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Atmospheric Emissions from Offshore Oil and Gas Development and Production

Energy Resources Co, Inc, Cambridge, Mass

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ATMOSPHERIC EMISSIONS FROM OFFSHORE OIL AND GAS DEVELOPMENT AND PRODUCTION

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Waste Management
Office of Air Quality Planning and Standards
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This study is the first phase of a program to develop reliable emissions estimates for offshore oil and gas development and production. The objectives of this screening phase are to characterize the equipment used offshore, to evaluate the sources of emissions, to make preliminary estimates of emissions rates, and to identify current control technologies and control technologies which require further study. The two major sources accounting for over seventy percent of total non-methane hydrocarbon emissions are oil storage or storage tanks on board the platforms and vents which discharge intermittently during gas processing. Power generation during production operations is the largest source of essentially continuous emissions of oxides of nitrogen, sulfur oxides, carbon monoxide and particulates, but accounts for only about ten percent of total non-methane hydrocarbon emissions. The most likely means of achieving emissions reductions are the use of vapor recovery systems, development of combined cycle power systems suitable for offshore use, and maximum utilization of waste heat.

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This study is the first phase of a program to develop reliable emissions estimates for offshore oil and gas development and production. The objectives of this screening phase are to characterize the equipment used offshore, to evaluate the sources of emissions, to make preliminary estimates of emissions rates, and to identify current control technologies and control technologies which require further study. The two major sources accounting for over seventy percent of total non-methane hydrocarbon emissions are oil storage or storage tanks on board the platforms and vents which discharge intermittently during gas processing. Power generation during production operations is the largest source of essentially continuous emissions of oxides of nitrogen, sulfur oxides, carbon monoxide and particultes, but accounts for only about ten percent of total non-methane hydrocarbon emissions. The most likely means of achieving emissions reductions are the use of vapor recovery systems, development of combined cycle power systems suitable for offshore use, and maximum utilization of waste heat.

TABLE OF CONTENTS

TABLE OF CONTENTS (CONT.)

TABLE OF CONTENTS (CONT.)

LIST OF FIGURES

LIST OF FIGURES (CONT.)

LIST OF TABLES

LIST OF TABLES (CONT.)

LIST OF TABLES

CHAPTER ONE

INTRODUCTION AND SUMMARY

1.1 Introduction

Offshore oil and gas production on the Outer Continental Shelf máy contribute 11 to 54 billion barrels of oil and 54 to nearly 236 trillion ft^3 of gas to domestic supplies in the future.[1] The resource potential of these petroleum provinces will be increasingly important to fulfill the nation's needs for energy.

This study is the first phase of a program to develop reliable emission estimates for offshore drilling and oil production facilities. The objectives of this engineering assessment are:

1. To characterize the equipment and processes found on offshore facilities used for petroleum resource development on the Outer Continental Shelf.

2. To evaluate the sources of emissions from offshore facilities, to make preliminary estimates of emission rates, and to identify control technologies for these emissions.

3. To identify emission sources and control technologies which require further study. Field testing of both point sources and ambient air concentrations is one response to this objective; control technology development is another.

1.2 Conclusions

Offshore oil operations generate a small but significant amount of air pollutants resulting from stationary combustion or from venting produced gas.

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[1]U.S. Department of the Interior, Geological Survey estimates.

This conclusion is based upon the preliminary estimates contained in this report and is subject to the following limitations:

1. Because this work was intended as a preliminary screening, several simplifying assumptions have been made. While the accuracy of these assumptions will affect the accuracy of emissions estimates, they will not significantly alter the qualitative findings of this work.

2. Several potential emission sources have been identified for which supporting data are unavailable. However, the project team has elected not to carry out an "in-depth" analysis of such data because the level of effort required could not be justified within the scope and level of effort of this preliminary survey.

3. There are major difference in the operating and design practices of major oil companies as well as differences in offshore leases. Hence, there is no such thing as a "typical platform." In carrying out this project, however, quantitative estimates have been required which have been based upon generalizations of specific practices reported in the literature or observed by the project team during visits to several offshore facilities. Although these estimates are believed to be qualitatively accurate and of sufficient reliability to establish priorities for subsequent work, the authors recognize that there are a large number of exceptions to the general rules followed here.

1.2.1 Emission Sources and Rates

Table 1-1 outlines the sources reviewed in the study by phase of activity and major subsystem. Table 1-2 ranks the sources of emissions in terms of their anticipated uncontrolled rates of emissions for 1985. The major source of total hydrocarbon emissions is from oil storage or surge tanks onboard the production platform (136×10^3 Mg/yr) and from vents which discharge intermittently during gas processing (93×10^3 Mg/yr) as required by process upsets and maintenance. These two sources account for over 70 percent of the total non-methane hydrocarbons (29,403 Mg/yr) emitted offshore. By comparison, this is only 2 percent of the non-methane

TABLE 1-1

OUTLINE OF POSSIBLE EMISSIONS SOURCES REVIEWED

Phase:	EXPLORATORY/DEVELOPMENT DRILLING
Subsystems:	Electric Power Generation Mud Conditioning - Mud tanks - Degasser - Shale Shaker Fuel Storage Deck Sumps Flow Line (Blowouts)
Phase:	WELL COMPLETION/TEST
Subsystems:	Electric Power Generation Flow Line Wellhead - Plaform Riser - Submerged Production System - Underwater Completion - SEAL
Phase:	PRODUCTION
Subsystems:	Production Energy Source-Lifting Natural or Primary Electric Submergible Pump Gas Lift Systems Power Oil/Water Systems Phase of Production Natural/Primary Pressure Maintenance or Secondary - Gas Reinjection - Water Injection

TABLE 1-1 (CONT.)

Electric Power Generation
- Submarine Cable
- Turbines
- Gas Engines
- Diesels

Subsystems:

Processing
Separation
- Free Water Knockout
- Two Phase Separator
- Pressure Stage Separators
- Test Separator
- Desander

Gas Preparation for Pipelining
- Glycol Dryers (Waste Heat and Direct-Fired)
- Amine Systems (H_2S)

Gas Compression to Higher Pressure
- Combustion Turbine
- Gas-Fired Reciprocating
- Electric Motor
- Diesel

Oil Preparation for Pipelining
- Treater (Direct, chem-electric, indirect)

Oil Shipment
- Storage
  - Dead Oil Tank
  - Shipping Surge Tank
  - Fuel Storage

Pumping
- Electric/Diesel
- Charge Pumps/Valves
- Turbine
- Gas

Water Cleanup (for Disposal/Injection)
- Skim Tank
- Flotation Cell
- Skim Pile
- Floor Drain System
- Injection Pump
  - Electric Motor
  - Gas Turbine
  - Diesel

TABLE 1-2

RANKING OF EMISSION SOURCES FROM OFFSHORE OIL AND GAS ACTIVITIES, 1985

SOURCES RANKING	POLLUTANT NO_x	SO_2	HC[a]	CO	PARTICULATES	H_2S
Largest Emitter	Power Generation (Gas Turbine - Gas Production)	Power Generation (Gas Turbine - Gas Production)	Oil Storage (none)	Power Generation (Gas Turbine - Gas Production)	Power Generation (Gas Turbine - Gas Production)	Oil Storage Vents
	Power Generation (Gas Turbine - Oil Production)	Power Generation (Gas Turbine - Oil Production)	Vents (Gas Processing) (1)	Power Generation (Gas Turbine - Oil Production)	Power Generation (Gas Turbine - Oil Production)	Vents (Gas Processing)
	Power Generation (Diesel - Electric Drilling)	Power Generation (Diesel - Electric Drilling)	Mud Degassing (2)	Power Generation (Diesel - Electric Drilling)	Fired Oil Treaters	Valve Seals (Gas Service)
	Fired Oil Treaters	Fired Oil Treaters	Power Generation (Gas Processing) (3)	Fired Oil Treaters	Fired Gas Dryers	
	Fired Gas Dryers	Fired Gas Dryers	Power Generation (Oil Processing) (4)	Fired Gas Dryers		
			Gas Dehydration (7)			
			Valve Seals (Gas Service) (6)			
			Power Generation (Diesel - Electric Drilling) (10)			
			Oil-Based Muds (5)			
Smallest Emitter			Valve Seals (Oil Service) (8)			
Unknown	Blowouts/Fires	Blowouts/Fires	Blowouts/Fires	Blowouts/Fires	Blowouts/Fires	Blowouts/Fires
	Well Completion	Well Completion	Well Completion	Well Completion	Well Completion	Well Completion
			Compressor Seals		Power Generation (Diesel - Electric Drilling)	Mud Degassing
			Water Treating			

[a] Includes vapor recovery in California per 1975 practice (California source ranking shown in parentheses).

emissions for all petroleum storage or less than 0.2 percent of the total non-methane emissions from all stationary combustion.[2]

Power generation during production operations in 1985 is the largest source of essentially continuous emissions of oxides of nitrogen (36.3×10^3 Mg/yr), sulfur dioxide (1.7×10^3 Mg/yr), non-methane hydrocarbons (3.12×10^3 Mg/yr), carbon monoxide (9.0×10^3 Mg/yr) and particulates (1.1×10^3 Mg/yr).

1.2.2 Control Techniques

The types of facilities onboard an offshore platform are chosen based upon the extent of processing required, the space available, and the cost of onshore alternatives. While there is a wide range of process alternatives, there are few available process changes which offer significantly reduced emissions. Hence, the most likely means of achieving emissions reduction are:

- Use of vapor recovery systems for major vent exhausts such as flash gas generated in the surge tank from the low pressure separator to the sendout pump.
- Reduction of fuel combustion through maximum use of waste heat recovery or through the development of combined cycle power units which would be economically feasible for offshore use.
- Minimization of onshore emissions (which lessens the population at risk) through maximization of offshore power generation and oil/gas processing.

Specific control technologies for point sources of emissions on offshore oil and gas facilities are illustrated in Table 1-3. Among the control technologies listed, application of combined cycles to gas turbine operations and other engines offers the largest potential reduction in non-hydrocarbon emissions. Although this technology is still under development at present, it has the potential to reduce power generation emissions by as much as 54 percent based

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[2] U.S. Environmental Protection Agency, Control of Hydrocarbon Emissions from Petroleum Liquids, EPA No. 600/2-75-042, September 1975.

TABLE 1-3

CONTROL TECHNOLOGIES FOR OFFSHORE OIL AND GAS OPERATIONS

SOURCE	CONTROL TECHNOLOGY	POLLUTANTS CONTROLLED
Power Generation-Drilling	Waste Heat Utilization, Combined-Cycle Operations (Developmental)	NO_x, SO_2, HC, CO, Part.
Mud Degassing	Combustion Flares	HC
Mud Tanks (Oil-Based Muds)	Covers, Dilution Flares	HC
Fuel Storage	Vapor Recovery	HC
Power Generation-Production	Waste Heat Utilization	NO_x, SO_2, HC, CO, Part., H_2S
	Combined-Cycle Operation (Developmental)	NO_x, SO_2, HC, CO, Part., H_2S
Gas Drying	Waste Heat Utilization	NO_x, SO_2, CO, Part.
Compressor Seals	Maintenance	HC
Gas Processing Vents	Operating Practice	HC
Valve Seals (Gas Service)	Maintenance	HC
Oil Treaters	Waste Heat Utilization	NO_x, SO_2, CO, Part.
Pump Seals	Maintenance	HC
Valve Seals (Oil Service)	Maintenance	HC
Oil Storage/Surge	Vapor Recovery, Dilution Flares, Combustion Flares	HC
Water Treating	Maintenance, Design, Vapor Recovery	HC

upon a cycle efficiency of 40 percent as compared with current operations at 26 percent efficiency.[3] Fuel rate reductions of 24 to 37 percent have been achieved in gas turbine combined-cycle tests to date. Application of vapor recovery systems may reduce hydrocarbon emissions from offshore operations projected for 1985 by up to approximately 80 percent in the Gulf of Mexico and in the Atlantic. Vapor recovery is already required in the offshore California region.

Waste heat utilization may reduce pollutants by approximately 10 percent or more depending upon the extent of application. It is necessary to evaluate the economics of waste heat recovery system applications in order to assess the actual extent to which the industry will adopt this control technology in the absence of new regulations.

These conclusions are based upon the control technology scenario for 1985 discussed in Chapter Five. A different scenario may alter these conclusions somewhat.

1.3 Recommendation and Research Needs

1.3.1 Field Sampling

The following potential point sources of emissions on offshore oil and gas facilities have the highest priority for characterization study by field sampling of all pollutants:

- Gas vents
- Oil storage vents
- Water separators
- Compressor seals and thrust-bearing vents
- Well completion, blowouts and oil spills

The emissions from a blowout could be very large if the well remained out of control for a significant period of time, but such emissions are clearly uncontrollable once a blowout occurs. Fortunately, blowouts are an infrequent occurrence.

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[3] R.M. Wardall and E.E. Doorly, Current Prospects for Efficient Combined Cycles for Small Gas Turbines, presented at ASME Gas Turbine Conference, New Orleans, Louisiana, March 1976.

1.3.2 Control Technology

Development of a combined cycle for gas turbines and other engines generating power onboard offshore facilities should be encouraged because of the substantial potential emissions reduction and concomitant energy savings. Specific development should be focused on systems that would be economically feasible even on scales in the range of 1,000 hp to 5,000 hp.

Waste heat utilization to replace electrical resistance heating and direct-fired vessels onboard operating platforms should be studied for immediate application where energy savings and pollutant reductions may be achieved.

The costs and feasibility of changes in operating practices onboard platforms, particularly during periods of compressor shut-down, should be evaluated. The impact on emissions as well as the effect of any changes in operating practice on the long-term productive potential of the reservoir should be examined.

1.4 Methodology and Scope of Report

1.4.1 Approach

Data on the major offshore drilling and production facilities, processing schemes, operating practice and future planned configurations were compiled from discussions with the industry, the U.S. Geological Survey (USGS), state agencies, industry associations and technical journals. Published emission factors to be applied to these operations have been supplemented with independent estimates developed in the study and with data collected from operators' records analyzed during the project team's field visits. Detailed dispersion modeling and sampling program planning were subordinated as objectives of the study in order to develop projections of oil and gas drilling and production activities for the 1985 time frame. The emissions from the projected activity level were utilized to rank the sources of emissions and to evaluate the potential emissions reduction from applying control technologies.

1.4.2 Limits of the Analysis

The geographical scope of this report encompasses the Outer Continental Shelf in Federal waters offshore of the 48 contiguous states. Where data were available for the Alaska Outer Continental Shelf activities, these were included in the report. Offshore activities in waters under California State jurisdiction were included in the report to provide a complete picture of the emissions in that region. Production in state waters along the Gulf of Mexico was not included because of the difficulty in delineating offshore activities from onshore activities there and because oil and gas production in these areas is relatively mature.

Emissions from all activities during drilling, completion and production of an offshore oil and/or gas well were included in the analysis as data permitted. The major exceptions would be support activities emissions from such sources as transportation equipment, cranes, and workover rigs which operate intermittently.

In terms of the flow path of hydrocarbons the emissions evaluated included sources at any point from the oil or gas reservoir beneath the sea to the point at which the oil and gas were dispatched from an offshore processing facility or up to the point at which loading and transportation operations began. Onshore facilities emissions would be the subject of a separate project.

The emissions estimates are based upon a single composite processing scheme for each region. The USGS has under development a data compilation program which may enable further segmentation of oil and gas production into their respective processing schemes. However, the USGS project was at too early a stage to include these production schemes in this report. Considering that three sources account for over 90 percent of the total hydrocarbon emissions identified and that power generation is the major contributor of other pollutant emissions, it is doubtful that a more detailed partitioning of oil and gas production into various schemes would provide meaningful insights.

Although some gas-fired reciprocating compressors are present on offshore platforms, the total emissions estimates are based upon gas turbines as the prime movers in operation. No data were found on the number of reciprocating compressors installed offshore. Although accounting for these units would increase estimates of pollutant emissions of nitrogen oxides, hydrocarbons and carbon monoxide, the change in total emissions estimates would not be sufficient to significantly alter the preliminary conclusions stated in this chapter.

CHAPTER TWO

OVERVIEW OF THE INDUSTRY

2.1 Introduction

The oil and natural gas industry is a highly complex mixture of many companies, large, medium, and small in size, actively competing with each other yet, in total, working as a gigantic system to supply the energy needs of the nation.

Figure 2-1 shows a model of the total petroleum and natural gas system.[1] Stephens identified the following functions of the industry:

1. Seeking out of accumulations hidden in geological structures (Geological Exploration).
2. Drilling of exploratory wells and completing them so as to extract safely the crude petroleum and natural gas from its resevoir (Drilling).
3. Producing crude oil and gas - The development drilling of "discovered" resevoirs and the production of oil and gas (Production or Operations).
4. Transporting crude oil to refineries (Crude Oil Transportation).
5. Refining or separating the crude oil into usable products. Petroleum is a mixture of many natural hydrocarbon compounds (Refining).
6. Transporting refined products to consumer areas (Product Transportation).
7. Distributing oil, gasoline, jet fuel, asphalt and the many other products to consumers (Marketing).

This chapter addresses offshore activities of the industry primarily in the second and third functions listed.

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[1] M.M. Stephens, Vulnerability of Total Petroleum Systems, Department of Interior Office of Oil and Gas and Defense, Civil Preparedness Agency, Washington, D.C., May 1973.

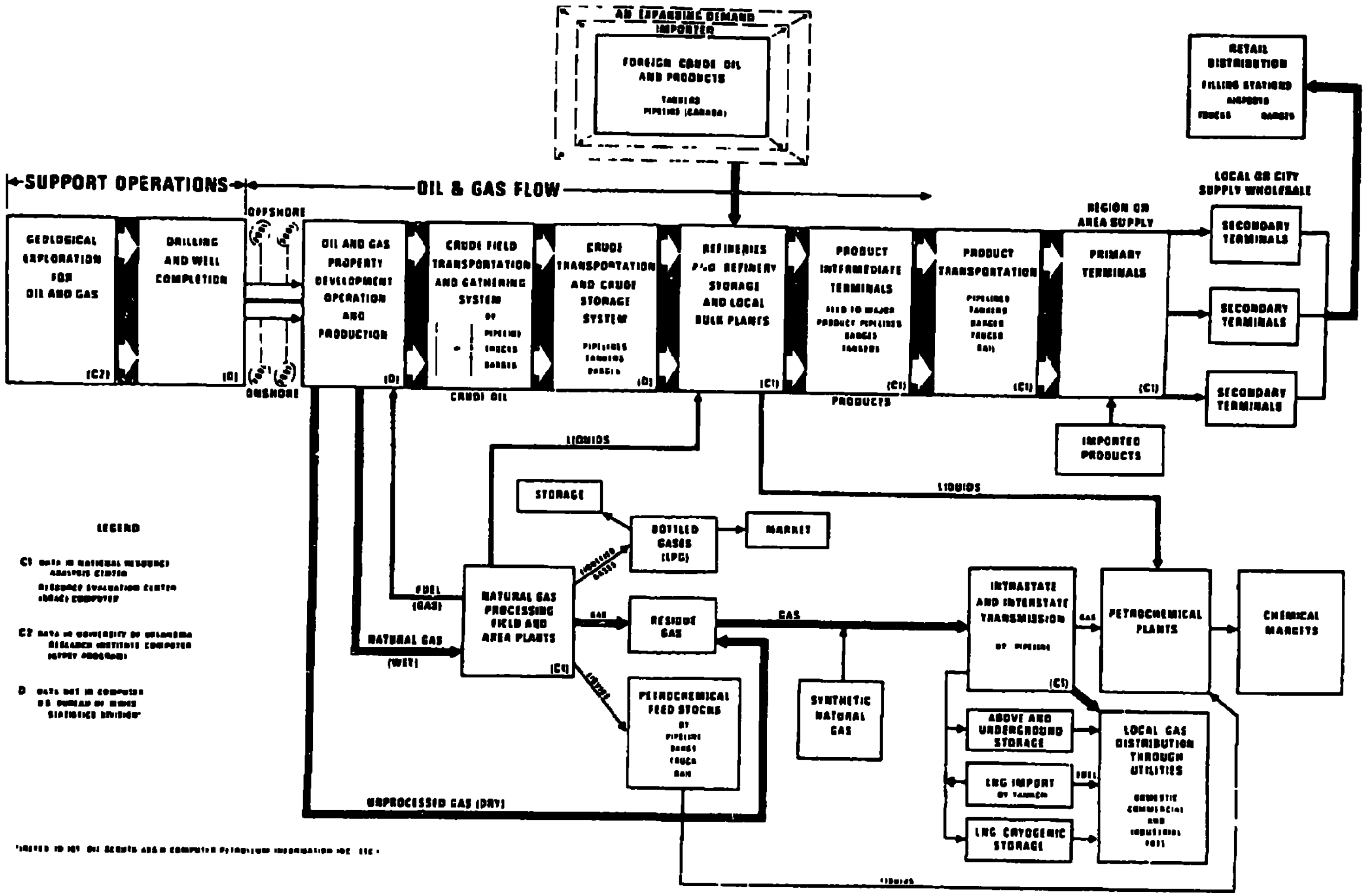

Figure 2-1. The national petroleum and natural gas system model. (M.M. Stephens, "Vulnerability of Total Petroleum Systems," Department of Interior Office of Oil and Gas and Defense, Civil Preparedness Agency, Washington, D.C., May 1973.)

Upward from 75 percent of the total energy used in the United States comes from the petroleum and natural gas industries. A plot of the Gross National Product with energy use indicates that the two parallel each other. It follows, therefore, that the petroleum and natural gas industries are of utmost importance to the nation.

Each day the country produces about 8.2 million barrels of crude oil from domestic sources. Added to this are roughly another 1.5 million barrels of natural gas liquids. But the country uses about 17 million barrels of petroleum products daily. Much of the relatively easy-to-find land-based oil, or relatively shallow depth oil, has long ago been discovered and most such wells either are now marginal producers or have been abandoned.

To date, in excess of 100 billion barrels of petroleum have been discovered and produced in the United States. There is a never-ending search for new oil. Our future domestic crude oil supply is in a critical situation, for present estimates of known reserves indicate that only 32 billion barrels are available, scarcely 10 years at present domestic production rate and only 5.5 to 6 years of our total annual demand. Of this known reserve, it is estimated that possibly as much as one-fourth will come from offshore California and Louisiana.

Most present day domestic petroleum and natural gas exploration is looking to potentially oil-bearing formations beneath the sea, the outer continental shelf areas of the Atlantic, Pacific and the Gulf of Mexico. Oil and gas production is well established in the Gulf and smaller areas of the nation's Pacific shelf off of California and Alaska, but the Atlantic and Alaska are horizons for exploration and development in the future.

2.2 Offshore Petroleum and Natural Gas Operations

The major offshore oilfields are shown in Table 2-1. In 1975, the offshore oil production from all major fields amounted to 964,383 bbl/d, about 11 percent of the nation's total output.[2] In 1974, the Gulf of Mexico offshore

[2] J.C. McCaslin, "Gulf of Mexico Current is Offshore Leader," Oil and Gas Journal 74(35) (August 30, 1976); Oil and Gas Journal 74(18) (May 3, 1976).

TABLE 2-1

OFFSHORE OIL PRODUCTION AND RESERVES MAJOR FIELDS IN THE UNITED STATES

(million bbl)

State	Field, Discovery Date	No. Wells	1975 Production	Cumulative Production	Estimated Remaining Reserves	Pay Zone Depth, ft
Alaska	Granite Point	23	4	60	50	Kenai, 8,772
	McArthur River	57	41	294	208	Kenai, 9,572
	Middle Ground Shoal	35	8	96	89	Kenai, 7,776
California	Dos Cuadras, 1969	123	14	116	79	Pliocene, 3,673
	Santa Ynez, 1970	-	-	-	1,000	Miocene, 10,006
	Huntington Beach, 1920	1,097	17	941	125	Mio-Plio., 2,100
	Wilmington, 1932	2,249	66	1,787	632	Mio-Plio., 1,200+
Louisiana	Bay Marchard, Bk. 2(incl. onshore), 1949	195	22	452	198	2,472+
	Eugene Island Bk. 126, 1950	50	4	93	32	Miocene, 4,000+
	Eugene Island Bk. 330, 1971	136	78	68	162	Miocene, 6,953
	Eugene Island Bk. 175, 1956	60	5	42	78	Miocene, 9,458
	Eugene Island Bk. 276, 1964	60	4	51	114	Pliocene, 6,083
	Grand Isle Bk. 16, 1948	77	11	222	127	Miocene, 1,539+
	Grand Isle Bk. 43, 1956	220	17	181	189	Miocene, 2,325+
	Grand Isle Bk. 47, 1955	65	3	68	32	Miocene, 4,096+
	Main Pass Bk., 35, 1951	66	1	81	19	Miocene, 6,000+
	Main Pass Bk 69, 1966	117	6	196	63	Miocene, 5,500+
	Main Pass Bk. 306, 1969	124	5	37	113	Miocene, 6,167
	Ship Shoal Bk. 204, 1960	48	4	31	73	Miocene, 9,832+
	Ship Shoal, Bk. 207, 1967	49	5	49	125	Miocene, 11,814+
	Ship Shoal Bk. 208, 1962	73	8	101	124	Miocene, 9,859+
	South Marsh Island Bk. 73, 1963	43	3	44	60	Miocene, 6,780+
	South Pass Bk. 24, (inc. onshore) 1950	434	13	384	106	Miocene, 6,520+
	South Pass Bk. 27, 1954	327	9	268	116	Miocene, 6,542+
	South Pass Bk. 62, 1965	61	5	54	136	Miocene, 5,392+
	South Pass Bk 65, 1969	65	8	55	136	Miocene, 8,033+
	Timbalier Bay, Bk. 21, 1959	169	6	165	55	Miocene, 3,556+
	West Delta Bk. 30, 1949	194	18	330	120	Miocene, 2,152+
	West Delta Bk. 53, 1964	70	9	47	153	Miocene, 11,668+
	West Delta Bk. 73, 1962	112	8	136	138	Miocene, 8,320+

Source: Oil and Gas Journal 74(18) (May 3, 1976): 149-150.

fields shown in Figures 2-2, 2-3 and 2-4 produced about 390 million barrels of oil or about 73 percent out of a total of 533 million barrels produced offshore. Until offshore Alaska and Atlantic are developed, the Gulf of Mexico is likely to continue to be the most important domestic offshore source of oil and gas.

In Louisiana, there has been considerable dispute over where the state ownership ends offshore and where Federal jurisdiction begins. This is due to the fact that at places where the wetlands merge into the sea, it is difficult to determine exactly where the shore might be. Further, grants related to early Spanish and French treaties have been declared by the state to give rights beyond the 3-mile limit. Recent court decisions have partially settled this dispute, but still, title to some offshore lands is in question. Deep embayments along the coast, most of them having oil structures, create many shallow water and amphibious operations that might or might not be considered to be "offshore." Although much of the technology for offshore operation was developed in these areas, these nearshore activities are not considered to be within the scope of this report. Furthermore, these nearshore operations are in a mature stage of development compared to the activities on the Outer Continental Shelf. Emissions from these sources will be considered in a future report.

The first offshore well was drilled in 1945 by Magnolia Petroleum Company (now Mobil Oil Company).[3] A converted land rig was built on a wooden structure in 20 feet of water in Ship Shoal Block No. 58. The well was a dry hole.

The industry expanded in the Gulf from 2 platforms in 1947 to 668 active multiple-well platforms in Texas and Louisiana by March 1974 (see Table 2-2). Of the original 804 multiple-well platforms built, hurricanes have claimed 17 and only 6 were lost by fires, blowouts or other unusual causes.[4] Table 2-3 summarizes the frequency of incidents since 1964. Eight companies own 498 major platforms containing six or more wells or 77 percent of the total major structures. Some platforms have dual ownership.

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[3]J. Carmichael, "The Industry Has Built Over 800 Platforms in the Gulf of Mexico," Offshore 35(5) (May 1975): 83.

[4]U.S. Geological Survey, Conservation Division, Accidents Connected with Federal Oil and Gas Operations on the Outer Continental Shelf, July 1976.

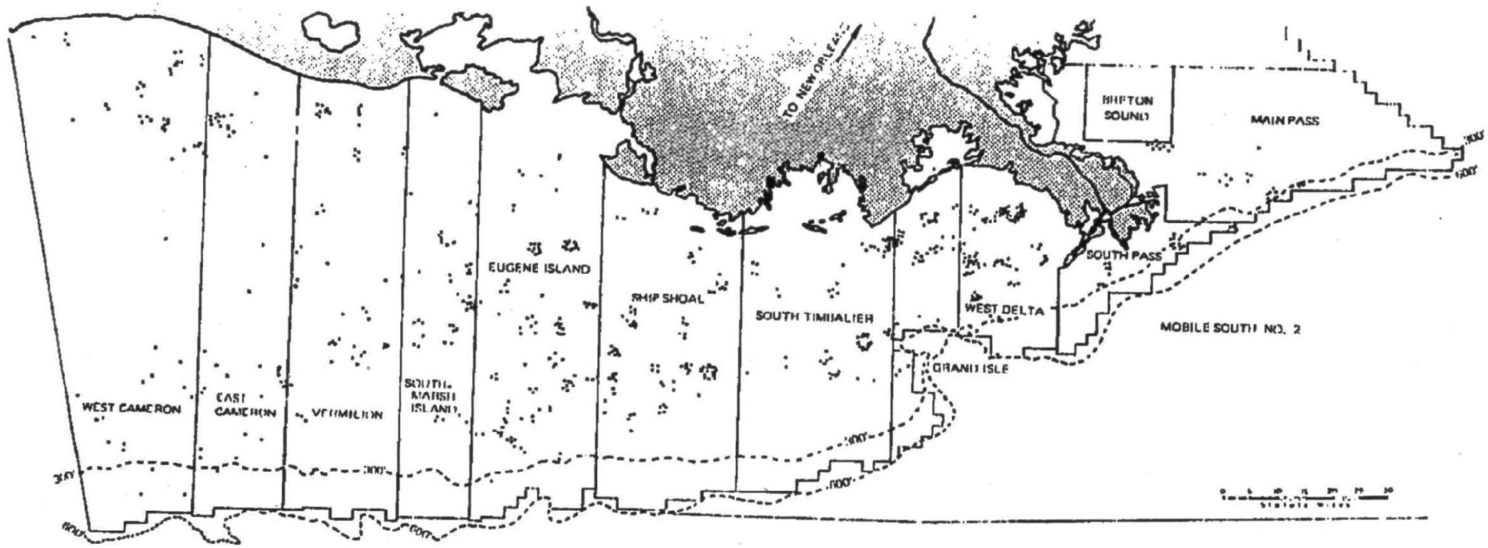

Figure 2-2a. Offshore Louisiana oil and gas fields. (L. Leblanc, "Development Occupies Operators Who Stay Busy Working Gulf of Mexico," Offshore 36(7) (June 20, 1976).)

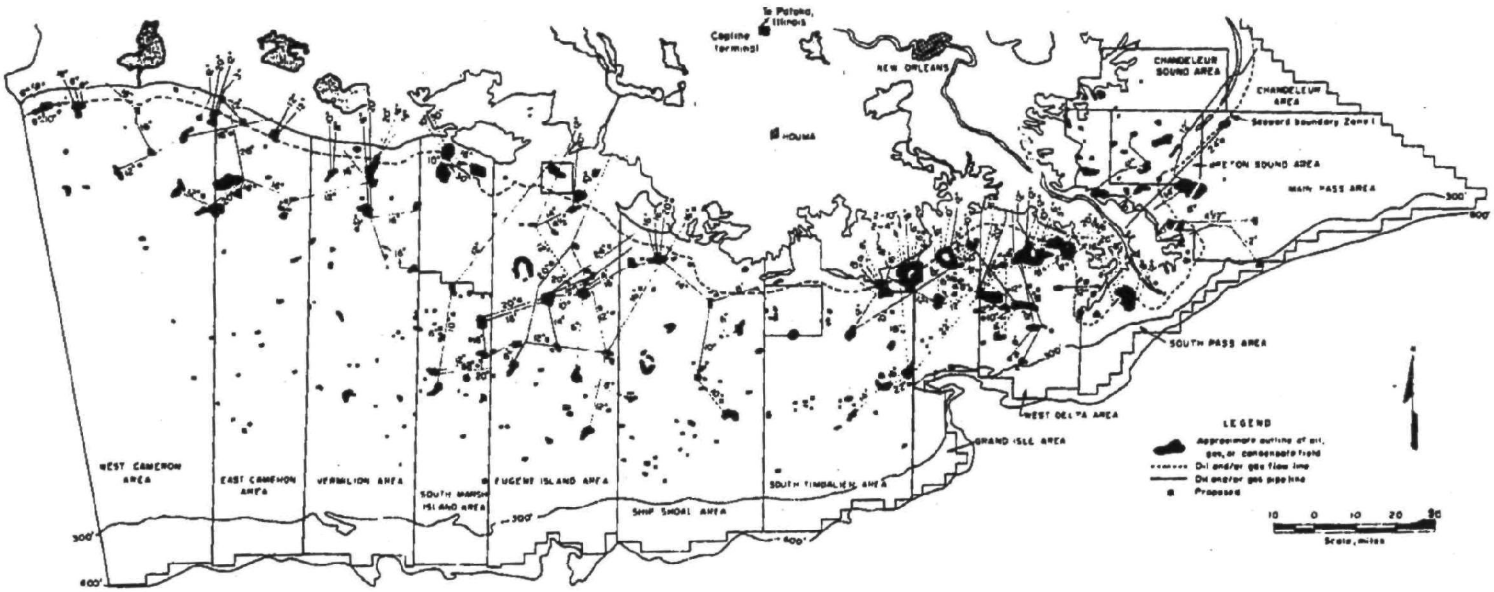

Figure 2-2b. Approximate location of the proposed and existing pipeline-flowline system, Offshore Louisiana, March 1974. (W.M. Harris, S.K. Piper, and B.E. McFarlane, <u>Outer Continental Shelf Statistics</u>, U.S. Geological Survey, Department of the Interior, 1976, p. 8).

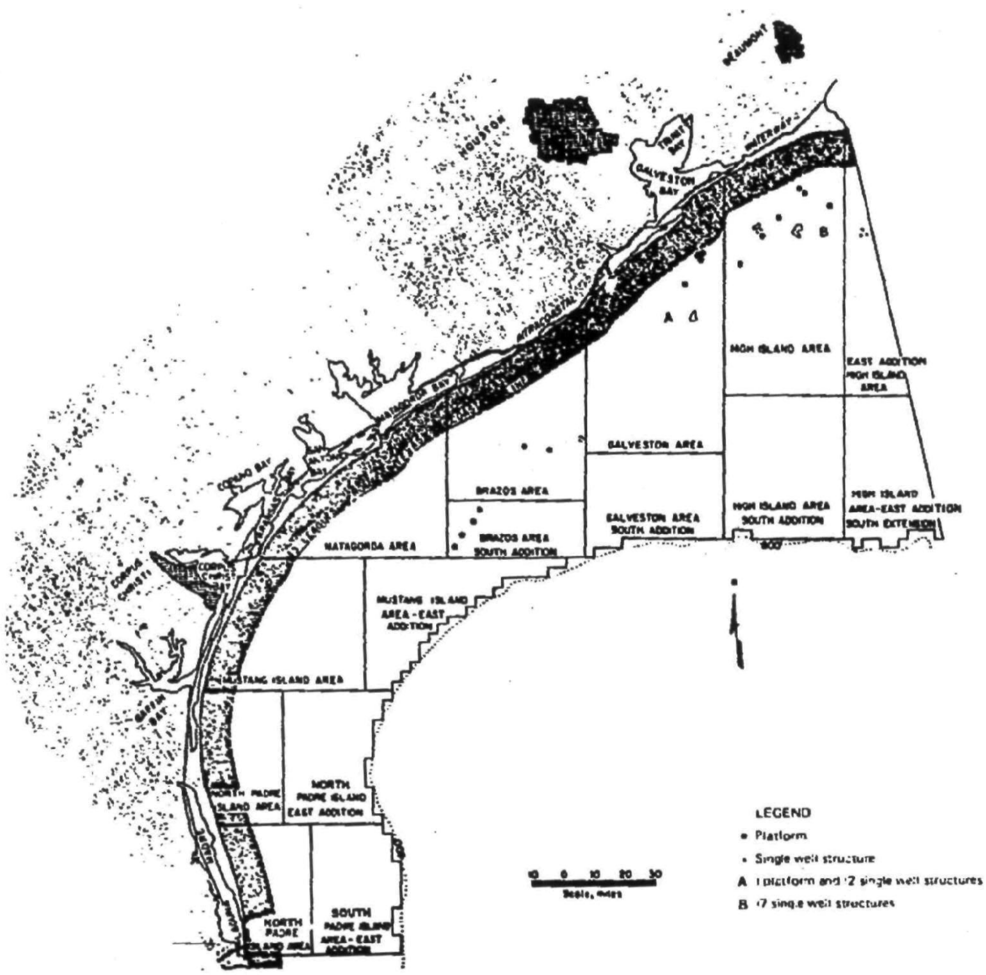

Figure 2-3. Offshore Texas oil and gas fields. (Bureau of Mines Information Circular 8408.)

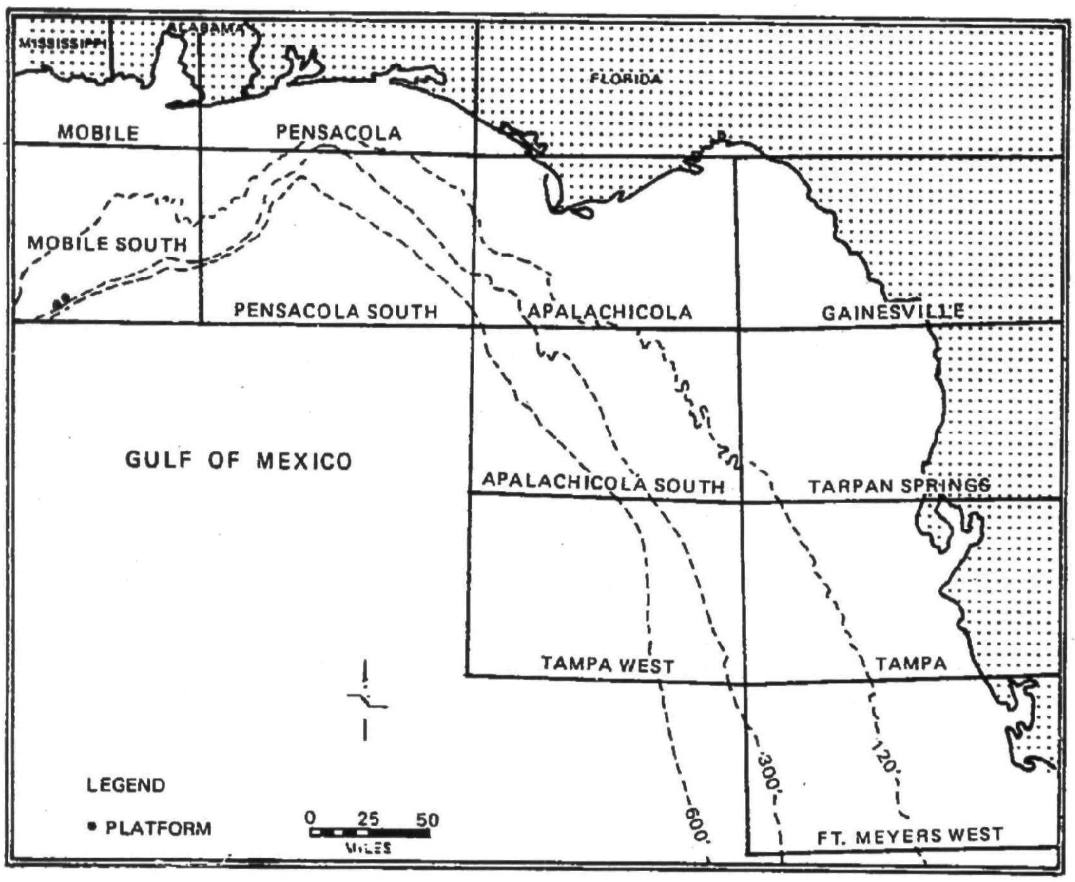

Figure 2-4. Gulf of Mexico leasing areas and oil and gas fields, offshore Mississippi, Alabama, and Florida. (Offshore, 36(7) (June 20, 1976), Supplement.)

TABLE 2-2

OFFSHORE PLATFORMS IN FEDERAL WATERS

LOUISIANA	
West Cameron	45
East Cameron	39
Vermillion	42
South Marsh Island	47
Eugene Island	107
Ship Shoal Area	85
South Timbalier	62
Grand Isle	62
West Delta	94
South Pass	15
Main Pass	40
Bay Marchand	15
South Pelto	2
TOTAL	655
TEXAS	
High Island	6
Galveston	3
Brazos	4
TOTAL	13
MISSISSIPPI, ALABAMA, FLORIDA (MAFLA)	
Mobil South #1	1
TOTAL	1
CALIFORNIA	
Santa Ynez	1[a]
Santa Barbara Channel	5
TOTAL	6
GRAND TOTAL	675

[a]Under construction.

Source: Offshore 35(5) (May 1975): 84.

TABLE 2-3

MAJOR OIL SPILL INCIDENTS

CALENDAR YEAR	INCIDENTS	OIL SPILLED (bbl)	NUMBER OF FIXED STRUCTURES	ANNUAL OCS PRODUCTION (10^6 bbl)
1964	5	14,928	1,100	123
1965	2	2,188	1,200	145
1966	0	None	1,325	189
1967	1	160,639	1,450	222
1968	1	6,000	1,575	269
1969	6	30,024	1,675	313
1970	3	83,895	1,800	361
1971	1	450	1,891	419
1972	0	None	1,935	412
1973	4	22,175	2,001	395
1974	2	22,046	2,054	361
1975	1	Unknown	2,079	328[a]
TOTALS	26	342,345		3,537[a]

[a]Estimate

Early platforms had from 3 to 12 slots or positions for wells. As recently as 1974 one 40-slot, three 32-slot, and numerous 24-slot platforms were installed in water depths from shallow water to 375 feet in depth. At present, Shell Oil Company is completing its 40-slot platform in South Pass Block No. 70 and is constructing another 40-slot platform close by in 290 feet of water. Shell's platform slated for the Cognac structure in the Gulf will be 1,265 feet tall and will have 62 slots and will stand in 1,020 feet of water about 100 miles southeast of New Orleans. All told, the U.S. Geological Survey (USGS) reports 2,079 (1975) single- and multiple-well platforms under their jurisdiction in offshore Louisiana and Texas.

California offshore areas are shown in Figures 2-5 and 2-6. Five platforms presently operate offshore in the Ventura-Santa Barbara area in Federal waters. Eight near-shore production platforms and one production island are also located here. On the Pacific coast, the water becomes deep at a fast rate, so even the site of the newest platform, Exxon's Hondo, is in 850 feet of water only 5.5 miles off-shore. This platform, the world's tallest, will be 945 feet high when set -- the cost over $67,000,000. Twenty-eight wells can be drilled from this installation. It will have about 40,000 ft^2 of deck space.[5]

As of September 1976, 1,748 rigs were active and working. In California three rigs are drilling offshore, as compared to 84 on land; in Louisiana 73 are operating offshore as compared to 53 in inland waters, and 104 on land; in Texas 41 are offshore and 635 on land.[6] Tables 2-4 and 2-5 summarize the rigs and vessel types which are available.

The jack-up type rig has considerable popularity in relatively shallow water up to 300 feet in depth. Submersibles, drilling vessels and semisubmersibles are used in deeper water. As of June 1976, 283 offshore rigs were working, 50 were idle, 10 were en route and 87 were under construction.[7]

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[5]T.R. Wright, Jr., "Exxon Begins Installing World's Tallest Platform," World Oil 193(1) (July 1976).

[6]"Hughes Rig Count," Oil and Gas Journal 74(30) (September 29, 1976): 108.

[7]"Mobile Units," Offshore 36(6) (June 5, 1976): 91.

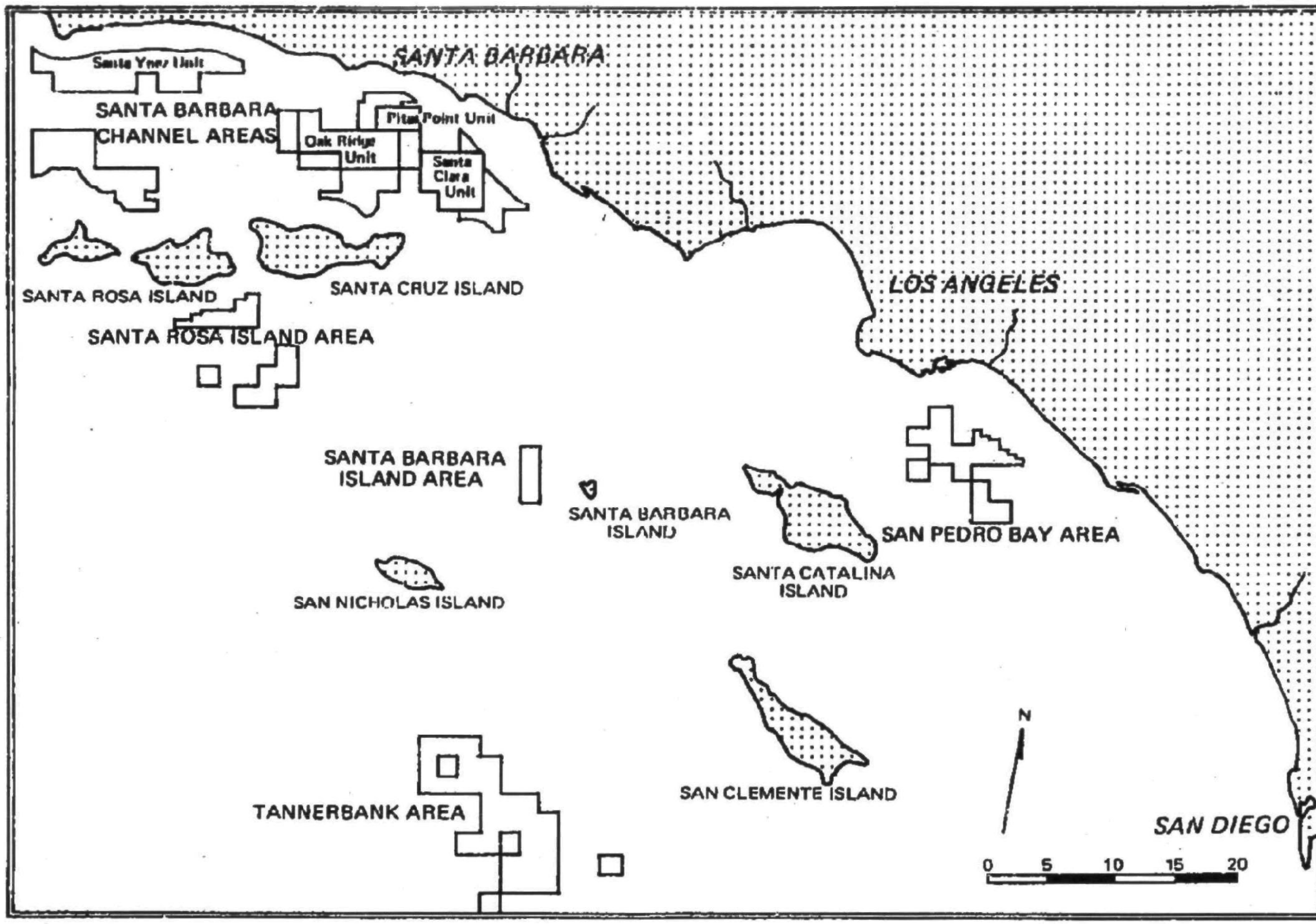

Figure 2-5. Offshore Southern California Borderland Area. (U.S. Department of the Interior, Bureau of Land Management, Pacific Outer Continental Shelf Office.)

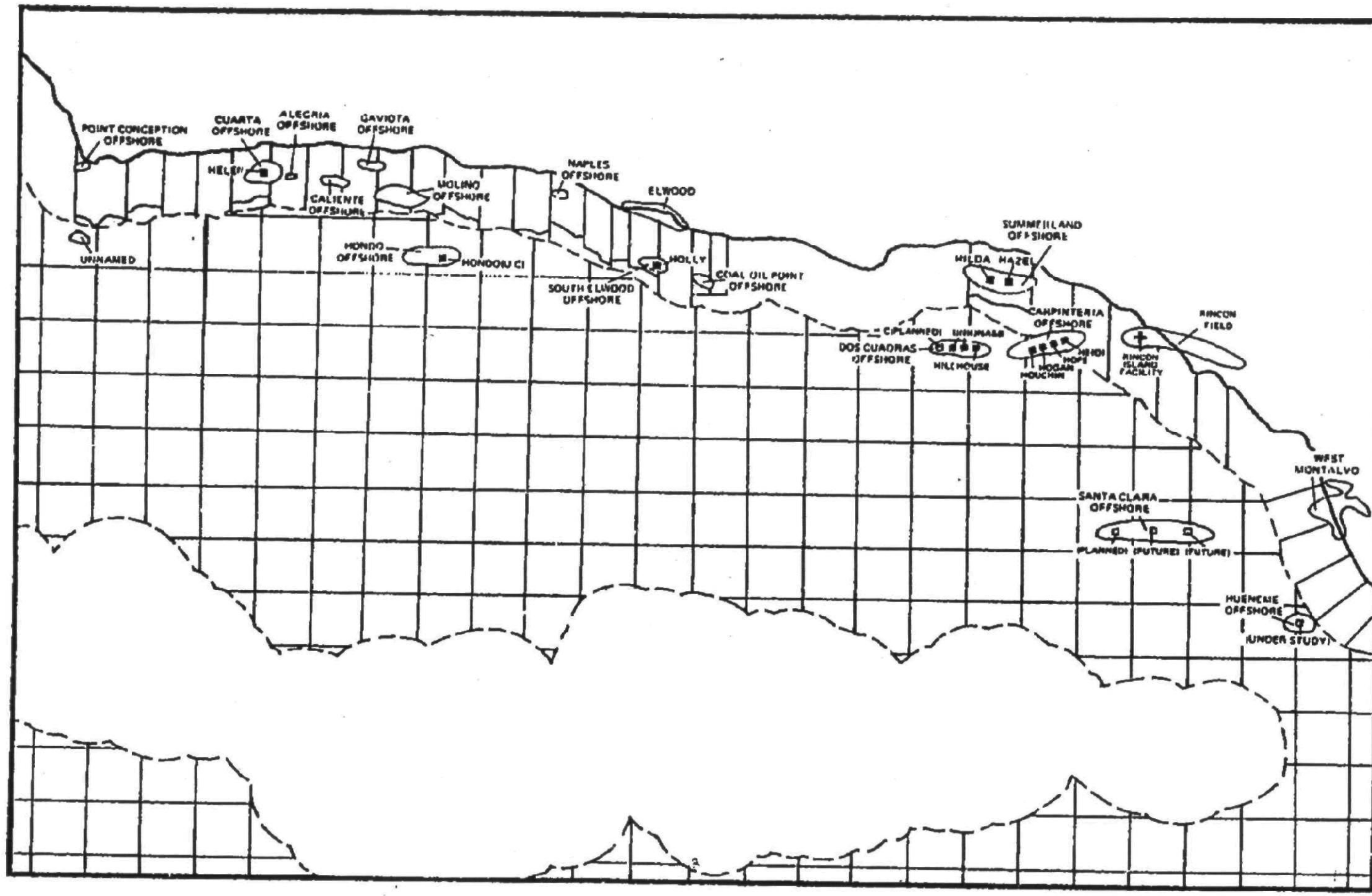

Figure 2-6. Oil and gas fields and offshore facilities in the Santa Barbara Channel region. (U.S. Geological Survey, Department of the Interior, Petroleum Development in the Region of Santa Barbara Channel, Appendix B, Professional Paper 674, Plate 2, 1969.)

TABLE 2-4

RIGS AVAILABLE BY TYPES - 1976

RIGS	ATLANTIC OCEAN	PACIFIC OCEAN	LOUISIANA GULF	TEXAS GULF
Working	7	4	51	5
Idle	1	4	6	3
En Route	-	2	-	-
Drill Ships	3	7	5	4
Semisubmersibles	5	2	11	5
Submersibles	-	-	15	1
Jack-Ups	-	1	26	18

TABLE 2-5

LOCATION OF AND TYPE OF DRILLING RIGS AVAILABLE FOR U.S. OFFSHORE OPERATIONS

ATLANTIC

7 working; 1 idle

NAME & LOCATION	OWNER
BIDEFORD DOLPHIN Semisubmersible drills to 30,000' in 1,500' Chevron, Spain	Dolphin Drilling
GLOMAR CHALLENGER Drillship drills to 25,000' in unltd. water depth Scripps, Atlantic	Global Marine Inc.
GLOMAR SIRTE Drillship drills to 25,000' in 600' Challenger, Faro Portugal	Global Marine, Inc.
M. V. HERON Drillship drills to 1,500' in 600' Idle, Boston, Mass.	Associated Marine Services, Inc.
PENTAGONE 84 Semisubmersible drills to 20,000' in 660' S N P.A . France, Britanny Brezelle 1 Mer d'Iroise	Forex Neptune (and/or affiliated Cy)
MEDUSA Semisubmersible drills to 16,400' in 660' Shell, Spanish Bay of Biscay, Mar Cantabrico C-2	Offshore Drilling Inc. (Kalukundis)
SEDCO I Semisubmersible drills to 25,000' to 800' Union Texas, Spain Terragona E-2	Southeastern Commonwealth Drilling Ltd.
SEDCO J Semisubmersible drills to 25,000' in 800' Ocean Production Co., Atlantic OCS	Southeastern Commonwealth Drilling, Ltd.

CARIBBEAN

4 working; 2 en route

NAME & LOCATION	OWNER
DISCOVERER 511 Drillship drills in 2,000' Trinidad, May 76	Amoshore
LOUISIANA Semisubmersible drills to 20,000' in 600' En route Trinidad for Dominez	Zapata Off-Shore Co.
PAT RUTHERFORD, SR. Semisubmersible drills to 25,000' in 600' Texaco, Trinidad, Galeota Point	Field-Viking Drilling S. de R L

LOUISIANA

31 working; 6 idle

NAME & LOCATION	OWNER
BARGE A Submersible drills to 25,000' in '75 Gulf, South Timbalier 21	ODECO Inc
BLUE WATER No 2 Semisubmersible drills to 20,000' in 600' Union, West Cameron 593	Santa Fe Int'l.
BLUEWATER NO. 4 Semisubmersible drills to 25,000' in 1,500' American Petrofina, Mobile South. #2 N663 E68	Santa Fe Int'l. Corp.
CENTURY Semisubmersible drills to 30,000' in 600' Marathon, Vermilion, 369	Diamond M Drilling Co.
DIXILYN TWO SIXTY Jackup drills to 30,000' in 260' Skelly, West Cameron 402	Dixilyn International Inc.
EL DORADO Submersible drills to 25,000' in 70' Ocean Production, Ship Shoal 119	ODECO, Inc.
FJELLDRILL Jackup drills to 25,000' in 250' Shell, Vermilion 22	Olsen & Ugelstad A/S
GEM Jackup drills to 30,000' in 300' Shell, Vermilion 144	Diamond M Drilling Co.
GLOMAR II Drillship drills to 25,000' in 600' Available, Gulf Coast	Global Marine, Inc.
GLOMAR CONCEPTION Drillship drills to 25,000' in 600' Idle Gulf Coast	Global Marine Inc.
GLOMAR GRAND ISLE Drillship drills to 25,000' in 600' Available, Gulf of Mexico	Global Marine Inc.
INTREPID Jackup drills to 20,000' in 300' Pennzoil, Eugene Island 120	Zapata Off-Shore Co.
J. STORM I Jackup drills to 20,000' in 225' Mesa, So. Pelto 13	Marine Drilling Co.
JOHN HAYWARD Submersible drills to 25,000' in 30 Marathon, Eugene Island 58	ODECO, Inc.
MARLIN NO. 3 Jackup drills to 25,000' in 250 Skelly, Main Pass 28	Marlin Drilling Co., Inc.
MARLIN NO. 6 Jackup drills to 30,000' in 300' Tenneco, West Cameron 165#12	Marlin Drilling Co., Inc.
MISSION EXPLORATION Drillship drills to 30,000' in 600' Pennzoil, Gulf Mexico	Mission Drilling & Exploration
MOVIBLE NO. 2 Submersible drills to 25,000' in 80' Shell, South Pass, 27	Teledyne Movible Offshore, Inc.
MOVIBLE NO. 3 Submersible drills to 20,000' in 45' Union, South Marsh Island 280	Teledyne Movible Offshore, Inc.
MR. CHARLIE Submersible drills to 25,000' in 40' Quintana, Bay of Marchand 5	ODECO Inc.
MR. GUS II Jackup drills to 25,000' in 150' Union, Eugene Island 179 OCS-G-1221 #F-1	Fluor Drilling Services, Inc., Coral
MR 51 Jackup drills in 350' Gulf Oil, West Cameron 368 OCS-G-2842 #1	Fluor Drilling Services, Inc., Coral
NEW ERA Semisubmersible drills in 1,000' Amoco, Mobile So. #2 661-N	Diamond M Drilling
OCEAN 66 Jackup drills to 25,000' in 120' Chevron, South Marsh Island 285	ODECO Inc.
OCEAN DRILLER Semisubmersible drills to 25,000' in 600' Chevron, Main Pass 252	ODECO Inc.
OCEAN LEADER Jackup drills to 25,000' in 175' Pennzoil, Vermilion 228	ODECO Inc.
OCEAN QUEEN Semisubmersible drills to 25,000 in 1,200 Shell, Vermilion 395	ODECO Inc.
OCEAN PRIDE Jackup drills to 25,000' in 150 Shell, Vermilion 22	ODECO Inc.
OCEAN SCOUT Semisubmersible drills to 20,000' in 600 Pennzoil, Eugene Island 337	ODECO Inc
OCEAN STAR Jackup drills to 25,000' in 173' Ocean Prod., So. Timbalier 86	ODECO Inc.
ODECO SEVEN Submersible drills to 25,000' in 35' Chevron, South Timbalier 11	ODECO Inc.
OCEAN TRAVELER Semisubmersible drills to 25,000' in 600' Gulf, West Cameron 323	ODECO Inc.
PMI III Jackup drills in 70' Shell, South Pass 27	Progress Marine, Inc.
PMI IV Jackup drills in 70' Mobile shipyard for repairs	Progress Marine, Inc.
PMI V Jackup drills in 70' Mobil, Main Pass 92	Progress Marine, Inc.
PMI VI Jackup drills in 70 Exchange Oil & Gas, West Cameron 21-6-NER-16	Progress Marine, Inc
PENROD 50 Submersible drills to 25,000 in 50' Shell, Vermilion 22	Penrod Drilling Co.
PENROD 51 Submersible drills to 25,000' in 60 Kerr-McGee, West Cameron 147	Penrod Drilling Co.

TABLE 2-5 (CONT.)

NAME & LOCATION	OWNER
PENROD 53 Jackup drills to 30,000' in 300' Vicksburg for repairs	Penrod Drilling Co.
PENROD 54 Jackup drills to 30,000' in 300' Getty, West Cameron 487	Penrod Drilling Co.
PENROD 60 Jackup drills to 30,000' in 340' Placid, South Marsh Island 122	Penrod Drilling Co.
PENROD 66 Jackup drills to 30,000' in 340' Mobil, Grand Isle 31	Penrod Drilling
PENROD 72 Semisubmersible drills to 30,000' in 2,000' Placid, Mobile South #2 N662 E69	Penrod Drilling Co.
RANGER III Jackup drills to 11,000' in 75' Mobil, East Cameron 14	Atlantic Pacific Marine
RIG 44 Submersible drills to 20,000' in 40' Kerr-McGee, Ship Shoal	Transworld Drilling Co.
RIG 45 Submersible drills to 20,000' in 35' Kerr-McGee, Breton Sound 28	Transworld Drilling Co.
RIG 47 Submersible drills to 20,000' in 70' Superior, West Cameron, 71	Transworld Drilling Co.
RIG 54 Submersible drills to 20,000' in 175' Mobil, Main Pass 73	Transworld Drilling Co.
RIG 59 Jackup drills to 20,000' in 125' Mobil, Vermilion 23	Transworld Drilling Co.
ROWAN-HOUSTON Jackup drills to 25,000' in 225' Energy Resources Grp., Brazos 747 L-1	Rowan International, Inc.
ROWAN-LOUISIANA Jackup drills to 30,000' in 350' Consolidation Natural Gas, Vermilion 329	Rowan Cos., Inc.
S-55 Submersible drills to 25,000' in 60' In shipyard for equipment revision	Noble Drilling
ST. LOUIS Submersible drills to 25,000' in 35'. Quintana, Eugene Island 82	ODECO, Inc.
TEMPEST Drillship drills to 25,000' in 600' Mesa, South Marsh Island, 174	Japan Odeco S.A.
TOPPER I Jackup drills to 12,000' in 120' Houston Oil & Minerals, Gulf of Mexico	Zapata Off-Shore
WESTERN PACESETTER III Semisubmersible drills to 25,000' in 1,200'+ Exxon, Mobile South 2 N658 E048	Western Oceanic
ZAPATA LEXINGTON Semisubmersible drills to 25,000' in 2,000' Exxon, Mobile So. #2 N658 E061	Zapata Off-Shore
WESTERN POLARIS II Jackup drills to 25,000' in 250 Cities Service, Burmah Bay of Bengal	Western Oceanic

TEXAS

25 working; 3 idle

NAME & LOCATION	OWNER
DIAMOND M GENERAL Semisubmersible drills to 30,000' in 1,000' Available, Sabine Pass	Diamond/General Drilling Ltd.
DIAMOND M 99 Jackup drills to 30,000' in 300' Exxon, West Delta 117	Diamond M Drilling Co.
DIXILYN THREE-SEVENTY Jackup drills to 20,000' in 370' Clark, High Island A561	Dixilyn International Inc.
GLOMAR GRAND BANKS Drillship drills to 25,000' in 600 Exxon, West Delta 73	Global Marine Inc.
GLOMAR JAVA SEA Drillship drills to 25,000' in 1,500' Arco, West Delta 120	Global Marine Inc.
J. STORM III Jackup drills in 250' Oil & Minerals, Galveston 182-S	Marine Drilling Co.
J. STORM IV Jackup Conoco, Matagorda 485-L	Marine Drilling
MARLIN NO. 7 Semisubmersible drills to 30,000' in 1,000' Stacked, Sabine Pass	Marlin Drilling Co., Inc
MISSION VIKING Drillship drills to 30,000' in 1,500' Texaco, Bay City No.19 E73	Mission Viking
MR. ARTHUR Submersible drills to 20,000' in 80' Getty, High Island 74, OCS-G-3116 #1	Field-Swire Drilling Co
MR. MEL Jackup drills to 30,000' in 350' Burmah Oil & Gas, High Island A-317 OCS-G-2412 #3	Fluor Drilling Services, Inc., Coral
MR. SAM Jackup drills to 25,000' in 155' Rutherford Oil Corp., Galveston #1 104-L	Fluor Drilling Services, Inc., Coral
OCEAN CHIEF Jackup drills to 25,000' in 224' Occidental, High Island A-510	ODECO Inc.
OCEAN EXPLORER Semisubmersible drills to 25,000' in 600' Shell, Mustang Island 760	ODECO Inc.
OCEAN EXPRESS Jackup drills to 25,000' in 250' Marathon, Mustang Island A-03L	Odeco
OCEAN KING Jackup drills to 25,000' in 340' Superior, Mustang Island 850	ODECO Inc.
PENROD 61 Jackup drills to 30,000 in 340' Cities Service, Mustang Island A-54	Penrod Drilling Co
RANGER I Jackup drills to 10,000' in 70' McMoran Exploration, Matagorda Island, S/T 691 L#2	Atlantic Pacific Marine
RIG 50 Jackup drills to 12,000' in 70' Superior, Matagorda Island ST 582-S	Transworld Drilling Co.
SEDNETH 1 Semisubmersible drills to 25,000' in 600' Texaco, High Island A-586	Sea Drilling Netherlands, N.V.
STORMDRILL V Jackup drills to 20,000' in 175' Continental, High Island 137	Marine Drilling Co.
TELEDYNE NO. 16 Jackup drills to 25,000' in 250' ETA, Gulf of Mexico	Teledyne Movible Offshore Inc.
TRANSWORLD RIG 62 Jackup drills to 20,000' in 300' Citgo, Galveston A-54	Transworld Drilling Co.
TRANSWORLD RIG 64 Jackup drills to 20,000' in 300' Kerr-McGee, Gulf of Mexico	Transworld Drilling Co.
TRANSWORLD RIG 67 Jackup drills to 10,000' in 40' Mitchell Energy, High Island 22-L	Transworld Drilling Co
WESTERN DELTA Jackup drills to 15,000' in 175' Kilroy, High Island ST 98-L#3	Western Oceanic
ZAPATA CONCORD Semisubmersible drills to 25,000' in 2,000' Mobil, Bay City N638 E071	Zapata Off-Shore
ZAPATA TRADER Drillship drills to 20,000' in 600' Stacked, Gulf Coast	Zapata Off-Shore Co

PACIFIC

4 working, 4 idle, 2 en route

NAME & LOCATION	OWNER
CALDRILL I Drillship drills to 6,000' in 5,000'+ Idle, Calif	Marine Drilling & Coring Co.
CANMAR EXPLORER II Drillship drills to 25,000' in 600' Dome Petroleum, Beaufort Sea	Canmar (Dome Petroleum
CUSS I Drillship drills to 16,000' in 600' Union, California	Global Marine Inc.
GEORGE F. FERRIS Jackup drills to 18,000' in 200' Union, Upper Cook Inlet, Alaska	Sun Marine Drilling & Offshore Constructors, Inc
GLOMAR CORAL SEA Drillship drills to 25,000' in 1,500' Gulf, California	Global Marine Inc.
GOLDRILL 4 Drillship drills to 12,000' in 600' Remodeling, Long Beach, Calif.	Golden Lane Drilling Co
HUGHES GLOMAR EXPLORER Drillship drills to 12,000' in 18,000'+ Idle, Long Beach, Calif.	Summa Corp. (Global Marine Inc)
LA CIENCIA Drillship drills to 1,500' in 600' Idle, Seattle, Wash.	Associated Marine Services, Inc.
OCEAN PROSPECTOR Semisubmersible drills to 25,000' in 600 En route U S. west coast	ODECO/IILD
ALEUTIAN KEY, OFFSHORE CALIFORNIA Semisubmersible drills to 25,000' in 1,000' Tanners Bank	Key Drilling Co.

Source: <u>Offshore</u> 35(5) (May 1975): 397-417.

A trend in rig design popularity is indicated by those under construction as of June 1976 which include 19 drill ships, 32 jack-ups and 36 semisubmersibles. An estimated 361 mobile offshore rigs will be available worldwide by 1978.[8]

In the United States, in 1975, a total of 932 offshore wells were drilled.[9] Of these, 581 were exploratory and 351 were drilled on known structures. In total, 256 oil wells, 194 gas wells and 482 "dry" holes were drilled. Table 2-6 shows that most of the successful activity occurs offshore Louisiana. Texas offshore provided 12 gas wells, no oil wells, out of 172 tries.

In California, there has been an increase in drilling activity. Two recent discovery wells have been drilled in the San Pedro Bay area by Shell and Standard Oil of California in about 650 feet of water 15 miles south of Long Beach. It is reported that the oil is 19.5 degrees API gravity on the average. If production is typical of other fields in offshore California, a gas-oil ratio of 200 to 500 ft^3/bbl would be expected. Exxon expects a gas-oil ratio of about 1,000 in the Santa Ynez field where platform Hondo is located. The oil has a sulfur content of 4 to 5 percent and is 18 to 19 degrees API gravity.

Three rigs are drilling in Federal waters of California. The Aleutian Key, under contract to Gulf Oil Company, is drilling in 680 feet of water on OCS-P0258 (Tract 76) at Tanner Bank in the Santa Rosa-Cortes South area. Texaco is drilling with a semisubmersible rig in the San Pedro area adjacent to the earlier discoveries. Well depths are typically 10,000 feet or less.

Table 2-7 shows the trend of wells drilled and production offshore during the past 5 years. In most statistics, the completion of two zones or more in a single hole is reported as two or more wells, as the case may be. The above data varies slightly with that of the USGS because some offshore wells in state waters are included.

Offshore production of oil, gas, and condensate by area is shown in Tables 2-8, 2-9, and 2-10. This production

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[8] J.W. Speer, Manager of Drilling and Production Operations, Shell Oil Company, in "Lengthy World Mobile-Rig Surplus Seen," Oil and Gas Journal 74(45) (November 8, 1976): 130.

[9] "Worldwide Statistics," Offshore (June 20, 1976): 65, 77.

TABLE 2-6

1975 EXPLORATORY AND DEVELOPMENT WELLS

DEVELOPMENT WELLS

STATE OR DISTRICT	OIL WELLS		GAS WELLS		DRY HOLES		TOTAL DEVELOPMENT WELLS	
	WELLS	FOOTAGE	WELLS	FOOTAGE	WELLS	FOOTAGE	WELLS	FOOTAGE
Alaska	13	124,504	--	--	--	--	13	124,504
California	60	214,264	--	--	2	4,774	62	219,038
Louisiana	179	1,578,602	177	1,771,008	139	1,338,431	495	4,688,041
Texas	--	--	5	42,294	5	50,713	10	93,037
Gulf of Mexico North	--	--	--	--	1	9,489	1	9,489
TOTALS	252	1,917,370	182	1,813,302	147	1,403,437	581	5,134,109

EXPLORATORY WELLS

STATE OR DISTRICT	OIL WELLS		GAS WELLS		DRY HOLES		TOTAL EXPLORATORY WELLS	
	WELLS	FOOTAGE	WELLS	FOOTAGE	WELLS	FOOTAGE	WELLS	FOOTAGE
Alaska	--	--	--	--	1	14,015	1	14,015
California	2	12,340			4	32,579	6	44,919
Louisiana	2	25,684	5	44,924	144	1,302,702	151	1,373,310
Texas	--	--	7	70,504	155	1,345,956	162	1,416,460
Gulf of Mexico North	--	--	--	--	31	336,593	31	336,593
TOTALS	4	38,023	12	115,428	335	3,031,845	351	3,185,297

Source: "1975 Totals for Exploratory and Development Wells," Offshore 36(7) (June 20, 1976): 77.

TABLE 2-7

TREND OF THE NUMBER OF OFFSHORE WELLS DRILLED IN THE UNITED STATES

YEAR	1975	1974	1973	1972	1971
Number of Wells Drilled	932	1,128	1,029	926	916
Production[a] (10^3 bbl/day)	964	1,148	1,589	1,667	1,692

[a]Includes some production in state waters (e.g., 135,000 bbl/day in 1975).

Source: Oil and Gas Journal 74(18) (May 3, 1976): 150.

TABLE 2-8

ANNUAL PRODUCTION ON THE OUTER CONTINENTAL SHELF

OFFSHORE AREAS	OIL PRODUCTION[a] (barrels)	GAS PRODUCTION[a] (thousands of ft^3)	CONDENSATE LPG GASOLINE (barrels)
California	15,304,757	3,951,633	-
Louisiana	287,515,795	3,332,169,057	72,463,738
Texas	338,589	1,218,139,769	10,959,837

[a]Delivered onshore, i.e., sales volume.

TABLE 2-9

PRODUCTION FROM OFFSHORE CALIFORNIA OILFIELDS IN STATE WATERS, 1975[a]

FIELD NAME	OIL (10^6 bbl)	GAS (10^9 ft^3)	LOCATION AND TYPE OF FACILITIES
Belmont	2.48	0.62	Manmade islands (2)
Huntington Beach	13.90	1.95	Platforms (2), onshore wells
Newport, West	0.10	0.04	Onshore wells
Torrance	0.46	0.60	Onshore wells (Redondo Drill Site)
Venice Beach	0.12	0.05	Onshore wells (Venice Drill Site)
Wilmington	44.00	10.00	Manmade islands (4), onshore wells
Carpenteria	1.44	1.76	Platforms (2) plus 2 platforms in Federal
Montalvo, West	0.07	-	Onshore wells
Rincon	0.41	0.21	Onshore wells, seafloor well, piers, manmade island
Summerland	0.25	1.28	Platforms (2)
Caliente	-	0.35	Seabed wells
Alegria	0.03	0.08	Seabed wells
Coal Oil Point	0.01	0.04	Seabed wells
Elwood	0.04	0.20	Onshore wells, piers (abdn.)
Elwood, South	1.17	0.04	Platform
Point Conception	0.08	0.04	Onshore sites (2), platform
Molino	-	3.49	Seabed well
TOTAL	65.50	21.44	

[a]Totals may not agree with totals due to rounding. Excludes Ryers Island gas field which is located in the Sacramento delta area (1975 production, 3.1 x 10^9 ft^3).

Source: Resources Agency of California, Department of Conservation, Division of Oil and Gas, California Oil and Gas Production Statistics and New Well Operations, Report PR03, 1975.

TABLE 2-10

ANNUAL PRODUCTION IN OFFSHORE CALIFORNIA OILFIELDS TO OFFSHORE FACILITIES IN STATE WATERS, 1975

FIELD NAME	PRODUCTION TO OFFSHORE FACILITIES		FACILITIES TYPE AND NAME	
	OIL (10^6 bbl)	GAS (10^9 ft)	MANMADE ISLAND	PLATFORM
Belmont	2.48	0.62	Ester, Belmont	-
Huntington Beach	3.5 (E)	0.5 (E)	-	Emmy, Era
Wilmington	14.5 (E)	3.3 (E)	THUMS Islands (4)	-
Carpenteria	1.44	1.76	-	Hope, Heidi
Summerland	0.25	1.28	-	Hilda, Hazel
Elwood, South	1.17	0.04	-	Holly
Rincon	0.02 (E)	0.01 (E)	Rincon	-
Conception	NR	NR	-	Heiman
Cuarta	NR	NR	-	Helen
TOTAL	23.36	7.51	7	9

E = Estimated.

NR = Non reported, shut in.

reaches shore facilities by pipeline or barge following various degrees of processing onboard platforms as discussed in Chapter Three. The current distribution system is summarized in Table 2-11. Some 66 pipelines and 14 barge systems deliver production to shore with pipeline systems handling over 95 percent of the production. Tables 2-12 and 2-13 list the pipeline and barge systems, respectively. Exxon will utilize a tanker system to handle oil from its platform Hondo in the Santa Ynez field off of California. At present, Exxon plans to reinject the gas rather than pipeline it to shore. The reasons given for this are environmental costs and the inability of the company to obtain required permits for movement to shore.[10] The crude oil production will be sent to an offshore storage and treating facility onboard a converted tanker moored near the platform. Up to 200,000 barrels of crude can be stored there for loading later onto tankers for shipment to refineries.

2.3 Government Regulations

With some noted exceptions, the USGS is now responsible for control of the oil and gas activities offshore beyond the 3-mile limit. The U.S. Coast Guard, the U.S. Corps of Engineers, the U.S. Navy and some other Federal agencies cooperate to allow the oil operations and coastal barge and sea traffic to mutually exist in relative safety.

The operation of the offshore platforms must be kept safe for the personnel aboard as well as serious accidents or damage to the platforms from outside sources. Kessler discusses the issues and government agencies that have some involvement in the protection of these structures.[11] There have been some collisions. There is a constant trend to enhance the physical security of these structures but at this time there is little protection for the structure itself. Major damage to the structure could cause a release of oil or gas and possibly extensive and expensive fires as well as possible loss of life. The U.S. Geological Survey of the Department of the Interior makes daily inspections of the offshore facilities to assure that regulations and safe operating standards are maintained. Twelve basic orders cover their efforts as shown in Table 2-14.

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[10] Personal communication to R.K. Burr from E.P. Crockett (for API), February 14, 1977.

[11] C.J. Kessler, "Legal Issues in Protecting Offshore Structures," Prof. Paper No. 147, Center for Naval Analyses, Arlington, Va., June 1976.

TABLE 2-11

SUMMARY OF OFFSHORE TRANSPORTATION SYSTEMS IN FEDERAL WATERS

OFFSHORE AREA	PIPELINE COMMINGLING SYSTEMS	BARGE SYSTEMS
Louisiana	59	10
Texas	5	4
California	2	-

TABLE 2-12

OFFSHORE PIPELINE SYSTEMS
(MARCH 1976)

AREA	SYSTEM NAME OR TERMINAL	OPERATOR	AVERAGE DAILY OIL VOLUME (barrels)
GULF OF MEXICO			
Brazos	Brazos	Cities Service	757
Galveston	Blue Dolphin	Shell	1,080
High Island	Black Marlin	Shell	210
	McFadden Beach	Chevron	348
	Sabine Pass	Texaco	42
West Cameron	Sabine Terminal	Chevron	468
	Mobil No. 1	Mobil	388[a]
	Cameron Meadows	General American	78[a]
	Cameron Meadows	Gulf	222
	Mobil No. 2	Mobil	2
	Cameron Meadows Stingray	Sun	4,190
	Cameron Creole	Chevron	72
	Iowa	Mobil	1,140
	Grand Chenier	Transocean	120
	Deep Lake	Superior	696
	Grand Lake	Superior	1,760[a]
East Cameron	Geffstown	TGTC Continental	3,785
	Grand Chenier	Mobil/Amoco	408
	South Pecan Lake	Amoco	84
	Sea Robin-Hewy	Texaco	2,810
Vermilion	White Lake	Trans-Union	1,240
	Jupiter	Union	493
	Freshwater City	Conoco	5,616
	Freshwater Bayou	Union	535
South Marsh Island	South Bend	Exxon	26,073
	Tiger Shoal		3,973[b]

[a]Condensate

[b]Oil and Condensate

TABLE 2-12 (CONT.)

AREA	SYSTEM NAME OR TERMINAL	OPERATOR	AVERAGE DAILY OIL VOLUME (barrels)
Various	MCN-Burns	Mobil	14,400
Eugene Island	South Bend	Pennzoil	18
	Calumet	Continental	178
	Exxon Trunkline	Exxon	1,182
Ship Shoal	Tarpon Whitecap Bonito	Shell	228,150
	Coon Point	Skelly	1,482
South Timbalier	Cocodrie and Pecan Isle.	Tenneco	7,452
	Cocodrie	Odeco	7,438
	Gulf No. 3	Gulf	2,826
	Gulf No. 1	Gulf	16,516
Bay Marchand	-	Tenneco	798
South Timbalier	-	Chevron	6,876
Bay Marchand	-	Shell	23,298
South Timbalier	Gulf No. 2	Gulf	28,020
Bay Marchand	-	Chevron	336
Grand Isle	-	Exxon	29,850
	-	Conoco	29,166
West Delta	Pelican Isle	Shell	5,562
	Pelican Isle	Exxon	2,700
	Pelican Isle	Chevron	11,990
	Gulf No. 1	Gulf	12,348
	Gulf No. 2	Gulf	12,011
	Gulf No. 3	Gulf	218
	Venice	SLAM	28,056
South Pass	Burrwood	Conoco	1,200
	Shell No. 1	Shell	5,670
	Burrwood	Gulf	774
	Garden Island	Texaco	1,560
	Shell No. 2	Shell	34,495

TABLE 2-12 (CONT.)

AREA	SYSTEM NAME OR TERMINAL	OPERATOR	AVERAGE DAILY OIL VOLUME (barrels)
Main Pass	Shell No. 2	Shell	32,628
	Venice-Getty Terminal	SLAM	14,148
	Chevron No. 1	Chevron	7,806
	Chevron No. 2	Chevron	7,872
	Chevron No. 3	Chevron	-
	Chevron No. 4	Chevron	11,670
	Grand Bay	Gulf	7,419
<u>PACIFIC</u>			
Santa Barbara	-	Standard of California	21,000
	-	Phillips	11,000

TABLE 2-13

OFFSHORE BARGING SYSTEMS
IN OPERATION AS OF MARCH 1976

AREA	SYSTEM NAME	OPERATOR	APPROXIMATE DAILY OIL OR CONDENSATE PRODUCTION (barrels)
GULF OF MEXICO			
Eugene Island	Beaumont	Union	2,910
Eugene Island	Gibson	Chevron	unknown
West Cameron	Cameron	General American	155
Main Pass	Chalmette	Mobil	1,150
Various	Shell "A"	Shell	4,900-6,680
Various	Shell "B"	Shell	890-2,640
Vermilion	Lake Charles	Tenneco	4,050
South Marsh	Port Arthur	Gulf	1,400
Ship Shoals	Morgan City	Mobil	155
Galveston	Texas City	C&K	140
High Island	Texas City	Texaco	2,232

TABLE 2-14

ORDERS ISSUED TO OPERATORS ON THE OUTER CONTINENTAL SHELF BY THE U.S. GEOLOGICAL SURVEY, DEPARTMENT OF INTERIOR

OCS ORDER	
1	Marking of wells, platforms and fixed structures.
2	Drilling procedures.
3	Plugging and abandonment of wells.
4	Suspensions and determination of well producibility.
5	Installation of subsurface safety devices.
6	Procedure for completion of oil and gas wells.
7	Pollution and waste disposal.
8	Approval procedure for installation and operation of platforms, fixed and mobile structures.
9	Approval procedures for pipelines.
10	Sulfur drilling procedures off Louisiana and Texas.
11	Oil and gas production rates, prevention of waste and protection of correlative rights.
12	Public inspection of records.

It is possible for more than 70 persons to be on a platform or rig at one time so personnel safety is of major consideration in the inspection program. Control of pollution of the sea and air is also an important aspect of the inspections.

Each state, as well as the Federal government, has environmental laws and regulations which apply to the drilling and production of oil and gas. While these may vary from state to state, basically the laws are designed to protect the offshore environment. The American Petroleum Institute has published a review of various state and Federal regulations related to environment protection and oil operations.[12]

2.4 Future Activity

On the Outer Continental Shelf of the contiguous 48 states, several new provinces have been or are likely to be leased for exploratory drilling and development of oil and gas resources. As discussed above, the availability of mobile offshore rigs, particularly semisubmersibles, should not be a constraint to activity in these offshore areas. Over the next 10 years, the industry's offshore exploration and development budget, the state-of-the-art and the anticipated economics of these new areas will set the course of development.

The implications of these factors for development through 1985 are recognized by the industry. Drilling will be carried on in water depths where platforms can be installed. Table 2-15 illustrates the present and anticipated capabilities of the technology. As Table 2-15 shows, this means water depths of less than 600 feet in the East coast areas and less than 1,500 feet for the Gulf of Mexico and offshore California areas of the Pacific.[13] In 1975 the offshore exploratory drilling cost for the industry was approximately $4,300,000/day and planned increases for 1976 over 1975 are 7.8 percent.[14]

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[12] American Petroleum Institute, Environmental Protection Laws and Regulations Related to Exploration Drilling, Production and Gas Processing Plant Operations, API Bulletin D18, 1st ed., Washington, D.C., March 1976.

[13] Speer, in "Lengthy World Mobile-Rig Surplus Seen," p. 130.

[14] W. Plamondon, Director of Sales, Zapata Offshore, in "Lengthy World Mobile-Rig Surplus Seen," p. 130.

TABLE 2-15

PLATFORM WATER DEPTH CAPABILITY

OSC AREA	WATER DEPTH OF TRACTS CURRENTLY LEASED (meters)	MAXIMUM DEPTH OF WATER AT PLATFORM LOCATIONS[a] [(meters) (feet)]		OPERATOR AND PLATFORM IDENTIFIER
Atlantic				
Baltimore Canyon	to 200	-		
Gulf of Mexico	to 600	315	(1,020)	Shell Cognac
Southern California	to 750	262	(850)	Exxon Hondo

[a]Current or planned and under construction.

Table 2-16 shows the estimated discoverable and known reserves offshore the United States. The level of activity in the Atlantic will depend on the size of the oil and gas reserves that are discovered. The first lease sale in the Atlantic was held by the Department of Interior on August 17, 1976. In this lease sale 101 tracts out of 154 offered were acquired by the industry in the Baltimore Canyon through 47 to 92 miles off of New Jersey and Delaware, as shown in Figure 2-7. Other prospective petroleum provinces in the Atlantic are also shown in Figure 2-8.

If USGS resource estimates are verified, these tracts could contain 400 million to 1.4 billion barrels of oil and 2.6 to 9.4 trillion ft^3 of gas. Projections of drilling and production in new areas are greatly dependent upon the results of early exploratory efforts. However, development and production activities have been estimated;[15] these are given in Tables 2-17 and 2-18. To develop the Santa Ynez field, where Hondo will operate, and the nearby Pescado and Sacate offshore fields, it is estimated that three to five platforms will be required and may be supplemented by one or more subsea production systems.[16]

Using the estimates given in Tables 2-17 and 2-18 and assuming an exponential decline rate of 5 percent on current oil production and 14 percent on current gas production, offshore activities for the time frame to 1985 would be as shown in Table 2-19.

Based upon the drilling activity shown in Table 2-19 and an assumed drilling program of 30 days in the Pacific and Gulf of Mexico and 45 days in the Atlantic, with 75 percent availability, an average of 22 drilling rigs would be working in the Pacific offshore California; 36 in the Gulf of Mexico; and 11 in the Atlantic. These totals would include mobile rigs as well as platform-based rigs, but exclude service rig activities. Recent data from the Gulf of Mexico operations[17] indicate that 467 new major (two or

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[15]U.S. Department of the Interior, Environmental Impact Statements for Oil and Gas Lease Sales on the Outer Continental Shelf. Lease sales CI, 33, 34, 35, 39, 40, 41, and 42 are included herein.

[16]"Alaska and California on Threshold of Exploratory Expansion," Offshore 36(70) (June 20, 1976): 94-95.

[17]Bynum, "Survey Indicates Gulf of Mexico Equipment Needs," Oil and Gas Journal 74(51) (December 20, 1976): 49.

TABLE 2-16

U.S. OFFSHORE OIL AND GAS RESOURCES AND RESERVES

	RESERVES		ESTIMATED UNDISCOVERED RESOURCES		
	OIL (10^9 bbl)	GAS (10^{12} ft^3)	OIL (10^9 bbl)	GAS (10^{12} ft^3)	GAS LIQUID (10^9 bbl)
Alaska	0.150	0.145	3-31	8-80	1.1
Pacific	1.116	0.463	2-5	2-6	0.1
Gulf of Mexico	2.262	35.348	3-8	18-91	1.3
Atlantic	-	-	0-6	0-22	0.3
TOTAL	3.528	35.956	8-50	28-199	2.8
STATISTICAL MEAN	-	-	26	107	-

Source: U.S. Department of the Interior, Geological Survey, in Oil and Gas Journal 74(34) (August 23, 1976): 160.

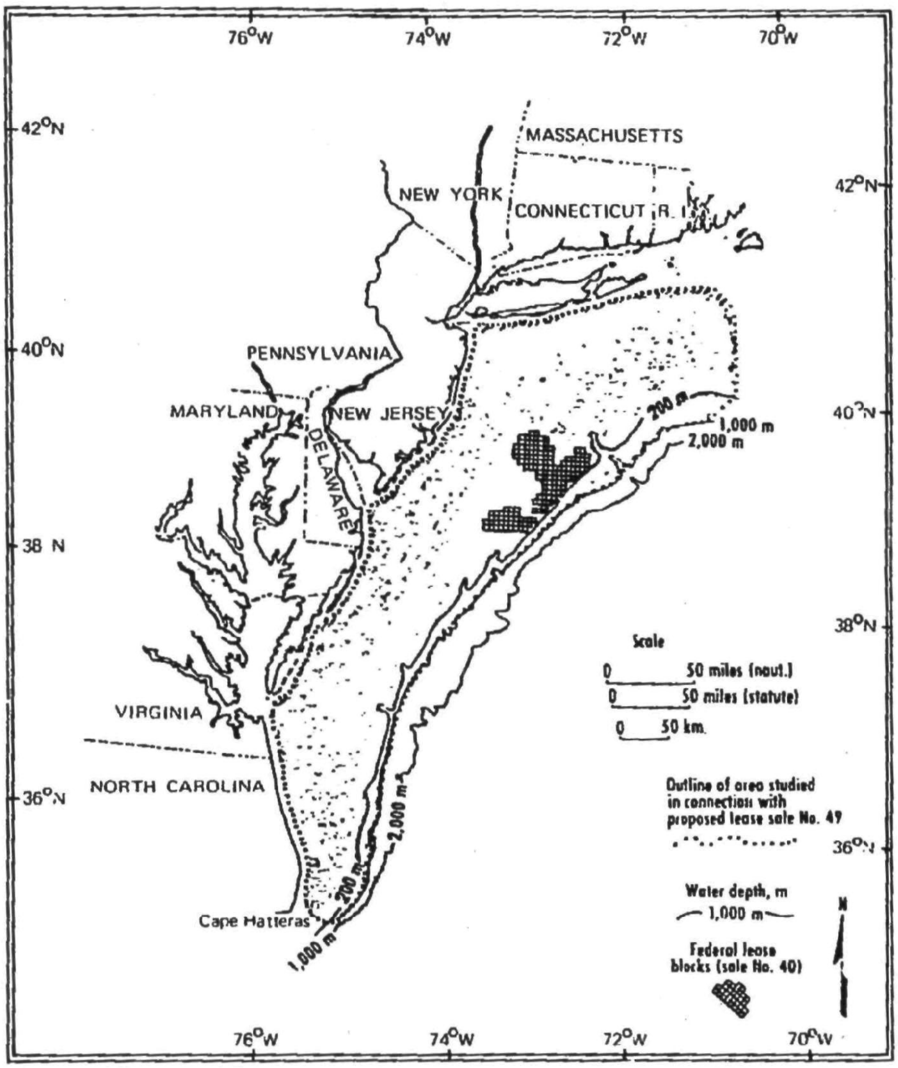


Figure 2-7. Offshore leasing areas in the Mid-Atlantic Region. (R.E. Mattick, P.A. Scholl, K.C. Bayer, U.S. Geological Survey, "Second Atlantic Sale May Involve Tracts Off Virginia, Maryland," Oil and Gas Journal 74(47) (November 22, 1976): 168.)

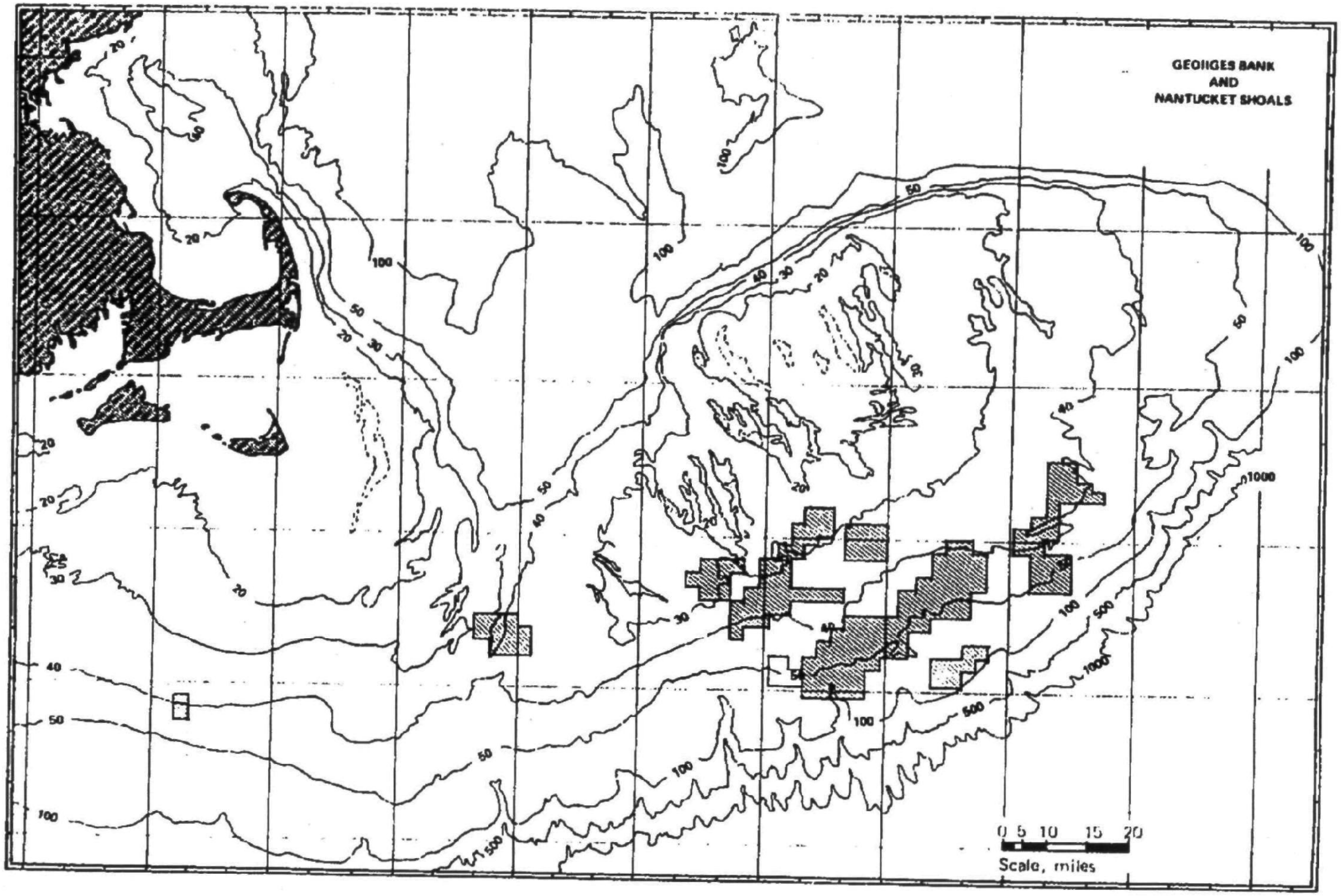


Figure 2-8. Offshore leasing areas on the Georges Bank of primary interest to the petroleum industry. (New England Regional Commission, Fishing and Petroleum Interactions on Georges Bank, Boston, Mass. 1976.)

TABLE 2-17

PROJECTED OIL AND GAS PRODUCTION IN NEW AREAS ON THE OUTER CONTINENTAL SHELF

OFFSHORE AREA	OCS LEASE SALE NO.	TIME FRAME	ESTIMATED NO. OF PLATFORMS	ESTIMATED NO. OF WELLS	OIL PRODUCTION (BARRELS PER DAY)	GAS PRODUCTION (THOUSANDS OF FT^3 PER DAY)
PACIFIC						
N. Gulf of Alaska	39	1986 (Peak)	22	900	550,000	905,000
Lower Cook Inlet	CI	1984-85 (Peak)	23	562	930,000	465,000
Southern California	35	1981			269,000	
		1987			762,000	
		2000	14-60	860-5,455	1,000,000	
GULF OF MEXICO						
Texas	34	NS	160-275	700-900	6,000-12,000	900,000-1,500,000
Louisiana	33	NS	80-120	600-1,200	50,000-110,000	1,000,000-2,000,000
Outer Continental Shelf	41	NS	20-50	150-400	35,000-120,000	500,000-1,100,000
ATLANTIC						
Mid-Atlantic	40	NS	10-50	260-1,455	90,000-320,000	850,000-3,000,000
North Atlantic	42	NS	10-25	260-724	53,000-181,000	470,000-1,540,000

Source: U.S. Department of the Interior, Environmental Impact Statements for Oil and Gas Lease Sales on the Outer Continental Shelf. Lease Sales CI, 33, 34, 35, 39, 40, 41, and 42 are included herein.

TABLE 2-18

PROJECTED PRODUCTION FROM
NEW FEDERAL OFFSHORE AREAS IN 1985[a]

AREA	EXPECTED VOLUME OF PRODUCTION	
	OIL (10^6 bbl)	GAS (10^6 bbl)
OCS Atlantic	145	340
Gulf of Mexico	197	1,692
Pacific	165	180
Alaska	465	254

[a]Assuming constant 1975 dollar costs, oil price of \$12/bbl, gas price of \$1.25/MCF and Bureau of Land Management estimates of areas to be leased through 1978.

Source: Arthur D. Little, Inc., OCS Oil and Gas Costs and Production Volumes - Their Effect on the Nation's Energy Balance to 1990, for the U.S. Department of Interior, Bureau of Land Management, Contract No. 08550-CTS-48, December 1976, as cited in personal communication with F.W. Mansvelt-Beck, Arthur D. Little, Inc., Cambridge, Mass., December 4, 1976.

TABLE 2-19

SUMMARY OF PROJECTED OFFSHORE ACTIVITIES, 1985

AREA	CUMULATIVE WELLS DRILLED TO 1985		NUMBER OF PRODUCTION PLATFORMS	PRODUCTION 1985	
	NUMBER	TOTAL FOOTAGE		OIL (10^6 bbl)	GAS (10^9 ft^3)
PACIFIC:					
Federal - 1976 existing fields	-	-	5	9[c]	1[c]
New areas	916	9,160,000	16	165[d]	180[d]
California State - 1976 existing[a]	-	-	16[b]	14[c]	2[c]
				188	183
GULF OF MEXICO:					
Federal - 1976 existing fields	-	-	669	175[c]	1,122[c]
New areas	3,000	30,000,000	300	197[d]	1,692[d]
				372	2,814
ATLANTIC:					
North - New areas	600	9,000,000	4	36	90
Middle - New areas			12	109	250
				145[d]	340[d]

[a] Assumes no expansion of Elwood South, Carpenteria or Summerland offshore fields or other fields in state waters is permitted. Expansion of these three fields if begun in 1977 could result in drilling 53 additional wells and production totals of 22×10^6 bbl of oil and 8×10^9 ft^3 of gas to offshore facilities in California state waters in 1985.

[b] Includes existing manmade islands.

[c] Based upon a 5 percent exponential decline in oil production and a 14 percent exponential decline in gas production,

$$\text{Production}\Big|_{1985} = \text{Production}\Big|_{1975} \cdot e^{-at}$$

where a = percent decline ÷ 100 and t = years elapsed (10).

[d] See Table 2-18.

more wells) platforms could exist in the Gulf, in the 1985 time frame. Actual facilities requirements will depend upon the economics of the petroleum resources discovered.
Table 2-20 indicates projected platforms offshore California.

TABLE 2-20

PROJECTED PLATFORMS OFFSHORE CALIFORNIA, 1985

AREA, UNIT OR FIELD	1976 EXISTING	1985 PROJECTED
Santa Ynez Unit (Hondo Offshore, Pescado Offshore, Sacate Offshore)	1[a]	3
Carpenteria Offshore	4	5
Dos Cuardras Offshore	3	4
Hueneme Offshore	-	1
Pitas Point Unit	-	1
Santa Clara Unit (San Miguelito Offshore, Sockeye Offshore)	-	3
San Pedro Bay	-	7
TOTAL	8	24

[a]Under construction.

CHAPTER THREE

TECHNOLOGY OF OFFSHORE OIL AND GAS PRODUCTION

3.1 Introduction

This section of the report describes the technology and current practices to develop oil and natural gas resources beneath the sea. Trends in technology which may be applied within the next 10 years are identified. The scope of this discussion encompasses the oil reservoir, drilling, fluids, production and processing of oil and gas offshore. The operations of specific pieces of equipment or subsystems which may be sources of emissions are covered in further detail in Chapter Four.

3.2 Geology

A well is drilled in the hope that it will penetrate some geologic structure holding commercial amounts of oil or gas. Crude oil and natural gas occur in void spaces created by the pores in sandstone or in the pore space between granules of a porous limestone. The older the formation, and the deeper it is buried, usually the more cemented are the granules forming the rock. Is is also harder and has lower porosity, less capacity to hold oil, gas and water. Most oil sands in currently producing areas offshore are soft and highly porous; in California offshore, much of the sand has little or no cement bond between the grains. Oil is held in pore space within rock or sand formation like a sponge or paper towel holds liquid. An area of oil-saturated rock is called an oil pool or reservoir, and a group of reservoirs an "oil field," or gas, as the case might be.

The exact origin of petroleum is unknown, but most theories agree on the following points. Throughout past geologic ages, ancient shallow seas became the burial ground of dead animal and plant life. In geologic time, the decomposed organic life created petroleum and natural gas, the oil mass, or gas, collected in porous rock being formed at the same time. As the sand bars and beaches of the seas of geologic past became further buried under additional sediments, the differential compaction, and flexing and shifting (faulting) of the earth or the upward invasion of a salt plug, created geologic structures in which the products of organic decompositions (oil and gas) were trapped. These geologic structures may be subtlely hidden and can be found only by geophysical surveys, careful geological work and exploratory drilling. In some areas, such as the Santa Barbara Channel, natural seeps of oil occur which give the explorationist hopeful indications of larger reservoirs. A porous formation, the reservoir, must be overlain and sealed by an impermeable layer of shale or anhydrite, to complete the oil or gas trap. Figure 3-1, although highly idealized, graphically illustrates various types of geologic structures one might search for, thousands of feet below the surface. Gas, oil and water separate within the structure and reservoir according to their specific gravities, water being the heaviest. "Associated gas" is gas dissolved in the oil and held in solution because of the formation pressure. It comes out of the oil during its production, like bubbles from a freshly opened bottle of ginger ale.

Many of the oil reservoirs of the Gulf of Mexico are formed by salt domes -- thick salt plugs that have pushed up and through zones of earth weakness, and domed the rock over it into oil traps. They are highly cracked or faulted. Several sedimentary rock zones often produce at the same well. In California, faulted blocks of porous sedimentary formations form many of the oil and gas structures.

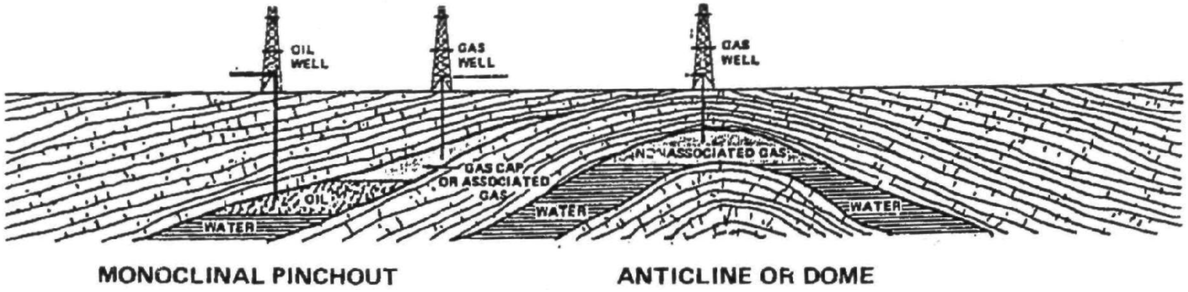
In general, most oil reservoirs are highly complex, geologically speaking, and might well be a combination of several types of structures. Also, at a specific location, oil and/or gas might occur in several zones of differing geologic age and, of course, depth.

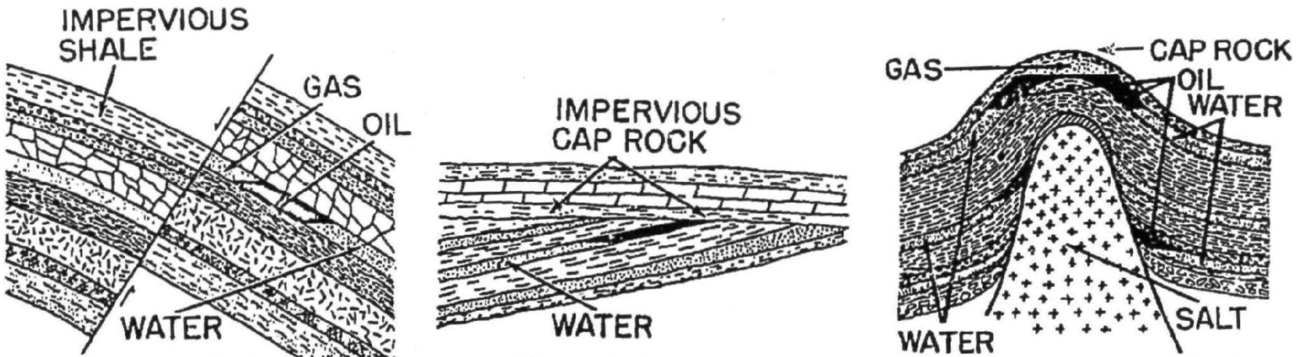
3.3 Drilling

3.3.1 Drilling Rigs

A drilling rig is basically a derrick; a drawworks, equipment to lift pipe into and out of the hole; a system for turning pipe (rotary table) to which is attached a drill bit; and a drilling fluids circulating system.

The drawworks and rotary table on offshore rigs are driven by electric motors. Electricity for rig operations may be provided by submarine cable to shore, or more commonly is generated onboard by diesel engines on No. 2 fuel. The installed diesel capacity on an offshore rig ranges from 2,500 hp to as high as 10,000 hp in the case of some drill ships.





This is a trap resulting from faulting in which the block on the right has moved up with respect to the one on the left.

Oil is trapped under an unconformity in this illustration.

Salt domes often deform overlying rocks to form traps like the one shown here

Figure 3-1. Idealized geologic structures in which offshore oil and gas occurs. (For upper illustrations, Maynard M. Stephens, "Vulnerability of Natural Gas Systems," Department of the Interior and Defense Civil Prepardness Agency, Washington, D.C., June 1970. For lower illustrations, Committee on Vocation Training, Primer of Oil and Gas Production (Dallas, Texas: American Petroleum Institute, 1976), Figs. 3,4,5, p. 9.)

A well is drilled by rotating a specially designed drill bit at the end of drill pipe. Pipe is added to the "drill string" as the hole gets deeper. Drilling fluid or mud circulates constantly through the pipe as drilling progresses, balancing the pressure of the geologic formations, cleaning the drill cuttings from the bottom of the hole, and carrying them to the surface.

When the drill bit wears out or another type of bit is needed to drill a particular formation, the drill string is pulled out of the hole, a 90-foot section of pipe at a time. A "trip" can take 4 hours or more in each direction. However, tripping is a normal and necessary part of the drilling program.

An offshore exploratory drilling rig has all of the features of one used solely onshore, but it must be further totally self-contained with racks for drill pipe, the drilling machinery, tanks for and devices to handle drilling fluids, fuel storage, and living quarters for the crew. Final well completion is often done with equipment of the production platform, discussed later.

The history of offshore rig development is traced by R.L. Geer.[1] He points out that in the early 1930's, land type oil derricks were mounted on barges and floated into the marsh lands of Louisiana. Nearshore wells were being drilled at this time in California off of long docks, some of which can still be seen. Soon jackup and spud barges became popular in Louisiana. By 1953, a Navy 176-foot patrol vessel, "Submarex" was made into a floating drill ship, a "deep" water venture. Cuss I, a 260-foot Navy barge also was constructed in 1956 for such drilling. At present, four types of rigs are popularly used: the jack-up, submersible, the semisubmersible and drill ship. Figure 3-2 illustrates the types of vessels in use today and the maximum water depths in which they can operate.

A jack-up type rig has considerable popularity in relatively shallow waters, up to 300 feet in depth; submersibles to 40 feet. Semisubmersibles and drilling vessels are used in deeper water.

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[1] R.L. Geer, "Offshore Drilling and Production Technology-Where Do We Stand and Where Are We Headed," Paper, Third Annual Meeting, American Petroleum Institute, Denver, Colorado, April 9-11, 1973.

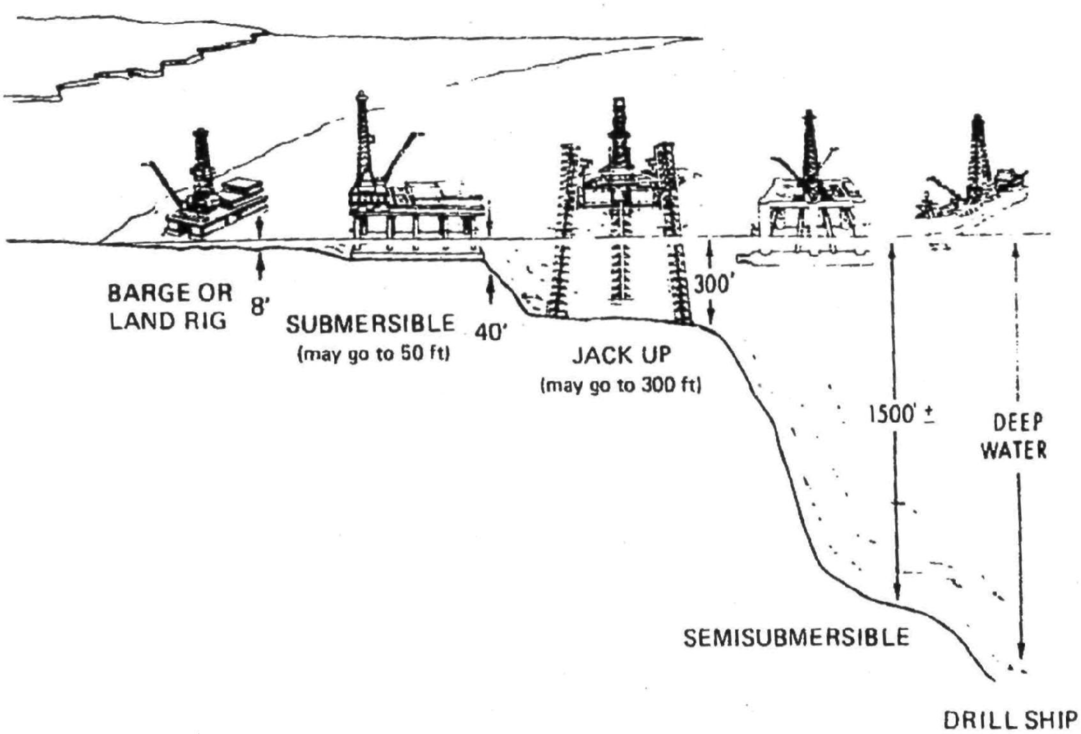

Figure 3-2. Trend in design as deeper water drilling becomes necessary. (M.V. Adams, C.B. John, and R.F. Kelly, "Mineral Resources Management of Outer Continental Shelf," U.S. Department of the Interior, Geological Survey, Circular 720, Reston, Virginia, 1975.)

The trend in deeper water drilling has led to other types of vessels. The drill ship Discoverer Seven Seas, owned by the Offshore Company, is being built for 6,000 feet of water. It should be ready for activity soon. This rig will have the capability to drill in the deepest water. Most semisubmersibles can operate in water depths up to 1,000 feet but three vessels being built are for use in water depths up to 3,000 feet. At present, there are no active wells in sea depths beyond 900 feet.

The rig chosen for use at a specific location is determined by water depth, environmental criteria, type of sea bottom, depth of drilling, wind and hurricane history of the area, rig availability contract terms and other factors. While a semisubmersible may operate either sitting on the ocean floor or floating, it is designed to operate as a floater in deep water. Anchoring becomes a most exact science so as to provide for a drilling platform that stays over the hole throughout any severity of wave action and weather that might be encountered.

3.3.2 Drilling Fluids

3.3.2.1 Purpose

There are constantly changing conditions as the drill bit penetrates the ground. At the surface, soft muds and silt cover the ocean floor; this layer can be several hundred feet thick. Soft semi-compacted materials are usually encountered below this and, in-depth, better consolidated materials. As the bit penetrates deeper, shale, salt, gypsum, sulfur, limestone or sandstone beds may be drilled. Each geologic layer has a different drilling characteristic related to its geologic age, physical and chemical composition.

As the drill penetrates deeper, the reservoir pressure in porous zones holding fluids usually increases with depth at a rate equal to the hydrostatic head of water. That is, for every foot of depth, one can expect an increase in pressure of about 0.433 to 0.465 psi, depending on the salt concentration in the water. For example, at 6,000 feet, a possible bottom hole pressure can be expected of about 2,700 psi. Sometimes geological conditions cause pressures in excess of this formula (geopressure), but most wells encounter pressures less than those determined by this rule-of-thumb. However, the driller must be on the alert to expect excessive pressures at any time.

Temperature also increases in depth. The geothermal gradient varies somewhat by locality, but in general, starting at an average surface temperature of 50° F to 60° F, the temperature of rock formations can be expected to increase 1° F to 2° F for every 100 feet of depth. At 6,000 feet depth, one can expect an increase in bottom hole temperature with respect to that of the near surface rocks of 60° F, a total of 120° F. In deep holes, the bottom hole temperature affects the mud used to drill the well. The drilling fluid, while constantly changing its composition as drilled material is added to it, nonetheless is mostly composed of prepared bentonitic clays, caustic soda, starch, lignin or lignocellulose and barium sulphate, a weight additive. Water or oil may be used as the basics of the mud.

The mud, besides acting as bit coolant and drill cutting lifter, also holds fluids from porous formations back until proper pipe and valves can be set in the well to control flow. Should the pressure in the formation exceed that of the drilling fluid, an influx of reservoir fluid into the wellbore will occur. When such flow occurs, it is called a kick.

If the kick occurs at a stage in the drilling after conductor pipe and casing have been cemented in the hole, special heavy-duty wellhead equipment (blowout preventors) can be shut, and the pressure on the well controlled, until the mud weight is increased to the point that the mud column controls the formation pressure.

A "blowout" is a well flowing out of control as opposed to a "kick" which can be controlled by equipment on the derrick or sea bottom. Some blowout occurrences have been disastrous, causing fires, great loss of expensive drilling equipment, and uncontrolled flow of oil and gas into the environment. The extent of such accidents is discussed in Chapter Four.

3.3.2.2 Drilling Fluid Conditioning

The drilling fluids are processed to remove drilling cuttings and any entrained formation gases. This condition, known as gas-cutting of the drilling mud, can hamper drilling efficiency and result in stuck pipe and a reduction in penetration rate.

Gas also gets into the mud system when the reservoir is being drilled at a high rate of penetration, as may occur in firm sandstone formations. If penetration rate is slow, mud filtrates below the bottom of the bit can drive the gas back into the reservoir. Miller identifies three forms in which gas may occur in the mud -- free gas, entrained gas, liquid gas or solution gas.[2]

Free gas entering the drilling fluid from reservoirs immediately adapts to well-bore pressure. This results in rapid enlargement of gas bubbles rising in the annulus as the hydrostatic pressure is reduced. These gas bubbles have a short life, due to the difference between the initial internal pressure of the bubble and the external pressure of the surrounding fluid. When these gas bubbles rupture in the annulus, they tend to accumulate, creating "gas heads."

The gas moves up the annulus until the bubbles are exposed to atmospheric conditions, usually inside the degasser (gas buster) or mud/gas separator. If the gas bubble ruptures inside this separator the gas is vented to the flare line.

Some hydrocarbons, in liquid forms under the conditions of heat and pressure found in a reservoir, can flow from the reservoir to the well bore and into the mud stream and still remain liquid. In some cases, they will assume gaseous form while still in the well bore, and in other cases will flash to gaseous form in the mud pit or in a degasser.

Certain types of gases, when combined with high pressures and temperatures, enter the intramolecular structure of the drilling fluid and cause only a very small fluid volume increase.

If hydrogen sulfide is present in an alkaline drilling fluid, it is not effectively removed by aeration. Hydrogen sulfide will react with the caustic to form the alkaline salt, sodium sulfide, and water. This is a reversible reaction. The higher the pH of the drilling fluid, the more the hydrogen sulfide will react.

Hydrogen sulfide poses special problems in surface degassing the drilling fluid. As discussed above, hydrogen sulfide is extremely poisonous and is hazardous in concentrations as low as 0.1 percent by volume.

The mud conditioning system consists of a mud-gas separator and degasser vessels, and a shale shaker to separate

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[2] C.D. Miller, "Proper Handling of Gas-Cut Mud Boosts Drilling Efficiency," Oil and Gas Journal 74(13) (March 29, 1976): 167.

out drill cuttings. After the shale shaker, the mud enters open tanks, where it is stored, mixed and conditioned to maintain the desired properties.

The compactness of the surface-mud system on an offshore facility results in enclosed areas with limited ventilation. To avoid these hazardous gas concentrations, the mud pit is adequately ventilated. Gas removed from the mud through the degasser is discharged to a flare line.

Both mechanical and chemical degassing in a closed system are usually used in handling hydrogen sulfide (H_2S). The system consists of a separator and a high-energy, or vacuum, degasser as shown in Figure 3-3. All of the gas must be removed from the system and vented to the flare line before the mud is released to the open mud pits.

Some companies operating offshore have established policies to plug the hole immediately and abandon the project when sour gas is encountered. This is because most rigs are not equipped to safely handle the lethal and corrosive gas. As natural gas becomes more in demand, however, gas containing hydrogen sulfide may be produced offshore and processed for sale. Areas east of the Mississippi Delta in the Gulf are expected to contain this impurity in the gas. Except for some small H_2S content in the gas coming from the Ship Shoals area offshore Louisiana, most Gulf of Mexico wells produce sweet gas. Two wells were drilled off the point of the Delta in a high-sulfur gas area -- these are now reported as abandoned.

3.2.3 The Casing Program

As drilling progresses downward to the target zone, pipe is set in the hole at intervals of depth, so as to avoid some of the problems discussed above and to maintain the integrity of the hole. The casing program varies with depth and the local geology. A system used in a relatively low pressure area will be inadequate in a deep, high pressure formation; so, very special care is given in offshore operation to the casing program.

When the hole is started a large diameter hole is drilled, up to 36 inches in some cases. In shallower zones, a smaller hole is adequate. As soon as the drill works its way through the mud, sand, and soft, near-surface material, a conductor or surface string of relatively large diameter pipe is placed in the hole. This pipe not only holds back the surface soil and mud but prevents the flow of mud from undercutting, as drilling continues, and from undermining

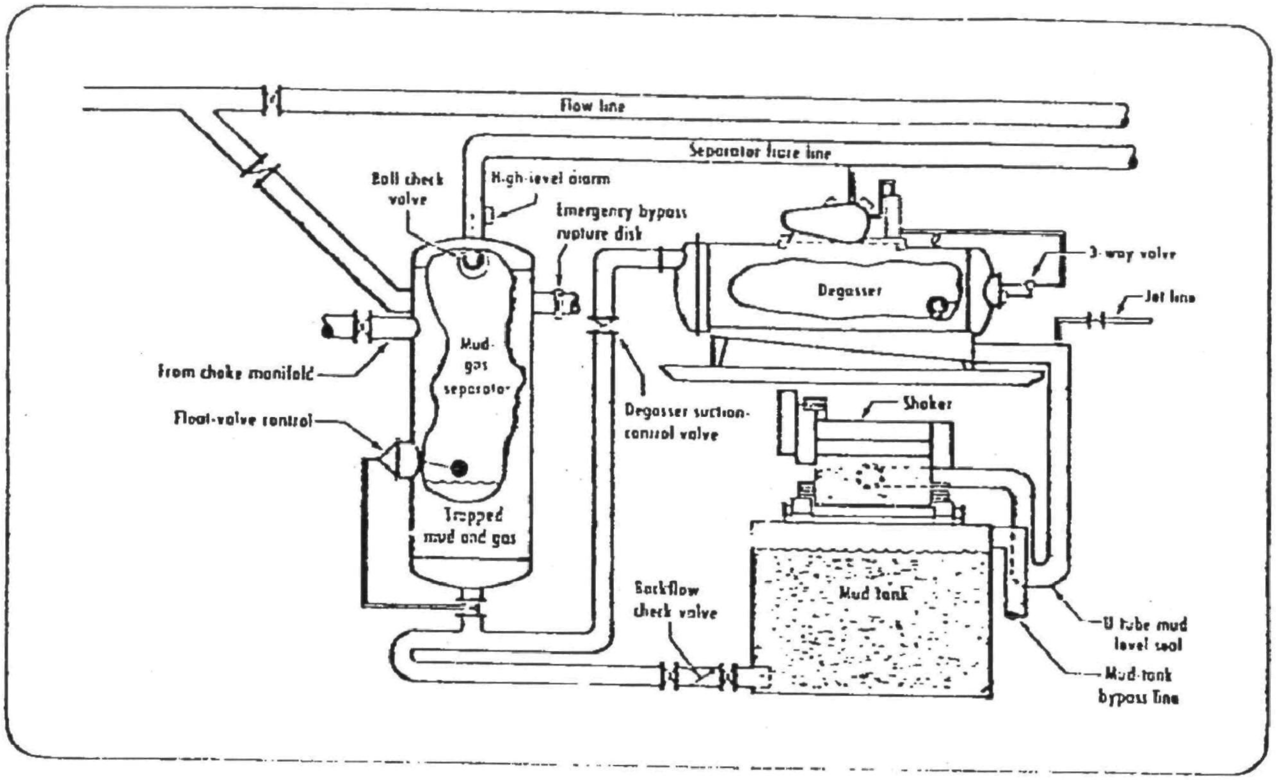

Figure 3-3. Handling toxic gas on offshore rigs. (C.D. Miller, "Proper Handling of Gas-Cut Mud Boosts Drilling Efficiency," Oil and Gas Journal 74(13) (March 29, 1976): 167.)

the seabed around the well. This string is relatively short, but in the Gulf Coastal area can be 1,500 feet or more long. A marine riser is installed to connect the conductor to the platform or drilling vessel in order to provide a path for return of the circulating drilling fluid. The joints of pipes run into the hole are 30 to 40 feet long. These are screwed or welded together as they are being run. This pipe is cemented in place by pumping a cement slurry down the inside of the pipe and allowing it to ciculate up through the annular space behind the pipe and the wall of the drilled hole, displacing the mud as it goes. Figure 3-4 illustrates the casing program.

If there are geological strata containing fresh water, the law requires that all such zones be protected from the fluids in the well. The surface pipe is cemented in place in its entirety. One function of this string is that, being held to the well wall by cement, it is firmly anchored so that it is used to support the blowout preventors. Recommendations for this equipment is made by the American Petroleum Institute.[3,4]

Usually, if the well is deeper than 5,000 or 6,000 feet an intermediate string is run. This string is also called the salt string, for in some areas salt and anhydrite/gypsum is encountered. These formations must be sealed off from the well, because they dissolve, increasing the hole size, and changing the chemical composition of the drilling mud. In areas of known faulting or higher than normal formation pressure, a shorter intermediate string may also be needed. Sometimes, several intermediate strings must be set on very deep wells.

After the anticipated oil/gas zone has been penetrated, a series of well tests are made to ensure that the well will produce enough oil and gas to be profitable. During the tests, the driller and engineer must be constantly alert, to prevent the fluids in the hole from becoming lightened by the movement of testing tools and causing the well to kick or blow out.

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[3]Subcommittee on Blowout Prevention, Blowout Prevention Equipment Systems, API RP53 (Washington, D.C.: American Petroleum Institute, February 1972).

[4]Committee on Offshore Safety and Anti-Polution Training and Motivation (OSAPTM), Training and Qualifications of Personnel in Well Control Equipment and Techniques for Drilling on Offshore Locations, API RPT3 (Washington, D.C.: American Petroleum Institute, July 1976).

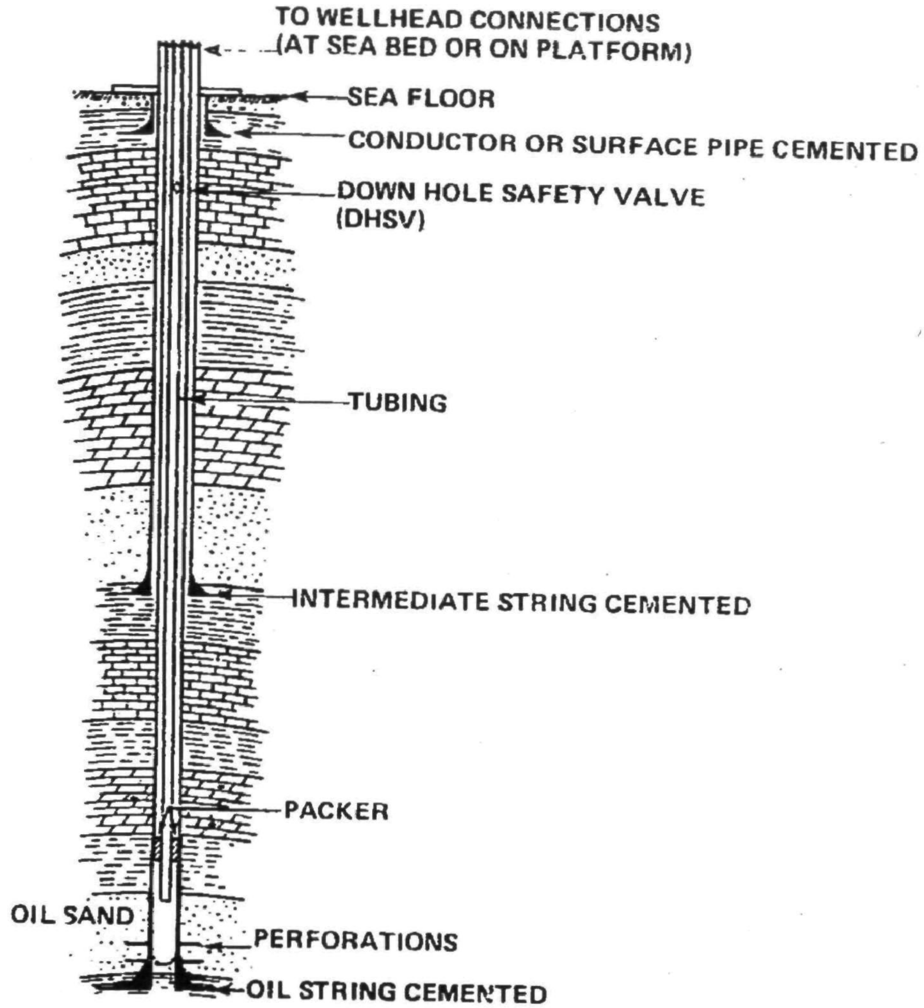

Figure 3-4. Casing program of a typical oil or gas well. The oil well is an almost vertical pipe line reaching from the sea floor to the oil pay, shown here by the sketch.

Once the decision has been reached to complete the well by "setting pipe," the final casing (the oil string) is lowered from the surface to the bottom of the hole or producing formation. In some areas of the country, these lower pipe strings (liners) are hung on the intermediate string in the well on special packers so as to reduce the cost of running pipe to the surface for each string. The oil string is also cemented into place, but usually not from its top to bottom as was done with the surface pipe. The string is usually set through the "pay" formation and cemented with enough cement to firmly seal off the producing zone and area immediately above it, and to hold the pipe in the hole against the high formation pressure.

After the oil string is firmly set, special logging devices are lowered in the hole to determine the quality of the cement bond and the location of the pipe collars. The casing is perforated, for example, using a string of shaped charges accurately set in the pipe so as to penetrate the oil/gas zones accurately. If the pay zone is associated with a saltwater zone, only the upper part of the zone is perforated, if possible, to reduce water handling during production. During all this operation, the hole is full of water, the mud having been removed or squeezed behind the pipe as the plug on top of the final cement slurry was pumped into place. This water holds back the pressure of the perforated formation.

3.4 Completion of the Wells

As the casing or pipe setting process progresses, various wellhead fittings are installed to form a "Christmas tree." The number of fittings varies with the number of strings used in the hole. Each string has valves connected to it for use during the cementing process and for control during well operation.

The design of the wellhead and the completion method depends upon the size of the casings, the well location, its producing pressure and proportions of oil, gas, saltwater and sand which may be produced.

On offshore wells a subsurface or down hole safety valve (DHSV) is located in the tubing about 100 to 200 feet belcw the sea bed or mud line.[5] This valve automatically shuts off well flow in case of a sudden release of back pressure held on the flowline. If the tubing in the well is suddenly broken by an accident, the valve shuts in the well.

Two general types of wellhead completions are currently in use in offshore operations and several systems for operation in deeper water are under development.

The most common offshore completion is a platform-completed marine riser system. In this completion technique, the well controls are located on the platform, and as discussed earlier, as many as 40 wells may be completed on a single platform. Single well platforms may be used in shallow water up to 100 to 150 feet in depth. Maintenance and operation of the well are performed on the platform.

Another completion technique is the subsea wellhead. In this type of completion, shown in Figure 3-5, all well controls are located on the sea floor. Well operation and maintenance are carried out through the production flowline, or hydraulic control lines as well as with diver assistance.[6,7] The need for diver support during some operations limits the application of this completion technique to water depths of less than about 250 feet. Furthermore, a jack-up rig must be moved in for well service. Subsea-completed wells may be located as far as 18,000 feet from the production platform. Advantages of subsea wells include lower vulnerability to storms and collision hazards, more rapid payoff of marginal fields, and reduced capital outlays. In some instances the use of subsea wells could facilitate larger production processing facilities on fewer offshore platforms. Between

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[5] Committee on Standardization of Offshore Safety and Anti-Pollution Equipment, Specification for Subsurface Safety Valves, API Spec 14A 1st ed. (Washington, D.C.: American Petroleum Institute, October 1973).

[6] D.L. Morrill, "Abandonment of a Subsea Well," SPE Paper 6074, Society of Petroleum Engineers Technical Symposium, New Orleans, Louisiana, October 5, 1976.

[7] D.F. Keprta, "Seafloor Wells and TFL - A Review of Nine Operating Years," SPE Paper 6072, Society of Petroleum Engineers Technical Symposium, New Orleans, Louisiana, October 5, 1976.

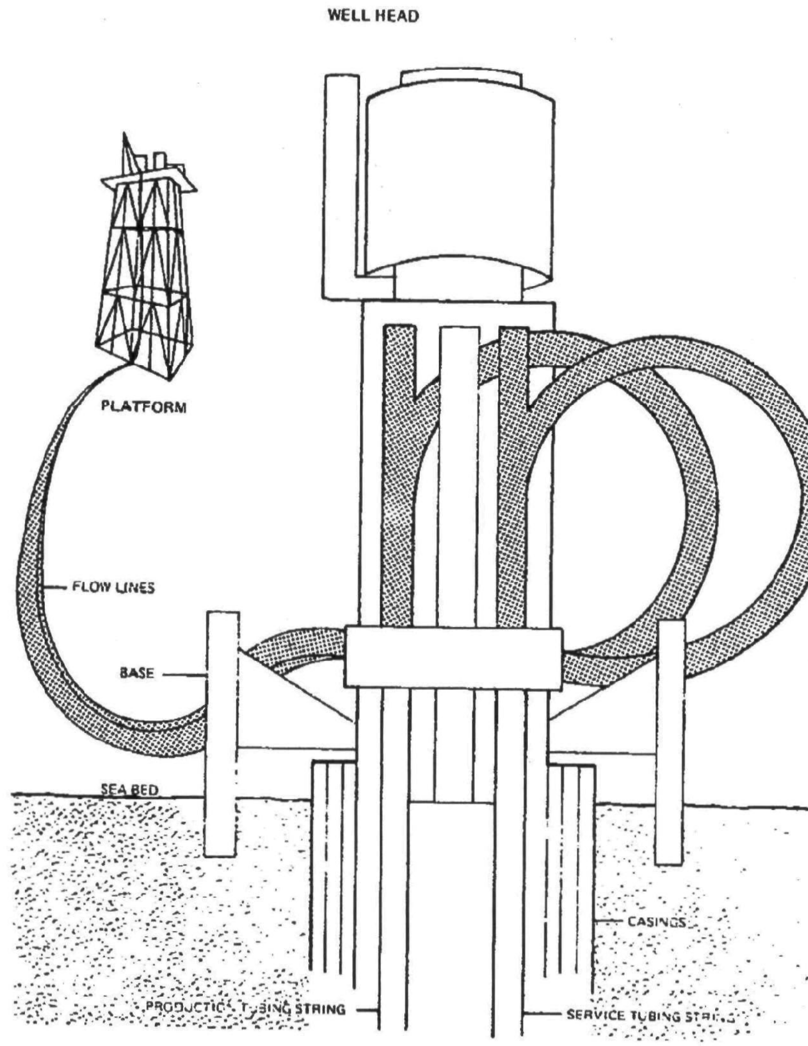

Figure 3-5. A subsea wellhead.

1960 and 1974 some 106 subsea wells were completed on the outer continental shelves of the free world in water depths ranging from 50 to 375 feet.[8]

The experience of Phillips in the North Sea reveals the problems of subsea wells.[9] Routine maintenance operations such as replacing downhole safety valves, other wireline work, and repair of the Christmas tree valves generally requires the use of a floating drilling vessel. Considering weather factors, mobilization cost, rig availability and cost, even the simplest job could cost $500,000 and cover 10 days. This compares with platform well costs for the same operations of only a few thousand dollars and a required time of 6 hours. When lost production during well downtime is considered, the spread in maintenance costs is even greater. In addition, the long submarine flowline to a seabed well can reduce well productive capacity to 25 to 50 percent of that attainable through similar platform wells.

In deeper waters where diver assistance is not feasible and platform structures are infeasible or prohibitively costly, remotely operated subsea completion and production is envisioned. Currently under development are several production completion systems for water depths in excess of 1,000 feet. These include the Exxon Submerged Production System (SPS),[10,11,12] the SEAL System and the Lockheed Dry Atmosphere System. Although these systems are not fully

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[8]R.L. Geer, "Offshore Technology, What Are the Limits," Petroleum Engineer 48(1) (January 1976): 26.

[9]T.J. Robin, R.S. Hoch, and D.A. Johnson, "Subsea Well Development and Producing Experience in the Ekofisk Field," SPE Paper 6073, Society of Petroleum Engineers Technical Symposium, New Orleans, Louisiana, October 5, 1976.

[10]J.A. Burkhardt, "Test of the Submerged Production System," SPE Paper 4623, Society of Petroleum Engineers, Dallas, Texas, October 1973.

[11]J.A. Burkhardt, "A Progress Test of the Submerged Production System," SPE Paper 5599, Society of Petroleum Engineers, Dallas, Texas, September 1975.

[12]T.W. Childers and W.D. Loth, "Test of a Submerged Production System - Progress Report," SPE Paper 6075, Society of Petroleum Engineers Technical Symposium, New Orleans, Louisiana, October 5, 1976.

operational, they are under various stages of development and testing and may extend the industry's capabilities for deep water production in the next 10 years. These systems generally require nearby surface or floating facilities if the production must be pumped more than a few miles.

When everything is ready to start the well producing, the fluid in the hole is carefully unloaded by swabbing to lower the height of the water load. If there is great pressure on the oil/gas zone, the hole may unload by itself.

The riser enters the well straight down or at a slant from the platform, but may also be curved, at the seabed, in the proper direction so that the well, while serviced on a central platform, may bottom out a mile or two from it. These directionally drilled holes fan out from the platform to the bottom hole location in a predetermined point in the reservoir, within the block or tract under lease by the operator. Because most wells are 10,000 to 16,000 feet or greater in depth in the Gulf, there is adequate depth to make the deflection in the hole when it is drilled. In California, because of the occurrence of oil and gas at shallower depth of 5,000 feet or more, it is often necessary to start the hole off on a slant at the surface.

3.5 Field Development

A number of test wells are usually drilled from a mobile drilling vessel in the manner described above in order to delineate the oil and gas reservoir and to evaluate the economics of various production alternatives. These early wells are usually not completed although some might be completed as single wells not operated from a platform.

There are several alternatives for producing the oil and gas. The reserves or quantity of oil and gas estimated to be economically producible from a field under a given set of capital and operating costs is the primary factor governing the pattern of development and type of production facilities.

When reserves are limited, it may be uneconomical to invest in completion of the well and the required production and transportation facilities. The size of required investment will depend upon the water depth at the field, the proximity of the field to other oil and gas fields under production, the engineering demands of the site (severity of wave action, storm action, sea bottom conditions), the most effective spacing of wells to drain the reservoir, and other factors.

A single well completed in shallow water might have only a piling around it for protection and to serve as a working platform support. Production of oil, gas, and water from these jacketed wells flows to other platforms or to shore for processing and transportation as described below.

Wells may also be completed on the sea bed and flowed to temporary floating or permanent platforms for processing and transportation of the oil and gas. In the Ekofisk field in the North Sea in 260 feet of water, temporary production began in this manner. A converted jack-up rig was used to support the production facilities serving four subsea wells. This type of facility may occur in other fields where reserves are found to be marginal. Similarly, another area of the North Sea, the Argyll field, has been producing to a floating production facility mounted on a semisubmersible vessel in 245 feet of water.[13]

If substantial reserves of oil and gas are delineated, a fixed platform for 40 or more wells is usually established. Many companies choose to drill and complete all wells on a platform before installing the oil and gas separation equipment. Since the amount of working space available on a platform does not readily allow for both drilling and oil/gas production to take place at the same time. There are situations, however, where such efforts coexist.

Over the next 10 years, fixed platform technology will probably be limited to oil and gas development in water depths of less than 1,200 feet with most activity occurring at water depths up to 600 feet.[14] Completion and production systems discussed above, such as the Exxon SPS and Lockheed-designed Shell System, are designed for use in water depths of 2,000 feet or greater. Other new platform designs have proceeded to the prototype stage and are considered ready for full-scale application at potential savings of up to 25 percent of the cost of a conventional stiff-leg platform. Two designs are the tension-leg platform which has been tested off of California by 17 operators, and the guyed-tower platform under test by Exxon, which has application in water depths of 600 to 2,000 feet of water. All of these systems will enable development of offshore oil and gas

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[13] P. Elwes and J. Johnson, "Role of FPF's (Floating Production Facilities) in the North Sea," <u>Petroleum Engineer</u> 12(48) (October 1976): 42.

[14] M. Long, "High Costs Driving Firms Out of Deepwater Tracts," <u>Oil and Gas Journal</u> 74(43) (October 25, 1976).

resources in deeper waters on the outer continental shelf and slope in the future.

3.6 Production Facilities

The planning and design of an oil/gas production platform is dependent on several site-specific factors. Many factors must be completely investigated, including expected wave height and force, force and direction of currents, maximum wind velocities and direction, depth and pressure of the wells, rates of flow, type of production (oil and/or gas, and saltwater), character of the sea floor, types and amount of equipment needed, pollution control safety, seismic activity, and many other considerations. Since a platform can cost as much as $20,000 to $30,000 per square foot, trade-offs must be made between having space completely utilized and safe spacing between equipment, so as to eliminate situations that might result in the release of explosive and toxic gases, or a loss of flammable liquids.

The American Petroleum Institute has published a number of recommended platform installation practices.[15, 16] In the design of the platform, high priority is placed on safety and environmental and equipment protection. It is recommended that atmospheric conditions be completely understood so as to know how adequately to ventilate the structure, thus avoiding toxic conditions and fires or explosions on the platform. Avoidance of oil spills, or their containment, is given great attention.

3.6.1 Oil and Gas Separation Equipment

Fluids coming from a well are a mixture of oil, gas, sand, and saltwater, which must be separated to obtain saleable oil or natural gas. The type of equipment installed on a platform is determined by the volume, pressure, temperature and composition of the production. Figures 3-6 and 3-7

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[15] Committee on Standardization of Offshore Structures, Recommended Practice for Planning, Designing and Constructing Fixed Offshore Platforms, API RP 2A, 7th ed., (Dallas: American Petroleum Institute, January 1976).

[16] Committee on Standardization of Offshore Structures, Recommended Practice for Production Facilities on Offshore Structures, API RP 2G, 1st ed., (Dallas: American Petroleum Institute, January 1974).

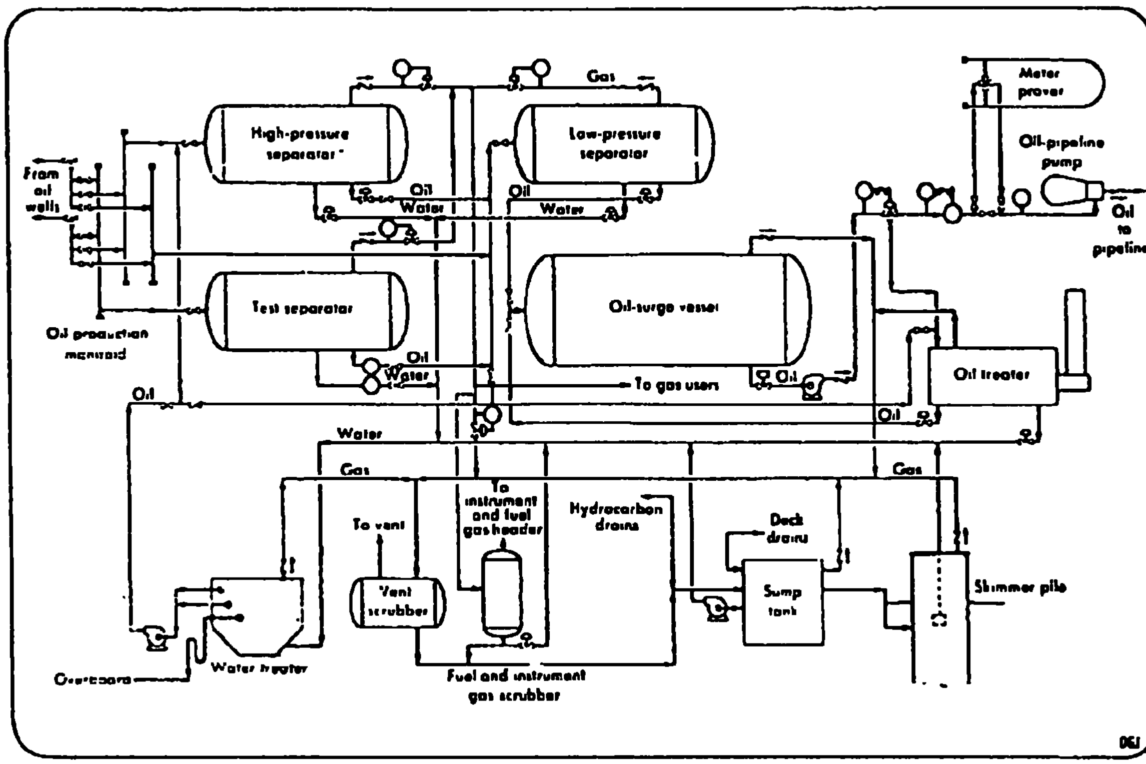


Figure 3-6. Oil processing scheme. (R.F. Kryska and B. Lindsey, Offshore Process System Design Requires Exact Planning, International Petroleum Exposition, Tulsa, Oklahoma, May 17-21, 1976.)

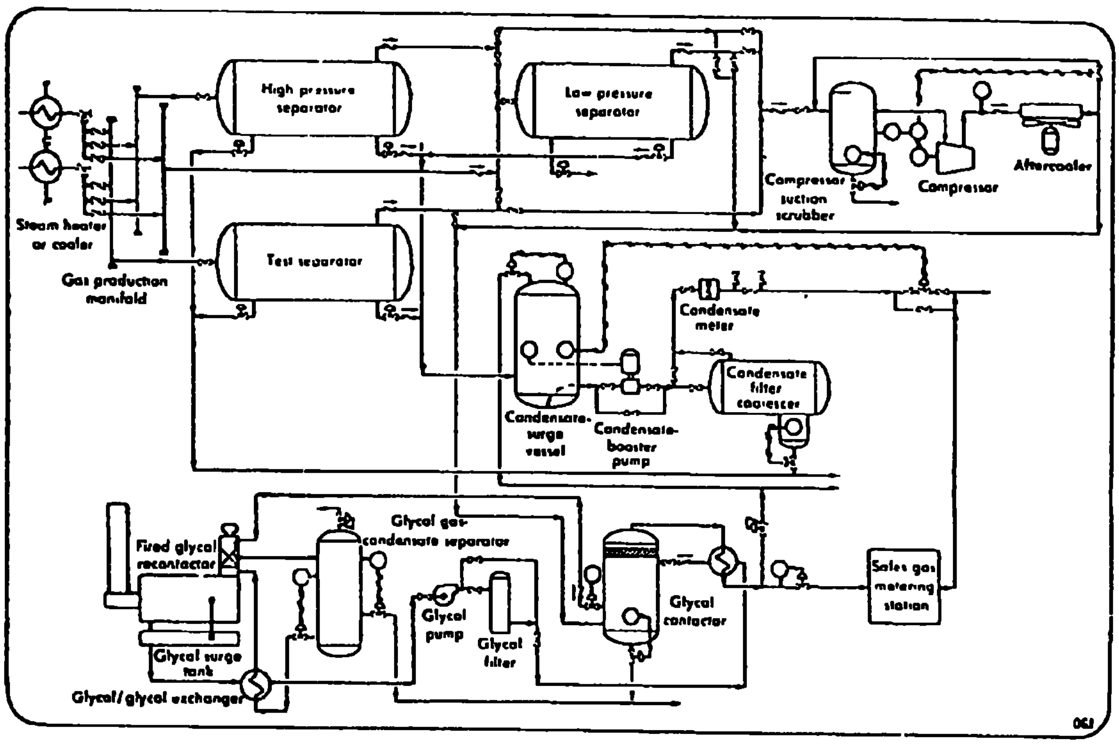


Figure 3-7. Gas processing scheme. (F.R. Kryska and B. Lindsey, Offshore Process System Design Requires Exact Planning, International Petroleum Exposition, Tulsa, Oklahoma, May 17-21, 1976.)

illustrate the basic steps of processing through which the fluids coming from the well pass. Actual platform complexes combine features of these two schemes as shown in Figure 3-8. In some cases where shore is nearby, some or all steps in gas and liquid separation are often done on land.

The fluids in a well are usually at sufficiently high pressure early in the life of the well so that they reach the platform under natural forces. These forces include water, a gas cap or solution gas pressure on the oil and water in the reservoir. As these natural forces are depleted flow rates into the well bore decrease. Since the column of fluids in the well applies pressure against the flow, pumps or artificial lift equipment are often installed to keep the wells pumped off.

Additional investment in pressure maintenance and pumping equipment can slow the decline in the production rates of oil. Pressure in the reservoir may be maintained by injecting water or gas back into the producing formation. This does not usually eliminate the need for pumping equipment, but is often carried out as part of an entire program to obtain as much oil and gas as can be economically produced.

Pumping or artificial lifting techniques to raise the produced fluids to the surface are of four types. The two most common lift techniques on offshore platforms are gas lift and electric submergible pumps. Less common on offshore facilities is power fluid (oil or water) lifting. Beam pumping or sucker-rod pumping, a technique which is ubiquitous in oil fields on land, is rare offshore.

Gas lift involves the injection of a part of the processed gas stream back down the well at high pressure to operate a series of gas-operated lifting valves in the tubing. Pressure work in the gas raises the produced fluids to the wellhead and the lifting gas is produced with the oil.

Electric submergible pumps can also be used to lift the oil. These devices, which are approximately 40 feet in length, are installed to within about 100 to 200 feet of the bottom of the well on the tubing string.

Power fluids lift techniques operate on principles similar to gas lift. Clean oil or water travels down a separate tubing string at high pressure to drive a hydraulic pump near the bottom of the well. The spent power fluid is produced along with oil and gas from the formation and a portion of the produced fluids are processed for reinjection. This is a relatively costly though efficient lifting technique which requires a clean power fluid. Sand control

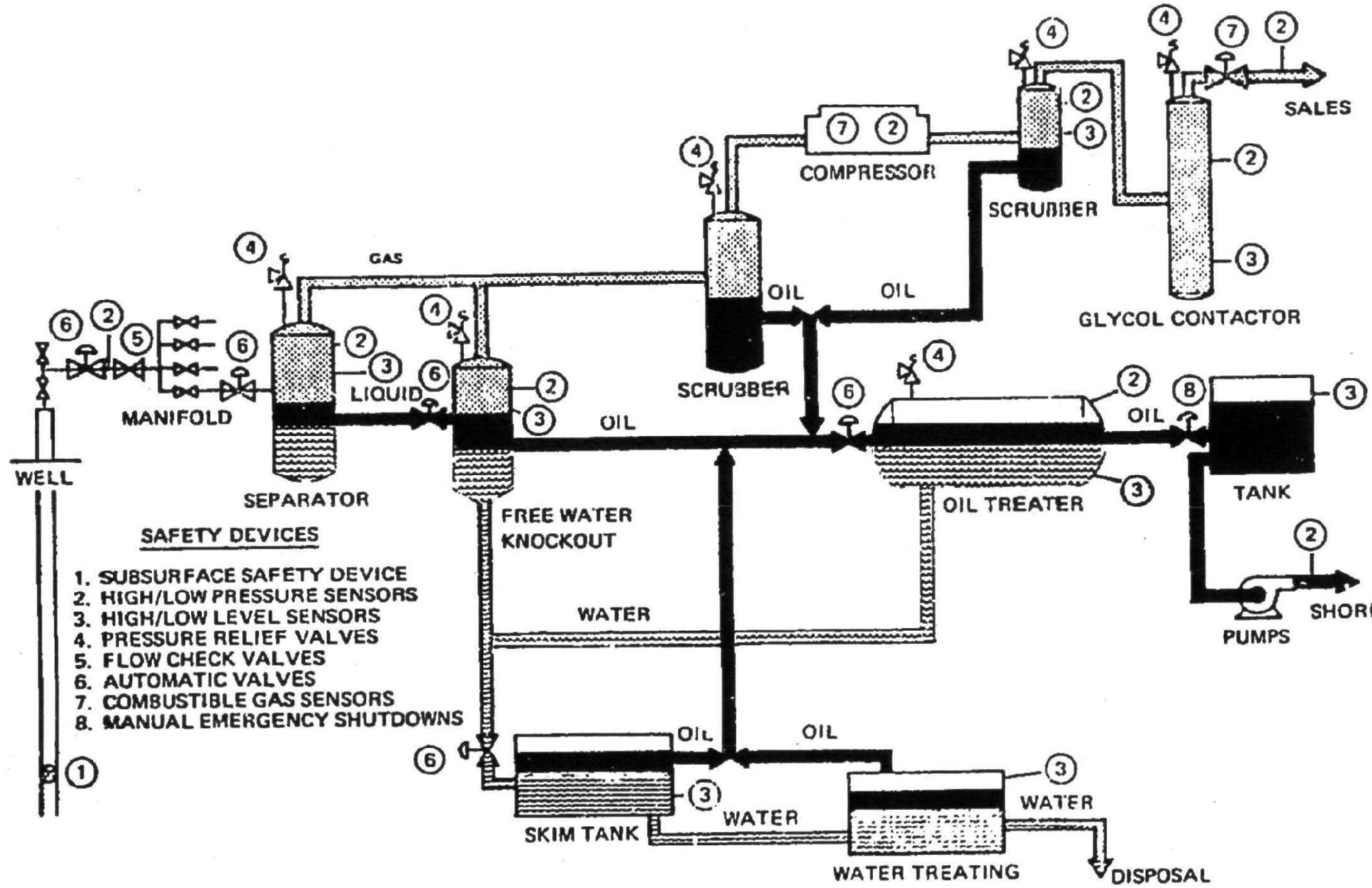


Figure 3-8. A typical production facility with safety equipment. (C.C. Taylor, "Status of Completion/Production Technology for the Gulf of Alaska and the Atlantic Coast Offshore Petroleum Operations," Resources for the Future, Inc., seminar, Washington, D.C., Dec. 5-6, 1973, Council on Environmental Quality.)

problems in most offshore California and Gulf Coast wells as well as space limitations onboard the platform are factors which have minimized use of this technique.

Beam pumping units involve a down hole pump driven by the reciprocating pumping rod. Lack of space onboard offshore facilities has limited use of this technique to only one known platform in the Gulf.

It is not unusual to have wells on the same platform that produce at different pressures (as much as 2,000 psi or so) and by different lift methods. Some wells have low bottom hole pressure and are pumped by various means discussed above. In case of high pressure production, typical of new wells in the Gulf of Mexico, three stages of gas-liquid separation take place. The gas from each stage is sent to gas treatment facilities or to the vapor recovery system, depending on its pressure. Cases were observed where some low pressure gas from the low stage separator was flared or vented (estimated at about 20 ft^3 for a barrel of oil produced). The U.S. Geological Survey has rules which restrict gas from being flared or vented except during emergencies or where special circumstances occur that make vapor recovery impractical.

The gas is compressed (before or after processing), scrubbed to remove treated entrained gas liquids or condensate (such as pentane and heavier hydrocarbons) and water vapor, and then is pipelined to shore. If hydrogen sulfide were present it could also be removed on the platform. Onshore complete natural gas processing occurs (de-ethanizing and recently demethanizing) prior to gas discharge into the main pipelines. In some cases, all of the gas processing is done onshore to save the cost of extra platform space. Unfortunately this practice also brings potential emissions closer to the population at risk.

The separation of oil-water-sand occurs in either a vertical or horizontal vessel known as a free water knockout. From there oil and water go their separate ways. Generally, some water is entrained in the oil. No more than 1 percent water is usually permitted in saleable oil. A final emulsion separator, which operates on chemical, electric or heat principles, breaks out water from the oil to make it marketable. The saltwater produced with the oil usually carries some oil in its stream. Clarification is required before water can be sent to disposal. Skim tanks are employed, followed by flotation cells to remove the entrained oil particles from the produced saltwater. Treated saltwater is disposed into wells, reinjected for pressure maintenance or dumped overboard.

Figures 3-9 and 3-10 illustrate the design and the layout of production facilities on typical production platforms in the Gulf. Figure 3-11 illustrates a shore-based scheme; Figure 3-12 shows a variety of offshore facilities installations.

The specific function and operating characteristics of each unit on an offshore facility are described in Chapter Four.

3.7 Transportation of Oil and Gas

Current offshore oil and gas operations employ pipelines and barges to move oil to shore. Some 64 submarine pipeline network systems transport 95 percent of the oil and all of the gas to shore in the Gulf of Mexico. Fourteen barge systems transport 5 percent of the offshore production in the Gulf of Mexico to shore. The latter systems are used to serve marginal or isolated fields which could not justify the construction of a new or extension of an existing submarine pipeline. In California all offshore production comes ashore by submarine pipeline. Exxon has proposed to barge the oil produced at its platform Hondo in the Santa Ynez field to refineries in northern or southern California. The configuration of transportation systems for Atlantic operations will depend upon the project economics and extent of the reserves discovered as well as environmental factors. It is possible that tanker transportation similar to that used in serving the floating production facilities at the Argyll Field in the North Sea might be utilized if very productive wells are drilled. Tanker loading is accomplished in the North Sea at a single point mooring buoy. Produced gas is flared in those operations.

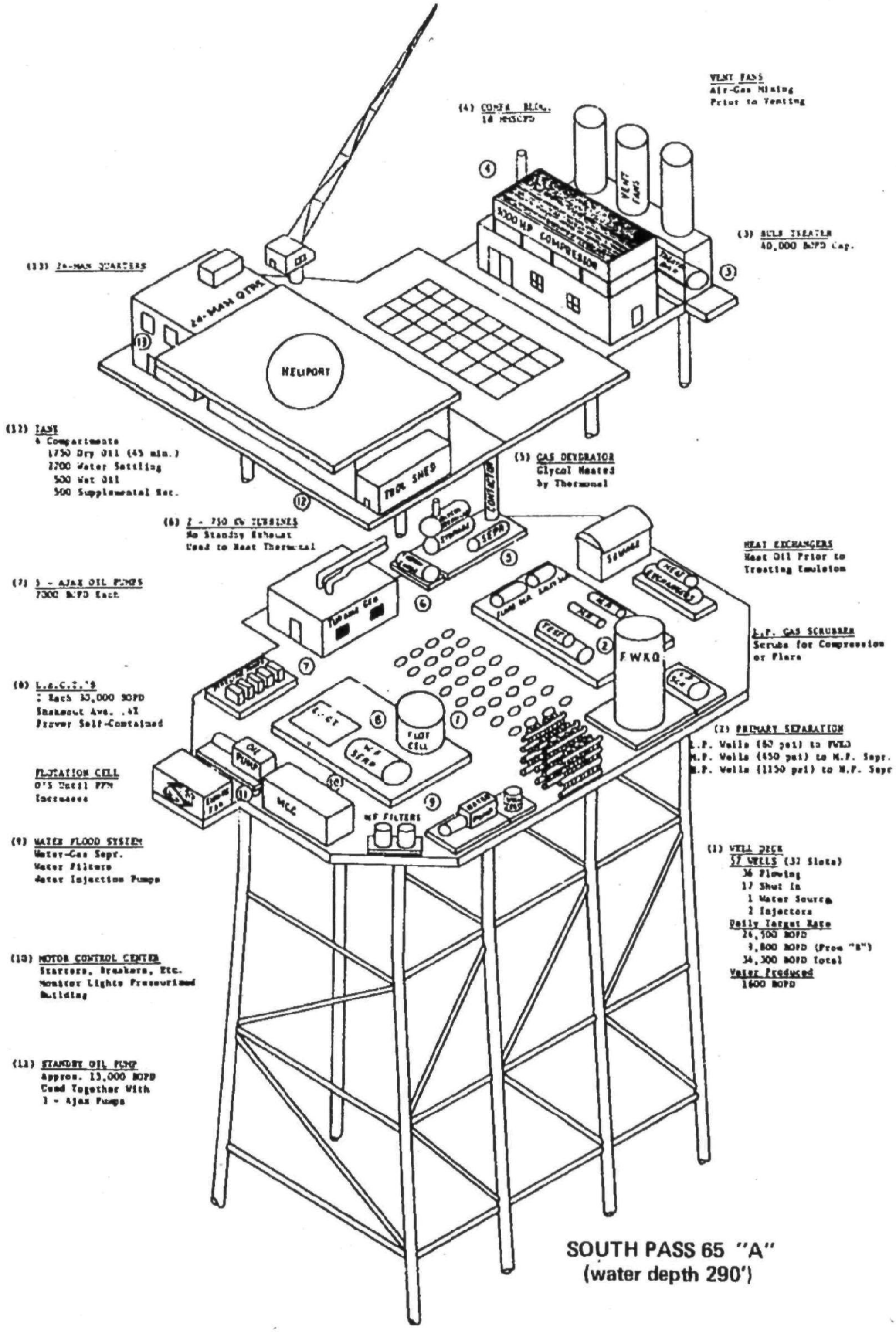
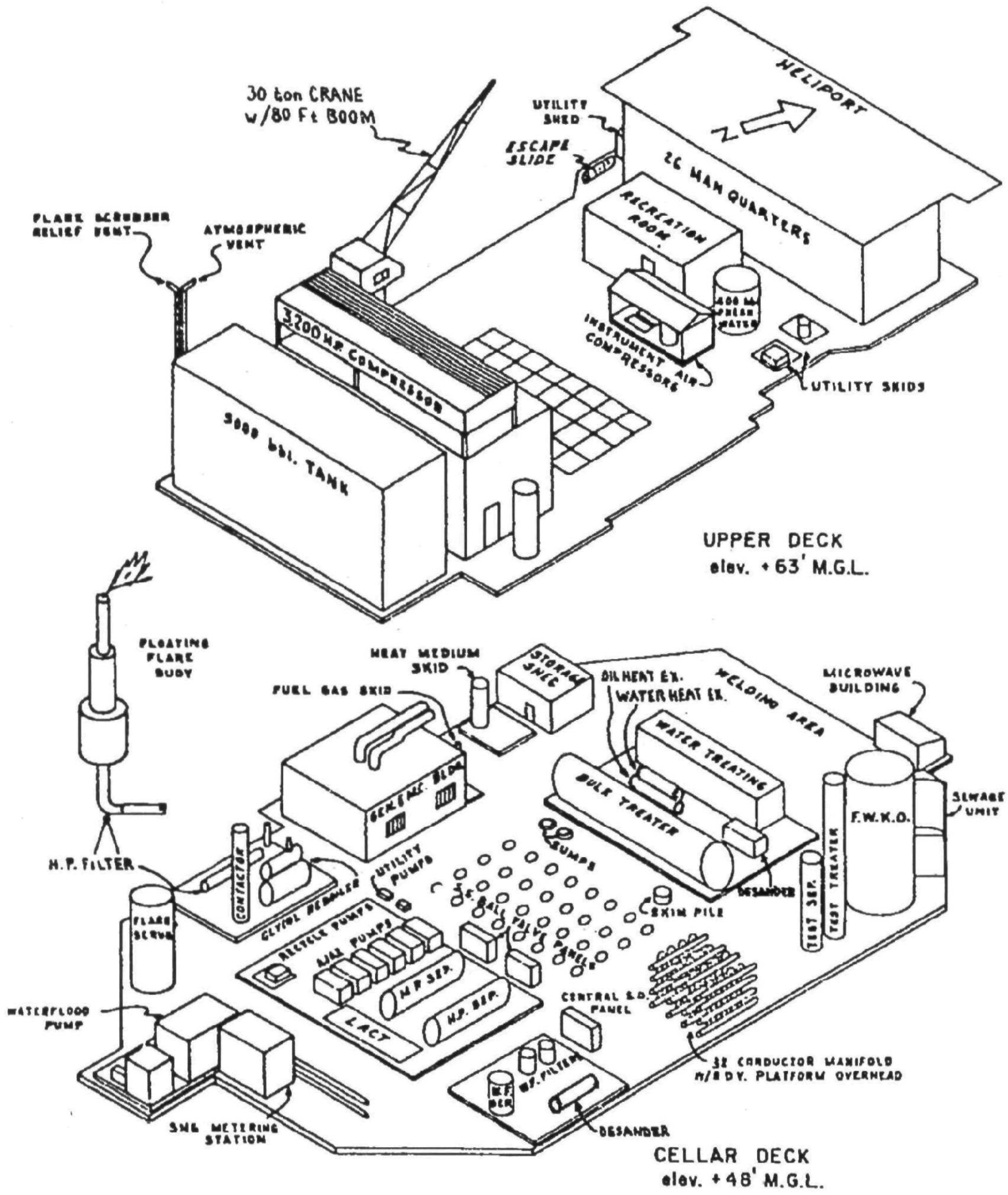


Figure 3-9. A pictorial sketch of the equipment layout on Platform A. (Shell Oil Co., New Orleans, Louisiana.)



SOUTH PASS 65 'B'

WATER DEPTH 290'

Figure 3-10. A pictorial sketch of the equipment on a production platform. (Shell Oil Co., New Orleans, Louisiana.)

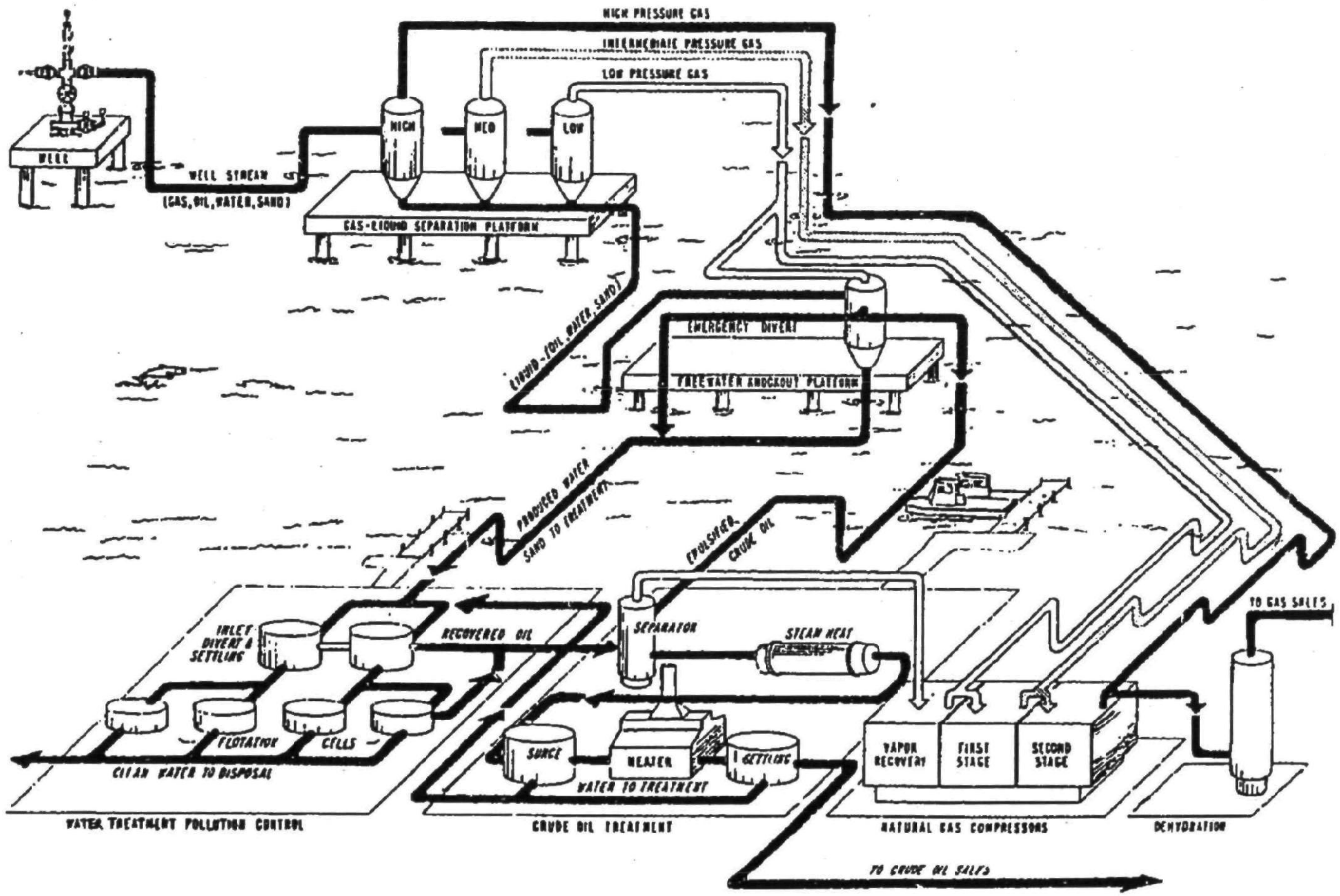


Figure 3-11. Flow diagram of produced fluids, South Pass blocks 24 and 27 fields. (Shell Oil Company.)

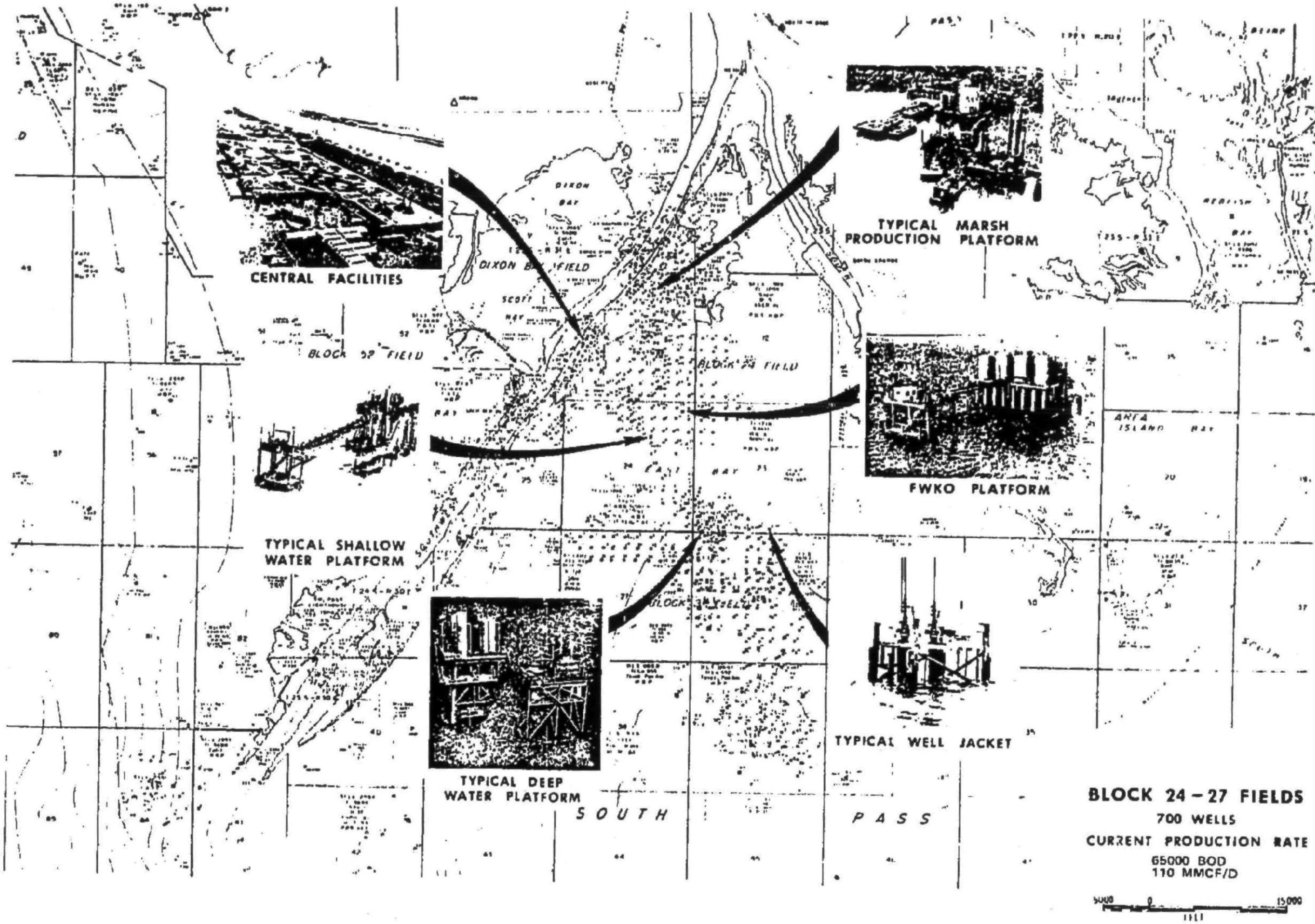


Figure 3-12. Typical platforms and facilities used in block 24-27 fields Offshore Louisiana. (M.M. Stephens, "Vulnerability of Total Petroleum Systems," Department of Interior Office of Oil and Gas and Defense, Civil Preparedness Agency, Washington, D.C. May 1973.)

CHAPTER FOUR

EMISSION SOURCES

4.1 Introduction

The emission sources inherent in offshore operations are the same in many respects as the emission sources onshore, the major difference found in the very nature of offshore operations. The offshore platform usually has either one or two decks, each no larger than about a 200-ft square. Within this space, not only must all wells, rigs, and process equipment be located, but because of the often long distances from shore, the platform must also have living quarters, power generating equipment, and product sendout equipment.

There is a very real danger of a major catastrophe resulting from a fire on an offshore platform because of the crowded conditions and the combustibility of the products. Special precautions are taken on all platforms to minimize the probability of such an occurence. The platforms observed by the project team were well maintained, run more like a ship than an oil field. There were no obvious leaks and spills or other signs of careless operation or lack of proper maintenance. In this regard, offshore platforms are much "cleaner" than onshore operations.

However, there are still several major sources of air pollutant emissions to be found offshore and there is currently an ongoing debate between operators and state agencies as to the impact these operations may have on ambient air quality. In this chapter, the emissions inherent in offshore activities are examined in depth. Emission rates have been estimated using available data whenever applicable, but also taking into account the unique characteristics of the offshore environment.

4.2 Drilling Operations

4.2.1 Power Generation

The only continuous source of emissions during drilling operations is from the generation of power. The two major load requirements on a drilling platform are the mud pumps and the rig drawworks. The total installed capacity in September 1975 of these two items is shown in Table 4-1 for

TABLE 4-1

DRILLING POWER CAPACITIES OF EXPLORATORY RIGS[a]

LOCATION	NUMBER OF RIGS	TOTAL hp		AVERAGE	
		MUD PUMPS	DRAW-WORKS	MUD PUMPS	DRAW-WORKS
Alabama	2	6,800	4,000	3,400	2,000
Alaska	2	4,600	6,400	2,300	3,200
California	2	4,600	4,500	2,300	2,250
Florida	1	4,800	1,600	4,800	1,600
Louisiana	118	243,060	181,930	2,060	1,540
Gulf of Mexico	15	27,800	21,550	1,850	1,440
New Mexico	2	2,000	2,630	1,000	1,320
Texas	22	59,750	43,360	2,720	1,970
Washington	1	2,800	2,000	2,800	2,000
TOTAL	165	356,210	267,970	2,160	1,620

[a]Does not include operator-owned rigs.

Source: Petroleum Engineer (September 1975).

the offshore areas surrounding the United States.[1] The average for all platforms was slightly greater than 2,100 hp for mud pumps and 1,600 hp for rig drawworks. Although the total installed capacity may change from month to month, the average capacity used for this report should remain relatively constant.

In addition, between 400 hp and 800 hp is required for the rotary, and 500 hp is required for accessories and housekeeping.[2]

The actual power demand depends upon the activity in progress at a given time. For a typical drilling platform, the design load (maximum available horsepower) is shown in Table 4-2. The actual power required will be considerably less than full capacity. For example, power usage during drilling depends upon the size of the hole, the rate of drilling, and the depth of the hole. Randall estimates that the average hydraulic power at the bit required for optimum drilling is in the range of 0.2 to 0.3 horsepower-hours per foot square inch of bottom hole area.[3] Additional hydraulic power is required to compensate for string losses. In this report, total hydraulic power requirements have been estimated at approximately 40 hph/ft drilled, based upon a 10-in bit size with 50 percent of the total hydraulic power delivered at the bit and the remaining 50 percent dissipated as string losses. An additional 20 hph/ft is required for auxiliaries as discussed below.

The relationship between drilling power and total power can be seen from the drilling scenario shown in Table 4-3. The primary activity is drilling, which will be ongoing over 70 percent of the time. The power requirements will be relatively low during the initial stages but will increase with hole depth. An overall load factor of only 25 percent has been assumed to take into account the greatly reduced loads which will be encountered initially. Such a load factor is in reasonable agreement with the rule of thumb presented above.

The expected load factor is assumed to be somewhat higher for other operations. In the absence of published

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[1] "Fall 1975 International Rotary Rig Locator," Petroleum Engineer 10(47) (September 1975).

[2] Douglass Bynum, "Drilling Rig Cost Effectiveness," Petroleum Engineer 10(48) (September 1976): 98-105.

[3] B.U. Randall, "Optimum Hydraulics in the Oil Patch," Petroleum Engineer 10(47) (September 1975): 36-52.

TABLE 4-2

SCENARIO OF INSTALLED POWER DISTRIBUTION[a]
(Horsepower)

REQUIREMENT	CONDITION		
	DRILLING	TRIPPING CASING, CORING	SURVEYS & LOGS
Draw Works	0	1,600	0
Mud Pumps	2,100	0	0
Rotary	800	0	0
Accessories	400	200	200
Housekeeping	100	100	100
TOTAL	3,400	1,900	300

[a]These values are assumed to be "typical" and have been used in this report to estimate potential rates of emission.

Source: Adapted from Douglass Bynum, "Drilling Rig Cost Effectiveness," Petroleum Engineer 10(48) (September 1976): 98-105.

TABLE 4-3

DRILLING SCENARIO[a]

(Basis: 10,000 ft. hole)

ACTIVITY	NUMBER OF DAYS	AVAILABLE POWER (hp)	LOAD FACTOR (Percent)	USAGE (hp hr.)
Drilling	22	3,400	25	448,800
Coring	2	1,900	50	45,600
Casing	4	1,900	50	91,200
Surveys & Logs	2	300	80	11,500
TOTAL	30			597,120

[a]Based upon an analysis of notices to drill submitted by oil companies to the U.S. Geological Survey and discussions with operators.

data, a load factor of 50 percent and 80 percent for tripping and logging, respectively, has been estimated. Note, however, that uncertainty in these factors will have little impact on the total power consumption for all offshore drilling operations.

Emission factors are given in Table 4-4 for diesel reciprocating and turbine engines, both of which are used in offshore operations. The rate of emission is dependent upon the type of engine and the fuel form. In exploratory drilling, distillate oil is used almost exclusively. In developmental drilling, the fuel will depend upon the extent to which the field has been opened. Specifically, if gas is available, the operator may switch to gas rather than transporting oil to the platform. On the other hand, the operator may choose to shut in completed wells until producing equipment can be placed on the platform. Often this conversion from a drilling to a producing configuration does not occur until the drilling schedule is completed.

In calculating the total emission load from drilling operations, it is assumed that almost all of the power generating equipment on drilling rigs is of the diesel-electric type using reciprocating engines.

The calculated total emissions are shown in Table 4-5 for each offshore drilling area. These emission rates are based upon the following equation.

$$\underset{\text{(Table 4-5)}}{\text{Emission Rate}} = \underset{\text{(Table 4-4)}}{\text{Emission Factor}} \times \underset{\text{(Table 2-5)}}{\text{Total Well Footage}} \times \underset{\text{(Table 4-3)}}{60 \text{ hph/ft}}$$

Note that over 90 percent of the drilling during 1975 took place in offshore Louisiana. Note also that as drilling activity picks up in the Atlantic OCS area and in the California OCS area, the emissions due to power generation will increase proportionately.

4.2.2 Mud Degassing

Although power generation is the only continuous emission source of any significance on a drilling rig, there are other sources having an intermittent character that should also be considered. The most important of these is mud degassing.

TABLE 4-4

EMISSION RATES FOR TURBINES AND RECIPROCATING ENGINES

ENGINES	EMISSION RATE (g/hp-hr) NITROGEN OXIDES	SULFUR[1] OXIDES	HYDRO-CARBONS	CARBON MONOXIDE	PARTI-CULATES	REFERENCE
Turbine						
Gas-fired	1.41	0.06	0.14	0.38	0.05	1
Oil-fired	1.65	0.87	0.14	0.38	0.12	1
Reciprocating						
Gas-fired	11.5	0.06	4.86	2.81	UNK	2
Oil-fired	12.9	0.87	0.43	1.89	UNK	2

[1]Sulfur content in fuel assumed to be 0.25 percent for oil and 100 ppm for gas.

SOURCES:

(1) U.S. Environmental Protection Agency, Compilation of Air Pollutant Emission Factors, 2nd ed., Pub. No. AP-42 (March 1975).

(2) Aerotherm, Inc., Standard Support Document and Environmental Impact Statement -- Stationary Reciprocating Internal Combustion Engines, Prepared for the U.S. Environmental Protection Agency, Contract 68-02-1318, to be released.

TABLE 4-5

NATIONWIDE EMISSIONS FROM POWER GENERATION DURING DRILLING[a] (1975)

AREA	TOTAL WELL FOOTAGE	EMISSIONS (Mg/yr)				
		NO_x	SO_2	HC	CO	PARTICULATES
Alaska	138,519	107.2	7.2	3.6	15.7	UNK
California	263,957	204.3	13.8	6.8	29.9	UNK
Louisiana	6,061,351	4,691.5	316.4	156.4	687.4	UNK
Texas	1,509,497	1,168.4	78.8	38.9	171.2	UNK
Gulf of Mexico[b]	346,082	267.9	18.1	8.9	39.2	UNK
TOTAL	8,319,406	6,439.2	434.3	214.6	943.4	UNK

[a]Based upon average power requirement of 60 hp-hr/ft.

UNK = unknown

[b]Refers to outer Gulf of Mexico provinces not included in Texas or Louisiana figures.

As the drilling bit passes through a producing formation, gas may seep into the well bore and become dissolved or entrained in the drilling mud. The gases are separated from the mud in a mud separator, as shown in Figure 4-1.[4] Additional gases are removed from the mud in the degasser vessel, which operates under a vacuum. Finally formation fragments and debris are screened out of the mud in the shale shaker. The cuttings are dropped overboard, and the conditioned mud is recycled to the well.

The gases that are removed from the mud are usually vented to the atmosphere without flaring. During the course of this work, we have been unable to find sources of data that would indicate the rate at which gases are emitted. The total amount of gases emitted annually is considered to be very small, although the rate of emission during a single 24-hour period could be as much as 20,000 ft^3 of gas, based upon 400 ft of 12-in hole per 24-hour day, 25 percent porosity and 4,000 psig resevoir pressure. This is equivalent to 0.4 Mg/d while drilling through producing formation.

A second type of emission from the mud separation system will occur during the infrequent times that oil-based drilling muds are used, primarily when the pipe becomes stuck, for example. In this case, the mud will be dissolved in oil rather than water so that as the mud passes through the shaker, the oil vapors are exposed directly to the atmosphere. An order of magnitude estimate for these emissions can be made using the appropriate emission factor[5] (0.36 lb/1,000 gal throughout) for a fixed-roof storage tank for distillate fuels with a turnover factor of 0.5. Assuming an average mud flow of 400 gal/min, the corresponding emission rate is on the order of 90 kg/d. However, since oil-based drilling muds are used very infrequently, the annual rate of emission is not expected to exceed 0.5 Mg/yr per rig based upon an average usage of about 5 d/yr.

4.2.3 Blowouts

At times during drilling operations, the bit may pass through pockets of gas prior to reaching the oil producing

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[4]C.D. Miller, "Proper Handling of Gas-Cut Mud Boosts Drilling Efficiency," The Oil and Gas Journal 74(13) (March 29, 1976): 166-173.

[5]Personal communication to R.K. Burn, A.O. Spauldry, Western Oil and Gas Association, February 25, 1977.

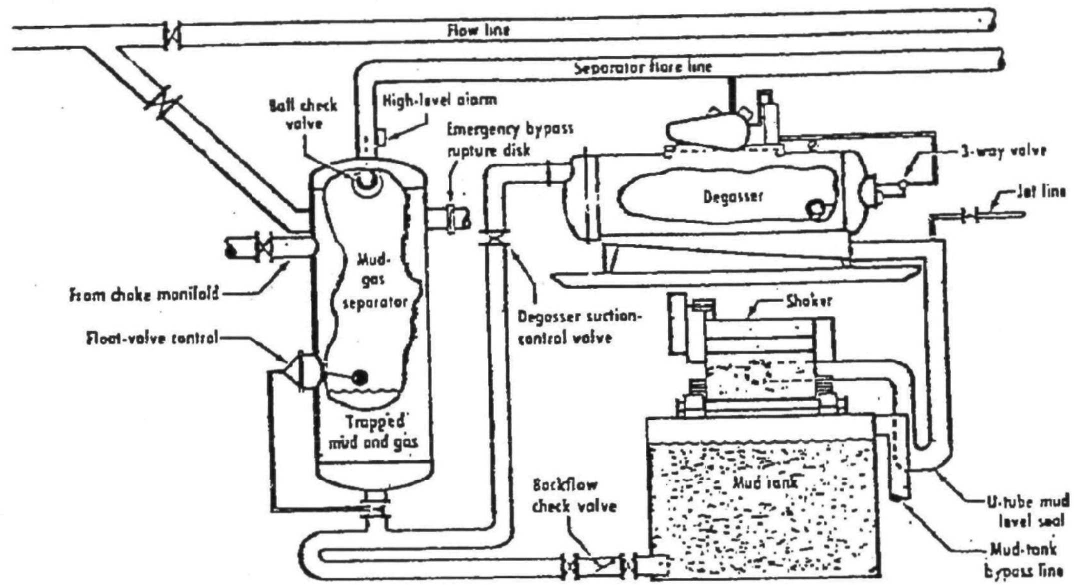

Figure 4-1. Handling toxic gas on offshore rigs. (C.D. Miller, "Proper Handling of Gas-Cut Mud Boosts Drilling Efficiency," Oil and Gas Journal 74(13) (March 29, 1976): 167.

formation. Such an occurrence is often unexpected and the density of the mud may not be great enough to control the sudden increase in pressure. Reduction of mud density by entrained gas further compounds the problem. The expanding gas will rapidly push mud out of the hole. When a kick does occur, the blowout preventers are closed and measures are taken to increase the density of the mud until it can control the increased pressure in the well bore. On rare occasions, however, prevention techniques prove to be inadequate and the well will get out of control, resulting in a blowout. A blowout can be very costly in terms of the loss of equipment and lives. Needless to say, the industry goes to great expense to prevent such occurrences.

Blowouts usually occur during drilling, but they may also develop during remedial work done after the well has been completed. One particularly dangerous type of blowout is that which occurs during the drilling of the surface conductor hole. Five accidents have been reported which resulted in the loss of several lives. These are listed in Table 4-6.[6]

Some blowouts have been caused by the loss or damage of a platform as a result of rough seas churned up by hurricanes. Others have been caused by collisions with ocean-going vessels. The USGS reports 57 blowouts since 1956 ranging in duration from 15 minutes to over 5 months with the average being on the order of a few days. The quantities of gas which escaped during these accidents are comparable to the full production rate of the blown wells. Note that a single gas well can produce over 1 million SCFD (approximately 20 MG/d).

4.2.4 Dynamic Positioning and Stabilizing

One aspect of offshore drilling not common to onshore operations is that drilling in deep water requires drill ships or semisubmersible rigs, neither of which rests on the ocean floor. In order to stay over the hole, a drill ship will use its engines to counteract the current normally encountered. Dames and Moore[7] have estimated the power

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[6] J. Beall, "Riserless Shallow Blowout-Control Method Is Safe and Effective," Oil and Gas Journal 74(31) (August 2, 1976): 125.

[7] Dames and Moore, Inc., Environmental Assessment Study, Proposed Sale of Federal Oil and Gas Leases, Southern California Outer Continental Shelf, Volume 3, Section IV, Prepared for Western Oil and Gas Association, October 1974, pp. 2-41 to 2-42.

TABLE 4-6

HISTORY OF SHALLOW HOLE BLOWOUTS IN THE GULF OF MEXICO

CONTRACTOR	RIG	TYPE OF RIG	YEAR
Reading and Bates	C. P. Baker	Catamaran	1964
Fluor	Little Bob	Jack-up	1968
Marine	J. Storm II	Jack-up	1970
Odeco	Ocean Patriot	Jack-up	1970
Odeco	Ocean Driller	Semi-submersible	1971

Source: J. Beall, Oil and Gas Journal 74(31) (August 2, 1976): 125.

requirements for dynamic positioning to be as much as 7,500 hp. Data obtained during the course of Energy Resources Co.'s work indicates that the 7,500 hp estimate relates to available capacity. An estimate of actual usage of 7,500 hp is believed to be excessive, but published literature to the contrary cannot be found.

4.3 Production

Flow sheets of a production platform were shown previously in Figures 3-11 and 3-12. For the purpose of emissions estimates five different components of the processing scheme have been considered:

- Power generation
- Gas processing
- Oil processing
- Water treatment and disposal
- Miscellaneous services and transportation

Each of the first four areas is described in detail in the following paragraphs. The last category primarily includes numerous mobile sources not within the scope of this study.

4.3.1 Power Generation

One of the requirements of most offshore platforms that is not similar to onshore operations is that the platforms must be self-sufficient. In only a few instances (primarily offshore California) is power delivered to the production platform from onshore. In all other cases, power is generated using onboard generating equipment. In order to estimate the power capacity found on typical offshore installations, Energy Resources Co. reviewed the installation lists for major manufacturers of power generating equipment. Table 4-7 shows estimates of installed turbine capacity and corresponding power usage requirements based upon manufacturers' records and data obtained by Energy Resources during visits to offshore platforms.

The power used in offshore platforms is required primarily for gas compression (for transmission or artificial gas lift) oil pumping (the major use for electricity), and water injection, either for water flood or disposal.

TABLE 4-7

POWER GENERATION, INSTALLED CAPACITY AND ESTIMATED USAGE REQUIRED FOR OFFSHORE PRODUCTION

AREA	GAS COMPRESSION[a,b]		GAS COMPRESSION AND BOOSTING		GAS INJECTION		WATER INJECTION		ELECTRIC GENERATION[c]	
	CAPACITY[d] (hp/10^6CFD)	USAGE (hphr/10^6CF)	CAPACITY (hp/10^6CFD)	USAGE (hphr/10^6CF)	CAPACITY (hr/10^6CFD)	USAGE (hphr/10^6CF)	CAPACITY (hp/10^3BOPD)	USAGE (hphr/10^3BBL)	CAPACITY (hp/10^3BOPD)	USAGE (hphr/10^3BBL)
Alaska	300	6,061	unk	unk	unk	unk	-	-	250	5,300
California	300	6,061	-[e]	-[e]	-	-	-	-	250	5,300
Louisiana	150	3,170	120	2,530	3	60	150	3,000	150	3,000[f]
Texas	150	3,170	120	2,530	-	-	150	3,000	150	[illegible],000[f]
Gulf of Mexico	150	3,170	120	2,530	-	-	150	3,000	150	3,000[f]

[a] Includes requirements for gas lift, gathering, and sendout

[b] Design Factors:

	Inlet (psig)	Discharge (psig)
Alaska, Calif.	15	325
La., Tex., Gulf of Mexico	80 to 150	1,150

[c] Includes oil pumping and miscellaneous services; also includes power for fixed platforms.

[d] Based upon total production; sales in 60 percent of production in California and 60 percent of production in the Gulf of Mexico.

[e] Transmission facilities onshore.

[f] Based upon barrels of oil plus condensate.

Source: Energy Resources Co. estimates (based in part upon data obtained during offshore visits).

The power requirements for gas compression (which include artificial gas lift as well as gathering and send-out) are based upon the average field pressures determined during the project team's offshore visits. In California (also true of Alaska) the wells operate at no more than a few atmospheres pressure and the gas transmission system compresses the gas to approximately 325 psig. Some of this gas is used for gas lift or as platform fuel; the remaining portion is sent to shore for further compression and pipeline transmission.

The offshore operations in the Gulf of Mexico produce gas at pressures up to 1,200 psig, and hence, less power is required for compression to pipeline pressures of about 1,000 psig. However, because many of the offshore platforms are located at distances much further than characteristic of offshore California operations, there is also additional requirements for pressure boosting on some platforms in order to deliver the produced gas at pipeline pressures to receiving terminals onshore. In some cases, however, the platforms offshore Louisiana are too remote to economically pipeline gas to shore. In these cases, the gas is reinjected into the formation. A similar practice is carried out in Alaska at the present time, but specific data are unavailable.

Water injection is another major use for onboard power. A survey of manufacturers' records revealed that there was as much horsepower committed to water injection projects as there was to the generation of platform electricity, even though the water injection capacity seemed to be a bit more concentrated, having as much as 13,000 hp installed on a single major platform.

Finally, platforms use considerable amounts of electricity, primarily to pump oil to shore and to operate submergible electric pumps in the wells. Other miscellaneous uses include lighting, cooking, operation of process motors and so on. A few platforms also have working rigs which require power (see Table 4-8).

Although a mix of gas turbines and reciprocating engines (and also diesel turbines and engines) can be found in use offshore, the project team has not attempted to estimate the distribution of equipment. To be conservative, the power requirements for production have been assumed to be generated by gas turbines only.

The emission factors for gas turbines were shown previously in Table 4-3. Based upon these numbers, the estimated total

TABLE 4-8

DRILLING RIGS ON FIXED PLATFORMS

AREA	NUMBER OF RIGS		
	DRILLING	WORKOVER	TOTAL
Alaska	7	1	8
California	1	8[a]	9[a]
Louisiana, Texas Gulf of Mexico	62	41	103
TOTAL	70	50	120

[a]Includes 6 workover rigs working on THUMS (Longbeach Harbor (California).

emissions from power generation are shown in Table 4-9. Note that accounting for the proper mix between turbines and reciprocating engines (gas or diesel) results in a net increase in the total emissions estimates.

4.3.2 Gas Processing

An estimate of the total production at the well of natural gas is shown in Table 4-10, broken down into the major use categories, i.e., sales, lifting, injection, and platform fuel. In estimating the air pollution emissions from the processing of gas, the total gas production at the well (rather than sales) must be considered since the total gas is usually processed prior to reinjection (gas lift) or sales or use as platform fuel (some high pressure produced gas will not regain compression).

In the paragraphs below are presented details of gas processing operations, specifically:

- Compression
- Dehydration
- Venting

4.3.2.1 Gas Compression

The oil/gas mixture produced from the well is pumped directly to a separation vessel where gas (and gas liquids) are separated from a mixture of oil and water. The water-laden gas must then be compressed and dehydrated prior to send-out. Dehydration of the gas is necessary to avoid hydrate formation in processing equipment or pipelines.

The emissions from gas compression result from the combustion of fuel necessary to generate power to drive the gas compressor. These emissions have been discussed previously with respect to power generation. There are three significant differences between California operations and operations in the Gulf of Mexico which have an effect on emissions:

1. The formation pressures in the Gulf of Mexico are higher and therefore less power is needed to compress the gas to pipeline pressures.
2. The ratio of associated gas to oil produced in the Gulf of Mexico is considerably higher than in California, and hence, a much lower proportion

TABLE 4-9

TOTAL EMISSIONS FROM POWER GENERATION ON OFFSHORE PRODUCTION PLATFORMS

AREA	OIL [10^6bbl/yr]	PRODUCTION CONDENSATE [10^6bbl/yr]	GAS [10^9CF/yr]	TOTAL POWER [10^6hphr/yr]	EMISSIONS (Mg/yr)				
					NO_x	SO_2	HC	CO	PARTIC-ULATES
California	15.3	--	4.0	105.3	148.5	6.3	14.7	40.0	5.2
Louisiana	287.5	72.5	3,332.2	21,136.0	29,801.6	1,268.2	2,959.1	8,031.7	1,056.8
Texas	0.3	11.0	1,218.1	6,987.0	9,839.0	418.7	976.9	2,651.6	349.4
TOTAL	303.1	83.5	4,554.3	28,228.3	39,789.3	1,693.2	3,950.7	10,723.3	1,411.4

TABLE 4-10

APPROXIMATE GAS BALANCE

AREA	TOTAL PRODUCTION[a] [10^9CF/yr]	GAS SALES[b] [10^9CF/yr]	GAS LIFT [10^9CF/yr]	GAS INJECTION [10^9CF/yr]	PLATFORM FUEL [10^9CF/yr]	OTHER FUEL[c] [10^9CF/yr]	VENTED OFFSHORE [10^9CF/yr]
California	6.7	4.0	1.5	-	1.2	0.8	0.02[d]
Louisiana	3,914.8	3,332.2	287.5	66.6	218.4	-	11.30[e,f]
Texas	1,291.3	1,218.1	0.3	-	72.9	-	0.40
TOTAL	5,212.8	4,554.3	289.3	66.6	292.5	0.8	1.58

[a]At well.

[b]Delivered onshore.

[c]Used onshore; included in Gas Sales.

[d]Vapor recovery systems in use (approximately 90 percent efficiency).

[e]Assumes no vapor recovery and continuous venting of solution gas released at oil pressures below 65 psig (approx. 20 ft^3/bbl).

[f]Assumes vented gas proportional to liquid production rather than gas production.

Source: Energy Resources Co. estimates (based upon data obtained during offshore visits.

of the available gas is burned in the Gulf (approximately 6 percent) as compared to offshore California (30 percent).

3. Much of the gas production in Louisiana and Texas is from gas wells rather than as associated gas in oil wells.

In addition to the emissions from fuel combustion, fugitive emissions from compressor seals have characteristically been a minor source of air pollutant emissions, being about the same order of magnitude as emissions from vapor recovery systems, leaks from pump seals or pressure relief valves.

4.3.2.2 Gas Dehydration

In most offshore operations tri-ethylene glycol is used as a dehydrating agent. A schematic of a glycol dehydration unit is shown in Figure 4-2. The wet gas enters the desorber at the bottom of the column and passes up through a series of bubble cap or sieve trays. The direct contact with glycol results in the reduction of water in the gas to a level of less than 1 lb/million ft^3 of gas. The spent glycol passes through a glycol storage tank and then to the reboiler where the water is removed by heating. Note that on many offshore installations this heating can be carried out using direct-fired heaters or a heat transfer fluid circulating between the reboiler section and a suitable (above 400° F) source of waste heat such as the gas turbine exhausts.

The emissions from the glycol dehydration unit include:

- Combustion emissions (only if direct fired)
- Glycol losses

The fuel requirements for a glycol dehydrator depend upon the inlet water content of the gas, but they average about 350,000 Btu/10^6 ft^3 processed. This is equivalent to only 0.5 percent of the total platform fuel requirements estimated previously in Table 4-10.

Very little data are available on the amount of glycol emissions from the dehydrator. Mapes[8] has reported a total

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[8] G.J. Mapes, "The Glycol Dehydration," in Gas/Oil Production Practices Handbook (Houston: Gulf Publishing Co., 1971), pp. 37-44.

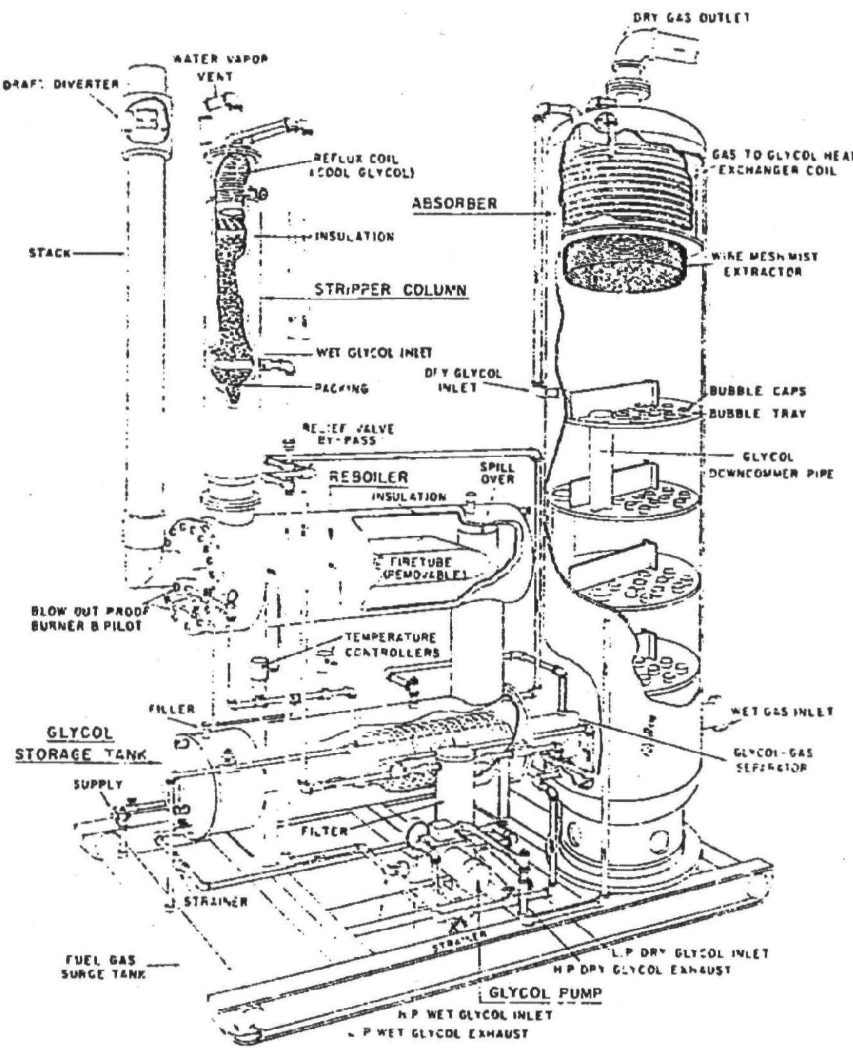

Figure 4-2. Typical glycol dehydration installation. (World Oil, Gas/Oil Production Practices Handbook, 1971, p.38.)

glycol loss in dry gas plus the reboiler vent of approximately 0.1 gal/million ft^3 of gas. If the entire loss went to the vent, approximately 420 g/million ft^3 would be emitted, which is a rate of hydrocarbon emissions comparable to the anticipated emissions from power generation using gas turbines. The actual emission would be considerably less since most of the glycol is believed to go with the dry gas. However, the project team was unable to find data in support of this hypothesis.

4.3.2.3 Vents

Under certain circumstances, gases will be vented rather than compressed. For example, a certain amount of gas will be vented in the unusual circumstance that the pressure relief valves on the high pressure separators must open in order to protect process vessels. Similarly, when there is a compressor malfunction, the compressor will often be bypassed while the malfunction is being corrected or until the well can be shut in. Finally, some of the gases dissolved in the oil may be released in storage and must then be vented. For example, in the Gulf, the low pressure separator often operates at pressures as high as 80 psig. When the oil leaves the low pressure separator it is sent to a small storage (surge) tank operating at pressure between 15 psig and atmospheric. Because the pressure is reduced, additional gases (approximately 20 ft^3/bbl) will come out of the solution. These are vented.

The total amount of gas being released to the atmosphere depends upon:

- The characteristics of the oil and gas processing.
- The nature of the control techniques in use.

In the Gulf coast the oil is characteristically at high pressure (as much as a 1,000 psig) and the gas/oil ratio is relatively high, on the order of 1,200 ft^3/bbl. In California, vapor recovery systems are in use which reduce the amount of vented gases by as much as 90 percent. In terms of oil production, it is estimated that vented gas is equivalent to approximately 1.5 ft^3/bbl in the California area and as much as 35 ft^3/bbl in the Gulf of Mexico. In both cases this amounts to less than 0.5 percent of the total gas produced.

4.3.3 Oil Processing

Produced fluids from an oil well are a mixture of gas, oil, and water. The oil processing train considered in this section includes all of the necessary operations for separating the oil from gas and water and upgrading the oil quality to pipeline standards, i.e., free of entrained solids and containing less than 1 percent water.

The oil will first pass through a series of separators where the gases and free water are removed from the oil. At this point the oil will still contain as much as 25 percent water in the form of an emulsion. The oil is then heated in a heater treater or passed through a chemical-electric unit to break the emulsion and remove the remaining water from the oil. This process reduces the moisture content in the oil to 1 percent or less. From the heater treaters, the processed oil is pumped to a storage tank that stores the oil until it can be pumped ashore.

Each of these steps is discussed in detail in the paragraphs below.

4.3.3.1 Separators

The first step in the oil processing train is to separate the liquids from produced gas using a series of two phase separators. In the Gulf Coast, the project team observed a 3-stage system having a high-pressure separator operating at approximately 1,000 psig, a medium-pressure separator operating at approximately 400 psig, and a lower-pressure separator operating at approximately 80 psig. As the pressure of the oil is reduced, solution gas will be evolved. A typical separator is shown in Figure 4-3. Note that the gases pass through a mist extractor to prevent the entrainment of oil in the gas phase. Separators such as these are constructed in the horizontal configuration shown in a figure and in vertical and spherical configurations as well. The primary difference in these designs is in the relative ability of each one to handle different ratios of gas to liquid.

The final separator is usually a three phase free water knockout. A schematic of a typical unit is shown in Figure 4-4. The fluid from the higher pressure separators enters the low pressure separator at the centrifugal inlet where initial separation of liquid and gas takes place. The separator itself is of sufficient size to allow the oil and water to separate into two phases. The interface between oil and water is controlled by controlling the rate of removal of oil and water independently.

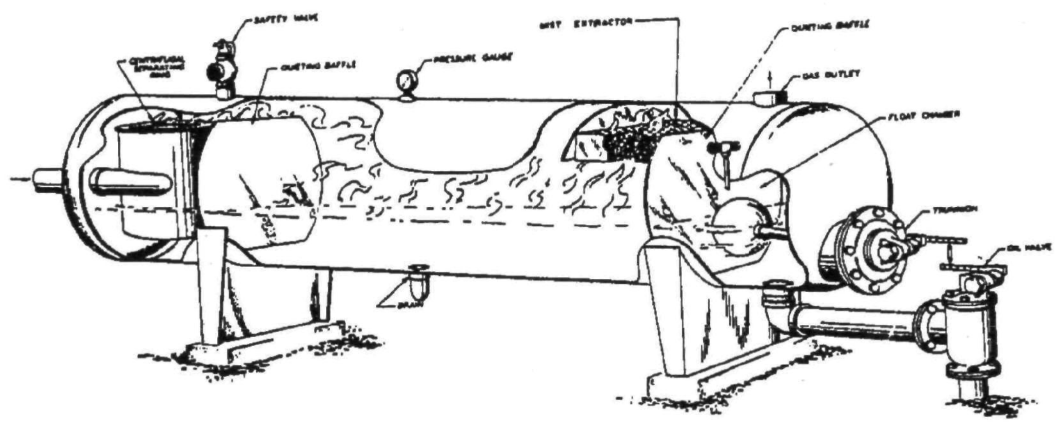

Figure 4-3. Horizontal low pressure oil and gas separators. (Sivalls Tanks Inc., <u>Engineering Catalog</u>: 322)

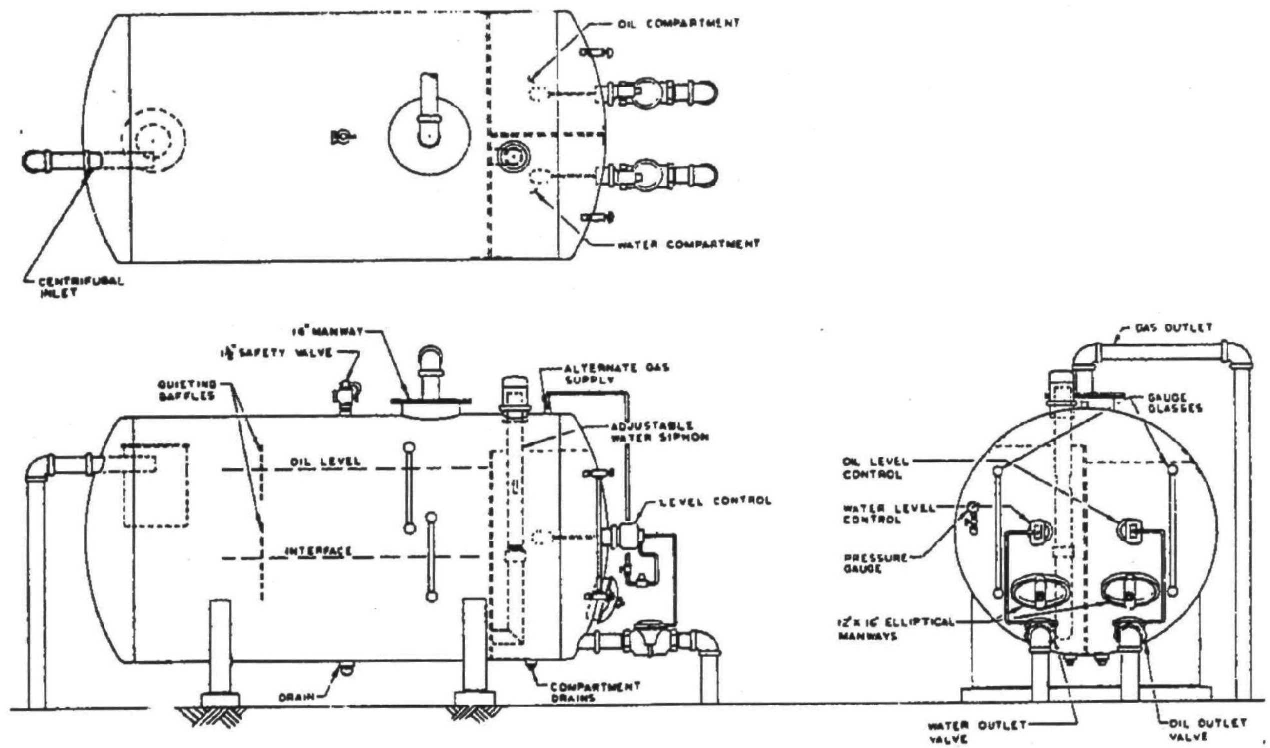

Figure 4-4. Horizontal oil-gas-water separators. (Sivalls Tanks Inc., Engineering Catalog: 602.)

The separators are all closed systems, often operating at high pressures. The only emissions would result whenever the pressure release valve opens to relieve excess pressure. Under this condition, the gases would be vented to the platform flare system and would subsequently be exhausted or burned. On platforms equipped with vapor recovery systems, low pressure gas would be compressed and transferred to the gas processing system.

4.3.3.2 Emulsion Breakers

The oil phase from the separator train will contain as much as 25 percent moisture in the form of an oil emulsion. In order to break the emulsion a demulsifier chemical may be added. Then the oil is heated to temperatures as high as 150° F or passed between electrically charged plates (not shown) whereupon the oil and water will separate.

A typical horizontal heater treater is shown in Figure 4-5. The oil enters the separator on the heated side where it is contacted with the firebox tubes. As the emulsion breaks, the oil phase and the water phase collect on the opposite side of the heater and are pumped away at differing rates to maintain a proper interface level. Note that during the heating of the oil additional gas is released which leaves the separator at the gas outlet. This gas will be combined with the exhaust from the low-pressure separator and sent to the vent or vapor recovery system.

A variation of the conventional heater treater design is shown in Figure 4-6 showing a vertical configuration. This unit is slightly more compact than the horizontal treater and it allows for better heat exchange between the inlet oil emulsion and the outlet processed oil. The manufacturer claims that this design extends the life of the firebox and results in reduced fuel consumption.

In conventional heater treater units the fuel requirements have been estimated at a maximum of 15,000 Btu/bbl of oil processed. The emissions from heater treaters are comparable to emissions from most direct-fired process heaters. Estimated emission factors are shown in Table 4-11.

While the equipment described above is in use on many offshore platforms, some producers have found it economical to heat the oil with waste heat from the gas turbine exhausts using a heat transfer fluid such as Therminol. Since gas turbines can provide as much as 5,000 Btu waste heat/hph, there is more than enough heat available for heat treating.

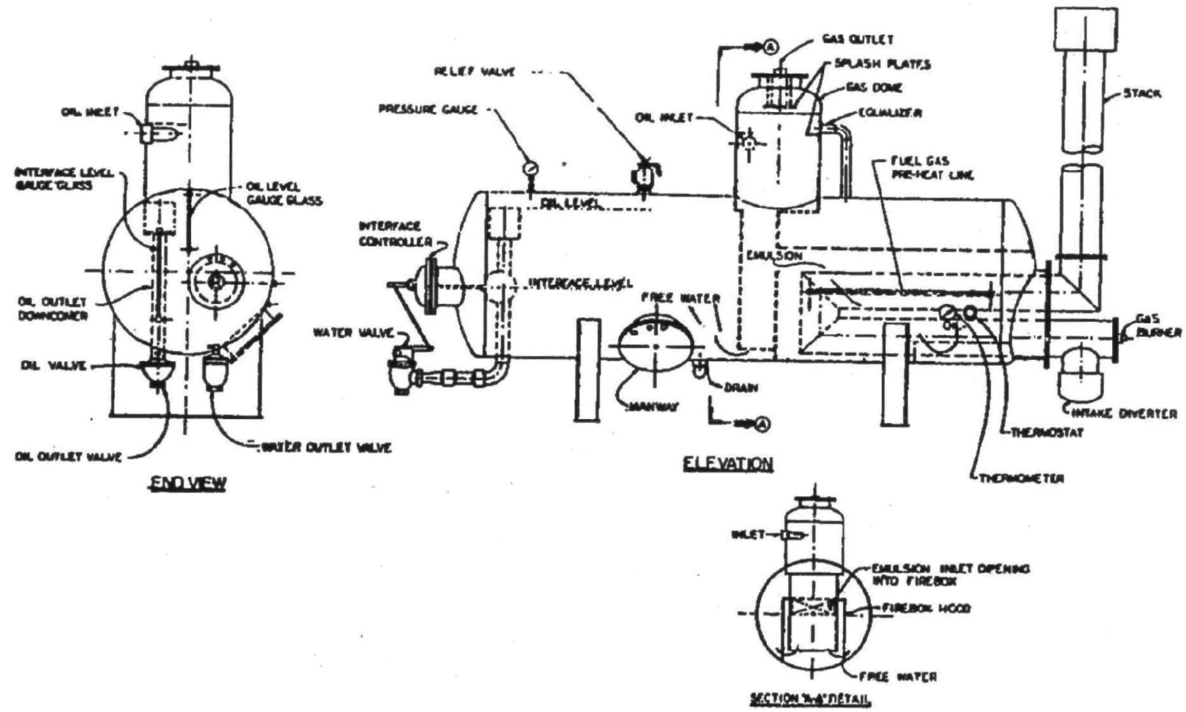

Figure 4-5. Horizontal heater treater. (Sivalls Tanks Inc., Engineering Catalog: 465.)

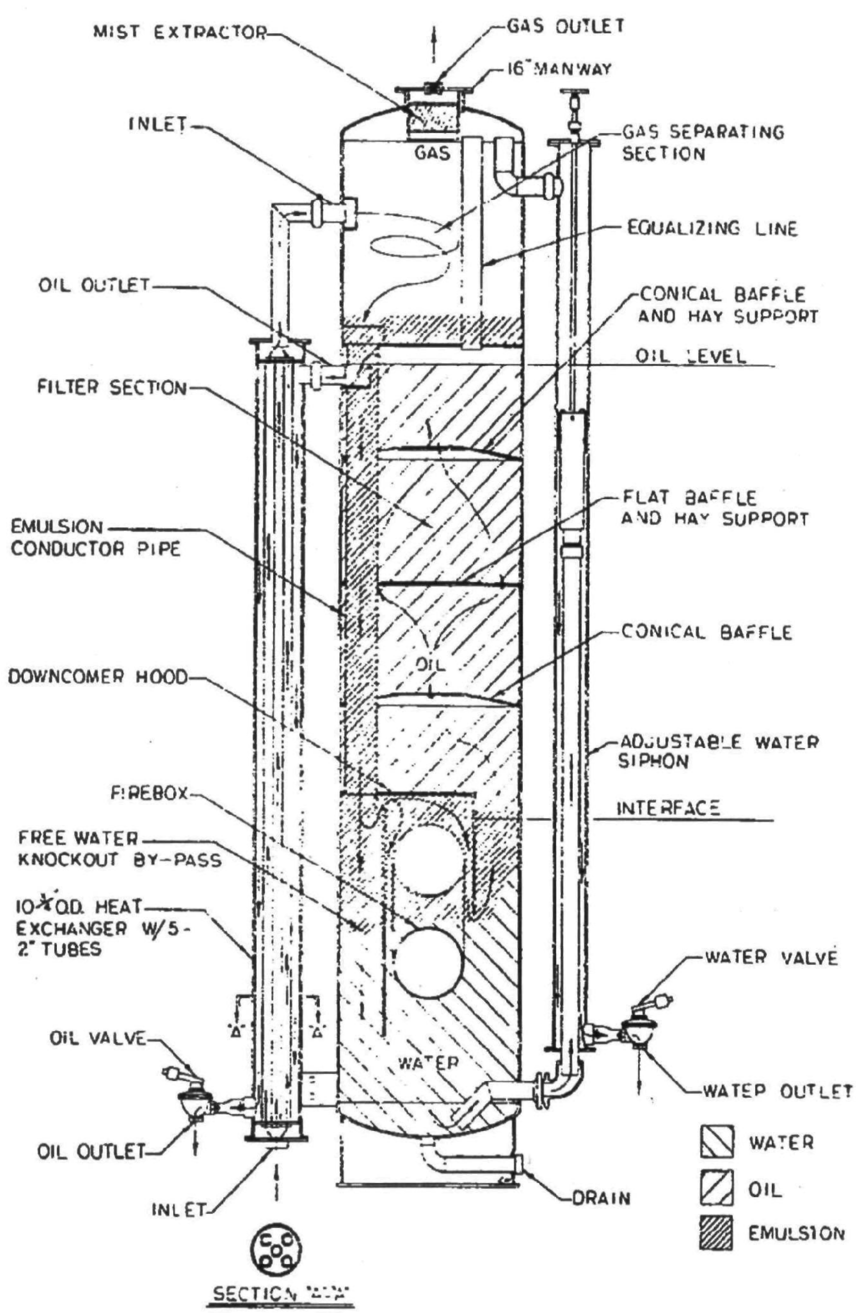

Figure 4-6. Type "A" vertical downflow treaters. (Sivalls Tanks Inc., <u>Engineering Catalog</u>: 409.)

TABLE 4-11

EMISSIONS FROM HEAT TREATING

POLLUTANT	NO_x	SO_x	HC	CO	PARTICULATES
$Kg/10^6 m^3$ of fuel	1,600	9.6	128	320	160
$(lb/10^6 ft^3)$	100	0.6	8	20	10
$Kg/10^6 bbl^a$ of oil	647	3.9	52	129	65
$(lb/10^6 bbl)$	1,426	8.6	114	285	143

[a]Based upon heat requirement of 3,780 Kcal/bbl (15,000 Btu/bbl), natural gas fired.

Source: U.S. Environmental Protection Agency, Compilation of Air Pollutant Emission Factors, March 1975.

Hence, this could be used to completely eliminate the emissions from direct fired heaters. Hence, since the Therminol system is a closed system, the only heat treating emissions would be from the occasional vapor losses resulting from the over-pressuring of the separator vessel.

4.3.3.3 Product Send-Out

When the dehydrated oil leaves the heater treaters, it is sent to a storage vessel where the pressure is reduced from the operating pressure of the low pressure separator to essentially atmospheric pressure. On the Gulf Coast, the pressure reduction from 80 psig to atmospheric pressure results in a liberation of an additional 20 ft^3 gas/bbl. On the West Coast, the wells operate at essentially atmospheric pressure and hence little gas is emitted from the oil surge tank.

The oil is sent to shore for sale either by pipeline or by barge. In the case of pipelines, almost all of the oil is pumped using electric pumps, drawing power from the platform's electric generation capacity. The emissions resulting from the generation of electric power were discussed previously.

A second source of hydrocarbon emissions from pumping result from occasional leaks of pump seals. This problem was studied in considerable depth during the late 1950s when the Public Health Service was studying refinery emissions in the Los Angeles area. The data from the Los Angeles study are summarized in Table 4-12. This work showed that the emissions were related to the vapor pressure of the fluid being handled, the type of pump seal, and the effectiveness of pump maintenance. With respect to the latter point, the researchers found that only one pump seal in four actually leaked and of the leaks recorded, approximately 95 percent of the measured loss of hydrocarbon could be attributed to less than 15 percent of the pumps inspected. The study also showed that these large leaks could be corrected in most cases through proper maintenance.

The data obtained from the Los Angeles study are not representative of offshore practice in two respects:

1. Since the time that the data were taken (1958), there has been a moderate change in pump seal designs which has tended to reduce the rate of leakage; and

TABLE 4-12

EFFECTIVENESS OF MECHANICAL AND PACKED SEALS ON VARIOUS TYPES OF HYDROCARBONS

SEAL TYPE	PUMP TYPE	TYPE HYDROCARBON BEING PUMPED LB REID	AVG. HYDROCARBON LOSS PER INSPECTED SEAL, LB/DAY	LEAK INCIDENCE	
				SMALL LEAKS[a] % OF TOTAL INSPECTED	LARGE LEAKS % OF TOTAL INSPECTED
Mechanical	Centrifugal	26	9.2	19	21
		5 to 26	0.6	18	5
		0.5 to 5	0.3	19	4
Avg		0.5	3.2	19	13
Packed	Centrifugal	26	10.3	20	37
		5 to 26	5.9	32	34
		0.5 to 5	0.4	12	4
Avg		0.5	4.8	22	23
Packed	Reciprocating	26	16.6	31	42
		5 to 26	4.0	24	10
		0.5 to 5	0.3	9	0
Avg		0.5	5.4	20	13

[a]Small leaks lose less than 1 pound of hydrocarbon per day.

Source: B.J. Steigerwald, Emissions of Hydrocarbons to the Atmosphere From Seals on Pumps and Compressors, Report No. 6, Los Angeles County Air Pollution Control District, 1958. In John A. Danielson, ed., Air Pollution Engineering Manual, 2nd ed., U.S. Environmental Protection Agency, Office of Air and Water Programs, May 1973, p. 686.

2. Because all of the equipment on a platform, particularly the pumps, are located close to each other and also because of the hazards of fire, it is extremely unlikely that major hydrocarbon leaks would go undetected or unrepaired.

Therefore, in estimating the rate of hydrocarbon loss from pumps, the frequency of leaks on an offshore platform is assumed to be the same as the frequency of "small leaks" as shown previously in Table 4-12, i.e., 20 percent. Likewise, the rate of leakage is assumed to be 1 lb/d for each leaky seal.

On the platforms visited by the project team during the course of this work, there was approximately one large pump per 1,000 BOPD capacity, suggesting an emissions rate of approximately 200 lb/10^6 bbl, i.e.:

$$\frac{\text{1 pump x 1 lb/d x 0.2 leakage factor}}{\text{1,000 BOPD}}$$

In the above study, an additional source of fugitive hydrocarbon emissions was from leaky process and safety valves. The leakage data from this study are summarized in Table 4-13. The average leakage rate per valve was approximately 0.5 lb/d for valves and gaseous service and 0.1 lb/d for liquid service. In both cases, the frequency of leakage was approximately 7 percent of all valves, with almost all of the pollutants being produced by so-called "large leaks." In the case of valves in gaseous service, over 97 percent of the material was emitted from only 5 percent of the valves; in the case of valves in liquid service, 90 percent of the emissions were produced by slightly over 1 percent of the valves inspected.

With respect to offshore operations, it is believed that the emissions rate will be less than those reported in the Los Angeles study because of improvement in valve technology since 1958 and also because maintenance practice onboard offshore platforms is considerably better than would be expected from onshore refineries. Although the exact number of valves in service is unknown, an order of magnitude estimate would be approximately as follows:

TABLE 4-13

LEAKAGE OF HYDROCARBONS FROM VALVES OF REFINERIES IN LOS ANGELES COUNTY

	VALVES IN GASEOUS SERVICE	VALVES IN LIQUID SERVICE	ALL VALVES
Total number of valves	31,000	101,000	132,000
Number of valves inspected	2,258	7,263	9,521
Small leaks[a]	256	768	1,024
Large leaks	118	79	197
Leaks measured	24	76	100
Total measured leakage, lb/day	218	670	888
Average leak rate -- large leaks, lb/day	9.1	8.8	8.9
Total from all large leaks, lb/day	1,072	708	1,780
Estimated total from small leaks, lb/day[b]	26	77	103
Total estimated leakage from all inspected valves, lb/day	1,098	785	1,883
Average leakage per inspected valve,	0.486	0.108	0.198

[a]Small leaks are defined as leaks too small to be measured -- those estimated to be less than 0.2 pounds per day.

[b]Leaks too small to be measured were estimated to have an average rate of 0.1 pound per day. This is one-half the smallest measured rate.

Source: C.V. Kanter et al., Emissions to the Atmosphere From Petroleum Refineries in Los Angeles County, Report No. 9, Los Angeles County Air Pollution Control District, 1958. In John A. Danielson, ed., Air Pollution Engineering Manual, 2nd ed., U.S. Environmental Protection Agency, Office of Air and Water Programs, May 1973, p. 691.

	GASEOUS SERVICE (per 10^6 SCFD)	LIQUID SERVICE (per 10^4 BOPD)
Number of Valves	100	500
Emission Rates kg/d/valve[a]	0.01	0.0007[b]
Estimated Emissions, kg/d	1	0.4

[a]Based upon a leak rate of 0.015 lb/d for gaseous service and 0.01 lb/d for liquid service as would be expected with proper maintenance.

[b]Assumes 15 percent of liquid evaporates.

By comparison with other hydrocarbon emission sources on the offshore platform, the above estimates appear to be insignificant.

4.3.4 Water Treating

The water leaving the free water knockout and the heater treater will be contaminated with oil and must be treated in oil/water separators to prevent water pollution. Two levels of water treatment are currently in use in offshore platforms:

- Skim piles and oil/water separators
- Froth flotation units

Skim piles and oil/water separators are vessels which provide sufficient residence time to allow the small quantities of oil to separate from the water and subsequently be skimmed off the top and returned to the oil processing train. A typical offshore oil/water separator is shown in Figure 4-7. The tank is designed with a series of chambers separated by baffles so that as the water progresses from stage to stage, it becomes cleaner and cleaner. Oil is skimmed off the top of each chamber, using skim pipes. On offshore platforms, systems such as these are closed systems and, as such, will have no emissions. In some cases, platforms will not have

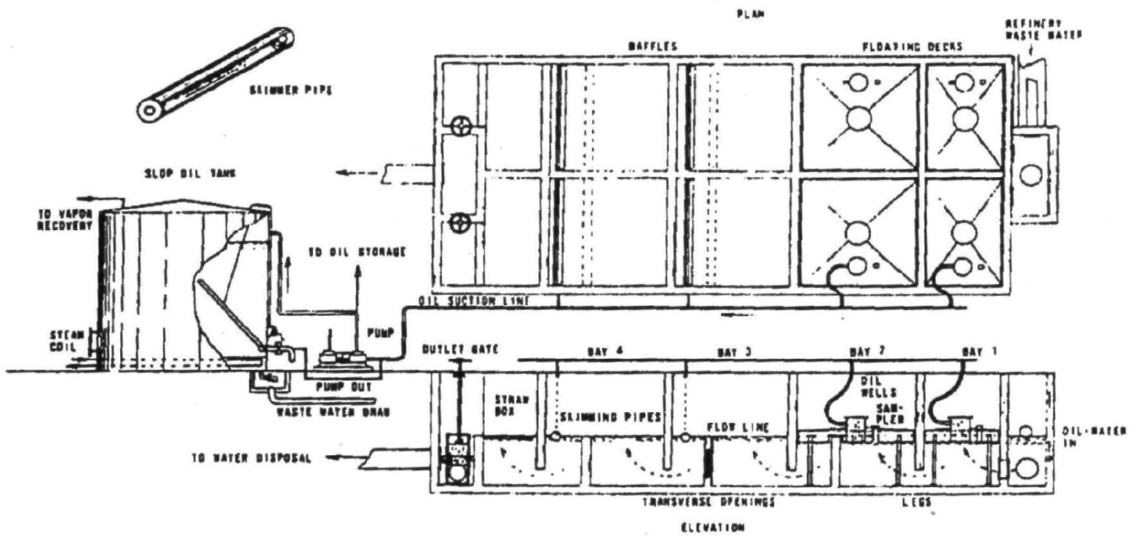

Figure 4-7. A modern oil-water separator. (J. A. Danielson, U.S. Environmental Protection Agency, Air Pollution Engineering Manual, May 1973, p. 674)

oil/water separators if, for instance, the oil content of the water is sufficiently low to pass directly to the flotation unit.

A typical froth flotation unit is shown in Figure 4-8. In this unit, air or natural gas is bubbled up through the water, thereby stripping out any residual hydrocarbons that remain after the initial separation steps. These units are designed with sealed vapor spaces to prevent atmospheric emissions. Unfortunately, the seals often fail or the hatches are left loose or opened following the required maintenance of the moving parts within the device which skim off the oil froth. During the offshore visits, not a single froth flotation unit was observed that was not accompanied by a very noticeable hydrocarbon odor. No published data have been found, however, to indicate a rate of emission.

4.4 Control Technology

The air pollution emission sources found on offshore platforms are not amenable to tail-end control systems. Major sources and the possible control technologies are listed below:

Emission Source	Control Technology
Power generation	Combustion controls, conservation
Direct-fired heaters	Elimination
Waste gas disposal (kicks, blowouts, venting systems)	Underwater flares, dilution stacks, combustion flares, vapor recovery systems
Pumps, valves and com pressor seals	Proper maintenance, mechanical seals

Each of these items is discussed in more detail in the sections below.

4.4.1 Power Generation

The major single source of air pollutants from offshore platforms is power generation required for drilling, gas compression, water disposal, and electric power generation (primarily for oil pumping). This power is generated using

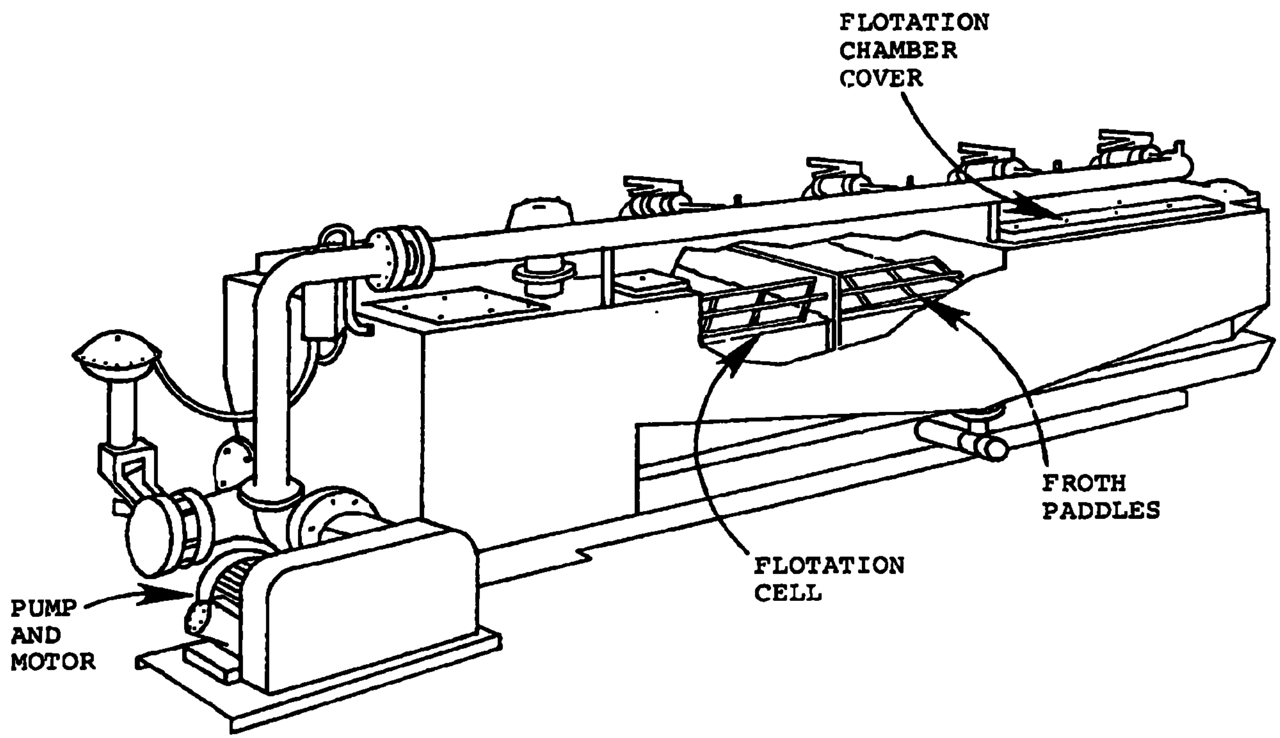

Figure 4-8. Froth flotation unit for removal of emulsified oil and suspended solids from produced water. (WEMCO Division, Envirotech Corporation).

either gas or liquid-fueled turbines or gas or liquid-fueled reciprocating engines. The emissions from these types of engines were shown previously in Table 4-3.

The EPA has spent considerable effort in researching control technology for turbines and reciprocating engines. Although much of this work has concentrated on vehicle emissions, more recent work[9] has dealt with the emissions from stationary engines as well.

The appropriate methods of control for turbines or reciprocating engines are combustion modifications aimed at reducing nitrogen oxide emissions without significantly increasing hydrocarbons or carbon monoxide. However, because of the unique character of offshore operations, a second method of control of emissions is possible through the utilization of waste heat. This could eliminate the need for direct-fired heaters, for example, or increase the efficiency of the power generating equipment through the use of combined gas turbine/steam turbine power cycles. Each of these techniques is discussed below.

4.4.1.1 Combustion Controls

The pollutants arising from power generation can be directly attributed to the conditions within the combustion chamber of the prime mover. By altering combustion conditions, the relative proportion of pollutants can be changed. This is shown in Figure 4-9. Research has shown that nitrogen oxides are formed at high combustion temperatures and in the presence of oxygen. Therefore, by reducing the air-to-fuel ratio (fuel rich), the amount of available oxygen will be reduced and hence the amount of nitrogen oxides that are formed will also be reduced. Unfortunately, because of the relatively low excess air available, the amount of carbon monoxide and unburned hydrocarbons that are emitted will increase under fuel-rich conditions. On the other hand, for fuel-conditions, the amount of carbon monoxide and unburned hydrocarbons can be reduced but the level of nitrogen oxides that are produced will increase at air/fuel ratios close to stoichiometric proportions. Only at air/fuel ratios in excess of 20-to-1 will the rate of nitrogen oxide emissions

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[9] Aerotherm, Inc., Standard Support Document and Environmental Impact Statement -- Stationary Reciprocating Internal Combustion Engines, prepared for the U.S. Environmental Protection Agency, Contract 68-02-1318, to be released.

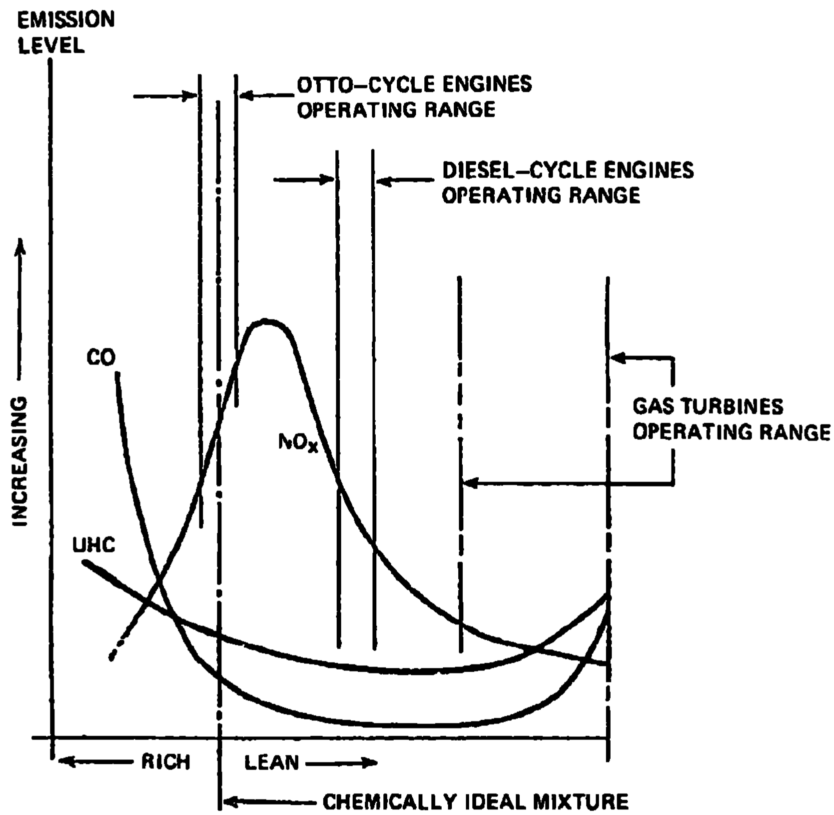

Figure 4-9. Correlation of emission level and engine type operating range. (Adapted from Toward Bluer Skies, International Harvester Company.)

be reduced. Unfortunately, as the air-to-fuel ratio increases, the fuel efficiency decreases and, hence, the reduction in air pollution emissions is accompanied by an increase in energy consumption.

For production operations where the primary prime mover is a gas turbine engine, the expected emissions are relatively low. This is because a turbine normally operates with an air/fuel ratio of 50- or 60-to-1. The high air/fuel ratio required of turbines is necessary because the inlet gas temperature to the turbine must remain below about 1,800° F in order to avoid severe thermal damage to the turbine blades.

4.4.1.2 Control by Conservation

Because of the characteristics of gas turbines described above, the turbine will produce large volumes of hot exhaust which is ideally suited for waste heat recovery. Manufacturers have estimated that as much as 5,000 Btu/hph can be recovered. This waste heat can be used on the platform in one of two ways:

1. Combined-cycle operation - Waste heat could be used to generate steam which could then be used to produce more electricity; the net result is an increase in the efficiency of the gas turbine operation from approximately 26 percent to as much as 40 percent. The amount of emissions would be correspondingly reduced.

2. Fuel conservation - Waste heat could also be used to provide low-grade heat for regeneration of glycol used in gas dehydration, for breaking of the oil-water emulsion in the heater treaters, for space heating or water purification, and several others. By eliminating direct-fired heaters, the emissions, obviously, are also eliminated.

Combined-cycle operations are currently under development by most of the gas turbine manufacturers and could be introduced in the field in the near future. With respect to the elimination of direct-fired heaters, for example, through waste heat utilization, the project team observed offshore platforms which were designed to eliminate all fuel combustion requirements except those relating directly to power generation, i.e., gas compression, water injection, and electricity generation. The team observed that there was far more waste heat available on the platform from power generation than was required for process or heating use.

The advantages of air pollution control using waste heat utilization are obvious. The technique does not merely reduce emissions, it totally eliminates emission sources from direct-fired heaters. In addition, this type of pollution control results in a net savings in energy rather than a net increase as is common to combustion modification controls currently being considered (which result in an increase in fuel consumption of approximately 5 percent).

4.4.2 Direct-Fired Heaters

Because of the availability of waste heat on offshore platforms, it is the opinion of the project team that the only acceptable air pollution control for this source of emissions is through the utilization of waste heat. In the team's judgment, the need for direct-fired heaters such as are common to oil heater treaters or to gas dehydration units could be substantially curtailed or even eliminated through the use of waste heat recovery systems. Such systems appear to be cost-effective and technically feasible and should be exploited to the maximum.

4.4.3 Waste-Gas Disposal

Both the offshore drilling and production-type platforms require vents to handle waste gas. During drilling operations, the waste gas is released within the mud separator during a pressure kick. In most cases this gas is vented into the atmosphere without further control. On a production platform waste gas sources include pressure-relief valves, compressor bypass loops, oil storage tanks and so on. Three types of waste gas control techniques are currently in operation on production platforms. They are:

- Dilution stacks and underwater flares
- Smokeless (combustion) flares
- Vapor recovery systems

Each of these systems is discussed in the following paragraphs.

4.4.3.1 Dilution Stacks and Underwater Flares

On many of the offshore platforms waste gas is vented directly to the atmosphere in dilution stacks or underwater flares. The purpose of these two types of control techniques is to process the gas in such a way that it will not ignite on the platform.

In the case of dilution stacks, the waste gas is diluted with a large volume of air prior to exhaust. A typical dilution stack would appear as a large-diameter vessel having a fan at the bottom to suck in air and drive the diluted gas out the top. Gas treated in this way will not ignite because the mixture is maintained far below the lower explosive limit of the gas.

In the case of underwater flares, the gas is piped away from the platform and released under water. Tests have shown that gas which has bubbled up through the ocean in this manner will not self-ignite, nor will it reduce the buoyancy of the water enough to capsize boats which accidentally float over the flare.

During the field visits, the project team discussed at length the use of dilution stacks and underwater flares for offshore platforms. The team was informed that this practice was no longer in vogue and only a small percentage of platforms were currently using this type of control technique.

4.4.3.2 Smokeless (Combustion) Flares

The preferred method of control in the Gulf Coast is to use a combustion flare as shown in Figure 4-10. The theory behind the operation of this type of device is obvious. The combustible waste gases are converted to CO_2 which is not a pollutant. The combustion is controlled at appropriate conditions to maximize the combustion of hydrocarbons and at the same time minimize the formation of nitrogen oxides. Emission factors from smokeless flares are shown in Table 4-14. Although the flare achieves a 99.5 percent reduction in hydrocarbons, it results in the formation of carbon monoxide and aldehydes, both of which are far more photochemically reactive than methane.

4.4.3.3 Vapor Recovery Systems

Vapor recovery systems appear to be both the most expensive means of control and also the most effective from the point of view of reduction of photochemical emissions. Using a vapor recovery system, all waste gas sources are conducted to a small compressor. The gases are compressed and recycled to the gas processing system. Tests on such

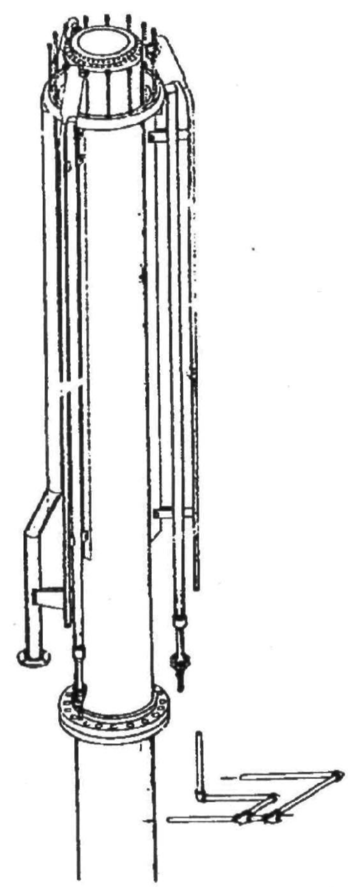

Figure 4-10. View of John Zink smokeless flame burner. (J. A. Danielson, U.S. Environmental Protection Agency, Air Pollution Engineering Manual, May 1973, p. 606.)

TABLE 4-14

EMISSIONS FROM FLARES

POLLUTANT	NO_x	SO_x	HC	CO	PARTICULATES
Emission Rate, Kg/10^6 CF, flared	neg.	8	10	145	neg.
TOTAL EMISSIONS, MT/yr					
California	--------------Gas Not Flared-------------------------				
Louisiana	neg.	9.3	11.6	168.2	neg.
Texas	neg.	3.2	4.0	58.0	neg.
TOTAL	neg.	12.5	15.6	226.2	neg.

systems have indicated recovery efficiencies of 90 percent or greater. One important factor to note, however, is that uncontrolled emissions from the system are predominantly methane which is very low in photochemical reactivity. Partial combustion products emitted by ignited flares are both reactive and carcinogenic although greatly reduced.

Vapor recovery systems are currently required in all offshore California operations. They have not been considered necessary in offshore operations in the Gulf of Mexico.

4.4.4 Fugitive Emissions

The only major source of fugitive emissions that have been identified in the course of this work has been from leaks to seals of compressors, pumps, and valves. With respect to pumps and compressors, the most effective type of seal appears to be a mechanical seal which results in as much as 50 percent lower leakage rates than comparable packed seals.

However, once the pumps, compressors, and valves are put into service, the most appropriate method for pollution control is proper maintenance of the seals to insure that major leaks do not occur. Offshore operations are expected to be much better in this regard than onshore operations because the equipment is all located in one area (on the platform) and it is in open view where leaks can be readily detected. Secondly, because of the potential hazard of a fire onboard, the crew will be more likely to fix leaks for their own protection than will their onshore counterparts.

Although critical, rigorous inspection was not the objective of the site visits made by the project team, none of the valves and pump seals examined by the team appeared to have a significant and measureable leakage rate. The team has concluded from this observation that further controls would be impractible and unwarranted.

CHAPTER FIVE

IMPACT ANALYSIS

5.1 Introduction

In this chapter the source estimates of emissions which are developed in Chapter Four are summarized and applied to offshore oil and gas production activities in 1975 and projected activities for 1985 which are presented in Chapter Two. The impact of applying control techniques identified in Chapter Four to these emissions sources is assessed. A preliminary estimate of the impact on ambient air quality is also presented and considerations for a test program to obtain data not presently available is outlined.

5.2 Total Emissions Estimate

Table 5-1 summarizes the emissions factors developed from the data and analysis in Chapter Four. The total hydrocarbons are based upon a produced gas analysis as follows:[1] 83.6 percent (by volume) methane; 5.4 percent ethane; 6.1 percent propane; 3.2 percent butane; 1.4 percent pentane; 0.3 percent carbon dioxide. Non-methane hydrocarbons have been rounded to 10 percent for estimating purposes. The upper value for mud degassing emissions is based upon a maximum emission of 20,000 SCFD during the last 7 days of drilling a well and a maximum H_2S concentration of 100 ppm in California gas.[2] Oil-based mud emissions are based upon uncovered mud tanks and assume use of this type of mud 5 d/yr per rig. Fuel storage emissions during drilling operations are based upon No. 2 diesel oil, and EPA emissions factor of 0.5 pounds of hydrocarbon per 1,000 gallons of tank throughput for a fixed roof tank, 75 percent rig availability and the drilling scenario shown in Table 4-3. Hydrocarbon emissions from dehydration in gas processing are primarily

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[1] F.E. Vandaveer, Gas Engineers Handbook (New York: The Industrial Press, 1965), pp. 2/11 for Ventura, California. No values for Gulf of Mexico gas were found but analyses are believed to be comparable to Ventura.

[2] Personal communication, USGS Santa Barbara District, Ventura, California, October 11, 1976.

TABLE 5-1

SUMMARY OF EMISSION FACTORS[a]

EMISSION SOURCE	CALIFORNIA						GULF OF MEXICO					
	NO_x	SO_2	HC	CO	PARTICULATES	H_2S	NO_x	SO_2	HC	CO	PARTICULATES	H_2S
DRILLING												
Power Generation (Mg/10^6 ft drilled)	774	52	26	111	unk	-	774	52	26	111	unk	-
Mud Degassing (Mg/well)	-	-	2.8	-	-	-	-	-	2.8	-	-	-
Oil-Based Mud Drilling (Mg/rig-yr)	-	-	0.5	-	-	-	-	-	0.5	-	-	-
Blowouts (Mg/well/day)	-	-	20	-	-	0.03	-	-	20	-	-	[illegible]
Fuel Storage (Mg/rig-yr)	-	-	0.1	-	-	-	-	-	0.1	-	-	-
PRODUCTION												
Well Completion (Mg/well)	unk	unk	unk	unk	unk	unk	unk	unk	unk	unk	unk	unk
Power Generation												
Gas Production (Mg/10^6 SCF)	8.6	0.4	0.8	2.3	0.1	-	8.1	0.4	0.8	2.2	0.1	-
Oil Production (Mg/10^6 bbl)	7.5	0.4	0.7	2.0	0.1	-	8.5	0.4	0.8	2.1	0.1	
Gas Processing												
Dehydration (Mg/10^9 SCF)	0.02	neg.	0.4[b]	neg	neg	-	0.02	neg.	0.4[b]	0.004	0.002	-
Compressor Seals	-	-	unk	-	-	-	-	-	unk	-	-	-
Vents[c] (Mg/10^6 bbl)	-	-	25	-	-	0.04	-	-	250	-	-	0.4
Valve Seals (Mg/10^9 SCF)	-	-	1	-	-	-	-	-	1	-	-	-
Oil Processing												
Direct-Fired Heaters (Mg/10^6 bbl)	0.65	0.004	0.05	0.13	0.07	-	0.65	0.004	0.05	0.13	0.07	-
Pump Seals (Mg/10^6 bbl)	-	-	0.1	-	-	-	-	-	0.1	-	-	-
Valve Seals (Mg/10^6 bbl)	-	-	0.04	-	-	-	-	-	0.04	-	-	
Oil Storage & Surge Tank (Mg/10^6 bbl)	-	-	-	-	-	-	-	-	367	-	-	0.6
Water Treating Units	-	-	unk	-	-	-	-	-	unk	-	-	-

[a]Emission factors may not agree exactly with Chapter Four values due to rounding.
[b]Glycol losses (some of the loss may be in process gas rather than exhaust).
[c]Based upon liquid process volume.

glycol. Vent emissions from gas processing and other platform operations in California offshore facilities take into account vapor recovery at 90 percent efficiency which is current practice. It is assumed that these emissions in the Gulf of Mexico are uncontrolled.

The total emissions estimates for 1975 from offshore oil and gas activities (before application of control technologies) are shown on Table 5-2 and for 1985 on Table 5-3. It is assumed that no energy conservation technologies are in use. Although no published information on the extent of application of energy conserving technologies was found during the study, systems to utilize a portion of the available waste heat were observed on two of the six offshore facilities visited by the project team. For example, the emission factors for gas dehydration are based upon a fired glycol reboiler whereas the two systems observed offshore utilized waste heat from power generation to reboil the glycol. No waste heat utilization systems were observed on the drilling operations visited. No emission factors were found for open burning of produced oil and gas which could be used to assess the emissions from burning the initial well flow to clean up a newly completed well. During initial flow from a new well displacement of the saltwater, drilling fluid filtrate and completion fluids combine with gas, oil, sand and other debris. Depending on the production facilities available, this flow may be processed through the treatment steps or flared until a clean flow is established.

Table 5-4 lists the control technology options for the emissions sources and identified the control technologies utilized in the assessment of emission reduction potential for offshore facilities. This hypothetical case with pollution controls illustrates the large emission reduction potential of higher efficiency combined cycle operations for gas turbines. This technology is currently under development and economic analysis is required. Although significant reductions in hydrocarbon emissions can be achieved through the application of vapor recovery in the Gulf of Mexico and Atlantic, the economics of installing this control technology should be evaluated. The costs of emission control technologies for the drilling phase of oil and gas activities requires further evaluation before particular applications are selected because drilling emissions are only 10 to 20 percent of production emissions.

Another observation is that the U.S. Geological Survey's "no flare" order does address the most significant source of total hydrocarbon emissions. The emission factors used

TABLE 5-2

ESTIMATES OF TOTAL UNCONTROLLED EMISSIONS FROM OFFSHORE FACILITIES, 1975
(Mg/yr)

	CALIFORNIA (STATE & FEDERAL)						OFFSHORE TEXAS, LOUISIANA, AND GULF OF MEXICO (FEDERAL)					
	NO_x	SO_2	HC	CO	PARTICULATES	H_2S	NO_x	SO_2	HC	CO	PARTICULATES	H_2S
DRILLING (average of [illegible] years)												
Power Generation	204.1	11.8	[illegible]	[illegible]	unk	unk	[illegible]	[illegible]	[illegible]	[illegible]	unk	
Mud Degassing	-	-	190[b]	-	-	-	-	-	[illegible][b]	-	-	
Oil-Based Muds	-	-	6	-	-	-	-	-	109	-	-	
Blowouts	-	-	unk	-	-	unk	-	-	unk	-	-	unk
Fuel Storage	-	-	0.4	-	-	-	-	-	14	-	-	
PRODUCTION												
Power Generation	148.5	6.1	14.7	40.0	[illegible]	-	39,641	1,687	3,936	10,683	1,406	-
GAS PROCESSING												
Dehydration	neg	neg	1.6[c]	neg	neg	-	73	-	1,820[c]	14	[illegible]	
Compressor Seals	-	-	unk	-	-	-	-	-	unk	-	-	-
Vents	-	-	[illegible][b]	-	-	0.2	-	-	[illegible][b]	-	-	[illegible]
Valve Seals	-	-	4[b]	-	-	-	-	-	[illegible][b]	-	-	-
OIL PROCESSING												
Direct Fired Heaters	[illegible]	neg	0.8	2.0	[illegible]	-	241	1	[illegible]	48	[illegible]	-
Pump Seals	-	-	1.5	-	-	-	-	-	[illegible]	-	-	-
Valve Seals	-	-	[illegible][b]	-	-	-	-		15[b]	-	-	
Oil Storage and Surge	-	-	-	-	-	-	-	-	[illegible][b]	-	-	[illegible]
WATER TREATING	-	-	unk	-	-	-	-	-	unk	-	-	
TOTAL UNCONTROLLED EMISSIONS	[illegible]	20.1	611 ([illegible])[d]	71.9	6.1	0.2	43,083	2,101	237,893 (39,313)[d]	11,643	1,439	[illegible]

[a]Based on average rig count 1975.

[b]Primarily methane, non-methane hydrocarbon content approximately 10 percent.

[c]Glycol losses (some of the loss may be in process gas rather than exhaust).

[d]Non-methane hydrocarbon emissions shown in parentheses.

TABLE 5-3

ESTIMATES OF TOTAL EMISSIONS FROM OFFSHORE FACILITIES, 1985
(Mg/Yr)

	CALIFORNIA (STATE AND FEDERAL)					
	NO_x	SO_2	HC	CO	PARTIC-ULATES	H_2S
DRILLING (average of nine years)						
Power Generation	788	53	27	115	unk	-
Mud Degassing	-	-	286[b]	-	-	-
Oil-Based Muds	-	-	9	-	-	-
Blowouts	-	-	unk	-	-	-
Fuel Storage	-	-	2	-	-	-
PRODUCTION						
Power Generation	2,984	130	278	797	111	-
GAS PROCESSING						
Dehydration	4	neg	73	1	neg	-
Compressor Seals	-	-	unk	-	-	-
Vents	-	-	4,700[b]	-	-	8
Valve Seals	-	-	183[b]	-	-	-
OIL PROCESSING						
Direct-Fired Heaters	122	1	9	24	13	-
Pump Seals	-	-	19	-	-	-
Valve Seals	-	-	8[b]	-	-	-
Oil Storage	-	-	-	-	-	-
WATER TREATING	-	-	unk	-	-	-
TOTAL UNCONTROLLED EMISSIONS	3,898	184	5,594 (935)[c]	937	124	8
REDUCTION FROM POLLUTION CONTROL (Per Table 5-4 Scenario)						
Waste Heat Utilization	126	1	9	25	13	-
Combined Cycles Operation	1,044	46	97	279	39	-
Vapor Recovery	-	-	-	-	-	-
TOTAL REDUCTION FROM SCENARIO	1,170	47	106	304	52	-
TOTAL CONTROLLED EMISSIONS	2,728	137	5,488 (829)[c]	633	72	8
PERCENT REDUCTION	30	26	2 (11)[c]	32	42	0

[b]Primarily methane; non-methane hydrocarbon content approximately 10 percent.

[c]Non-methane hydrocarbons shown in parentheses.

TABLE 5-3

ESTIMATES OF TOTAL EMISSIONS FROM OFFSHORE FACILITIES, 1985

(Mg/Yr)

	OFFSHORE TEXAS, LOUISIANA, AND GULF OF MEXICO (FEDERAL)					
	NO_X	SO_2	HC	CO	PARTIC-ULATES	H_2S
DRILLING (average of nine years)						
Power Generation	2,580	173	87	377	unk	-
Mud Degassing	-	-	932[b]	-	-	-
Oil-Based Muds	-	-	43	-	-	-
Blowouts	-	-	unk	-	-	-
Fuel Storage	-	-	9	-	-	-
PRODUCTION						
Power Generation	25,955	1,274	2,549	7,046	956	-
GAS PROCESSING						
Dehydration	56	neg	1,126		6	-
Compressor Seals	-	-	unk	-	-	-
Vents	-	-	93,000[b]	-	-	149
Valve Seals	-	-	2,814[b]	-	-	-
OIL PROCESSING						
Direct-Fired Heaters	242	1	19	48	26	-
Pump Seals	-	-	37	-	-	-
Valve Seals	-	-	15[b]	-	-	-
Oil Storage	-	-	136,524[b]	-	-	223
WATER TREATING	-	-	unk	-	-	-
TOTAL UNCONTROLLED EMISSIONS	28,833	1,448	237,155 (27,162)[c]	7,471	988	372
REDUCTION FROM POLLUTION CONTROL (Per Table 5-4 Scenario)						
Waste Heat Utilization	298	1	19	59	32	-
Combined Cycles Operation	9,084	446	892	2,466	335	-
Vapor Recovery	-	-	206,572[b]	-	-	335
TOTAL REDUCTION FROM SCENARIO	9,382	447	207,483 (21,568)[c]	2,525	367	335
TOTAL CONTROLLED EMISSIONS	19,451	1,001	29,672 (5,594)[c]	4,946	621	37
PERCENT REDUCTION	33	31	87 (79)[c]	34	37	90

[b]Primarily methane; non-methane hydrocarbon content approximately 10 percent.

[c]Non-methane hydrocarbons shown in parentheses.

TABLE 5-3

ESTIMATES OF TOTAL EMISSIONS FROM OFFSHORE FACILITIES, 1985

(Mg/Yr)

	ATLANTIC (FEDERAL)[a]					
	NO_x	SO_2	HC	CO	PARTIC-ULATES	H_2S
DRILLING (average of nine years)						
Power Generation	774	52	26	113	unk	-
Mud Degassing	-	-	188[b]	-	-	unk
Oil-Based Muds	-	-	9	-	-	-
Blowouts	-	-	unk	-	-	-
Fuel Storage	-	-	2	-	-	-
PRODUCTION						
Power Generation	3,987	194	388	1,082	146	-
GAS PROCESSING						
Dehydration	7	neg	136	1	1	-
Compressor Seals	-	-	unk	-	-	-
Vents	-	-	36,250[b]	-	-	58
Valve Seals	-	-	340[b]	-	-	-
OIL PROCESSING						
Direct-Fired Heaters	94	1	7	19	10	-
Pump Seals	-	-	15	-	-	-
Valve Seals	-	-	6[b]	-	-	-
Oil Storage	-	-	53,215[b]	-	-	87
WATER TREATING	-	-	unk	-	-	-
TOTAL UNCONTROLLED EMISSIONS	4,862	247	90,582 (9,583)[c]	1,215	157	145
REDUCTION FROM POLLUTION CONTROL (Per Table 5-4 Scenario)						
Waste Heat Utilization	101	1	7	20	11	-
Combined Cycles Operation	1,395	68	136	379	51	-
Vapor Recovery	-	-	80,519[b]	-	-	131
TOTAL REDUCTION FROM SCENARIO	1,496	69	80,662 (8,195)[c]	399	62	131
TOTAL CONTROLLED EMISSIONS	3,336	178	9,920 (1,388)[c]	816	95	14
PERCENT REDUCTION	31	28	89 (86)[c]	33	39	90

[a]Atlantic emission factors assumed to be the same as Gulf of Mexico.

[b]Primarily methane; non-methane hydrocarbon content approximately 10 percent.

[c]Non-methane hydrocarbons shown in parentheses.

TABLE 5-4

CONTROL TECHNOLOGY OPTIONS AND 1985 CONTROL SCENARIO

EMISSIONS SOURCE	CONTROL TECHNOLOGY OPTIONS	OPTION FOR TABLE 5-3 SCENARIO[a]
Power Generation - Drilling	Combustion Control (auxil-liaries) Waste Heat Utilization	None
Mud Degassing	Dilution Flares, Combustion Flare, Vapor Recovery System	None
Oil-Based Fuel Storage	Dilution Flare, Combustion Flare, Vapor Recovery	None
Power Generation - Production	Combined-Cycle Operation (developmental)	Combined-Cycle Operation
Gas Dehydration	Waste Heat Utilization	Waste Heat Utilization
Compressor Seals	Vapor Recovery	None
Vents (Gas Processing)	Vapor Recovery, Combustion Flares, Dilution Flares, Operating Practice	Vapor Recovery[b]
Valve Seals (Gas)	Maintenance	None
Direct-Fired Heaters	Waste Heat Utilization	Waste Heat Utilization
Pump Seals, Valve Seals (Oil)	Maintenance	None
Oil Storage and Surge Tanks	Vapor Recovery, Combustion Flare, Dilution Flare	Vapor Recovery[b]

[a]100 percent application to sources assumed.

[b]Vapor recovery at 90 percent efficiency.

herein are based upon operators data and in each case some gas release occurs despite such operating practices as shutting in productive wells when the gas compressors must be shut down for maintenance.

5.3 Ambient Air Quality

As an example impact a typical offshore California platform producing oil and gas is selected for evaluation. Based upon the projections developed in Chapter Two, the 16 projected new offshore production facilities would be producing an average of approximately 28,250 barrels of oil and 30,800,000 ft^3 of gas per day in 1985. Emission rates for this typical platform are summarized in Table 5-5.

Based upon the graph shown in Figure 5-1, the contribution to short-term ambient offshore concentrations of non-methane hydrocarbons would be 48.5 $\mu g/m^3$. This assumes the platform is represented by a single point source of emissions release at a height of 27 meters above sea level, a wind-speed of 1 m/sec which persists in the onshore direction under stability class D, and a platform location at the 3-mile limit.

The primary 3-hour ambient standard for non-methane hydrocarbons is 160 $\mu g/m^3$, or the equivalent of about 199 $\mu g/m^3$ for a 1-hour standard using the interpolation formula as given in Turner's Workbook of:

$$\chi_1 = \chi_3 (t_3/t_1)^p$$

where p may take a value between 0.17 and 0.20. Therefore, the emissions from a single typical platform at the 3-mile limit (4.8 kilometers) would be 24 percent of the standard. By comparison, a platform 10 miles from shore would contribute only 4 percent of the interpolated 1-hour ambient standard for non-methane hydrocarbons at the shoreline. Note that another important difference between California and Louisiana or Texas is that the existing platforms are much closer to the shore and they are much closer together as well. Analysis of the ambient air quality impacts of multiple sources for long averaging times requires more detailed modeling beyond the scope of this study. The following discussion presents some further considerations for carrying out such modeling and in interpreting the results of the above calculations.

TABLE 5-5

SUMMARY OF EMISSION RATES FOR A TYPICAL OFFSHORE CALIFORNIA PRODUCTION PLATFORM - 1985 (g/sec)

SOURCE	NO_x	SO_2	THC	NMHC[a]	CO	Particulates	H_2S[b]
Power Generation	5.5	0.2	0.5	0.01	1.5	0.2	-
Gas Processing	0.4	neg	10.8	1.74	0.04	0.04	0.02
Oil Processing	0.2	neg	14.2	2.29	0.03	0.03	0.02
TOTAL EMISSION	6.1	0.2	25.5	4.04	2.57	0.27	0.04

[a]Based upon 2 percent NMHC:THC ratio for power generation (average of data from C.M. Urban, and K.J. Springer, Study of Exhaust Emissions from Natural Gas Pipeline Compressor Engines (San Antonio, Texas: Southwest Research Institute, February 1975), p. 18, and 16 percent NMHC:THC ratio for produced gas. Ventura, California, Gas Engineers Handbook (New York: The Industrial Press, 1965), p. 2/11.

[b]Assumed concentrations of 100 ppm as maximum for estimating purposes only. Almost all existing offshore gas production has negligible H_2S content.

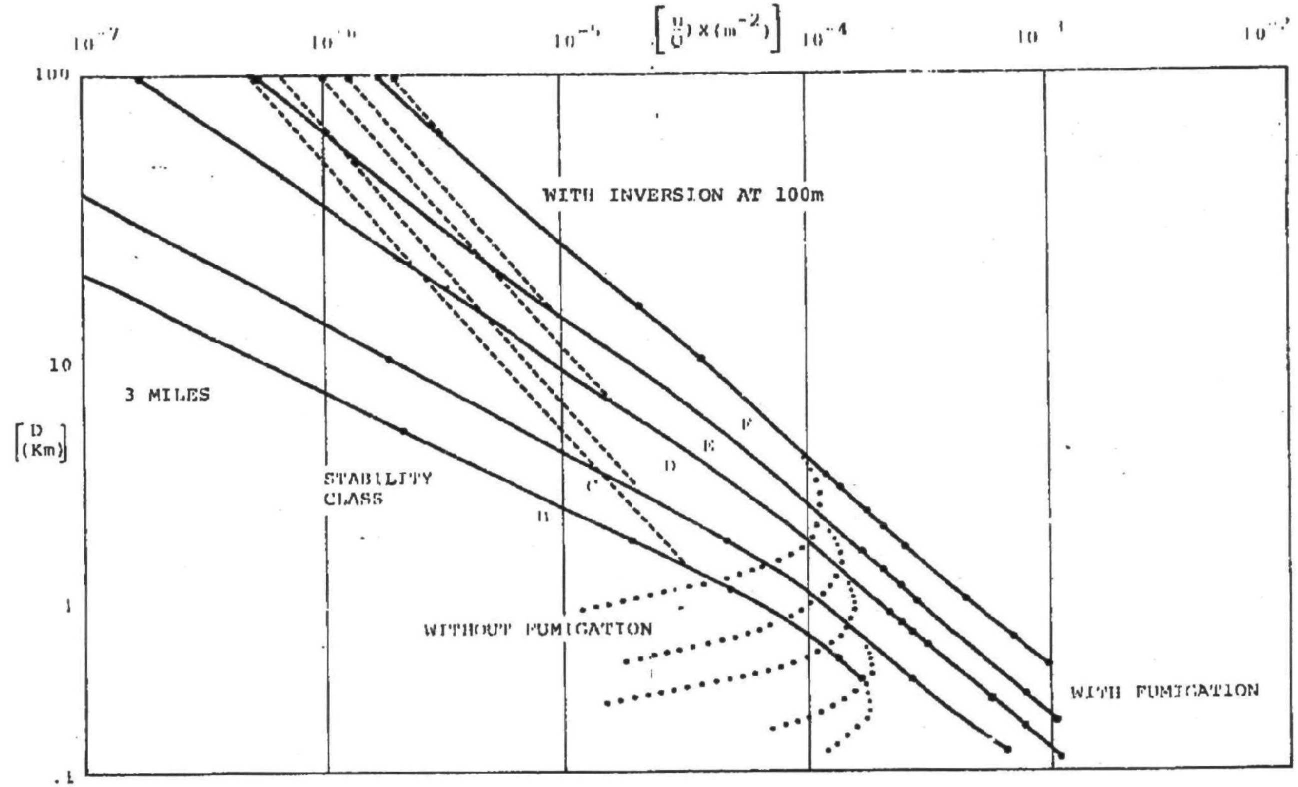

Figure 5-1. Modified concentration versus downwind distance for H = 27m.

In assessing short-term impacts, one must develop a conceptual model of the processes that are expected to be active at the site of assessment. The quality of the air being advected from a large body of water containing some oil development activity, to a shoreline area is of concern here. This implies that the air mass will likely be almost completely maritime, with fairly little continental influence in most cases.

This air mass is considered to be adjusted to the average sea surface temperature, which means that a thermal discontinuity will often exist at the shore. Under these conditions, if a cooler, stable air mass, for example, penetrates inland over a strongly heated land mass, the lower layers of the air mass will become highly unstable, and a thermal boundary layer will grow in height as the air moves further inland. The dispersion within the boundary layer will greatly exceed that above it, producing a situation that is very similar to early morning fumigation conditions. The main difference between these two situations is that the morning fumigation involves a thermal boundary layer that grows in time, but remains nearly fixed in the horizontal plane. The shoreline fumigation height is relatively constant in time (over a period of several hours, say), but varies with distance from the shore. Since air quality criteria are developed for time-average concentrations at discrete points, then the case of the shoreline fumigation is clearly of greater concern. Here, a segment of a community may be subjected to relatively high pollutant concentrations for a period of several hours.

Another situation may also lead to enhanced ground level concentrations of plume material. Elevated inversions may exist over nearshore waters just as they do over land. Should meteorological conditions produce a shallow mixing barrier, then the resultant trapping of pollutants beneath this level can cause increased downwind concentrations within the mixing layer.

Both of these processes are included in this dispersion analysis. Outside of these external influences, the major parameters that have a direct bearing on downwind ground level concentrations are the marine atmospheric stability class (based on Pasquill stability classes), average wind speed at the height of release, the height of the plume centerline, and the source strength (rate of pollutant release).

Dispersion in the marine atmosphere is quite different from that over land. Substitution of a vast water surface for dry land has far-reaching implications. The diurnal temperature cycle of a land surface is quite pronounced; insolation is readily absorbed in a very thin layer, and the resultant heat gain is trapped in a rather shallow layer owing to the poor thermal conductivity of the medium. At night, this heat is rapidly lost due to conduction to the atmosphere, and radiation to space. Under conditions of low relative humidity, the air above the surface is especially transparent to the long-wave radiation, and the rapid heat loss gives rise to a rapid cooling of the surface.

Over the oceans, insolation penetrates the lower boundary of the atmosphere, with absorption taking place over a discrete layer, instead of only a thin skin. Wind-mixing of the upper ocean bastens the redistribution of this heat energy, so any temperature gradients near the surface are very small compared to those of a land surface. The heat capacity of water also tends to reduce a rapid rise in surface temperature during the day, owing to its larger heat capacity. The final significant difference lies in the ability of evaporation at the sea surface to remove heat energy from this surface, thereby reducing its temperature.

At night, temperature changes of the sea surface are also less than those over land. This is primarily a result of the more uniform distribution of temperature in the vertical (beneath the surface), the greater heat capacity of water, and the greater water vapor content of the overlying atmosphere (a partial "screen" reflecting some of the long-wave radiation back to the surface).

All of the differences noted above tend to suggest that a water boundary has a great deal more thermal inertia than a land boundary, so the extremes of stabilities encountered over land are quite rare over the oceans. In fact, the brief remarks made above might lead one to question the possibility of observing even mildly unstable atmospheric conditions over the ocean. These do indeed occur quite frequently. The great amount of water vapor present in the lower layers of the marine atmosphere tend to reduce the resistance of the column of air to vertical mixing. Any displacement of an air parcel in the vertical which leads to some condensation will cause that volume of air to absorb that latent heat of condensation, with a resultant rise in temperature. This increases the net buoyancy of that volume, which leads to further vertical movement and mixing. Temperature profiles alone do not establish the stability of maritime air; water vapor profiles must also be known. Therefore a weak temperature gradient near the ground may be associated with a mildly unstable atmospheric surface layer if proper account of the water vapor distribution is allowed.

5.4 Outline of Field Sampling Program

A complete characterization of pollutant emissions from offshore oil facilities is needed for any detailed assessment of air quality impact. Parameters influencing the effective height of release are particularly important to obtain since release height (including plume rise) plays a major role in determining ground level concentrations downwind of the site. Secondary aerodynamic modification of the releases is also of major significance in that the wake structure formed by the platform causes both rapid dispersion and release height modifications near the structure. These two factors emphasize the scope of problems that must be addressed in any field monitoring endeavor.

Sources with the highest priority to be monitored include compressor seals and thrust bearings, oil storage/surge tank vents and gas vents. Emissions from open burning of produced oil and gas should be developed for use in assessing the impacts of blowouts and well completions. Emissions from the glycol reboiler in gas dehydration systems should also be characterized.

Sampling frequencies shall be tailored to the typical operating sequence of each of the components tested. For example, gas vents, compressor seals and thrust bearing samples must encompass a complete maintenance cycle of the gas compressor.

Operating variations due to variations in the load or throughput of the equipment source being sampled shall also be accounted for in the sampling schedule. Data will be collected on all relevant operating variables to include oil and gas production volumes, equipment status, electric power demand, and gas content and drilling activities.

Testing equipment shall be selected for its suitability to the measure pollutants from the point sources in the concentrations expected, sensitivity of the instruments and reliability in the marine environment, support materials and personnel required (including sample storage precautions where necessary), and sampling cycle time required for the acquisition of one measurement. The overall sampling program will be designed to obtain representative data from the planned data collection on a limited number of platforms, in terms of the range of operating conditions and system configurations sampled, and the degree of compatibility between the point source sampling periods, and the ambient measurements required.

The ambient air measurements scheduled will be designed to take advantage of simultaneous point source measurements and meteorological measurements. Precautions must be taken to avoid undesirable wake effects in developing the meteorlogical data base and in determining the ambient flow characteristics. Turbulence data from selected points in the wake of the tower shall be collected to assess the small scale dispersion parameters in regions of point source release and suspected fugitive emissions. Simple "smoke" releases may suffice for this purpose.

One of the two ambient air measurement approaches may be applied at a sampling site; platform mounted or free-floating instrument vehicles. Precautions necessary to collect ambient air data include sampling in such a way that several wind speed-stability class regions are documented several times during each operational activity of importance to the fugitive emissions level. In the case of free-floating vehicles, this requires methodology for inferring fugitive emissions levels from a limited number of downwind measurements. One possible approach is to determine those meteorological conditions which minimize the uncertainty of the inversion process, and sample only during these occurrences.

The final monitoring program that promises technically reliable emissions estimates will be selected by evaluating the cost-effectiveness of each sampling option.