. After installation, each line will be hydrostatically tested to 1.25 times the maximum design operating pressure. The test duration will be at least eight hours. Test water will be treated as required prior to disposal to assure no adverse impact on the environment.

8.7 Pipeline Operations

The crude emulsion pipeline system will be equipped with a volumetric comparison leak detection system. Volume data from the offshore platform ACT units will be received onshore via telemetry, and compared to the volume being received at the onshore receiving ATC unit. Significant deviations will trigger an alarm, as per MMS Pacific Region OCS Order 9, in the OTP Control Room. Upon receipt of such an alarm, appropriate air or sea reconnaissance will be initiated to assess the validity of the alarm and to determine if a pipeline system shutdown should be initiated.

Each pipeline will be equipped with high and low pressure sensors which will automatically shut in the pipelines if safe operating limits are exceeded. Each end of the line will also have a check valve and an automatic shut-in valve activated by the above high/low pressure sensors.

All emulsion and gas pipelines will be maintained in good operating condition at all times and supported by a comprehensive corrosion monitoring program. The ocean surface above the lines will be inspected for any indication of leakage as required by State and Federal regulations.

SECTION IX

ONSHORE FACILITIES

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Section 9.6.5 contains information which is considered EXXON PROPRIETARY and is located in a separate "Appendix A." NO DISCLOSURE OF THIS INFORMATION BEYOND THE MINERALS MANAGEMENT SERVICE IS ALLOWED WITHOUT PRIOR WRITTEN AUTHORIZATION FROM EXXON.

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SECTION IX

9.1 Introduction

Various oil and gas treating facilities associated with the expanded development of the Santa Ynez Unit are discussed including the location of the proposed onshore sites, the POPCO Gas Plant, the installation of the Oil Treating Plant (OTP), Stripping Gas Treating Plant (SGTP), and a central Cogeneration Power Plant (CPP).

Onshore safety and environmental impact mitigation measures will also be highlighted.

9.2 Onshore Site

Las Flores Canyon is about 20 miles west of the city of Santa Barbara, California along U.S. Highway 101. The site of the primary onshore facilities is near the confluence of Las Flores and Corral Creeks and is approximately 1.3 miles north of the highway, in the county of Santa Barbara. The terrain is hilly with gentle to moderately steep slopes and the elevation of the site ranges from 130 feet mean sea level (MSL) at the creek to over 400 feet MSL at the highest point of site development. Most of the plant site is in Rincon Formation. Recent landslide areas are visible in the weathered Rincon Formation.

The purpose of the Site Development effort is to create approximately 35 additional acres of level pads at various elevations for construction of the proposed onshore facilities in Las Flores Canyon.

The scope of this work includes site preparation for or the development of the following facilities:

- Transportation Terminal Pump Station and All American Pipeline Company Pump Station (3.5 acre pad)
- Transportation Terminal Storage Tanks and Emergency Containment Basin (13.0 acre pads), net area not including emergency containment basin
- Oil Treating and Cogeneration Power Plants (14.4 acre pad)
- Three road crossings over Corral and Las Flores Creeks
- SCE and SYU offshore electrical transformer pads (1.5 acre pads)
- LPG Storage (1.1 acre) and Loading (1.0 acre)
- Lower Canyon Fill
- Water Supply System (interim during facility development)
- Sanitary Sewage Leach Field
- Irrigation system
- Drainage system
- Roadways

Preliminary design for site preparation requires earthwork quantities of approximately 2.4 million cubic yards of net cut and fill and 2.3 million cubic yards of overexcavation. Approximately 35 acres of usable upper canyon facility pad area, excluding the emergency containment basin area and slopes, will be required.

9.3 POPCO Gas Plant

The existing POPCO Gas Plant is designed to produce salable natural gas with minimum impact to the environment. The facility includes inlet separation, inlet dehydration, cooling, stabilization of the natural gas liquids, gas sweetening, sales gas dehydration, sales gas recompression, sulfur recovery, tail gas treating, sour water stripping, and associated utilities. The sales gas is then pipelined to a regional gas transmission line. The facilities currently process 30 MSCFD of gas, but an expansion to 60 MSCFD is planned.

The processing expansion will start up in 1992 to accommodate 30 MSCFD gas sales from Platform Hondo and 30 MSCFD gas sales from Platform Harmony. Platform Harmony gas production in excess of 30 MSCFD and all Platform Heritage gas production will initially be reinjected to maximize oil recovery by maintaining reservoir pressure.

9.4 Offshore Storage and Treating Vessel Removal

At such time as the oil and gas treating, power generation, and crude transportation facilities are operational and debugged, the OS&T will be disconnected and towed away. The offshore pipelines connecting to the SALM will be purged and abandoned in place. The SALM will be removed. The SALM base piles will be cut below the mud line so that no obstruction will remain.

9.5 Oil Treating Plant

9.5.1 Overview

The proposed Oil Treating Plant (OTP) will remove produced water (brine) from the oil/water emulsion, reduce the H_2S content in the treated crude oil from approximately 300 ppm to 10 ppm or less, treat the separated brine to render it suitable for ocean disposal, and reduce the crude oil vapor pressure to the level required for storage and transportation. There are two initial oil treating trains which can be expanded to three trains with an ultimate total capacity of 140 kBOD.

The general plot plan configuration is given in Figure 9.3 and the crude oil sales specifications are given in Table 9.1. The generalized process flow diagram for the OTP is shown in Figure 9.4.

The OTP will receive produced crude oil emulsion from the offshore platforms and will supply sweet crude to the Transportation Terminal (TT). Sour stripping gas leaving the OTP (up to 11 MSCFD) will be sent to the Stripping Gas Treating Plant (SGTP) for treating.

9.5.2 Inlet

A stock tank mixture of emulsified crude and free brine will be delivered to the crude oil treating and storage facilities from the offshore production platforms via a produced emulsion pipeline extending from the shoreline to the facilities. The supply pressure of this emulsion stream will normally be 150 to 250 psig.

Upon delivery to the facilities, the emulsion stream will pass through an inlet metering system. This metering system will provide input for continuous volumetric comparison with the offshore platform production rates to identify any volumetric differences. The emulsion pipeline leak detection system will include an alarm trigger of adequate sensitivity to detect significant variations between the pipeline input and output volumes.

Downstream of the metering system, a pressure control device will monitor the line pressure of the inlet emulsion stream. If the pressure exceeds the normal operating range, the control device will open a bypass valve which will divert the inlet stream to the rerun tankage. The rerun tankage will perform the dual function of either providing surge capacity in the event of an onshore facilities shutdown or acting as a transfer point to reintroduce production into the treating facilities.

9.5.3 Crude Dehydration and Stabilization

The inlet sour crude emulsion will be heated by cross exchange with the crude leaving the crude stabilizer and produced water from crude dehydration. Waste heat from the CPP will be supplied via a steam system to further heat the sour crude to approximately 200° F. The hot emulsion will be dehydrated in the freewater knockout drum and the electrostatic emulsion treaters from which the sour crude will flow to the crude stabilizers. H_2S will then be stripped from the sour crude utilizing vapor generated from the crude stabilizer reboilers. A reflux stream at the top of the tower will help to recover NGL back to the crude. Condensate stabilizer bottoms will be routed to the crude stabilizer bottom, thereby maximizing crude production. The treated crude will leave the crude stabilizers at 240 to 270° F, be cooled against the emulsion feed, and then combine with the treated crude from the second and third processing trains before flowing to product metering.

The process is designed to maximize the amount of NGL leaving the plant in the crude consistent with the vapor pressure specification of 11 psia at 110° F.

9.5.4 Gas Compression and Condensate Stabilization

Crude stabilizer overhead vapors will be combined with the freewater knockout drum vapors and routed to the stabilizer overhead vapor (SOV) first stage suction scrubber. The hydrocarbon phase separated here will be pumped back to the crude stabilizers as reflux. The gas will then be compressed in two stages and routed to the condensate stabilizer. The hydrocarbon liquid from the SOV second stage suction scrubber will be pumped forward to the condensate stabilizer.

The condensate stabilizer will be a conventional fractionation tower with a reflux condenser system and a reboiler. The reflux system will utilize an air-cooled overhead condenser to achieve the necessary conditions for the selected product split. The condensate stabilizer will have the flexibility to operate as either a depropanizer or a debutanizer. During normal operation as a depropanizer, the overhead product will contain nearly all the H_2S fed to this tower along with most of the propane and lighter constituents. The bottoms stream from this tower will contain some of the propane and most of the butanes and heavier components. Alternate operation as a debutanizer will produce a more propane-butane rich overhead product which will create a greater NGL recovery in downstream gas processing facilities. This flexibility in the condensate stabilizer will allow fine tuning the amount of NGL and hence the vapor pressure, of the final crude oil leaving the OTP. The condensate stabilizer bottoms stream will be reboiled, the liquid product being sent to the crude stabilizers and ultimately to the emulsion exchangers for cooling. The overhead vapor from the condensate stabilizer will be delivered to the SGTP.

9.5.5 Oil Storage

The treated oil basic sediment and water (BS&W) content will be monitored to ensure that product specifications are maintained. Off-specification crude will be routed to the rerun tanks.

On-specification crude will pass to the treated crude storage tanks. Section 10.2.1.1 discusses the oil storage facilities requirements for the TT.

The rerun tanks, 30,000-barrel dome roof tanks, will provide both inlet surge capacity and transient storage for off-specification crude prior to reprocessing. Oil recovered in the produced water treating facilities will also be routed to these tanks. The rerun crude oil will be transferred to the inlet facilities by the crude rerun pumps. This operation will be non-continuous and performed when necessary to restore adequate inlet surge capacity. Liquids from the drains will also be pumped to the rerun tanks.

9.5.6 Produced Water Treating

The produced water treating system will consist of plate separators for oil and grease removal, multi-media filters for final oil and grease removal, a vacuum flash system for H_2S removal, a biological treatment system for organics removal, and associated pumps, piping, and tankage. The produced water treating system will continuously treat the water removed from the incoming crude oil/water emulsion and will treat, on an as needed basis, waste water streams from the Oil Treating Plant, Stripping Gas Treating Plant, Cogeneration Power Plant, and the Transportation Terminal. Treated water will be pumped back to the Harmony Platform for ocean disposal via outfall diffusers. The Exxon Proprietary produced water treating system is described in more detail and a schematic (Figure 9.5) is presented in "Appendix A."

9.5.7 Vapor Recovery System

The vapor recovery system will collect excess vapors from tanks and equipment containing volatile hydrocarbons or acid gas but operating below the SOV compressor suction pressure (35 psig). The system will have a suction scrubber, two compressors, and a recycle cooler. One compressor is sized for the normal vapor flow rate. The other compressor is sized to operate in conjunction with the first compressor and handle the normal flow plus the vapor flow from the rerun tanks when all the inlet crude emulsion is diverted to the rerun tanks. The larger compressor will start automatically on high suction pressure to minimize flaring vapors. The compressors will discharge into the inlet of the SOV suction cooler.

9.5.8 Utility Systems

9.5.8.1 Steam System

The CPP supplies steam to the following OTP users:

- Condensate stabilizer reboiler
- Crude stabilizer reboilers
- Emulsion heaters
- Rerun tank heater

9.5.8.2 Drains

Open Drain System. One drain system will serve the manual sight drains, drain pans, and floor drains from all items of equipment and buildings in the OTP in which oily water, hydrocarbons, or sludge may be drained. In addition to vessel and tank drains, this system will handle hydrocarbon drains from pump cases, pump pads, oil coolers, and oil exchangers.

A separate header will be provided to handle water from sight drains at equipment located in the water treating areas. A similar open drain header will be installed in the compressor and generator areas. Each open drain header will drain by gravity to the open drain sump which will be equipped with a carbon canister on the vent to eliminate emissions of any hydrocarbons which might enter the sump. Sump pumps will pump collected oily water to the rerun tanks.

Closed Process Drain System. The closed drain system will serve the manual drains from all items of equipment that normally handle hydrocarbons under pressure. Vapors from the closed drain sump will be routed to the vapor recovery system. Liquids will be pumped to the rerun tanks.

Area Drain System. Rainwater falling on oil plant areas which can be contaminated from process equipment drainage will be handled by the area drain system. This system will collect process area runoff water and route it to the area drain bypass basin. Oily water collected in this basin will flow to the area drain oil/water separator. The oil will be separated and pumped to the rerun tanks. The clean water will be released to the storm sewer via the area drain bypass basin. The area drain oil/water separator will be equipped with a carbon canister on its atmospheric vent. The area drain collection system will be sized to handle the maximum fire water rate for any given curbed areas.

Storm Drain System. Rainwater falling on oil plant acreage that is not served by the area drain system will be handled by a storm drain system. This system will collect surface water from areas other than process equipment drainage areas for release into Corral Creek without treating.

9.5.8.3 Blanket Gas System

Vessels, tanks, and other process equipment operating at or near atmospheric pressure and containing hydrocarbons or H_2S will be connected to a gas blanketing system. This system, in concert with the Vapor Recovery System, will maintain a slightly positive pressure on the equipment fluid interface. As fluids are withdrawn from the equipment, blanket gas will be made up from the sweet stripping gas system. This will prevent the inbreathing of air, which would otherwise render the tank vapors unsuitable for vapor recovery.

9.5.8.4 Relief, Vent and Flare Systems

To protect against overpressure, pressure vessels and blanketed tanks will be equipped with pressure relieving devices which will allow the excess pressure to be vented to the flare system wherever possible. The flare system will include low pressure, high pressure, and acid gas flare headers. The pressure relief for tankage and equipment designed for 0.5 to 50 psig will be piped to the low pressure flare scrubber. Pressure relief valves on pressure vessels designed for greater than 50 psig will be piped to the high pressure flare scrubber. Emergency relief valves on the Vacuum Flash System will be piped to the acid gas flare scrubber. The foregoing summary of relief valve discharges covers only relief valves in the OTP.

The gases from each of the three flare headers will be burned (in separate burners) in a common Thermal Oxidizer Unit. The Thermal Oxidizer will be a refractory-lined stack with burners near the base. Its stack is designed as a radiation barrier and to provide a natural convection air flow to enhance the combustion process. Because combustion occurs well below the top of the stack, the flame will not be visible.

High pressure burners will be arranged in several stages, each with its own pilot. The first stage is sized for low flaring rates and will be continuously purged with blanket gas to prevent air intrusion. There will be sufficient air flow to provide for complete, smokeless combustion at low relieving rates. When flare header back-pressure and flow rate measurements indicate a relieving rate above the capacity of the first stage, a valve will be opened to send part of the relief flow to the second stage burners. Additional stages will be added until the cumulative capacity is equal to the maximum required. The valve on the final stage will have a bypass line equipped with a rupture disc (pressure safety element) to provide a path for relieving vapors to reach the burners should the controls fail.

The low pressure burners are designed and arranged to operate in a similar fashion. The acid gas relief header also will have its own burners in the Thermal Oxidizer. The burners are designed for complete combustion of acid gases.

The following methods of protection against underpressuring will be used in the onshore facilities:

1. Certain pressure vessels will be full vacuum service vessels.

2. All tankage will be provided with primary protection against underpressuring by the gas blanketing system.

3. Secondary protection against underpressuring the tankage will be supplied by vacuum relief valves. All vacuum relief valves will be supplemented by an alarm system which will notify operators that air may have been drawn into the tank.

9.5.8.5 Utility Air, Water and Power Systems

Instrument and utility air will be supplied by either the CPP turbine (bleed air) or by the OTP air compressors. A portion of this air will be dehydrated for use as instrument air while the remainder will be used for utility air. The OTP air system will provide air to the CPP, SGTP, and TT.

Fresh water will be supplied by Water Well #3 (north of the TT emergency containment basin) and tied into the fire water tank. Utility water pumps will supply utility and potable water to the OTP, SGTP, CPP, and TT, and also will maintain pressure on the fire water headers. Potable water will be sterilized by UV light.

Power for the OTP will be supplied from the central CPP. SCE grid power will serve as a backup for emergency operations in the event of a power failure.

9.5.9 Safety Systems

9.5.9.1 Process Controls, Monitoring, and Alarms

The OTP central control room will contain the operator station for the microprocessor-based distributed control system (DCS), which has computerized recording, reporting, and graphics features. The operator control interface will be a video display which will increase operator efficiency and provide a method to diagnose abnormal process conditions for quickly correcting upsets. The control room will also contain monitors for the plant-wide fire protection systems, area hydrocarbon and H_2S gas detectors, and UV fire detectors.

In the event that normal process controls are unable to maintain the process within prescribed operating limits, alarms will trigger in the control room to warn the operators of impending upset conditions. The alarmed units will be set generally to allow attending operators sufficient time to determine the proper action necessary to either diagnose the abnormality and remedy it or to proceed with an orderly and safe facility or unit shutdown. The alarm and shutdown system will be controlled by logic in the DCS.

9.5.9.2 Hazard Detection

Continuous monitoring fire sensors (ultraviolet, ionization, thermal, or fusible plug types) will be used in all high hazard areas. Combustible gas and/or H_2S sensors will be strategically located in hazardous or inadequately ventilated areas. Detection of a hazard will trigger visual and audible alarms in the central control room, and will activate shutdowns or fire protection systems where appropriate.

9.5.9.3 Fire Protection

A fire water system will be provided for the facility. The fire water tank and pumps will be located in the OTP. The fire water distribution system will consist of several piping loops designed for redundant paths of water supply to each lateral. Water spray systems will be provided for certain high risk areas or equipment. Upon detection of a fire, the water spray systems will be activated manually or automatically as appropriate. In the OTP, the rerun tank will be equipped with a foam generating unit to help suppress any major tank fire. Electrical and electronics buildings will be equipped with Halon systems.

9.5.10 Emission Controls

The plant design will incorporate features to minimize fugitive hydrocarbon emissions and to assist in implementing a fugitive emissions control program.

Equipment. Tanks and sumps which breathe to the atmosphere and have the potential to contain volatile organic hydrocarbons will be fitted with carbon canisters. Pressure relieving devices on all pressurized equipment in hydrocarbon service will be vented to the vapor recovery system or closed flare system discussed previously wherever possible. Examples of exceptions are pump discharge relief back to the suction, reliefs routed to other vessels in the plant, and atmospheric tanks with secondary reliefs to the atmosphere. Pumps in light hydrocarbon service will be fitted with tandem mechanical seals. Compressors in hydrocarbon service will be equipped with closed seal systems venting to the vapor recovery system.

Piping and Valves. A graphite-based packing will be used on valves two inches and larger which require valve stem packing. To avoid the materials control problem associated with having different packing types, we will not differentiate between ROC and other services. In ROC service, 1-1/2 inch and smaller valves will be gate or globe valves with bellows stem seals rather than ball valves. To eliminate open-ended connections, plugged or capped ends will be used on drain valves, sample tap valves, and test connections. For samples that must be taken on a frequent schedule or continuous basis, a closed, fast loop sampling system will be used to supply samples directly to analyzers.

Once plant operations commence, the effective control of fugitive emission of volatile hydrocarbons will be based on the implementation of a rigorous inspection and maintenance program. Valve accessibility will be considered in the piping design.

9.6 Central Cogeneration Power Plant

9.6.1 General Description of Facilities

The proposed nominal 49 MW onshore, central Cogeneration Power Plant (CPP) will be located on the east side of the OTP pad. The general plot plan is shown in Figure 9.3. The CPP provides a portion of the power for the onshore OTP, SGTP, TT, and the offshore platforms. Heat from the gas turbine exhaust will be recovered by generating steam for process heat and electrical power through a heat recovery steam generator (HRSG). Emissions of nitrogen oxides (NOx) from the gas turbine will be controlled by steam injection and a Selective Catalytic Reduction (SCR) Unit.

The power plant is designed to operate in parallel with Southern California Edison (SCE). Emergency back-up, start-up, and balance power will be provided by SCE. This tie-in will also provide the flexibility to sell power to SCE when the platform generating capacity exceeds the SYU power demand. However, the design will also include controls that can minimize backflow of power to SCE if that operating mode is desired.

9.6.2 Gas Turbine Generator

One gas turbine will be installed and a bypass stack will be provided between the gas turbine and HRSG. The bypass stack has been determined to be necessary to prevent thermal transients, which occur during start-up and shutdown, from passing through the HRSG. These transients could damage the SCR catalyst or cause a pressure excursion in the steam generation system, subsequently causing process upsets in the OTP or SGTP.

9.6.3 Heat Recovery Steam Generator

Exhaust from the gas turbine will be directed to the duct-fired HRSG. Steam from the HRSG will be used to provide process heat to the adjacent OTP, TT, and SGTP. Steam will also be used to drive a steam turbine generator for power supplemental to the gas turbine generator up to a total plant nominal capacity of 49 MW.

The basic function of the HRSG is to exchange the heat of the gas turbine/duct burner exhaust with water/steam circulating through tubes in the HRSG. The maximum recoverable heat from the gas turbine is less than the peak heat demand, so low NOx duct burners will be placed upstream of the HRSG heating coils to provide the balance of the required heat. Process heat demand and facilities electrical power demand will determine how much duct burner firing will be needed. Fuel gas flow to the burner will be controlled to maintain a desired steam pressure leaving the HRSG.

9.6.4 Utilities

A closed loop cooling water system using air-cooled heat exchangers will provide cooling water to the gas turbine and steam turbine generator air coolers and lube oil coolers. It will also be distributed at the CPP for use in the OTP and the SGTP.

Demineralized water will be required for feedwater to the HRSG. The demineralization system will consist of cation and anion deionizers, regeneration equipment, neutralization facilities, and a demineralized water storage tank. The system will consist of two trains with a train defined as one cation and one anion unit.

Fuel gas will be supplied from the SGTP. Utility water, utility and instrument air, and fire water will be supplied from the OTP. Power plant process drain systems will be routed to the OTP process drain systems.

9.6.5 Emission Controls

In the CPP, emission controls will be included to reduce the NOx emissions. The gas turbine NOx emissions will be controlled by a steam injection system. The combined gas turbine exhaust and the combustion gases from the supplemental firing of the HRSG will be further treated by an SCR unit for additional NOx reduction. The supplemental firing will use low NOx duct burners.

9.6.5.1 Steam Injection NOx Control

The steam injection equipment for primary NOx control on the gas turbine will consist of a steam pressure regulator, a steam injection manifold, a flexible hose connecting the manifold to the combustion system, and steam injection nozzles. The total steam flow to the turbine will be regulated by a microprocessor computational module as a function of fuel flow. Combustion flame detectors (ultraviolet detectors) will also be furnished to detect any abnormal operation of the steam injection system which may extinguish the flame in the combustors.

The steam injection system will have controls and instrumentation for continuous monitoring of steam/fuel ratio. The rate of steam injection will vary with turbine output to maintain optimum NOx removal but also to keep a stable flame at reduced load. No steam will be injected when output is less than approximately 25 percent of base load because flame stability cannot be maintained with steam injection. Due to the lower combustion zone temperatures at part load, total pounds per hour NOx emissions limits will not be exceeded even without steam injection at this low operating level.

9.6.5.2 Selective Catalytic Reduction NOx Control

The principal element of NOx control in the HRSG will be an SCR unit which will act to reduce the NOx emissions from the duct burners in the HRSG and further reduce the NOx emissions from the gas turbine. SCR is a technology that uses ammonia and a catalyst to convert NOx in combustion products to nitrogen and water. The major control loop for the SCR unit is the automatic ammonia injection system. Miscellaneous temperature indicators, flow indicators, and alarms will be provided as required for general monitoring purposes and to warn the operators of specific upset conditions.

9.7 Stripping Gas Treating Plant

9.7.1 Overview

The Stripping Gas Treating Plant (SGTP) will process stripping gas and other vapors from the OTP and make-up gas from the Hondo and Harmony Platforms to produce a sweet stripping gas and/or fuel gas for the OTP, the CPP, and the TT. A plot plan is shown in Figure 9.6. The facility processes are comprised of:

- Separation of the OTP condensate stabilization overhead gas into a sour deethanizer overhead gas and LPG.

- Separation of the Hondo/Harmony Platform make-up gas into a sour flash gas and a flash condensate.

- Treating of the combined sour deethanizer overhead gas and platform flash gas to produce fuel gas and acid gas.

- Sweetening and fractionation of the LPG to produce separate propane and butane products meeting sales quality specifications.

- Sulfur recovery and tail gas clean-up of the acid gas by-products from the treating processes and from the OTP produced water treating to ensure environmentally acceptable atmospheric disposal of the resultant tail gas.

- Facilities shared with the adjacent OTP and CPP including the steam system which will be utilized by the SGTP to supply all heating needs in excess of waste heat generated by the SGTP processes themselves. Other shared facilities include a centralized control room and certain utilities such as boiler feedwater supply, electrical power supply, instrument/utility air supply, a Thermal Oxidizer, low pressure vapor recovery, and sour water treatment.

A simplified Block Flow Diagram given in Figure 9.7 provides an overall summary of the process flow.

9.7.2 Feed Separation

Platform Gas Separation/OTP Gas Cooling. The Hondo/Harmony Platform make-up gas will be taken off downstream of the POPCO slug catcher and will be fed to the SGTP platform gas inlet scrubber to separate and remove any possible entrained and/or condensed hydrocarbons and water.

The platform gas from the inlet scrubber will then be autorefrigerated in a Joule-Thomson expansion. Ethylene glycol (EG) will be mixed with the gas during this cooling/chilling step to prevent hydrate and ice formation. The chilled gas/EG mixture will then be flashed and the overhead gas will be mixed with deethanizer offgas, heated, and then sent to the fuel gas amine contactor. The hydrocarbon condensate/EG water phases will also be flash separated. The rich EG water phase will be sent to the EG regeneration unit.

The hydrocarbon condensate will be pressured to the deethanizer feed surge tank.

OTP condensate stabilization overhead gas will be cooled and fed to the deethanizer feed surge tank along with hydrocarbon condensate from the platform gas flash separator. The condensed hydrocarbons will be pumped through a coalescer and then fed to the deethanizer.

Deethanizer. The function of the deethanizer is to separate the light end components (methane, ethane, CO_2, and most of the H_2S) from the platform gas flash condensate and the OTP condensate stabilization gas. The deethanizer will also be used to control the composition of the LPG product and the heating value of the fuel gas, since its operation determines the relative split of propane and heavier hydrocarbons between fuel gas and the LPG product streams.

The vapor overhead from the deethanizer tower plus the wet gas from the deethanizer feed surge tank will be mixed with EG and partially condensed in the deethanizer overhead condenser. The rich EG liquid will be pressured to the EG regeneration unit for regeneration. The deethanizer reboiler will provide bottom heating for the deethanizer using 65 psig steam as a heating medium. The hot LPG product from the deethanizer bottom will be pressured through the deethanizer feed/bottoms exchanger to the carbonyl sulfide (COS) converter for further processing.

Ethylene Glycol Regeneration. The rich EG streams from platform gas separation and deethanization will be heated, depressured and fed to the rich EG flash tank. Here, most dissolved sour gases will separate from the rich EG.

Rich EG will then flow to the lean/rich EG exchanger to be heated by cross exchange with hot, lean EG from the EG reboiler. The rich EG will then enter the packed EG stripping column. Overhead gas, composed of water vapor and sour gas, will be cooled and partially condensed in a self-refluxing section of the stripping column. Vapor from the stripping column and vapor from the flash drum will be sent to the vapor recovery system. Hot, lean EG will flow from the reboiler and be cooled in the lean/rich EG exchanger before being stored in the lean EG surge tank. The lean EG will be filtered and then returned to the platform gas separation and deethanizer units for hydrate inhibition.

9.7.3 Fuel Gas Amine Treating

Sour overhead gas from the platform gas flash separator and the deethanizer will enter the bottom of the fuel gas amine contactor. In this vessel the gas will contact a proprietary amine solvent which absorb H_2S, CO_2, and other sulfur compounds.

Rich amine solvent will leave the bottom of the fuel gas amine contactor and flow to the fuel gas amine flash tank to flash off any hydrocarbons picked up by the amine solvent in the contactor. The produced flash gas will then flow to the vapor recovery system. Rich amine solvent from the flash tank will be heated and sent to the fuel gas amine regenerator. The regenerator will recondition the amine solvent by removal of the acid gases which are sent to the tail gas amine contactor.

In the regenerator, solvent will be steam stripped of its acid gas components. The regenerator overhead will pass to a condenser to condense water contained in the acid gas. The acid gas will be separated from the water and sent to the tail gas amine contactor. The water will be pumped back to the regenerator.

Heat will be provided to the regenerator by the regenerator reboiler which vaporizes a portion of the water in the amine solvent for steam stripping in the regenerator. The residual or lean amine solvent will be cooled and then flow to the fuel gas amine surge tank. From the surge tank, the lean amine will be cooled, filtered, and pumped to the fuel gas amine contactor.

9.7.4 LPG Sweetening

COS Converters. Each of the three COS converters will have a bed of activated alumina catalyst. This catalyst promotes the COS hydrolysis reaction of COS and H_2O to form CO_2 and H_2S. The three COS converters will be in three different services: raw LPG service, polishing LPG service, and regeneration mode. They will be connected such that any reactor can be in any mode.

LPG from the bottom of the deethanizer will be injected with a small amount of water and enter the bottom of the COS converter reactor which is in raw LPG service. In this first reactor, the bulk of the COS will be converted to H_2S. The LPG from this COS converter will then go to the LPG amine contactor for bulk H_2S and CO_2 removal. The LPG from the amine contactor will then go to a second COS converter in polishing LPG service. This reactor will convert most of the remaining COS to H_2S. The LPG stream entering the polishing COS converter will not require water injection since it has been saturated with water at the LPG amine contactor. The LPG from the polishing COS converter will be cooled before entering the LPG caustic prewash tower.

Occasionally, water in the LPG may accumulate on the COS converter catalyst to a point where the rate of reaction drops to an unsatisfactory level. In regeneration mode, the catalyst will be regenerated in a closed loop system. The regeneration medium will be propane/LPG product. The cycle will begin as liquid butane is fed from a separator drum via the recirculation pumps to the COS regeneration gas vaporizer. The butane will be vaporized in this exchanger and the vapor phase butane will be further heated to the desired regeneration temperature. This hot gas will then be passed through the COS converter catalyst bed. The hot gas will vaporize any water on the catalyst. The outlet gas is then cooled. This cooling will condense the butane as well as any water picked up from the catalyst bed. The liquid outlet stream from the gas cooler will flow to the COS regeneration water separator. The water will be collected in the drum and sent to the sour water accumulation tank. The butane will then be recycled through the regeneration loop.

LPG Amine Treating. The LPG from the raw LPG COS converter will enter the bottom of the liquid/liquid LPG amine contactor where it is contacted with an MEA amine. This amine will convert much of the remaining COS to H_2S and provide bulk removal of H_2S and CO_2. Treated LPG from the contactor will go to a settling tank where any entrained amine will be separated.

Some of the COS removal will be by direct reaction of the COS with the amine to form a urea type degradation product. This degradation product will be separated from the amine solution and will, on occasion, need to be properly disposed of offsite. Degradation by COS will be minimized by the COS converters immediately upstream of this unit.

As discussed previously, the LPG from the LPG amine contactor will go to a polishing COS converter and then to caustic treating.

LPG Caustic Treating. LPG previously treated for H_2S and COS removal will be initially contacted in the LPG caustic prewash tower with recirculating caustic solution for residual H_2S removal. The prewashed LPG will then enter the LPG mercaptan extractor for mercaptan sulfur extraction by caustic. The mercaptan-reduced LPG will leave the extraction tower from the top, and the caustic containing extracted mercaptans and mercaptides will leave the extraction tower from the bottom. The treated LPG stream will then be water washed to remove any entrained caustic carryover.

The caustic containing the extracted mercaptans and a catalyst will be heated and mixed with air before entering the oxidizer vessel. In the oxidizer vessel, mercaptides in the presence of the catalyst will be oxidized to disulfides. The caustic, disulfide oil, catalyst and air mixture will then flow to the disulfide oil separator where the air will be disengaged and the caustic and catalyst will be separated from the disulfide oil. The disulfide oil will then be pressured to the waste liquid storage tank or to the OTP rerun tank for recovery in the product crude. The regenerated caustic will be recirculated to the LPG mercaptan extraction.

Depropanizer and Propane Drying. Treated LPG will be separated into commercial grade propane and butane products in a depropanizer system. This column will be refluxed by an air fan cooler and reboiled. Butane product from the reboiler will flow to product storage after being cooled against incoming feed. Water saturated propane product will be dried by adsorption in a molecular sieve bed.

9.7.5 Vapor Recovery Compression

Sour water (containing H_2S and CO_2) from miscellaneous SGTP sources will be collected in the sour water accumulation tank. Sour gases from various SGTP sources will also be routed to the sour water accumulation tank. Hot vapor streams from propane dryer regeneration and from EG regeneration will be cooled in the vapor recovery compressor suction cooler prior to entering the sour water accumulation tank.

Sour water will be pumped in a batch-wise fashion from the tank to the OTP produced water treating system for further processing. Sour gas from the tank will be compressed by the vapor recovery compressor and then mixed with gases from the rich amine flash tanks, the pressure drain sump, and the rich EG flash tank. This combined stream will be sent to the OTP vapor recovery system.

9.7.6 Acid Gas Sulfur Recovery and Tail Gas Clean-Up

Acid gas sulfur recovery and tail gas clean-up will be accomplished by a Claus Plant with steam reheat, followed by a selective amine type Tail Gas Clean-Up Unit (TGCU). The TGCU will contain two sections: a hydrogenation section and an amine absorption/ regeneration section which recycles acid gas to the Claus Plant. This amine section will also be used to enrich the acid gas produced in the fuel gas amine unit by selective removal of H_2S, thereby providing a rich H_2S acid gas feed to the Claus Plant.

Sulfur Recovery. Acid gas produced in the TGCU amine section will be scrubbed to remove any entrained liquids and then burned. Air for the combustion will be controlled so that the H_2S and SO_2 are in proper proportions for the Claus reaction.

Hot gases from the combustor will be fed to a waste heat reclaimer where the gases will be cooled by generating steam. The process gas will proceed to the first pass of a four-pass sulfur condenser where the gases will be cooled and sulfur will be condensed by generating steam. Condensed sulfur is withdrawn through a liquid seal to the sulfur pit.

Process gas from the first pass of the sulfur condenser will be reheated to Claus reaction temperature and then will enter the first stage reactor where more sulfur will be produced. The effluent from the first reactor will be cooled in the second pass of the four-pass sulfur condenser. Once again, the condensed sulfur will be withdrawn through a liquid seal to the sulfur pit.

The cooled process gas will now pass to the second stage reactor where the same sequence of steam reheat, Claus reaction, gas cooling/sulfur condensation, and withdrawal is repeated. Gas cooling/sulfur condensation will occur in the third pass of the sulfur condenser. The cooled gas will then repeat the same step-by-step sequence in the third catalyst stage. Gas from the fourth pass of the sulfur condenser will then flow to the TGCU.

Sulfur Pit Degassing. The sulfur pit is designed in accordance with a proprietary Exxon system for degassing liquid sulfur, to decrease the dissolved H_2S content in the sulfur. Product sulfur will be pumped to the sulfur storage tank. Sulfur is stored in the sulfur storage tank between sulfur truck loadings. To keep the sulfur molten, the tank will be steam heated.

Tail Gas Clean-Up. In the hydrogenation section, the tail gas will first be reheated in the TGCU combustor by mixing with the hot flue gases generated by the mild combustion of fuel gas. The hot tail gas will proceed to the hydrogenation reactor where the non-H_2S sulfur compounds will be converted to H_2S. The hydrogenated tail gas will then be cooled. Tail gas will then be combined with acid gas from the OTP sour water stripper.

The combined stream will be cooled in the quench section of the TGCU quench/condensing tower by direct contact with a circulating mild caustic solution. This caustic solution will protect the downstream amine facilities from contamination due to any abnormal SO_2 breakthrough from the hydrogenation reactor.

The tail gas will proceed to the condensing section of the tower, where most of the water vapor in the tail gas will be condensed by direct contact with a circulating water stream. The net condensed water from the tower will be pumped to the sour water accumulation tank.

The gas from this tower will then be combined with the acid gas from the fuel gas/LPG amine units. The mixed gas will enter the bottom of the tail gas amine contactors. An aqueous amine solution will selectively remove H_2S from the tail gas while permitting most of the CO_2 to pass through unabsorbed. The treated mixed gas will exit from the top of the contactor and be scrubbed to remove any entrained amine. The tail gas from the scrubber will go to the waste gas incinerator.

Regeneration of the aqueous amine solution will be similar to the regeneration steps in the fuel gas amine treating unit and the LPG amine treating unit. A flash drum for the rich amine solution will not be required in the TGCU because this amine does not absorb hydrocarbons. The acid gas from the regenerator reflux drum will be routed to the sulfur recovery unit.

9.7.7 Utilities

Fuel Gas Distribution. The majority of the gas from the tail gas contactor will be sent to the CPP for fuel gas distribution to the other SYU onshore components. A purchased fuel gas tie-in will be provided to fill any shortfall in SGTP fuel gas production and to allow power plant operation when the SGTP is down. A small side stream of fuel gas will be used for the SGTP.

Flare System. The SGTP will include three separate flare collection systems which will be integrated with the OTP flare systems. Safety valves and vents will be routed either to the flare scrubber or the acid gas flare header based on compositional considerations. Liquid from the flare scrubber will flow to the closed drain. Gases from the two collection systems will be routed to the OTP thermal oxidizer in separate headers.

Steam Distribution/Condensate Collection. Steam will be supplied by waste heat boilers in the sulfur recovery unit and TGCU and by the CPP steam distribution system. The primary distribution of steam will be to the three amine tower reboilers, the deethanizer reboiler, the EG reboiler, two fuel gas heaters, and a caustic heater. The steam will also be used for line tracing, COS converter regeneration, LPG amine reclaiming, sulfur pit and tank heating, and other miscellaneous small consumers.

Lower pressure steam will be produced in the sulfur recovery unit and from flashed condensate. This steam will be used in the depropanizer reboiler and as injection steam for the TGCU combustor, waste gas incinerator, and sulfur plant combustor.

High pressure steam from the CPP steam distribution system will be used for sulfur plant reheating, COS regeneration gas heating, and propane dryer regeneration.

Low pressure condensate from the depropanizer reboiler will be pumped to the steam condensate flash tank, which will also collect other condensates. Condensate from the flash tank will be pumped to the sulfur recovery unit and TGCU for process feedwater. Remaining condensate will be returned to the CPP deaerator.

<u>Waste Gas Incinerator</u>. The waste gas incinerator will burn fuel gas to raise the temperature of the effluent waste gas from the TGCU. The hot, air-rich atmosphere will oxidize trace hydrocarbon and sulfur compounds and, with the addition of small amounts of ammonia, control NOx emissions. The hot flue gas effluent from the incinerator will be dispersed to the atmosphere via the elevated stack.

<u>Pressure Drain System</u>. The pressure drain system will extend throughout the plant and is intended to catch all intermittent high pressure LPG process drain flows. The receiving pressure drain vessel will operate under a fuel gas blanket pressure to prevent autorefrigeration of the LPG drainage. Vapors flashed off in the pressure drain sump will be routed to vapor recovery.

Closed Drain System. Closed drain system connections are provided for all equipment items that normally handle hydrocarbons under pressure. Drain sump liquids will be pumped either to the OTP rerun tank or to the SGTP waste liquid storage tank, depending on their content. Excess vapors from the sump will be collected by the vapor recovery system.

Area Drain System. The area drain system will handle storm rain water, fire water run-off, and washdown from process areas which may contain trace quantities of oil.

Open Drain Systems. The underground open drain system will extend throughout the plant and is intended to catch all atmospheric drains except rain water. This includes drain funnels and equipment drip pans.

Ethylene Glycol Drain System. The underground EG drain system will be located only in the area of the facility where EG is present. The liquid from the EG drain sump will normally be pumped back to the EG regeneration unit (via the EG drain filter) if the EG liquid collected is clean and reusable. The EG drain vessel will operate under a gas blanket which will maintain a nominal positive vessel pressure. The vapor piping from the drain vessel will be connected to the vapor recovery system.

Fuel Gas Amine, LPG Amine, Tail Gas Clean-Up Amine, and Caustic Drain Systems. These separate but similar systems will catch any process drain flows which may contain fuel gas amine, LPG amine, tail gas clean-up amine, and caustic.

With the exception of the caustic drain system, liquids collected by the drain vessels will normally be recycled back to their respective units (via drain filters) if they are clean and reusable. Caustic drain liquids will normally be pumped to the waste liquid storage tank.

The drain vessels will operate under a natural gas blanket which will maintain a nominal positive vessel pressure. Excess vapors from the sumps will be collected by the vapor recovery system.

9.7.8 LPG Storage and Loading

Treated propane and butane LPG from the SGTP will flow to four LPG loading bullets located at the south end of the canyon. In addition, an off-spec LPG bullet will be located in the SGTP. A plot plan is given in Figure 9.8.

Two of the bullets will normally receive propane and two will normally receive butane. LPG from the bullets will gravity flow to either of the two truck loading stations. Vapors displaced from trucks during loading will be returned to the top of the LPG loading bullets via a vapor balance line.

Excess vapors from the LPG loading bullets and the off-spec LPG bullet will flow to the second stage suction of the OTP stabilizer overhead compressor for recovery of LPG. Hydrocarbon trapped in the coupling between the loading stations and the LPG truck will be vented to the vapor recovery system in the OTP.

9.7.9 Emission Control

Vapor Recovery. The vapor recovery system in the SGTP will consist of a low pressure header collection system and a vapor recovery compressor that discharges into the vapor recovery system of the OTP. The SGTP vapor recovery systems will collect gas released from process fluids or forced out of vessels and tanks as they are filled. There will be a separate vapor recovery system to collect vapors from the sulfur pit and tank and recycle them to the TGCU combustor for sulfur recovery.

Flash vapors from the two amine flash tanks will be routed to the vapor recovery system, rather than to the incinerator, so that fuel gas to the incinerator will contain less than 24 ppm sulfur.

All drain sumps, except the open drain sump, will be tied to the vapor recovery system in order to mitigate emissions should volatile organic compounds be introduced into one of the sumps.

Another vapor recovery system will be used to collect vapors from the LPG loading and storage operation and route them to the OTP compression system. A low pressure vapor recovery line, also tied to the OTP vapor recovery system, will be provided to reduce emissions during the coupling operation between the LPG loading arm and the LPG trucks.

Incinerator - Combustion Efficiency, NOx Control, and Sulfur Recovery. The incinerator is a custom design due to the uniqueness of the application. The unit is designed for a hydrocarbon destruction efficiency greater than 99.9 percent. It is also designed for a minimum of auxiliary firing to minimize NOx formation. Low NOx burners and a THERMAL DeNOx system have also been incorporated into the design of the SGTP incinerator to further reduce NOx emissions. This combination should provide at least a 70 percent overall reduction in NOx emissions. The THERMAL DeNOx process operates by mixing NH_3 with NOx-containing flue gases in an effective temperature range for a certain residence time.

The SGTP will contain a sulfur plant and TGCU to ensure environmentally acceptable disposal of the resultant tail gas in the incinerator. Recovery of sulfur components entering the plant will be in excess of 99.9 percent at design rates. At this recovery, peak sulfur emissions from the incinerator under normal operation will be 1.75 pounds per hour when the plant is at full load. At reduced load, the sulfur emissions from the incinerator will be less than 1.75 pounds per hour; however, the percentage recovery of inlet sulfur may be less than 99.9 percent because of equipment turndown restrictions.

Fugitive Emission Controls. In addition to the vapor recovery system, design features that have been incorporated which minimize fugitive emissions and assist in the implementation of a control program include the following:

Equipment. Tanks and sumps which breathe to the atmosphere and have the potential to contain volatile organic hydrocarbons will be fitted with carbon canisters. Pressure relieving devices on all pressurized equipment in hydrocarbon service will be vented to a closed flare system wherever possible. Pumps in light hydrocarbon service will be fitted with tandem mechanical seals. Compressors in hydrocarbon service are equipped with closed seal systems venting to the vapor recovery system.

Piping and Valves. A graphite-based packing will be used on 2-inch and larger valves requiring valve stem packing. 1-1/2 inch and smaller gate and globe valves in ROC service will be provided with bellows-type stem seals. Plugged or capped ends will be used on drain valves, sample tap valves, and test connections. Closed loop sampling systems will be used to supply samples directly to analyzers.

9.8 Power Distribution System

9.8.1 System Configuration

Electrical power for the SYU onshore and offshore facilities will be provided primarily from two sources. The first source will be the CPP with emergency back-up, start-up, and balance power being provided by SCE. Power at 66 KV will be received from SCE at the SCE substation located next to the Exxon Offshore Substation (OSS), south of the TT. Redundant cable feeds are provided from SCE for improved reliability. Power from the CPP will be generated at 13.8 KV and distributed to the OTP at 13.8 KV.

Power for the CPP, TT, and the SGTP will be provided through the OTP. Power from Exxon OSS (via pole lines) will be received at the OTP at 66 KV and transformed down to 13.8 KV for tie-in to the CPP generated power and then transformed to 4.16 KV and 480 V for use at the OTP and CPP and for distribution to the SGTP and the TT. Power for the offshore facilities will be provided through two 66 KV to 34.5 KV step-down transformers located at the Exxon OSS. See Figure 9.9 for the OSS plot plan.

9.8.2 SCE Substation

An approximate area of 37,200 square feet (120 feet by 310 feet) has been provided next to the Exxon OSS for the SCE substation.

It is assumed that SCE will design and construct the substation. Exxon will provide the developed pad space. Exxon will also provide space as necessary in the pipeline corridor down to Highway 101 to allow for a south feed or tie-in to existing power lines along Highway 101. All design and construction aspects of the north feed are SCE's responsibility, as this is expected to be strung on overhead poles or towers. Exxon will provide an easement for the northern tie line.

9.8.3 Power Factor Control

Based on the current SCE rate schedule, a financial penalty will be imposed if the SYU power system's power factor (PF) falls below 0.98. The expected SYU system PF without any correction will be between 0.80 and 0.90. Therefore, to avoid a penalty, PF correction will be applied. For offshore, the PF will be corrected through the use of PF correction capacitors. For onshore, the PF will be corrected by over-exciting the CPP turbine generators. The PF value to be controlled to will be determined by weighing the cost of the correction equipment to the penalty imposed.

9.8.4 Power Metering

Equipment for metering electrical power from or to SCE for the purposes of accounting will be provided by SCE and installed in the SCE substation. The following power units will be metered: KW (in), KWH (in), KVARh (in), KW (out, if required). Redundant accounting metering at the Exxon/SCE interface will not be provided by Exxon. However, metering (KW, KWH, PF) will be provided as required for surveillance purposes which, if totalized, could be used to check the SCE metering equipment.

The tie-in to SCE will provide the ability to sell power to SCE when there is excess CPP generator capacity. Appropriate transducers, alarm, and control devices will also be provided to prevent the backflow of power from Exxon to SCE if this becomes the desired operating mode. It is assumed that a momentary backflow of unmetered power will be acceptable to allow time for manual or automatic controls to eliminate the surplus power condition.

9.8.5 Interface to Offshore Cables

The transformers which step down the 66 KV power to 35 KV for offshore use will be located next to the SCE substation. The three offshore cables will be buried from the offshore substation to the pipeline underground corridor, and then will remain underground or will be placed on pipe racks consistent with the pipelines down the corridor to just north of Highway 101. At the pipeline valve box, the onshore cable will be spliced to the offshore cables.

9.9 Environmental Impact Mitigation Measures and Safety Standards

9.9.1 Oil Spill Prevention and Containment

A Spill Prevention Control and Countermeasure (SPCC) Plan is not required until start-up of operations begin at a facility which may reasonably be expected to discharge oil into navigable waters. The following is the best estimation at this time of the provisions to be made in the SPCC Plan dealing with spill prevention and containment design features for the onshore oil treating facilities. The Oil Spill Contingency Plan for California Operations, overviewed in Attachment C, will address procedures taken in the event of an oil spill.

First Phase: On Site

On site containment design features of the onshore facility include:

- The curbed area drain system will pump oil back to the rerun tanks.

- Gates will be provided on appropriate road crossing culverts which can be closed in the unlikely event that a spill threatens to leak beyond the confines of the oil and gas treating facilities.

- The Emergency Containment Basin will be sized to contain the volume of the largest tank plus rainfall run-off or firewater overflow.

- All operating personnel will be trained in emergency procedures such as reducing flow from a damaged vessel and closing a gate at a culvert.

These containment design features will be extremely effective in dealing with most spills that might occur at the onshore facilities. These spills are typically small (less than 5 barrels) and are usually caused by a failure of valves and other equipment located within the containment area of the facilities.

Second Phase: At the Creek

The primary objectives of the second phase of the contingency plan would be (1) to stop any flow of oil downstream as quickly as possible, particularly in order to keep the oil from reaching ocean waters, and (2) to remove the oil as quickly as possible. In order to contain the oil, Exxon would do one or all of the following:

- The gate at road crossing #1 will be provided with an automated closure device which can be closed in the unlikely event that the spill threatens to leak beyond the confines of the oil and gas treating facilities.

- Lay portable containment barriers across Corral Creek at various locations.

- Lay a large floating boom across the mouth of Corral Creek.

- Construct a temporary earthen dam across Corral Creek with bulldozers.

Some absorbent and boom material for minor spills will be stored on site. Additional equipment needed for larger spills would be obtained from Clean Seas, Inc. of Santa Barbara within one hour of the request. Grading equipment would be immediately available from nearby sources at the mouth of the canyon. Other equipment could be made available within one hour of the request.

Third Phase: In the Channel

If any oil were to reach the ocean, the offshore phase of the Oil Spill Contingency Plan for California Operations would be activated. Clean Seas, Inc., the local oil spill cooperative, would be available for immediate assistance. Clean Seas, Inc. will provide the necessary equipment, personnel, materials and an adequate response time to contain and clean up an oil spill as required by the criteria of the USCG/USGS Memorandum of Understanding (effective date of December 18, 1980). Specific cleanup techniques for sand and other onshore terrains are also discussed in Attachment C.

9.9.2 Safety Standards

The safety of the contractors' employees, Exxon personnel, suppliers and other persons affected by the installation of the onshore facilities shall be the prime consideration in their design, construction, start-up and operation. The onshore facilities will be designed, constructed and operated to comply with all applicable codes and regulations. A partial listing of these is provided on Table 9.2. No person other than facilities employees will be allowed on the premises unless special permission is granted by the proper supervisory authority.

Hard hats and safety glasses will be worn by all personnel in the processing areas. Specific areas requiring further protection, such as ear protection or gloves, will be clearly marked with warning signs. Emergency showers and eyewash stations will be located at various places throughout the facilities. In addition, emergency breathing air apparatus will be available at various stations within the facilities.

TABLE 9.1

CRUDE OIL SALES SPECIFICATIONS

Basic Sediment and Water Content	1.0 % max.
Vapor Pressure @ 110°F	11.0 psia max.
Hydrogen Sulfide Content	10 ppm by wt. max.
Estimated Treated Crude Oil Gravity	16-18° API

TABLE 9.2
MAJOR DESIGN CODES, ORDINANCES, AND REGULATIONS [1]

- Applicable California Administrative Codes:

Title 2	Administration
Title 7	Harbors & Navigation
Title 8	Industrial Relations (Safety Codes)
Title 14	Natural Resources
Title 19	Public Safety
Title 20	Public Utilities & Energy
Title 22, Division 4	Social Security, Environmental Health
Title 23	Waters
Title 24	Building Standards
Title 25, Part I	Housing and Community Development

California Department of Oil and Gas Regulations
California General Industry Safety Orders (in Title 8)
California Petroleum Safety Orders (in Title 8)
California Fire Marshall's Standards (in Title 19)
California Electrical Safety Orders (in Title 8)

- Applicable Chapters of Santa Barbara County Code:

Chapter 1	General Provisions
Chapter 2	Administration
Chapter 9A	Brush Removal
Chapter 10	Building Regulations
Chapter 14	Excavations
Chapter 15	Fire Prevention
Chapter 15A	Flood Plain Management
Chapter 15B	Development Along Watercourses
Chapter 17	Garbage and Refuse
Chapter 18	Health and Sanitation
Chapter 21	Land Division
Chapter 25	Oil and Petroleum Wells
Chapter 28	Roads
Chapter 29	Sewers
Chapter 34	Underground Utility Districts
Chapter 34A	Wells
Chapter 34B	Domestic Water Systems
Chapter 35	Zoning
Appendix A	Table of Disposition of Ordinances

- Santa Barbara County Ordinances:

3503	Hazardous Waste General Permits
3421	Underground Storage Tanks for Hazardous Materials

- Santa Barbara County Comprehensive Plan (Compendium)

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1 Table is not intended to be all-inclusive.

TABLE 9.2
MAJOR DESIGN CODES, ORDINANCES, AND REGULATIONS [1]
(Continued)

- Applicable Parts of Code of Federal Regulations, including the following specifically referenced sections:

33 CFR 67	Aids to Navigation on Artificial Islands and Fixed Structures
33 CFR 159	Marine Sanitation Devices
36 CFR 60	National Register of Historic Places
36 CFR 800	Protection of Historic and Cultural Properties
40 CFR 52	Approval and Promulgation of Implementation Plans
40 CFR 60	Standards of Performance for New Stationary Sources
40 CFR 112	Oil Pollution Prevention
40 CFR 117 40 CFR 260-271 40 CFR 300	Hazardous Wastes
46 CFR	Shipping
49 CFR 192	Transportation of Natural and Other Gas by Pipeline: Report of Leaks
49 CFR 195	Transportation of Hazardous Liquids by Pipeline

- American Bureau of Shipping "Rules for Building and Classing Single Point Moorings"

- Latest Edition of Following Codes:

  Uniform Fire Code
  Uniform Building Code
  Uniform Mechanical Code
  Uniform Plumbing Code
  National Electric Code

- U.S. Coast Guard Port and Tanker Safety Act of 1978

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[1] Table is not intended to be all-inclusive.

TABLE 9.2

MAJOR DESIGN CODES, ORDINANCES, AND REGULATIONS [1]

(Continued)

- American National Standards Institute (ANSI)

  B31.1 - Power Piping
  B31.2 - Fuel Gas Piping
  B31.3 - Petroleum Refinery Piping Code
  B31.4 - Liquid Petroleum Transportation Piping Systems
  B31.5 - Refrigeration Piping
  B31.8 - Natural Gas Transmission and Distribution Piping

- ASME Boiler and Pressure Vessel Code, Section 8, Division I, plus all Addenda

- California OSHA Requirements

- California Air Resources Board and Environmental Protection Agency Regulations

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1 Table is not intended to be all-inclusive.

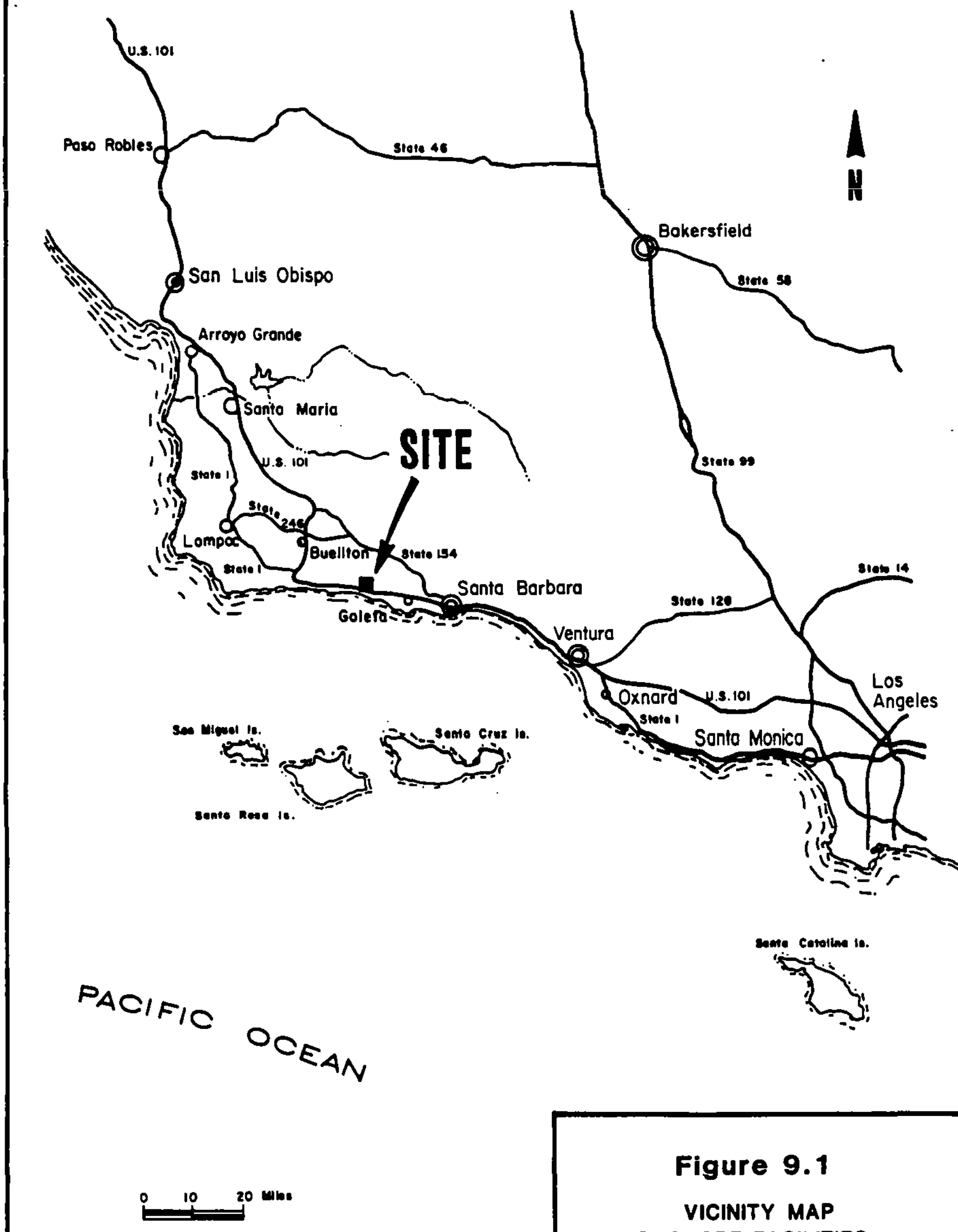

Figure 9.1

VICINITY MAP
ONSHORE FACILITIES

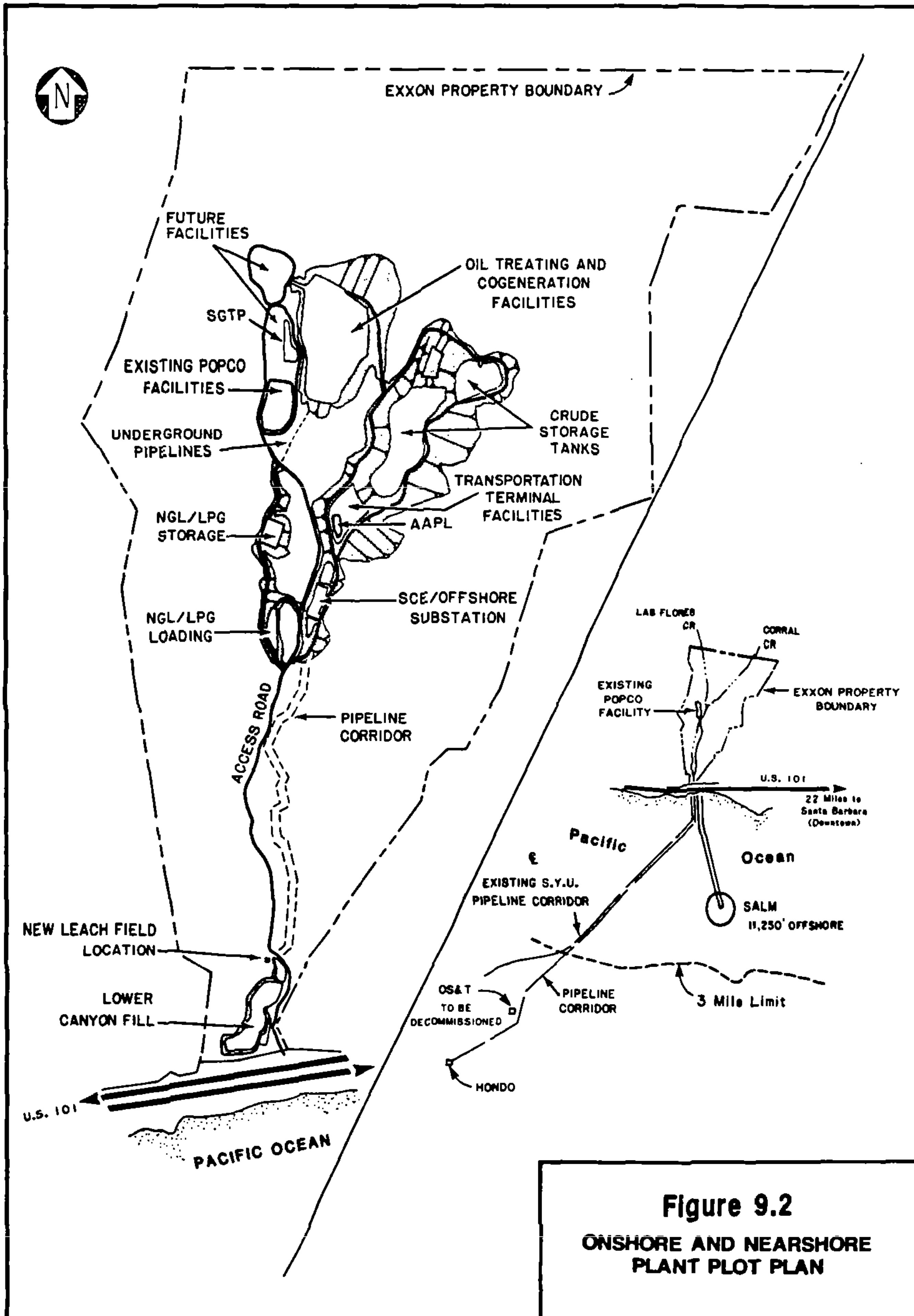

Figure 9.2

ONSHORE AND NEARSHORE PLANT PLOT PLAN

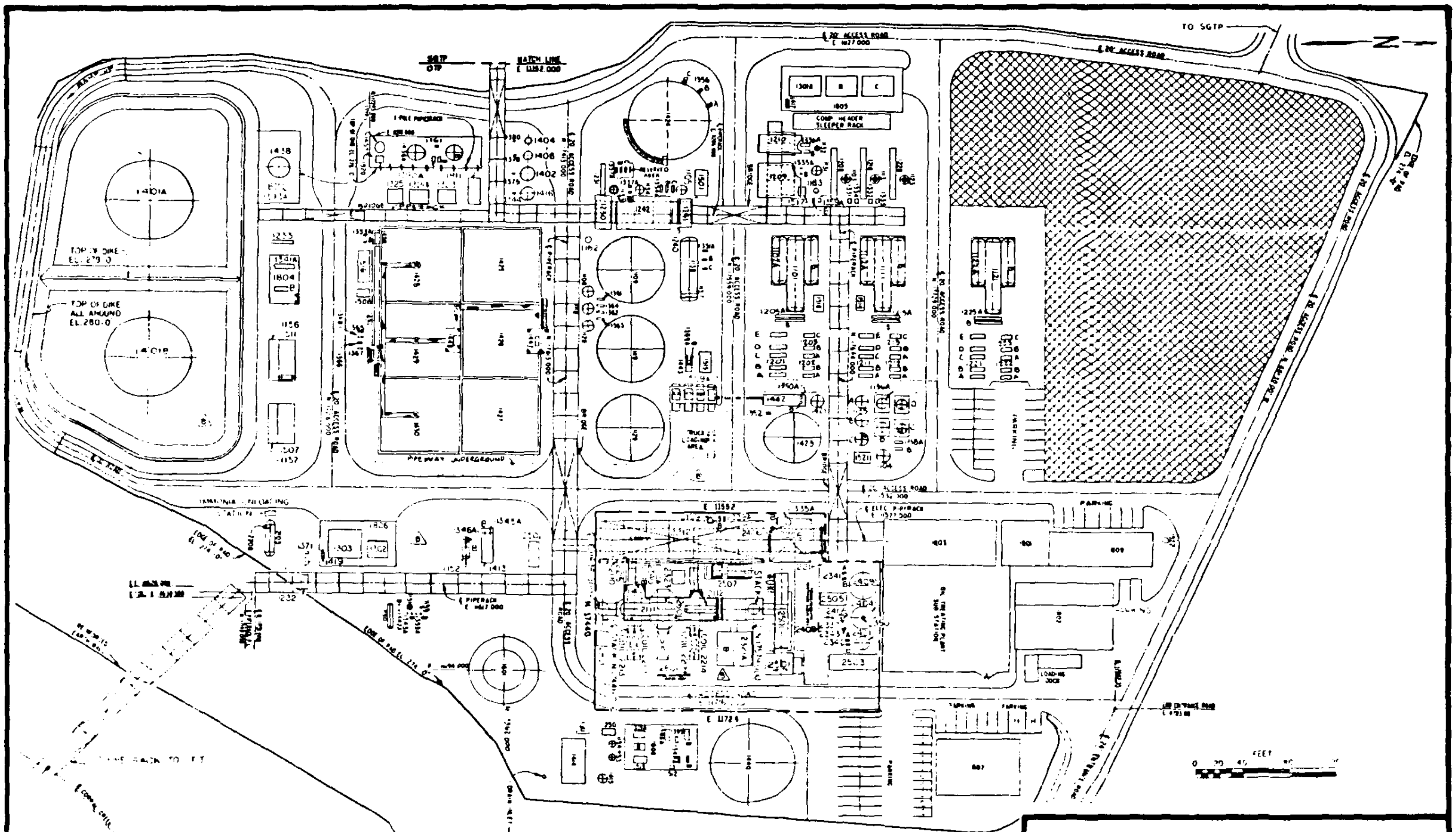

Figure 9.3

OIL TREATING PLANT & COGENERATION POWER PLANT

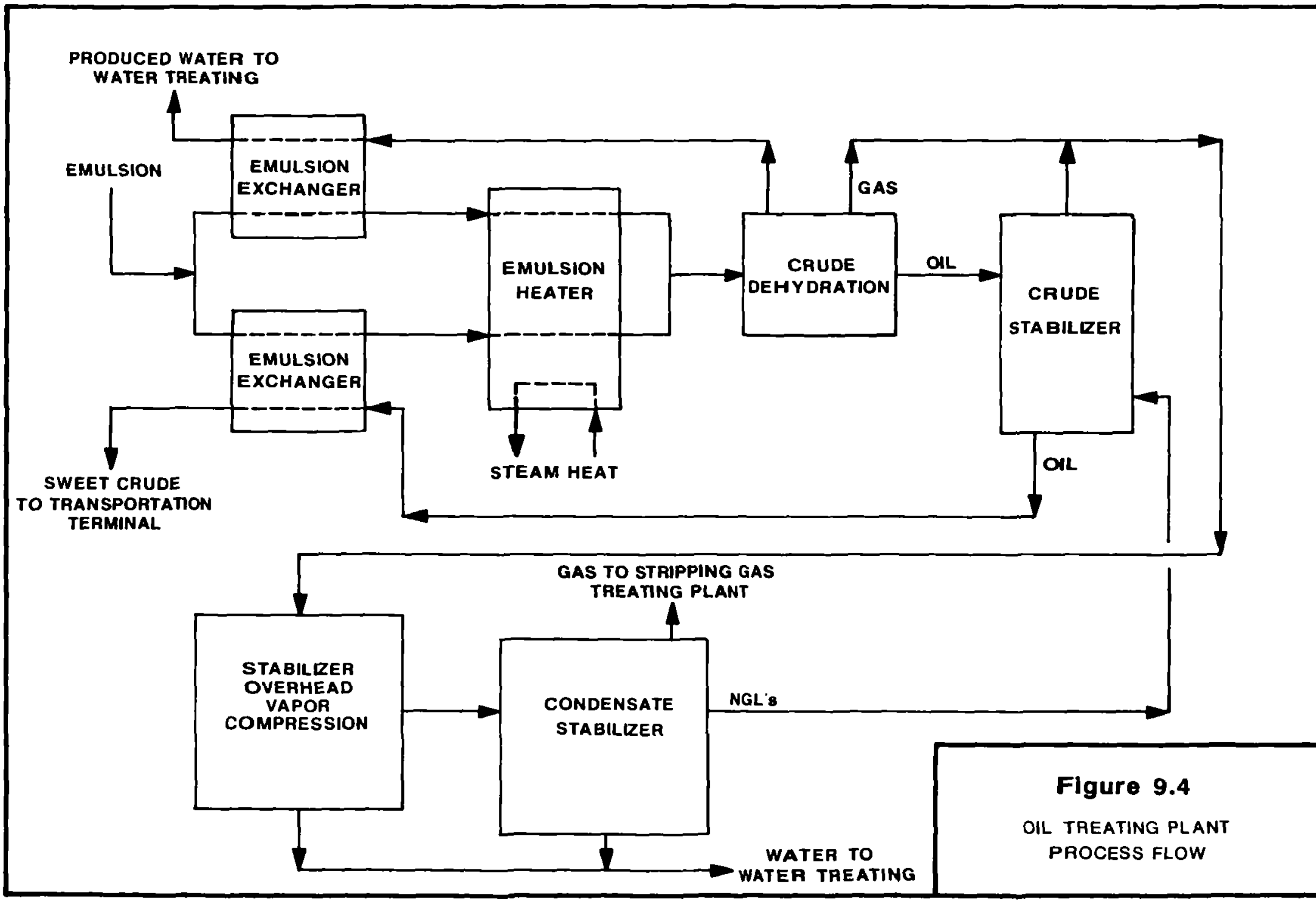

Figure 9.4

OIL TREATING PLANT
PROCESS FLOW

FIGURE 9.5

EXXON COMPANY, U.S.A. PROPRIETARY FIGURE

ONSHORE WATER TREATING FACILITIES

SEE APPENDIX A

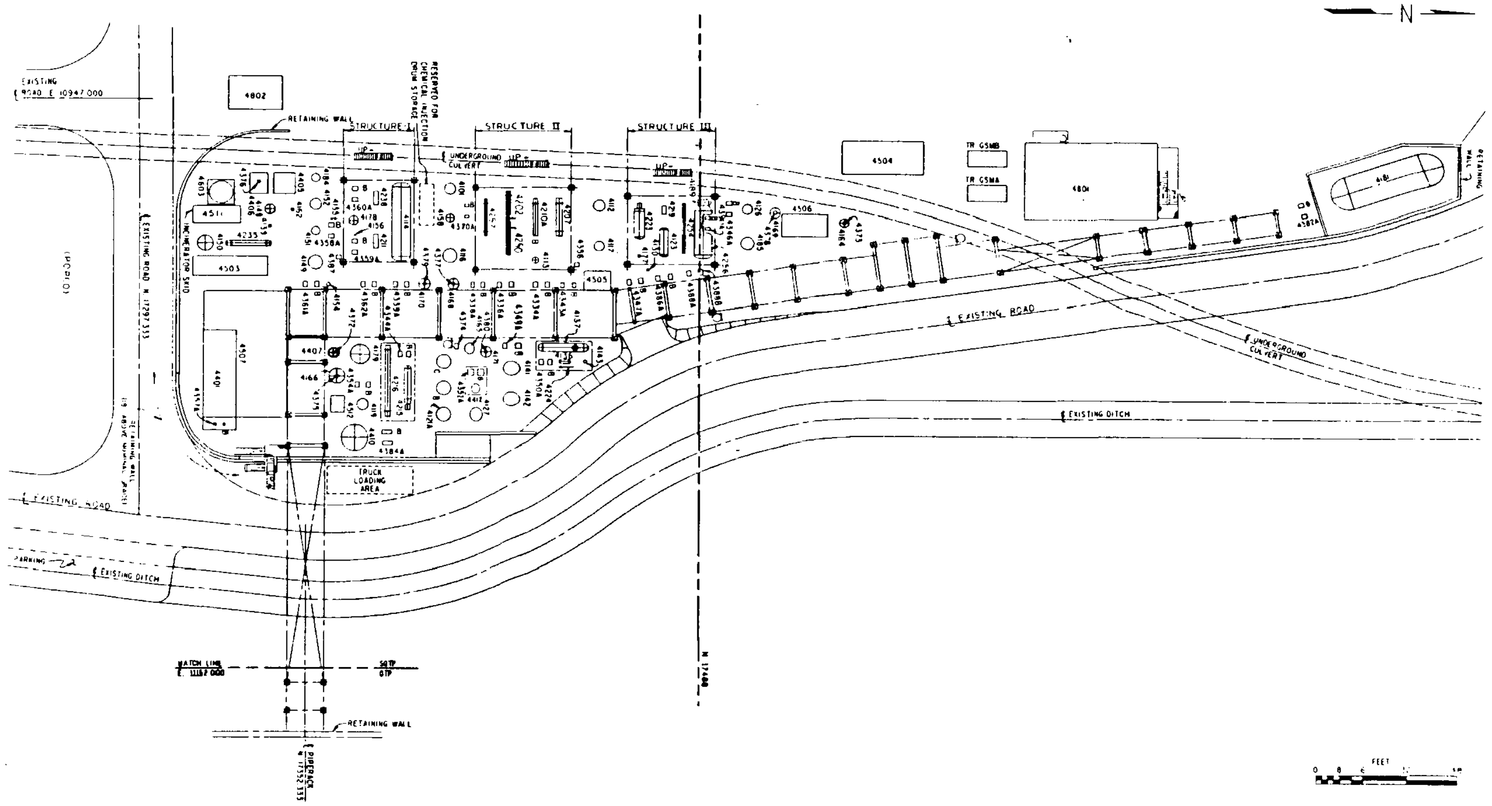

Figure 9.6

STRIPPING GAS TREATING PLANT

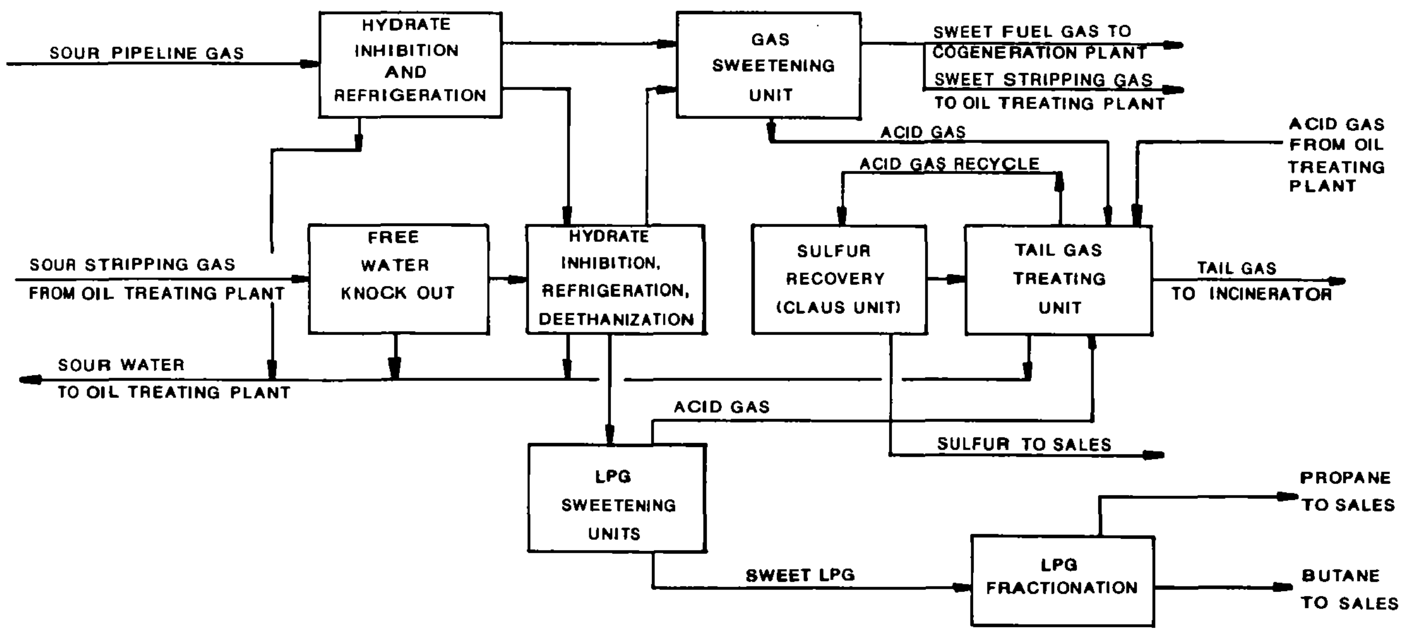

Figure 9.7

STRIPPING GAS TREATING PLANT PROCESS FLOW

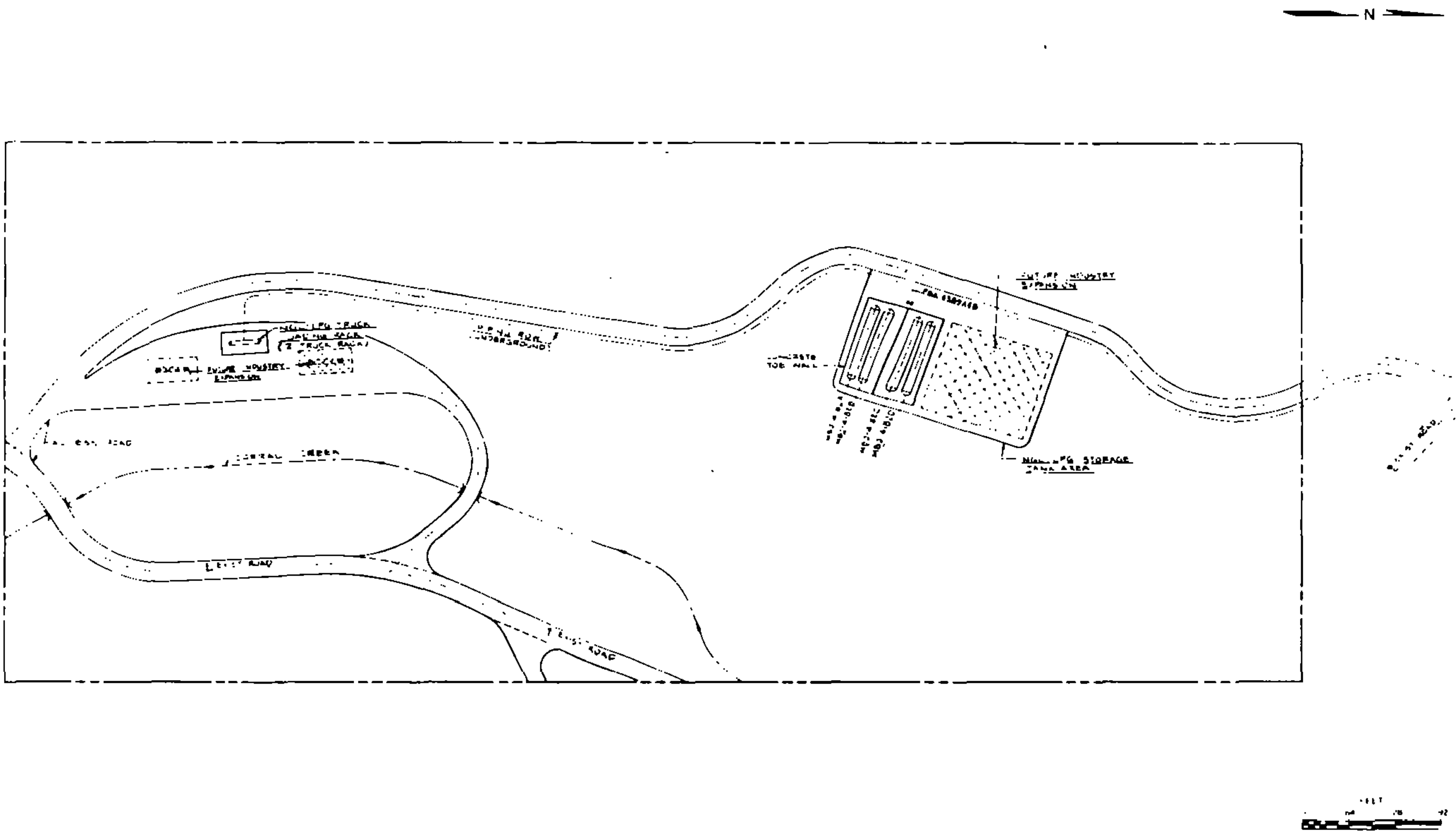

Figure 9.8

NGL/LPG STORAGE & LOADING

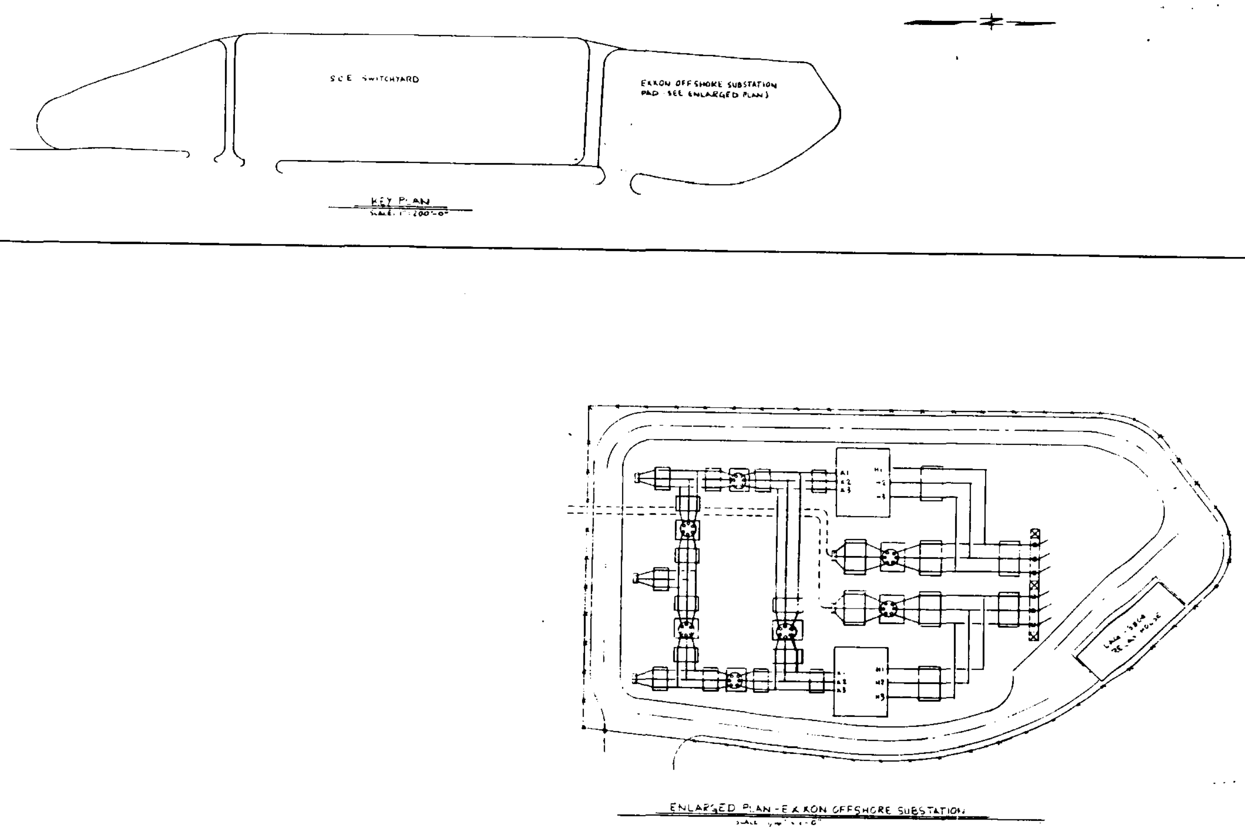

Figure 9.9

EXXON OFFSHORE SUBSTATION

SECTION X

CRUDE TRANSPORTATION

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SECTION X

CRUDE TRANSPORTATION

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SECTION X

CRUDE TRANSPORTATION

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SECTION X

10.1 Introduction

The Transportation Terminal (TT) is a part of the onshore facilities of the SYU Expansion Project. The purposes of the Transportation Terminal are to receive, store, and transport sweetened and stabilized crude oil from the adjacent Oil Treating Plant (OTP) or from other facilities. Two methods of crude transportation will be utilized: pipeline transportation and tanker loading. The TT will be designed for pipeline transportation as the base case or Phase I. Facilities required for tanker loading will be defined as Phase II facilities, incremental to Phase I.

The TT will be located in Las Flores Canyon, Santa Barbara County, California (see Figure 9.2). Tanker loading facilities such as the Single Anchor Leg Mooring (SALM) system and submarine pipelines will be located offshore in the Pacific Ocean adjacent to the onshore facilities.

The TT will be equipped with two 270,000 barrel cone-roofed crude storage tanks with internal floating roofs. In Phase I development of the TT, crude will be pumped to the proposed All American Pipeline (AAPL) station located on the TT pad. In Phase II development, tanker loading facilities will be provided to transport the crude oil through a large diameter onshore and submarine pipeline to a SALM located about 11,250 feet from shore in 160 feet of water. Provisions will be made in the Phase I design to facilitate expansion to Phase II.

10.2 Phase I Facil

10.2.1 Process Description

Treated crude oil will be received from the OTP and stored in two heated crude storage tanks. As the crude oil level rises in the tanks, the displaced vapors will be compressed by the tank vapor compressors and transferred to the OTP vapor recovery unit. Oil from the tanks will periodically be transferred to the transportation system pipeline, using the pipeline booster pumps. When the crude oil level drops in the tanks, blanket gas will be made up from the fuel gas system.

10.2.1.1 Oil Storage Facilities

Treated crude oil will be stored in two crude storage tanks with a net working capacity of 270,000 barrels each. The tanks are of the cone-roofed type with an internal floating roof and will be equipped with breathing valves connecting to the tank vapor blanketing system of the OTP. In addition, all tanks will be equipped with pressure protection devices to prevent over- or under-pressuring. The tanks will be heated by recirculating crude product through a steam heater to maintain the proper crude oil storage temperature.

The oil storage facilities will be separated from the oil and gas processing facilities. An emergency containment basin (ECB) will be constructed to contain possible oil spills. The ECB will be designed to contain approximately 110 percent of the volume of the largest tank.

10.2.1.2 Pump and Meter Station

The pump and meter station associated with the terminal will be located near the oil storage area (see Figure 9.3). The treated oil will flow by gravity from the oil storage tanks to the pump suction. Due to the relatively high viscosity of the treated oil, the crude oil temperature in the storage tanks will be maintained between 95 and 120°F.

Treated crude oil from the OTP will be received in the TT at a rate of up to 5,833 Bbl per hour (4,083 gpm) on a continuous basis. Oil will be transferred on a batch basis to the transportation system pipeline. Three centrifugal pipeline booster pumps will be provided with a capacity of 6,250 Bbl per hour (4,375 gpm) each. Two units will normally be utilized at a combined rate of 12,500 Bbl per hour (8,750 gpm). The third will be a standby spare.

A shell and tube heat exchanger will heat the crude to meet transportation pipeline viscosity specifications and maintain tank temperature. Steam from the CPP heat recovery steam generator will be used as the heating medium.

10.2.1.3 Crude Tank Blanketing and Vapor Recovery

Because of the continuous arrival of oil at the TT and the batch-wise transfer to the pipeline, the oil level in the crude storage tanks will rise and fall. The pressure in the vapor space between the internal floating roof and the external fixed cone roof will normally be maintained at a pressure between +0.3" and +1.3" Water Column (W.C.). Vapor will be made up from the fuel gas system, as required. When there is a displacement of vapor, it will be routed to the tank vapor compressors suction header.

As vapor is displaced from the crude storage tanks, it will be compressed and transferred to the OTP vapor recovery unit. There the gas will be combined with other streams, further compressed and sent to the SGTP for recovery as fuel gas. Any condensate collected in the compressor scrubbers will be pumped to the closed drain sump.

The overall blanketing and vapor recovery described above will result in no emissions from Phase I facilities, except for fugitive emissions associated with valves and connections.

10.2.1.4 Waste Water Treating

A closed drain sump will collect liquids from the tank vapor compressor system and other sources where volatile hydrocarbons are present. This liquid will be pumped to the OTP rerun tanks. Any flashed vapors from the closed drain sump will be returned to the tank vapor compressors.

Water from the open drain system, area drain system, and the ECB will be collected and processed through the area drain oil/water separator before being discharged to Corral Creek. The discharged water shall meet applicable water quality standards. Any oil skimmed by the separator will be pumped to the OTP for processing. The separator will be equipped with a carbon canister on the vent to eliminate emissions of any volatile hydrocarbons.

10.2.1.5 Miscellaneous Utilities

Firewater, potable water, utility water and utility and instrument air will be supplied from the OTP. Blanket gas will be provided from the main fuel gas system located at the CPP.

10.2.2 Plant Emission Control

All liquid and vapor streams produced by equipment in the TT containing volatile hydrocarbons will be collected and processed in the OTP to eliminate vapor emissions in normal operation. In addition, a program will be implemented to control fugitive emissions.

10.2.2.1 Gas Blanketing and Vapor Recovery

The crude storage tanks' vapor spaces will be connected by a vapor transfer line. This line will allow natural transfer of vapor between the tanks during tank filling, tank emptying, and barometric and thermal volume changes in the vapor space. During transfer to the pipeline, when crude is being withdrawn from a tank, a pressure controller on the common line will sense low pressure and allow gas from the blanket gas header to enter the line and provide vapor blanketing. When the tank is filling, another pressure controller will sense high pressure and release excess vapors to the tank vapor compressors suction header.

10.2.2.2 Fugitive Emission Controls

Design features that have been incorporated in the plant design which minimize fugitive emissions and assist in the implementation of a control program include the following:

Equipment - Tanks and sumps which normally breathe to the atmosphere and have the potential to contain volatile organic hydrocarbons will be fitted with carbon canisters. Pressure relieving devices on all pressurized equipment in hydrocarbon service will be vented to a vapor recovery system or a closed flare system wherever possible. Pumps in light hydrocarbon service will be fitted with tandem mechanical seals. Compressors in hydrocarbon service will be equipped with closed seal systems venting to the vapor recovery system.

Piping and Valves - A graphite-based packing will be used on 2-inch and larger valves requiring valve stem packing. 1-1/2-inch and smaller gate and globe valves in ROC service will be provided with bellows-type stem seals.

10.2.3 Plant Safety Features

10.2.3.1 Process Controls, Monitoring, and Alarms

Major process control will be via the microprocessor-based distributed control system (DCS) with computerized recording, reporting, and graphics features located in the central control room in the OTP. See Section 9.5.9.1 for a description of this system.

10.2.3.2 Overpressure Protection

The pressure relieving devices will allow excess pressure from process vessels to be relieved by venting to the OTP vapor recovery unit, to the flare system, or to atmosphere, as appropriate. The flare system in the OTP is described in Section 9.5.8.4.

In the TT, the only pressure relieving devices which will not relieve to the flare are pressure-vacuum vents on the vapor space of the crude storage tanks. The design pressure for these tanks is below the low pressure flare header pressure. Normally, the pressure will be controlled by make-up from the blanket gas system and relief to the tank vapor compressors.

10.2.3.3 Hazard Detection

Continuous monitoring fire sensors (ultraviolet, ionization, thermal, or fusible plug types) will be used in all high hazard areas. Combustible gas and/or H_2S sensors will be strategically located in hazardous or inadequately ventilated areas. Detection of a hazard will result in a visual and audible alarm in the central control room.

10.2.3.4 Fire Protection

A fire water system will be provided for the facility. The fire water tank and pumps are located in the OTP. See Section 9.5.9.3 for a description of this system. One special firefighting feature applicable to the TT will be the provision for internal foam injection to combat a fire at the seal area around the floating roof within the vapor space of the crude storage tanks.

A facility fire prevention program will be established including operator fire safety training and fire prevention inspections. Further details of the program and the fire protection design basis are contained in the LFC Fire Protection Plan, which has been approved by Santa Barbara County.

10.3 Phase II Incremental Facility Description

10.3.1 Process Description

Phase II of the TT involves facilities and pipelines necessary to load marine tankers and to control emissions from the loading operation. See Figure 10.2 for the nearshore site plan.

Pumps will be utilized to load marine tankers at a maximum rate of 45,000 Bbl per hour through a 48-inch loading line terminating at a Single Anchor Leg Mooring (SALM) located approximately 11,250 feet offshore. Positive displacement meters will be used for volume measurement for custody transfer.

A vapor balance system will capture virtually all hydrocarbon emissions associated with crude oil storage and tanker loading. The vapor which is displaced from the tanker's compartments as they are filled will be transferred to shore through an 18-inch looped vapor balance line. Compressors located onshore will maintain a vacuum in the 18-inch lines, providing the pressure differential needed to transfer the vapor from the tanker to the shore. Onshore, the vapor will be compressed and used to blanket the crude storage tanks as they are emptied. Vapor in excess of that required for blanketing will be routed to a refrigerated hydrocarbon recovery unit. Vapors not condensed in this unit will be fed to an incinerator for disposal.

10.3.1.1 Crude Oil Storage

The same crude storage tanks described for Phase I will be used for storage of crude oil in Phase II.

10.3.1.2 Crude Oil Pumping

During Phase II, crude oil can be transferred either to the transportation system pipeline or to tankers. Oil will be received in the TT at a rate of up to 5,833 Bbl per hour (4,083 gpm) on a continuous basis. Oil will be transferred to tankers at a rate of up to 45,000 Bbl per hour (31,500 gpm) and may be transferred to the transportation system pipeline on a batch basis at a rate of 12,500 Bbl per hour.

Six pumps at a capacity of 5,250 gpm (7,500 Bbl per hour) each are required to meet the maximum loading rate. A spare pump will be provided to ensure that the maximum loading rate can be achieved even when one pump is out of service. It is important to terminal operations to load at the fastest possible rate in order to minimize tanker on-station time.

Before the start of loading, the crude in the pipeline will be cold. In order to avoid excessive recycling due to high friction pressure drop, a low flow rate will be set initially. As the line warms, it will be possible to increase the throughput gradually up to the full desired flowrate. At the end of the loading operation, the sequence will be reversed. The loading rate will be incrementally reduced, thereby shutting down loading pumps.

10.3.1.3 Crude Tank Blanketing

The crude tank blanketing will operate during Phase II as was described for Phase I, with the exception that make-up will normally be from the vapor balance line via the SALM vapor compressors.

In the event that a malfunction causes an interruption in the vapor balance transfer to the tanks, fuel gas will automatically make up into the tank blanket gas header.

10.3.1.4 Vapor Recovery

The vapor recovery system for Phase II is designed to accommodate the vapors displaced as crude oil is loaded into tankers. The tanker gas will contain significant quantities of non-condensible gases (nitrogen, oxygen, CO_2, etc.) which will make it unsuitable for processing in the OTP vapor recovery unit and the SGTP.

The tanker vapors from the vapor balance line will be used to pad the crude storage tanks as they are emptied, but the excess, due to vapor growth, will be refrigerated to remove condensible hydrocarbons with the residual non-condensible vapors incinerated. All connections to the OTP vapor recovery system will be shut off during Phase II operations except for the pigging operation. Sweet fuel gas remaining in the vapor balance line after pigging will be bled off to the vapor recovery system.

The dual 18-inch vapor balance lines will permit the vapor displaced during tanker loading to travel to shore where it will be used for make-up to the blanket gas system. The majority of this gas will be used to pad the crude storage tanks. The remainder will be processed through the hydrocarbon recovery unit as described later.

As vapor from the tankers travels to shore through the underwater vapor balance line, condensate is likely to form on the pipe walls. Over a period of time, liquid could build up and restrict flow in the line. To mitigate this potential problem, a pigging system will be used to clear out the fluids.

The design provides for a looped pigging system using an 18-inch looped vapor return line. The pig can be launched from either onshore end of the line. After the line is pigged, the pigging gas will be slowly depressured either to the OTP vapor recovery system or to the terminal incinerator until the line returns to its normal vacuum state.

10.3.1.5 Hydrocarbon Recovery Unit/Excess Vapor Incinerator

Vapors from the SALM vapor compressor in excess of the quantity needed for tank blanketing will be treated to reduce hydrocarbons fed to the excess vapor incinerator. Vapors displaced from the crude storage tanks during tank-filling will be processed through the same system.

Excess vapors from the vapor balance system will first flow to three parallel, condensation-type hydrocarbon recovery units. Here, the vapors will be cooled to remove the majority of the water and some of the heavier hydrocarbons. Remaining vapors will enter a series of staged condensers where they will be cooled to remove the majority of the hydrocarbons. Collected liquid from each condenser stage will be combined and separated from the water in a common gravity separator, and the liquid hydrocarbon will be pumped back to crude storage. The recovered water will be sent to the closed drain sump. The vapors which are not condensed will flow to the excess vapor incinerator where the residual hydrocarbon will be destroyed.

Despite the water removal, the condensing coil will still require periodic defrosting. This will be accomplished by taking the condenser section out of service and melting the frost by indirect heating with a warm defrost fluid, typically d-Limonene. The defrost fluid will also be used to warm the vapors exiting the condensation unit to avoid potential freezing problems in the water seal upstream of the incinerator. One recovery unit may be off-line in defrost mode without curtailing tanker loading rates.

10.3.1.6 Waste Water Treating

The closed drain sump will collect condensate from the SALM vapor compressors and the aqueous phase from the hydrocarbon recovery unit decanter in addition to those streams whose collection was discussed under Phase I. The liquid will, as before, be pumped to the OTP rerun tank and any flashed vapors returned to the tank vapor compressors. Open drain and rainwater collections will be processed as in Phase I.

10.3.2 Offshore Facilities

10.3.2.1 Single Anchor Leg Mooring

The SYU TT tanker berth will consist of one SALM approximately 11,250 feet offshore Las Flores/Corral Canyons. Marine vessels of up to approximately 60,000 deadweight tons are expected to routinely moor at the SALM, while larger vessels may be employed for individual movements in special situations. The preliminary location of the SALM is based on maneuvering area, underkeel clearance requirements, the location of the kelp beds, and potential interference with California State tidelands oil/gas development. The minimum maneuvering area is a radius about the SALM of three times the length of the maximum size marine vessel expected to routinely use the SALM. The new location of the SALM away from the kelp beds will provide ample vessel underkeel clearance.

The SALM will transfer crude oil and displaced inert gas and hydrocarbon vapors between the pipelines and the moored tanker. Each tanker will have been equipped with crude and vapor manifolds with quick release couplers similar to the design presently employed on the Hondo trader fleet shuttle tankers.

The SALM will be designed to withstand the maximum operating loads induced by moored marine vessels and to withstand survival conditions based on a 100-year design storm with no vessel moored. Final design loads will be based on data supplied by a model test program. The SALM will be classified as an "A1 Single Point Mooring" in accordance with the American Bureau of Shipping "Rules for Building and Classing Single Point Moorings". Figure 10.3 schematically shows the SALM and its major components. Descriptions of the major components are as follows:

1. A mooring base founded on piles or designed as a gravity type structure will be provided and designed to withstand the maximum horizontal and vertical loads induced on the SALM.

2. A riser shaft constitutes the single anchor leg. It will extend from the mooring base to the mooring buoy and is designed to safely resist maximum forces by a moored shuttle tanker or by the maximum survival environment. The riser will include crude oil and vapor return piping and valves for connection to the base hoses which connect the SALM to the pipeline end manifold (PLEM).

3. <u>Universal joints</u> will be located in the anchor leg at the top and bottom of the riser shaft. The base universal joint will connect the mooring base to the riser shaft, and the buoy universal joint will connect the riser shaft to the mooring buoy.

   The base and buoy universal joints will be capable of rotating up to 60 degrees from the vertical in any azimuthal direction while carrying the design anchor leg load without distortion or overstressing.

4. A <u>mooring buoy</u> will be located at the water surface, connected to the riser shaft subsurface and the tanker mooring hawser(s) topside. It will be attached in a manner which allows full and continuous 360 degree rotation. A radar reflector and a beacon light will be mounted atop the mooring buoy to assist marine vessels in determining the SALM position. Fenders will be attached around the circumference of the buoy to prevent damage to either the buoy or any tanker alongside.

5. A <u>mooring hawser(s)</u> having chafing chains attached at the mooring buoy and marine vessel ends will be provided. The hawser will attach to the mooring buoy and will extend into the water, with a messenger line attached at the vessel end to aid in

mooring operations. Floats will be attached, as necessary, to the mooring line and chafing chain.

6. A <u>dual product fluid swivel assembly</u> will be provided near the mooring base to allow for the simultaneous transfer of crude oil and displaced marine vessel vapors. The fluid swivel assembly will be mounted in the mooring buoy to facilitate inspection and periodic maintenance and will be designed for continued rotation of the mooring buoy and shuttle tanker. The two fluid conduits will be segregated from each other within the swivel assembly to minimize any chance of product mixing.

   A leak detection system will automatically check for any leakage past the first seal of each of the sets of internal seals in the dual product fluid swivel assembly. The system will alert maintenance personnel in the buoy if leakage occurs or when seal integrity is suspect.

7. The <u>hose system</u>, consisting of two hoses, each approximately 450 feet in length, will be provided for crude oil and marine vessel vapor transfer between the dual product swivel assembly and the vessel. The hose system will consist of dual underwater and floating hose strings of suitable length and arrangement between the lower portion of the mooring buoy and the tanker's midship manifolds.

10.3.2.2 <u>Pipelines</u>

Three major pipelines, approximately 14,000 feet in length, will be installed from the onshore facilities to the SALM. These three pipelines will be for crude oil and marine vessel vapor balance. The crude oil line will be 48 inches in diameter and the vapor balance lines will be 18 inches in diameter. In addition to the three major pipelines, a hydraulic service cable bundle will also service the SALM. The hydraulic lines will permit automatic operation of the subsea manifold valves on the crude oil transfer and marine vessel vapor balance lines.

The onshore pipeline corridor was described in detail in Section 8.3.6. It runs from the onshore facilities in Las Flores Canyon under or alongside the road to a valve box at the north end of the pipeline tunnel. The 48-inch pipeline will have a motor actuated shoreline block valve located in this valve box.

From the valve box at the north end of the pipeline tunnel, the offshore pipeline corridor runs through the tunnel, crossing State Highway 101 and the Southern Pacific Railroad right-of-ways, and enters the corridors described in state lease PRC 4977.1. At the SALM site, the pipelines will be manifolded and connected to the underwater base hoses of the SALM.

The crude line is designed to accommodate a peak loading of 45,000 Bbl per hour. The crude oil manifold will be equipped with a hydraulically activated ball valve. To avoid pressure surges in the submarine line, this valve will be interlocked with the shoreline block valve.

The dual 18-inch vapor balance lines are designed to handle the tank vapor displaced during filling at the 45,000 Bbl per hour rate plus allowance for vapor expansion. The vapor balance manifold will be equipped with two hydraulically-operated ball valves. This equipment will allow removal of condensed vapors, mainly water with some hydrocarbons possibly present, and will permit the application of corrosion inhibitors.

The geologic/geotechnical design considerations in these onshore and offshore pipeline corridors are discussed in Sections 8.3.4, 8.3.5 and 8.3.6. The design approach discussed in Section VIII (Pipelines) is fully applicable to the TT pipelines.

10.3.3 Emission Control

10.3.3.1 . .

The TT will be equipped with a closed system to transfer vapors displaced from the marine vessel during crude oil loading. The vapors displaced by crude oil loading will be transferred to the onshore tank farm by a shore mounted compressor. This compressor will take suction on the 18-inch vapor balance line and the resulting vacuum (approximately seven to eight psia) will provide the differential pressure needed to transport the vapors from the marine vessel to the tank farm.

At the tank farm, the vapors will enter the tank vapor blanketing system. Because the transferred vapors will be volumetrically equivalent to the transferred crude, a closed, balanced system will be established. Thus, the inclusion of the vapor balance system in the TT design will not only prevent any uncontrolled marine vessel vapor emissions, but it will also minimize vessel modifications by locating the required equipment onshore. To prevent the vacuum in the vapor balance line from opening the ship's emergency vacuum vents, thus introducing air into the ship's cargo tanks, a pressure regulating valve on the ship's vapor collection manifold will maintain a preset pressure level in the cargo tanks.

All marine vessels in dedicated service to the TT will be compatible with the crude loading and vapor balance systems. In the event of an emergency or unforeseen disruption to normal operations of the dedicated fleet, alternate marine vessels may be called upon to maintain cargo deliveries. Alternate marine vessels may temporarily load without vapor balance if vessels equipped for vapor balance are not available, but all reasonable steps will be taken to restore full vapor balance operation as soon as practicable.

Because the vapor balance system will operate at a vacuum, the possibility of partial condensation represents a potential problem in system operability (increased pressure drop) and/or reduction of system life (corrosion). The SALM vapor compressor suction scrubber will remove condensate entrained in the vapors transferred through the underwater vapor balance line. Because draining of the scrubber will be necessary during normal operation, a high liquid level cut-in device will automatically activate a pump to drain the liquid. The condensate pumped from the scrubber will be piped to the closed drain sump for disposal.

10.3.3.2 Hydrocarbon Recovery Unit

All gas from the SALM vapor compressors, in excess of that needed for blanket gas system make-up, will be sent to the hydrocarbon recovery unit. This refrigerated condensation unit will remove condensibles at a final condensing temperature of approximately -100° F due to the high concentration of CO_2 in the excess vapor stream. Non-condensibles will then be sent to the excess vapor incinerator for destruction of residual hydrocarbons.

Each condensation unit has a precooler and several stages of condensing coils operating in series. Each stage, including the precooler, has an independent cascade refrigeration system with the refrigeration compressors cycling on and off with vapor loading as necessary to maintain a preset condenser temperature.

The recovered hydrocarbon liquids will be returned to the crude storage tanks. With proper distribution, the condensate will be absorbed into the body of the crude and not immediately flash off to recycle to the vapor balance system.

10.3.3.3 Incineration

The incinerator is a custom design due to the uniqueness of the application. The unit is designed for a hydrocarbon destruction efficiency greater than 99.9 percent. It is also designed for a minimum of auxiliary firing to minimize NOx formation. A THERMAL DeNOx system is included to further reduce NOx emissions. The excess vapors burn with a low flame temperature as is, therefore combustion modifications would have no further effect. Applying combustion modifications to the auxiliary fuel would only increase the amount of auxiliary fuel required to ensure complete destruction of the remaining hydrocarbons. A state-of-the-art control system will be provided to maintain combustor conditions as the excess vapor stream changes in rate and composition. The controls will guarantee a sufficient minimum of combustion air and add additional air as necessary to control the temperature of the flue gas entering the THERMAL DeNOx chamber. The controls will also adjust the ammonia injection rate for the THERMAL DeNOx system.

10.3.3.4 Fugitive Emission Controls

The fugitive emission controls features described in Phase I are entirely applicable to Phase II.

10.3.4 Plant Safety Features

The plant safety features described for Phase I are entirely applicable to Phase II with the following additions:

10.3.4.1 Vapor Balance Line Oxygen Monitor

Of special significance for Phase II of the TT are detection of oxygen in the vapor recovery system and limiting of hydrocarbon release during tanker loading.

To prevent the accidental introduction of air from the tankers into the vapor recovery system, an oxygen analyzer on the SALM vapor combustion discharge scrubbers will alarm if the oxygen content exceeds seven volume percent. If the oxygen content exceeds eight volume percent, then an emergency shutdown system activates which will automatically shut down the compressors and the crude oil loading pumps and close the block valves upstream and downstream of the compressors. The block valves will isolate the compressors and prevent the flow of the oxygen contaminated vapors to the crude tankage.

10.3.4.2 Transfer Shutdown System

A shutdown system will also be provided for the crude loading system to limit any release of hydrocarbons in the event of an emergency. There are two ways this could occur:

- Leakage of crude oil
- Loss of the vapor recovery system and opening of tanker vents due to overpressure

The first contingency will be covered by a manual shutdown system which shuts off the loading pumps and closes the block valves in the loading line. Three block valves will be provided, one at the pump area battery limits, one to the north of U.S. Route 101 and the third on the sea bed at the SALM. These valves will block off the crude line into segments and thus minimize the volume of leakage.

If the vapor recovery system shuts down while crude is still being loaded onto the tanker, it will be possible to overpressure the tanker vapor space and open the pressure vents. To prevent this, the emergency shutdown systems on the vapor recovery will also shut down the loading system. This will occur automatically rather than manually and will be alarmed to indicate to the operator that the loading system has been shut down.

10.3.4.3 Navigational Aids

The SALM system will be equipped with aids to navigation in accordance with the Department of Transportation, Code of Federal Regulations, Title 33. The SALM buoy will include a radar reflector, an obstruction light, and a fog horn. Floating hoses for the cargo transfer system will have marker lights.

10.4 Construction and Installation

10.4.1 Onshore Facilities

The onshore facilities associated with the TT will be constructed and installed along with the other onshore facilities. It is anticipated that the tank farm area will be an initial staging and marshalling area for the construction activities associated with the OTP.

10.4.2 Pipelines

The pipeline construction and installation details of Section 8.6 are applicable to the TT pipelines.

10.4.3 Single Anchor Leg Mooring

Components of the SALM will be fabricated in the contractor's shops and transported to the site for assembly, installation and testing. All elements of the construction and installation shall be in strict accordance with the detailed design drawings and specifications which will be developed based on applicable codes, rules, and regulations. To assure quality control and conformance with the drawings and specifications, all phases of the fabrication, assembly, testing and installation will be closely inspected.

Protection against corrosion will be provided by the use of special materials, extra material thickness and cathodic protection. Current planning indicates that a galvanic cathodic protection system will be installed.

10.4.4 Operations

A manned control, surveillance and communications center will be provided in the OTP control room. TT data displayed within the control center will include the following:

1. The open/close position of all automated valves and the on/off condition of each shipping pump.

2. Flow rate and total flow for each meter.

3. Shipping pump suction and discharge pressure. Discharge pressure will be recorded and remotely controlled downstream of the meter battery.

4. Temperature of the flowing stream. Temperature will also be recorded.

5. The status of the vapor balance system.

Radio communications equipment will be installed to permit continuous communication with the marine vessel during mooring, loading, and deberthing.

A manually and/or automatically activated safety shutdown system will be provided. Automatic safety shutdown will be triggered by excessive total flow rate as registered by the flow meter totalizers and by a pressure ten percent over normal, as detected by the high pressure shutdown switch at the shoreline valve.

The safety shutdown system can be manually activated at any time by the control room operator and will be activated if communication with the marine vessel is lost at any time during loading operations.

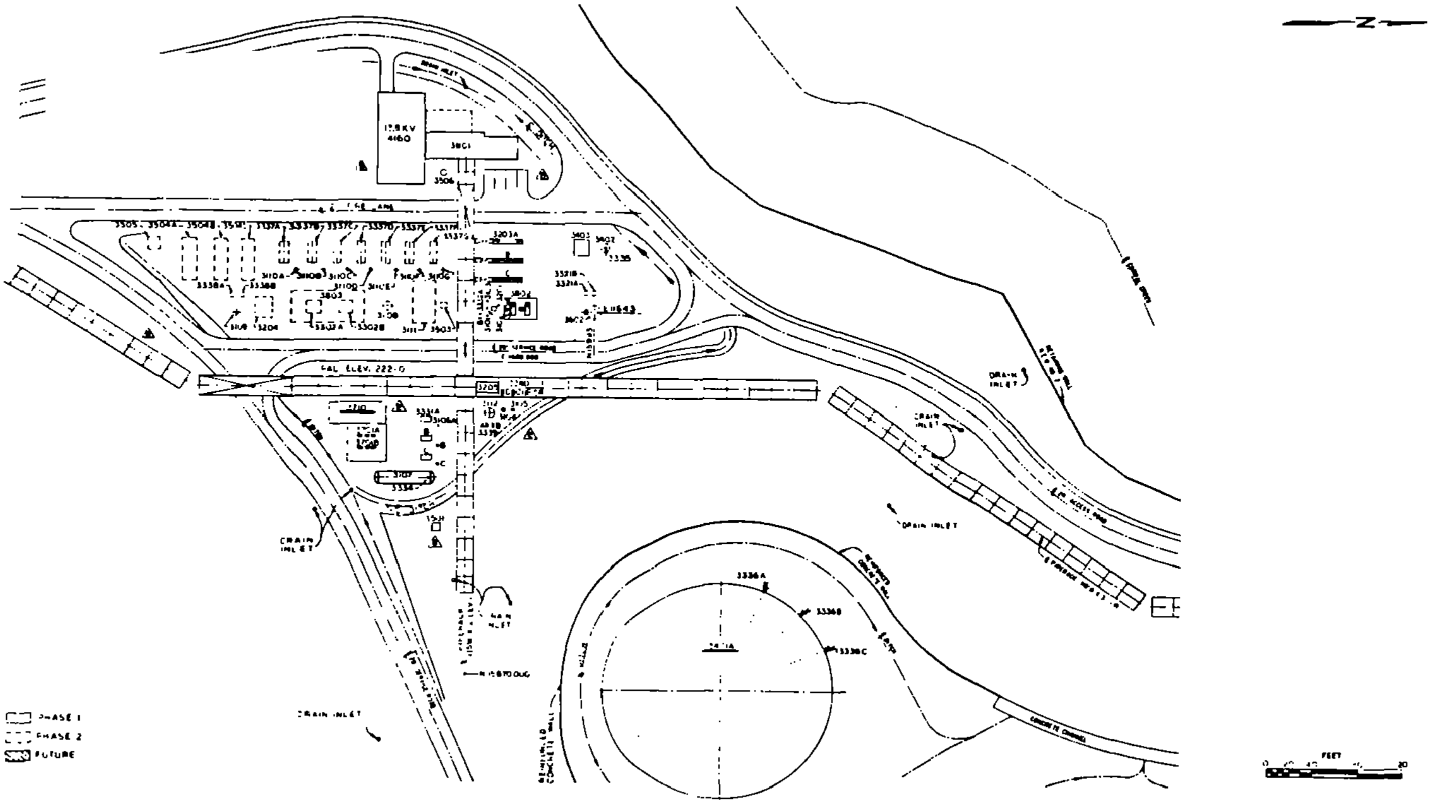

Figure 10.1
TRANSPORTATION TERMINAL

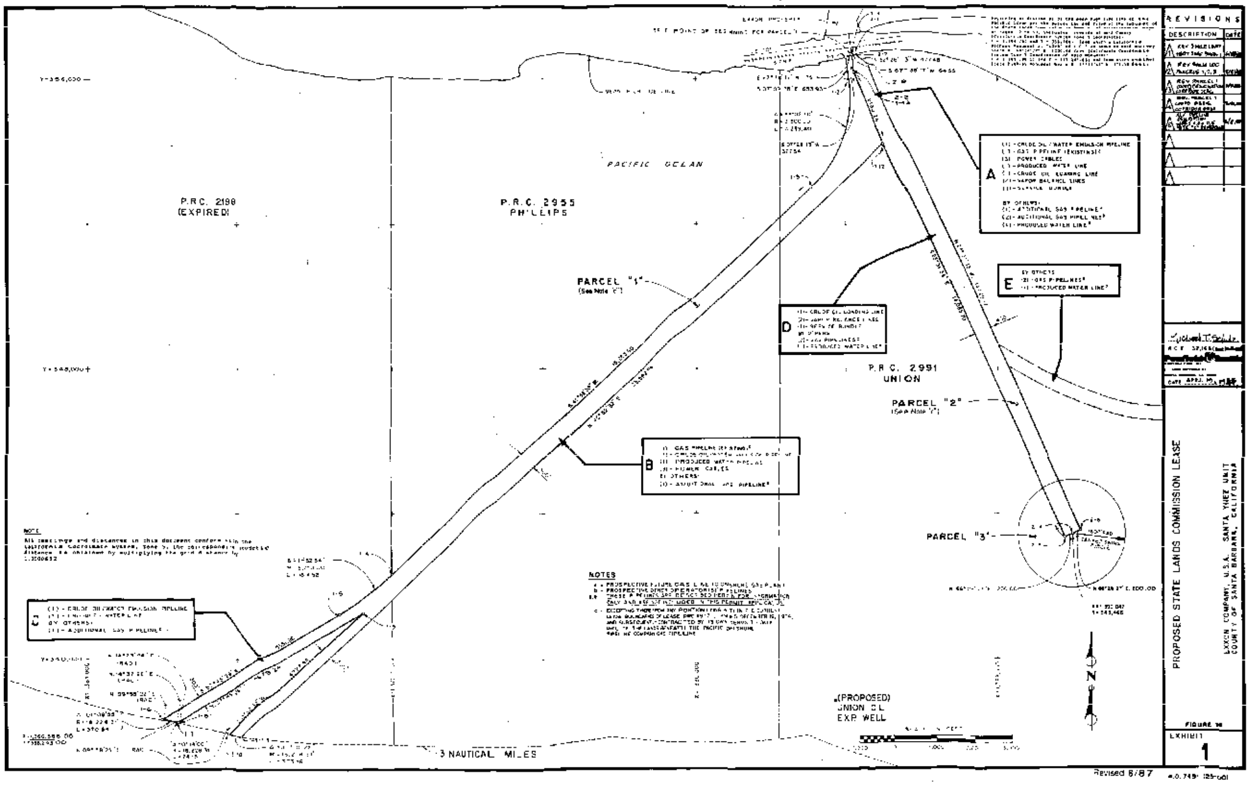

Figure 10.2
SITE PLAN
NEARSHORE FACILITIES

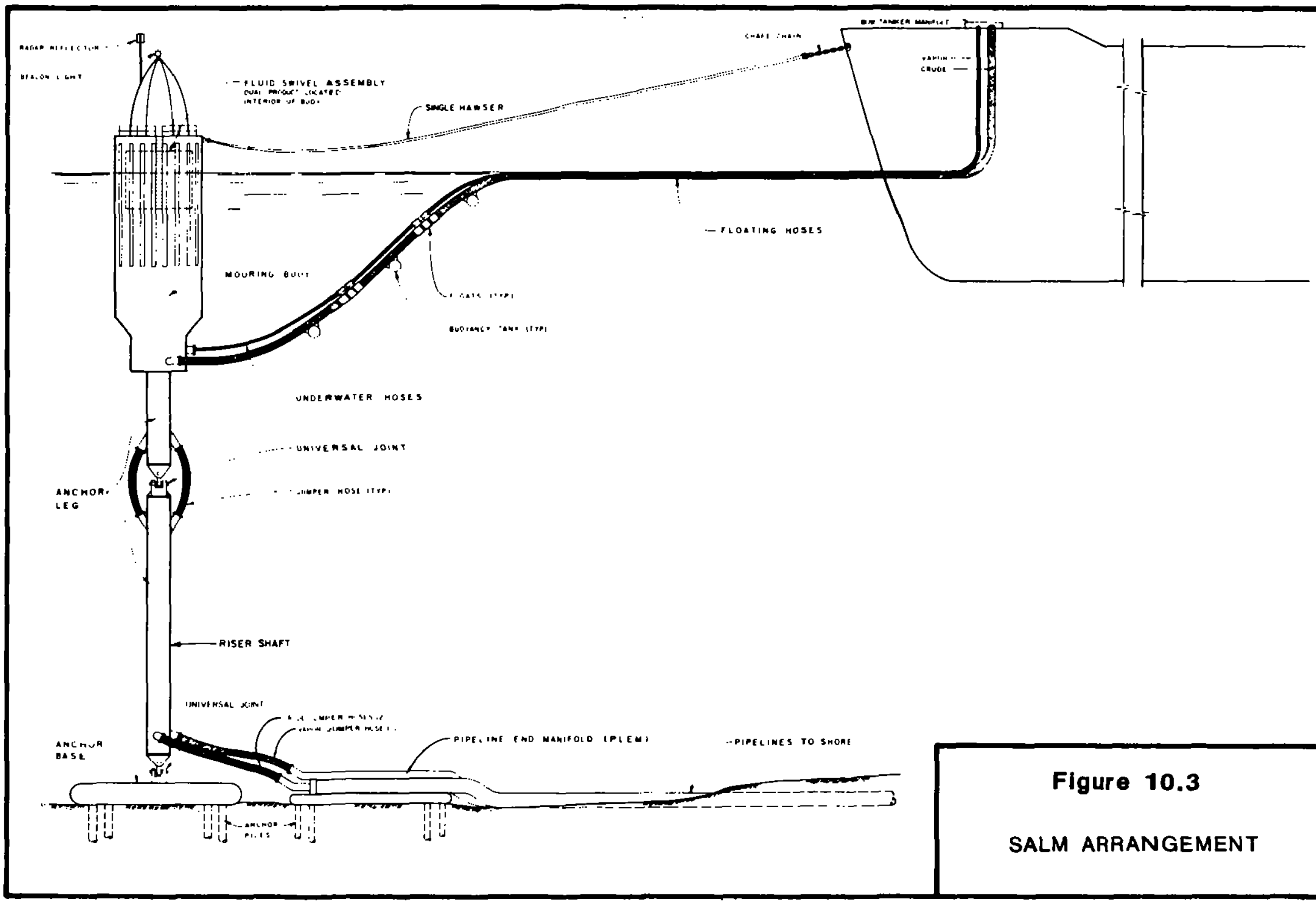

Figure 10.3

SALM ARRANGEMENT

SECTION XI

OPERATIONS

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SECTION XI

11.1 Introduction

This section describes the general procedures Exxon will use in the construction and operation of the offshore platforms, the onshore facilities and the Las Flores Canyon Consolidated Marine Terminal proposed for this development of the Santa Ynez Unit.

11.2 Construction

Construction of the offshore and onshore Santa Ynez Unit facilities is scheduled to begin in 1987 and will continue through 1992 (excluding Platform Heather and the expansion of the OTP to 140 kBOD). Construction manpower requirements will peak in 1991 with approximately 1,000 personnel simultaneously employed on offshore platform and pipeline installations and onshore facilities construction.

11.2.1 Offshore

Offshore construction operations will support installation of the platforms, pipelines and power cables, installation of the marine terminal, and the hookup of the platform drilling and production facilities. Procedures for major construction activities are detailed in the individual applicable sections of this Plan. All offshore construction will conform to applicable codes and regulations.

The platform structures will each be composed of two major components: the platform jacket and the platform decks. Both platform components will be fabricated outside of the local area and transported to the installation site by barge. Once on location, the platform jacket will be launched from its transport launch barge, upended, and then piles and conductors installed as described in Section 4.7.

The platform decks will be fabricated in modular form with production equipment preinstalled. Upon delivery to the platform installation site, the deck modules will be lifted by the installation derrick barge, set atop the jacket cap and then welded into place. Production facilities will then be hooked up between the modules, tested and finally, commissioned.

Installation of the offshore pipelines is not expected to require development of new technology buy may require the extension of current technology to deeper water depths with larger pipelines. The primary construction method anticipated for pipeline installation is the conventional lay barge method.

Assuming a lay barge installation, individual lengths of precoated pipe will be taken aboard the barge and stored on racks. The pipe joints will then be welded into a continuous string on a long, gently curved production ramp and the barge will be pulled forward one pipe length as each new joint is added. During pull-up, the pipe string will pass down the ramp, onto a stinger, and down to the ocean floor in an S-curved configuration. Deployment of the lay barge anchors will require a construction corridor approximately 12 times as wide as the local water depth. Pipelines will be laid in the approximate center of this corridor.

Power cables will be installed in the same corridors as the offshore pipelines. For installation of the power cables between platforms the cable will be pre-wound on a spool mounted on a barge. A free end of the power cable will be pulled onto the first platform through a pre-installed J-tube. The spool barge will then move away from the platform, unreeling the power cable as it proceeds. As the spool barge approaches the second platform, the cable will be cut and then pulled through a J-tube onto the second platform. After visual inspection and high voltage testing, the ends of the power cable will be terminated to the platform switchgear equipment.

Major items of equipment that will be used in the offshore construction operations include: a derrick barge, a pipelay barge, a trenching barge, cargo barges, tug boats, generators, compressors, and welding machines. Construction crews of 75 to 100 contract labor and supervisory personnel will be required for most of the major offshore construction activities.

Offshore construction crews for platform installation, pipelaying, hook-up, and marine terminal installation will be berthed aboard the derrick or pipelay barge and will work on a two weeks on, one week off basis. The work schedule for these operations will be a seven day work week with the working day split into two 12-hour shifts.

Platform facilities hookup and commissioning, Hondo platform modifications and power cable installation operations will be conducted on a seven day per week, two shifts per day basis. The crews will live on shore and be transported to and from the platforms by crew boats.

Crews will report to the Goleta parking lot at the beginning of each shift; from there they will be transported by bus to the Ellwood Pier. A crew boat will then be used to take them to the specific work site. Typically the crew boat will make four trips per day to and from Ellwood Pier.

In general, materials and supplies will be delivered by truck to a marshalling area at Port Hueneme. It is estimated that truck deliveries will not exceed an average of eight trips per day for any individual project. From Port Hueneme, offshore transportation will be by supply boat or tug and barge, as appropriate. It is estimated that the offshore supply boat runs will not exceed an average of four per week for any individual project.

Exxon will conduct all offshore construction operations in a manner which maximizes the safety of the construction personnel and minimizes environmental impact. Exxon will strictly adhere to all applicable OSHA, USCG and MMS safety requirements.

11.2.2 Onshore

Onshore construction activities will include construction of oil treating and storage and transportation, gas treating, power generation facilities, NGL storage/loading facilities, and construction of the onshore portions of the power cables and pipelines. All onshore construction will conform to applicable codes and regulations.

Major components of the onshore treating and power generation facilities will be manufactured outside of the local area and delivered to the construction site by rail and/or truck.

After initial layout and grading, equipment foundations will be constructed. Concrete and reinforcing steel will probably be provided by local suppliers. Most major components will be installed directly onto the prepared foundations, however, necessary yarding will be provided on site. After equipment installation, the valves, piping and associated hardware will be installed and the facilities electrically wired. Offices and miscellaneous buildings will be constructed. Construction is anticipated to take 30 months and require a peak labor force of 900 to 1,100 men.

The onshore pipelines will be installed between the onshore treating facilities and the offshore pipeline landfall. Conventional land pipeline construction methods and equipment will be used. A staging area of approximately two acres will be located in the lower part of Las Flores Canyon where pipe will be double jointed and loaded onto trucks for transport to the construction site. At the construction site the pipe joints will be placed and welded end-to-end in a pipeline trench and through the existing bored tunnels that pass under U.S. Highway 101 and the railroad tracks. Backfill operations will follow emplacement of the pipelines and the pipelines will then be hydrostatically tested. Construction activities will be carried out by approximately 45 to 60 men working a five-day week, eight hours per day for six months.

It is expected that the majority of personnel required for the construction of the onshore facilities and pipelines will be acquired from the existing labor pool of the Santa Barbara-Ventura-San Luis Obispo-Los Angeles area.

Major items of equipment that will be used in the onshore construction operations include: bulldozers, backhoes, cranes, generators, compressors, welding machines and service trucks.

Exxon will conduct all onshore construction operations in a manner which maximizes the safety of the construction personnel and minimizes environmental impact. Exxon will adhere to all applicable safety requirements.

11.3 Operations

Previous sections of this Development and Production Plan have presented detailed designs and operating features of the various proposed and existing facilities and equipment, including the monitoring, safety and shutdown systems.

This subsection outlines operating, surveillance and communication plans for the facilities. These plans are intended to provide an overall view of the staff and operational responsibilities of each facility, the use of monitoring, surveillance and shutdown systems, and the contingency plans for reacting to abnormal conditions.

11.3.1 Platform

Platform operations are divided into two phases: drilling and production. Simultaneous operations will be covered in the "General Plan for Conducting Simultaneous Operations" which will be approved by the MMS as per Pacific Region OCS Order 5.

11.3.1.1 Drilling

Upon completion of the platform jacket and deck installation, the drilling rig(s) will be set and drilling operations will begin.

Each drilling rig will have separate crews and supervision. Dual rig platforms will contain twice as many drilling personnel as single rig platforms.

Twenty to twenty-four drilling contractor personnel and two to five drilling service company personnel will work on each rig per shift. Each rig will have two Exxon drilling supervisors: one drilling superintendent and one drilling technician. Normally, the drilling superintendent and technician will work alternating 12-hour shifts. The Exxon drilling superintendent will oversee the drilling operations.

Drilling contractor crews and Exxon supervisors will work alternating 12-hour shifts and live on the platform. They will alternate working seven days on and seven days off. Service company personnel will work and live on the platform as drilling operations dictate.

Most drilling personnel will normally travel to the platform by crew boat from Ellwood Pier in Goleta. Helicopters will occasionally be used for personnel transport from the Santa Barbara Airport.

Exxon will conduct all drilling operations in a manner which maximizes the safety of the platform personnel and minimizes the impact to the environment. Safety equipment will be installed on the drilling equipment to meet or exceed MMS and OSHA requirements. All ocean discharges will comply with NPDES requirements.

11.3.1.2 Production

Start-up of production will occur after the drilling of a sufficient number of wells is completed and construction of the production facilities and pipelines is concluded.

A field superintendent will have operational responsibility for the platform and the associated production equipment. Voice communication with shore will be available at all times via telephone, microwave and radio systems. Personnel living on the platform will operate the wells and production equipment located on the platform. Crews will work 12-hour shifts, seven days on and seven days off. The platform will be serviced by both helicopter and boat transportation. Normally, only supervisory and engineering personnel will be transported by helicopter. Operating personnel will normally be transported to and from the platform by crew boats operating from Ellwood Pier. Helicopter transportation will be available to them in emergency conditions.

Operating supplies will normally be transported by the crew boats or special supply boats. Seagoing barges will be used to transport bulky equipment items too large or too heavy for transport on crew and supply boats. Helicopters will be available to transport light loads of equipment and supplies during rough weather or at other times when rapid delivery is desired.

Emergency shutdown of operations and evacuation of the platform is expected to be highly infrequent. However, formal detailed contingency plans and procedures have been developed and are included in Attachments A and B. A synopsis of contingency plans will be posted in strategic locations on the platform and reviewed in detail with all personnel.

Emergency life support equipment, including gas masks, respiratory equipment, protective fire suits, life preservers, and life rafts will be stocked and maintained on the platform to meet or exceed USCG regulations.

The platform fire and gas detection system, emergency shutdown system and firefighting system will provide protection to personnel as well as to the platform structure and facilities. Manual or automatic activation of the fire or emergency shutdown system will activate audible and visual alarms, shut down the entire platform (including the shut-off of each well), and secure all pipelines leaving the platform. Automatic detection of out-of-bound gas concentrations will activate audible and visual alarms and may selectively shut down part of the production facilities depending upon the location and concentration of gas detected.

Emergency manually operated platform shutdown controls will be located at several strategic locations on the platforms. Portable fire extinguishers will be provided to meet USCG regulations and may be used to augment the deluge fire water system. Design details of the fire system, emergency shutdown system, and gas detection system are included in Section VII. A comprehensive program of monitoring production equipment and systems will be developed. The main feature of this program will be the central control room which will be manned at all times. The control room operator will be able to monitor all platform processes and safety systems and initiate appropriate actions via the controls provided or through the audio communications systems to other operators.

Detection of certain abnormal conditions will result in an automatic platform shutdown. Activation of the emergency shutdown (ESD) will stop the crude oil pumps and the gas compressors, close the block valves on the pipelines leaving the platform, and shut in wells at both the wellhead safety valves and at the subsurface valves below the ocean floor. The following conditions will result in an automatic shutdown:

1) Detection of a fire.
2) Loss of the electrical system.
3) Low pressure in the instrument air system.

4) High level or pressure in certain critical vessels.

Platform shutdown could also be manually initiated by activation of the emergency shutdown or fire systems. These systems will be activated by platform personnel in the event of an emergency situation.
Many subsystems will also be protected by local shutdown systems. These are activated by high/low pressures or levels in treating vessels, a high level in surge tanks, etc.

All safety equipment will be checked for proper operation and set point at least once per month by skilled technicians who must attend training courses certified by the MMS. Prevention is the most effective method of pollution control and will be a primary objective of all operations. A general prevention policy has been developed and will be followed during all phases of platform operations. This policy includes:

1) Personnel education.
2) Periodic pollution inspections and follow-up on corrective actions.
3) Frequent "spill drills" which include deployment of containment and recovery devices.
4) Periodic review of well control procedures.

5) Regular inspections of equipment and safety shutdown systems.

Exxon has prepared a detailed "Oil Spill Contingency Plan for California Operations" which sets forth specific procedures to be followed in the event of an oil spill. An overview of this plan is included in Attachment C.

11.3.2 Onshore Facilities

Voice communication with the offshore platforms will be available at all times via telephone and radio systems. Regularly assigned personnel will be responsible for operation, surveillance, inspection and maintenance.

Most full-time employees will come from the local Santa Barbara-Ventura-San Luis Obispo County area. There will typically be three 8-hour shifts per day and 40-hour work weeks. The facilities will be operated on a 24-hour per day, 7-day per week basis. Maintenance crews will normally work the day shift only. Service contracts with outside firms will be used to provide manpower and equipment for non-routine operations.

After completion of the construction phase, the facilities will go through start-up operations where all equipment will be subjected to comprehensive testing procedures. A carefully planned start-up procedure will be used to minimize processing upsets experienced during start-up operations. The OTP, CPP, and SGTP will be controlled from the central control room in the OTP. All significant process variables will be transmitted to the control room where operating personnel can evaluate the facilities performance, make necessary adjustments, shut down and/or bypass various units, or completely shut down the entire facilities area through use of the emergency shutdown system.

All critical vessels will have high and low liquid level controllers/alarms and pressure relief valves. Although evacuation of the facilities is highly improbable, formal detailed contingency plans and procedures will be developed for emergency situations. The contingency plans will be posted in strategic locations and reviewed in detail with all personnel. These plans will be developed after consultation with local fire department authorities. Emergency life support equipment, including gas masks, respiratory equipment and protective fire suits, will be stocked and maintained as required.

The onshore facilities will have emergency shutdown and fire fighting systems to provide protection to personnel as well as to the individual facilities. Emergency shutdown control stations will be located at several points within the facilities area. Purchased power will provide power to critical systems in the event of a power failure.

A central control room will allow comprehensive monitoring and surveillance of processing facilities and systems. Operating variables such as pressures, temperatures, flow rates and liquid levels from the various units will be transmitted to the control room where they will be displayed. Alarm points and automatic shutdown alarms will also be displayed in the control room.

Complete shutdown of the facilities can be initiated by the facilities control room operator. In addition to total shutdown, certain units and individual pieces of equipment will have their own safety shutdown systems. Surveillance, control and shutdown equipment will be tested and inspected at regular intervals.

The following conditions will result in automatic shutdown of the facilities:

1) Electrical power failure.
2) Low pressure in the instrument air system.
3) Fire detection.
4) Critical conditions on key units.

The manual emergency shutdown system could be activated by facilities personnel in the event of any hazardous or emergency polluting situation. Manual emergency shutdown stations will be located at several locations within the facilities area.

11.3.3 Marine Terminal

The location and general description of the marine terminal were presented in Section 10.3. In general, this terminal will be classified an "A1 Single Point Mooring" in accordance with American Bureau of Shipping rules and designed, constructed and operated to comply with applicable U.S. Coast Guard regulations.

The terminal facilities will be available for crude loading 24 hours per day. It is anticipated that a single grade of crude oil will be delivered through these facilities although modifications in the onshore facilities and operating procedures could permit a batch operation.

The SALM will be designed to minimize the need for mooring launch assistance during marine vessel mooring and unmooring maneuvers. Mooring and hose lines will float on the water surface and will be capable of being lifted from the water and released in an emergency situation without the aid of an additional vessel. However, operational experience may dictate that mooring launches will be required to assist in the mooring operations. In any event, launches will be required on an occasional basis to straighten out tangled lines and to perform periodic inspection of the SALM components.

The marine terminal will not require any dedicated full-time personnel. Personnel stationed at the onshore oil treating and storage facilities will have the responsibility for maintaining and operating the SALM. Radio communications equipment will be installed to permit continuous communication with the marine vessel during mooring, loading and deberthing.

A manually and automatic activated safety shutdown system will be provided for the loading system. Automatic safety shutdown will be triggered by:

1) Excessive total flow rate as registered by the flow meter totalizer.
2) Excessive line pressure as detected by the high pressure shutdown switch at the shoreline valve.
3) Malfunction of the vapor balance system.

The safety shutdown system could be manually activated at any time from the onshore oil treating and storage facilities control room. It will be activated upon request from the marine vessel being loaded or if communication with the vessel is lost at any time during loading operations.

11.4 Termination and Abandonment

11.4.1 Offshore Facilities

When a platform is no longer needed to support production or pipeline operations, all wells will be plugged and abandoned. Cement plugs will be set to confine fluids in their parent formations to prevent them from intermingling or flowing to the surface. During plugging operations, well control equipment will remain in use. Casings will be cut off at least 16 feet below the mud line and all obstructions removed from the ocean floor.

Plugging and abandonment operations will be in conformance with MMS regulations and such activities will not be commenced prior to obtaining approval from the MMS. These regulations identify acceptable alternate abandonment procedures for various well conditions and specify tests to ensure that formations are isolated and that wells are left in a safe condition.

All equipment will be removed from the platform. The decks will be dismantled and transported to shore for disposal, salvage or reuse. Jacket legs and pilings will be cut off below the mud line. The jacket will be cut into sections and transported to shore for disposal, salvage or reuse. All obstructions will be removed from the ocean floor. The offshore pipelines will be purged and abandoned in place.

Assuming it could not be utilized with any other existing or planned projects, the nearshore marine terminal will be dismantled. If a pile founded base is installed at the SALM, the piling will be cut off below the mud line. The SALM will be recovered and transported to shore for disposal, salvage or reuse. All obstructions will be removed from the ocean floor.

11.4.2 · 'e Facilities

Assuming they could not be utilized with other existing or planned projects, the onshore oil treating facilities, gas treating facilities, storage facilities, transportation facilities, and/or power generation plant will be dismantled. Equipment will be salvaged or reused to the extent possible. The foundations will be broken up and all refuse will be hauled away for disposal at an approved disposal site.

The site will then be revegetated in accordance with County of Santa Barbara or other applicable agency regulations in effect at that time. Onshore pipelines will be purged and abandoned in place unless regulations existing at the time require their removal. In that case, the pipelines will be excavated, dismantled, and the individual segments hauled away for salvage or reuse. The disturbed land will then be restored.

ATTACHMENT A

CRITICAL OPERATIONS AND CURTAILMENT PLAN

EXXON COMPANY, U.S.A.

SANTA YNEZ UNIT

SANTA BARBARA CHANNEL

OFFSHORE CALIFORNIA

GENERAL

This plan is filed under the legal jurisdiction of the Department of the Interior - Minerals Management Service - Revised Outer Continental Shelf Orders Governing Oil and Gas Lease Operations, OCS Order No. 2 - Effective Jan. 1, 1980, Pacific.

OPERATING AREA

United States Outer Continental Shelf.

OCS Leases P-0180 to P-1085, P-0187 to P-0197, P-0326, P-0329, and P-0461.

RIG TYPE

Fixed Platform Rigs

EXXON COMPANY, U.S.A. - WESTERN DIVISION CONTACTS

Drilling Manager	To be communicated to the
Operations Superintendent	MMS at a later date.

CRITICAL OPERATIONS LIST

Exxon considers the following to be critical operations:

1. Directional Control of Wellbores From Fixed Conductor Locations.

Sufficient directional surveys will be taken on all wells to accurately define the well courses so that all upcoming wells can be preplanned to avoid well interference problems. While drilling out from beneath platform conductors, drilling weights and rotary speed will be controlled until sufficient distance from other wellbores is obtained.

If the wellbore direction passes near an adjacent well, the adjacent well will be shut in and the annulus will be pressurized and monitored while drilling until the well is drilled beyond the interference depth.

If communication with a producing wellbore occurs at a shallow depth beneath a conductor and a blowout is imminent, then the drilling well will be diverted and all attempts will be made to kill the well by pumping kill weight fluids down the drill pipe.

2. Running and Cementing of Casing

The hole will be conditioned to minimize casing running problems. The casing will be filled with mud as run and the hole monitored for wellbore flow or lost circulation. Casing rams will be installed to allow for well shut-in if required. Mud weights will be carefully checked and maintained to over-balance any formation pressures.

All attempts will be made to obtain a good cement job. All cement slurries will be laboratory checked to ensure that sufficient thickening time is available for the casing cementing job plus contingency for unforeseen problems. Mud and cement returns will be monitored. Preventative measures will be applied to the cement if gas migration calculations indicate possible gas flow through the cement during hardening.

3. Drilling Ahead Into Untested Fault Blocks.

A mud logging unit will be used to monitor drilling rates, shale densities, chlorides, flowline temperature, gas units, and formation cuttings for indications of abnormal pressure. Sufficient drilling recorders along with pit volume indicators, flowline monitors, and a trip tank will be used to detect wellbore kicks. Proper blowout preventers will be tested and used to control any well problems.

4. Production Testing.

All production testing operations shall be conducted within the cased hole by using production packers, downhole recorders, and production tubing. All liquid hydrocarbons will be contained within tanks. Natural gas will be burned through the flare system. No production testing will be commenced during or in the event of imminent unsafe inclement weather.

5. Wireline Logging Operations.

Logging operations will be conducted in open hole sections below the prior casing string. Blind rams and an annular will be available to control the well if a kick occurs during logging. If necessary, the wireline will be cut and dropped below the BOP stack to allow the BOP stack to seal the wellbore. The kick will be controlled by lubricating and bleeding the kick to the surface. Stripping operations would be conducted to reestablish circulation in the wellbore.

6. Well Completion Operations.

In all subsurface completions that involve conventional perforated cased hole completions, the casing string will be tested to the anticipated flowing tubing pressure prior to completion. Tubing, packers, and any other flow control devices such as subsurface safety valves will be fully tested prior to being run and also tested after the tubing and packer are set. Tubing rams will be installed in the drilling rig BOP stack and tested before beginning any well work. Back-pressure valves will be installed in the tubing head prior to removing the BOP stack and installing the Christmas tree. Full wellbore control will be maintained at all times. At no time will the wellhead be open without kill weight fluid throughout the wellbore.

7. Cutting and Removing Casing.

If after open hole logging and/or production testing operations, it is determined that a well is not capable of sustaining production, and if a sidetrack to the same location is not feasible, then proper cement plugs will be set across uncased hydrocarbon zones and the deepest casing shoe. The casing will be cut and recovered above the top of the cement within the casing or open hole annulus. After properly plugging the stub, the conductor and surface casing strings will then be reused and another well drilled to a different bottom hole location. The fluid left inside the casing will be properly conditioned and of sufficient weight to maintain well control.

8. H_2S Safety Precautions.

Sufficient H_2S monitors and alarms will be installed on the rig in critical locations (see Attachment B). Safety air packs will be properly maintained and stored in accessible areas. A safety consultant will train all personnel in H_2S safety and provide the necessary preventative measures to assure equipment readiness.

9. Transfer of Fuel and Materials.

No transfer operations will be conducted if weather conditions endanger the safety of the operation.

RIG PERSONNEL AND ENVIRONMENTAL SAFETY

Exxon considers personnel safety and environmental protection to be of the highest priority. Every effort will be made to prevent pollution and maintain safe working conditions.

Sufficient oil spill equipment will be stored at a nearby port and on the drilling location to combat the spread of any hydrocarbon discharge from the platform. A thoroughly trained team of Exxon personnel will be designated to respond to any possible emergency condition (see Attachment C).

CRITICAL OPERATIONS AND CURTAILMENT PLAN REVIEW

This plan will be reviewed annually after receiving Minerals Management Service approval. Any changes will be transmitted to the District Supervisor for approval.

ATTACHMENT B

H$_2$S CONTINGENCY PLAN

EXXON COMPANY, U.S.A.

PLATFORMS IN THE SANTA YNEZ UNIT

SANTA BARBARA CHANNEL

OFFSHORE CALIFORNIA

I. INTRODUCTION

This plan sets out precautionary measures, safety equipment, emergency procedures, responsibilities, and duties to be implemented when drilling wells which may contain hydrogen sulfide (H_2S) on platforms in the Santa Ynez Unit of the Santa Barbara Channel, offshore California. This plan is presented because of the potential hazards involved when drilling in formations that may contain H_2S and complies with the rules and regulations of the Minerals Management Service under Pacific Region OCS Order 2 and GSS-OCS1 (April, 1977).

Exxon will provide adequate safeguards against harm from the effects of H_2S to persons both on location and in the immediate vicinity. However, to be effective, this plan requires the cooperation and effort of each individual participating in the drilling of an H_2S well. Each individual should know his responsibilities and duties in regard to normal drilling operations and emergency procedures. He should thoroughly understand and be able to use, at a moment's notice, all safety equipment on the platform. He should familiarize himself with the location of all safety equipment and see that his equipment is properly stored, easily accessible, and routinely maintained.

II. SPECIAL EQUIPMENT REQUIREMENTS

The following special equipment and plans must be operational before spudding a potential H_2S well.

A. At least two areas will be designated as Safe Briefing Areas for personnel during an H_2S alert. In the event that H_2S is detected in excess of 20 ppm, all personnel not assigned emergency duties are to assemble in the designated Safe Briefing Area for instructions. The Safe Briefing Areas should be selected so that at least one is upwind of the wellbore under most wind conditions.

B. Windsocks and streamers will be installed on the derrick and off of each corner of the Drilling Deck. They will be positioned so that they are easily seen by all personnel on the Drilling Deck and Rig Floor.

C. Operational danger signs will be displayed from all sides of the platform in a manner visible to watercraft and aircraft in the event that H_2S is detected in concentrations equal to or exceeding 10 ppm. The signs will be at least four feet by eight feet and painted a highly visible yellow with the following warning painted in 12-inch high black, block lettering:

DANGER

HYDROGEN SULFIDE

(H_2S)

In addition, two-foot by three-foot red flags will be displayed from high points off of each corner of the Drilling Deck along with the MY6 Flag System if H_2S concentrations reach 20 ppm or greater at the surface. All signs and flags shall be illuminated at night and under conditions of poor visibility. Signs indicating the designated Safe Briefing Areas and Condition I and II signals will be posted in appropriate locations on the platform, workboats, and crewboats.

D. Continuous monitoring-type H_2S detectors, complete with area beacons and audio alarms, will be located in appropriate areas and will be monitored by both Control Room personnel and the Driller from the time the intermediate casing shoe is set until total well depth is achieved. The monitors shall be capable of sensing a minimum concentration of 5 ppm and the alarm will be set to go off when the detectors sense an H_2S concentration exceeding 10 ppm.

E. Proper personal protective positive-pressure breathing apparatus shall be available for all personnel on the platform and on board the marine vessels serving the platform. Helicopters attendant to rig operations will also be equipped with a protective breathing apparatus for the pilot. In addition, other personnel safety equipment shall be available for use as needed, such as:

1. Portable H_2S detectors.
2. Retrieval ropes with safety harnesses to retrieve incapacitated personnel from contaminated areas.
3. Chalk boards and note pads for communication purposes located on the rig floor, in the shale shaker area, and in the cement pump area.
4. Bull horns and flashing lights.

5. Resuscitators.

6. Explosion-proof electric fans.

F. A system of breathing air manifolds, hoses, and masks shall be provided in critical locations, including the rig floor and the Safe Briefing Areas. Cascade air bottle systems shall be provided to refill individual protective breathing apparatus bottles. The cascade air bottle systems will be recharged by a high pressure compressor suitable for providing breathing-quality air, provided that the compressor suction is located in an uncontaminated atmosphere. All breathing air bottles should be labeled as containing breathing-quality air fit for human usage.

Workboats attendant to rig operations shall be equipped with pressure demand-type masks connected to a breathing air manifold. Extra protective breathing apparatus shall be provided for evacuees.

G. The mud/gas separator equipment will be rigged so that the gas can be flared in the event that H_2S is encountered. A standby vacuum pump for the degasser is to be on location.

H. All well control equipment, including the blowout preventers and choke manifold, will be trimmed for H_2S service as required by Exxon. The hydraulic choke will be remotely operable. Inside blowout preventers will be provided for each size drill pipe, and safety valves and kelly valves will be trimmed for H_2S service.

I. A sufficient supply of "Milgard" (100 percent zinc carbonate), or an equivalent scavenger, will be stored on the platform for use in the event the mud becomes contaminated with H_2S.

III. VARIOUS OPERATING CONDITIONS AND THEIR RESPECTIVE PROCEDURES

The operating conditions when drilling in H_2S prone areas have been broken down into three categories. A description of each of these conditions and the required actions to take follows.

A. Possible Hazardous Conditions (Normal operating conditions for any well in possible H_2S area).

1. Warning Sign: None

2. Alarm: None

3. Characterized by:
   Drilling operations are under control during routine drilling operations in zones that may contain H_2S. This condition will be in effect continuously from the setting of the intermediate casing shoe to achieving total well depth.

4. Required Actions:
   a. Prior to Setting Intermediate Casing:

1. A list of emergency stations and phone numbers of personnel to be contacted will be sent to the platform prior to spudding and should be posted at the following places:

   a) Exxon Drilling Superintendent's office.

   b) Contractor Tool Pusher's office.

   c) Radio Operator's room.

   d) On each marine vessel attending the rig.

2. All safety equipment and H_2S related hardware must be set up as outlined under "SPECIAL EQUIPMENT REQUIREMENTS." All safety equipment must be inspected routinely, paying particular attention to resuscitators and breathing air facilities. Routine maintenance will include checking for leaks.

3. Contractor personnel, necessary service company personnel, and Exxon personnel must be thoroughly trained in the use of breathing equipment, emergency procedures, responsibilities, and first aid for H_2S victims.

   The Exxon Drilling Superintendent must keep a list of all personnel who have been through the special training programs on the platform. All personnel should be given a copy of "Considerations During the Drilling of a Sour Gas Well." This report summarizes the steps to be taken during the three conditions under which the well may be drilled. It lists general information about toxic gases, explains the physiological effects of H_2S, classifies operating conditions, and informs each reader of his general responsibilities concerning safety equipment and emergency procedures. The Exxon Drilling Superintendent must keep a list of all persons who have copies of the report, with signatures verifying that they have read and thoroughly understand the report. All personnel should read this document and sign the verification immediately upon their arrival at a platform.

4. A copy of the "H_2S Contingency Plan" will be given to the Masters of the attending marine vessels and to the helicopter coordinator. They will, by appropriate signature, indicate that their crews have read and do understand the Plan.

b. Below Intermediate Casing:

1. All personnel on the platform will be instructed in the use of breathing equipment until supervisory personnel are satisfied that they are capable of using the equipment. This training must include all construction personnel, production operations personnel, and visitors who are allowed on the platform during drilling operations. All personnel in the working crew shall have completed a basic first aid course.

   After initial familiarization with the breathing equipment, each rig and roustabout crew must perform a weekly drill with the breathing equipment. The drill should include getting the breathing equipment, putting it on, and then a short work period. As required by the MMS, a record should be kept of the crews drilled and the dates.

2. Along with the normal weekly fire drill and safety meeting, an H_2S training session must be held for all off-duty personnel and a record of attendance must be kept as required by the MMS.

3. Rig crews and service company personnel should be made aware of the locations of spare air bottles, the resuscitation equipment, portable fire extinguishers, and H_2S detectors. Knowledge of the location of the H_2S detector monitors is vital to understanding the emergency conditions. In addition, key personnel must be trained in the use of the resuscitator and the portable H_2S detectors.

4. H_2S detector ampoules shall be available for use by all working personnel. After H_2S has been initially detected by any device, periodic inspections of all areas of poor ventilation shall be made with a portable H_2S detector instrument.

5. All personnel on location should become "wind-conscious" and be aware at all times of the prevailing wind direction. Remember, H_2S is [illegible] places during times of still air.

6. All personnel should stay alert for any detection of H_2S. Should the presence of H_2S be indicated by any detection device, make it known to those personnel in the area and to the proper supervisors.

7. During the logging of suspected H_2S bearing zones, all equipment used in logging operations must be treated with H_2S corrosion inhibitors or be made of H_2S-resistant materials.

8. The H_2S continuous monitoring variety of detectors will be in operation at all times. These units must be tested and, if necessary, recalibrated every 24 hours under normal drilling conditions. In the event that H_2S is detected, or when drilling in a zone containing H_2S, the units will be tested at least once every 12 hours. The time and results of each test will be logged and reported each day to the Exxon Drilling Superintendent. The log will include the initial response time and ppm reading and the final response time and ppm reading.

9. In the event that an H_2S detector does not test successfully, drilling will cease until the detector is 1) repaired or 2) approval to proceed is received from the Exxon Drilling Superintendent.

10. A pH of 10 or above shall be maintained in any water-based mud system unless a lower pH is specifically authorized by the MMS.

B. Condition I - Potential Danger to Life

1. Warning Sign:

   "DANGER - H_2S" signs on all sides of the platform.

2. Alarm:

   Emergency Alert pulsating horn and flashing lights. White light flashing in Control Room alarm panel and flashing amber light on rig alarm panel.

3. Characterized by:

   Drilling operations are under control during routine drilling in zones containing H_2S. Poisonous gases are present in concentrations between the threshold level of 10 ppm and 20 ppm and may or may not be detectable by odor. This condition will be in effect continuously from the time H_2S is first detected until total well depth is reached (unless it is necessary to go to Condition II). This condition remains in effect up to H_2S concentrations of 20 ppm.

4. General Procedures:

   If, at any time, H_2S is detected in concentrations of 10 to 20 ppm, the following steps will be taken:

   a. The person detecting the H_2S must immediately notify the Driller. He must then notify the Exxon Drilling Superintendent and the on-duty Contractor Tool Pusher.

b. The on-duty Exxon and contractor supervisor will bring gas detectors to the rig floor in order to find the source of H_2S.

c. Upon notification of the Condition I emergency, the Driller will shut down the mud pumps and continue to rotate the drill pipe off bottom while donning his breathing equipment.

d. The following personnel will immediately put on breathing air masks:

   1. All personnel on the rig floor (as soon as he has his air mask on, the Driller should pick up the kelly, check for flow, and then keep the pipe moving by reciprocating).

   2. All personnel at the mud pits.

   3. All personnel in the BOP area.

   4. All personnel required to work below and downwind.

e. The Exxon Drilling Superintendent will alert all personnel that a Condition I exists.

f. The Mud Engineer will run a sulfide determination on the flowing mud. A pH of 10 or above is to be maintained in any water-based mud system unless a lower pH is specifically authorized by the MMS.

g. A maximum effort must be made by supervising personnel to resolve the cause of the H_2S as quickly as possible. Drilling must not proceed until the cause of the H_2S is determined and the well is circulated. Personnel on the rig floor, in the mud pit area, and in the BOP area will keep their breathing equipment on while monitoring this circulation.

h. The Exxon Drilling Superintendent and the on-duty Contractor Tool Pusher will make sure that all non-essential personnel are out of the potential danger areas, i.e., mud pit area, shale shaker area, and all areas below and downwind. All personnel who remain in the potential danger areas must utilize the "Buddy System."

i. The Exxon Drilling Superintendent in charge will order all personnel to check that their safety equipment is in the proper location and that it is working properly.

j. The Exxon Drilling Superintendent in charge will notify the Exxon Operations Superintendent of current conditions and actions taken.

k. The Exxon Drilling Superintendent will see that all monitoring devices are functioning properly and reading accurately and will increase gas monitoring activities with portable gas detection units.

l. The Exxon Drilling Superintendent in charge will notify work boats in the area to go upwind, to stay on power, and to maintain a continuous radio and visual watch.

m. The Exxon Drilling Superintendent in charge will alert the heliport dispatcher to assure continuous radio watch. The MMS and the USCG must also be notified.

C. Condition II - Moderate to Extreme Danger to Life

1. Warning Sign:
MY6 Flag System, two-foot by three-foot red flags at each corner of the platform.

2. Alarm:
Continuous ringing of alarm bell and siren and flashing lights. Flashing red lights on Control Room and Rig alarm panels.

3. Characterized by:
Poisonous gases are present or expected to be present at or above 20 ppm (critical well operations, well control problems or, in the extreme, loss of well control).

4. General Procedures:
If the H_2S concentration exceeds 20 ppm (from an increase in gas cut mud) and the well is not attempting to flow, the following steps will be taken:

a. The person detecting the H_2S must immediately notify the Driller. He must then notify the Exxon Drilling Superintendent and the on-duty Contractor Tool Pusher.

b. The Exxon Drilling Superintendent and the on-duty Contractor Tool Pusher will assess the situation and assign duties to each person to bring the situation under control. When the severity of the situation has been determined, all persons will be advised. The Exxon Drilling Superintendent and the on-duty Contractor Tool Pusher will:

1. Direct corrective action.

2. Notify the Exxon Operations Superintendent and the Contractor Drilling Superintendent.

c. The Driller will shut down the mud pumps and continue to rotate the drill pipe while donning his breathing air mask.

d. The following personnel will immediately put on air breathing units:

1. Exxon Drilling Superintendent.

2. Contractor Tool Pusher.

3. Driller.

4. Derrick Men.

5. Floor Hands.

6. Mud Pit Personnel.

7. Any other personnel in the high concentration area should evacuate to the upwind Safe Briefing Area.

e. Once his breathing-air equipment is on, the Driller should:

1. Stop the rotary and pick up the kelly.

2. Check for flow.

3. If well control problems develop, follow the appropriate well control procedures.

f. The Exxon Drilling Superintendent will alert all personnel that a Condition II exists.

g. All personnel <u>not</u> listed above must get to the upwind Safe Briefing Area for further instructions from the off-duty Contractor Tool Pusher or supervisor. If it becomes necessary to go through the rig floor/substructure area to get to the Safe Briefing Area, breathing equipment should be put on as soon as the equipment is reached.

h. Always put on a portable breathing air mask before proceeding to assist a person affected by the gas and utilize the "Buddy System." If the affected person is stricken in a high concentration area, put on a safety belt with 50 feet of tail line and obtain standby assistance before entering the area. Always use the "Buddy System" when entering possible contaminated areas.

i. Notify work boats to go upwind, stay on power, and maintain a 24-hour radio and visual watch. Fly the MY-6 warning flags and two-foot by three-foot red flags at each corner of the platform. Notify all aircraft and watercraft in the immediate vicinity of the conditions.

j. Notify the heliport dispatcher to establish a 24-hour watch.

k. All personnel will go and stay in the upwind Safe Briefing Area if not specifically assigned to correct or control the situation. If deemed advisable by the Exxon Drilling Superintendent, all personnel not assigned to the well control operations will be evacuated. The MMS requires immediate evacuation of nonessential personnel if the H_2S concentration reaches 50 ppm.

l. In the extreme event of total loss of well control, the flowing well will be diverted out the flare line. If this and all else fails, the Exxon Drilling Superintendent will determine if ignition of the well is deemed necessary and will conduct any necessary operations with an absolute minimum of personnel. All persons working in the hazardous area will wear self-contained breathing apparatus. All other personnel will restrict their movements as directed by the Exxon Drilling Superintendent and the on-duty Contractor Tool Pusher.

m. If the well is ignited, the burning H_2S will be converted to sulfur dioxide which is also poisonous. Therefore, DO NOT ASSUME THAT THE AREA IS SAFE AFTER THE GAS IS IGNITED. CONTINUE TO OBSERVE EMERGENCY PROCEDURES. FOLLOW THE INSTRUCTIONS OF SUPERVISORS.

n. The Exxon Drilling Superintendent will be responsible for notifying the following regulatory agencies as required by the MMS:

1. Minerals Management Service.
2. U.S. Coast Guard

If a 50 ppm concentration is recorded, also notify:

3. Department of Defense.
4. Appropriate State Agencies.

IV. PERSONNEL RESPONSIBILITIES AND DUTIES

A. All Personnel:

1. It is the responsibility of all personnel on the platform, as well as any other personnel assisting in the drilling of the sour gas wells, to familiarize themselves with the procedures outlined in this "H_2S Contingency Plan."

2. Each individual is responsible for seeing that his assigned safety equipment is properly stored, easily accessible and routinely maintained.

3. Each person must familiarize himself with the location of all safety equipment on the platform and be able to use all safety equipment at a moment's notice.

4. All personnel must have read and understand the "Considerations During The Drilling of a Sour Gas Well" report.

5. Report any indications of H_2S to those in the area and to a supervisor.

B. Exxon Drilling Superintendent:

1. The Exxon Drilling Superintendent is responsible for thoroughly understanding and enforcing all aspects of this "H_2S Contingency Plan."

2. The Exxon Drilling Superintendent is responsible for seeing that all safety and emergency procedures outlined in the "H_2S Contingency Plan" are observed by all personnel participating in the drilling of the H_2S well.

3. The Exxon Drilling Superintendent will advise the Exxon Operations Superintendent whenever the procedures as specified herein are not or cannot be complied with.

4. The Exxon Drilling Superintendent is responsible for preparing for the drilling of a sour gas well as described under "Special Equipment Requirements."

5. The Exxon Drilling Superintendent, in conjunction with the Contractor Tool Pushers, is responsible for seeing that all hardware in the choke manifold lines, flare lines, and all other piping which may be required to carry H_2S contaminated fluids under high pressure, is suitable for H_2S service and that <u>all replacement parts are suitable for H_2S service</u>.

6. The Exxon Drilling Superintendent, in conjunction with the Contractor Tool Pushers, is responsible for personnel training as specified under "Various Operating Conditions and Their Respective Procedures."

7. The Exxon Drilling Superintendent is responsible for the operation and maintenance of the H_2S detection and monitoring equipment.

8. The Exxon Drilling Superintendent is responsible for the storage and maintenance of all H_2S safety and emergency equipment on the platform.

9. The Exxon Drilling Superintendent will be responsible for designating the Safe Briefing Areas. These areas will change depending upon wind direction and must be redesignated as soon as a wind change occurs. Another safe assembly point may be designated if the originally designated Safe Briefing Areas are found to be unsafe for the conditions.

10. The Exxon Drilling Superintendent is responsible for keeping all personnel advised of the current Safe Briefing Areas.

11. The Exxon Drilling Superintendent will be responsible for inspecting the platform to make sure that all passageways are unobstructed and remain so for maximum access from the rig area to the Safe Briefing Areas and the living quarters.

12. The Exxon Drilling Superintendent is responsible for alerting all personnel during a "Condition I" or "Condition II" alert and for displaying warning signs and flags.

13. The Exxon Drilling Superintendent is responsible for notifying all personnel in the area of the platform of a change in conditions. This includes the work boats and the helicopters.

14. The Exxon Drilling Superintendent is responsible for holding weekly H_2S drills and training sessions and for keeping a record of attendance.

15. The Exxon Drilling Superintendent is responsible for performing a weekly inventory and inspection to assure that all safety equipment is being properly stored, maintained, and is easily accessible.

C. Contractor Tool Pusher:

1. It is the responsibility of the Contractor Tool Pusher, along with the Exxon Drilling Superintendent, to see that all safety and emergency procedures outlined in the "H_2S Contingency Plan" are observed by all personnel on the platform.

2. The Contractor Tool Pusher shares the responsibility of the Exxon Drilling Superintendent in the training of all personnel on the platform as specified under "Various Operating Conditions and Their Respective Procedures."

3. It is the responsibility of the off-duty Contractor Tool Pusher to advise and instruct all personnel at the designated Safe Briefing Area during a "Condition II" alert.

4. The Contractor Tool Pusher is responsible for thoroughly understanding the contents of this "H_2S Contingency Plan." In the absence or incapacitation of all Exxon supervisors, he will assume all responsibilities designated herein to the Exxon Drilling Superintendent.

5. The Contractor Tool Pusher, in conjunction with the Exxon Drilling Superintendent, is responsible for seeing that all hardware in the choke manifold lines, flare lines, and all other piping which may be required to carry H_2S, is suitable for H_2S service, and that <u>all replacement parts are suitable for H_2S service</u>.

D. Driller:

1. The Driller must be completely familiar with the steps he must take during a "Condition I" and "Condition II" emergency.

2. The Driller must be completely familiar with his special duties while coring and testing an H_2S well as outlined under "Special Operations."

3. The Driller must be completely familiar with his duties during well control and lost circulation problems as outlined under "Special Operations."

4. In the absence or incapacitation of all Exxon supervisors and Contractor Tool Pushers, the Driller will assume their responsibilities as designated herein.

5. In the absence or incapacitation of an off-duty Contractor Tool Pusher, the off-duty Driller will be responsible for instructing personnel at the designated Safe Briefing Area of the emergency action required.

E. Mud Engineer:

1. The Mud Engineer is responsible for assuring that the platform has a sufficient supply of Milgard (100 percent zinc carbonate) or an approved equivalent as outlined under "Special Equipment Requirements."

2. The Mud Engineer must be familiar with the mud treating procedure for H_2S cut mud.

3. The Mud Engineer must be familiar with the barite plug setting procedure.

4. The Mud Engineer must have two (2) "Garrett Gas Train" kits.

5. The Mud Engineer is responsible for maintaining a pH of 10 or above in a water-based mud system unless a lower pH is specifically authorized by the MMS.

F. Cementing Men:

1. The Cementing Men must be familiar with the barite plug setting procedure.

V. SPECIAL OPERATIONS

A. Coring:

During drilling operations below the intermediate casing, a decision to core may be made. This operation takes on critical complexities when attempted in a sour gas well. Specific coring procedures will be issued for cutting cores. The following practices should be followed during coring operations.

1. After a core has been cut, circulate the bottoms up and monitor the mud for H_2S.

2. Unless hole conditions (and/or H_2S detectors) indicate extreme conditions, put on breathing air equipment at least 10 stands of drill pipe before the core barrel reaches the surface. If worse conditions are suspected or the H_2S detector reaches 20 ppm, breathing air equipment should be put on earlier. Breathing air equipment should be worn by all personnel in the area while the core barrel is pulled, broken out and opened. Gas detection units and individual ampoules should then be used to monitor for H_2S around the core barrel. When these detectors indicate a safe atmosphere, the breathing air equipment can then be removed.

The following practices must be followed for every core barrel pulled:

1. Due to the difficulty in communicating with breathing air equipment on, it is required that a chalk board and chalk or note pads be provided during coring operations.

2. The importance of leaving the breathing air equipment on must be stressed to personnel connected with the coring operation. The most critical moment is when the core barrel is opened.

3. All personnel on the platform not wearing breathing air equipment should stay a safe distance upwind of the core barrel.

4. The cores to be transported must be sealed and marked to indicate the possible presence of H_2S.

B. Well Testing:

1. Well testing must be performed with the minimum number of personnel required in the immediate vicinity of the rig floor and test equipment. This minimum number of personnel must be able to safely and adequately perform the test and to adequately maintain the equipment.

2. Prior to initiation of the test, special safety meetings must be conducted for all personnel who will be on the drilling facility during the test, with particular emphasis placed on the use of personnel safety equipment, first aid procedures, and the H_2S Contingency Plan.

3. During the test, the use of H_2S detection equipment will be intensified. All produced gases must be vented and burned through a flare system equipped with a continuous pilot and an automatic ignitor. Back-up ignition must be provided. Produced fluids which are stored must be vented into the flare system.

4. "No Smoking" rules will be rigorously enforced.

C. Well Control:

The following well control practices should be initiated below the surface casing level.

Any influx of foreign fluid into the wellbore below the intermediate casing should be considered to contain H_2S. If the decision is made to circulate out the kick, all personnel involved in the well control will wear breathing air equipment until it is known that H_2S is not present. The following steps should be taken when the influx occurs:

1. Close in the well by using normal well control techniques. Record the drill pipe pressure, the casing pressure, and the volume of influx.

2. Notify the Exxon Drilling Superintendent and the on-duty Contractor Tool Pusher.

3. Purge the flare system. Put the automatic ignitors and pilots into operation to burn the H_2S bearing gas from the gas buster during kick circulation.

4. Proceed with standard well control procedures.

In the event that the mud has been contaminated with H_2S, it will be necessary to treat the mud with Milgard (or an equivalent) to remove the H_2S from the mud system. If H_2S is known to be present and a kick is taken, the size of the bubble, the intermediate casing depth, the leak-off test results, the amount and type of open hole, and the weather conditions will enter into the decision of whether to circulate out or "pump away" the bubble.

D. Lost Circulation

In the event lost circulation occurs, proceed with standard corrective procedures. The individual Well Drilling Program will have additional information relative to the probability of lost returns in each general drill site.

E. Partial Evacuation Procedure

When drilling in H_2S prone areas, particularly during critical operations, the Exxon Drilling Superintendent should develop evacuation plans. These plans should be continuously updated as conditions change.

ATTACHMENT C

OIL SPILL CONTINGENCY PLAN FOR CALIFORNIA OPERATIONS

AN OVERVIEW

EXXON COMPANY, U.S.A.

SANTA YNEZ UNIT

SANTA BARBARA CHANNEL

OFFSHORE CALIFORNIA

I. INTRODUCTION

The objective of the Exxon Oil Spill Contingency Plan for California Operations is to establish procedures, responsibilities, and actions to be taken in the event of an oil spill from any Exxon facility. The oil spill plan is comprehensive, meets all requirements of Pacific Region OCS Order 7, and complies with the Memorandum of Understanding between the United States Coast Guard and the United States Geological Survey, now known as the Minerals Management Service. Exxon's policy is to design our facilities to the safest and best available technology and to train our personnel in awareness and protection of the environment from oil spills through the use of good working practices.

Existing Exxon offshore and onshore production facilities are presently covered by the Oil Spill Contingency Plan for California Operations approved by both the Minerals Management Service and the U.S. Coast Guard. Subject to MMS approval, these same criteria will apply to the future facilities proposed in this Development and Production Plan.

These proposed facilities will then be included in this one comprehensive plan.

II. OFFSHORE SPILL RESPONSE

The existing Exxon OCS offshore production facilities are equipped with MMS/USCG-approved types and quantities of open ocean oil spill response equipment and materials. The spill equipment and clean-up materials are state-of-the-art which are to be utilized as the primary response for containment and clean-up of most perceived spills. This equipment can be deployed and used effectively by trained Exxon and contract employees. Clean Seas, the local oil spill cooperative, will be utilized for secondary response, should their assistance be required.

A. Onsite Response Team

Each offshore production facility has an Onsite Response Team (ORT). The ORT is comprised of Exxon onsite personnel trained in all aspects of oil spill response. The ORT Organization is shown in Figure C-1. The ORT, as the first line containment and clean-up operations group, will be directed by the onsite superintendent.

Responsibilities of the Onsite Response Team

- Acknowledge and shut down the spill source as quickly as possible. If fuel oil loading created the spill, shut down the transfer pump(s) and close the appropriate valves.

- Notify the site superintendent immediately. Describe the nature and the extent of the spill.

- On the supervisor's instruction, shut down all contributing source equipment such as pumps, compressors, vessels, wells, etc.

- Ensure that the spill source is isolated if it is not automated or should the automated shut-offs fail (both upstream and downstream of the leak).

- If offshore, at the supervisor's command, deploy the containment boom, work boat, skimmer, floating storage container, and absorbent materials as needed.

- All offshore personnel are to be thoroughly trained in the use of all pollution control equipment.

- All offshore personnel assigned to the ORT will participate in practice drills with response equipment at least annually.

B. Emergency Response Team

The Western Production Division, as the responsible Exxon organization for all drilling and production operations in the offshore California area, also has an organized Emergency Response Team (ERT). The Emergency Response Team is a standing organization of Exxon employees whose purpose is to provide administrative, operational, functional, and logistic support in the event of a significant offshore oil spill.

These four major support categories are further subdivided and specific responsibilities are assigned to the ERT members. Each primary member has an alternate to perform his or her function in the event of a significant spill and the primary member is unavailable. The positions, names, office and home telephone numbers for all ERT members/alternates are listed in Section 400, Offshore Response Teams or of the Oil Spill Contingency Plan for California Operations. The ERT organization is shown in Figure C-2.

The Division Operations Manager or his alternate will be Exxon's on-scene management representative and will direct and control the ERT as the designated Oil Spill Clean-Up Manager. He will determine the magnitude and gravity of the oil spill and, if required, activate all or selected members of the ERT depending upon his assessment of the spill situation.

Once the decision to activate the ERT has been made, any activated member will be available 24 hours a day until the clean-up operations are complete. The ERT member's responsibilities to the oil spill incident will supersede his or her normal duties until relief, rotation, or release is approved by the Oil Spill Clean-Up Manager.

Members of the Emergency Response Team participate in periodic training sessions to ensure that they are familiar with their assigned responsibilities.

C. Interfunctional Oil Spill Response Team

In 1980, Exxon established a nationwide internal spill organization, the Interfunctional Oil Spill Response Team (IOSRT). This organization is made up of oil spill advisory specialists and experienced people trained in oil spill response. The members of IOSRT are from various Exxon operating functions located throughout the United States. Through the IOSRT organization, their expertise is available to any Exxon operating area. The IOSRT organization is shown in Figure C-3.

The purpose of the IOSRT is to augment the existing functional manpower in an operating area in the event of a major oil spill. Although each Exxon operating function is responsible for oil spills in their own area, a major spill could severely impact their manpower. By utilizing the IOSRT for manpower and advisory expertise, the operating area response capabilities are strongly enhanced.

IOSRT Team Requirements

- Team members must be able to respond to the scene of a major oil spill within their designated areas (i.e. Gulf Coast, West Coast, East Coast) within 24 hours from the time of the initial call for assistance.

- The alert/release procedures enable the activation of the team at any time, 24 hours per day, 7 days per week, including holidays.

- Team members, when asked to respond to a spill, are to be prepared to stay on scene for at least one week. Relief or rotation of personnel at the scene will be arranged for by the On-Scene Commander.

IOSRT Training

- All clean-up supervisors must attend the Texas A&M Oil Spill Control course or have similar training. Specialty/Advisor team members are encouraged to attend the Texas A&M course.

- All three teams will hold periodic seminars. Team member seminars are held for the following purposes:

  1. To establish a team identity between the team members.

  2. To brief the team members on the overall team organization, policy, response procedures, state-of-the-art developments, and future plans.

  3. To incorporate new members into the team.

  4. To conduct refresher field training and preparedness testing exercises as appropriate.

D. Oil Spill Cooperative

In the event of a spill occurring that is larger than the onsite personnel and equipment can contain and clean up, the local oil spill cooperative will then be called for assistance. Clean Seas provides assistance in the Santa Ynez Unit area. Procedures to activate Clean Seas are clearly outlined in Section 800 of the Oil Spill Contingency Plan for California Operations. Clean Seas response time to any planned facility located within the Santa Ynez Unit can be accomplished within the guidelines of the USCG/USGS Memorandum of Understanding, weather permitting. Clean Seas has the state-of-the-art equipment, personnel, and material to contain and clean an oil spill as required by the criteria of the USCG/USGS Memorandum of Understanding guidelines.

III. ONSHORE SPILL RESPONSE

Special precautions are to be taken for onshore facilities that have a potential for spills that could enter navigable or state waters. Onshore operations include guidelines similar to the offshore operations in the areas of notifications, response, responsibility, contractor contacts, emergency aid, and instructional sections. The main difference occurs in the site-specific information which conforms to requirements of Title 40 CFR 112, the Spill Prevention Control and Countermeasures Plan (SPCC) regulated by the Environmental Protection Agency. Exxon's Oil Spill Contingency Plan for California Operations outlines many modes of containing and cleaning up oil spills on land. Several means of containing or diverting continuous flowing oil from entering or continuing into drainage courses are described and illustrated.

These include diversion barriers, containment dams, blocking dams, underflow dams, various types of berms, and culvert blocking. Once the flow of oil is contained, clean-up is undertaken.

Specific clean-up techniques for onshore area will depend upon the type of terrain and the area's ecological sensitivity. Generally, soil or other natural substrates that are contaminated with oil will require removal. Shoreline areas that have high energy wave action or are of highly compacted material will generally clean themselves within a few weeks. However, fine-grained sand beaches will require oil removal as the oil does not penetrate into the sediment and may persist for several months. The best mechanical means of removing oil from a fine-grained sand beach or similar area is a motor grader elevating scraper. The same equipment is also very effective in removing oily soil from relatively flat areas, providing that trees and heavy vegetation do not create difficulties. To clean up oily debris from areas with steep slopes or uneven terrain, bulldozers or front-end loaders are normally used. Areas of excessively steep or rough terrain where vegetation is coated with oil will generally be cleaned by using low pressure water flushing. Water flushing will not be used in areas with high erosion potential.

Oil which has formed pools in natural depressions or containment areas will be picked up by vacuum trucks. In less accessible areas, portable pumps discharging into barrels can effectively be used for this purpose. Sorbents will be used to remove small pools of oil, to clean light accumulations of oil from impervious surfaces, or to complete finish-up cleaning. A major consideration with any type of clean-up operation will be the restoration of the damaged area to its natural state.

IV. WILDLIFE [illegible]ECTION, CARE, AND REHABILITATION

In the ev[illegible] an oil spill occurs in Federal OCS waters, some marine mammals and/or bi[illegible] may come in contact with oil. If oiled marine mammals and/or birds ar[illegible]ghted, the appropriate Federal agencies will be notified as follows:

1. The U.S. Fish & Wildlife Service (USF&WS) in the event of oiled sea otters and birds. 213/642-3933 or (800/424-8802, 24-hour)

2. The National Marine Fisheries Service (NMFS) in the event of oiled seals and sea lions (pinnipedia), or porpoises and whales (cetacea) other than walrus. 213/548-2575 or (206/343-3432, 24-hour).

If an oil spill should occur in or threaten to enter State waters from Federal waters, the California Department of Fish & Game (CDF&G) (800/852-7550) shall be notified if oiled marine mammals or birds are observed.

Exxon has an existing agreement with the International Bird Rescue Research Center for necessary support in the event we have an oil spill requiring their services. At Exxon's request, the Bird Rescue Center will set up a bird cleaning and rehabilitation center and will provide experienced supervisory personnel to direct the clean-up of oiled birds. They will coordinate their activities with the California Department of Fish & Game and the U.S. Fish & Wildlife Service. Exxon will provide any assistance required in this effort.

Under both the Migratory Bird Treaty of 1918 and California State Law, it is illegal to capture and hold most species of migratory birds without a permit from both the USF&WS and the CDF&G. No marine mammal will be taken in any manner except by USF&WS, NMFS, or CDF&G personnel. It is anticipated that state or federal facilities will be made available for the care and treatment of oiled sea otters and other marine mammals. No marine mammal will be retained at private facilities. Sea otters will be picked up and treated by CSF&G and USF&WS personnel only. Under no circumstances will marine mammals or birds be taken by Exxon employees or any other unauthorized personnel.

V. PLAN MAINTENANCE

To keep Exxon's Oil Spill Contingency Plan for California Operations as current as possible, it is reviewed and modified periodically to update personnel, procedural, regulatory, or equipment changes. In addition, an annual review of the plan is made pursuant to Pacific Region OCS Order 7 and all modifications are submitted to the MMS for approval.

SITE SUPERINTENDENT

ONSITE REPONSE TEAM
(Response Operating Team)

ASSIGNED TO BOOM DEPLOYMENT BOAT

One-Boat Captain/Supervisor
Two-Spill Boom/Equipment Handlers

ASSIGNED TO BOAT WITH SKIMMER

One-Deck Crane Operator
Two-Equipment Handlers

ONSITE SUPPORT GROUP

Supervisor	**(1)**
Equipment Handlers	**(3)**

*As Required

Figure C- 1

ONSITE RESPONSE TEAM

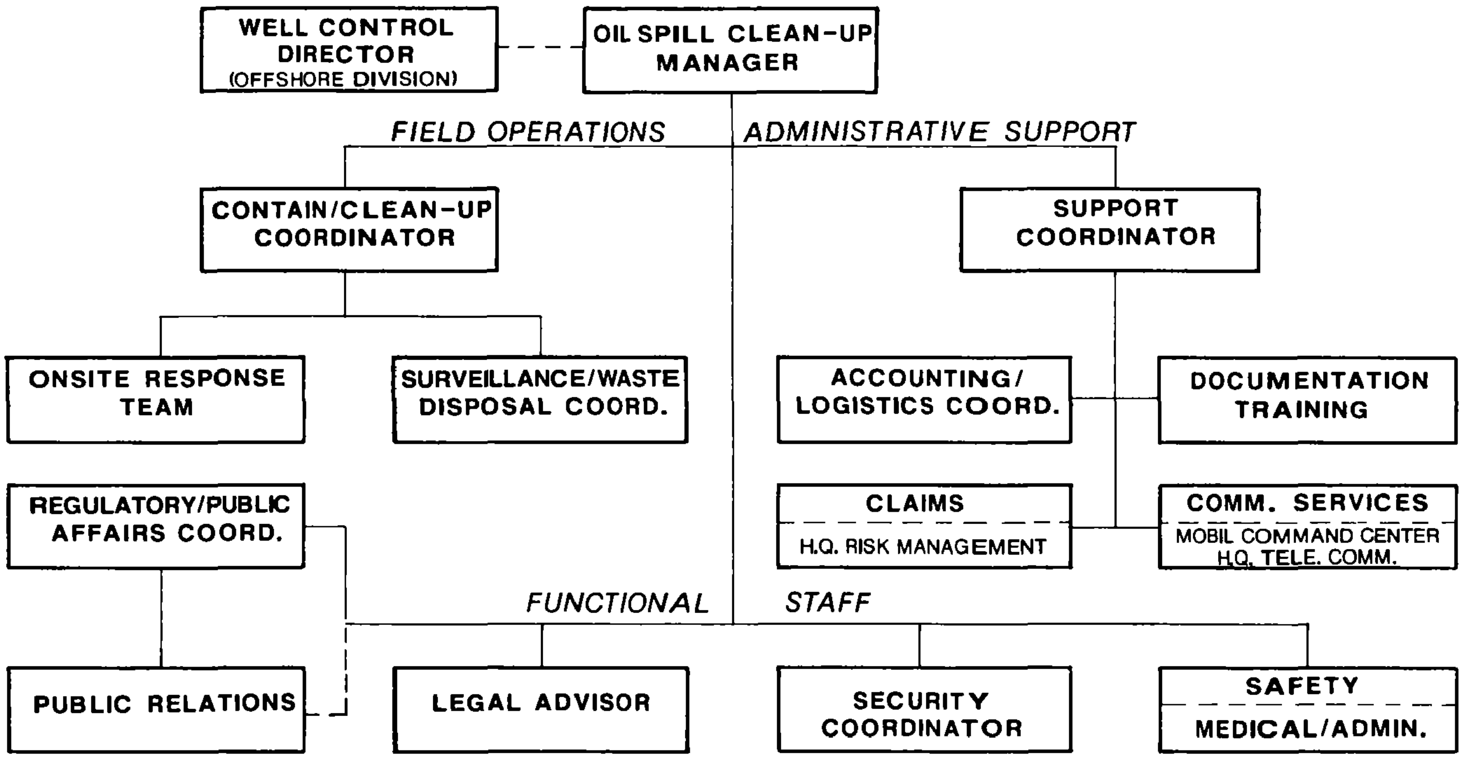
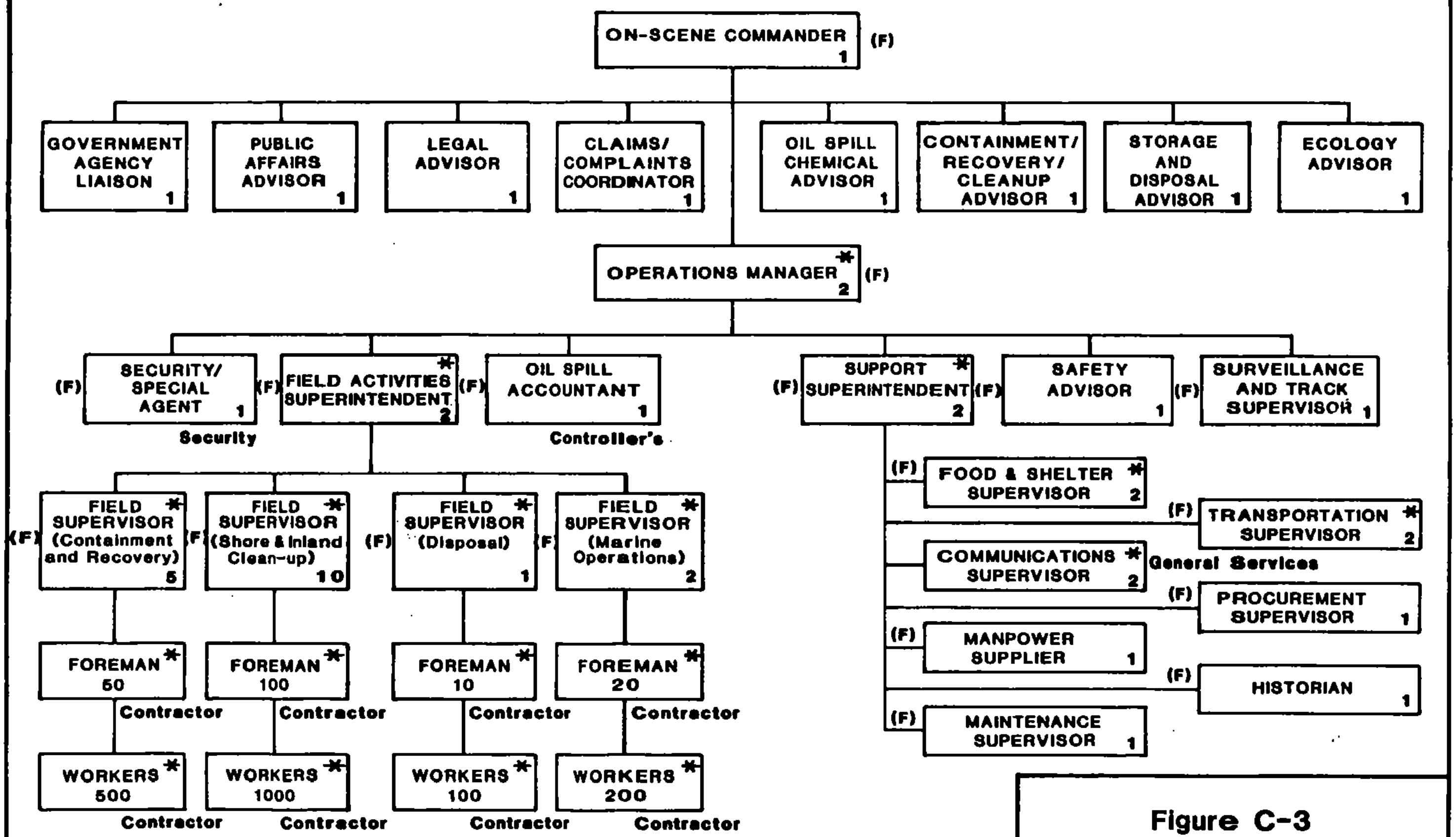


Figure C-2

OIL SPILL
EMERGENCY RESPONSE TEAM



(F) – Function Incurring Spill

* – Twenty Four Hour Coverage

Figure C-3

INTERFUNCTIONAL OIL SPILL RESPONSE TEAM

Drill Stem Test 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