

DEVELOPMENT AND PRODUCTION PLAN
SANTA YNEZ UNIT DEVELOPMENT

PACIFIC OCS AREA
OFFSHORE SANTA BARBARA COUNTY, CALIFORNIA
SANTA YNEZ UNIT
HONDO, PESCADO, AND SACATE FIELDS

EXXON COMPANY, U.S.A., UNIT OPERATOR
OCTOBER, 1982

INQUIRIES SHOULD BE ADDRESSED TO:
MR. B.L. BOYD, CALIFORNIA OPERATIONS MANAGER
EXXON COMPANY, U.S.A.
1800 AVENUE OF THE STARS
LOS ANGELES, CALIFORNIA 90067
(213) 552-5400

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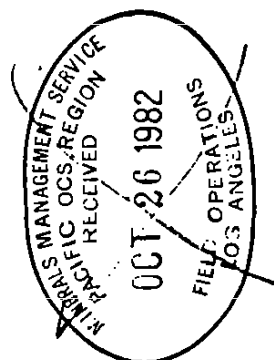
EXXON COMPANY, U.S.A.

1800 AVENUE OF THE STARS • LOS ANGELES, CALIFORNIA 90067 • (213) 552-5771

PRODUCTION DEPARTMENT
WESTERN DIVISION

K. TERRY KOONCE
DIVISION PRODUCTION MANAGER

October 25, 1982



Mr. Reid T. Stone
Minerals Manager
Minerals Management Service
Pacific OCS Regional Office
1340 West Sixth Street
Los Angeles, CA 90017

Reference: Santa Ynez Unit,
Santa Barbara Channel, Offshore California
Development and Production Plan,
Environmental Report (Production)



Dear Mr. Stone:

In accordance with the provisions of 30 CFR 250.34-2 and 250.34-3, Exxon Company, U.S.A., as Unit Operator, submits for your approval the enclosed Development and Production Plan and corresponding Environmental Report (Production) for further Santa Ynez Unit (SYU) Development in the Santa Barbara Channel. As required by 30 CFR 250.34-2(q), Exxon is also contemporaneously submitting appropriate portions of the Development and Production Plan relating to the production of natural gas and the facilities for transportation of natural gas to the Federal Energy Regulatory Commission. Please note that Exxon is not planning to invest in the gas transport or gas treatment facilities which are described in the Development and Production Plan and Environmental Report (Production).

As you know, an amendment to the Santa Ynez Unit Agreement incorporating OCS Leases P-0326 and P-0329 is being processed to be effective October 1, 1982. SYU is therefore defined in these documents as including these two leases. These documents build upon the initial SYU development plans approved by the U.S. Geological Survey on August 16, 1974 (Supplemental Plan of Operations - Santa Ynez Unit).

Attached please also find a copy of the "Memorandum of Agreement II - Development of Santa Ynez Unit - Santa Barbara Channel", which is being executed between Exxon and the noted state and county agencies. This MOA II will be submitted as part of Exxon's certification of consistency with the California Coastal Program. The MOA II has been signed by the California Air Resources Board, the County of Santa Barbara and the Santa Barbara County Air Pollution Control District. The State of California and the California State Lands

Mr. Reid T. Stone
October 25, 1982
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Commission (SLC) currently have this MOA II under consideration. Upon receipt of the these signatures, Exxon will provide the MMS with a copy of the fully executed document.

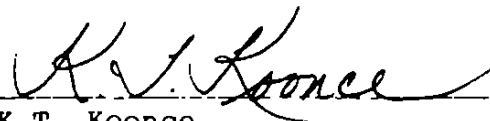
The Development and Production Plan is submitted as two volumes. Appendix A (Geology and Reservoir Data) contains Exxon Company, U.S.A. proprietary information not subject to release under the Freedom of Information Act, or otherwise, without notice to and the express written consent of Exxon. The Environmental Report (Production) and its supporting technical data are submitted in five volumes. Based upon discussions with MMS staff personnel, thirty (30) copies are being provided for your use.

The Santa Ynez Unit Development and Production Plan presents two oil treating options for concurrent processing and approval by the MMS. Both the offshore option (an expanded Offshore Storage and Treating Vessel) and the onshore option (onshore oil treating facilities) are presented in an equivalent level of detail. No preference is shown in these submittal documents. Please also note that the MOA II is based on the assumption that Exxon will develop the SYU by using the onshore option. Exxon's commitments in this agreement are conditioned upon expeditious approval of all necessary permits, leases, and other approvals or findings consistent with the provisions of this agreement.

All inquiries should be addressed to our California Operations Manager, Mr. B.L. Boyd, on (213) 552-5761.

Sincerely yours,

EXXON CORPORATION

By: 
K.T. Koonce
Western Division
Exxon Company, U.S.A.
(A Division of Exxon Corporation)

MEF:ss

Enclosures: - Memorandum of Agreement II
- SYU Development and Production Plan (2 volumes) - 30
copies
- SYU Environmental Report (Production) (5 volumes) - 30
copies

MEMORANDUM OF AGREEMENT II
DEVELOPMENT OF SANTA YNEZ UNIT,
SANTA BARBARA CHANNEL

Between

THE STATE OF CALIFORNIA,
CALIFORNIA STATE LANDS COMMISSION,
CALIFORNIA AIR RESOURCES BOARD,
COUNTY OF SANTA BARBARA,
SANTA BARBARA COUNTY AIR POLLUTION CONTROL DISTRICT

and

EXXON COMPANY, U.S.A.

October 8, 1982

I. Parties

This Memorandum of Agreement II (MOA II) is a result of discussions among the State of California (State), the California State Lands Commission (SLC), the California Air Resources Board (CARB), the County of Santa Barbara (CSB), Santa Barbara Air Pollution Control District (APCD) and Exxon Company, U.S.A. (Exxon). This MOA II is a successor to and amends the Memorandum of Agreement (MOA) of February 12, 1980.

State, SLC, and CARB are hereinafter jointly referred to as State. CSB and APCD are herein jointly referred to as County. State, County and Exxon are hereinafter sometimes referred to collectively as the Parties.

II. Common Goal and Purpose

The Parties have determined, given the existence of leases and substantial petroleum discoveries, that there is a common goal to provide for protection of the environment while undertaking the production of oil and gas resources. Under the MOA, the Parties have recognized this common goal and established a spirit and atmosphere of cooperation within which to implement this goal. The actions of the Parties described in this MOA II will continue the cooperative efforts toward accomplishing their mutual goal.

Exxon, in 1981, initially discussed its proposal for developing the substantial Santa Ynez Unit reserves. In the course of meetings among the Parties, the State and County have stated certain concerns in response to Exxon's proposal. Specifically, these relate to the continued presence of the OS&T, potential air emissions from development activities, consolidation of onshore energy facilities, and planning and development of a total transportation system.

After several discussions of the issues, the Parties therefore agreed that pursuing the following concepts will promote the Parties' common goal so that Exxon's proposed activities may eventually go forth in response to all concerns raised by State and County.

The purpose of this MOA II is to state the objectives and plans of Exxon for achieving this goal and to memorialize State's and County's obligations to review these objectives and goals through their decision making processes in an efficient and expeditious manner. This MOA II is the result of extensive discussions among the Parties during the pre-application phase of Exxon's plans.

Insofar as any determinations by State and County under this Agreement relate to decisions to be made pursuant to specific permits, leases, land-use policy or zoning issues, or any other discretionary approvals, it is understood by the Parties that all such decisions shall be subject to the procedures, public participation and appropriate environmental review as provided by law. Nothing in this agreement shall be construed to deprive State and County of any of their discretionary decision making authority. Moreover, State law and County ordinances require that all development projects and permits be consistent with the County's comprehensive general plan including all elements thereof, and to the extent that any part of this agreement conflicts with such policies, laws or ordinances, such policies, laws or ordinances shall prevail.

III. Jurisdiction

There has been an ongoing dispute among the Parties concerning jurisdiction over air emissions on the Outer Continental Shelf (OCS). The State and County maintain that they have the power to require air pollution permits for and otherwise regulate sources of air emissions on the OCS. The State and County further maintain that the DOI air quality regulations are inadequate to protect California's air quality and are otherwise invalid and that any DOI regulations relating to OCS air emissions, whether valid or not, do not affect the authority of the State and County to regulate OCS activities. The State and County further maintain that Exxon's OCS activities, if not conducted in full compliance with the County's rules and regulations, would have a significant adverse effect on onshore air quality in violation of state and federal law. Exxon maintains that the Department of the Interior (DOI) has exclusive control to regulate such emissions under federal law, and that the DOI air quality regulations found at 30 CFR § 250.57 adequately protect the air quality of the State and County regarding any air emissions from OCS activities. Exxon also maintains the position that these regulations should be determinative of any consistency review concerning air quality aspects of OCS exploration or production activities. In accordance with these federal regulations, Exxon holds that its OCS activities will have no significant adverse impact on the onshore air quality of the State or County. In addition, Exxon reserves the right to challenge any State or County law or regulation which attempts, directly or indirectly, to assert jurisdiction over OCS activities or marine vessel air emissions. The Parties wish to reserve their respective legal positions, but in the interest of expediting the permitting process for future Santa Ynez Unit development, have agreed on the processes as provided herein.

IV. Exxon OCS Plans

Exxon, as operator of SYU, is currently preparing to submit to the Minerals Management Service of the United States Department of the Interior (MMS) a Development and Production Plan (the Plan) for the Santa Ynez Unit. The Santa Ynez Unit, which Exxon operates, is located in the Santa Barbara Channel on the OCS. It consists of 17 lease tracts and three identified major reserve fields: Hondo, Pescado and Sacate. The Hondo "A" facilities, currently operating in the eastern half of the Hondo field, are the subject of a Supplemental Plan of Operations approved by the Department of the Interior in 1974. The facilities described herein will serve the Hondo field and the Pescado and Sacate fields, if developed, including OCS tracts 326 and 329 which are expected to be incorporated into the Unit in 1982.

V. Future Activities

A. Production Facilities Description: Base Plan

If Exxon, as operator of SYU, submits to the MMS a Plan for two or more additional platforms, then Exxon will submit a Plan to the MMS for two alternative types of facilities for producing, treating and transporting reserves.

The Base Plan facilities are expected by Exxon to include: (1) two to four conventional platforms in OCS waters, (2) crude oil treating and storage facilities all capable of handling production rates in the range of 140 thousand barrels per day to be constructed on Exxon's land in the Las Flores and Corral Canyons area (Canyon) of Santa Barbara County, (3) a power generation facility for 50 megawatts at the same location with a tie-in to Southern California Edison (SCE), (4) interconnecting oil and gas gathering pipelines, power cables, and water lines some of which will cross the State's submerged lands between the OCS and the onshore facilities, and (5) a permanent Exxon modernized marine terminal to be located in State waters off Las Flores Canyon in Santa Barbara County, to be served by crude oil lines from storage facilities in the Canyon. Exxon also anticipates that the natural gas facilities now under construction in the Canyon by Pacific Offshore Pipeline Company (POPCO) will be expanded or new facilities constructed to accommodate natural gas production rates in the range of 135 million cubic feet per day (MCPD). Exxon will file application with the appropriate State and County agencies for required permits or other approvals. Such applications will be subject to public participation and approved environmental review as provided by law.

If Exxon proceeds with the Base Plan for two or more additional platforms and at such time as the aforementioned oil and gas treatment and transportation facilities are operational and debugged, Exxon will discontinue use of the OS&T for Santa Ynez Unit operations and will remove it and the facilities currently located near Highway 101 serving the existing El Capitan marine terminal.

B. Alternate Plan

Parties understand Exxon's Alternate Plan is discussed herein for information only. This Agreement is based on the assumption that Exxon will develop the SYU by using the Base Plan facilities described hereinabove with the mitigation measures provided and shutting down its present offshore storage and treatment facility as provided herein. Should Exxon not pursue this Base Plan, no part of this Agreement will be operative.

In the event that Exxon's SYU Plan does not involve two or more additional platforms, or in order to accommodate the possibility that all necessary permits, leases, and other approvals for the Base Plan are not issued expeditiously in accordance with the Permit Streamlining Act, or are not accepted by applicant as consistent with the provisions of this MOA, Exxon proposes to include an offshore treating and storage alternative in its Plan. These facilities, (in lieu of the aforementioned onshore oil facilities, marine terminal, cable and pipelines) would include equipment for expanding the OS&T to accommodate optimum production rates, and power generation facilities on the platforms. Vessel loadings at the OS&T would continue in OCS waters. Also onshore gas treating facilities are anticipated to be expanded so as to treat approximately 90 MCFD of natural gas.

C. Air Pollution Control Technology

Exxon's proposed plans for development as operator of the Santa Ynez Unit (SYU) with onshore oil treating and storage facilities, expanded onshore gas treating facilities, three or four new offshore oil and gas production platforms, an onshore power generation facility and a permanent modernized nearshore marine terminal, as described in detail elsewhere in this MOA II will include use of air emissions control measures as set forth in this Agreement, which are intended by Exxon, to respond to the air quality concerns expressed by ARB and County, and in accordance with requirements for new sources subject to the jurisdiction of Santa Barbara County.

County understands that reductions in air emissions can be achieved through the application of innovative technology as contained

herein. County recognizes the positive efforts on the part of Exxon to provide an effective air quality mitigation program, however County reserves the option to perform full primary (eg. NO_x) and secondary (eg. O_3) air quality modeling under APCD and CEQA procedures as required. The Air Resources Board will perform modeling if requested by the County.

In recognition of the Parties' needs and concerns, the Parties have reached a preliminary understanding with respect to mitigation of air pollutant emissions associated with the SYU development. Exxon will file an application with the County APCD for the new sources discussed above. This application will be subject to public participation and appropriate environmental review.

1. ONSHORE CENTRAL POWER PLANT

To meet electrical and process heat needs of SYU development Exxon will construct a cogeneration facility of no more than 50 MW capacity incorporating the following:

- Sweetened natural gas as specified in the County's rules and regulations for gaseous fuel.
- Turbine water or steam injection designed to reduce NO_x emissions by 70 percent. The turbine NO_x emissions rate before application of water injection will be no greater than 0.6 lbs NO_x /million BTU of fuel input.
- Cogeneration in the form of waste heat recovery to minimize and when feasible eliminate fired supplemental heater requirements for the oil and expanded gas treating facilities. The total annual supplemental firing emissions and the power plant emissions shall not exceed the annual emissions of the power plant at full rated capacity (50MW).
- Institution of an innovative control equipment demonstration program on the partial exhaust of one power generation turbine with the intent to further the state of the art in NO_x control. Selective catalytic reduction (SCR) or an alternative which is mutually agreeable to the Parties will be used for this demonstration program. The test program including scale and test duration will be mutually agreed to by the Parties prior to the time of turbine purchase. The test program will be of sufficient size to allow full-scale application of the demonstrated technology. The test program will commence following the

startup and debugging phase at the time stipulated in the APCD authority to construct for the central power plant. Exxon will not as part of this Agreement be required to retrofit the demonstrated technology on the co-generation facility turbines.

- A tie-in to SCE for increased reliability and backup resulting in less emissions due to process facility upsets.

2. OIL TREATING AND EXPANDED GAS TREATING FACILITIES

The existing gas treating facilities in Las Flores Canyon are expected by Exxon to be expanded to 135 MCFD. An oil treating facility with a treating capacity of 140 thousand barrels per day (peak design rate) and crude storage capacity of 650,000 barrels are expected by Exxon to be constructed. These facilities will incorporate the following:

- Tandem mechanical seals on pumps in hydrocarbon service where feasible.
- Vapor recovery systems on all crude oil storage tanks and crude processing vessels to essentially eliminate volatile organic compound (VOC) emissions.
- Implementation of a written comprehensive maintenance program to minimize fugitive hydrocarbon emissions.
- The recovery of sulfur compounds from the acid gas stream of the gas treating facilities by a sulfur recovery unit and a tail gas unit.

3. OFFSHORE OIL AND GAS PRODUCTION PLATFORMS

Exxon's proposed plans are to construct three or four new offshore oil and gas production platforms and to modify the existing Bongo A platform to develop the SYU, incorporating the following:

- Sweet or sweetened natural gas for turbine and process heater fuel. Total sulfur compounds contained in this fuel will not exceed 15 grains per 100 cu. ft. (calculated as H₂S at standard conditions).
- Turbine waste heat recovery to minimize fired heater requirements.
- Drilling rigs powered by electricity from onshore with diesel engines on the platforms for stand-by use only.

- Low NO_x burners on any new process heater installed on the Hondo A Platform.
- Innovative technology in the form of water injection on platform turbines to reduce NO_x emissions by 50% from levels representative of current typical small turbines (less than 10,000hp). This technology is currently not available for this application but is under development. It is agreed that this technology must be available for purchase from at least three manufacturers of suitable turbines at turbine selection time. Exxon will review the status of turbine selection in the annual reviews provided for elsewhere in this MOA. If during the project Exxon clearly determines from operating experience that turbine water injection causes undue safety or equipment risk in this particular application, Exxon may terminate the operation of water injection and will advise the other parties of the basis for its action.
- In the event that water injection technology is not developed by the time SYU turbines are selected, Exxon will select the lowest NO_x emitting turbines from those that are cost and performance competitive and meet all operational requirements determined by Exxon.
- Implementation of a written comprehensive preventive maintenance program to minimize fugitive hydrocarbon emissions.

4. MODERNIZED NEARSHORE MARINE TERMINAL

Exxon proposes that a modernized nearshore marine terminal be constructed for crude transportation from the SYU area. The facility will incorporate the following:

- Innovative technology in the form of a hydrocarbon vapor control system designed to essentially eliminate hydrocarbon emissions from marine vessel loadings. The Parties recognize that this is the first application of such a system. Although no major safety problems have been identified, final regulatory approval from the USCG for operation of the system cannot be obtained until it is installed and operationally tested.

5. CREW AND SUPPLY BOATS

Crew and supply boats associated with future SYU development will incorporate the following:

- Innovative control technology on diesel driven crew and supply boats through application of NO_x control technology as identified by the Radian study of drill-ship NO_x emissions. The identified NO_x control technology must be reasonably available, cost effective, and applicable to supply and crew boat engines. Exxon will make a good faith effort to secure agreement from vessel owners under contract to Exxon to apply such controls found to be acceptable by all appropriate regulatory agencies and certifying bodies and Exxon will encourage efforts by vessel owners to secure regulatory approvals and certifications. It is expected that such controls could reduce NO_x emissions from vessels it is applied to, by about 20 percent.

6. MARINE CRUDE OIL TRANSPORTATION VESSELS

The crude vessels associated with the SYU development will incorporate the following:

- No higher than 0.7% sulfur Low Sulfur Fuel Oil (LSFO) will be consumed by crude vessels while in the vicinity of the marine terminal. Fuel switch will be made as soon as practicable after the vessel leaves the traffic separation lane and prior to maneuvering for docking at the terminal and after leaving the mooring and before entering the traffic separation lane.

7. DATA ACQUISITION SYSTEM

- In addition to the above, Exxon agrees to fund (not to exceed \$25,000) the County's proposed upgrade/expansion of the SBCAPCD data acquisition system.

8. REMOVAL OF OS&T

- If a permanent marine terminal as described elsewhere in MOA II is permitted consistent with the provisions of this agreement and as part of this air mitigation package to offset project emissions, Exxon will remove its OS&T when its new onshore oil and gas treatment and transportation facilities are operational and debugged.

9. OTHER CONSIDERATIONS

Exxon's implementation of the air pollution control measures set forth in this Agreement will substantially reduce emissions from the planned development. Additionally, the development of

innovative air pollution control technology and the demonstration program called for in this Agreement are expected to provide substantial air pollution control technology information.

In the 1980 MOA Exxon agreed to endeavor to use water injection on an OS&T turbine to reduce NO_x emissions, which Exxon has done in good faith. Those efforts have proven water injection infeasible for the OS&T turbines. The Parties agree that the demonstrated infeasibility of water injection in an OS&T turbine does not necessarily mean that water injection is not feasible for other offshore applications.

To continue the cooperative relationship established between the Parties in the Hondo A development agreement, Exxon agrees to arrange for annual reviews with the ARB and County to discuss the status of the SYU development project so long as it is mutually agreed that they are desirable. These annual reviews will supersede the semi-annual reviews agreed to in the 1980 MOA.

To the extent control measures addressed in this Agreement are not subject to the breakdown provisions of the SBCAPCD rules and regulations, the temporary malfunction or non-availability of any of the foregoing mitigation measures, including without limitation a severe logistics system upset or non-availability of 0.7% sulfur LSFO shall not limit Exxon's right to continue operations. Exxon will expeditiously attempt to correct the malfunction or obtain the availability of the 0.7% sulfur LSFO.

The Parties recognize that the County's permit authority must be exercised in accordance with the rules and regulations of the Santa Barbara County Air Pollution Control District and other applicable laws. Nothing in this Agreement shall in any way operate to limit or abridge the authority and responsibility of the County to comply with its rules and regulations and all applicable provisions of state law in issuing permits, nor limit or abridge the authority and responsibility of the County to ensure compliance with emission standards or limitations in its rules and regulations, or in State law.

Exxon states that its intention to burn LSFO in tankers and apply mitigation measures to OCS sources or other marine vessels is done voluntarily as part of a good faith effort by Exxon to mitigate air emissions. Exxon maintains that the Department of the Interior has the sole authority to regulate OCS air emissions, and that State and local authorities lack jurisdiction with respect to marine vessels and their operation. In entering into this Agreement, Exxon expressly reserves its legal position.

The ARB and County maintain that they have jurisdiction and authority to regulate air emissions from all aspects of Exxon's planned development, including emissions from facilities onshore, nearshore, and offshore on the OCS and from marine vessels. In entering into this Agreement, the ARB and County expressly reserve their legal position.

D. Utilization of Canyon

Exxon owns approximately 1500 acres of land in Santa Barbara County (Canyon) which is currently zoned "UPM" to allow construction and operation of oil and gas facilities. The Canyon Zoning Ordinance designated an 81 acre portion of Exxon's land by an approved development and precise plan as the location for POPCO's gas facilities and Exxon's future oil facilities.

Within the last year, POPCO has undertaken substantial construction of the gas facilities on the 81 acres and contiguous State lands and, in doing so, has used and satisfied the precise plan, the conditional use permits and the APCD permit for the POPCO gas facilities.

The County's General Plan, Local Coastal Program, and Zoning Ordinance provide that portions of the Canyon are appropriate locations for coastal dependent onshore facilities required for future western Santa Barbara Channel oil and gas developments. Eighty-one acres of the Canyon has an approved precise plan, and development in accordance with that plan is in progress. The Parties will, therefore, exert their best efforts to ensure that the Canyon area is maintained as an appropriate location for energy-related facilities. Exxon will require an approximate 10-acre facility site expansion, some of which is outside the 81 acres already approved for construction and operation of the onshore facilities described herein. This will necessitate filing applications for approvals under the Zoning Ordinance in effect at that time. To ensure this availability, the County will make every effort to expedite decisions on Exxon's and POPCO's or other gas purchaser's zoning and land use applications.

In considering such decisions, the County will review to determine that Exxon's plans will not preclude the attainment of the County's general plan and its goal of maintaining the Canyon as a possible future site for consolidated or collocated facilities. Therefore, in recognition of this goal, if an offshore oil production operator in the future desires to use any of the remaining Exxon Canyon acreage outside of the land for use by Exxon and POPCO or other gas purchasers, Exxon would allow such use upon mutually agreeable terms and receipt of fair market value, so long as the proposed operations

did not preclude or substantially interfere with use of the property by Exxon or POPCO or other gas purchaser. Exxon will not unreasonably withhold its consent to such use of Canyon acreage by other operators. Such use would be contingent upon the other operator obtaining the necessary land use and other required approvals from the State and County. Since the MOA, Exxon has continued to study siting opportunities in the Canyon, and to communicate those to members of the Santa Barbara County Petroleum Transportation Committee. This section amends the 1980 MOA to include Exxon's request for an additional approximate 10-acre facility site expansion and to provide that the County will review to determine Exxon's plans will not preclude attainment of the County's General Plan as discussed above.

E. Transportation System

This section E specifically amends and supersedes Part III of the 1980 MOA. The Parties anticipate need for an integrated transportation system for Southern California offshore petroleum activities. The system should reflect the need for environmental protection and market and logistical flexibility. The major elements being considered are a permanent modern marine terminal at Las Flores Canyon for shipment of crude to refineries not adequately served by pipeline and crude pipelining to California markets where feasible. The Parties understand that the County, in order to reach a decision whether Las Flores Canyon is the designated consolidated terminal location, intends to process amendments to its Local Coastal Plan and Local Coastal Ordinance. Such amendments will be subject to public participation and appropriate environmental review, as provided by law. Accordingly, the Parties will pursue the following approach in an effort to further the development of a mutually acceptable system. It is understood that nothing herein precludes the consideration by the County of other proposals for different transportation systems or different terminal companies.

1. Terminal Company

The Parties recognize that Section 30261 of the California Coastal Act and the County Coastal Plan provide that multicompany use of new marine terminals be encouraged to the maximum extent feasible. Pursuant to this provision, the Parties have discussed the structuring of a marine terminal company, as follows.

The Parties anticipate that when and if all necessary permits and approvals are obtained and accepted by applicant, a modernized, permanent nearshore marine terminal will be constructed by the terminal company for producers' use in shipping crude oil by marine

vessel. Exxon or an affiliate will establish or participate in establishing a joint interest terminal company. Parties recognize that the terminal and associated crude oil storage may be developed in phases and expanded if justified by throughput commitments and feasibility findings. It is further anticipated that the ownership of the terminal company will be held by the companies participating in the terminal company or their designees desiring to utilize the terminal in proportion to their estimated volumes of crude to be shipped through the terminal, and that they will share responsibility for financing terminal design, construction, and other costs on mutually agreeable terms.

As herein above provided, the terminal will be designed for hydrocarbon vapor recovery and vessels using the terminal will employ technology compatible with the terminal's vapor recovery system. The Parties agree that unforeseen severe logistics system upsets could give rise to occasions necessitating loading of a vessel not equipped with vapor recovery technology to avoid shut-in of one or more fields producing to the terminal as provided under County regulations.

Absent circumstances beyond the terminal company's control, it is anticipated that the terminal would be ready for use approximately two years after all permits are received and accepted or by the time the first crude of one of the terminal company's owners is scheduled to be shipped through the terminal, whichever is later; but no earlier than 1st Quarter 1986. In order to implement the policy of multicompany use of the marine terminal the State and County plan to identify the amount of crude oil to be transported and the method of transportation taking into account environmental protection and feasibility. It is anticipated that the terminal company would expeditiously apply for the necessary permits and other authorities for the construction of a terminal of sufficient size to handle the projected throughput commitments. The Parties recognize that Exxon, as SYU operator, has already conducted extensive engineering and environmental studies for a terminal capable of accommodating 125 thousand barrels per day (annual average). In the interest of expediting the terminal permitting process, Exxon, as SYU operator, will apply for the lease and other approvals required for a terminal based on the information it has developed, and that these applications or approvals may be transferred to the terminal company for its use in obtaining the necessary approvals to construct the first phase of the terminal on this basis. The State and County acknowledge that such a terminal, if approved, constructed and operated in conformance with provisions of this agreement and with mitigation of impacts as provided by law would satisfy their concerns, and agree to expeditiously process applications for the lease or other permits

required for such terminal in a manner and on terms consistent with applicable law and regulations.

The State and County recognize that implementation of this proposal will provide for a terminal that may be initially utilized by others and may require expansion to fully accommodate Exxon's production. Based on the policy of the County, not to require crude oil to be pipelined to California destinations if the crude oil producer intends to directly transship such crude outside California, and a County determination of pipeline infeasibility for Exxon "as a particular operator" according to the Local Coastal Plan and mitigation of impacts, including vessel traffic safety and spill risks as provided by law, the State and County would undertake to assure transport of Exxon's total share (approximately 105 thousand barrels per day) of the SYU production through the terminal. The State and County recognize that Exxon has agreed to apply air mitigation measures to offset throughput of 125 thousand barrels per day (total SYU production) through the marine terminal, and recognize that such mitigation measures are reserved for Exxon as SYU operator. Any throughput by other operators must be consistent with terminal approvals and must be mitigated by other users as provided by law. Exxon agrees, that when both its onshore oil and gas treatment and transportation facilities are operational and debugged, to discontinue use of the existing OS&T and SALM for SYU operations and will remove it and the facilities currently located near Highway 101 serving the existing El Capitan marine terminal on the condition that it will be able to utilize the terminal when Exxon has a requirement to transport its SYU production (approximately 105 thousand barrels per day).

2. Pipeline Considerations

a. Exxon Participation

Since the early 1970's, there has been discussion among the State, County, Exxon and other companies on the subject of construction of a Southern California coastal pipeline from the Santa Barbara County area. In the MOA, Exxon agreed to, and will continue to participate in and support, the joint company/government pipeline working group study of the feasibilities of an onshore pipeline, which has been superseded and expanded by the Santa Barbara County Petroleum Transportation Committee; and Exxon has in good faith done so. Also, Exxon has been a participant in all areas of the Industry Pipeline Study known as the Southern California Coastal Pipeline Feasibility Study. Exxon agrees to fund, at the time of permit application, in the amount of \$25,000, the County's study of planning, environmental review and permitting of a pipeline.

Exxon also will, by this agreement, which supersedes the MOA in this respect, continue to participate in the study of the feasibility of such a pipeline. If and when the County determines under its Local Coastal Plan that a pipeline is feasible, Exxon will make the following commitments. Exxon will participate and provide funding, with its share not to exceed \$2 million on an equal basis with other joint participants if four or more other participants elect to form a company to initiate engineering and environmental studies preparatory to application for permits, licenses, certificates, franchises and other approvals necessary for construction of a pipeline, and if Exxon has received the necessary permits for its Base Plan. Further, after the pipeline company receives permits for a pipeline which is scheduled to be in operation by 1992 and, with four or more companies participating, elects to proceed to acquire right-of-way for pipeline construction, Exxon will provide funding of a one fifth share up to an additional \$2 million toward the pipeline company's costs of right-of-way acquisition.

Exxon also agrees to (1) transfer land in the Canyon to such pipeline company's for the purpose of establishing a pipeline terminal and/or oil storage space and/or a pump/heater station, or (2) tie Exxon's crude oil shipping facilities into such a pipeline when constructed for the purpose of collecting crude oil other than Exxon's crude if a pipeline is built by operators for the purpose of transporting crude oil from the Santa Barbara Channel area, upon reasonable terms and conditions and payment of fair market value to Exxon, and provided that such use would not preclude or substantially interfere with use of the Canyon or marine terminal by Exxon or POPCO.

b. Pipeline Feasibility

Exxon represents that, regardless of the existence of a pipeline(s) from Santa Barbara County to the Los Angeles Basin or other refining centers in California, pipeline transportation of Exxon's crude (approximately 105 thousand barrels per day) for transshipment outside of California is infeasible. Exxon represents this is based on Exxon's lack of refining capacity in the Los Angeles Basin and limited refining capacity elsewhere in California, its need for logistical and marketing flexibility in the handling of its crude, recognition of its extensive investment in an existing marine based transportation system, and the

environmental consequences of pipelining and retanking such crude. Exxon believes any tender of crude to the pipeline(s) by Exxon should be a business decision to be made by Exxon. In response to this, the County states it is its policy not to require the shipment by pipeline of locally produced crude oil to a destination in California where it is intended by the oil producer or purchaser for direct transshipment by tanker to points outside California. Further, County agrees to expeditiously make a finding of whether pipeline transportation is infeasible for Exxon "as a particular operator" according to the Local Coastal Plan. Exxon's agreements under this MOA are conditioned upon the County making the finding within 5 months from the date of this agreement. The Parties further recognize that the existence of a pipeline to Los Angeles, however justified, does not preclude marine transportation of some of Exxon's crude from offshore Santa Barbara County to California refineries outside the Los Angeles Basin until such time as common carrier pipelines are in existence to those locations. In light of this, the Parties recognize that such transportation may be permitted through the terminal company. On the other hand, when a competitive common carrier pipeline system is in existence which is capable of timely delivery of Exxon's crude to the destination specified by Exxon for refining in California, Exxon agrees that marine transportation through the terminal company to those destinations will be discontinued. Exxon's agreement on the transportation system, as discussed herein, is based on its anticipation that the County will render the determination of infeasibility as discussed above. If the County does not render such determination of infeasibility, Exxon will not be bound to its undertakings in this MOA II.

Exxon represents that these commitments described in this section are the full extent of Exxon's intended obligations regarding a pipeline.

3. Terminal Consolidation

Exxon asserts that its role in terminal consolidation shall be limited to abandoning and removing the existing Capitan Terminal and setting up the companies described above.

4. Supply Base

At such time as there is a consolidated Supply Base operating to

serve western Santa Barbara Channel OCS operations, Exxon, as operator, may make use of it for the Santa Ynez Unit as needed.

VI. Approvals and Other Considerations

A. Approvals

Exxon, as SYU operator, will submit the foregoing facility plans to the MMS for approval. This MOA II will be submitted as part of Exxon's certification of consistency with the California Coastal Program.

It is understood by the Parties that the permits, leases and other requirements for the Base Plan facilities and onshore gas facilities for the Alternate Plan will be expeditiously processed upon application, within the time limits provided by the California Permit Streamlining Act (California Government Code, Title 7, Chapter 4.5, Section 65920 et seq.), including all necessary land use applications to enable facilities to be constructed on Exxon's land in the Las Flores Canyon area, within or outside the already permitted acreage. Further, the Parties understand that all applications may not be submitted simultaneously or by the same applicant because of the necessary sequence of construction and the separate ownership of facilities. State and County will therefore process all necessary permits, leases and other applications for the above referenced Plans expeditiously upon submittal in accordance with the requirements of applicable statutes or rules and regulations. If any provisions of this MOA II are inconsistent with applicable federal, state, or local law, rules, or regulations, such laws, rules, or regulations shall prevail.

Exxon's commitments in this agreement are conditioned upon expeditious approval of all necessary permits, leases, and other approvals or findings consistent with the provisions of this agreement.

B. Other Considerations

State and County will comment to the Coastal Commission prior to its decision regarding the consistency of Exxon's plan with California's Coastal Management Program.

Based on the air mitigation measures included on Exxon's OCS facilities in the Base Plan described herein, State and County will not challenge Exxon's compliance under the DOI air regulations in effect as of the effective date of this agreement in developing the SYU project.

VIII. Conclusion

The Parties recognize that the concepts discussed in this document represent a means of accomplishing their goals on mutually agreeable terms, and that the addition of SYU's offshore California oil and gas reserves at the earliest possible date will provide additional vital energy for California and the Nation while providing environmental protection. In addition, this MOA II will continue the successful, cooperative relationship among the Parties.

The Parties hereby execute the above recited Memorandum of Agreement II as indicated by the signatures of their duly authorized officials below.

This agreement is effective October 11, 1982.

State of California

California Air Resources Board

Subject to the terms of the attached letter of this date.

By: _____

By: _____

Date: _____

Date: _____

10/22/82

County of Santa Barbara

California State Lands Commission

By: _____

By: _____

Date: DEC 11 1982

Date: _____

Santa Barbara County

Exxon Corporation

Air Pollution Control District

By: _____

By: _____

Date: DEC 11 1982

Date: October 20, 1982

APPROVED AS TO FORM
KENNETH L. NELSON
COUNTY COUNSEL

By: _____

DEC 11 1982

DEVELOPMENT AND PRODUCTION PLAN

SANTA YNEZ UNIT DEVELOPMENT

Table of Contents

- I. Development and Production Overview
- II. Geology
- III. Reservoir Evaluation
- IV. Platform Sites and Structures
- V. Drilling Plans and Facilities
- VI. Subsea Production Systems
- VII. Offshore Platform Facilities
- VIII. Pipelines
 - IX. Oil and Gas Treating Facilities
 - X. Crude Transportation
 - XI. Operations

ATTACHMENTS

- A. Critical Operations and Curtailment Plan
- B. Hydrogen Sulfide Contingency Plan
- C. Oil Spill Contingency Plan for California Operations -
An Overview

APPENDIX [Proprietary]

- A. Geology Plates 2.1 to 2.16, Reservoir Evaluation
Tables 3.2 to 3.17, and Reservoir Evaluation Figures
3.2 to 3.5.

ABBREVIATIONS

ac	acre(s)
AC	alternating current
ACT	automatic custody transfer
ANSI	American National Standards Institute
API	American Petroleum Institute
BHP	brake horsepower
BO	barrels of oil
BML	below mud line
BOD	barrels of oil per day
BOP	blowout preventer
BS&W	basic sediment and water
BSCF	billion standard cubic feet
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
cp	centipoises
CVA	Certified Verification Agent
DC	direct current
DEA	diethanolamine
DOE	U.S. Department of Energy
DOI	U.S. Department of the Interior
EPA	U.S. Environmental Protection Agency
F	Fahrenheit
ft	feet
H ₂ S	hydrogen sulfide
kg	kilogram(s)
kHz	kilohertz
kPa	kilopascals
kV	kilovolt(s)
kVA	kilovolt-ampere(s)
kW	kilowatt(s)
L	liter(s)
m	meter(s)
m ²	square meter(s)
MBD	thousand barrels per day
MBH	thousand barrels per hour
MBOD	thousand barrels of oil per day
md	millidarcies

ABBREVIATIONS (Cont.)

MD	measured depth
MHz	megahertz
MLLW	mean lower low water
MMB	million barrels
MMS	Minerals Management Service (formerly U.S. Geological Survey)
MPDU	Multi-Product Distribution Unit
MSCF	thousand standard cubic feet
MSCFD	thousand standard cubic feet per day
MMSCFD	million standard cubic feet per day
MW	megawatt(s)
MWL	mean water level
NGL	natural gas liquids
NOC	net oil computer
NO _x	oxides of nitrogen
NPDES	National Pollutant Discharge Elimination System
OCS	Outer Continental Shelf
OS&T	Offshore Storage and Treating Vessel
OSHA	Office of Safety and Health Administration
POPCO	Pacific Offshore Pipeline Company
ppm	part(s) per million
psia	pound(s) per square inch (absolute)
psig	pound(s) per square inch (gauge)
SALM	Single Anchor Leg Mooring
SCE	Southern California Edison Company
SCF	standard cubic feet
SCR	selective catalytic reduction
SPCC	Spill Prevention Control and Countermeasure
SPM	single point mooring
SPRR	Southern Pacific Railroad
SRU	sulfur recovery unit
ss	subsea
STB	stock tank barrel(s)
SYU	Santa Ynez Unit
TEG	triethylene glycol
TFL	through flowline
TOS	top of steel
USCG	U.S. Coast Guard
USGS	U.S. Geological Survey
VBL	vapor balance line
VBS	vapor balance system
VOC	volatile organic compounds
VRL	vapor return line

SECTION I

DEVELOPMENT AND PRODUCTION OVERVIEW

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SECTION I
DEVELOPMENT AND PRODUCTION OVERVIEW

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- 1.1 Santa Ynez Unit.
- 1.2 Offshore Oil Treating - Development Option A1 - One Pescado Platform.
- 1.3 Offshore Oil Treating - Development Option A2 - Two Pescado Platforms.
- 1.4 Onshore Oil Treating - Development Option B1 - One Pescado Platform.
- 1.5 Onshore Oil Treating - Development Option B2 - Two Pescado Platforms.
- 1.6 Offshore Facility Locations.
- 1.7 Offshore Oil Treating - Development Option A - Schedule.
- 1.8 Onshore Oil Treating - Development Option B - Schedule.

SECTION I

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 nineteen leases on the Federal Outer Continental Shelf 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 (P-0326) in Lease Sale 48 and were added to the Santa Ynez Unit in October, 1982. Exxon owns eight leases in the Unit, one-half interest with Chevron U.S.A. (hereinafter called 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 Co.

Three field developments are addressed in this Development and Production Plan - the Hondo field, the Sacate field and the Pescado field. Hydrocarbons have been found in the Government Point and Abalone prospects located in the western area 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 on OCS Lease P-0188. The Hondo A platform will develop only the eastern portion of the Hondo field and a second platform structure will be necessary to recover additional reserves. In addition, the Pescado and Sacate fields appear to provide commercial development opportunities. Exxon estimates that primary recovery by the proposed development will amount to approximately 300 to 400 million barrels (MMB) of crude oil and 600 to 700 billion standard cubic feet (BSCF) of natural gas. Recovery of these reserves will take place over a period of approximately 25 to 35 years.

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 the Hondo A platform, geologic and reservoir studies, and engineering analyses. Changes to the definition of the extent and producing characteristics of the Hondo, Pescado and Sacate fields 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, Pescado, and Sacate fields. However, the proposed development, or any part of the development, is dependent on receipt of an equitable return on invested capital.

Project engineering for the SYU Development is still in the conceptual stage. Specific details concerning methods, processes, facilities, and 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 the environmental review process as well as those from engineering and economic analyses to ensure that the SYU Development is conducted in an environmentally sound manner.

Present plans for continuing development of the Santa Ynez Unit call for the installation of three or four new platforms. The Hondo B platform, located in the western portion of the Hondo field, will be a conventional jacket with two decks in approximately 1,200 feet of water. It will have 60 conductors arranged for the simultaneous operation of two drilling rigs.

Based on the current reservoir assessment, the Pescado field will be developed from a twin rig, 60-well, two-deck, conventional platform, Pescado A, in approximately 1,075 feet of water. There is a possibility that outpost drilling could justify a second platform to further develop the Pescado

field. In that case, two conventional platforms, a three-deck Pescado B-1 platform with 28 wells and a two-deck Pescado B-2 platform with 60 wells, would be installed in water depths of approximately 1,025 feet and 1,140 feet, respectively. The development of Sacate will require one 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 all of the platforms (Sacate to Pescado to Hondo B to Hondo A). From the Hondo A platform the total production will be sent to oil treating facilities. Two oil and gas production and treating options are presented in this Development & Production Plan.

In Development Option A (Offshore Oil Treating), crude emulsion will be pumped to the existing Offshore Storage and Treating vessel (OS&T). Figures 1.2 and 1.3 show Development Option A for one and two Pescado platform configurations, respectively. The current OS&T design capacity of about 40 MBD of treated oil will be increased to a maximum of about 80 MBD. The gas will be pipelined to onshore gas treating facilities located on Exxon-owned land in Las Flores Canyon. Gas treating facilities of 30 MMSCFD capacity are currently being constructed (further referred to herein as "existing" or "initial" gas treating facilities). Gas treating facilities capacity will be increased by about 60 MMSCFD to a total

of approximately 90 MMSCFD. The sales gas will be pipelined to the Pacific Lighting Service Company regional gas transmission line. The OS&T and the platforms will have gas turbine driven generators connected to a common grid electrical distribution network in order to minimize the amount of installed electric generating capacity. Crude oil transshipment will continue by marine vessel in accordance with present OS&T operations.

Development Option B (Onshore Oil Treating) will bring both oil and gas production on shore. Figures 1.4 and 1.5 show Development Option B for one and two Pescado platform configurations, respectively. Gas treating facilities presently under construction have a design capacity of 30 MMSCFD which will be increased to a peak design rate of approximately 135 MMSCFD. The sales gas will be pipelined to the Pacific Lighting Service Company regional gas transmission line. Oil treating facilities with a peak design capacity of approximately 140 MBOD will be built adjacent to the gas treating facilities in Las Flores Canyon to handle the optimum platform production rates.

Crude oil transportation will be via marine vessels from a modernized nearshore marine terminal in approximately 140 feet of water. The locations of all the proposed platforms, the OS&T, and the nearshore marine terminal are given in Table 1.1. and shown in Figure 1.6.

A central cogeneration power plant will supply the electrical power requirements of the onshore oil treating facilities, marine terminal, drilling rigs, and the offshore platforms while efficiently utilizing waste heat recovery to provide process heat to both onshore oil treating and gas treating facilities. Electrical power will be sent offshore through a submarine cable system. No gas turbine generators will be installed on any of the new platforms.

The projected schedules for Development Options A and B are shown in Figures 1.7 and 1.8, respectively. In both cases, production from the Hondo B platform is anticipated to begin in late 1988. Production startup from the 60-well Pescado platform, either Pescado A or Pescado B-2, is scheduled for late 1989. Sacate production should come onstream in late 1990. If the two-platform configuration is used to produce the Pescado reservoirs, the Pescado B-1 platform would initiate production in late 1999 (Development Option A) or early 1994 (Development Option B). The projected schedules are contingent in part upon the time which will be required to obtain all necessary federal, state, county and other governmental permits, approvals, and right-of-ways and are therefore approximate.

In accordance with Title 30, Code of Federal Regulations 250.34, and Pacific Region OCS Order Number 8, this Development and Production Plan for further development of the Santa Ynez Unit is hereby submitted for approval. This document

should be read in conjunction with the Environmental Report (Production) for this Santa Ynez Unit development.

This Plan is a complete description of 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 H₂S 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 A	832,341	830,947	120° 07' 14" W	34° 23' 27" N
OS&T & SALM	838,727	835,892	120° 05' 60" W	34° 24' 18" N
Hondo B	817,960	826,503	120° 10' 03" W	34° 22' 37" N
Pescado A	780,320	816,840	120° 17' 28" W	34° 20' 48" N
Pescado B-1	773,330	818,290	120° 18' 52" W	34° 20' 59" N
Pescado B-2	787,400	817,800	120° 16' 04" W	34° 20' 60" N
Sacate	769,640	834,300	120° 19' 43" W	34° 23' 36" N
Marine Terminal	858,737	851,261	120° 02' 08" W	34° 26' 57" N

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

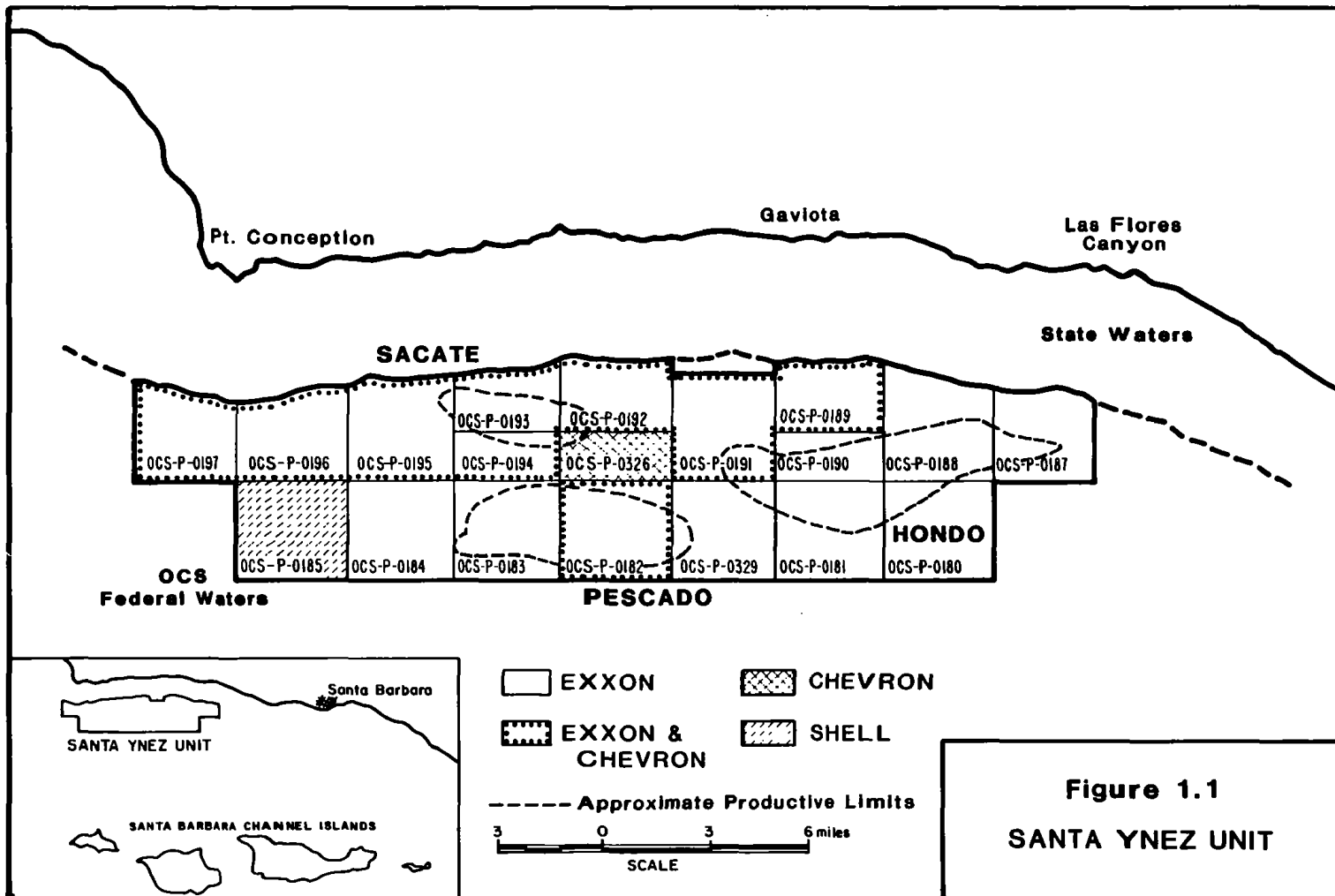


Figure 1.1
SANTA YNEZ UNIT

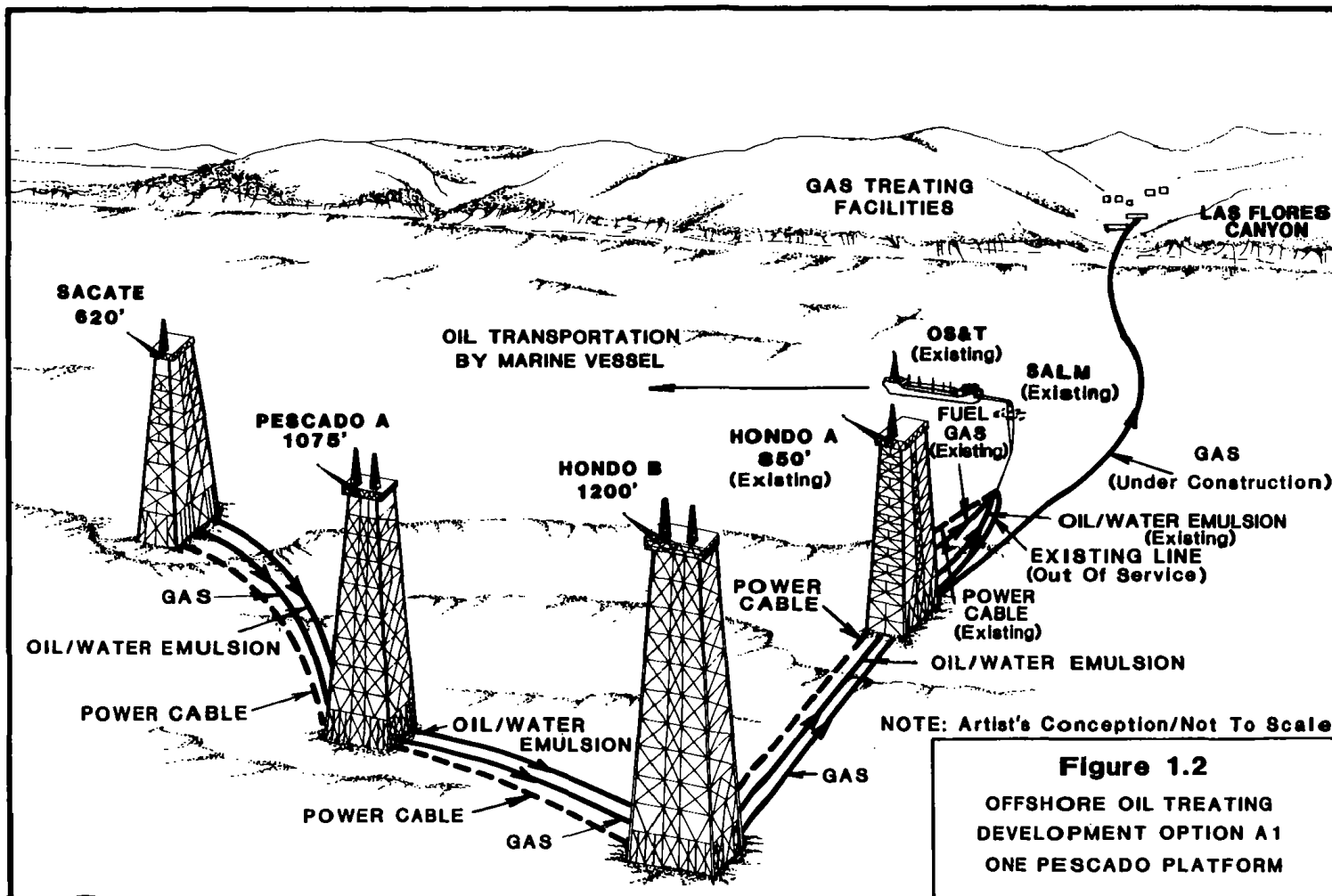


Figure 1.2

**OFFSHORE OIL TREATING
DEVELOPMENT OPTION A1
ONE PESCADO PLATFORM**

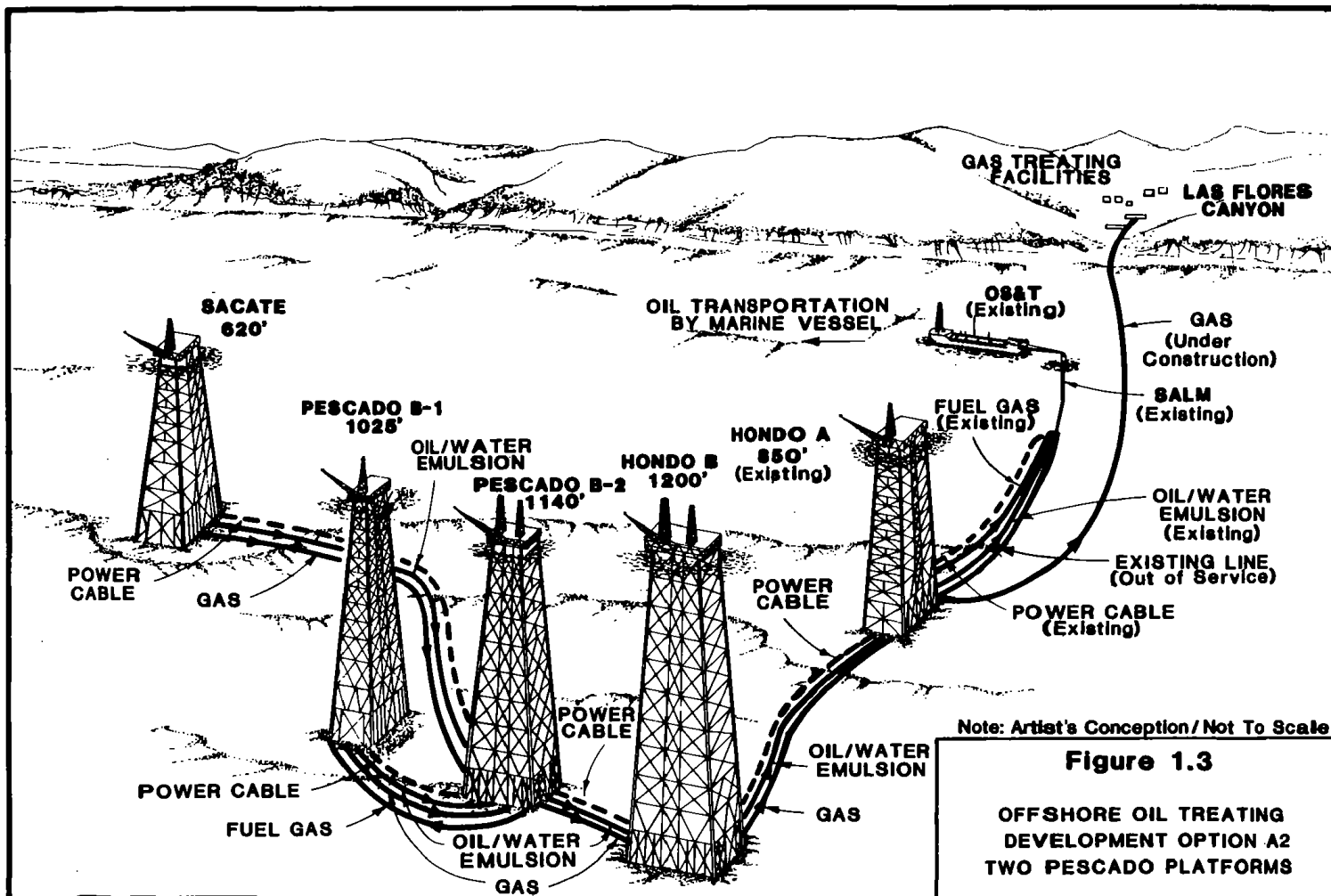


Figure 1.3

**OFFSHORE OIL TREATING
DEVELOPMENT OPTION A2
TWO PESCADO PLATFORMS**

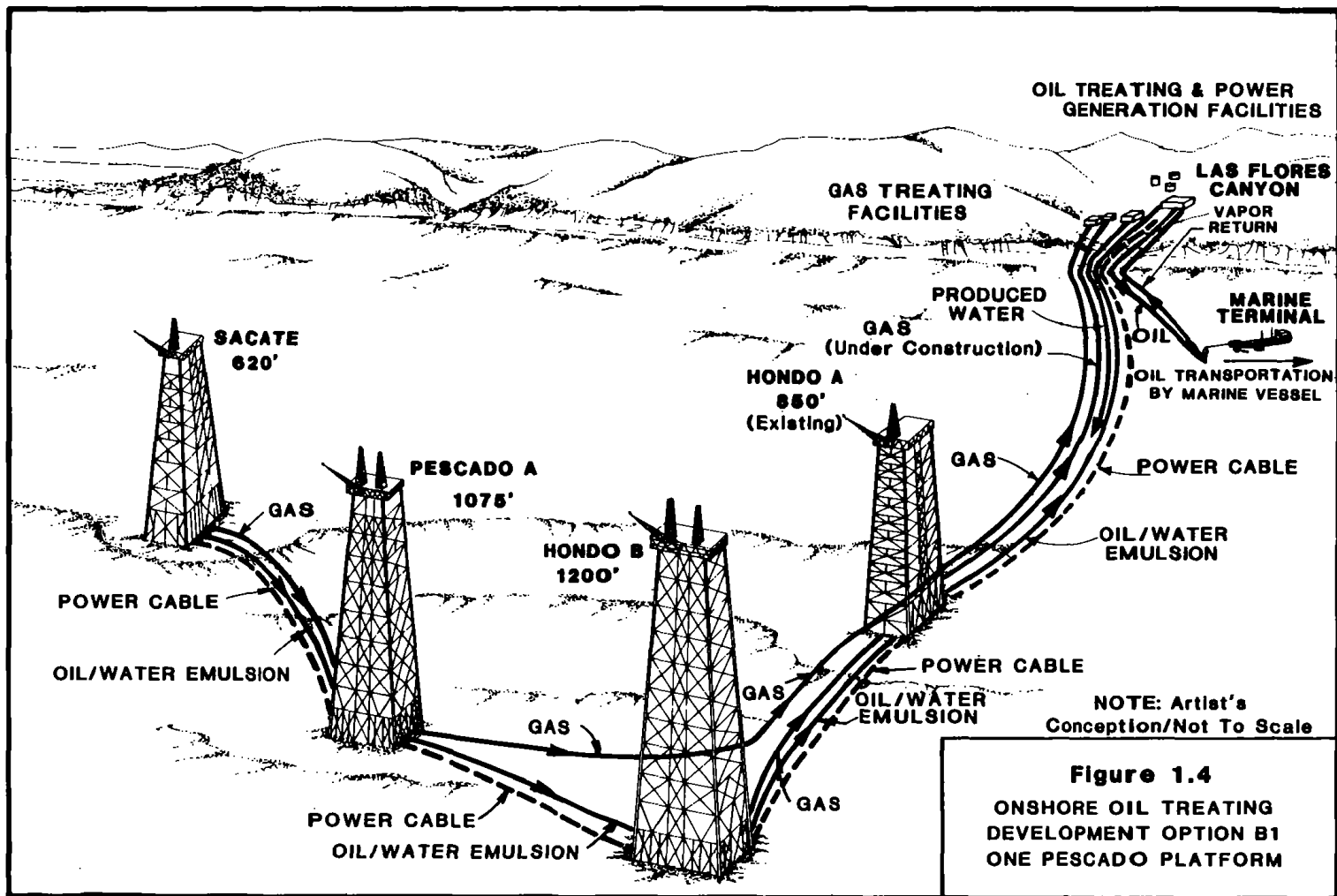


Figure 1.4
ONSHORE OIL TREATING
DEVELOPMENT OPTION B1
ONE PESCADO PLATFORM

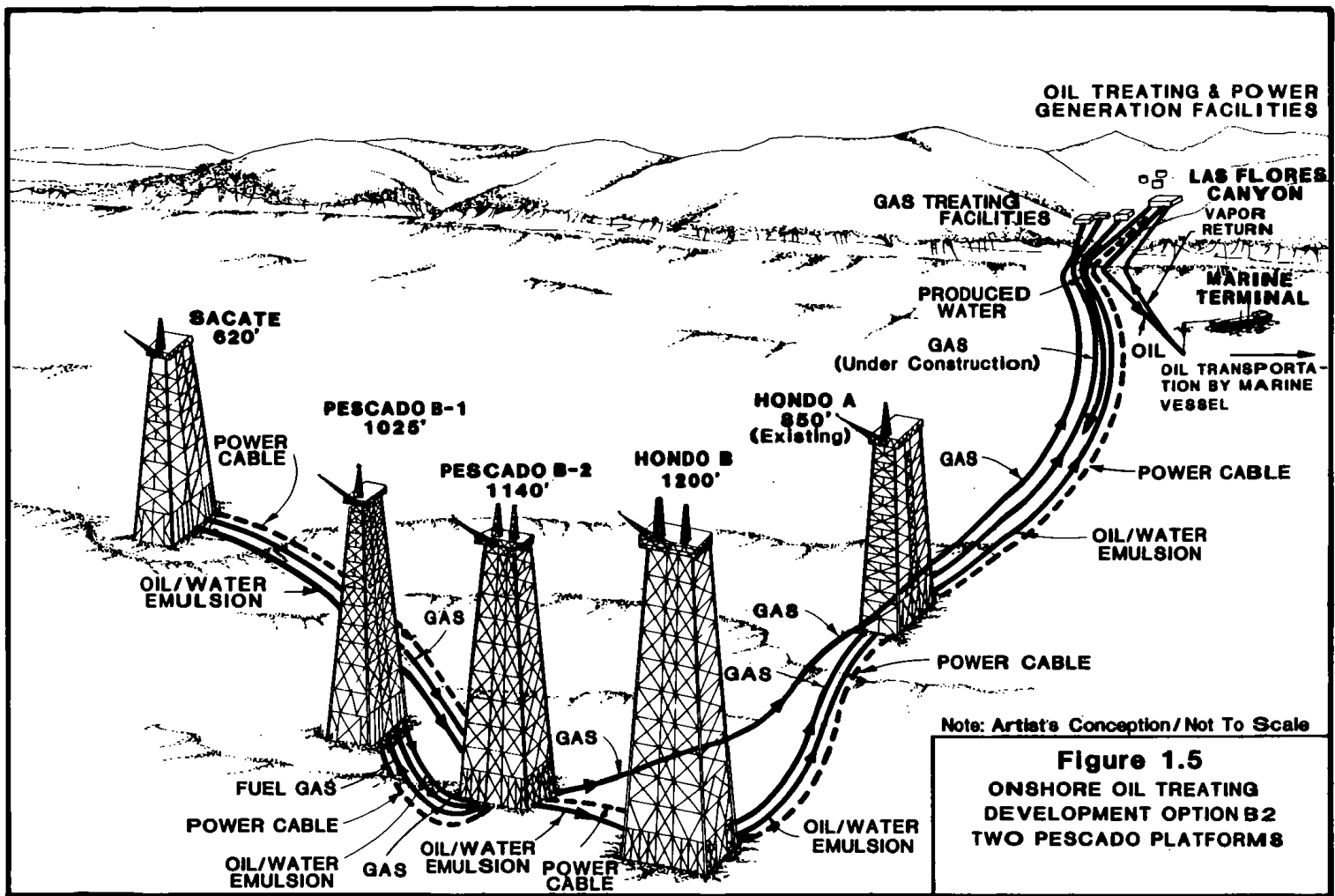


Figure 1.5
ONSHORE OIL TREATING
DEVELOPMENT OPTION B2
TWO PESCADO PLATFORMS

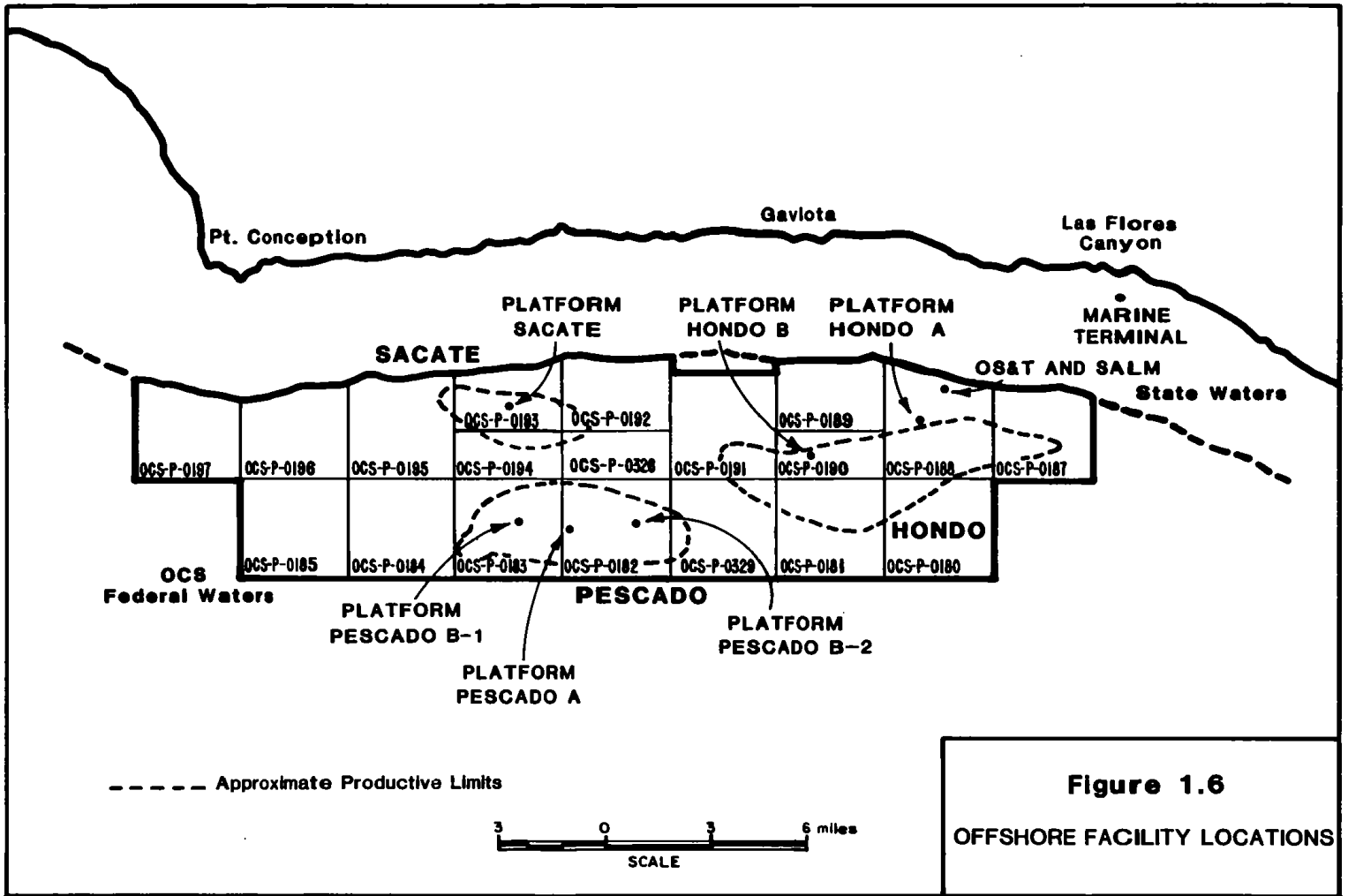


Figure 1.6
OFFSHORE FACILITY LOCATIONS

DETAILED DESIGN

PLATFORM HONDO B
 PLATFORM PESCADO A OR PESCADO B-2
 PLATFORM SACATE
 PLATFORM PESCADO B-1 (Possible Addition)
 PLATFORM HONDO A MODIFICATIONS
 OS&T MODIFICATIONS
 OFFSHORE PIPELINES AND POWER CABLES (Sequential by Platform)
 ONSHORE GAS TREATING FACILITIES EXPANSION

CONSTRUCTION (Includes Procurement, Fabrication, Installation, & Commissioning)

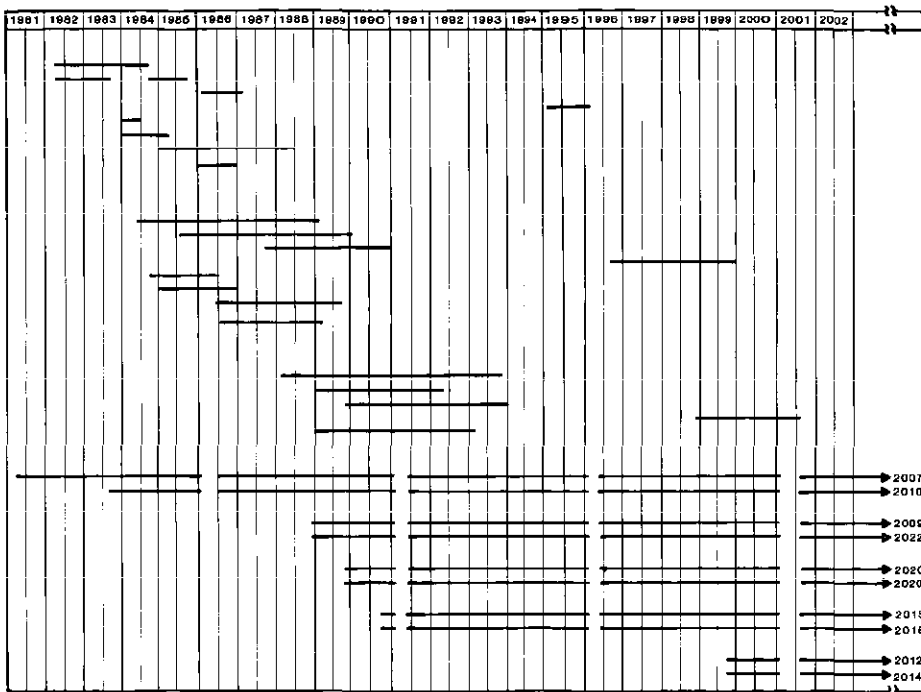
PLATFORM HONDO B
 PLATFORM PESCADO A OR PESCADO B-2
 PLATFORM SACATE
 PLATFORM PESCADO B-1 (Possible Addition)
 PLATFORM HONDO A MODIFICATIONS
 OS&T MODIFICATIONS
 OFFSHORE PIPELINES AND POWER CABLES (Staggered Installation)
 ONSHORE GAS TREATING FACILITIES EXPANSION

DRILLING

HONDO B
 PESCADO A
 SACATE
 PESCADO B-1 (Possible Addition)
 PESCADO B-2 (In Place Of Pescado A)

PRODUCTION

HONDO A
 OIL
 GAS
 HONDO B
 OIL
 GAS
 PESCADO A OR PESCADO B-2
 OIL
 GAS
 SACATE
 OIL
 GAS
 PESCADO B-1 (Possible Addition)
 OIL
 GAS



- NOTES:
1. All Durations And Schedule Dates Are Approximate.
 2. The Design And Construction Times For Pescado B-1 Indicated Above Include Allowances For Work Associated With The Additional Required Pipelines And Power Cables.
 3. OS&T Drydocking Will Also Interrupt Production For 17 Weeks In 2011 And 14 Weeks In 2006, 2016. Durations And Years Are Approximate.
 4. The Current Production Plan Is Based Only On Primary Recovery. Successful Application Of Improved Recovery Techniques Would Extend The Field Lives Beyond The Dates Given Above.

Figure 1.7
 OFFSHORE OIL TREATING
 DEVELOPMENT OPTION A
 SCHEDULE

DETAILED DESIGN

PLATFORM HONDO B
 PLATFORM PESCADO A OR PESCADO B-2
 PLATFORM SACATE
 PLATFORM PESCADO B-1(Possible Addition)
 PLATFORM HONDO A MODIFICATIONS
 MODERNIZED NEARSHORE MARINE TERMINAL
 OFFSHORE PIPELINES AND POWER CABLES (Sequential By Platform)
 ONSHORE GAS TREATING FACILITIES EXPANSION
 ONSHORE OIL TREATING FACILITIES
 ONSHORE COGENERATION POWER PLANT
 ONSHORE PIPELINES

CONSTRUCTION (Includes Procurement, Fabrication, Installation, & Commissioning)

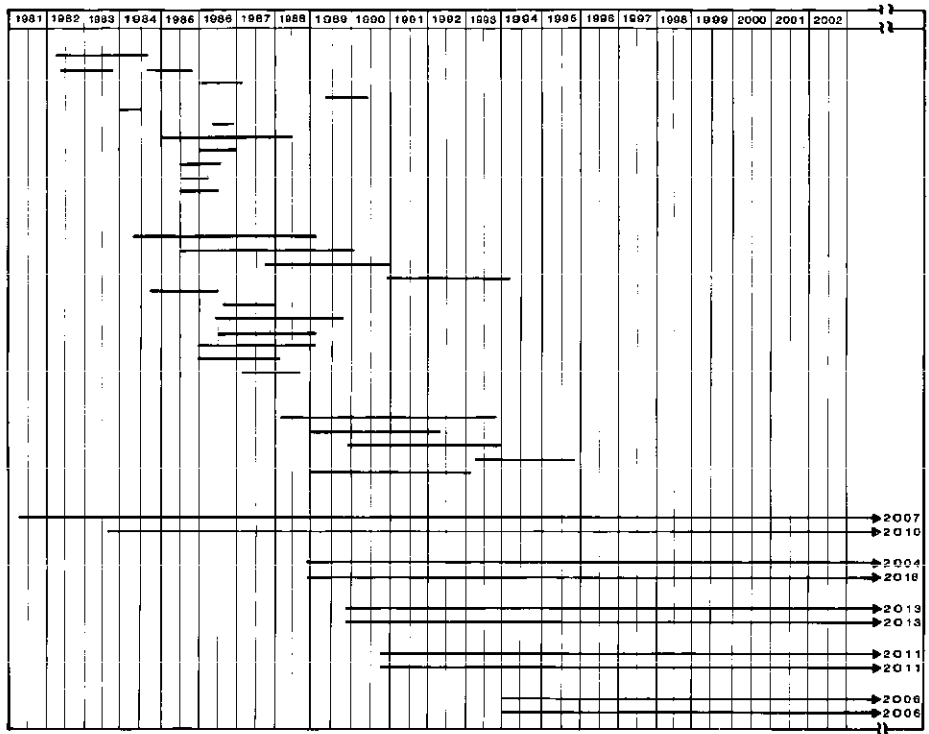
PLATFORM HONDO B
 PLATFORM PESCADO A OR PESCADO B-2
 PLATFORM SACATE
 PLATFORM PESCADO B-1(Possible Addition)
 PLATFORM HONDO A MODIFICATIONS
 MODERNIZED NEARSHORE MARINE TERMINAL
 OFFSHORE PIPELINES AND POWER CABLES (Staggered Installation)
 ONSHORE GAS TREATING FACILITIES EXPANSION
 ONSHORE OIL TREATING FACILITIES
 ONSHORE COGENERATION POWER PLANT
 ONSHORE PIPELINES

DRILLING

HONDO B
 PESCADO A
 SACATE
 PESCADO B-1(Possible Addition)
 PESCADO B-2 (In Place Of Pescado A)

PRODUCTION

HONDO A
 OIL
 GAS
 HONDO B
 OIL
 GAS
 PESCADO A OR PESCADO B-2
 OIL
 GAS
 SACATE
 OIL
 GAS
 PESCADO B-1(Possible Addition)
 OIL
 GAS



- NOTES: 1. All Durations And Schedule Dates Are Approximate.
2. The Design And Construction Times For Pescado B-1 Indicated Above Include Allowances For Work Associated With The Additional Required Pipelines And Power Cables.
3. The Current Production Plan Is Based Only On Primary Recovery. Successful Application Of Improved Recovery Techniques Would Extend The Field Lives Beyond The Dates Given Above.

Figure 1.8
 ONSHORE OIL TREATING
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- 2.2 Generalized Columnar Section - Santa Ynez Unit.
- 2.3 Regional and Site-Specific Geophysical Survey Areas.
- 2.4 Pipeline and Marine Terminal Geophysical Survey Areas.
- 2.5 Geotechnical and Geologic Survey Area.
- 2.6 Bathymetric and Geomorphic Provinces in the Vicinity of the Santa Ynez Unit.
- 2.7 Oblique Map of Conception Fan.
- 2.8 Surface and Near-Surface Geologic Features and Structures in the Santa Ynez Unit Area.

SECTION II

GEOLOGY

NOTE: PLATES 2.1 TO 2.16 CONTAIN DETAILED GEOLOGIC AND RESERVOIR INFORMATION WHICH IS CONSIDERED EXXON PROPRIETARY AND ARE LOCATED IN A SEPARATE "APPENDIX A." NO DISCLOSURE OF THESE PLATES BEYOND THE MINERALS MANAGEMENT SERVICE IS ALLOWED WITHOUT PRIOR WRITTEN AUTHORIZATION FROM EXXON.

The structure maps show contours drawn on top of the horizon, major faults, well locations and lease block outlines. The structure cross sections are profile views. Type logs are representative electric well logs.

PLATES

- 2.1 Monterey Formation Siliceous Zone: Development Well Plan (Siliceous Zone Structure Top), Hondo Field.
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- 2.3 Type Log, Hondo Field.
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- 2.5 Monterey Formation Siliceous Zone: Pescado B-1 and B-2 Development Well Plan (Siliceous Zone Structure Top), Pescado Field.
- 2.6 Vaqueros/Alegria Formation: (Vaqueros/Alegria Structure Top), Pescado Field.
- 2.7 Gaviota Formation: Development Well Plan (Gaviota Formation Lower Sand Structure Top), Pescado Field.

SECTION II

GEOLOGY

PLATES (Cont.)

- 2.8 Matilija Formation: Development Well Plan (Matilija Formation Zone II Structure Top), Pescado Field.
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- 2.13 Gaviota Formation: Development Well Plan (Gaviota Formation Lower Sand Structure Top), Sacate Field.
- 2.14 Matilija Formation: Development Well Plan (Matilija Formation Structure Top), Sacate Field.
- 2.15 Structure Cross Sections, Sacate Field.
- 2.16 Type Log, Sacate Field.

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

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RESERVOIR EVALUATION
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SECTION III

RESERVOIR EVALUATION

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SECTION III

RESERVOIR EVALUATION

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SECTION III

RESERVOIR EVALUATION

NOTE: FIGURES 3.2 TO 3.5 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.

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Reservoir Evaluation 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 IV
PLATFORM SITES AND STRUCTURES

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PLATFORM SITES AND STRUCTURES

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SECTION IV

4.1 Introduction

The Hondo, Pescado and Sacate platform structures will be 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 will be 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 8.

4.2 Design Standards

The platform structures will be designed to satisfy the MMS 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 6-21 of Section 2.5.

Site-specific geologic studies were conducted for three platform areas (Fig. 4.1): one on the Slope Province (Hondo B platform) and two on the Conception Fan (Pescado and Sacate platforms). 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.

Hondo B Platform Site

A north-south trending rectangular area, 12,000 feet by 10,000 feet, was studied to evaluate potential sites for the Hondo B platform (Fig 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.

Pescado Platforms Site

An east-west trending rectangular area, 17,500 feet by 5,000 feet, was studied to evaluate potential sites for the Pescado A, Pescado B-1 and Pescado B-2 platforms (Fig. 4.1). The sites are in interchannel areas on the middle part of the Conception Fan and are 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.

Sacate Platform Site

An east-west trending rectangular area, 10,000 feet by 4,000 feet, was studied to evaluate the proposed Sacate platform site (Fig. 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 Pescado platforms site.

4.4 Geotechnical Design Criteria

The platform foundation design criteria will be based on soils information obtained from extensive, state-of-the-art geotechnical investigations conducted in late 1981 by McClelland Engineers, Inc. at each platform location.

Offshore activities included pushed sample recovery, downhole cone penetrometer testing, in-situ remote vane testing, and gamma ray logging in deep boreholes. 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 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 are 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 the 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 will be based on a detailed evaluation of earthquake potential in the western portion of the Santa Barbara Channel and will specifically account for the regional and local geologic structure, local active faulting and local soil conditions. The design criteria will be site-specific for each platform. The platform design will meet both strength and ductility requirements for earthquake loading.

The strength requirements will 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 will be 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 will 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 will be insured to guarantee that the structures perform as designed under earthquake loadings.

Exxon Production Research Company's preliminary 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 will provide for waves, currents, tides and winds which may occur during the expected life of the structure. Existing oceanographic data have been reviewed to develop preliminary 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 indicate that oceanographic conditions in the Santa Barbara Channel offer no problems that preclude the safe 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 will be 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 will be calibrated with existing data to insure its accuracy. Using this state-of-the-art technology, design wave heights will be 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 will account for storm wind generated currents during the same storms for which wave conditions were generated. Existing current measurements will be used to estimate expected values of background and tidal currents which will be combined with the simulated storm currents to develop the maximum expected currents for each of the platform sites.

Wind

Oceanweather, Inc. will develop accurate representations of sustained wind fields during severe historical storms based on all available atmospheric pressure and wind

velocity measurements. These winds will be 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) will be determined by extrapolating local wind speed statistics. These gusts will be used in designing deck facilities to withstand aerodynamic loads.

Marine Growth

An extensive study of marine growth on the Hondo A platform and a concurrent analysis of marine growth on nearshore Santa Barbara Channel platforms will provide the basis for the marine growth design criteria.

4.6 Platform Design

Design of the Hondo B, Pescado and Sacate platforms will be performed by Exxon and verified by a Certified Verification Agent pursuant to Pacific Region OCS Order No. 8. Exxon's design effort will consist primarily of stress analyses using established site-specific design criteria to evaluate structural responses to extreme oceanographic, installation, operational, fatigue, and earthquake loading conditions. A comprehensive detailing of design criteria, site conditions, design analyses, and structural designs for each of the platforms will be provided as part of the Verification

Documentation. A conceptual description of each of the proposed platforms follows.

4.6.1 Hondo B Platform

The Hondo B platform will be a conventional eight-leg jacket-type platform with a two-level deck and 60 well conductors. Fabricated and transported in two pieces, the jacket structure will be joined at the site and installed in approximately 1,200 feet of water.

Preliminary elevation views of the Hondo B platform jacket are shown in Figure 4.2. Preliminary plan views of the platform's decks are shown in Figure 4.3. The jacket structure is comprised of eight main legs framed with diagonal and horizontal bracing. The jacket will be designed and fabricated in two sections for ease of transport to the installation site. During the installation phase the jacket's two sections will be connected at the jacket legs. 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 Pescado Platforms

Two platform installation configurations are currently

being evaluated for development of the Pescado field. The first configuration calls for the installation of a single, 60-well platform, Pescado A, in approximately 1,075 feet of water. The second configuration requires two platforms, Pescado B-1 and Pescado B-2, with 28 and 60 wells, in water depths of approximately 1,025 feet and 1,140 feet, respectively. All three platforms may be fabricated and transported in two pieces and the jacket structure joined on site.

Preliminary elevation views of the proposed Pescado A, B-1, and B-2 platform jackets are presented in Figures 4.4, 4.6, and 4.8, respectively. Corresponding preliminary deck plan views are shown in Figures 4.5, 4.7, and 4.9. All three jackets will have a basic configuration similar to the Hondo B jacket - eight legs interconnected with diagonal and horizontal bracing, eight main piles and twenty skirt piles. The decks for the Pescado A and B-2, 60-well platforms are two-level and will support two drilling rigs and oil and gas production operations. Pescado B-1 is a 28-well platform and will have a three-level deck which will support a single drilling rig and oil and gas production operations.

4.6.3 Sacate Platform

The Sacate platform 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 platform jacket are shown in Figure 4.10 and preliminary deck plan views are shown in Figure 4.11. The jacket configuration will be similar to that of the other platforms - eight legs interconnected with diagonal and horizontal bracing, eight main piles and sixteen 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.

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.

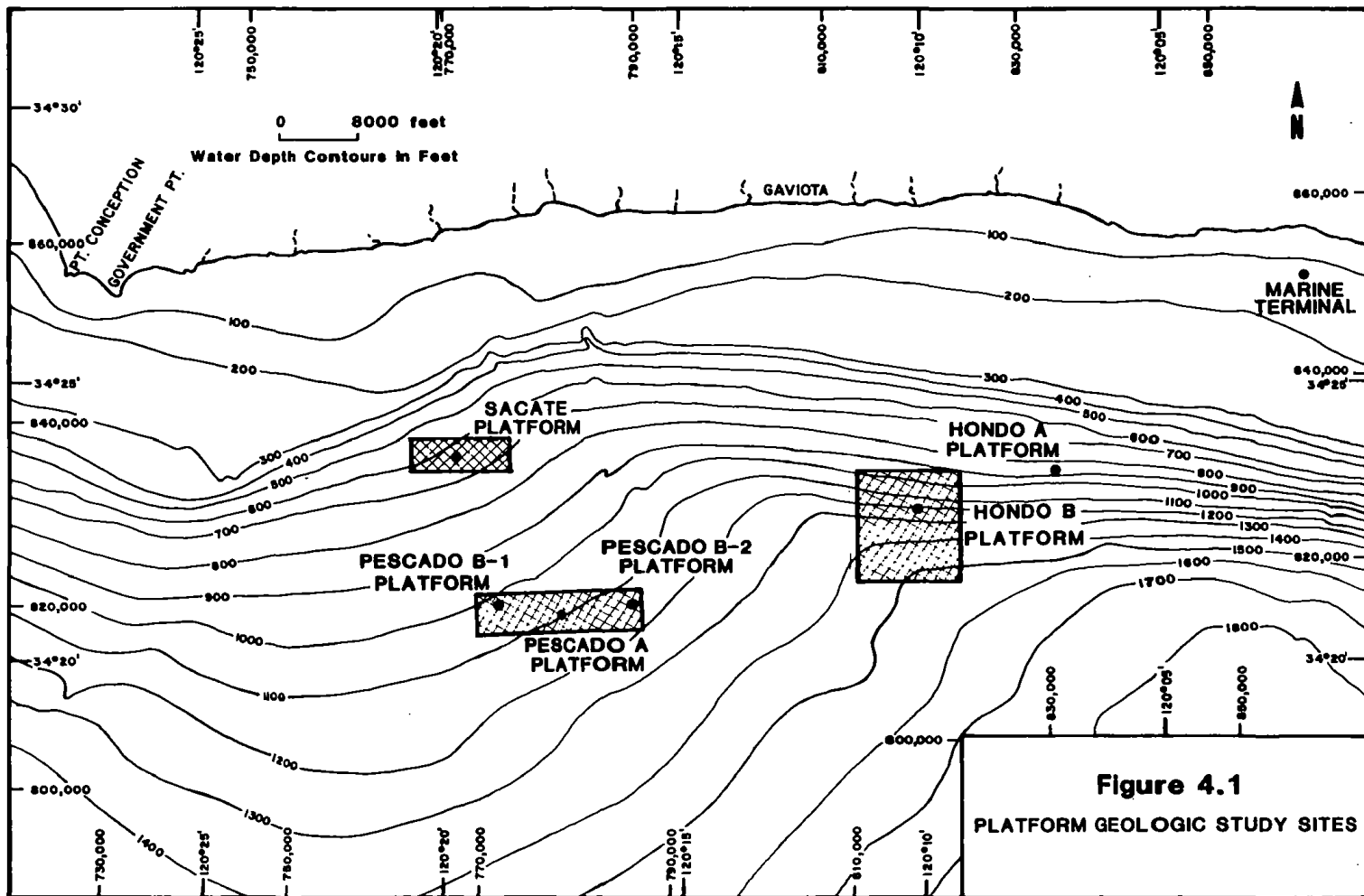
Jacket Joining (Two-Piece Jacket Only) - The larger jacket(s) will be built, transported, and launched in two pieces. After launch, both halves of the jacket will be positioned end-to-end while floating horizontally in the water. The two jacket sections, guided by stabbing cones attached to the outer legs, will be winched together and then joined.

Jacket Upending - Following launch (or final connection of the two-piece jacket halves) 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 Conductor 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 of a retrievable follower. 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 preinstalled. 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 and other miscellaneous components will then be attached to the deck structure.



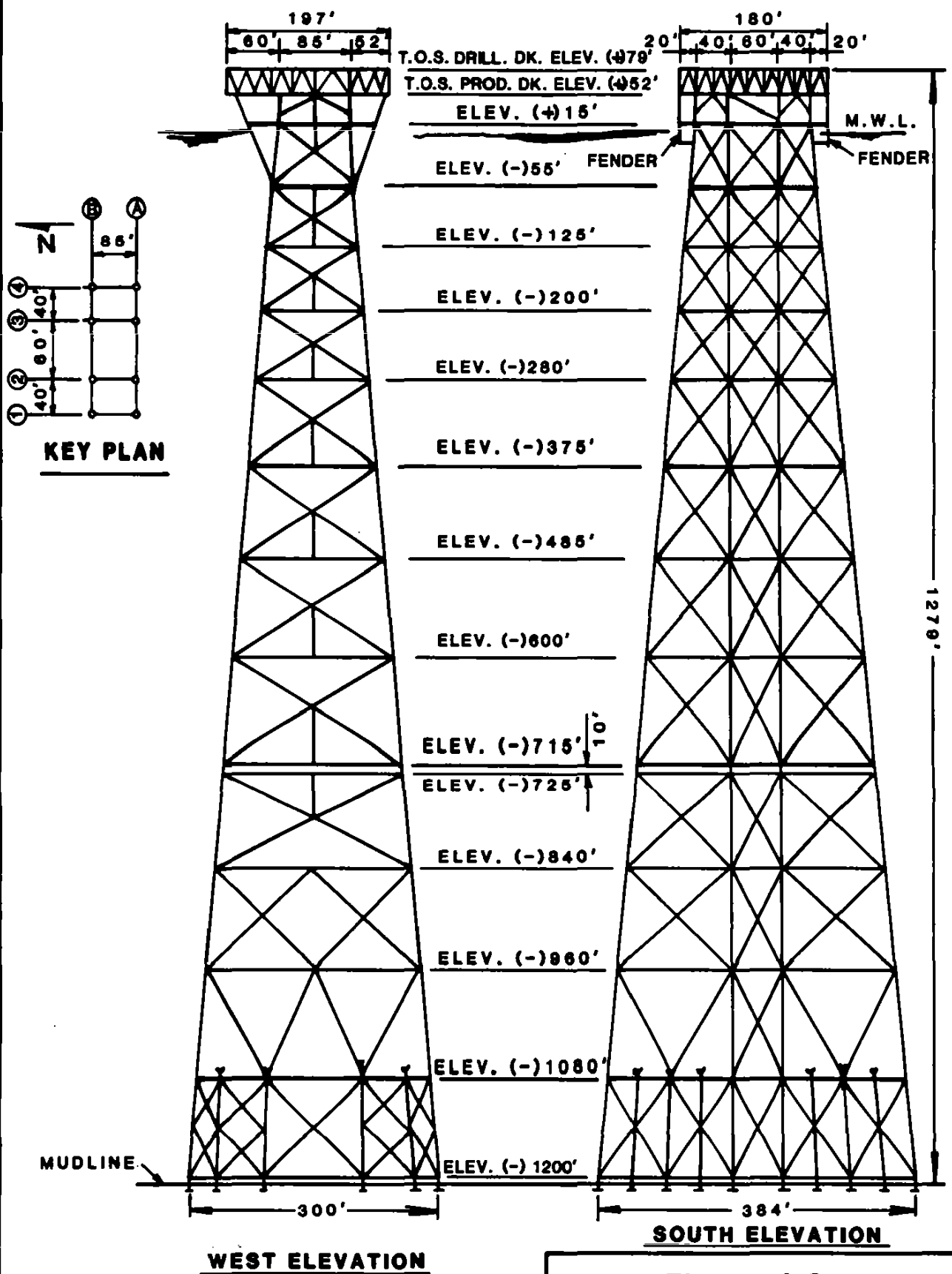


Figure 4.2

**HONDO B PLATFORM
ELEVATIONS**

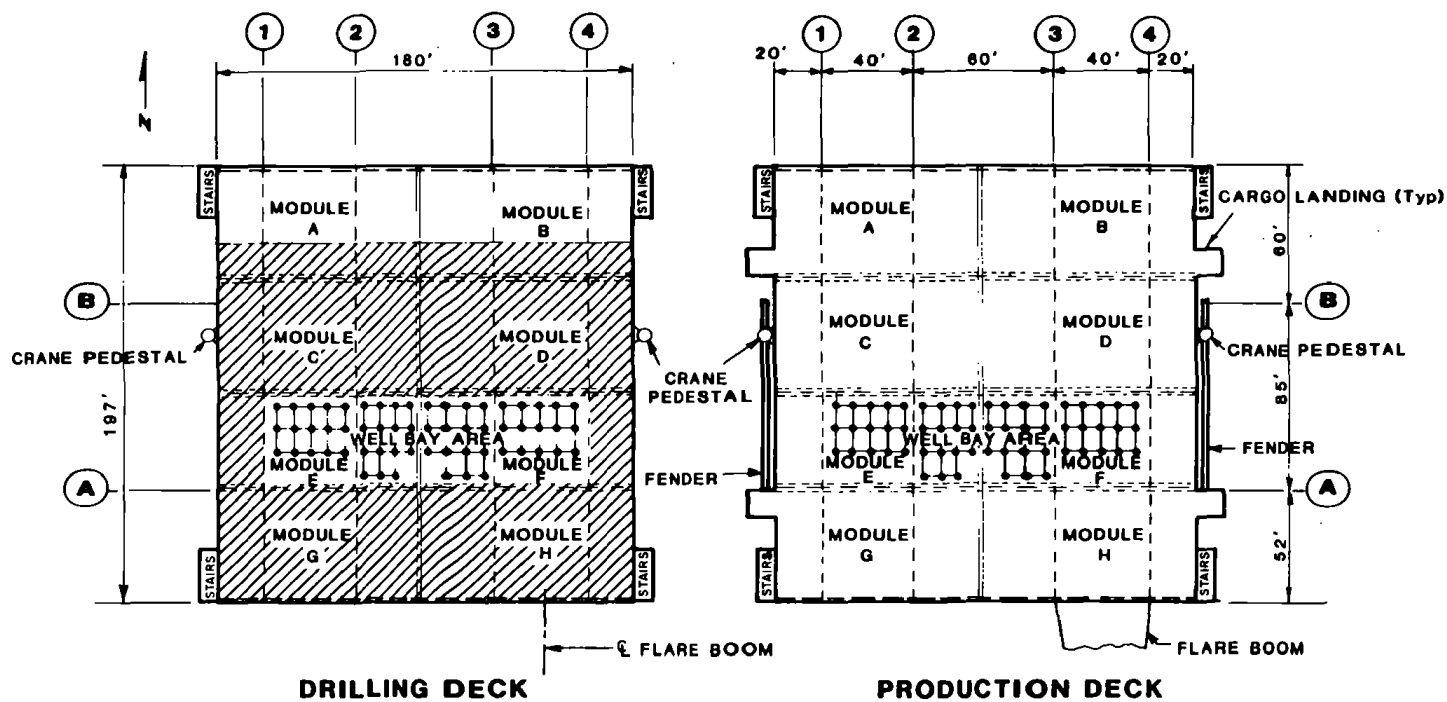


Figure 4.3

**HONDO B PLATFORM
DECK ARRANGEMENTS**

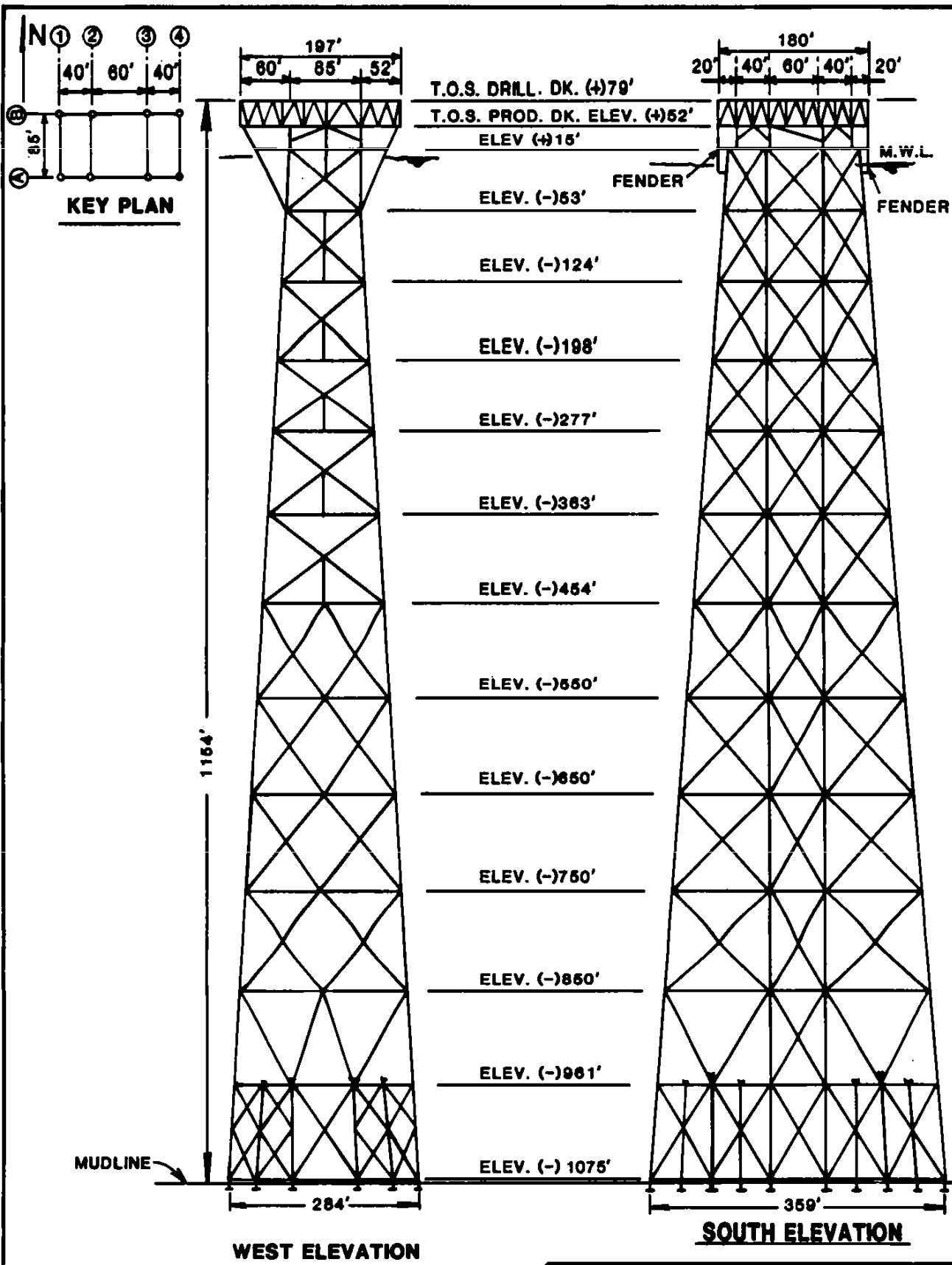


Figure 4.4

**PESCADO A PLATFORM
ELEVATIONS**

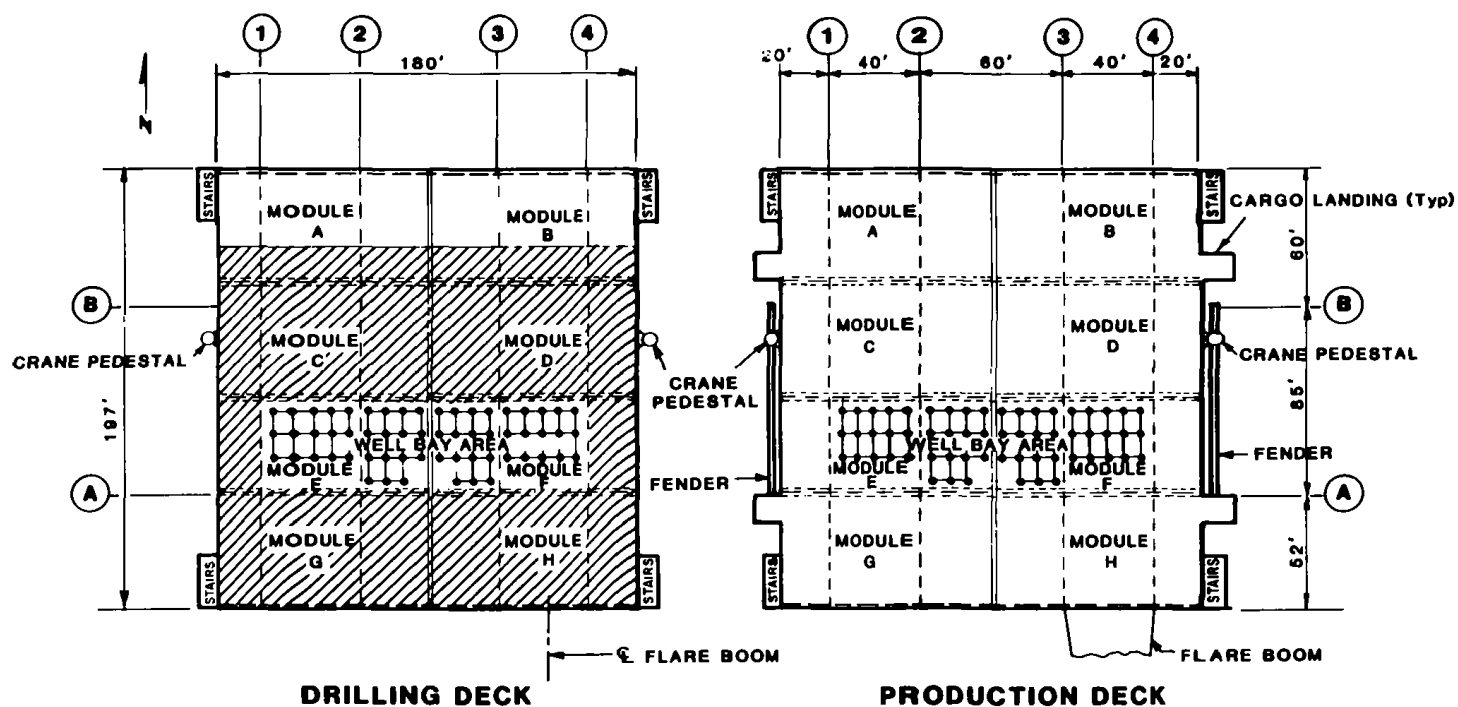
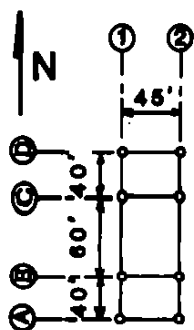
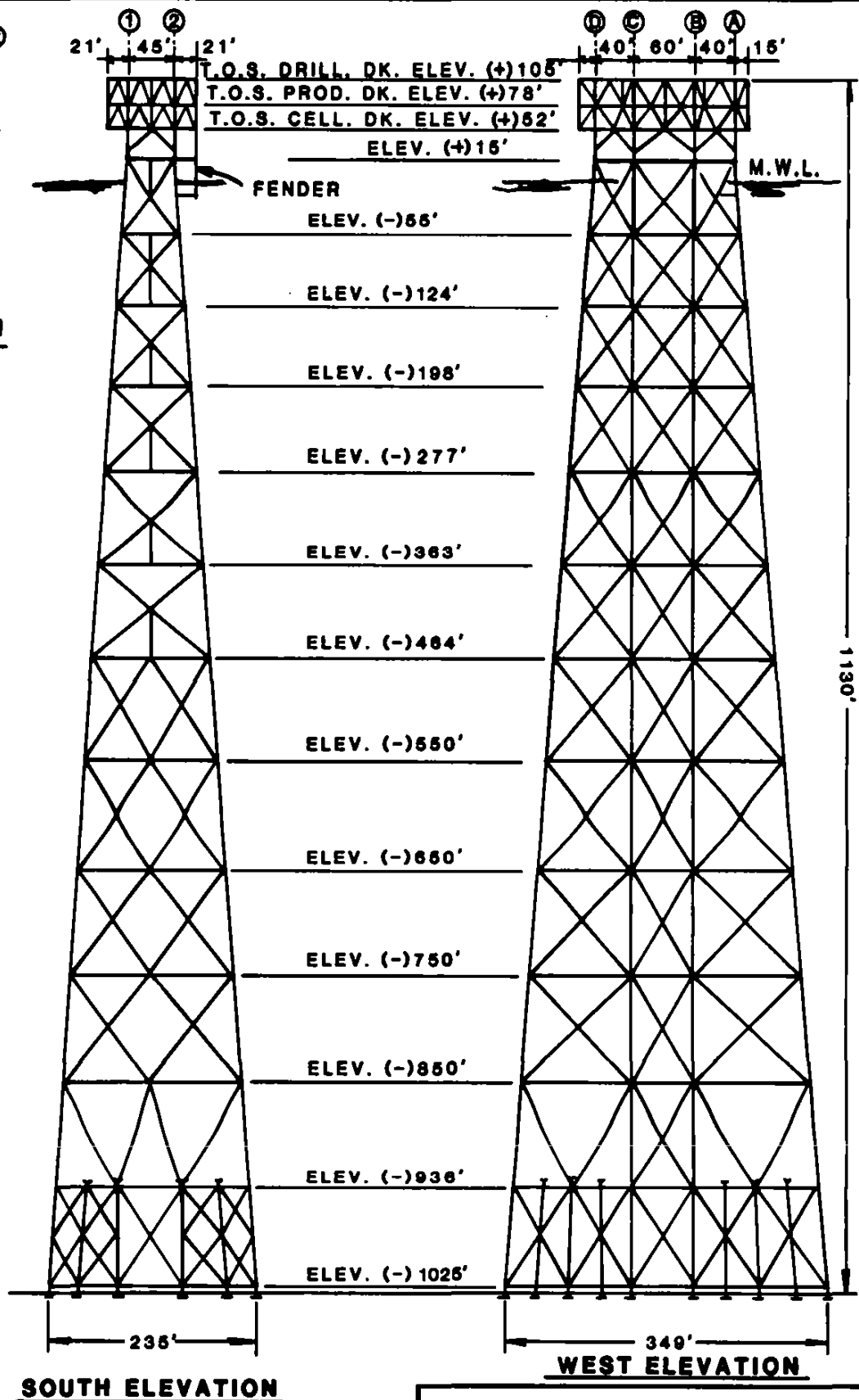


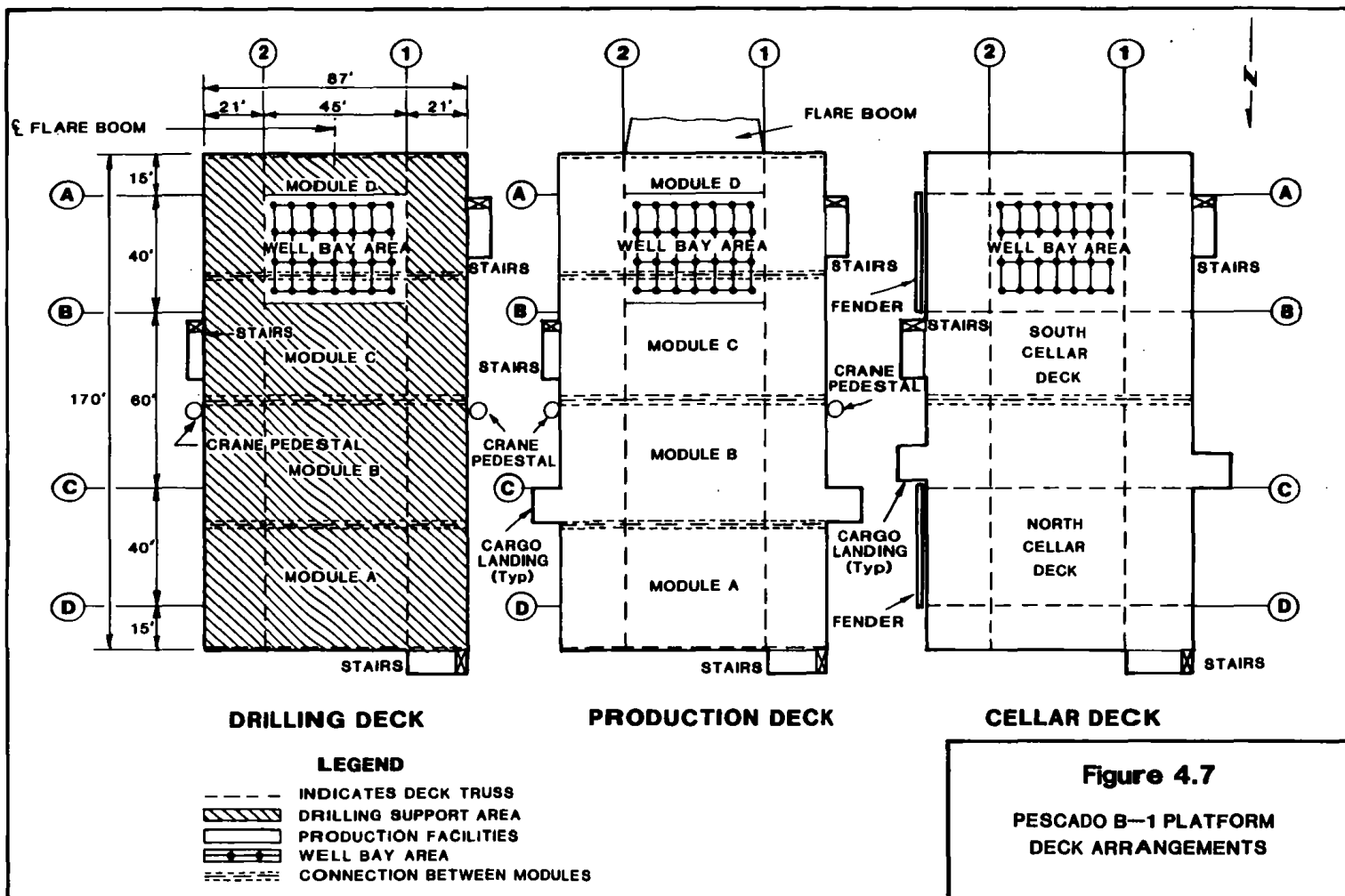
Figure 4.5

**PESCADO A PLATFORM
DECK ARRANGEMENTS**



KEY PLAN





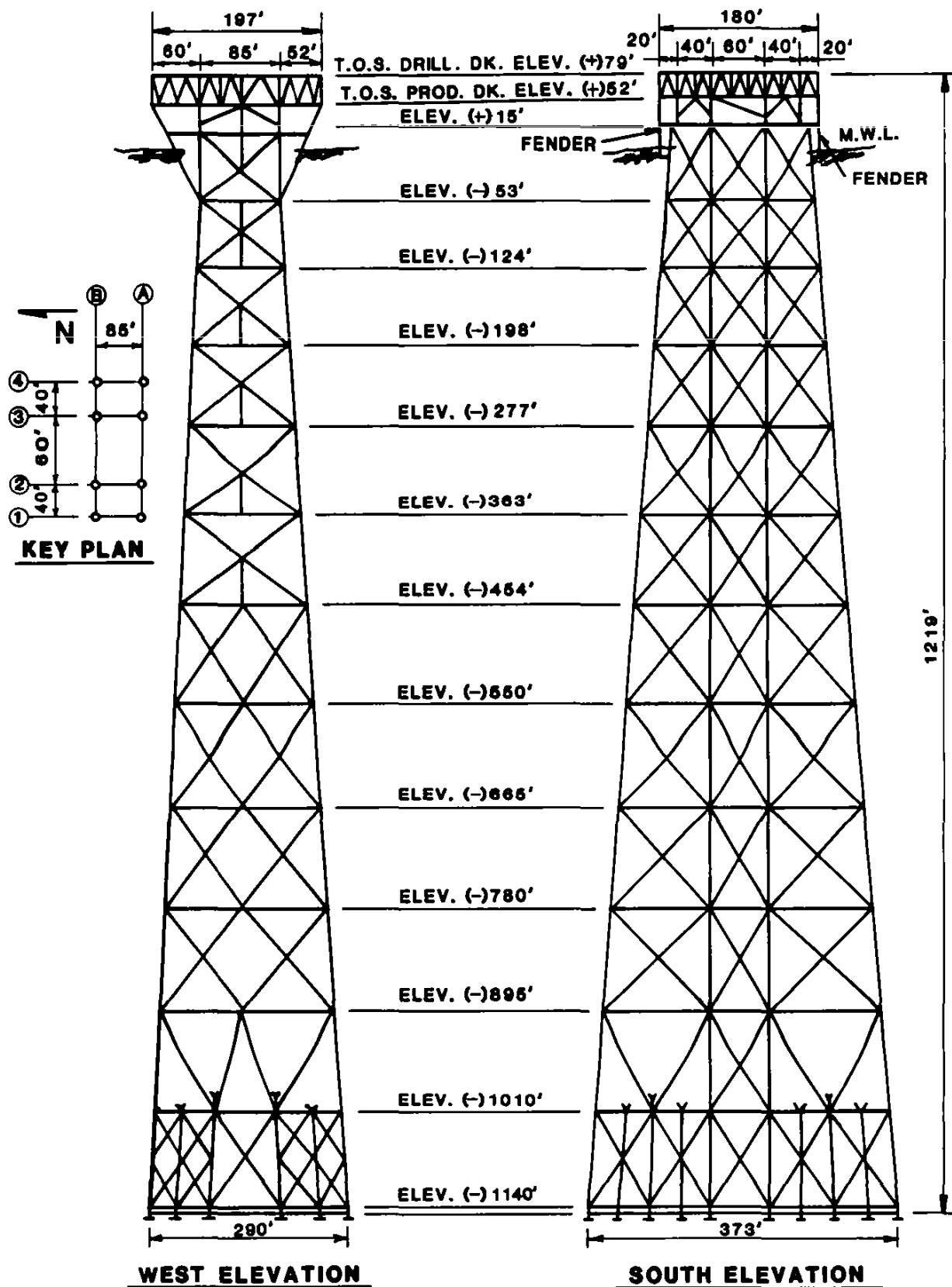


Figure 4.8
PESCADO B-2 PLATFORM
ELEVATIONS

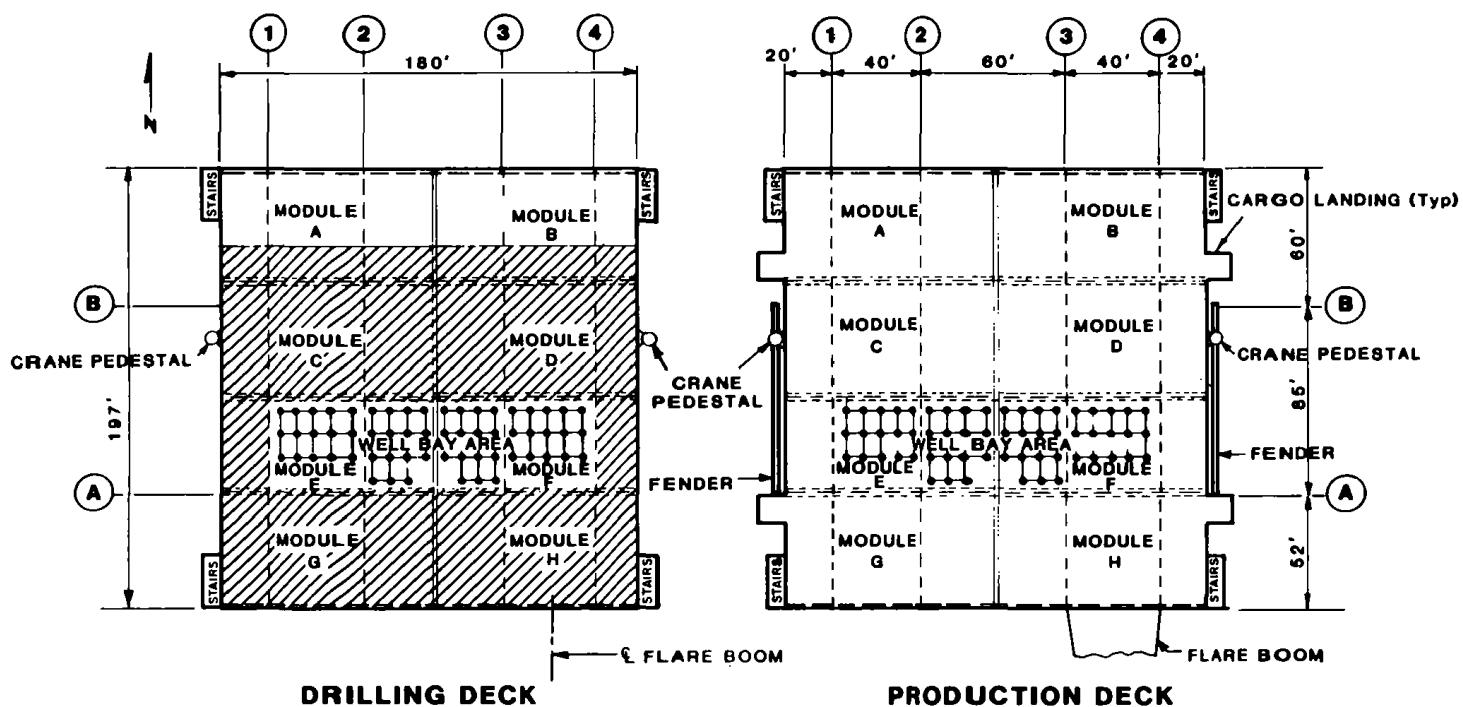
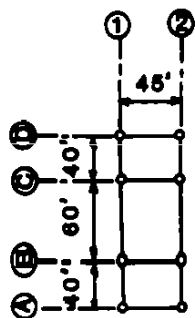


Figure 4.9
PESCADO B-2 PLATFORM
DECK ARRANGEMENTS



KEY PLAN

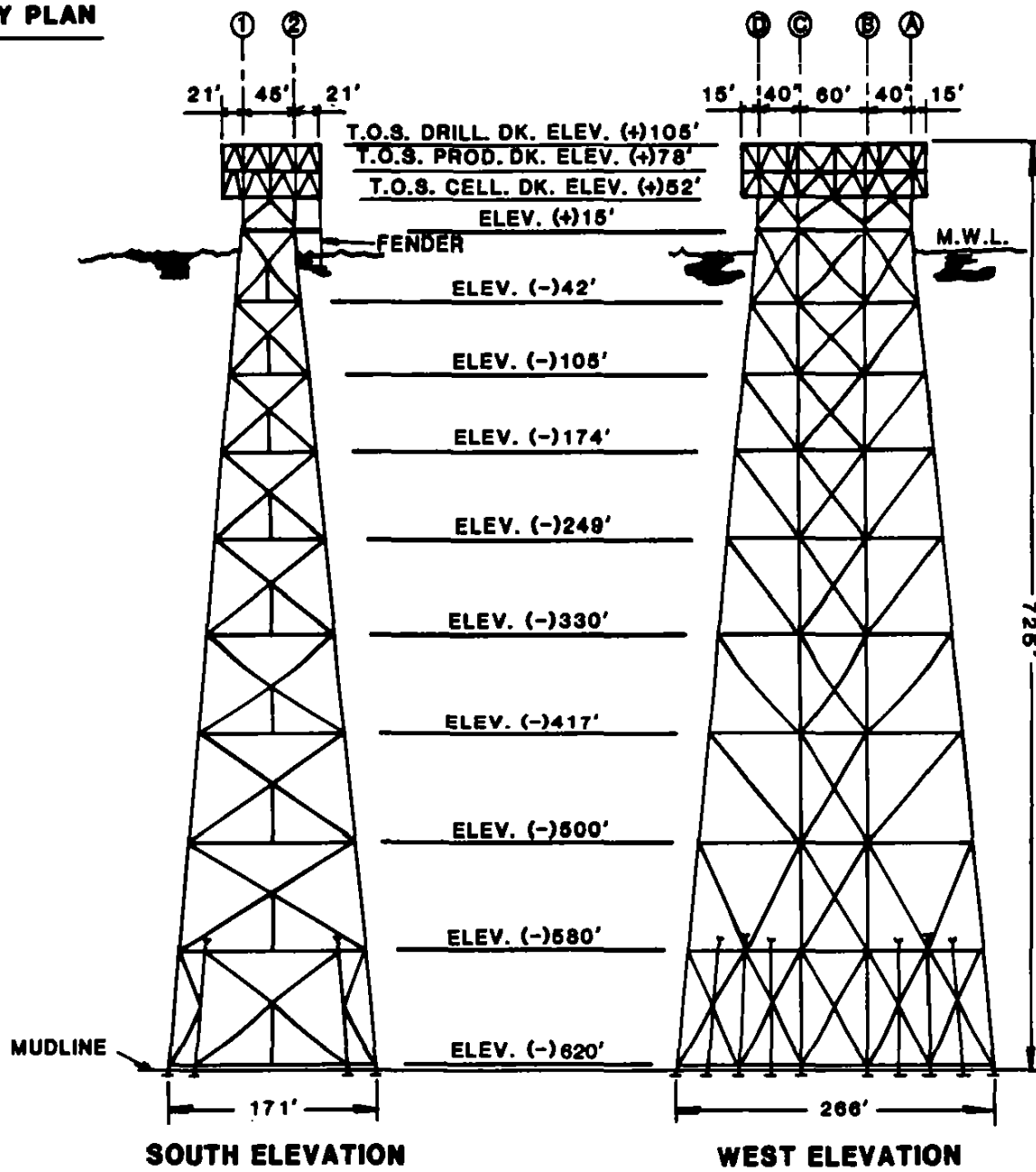
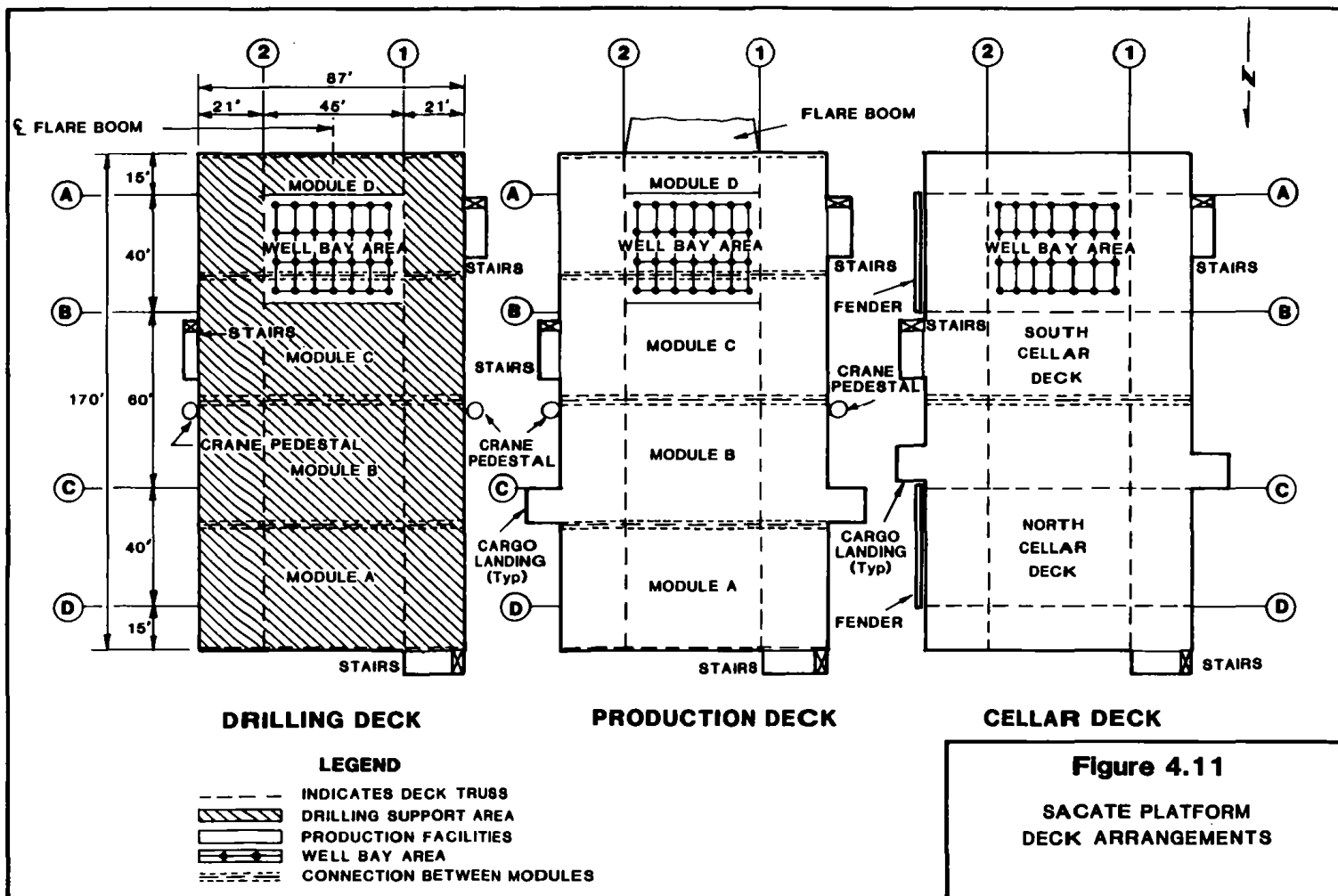


Figure 4.10

**SACATE PLATFORM
ELEVATIONS**



SECTION V
DRILLING PLANS AND FACILITIES

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SECTION V
DRILLING PLANS AND FACILITIES
TABLES

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- 5.8 Proposed Well Completion - Cemented and Perforated.
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- 5.10 Diverter System.
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SECTION V

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 Hondo, Pescado and Sacate field developments. 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

The Hondo B, Pescado A, Pescado B-1, Pescado B-2 and Sacate platforms will all be conventional steel jacket structures with 60, 60, 28, 60 and 28 well slots, respectively. The Hondo B, Pescado A and Pescado B-2 platforms will each use two silicon controlled rectifier electric drilling rigs. Each rig will be entirely independent of the other but may

have interconnection provisions for emergency purposes. The Pescado B-1 and Sacate platforms will be one drilling rig operations. 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: the Hondo B platform (Figs. 7.9 & 7.15); the Pescado A platform (Figs. 7.16 & 7.21); the Pescado B-2 platform (Figs. 7.22 & 7.27); the Pescado B-1 platform (Figs. 7.28 & 7.33); and the Sacate platform (Figs. 7.34 & 7.39). Preliminary well bay area layouts are shown in Figures 5.1 to 5.5. The drilling rigs will be especially designed and/or adapted for use on off-shore 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 750-horsepower direct current motors. The unit will include a sand line reel.

The rotary table will be independently driven by a 750-horsepower direct current motor. The hook, traveling

block and crown block 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 will be 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. A cuttings washer will be used to clean oil-contaminated cuttings and remove the oil before ocean disposal.

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 750-horsepower direct current motors. Each rig will have up to three 1,000 cubic foot bulk cement storage tanks.

5.3.5. Power Generation

In Development Option A (Offshore Oil Treating), each rig will generate its own electrical power using four + 1125 horsepower diesel engines each driving one + 930 kilowatt alternating current generator. In

Development Option B (Onshore Oil Treating), electrical power will be supplied from the onshore cogeneration power plant via a submarine cable system. The electrical power system described for Development Option A could be installed for standby purposes.

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" conductor, 20" or 18-5/8" surface, 13-3/8" intermediate and 9-5/8" production casing, as shown in Figure 5.6. On wells with a slotted casing completion, a 7" liner would be hung below the 9-5/8" casing, set at the top of the productive interval (Fig. 5.7). Depending upon individual well conditions, a 7" 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" 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 (Fig. 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 (Fig. 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 60 Hondo B wells will be completed in the Monterey Formation using tubing inside of either perforated or slotted production casing.

Three types of Pescado A wells are tentatively planned: 54 Monterey Formation producers, 5 Lower Gaviota-Upper Gaviota Formation dual producers, and one Matilija Formation producer. In addition, the Vaqueros/Alegría

Formation will be produced in the future by recompleting depleted Lower Gaviota-Upper Gaviota and/or Matilija wells. The Lower Gaviota-Upper Gaviota dual completion wells and the Matilija 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.

One type of Pescado B-1 well is tentatively planned: 28 Monterey Formation producers. The Monterey wells would be produced using tubing inside of either perforated or slotted production casing.

Three types of Pescado B-2 wells are tentatively planned: 54 Monterey Formation producers, 5 Lower Gaviota-Upper Gaviota Formation dual producers, and one Matilija Formation producer. In addition, the Vaqueros/Alegria Formation will be produced in the future by recompleting depleted Lower Gaviota-Upper Gaviota and/or Matilija wells. The Lower Gaviota-Upper Gaviota dual completion wells and the Matilija 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 Sacate wells are tentatively planned: 14 Monterey Formation producers, 11 Vaqueros/Alegria

Formation producers, one Lower Gaviota-Middle Gaviota Formation dual producer, and two Matilija-Vaqueros/Alegria Formations dual producers. The Monterey wells would be produced using tubing inside of either perforated or slotted production casing. The remaining Sacate 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" conductor casing, an annular blowout preventer and diverter system would be installed (Fig. 5.10).

Before drilling below the 20" or 18-5/8" surface casing, the blowout prevention system would include four remotely controlled, hydraulically operated blowout preventers (Fig. 5.11). Two would be equipped with

pipe rams, one with blind rams, and one would be an annular type. The blowout prevention system would have a rated working pressure of 5,000 psig (34,475 kPa). This pressure exceeds the maximum anticipated surface pressure.

The blowout prevention system would 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.

Controls 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 Order 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" hole to 1,000 feet below the mud line (BML) through the 26" driven conductor. Underream to 26".
3. Run and cement 20" or 18-5/8" casing at 1,000' BML. Install and test BOP stack.
4. 17-1/2" hole to 3,500' BML. Run logs as needed.
5. Run and cement 13-3/8" casing at 3,500' BML.

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

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

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

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

6. Directionally drill 12-1/4" hole to the proper depth for setting 9-5/8" casing (see Table 5.1).
Run logs.
7. Run and cement 9-5/8" casing.
8. Run correlation log.
9. Perforate the Lower and Upper Gaviota intervals.
10. Install completion equipment on dual 2-7/8" tubing.
11. Remove BOP stack and install Christmas tree.

NOTE: After the Lower and Upper Gaviota Formation is depleted, this formation would be plugged back, and the well could be recompleted in the Vaqueros/Alegria Formation.

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

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

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

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

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

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

8. Run correlation log.
- 9 Perforate the Vaqueros/Alegria interval.
10. Install completion equipment on 2-7/8" tubing.
11. Remove BOP stack and install Christmas tree.

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

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

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

1. Move and rig up. Install diverter.

2. 17-1/2" hole to 1,000' BML through the 26" driven conductor. Underream to 26".
3. Run and cement 20" or 18-5/8" casing at 1,000' BML. Install and test BOP stack.
4. 17-1/2" hole to 3,500' BML. Run logs as needed.
5. Run and cement 13-3/8" casing at 3,500' BML.
6. Directionally drill 12-1/4" hole to the proper depth for setting 9-5/8" casing (see Table 5.1). Run logs.
7. Run and cement 9-5/8" casing.
8. Directionally drill 8-1/2" hole to the proper depth for setting 7" liner (See Table 5.1). Log.
9. Run and cement 7" liner.
10. Run correlation log.
11. Perforate the Matilija-Vaqueros/Alegria intervals.
12. Install completion equipment on dual 2-7/8" tubing.
13. Remove BOP stack and install Christmas tree.

5.4.6. Pollution Prevention

No oil or contaminated drill cuttings, sand or other solids will be discharged into the ocean.

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.

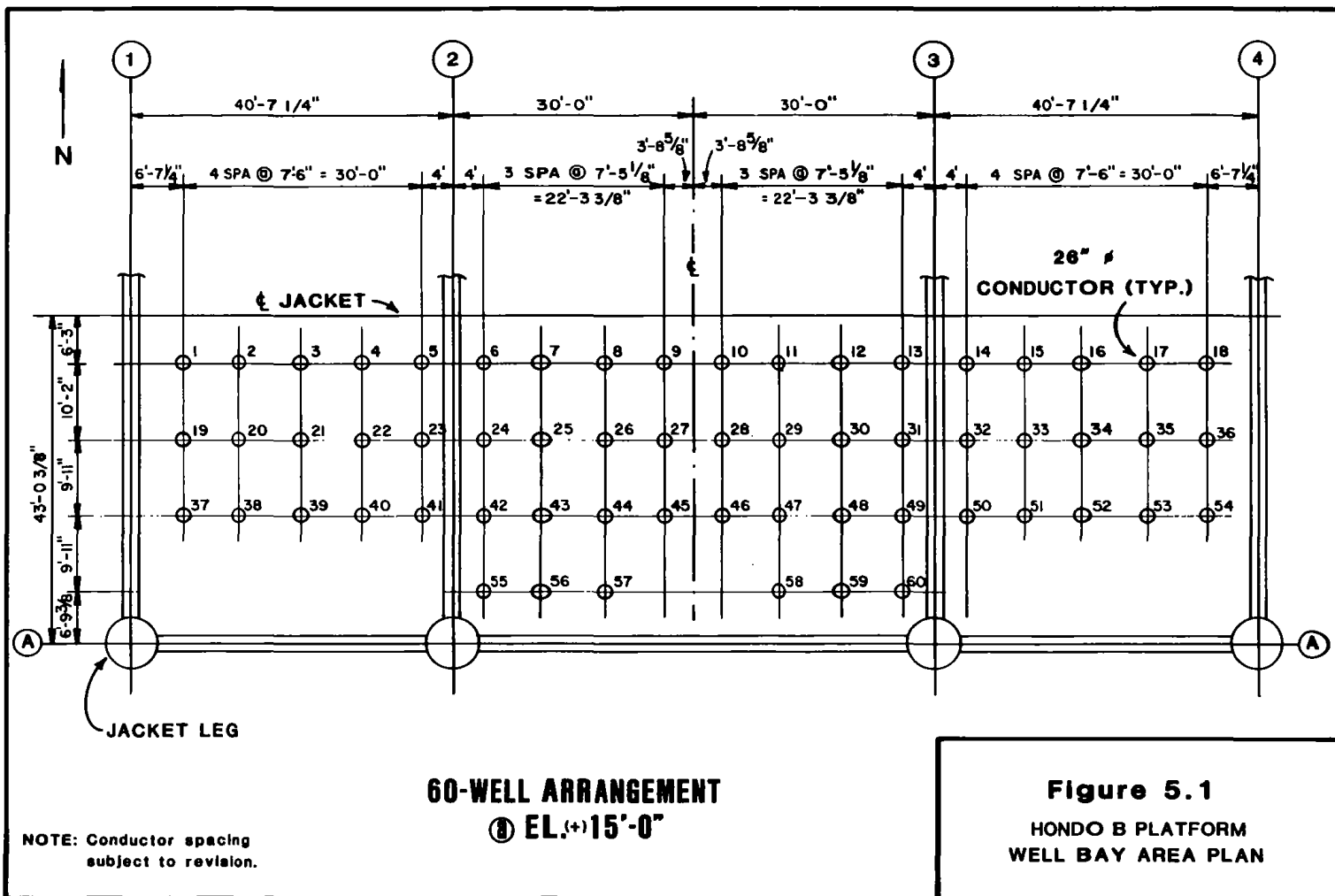
Trash and garbage will be transported to shore for disposal. Containers will be constructed to prevent accidental loss onboard or enroute to the disposal site.

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

TABLE 5.1

PROPOSED TYPICAL WELL PROGRAMS

<u>Platform</u>	<u>Completion Type</u>	<u>Number Of Wells</u>	<u>Producing Formation</u>	<u>9-5/8" Casing Set (feet below mud line)</u>	<u>7" Liner Set (feet below mud line)</u>	<u>Reference Figure</u>
Hondo B	Single	60	Monterey	8,500	-	5.6
Pescado A	Single	54	Monterey	7,200	-	5.6
Pescado A	Dual	5	Lower Gaviota- Upper Gaviota	8,850	-	5.6
Pescado A	Single	1	Matilija Gas	10,600	10,300-11,000	5.7
Pescado B-1	Single	28	Monterey	7,300	-	5.6
Pescado B-2	Single	54	Monterey	7,100	-	5.6
Pescado B-2	Dual	5	Lower Gaviota- Upper Gaviota	8,700	-	5.6
Pescado B-2	Single	1	Matilija Gas	10,600	10,300-10,900	5.7
Sacate	Single	14	Monterey	6,100	-	5.6
Sacate	Single	11	Vaqueros/Alegria	8,800	-	5.6
Sacate	Dual	1	Lower Gaviota- Middle Gaviota Gas	9,600	-	5.6
Sacate	Dual	2	Matilija- Vaqueros/ Alegria Gas	11,000	10,700-11,500	5.7



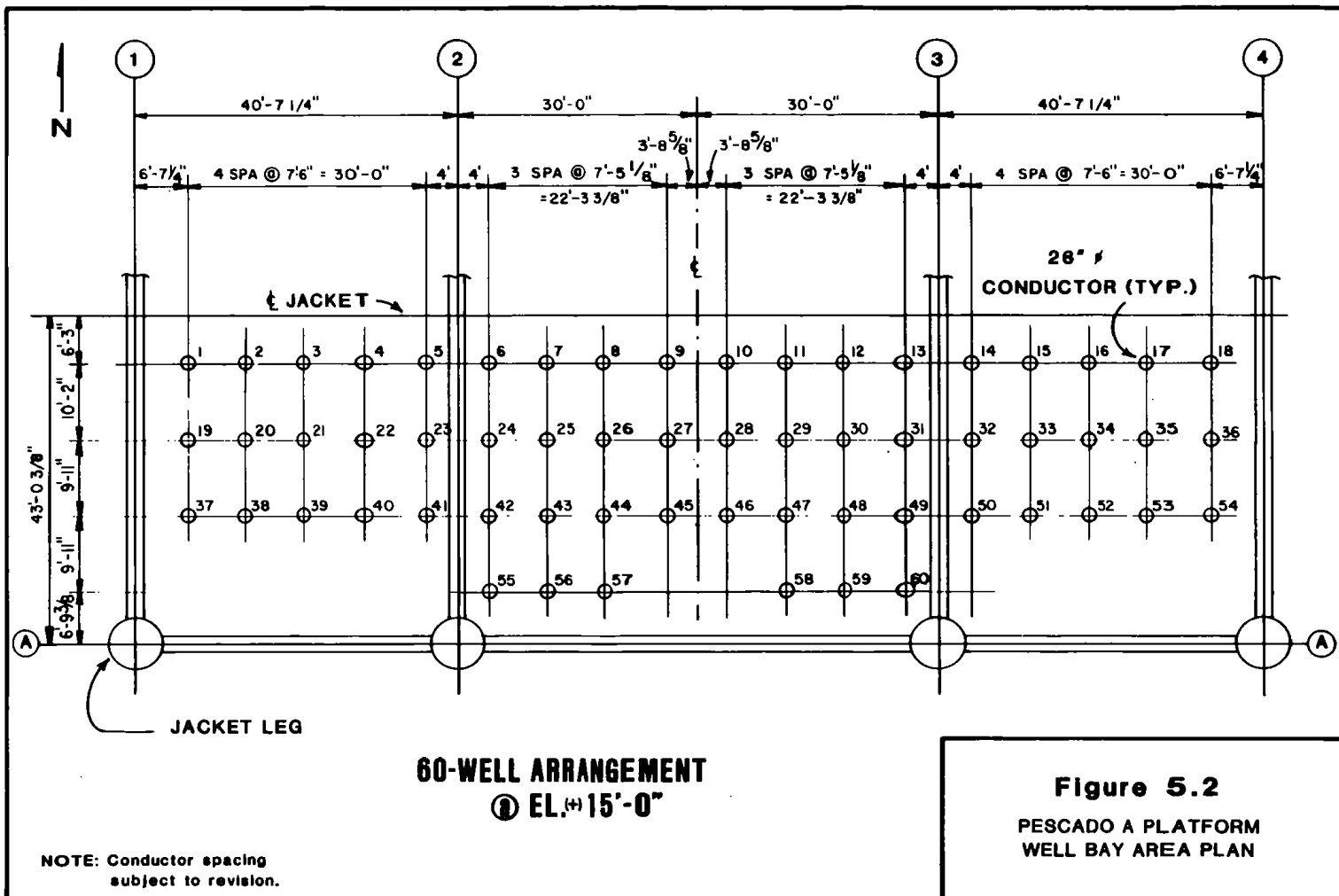
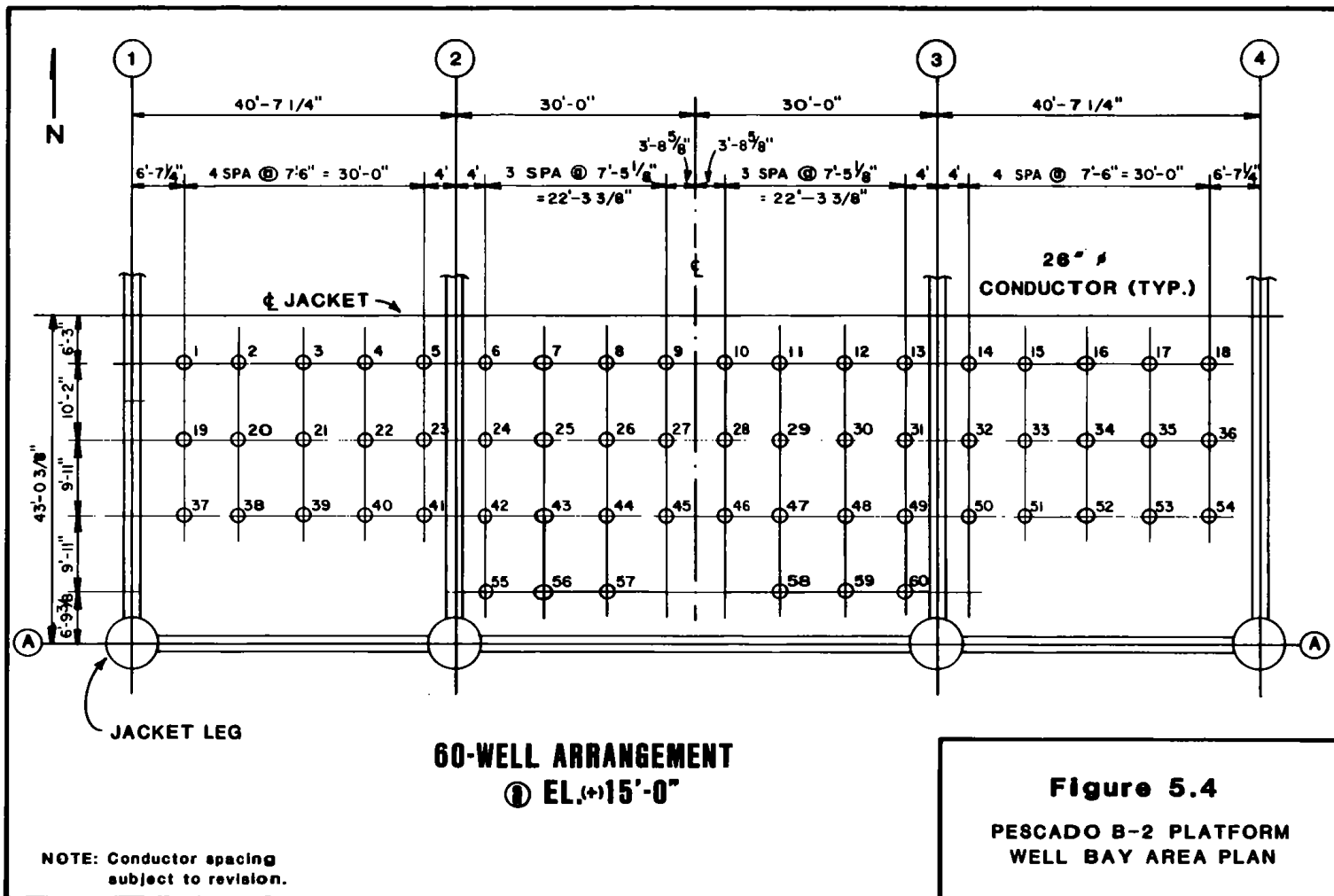
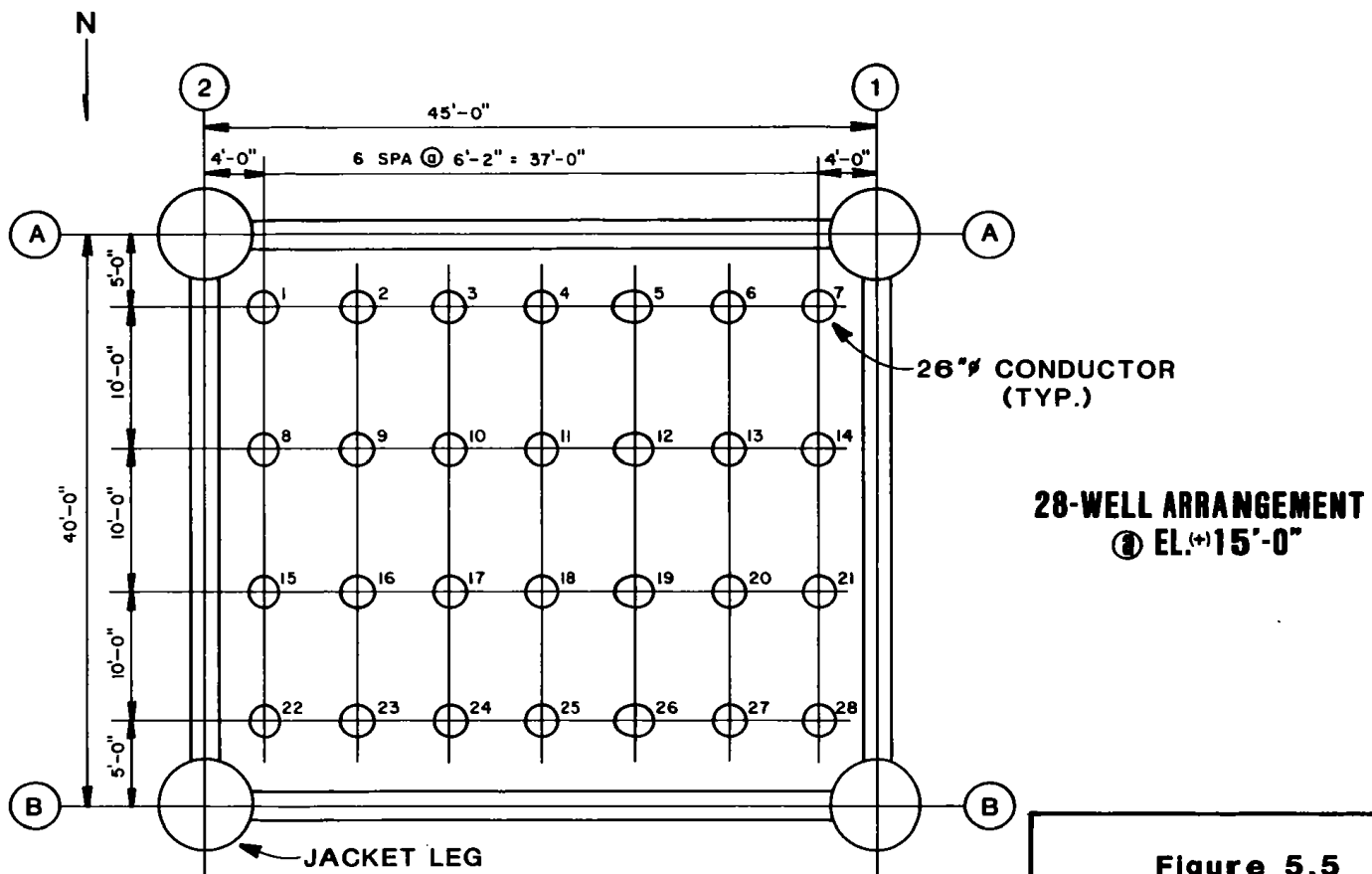




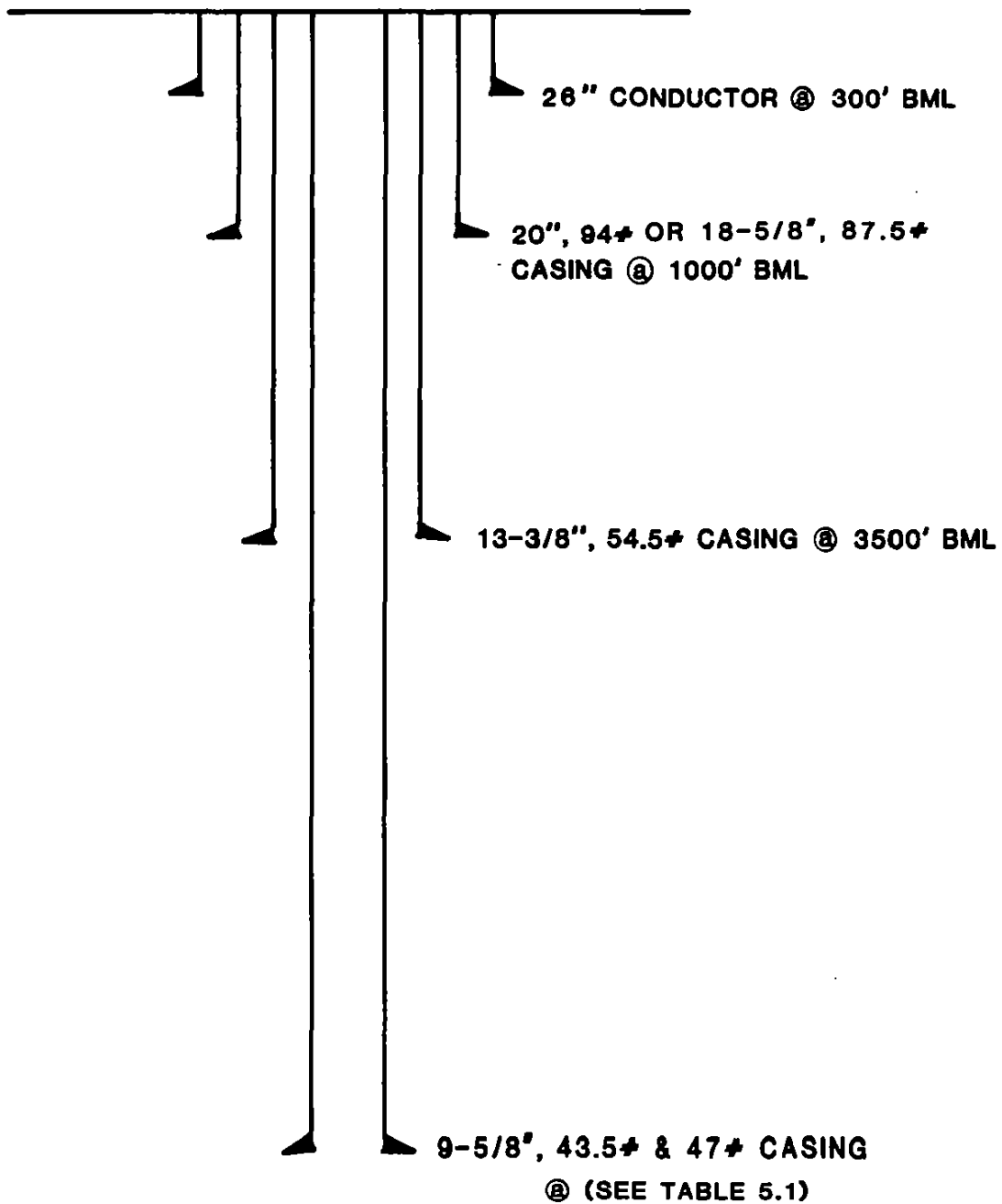
Figure 5.3
PESCADO B-1 PLATFORM
WELL BAY AREA PLAN





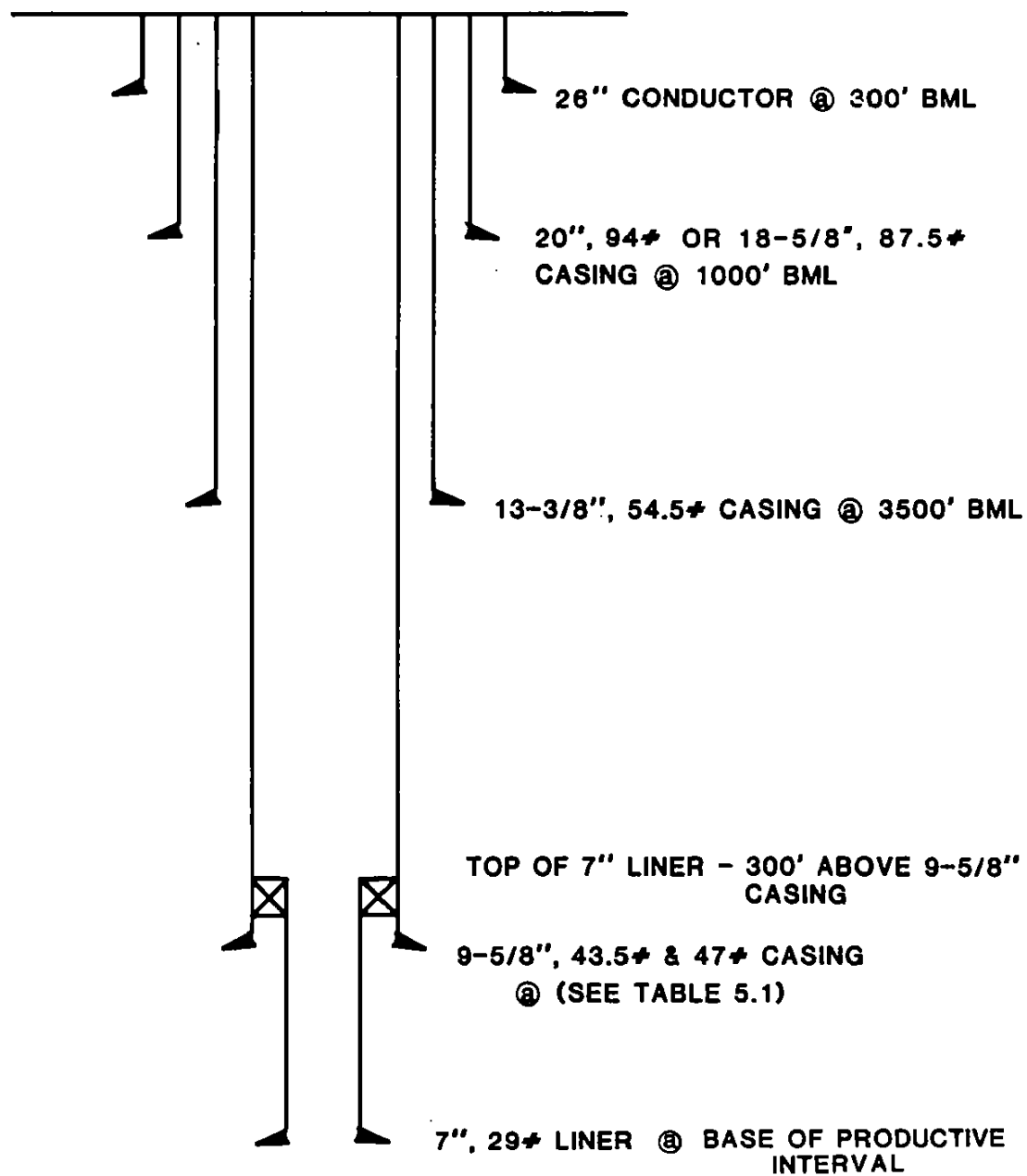
NOTE: Conductor spacing
 subject to revision.

Figure 5.5
 SACATE PLATFORM
 WELL BAY AREA PLAN



NOTE: BML - BELOW MUD LINE

Figure 5.6
PROPOSED CASING PROGRAM
TYPICAL WELL SKETCH
WITHOUT LINER



NOTE: BML - BELOW MUD LINE

Figure 5.7
PROPOSED CASING PROGRAM
TYPICAL WELL SKETCH
WITH LINER

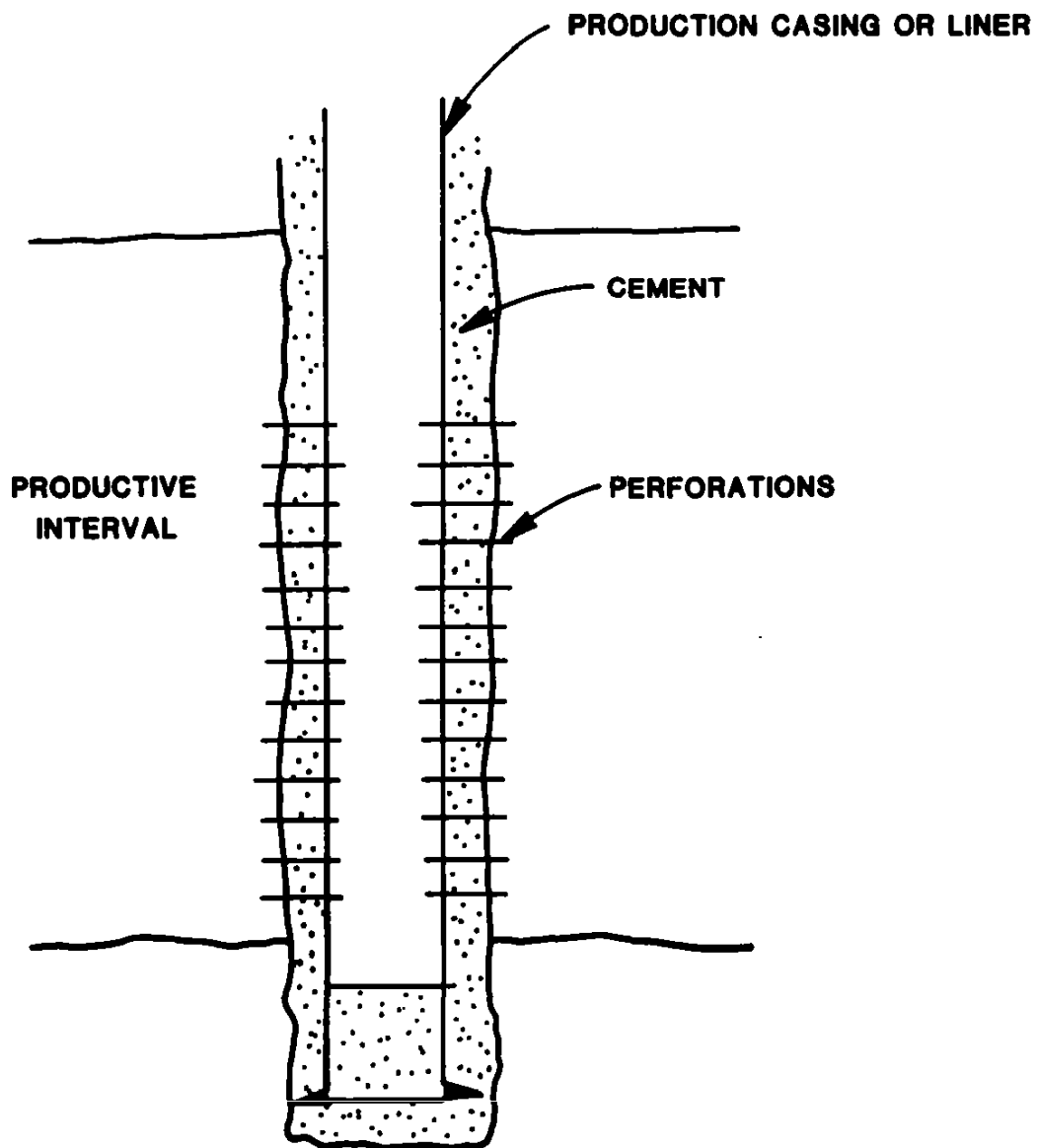


Figure 5.8

**PROPOSED WELL COMPLETION
CEMENTED & PERFORATED**

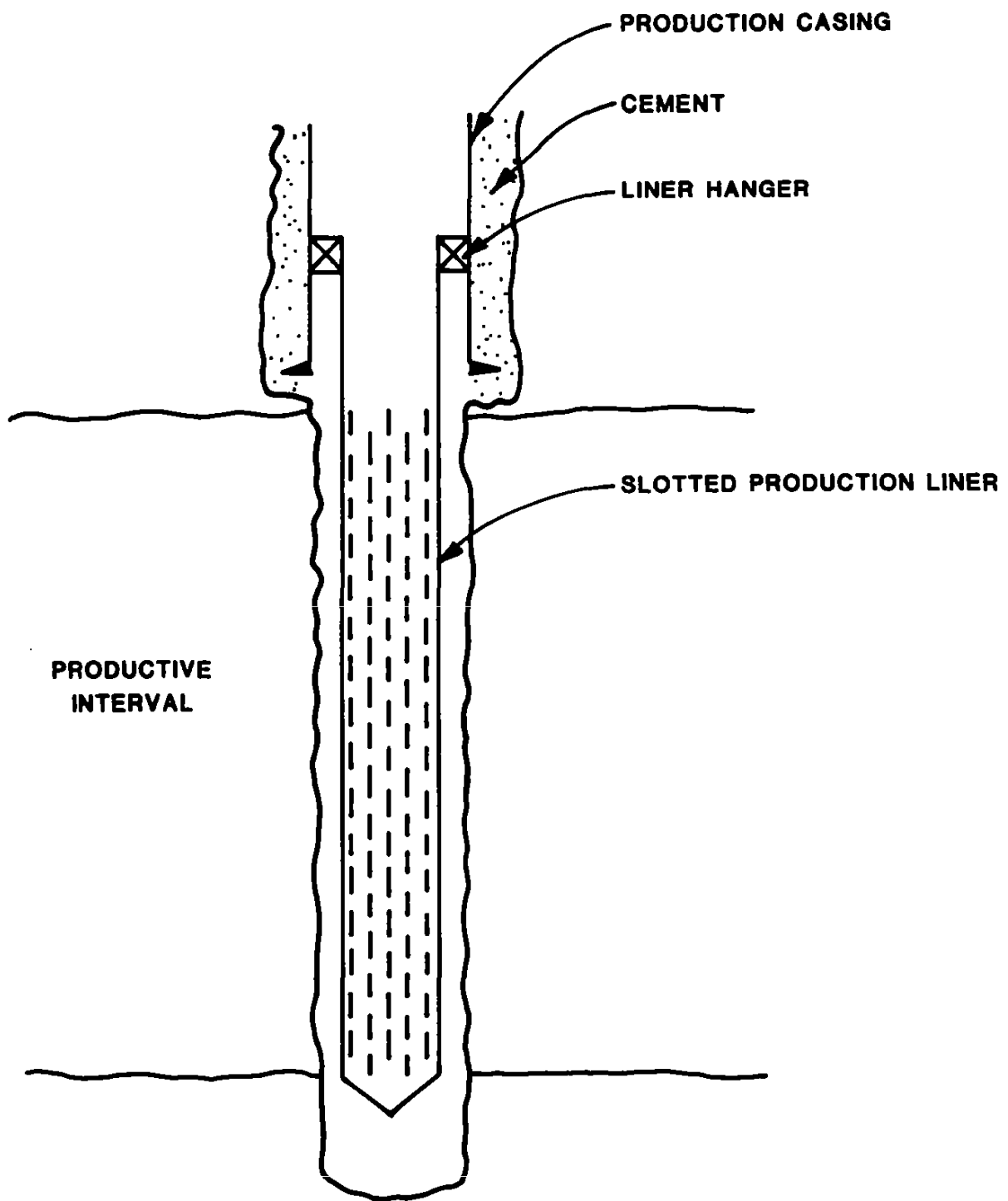
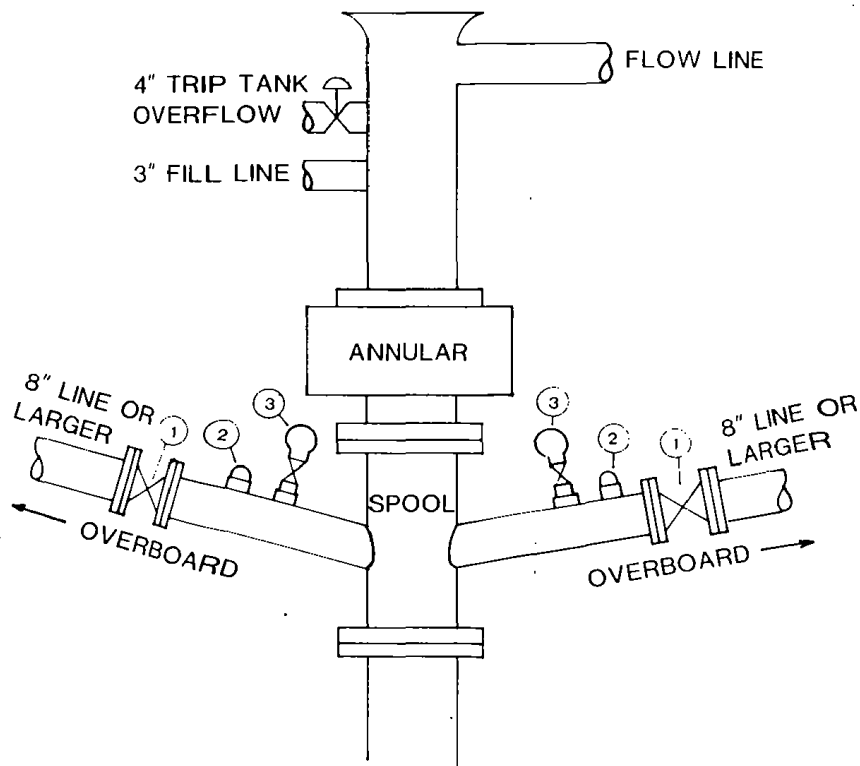


Figure 5.9

**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

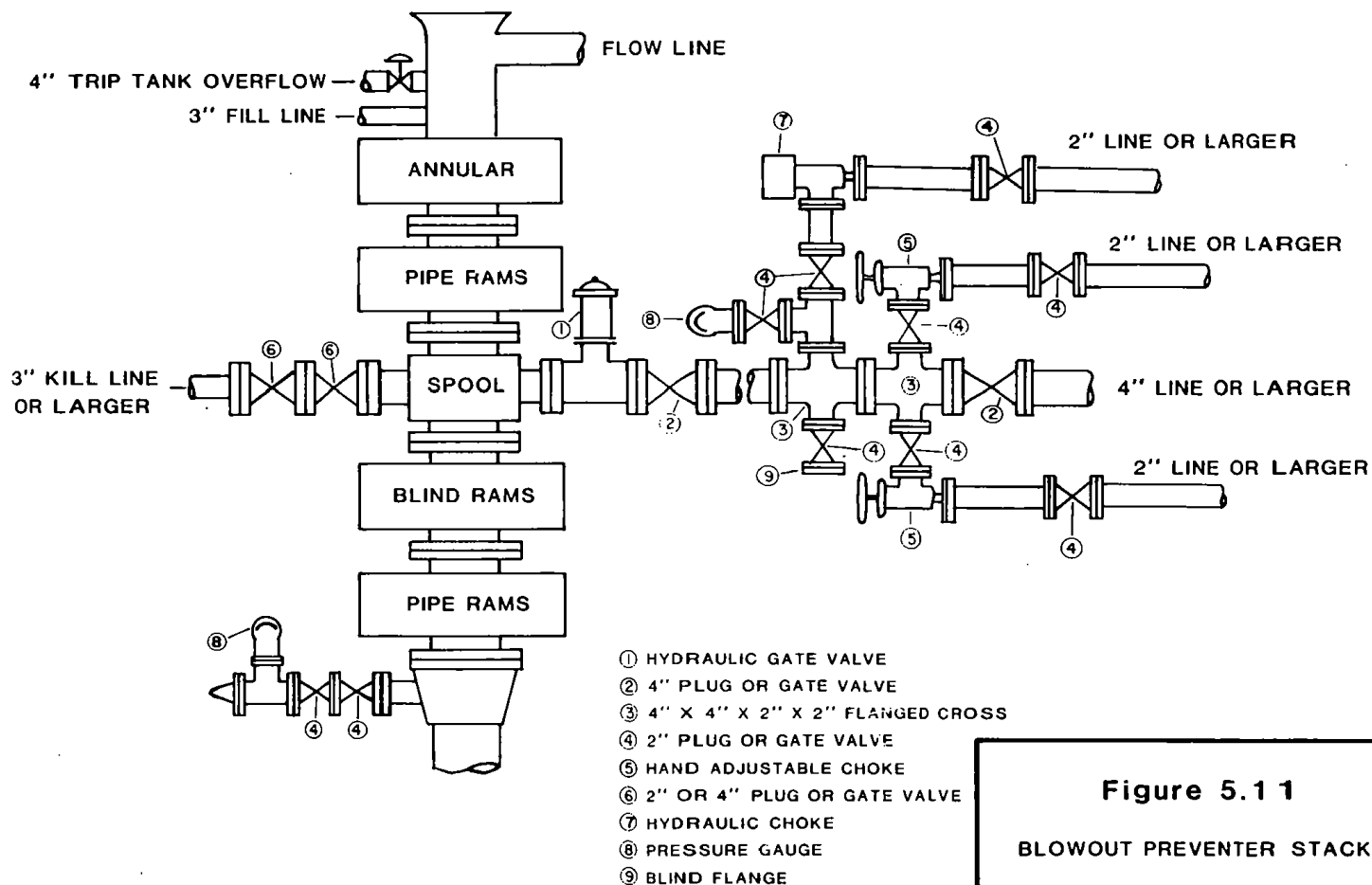


Figure 5.1 1

BLOWOUT PREVENTER STACK

SECTION VI
SUBSEA PRODUCTION SYSTEMS

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SECTION VI
SUBSEA PRODUCTION SYSTEMS

FIGURES

- 6.1 Subsea Production Configurations.
- 6.2 Single Satellite Well System.

SECTION VI

6.1 Introduction

This section discusses the potential application of subsea production systems to offshore reservoir development in the Santa Ynez Unit. Subsea satellite wells described here are state-of-the-art technology.

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 Hondo, Pescado and Sacate fields. The location and number of possible subsea completions will be determined by requirements for effective field development.

6.2 Santa Ynez Unit Applications

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. Each of these concepts would require hydrocarbon treating facilities on a conventional platform or floating vessel for support.

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 20-30 well 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 that might be either a platform or a floating 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

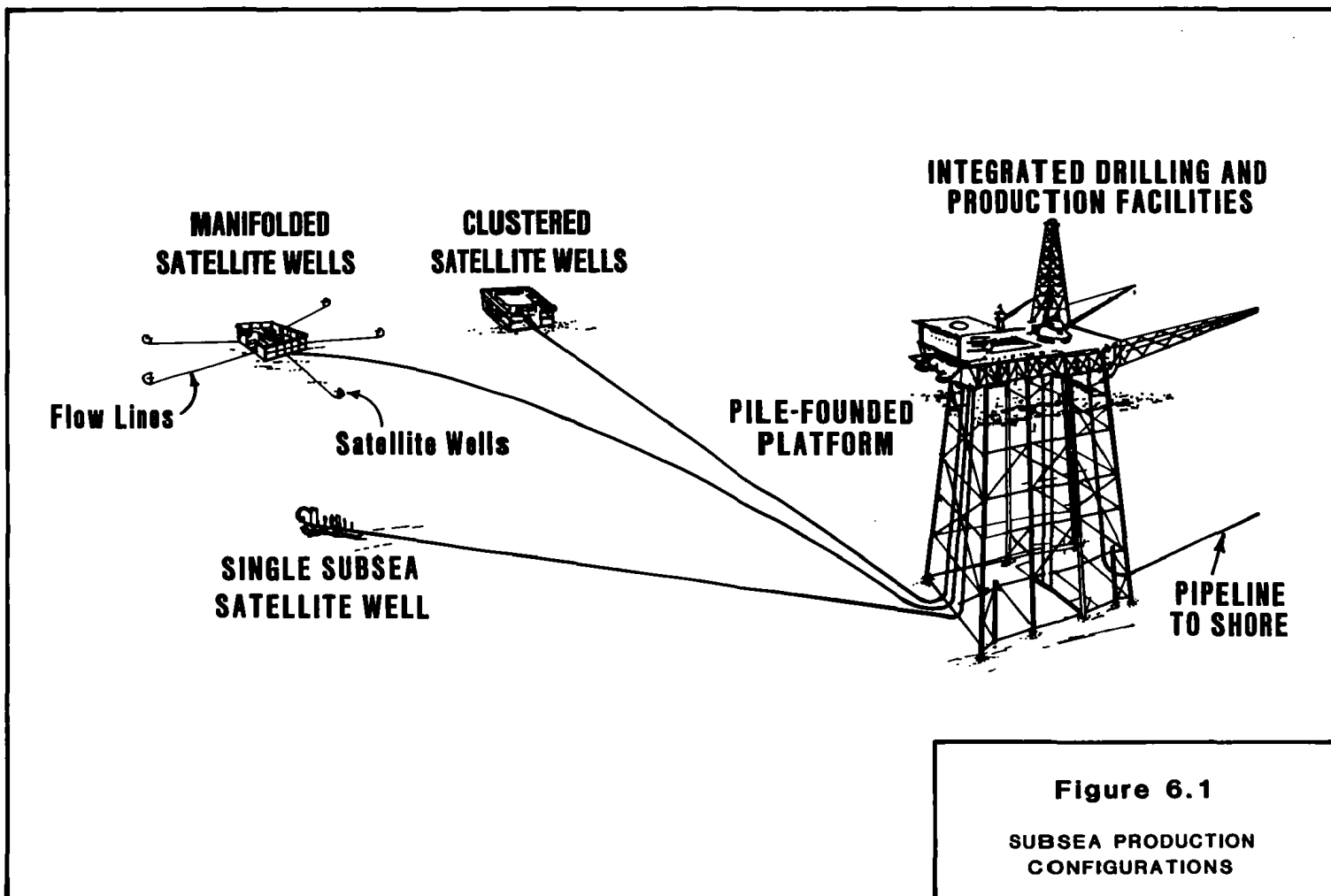
support frame to provide both the mechanical strength and the foundation for all of the underwater piping and valving and the pre-designated well slots.

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 a gathering header and then produced to the production platform through a common flowline bundle.

6.5 Manifolded 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.



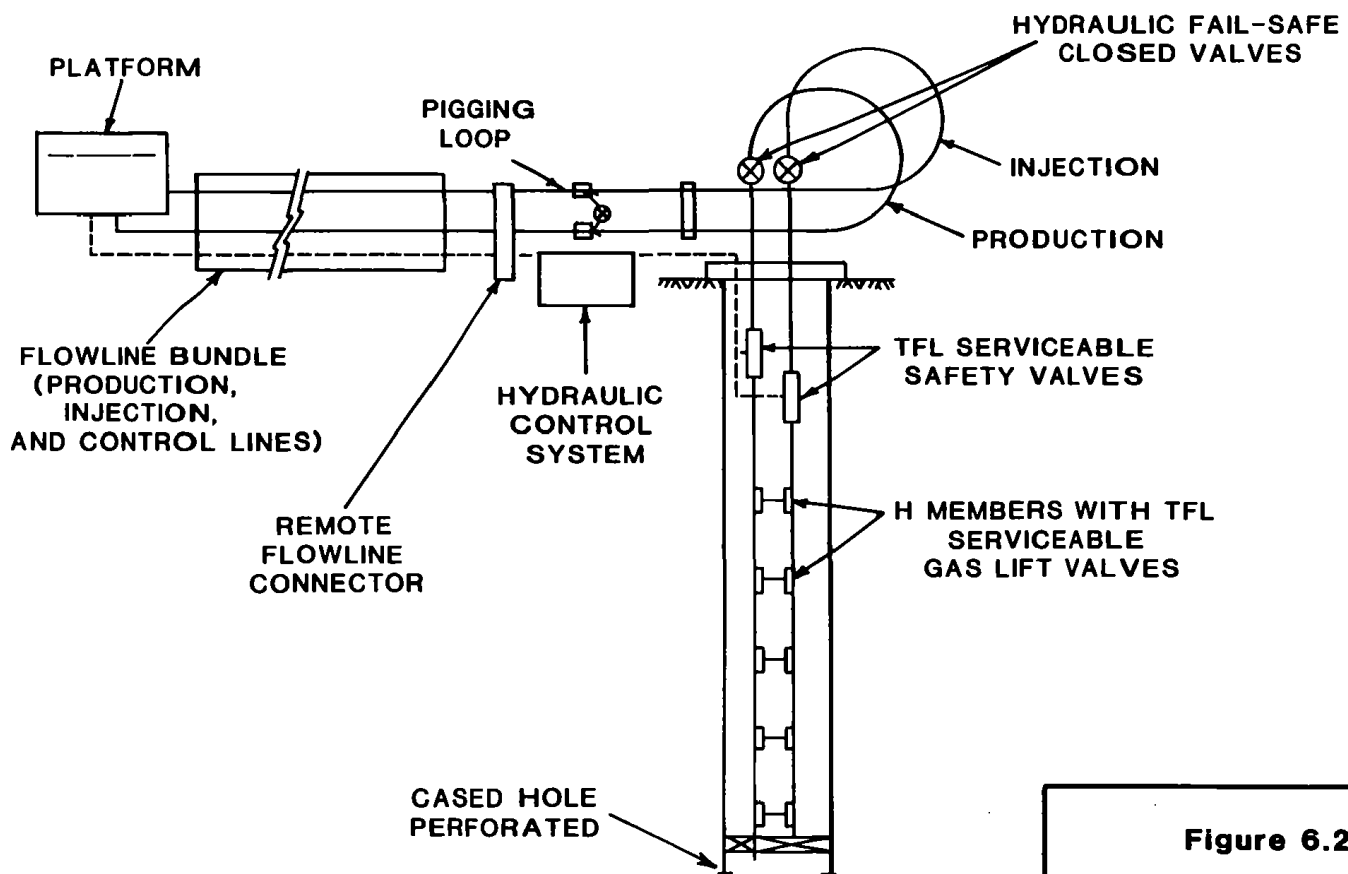


Figure 6.2
SINGLE SATELLITE WELL SYSTEM

SECTION VII
OFFSHORE PLATFORM FACILITIES

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SECTION VII

7.1 Introduction

This section discusses the facilities to be installed on the new offshore platforms and the modifications planned for the Hondo A platform as a result of the Santa Ynez Unit expanded development. The production facilities design standards that will be used are listed in Section 7.2. Platform-specific system descriptions for each individual platform will then follow. The legend shown in Figure 7.1 should be referenced when looking at the new platform process flow diagrams. The differences in equipment requirements for the offshore and onshore oil treating options will be highlighted. Control and monitoring systems, support and utility systems, safety equipment, and environmental impact mitigation measures will then be described as facilities with a common design basis.

An overview of the development options will provide the necessary background to aid in understanding the interrelationship of the offshore platform facilities. A functional block diagram of Development Option A (Offshore Oil Treating) is shown in Figure 7.2. The stated pipeline dimensions are approximate sizes based on currently available design data and are subject to change based on continuing design studies. Primary gas and emulsion separation will occur on the individual platforms with the bulk of the gas going to expanded

onshore gas treating facilities and the remainder of this gas going to the offshore storage and treating vessel (OS&T) as fuel gas for the gas turbine generators. Gas will also be pipelined to the Pescado B-1 platform (if installed) as fuel gas for the gas turbine driven machinery. The oil emulsion will be sent to the OS&T for crude dehydration and stabilization and water treatment. The crude will be directly offloaded to marine vessels and the treated water disposed of by ocean discharge in accordance with an NPDES permit. Gas turbine generators on all the platforms (except Pescado B-1, if installed) and on the OS&T will be interconnected by a submarine cable to form a power distribution network.

A functional block diagram of Development Option B (Onshore Oil Treating) is shown in Figure 7.3. The stated pipeline dimensions are approximate sizes based on currently available design data and are subject to change based on continuing design studies. Primary gas and emulsion separation will occur on the individual platforms with the bulk of the gas going to expanded onshore gas treating facilities. Gas will also be pipelined to the Pescado B-1 platform (if installed) as fuel gas for the gas turbine driven machinery. The oil emulsion will be sent to onshore oil treating facilities for crude dehydration and stabilization and water treatment. The crude will be offloaded to marine vessels through a modernized nearshore marine terminal and the treated water will be pipelined to an offshore outfall discharge point in accordance with an NPDES permit. An onshore cogeneration power

plant will supply the electrical needs of the onshore oil treating facilities, the marine terminal and all the offshore platforms through a common power distribution network.

7.2 Design 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 the minimum 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 Plat-
forms.

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 Hondo A Platform Facilities

7.3.1 Existing Hondo A Platform Facilities

The deck layouts for the existing Hondo A platform are given in Figure 7.4. The facilities presently installed and operating on the Hondo A platform are designed to handle approximately 48 MBD of total emulsion and to compress 20 MMSCFD of gas. A single water injection pump with a 14 MBD capacity disposes of all the produced water returned to the platform from the OS&T. The process flow schematic is shown in Figure 7.5.

Primary production is sour gas and emulsion (crude oil and water) from completions in the Monterey Formation. Sweet gas for fuel use is provided by completions in the sandstone formations. Sandstone produced liquids are

combined with Monterey liquids for pipeline shipment to the OS&T.

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

The main compression system utilizes two parallel three-stage electric motor driven reciprocating compressors. Dehydration of the 2nd stage discharge gas, after cooling and scrubbing, is accomplished by conventional glycol dehydration. Except for the fuel gas sent to the OS&T, all of the gas is presently reinjected; initiation of gas sales is anticipated in 1983.

Water produced with the hydrocarbon fluids from the Monterey and sandstone formations is transported with the crude oil in an emulsion state 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 the Hondo A platform 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 for disposal.

All process equipment and compressors on the Hondo A

platform are powered 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 has to be 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.

This initial Hondo A development is shown in Figure 7.6.

7.3.2 Hondo A Platform Modifications - Development

Option A .

As part of the Development Option A (Offshore Oil Treating) program for the Santa Ynez Unit, several additions must be made to the existing Hondo A platform. The modified process schematic shown in Figure 7.7 should be used as a reference.

1. Oil and Gas Gathering System Tie-ins: Emulsion and gas gathering system pipeline tie-ins will be made at the Hondo A platform to connect the new pipelines from the Hondo B platform into the existing 12" emulsion line to the OS&T and the soon to be completed 12" gas line to shore. The incoming 18" gas

line tie-in will be an on-deck arrangement involving a receiving pig trap with its associated valving, pressure safety sensors, shutdown valves and check valves. The incoming gas will not be recompressed at the Hondo A platform.

The incoming 20" emulsion line tie-in will also be made on deck and will include a riser connection, a receiving pig trap with its associated valving, a heat exchanger, pressure and temperature safety sensors, shutdown valves and check valves. The heat exchanger will heat the incoming crude to approximately 160°F for viscosity reduction using heat obtained from the enlarged platform hot oil system. No crude booster pumps will be installed initially; however, future tie-in connections for a surge tank and booster pumps will be provided in the event that future production volume increases or low gravity crude characteristics necessitate increased pipeline capacity.

2. Process Heating: The additional heat requirements imposed on the existing heating oil system by the new emulsion pipeline heat exchanger will require the addition of a fired heater to supplement waste heat recovery on the turbine generators. Provisions for this heater were made in the original heating oil piping system design. The heater will use sweet

sandstone gas as fuel. New heating oil pumps will also be added to increase the circulation rate of the hot oil system.

3. Electrical Power: As part of Development Option A, the existing OS&T to Hondo A platform 35 kV submarine cable system will be extended to the Hondo B, Pescado and Sacate platforms. The Hondo A platform will then be able to draw power from the OS&T turbine generators or from any of the generators installed on the new platforms. The only significant physical change to the platform will be the addition of a 10" J-tube for the power cable riser on the west side of the platform jacket.

7.3.3 Hondo A Platform Modifications - Development Option B

In Development Option B (Onshore Oil Treating) the Hondo A platform will also have to be modified. The modified process schematic shown in Figure 7.8 should be used as a reference.

1. Oil and Gas Gathering System Tie-ins: The pipelines coming into the platform will be a 26" emulsion line and a 10" gas line from Hondo B. The outgoing pipelines will consist of a 26" emulsion line and a 12" existing gas line, both going to shore. The on deck tie-ins, heaters, valves, and controls will be

the same as described for Development Option A. The existing 12" emulsion, 6" gas and 8" water lines to/from the OS&T will be disconnected and removed or abandoned.

2. Process Heating: Same as in Development Option A.

The heater size may increase due to higher production rates.

3. Electrical Power: Development Option B includes an

onshore central power plant with a 35 kV submarine cable system out to all of the platforms. Therefore, a new cable from shore will be brought onto the Hondo A platform, terminated, and then extended to the Hondo B, Pescado and Sacate platforms. The incoming and outgoing power cables at the Hondo A platform will be handled by J-tubes.

7.4 Hondo B Platform Facilities

7.4.1 Hondo B Platform - Development Option A

7.4.1.1 General Description

The deck layouts for the Hondo B platform in Development Option A (Offshore Oil Treating) are given in Figure 7.9. Production on the Hondo B platform is initially expected to be sour oil and associated sour gas from the Monterey Formation.

Oil and water will remain in the emulsion state and will leave the platform at temperatures up to approximately 160°F. Since there is no sweet gas available for fuel, a sweetening process will be installed for fuel gas. Turbine driven generators will provide electrical power. Process gas and gas lift compression will be provided by electric motor driven reciprocating compressors and/or by gas turbine driven centrifugal compressors.

7.4.1.2 Facility Descriptions

Reference the process flow diagrams given in Figures 7.10 through 7.14.

1. Wellbay Manifolds: There will be 60 well slots, all initially drilled as Monterey producers. Wellhead valves and manifolds will be provided to allow the connection of each well to either a production separator, a test separator or the well cleanup separator. There will also be a gas lift manifold connected to each well's production casing.
2. Production/Separation: Primary sour emulsion and gas separation will take place in two parallel production trains. Each train will consist of an inlet heater, a three

phase separator and a production surge tank. Produced well fluids, at roughly 100°F, will be heated to approximately 160°F by heat exchange with a heating oil medium. The hot fluids will then flow into the three phase production separator operating at 80 psig from which gas will flow to the second stage of compression, emulsion will flow to the production surge tank, and free water will flow to the water surge tank. The production surge tanks will operate at about 15 psig and will contain heating coils to further assist in degassing and in lowering the emulsion viscosity.

Two test separators and heaters will also be provided. These separators will be three phase and will be equipped with gas, free water and net oil meters. Each well will be tested at least once per month in order to facilitate commingled production allocation.

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

3. Shipping and Metering: Emulsion collected in

the production surge tanks and free water in the water surge tank will be boosted to pipeline pressure by pumping. Metering of the emulsion, gas, and free water is discussed in Section 7.10.4. The maximum normal operating pressure for the emulsion shipping pumps will be 1100 psig.

4. Gas Compression: All formation gas will be compressed to a pipeline pressure of approximately 1100 psig by three stages of compression. Each stage will be equipped with suction scrubbers, discharge coolers, and various controllers to allow for the handling of varying gas production rates.

Significant additional amounts of second and third stage compression will be required early in the producing life of the field to provide gas lifting capability for the wells. This compression will be installed as gas turbine driven centrifugal compressor modules on the drilling deck.

5. Fuel Gas: Fuel gas for the platform will be provided from the third stage compressor suction. The absence of sweet gas for fuel on the Hondo B platform will require that a gas sweetening process be added. This

process will be essentially the same as the TEG dehydration process except that the circulating liquid will be a special solvent. Non-condensable vapors from the solvent regenerator overhead (commonly referred to as acid gas) will contain H₂S and CO₂. These gasses will flow to the first stage vapor recovery compressor suction and will be diluted into the gross production gas compression stream. Sweetened gas will enter the high pressure fuel gas scrubber for liquid removal and then flow through filters and a heater to the high pressure fuel gas system. High pressure fuel gas will be used both as turbine fuel and as a makeup into the low pressure fuel gas system (flare pilots, purges, and blanket gas).

6. Artificial Lift: Gas lifting will be the primary means of artificial lift used to maintain Monterey well productivity.
7. Power Generation: Electrical power on the Hondo B platform will be generated at 4160 volts by gas turbine driven generators. The turbines will have diesel alternate fuel capability to allow for facility production startup without fuel gas. Large electric

motors for shipping pumps and produced gas compressors will operate at 4160 volts. Step down transformers and motor control centers will operate general process and utility loads at 480 volts. The Hondo B platform will be tied into the field-wide subsea cable 35 kV power grid by a 4.16/35 kV step up transformer to allow for power sharing with the other platforms. The drilling rigs will provide their own power (Ref. Section 5.3.5).

8. Process Heating: A heating oil system will be used for production and test separator heat exchangers, production surge tanks, the pipeline boost heater, glycol regeneration, sweetening solvent regeneration and fuel gas heating. The heat source for the heating oil will be waste heat recovery on the turbine drivers for the electrical generators and the centrifugal compressors.

7.4.2 Hondo B Platform - Development Option B

7.4.2.1 General Description

The deck layouts for the Hondo B platform in Development Option B (Onshore Oil Treating) are given in Figure 7.15. Production on the Hondo B

platform is initially expected to be sour oil and associated sour gas from the Monterey Formation. Oil and water will remain in the emulsion state and will leave the platform at temperatures up to approximately 160°F. Since there is no sweet gas available for fuel, a sweetening process will be installed for fuel gas. Electrical power will be generated onshore and brought to the Hondo B platform by a 35 kV submarine cable. Process gas and gas lift compression will be provided by electric motor driven reciprocating compressors and/or gas turbine driven centrifugal compressors.

7.4.2.2 Facility Descriptions

1. Wellbay Manifolds: Same as in Development Option A.
2. Production/Separation: Same as in Development Option A.
3. Shipping and Metering: Same as in Development Option A.
4. Gas Compression: Same as in Development Option A.
5. Fuel Gas: Same as in Development Option A.

6. Artificial Lift: Same as in Development Option A.

7. Power Generation: Electrical power will be received at the Hondo B platform from a 35 kV submarine cable system fed by an onshore central power plant. Step down 35/4.16 kV and 4160/480 volt transformers will provide power to the platform electrical loads. Large electric motors for shipping pumps and produced gas compressors will operate at 4160 volts. General process and utility loads will operate at 480 volts.

8. Process Heating: The Development Option A design will be used except that waste heat can now be recovered only from the turbines driving gas lift compressors. Therefore, the waste heat recovery unit will have supplemental gas firing capability to boost the available waste heat when required to meet the total platform heat needs.

7.5 Pescado A Platform Facilities

7.5.1 Pescado A Platform - Development Option A

7.5.1.1 General Description

The deck layouts for the Pescado A platform in

Development Option A (Offshore Oil Treating) are given in Figure 7.16. Production on the Pescado A platform is expected to be of three types: sour oil and associated sour gas from the Monterey Formation; sweet oil and associated gas from the Upper and Lower Gaviota Formation; and sweet non-associated gas from the Matilija Formation. Each of these production streams will be handled by separate production systems. Oil and water will remain in the emulsion state and will leave the platform at temperatures up to approximately 160°F. Turbine driven generators will provide electrical power. Process gas and gas lift compression will be provided by electric motor driven reciprocating compressors and/or by gas turbine driven centrifugal compressors. Sweet produced gas will be used as fuel.

7.5.1.2 Facility Descriptions

Reference the process flow diagrams given in Figures 7.17 through 7.20.

1. Wellbay Manifolds: There will be 60 well slots. Of the 60 wells, 54 will be initially completed as sour Monterey producers, 5 as sweet oil producers, and one as a non-associated sweet gas well. Wellhead valves and manifolds will be provided to allow for the

connection of each well to either a production separator, a test separator or the well cleanup separator. There will also be a gas lift manifold connected to the production casing of each Monterey well.

2. Production/Separation: Primary sour emulsion and gas separation will take place in two parallel low pressure production trains. Each train consists of an inlet heater, a three phase separator, and a production surge tank. Produced well fluids, at roughly 100°F, will be heated to approximately 160°F by heat exchange with a heating oil medium. The hot fluids will then flow into the three phase production separator operating at 80 psig from which gas will flow to the second stage of compression, emulsion will flow to the production surge tank, and free water will flow to the water surge tank. The production surge tanks will operate at about 15 psig and will contain heating coils to further assist in degassing and in lowering the emulsion viscosity.

Separation of sweet oil and gas will occur in the intermediate pressure three phase separator operating at 335 psig. A heat exchanger

will be provided ahead of the separator to heat the fluids to approximately 160°F. The oil from this intermediate pressure separator will flow into a flash tank and then to the production surge tank, while the free water will flow to the water surge tank. The sweet gas will flow primarily to the fuel gas system, with the excess going to the third stage compression suction.

The non-associated gas will flow through a heater into a vertical three phase separator for condensate and water removal. Condensate and free water will be returned to the emulsion system and the water surge tank, respectively. The gas will flow to the third stage of compression.

There will be four test separators: two for Monterey production, one for sweet oil production, and one for non-associated gas production. These separators will be three phase and will have meters on each phase. Each well will be tested at least once per month in order to facilitate commingled production allocation.

A well cleanup separator will be used for the initial unloading of wells to remove mud and

water until the well is flowing sufficiently to be turned into the normal production separators.

3. Shipping and Metering: Emulsion collected in the production surge tanks and free water in the water surge tank will be boosted to pipeline pressure by pumping. Metering of the emulsion, gas and free water is discussed in Section 7.10.4. The maximum normal operating pressure for the emulsion shipping pumps will be 1100 psig.

4. Gas Compression: All low and intermediate pressure gas will be compressed to a pipeline pressure of approximately 1100 psig by three stages of compression. Each stage will be equipped with suction scrubbers, discharge coolers, and various controllers to allow for the handling of varying gas production rates.

Significant additional amounts of second and third stage compression are required early in the producing life of the field to provide gas lifting capability for the wells. This compression will be installed as gas turbine driven centrifugal compressor modules on the drilling deck.

5. Fuel Gas: Fuel gas for the platform is provided from the sweet associated and non-associated gas production.
6. Artificial Lift: Gas lifting will be the primary means of artificial lift used to maintain Monterey well productivity.
7. Power Generation: Electrical power on the Pescado A platform will be generated at 4160 volts by gas turbine driven generators. The turbines will have diesel alternate fuel capability to allow for facility production startup without fuel gas. Large electric motors for shipping pumps and produced gas compressors will operate at 4160 volts. Step down transformers and motor control centers will operate general process and utility loads at 480 volts. The Pescado A platform will be tied into the field-wide subsea cable 35 kV power grid by a 4.16/35 kV step up transformer to allow for power sharing with the other platforms. The drilling rigs will provide their own power (Ref. Section 5.3.5).
8. Process Heating: A heating oil system will be used for production and test separator heat exchangers, production surge tanks, the

pipeline boost heater, glycol regeneration and fuel gas heating. The heat source for the heating oil will be waste heat recovery on the turbine drivers for the electrical generators and the centrifugal compressors.

7.5.2 Pescado A Platform - Development Option B

7.5.2.1 General Description

The deck layouts for the Pescado A platform in Development Option B (Onshore Oil Treating) are given in Figure 7.21. Production on the Pescado A platform is expected to be of three types: sour oil and associated sour gas from the Monterey Formation; sweet oil and associated gas from the Upper and Lower Gaviota Formation; and sweet non-associated gas from the Matilija Formation. Each of these production streams will be handled by separate production systems. Oil and water will remain in the emulsion state and will leave the platform at temperatures up to approximately 160°F. Electrical power will be generated onshore and brought to the Pescado A platform by a 35 kV submarine cable. Process gas and gas lift compression will be provided by electric motor driven compressors and/or by gas turbine driven centrifugal compressors.

7.5.2.2 Facility Descriptions

1. Wellbay Manifolds: Same as in Development Option A.
2. Production/Separation: Same as in Development Option A.
3. Shipping and Metering: Same as in Development Option A.
4. Gas Compression: Same as in Development Option A.
5. Fuel Gas: Same as in Development Option A.
6. Artificial Lift: Same as in Development Option A.
7. Power Generation: Electrical power will be received at the Pescado A platform from a 35 kV submarine cable system fed by an onshore central power plant. Step down 35/4.16 kV and 4160/480 volt transformers will provide power to the platform electrical loads. Large electric motors for shipping pumps and produced gas compressors will operate at 4160 volts. General process and utility loads will operate at 480 volts.
8. Process Heating: The Development Option A design will be used except that waste heat

can now be recovered only from the turbine driving gas lift compressors. Therefore, the waste heat recovery unit will have supplemental gas firing capability to boost the available waste heat when required to meet the total platform heat needs.

7.6 Pescado B-2 Platform Facilities

The Pescado B-2 platform facilities are essentially identical to the Pescado A platform facilities just described in Section 7.5. The only difference is platform location, water depth and facility design volumes. The production volume differences between the Pescado A and Pescado B-2 platforms are discussed in Section III (Reservoir Evaluation).

Reference Figures 7.22 through 7.27 for the Pescado B-2 platform deck layouts (both development options) and for the process flow diagrams.

7.7 Pescado B-1 Platform Facilities

7.7.1 Pescado B-1 Platform - Development Option A

7.7.1.1 General Description

The deck layouts for the Pescado B-1 platform in Development Option A (Offshore Oil Treating) are given in Figure 7.28. Production on the Pescado

B-1 platform is initially expected to be sour oil and associated sour gas from the Monterey Formation. Oil and water will remain in the emulsion state and will leave the platform at temperatures up to approximately 160°F. Process gas and gas lift compression will be provided by electric motor driven reciprocating compressors and/or by gas turbine driven centrifugal compressors. Sweet produced gas pipelined from the Pescado B-2 platform will be used as fuel gas. No electrical power will be generated on the platform.

7.7.1.2 Facility Descriptions

Reference the process flow diagrams given in Figures 7.29 through 7.32.

1. Wellbay Manifolds: There will be 28 well slots, all initially drilled as Monterey producers. Wellhead valves and manifolds will be provided to allow for the connection of each well to either a production separator, a test separator or the well cleanup separator. There will also be a gas lift manifold connected to each well's production casing.
2. Production/Separation: Primary sour emulsion and gas separation will take place in a low

pressure production train consisting of an inlet heater, a three phase separator and a production surge tank. Produced well fluids, at roughly 100°F, will be heated to approximately 160°F by heat exchange with a heating oil medium. The hot fluids will then flow into the three phase production separator operating at 80 psig from which gas will flow to the second stage of compression, emulsion will flow to the production surge tank, and free water will flow to the water surge tank. The production surge tank will operate at about 15 psig and will contain heating coils to further assist in degassing and in lowering the emulsion viscosity.

Two test separators and heaters will also be provided. These separators will be three phase and will be equipped with gas, free water and net oil meters on each phase. Each well will be tested at least once per month in order to facilitate commingled production allocation.

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

3. Shipping and Metering: Emulsion collected in the production surge tank and free water in the water surge tank will be boosted to pipeline pressure by pumping. Metering of the emulsion, gas and free water is discussed in Section 7.10.4. The maximum normal operating pressure for the emulsion shipping pumps will be 1100 psig.
4. Gas Compression: All formation gas will be compressed to a pipeline pressure of approximately 1100 psig by three stages of compression. Each stage will be equipped with suction scrubbers, discharge coolers, and various controllers to allow for the handling of varying gas production rates.

Significant additional amounts of second and third stage compression are required early in the producing life of the field to provide gas lifting capability for the wells. This compression will be installed as gas turbine driven centrifugal compressor modules on the drilling deck.

5. Fuel Gas: Sweet fuel gas for the platform will be provided from the Pescado B-2 platform via a 6" pipeline.

6. Artificial Lift: Gas lifting will be the primary means of artificial lift used to maintain Monterey well productivity.
7. Power Generation: Electrical power will be brought to the Pescado B-1 platform from the Pescado B-2 platform by a submarine cable operating at 35 kV. Large electric motors for shipping pumps and produced gas compressors will operate at 4160 volts. Additional step down transformers and motor control centers will operate general process and utility loads at 480 volts. The drilling rig will provide its own power (reference Section 5.3.5).
8. Process Heating: A heating oil system will be used for production and test separator heat exchangers, production surge tank, the pipeline boost heater, glycol regeneration and fuel gas heating. The heat source for the heating oil will be waste heat recovery on the turbine drivers for the gas lift compressors with supplemental gas firing capability to boost the available waste heat.

7.7.2 Pescado B-1 Platform - Development Option B

7.7.2.1 General Description

The deck layouts for the Pescado B-1 platform in Development Option B (Onshore Oil Treating) are given in Figure 7.33. Production on the Pescado B-1 platform is initially expected to be sour oil and associated sour gas from the Monterey Formation. Oil and water will remain in the emulsion state and will leave the platform at temperatures up to approximately 160°F. Electrical power will be generated onshore and brought to the Pescado B-1 platform by a 35 kV submarine cable. Process gas and gas lift compression will be provided by electric motor driven compressors and/or by gas turbine driven centrifugal compressors.

7.7.2.2 Facility Descriptions

1. Wellbay Manifolds: Same as in Development Option A.
2. Production/Separation: Same as in Development Option A.
3. Shipping and Metering: Same as in Development Option A.

4. Gas Compression: Same as in Development Option A.
5. Fuel Gas: Same as in Development Option A.
6. Artificial Lift: Same as in Development Option A.
7. Power Generation: Electrical power will be received at the Pescado B-1 platform from a 35 kV submarine cable system fed by an on-shore central power plant. Step down 35/4.16 kV and 4160/480 volt transformers will provide power to the platform electrical loads. Large electric motors for shipping pumps and produced gas compressors will operate at 4160 volts. General process and utility loads will operate at 480 volts.
8. Process Heating: Same as in Development Option A.

7.8 Sacate Platform Facilities

7.8.1 Sacate Platform - Development Option A

7.8.1.1 General Description

The deck layouts for the Sacate platform in Development Option A (Offshore Oil Treating) are

given in Figure 7.34. Production on the Sacate platform is expected to be of three types: sour oil and associated sour gas from the Monterey Formation; sweet non-associated gas from the Matilija-Vaqueros/Alegria and Lower Gaviota-Middle Gaviota Formations; and sweet oil and associated gas from the Vaqueros/Alegria Formation. Each of these production streams will be handled by separate production systems. Oil and water will remain in the emulsion state and will leave the platform at temperatures up to approximately 160°F. Turbine driven generators will provide electrical power. Process gas and gas lift compression will be provided by electric motor driven reciprocating compressors and/or by gas turbine driven centrifugal compressors. Sweet produced gas will be used as fuel.

7.8.1.2 Facility Descriptions

Reference the process flow diagrams given in Figures 7.35 through 7.38.

1. Wellbay Manifolds: There will be 28 wells, of which approximately 14 will be initially completed as sour Monterey producers, 11 as Vaqueros/Alegria sweet oil producers, one as a Lower Gaviota-Middle Gaviota sweet non-associated gas producer, and two as Matilija-

Vaqueros/Alegria sweet non-associated gas producers. Wellhead valves and manifolds will be provided to allow for the connection of each well to either a production separator, a test separator or the well cleanup separator. There will also be a gas lift manifold connected to the production casing of each Monterey well.

2. Production/Separation: Primary sour emulsion and gas separation will take place in a low pressure production train consisting of an inlet heater, a three phase separator and a production surge tank. Produced well fluids, at roughly 100°F, will be heated to approximately 160°F by heat exchange with a heating oil medium. The hot fluids will then flow into the three phase production separator operating at 80 psig from which gas will flow to the second stage of compression, emulsion will flow to the production surge tank, and free water will flow to the water surge tank. The production surge tank will operate at about 15 psig and will contain heating coils to further assist in degassing and in lowering the emulsion viscosity.

Separation of sweet oil and gas will occur in the intermediate pressure three phase separator operating at 335 psig. A heat exchanger will be provided ahead of the separator to heat the fluids to approximately 160°F. The oil from this intermediate pressure separator will flow into the flash tank and then to the production surge tank, while the free water will flow to the water surge tank. The sweet gas will flow primarily to the fuel gas system, with the excess going to the third stage compression suction.

The non-associated gas will flow through a heater into a vertical three phase separator for condensate and water removal. Condensate and free water will be returned to the emulsion system and the water surge tank, respectively. The gas will flow to the third stage of compression.

There will be three test separators: one for Monterey production, one for sweet oil production, and one for non-associated gas production. These separators will be three phase and will have meters on each phase. Each well will be tested at least once per

month in order to facilitate commingled production allocation.

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

3. Shipping and Metering: Emulsion collected in the production surge tank and free water in the water surge tank will be boosted to pipeline pressure by pumping. Metering of the emulsion, gas and free water is discussed in Section 7.10.4. The maximum normal operating pressure for the emulsion shipping pumps will be 1100 psig.

4. Gas Compression: All produced gas will be compressed to a pipeline pressure of approximately 1100 psig by three stages of compression. Each stage will be equipped with suction scrubbers, discharge coolers, and various controllers to allow for the handling of varying gas production rates.

Significant additional amounts of second and third stage compression are required early in the producing life of the field to provide

gas lifting capability for the wells. This compression will be installed as gas turbine driven centrifugal compressor modules on the drilling deck.

5. Fuel Gas: Fuel gas for the platform is provided from the intermediate pressure sweet associated and non-associated gas production.
6. Artificial Lift: Gas lifting will be the primary means of artificial lift used to maintain Monterey well productivity.
7. Power Generation: Electrical power on the Sacate platform will be generated at 4160 volts by gas turbine driven generators. The turbines will have diesel alternate fuel capability to allow for facility production startup without fuel gas. Large electric motors for shipping pumps and produced gas compressors will operate at 4160 volts. Step down transformers and motor control centers will operate general process and utility loads at 480 volts. The Sacate platform will be tied into the field-wide subsea cable 35 kV power grid by a 4.16/35 kV step up transformer to allow for power sharing with the other platforms. The

drilling rig will provide its own power (Ref. Section 5.3.5).

8. Process Heating: A heating oil system will be used for production and test separator heat exchangers, production surge tanks, the pipeline boost heater, glycol regeneration and fuel gas heating. The heat source for the heating oil will be waste heat recovery on the turbine drivers for the electrical generators and the centrifugal compressors.

7.8.2 Sacate Platform - Development Option B

7.8.2.1 General Description

The deck layouts for the Sacate platform in Development Option B (Onshore Oil Treating) are given in Figure 7.39. Production on the Sacate platform is expected to be of three types: sour oil and associated sour gas from the Monterey Formation; sweet non-associated gas from the Matilija-Vaqueros/Alegria and Lower Gaviota-Middle Gaviota Formations; and sweet oil and associated gas from the Vaqueros/Alegria Formation. Each of these will be handled by separate production systems. Oil and water will remain in the emulsion state and will leave the platform at temperatures up to

approximately 160°F. Electrical power will be generated onshore and brought to the Sacate platform by a 35 kV submarine cable. Process gas and gas lift compression will be provided by electric motor driven compressors and/or by gas turbine driven centrifugal compressors.

7.8.2.2 Facility Descriptions

1. Wellbay Manifolds: Same as in Development Option A.
2. Production/Separation: Same as in Development Option A.
3. Shipping and Metering: Same as in Development Option A.
4. Gas Compression: Same as in Development Option A.
5. Fuel Gas: Same as in Development Option A.
6. Artificial Lift: Same as in Development Option A.
7. Power Generation: Electrical power will be received at the Sacate platform from a 35 kV submarine cable system fed by an onshore central power plant. Step down 35/4.16 kV and 4160/480 volt transformers will provide

power to the platform electrical loads. Large electric motors for shipping pumps and produced gas compressors will operate at 4160 volts. General process and utility loads will operate at 480 volts.

8. Process Heating: The Development Option A design will be used except that waste heat can now be recovered only from the turbines driving gas lift compressors. Therefore, the waste heat recovery unit will have supplemental gas firing capability to boost the available waste heat when required to meet the total platform heat needs.

7.9 Potential Future Offshore Platform Facility Additions

7.9.1 Gas Injection Compression

The amount of associated gas produced in conjunction with solution gas drive crude oil increases rapidly as the reservoir bottom-hole pressure drops. Due to potential onshore gas processing facilities and transportation system capacity restrictions, it may become necessary to reinject a portion of the produced gas in order to maintain the optimum desirable oil production rates. This injection need will most likely be handled by the addition of small electric motor or gas engine

driven reciprocating compressors on the drilling deck of the platform.

7.9.2 Emulsion Pipeline Booster Pumping Stations

In order to provide for future increases in offshore emulsion pipeline capacity, allowance has been made for the addition of series boost pumping at each downstream platform in the emulsion pipeline gathering system. The booster equipment will consist of an incoming heater for viscosity reduction, a surge tank, and booster and/or shipping pumps. Initially, only the heater will be installed. The remaining equipment would be installed only to satisfy pipeline operations requirements due to increased volumes or viscosity.

7.9.3 Fired Heaters

The amount of waste heat available from the gas turbine drivers on the offshore compressors and electric generators decreases with time due to the declining production rates. However, the need for heat does not necessarily decline proportionately due to the increased water cut in the produced fluids. Therefore, it may become necessary to augment the available waste heat on any of the platforms with either gas fired heaters or supplemental firing of the waste heat recovery units.

7.10 Control and Monitoring Systems

The general process and associated equipment on each platform will be controlled and monitored for safe operation by the following types of systems.

7.10.1 Process Controls

The primary means of controlling process temperatures, pressures, flow rates and liquid levels will be by closed loop analog proportional controllers. Both local and remote (control room) loops will be used. Only those controlled variables requiring routine operation monitoring will be handled from the control room.

7.10.2 Alarms

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

7.10.3 Shutdown Systems

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

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

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

7.10.4 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 marine vessel loading terminal will be considered absolute and will be the basis for royalty payment and sales. These meters will be proven during each transfer. This volume will then be allocated to the platforms based on net oil measurements and samples taken at each platform oil and water emulsion metering station. Platform volumes will then

be allocated back to each well based on separator metered volumes and actual well test data multiplied by hours on production. See Figures 7.40 and 7.41.

The platform emulsion shipping and metering system, as shown in Figure 7.42, will consist of the surge tank(s), booster and/or shipping pumps, positive displacement meters, meter prover, and a net oil computer (NOC) with a BS&W (basic sediment and water) probe and a mechanical sampler. As the emulsion stream flows through the BS&W probe, a capacitance measurement will be continually read. The large difference between the dielectric constants of crude oil (2 to 2.7) and water (80) makes the change in capacitance of a coaxial cell a sensitive indicator of the water content of the emulsion stream. This 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.

The platform free water shipping and metering system will consist of a surge tank, shipping pumps and meters. The free water and emulsion streams will be recombined

downstream of the metering stations into the emulsion pipeline gathering system.

Each production and test separator will be three phase and 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 7.43. Each meter will have static, differential, and temperature transmitters tied into a local electronic 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."

For pipeline leak detection monitoring purposes, the platform emulsion metering systems will transmit volume pulses to a comparator located at the receiving oil treating facilities where a leak detection counter 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.

7.11 Support and Utility Systems

Each of the new platforms will be equipped with the utility and support systems described in the following subsections.

7.11.1 Instrument and Utility Air

Air compressors will provide compressed air at a pressure of 115 psig. A desiccant absorber will dehydrate a portion of this air for use as instrument air. The remainder will be used as service air.

7.11.2 Potable and Deionized Water

Seawater will be converted to fresh water in a distillation or reverse osmosis unit and will flow to a utility water storage tank. Fresh water from the storage tank will go to either the potable water or the deionized water system. Pumps will transfer part of the fresh water through an ultraviolet sterilizer to the pressurized potable water system. Pumps will also transfer part of the water through deionizer bottles to pumps which inject the deionized water into the turbines for NO_x control purposes.

7.11.3 Diesel Fuel

Diesel fuel will be stored in the pedestal columns which support the two-deck cranes. Pumps will transfer fuel as needed to a day tank from which the cranes, turbine generators or diesel engines will draw their fuel. The drilling rigs may have additional diesel fuel storage as required for power generation.

7.11.4 Flare

The platform will be equipped with a relief header that gathers all safety valve discharges, emergency backpressure control valve discharges, and manual blowdowns. This header will flow through a flare knockout 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 blowers mounted on the platform.

Flaring of gas will occur only as provided in MMS Pacific Region OCS Order 11.

7.11.5 Deck Drains

All deck drainage will be gathered in an open drain sump and pumped to the slop sump. Process drains will be gathered in a hydrocarbon process drain sump and pumped to the slop oil rerun tank. All drainage

eventually is returned to the emulsion system. During the drilling phase, all deck drain fluids will be processed through the drilling rig cuttings washer system due to the high volume of drilling fluids retrieved in the deck drains system.

7.11.6 Heating Oil

A circulating heating oil medium system will be employed to provide heat to the process and pipeline heat exchangers. The system consists of a heating oil surge tank, circulating pumps, supply and return headers, and a heat source. The heat source will initially be waste heat recovered from the turbines driving the gas lift compressors. In Development Option A (Offshore Oil Treating), additional waste heat will be recovered from the turbines generating electrical power. In Development Option B (Onshore Oil Treating), the waste heat recovery units will have supplemental gas firing capability to boost the available waste heat.

7.11.7 Sewage Treatment

Raw sewage from the quarters will flow to a marine sewage treatment unit wherein it will be aerated, biodegraded and chlorinated. The effluent from this unit will comply with U.S. Coast Guard requirements found in 33 CFR 159.53(b) and a NPDES permit. It will be discharged into the ocean through a subsea disposal tube.

7.11.8 Chemical Injection

Numerous small storage tanks and metering pumps will be provided for injection of corrosion inhibitors, emulsion breakers, antifoam agents, and methanol into the process streams.

7.11.9 Central Hydraulic Unit

A centrally located hydraulic supply pump unit will be used to provide high pressure hydraulic fluid to the emergency shutdown valves. This is a closed loop system with spent fluid returning to a pump suction reservoir.

7.11.10 Lighting

General platform lighting levels will meet or exceed standards set forth by the Illuminating Engineering Society for safety and efficiency of visual operations. Outdoor lighting will be by mercury vapor lights, whereas indoor lighting will come from fluorescent fixtures. Battery powered emergency egress lighting will also be provided.

7.11.11 Communications

Each platform will have an intra-platform page-party voice communications system which uses hard-wired speakers and handsets. Additionally, there will be hand-held portable radios for intra-platform opera-

tional communications.

For external communication with crew boats, supply boats, shore bases, and other necessary parties, there will be a wide-area 450 MHz radio system. There will also be telephone circuits furnished over a company-owned microwave system.

7.11.12 Personnel Quarters

A three-story living quarters building will be placed on the drilling deck of each platform. It will include sleeping accommodations, a galley, restrooms, a washroom, a recreation room, repair shops and supervisor offices. A heliport will be situated on top of the quarters building. Temporary portable quarters for drilling personnel will be supplied with each drilling rig.

7.11.13 Corrosion Control

Corrosion of equipment and piping will be minimized through the use of sacrificial anodes, internal and external coatings, corrosion inhibitor chemicals and the careful selection of materials.

7.11.14 Gas Dehydration

Gas from the compression system on each platform will be dehydrated in a triethylene glycol (TEG) contacting system. The wet gas will enter the bottom of a contac-

tor tower and flow upward through a packed bed where close contact with downward flowing glycol will be made. The gas will give up the water vapor to the glycol and then pass out of the top of the contactor, through the contactor overhead scrubber, and on to sales or gas lift. Lean concentrated glycol will be continuously pumped into the top of the contactor. As the glycol flows downward through the packed bed it will absorb the water from the rising gas stream. The water-rich glycol will be removed at the bottom of the tower and flow through a flash tank, filters, and heat exchangers into the reboiler. In the reboiler, heat will be added to vaporize the water from the glycol. The water will leave the top of the reboiler column as steam and will be condensed by a cooler. The regenerated glycol will leave the bottom of the reboiler where it will pass through heat exchangers, pumps, and a cooler before returning to the top of the contactor.

7.11.15 Solid Waste Disposal

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

7.11.16 Cranes

Each platform will be equipped with two outboard

pedestal mounted cranes. Each crane will have at least a 100-foot boom. A third crane in the center of the drilling deck will be part of the packaged drilling rig equipment on the two-level platforms.

7.12 Safety

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

7.12.1 Safety Standards

The U.S. Coast Guard establishes systems and equipment requirements for personnel quarters, personnel safety, means of escape, lifesaving, fire detection, fire control, fire extinguishing, navigation lights, obstruction lights, and sound signals to be used on fixed structures in navigable waters and on the OCS. These requirements are detailed in 33 CFR 67 and 33 CFR Subchapter N.

The MMS establishes rules for detection and control of combustible gases and hydrogen sulfide in Pacific Region OCS Order 5.

7.12.2 Hazard Detection and Warning Systems

Continuous monitoring fire sensors (ultraviolet, ionization, thermal, or fusible plug types) will be

used in all high-hazard areas. Detection of a hazard will result in a visual and audible alarm in the central control room. Only those fire sensors installed inside gas turbine driver enclosures or as part of an area fusible plug loop will result in automatic actuation of fire extinguishing equipment in the immediate area.

Combustible gas and/or hydrogen sulfide sensors will be strategically located throughout the platform in hazardous or poorly ventilated areas. Detection of a low (first level) concentration limit will result in a control room audible and visual alarm. Detection of a high (second level) concentration will result in a platform wide audible alarm, as well as a visual indication in the control room to indicate the source area. High level gas concentrations in poorly ventilated areas will also result in automatic shutdown and isolation of all incoming sources of gas.

7.12.3 Firefighting Equipment and Systems

Each platform will be equipped with a pressurized firewater system consisting of rigid pipe with multiple hose reels and fixed monitors stationed around the platform. Certain process equipment containing hydrocarbons and the well bay area will be covered by an automatic deluge system activated by fusible plug detectors. The water system will be supplied by four

fire pumps. One will be a small electric type jockey pump designed to keep the system pressurized and to provide daily-use hose water for deck washdown. The other three will be large high volume types, one electric motor driven and the other two diesel engine driven. Sufficient fuel will be stored at each of the diesel engines to provide at least 30 minutes of run time.

In addition to the water-based firefighting systems, the platforms will be provided with numerous portable and semiportable dry chemical or CO₂ fire extinguishers placed according to 33 CFR 145.

Each gas turbine driver will be enclosed and equipped with a Halon 1301 extinguishing system tripped automatically by an ultraviolet fire detector.

7.12.4 Escape and Lifesaving Equipment

Each platform will be equipped with a U.S. Coast Guard approved escape capsule(s) or lifeboat(s), plus an adequate number of life preservers, life floats, ring life buoys, first aid kits, litters, and other lifesaving appliances as required by 33 CFR 144.

7.12.5 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 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.

7.12.6 Aids to Navigation

Offshore platforms are generally classified as Class B structures by the U.S. Coast Guard and therefore will require Class B obstruction lights and fog signal as per 33 CFR 67. However, the USCG has required that the Hondo A platform carry a Class A fog signal due to its strategic location and proximity to the northbound channel sea lane. Therefore, the USCG may conceivably require the stronger type Class A signal on one or more of the new platforms.

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

The heliport perimeter will be outlined with lights

plus one flashing amber beacon. The heliport lights will be illuminated only when needed.

7.13 Environmental Impact Mitigation Measures

7.13.1 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 will be 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 will be 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, will reduce H₂S exposure to personnel, will eliminate VOC (volatile organic compounds) emissions normally associated with atmospheric tanks and vessels, and will recover energy that would otherwise be lost.

7.13.2 Waste Heat Recovery

A significant amount of heat will be required on each platform to reduce emulsion viscosity and to assist in degassing the emulsion before shipment. Heat will also

be required to regenerate glycol or solvent solutions used in the dehydration and fuel sweetening systems. On each platform where gas turbines will be used for power generation or compressor drivers, waste heat will be recovered from the turbine exhaust to the extent required to satisfy platform heat requirements. This measure will conserve fuel and reduce emissions by reducing or eliminating the need for fired heaters. Lowering the emulsion viscosity with recovered waste heat will also result in less shipping pump horsepower and its associated emissions.

7.13.3 Spill Prevention and Containment

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

will be routed to the flare; liquids will flow to a surge rerun tank from which they will be pumped back into the emulsion system.

In the unlikely event that an overboard spill does occur, the offshore facilities will be equipped with a spill containment boom and boom deployment boat that can be used to minimize the impact of such an occurrence. Exxon's Oil Spill Contingency Plan for California Operations is overviewed in Attachment C.

7.13.4 Emergency Flare

All vapor safety relief valves and back-pressure surge control regulators will exhaust into a closed flare header system which gathers the emergency releases and routes them through a scrubber to a flare burner. The burner will be of a smokeless design which utilizes electric motor driven air blowers to provide adequate air for complete combustion. This measure will reduce VOC, H₂S and particulate emissions and smoke.

7.13.5 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.

7.13.6 Common Grid Electrical Power Generation and Distribution

In order to minimize the amount of installed electric generating capacity, all platforms will be interconnected with a 35 kV submarine cable. Each platform could thus draw upon the spare capacity of the overall system to start large motors and during generator maintenance rather than having to install spare generating capacity on each platform.

By reducing the overall amount of generating horsepower installed, the per unit percent load will be increased. This will result in an increased thermal efficiency of each unit and thus reduce overall fuel consumption and emissions.

In Development Option A (Offshore Oil Treating), the

OS&T will be connected to the 35 kV power grid via the existing OS&T to Hondo A platform submarine cable. Each of the new platforms will have installed gas turbine driven generator sets.

In Development Option B (Onshore Oil Treating), an onshore central power plant will send electrical power to all of the offshore platforms through a submarine cable system. No turbine generator sets will be installed on any of the new platforms.

7.13.7 Gas Turbine NO_x Reduction Equipment

For Development Option B (Onshore Oil Treating), all new turbines installed on the offshore platforms will be equipped with a water injection type NO_x reduction process if the technology is commercially feasible and available.

7.13.8 OS&T Gas Sweetening, Sulfur Recovery, Acid Gas Incineration

The OS&T is equipped with a solvent type gas sweetening system which reduces the total sulfur in the turbine fuel gas to less than 100 ppm. The acid gas produced from solvent regeneration is processed in a Claus sulfur recovery unit to recover about ninety-three percent (93%) of the sulfur compounds as elemental sulfur. The remaining tail gas from the Claus sulfur recovery unit is incinerated at 1600°F to convert

all remaining sulfur compounds to sulfur dioxide. These measures drastically reduce sulfur dioxide emissions from the OS&T.

7.13.9 Hondo B Platform Fuel Gas Sweetening

Due to the absence of sweet gas production on the Hondo B platform, it will be equipped with a solvent type gas sweetening facility sized to handle the necessary fuel gas volumes. Acid gas produced from solvent regeneration will be commingled with the vapor recovery gas and compressed into the sales gas. This measure will greatly reduce sulfur dioxide emissions from all fuel burning equipment on this platform.

7.13.10 Marine Vessel Loading Vapor Balance System

Potentially, the largest source of volatile organic compound (VOC) emissions in the Santa Ynez Unit would come from an uncontrolled marine loading of cargo oil into a marine vessel. This source of emissions is almost totally eliminated by the vapor balance system which transfers vapors from the receiving marine vessel via a floating hose back to the storage tanks being emptied. Any excess vapors are compressed by the vapor recovery system of the storage facilities. This type of vapor balance system is presently in operation at the OS&T, and the vapor balance concept will be utilized for the modernized nearshore marine terminal

proposed in Development Option B.

7.13.11 Low NO_x Heater Burners

The new fired heaters on the Hondo A platform will have burners and air control systems specifically designed to reduce NO_x formation.

7.13.12 Large Diameter Pipelines

Large diameter pipelines have been selected for the gathering system as a means of minimizing the amount of pumping and compression horsepower installed. This will result in lower fuel consumption and an overall emissions reduction.

VALVE SYMBOLS



BLOCK VALVE



CHECK VALVE



CHOKE



3-WAY DIVERTER VALVE



4-WAY DIVERTER VALVE



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**



FLOW RECORDER

MISCELLANEOUS



HEAT EXCHANGER



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**

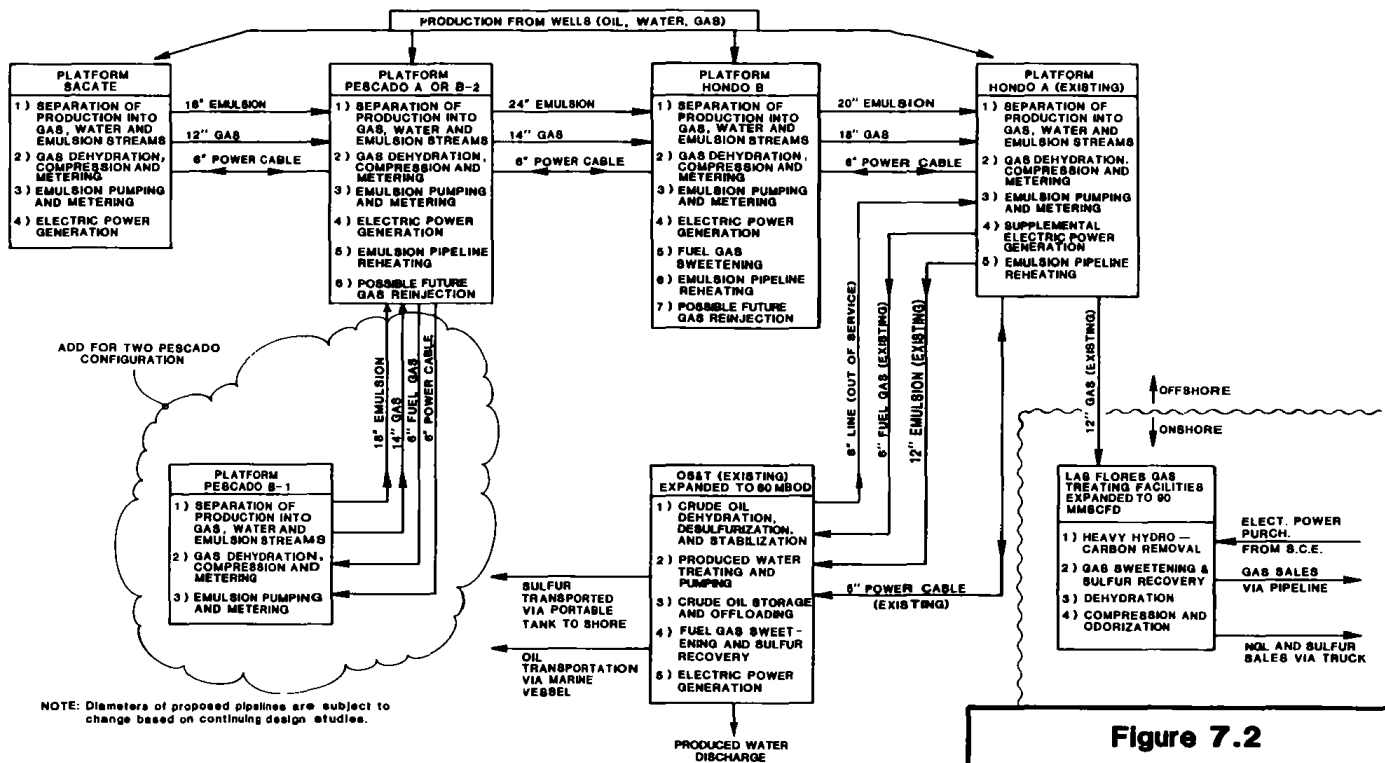
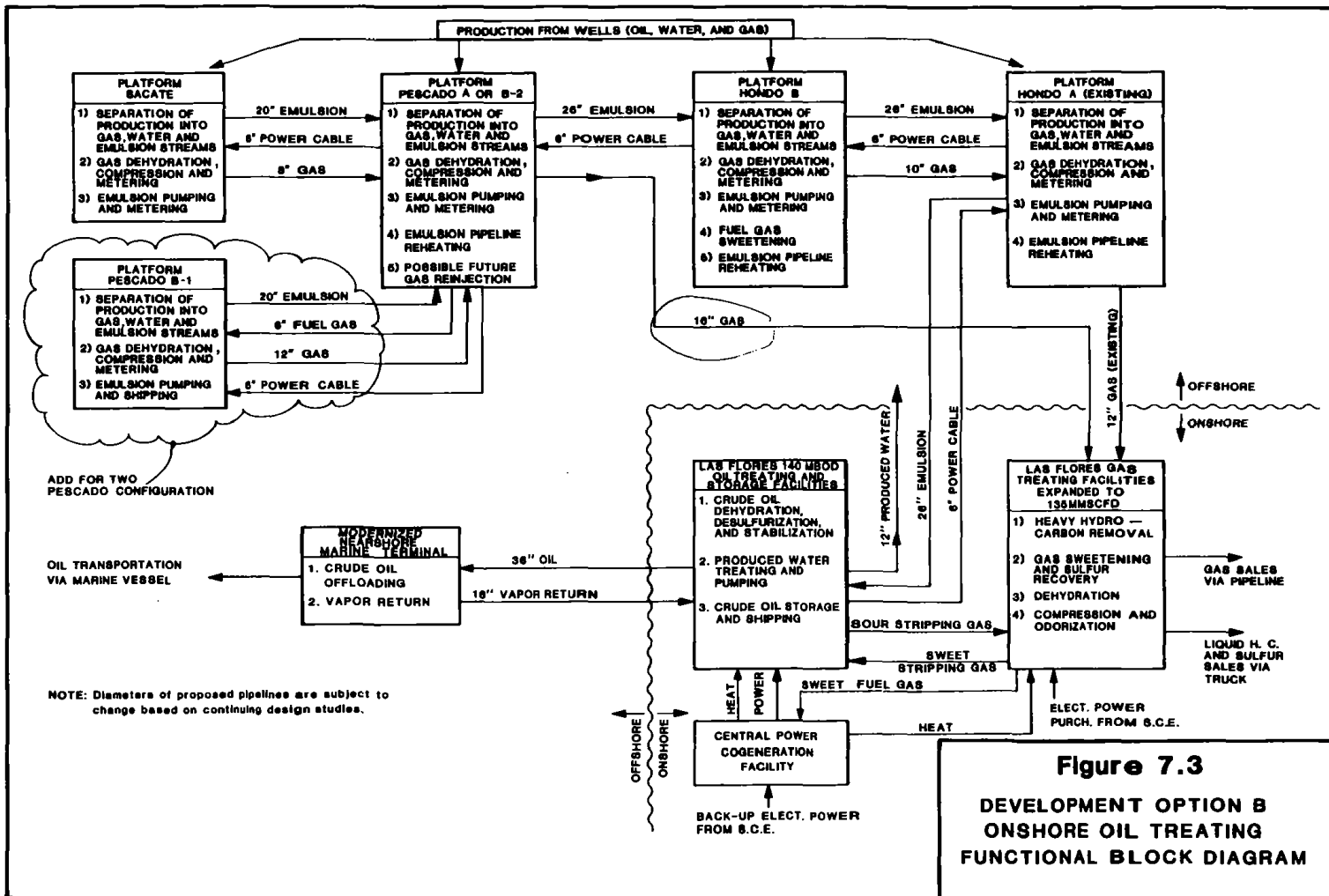
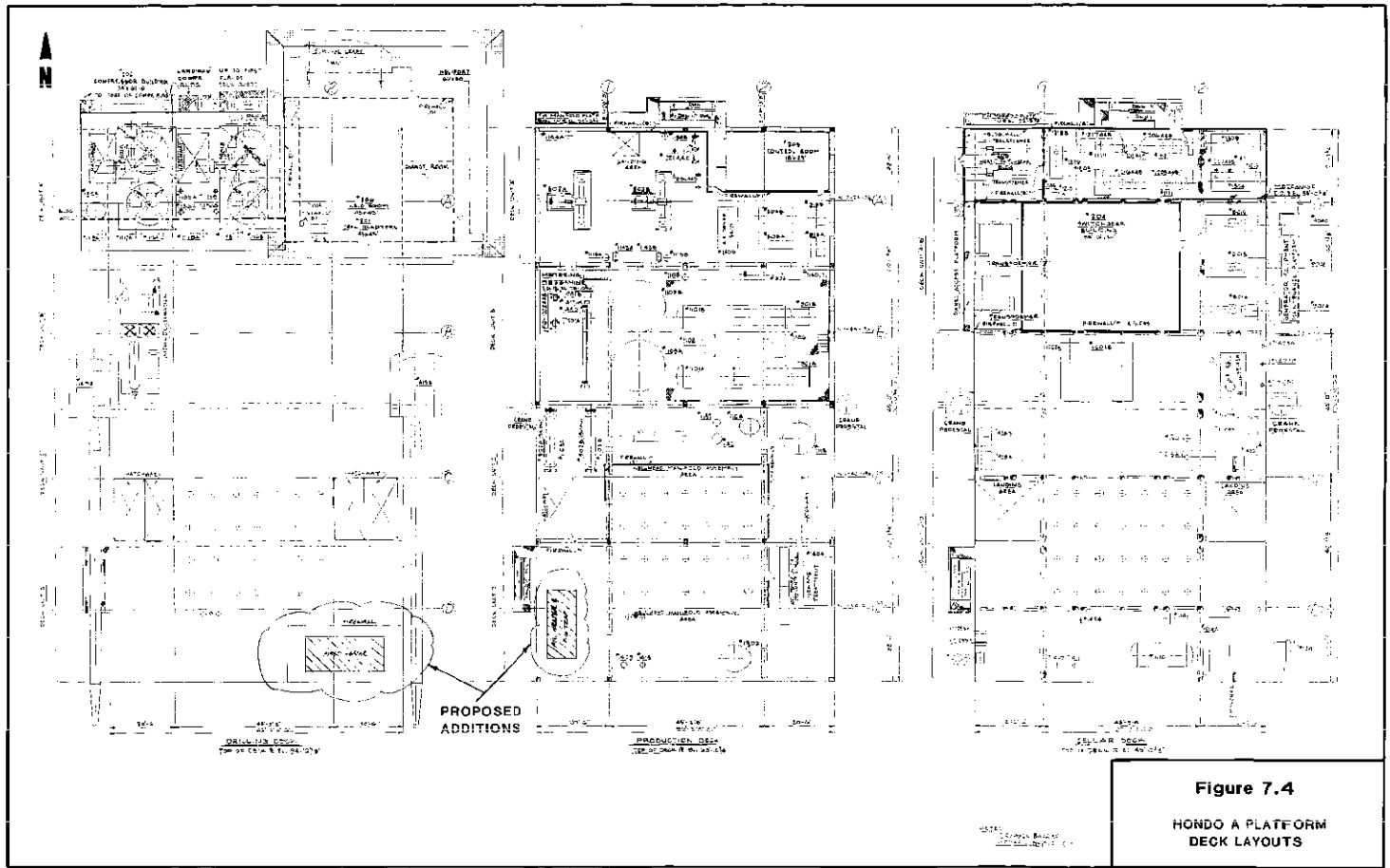


Figure 7.2
DEVELOPMENT OPTION A
OFFSHORE OIL TREATING
FUNCTIONAL BLOCK DIAGRAM





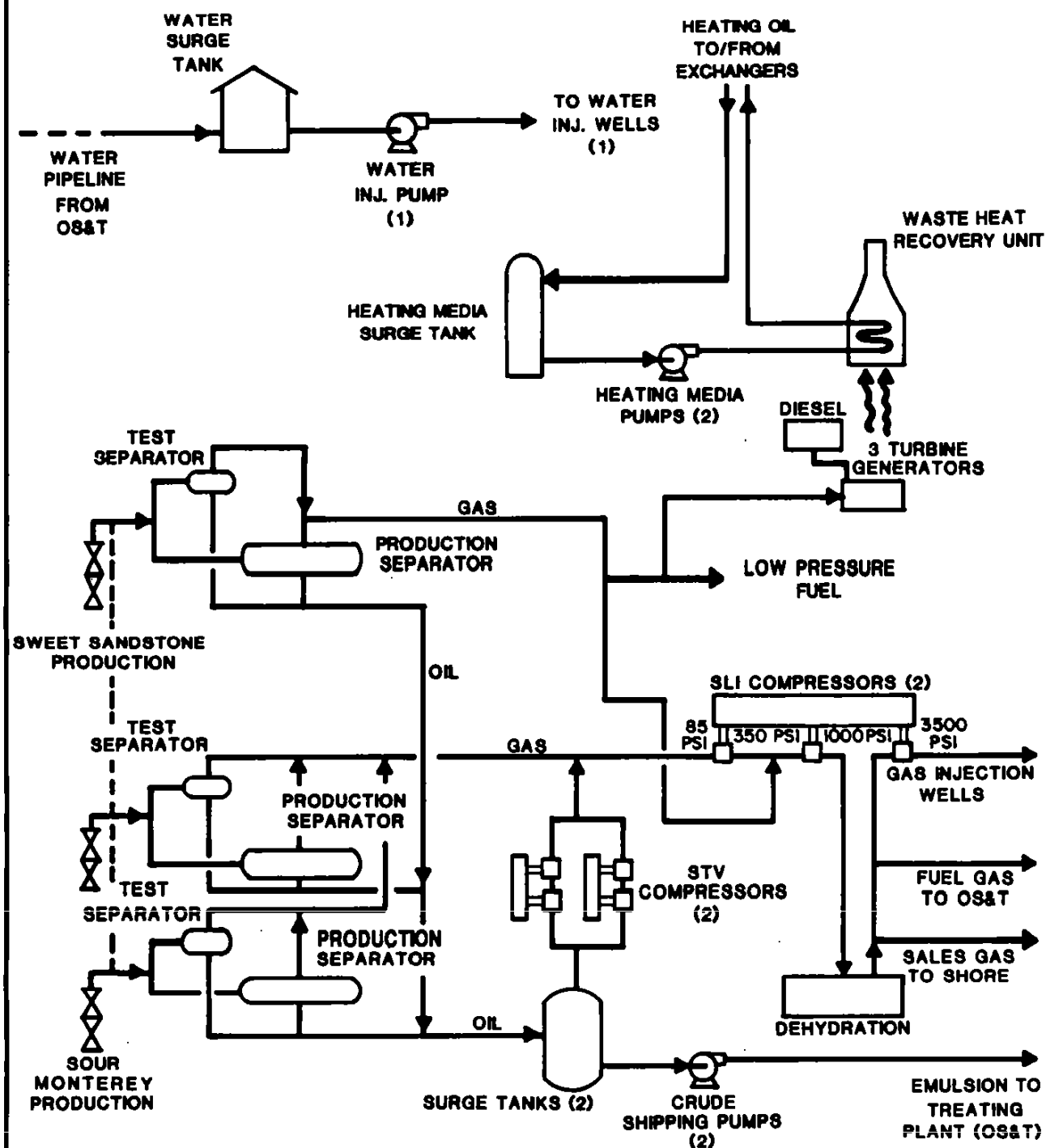
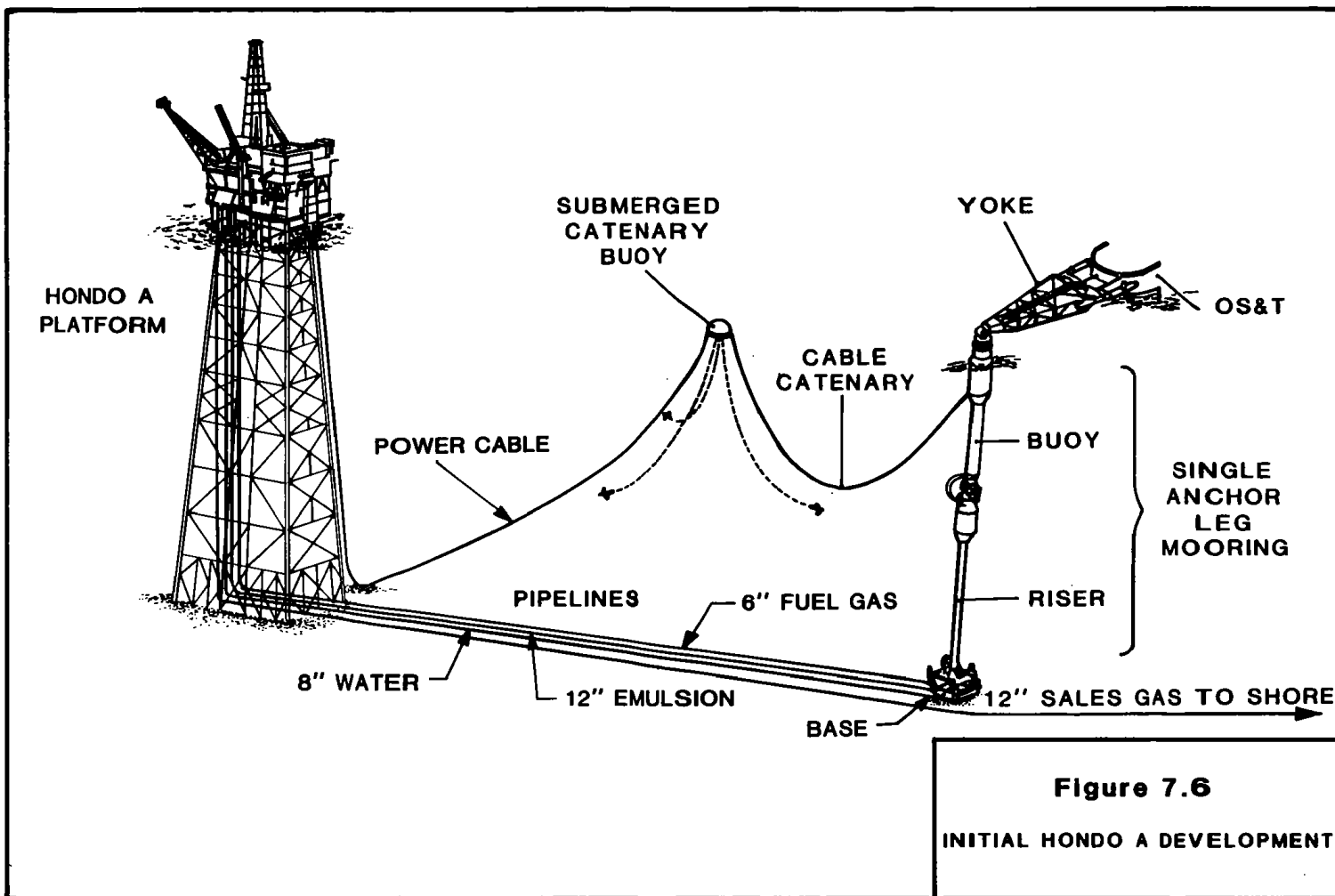


Figure 7.5

**HONDO A PLATFORM
PROCESS SCHEMATIC
EXISTING FACILITIES**



NOTE:

PROPOSED
ADDITION

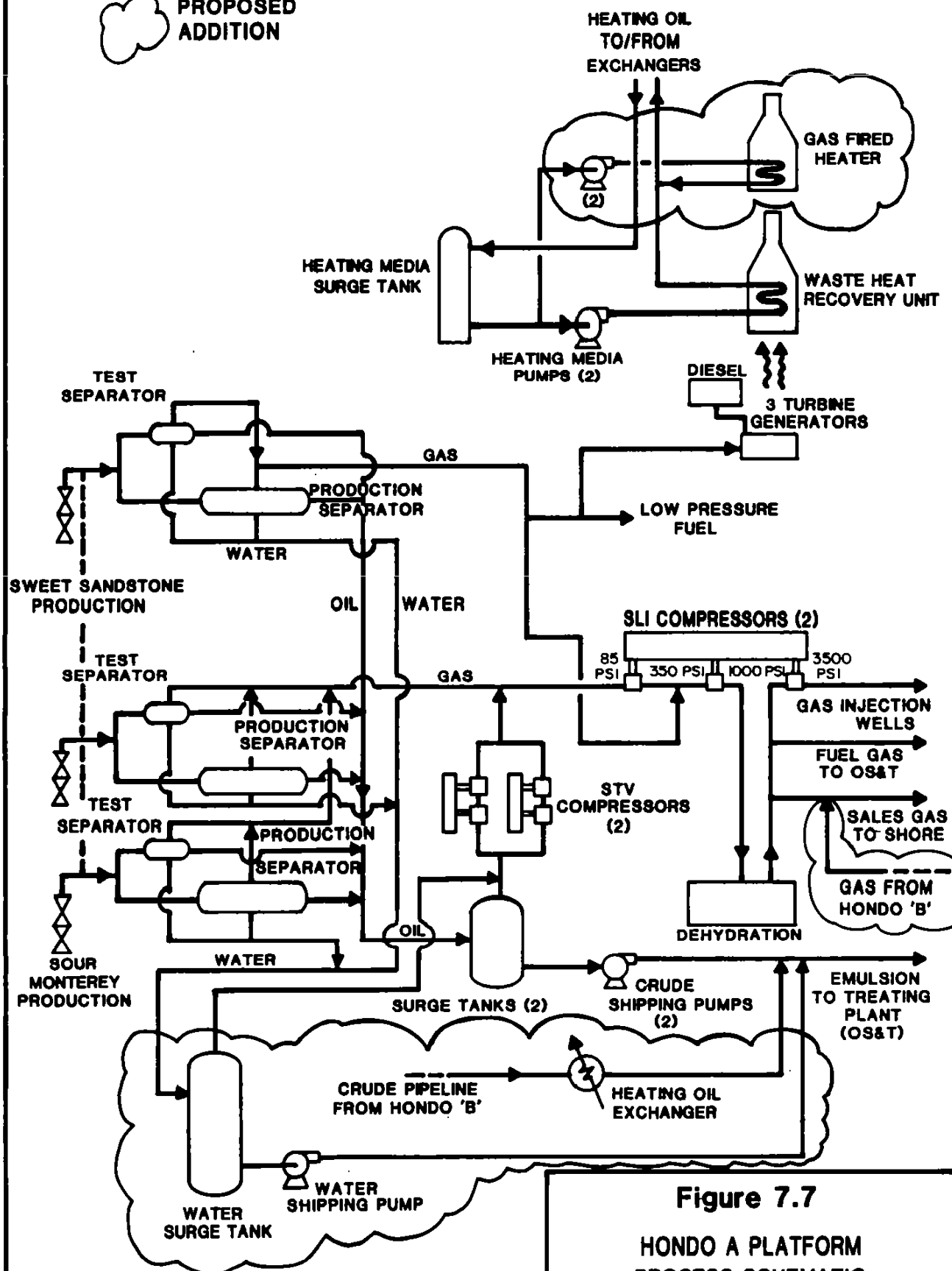


Figure 7.7

HONDO A PLATFORM
PROCESS SCHEMATIC
MODIFIED FACILITIES
DEVELOPMENT OPTION A

NOTE:



PROPOSED
ADDITION

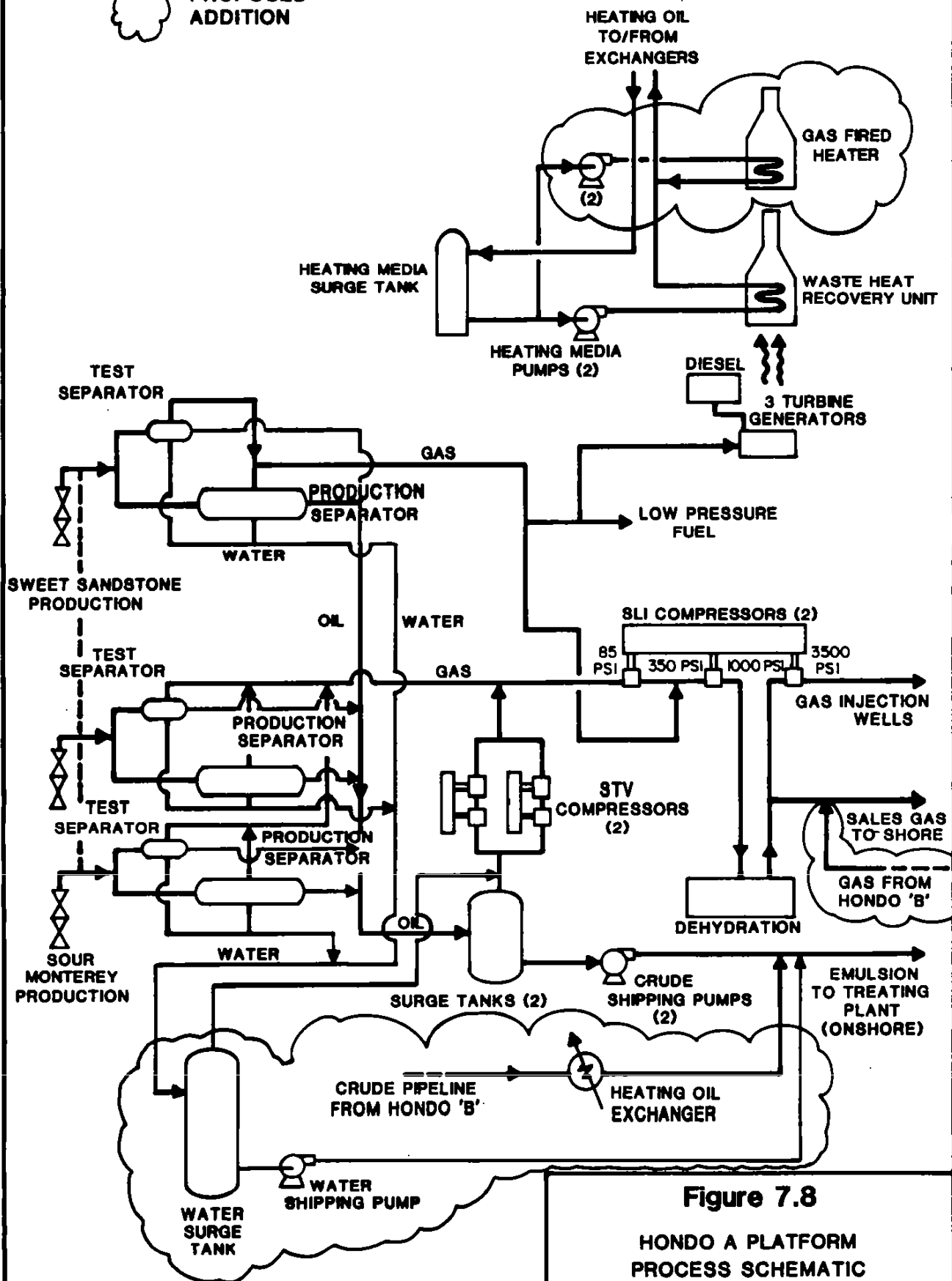
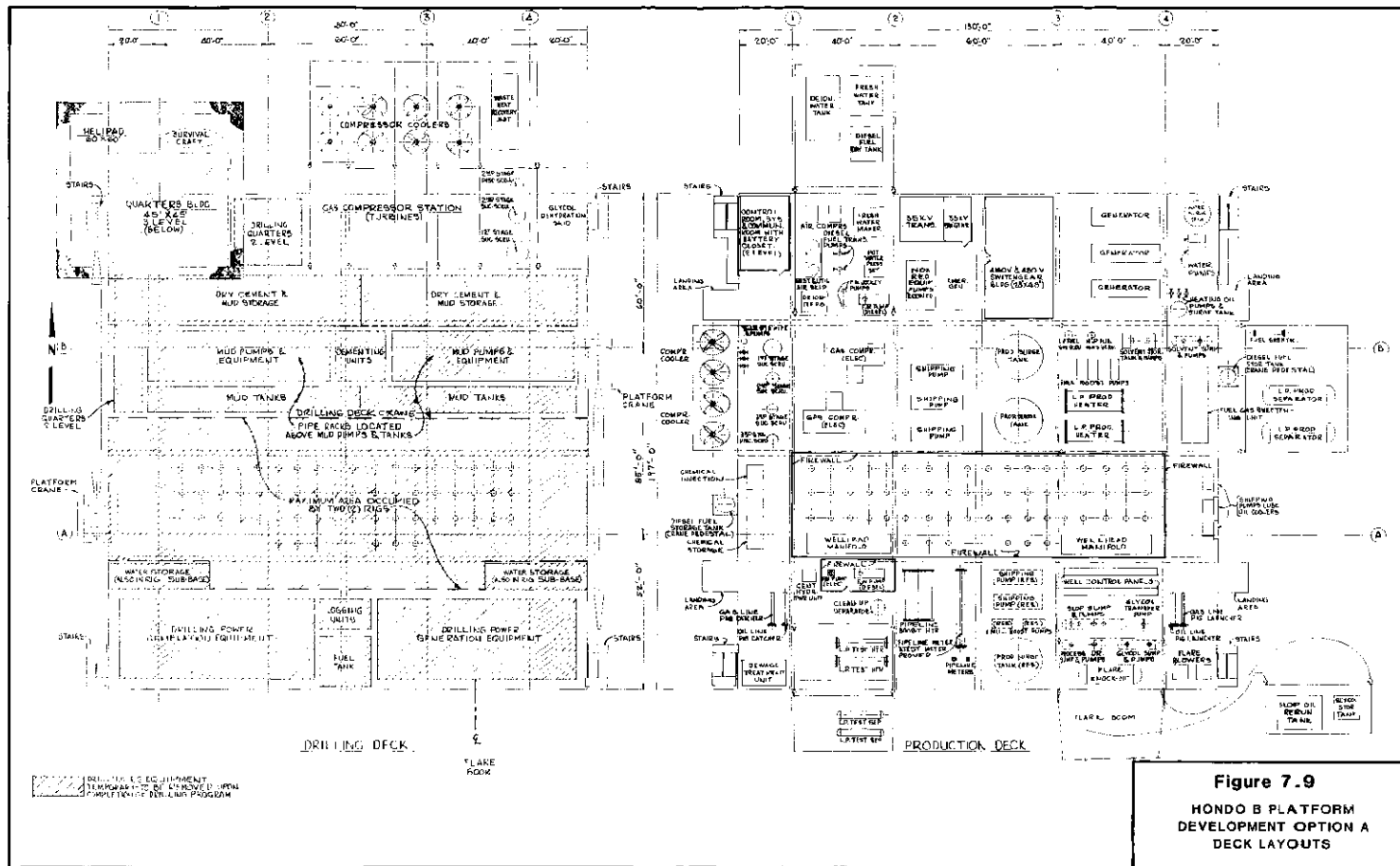


Figure 7.8

HONDO A PLATFORM
PROCESS SCHEMATIC
MODIFIED FACILITIES
DEVELOPMENT OPTION B



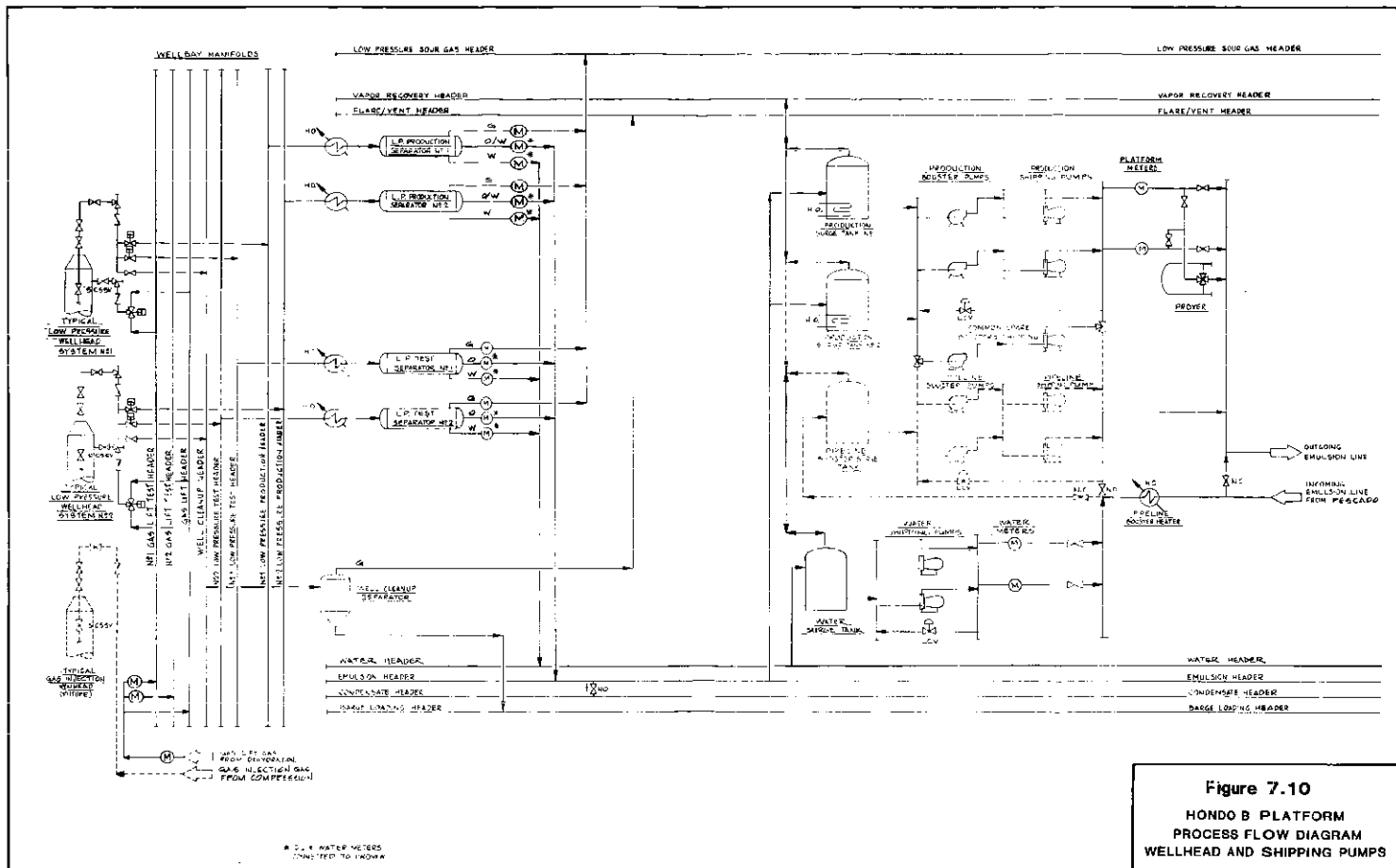
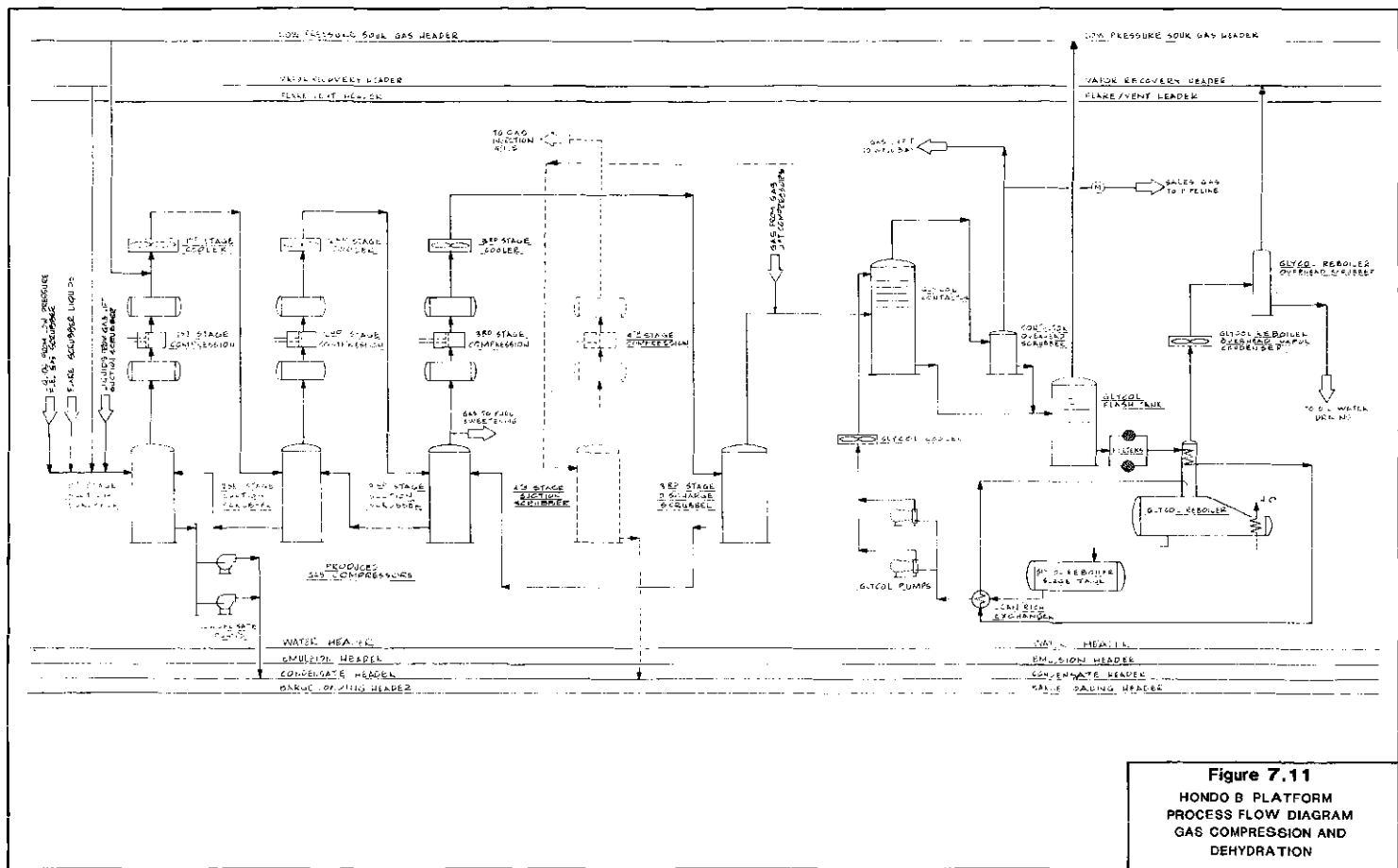


Figure 7.10
HONDO B PLATFORM
PROCESS FLOW DIAGRAM
WELLHEAD AND SHIPPING PUMPS



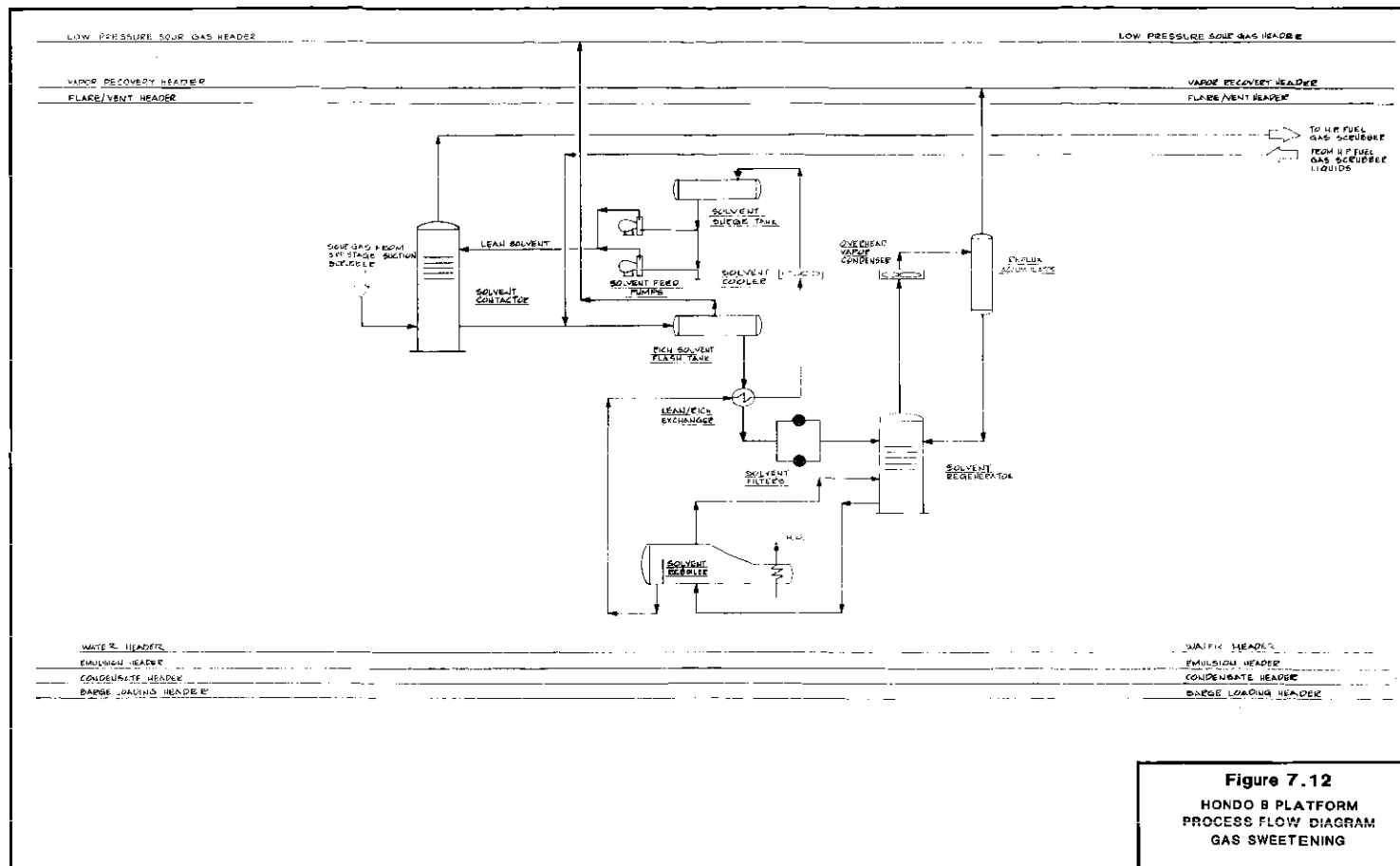


Figure 7.12
HONDO B PLATFORM
PROCESS FLOW DIAGRAM
GAS SWEETENING

LOW PRESSURE SQUEE GAS HEADER

LOW PRESSURE SQUEE GAS HEADER

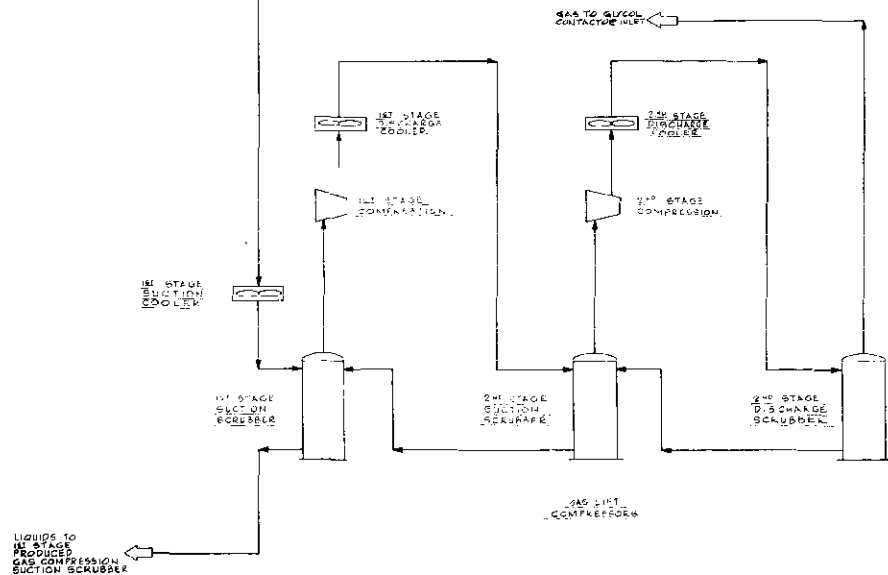
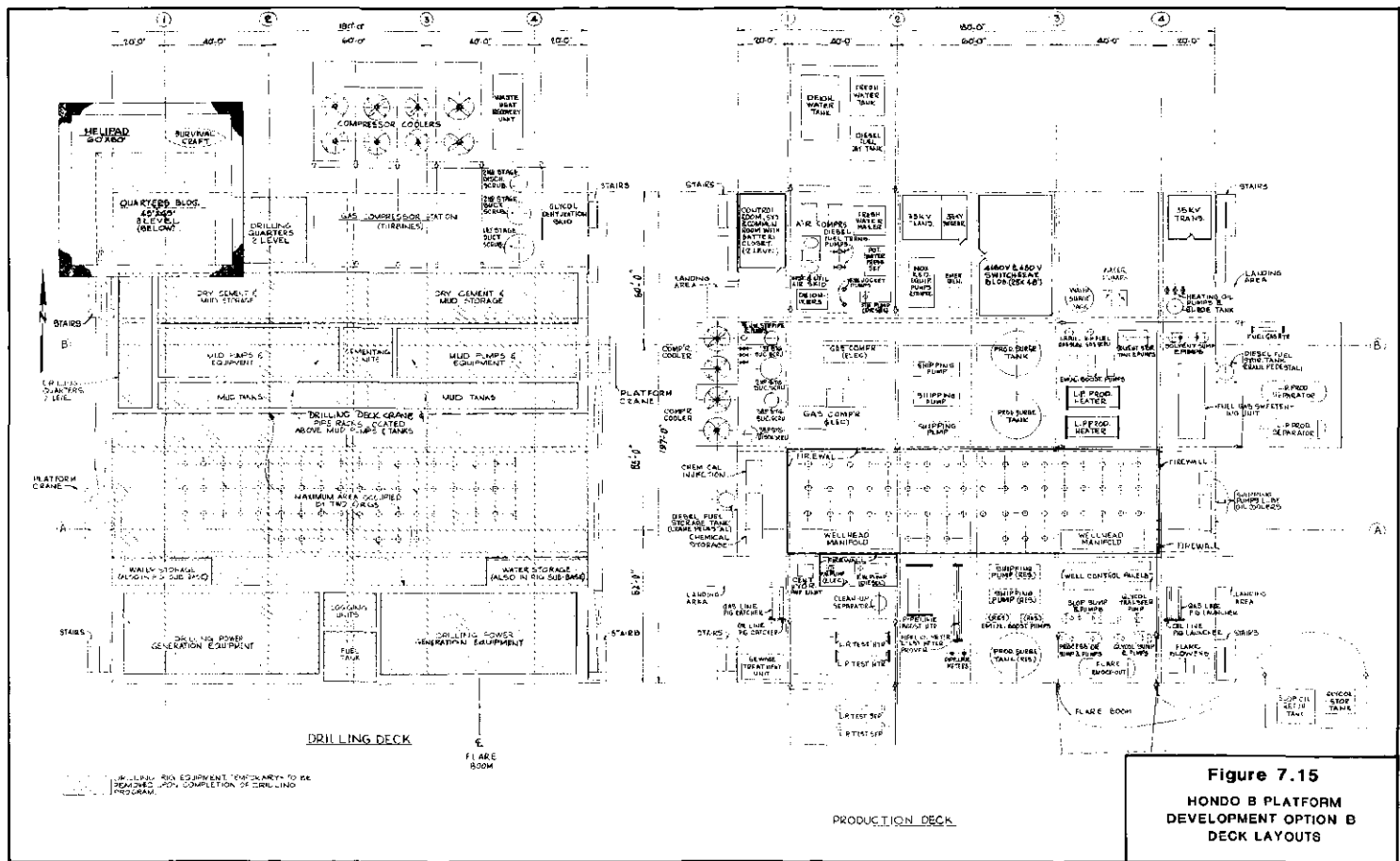
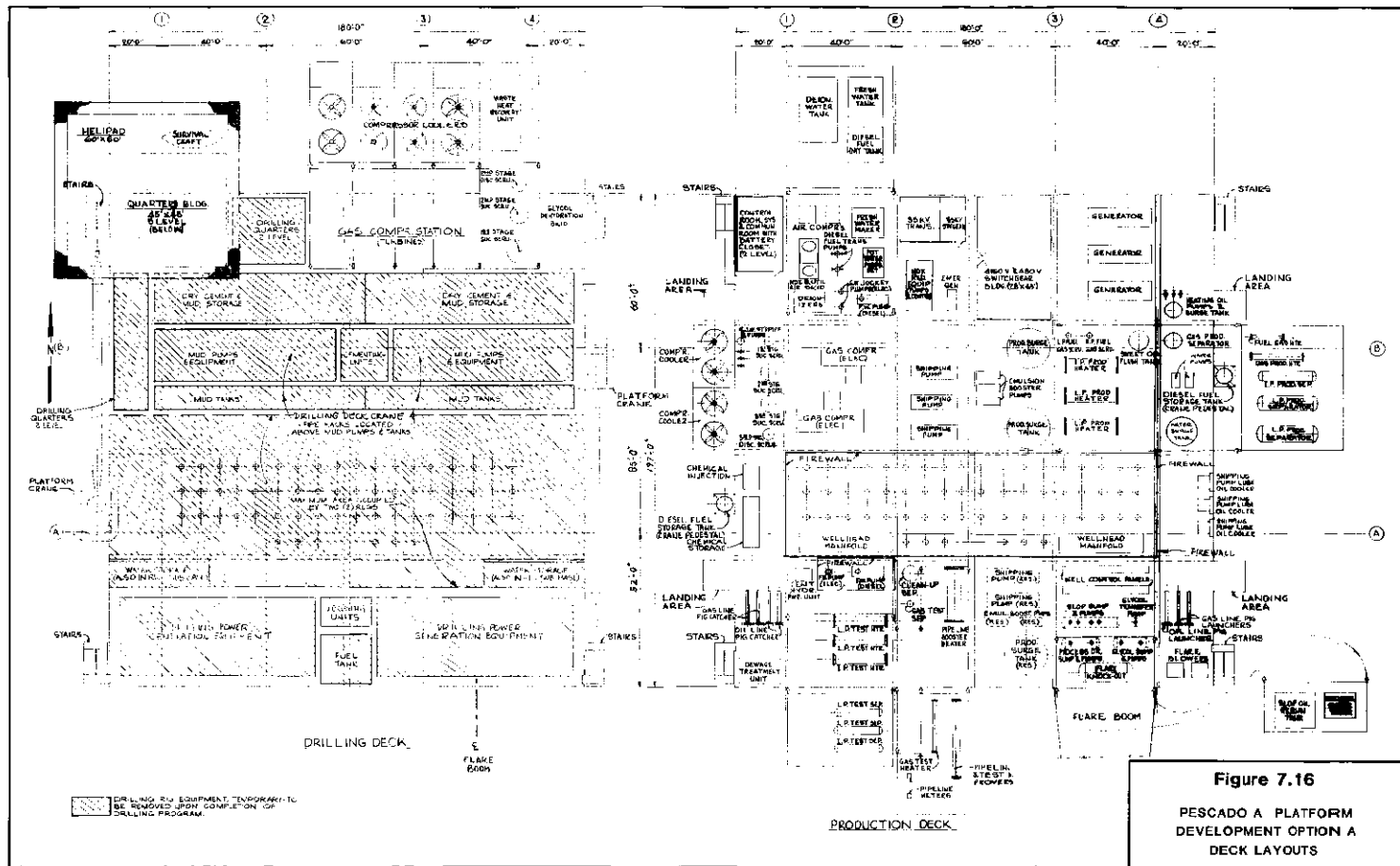


Figure 7.14
HONDO B PLATFORM
PROCESS FLOW DIAGRAM
GAS LIFT COMPRESSION





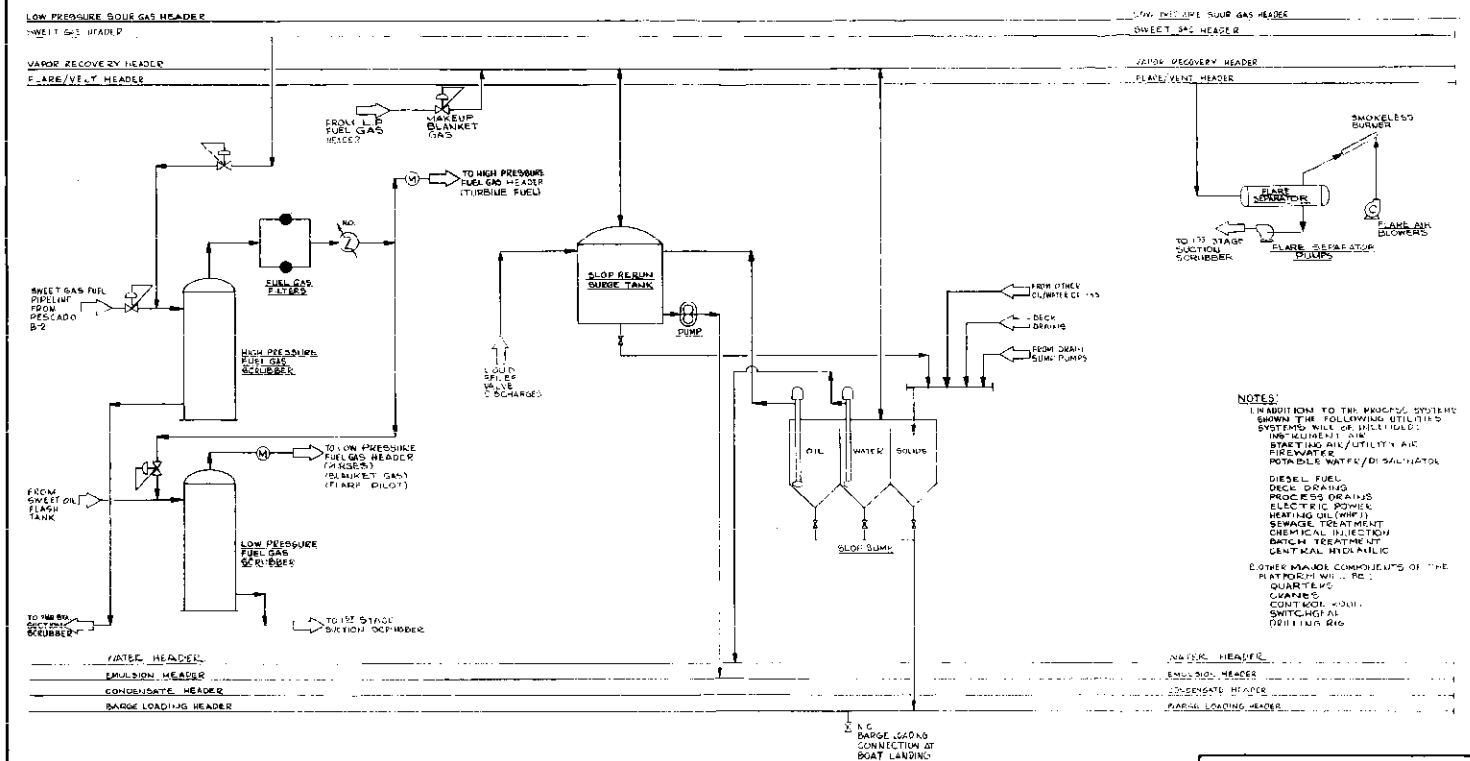


Figure 7.19
PESCADO A PLATFORM
PROCESS FLOW DIAGRAM
FUEL GAS AND SUMP SYSTEMS

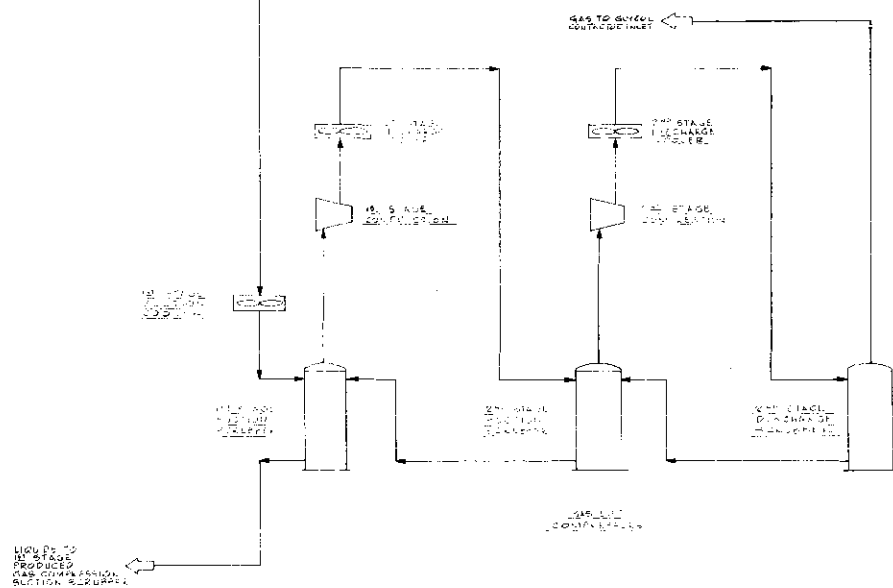
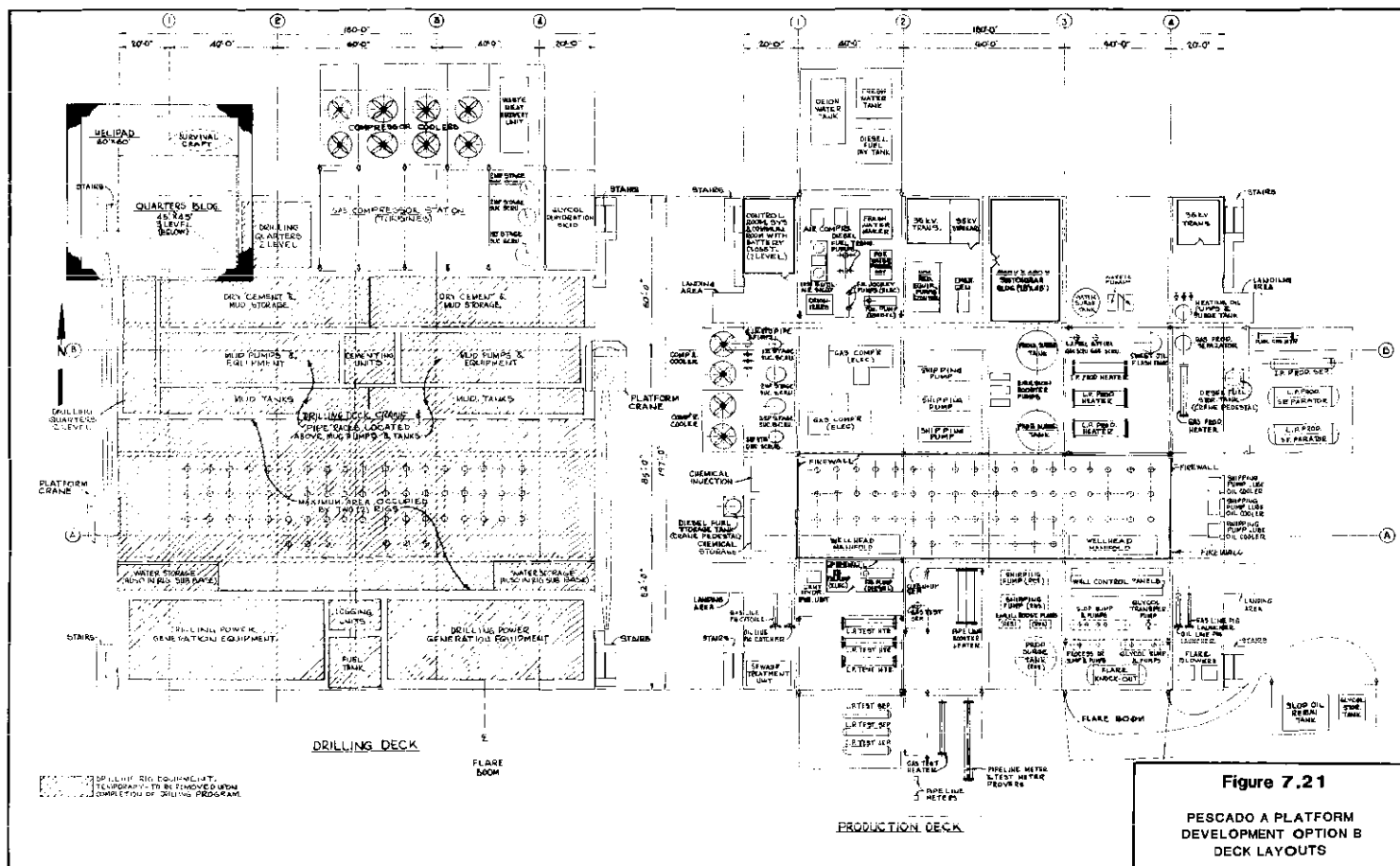
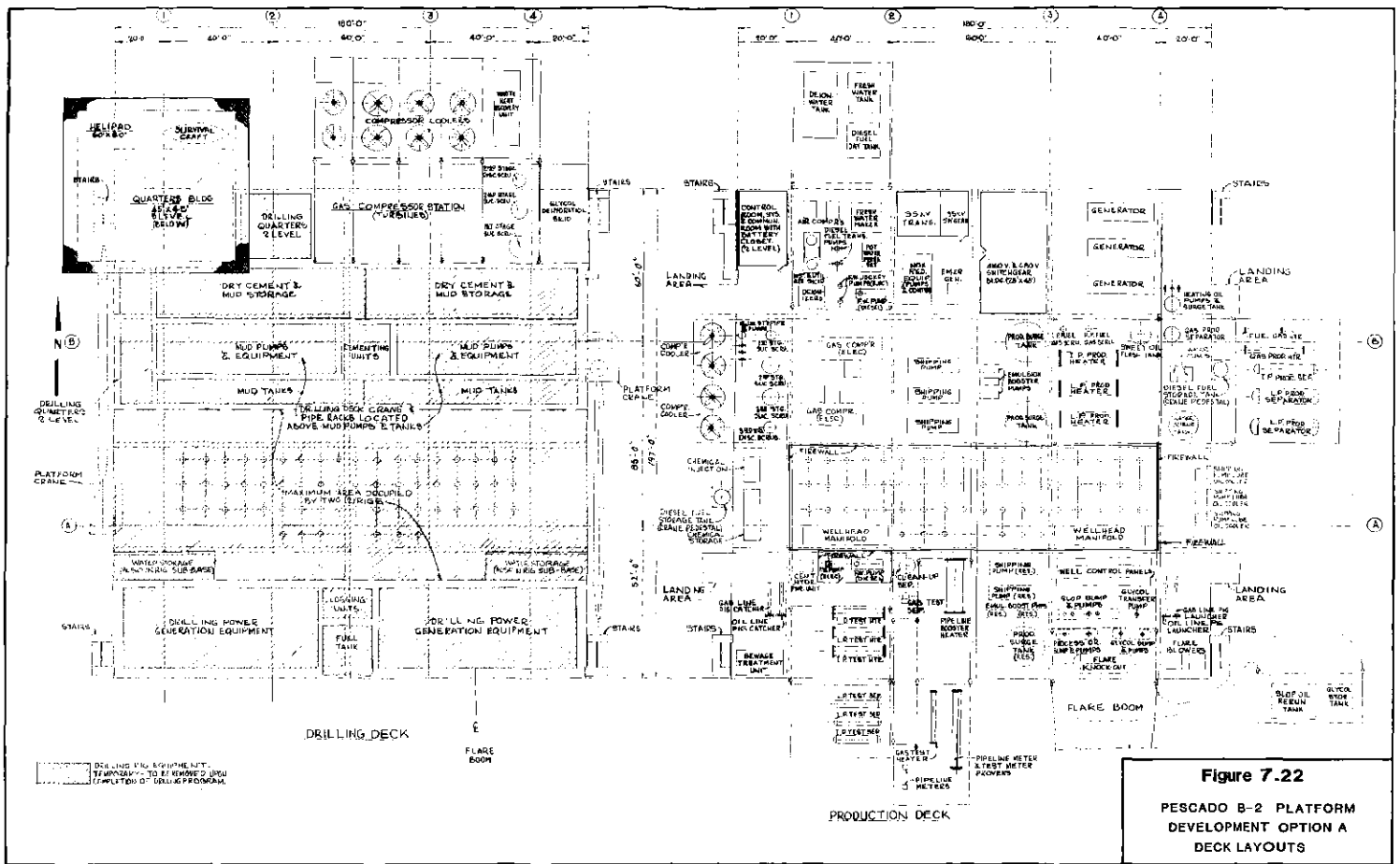


Figure 7.20

**PESCA DO A PLATFORM
PROCESS FLOW DIAGRAM
GAS LIFT COMPRESSION**





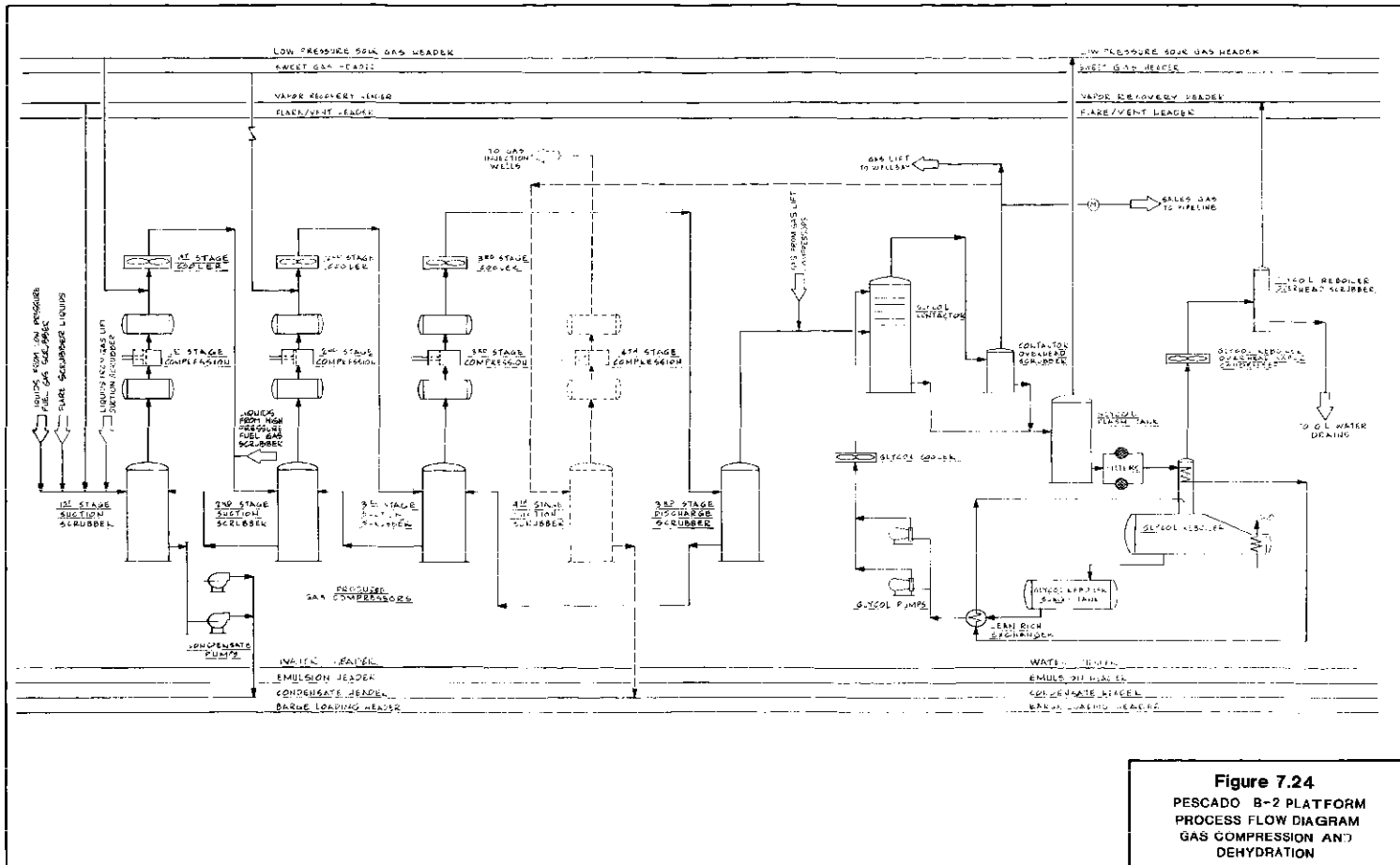


Figure 7.24
PESCADO B-2 PLATFORM
PROCESS FLOW DIAGRAM
GAS COMPRESSION AND
DEHYDRATION

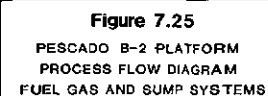


Figure 7.25
PESCADO B-2 PLATFORM
PROCESS FLOW DIAGRAM
FUEL GAS AND SUMP SYSTEMS

LOW PRESSURE BOLESAO LEADER

LOW PRESSURE BOLESAO GAS HEADER

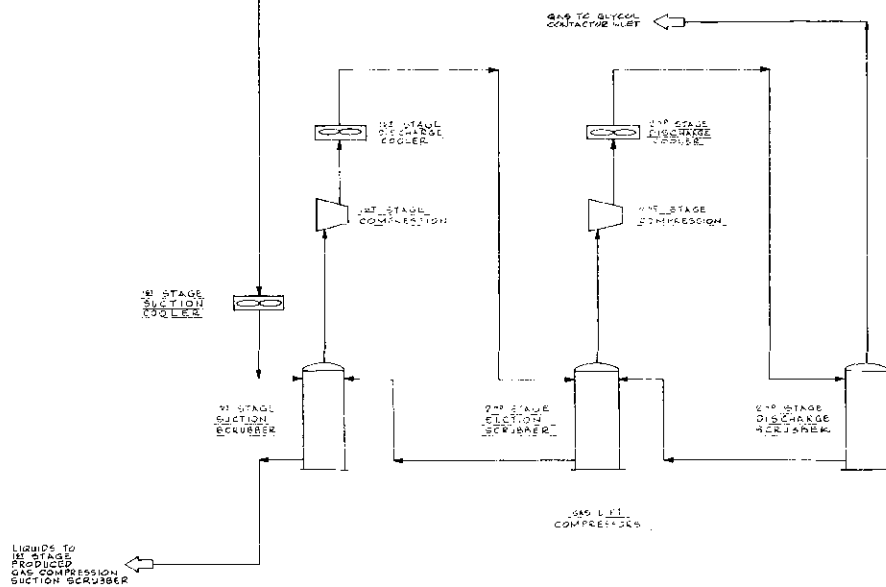
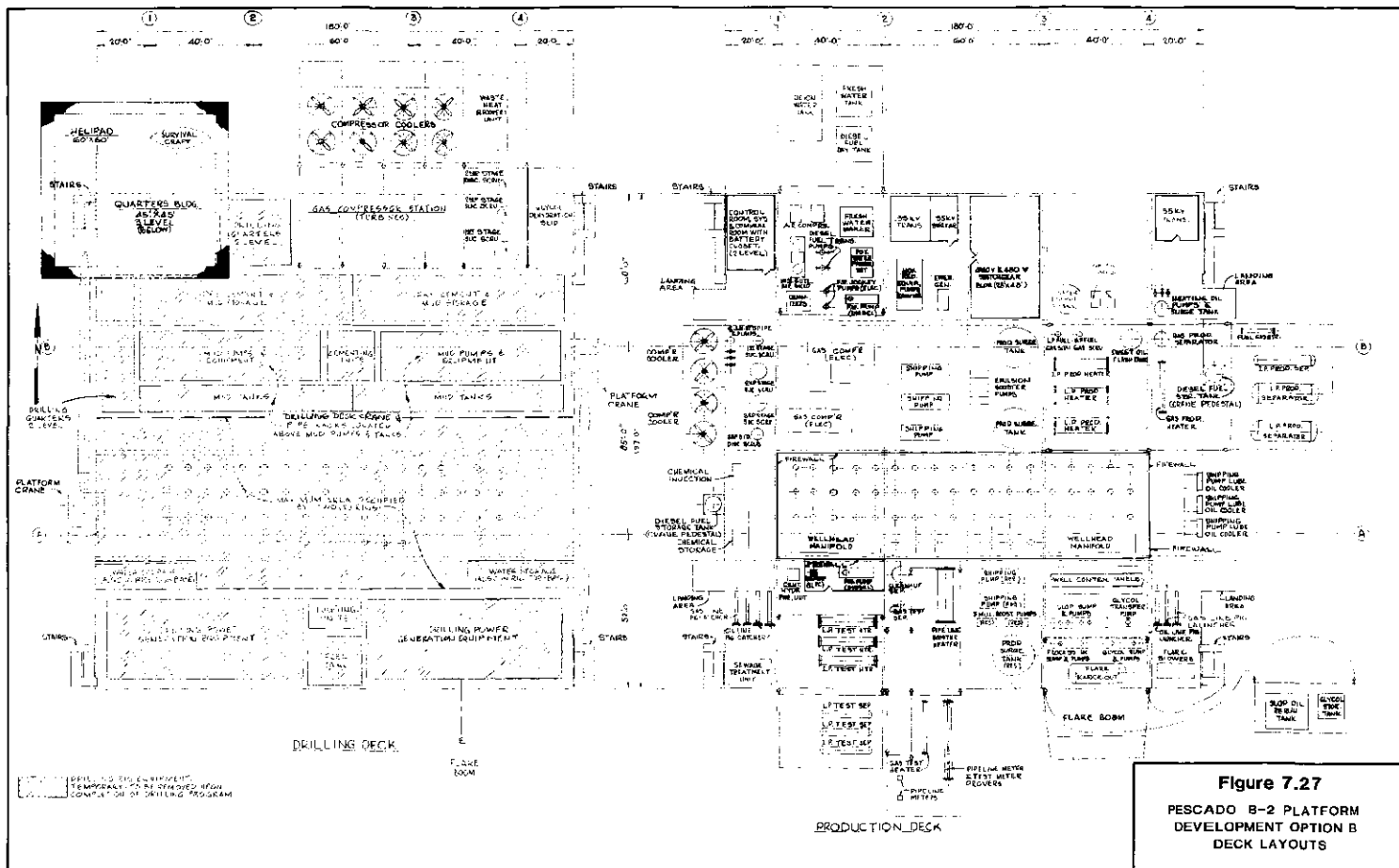


Figure 7.26

PESCADÓ B-2 PLATFORM
PROCESS FLOW DIAGRAM
GAS LIFT COMPRESSION



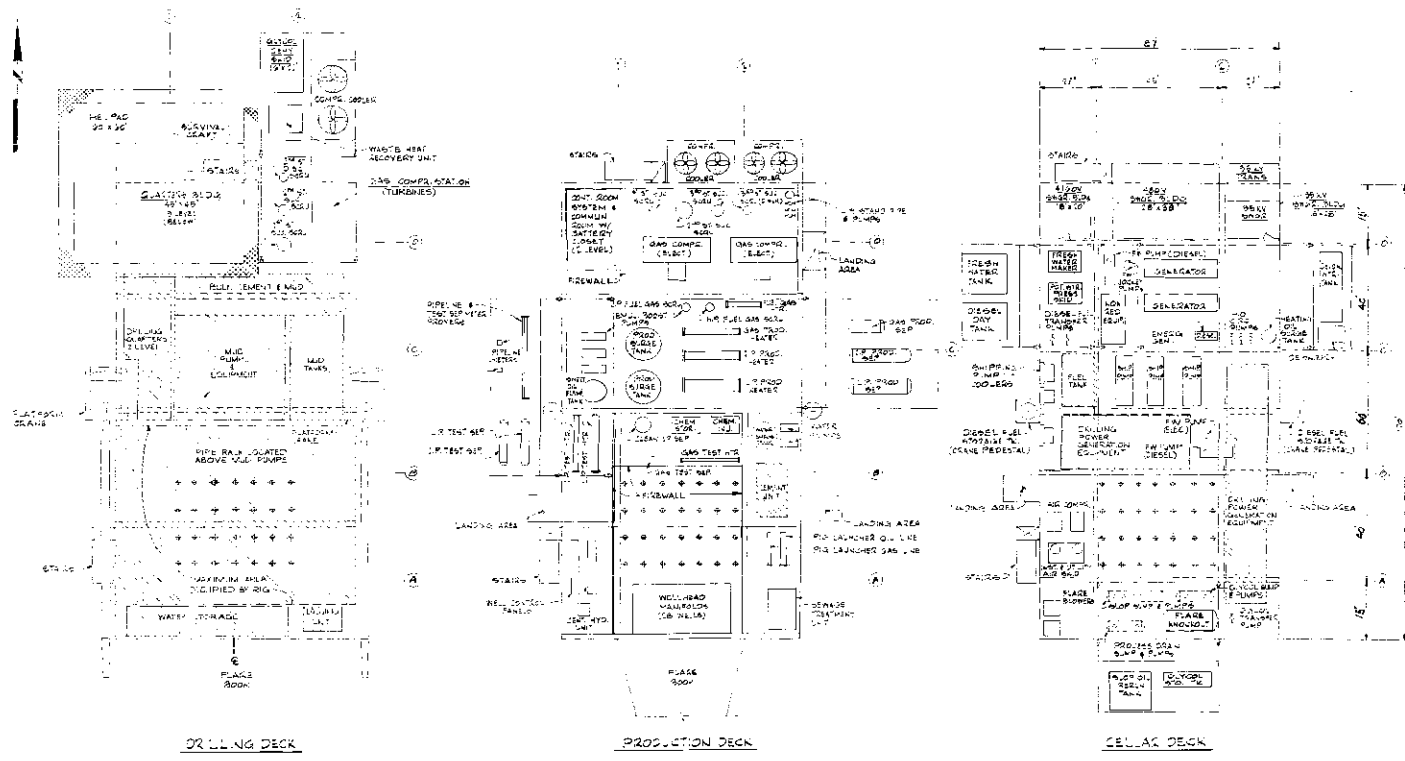
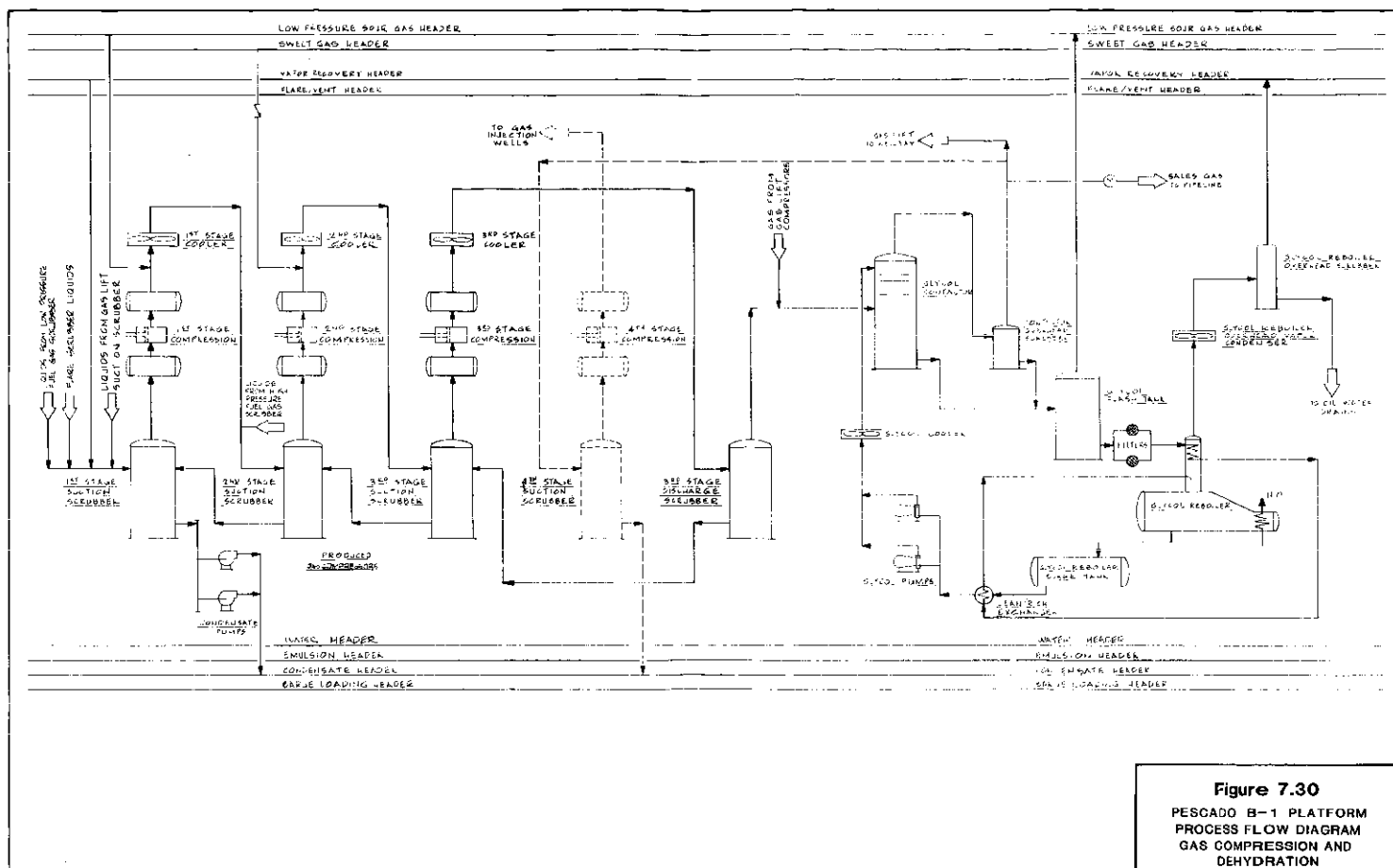


Figure 7.28
PESCAO B-1 PLATFORM
DEVELOPMENT OPTION A
DECK LAYOUTS



LOW PRESSURE SOUR GAS HEADER

LOW PRESSURE SOUR GAS HEADER

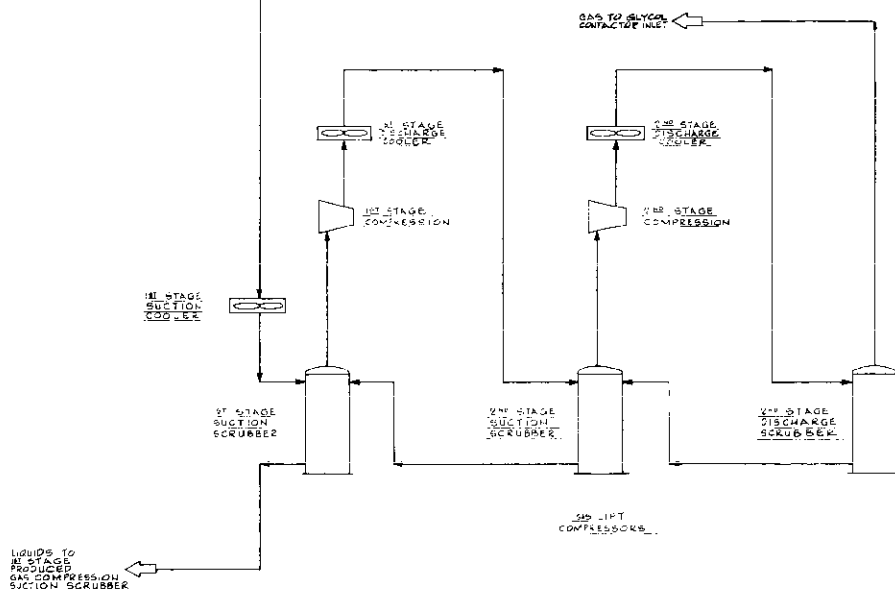


Figure 7.32

PESCADO B-1 PLATFORM
PROCESS FLOW DIAGRAM
GAS LIFT COMPRESSION

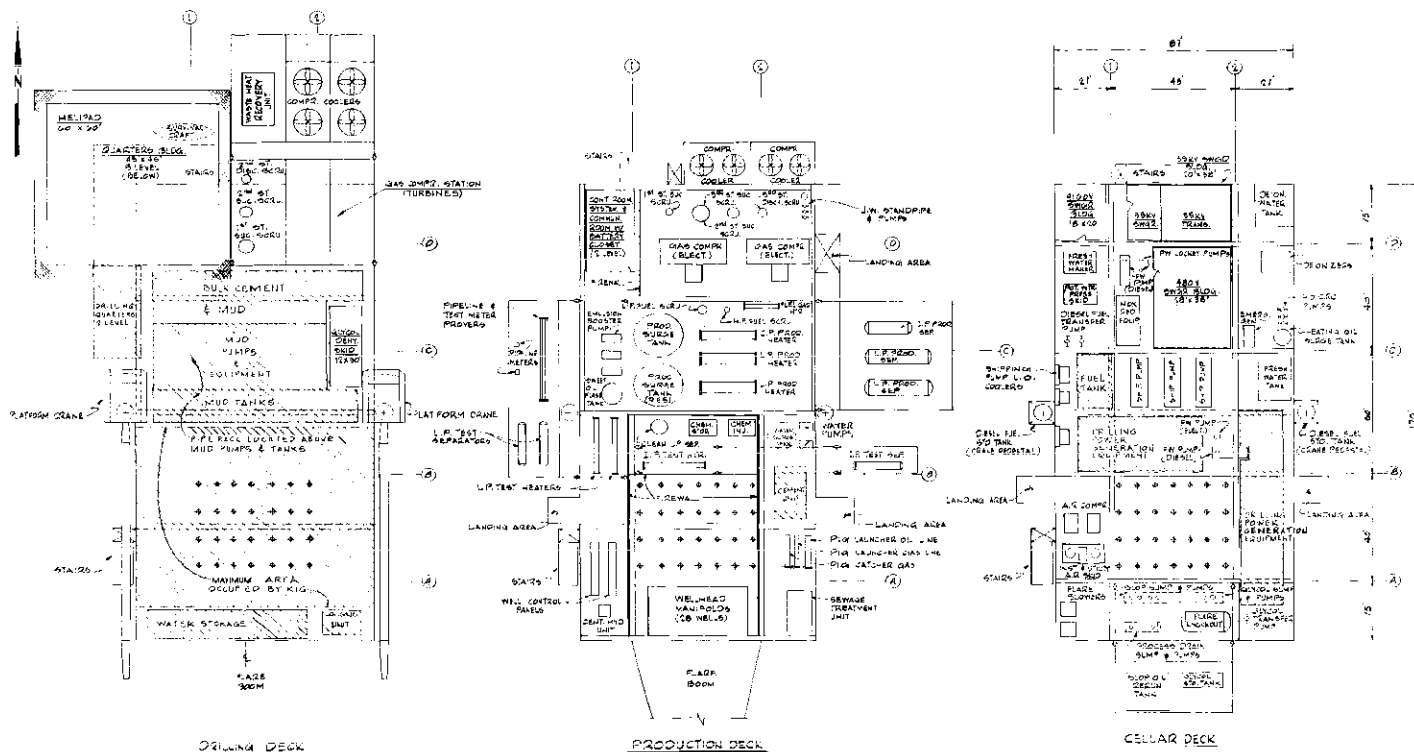
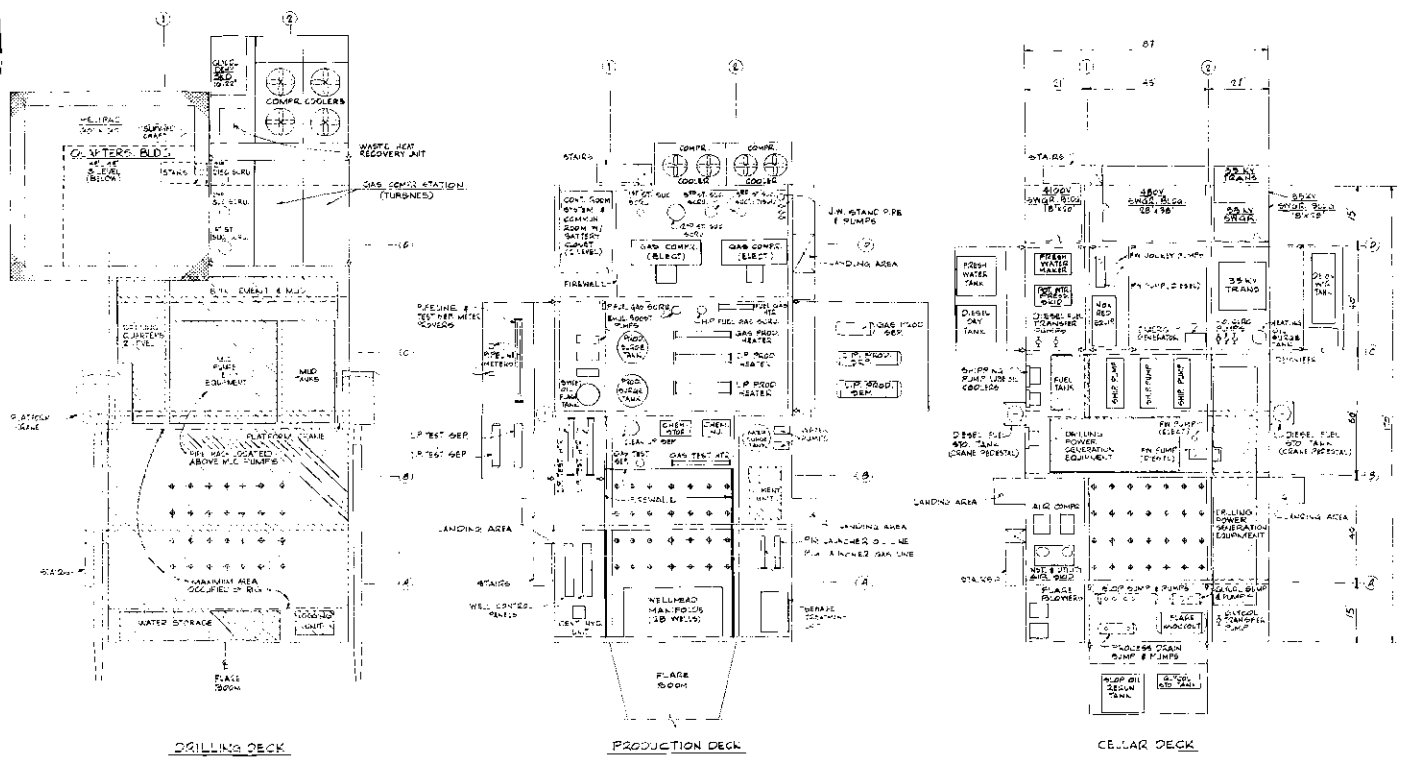
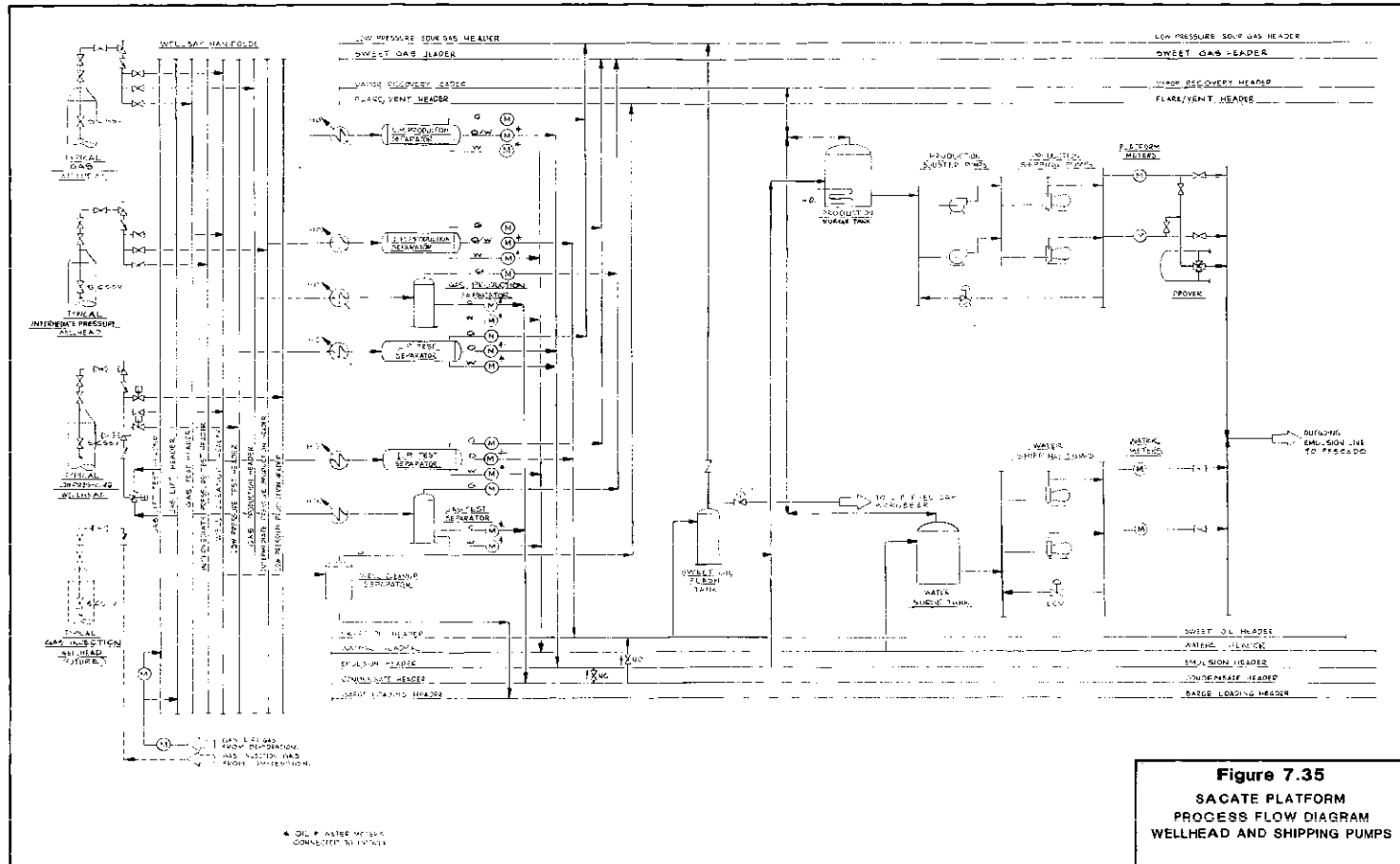


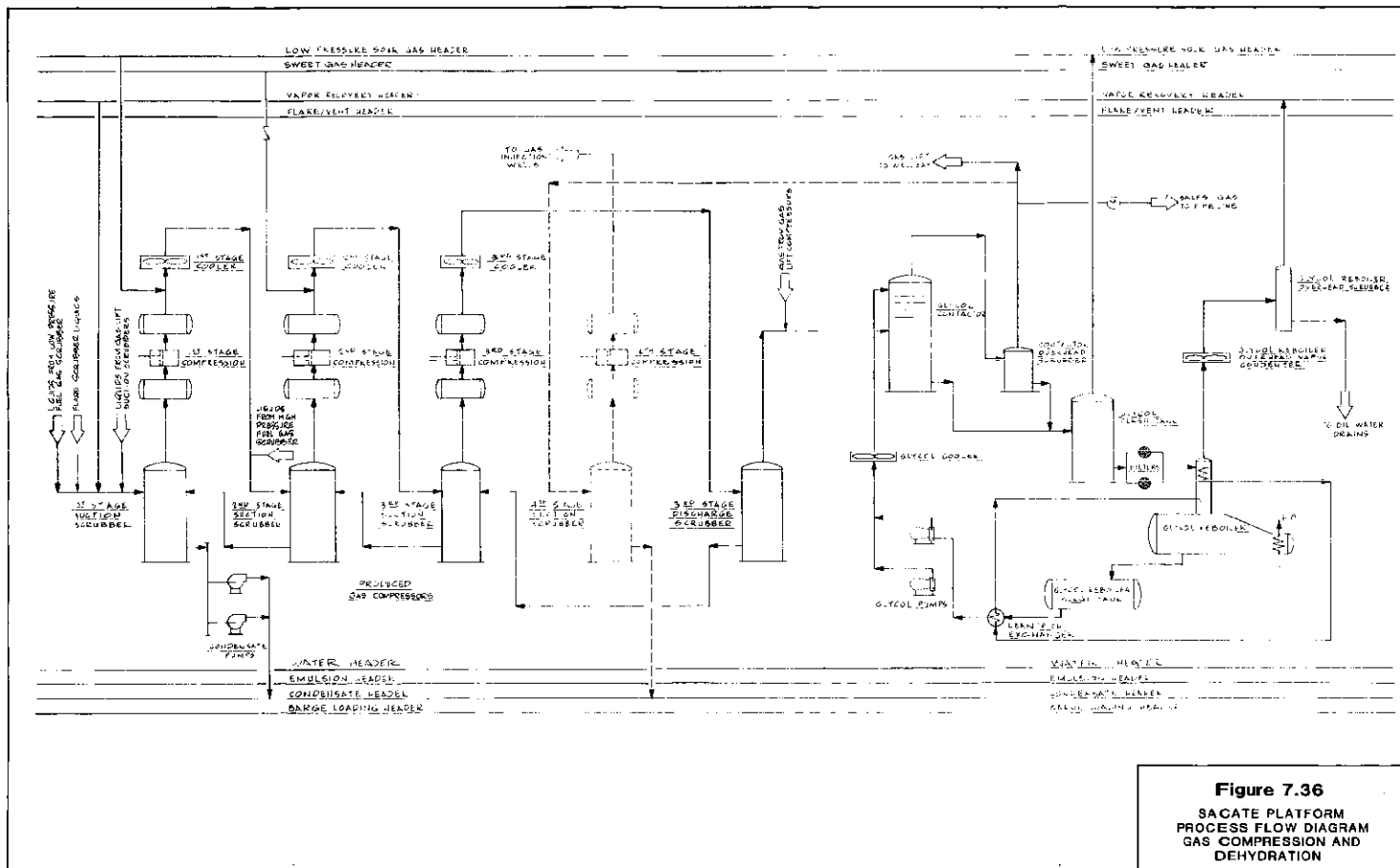
Figure 7.33
PESCADO B-1 PLATFORM
DEVELOPMENT OPTION B
DECK LAYOUTS

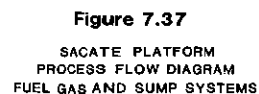


□ EQUIPMENT TO BE REMOVED UPON COMPLETION OF DRILLING PROGRAM

Figure 7.34
SACATE PLATFORM
DEVELOPMENT OPTION A
DECK LAYOUTS







SACATE PLATFORM
PROCESS FLOW DIAGRAM
FUEL GAS AND SUMP SYSTEMS

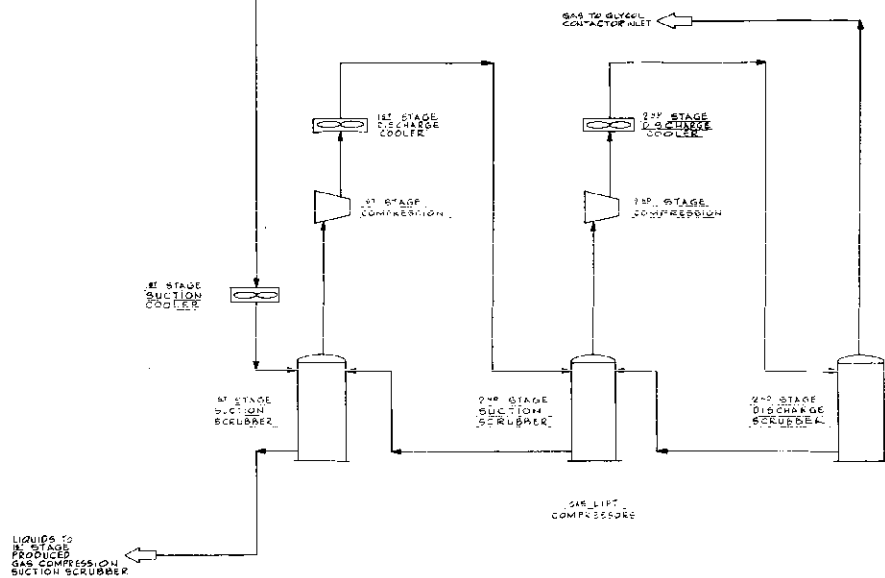
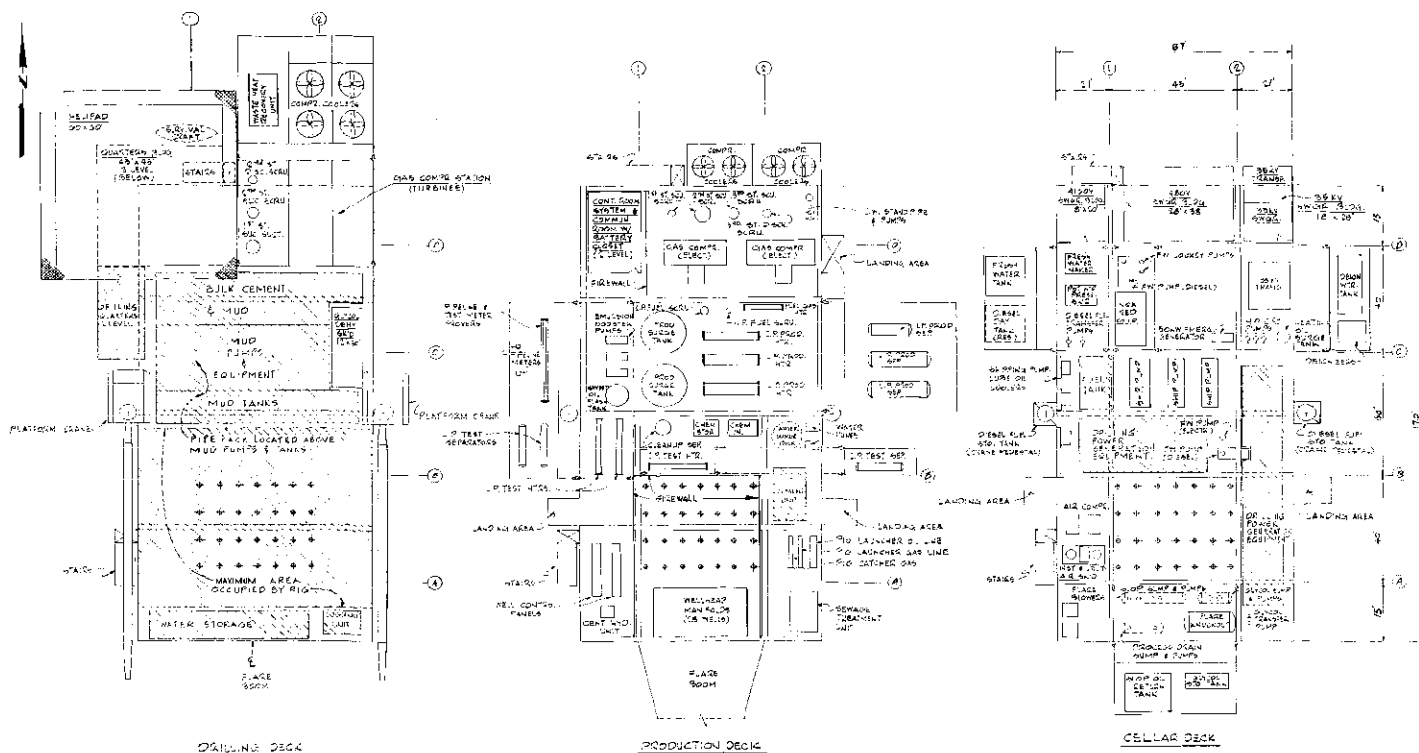
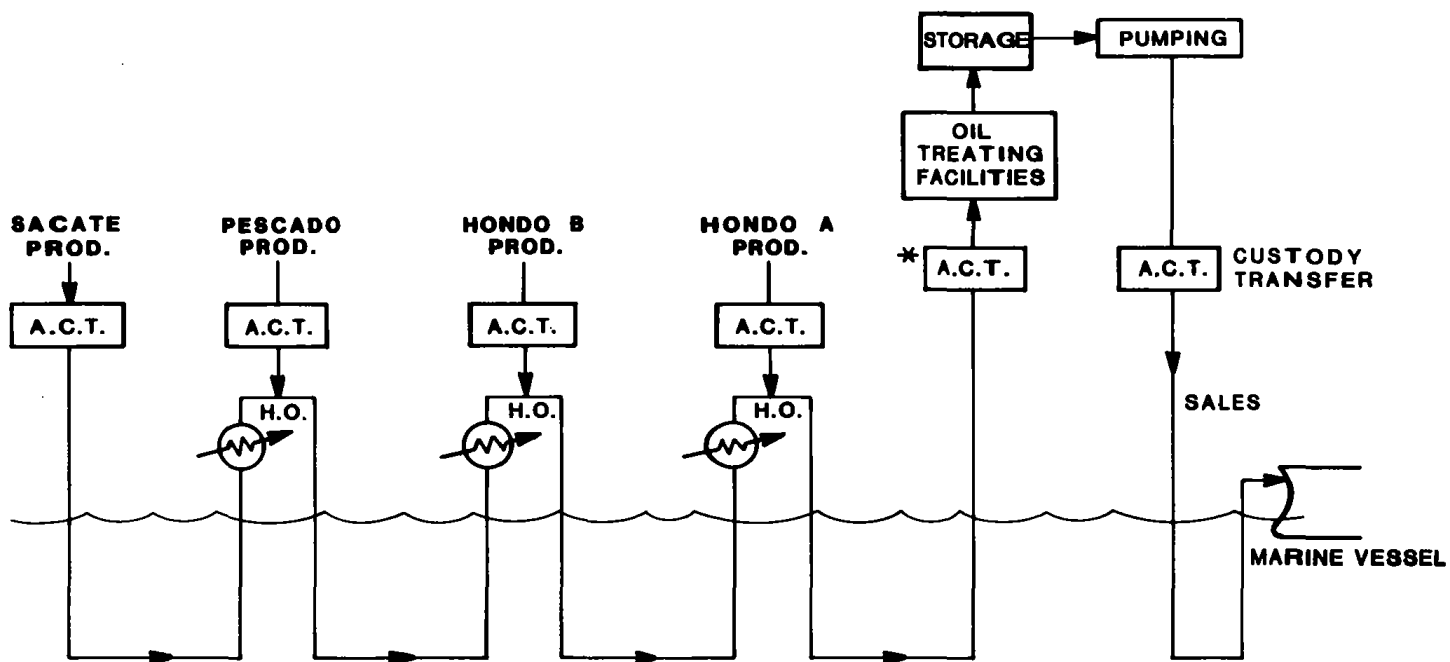


Figure 7.38
SACATE PLATFORM
PROCESS FLOW DIAGRAM
GAS LIFT COMPRESSION



1. ALL WELLS ARE 30" DIA.
2. ALL PIPING IS 3" DIA.
3. ALL PIPING IS 3" DIA.

Figure 7.39
SACATE PLATFORM
DEVELOPMENT OPTION B
DECK LAYOUTS



* **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 7.40
COMMINGLED EMULSION
METERING SYSTEM

BATTERY

SUB-BATTERIES

**PRODUCTION
SYSTEM HEADERS**

ZONES

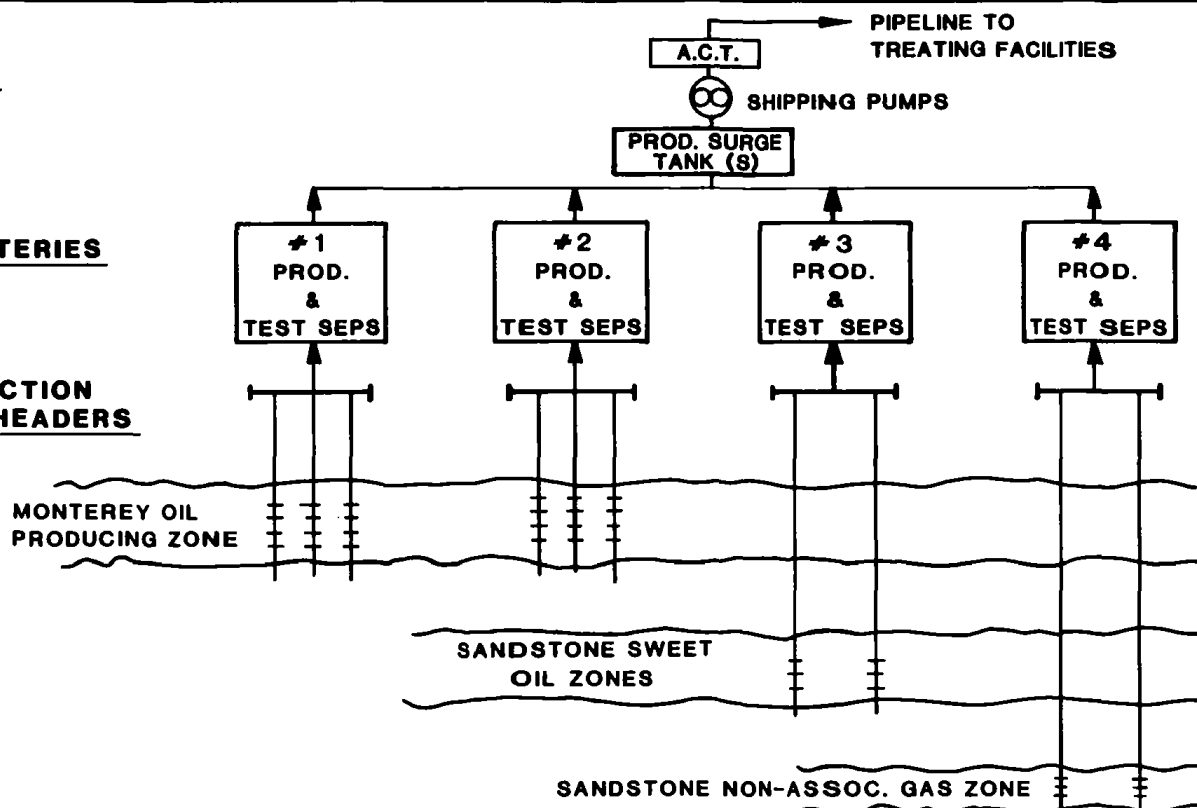


Figure 7.41

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

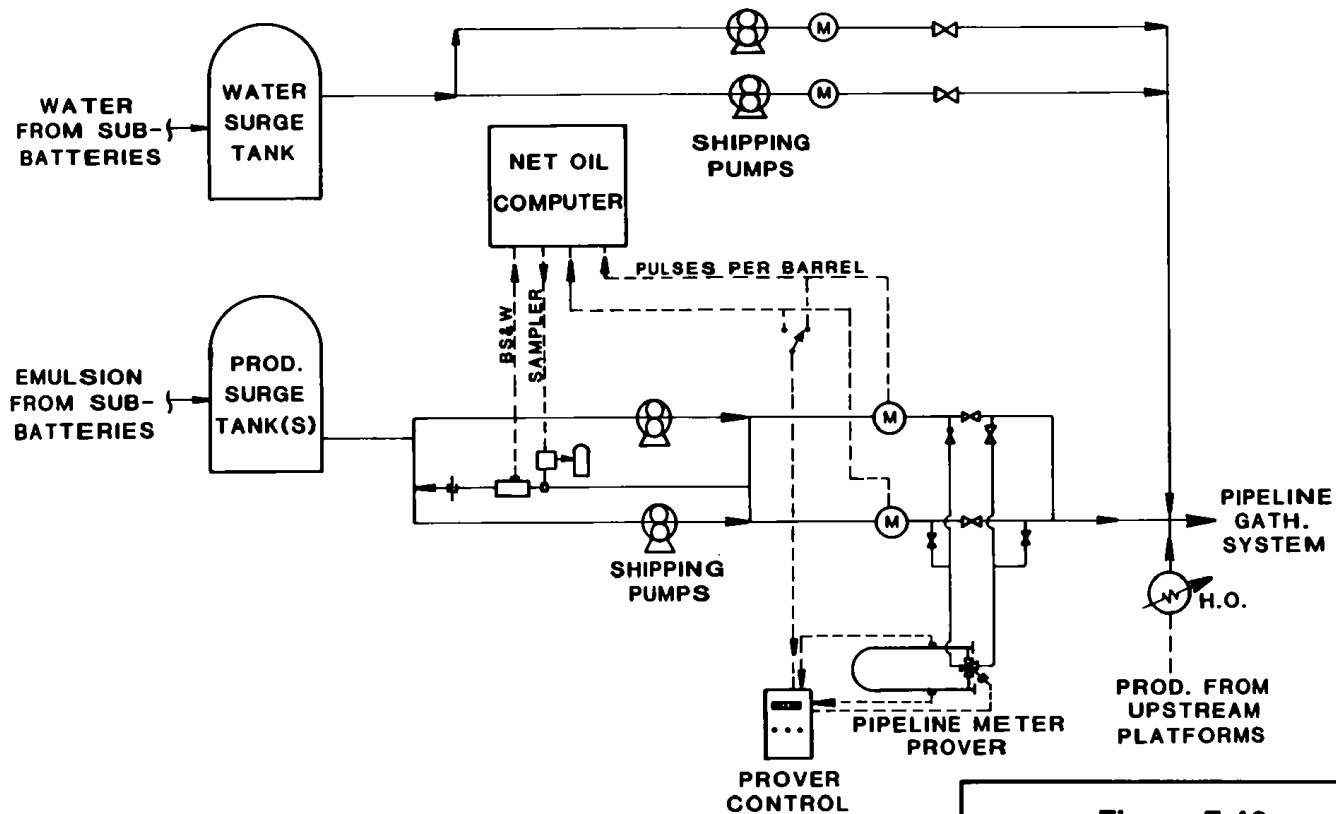
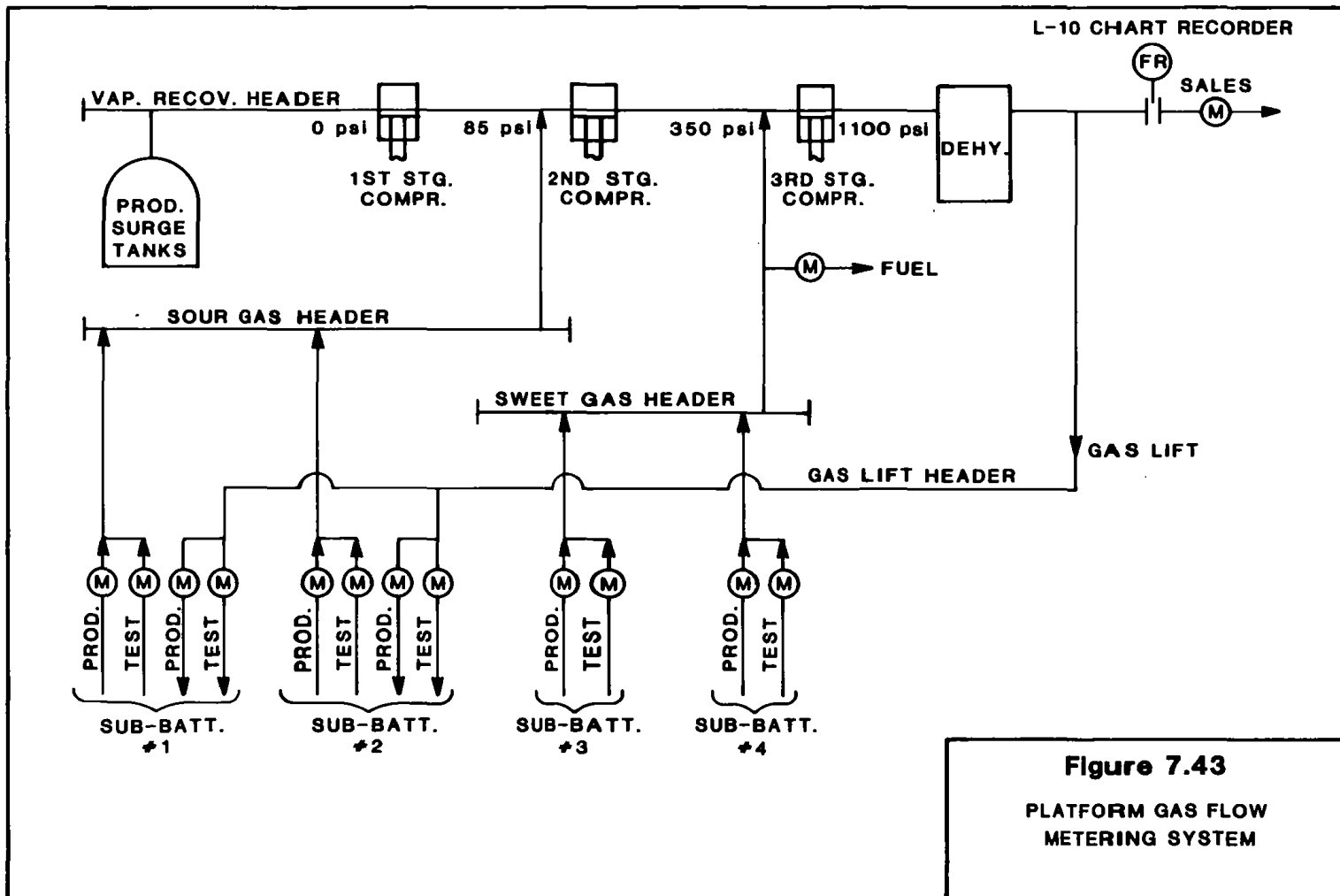


Figure 7.42
TYPICAL PLATFORM
(BATTERY) A.C.T. METER SYSTEM



SECTION VIII

PIPELINES

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SECTION VIII

PIPELINES

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SECTION VIII

PIPELINES

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SECTION VIII

PIPELINES

FIGURES

8.1 Pipeline Corridors.

SECTION VIII

8.1 Introduction

This section describes the pipelines associated with each of the two proposed development options. The pipeline systems are 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 for each option 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 Offshore Oil Treating - Development Option A

The proposed pipeline system for Development Option A (Offshore Oil Treating), as allowed by safety and engineering studies, will be routed through the pipeline corridors shown in Figure 8.1. The design flow rates for this development option are 120 MBD of emulsion and 90 MMSCFD of gas. Reference Figure 7.2 for the pipeline system schematic and Tables 8.1 and 8.2 for pipeline system characteristics.

The single platform (Pescado A) configuration features emulsion pipelines between the platforms with a diameter

range of 18 to 24 inches. The produced oil and water emulsion will be shipped to the OS&T through the existing 12-inch emulsion pipeline. Gas will be moved between platforms in pipelines ranging from 12 to 18 inches in diameter. The existing gas pipeline from the Hondo A platform to the Las Flores Canyon gas treating facilities has a 12-inch diameter. The existing 6-inch gas line from the Hondo A platform to the OS&T will continue to supply the OS&T with fuel gas. The existing 8-inch produced water line to the Hondo A platform will be taken out of service and the treated water will be disposed of overboard in accordance with an NPDES permit.

The pipeline system for a two platform (Pescado B-1 and Pescado B-2) configuration includes an additional 18-inch emulsion pipeline and a 14-inch gas pipeline from the Pescado B-1 platform to the Pescado B-2 platform. A 6-inch fuel gas line will be installed from the Pescado B-2 platform to the Pescado B-1 platform. All of the other pipeline sizes and design flow rates are identical to those in the one platform configuration.

8.3 Onshore Oil Treating - Development Option B

The proposed pipeline system for Development Option B (Onshore Oil Treating), as allowed by safety and engineering studies, will be routed through the pipeline corridors shown in Figure 8.1. The design flow rates for this development option are 220 MBD of emulsion and a combined "to-shore" gas

flow rate of 190 MMSCFD. Reference Figure 7.3 for the pipeline system schematic and Tables 8.2 and 8.3 for pipeline system characteristics. The offshore pipelines connecting to the OS&T will be purged and abandoned in place.

The single platform (Pescado A) configuration features interplatform emulsion pipelines ranging from 20 to 26 inches in diameter. A 26-inch pipeline transports emulsion from the Hondo A platform to the Las Flores Canyon oil treating facilities. Gas is moved to shore via two pipelines. The first pipeline brings gas onshore from the Sacate and Pescado fields via a new 16-inch pipeline originating at the Pescado A platform. The second gas pipeline brings Hondo field gas onshore via an existing 12-inch pipeline originating at the Hondo A platform. Additionally, a 12-inch pipeline carries produced water from the onshore oil treating facilities to an offshore outfall discharge point. The pipelines connecting the modernized nearshore marine terminal with the Las Flores Canyon facilities include: a 36-inch crude oil offloading line, a 16-inch vapor balance line, and a service bundle containing two 2-inch hydraulic lines and one 2-inch gas supply/condensate removal pipeline.

The pipeline system for a two-platform (Pescado B-1 and Pescado B-2) configuration includes an additional 20-inch emulsion line and a 12-inch gas line from the Pescado B-1 platform to the Pescado B-2 platform. A 6-inch fuel gas line will be installed from the Pescado B-2 platform to the Pescado B-1

platform. All of the other pipeline sizes and design flow rates are identical to the one platform configuration.

8.4 Pipeline Corridors

8.4.1 Sacate to Pescado Corridor

8.4.1.1 Geologic Design Considerations

A geologic evaluation was made of the Sacate to Pescado pipeline corridor. This corridor is 7,500 feet wide and 24,000 feet long. 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.

8.4.1.2 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.

8.4.2 Pescado to Hondo B Corridor

8.4.2.1 Geologic Design Considerations

The Pescado to Hondo B pipeline corridor is approximately 39,000 feet long and 5,000 feet wide. 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 in width and between 20 feet and 70 feet in depth. Slopes along the channel walls, the steepest encountered along the corridor, are generally less than 10 degrees. Axial gradients within the channels and downslope gradients in the interchannel area are less than 7 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 6 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.

8.4.2.2 Geotechnical Design Considerations

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.

However, local areas of potential instability due to either liquefaction, slumping, or gas charged sediment will be analyzed based on the specific soil properties, bathymetry, and loadings from the design environmental conditions. The existence and location of any areas of potential instability will be defined by a route analysis survey. If such areas are defined, 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.

8.4.3 Hondo B to Hondo A Corridor

8.4.3.1 Geologic Design Considerations

The Hondo B to Hondo A pipeline corridor is

approximately 15,000 feet long and 5,000 feet wide and lies wholly within the Smooth-Slope Province at a depth range of 850 to 1,400 feet. The interconnecting pipelines between the Hondo B and Hondo A platforms will be installed within this corridor. The surface sediment and shallow subsurface stratigraphy is identical to that of the eastern half of the Pescado to Hondo B route. The slope gradient averages 6%.

8.4.3.2 Geotechnical Design Considerations

Soil properties within this corridor are identical to those found at the eastern side of the Pescado to Hondo B corridor, and similar design considerations will prevail. 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.

8.4.4 Hondo A to Corral Canyon Shorefall

8.4.4.1 Geologic Design Considerations

The pipeline route from the Hondo A platform is approximately 37,000 feet long and 2,000 feet wide. It extends northeastward across the upper

slope area of the Smooth-Slope Province and then across the shelf 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 one-to-three-foot high ridges and a zone just offshore of the beach where there are low (3-5 foot) bedrock ridges.

Sediment along the route ranges from fine silt offshore to sand inshore. The pipeline route starts at a depth of 850 feet and terminates at the shoreline.

8.4.4.2 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 no significant soil instabilities are indicated as a result of this feature. 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.

8.4.5 Marine Terminal to Hondo A/Corral Canyon Corridor Intersection

8.4.5.1 Geologic Design Considerations

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

8.4.5.2 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. The existence and location of any areas of potential instability will be defined by a route analysis survey. If such areas are defined, the pipeline 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.

8.4.6 Onshore Pipeline Corridor

8.4.6.1 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 Facility At Las Flores Canyon, Santa Barbara County, California," dated October, 1974.

8.5 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 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.

8.6 Design

8.6.1 Offshore Pipelines

The proposed offshore pipelines will be designed to insure 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 MMS Pacific Region OCS Order 9.

8.6.1.1 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 insure that the level of stress imposed by these conditions will not exceed known 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 8.5.

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 for Development Option A (Offshore Oil Treating) are 120 MBD of emulsion and 90 MMSCFD of gas. Design flow rates for Development Option B (Onshore Oil Treating) are 220 MBD of emulsion

and 190 MMSCFD 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 1,400 feet (in the Pescado to Hondo B corridor). The design minimum value for 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 assure 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 9.

8.6.1.2 Mechanical Design

The emulsion and gas pipelines will be designed for a maximum allowable net internal working pressure corresponding to an ANSI 600 class (1480 psig @ 100°F) of valves, flanges and fittings. Fuel gas and produced water pipeline designs 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 strength will be determined based on the above design analyses and on corrosion protection requirements.

8.6.1.3 Stability

The pipelines will be designed to resist significant horizontal and vertical deflection under the action of on 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.

8.6.1.4 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. Injection of corrosion inhibitor chemicals will be used as needed to keep internal corrosion rates within acceptable limits.

8.6.2 Onshore Pipelines

No additional onshore pipelines will be required for Development Option A (Offshore Oil Treating). Gas production will be transported from the Hondo A platform to expanded onshore gas treating facilities through the existing 12-inch gas line.

Development Option B (Onshore Oil Treating) will require five new onshore pipelines in addition to the existing 12-inch gas line: a 26-inch crude emulsion line, a 12-inch produced water return line, a 16-inch sour gas line, and 36- and 16-inch pipelines associated with the marine terminal. In addition, a service bundle containing two 2-inch hydraulic lines and one 2-inch gas supply/condensate removal pipeline will accompany the larger marine terminal pipelines.

8.6.2.1 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 insure that the levels of stress imposed by these conditions will not exceed known 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 8.5. The design flow rates for the onshore pipeline segments are given in Table 8.2.

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.

8.6.2.2 Mechanical Design and Corrosion Protection

The emulsion and gas pipelines will be designed for a nominal working pressure of 1,440 psig. 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 will be designed for a nominal working pressure of 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 corrosion protection. Insulation flanges will be installed where needed. The alternatives of using a rectified system or an all galvanic system will also be investigated.

8.7 Construction

8.7.1 Offshore Pipelines

The primary construction method anticipated for installation of the offshore pipelines is the conventional pipelay barge stinger method. Installation of the pipelines is not expected to require development of new technology, but may require applications of current technology to deeper water and larger pipe diameters than encountered in previous installations. Other

installation methods, such as pipe tow techniques, will also be evaluated.

Assuming that pipeline construction will be by a pipelay 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 stages 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.

Pipeline risers and connections between the riser and the pipeline may be installed by one of several methods selected on the basis of technical and economic analyses. Pipelines may be installed by the conventional or

reverse J-tube methods through J-tubes which will have been pre-installed on the platform jackets. Alternatively, the risers themselves may be preinstalled on the platform jackets and the pipelines connected to them by either subsea welding, mechanical connectors, or a combination of both.

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 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 are 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 pipelay barge anchors should be short term and therefore are not

expected to interfere with trawling. Since the seafloor soils are generally of low shear strength, granular materials, any soil disturbances should not obstruct trawl boards or fishing nets and in a short time should probably smooth out to near original contours. For the option which incorporates producing to onshore facilities, the beach zone portions of the pipelines will be installed in a trench and buried. Pipelines will be trenched out to an optimum water depth as determined by regulatory requirements and by engineering analysis of pipeline stability. Any blasting which may be required to trench for pipelines will be minimized. It is not planned to mechanically backfill the trenches seaward of the approximate 12-foot depth contour. Natural backfill by the process of longshore sedimentation is expected to rapidly occur.

8.7.2 Onshore Pipelines

The onshore pipelines will be routed from the shoreline landfall, under the Southern Pacific Railroad tracks and U.S. Highway 101 and along the site access road to the onshore facilities.

The pipelines will be constructed under the railroad and highway right-of-ways using the bored casing previously installed during the installation of the original 12-inch gas line. This will avoid any disruption of traffic during construction.

The trenching, bedding and backfilling for the pipeline construction will be performed within or adjacent to the plant access road. The pipelines will be constructed outside of the paved limits wherever possible, i.e., where the terrain is relatively flat.

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 3-foot cover on a pad of rock-free fill. The bottom of the trench will be overexcavated a minimum of 6 inches and a layer of sand placed in the bottom. Sand should 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% 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 needed prior to disposal to assure no adverse impact on the environment.

8.8 Pipeline Operations

Oil and water will leave the platforms as an emulsion at approximately 160°F. This emulsion will be metered by positive displacement type meters equipped with a mechanical prover. The platform emulsion metering systems will transmit volume pulses to a comparator located at the receiving treating facilities, where a leak detection counter will provide a continuous volumetric comparison of inputs to the lines with deliveries at the treating facilities. The system will include an alarm trigger of adequate sensitivity to detect significant variations between input and output volumes, as per MMS Pacific Region OCS Order 9. 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 segment will be equipped with high and low pressure sensors which will automatically shut in the pipelines if preset limits are exceeded. Each end of the line segment will also have a check valve and an automatic shut-in valve tied to 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 a minimum of once per week for any indication of leakage.

TABLE 8.1

OFFSHORE PIPELINE SYSTEM CHARACTERISTICS
OFFSHORE OIL TREATING - DEVELOPMENT OPTION A

Pipeline Segment	Development Option	Segment Length (miles)	Gas Pipeline		Emulsion Pipeline	
			Design Flow Rate (MMSCFD)	Diameter ^a (inches)	Design Flow Rate (MBD) ^b	Diameter ^a (inches)
Sacate to Pescado A	A1	4	40	12	20	18
Sacate to Pescado B-2	A2	5	40	12	20	18
Pescado B-1 to Pescado B-2 ^c	A2	3	50	14	40	18
Pescado A to Hondo B	A1	7	60	14	60	24
Pescado B-2 to Hondo B	A2	6	60	14	60	24
Hondo B to Hondo A	A1,A2	3	90	18	120	20
Hondo A to OS&T ^d	A1,A2	2	--	--	120	12 ^e
Hondo A to shore	A1,A2	7	90	12 ^e	--	--

^a Pipeline diameters optimized to minimize construction and operating costs. Diameters listed are subject to change based on continuing design studies.

^b Volume of emulsion throughput (oil plus water).

^c Plus 6-inch diameter fuel gas line.

^d Plus 6-inch diameter fuel gas line and 8-inch diameter return water line (both existing; water line out of service).

^e Existing line.

NOTE: 1. Development Option A1 - One Pescado Platform Configuration.
2. Development Option A2 - Two Pescado Platforms Configuration.

TABLE 8.2

ONSHORE PIPELINE SYSTEM CHARACTERISTICS

Fluid	Development Option	Pipeline Origin	Pipeline Destination	Onshore Length (miles)	Pipeline Diameter (inches) ^b	Design Flow Rate
Produced gas ^a	A,B	Platform Hondo A	Gas treating facilities	1.3	12	90 MMSCFD
Produced gas	B	Platform Pescado A(B-2)	Gas treating facilities	1.3	16	100 MMSCFD
Sales gas ^a	A,B	Gas treating facilities	Gas distribution system tie-in	1.2	12	110 MMSCFD
Crude oil/water emulsion	B	Platform Hondo A	Oil treating facilities	1.3	26	220 MBD
Treated produced water	B	Oil treating facilities	Offshore outfall	1.3	12	70 MBD
Product crude oil	B	Oil treating facilities	Nearshore SALM	1.3	36	30 MBH
Inert gases and hydro- carbon vapors (vapor-balance line)	B	Nearshore SALM	Oil treating facilities	1.3	16	4 MMSCFD
Hydraulic fluid (hydraulic control line bundle)	B	Oil treating facilities	Nearshore SALM	1.3	2	--

^a Existing pipeline.^b Diameters of proposed pipelines are subject to change based on continuing design studies.

NOTE: 1. Development Option A - Offshore Oil Treating
2. Development Option B - Onshore Oil Treating.

TABLE 8.3

OFFSHORE PIPELINE SYSTEM CHARACTERISTICS
 ONSHORE OIL TREATING - DEVELOPMENT OPTION B

Pipeline Segment	Development Option	Segment Length (miles)	Gas Pipeline		Emulsion Pipeline	
			Design Flow Rate (MMSCFD)	Diameter ^a (inches)	Design Flow Rate (MBD) ^b	Diameter ^a (inches)
Sacate to Pescado A	B1	4	30	8	30	20
Sacate to Pescado B-2	B2	5	30	8	30	20
Pescado B-1 to Pescado B-2 ^c	B2	3	30	12	50	20
Pescado A to Hondo B	B1	7	100	16	120	26
Pescado A to Shore	B1	17	100	16	--	--
Pescado B-2 to Hondo B	B2	6	--	--	120	26
Pescado B-2 to Shore	B2	16	100	16	--	--
Hondo B to Hondo A	B1,B2	3	70	10	210	26
Hondo A to/from Shore ^d	B1,B2	7	90	12 ^e	220	26
Shore to Nearshore SALM ^f	B1,B2	1	4	6	30 MBH (product oil)	36

^a Pipeline diameters optimized to minimize construction and operating costs. Diameters listed are subject to change based on continuing design studies.

^b Volume of emulsion throughput (oil plus water), except where noted.

^c Plus 6-inch diameter fuel gas line.

^d Plus produced water outfall pipeline.

^e Existing line.

^f Plus VBL and hydraulic control line bundle.

NOTE: 1. Development Option B1 - One Pescado Platform Configuration.
 2. Development Option B2 - Two Pescado Platforms Configuration.

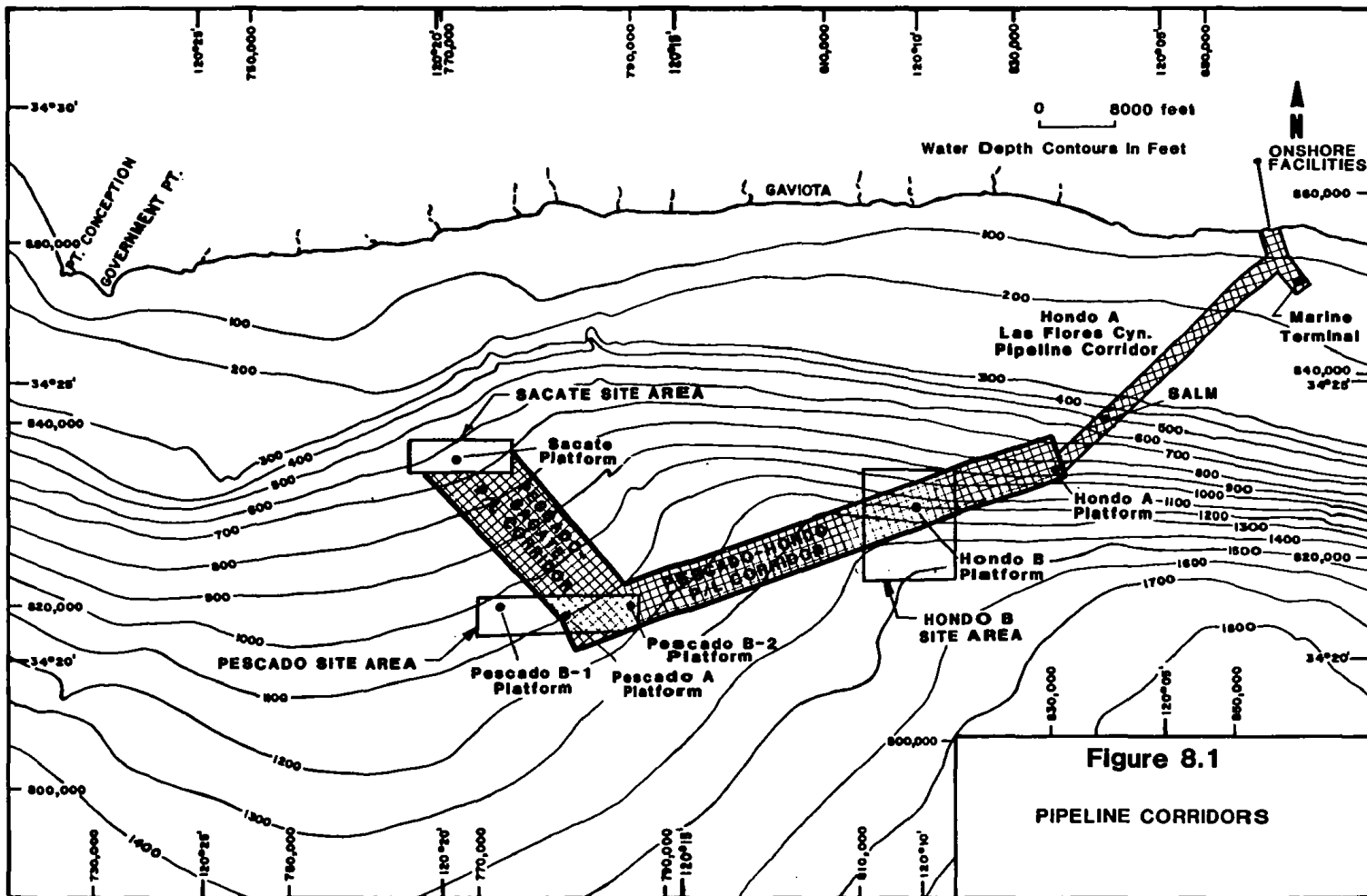


Figure 8.1

PIPELINE CORRIDORS

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OIL AND GAS TREATING FACILITIES

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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, starting with the location of the proposed onshore sites, the existing Offshore Storage and Treating vessel (OS&T), and the existing initial 30 MMSCFD gas treating facilities. The Development Option A (Offshore Oil Treating) subsection then highlights the major requirements needed to expand both the OS&T maximum design capacity from 40 MBD to 80 MBD of treated oil and the gas treating facilities maximum design capacity from 30 MMSCFD to 90 MMSCFD of gas.

The Development Option B (Onshore Oil Treating) subsection highlights the expansion of gas treating facilities to a peak design rate of 135 MMSCFD of gas and the installation of oil treating facilities and a central cogeneration power plant with peak design rates of 140 MBD of treated oil and 50 megawatts, respectively.

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

9.2 Onshore Site

Santa Barbara County Ordinance No. 2686 authorized Exxon Company, U.S.A. to build oil and gas treating facilities on

a site containing approximately 13.6 acres located in Las Flores Canyon. Las Flores Canyon is a small tributary of Corral Canyon, located approximately 20 miles west of the city of Santa Barbara. The site is more than one mile inland from the coastline and U.S. Highway 101.

Figure 9.1 is a vicinity map showing the location of the onshore site. Figure 9.2 is a location map showing in more detail the locations of the originally approved and proposed expansion sites. A full description of the originally approved site location is given in Exxon's (then Humble Oil & Refining Co.) Supplemental Plan of Operations, Santa Ynez Unit, submitted to the USGS in 1971.

The originally approved site (shown as Site (1) in Fig. 9.2) provided space for the construction of gas treating facilities to handle up to 90 MMSCFD of gas and oil treating facilities capable of processing 80 MBD of oil. Oil storage facilities space was also provided for within the site.

At the present time the entire 13.6-acre site has been leveled, compacted and prepared for construction. Gas treating facilities capable of handling 30 MMSCFD of gas are currently being constructed on 4.3 acres of the site. The general plot plan for these initial facilities is shown in Figure 9.3.

No onshore oil treating facilities will be required under Exxon's Development Option A. Onshore gas treating facil-

ities will be expanded to handle 90 MMSCFD of gas. This expansion will be contained on the original 13.6-acre site, and its general plot plan is shown in Figure 9.4.

Development Option B proposes that treating facilities capable of handling maximum flow rates of 135 MMSCFD of gas and 140 MBD of oil and a central cogeneration power plant be built. Studies to date have indicated that these facilities cannot be completely constructed within the presently approved 13.6-acre site (site (1) in Fig. 9.2). The expansion of gas treating facilities to 135 MMSCFD will be accommodated on the originally approved site. The addition of site (2) (see Fig. 9.2) will supply the additional plot space needed to accommodate the oil treating and power generation facilities.

Site (1) is the original 13.6-acre tract approved for the construction of both onshore oil and gas treating facilities. The initial 30 MMSCFD gas treating facilities are currently being built within an approved construction area. These initial gas treating facilities and the two development gas treating facilities expansion options (90 and 135 MMSCFD) will be constructed within this tract. Current plans anticipate that it will also be used for crude storage facilities required by Development Option B.

Site (2) is being proposed for the installation of oil treating and power generation facilities in Development Option B. Site (3) would be available for future oil and

gas facility development. Preparation of these sites requires earthwork of approximately 510,000 cubic yards to create 16.8 acres of useful plot space, 9.2 acres in Site (2) and 7.6 acres in Site (3).

A general plot plan for the 135 MMSCFD expanded gas treating facilities is shown in Figure 9.5. Figure 9.6 shows the general plot plan for the 140 MBD oil treating facilities, the oil storage area and the central cogeneration power plant.

9.3 Existing Oil and Gas Treating Facilities

9.3.1 Offshore Storage and Treating Vessel

The existing Offshore Storage and Treating vessel (OS&T), the Exxon Santa Ynez, is a converted 50,000 deadweight ton tanker permanently moored in 500 feet of water by a Single Anchor Leg Mooring (SALM) buoy. It is located approximately 3.2 miles offshore in the northeastern portion of OCS lease No. P-0188. The OS&T presently receives a degassed crude emulsion from the Hondo A platform via a 12-inch subsea pipeline. Sour fuel gas is provided to the OS&T from the Hondo A platform via a 6-inch gas pipeline. Produced water separated from the crude oil on the OS&T is returned to the Hondo A platform via an 8-inch produced water pipeline. These three pipelines are connected to the OS&T

through the SALM which incorporates a three-stream fluid swivel unit referred to as the MPDU (Multi-Product Distribution Unit) which allows rotation of the OS&T around the SALM. A 5-inch power cable also connects the OS&T and the Hondo A platform. This initial Hondo A development by the OS&T is shown in Figure 9.7

9.3.1.1 Single Anchor Leg Mooring

The Single Anchor Leg Mooring (SALM) shown in Figure 9.8 consists of: a mooring base secured to the sea floor by piles; a tubular riser attached to the center of this base by the lower universal joint; a mooring buoy secured to the riser by the middle universal joint; a triaxial swivel attached between the top of the buoy and the end of the mooring yoke; and a mooring yoke attached by hinges to the stern of the OS&T vessel. The SALM is designed to moor the OS&T alone in seas of up to 22-foot significant wave height, 65-knot sustained winds, and a 2-knot water current. With a marine vessel moored in tandem, these limits are reduced to a 15-foot significant wave height and 40-knot winds. In the unlikely event that the OS&T should break away from the SALM, self-closing safety valves are located on each of the three pipelines at the lower and middle universal joints.

9.3.1.2 Vessel Structure and Tankage

The layout of the existing OS&T facilities and tankage is shown in Figure 9.9.

9.3.1.3 Processing Facilities

The primary function of the process equipment on the OS&T is to separate free and emulsified water from the crude oil emulsion received from the Hondo A platform and to remove H_2S and light hydrocarbon gasses by stripping the dehydrated crude oil in stabilizers.

Figure 9.10 is a simplified process flow diagram of the major process equipment on the OS&T. Free water is removed from the incoming emulsion in a water knockout drum. The crude oil is next split into two parallel processing streams and heated in heat exchangers. The hot crude oil then flows to electrostatic emulsion treaters which separate and remove emulsified water from the oil.

The dehydrated crude oil is then stripped of H_2S and light hydrocarbon gasses in vertical stabilizer towers. The stabilizers are heated by circulating hot oil loops and stripping gas is supplied from the fuel gas treating unit. Overhead vapors from the stabilizers pass through air-cooled condensers, and condensed liquid

refluxes the stabilizers. Uncondensed vapors (primarily H_2S and light hydrocarbon gasses) are recycled to a low pressure contactor in the fuel gas treater where the H_2S and any CO_2 in the vapors are removed by an absorbent solution. The sweetened low pressure gas is compressed and returned to the stabilizers to provide additional stripping. In brief, H_2S and CO_2 stripped from the crude oil are transferred to the fuel gas treater absorbent solution in the low pressure contactor; and light hydrocarbons stripped from the crude oil flow are sent to the vapor recovery compressors (as excess stripping gas) for ultimate recovery and use as fuel gas on the OS&T.

The stripped crude oil from the stabilizer bottoms is cooled by exchange with incoming crude oil and depressurized in a flash tank. The flashed vapors are compressed and recycled to the stabilizer overhead condensers. The flashed crude oil is cooled and sent to storage to await transfer to a marine vessel.

The produced water removed from the incoming emulsion is processed in a water treating section for removal of oil and suspended solids. After filtration, the cleansed water is pipelined

to the Hondo A platform for injection into a subsurface formation.

Incoming sour gas from the platform is warmed by exchange with circulating hot oil to vaporize any slugs of liquid in the sour gas. The sour gas then flows through the fuel gas treater high pressure contactor where the absorbent solution removes H_2S and CO_2 . The resulting sweet gas contains no more than 5 grains of H_2S per 100 SCF (or 0.008 vol % H_2S) and is used as:

- Sweet fuel gas for the gas fired turbine generators, the acid gas incinerator, the flare pilot and the sulfur plant.
- Sweet blanket gas to exclude oxygen from the storage tanks and other equipment.
- Makeup stripping gas for the crude oil stabilizers.

Vapors recovered from the storage tanks and light hydrocarbons stripped from the crude oil are compressed and routed through the fuel gas treater high pressure contactor along with the incoming sour gas.

The absorbent solution from the high pressure and low pressure contactors (rich solvent) in the

fuel gas treater is regenerated by boiling out the absorbed H_2S and CO_2 . The regenerated solution (lean solvent) is cooled and recycled to the contactors for reuse. The H_2S and CO_2 removed from the rich solvent are fed to a Claus sulfur recovery unit. The tail gas from the sulfur plant is then burned in an acid gas incinerator.

9.3.1.4 Support and Utility Systems

The OS&T is equipped with several utility support systems. The major ones include:

1. A circulating hot oil system, heated by waste heat from the two gas-fired turbine generators, which supplies process heat to the OS&T.
2. A circulating water system, cooled by seawater, which supplies process cooling.
3. A flare system which provides for emergency venting requirements.
4. A vapor balance system and a gas blanket system for storage tanks and other atmospheric pressure vessels.
5. Instrument and utility air compressors and dryers.
6. A segregated seawater ballast system.
7. A cargo tank washing system.
8. A sewage treatment unit.

9. Potable water makers.
10. Deck, bilge, and process drain collection systems.

9.3.1.5 Electric Power Generation

Electric power for the OS&T is generated by two G.E. LM-2500 turbine driven 19 MW generators at 13.8 kV. Power is stepped up to 35 kV for transmission to the Hondo A platform via subsea cable and stepped down to 4160 volts and 480 volts for running onboard equipment.

An 800 kW diesel engine driven auxiliary generator is provided for use in starting up the main power plant. A 50 kW diesel engine driven emergency generator is utilized to automatically provide power for lighting, communications, battery chargers, controls and safety systems in the event of a main power plant failure.

9.3.1.6 Cargo Handling and Transfer Systems

Processed crude is stored in six center tanks, with a total capacity of 198,000 barrels. Off-spec crude can be stored in four wing tanks with a total of 37,000 barrel capacity while awaiting rerun through the process. A portion of the rerun tank capacity can be used for processed crude storage to minimize marine vessel turn-

around. This results in a nominal total crude storage capacity of about 210,000 barrels. Four 7,500 BHP cargo pumps located in the main pump room are used to offload cargo to marine vessels. Two smaller pumps (referred to as stripping or rerun pumps) are also provided to allow for stripping the tanks dry at low rates or for pumping the tank bottoms back into the process facilities.

All cargo tanks are gas blanketed to exclude oxygen as tanks are emptied and are connected to the vapor balance compression system to capture vapors as the tanks are filled. All tanks have multiple high level alarms and level indicators in the central control room.

9.3.1.7 Marine Vessel Operations

Basic marine vessel operations include mooring, hose connection, pumping and metering, vapor balance operation, hose disconnect and mooring release. Precise procedures for cargo transfer are contained in the U.S. Coast Guard approved "Oil Transfer Procedures Manual."

All marine vessels in dedicated service to the OS&T are equipped with vapor balance systems compatible with the OS&T. In the event of an

emergency or unforeseen disruption to normal operations of the dedicated marine vessel fleet, alternate vessels may be called upon to maintain cargo deliveries. Alternate vessels may temporarily load without using the vapor balance system if vessels equipped for vapor balance are not available, but all reasonable steps will be taken to restore full vapor balance system operation as soon as practicable.

9.3.2 Onshore 30 MMSCFD Gas Treating Facilities

9.3.2.1 Treating Facilities

The existing Las Flores Canyon gas treating facilities are designed to produce salable natural gas at minimum cost and with minimum impact to the environment. They include 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 will then be pipelined to a regional gas transmission line. The facilities will initially handle 30 MMSCFD of gas but are being designed and built to allow for expansion to 60 MMSCFD without significantly interrupting the ongoing operations. The general plot plan is

shown in Figure 9.3 and a simplified process flow diagram is shown in Figure 9.11.

Inlet Separation

Gas will be transported to the facilities by a pipeline which runs along the ocean floor from the Hondo A platform to shore and from there underground to the treating area. The gas from the platform will be cooled in the pipeline because of the lower temperatures on the ocean floor. The temperature of the gas will drop from about 120°F to about 65°F, causing the condensation of heavier hydrocarbons from the gas. The liquid that condenses in the pipeline may flow out at a constant rate or may build up in the pipeline and be forced out by the flowing gas in slugs. The gas will enter the treating facilities at about 920 psia and pass through an inlet separator, or slug catcher, which will remove any condensed liquids. The liquids that collect in the slug catcher will be withdrawn and sent to the stabilizer.

Inlet Dehydration

Gas from the slug catcher will then be treated with triethylene glycol (TEG) in a contacting column to remove water from the gas. The gas

entering the treating facilities will have a water content of about seven pounds per million standard cubic feet of gas. This water level is low enough to avoid the formation of water-hydrocarbon ice substances, called hydrates, in the pipeline. However, the gas treating process requires cooling of the gas to a much lower temperature, and thus further dehydration is necessary. The inlet dehydration will reduce the water content of the gas to between one and three pounds per million standard cubic feet of gas. The water that is absorbed in the TEG will be subsequently boiled off in a glycol regenerator, condensed, and sent to the sour water stripper for treating. The regenerated TEG will be recycled back to the TEG contactor.

Cooling

The dehydrated gas will then be cooled in heat exchangers using cold process gas. The purpose of cooling is to condense heavier hydrocarbons out of the gas in order to prevent them from condensing out of the sales gas in a transmission pipeline. This process is known as hydrocarbon dewpoint control. The temperature of the gas will be lowered to about 20°F in the heat exchangers, and the gas will next be chilled to

about -10°F using standard propane refrigeration. The liquid hydrocarbons that condense out of the gas are known as natural gas liquids (NGLs).

Stabilization of the Natural Gas Liquids

The NGLs from the chiller will be mixed with the condensed hydrocarbons from the slug catcher and dropped in pressure to about 270 psia. The NGLs that do not vaporize due to the pressure drop will be passed through a heat exchanger to cool the inlet gas and then sent to the stabilizer.

The NGLs will next be stabilized to remove lighter hydrocarbons (primarily methane, ethane and propane) that could later vaporize. This will be done in a distillation column called a stabilizer. The stabilizer will be a trayed column with a reboiler and a condenser. Heat will be supplied to the reboiler using process steam, and propane refrigerant will be used in the condenser. NGLs from the bottom of the stabilizer will be cooled by passing them through a heat exchanger with the feed to the stabilizer, thus heating the feed. The stabilized NGLs will be stored on site in pressurized, cylindrical tanks at approximately 150 psia.

Gas Sweetening

The gas being treated contains about two percent hydrogen sulfide (H_2S) which must be removed. This will be accomplished by using a proprietary process in which the gas is contacted in a column with a solution called Sulfinol. The Sulfinol absorbs the H_2S from the gas and is subsequently regenerated in a method similar to the regeneration of TEG. The regenerated Sulfinol will be recycled, and the gas liberated during the regeneration of the Sulfinol solution (known as acid gas) will be processed further in the sulfur recovery facilities.

High pressure gas from the chiller will be passed through a heat exchanger, counter-current with the treating facilities inlet gas. As a result of this heat exchange, the inlet gas is cooled and the high pressure process gas is warmed from $-10^{\circ}F$ to about $55^{\circ}F$. After being warmed, the high pressure gas will go to a high pressure Sulfinol contactor where H_2S will be removed. The high pressure Sulfinol solution from the contactor will then be lowered in pressure and sent to a low pressure Sulfinol contactor.

Gas liberated from the drop in pressure of the NGLs and the overhead gas from the stabilizer

will be combined and will make up the gas feed to the low pressure Sulfinol contactor. The overhead gas from the low pressure contactor will be compressed and combined with the overhead gas from the high pressure contactor. The H_2S content of the gas will have been reduced to about 3-4 ppm as a result of this process known as sweetening.

The Sulfinol solution from the low pressure contactor will then be further lowered in pressure. Sulfinol tends to absorb some hydrocarbons, as well as H_2S , and this pressure drop will cause the lighter hydrocarbons to vaporize. The hydrocarbons that vaporize will be treated in a small Sulfinol contactor to remove H_2S and then will be used as fuel in the gas treating facilities. The Sulfinol solution will be sent to a trayed separation column with a reboiler and condenser, where acid gas components will be removed from the solution. The regenerated Sulfinol solution will then be recycled by dividing it into three streams and sending it to the high pressure contactor, the low pressure contactor and the fuel gas contactor.

Sales Gas Dehydration

Because Sulfinol is an aqueous solution, the

treated gas will become water saturated and must be dehydrated to prevent water condensation during future transmission of the sales gas. This will be done in a TEG system similar to the one previously described. The water content of the sales gas will thus be reduced to pipeline specifications of seven pounds per million standard cubic feet of gas.

Sales Gas Recompression

The final pressure of the sales gas after dehydration will be about 875 psia. Since the pressure in the transmission line to which the sales gas will be delivered may vary from 600 psia to 975 psia, compression of the sales gas will be required. The compressors will be capable of compressing the sales gas up to approximately 1,000 psia. Specifications for the sales gas are given in Table 9.1. Natural gas odorization facilities will be provided immediately downstream of sales gas recompression.

Sulfur Recovery

Acid gas that is liberated during the regeneration of Sulfinol will be sent to a Claus sulfur recovery unit for conversion of H_2S to elemental sulfur. In a Claus sulfur recovery unit, some

H_2S is oxidized to form SO_2 , and the SO_2 and remaining H_2S are passed over catalyst beds and react to form sulfur vapor and water. The sulfur vapor will be condensed, stored and then trucked out for sale. The Claus sulfur recovery unit will remove about 97 percent of the inlet H_2S as sulfur. The remaining acid gas is called tail gas.

Tail Gas Treating

The tail gas from the Claus sulfur recovery unit will be further treated in a Beavon sulfur recovery unit. The Beavon process is a proprietary process which is used to convert H_2S to elemental sulfur and is used primarily on tail gas streams or gas streams with low H_2S contents. The remaining tail gas from the Beavon sulfur recovery unit will contain less than 10 ppm H_2S and will be mixed with the fuel stream to the boilers. The Beavon sulfur recovery unit can convert greater than 99.9 percent of the H_2S fed into it to sulfur, thus increasing the overall conversion. The recovered sulfur will be stored with the sulfur from the Claus sulfur recovery unit and then trucked out. Specifications for the sulfur from the Claus and Beavon sulfur recovery units are given in Table 9.2.

Sour Water Stripping

Since water from the dehydration systems and other parts of the process may have been in contact with the unsweetened gas, it may contain such undesirable components as H_2S . This water is known as sour water and must be treated before disposal. This will be done by contacting the sour water in a trayed column with steam. The steam will cause the undesirable gasses to vaporize, thus stripping them from the water. The overhead from the sour water stripper will be cooled to condense the stripping steam, and the remaining gas (containing H_2S) will be recycled to the Claus sulfur recovery unit. The condensed water will be returned to the sour water stripper. Treated water from the stripper will be piped to a local disposal well.

9.3.2.2 Associated Utilities

Boilers will supply process steam to the gas treating facilities and will be fired with gas from the process containing approximately 112 ppm H_2S . This gas will come from the small fuel gas/Sulfinol contactor. Some steam will be generated by recovering heat from the condensing sulfur vapor in the Claus sulfur recovery unit and will be used to reduce the boiler load.

Electrical power will be supplied by cable from Southern California Edison Company. A diesel powered emergency generator will serve as backup in the event of a power failure.

A compressed air system will be provided to supply instruments with clean, dry air. Dry nitrogen will be used as a backup in the event of an air system failure. In addition, dry nitrogen will be piped to all locations where it will be required for the purging of process piping and vessels.

Water will be supplied by two water wells drilled on the site, with a combined capacity of about 500 gallons per minute. Process water requirements are not expected to exceed 10,000 gallons per day. Water treating facilities will produce potable water, as well as treat the feed water to the boilers.

Process refrigeration requirements will be supplied by a standard propane refrigeration system. In this system, high pressure, liquid propane is flashed to a lower pressure, causing the propane to partially vaporize and to drop considerably in temperature. The remaining liquid propane, now at the colder temperature, is used in process heat exchangers to cool process

fluids. As the liquid propane absorbs heat from other process fluids, it is vaporized. The propane vapors are then compressed to their original pressure, which also raises the temperature of the vapors considerably. The high pressure propane vapors are air cooled to condense them, thus returning the propane to its original temperature and pressure. The propane is recycled continuously within this closed loop.

9.4 Offshore Oil Treating - Development Option A

9.4.1 Offshore Storage and Treating Vessel Modifications

Development Option A proposes the expansion of OS&T peak processing capacity from 40 MBD of treated crude oil to 80 MBD. This would require the addition of a third parallel water separation and oil stabilization train. A simplified process flow diagram of this expansion is shown in Figure 9.12.

Specifically this requires adding one electrostatic emulsion treater, one stabilizer tower, six heat exchangers, three pumps, one aerial fan condenser and one stabilizer reflux accumulator. Equipment space and tie-in points for the third train were allocated in the original OS&T process area design and therefore no compromises of an engineering, safety or aesthetic

nature are required in order to make the third train addition.

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

9.4.2 Gas Treating Facilities Expansion to 90 MMSCFD

Production of 80 MBD of oil from the Santa Ynez Unit will make enough gas available to supply gas treating facilities with an ultimate capacity of 90 MMSCFD. Because the initial facilities were only designed for expansion to 60 MMSCFD, it will be necessary to construct additional treating capacity in a 2.1-acre area to the north of the existing initial gas treating facilities.

Facilities that were originally planned for the expansion to 60 MMSCFD of gas will be located in the initial gas treating area. Other facilities, such as the offices, control building and firewater storage tank,

will not require expansion. Most of the remaining facilities necessary to handle the additional 30 MMSCFD of gas will be located in the area immediately north of the initial gas treating area. A list of the major equipment additions is given in Table 9.3. Figure 9.4 gives the general plot plan for this expansion.

The expanded gas treating facilities will basically operate just as described in Section 9.3.2. The only major difference between the existing and the expanded facilities will be those of capacity and plot plan area.

9.5 Onshore Oil Treating - Development Option B

9.5.1 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 Offshore Storage and Treating vessel (OS&T) will be disconnected and towed away. The offshore pipelines connecting to the SALM will be purged and abandoned in place. The Single Anchor Leg Mooring (SALM) will be removed. The SALM base piles will be cut below the mud line so that no obstruction will remain.

9.5.2 Gas Treating Facilities Expansion to 135 MMSCFD

The 30 MMSCFD gas treating facilities will be expanded to enable the treating of 135 MMSCFD of gas. This

expansion cannot be accommodated within the initial treating area, but will require that the gas treating facilities expand northward. The expansion will require approximately 2.4 acres more than the existing initial gas treating facilities.

Facilities that were originally planned for the expansion to 60 MMSCFD of gas will be located in the initial gas treating area. Other facilities, such as the offices, control building and firewater storage tank, will not require expansion. Most of the remaining facilities necessary to handle the additional 75 MMSCFD of gas will be located in the area immediately north of the initial gas treating area. A list of the major equipment additions is given in Table 9.4. Figure 9.5 gives the general plot plan for this expansion.

The expanded gas treating facilities will basically operate just as described in Section 9.3.2. The only major differences between the existing and the expanded facilities will be those of capacity and plot plan area. The utility boilers will generate steam by utilizing the waste heat recovery system of the central power plant. Sweet gas from the gas treating facilities will be used in the oil treating facilities for stripping H_2S from the oil. Sour gas from the crude stripping tower will be handled as described in Section 9.5.3.3 and returned either to the gas treating facilities inlet or to the NGL stabilizer.

9.5.3 Onshore Oil Treating Facilities

The oil treating and storage facilities will have an annual average daily capacity of 125 MBD of treated oil with a peak design rate of 140 MBD. The proposed oil treating facilities will: remove produced water from the mixture of emulsified crude oil and brine; reduce the hydrogen sulfide 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 provide storage and loading capabilities for offshore marine vessel loading.

Generalized process flow diagrams for the oil treating facilities, the water treating facilities and the blanket gas system are shown in Figures 9.13, 9.14 and 9.15, respectively. The general plot plan configuration is given in Figure 9.6 and the crude oil sales specifications are given in Table 9.5.

The oil treating facilities will receive stripping gas from and supply sour gas to the gas treating facilities. The stripping gas requirement of approximately 1.5-2.0 MMSCFD will be filled by the gas treating facilities. Sour gas leaving the stripping column at an approximate rate of 2.0-2.5 MMSCFD will be compressed and sent to the gas treating area for treating.

9.5.3.1 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 approximately 150 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 on-

shore facilities shutdown or acting as a transfer point to reintroduce production into the treating facilities.

After passing the pressure control station, the inlet emulsion stream will enter the free water knockout drums. Here the free brine will be separated from the oil emulsion and will be routed to the produced water treating facilities. A free brine/oil emulsion interface will be maintained in the bottom region of the drums by an emulsion/brine interface level control system.

Multiple trains will be used from the free water knockouts through the stripping columns and gas compression to allow for greater flexibility and operating efficiency.

9.5.3.2 Oil Treating

After leaving the free water knockout drum, the oil emulsion will be heated from an inlet temperature of 70-90°F to approximately 220°F by recovering the waste heat contained in the treated oil and brine streams (supplemented by heat from the emulsion heater).

The heated oil emulsion will enter the electrostatic emulsion treaters which will operate at the minimum temperature necessary to achieve

product specifications. A pressure controller will maintain an appropriate pressure level in the treaters to prevent vaporization of the light ends present in the crude.

Emulsion breaking will be achieved by a combination of elevated temperature, chemical addition, and the electrostatic field provided within the treater by potential differentials between metallic grids. Conceptual studies indicate that electrostatic treaters will achieve more efficient emulsion breaking at a lower operating temperature than conventional heater-treaters. The selection of electrostatic treaters coupled with an emulsion heater will result in a net fuel savings and a corresponding heater emissions reduction.

The produced water (brine) liberated in the electrostatic emulsion treaters will flow through the water/emulsion heat exchanger to transfer the waste heat available in the stream. An oil/water interface will be maintained in the bottom region of the treater by an oil/water interface level control system. After cooling, this stream will be combined with the free water (brine) from the inlet knockout drum and the resulting stream will be routed to the produced water treating facilities.

9.5.3.3 Oil Stripping

After leaving the electrostatic emulsion treaters, the treated oil will pass through a trim heater which provides operational flexibility by heating the oil to approximately 250°F (if needed for better column operation). Heat requirements for the emulsion and trim heaters will be supplied by a hot oil heating system.

In the crude stripping tower, the treated crude will be counter-currently contacted with sweet natural gas. The sweet natural gas stream will strip the majority of the light sulfur compounds as well as a portion of the light end components from the treated crude. The hot sour gas stream leaving the top of the tower will transfer waste heat to the inlet sweet gas feed to the stripping column before it enters the reflux separation facilities. Here the sour gas will be compressed and cooled in stages to permit the recovery of most of the light end components stripped from the treated crude. Part of these light ends will be returned to the stripping tower as a reflux stream to enhance the tower's performance as well as to reintroduce the light end components to the crude stream. The compressed sour gas stream will be then metered and piped to the gas

treating facilities for processing. Sour water collected in the reflux separators will be routed to the untreated brine tanks in the produced water treating system.

The treated and stabilized crude will leave the bottom of the stripping tower and be pumped to the tank farm. Prior to leaving the treating facilities, the treated crude will flow through the oil/emulsion heat exchanger to transfer the waste heat available in the stream. Downstream of the oil/emulsion heat exchanger, a level control valve will maintain an adequate oil level in the stripping tower and a liquid contact in the oil/emulsion heat exchanger.

Downstream of the level control valve, the treated and stabilized crude will be cooled to storage temperature. The oil cooler will be a trim cooler; it will be operated to the extent necessary to achieve vapor pressure specifications in the tank farm.

9.5.3.4 Oil Storage

Upon entering the tank farm, the treated oil basic sediment and water (BS&W) content will be monitored to insure that product specifications are maintained. Off-specification crude will

be routed to either the rerun tanks or to the treated crude tanks, depending upon tankage availability and the volume of crude involved. On-specification crude will pass to the treated crude storage tanks. Section 10.2.2.1 discusses the oil storage facilities requirements for the marine terminal.

The rerun tanks, 20,000 barrel cone roof tanks, will provide both transient storage for off-specification crude prior to reprocessing and inlet surge capacity. 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 oil transfer pumps. This operation will be non-continuous and will be performed when necessary to maintain adequate inlet surge capacity.

9.5.3.5 Produced Water Treating

The produced water treating system is shown in Figure 9.14. Brine from the free water knockout and electrostatic treaters, sour water from the stripper reflux drums and brine from the backwash sump will be stored in the untreated brine tanks. The brine will flow from these tanks to the flotation units which use flotation gas to

separate oil and suspended solids from the water. The oil and solids will be sent to the waste sump and the water will be pumped to the brine filter.

The brine filters will be designed for one filter to be on backwash cycle while the others are operating on full flow; normal operation will be parallel flow through all filters at reduced rates. Backwash water will be supplied from the treated brine tank.

After filtration, the brine will be periodically monitored for water quality and routed to either the treated brine tanks or pumped directly to the produced water outfall line for disposal by ocean discharge in accordance with an NPDES permit. If for some reason the required water quality is not achieved, the produced water will be routed back to the untreated brine tanks for further treatment.

Wastes from backwash operations will be sent to the backwash sump for separation of solids and water. The solids will be hauled away by vacuum truck, while the water will be pumped back to the untreated brine tanks.

A foam of suspended solids and oil will enter the

waste sump from the flotation unit. In the waste sump, oil, water and solids will be separated with the oil being pumped to the rerun tanks and the water being pumped to the untreated brine tanks. Solids will be hauled away by vacuum truck.

9.5.3.6 Blanket Gas System

The blanket gas system is shown in Figure 9.15. The flotation units and waste sumps in the produced water treating facilities and all storage tanks will be equipped with breathing valves which are connected to the tank vapor blanketing system. This system will be a closed loop system. Sweet gas provided from the gas treating facilities and inert gas/hydrocarbon vapors from the marine terminal vapor balance system will be used to blanket the storage tanks during unloading operations. During storage tank loading operations, the blanket gas will be displaced into the vapor blanketing system. Gas from the vapor blanketing system will be compressed by the blanket gas compressor. The majority of the gas from the blanket gas compressor will be sent to the gas treating facilities, although some gas will be routed to the flotation unit for use as flotation gas.

9.5.3.7 Relief and Vent Systems

All tankage will be equipped with a pressure relieving device which will allow any excess emergency overpressure to be vented to the flare system. The flare system will consist of low pressure and high pressure flares. The tankage pressure relief system will be piped to the low pressure flare knockout drum. Liquids from the knockout drums will be sent to the rerun tanks and vapors will be routed to the flare system. Vessel emergency relief valves on all pressure vessels will be piped to the high pressure flare knockout drum.

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

1. All 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.

9.5.3.8 Utility Systems

Instrument and utility air will be supplied throughout the facilities. Air compressors will provide compressed air at approximately 115 psig. A portion of this air will be dehydrated for use as instrument air while the remainder will be used for utility air.

Water source wells will be drilled in the area of the site to provide potable and utility water. Additional water will be required for the gas turbine water injection type NO_x reduction process and for cooling water systems make-up water.

Power for the onshore oil treating facilities will be supplied from the central cogeneration power plant. A diesel powered emergency generator will serve as a backup for emergency operations in the event of a power failure.

9.5.4 Central Cogeneration Power Plant

A 50 MW central cogeneration power plant will be designed to supply the electrical power requirements of the onshore oil treating facilities, the offshore

platforms, and the offshore drilling rigs, while efficiently utilizing waste heat recovery to provide process heat to the onshore oil treating and gas treating facilities.

Power will be produced at 13.8 kV by multiple gas turbine driven generators. Transformers will be used to step up the voltage to 35 kV for the offshore submarine cable system feeding the platforms. Step down transformers will be used at onshore and offshore facilities to provide the power to operating loads at 4160 volts, 480 volts, and other voltages as needed.

The gas turbines will be fueled by produced gas treated through the onshore gas treating facilities. The only other utilities required will be instrument air and cooling. The instrument air will be obtained from the oil treating facilities air system. Cooling for lubricating oil and generator windings will be provided by a closed loop water circulation system with heat dissipated through aerial coolers.

Cogeneration of heat for the onshore oil and gas treating facilities will be accomplished through a turbine exhaust heat recovery system which will minimize the need for new fired heaters or boilers in these facilities. A liquid heat transfer fluid will be circulated through heat exchanger bundles located in the exhaust stack of each turbine. The hot fluid will be piped to

the oil and gas treating facilities where it will be used to heat process streams. The used heating media will be returned to the power plant for reheating. The waste heat recovery unit will be provided with supplemental gas firing burners to be used for balancing heat needs with electrical power demand. The requirement for supplemental firing would be minimized through prudent turbine and waste heat recovery unit design.

The power plant will also be equipped with a water injection-type NO_x reduction process. Water injection lowers the combustion temperature, thereby reducing NO_x formation. Water will be supplied from water wells drilled in the immediate area and will be treated to turbine injection quality by deionization.

A demonstration-scale Selective Catalytic Reduction (SCR) unit, or other pilot program, will be installed on the partial exhaust of one turbine. Selective Catalytic Reduction is a technology that uses ammonia and a catalyst to convert the NO_x in combustion products to nitrogen and water. It has never, to Exxon's knowledge, been commercially applied in turbine service. The potential benefits of the pilot project would further the state-of-the art of NO_x control technology in a turbine application. The test program, including duration, scale and program requirements, will be determined prior to turbine purchase.

The turbine generators and electrical switchgear will be contained in one, large, totally enclosed building. Applicable noise level standards will be met by proper acoustical treatment in the building design.

9.6 Safety - Onshore Facilities

9.6.1 Safety Standards

The safety of the contractor's employees, Exxon personnel, suppliers and other persons affected by the installation of the onshore facilities shall be the prime consideration in their design, construction, startup and operation. The onshore facilities will be designed, constructed and operated to comply with all applicable codes and regulations (Table 9.6). 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 oxygen apparatus will be available at various stations within the facilities.

9.6.2 Fire Protection

Firewater storage tank(s) will provide fire protection for the oil and gas treating facilities. Firewater will be supplied to both facilities by electric motor driven pumps with diesel powered pumps as backup. The sprinkler irrigation system will be available to wet down the landscaped areas in the event of fire.

Preventative or mitigative measures include separation of the oil storage facilities from the oil and gas treating facilities, construction of a diked area around the storage tanks so that any leakage will be channeled to the waste water drain and the installation of lightning rods.

The firewater delivery system will be supplemented by foam generation facilities located to allow foam blanketing of the diked crude oil storage tank area and other vessels containing oil and gas requiring this protection. Dry chemical fire extinguishers, both hand portable and wheeled, will be located throughout the site. Cone roofed storage tanks make the facilities even less susceptible to fire by preventing vapor emissions.

9.6.3 Control and Monitoring

Critical operating parameters will be monitored continuously and alarms will be triggered whenever ab-

normal conditions occur. Hydrogen sulfide monitors will be located at numerous locations in the treating areas and will read out continuously in the control room. Any dangerous levels of hydrogen sulfide will be detected and an alarm will sound. Continuous monitoring fire sensors will be located throughout the sites. Detection will result in an alarm in the control room. Detection in critical areas will trigger automatic fire extinguishing equipment in the area.

9.6.4 Emergency Shutdown Systems

Emergency shutdown systems will be provided to allow for orderly shutdowns in the event of an emergency. The systems will be designed to provide for local equipment shutdowns while allowing as much of the facilities as possible to remain in service. Alarms will be provided in many instances to call operator attention to an abnormal condition. The alarm points will be set to allow attending operators sufficient time to determine the proper action necessary to either diagnose the abnormality and remedy it or to proceed on an orderly and safe facilities or unit shutdown. Manual shutdown stations will be provided at strategic locations to provide the operators with easy access.

9.7 Environmental Impact Mitigation Measures - Onshore Facilities

9.7.1 Waste Disposal

There will be various sources of waste from the onshore facilities operations. Sanitary wastes will be handled by on site septic tanks. Solid process wastes and general refuse will be collected and removed to an approved disposal site. Waste process water from the gas treating facilities will first be treated to remove hydrogen sulfide and other undesirable components and then injected into an onshore underground reservoir. Produced water from the oil treating facilities will be treated to required quality and then pipelined to an offshore outfall discharge in accordance with an NPDES permit.

All major effluents from the facilities will be monitored and an appropriate inventory maintained. The amount of water sent to disposal will be recorded and samples for analysis taken periodically.

9.7.2 Oil Spill Prevention and Containment

A Spill Prevention Control and Countermeasure (SPCC) Plan is not required until six months after 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.

While the probability of an oil spill leaving the confines of the onshore facilities area is small, Exxon has prepared second and third phases of containment as precautions against such an event. Sufficient time would exist to implement these phases, if needed, because oil from the Santa Ynez Unit is extremely viscous and, consequently, its rate of flow down Las Flores and Corral Creeks would be slow.

First Phase: On Site

On site containment design features of the onshore facility include:

- The dike around the storage area, which will contain approximately the volume of the largest tank (250,000 bbls).
- Gates will be provided on appropriate road crossing culverts which can be closed in the unlikely event that the spill threatens to leak beyond the confines of the oil and gas treating facilities.

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:

- Activate a flood gate at the most downstream road crossing of Corral Creek.
- 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.

9.7.3 Measures Taken to Reduce Air Pollutant Emissions

Every effort has been made in the design of the onshore oil and gas treating facilities to reduce energy requirements and their corresponding air pollutant emis-

sions by utilizing efficient process design and by utilizing waste heat recovery from the power plant in Development Option B.

Vessel emergency relief valves on all pressure systems will be piped to a flare knockout drum which separates liquids from the vapor in the event of an emergency over-pressure. The oil storage tank vapor blanketing system will be equipped with a pressure relieving device to protect the tankage from over-pressurizing. This system will also be piped to the flare knockout drum. Liquids from the knockout drum will be sent to the rerun tanks and vapors will be routed to the appropriate oil or gas facilities flares. The flares will be equipped with forced air blowers or steam injection to reduce smoke.

In Development Option A (Offshore Oil Treating), natural gas will be used as fuel for the boilers in the gas treating area. These boilers will use low NO_x burners designed to reduce the formation of nitrogen oxides. In Development Option B (Onshore Oil Treating), the added utility boilers will use waste heat recovered from the power plant for steam generation. The existing fired boilers will be shut down and used only for backup.

Emissions of hydrogen sulfide and sulfur dioxide from the gas treating facilities will be minimized by processing the acid gas in sulfur recovery units. Acid gas

containing hydrogen sulfide, which will be removed from the process gas, will be sent to the sulfur recovery units, where over 99 percent of the hydrogen sulfide will be converted to elemental sulfur. The remaining tail gas will then be incinerated by mixing it with natural gas in the boiler burners or by direct combustion in a tail gas incinerator.

Hydrocarbon pumps will be equipped with dual mechanical seals to minimize potential fugitive emissions. A preventative maintenance plan and operator attention will be used to minimize fugitive emissions.

Control of NO_x emissions will be accomplished through the injection of water into the turbine combustion zone, thereby reducing the combustion temperature and thus the formation of NO_x . A demonstration-scale Selective Catalytic Reduction (SCR) system will be installed on the slipstream of one turbine to test the applicability of this technology in a turbine application. These two NO_x reduction steps are discussed in more detail in Section 9.5.4.

Waste heat from the power plant turbine exhaust will be recovered and used to supply the oil treating facilities process heat requirements in Development Option B (On-shore Oil Treating). This will preclude the installation of fired heaters, thus eliminating the emissions from heater fuel gas combustion.

Electrical power to back up the power plant turbines during peak loads or supply interruptions will be provided via a tie-in to SCE. This will avoid the need to install backup or peak turbine capacity and the associated emissions.

TABLE 9.1

GAS SALES SPECIFICATIONS

Delivery pressure, min/max	600/975 psig
Carbon Dioxide, maximum	5 vol. %
Total Inerts	5 vol. %
Hydrogen Sulfide, maximum	0.25 grain/100 scf
Organic Sulfur, maximum	0.20 grain/100 scf
Total Sulfur, maximum	0.50 grain/100 scf
Gross Heating Value, minimum	1000 BTU/scf
Gross Heating Value, maximum	1220 BTU/scf
Oxygen	0.20 vol. % max.
Water Content	7 lb/mm scf
Liquid Water	None
Hydrocarbon Dew Point	45°F measured @ 400 psig
Temperature	35 ≤ T ≤ 100°F 120°F. allowable on hot days only

TABLE 9.2

PRODUCT SULFUR SPECIFICATIONS

H ₂ S content, maximum	10 ppm
Carbon content	0.05 wt. %
Ash content	30 ppm by wt.
Color	Bright yellow (#7 or less on reflectance scale)

TABLE 9.3

MAJOR EQUIPMENT ADDITIONS TO GAS TREATING FACILITIES
EXPANSION FROM 30 MMSCFD TO 90 MMSCFD

2 Inlet Gas/Gas Exchangers
2 Inlet Gas/Liquid Exchangers
2 Gas Chillers
2 Stabilizer Feed Preheaters
2 Stabilizer Condensers
2 Stabilizer Reboilers
7 NGL Storage Tanks
2 TEG Contactors
2 Main Separators
2 Water Separators
1 Flash Drum
1 Stabilizer
1 Stabilizer Reflux Accumulator
3 Refrigerant Condensers
2 Refrigerant Compressors
1 Refrigerant Surge Tank
2 Refrigerant Scrubbers
1 Refrigerant Flash Tank
1 Refrigerant Makeup Tank
2 Gas Sweetening Stripper Reboilers
2 Gas Sweetening Stripper Condensers
2 Gas Sweetening Lean/Rich Solvent Exchangers
2 Gas Sweetening Lean Solvent Coolers
1 High Pressure Gas Sweetening Contactor
1 Low Pressure Gas Sweetening Contactor
1 Gas Sweetening Stripper
1 Gas Sweetening Reclaimer
1 Gas Sweetening Stripper Reflux Accumulator
1 Low Pressure Solvent Flash Tank
1 Sales Gas TEG Contactor
3 Low Pressure Sales Gas Compressors
2 Sales Gas Compressors
1 Sour Water Stripper
1 Waste Liquid Storage Tank
2 Boilers
2 Sulfur Recovery Unit Trains
2 Tail Gas Treating Unit Trains
1 Air Compressor
Flare Knockout Drums (Replace Existing)
Flare Stack (Replace Existing)

TABLE 9.4

MAJOR EQUIPMENT ADDITIONS TO GAS TREATING FACILITIES

EXPANSION FROM 30 MMSCFD TO 135 MMSCFD

2 Inlet Gas/Gas Exchangers
2 Inlet Gas/Liquid Exchangers
2 Gas Chillers
2 Stabilizer Feed Preheaters
2 Stabilizer Condensers
2 Stabilizer Reboilers
11 NGL Storage Tanks
2 TEG Contactors
2 Main Separators
2 Water Separators
1 Flash Drum
1 Stabilizer
1 Stabilizer Reflux Accumulator
3 Refrigerant Condensers
2 Refrigerant Compressors
1 Refrigerant Surge Tank
2 Refrigerant Scrubbers
1 Refrigerant Flash Tank
1 Refrigerant Makeup Tank
2 Gas Sweetening Stripper Reboilers
2 Gas Sweetening Stripper Condensers
2 Gas Sweetening Lean/Rich Solvent Exchangers
2 Gas Sweetening Lean Solvent Coolers
1 High Pressure Gas Sweetening Contactor
1 Low Pressure Gas Sweetening Contactor
1 Gas Sweetening Stripper
1 Gas Sweetening Reclaimer
1 Gas Sweetening Stripper Reflux Accumulator
1 Low Pressure Solvent Flash Tank
1 Sales Gas TEG Contactor
3 Low Pressure Sales Gas Compressors
3 Sales Gas Compressors
1 Sour Water Stripper
1 Waste Liquid Storage Tank
2 Boilers
2 Sulfur Recovery Unit Trains
2 Tail Gas Treating Unit Trains
1 Air Compressor
1 Incinerator
Flare Knockout Drums (Replace Existing)
Flare Stack (Replace Existing)

TABLE 9.5

CRUDE OIL SALES SPECIFICATIONS

Basic Sediment and Water Content	1.0 % max.
Temperature	110°F 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 9.6

APPLICABLE CODES AND ORDINANCES

- a. Title 49, Code of Federal Regulations, Part 192 for Transportation of Natural and Other Gas by Pipeline.
- b. Title 49, Code of Federal Regulations, Part 195 for Transportation of Liquids by Pipeline.
- c. State of California Petroleum Safety Orders, Drilling and Production, Subchapter 14, Chapter 4, Title 8; and Refining, Transportation and Handling, Subchapter 15, Chapter 4, Title 8.
- d. State of California General Industry Safety Orders.
- e. State of California Fire Marshall's Standards, Title 19 - California Administration Code.
- f. ANSI B31.1, Power Piping.
- g. ANSI B31.2, Fuel Gas Piping.
- h. ANSI B31.3, Petroleum Refinery Piping Code.
- i. ANSI B31.4, Liquid Petroleum Transportation Piping Systems.
- j. ANSI B31.5, Refrigeration Piping.
- k. ANSI B31.8, Natural Gas Transmission and Distribution Piping.
- l. API Standard 1104, Standard for Welding Pipelines and Related Facilities.
- m. API 615, Sound Control of Mechanical Equipment for Refinery Services.
- n. API RP 50, 500A, 520, 550, 600, Refinery Practices.
- o. API 600 and 6D, Valve Design Standards.
- p. API 12D, Field Welded Tanks for Storage for Production Liquids.
- q. API 618, Reciprocating Compressors for General Refinery Services.

TABLE 9.6 (Cont.)

APPLICABLE CODES AND ORDINANCES

- r. ASME Boiler and Pressure Vessel Code, Section 8, Division I, plus all addenda.
- s. State of California, Electrical Safety Orders.
- t. National Electrical Code.
- u. California Administrative Code, Title 24, Part 3, Basic Electrical Regulations.
- v. CAL-OSHA Requirements.
- w. California Air Resources Board and Environmental Protection Agency Regulations.
- x. Santa Barbara County Air Pollution Control District Requirements.
- y. Division of Oil and Gas, State of California; Requirements for Injection of Substances Underground.
- z. NFPA Standard 58, Standard for the Storage and Handling of Liquefied Petroleum Gases.
- aa. AGA Measurement Report #3.

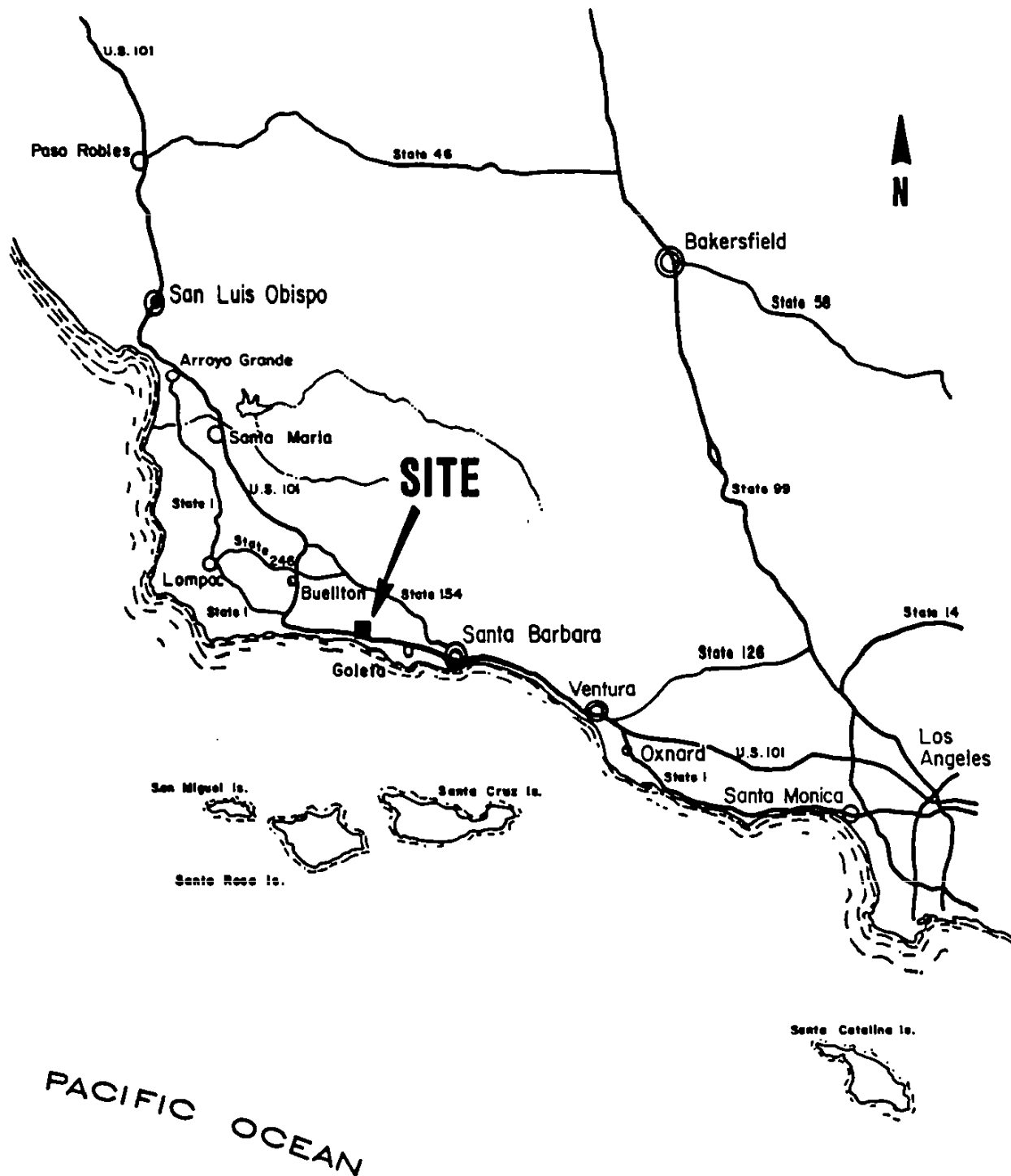
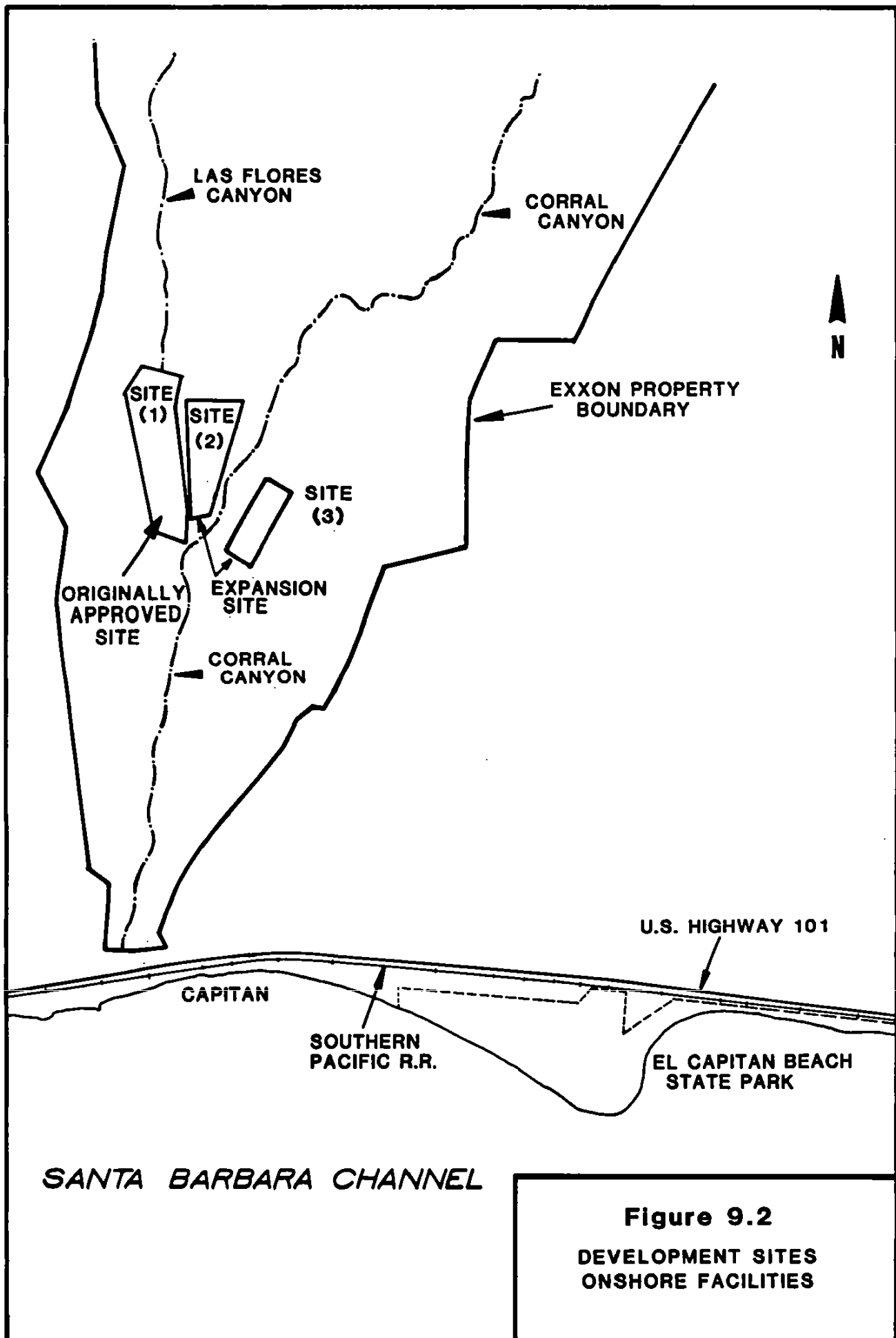


Figure 9.1

**VICINITY MAP
ONSHORE FACILITIES**

0 10 20 Miles



- | | | |
|------------------------------|---|-------------------------------|
| 1) GUARD HOUSE | 11) INLET SEPARATION | 20) BOILERS |
| 2) SALES GAS COMPRESSORS | 12) REFRIGERATION COMPRESSORS | 21) FLARES |
| 3) TRUCK LOADING | 13) LOW PRESSURE GAS COMPRESSORS | 22) BOILER FEEDWATER STORAGE |
| 4) SLUG CATCHER | 14) SALES GAS DEHYDRATION | 23) CLAUS / BEAVON UNITS |
| 5) NGL STORAGE | 15) SWEETENING | 24) FIREWATER STORAGE TANK |
| 6) WASTE LIQUID STORAGE (1) | 16) SULFINOL REGENERATION | 25) METHANOL STORAGE |
| 7) FLASH DRUM | 17) SOUR WATER STRIPPER | |
| 8) INLET DEHYDRATION | 18) OFFICES, LABORATORY, CONTROL ROOM,
MOTOR CONTROL ROOM, WAREHOUSE, PARKING | |
| 9) STABILIZATION | 19) UTILITY BUILDING | |
| 10) REFRIGERATION | | |

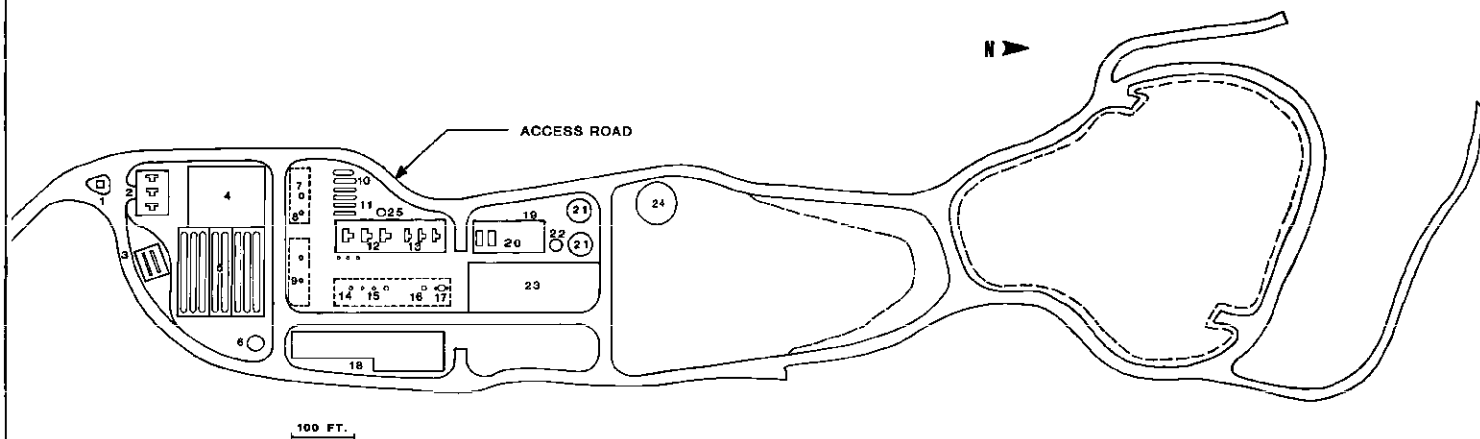


Figure 9.3
30 MMSCFD
GAS TREATING FACILITIES
GENERAL PLOT PLAN

- | | | |
|-----------------------------|--|------------------------------|
| 1) GUARD HOUSE | 10) REFRIGERATION | 19) UTILITY BUILDING |
| 2) SALES GAS COMPRESSORS | 11) INLET SEPARATION | 20) BOILERS |
| 3) TRUCK LOADING | 12) REFRIGERATION COMPRESSORS | 21) FLARES |
| 4) SLUG CATCHER | 13) LOW PRESSURE GAS COMPRESSORS | 22) BOILER FEEDWATER STORAGE |
| 5) NGL STORAGE | 14) SALES GAS DEHYDRATION | 23) CLAUSS / BEAVON UNITS |
| 6) WASTE LIQUID STORAGE (2) | 15) SWEETENING | 24) FIREWATER STORAGE TANK |
| 7) FLASH DRUM | 16) SULFANOL REGENERATION | 25) SULFUR RECOVERY UNITS |
| 8) INLET DEHYDRATION | 17) SOUR WATER STRIPPER | 26) SOLVENT REGENERATION |
| 9) STABILIZATION | 18) OFFICES, LABORATORY, CONTROL ROOM,
MOTOR CONTROL ROOM, WAREHOUSE, PARKING | 27) METHANOL STORAGE |

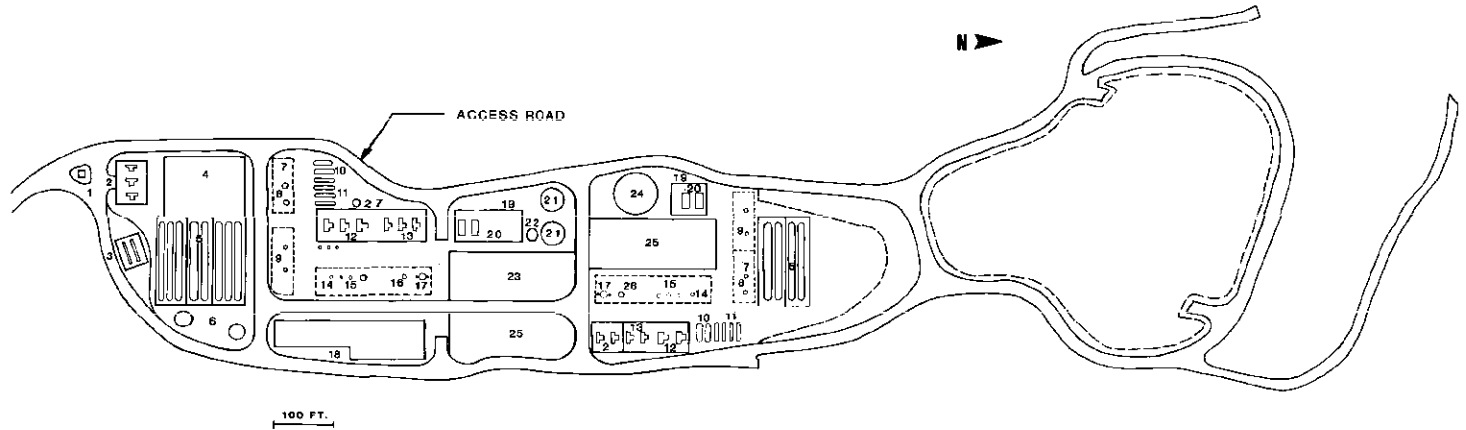


Figure 9.4
DEVELOPMENT OPTION A
90 MMSCFD EXPANDED
GAS TREATING FACILITIES
GENERAL PLOT PLAN

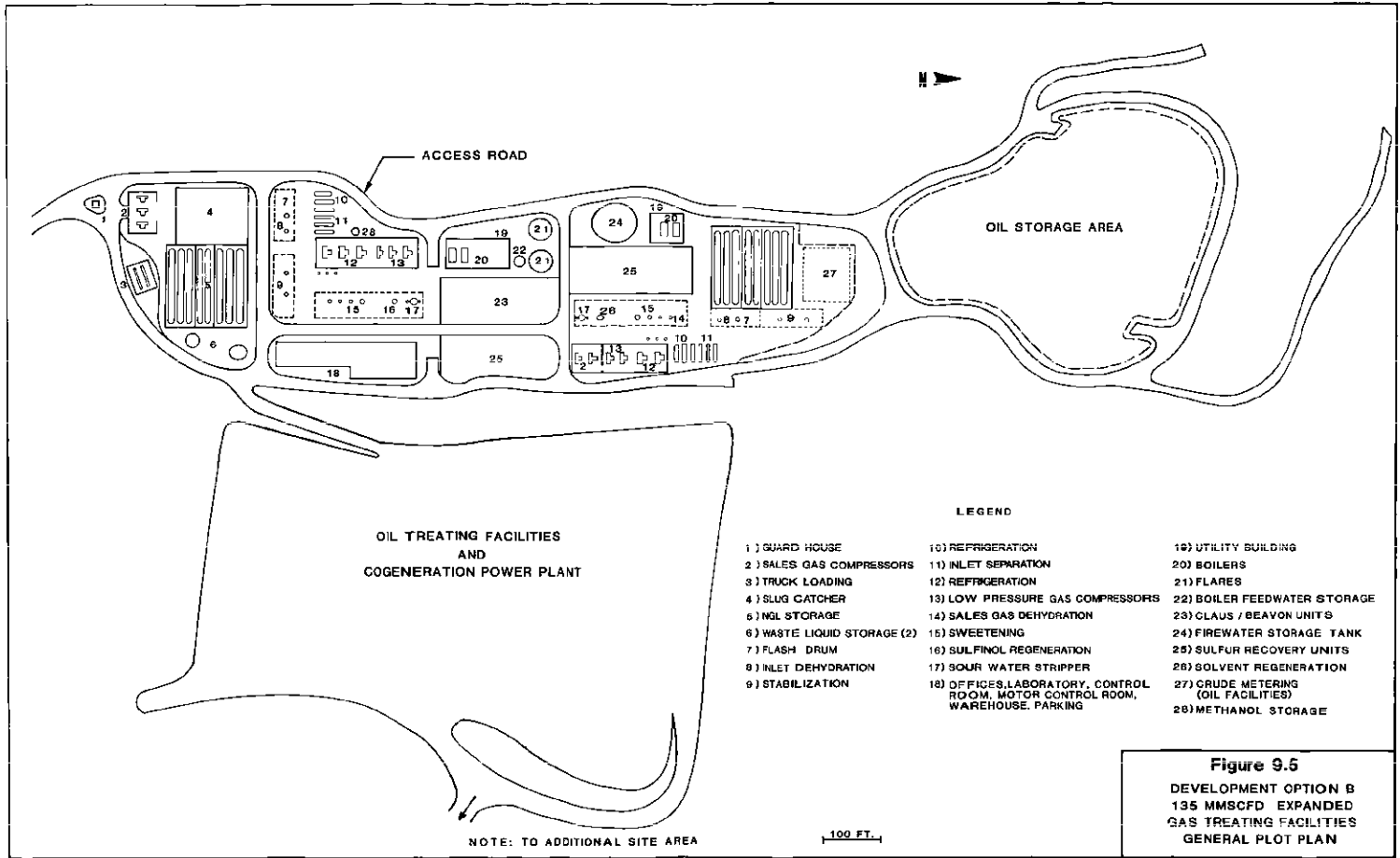


Figure 9.6
DEVELOPMENT OPTION B
135 MMSCFD EXPANDED
GAS TREATING FACILITIES
GENERAL PLOT PLAN

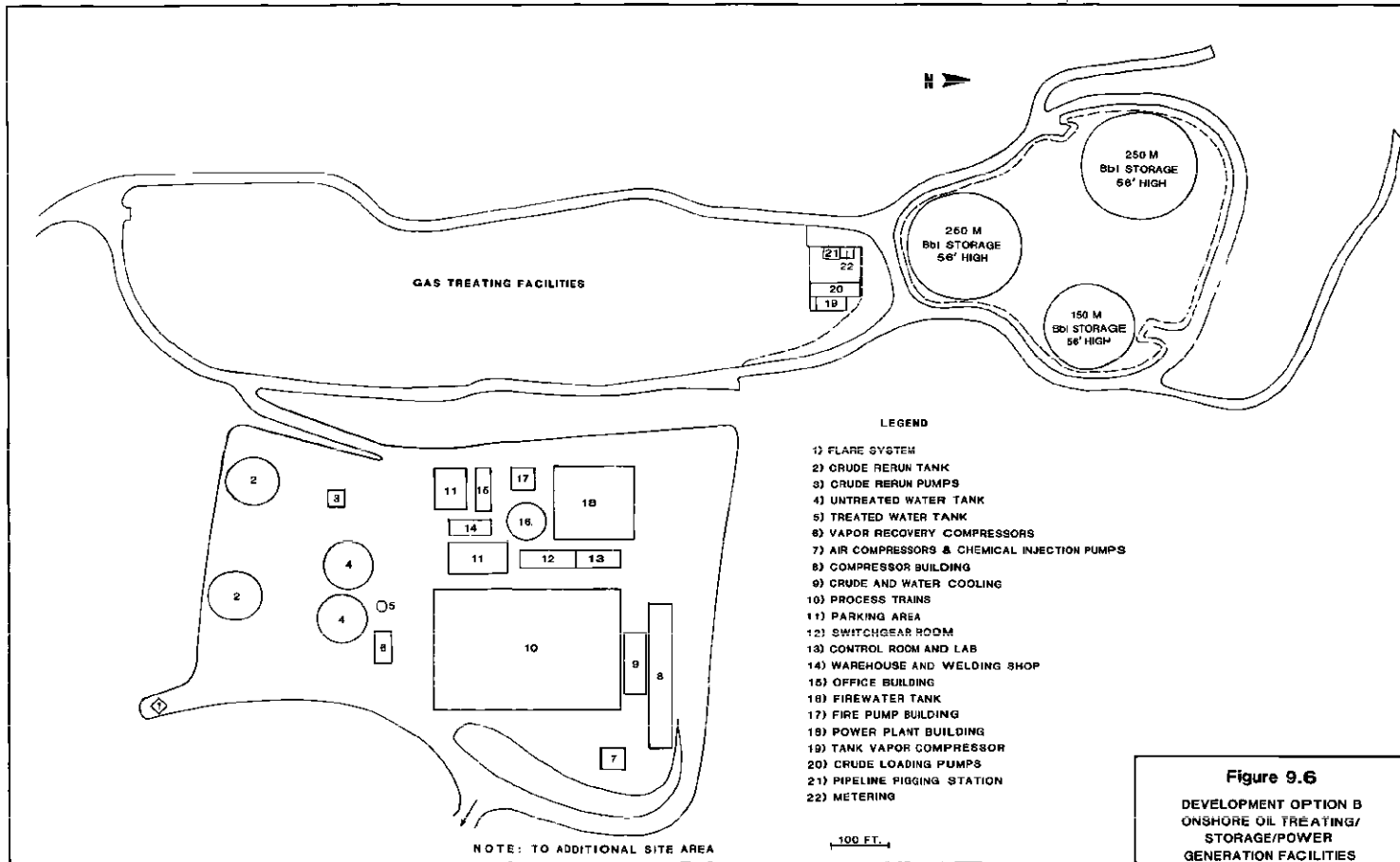


Figure 9.6
DEVELOPMENT OPTION B
ONSHORE OIL TREATING/
STORAGE/POWER
GENERATION FACILITIES

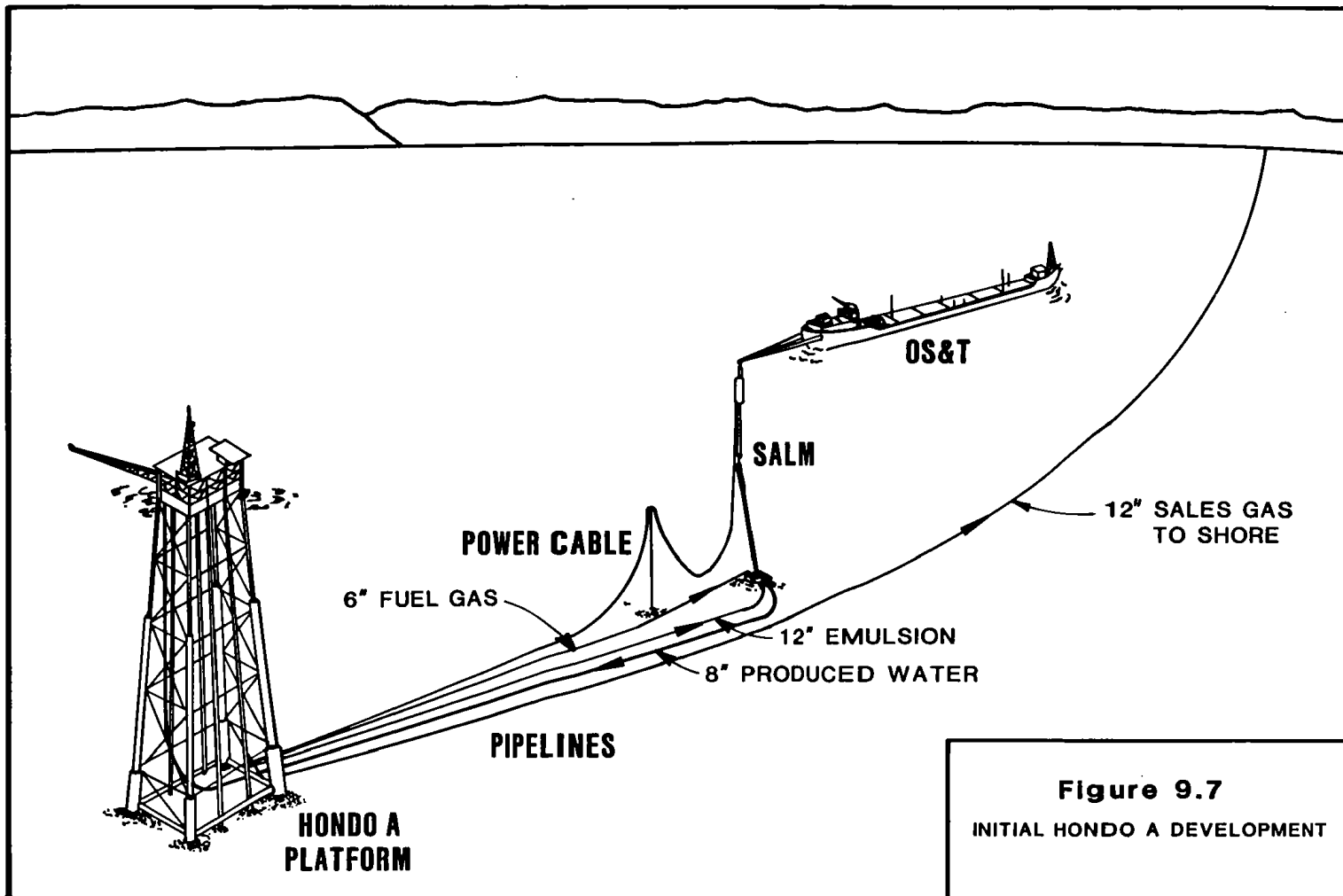


Figure 9.7
INITIAL HONDO A DEVELOPMENT

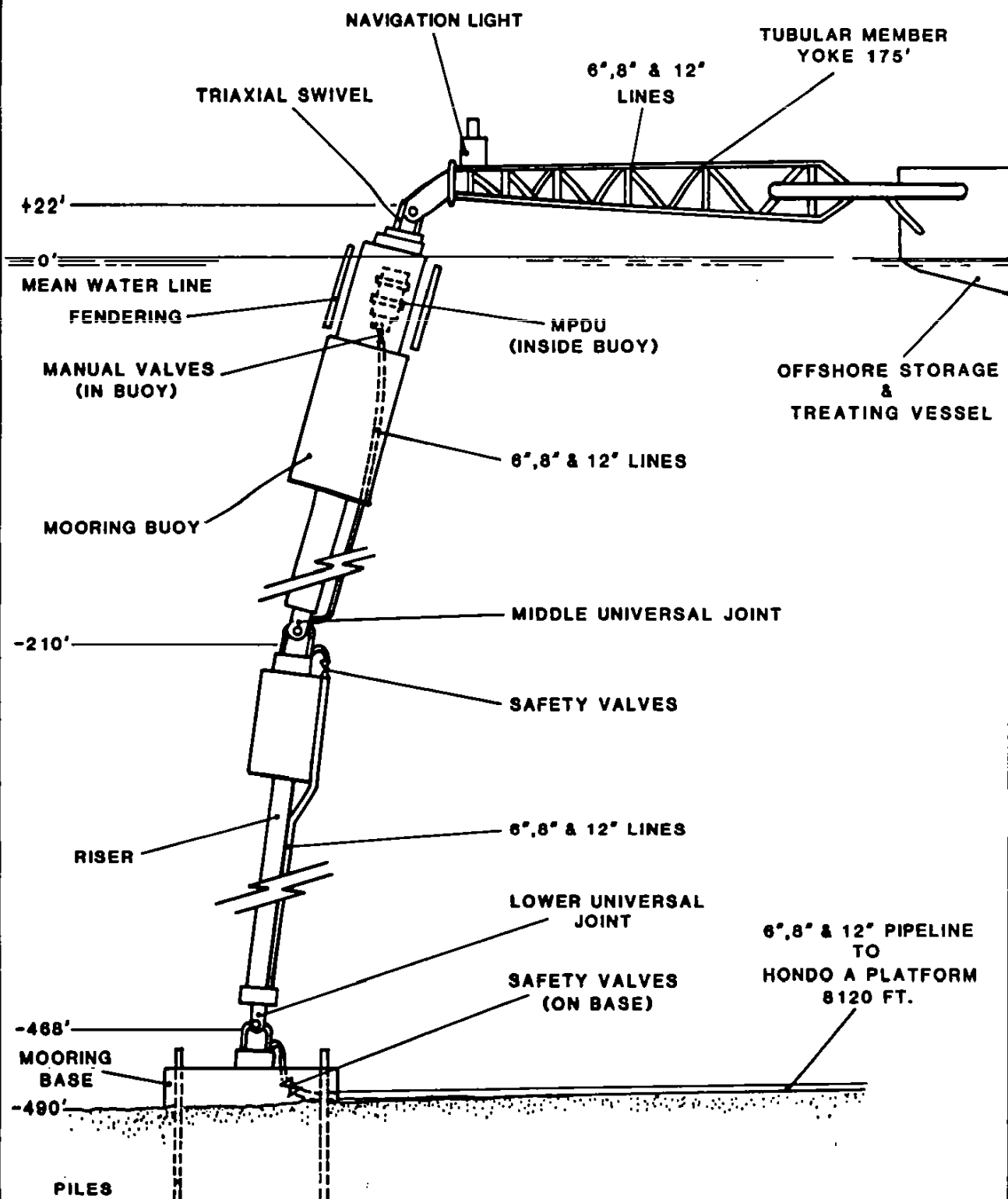


Figure 9.8
EXISTING
SINGLE ANCHOR LEG MOORING

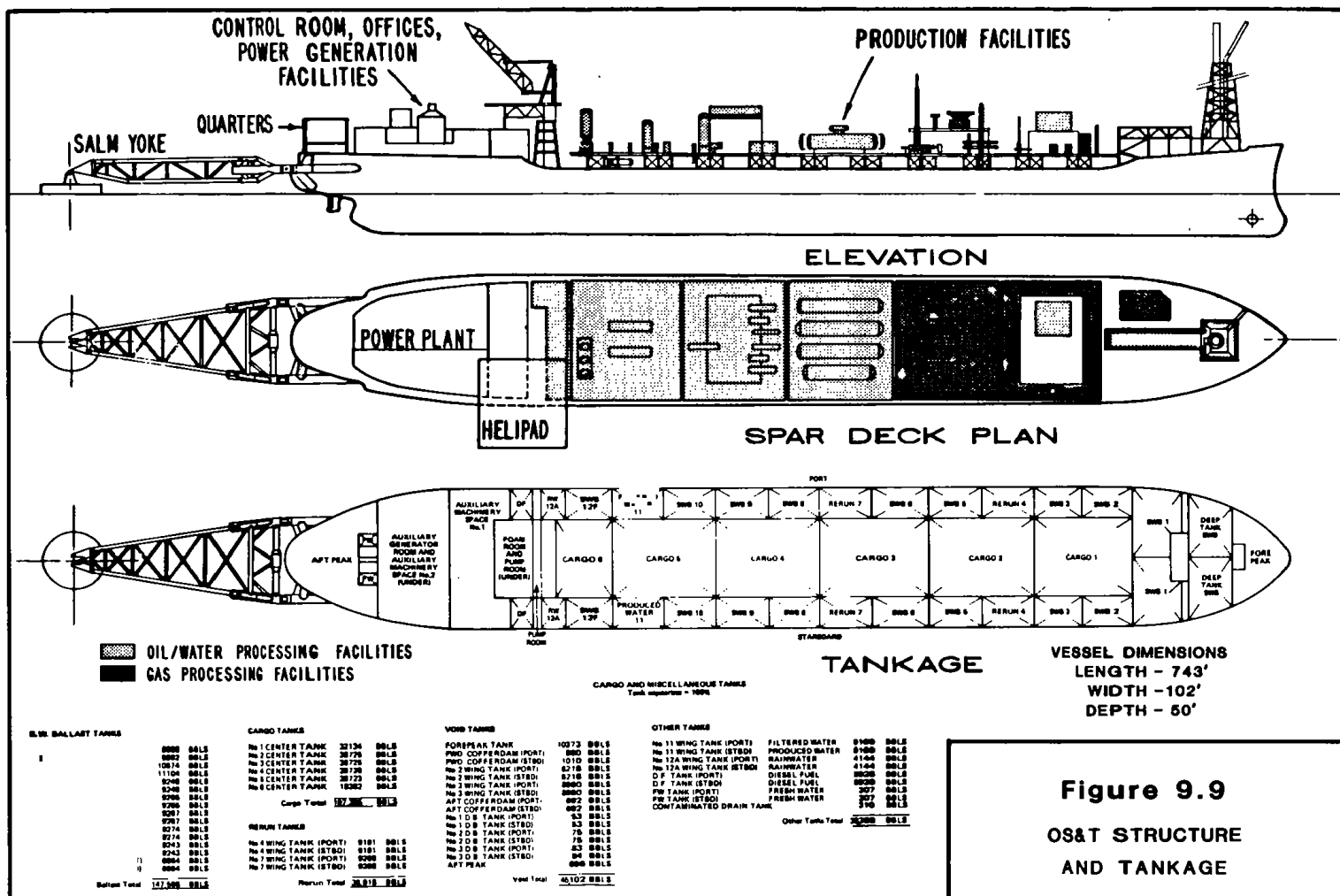


Figure 9.9
OS&T STRUCTURE
AND TANKAGE

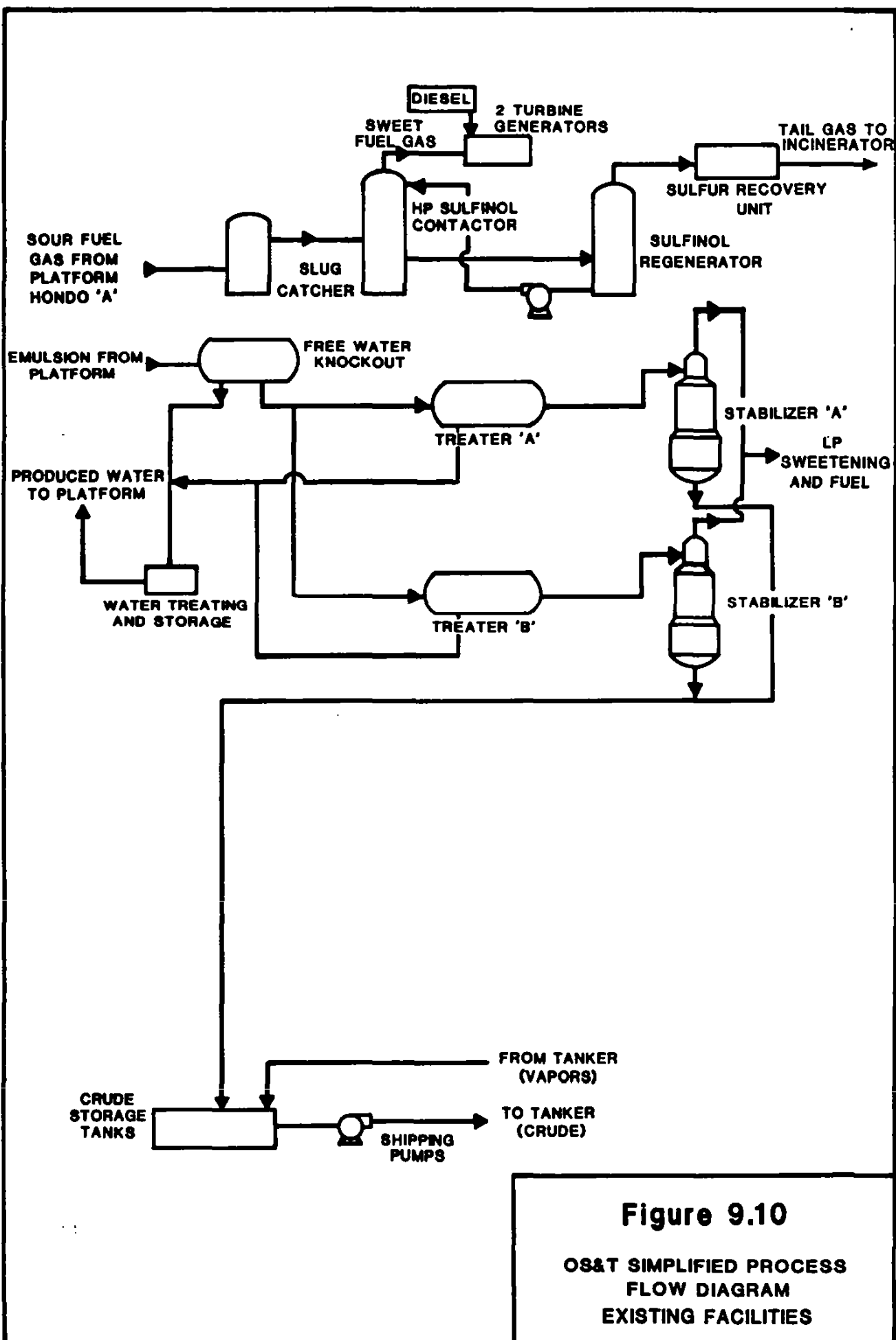


Figure 9.10

**OS&T SIMPLIFIED PROCESS
FLOW DIAGRAM
EXISTING FACILITIES**

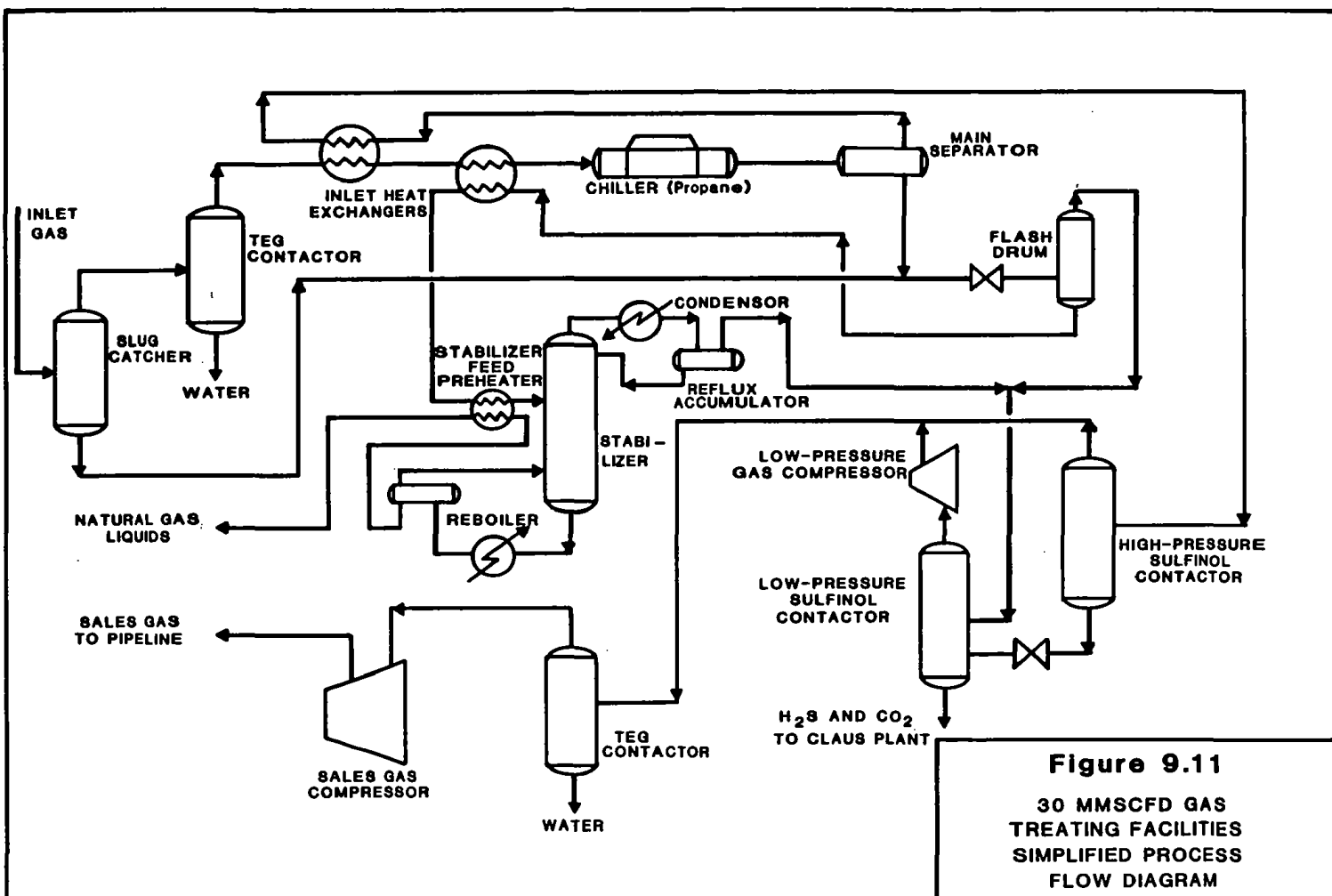


Figure 9.11
30 MMSCFD GAS
TREATING FACILITIES
SIMPLIFIED PROCESS
FLOW DIAGRAM

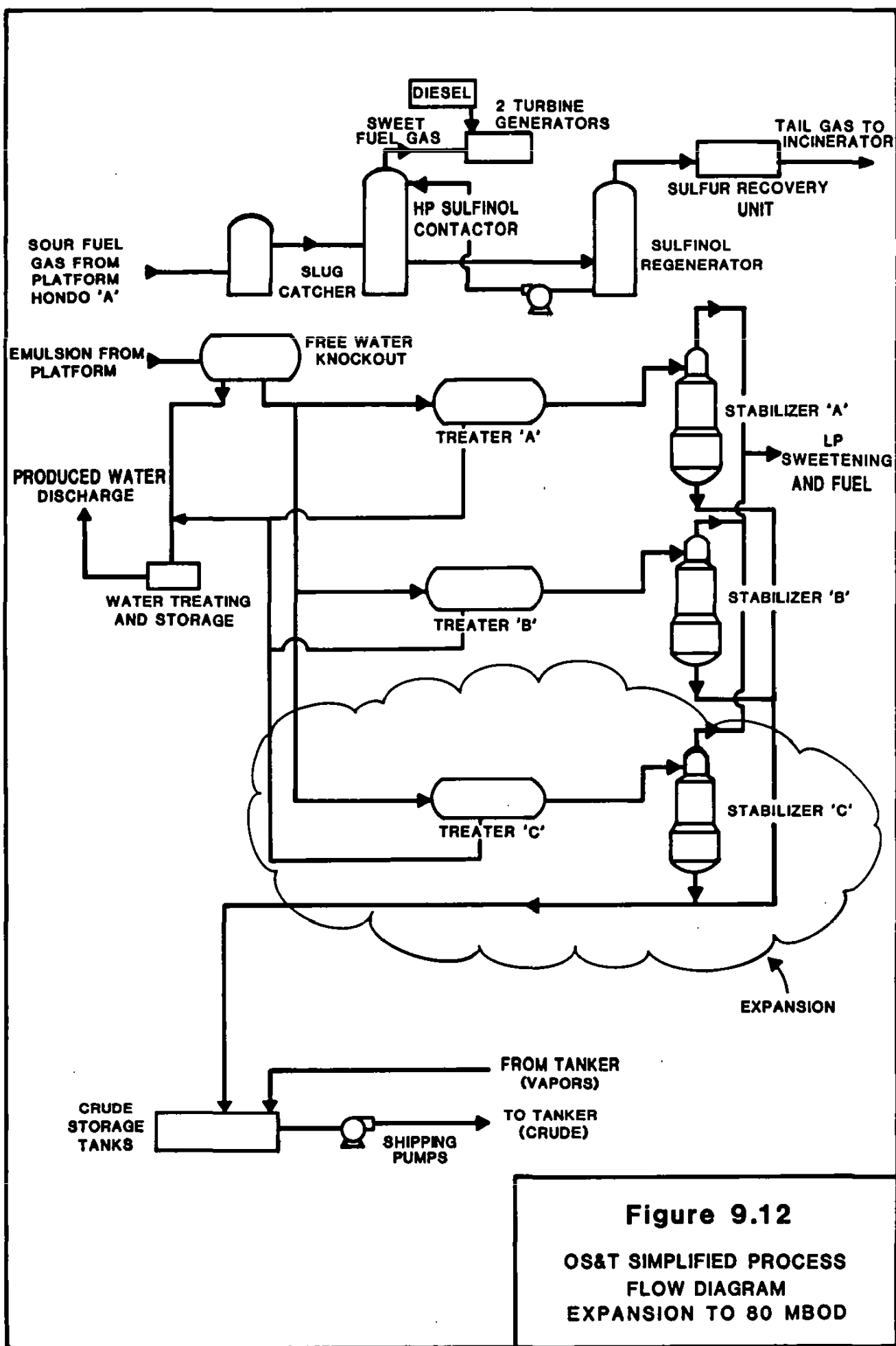


Figure 9.12

**OS&T SIMPLIFIED PROCESS
FLOW DIAGRAM
EXPANSION TO 80 MBOD**

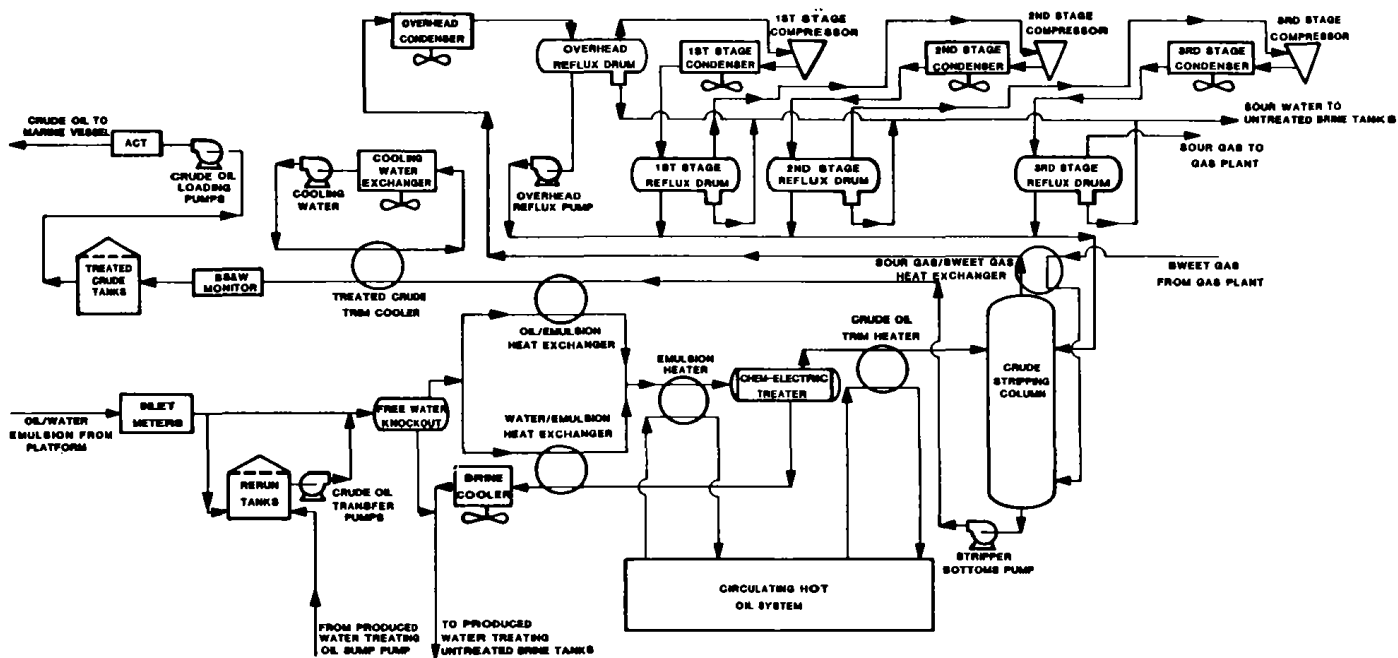


Figure 9.13
ONSHORE
OIL TREATING FACILITIES

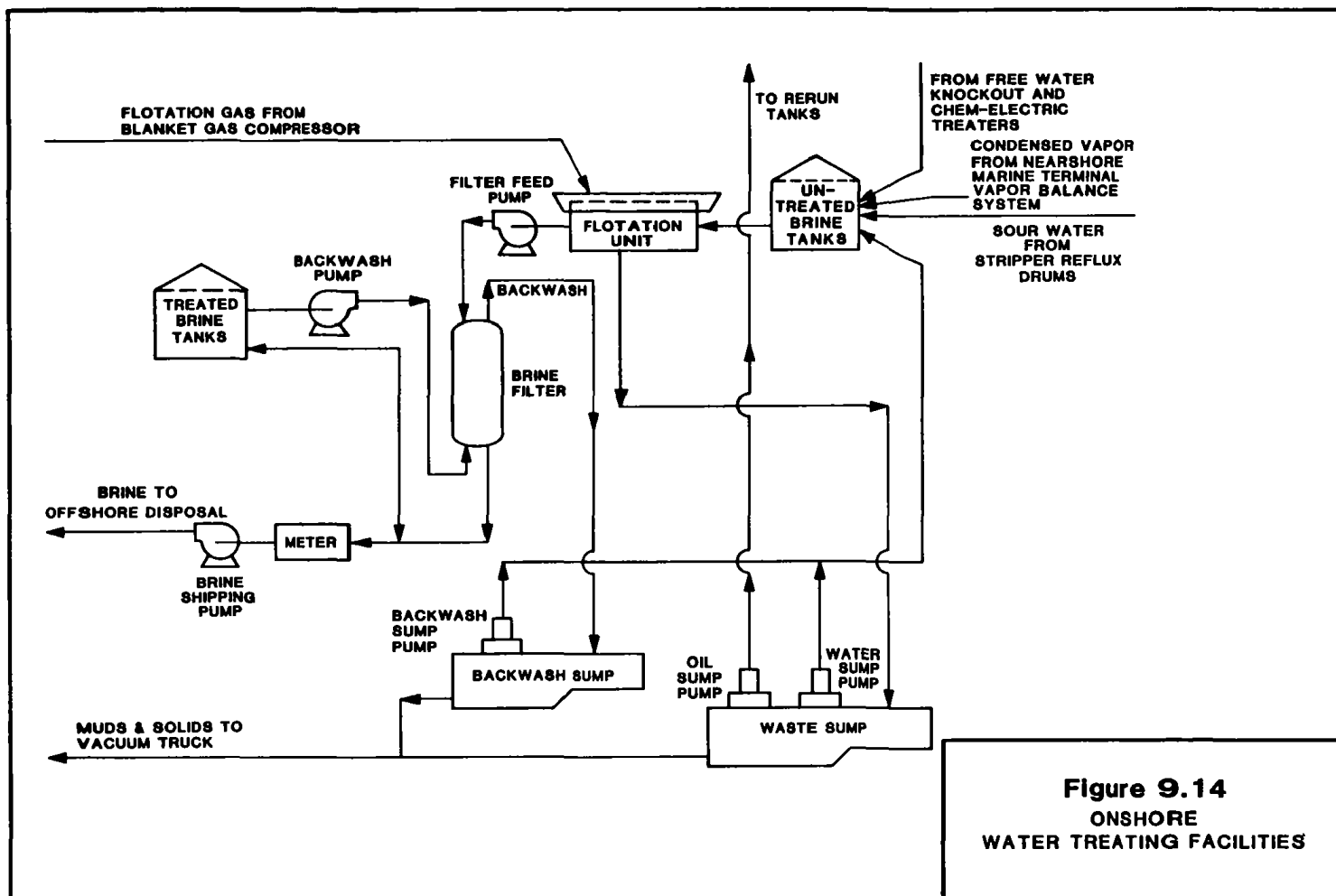


Figure 9.14
ONSHORE
WATER TREATING FACILITIES

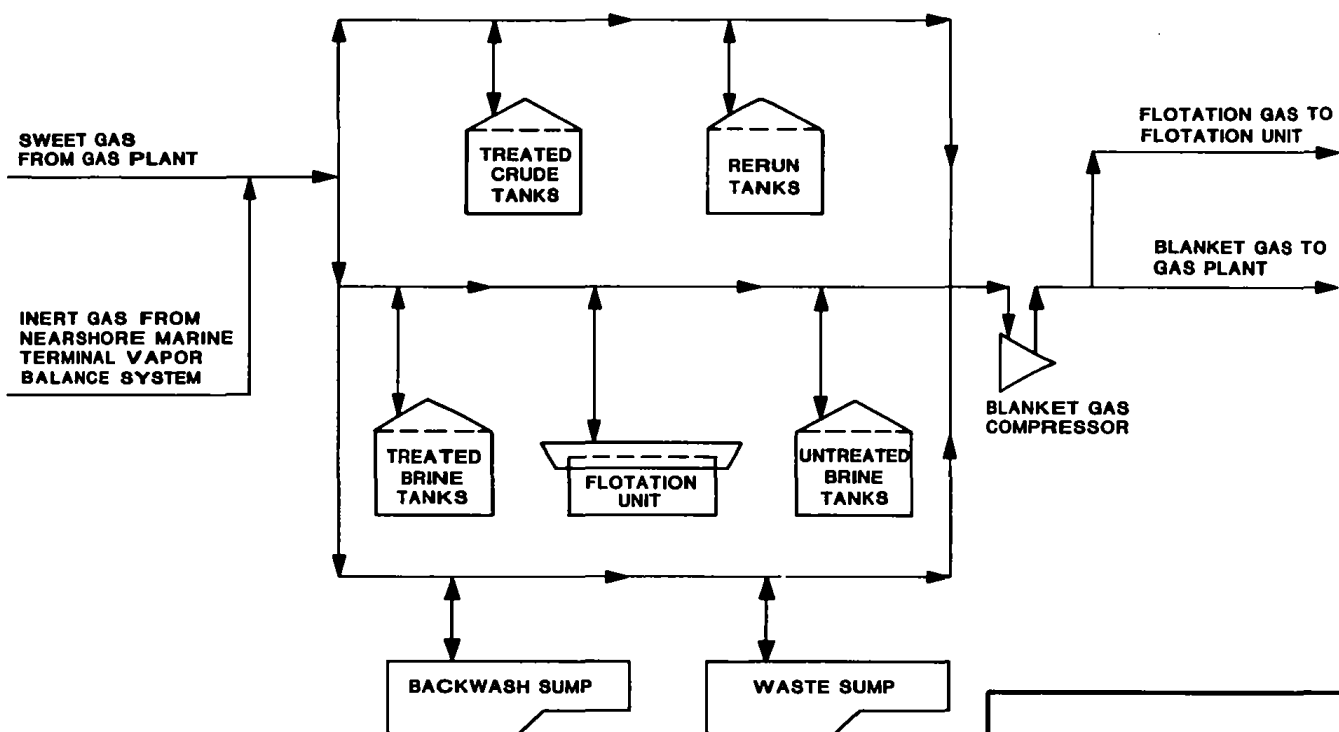


Figure 9.15
ONSHORE
BLANKET GAS SYSTEM

SECTION X
CRUDE TRANSPORTATION
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SECTION X
CRUDE TRANSPORTATION

FIGURES

- 10.1 Site Plan - Modernized Capitan Nearshore Marine Terminal.
- 10.2 Oil Pipeline End Manifold - Nearshore Marine Terminal.
- 10.3 Vapor Balance Pipeline End Manifold - Nearshore Marine Terminal.
- 10.4 Single Anchor Leg Mooring - Nearshore Marine Terminal.
- 10.5 Site Plan - Existing Capitan Marine Terminal.

SECTION X

10.1 Introduction

This section describes the alternate crude transportation systems associated with Development Option B (Onshore Oil Treating). The marine shuttle vessel crude transportation system associated with Development Option A (Offshore Oil Treating) was described in Section 9.3.1.

Two methods of transporting crude oil production from the proposed onshore oil treating facilities are by either pipeline or marine vessels. Section 10.2 addresses the onshore facilities (storage, pumping, metering), the connecting pipelines, and the marine loading systems for a modernized nearshore Single Anchor Leg Mooring (SALM) marine terminal located in state waters. Section 10.3 will address the proposed Southern California Coastal Pipeline. The abandonment of the existing Capitan marine terminal will be discussed in Section 10.4. And, finally, the concept of an integrated transportation system will be addressed in Section 10.5.

10.2 Modernized Capitan Nearshore Marine Terminal

10.2.1 Overview

One option for transporting the Santa Ynez Unit crude oil production is the installation of a modernized

nearshore single point mooring marine terminal in the Santa Barbara Channel. This option has been included in prior Santa Ynez Unit development plans. Two major modifications have been made in this concept since the last development plan was submitted in September, 1975 (permit application to the South Central Coast Regional Coastal Zone Commission). They are: 1) the expansion of the onshore storage facilities from approximately 440,000 barrels of storage to approximately 650,000 barrels of storage; and 2) the addition of a closed system to transfer vapors displaced from the marine vessel cargo compartments during the loading of crude oil to the onshore tank farm.

This subsection describes the modernized nearshore marine terminal and the related facilities located in Las Flores Canyon. The objective of these facilities is to provide onshore storage and marine loading facilities, capable of storing field production for 5-6 days and of loading approximately 30,000 barrels per hour of degassed 16-18°API gravity crude, which incorporate a closed system to transfer vapors displaced from the dedicated marine vessels during loading to the onshore tank farm. The terminal will be designed to comply with all applicable local, state, and national codes and regulations.

10.2.2 Design and Description of Major Components

General design descriptions, materials and characteristics of the onshore facilities, piping system, sea berth components, and vapor balance system are described below. The general layout of the facilities is shown in Figure 10.1.

The onshore facilities associated with the modernized Capitan marine terminal will be located on the onshore site described in Section 9.2. While these facilities are presented separate from the onshore treating facilities in this Development and Production Plan, they will be completely integrated with the onshore oil treating facilities.

10.2.2.1 Oil Storage Facilities

The oil storage facilities associated with the modernized Capitan marine terminal will consist of two nominal 250,000-barrel tanks and one nominal 150,000-barrel tank. All tanks will be cone roofed and will be equipped with breathing valves connecting to the tank vapor blanketing system of the onshore oil treating facilities. In addition, all tanks will be equipped with pressure protection devices to prevent over or under pressuring.

The oil storage facilities will be separated from the oil and gas processing facilities. A dike will be constructed to contain possible oil spills as well as to channel ground water to the waste water drain. The diked area will be designed to contain approximately the volume of the largest tank.

10.2.2.2 Pump and Meter Station

The pump and meter station associated with the terminal will be located near the oil storage area (see Fig. 9.6). 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 suction pipelines and pumps will be maintained in the 95-120°F temperature range. Insulation alone or in combination with heat tracing may be necessary to maintain the desired temperature range.

The pump station will include two to six pumps. The actual number and type of pumps will depend upon the equipment available for this service. The pumps will be rated for a total flow of approximately 30,000 barrels per hour. Thermal and over-pressure protection relief valves, discharging back to the tankage, will be

installed where codes and safe operating practices dictate.

The flow from the pump station will be metered in an automatic custody transfer (ACT) meter battery. The number and type of meters installed will depend upon turn down capability and the accuracy limitations of the equipment available. A meter prover will be provided to insure accuracy of the ACT meters.

10.2.2.3 Pipelines

Two major pipelines, approximately 14,000 feet in length, will be installed from the onshore facilities to the SALM. These two pipelines will be for crude oil and marine vessel vapor balance and will be 36 inches and 16 inches in diameter, respectively. In addition to the two major pipelines, a service bundle consisting of two 2-inch hydraulic lines and one 2-inch gas supply pipeline will be installed. The hydraulic lines will permit automatic operation of the subsea manifold valves on the crude oil transfer and marine vessel vapor balance lines. The gas supply line will permit operation of a subsea pigging station associated with the vapor balance line.

The onshore pipeline corridor was described in detail in Section 8.4.6. 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 36-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. In the state lease, the pipelines will run south through parcel 1 and southeast through parcels 3 and 4 to the SALM site. Reference Figure 10.1 for parcel designations. At the SALM site, the pipelines will be manifolded and connected to the underwater base hoses of the SALM.

The crude oil manifold will be equipped with a hydraulically activated 36-inch ball valve (see Fig. 10.2). To avoid pressure surges in the submarine line, this valve will be interlocked with the shoreline block valve.

The vapor balance manifold will be equipped with two hydraulically-operated, 16 inch ball

valves and an offshore pig launcher and receiver (see Fig. 10.3). This equipment will not only allow removal of condensed vapors, mainly water with some hydrocarbons possibly present, but will also permit the application of corrosion inhibitors to prolong pipeline life.

The geologic/geotechnical design considerations in these onshore and offshore pipeline corridors are discussed in Sections 8.4.4, 8.4.5 and 8.4.6. The design approach discussed in Section VIII (Pipelines) is fully applicable to the marine terminal pipelines.

10.2.2.4 Single Anchor Leg Mooring

A Single Anchor Leg Mooring (SALM) will be installed approximately 5,000 feet offshore in about 140 feet of water (see Fig. 10.1). 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 and under-keel clearance requirements and the location of the kelp beds. 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. Since location of the kelp beds and the underkeel clearance (distance from the vessel bottom to the seabed required to prevent vessel grounding in the most extreme environmental conditions) coincidentally limited the minimum water depth in the maneuvering area to approximately 60 feet, the SALM site is located along an extension of state lease PRC 4977.1, approximately three vessel lengths from the closest 60-foot water depth contour.

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 10.4 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 pro-

vided and designed to withstand the maximum horizontal and vertical loads induced on the SALM. Final foundation design will depend upon the outcome of future soils and geophysical investigations.

- 2) A dual product fluid swivel assembly will be provided near the mooring base to allow for the simultaneous transfer of crude oil and displaced marine vessel vapors.
- 3) A mooring buoy will be attached to the mooring base in a manner which allows full and continuous 360 degree rotation. The buoy will be equipped for the connection of a single mooring line. A radar reflector and a beacon light will be mounted atop the mooring buoy to assist marine vessels in determining the SALM position.
- 4) A single synthetic hawser 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. Required minimum

breaking strength will be based on data supplied by a model test program.

- 5) 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. These hoses may be longer than 450 feet if a midship manifold is used instead of bow connections. The hoses will be approximately 20 inches and 10 inches in diameter for the crude oil and marine vessel vapors, respectively. The crude oil hose will be reduced to approximately 16 inches in diameter at the vessel end and the vapor hose will be reduced to approximately 8 inches in diameter at the marine vessel end to facilitate connection to the vessel manifolds. At the water surface, the hoses will lie freely with messenger lines attached to aid in mooring operations.

10.2.2.5 Vapor Balance System

The modernized nearshore marine terminal 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 16 inch vapor balance line and the resulting vacuum (approximately 7-8 psia) will provide the differential pressure needed to transport the vapors from the marine vessel to the tank farm.

From the marine vessel, the vapors will travel to the onshore tank farm via the previously described SALM and submarine pipelines. There they 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 marine terminal design will not only prevent any uncontrolled marine vessel vapor emissions, but it will also minimize vessel modifications by locating the required equipment onshore.

All marine vessels in dedicated service to the nearshore marine terminal 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). To mitigate these potential problems, a condensate removal system will be installed. As presently envisioned, this system will consist of a pig launcher and receiver at the SALM base (see Fig. 10.3), a small diameter gas line from the underwater pig launcher and receiver to the onshore facilities, an onshore collection tank, and a bi-directional displacement pig.

10.2.3 Construction and Installation

10.2.3.1 Onshore Facilities

The onshore facilities associated with the modernized nearshore marine terminal 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 oil treating facilities.

10.2.3.2 Pipelines

The pipeline construction and installation details of Section 8.7 (Construction) are applicable to the marine terminal pipelines.

10.2.3.3 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 mate-

rial thickness and cathodic protection. Current planning indicates that a galvanic cathodic protection system will be installed.

10.2.4 Operations

A manned control, surveillance and communications center will be provided in the oil treating facilities control room. Marine terminal data displayed within the control center will include the following:

- 1) The open/closed position of all operating 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 10 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.

10.3 Southern California Coastal Pipeline

10.3.1 Overview

The use of a coastal pipeline to transport the Santa Ynez Unit crude to Los Angeles is the other crude transportation alternative. Since the mid-1970's, there have been discussions between the state and industry on the subject of constructing a pipeline from the Santa Barbara County area to the Los Angeles area. Various state and local governmental agencies have placed a high priority on realization of this proposed pipeline as the primary transportation method for OCS production. This subsection will address why this pipeline cannot be assessed in this development plan and what commitments the Unit Working Interest Owners can jointly or independently make regarding this issue.

10.3.2 Exclusion from this Document

The scope of the proposed coastal pipeline greatly exceeds the scope of this development plan. As presently envisioned, this pipeline would be a means of transporting crude oil from north of Santa Barbara County to Los Angeles. As such, this project would involve many fields and/or units. Since the majority of the crude oil reserves potentially tributary to the pipeline have not been addressed in a development plan, it is not possible to evaluate this proposed pipeline at a level consistent with the requirements of this document. Furthermore, concerns such as the ability of Los Angeles area refineries to handle the projected quantity and quality of pipeline crude, the ability to acquire pipeline permits and right-of-ways in a timely manner, and the ability to control environmental and sociological impacts associated with constructing and operating the line need to be objectively evaluated and compared with alternate means of transportation.

10.3.3 Transportation Flexibility

Given the uncertainties associated with the commercial viability of a coastal pipeline, flexibility to transport crude oil by marine vessels must be maintained. The Working Interest Owners must independently evaluate the commerciality of the pipeline and determine the feasibility of such a line to transport any or all of

their working interest crude. The commitment of future SYU production to a pipeline is not feasible for Exxon. This conclusion is based on the following considerations:

1. SYU crude is heavy, very viscous, and has a high sulfur and metals content. This makes it difficult to refine and transport, and hence limits its marketability.
2. Exxon's experience with marketing Hondo A crude has demonstrated that West Coast requirements for this type of crude are limited. Changing conditions on the West Coast in the foreseeable future could make it even more unfavorable for placement of any significant portion of Exxon's SYU production in this area.
3. This past experience and the future uncertainties clearly indicate the continued need for a transportation system with the flexibility to move crude directly and cost effectively to any refining center in the U.S.
4. Mandated movement of Exxon's future SYU production to Los Angeles by pipeline would result in incremental environmental and economic costs with a shift of existing marine vessel operations from the

Santa Barbara Channel to Los Angeles for a significant portion of the production.

Although Exxon does not foresee a need to distribute its SYU production by pipeline, provisions will be incorporated in the design of the onshore marine terminal facilities (storage, pumping, metering) to permit introduction of SYU crude into the proposed pipeline. This will allow Working Interest Owners to elect to utilize the proposed pipeline if or when it is constructed.

10.4 Existing Capitan Marine Terminal

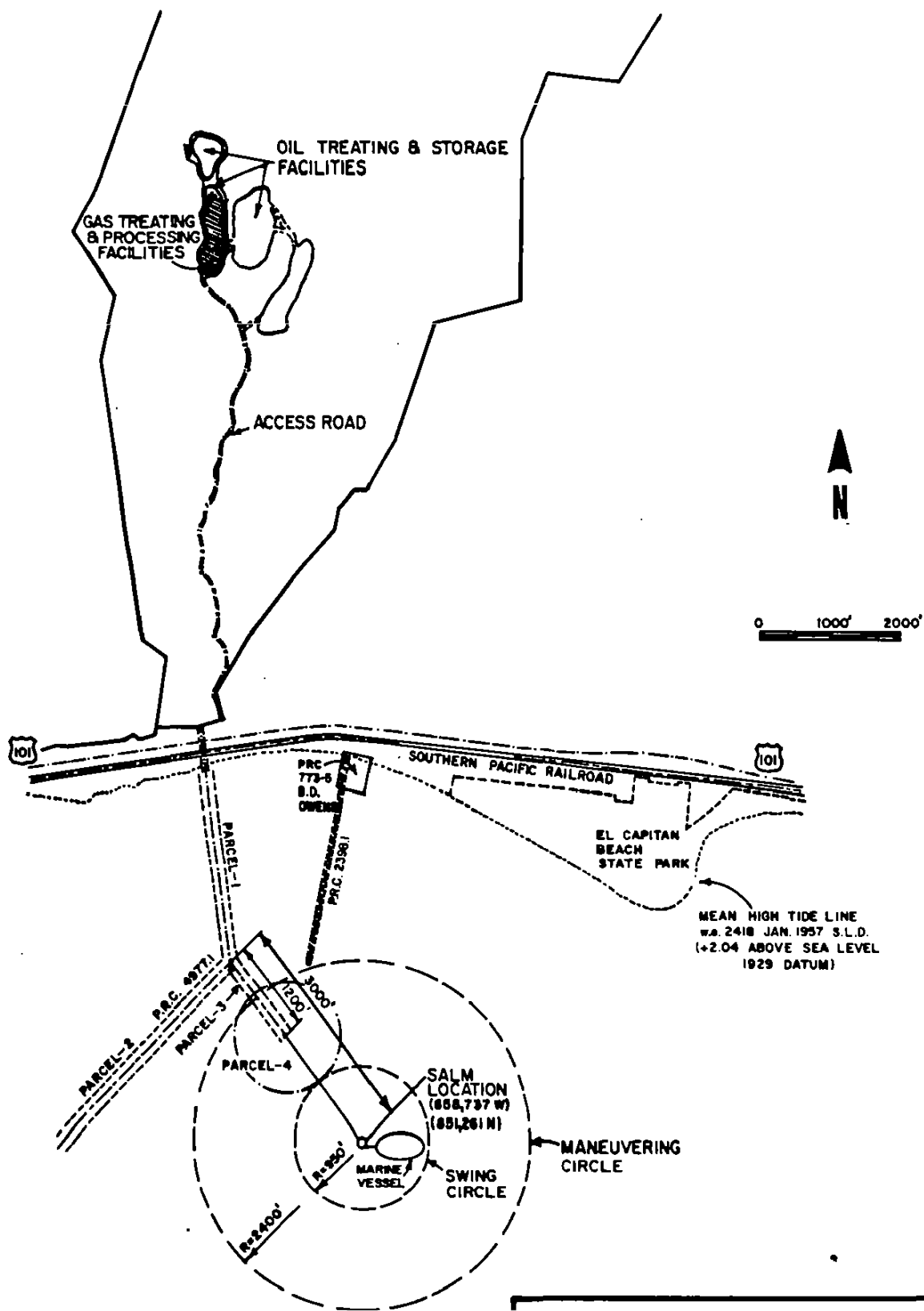
In 1975, Exxon obtained control of an inoperative terminal site at Capitan, state lease P.R.C. 2398.1, from Shell Oil Company. The site plan for the existing inoperative Capitan marine terminal is shown in Figure 10.5. This terminal was constructed in the early 1940's. In early 1977 the cathodic protection for the 16-inch marine loading line was discontinued. If a modernized nearshore marine terminal and the onshore oil treating facilities are constructed, Exxon intends to remove the above-ground facilities and to permanently abandon the offshore facilities. If required, a detailed restoration, screening and landscaping plan will be prepared and submitted to appropriate state and county agencies for the onshore restoration. A notice of abandon-

ment of the offshore facilities will be filed with appropriate federal, state and county agencies.

10.5 Industry Marine Terminal

Exxon, as unit operator, has offered the proposed SYU terminal described in Section 10.2 as the nucleus for a permanent industry marine terminal. Such a terminal venture would be set up as a separate company which would be open to participation by any operator who wished to ship crude through it.

Depending on crude production timing and through-put commitments, an expansion of the proposed SYU terminal may be required to accommodate industry's needs. Should this become necessary, the terminal company would apply for necessary permits and approvals to cover this expansion. It is anticipated that the permit applications already initiated by Exxon for the SYU terminal could be transferred to the terminal company, thus expediting the overall regulatory approval process.



NOTE: SALM LOCATION GIVEN IN
LAMBERT COORDINATES, ZONE 8

Figure 10.1
SITE PLAN
MODERNIZED CAPITAN NEARSHORE
MARINE TERMINAL

**CONCEPTUAL DRAWING
NOT TO SCALE**

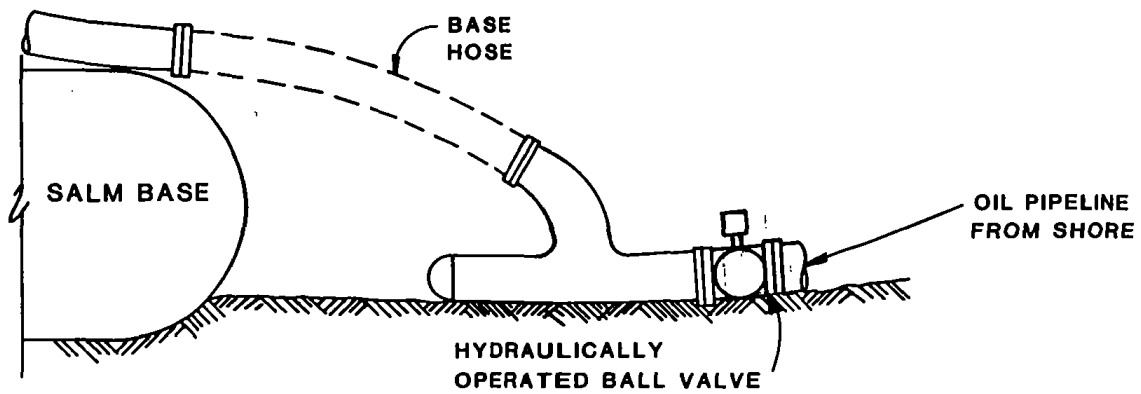


Figure 10.2
OIL PIPELINE
END MANIFOLD
NEARSHORE MARINE TERMINAL

**CONCEPTUAL DRAWING
NOT TO SCALE**

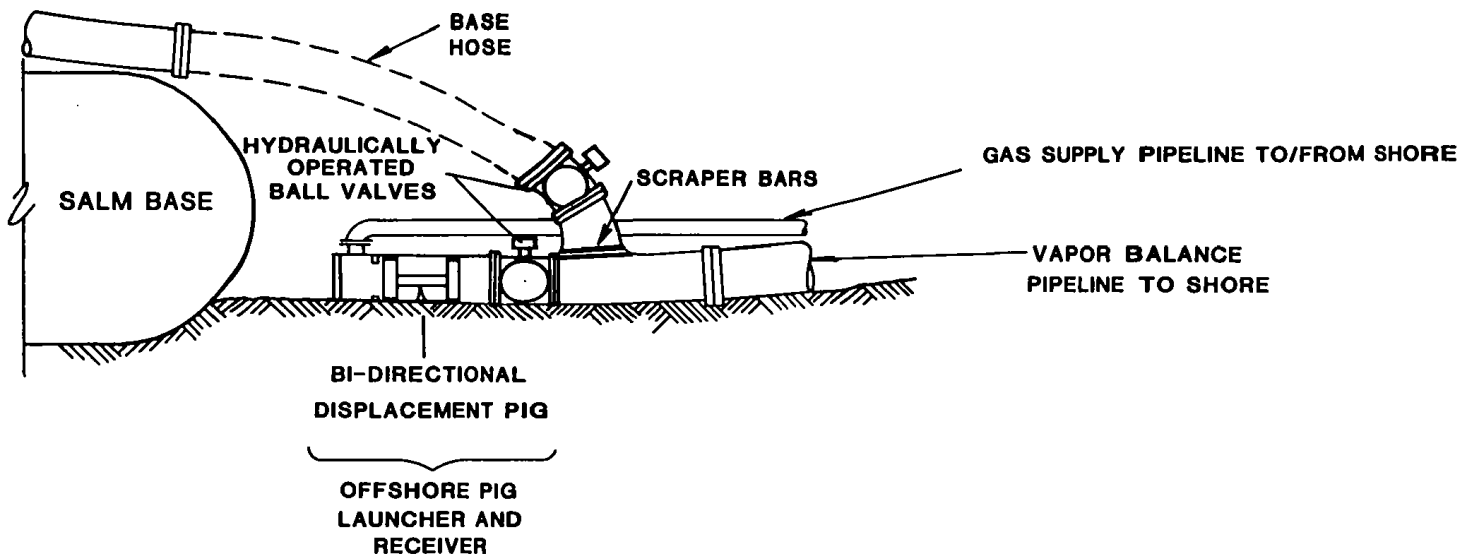
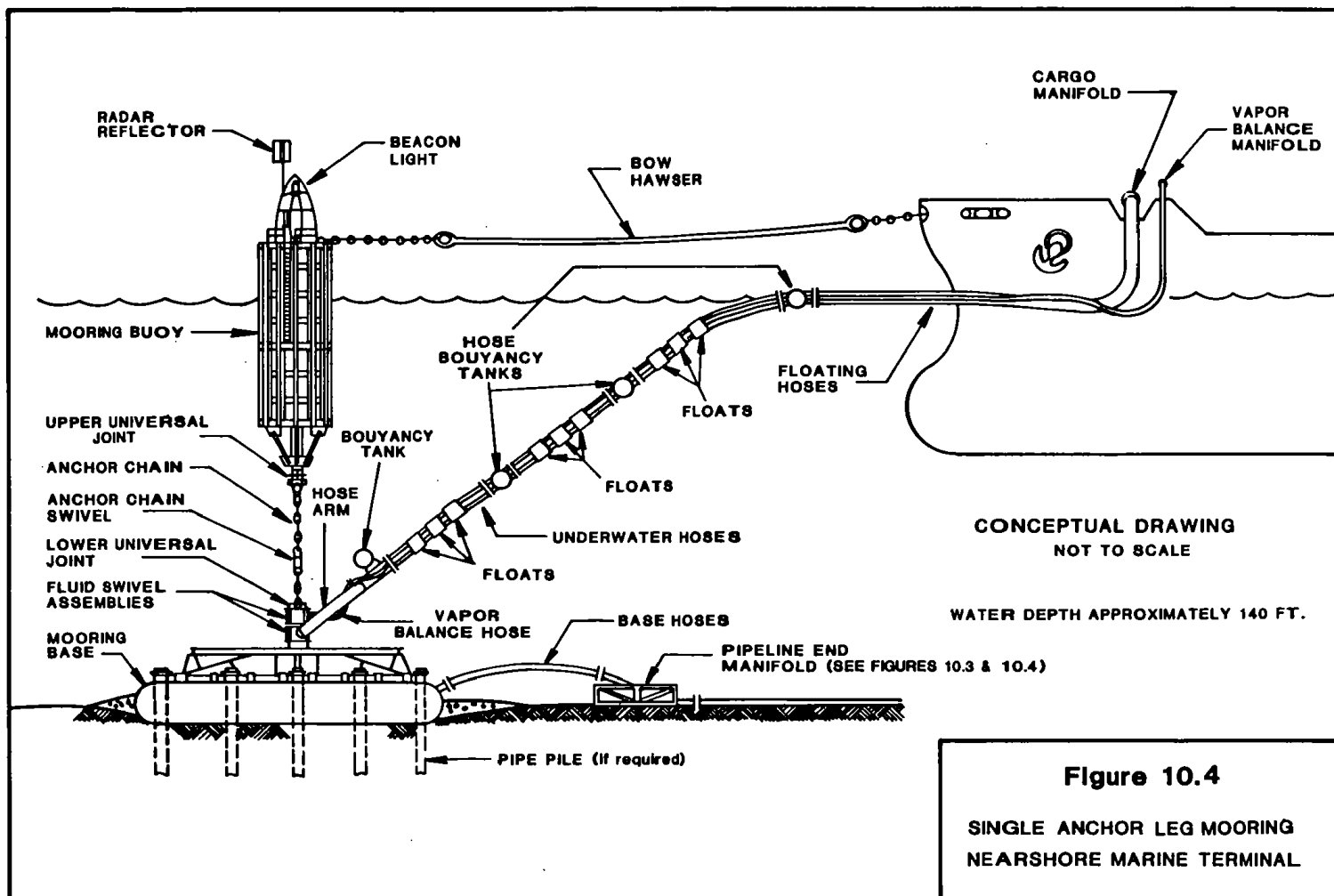
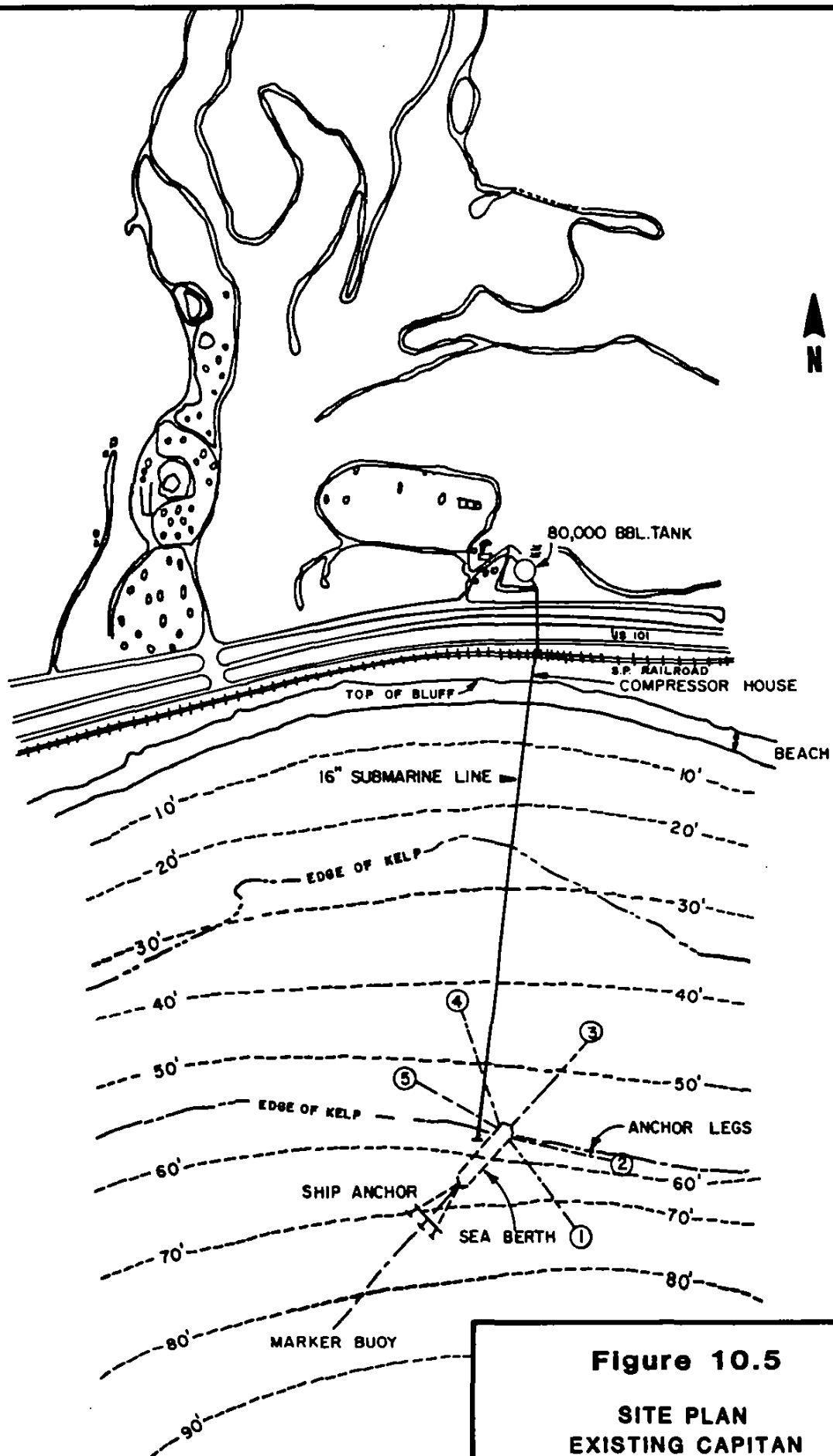


Figure 10.3

**VAPOR BALANCE PIPELINE
END MANIFOLD
NEARSHORE MARINE TERMINAL**





DATUM: M.L.L.W. 0.0 FT.

Figure 10.5

**SITE PLAN
EXISTING CAPITAN
MARINE TERMINAL**

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 offshore storage and treating vessel, the onshore facilities and the modernized nearshore marine terminal proposed for this further development of the Santa Ynez Unit.

11.2 Construction

On site construction of the offshore and onshore Santa Ynez Unit facilities is scheduled to begin in 1986 and will continue through 1990 (excluding the Pescado B-1 platform installation, if required). Construction manpower requirements will peak in 1988 with approximately 900-1,000 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, expansion of the OS&T (Development Option A), installation of the modernized nearshore marine terminal (Development Option B), 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 eight-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 but 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 pipelay barge stinger method. However, other installation methods, such as pipe tow

techniques, will be evaluated prior to installation.

Assuming a pipelay 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.

Offshore site construction associated with expansion of the OS&T facilities will include initial detachment of the OS&T from its SALM and then its hookup upon return from drydock where major structural steel, equipment, and pipe erection would have occurred. Completion of the expansion work will then take place while the vessel is in service processing Hondo A platform crude oil.

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, OS&T detachment and hookup, 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 A platform modifications and power cable installation operations will be conducted on a six day per week, one shift 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 two to 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 two 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 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, gas treating, and power generation 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 component 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 24 months and require a peak labor force of 600-700 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 tunnel that passes 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 men working a six-day week, ten hours per day for two 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 Los Angeles-Ventura-Santa Barbara 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. 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 probably 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 in Goleta.

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

Startup 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. Continuous 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 under 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 platform. 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 alarms will result in an automatic platform shutdown. Activation of an automatic shut-in alarm 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 alarms will result in an automatic shutdown:

- (1) Activation of the fire system.
- (2) Loss of fire system pressure.
- (3) Loss of the electrical system.
- (4) Low pressure in the instrument air system.
- (5) High level 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 Offshore Storage and Treating Vessel

The expanded offshore storage and treating vessel operations will remain unchanged from the present operations. The operating, surveillance and communication approaches described for the platform production

operations (Section 11.3.1.2) are fully applicable to the OS&T with the exception of the drilling interfaces. In addition, both manual and automatic shutdown of the OS&T treating facilities will result in an automatic shutdown of the producing platforms.

The unique operational difference between the platforms and the OS&T lies in the marine vessel operations. Basic vessel operations include mooring, hose connection, pumping and metering, vapor balance operation, hose disconnect and mooring release. Precise procedures for cargo transfer are contained in the U.S. Coast Guard approved "Oil Transfer Procedures Manual."

Present OS&T operations are carried out as follows. After radio-telephone communications are established between the marine vessel and the OS&T, the OS&T verifies the mooring approach clearance and the vessel's estimated time of arrival. The work boat is notified to assist with hose and hawser handling. The marine shuttle vessel obliquely approaches the floating messenger of the mooring hawser which is being held out away from the OS&T by the work boat. A tag line, attached to the hawser messenger, is passed from the work boat to the shuttle vessel. The shuttle vessel uses a traction winch to take in the messenger and hawser until the shuttle vessel is within 180 feet of the OS&T. After the mooring procedure is completed,

the work boat brings the cargo hose/vapor balance line hose bundle over to the bow of the shuttle vessel. The hose bundle is then attached to the crane and the hoses are brought aboard the shuttle vessel. A blank flange is removed from the cargo hose and the cargo hose is secured to the shuttle vessel manifold. The vapor balance hose is made up. Manifold valves, hose valves, and tank valves are lined up to receive crude oil. Vapor balance compressors are started and the hose is purged.

The shuttle vessel informs the OS&T that the vessel is ready to receive crude. The OS&T starts pumping gradually and then increases the pumping rate to a maximum of 30,000 barrels per hour. Radio-telephone communications are maintained throughout the transfer. Positive displacement meters on the OS&T record the volumes transferred. As the shuttle vessel fills, the number of pumps in use is reduced until final topping-off is accomplished at low speed with one pump. On signal from the shuttle vessel, the OS&T stops all pumping and shuts pump valves and hose valves.

The shuttle vessel valves are all shut. The cargo hose valve and shuttle vessel coupling valve are closed simultaneously and prior to disengaging the cargo hose coupling. The hose coupling cannot be disengaged until both of these valves are shut.

The shuttle vessel hose joint is drained. The vapor hose coupling is disengaged and blanked off. The cargo hose coupling is disengaged. The blank flange is replaced over the hose end valve. The cargo hose/vapor balance line hose bundle is lowered into the water and the shuttle vessel backs away from the OS&T. The mooring hawser, hoses, and messengers are then stowed alongside the OS&T until the arrival of the next shuttle vessel.

11.3.3 Onshore Facilities

The oil treating (including power generation) facilities and the gas treating facilities will be separate but interrelated operations. A close working relationship will exist between the two. Safety and environmental protection will be the prime consideration in both operations, as outlined in Sections 9.6 and 9.7. Usage of the word "facilities" in the remainder of Section 11.3.3, without any further qualifications, will be in reference to both the oil treating/power generation facilities and the gas treating facilities, but as separate facilities and operations.

The oil treating/power generation facilities and the gas treating facilities will have separate crews and supervision. Each superintendent will have operational responsibility for his facilities and associated production and storage equipment. 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 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.

Natural gas liquids, product sulfur and solid wastes will be trucked away on a regular basis. Except for normal rainfall or incidental landscape water, no water will be discharged to surface drainage.

After completion of the construction phase, the facilities will go through startup operations where all equipment will be subjected to comprehensive testing procedures. A carefully planned startup procedure will be used to minimize processing upsets experienced during startup operations. The oil treating/power generation facilities and the gas treating facilities will have their own separate central control rooms. 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 oil treating/power generation and the gas facilities will have independent 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. Auxiliary diesel generators will provide power to critical systems in the event of a power failure.

Separate control rooms for each of the oil treating/power generation and gas treating facilities will be

maintained. 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. The individual unit shutdowns, as well as the ability to bypass certain units by diverting fluid flow, will provide safety and the operational flexibility needed to effect onstream repairs or correct minor malfunctions. 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 alarms on key units.

- (5) Low flow in the inlet pipeline (gas facilities only).

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.

11.3.4 Nearshore Marine Terminal

The location and general description of the modernized nearshore marine terminal were presented in Section 10.2. 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 Single Point Mooring (SPM) 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 SPM components.

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

A manually and automatically 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 Onshore Facilities

Assuming they could not be utilized with other existing or planned projects, the onshore oil treating facilities, gas treating facilities, storage 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 restored and 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.

HONDO, PESCADO AND SACATE FIELDS

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, P-0181, P-0182, P-0183, P-0187, P-0188,
P-0189, P-0190, P-0191, P-0192, P-0193, P-0194,
P-0195, P-0326 and P-0329.

FIELDS

Hondo Field - Santa Barbara Channel

Pescado Field - Santa Barbara Channel

Sacate Field - Santa Barbara Channel

RIG TYPE

Fixed Platform Rigs

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

Drilling Manager	(805) 654-6905
Operations Superintendent	(805) 654-6906

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 insure 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) H₂S Safety Precautions.

Sufficient H₂S 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 H₂S 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

H₂S CONTINGENCY PLAN

EXXON COMPANY, U.S.A.

PLATFORMS IN THE HONDO, PESCADO AND SACATE FIELDS

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 (H₂S) 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 hydrogen sulfide and complies with the rules and regulations of the Minerals Management Service (MMS) under Pacific Region OCS Order 2 and GSS-OCS-1 (April, 1977).

Exxon will provide adequate safeguards against harm from the effects of hydrogen sulfide 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 H₂S 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 H₂S well.

- A. At least two areas will be designated as Safe Briefing Areas for personnel during an H₂S alert. In the event that H₂S 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. Windssocks 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 H₂S is detected in concentrations equal to or exceeding 10 ppm. The signs will be at least 4' x 8' and painted a highly visible yellow with

the following warning painted in 12" high black, block lettering:

DANGER
HYDROGEN SULFIDE
(H₂S)

In addition, 2' x 3' red flags will be displayed from high points off of each corner of the Drilling Deck along with the MY-6 Flag System if H₂S 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 & II signals will be posted in appropriate locations on the platform, workboats, and crewboats.

- D. Continuous monitoring-type H₂S detectors, complete with visual 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 H₂S 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 H₂S 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 H₂S 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 H₂S 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 H₂S service.
- I. A sufficient supply of "Milgard" (100% Zinc Carbonate), or an equivalent scavenger, will be stored on the platform for use in the event the mud becomes contaminated with H₂S.

III. VARIOUS OPERATING CONDITIONS AND THEIR RESPECTIVE PROCEDURES

The operating conditions when drilling in H₂S 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 H₂S 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 hydrogen sulfide. 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 H₂S 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 H₂S 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 H₂S, 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 "H₂S 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 H₂S 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 H₂S detectors. Knowledge of the location of the H₂S 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 H₂S detectors.

(4) H₂S detector ampoules shall be available for use by all working personnel. After H₂S has been initially detected by any device, periodic inspections of all areas of

poor ventilation shall be made with a portable H₂S detector instrument.

- (5) All personnel on location should become "wind-conscious" and be aware at all times of the prevailing wind direction. Remember, H₂S is heavier than air and will collect in low places during times of still air.
- (6) All personnel should stay alert for any detection of H₂S. Should the presence of H₂S 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 H₂S bearing zones, all equipment used in logging operations must be treated with H₂S corrosion inhibitors or be made of H₂S resistant materials.
- (8) The H₂S 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 H₂S is detected, or when drilling in a zone containing H₂S, 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 H₂S 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 - H₂S" 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 hydrogen sulfide. Poisonous gasses 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 H₂S 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 H₂S concentrations of 20 ppm.

4. General Procedures:

If at any time H₂S is detected in concentrations of 10 to 20 ppm, the following steps will be taken:

- a. The person detecting the H₂S 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 supervisors will bring gas detectors to the rig floor in order to find the source of H₂S.
- 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 H₂S as quickly as possible. Drilling must not proceed until the cause of the H₂S 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 persons 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 continu-

ous radio watch. The Minerals Mangement Service and the U.S. Coast Guard must also be notified.

C. Condition II - Moderate to Extreme Danger to Life

1. Warning Sign:

MY-6 Flag System, 2' x 3' 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 gasses 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 H₂S 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 H₂S 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 hold their breath and 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 not 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. If you are located on the downwind side of the platform or below the Drilling Deck when the Condition II alarm is sounded, hold your breath and proceed to the upwind Safe Briefing Area, donning the nearest breathing equipment if readily available.

- h. Always put on a portable air-breathing 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' 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 2' x 3' 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 H₂S 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 hydrogen sulfide 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 "H₂S 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 H₂S 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 "H₂S Contingency Plan."
2. The Exxon Drilling Superintendent is responsible for seeing that all safety and emergency procedures outlined in the "H₂S Contingency Plan" are observed by all personnel participating in the drilling of the H₂S 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 H₂S contaminated fluids under high pressure, is suitable for H₂S service and that all replacement parts are suitable for H₂S service.
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 H₂S detection and monitoring equipment.
8. The Exxon Drilling Superintendent is responsible for the storage and maintenance of all H₂S 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 H₂S 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 "H₂S 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 "H₂S 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 H₂S, is suitable for H₂S service, and that all replacement parts are suitable for H₂S service.

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 H₂S 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% 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 H₂S 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 H₂S.
2. Unless hole conditions (and/or H₂S 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 H₂S 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.

- a. 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.
- b. 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.
- c. All personnel on the platform not wearing breathing-air equipment should stay a safe distance upwind of the core barrel.
- d. 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 H₂S Contingency Plan.
3. During the test, the use of H₂S detection equipment will be intensified. All produced gasses must be vented and burned through a flare system equipped with a continuous pilot and an automatic igniter. 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:

- a. Close in the well by using normal well control techniques. Record the drill pipe pressure, the casing pressure and the volume of influx.
- b. Notify the Exxon Drilling Superintendent and the on-duty Contractor Tool Pusher.
- c. 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.
- d. 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 H₂S 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.

HONDO, PESCADO AND SACATE FIELDS

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. 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

Existing Exxon offshore production facilities are equipped with MMS approved oil spill containment and cleanup equipment. Each facility has a minimum of 1,500 feet of containment boom, a deployment boat, skimming apparatus, cleanup material and a quantity of EPA approved chemical dispersants and applicators. The amount and type of equipment installed on each facility is designed to handle any likely spill. The onsite facility personnel are trained to deploy and operate this equipment.

A. Onsite Response Team

Each offshore production facility has an Onsite Response Team (ORT). The Onsite Response Team is comprised of Exxon onsite personnel trained in all aspects of oil spill containment. The ORT Organization is shown in Figure C-1. The ORT, as the first line containment and cleanup 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 isn't automated or should the automated shutoffs 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 will perform practice drills with containment equipment at least twice annually.

B. Emergency Response Team

The Exxon Western 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 communication, administrative, operational and logistic support during offshore oil spills.

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 function in the event of an oil spill if he is unavailable. The positions, names, office and home telephone numbers for all ERT members/alternates are listed in the Notification Section of the Oil Spill Contingency Plan for California Operations (Section 200). The ERT organization is shown in Figure C-2.

The California 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 Cleanup Coordinator. 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 cleanup operations are complete. The ERT member's responsibilities to the oil spill incident will supersede his normal duties until relief, rotation or release is approved by the Oil Spill Cleanup Coordinator.

Members of the Emergency Response Team participate in an annual training session to ensure that they are familiar with their assigned responsibilities.

C. Interfunctional Oil Spill Response Team

During 1980 Exxon established a national internal 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 cleanup supervisors must attend the Texas A&M Oil Spill Control Course. Specialty/Advisor team members are encouraged to attend the Texas A&M course.
- All three teams will hold an annual seminar. This team member seminar is 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 possible 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, Inc. provides assistance in the Santa Ynez Unit area. Procedures to activate Clean Seas, Inc. are clearly outlined in Section 800 of the Oil Spill Contingency Plan for California Operations. Clean Seas, Inc. 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, Inc. also has the necessary 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 (SECC) 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 cleanup is undertaken.

Specific cleanup techniques for onshore areas 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 cleanup operation will be the restoration of the damaged area to its natural state.

IV. WILDLIFE PROTECTION, CARE, AND REHABILITATION

In the event an oil spill occurs in Federal OCS waters, some marine mammals and/or birds may come in contact with oil. If oiled marine mammals and/or birds are sighted, 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)

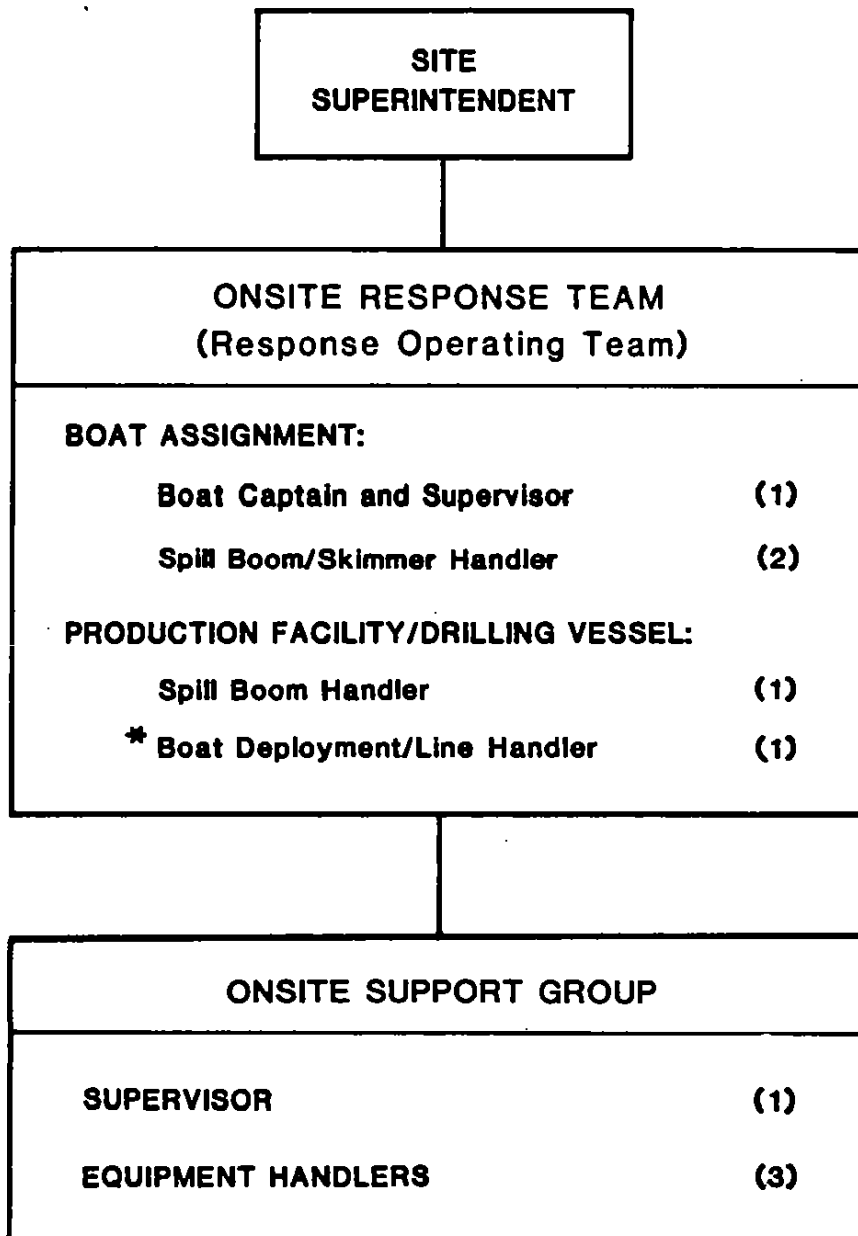
If an oil spill should occur in or threaten to enter State waters from Federal waters, the California Department of Fish & Game (CDF&G) (800/852-7550) shall be notified if oiled marine mammals or birds are observed.

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 cleanup 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 CDF&G and USF&WS personnel only. Under no circumstances will marine mammals or birds be taken by Exxon employees or any other unauthorized personnel.

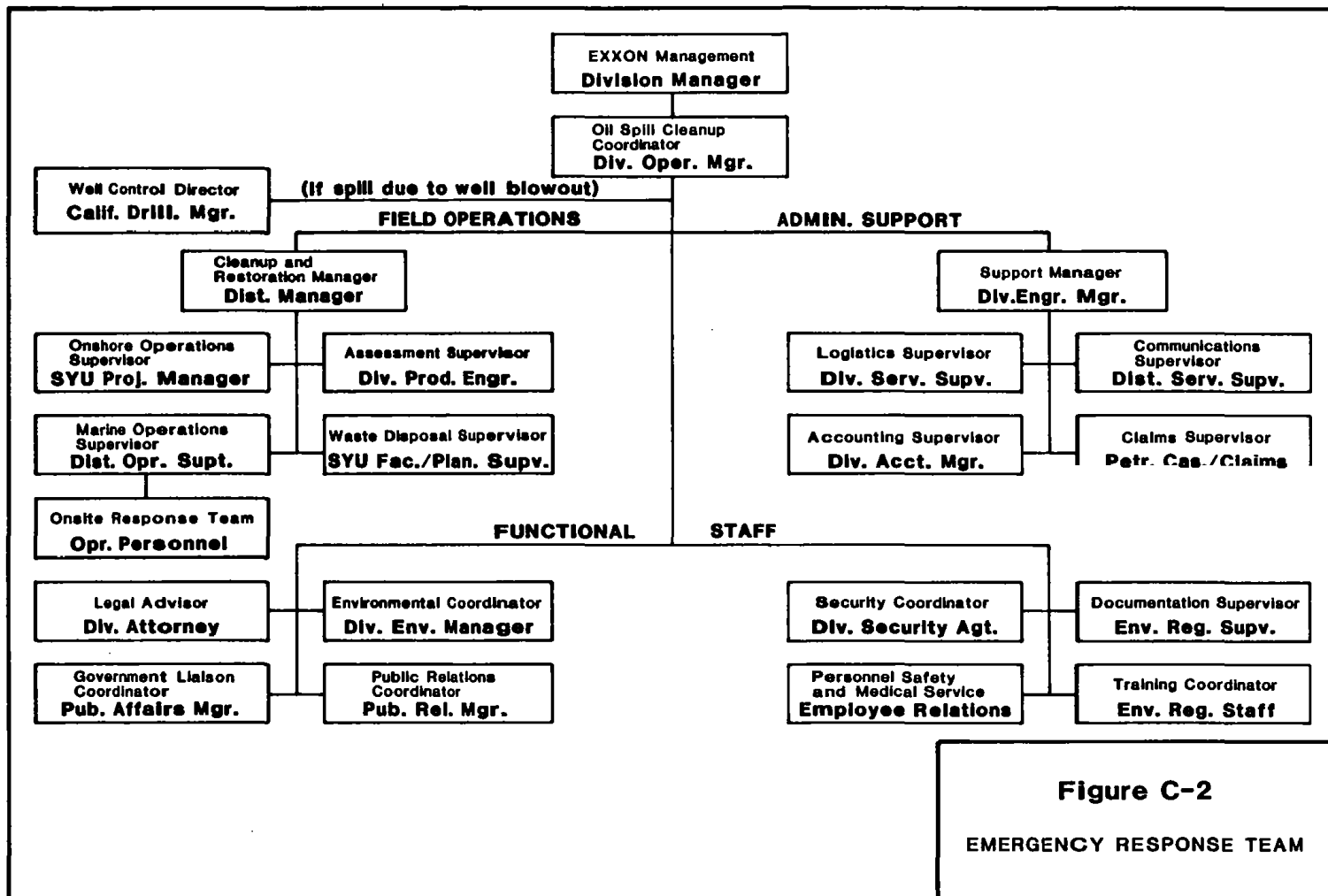
V. PLAN MAINTENANCE

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.



*** As Required**

Figure C-1
ONSITE RESPONSE TEAM



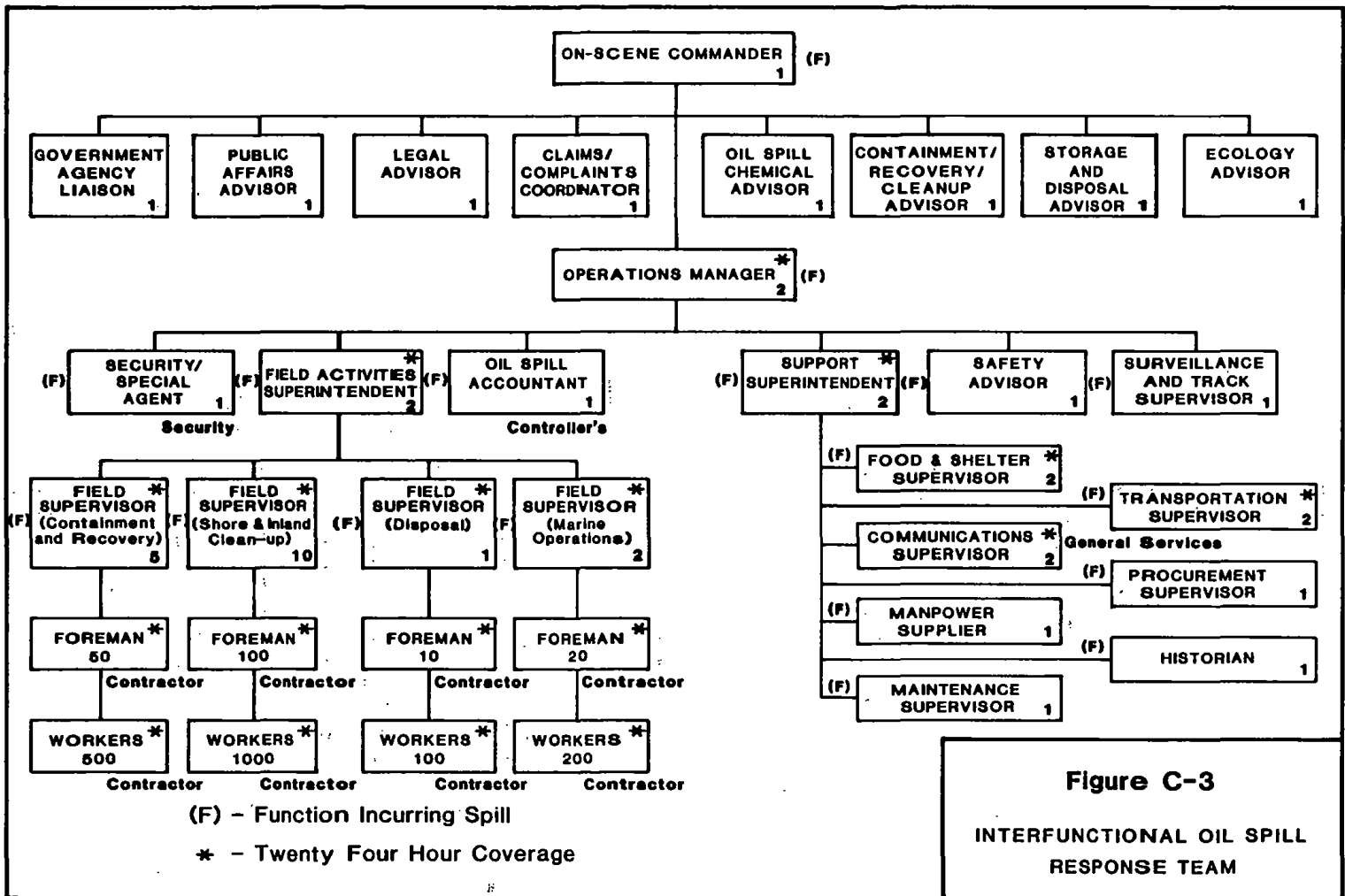


Figure C-3
**INTERFUNCTIONAL OIL SPILL
RESPONSE TEAM**