Exhibit 5

U.S. Envtl. Prot. Agency, EPA 440/1-76/055-a, *Development Document for Interim Final Effluent Limitations Guidelines and Proposed New Source Performance Standards for the Oil & Gas Extraction Point Source Category* (1976)

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Development Document for Interim Final Effuent Limitations Guidelines and Proposed New Source Performance Standards for the

OIL & GAS EXTRACTION

Point Source Category

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

SEPTEMBER 1976

DEVELOPMENT DOCUMENT

for

INTERIM FINAL

EFFLUENT LIMITATIONS GUIDELINES

and

PROPOSED NEW SOURCE PERFORMANCE STANDARDS

for the

OIL AND GAS EXTRACTION
POINT SOURCE CATEGORY

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ABSTRACT

This development document presents the findings of an extensive study of the Oil and Gas Extraction Industry for the purposes of developing effluent limitations guidelines, for existing point sources and standards of performance for new sources, to implement Sections 301, 304, 306 and 307 of the Federal Water Pollution Control Act, as amended (33 U.S.C. 1551, 1314, and 1316, 86 Stat. 816 et. seq.) (the "Act"). Guidelines and standards were developed for the Oil and Gas Extraction Industry, which was divided into 6 subcategories.

Effluent limitations guidelines contained herein set forth the degree of effluent reduction attainable through the application of the best practicable control technology currently available (BPCTCA) and the degree of effluent reduction attainable through the application of the best available technology economically achievable (BATEA) which must be achieved by existing point sources by July 1, 1977 and July 1, 1983, respectively. The new source performance standards (NSPS) contained herein set forth the degree of effluent reduction which are achievable through the application of the best available demonstrated control technology, processes, operating methods, or other alternatives.

Supporting data and rationale for the development of proposed effluent limitations guidelines and standards of performance are contained in this development document.

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SECTION I

CONCLUSIONS

This study covered the waste treatment technology for the Oil and Gas Extraction Point Source Category. The Oil and Gas Extraction Point Source Category covers the pollutants arising from the production of crude petroleum and natural gas, drilling oil and gas wells, and oil and gas field exploration services.

The wastes associated with this category result from the discharge of produced water, drilling muds, drill cuttings, well treatment, and produced sands for all subcategories and additionally, deck drainage, sanitary and domestic wastes for the offshore and coastal subcategories.

Since the raw waste loads and treatability of the wastes are independent of size, location and climate and the volume of production water varies with the age and nature of the producing formation, the limitations are set in terms of concentration and the subcategorization is based on a balance of the costs with the potential environmental benefits and energy use (loss). The subcategories developed for the oil and gas extraction industry for the purpose of establishing effluent limitations are as follows:

	Subcategory	Operations Included
1.	Near-Offshore	All facilities within offshore State waters.
2.	Far-Offshore	All facilities in Federal waters.
3.	Onshore	All facilities landward of the territorial seas (except as defined by 4, 5, and 6 below).
4.	Coastal	All facilites in the coastal bays and estuaries of Louisiana and Texas.
5.	Beneficial Use	These facilites with low TDS content produced waters who's discharge serves some beneficial use.
6.	Stripper	All facilities with less than 10 barrels of crude oil per calendar day of production.

SECTION II

RECOMMENDATIONS

The significant or potentially significant waste water constituents are oil and grease, fecal coliform, oxygen demanding parameters, heavy metals, total dissolved solids, and toxic materials. These waste water constituents were selected to be the subject of the effluent limitations.

Effluent limitations commensurate with the best practicable control technology currently available are promulgated interim final for each subcategory. These limitations, listed in Table 1 are explicit numerical values (whenever possible) or some other criteria.

BPCTCA end-of-pipe technology is based on the application of the existing waste water treatment processes currently used in the Oil and Gas Extraction Industry. These consist of equalization, chemical addition, and gas flotation (or its equivalent) for the treatment of produced water and deck drainage. The variability of performance of this type of waste water treatment system has been recognized in the development of the BPCTCA effluent limitations.

Effluent limitations commensurate with the best available technology economically achievable are proposed for each subcategory. These effluent limitations are listed in Table 2. The primary end-of-pipe treatment for the near offshore subcategory is the subsurface disposal of production water and for the far offshore subcategory it is similar to that for BPCTCA.

New source performance standards commensurate with the best available demonstrated technology are the same as the BATEA limitations. These effluent limitations are listed in Table 2.

TABLE 1
Oil and Gas Extraction Industry
Effluent Limitations - BPCTCA

Subcategory	Water Source	Oil & Grease - mg/l		Residual Chlorine - mg/l
		Maximum for any one day	Average of daily values for thirty consecutive days shall not exceed	
A. Near Offshore	produced water	72	48[d]	N/A
B. Far Offshore	deck drainage	72	48[d]	N/A
D. Coastal	drilling muds	a	a	N/A
	drill cuttings	a	a	N/A
	well treatment	a	a	N/A
	sanitary M10	N/A	N/A	greater than 1[b]
	M9IM[c]	N/A	N/A	N/A
	domestic[c]	N/A	N/A	N/A
	produced sand	a	a	N/A
C. Onshore	produced water	e	N/A	N/A
E. Beneficial Use	drilling muds	no discharge		
	drill cuttings	no discharge		
	well treatment	no discharge		
	produced sand	no discharge		

Notes:

a - No discharge of free oil to the surface waters.
b - Minimum of 1 mg/l and maintained as close to this concentration as possible.
c - There shall be no floating solids as a result of the discharge of these materials.
d - Not applicable to the coastal subcategory.
e - For the onshore subcategory - no discharge; for the beneficial use subcategory - 45 mg/l.

TABLE 2
Oil and Gas Extraction Industry
Effluent Limitations - BATEA and New Source

Subcategory	Water Source	Pollutant Parameter - Effluent Limitations: Oil & Grease - mg/l		Residual Chlorine - mg/l
		Maximum for any one day	Average of daily values for thirty consecutive days shall not exceed	
A. Near Offshore	produced water	No discharge		
D. Coastal	deck drainage	72	48	N/A
B. Far Offshore	produced water	52	30	N/A
	deck drainage	52	30	N/A
A. Near Offshore	drilling muds	a	a	N/A
B. Far Offshore	drill cuttings	a	a	N/A
C. Onshore	well treatment	a	a	N/A
D. Coastal	sanitary M10	N/A	N/A	greater than 1
E. Beneficial Use	M9IM	N/A	N/A	N/A
	domestic	N/A	N/A	N/A
	produced sand	a	a	N/A

Notes:

a - These BAT and New Source limitations are identical to those applicable for each subcategory as for BPT listed in Table 1.

SECTION III

INTRODUCTION

Purpose and Authority

Section 301(b) of the Federal Water Pollution Control Act Amendments of 1972 requires the achievement by not later than July 1, 1977, of effluent limitations for point sources, other than publicly owned treatment works. The limitations are to be based on application of the best practicable control technology currently available as defined by the Administrator pursuant to Section 304(b) of the Act. Section 301(b) also requires the achievement by not later than July 1, 1983, of more stringent effluent limitations for point sources, other than publicly owned treatment works. The 1983 limitations are to be based on application of the best available technology economically achievable which will result in reasonable further progress toward the national goal of eliminating the discharge of all pollutants, as determined in accordance with regulations issued by the Administrator pursuant to Section 304(b) of the Act.

Section 306 of the Act requires the Administrator, within one year after a category of sources is included in a list published pursuant to section 306(b)(1)(A) of the Act, to propose regulations establishing Federal standards of performances for new sources within such categories. The Administrator published, in the Federal Register of January 16, 1973 (38 F.R. 1624), a list of 27 source categories. Publication of an amended list will constitute announcement of the Administrator's intention of establishing, under section 306, standards of performance applicable to new sources within the Oil and Gas Extraction Industry. The list will be amended when proposed regulations for the Oil and Gas Extraction Industry are published in the Federal Register.The standards are to reflect the greatest degree of effluent reduction which the Administrator determines to be achievable through the application of the best available demonstrated control technology, processes, operating methods, or other alternatives; where practicable, a standard may permit no discharge of pollutants.

Section 304(b) of the Act requires the Administrator to publish within one year of enactment of the Act, regulations providing guidelines for effluent limitations. The guidelines are to set forth:

The degree of effluent reduction attainable through application of the best practicable control technology currently available.

The degree of effluent reduction attainable through application of the best control measures and practices economically achievable including treatment techniques, process and procedure innovations, operating methods, and other alternatives.

The findings contained herein set forth effluent limitations guidelines pursuant to Section 304(b) of the Act for certain segments of the petroleum industry.

General Description of Industry

The segments of the industry to be covered by this study are the following Standard Industrial Classifications (SIC):

1311 Crude Petroleum and Natural Gas

1381 Drilling Oil and Gas Wells

1382 Oil and Gas Field Exploration Services

1389 Oil and Gas Field Services, not classified elsewhere

Within the above SIC's, this study covers those activities carried out both onshore and in the estuarine, coastal, and Outer Continental Shelf areas.

The characteristics of wastes differ considerably for the different processes and operations. In order to describe the waste derived from each of the industry subcategories established in Section IV, it is essential to evaluate the sources and contaminants in the three broad activities in the oil and gas industry--exploring, drilling, and producing--as well as the satellite industries that support those activities.

Exploration

The exploration process usually consists of mapping and aerial photography of the surface of the earth, followed by special surveys such as seismic, gravimetric, and magnetic, to determine the subsurface structure. The special surveys may be conducted by vehicle, vessel, aircraft, or on foot, depending on the location and the amount of detail needed.

These surveys can suggest underground conditions favorable to accumulation of oil or gas deposits, but they must be followed by the drill since only drilling can prove the actual existence of oil.

Aside from sanitary wastes generated by the personnel involved, only the drilling phase of exploration generates significant amounts of water pollutants. Exploratory drilling, whether shallow or deep, generally uses the same rotary drilling methods as development drilling. The discussion of wastes generated by exploratory drilling are discussed under "Drilling System".

Drilling System

The majority of wells drilled by the petroleum industry are drilled to obtain access to reservoirs of oil or gas. A significant number, however, are drilled to gain knowledge of geologic formation. This latter class of wells may be shallow and drilled in the initial exploratory phase of operations, or may be deep exploration seeking to discover oil or gas bearing reservoirs.

Most wells are drilled today by rotary drilling methods. Basically the methods consist of:

1. Machinery to turn the bit, to add sections on the drill pipe as the hole deepens, and to remove the drill pipe and the bit from the hole.

2. A system for circulating a fluid down through the drill pipe and back up to the surface.

This fluid removes the particles cut by the bit, cools and lubricates the bit as it cuts, and, as the well deepens, controls any pressures that the bit may encounter in its passage through various formations. The fluid also stabilizes the walls of the well bore.

The drilling fluid system consists of tanks to formulate, store, and treat the fluids; pumps to force them through the drill pipe and back to the surface; and machinery to remove cuttings, fines, and gas from fluids returning to the surface (see Figure 1). A system of valves controls the flow of drilling fluids from the well when pressures are so great that they cannot be controlled by weight of the fluid column. A situation where drilling fluids are ejected from the well by subsurface pressures and the well flows uncontrolled is called a blowout, and the controlling valve system is called the blowout preventer (see Figure 2).

For offshore operations, drilling rigs may be mobile or stationary. Mobile rigs are used for both exploratory and development drilling, while stationary rigs are used for development drilling in a proven field. Some mobile rigs are mounted on barges and rest on the bottom for drilling in shallow waters. Others, also mounted on barges are jacked up above the water on legs for drilling in deeper water (up to 300 feet). A third class of mobile rigs are on floating units for even deeper operations. A floating rig may be a vessel, with a typical ship's hull, or it may be semisubmersible--essentially a floating platform with special submerged hulls and supporting a rig well

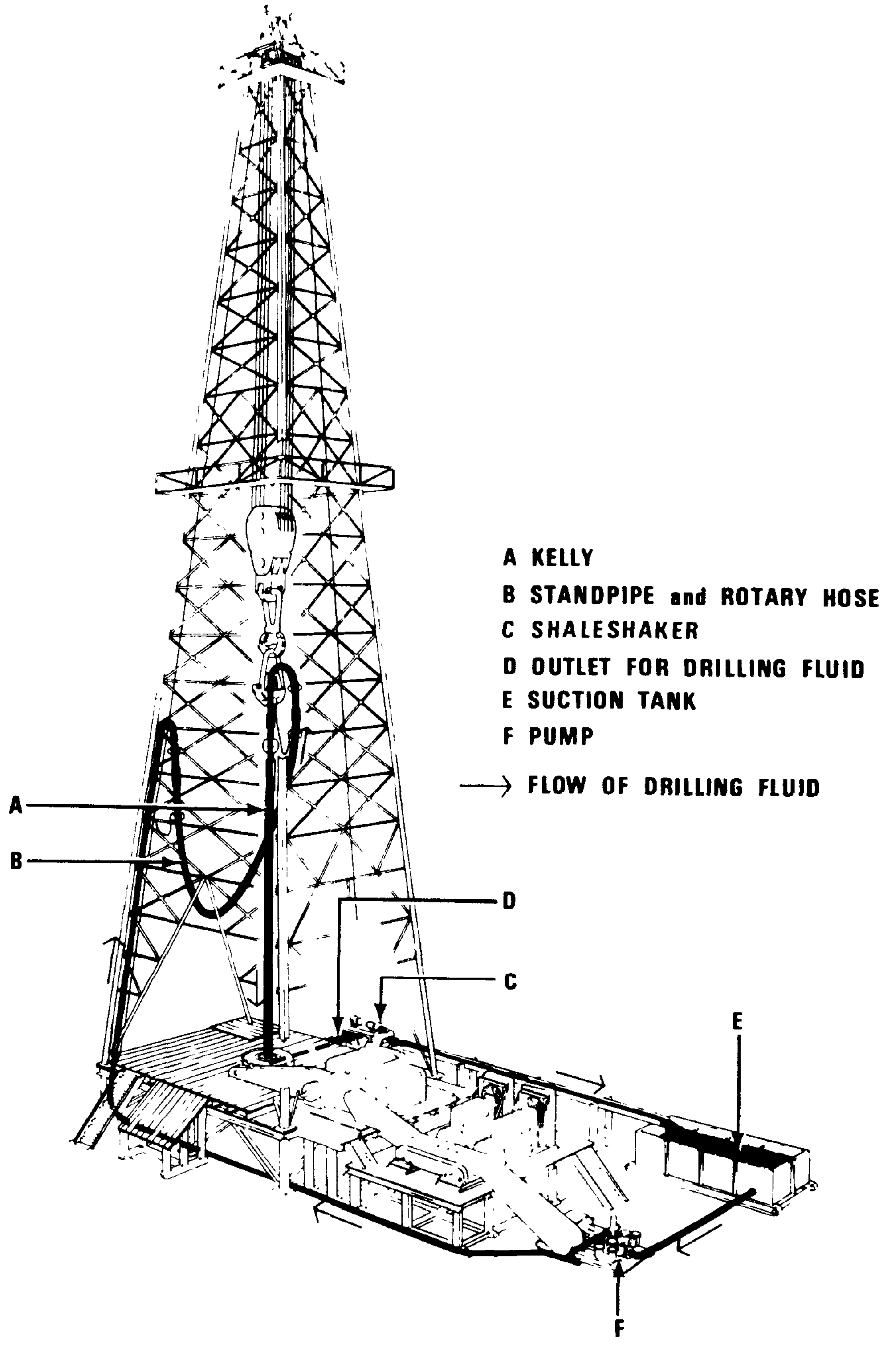

Fig. 1 -- ROTARY DRILLING RIG

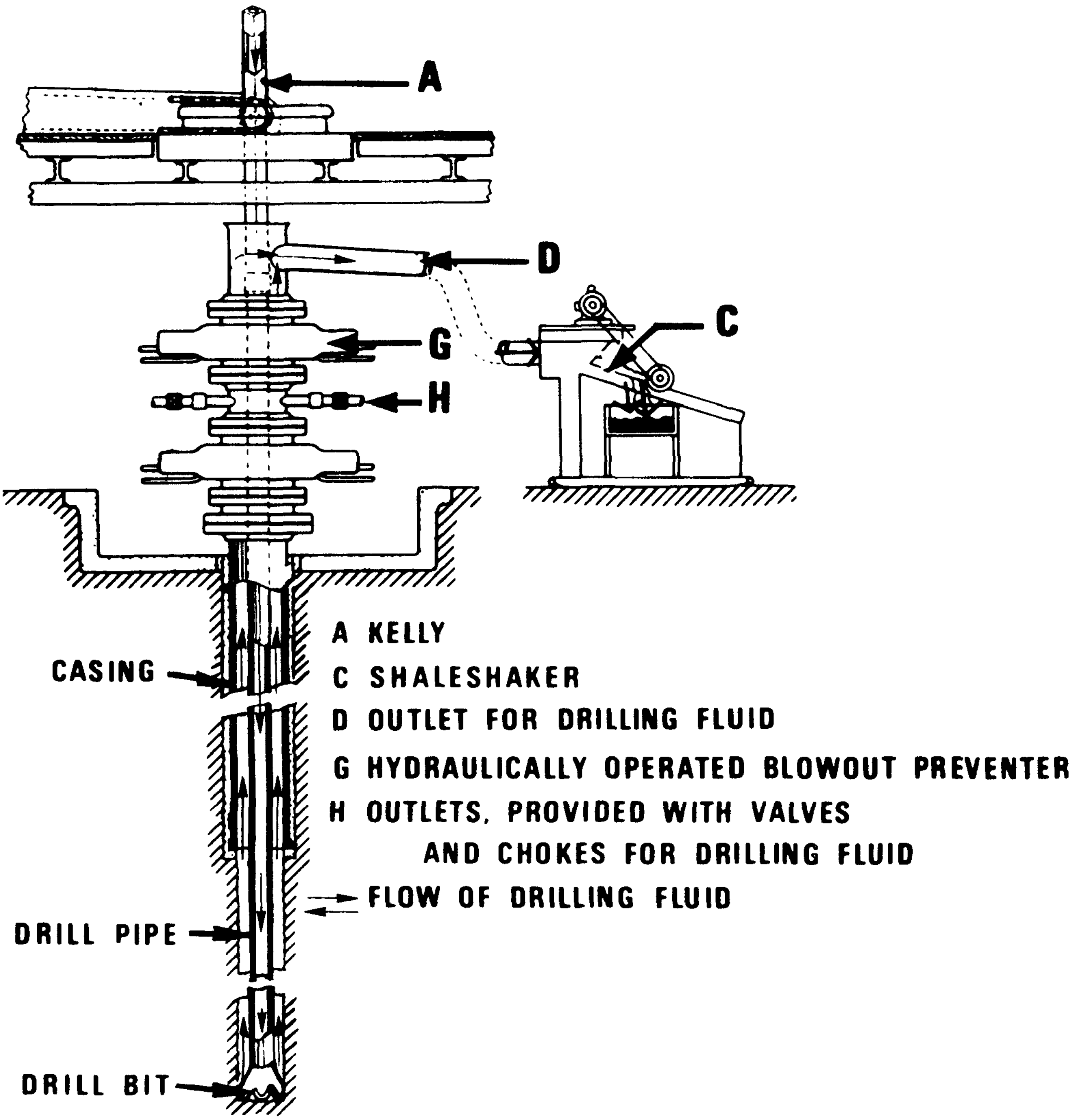

Fig. 2 -- SHALESHAKER AND BLOWOUT PREVENTER

above the water. Stationary rigs are mounted on pile-supported platforms.

Onshore drilling rigs used today are almost completely mobile. The derrick or mast and all drilling machinery are removed when the well is completed and used again in a new location.

Rigs used in marsh areas are usually barge mounted, and canals are dredged to the drill sites so that the rigs can be floated in.

The major source of pollution in the drilling system is the drilling fluid or "mud" and the cuttings from the bit. In early wells drilled by the rotary method, water was the drilling fluid, The water mixed with the naturally occurring soils and clays and made up the mud. The different characteristics and superior performance of some of these natural muds were evident to drillers, which led to deliberately formulated muds. The composition of modern drilling muds is quite complex and can vary widely, not only from one geographical area to another, but also in different portions of the same well.

The drilling of a well from top to bottom is not a continuous process. A well is drilled in sections, and as each section is completed it is lined with a section of pipe or casing (see Figure 2). The different sections may require different types of mud. The mud from the previous section must either be disposed of or converted for the next section. Some mud is left in the completed well.

Basic mud components include: bentonite or attapulgite clays to increase viscosity and create a gel; barium sulfate (barite), a weighting agent; and lime and caustic soda to increase the pH and control viscosity. (Additional conditioning constituents may consist of polymers, starches, lignitic material, and various other chemicals). Most muds have a water base, but some have an oil base. Oil based muds are used in special situations and present a much higher potential for pollution. They are generally used where bottom hole temperatures are very high or where water based muds would hydrate water-sensitive clays or shales. They may also be used to free stuck drill pipes, to drill in permafrost areas, and to kill producing wells.

As the drilling mud is circulated down the drill pipe, around the bit, and back up in annulus between the bore hole and the drill pipe, it brings with it the material cut and loosened by the bit, plus fluids which may enter the hole from the formation (water, oil, or gas). When the mud arrives at the surface, cuttings, silt, and sand are removed by shaleshakers, desilters, and desanders. Oil or gas from the formation is also removed, and the cleansed mud is cycled through the drilling system again. With offshore wells, the cuttings, silt and sand are discharged overboard if they do not contain oil. Some drilling mud clings to the sand and cuttings, and when this material reaches the water the heavier particles (cuttings and sand) sink to the bottom while the mud and fines are swept down current away from the platform.

Onshore, discharges from the shaleshakers and cyclone separators (desanders or desilters) usually go to an earthen (slush) pit adjacent to the rig. To dispose of this material the pit is backfilled at the end of the drilling operations.

The removal of fines and cuttings is one of a number of steps in a continuing process of mud treatment and conditioning. This processing may be done to keep the mud characteristics constant or to change them as required by the drilling conditions. Many constituents of the drilling mud can be salvaged when the drilling is completed, and salvage plants may exist either at the rig or at another location, normally at the industrial facility that supplies mud or mud components.

Where drilling is more or less continuous, such as on a multiple-well offshore platform, the disposal of mud should not be a frequent occurrence since it can be conditioned and recycled from one well to another.

The drilling of deeper, hotter holes may increase use of oil based mud. However, new mud additives may permit use of water based muds where only oil muds would have served before. Oil muds always present disposal problems.

Production System

Crude oil, natural gas, and gas liquids are normally produced from geological reservoirs through a deep bore well into the surface of the earth. The fluid produced from oil reservoirs normally consists of oil, natural gas, and salt water or brine containing both dissolved and suspended solids. Gas wells may produce dry gas but usually also produce varying quantities of light hydrocarbon liquids (known as gas liquids or condensate) and salt water. As in the case of oil field brines, the water contains dissolved and suspended solids and hydrocarbon contaminants. The suspended solids are normally sands, clays, or other fines from the reservoir. The oil can vary widely in its physical and chemical properties. The most important properties are its density and viscosity. Density is usually measured by the "API Gravity" method which assigns a number to the oil based on its specific gravity. The oil can range from very light gasoline like materials (called natural gasolines) to heavy, viscous asphalt like materials.

The fluids are normally moved through tubing contained within the larger cased bore hole. For oil wells, the energy required to lift the fluids up the well can be supplied by the natural pressures in the formation, or it can be provided or assisted by various man-made operations at the surface. The most common methods of supplying man-made energy to extract the oil are: to inject fluids (normally water or gas) into the reservoir to maintain pressure, which would otherwise drop during withdrawal; to force gas into the well stream in order to lighten the column of fluid in the bore and assist in lifting as the gas expands up the well; and to employ various types of pumps in the well itself. As the fluids rise in the well to the surface, they flow through various valves and flow control devices which make up the well head. One of these is an orifice (choke) which maintains required back pressure on the well and controls, by throttling the fluids, the rate at which the well can flow. In some cases, the choke is placed in the bottom of the well rather than at the well head.

Once at the surface, the various constituents in the fluids produced by oil and gas wells are separated: gas from the liquids, oil from water, and solids from liquids (see Figure 3). The marketable constituents, normally the gas and oil, are then removed from the production area, and the wastes, normally the brine and solids, are disposed of after further treatment. At this stage, the gas may still contain significant amounts of hydrocarbon liquids and may be further processed to separate the two.

The gas, oil, and water may be separated in a single vessel or, more commonly, in several stages. Some gas is dissolved in the oil and comes out of solution as the pressure on the fluids drops. Fluids from high-pressure reservoirs may have to be passed through a number of separating stages at successively lower pressures before the oil is free of gas. The oil and brine do not separate as readily as the gas does. Usually, a quantity of oil and water is present as an emulsion. This emulsion can occur naturally in the reservoir or can be caused by various processes which tend to mix the oil and water vigorously together and cause droplets to form. Passage of the fluids into and up the well tends to mix them. Passage through well head chokes, through various pipes, headers, and control valves into separation chambers, and through any centrifugal pumps in the system, tends to increase emulsification. Moderate heat, chemical action, and/or electrical charges tend to cause the emulsified liquids to separate or coalesce, as does the passage of time in a quiet environment. Other types of chemicals and fine suspended solids tend to retard coalescence. The characteristics of the crude oil also affect the ease or difficulty of achieving process separation.(1)

Fluids produced by oil and gas wells are usually introduced into a series of vessels for a two-stage separation process. Figure 4 shows a gas separator for separating gas from the well stream.

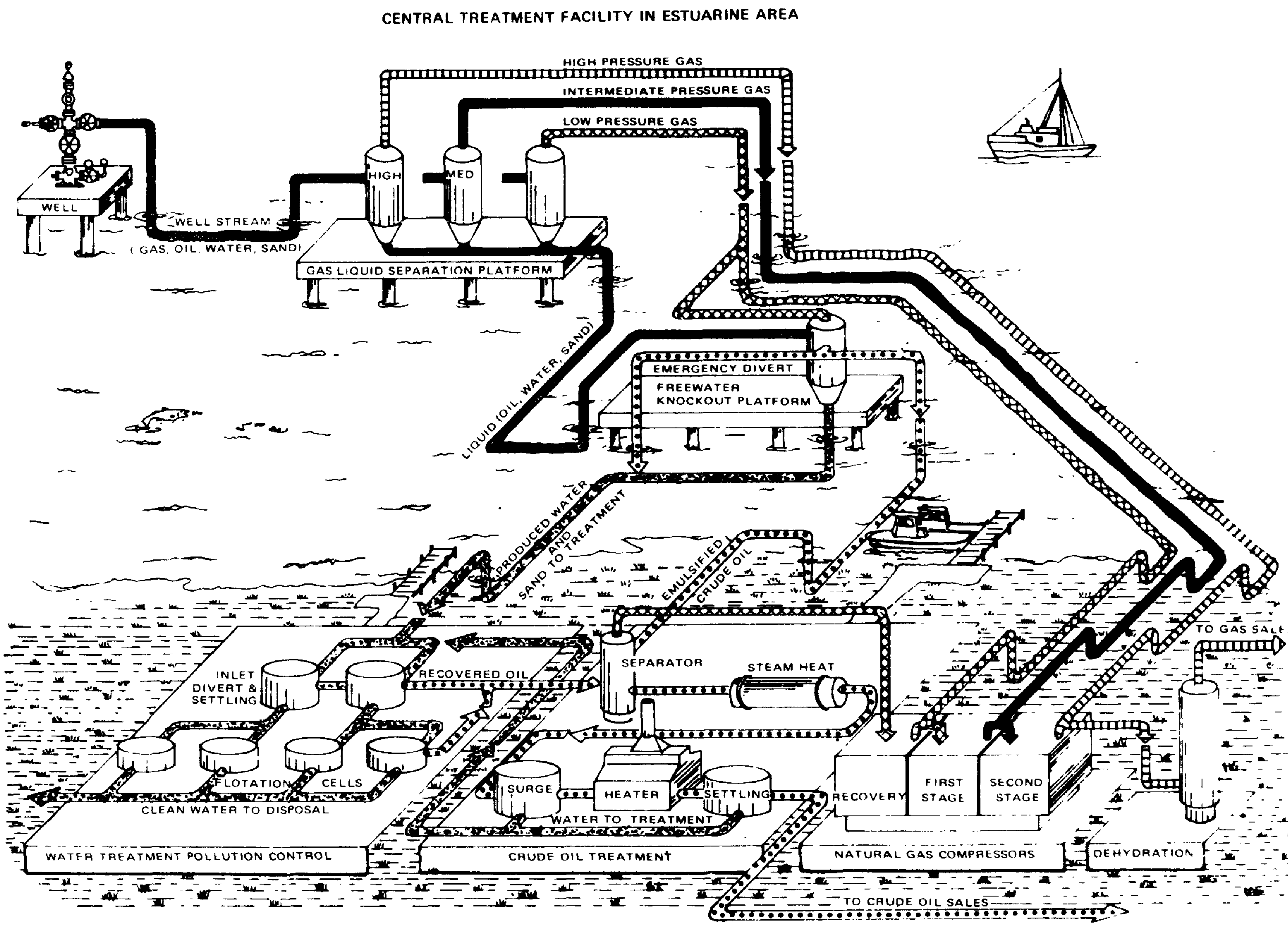

Fig. 3 -- CENTRAL TREATMENT FACILITY IN ESTUARINE AREA

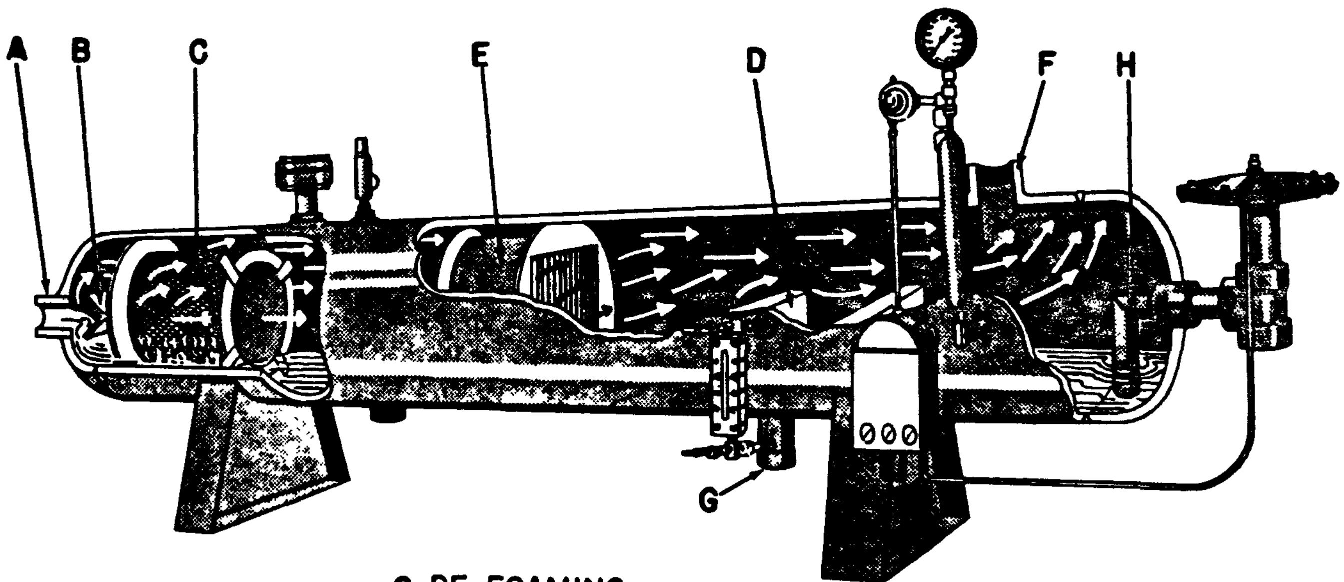

Fig. 4 -- HORIZONTAL GAS SEPARATOR

Liquids (oil or oil and water) along with particulate matter leave the separator through the dump valve and go on to the next stage: oil-water separation. Because gas comes out of solution as pressure drops, gas-oil separators are often arranged in series. High-pressure, intermediate, and low-pressure separators are the most common arrangement, with the high-pressure liquids passing through each stage in series and gas being taken off at each stage. Fluids from lower-pressure wells would go directly to the most appropriate separator. The liquids are then piped to vessels for separating the oil from the produced water. Water which is not emulsified and separates easily may be removed in a simple separation vessel called a free water knockout.

The remaining oil-water mixture will continue to another vessel for more elaborate treatment (see Figure 5). In this vessel (which may be called a heater-treater, electric dehydrator, gun barrel, or wash tank, depending on configuration and the separation method employed), there is a relatively pure layer of oil on the top, relatively pure brine on the bottom, and a layer of emulsified oil and brine in the middle. There is usually a sensing unit to detect the oil-water interface in the vessel and regulate the discharge of the fluids. Emulsion breaking chemicals are often added before the liquid enters this vessel, the vessel itself is often heated to facilitate breaking the emulsion, and some units employ an electrical grid to charge the liquid and to help break the emulsion. A combination of treatment methods is often employed in a single vessel. In three-phase separation, gas, oil, and water are all separated in one unit. The gas-oil and oil-water interfaces are detected and used to control rates of influent and discharge.

Oil from the oil-water separators is usually sufficiently free of water and sediment (less than 2 percent) so as to be marketable. The produced water or produced water/solids mixtures discharged at this point contain too much oil to be disposed of into a water body. The object of processing through this point is to produce marketable products (clean oil and dry gas). In contrast, the next stages of treatment are necessary to remove sufficient oil from the produced water so that it may be discharged. These treatment operations do not significantly increase the quality or quantity of the saleable product. They do decrease the impact of these wastes on the environment.

Typical produced water from the last stage of process would contain several hundred to perhaps a thousand or more parts per million of oil. There are two methods of disposal: treatment and discharge to surface (salt) waters or injection into a suitable subsurface formation in the earth. Surface discharge is normally used offshore or near shore where bodies of salt or brackish water are available for disposal. Injection is widely used onshore where bodies of salt water are not available for

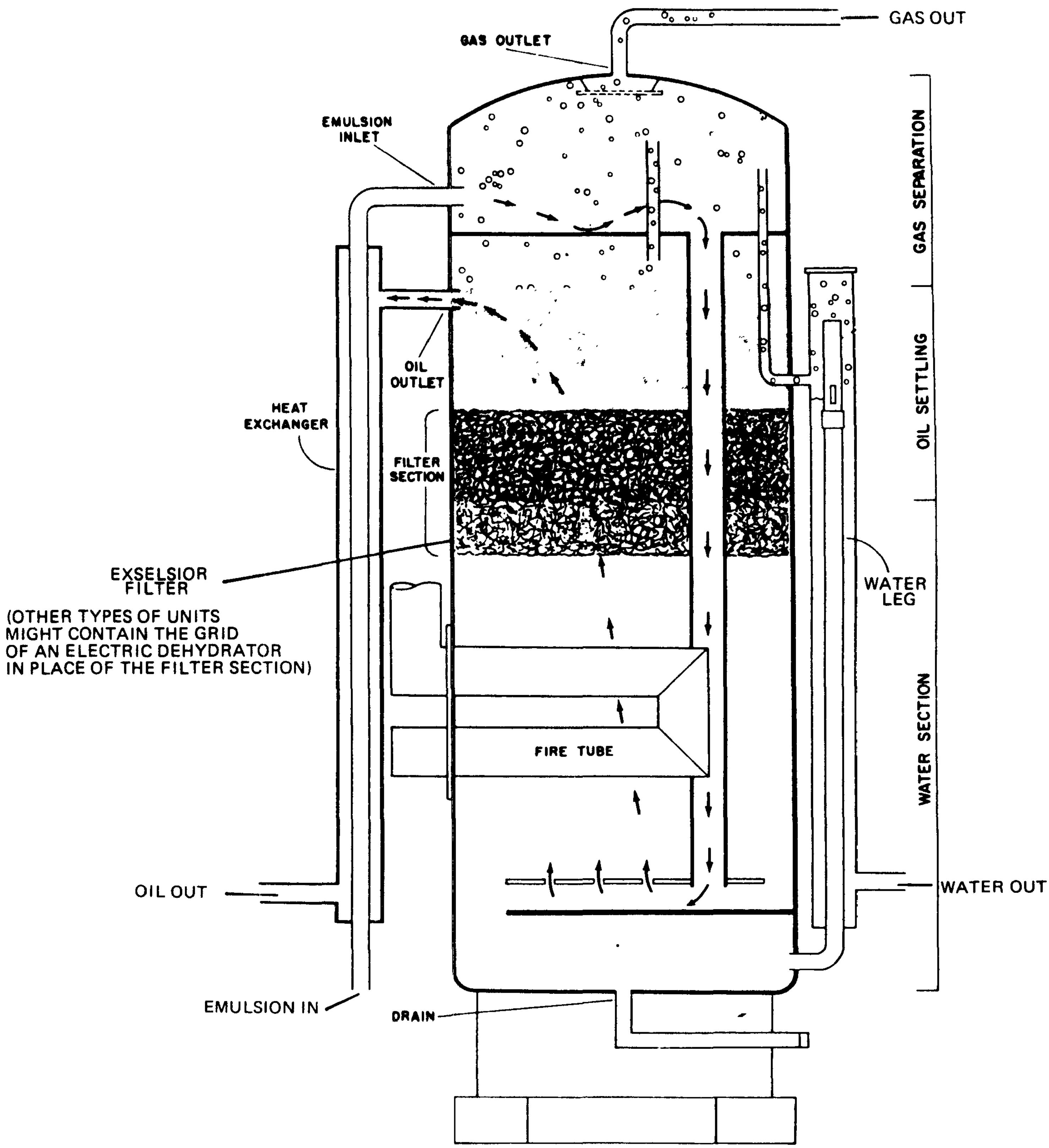

Fig. 5 -- VERTICAL HEATER-TREATER

surface disposal. (produced water to be disposed of by injection may still require some treatment).

Some of the same operations used to facilitate separation in the last stage of processing (chemical addition and retention tanks) may be used in waste water treatment, and other methods such as filtering, and separation by gas flotation are also used. In addition, combinations of these operations can be used to advantage to treat the waste water. The vast majority of present offshore and near shore (marsh) facilities in the Gulf of Mexico and most facilities in Cook Inlet, Alaska, treat and dispose of their produced water to surface salt or brackish water bodies.

The sophistication of the treatment employed by dischargers of produced water is dependent upon the regulation governing such discharges. For instance in the Appalachian states most produced water is discharged to local streams after only treatment in ponds; while in California dischargers utilize a high degree of treatment. The state of Wyoming allows discharge for beneficial use if the produced water meets oil and grease and total dissolved solids (TDS) requirements.

Several options are available in injection systems. Often water will be injected into a producing oil resorvoir to maintain reservoir pressure, and stabilize reservoir conditions. In a similar operation called water flooding, water is injected into the reservoir in such a way as to move oil to the producing wells and increase ultimate recovery. This process is one of several known as secondary recovery since it produces oil beyond that available by primary production methods. A successful water flooding project will increase the amount of oil being produced at a field. It will also increase produced water volume and thus affect the amount of water that must be treated. Pressure maintenance of water injection may also increase the amount of water produced and treated. Injection is also feasible solely as a disposal method. It (injection) is extensively used in onshore production areas except in the Appalchian states of Pennsylvania, West Virginia, New York and Kentucky, where useable shallow horizons do not exist. In California, produced water from offshore facilities is transported to shore for disposal by reinjection.

The treatment associated with produced water disposal by injection is dependent upon the permeability of the receiving formation. In most all cases corrosion-inhibiting chemicals are necessary, but the treatment can range from simply skim tanks to gas flotation followed by mixed-media filtration.

Evolution of Facilities

Early offshore development tended to place wells on individual structures, bringing the fluids ashore for separation and treatment (see Figure 3). As the industry moved farther offshore, the wells still tended to be located on individual platforms with the output to a central platform for separation, treatment, and discharge to a pipeline or barge transportation system.

With increasing water depth, multiple-well platforms were developed with 20 or more wells drilled directionally from a single platform. Thus an entire field or a large portion of a field could be developed from one structure. Offshore Louisiana multiple-well platforms include all processing and treatment, in offshore California and in Cook Inlet facilities, gas separation takes place on the platforms, with the liquids usually sent ashore for separation and treatment.

All forms of primary and secondary recovery as well as separation and treatment are performed on platforms, which may include compressor stations for gas lift wells and sophisticated water treatment facilities for water flood projects. Platforms far removed from shore are practically independent production units.

Platform design reflects the operating environment. Cook Inlet platforms are enclosed for protection from the elements and have a structural support system designed to withstand ice floes and earthquakes. Gulf Coast platforms are usually open, reflecting a mild climate. Support systems are designed to withstand hurricane-generated waves.

A typical onshore production facility would consist of wells and flowlines, gas-liquid and oil-water production separators, a waste water treatment unit (the level of treatment being dependent on the quality of the waste water and the demands of the injection system and receiving reservoir), surge tank, and injection well. Injection might either be for pressure maintenance and secondary recovery or solely for disposal. In the latter case, the well would probably be shallow and operate at lower pressure. The system might include a pit to hold waste water should the injection system shut down.

A more recent production technique and one which may become a significant source of waste in the future is called "tertiary recovery." The process usually involves injecting some substance into the oil reservoir to release or carryout additional oil not recovered by primary recovery (flowing wells by natural reservoir pressure, pumping, or gas lift) or by secondary recovery.

Tertiary recovery is usually classified by the substance injected into the reservoir and includes:

1. Thermal recovery

2. Miscible hydrocarbon

3. Carbon dioxide

4. Alcohols, soluble oil, micellar solutions

5. Chemical floods, surfactants

6. Gas, gas/water, inert gas

7. Gas repressuring, depletion

8. Polymers

9. Foams, emulsions, precipitates

The material is injected into the reservoir and moves through the reservoir to the producing wells. During this passage, it removes and carries with it oil remaining in pores in the reservoir rocks or sands. Oil, the injected fluid, and water may all be moved up the well and through the normal production and treatment system.

Nine economically successful applications of tertiary recovery have been documented (two of them in Canadian fields): one miscible hydrocarbon application; three gas applications; two polymer applications, and three combinations of miscible hydrocarbon with gas drive.

At this time very little is known about the wastes that will be produced by these production processes. They will obviously depend on the type of tertiary recovery used.

Field Service

A number of satellite industries specialize in providing certain services to the production side of the oil industry. Some of these service industries produce a particular class of waste that can be identified with the service they provide. Of the waste-producing service industries, drilling (which is usually done by a contractor) is the largest. Drilling fluids and their disposal have already been discussed. Other services include completions, workovers, well acidizing, and well fracturing.

When a company decides that an oil or gas well is a commercial producer, certain equipment will be installed in the well and on the well head to bring the well into production. The equipment from this process--called "completion"--normally consists of various valves and sealing devices installed on one or more strings of tubing in the well. If the well will not produce sufficient fluid by natural flow, various types of pumps or gas lift systems may be installed in the well. Since heavy weights and high lifts are normally involved, a rig is usually used. The rig may be the same one that drilled the well, or it may be a special (normally smaller) workover rig installed over the well after the drilling rig has been moved.

After a well has been in service for a while it may need remedial work to keep it producing at an acceptable rate. For example, equipment in the well may malfunction, different equipment may be required, or the tubing may become plugged up by deposits of paraffin. If it is necessary to remove and reinstall the tubing in the well, a workover rig will be used. It may be possible to accomplish the necessary work with tools mounted on a wire and lowered into the well through the tubing. This is called a wire line operation. In another system, tools may be forced into the well by pumping them down with fluid. Where possible, the use of a rig is avoided, since it is expensive.

In many wells, the potential for production is limited by impermeability in the producing geological formation. This condition may exist when the well is first drilled, it may worsen with the passage of time, or both situations may occur. Several methods may be used, singly or in combination, to increase the well flow by altering the physical nature of the reservoir rock or sand in the immediate vicinity of the well.

The two most common methods to increase well flow are acidizing and fracturing. Acidizing consists of introducing acid under pressure through the well and into the producing formation. The acid reacts with the reservoir material, producing flow channels which allow a larger volume of fluids to enter the well. In addition to the acid, corrosion inhibitors are usually added to protect the metal in the well system. Wetting agents, solvents, and other chemicals may also be used in the treatment.

In fracturing, hydraulic pressure forces a fluid into the reservoir, producing fractures, cracks, and channels. Fracturing fluids may contain acids so that chemical disintegration, as well as fracturing takes place. The fluids also contain sand or some similar material that keeps the fracture propped open once the pressure is released.

When a new well is being completed or when it is necessary to pull tubing to work over a well, the well is normally "killed"--that is, a column of drilling mud, oil, water, or other liquid of sufficient weight is introduced into the well to control the down hole pressures.

When the work is completed, the liquid used to kill the well must be removed so that the well will flow again. If mud is used, the initial flow of oil from the well will be contaminated with the mud and must be disposed of. Offshore, it may be disposed of into the sea if it is not oil contaminated, or it may be salvaged. Onshore, the mud may be disposed of in pits or may be salvaged. Contaminated oil is usually disposed by burning at the site.

In acidizing and fracturing, the spent fluids used are wastes. They are moved through the production, process, and treatment systems after the well begins to flow again. Therefore, initial production from the well will contain some of these fluids. Offshore, contaminated oil and other liquids are barged ashore for treatment and disposal; contaminated solids are buried.

The fines and chemicals contained in oil from wells put on stream after acidizing or fracturing have seriously upset the waste water treatment units of production facilities. When the sources of these upsets have been identified, corrective measures can prevent or mitigate the effects. (2)

Industry Distribution

1974, domestic production was 8.8 million barrels-per-day (bpd) of oil and 1.7 million bpd of gas liquids, for a total production of 10.5 bpd; down slightly from the four previous years. (3) Total imports were 6.1 million bpd for 1974.

There are approximately half a million producing oil wells and 126,000 gas and condensate wells in the United States. Of the 30,000 new wells drilled each year, about 55 percent produce oil or gas.

Oil is presently produced in 32 of the 50 states and from the Outer Continental Shelf (OCS) off of Louisiana, Texas, and California. Exploratory drilling is underway on the OCS off of Mississippi, Alabama, and Florida. In 1972, the five largest oil-producing States were: Texas, Louisana, California, Oklahoma, and Wyoming. With development of the North Slope oil fields and construction of the Alaska pipeline, Alaska will become one of the most important oil producing States.

Offshore oil production is presently concentrated in three areas in the United States: the Gulf of Mexico, the coast of California, and Cook Inlet in Alaska. Offshore oil production in 1973 was approximately 62 million barrels from Cook Inlet, 116 million from California, and 215 million from Louisiana and Texas,

Gulf of Mexico - Texas and Louisiana

Approximately 2,000 wells now produce oil and gas in State waters in the Gulf of Mexico and 6,000 on the OCS. Over 90 percent are in Louisiana, with the remainder in Texas. Recent lease sales have been held on the OCS off Texas and off the Mississippi, Alabama, and Florida coasts. Discoveries have been made in those areas, and development will take place as quickly as platforms can be installed, development drilling completed, and pipelines laid.

Leases have been granted in water as deep as 600 feet. These deep areas will probably be served by conventional types of platforms, but their size and cost increase rapidly with increasing depth.

In addition to offshore activities, onshore production in Texas for 1974 accounted for 1,226 million barrels of oil and 7,942,352 million cubic feet of gas, the largest contribution of any state. Oil production has been on a decline in Texas since the peak year of 1972. Oil and gas production in Texas is widespread, involving 212 out of 254 counties and approximately 165,000 gas, condensate, and crude oil wells. The amount of produced water generated is dependent on the method of oil production and the field location. Higher water cut ratios are experienced near the Gulf. Regulation by the State Railroad Commission prohibits discharge of produced water to fresh water bodies, and therefore reinjection for recovery and disposal technology has been developed to a high degree.

Onshore activity in Louisiana is also significant, accounting for 307 million barrels of crude in 1974 originating from 61 out of the 64 parishes (counties) in the State. There are approximately 11,500 wells producing crude oil onshore and less than one percent of these wells are in the stripper category (less than ten barrels per day production). Of the 1,068 million barrels of produced water generated in 1974 the majority was reinjected for either recovery or disposal purposes; the remainder was discharged to unlined puts, saltwater estuaries or fresh water streams. The discharge of production water to fresh water streams is limited to the southern and central parts of the State where drilling of reinjection wells is extremely costly. Discharge to saltwater estuaries is practiced along the Gulf Coast. Treatment prior to discharge consists of skim tanks and settling/separator ponds. Where reinjection is practiced the facilities are unsophisticated, consisting of a primary separator and sedimentation. The disposal formations are at 2000-5000 foot depth and are very permeable, resulting in low well head pressure and power costs. Approximately 60% of the oil production under State onshore leases is generated at facilities which discharge their produced water.

California

There has been a general moratorium on drilling and development in the offshore areas of California since the Santa Barbara blowout of 1969. (4)

Present offshore production in State waters comes from the area around Long Beach and Wilmington and also from the Santa Barbara area farther north. OCS production is confined to the Santa Barbara area. Except for one facility, all production from both State and Federal leases is piped ashore for treatment. A large and increasing amount of the produced brine is disposed of by subsurface injection.

Exxon Corporation has applied for permits to develop an area leased prior to 1969 in the northern Santa Barbara Channel (the "Santa Ynez Unit"). Several fields have been discovered on these leases in water depths from 700 to over 1,000 feet. Proposed development of the shallower portion of one of these areas calls for erection of a multiple-well drilling and production platform in 850 feet of water. If gas and oil are found in commercial quantities, the gas would be separated on the platform, with the water and oil sent ashore for separation and treatment. Produced water would be disposed of by subsurface injection ashore.

Additional lease sales have been made on the OCS off Santa Barbara in Southern California.

Total oil production in California for 1974 was approximately 390 million barrels (83 million barrels offshore), a decline from the previous year. In addition to offshore facilities, the major areas of production in California are in the southern San Jacquin Valley, centered around the city of Bakersfield, and in the Long Beach-Wilmington area. In California, steam, hot water, and water flooding methods of secondary recovery are used. The total produced water is approximately 2,044 million barrels per year, the majority of which is either reinjected for recovery or disposal or evaporated in ponds. Only eight producers in the State have discharge to navigable waters.

Cook Inlet, Alaska

Offshore production in Cook Inlet comes from 14 multiple-well platforms on four oil fields and one gas field. Development took place in the 1960's and has been relatively static for the past 5 years. The demarcation line between Federal and State waters in lower Cook Inlet is under litigation. The settlement of this dispute will probably lead to leasing and development of additional areas in the Inlet.

Present practice is to separate gas on the platforms, sending the produced water and oil ashore for separation and treatment. Some platforms are producing increasing amounts of produced water, and this, plus the occasional plugging of oil/water pipelines with ice in the winter, will encourage a change to platform separation, treatment, and disposal of produced waters.

Cook Inlet platforms are presently employing gas lift and treat Inlet sea water for water flooding.

Appalachia - Pennsylvania

Oil was discovered over 100 years ago in Pennsylvania, the earliest discovery in the United States. Today the State of Pennsylvania's oil production industry, like the other Appalachian states, is characterized by marginal production of 0.3 barrles per day per well average for the 31,000 producing wells in the State, operating on approximately 2,300 leases. Although the amount of oil production is low (only 0.1% of the U.S. total), Pennsylvania crudes supply 20% of all U.S. lube oil production. Small independent operators dominate the industry, accounting for 65-70% of the production. The oil fields are located primarily in the northwest section of the State, McKean County alone accounting for 50% of the State's production. The oil-bearing strata is shallow (1000-2000 feet) and relatively impermeable (1-20 millidarcies).

All produced water generated is discharged to the surface following ripple aeration and separation/sedimentation in earthen ponds. Where water flooding is practiced, ground water is used after treatment as the source. There are plans on some of the larger leases to utilize production water for flooding, despite earlier failure of this method from plugging of the formation strata. Current discharge practices are in part justified by the absence of formations acceptable for reinjection due to permeability, surface outcroppings, lack of void space and substandard well abandonment procedures in the past.

Industry Growth

From 1960 to 1970, the Nation's demand for energy increased at an average rate of 4.3 percent. Table 3 gives the projected national demands for oil and gas through 1985 and Table 4 the U.S. offshore oil production from 1970 through 1973.

U.S. offshore production declined by about 78,500 barrels/day from 1972 to 1973. Offshore production amounts to approximately 10 percent of U.S. demand and about 15 percent of U.S. production.

While offshore production declined slightly from 1972 to 1973, the potential for increasing offshore production is much greater than for increasing onshore production. The Department of the Interior has proposed a schedule of three or four lease sales per year through 1978, mainly on remaining acreage in the Gulf of Mexico and offshore California. Additional areas in which OCS lease sales will very probably be held by 1978 include the Atlantic Coast (George's Bank, Baltimore Canyon, and Georgia Embayment) and the Gulf of Mexico.

Not only will new areas be opened to exploration and ultimate development, but production will move farther offshore and into deeper waters in areas of present development.

Movement into more distant and isolated environments will mean even more self-sufficiency of platform operations, with all production, processing, treatment, and disposal being performed on the platforms. Movement into deeper waters will necessitate multiple-well structures, with a maximum number of wells drilled from a minimum number of platforms.

Offshore leasing, exploration, and development will rapidly expand over the next 10 years, and offshore production will make up an increasing proportion of our domestically produced supplies of gas and oil.

TABLE 3

U.S. Supply and Demand of Petroleum

and Natural Gas (5)

	1971	1980	1985
Petroleum (million barrels/day)			
Projected Demand	15.1	20.8	25.0
% of Total U.S. Energy Demand	44.1	43.9	43.5
Projected Domestic Supply	11.3	11.7	11.7
% petroleum demand fulfilled by domestic supply	74.9	56.3	46.7
Natural Gas (trillion cubic feet/year)			
Projected Demand	22.0	26.2	27.5
% of Total U.S. Energy Demand	33.0	28.1	24.3
Projected Domestic Supply	21.1	23.0	23.8
% gas demand fulfilled by domestic supply	96.0	87.8	86.6

TABLE 4

U.S. Offshore Cil Production - (million barrels/day) (6)

1970	1971	1972	1973
1.58	1.69	1.67	1.59

SECTION III

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SECTION IV

INDUSTRY SUBCATEGORIZATION

Rationale For Subcategorization

The Standard Industrial Classification's subcategorize industry into various groups for the purpose of analyzing production, employment, and economic factors which are not necessarily related to the type of wastes generated by the industry. In development of the effluent limitations and standards, production methodology, waste characteristics, and other factors were analyzed to determine if separate limitations need to be designated for different segments of the industry. The following factors were examined for delineating different levels of pollution control technology and possibly subcategorizing the industry:

1. Type of facility or operation
2. Facility's size, age, and waste volumes
3. Process technology
4. Climate
5. Waste water characteristics
6. Location of facility

Field surveys, waste treatment technology, and effluent data indicate that the most important factors are the type of facility, the facility's size, age, waste water volume, waste water characteristics, and location. The factor of climate is significant with respect to operational practices but has less influence on waste treatment technology. Process technology was found to have very little influence on the selection of pollution control technology.

An evaluation of industry's production units (barrels of oil per day or thousands of cubic feet of gas per day) and waste volumes indicated no relationship between them. Produced water production may vary from less than 1 to 90 percent of the production fluids. High volumes of produced waters are associated with older production fields and recovery methods used to extract crude oil from partially depleted formations. Similarly, the amount of waste generated during drilling operations is dependent upon the depth of the well, subsurface characteristics, recovery of drill muds, and recycling. Therefore, industry subcategorization could not include an analysis of segmenting the industry on waste load per unit of production.

Development of Subcategories

Based upon the type of facility, the industry may be subdivided into three major categories with similar type operations or activities: 1) crude petroleum and natural gas production; 2) oil and gas well field exploration and drilling; and 3) oil and gas well completions and workover. Further subdivision can be made within each to reflect location - offshore and onshore - and any wastes requiring specific effluent limitations and standards. Since sanitary wastes for onshore operations normally don't result in a discharge and since deck drainage is not applicable to onshore operations, these subcategories are only applicable to offshore facilities. Therefore, considering location and wastes, the major groups are subcategorized as follows:

I Crude Petroleum and Natural Gas Production

- A. Produced Water
- B. Deck Drainage
- C. Sanitary and Domestic Waste

II Oil and Gas Well Field Exploration and Drilling

- A. Drilling Muds
- B. Drill Cuttings
- C. Sanitary and Domestic Waste

III Oil and Gas Well Completions and Workover

- A. Chemical Treatment of Wells
- B. Production Sands

Facility's Size, Age and Waste Volumes

Offshore facilities in Category I differ little in the type of process or produced water treatment technology for large, medium, or small facilities. One of the most significant factors affecting the size of the facility is the availability of space for central treatment systems to handle waste from several platforms or fields. Treatment systems on offshore platforms are usually limited to meet the needs of the immediate production facility and are designed for 5,000 to 40,000 barrels/day. In contrast, onshore treatment systems for offshore production wastes may be designed to handle 100,000 barrels/day or more. For small facilities, wastes may require intermediate storage and a transport system to deliver the produced water to another facility for treatment and disposal. Comparable treatment technology has been developed for both large and small systems.

For onshore facilities, the type of produced water treatment technology does tend to differ according to the size of the facility but there are notable exceptions. Since for the primary unit treatment process (the separation of oil and water), ponds of sufficient size are feasible for smaller facilities while mechanical systems (such as flotation) are required where larger amounts of produced water are handled. Smaller facilities are least likely to have the type of operating staff required for sophisticated water treatment systems and are more likely to receive operating variances from local regulatory authorities.

The types of treatment for sanitary wastes for large and small offshore facilities are different, as are facilities which are intermittently manned. For small and intermittently manned facilities, the waste may be incinerated or chemically treated, resulting in no discharge. Because of operational problems and safety considerations, other types of treatment systems that will result in a discharge are being considered. Thus sanitary wastes must be subcategorized based on facility size.

The state of the art and treatment technology for Category I has been improving over the past several years; the majority of the facilities regardless of age have installed waste treatment facilities. However, the age of the production field can impact the quantity of waste water generated. Many new fields have no need to treat for a number of years until the formation begins to produce water. The period before initiating treatment is variable, depending on the characteristics of the particular field, and can also be affected by method of recovery. If wastes are to be treated off shore, the initial design should provide for the necessary space and energy requirements that will be needed for the treatment systems to be installed over the expected life of the platform.

Process Technology

Process technology was reviewed to determine if the existing equipment and separation systems influenced the characteristics of the produced waste. Most oil/water process separation units consist of heater-treaters, electric dehydration units or gravity separation (free water knockout or gun barrel). The type of process equipment and its configuration are based in part on the characteristics of the produced fluids. For example, if the fluids contain entrained oil in a "tight" emulsion, heat may be necessary to assist in separating water from the oil. Raw produced water data showed no significant difference in oil content between the various process units. When high influent concentrations to the produced water treatment facilities were observed they were found to be caused by malfunctions in the process equipment. It was concluded that there is no basis for subcategorization because of differences in process systems.

Climate

Climate was considered because conditions in the production regions differ widely. All regions treat by gravity separation or chemical/physical methods. These systems are less sensitive to climatic changes than biological treatment. Sanitary waste treatment can be affected by extreme temperatures, but in areas with cold climates, facilities are enclosed, minimizing temperature variations. The volume or hydraulic loading due to rainfall may be significant with respect to the offshore Gulf Coast, but the waste contaminants (residual oils from drips, leaks, etc.) from deck drainage are independent of rainfall. Proper operation and maintenance can reduce waste oil concentrations to minimal levels, thus reducing the effect of rainfall. Therefore, no subcategorization is required to account for climate.

Waste Water Characteristics

Treatability and other characteristics of produced water are one of the most significant factors considered for subcategorization. Produced water may be high in dissolved solids (TDS), oxygen demanding wastes, heavy metals, and toxics, in addition to the oil and grease contamination. The current treatment technologies for produced water are either subsurface disposal or oil removal prior to discharge. The technology developed for each area of the country has been primarily influenced by local regulatory requirements (water quality and individual state or local laws), but other factors associated with produced water treatability and cost effectiveness may also have had an effect. (1,2,3)

Factors which may affect produced water treatability are:

1. Physical and chemical properties of the crude oil, including solubility.

2. Concentration of suspended and settleable solids.

3. Fluctuation of flow rate and production method.

4. Droplet sizes of the entrained oil emulsification.

5. Other characteristics of the produced water.

The impact of these variables can be minimized by existing process and treatment technology, which include desanders, surge tanks, and chemical treatment.

Location of Facility

The location of the facility affects the applicable treatment, the cost of that treatment, and the makeup of the wastes produced. The factors that affect the treatment method based on location are as follows:

1. Availability of space and site conditions, such as, dry land, marsh area, or open water.

2. Proximity to shore.

3. Type and depth of subsurface formations suitable for injection of produced water.

4. Surface water availability (possible agricultural use of produced water).

5. Evaporation rate at location.

6. Local water quality and statues.

7. Type of receiving water body.

Location is a significant factor specifically with respect to areas where saline produced water discharges are not permitted. The usual procedure in inland areas is to reinject the produced water to the producing formation, where the formation configuration permits (to assist in oil recovery), or to other subsurface formations for disposal only. Evaporation ponds are used in some inland areas, with the assumption that all produced waters are evaporated and no discharge occurs. In an arid Western oil field an evaporation pond, if properly maintained, may provide for acceptable disposal of the produced waters; however, in humid areas in the East and South, evaporation ponds may not be acceptable.

In inland fields where produced waters are sufficiently low in total solids, discharges have been used for stock watering and other beneficial uses where the treated produced water is of sufficient quality to meet the regulations for other constituents, such as oil and grease.

In the Appalachian area, typified by the northwest portion of Pennsylvania, discharge of produced water is the rule, not the exception. Treatment consisting of ripple aeration and semimentation/separation in ponds achieves a high degree of free oil removal apparently due to the separability of the crude.

The technology for disposal of drilling muds, cuttings, solids, and other materials differs depending upon the location. In the open water offshore areas, the materials, if properly treated, are normally discharged into the saline waters. Onshore technology has been developed to ensure no discharge to surface waters, and waste materials are disposed of in approved land disposal sites.

Description of Subcategories

Based upon the above rationale and discussion the oil and gas extraction industry has been subcategorized as follows:

Subcategory A - near offshore (facilities located in offshore state waters)

1. produced water
2. deck drainage
3. drilling muds
4. drill cuttings
5. well treatment
6. sanitary wastes
   a. M10 continuously manned with 10 or more people
   b. M9IM - facilities with 9 or less people or intermittantly manned.
7. domestic wastes
8. produced sand

Subcategory B - far offshore (facilities located in federal waters)

1. produced water
2. deck drainage
3. drilling muds
4. drill cuttings
5. well treatment
6. sanitary wastes
   a. M10 continuously manned with 10 or more people

b. M9IM - facilities with 9 or less people or intermittantly manned.

7. domestic wastes

8. produced sand

Subcategory C - onshore

1. produced water

2. drilling muds

3. drill cuttings

4. well treatment

5. produced sand

Subcategory D - coastal

1. produced water

2. deck drainage

3. drilling muds

4. drill cuttings

5. well treatment

6. sanitary wastes

   a. M10 continuously manned with 10 or more people

   b. M9IM - facilities with 9 or less people or intermittantly manned.

7. domestic wastes

8. produced sand

Subcategory E - beneficial use

1. produced water

2. drilling muds

3. drill cuttings

4. well treatment

5. produced sand

Subcategory F - stripper

1. produced water
2. drilling muds
3. drill cuttings
4. well treatment
5. produced sand

Produced Water

Produced water includes all waters and particulate matter associated with oil and gas producing formations. Sometimes the terms "formation water" or "brine water" are used to describe produced water. Most oil and gas producing geological formations contain an oil-water or gas-water contact. In some formations, water is produced with the oil and gas in the early stages of production. In others, water is not produced until the producing formation has been significantly depleted and in some cases water is never produced. (4) The amount of produced water generated is also dependent on the method of oil recovery. If water injection is used some of the injected water is recovered by the production causing higher percentage water cuts.

Deck Drainage

Deck drainage includes all waste resulting from platform washings, deck washings, and run-off from curbs, gutters, and drains including drip pans and work areas.

Sanitary Waste

Sanitary waste includes human body waste discharged from toilets and urinals.

Domestic Waste

Domestic wastes are materials discharged from sinks, showers, laundries, and galleys.

Drilling Muds

Drilling muds are those materials used to maintain hydrostatic pressure control in the well, lubricate the drilling bit, remove drill cuttings from the well, or stabilize the walls of the well during drilling or workover.

Generally, two basic types of muds (water-based and oil muds) are used in drilling. Various additives may be used depending upon the specific needs of the drilling program. Water-based muds are usually mixtures of fresh water or sea water with muds and clays from surface formations, plus gelling compounds, weighting agents, and various other components. Oil muds are referred to as oil based muds, invert emulsion muds, and oil emulsion muds. Oil muds are used for special drilling requirements such as tightly consolidated subsurface formations and water sensitive clays and shales. (5)(6)(7)

Drill Cuttings

Drill cuttings are particles generated by drilling into subsurface geologic formations. Drill cuttings are circulated to the surface of the well with the drilling mud and separated there from the drilling mud.

Treatment of Wells

Treatment of wells includes acidizing and hydraulic fracturing to improve oil recovery. Hydraulic fracturing involves the parting of a desired section of the formation by the application of hydraulic pressure. Selected particles added to the fracturing fluid are transported into the fracture, and act as propping agents to hold the fracture open after the pressure is released. Chemical treatments of wells consists of pumping acid or chemicals down the well to remove formation damage and increase drainage in the permeable rock formations.(8)

Produced Sand

Produced sand or solids for this subcategory consist of particles used in hydraulic fracturing and accumulated formation sands, which are generated during production. These sands must be removed when they build up and block flow of fluids.

SECTION IV

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SECTION V

WASTE CHARACTERISTICS

Wastes generated by the oil and gas industry are produced by drilling exploratory or development wells, by the production or extraction phase of the industry, and, in the case of offshore facilities, sanitary wastes generated by personnel occupying the platforms. Drilling wastes are generally in the form of drill cuttings and mud, and production wastes are generally produced water. (1) Additionally, well workover and completion operations can produce wastes, but they are generally similar to those from drilling or production operations.

Approximately half a million producing oil wells onshore generate produced water in excess of 20 million barrels-per-day of which it is estimated 50% is reinjected for recovery purposes. Approximately 17,000 wells have been drilled offshore in U.S. waters, and approximately 11,000 are producing oil or gas. The offshore Louisiana OCS alone produces approximately 410,000 barrels of water per day (2); by 1983, coastal Louisiana production will generate an estimated 1.54 million barrels of water per day. (3)

This section characterizes the types of wastes that are produced at offshore and onshore wells and structures. The discussion of drilling wastes can be applied to any area of the United States since these wastes do not change significantly with locality.

Other than oils, the primary waste constituents considered are oxygen demanding pollutants, heavy metals, toxicants, and dissolved solids contained in drilling muds or produced water. (4)

Sanitary wastes are also produced during both drilling and production operations both onshore and offshore, but they are discussed only for offshore situations where sanitary wastes are produced from fixed platforms or structures. Drilling or exploratory rigs that are vessels are not part of this discussion.

Waste Constituents

Production

Production wastes include produced waters associated with the extracted oil, sand and other solids removed from the produced waters, deck drainage from the platform surfaces, sanitary wastes, and domestic wastes.

The produced waters from production platforms generate the greatest concern. The wastes can contain oils, toxic metals, and a variety of salts, solids and organic chemicals. The concentrations of the constituents vary somewhat from one geographical area to another, with the most pronounced variance in chloride levels. Table 5 shows the waste constituents in offshore Louisiana production facilities in the Gulf of Mexico. The data were obtained during the verification survey conducted by EPA in 1974. The only influent data obtained in the survey were on oil and grease. In planning the verification survey, it was decided that offshore produced water treatment facilities would have virtually no effect on metals and salinity levels in the influent, and that these constituents could be satisfactorily characterized by analyzing only the effluent.

Total organic carbon (TOC) is also tabulated under effluent in Table 5, but it is reasonable to assume that actual analysis of the influent would be higher. Since TOC is a measurement of all organic carbon in the sample and oil is a major source of organic carbon, it is logical to assume removal of some organic carbon when oil is removed in the treatment process. Suspended solids are also expressed as effluent data, and this parameter would be expected to be reduced by the treatment process.

TABLE 5

Pollutants in Produced Water

Louisiana Coastal(a)

Pollutant Parameter	Range mg/l	Average mg/l
Oil and Grease	7 - 1300	202
Cadmium	<0.005 - .675	<0.068
Cyanide	<0.01 - 0.01	<0.01
Mercury	---	<0.0005
Total Organic Carbon	30 - 1580	413
Total suspended solids	22 - 390	73
Total dissolved solids	32,000 - 202,000	110,000
Chlorides	10,000 - 115,000	61,000
Flow (bbl/day)	250 - 200,000	15,000

(a) - results of 1974 EPA survey of 25 discharges

< - less than

Industry data for offshore California describes a broader range of parameters (see Table 6). Similar data were provided for offshore Texas (see Table 7). Except as noted on the tables, all data are from effluents.

Sand and other solids are produced along with the produced water. Observations made by EPA personnel during field surveys indicated that drums of these sands stored on the platform had a high oil content. Sand has been reported to be produced at approximately 1 barrel sand per 2,000 barrels oil. (5,6)

TABLE 6

Pollutants Contained in Produced Water
Coastal California(a) (7)

Pollutant Parameter	Range, mg/l
Arsenic	0.001 - 0.08
Cadmium	0.02 - 0.18
Total Chromium	0.02 - 0.04
Copper	0.05 - 0.116
Lead	0.0 - 0.28
Mercury	0.0005 - 0.002
Nickel	0.100 - 0.29
Silver	0.03
Zinc	0.05 - 3.2
Cyanide	0.0 - 0.004
Phenolic Compounds	0.35 - 2.10
BOD	370 - 1,920
COD	400 - 3,000
Chlorides	17,230 - 21,000
TDS	21,700 - 40,400
Suspended Solids	
Effluent	1 - 60
Influent	30 - 75
Oil and Grease	56 - 359

(a) Some data reflect treated waters for reinjection.

TABLE 7

Range of Constituents in Produced

Formation Water--Offshore Texas (8)

Pollutant Parameter	Range, mg/l
Arsenic	<0.01 - <0.02
Cadmium	<0.02 - 0.193
Total Chromium	<0.10 - 0.23
Copper	<0.10 - 0.38
Lead	<0.01 - 0.22
Mercury	<0.001 - 0.13
Nickel	<0.10 - 0.44
Silver	<0.01 - 0.10
Zinc	0.10 - 0.27
Phenolic Compounds	53
BOD	126 - 342
COD	182 - 582
Chlorides	42,000 - 62,000
TDS	806 - 169,000
Suspended Solids	12 - 656

< - less than

As part of a recent EPA study (1976) to collect information on treatment technologies and costs, surveys were made of onshore production facilities in California, Wyoming, Texas, Louisiana and Pennsylvania. The data represented in tables 8-12 is from the effluent of the treatment facilities prior to reinjection for secondary recovery or disposal. It could be expected that the quality of the untreated produced water from the production separator would range from 200-1000 mg/l oil and grease and 100-400 mg/l suspended solids. The remainder of the analyzed constituents such as TDS, phenols and heavy metals would be unaffected by treatment.

The analytical methods used were from "Standard Methods for Waste and Wastewater" 13th edition (16) with the exception of the procedure for oil and grease. Prior to the utilization of the freon extraction method for oil and grease, the samples were screened for organic acids and if they were present in quantities greater than 100 mg/l the sample was not acidified. Therefore, the results for oil and grease as reported in tables 8-12, particularly in California where organic acids are known to be a part of the crude oil, are not comparable to data in other parts of this report and are shown only for information.

TABLE 8

Range of Constituents in Produced

Formation Water--Onshore California

Pollutant Parameter	Range, mg/l	Median, mg/l
Oil and Grease	16-191	75
Suspended Solids	3-51	31
Total Dissolved Solids	580-27,300	6,300
Phenol	0.07-0.15	0.11
Arsenic	<0.01-0.03	0.11
Chromium	<0.01	<0.01
Cadmium	<0.005-0.02	<0.005
Lead	<0.05	<0.05
Barium	<0.2-0.4	0.3

< = less than

TABLE 9

Range of Constituents in Produced

Formation Water--Wyoming

Pollutant Parameter	Range, mg/l	Median, mg/l
Oil and Grease	1.5-205	67
Suspended Solids	<1-64	12.8
Total Dissolved Solids	345-90,400	13,800
Phenol	0.07-0.33	0.16
Arsenic	<0.01-0.06	0.01
Chromium	<0.01	<0.01
Cadmium	<0.005-0.023	<0.005
Lead	<0.05-0.08	<0.05
Barium	<0.2-9.7	0.9

< = less than

TABLE 10

Range of Constituents in Produced

Formation Water--Pennsylvania

Pollutant Parameter	Range, mg/l	Median, mg/l
Oil and Grease	<0.2-114	25
Suspended Solids	1.4-666	107
Total Dissolved Solids	1500-109,400	29,000
Phenol	0.06-0.35	0.19
Arsenic	<0.01	<0.01
Chromium	<0.01-0.025	<0.01
Cadmium	<0.005-0.013	<0.005
Lead	<0.05-0.50	<0.05
Barium	0.1-36	8.6

< = less than

TABLE 11

Range of Constituents in Produced

Formation Water--Onshore Louisiana

Pollutant Parameter	Range, mg/l	Median, mg/l
Oil and Grease	16-441	165
Suspended Solids	20.8-155	82
Total Dissolved Solids	42,600-132,000	73,900

TABLE 12

Range of Constituents in Produced

Formation Water--Onshore Texas

Pollutant Parameter	Range mg/l	Median, mg/l
Oil and Grease	57-1,200	460
Suspended Solids	30-473	143
Total Dissolved Solids	42,600-132,000	94,000

Drilling

Drill cuttings are composed of the rock, fines, and liquids contained in the geologic formations that have been drilled through. The exact make-up of the cuttings varies from one drilling location to another, and no attempt has been made to qualitatively identify cuttings.

The two basic classes of drilling muds used today are water based muds and oil muds. In general, much of the mud introduced into the well hole is eventually displaced out of the hole and requires disposal or recovery. (13)

Water based muds are formulated using naturally occurring clays such as bentonite and attapulgite and a variety of organic and inorganic additives to achieve the desired consistency, lubricity, or density. Fresh or salt water is the liquid phase for these muds. The additives are used for such functions as pH control, corrosion inhibition, lubrication, weighting, and emulsification.

The additives that should be scrutinized for pollution control are ferrochrome lignosulfonate and lead compounds.(14)

Ferrochrome lignosulfonate contains 2.6 percent iron, 5.5 percent sulfur, and 3.0 percent chromium. In an example presented by the Bureau of Land Management in an Environmental Impact Statement for offshore development, the drilling operation of a typical 10,000-foot development well (not exploratory) used 32,900 pounds of ferrochrome lignosulfonate mud which contained 987 pounds of chromium.(2) Table 13 presents the volumes of cuttings and muds used in the Bureau's example of a "typical" 10,000-foot drilling operation. The amount of lead additives used in mud composition varies from well to well, and no examples are available.

Drilling constituents for onshore operations will parallel those for offshore, except for the water used in the typical mud formulation. Onshore drilling operations normally use a fresh water based mud, except where drilling operations encounter large salt domes. Then the mud system would be converted either to a salt clay mud system with salt added to the water phase, or to an oil based mud system. This change in the liquid phase is intended to prevent dissolving salt in the dome, enlarging the hole, and causing solution cavities in the formation.

In offshore operations, the direct discharge of cuttings and water based muds create turbidity. Limited information is available to accurately define the degree of turbidity, or the area or volume of water affected by such turbid discharges, but experienced observers have described the existence of substantial plumes of turbidity when muds and cuttings are discharged.

Oil-based muds contain carefully formulated mixtures of oxidized asphalt, organic acids, alkali, stabilizing agents and high-flash diesel oil.(14,15) The oils are the principal ingredients and so are the liquid phase. Muds displaced from the well hole also contain solids from the hole. There are two types of emulsified oil muds: 1) oil emulsion muds, which are oil-in-water emulsions; and 2) inverted emulsion muds, which are water-in-oil emulsions. The principal differences between these two muds and oil based muds is the addition of fresh or salt water into the mud mixture to provide some of the volume for the liquid phase. Newer formulations can contain from 20 to 70 percent water by volume. The water is added by adding emulsifying and stabilizing agents. Clay solids and weighting agents can also be added.

Sanitary and Domestic Waste

The sanitary wastes from offshore oil and gas facilities are composed of human body waste and domestic waste such as kitchen and general housekeeping wastes. The volume and concentration of these wastes vary widely with time, occupancy, platform characteristics, and operational situation. Usually the toilets are flushed with brackish water or sea water. Due to the compact nature of the facilities the wastes have less dilution water than common municipal wastes. This results in greater waste concentrations. Table 14 indicates typical waste flow for offshore facilities and vessels.

Table 13
Volume of Cuttings and Muds in Typical

10,000-Foot Drilling Operation (2)

Interval, Feet	Hole Size, inches	Vol. of Cuttings, bbl.	Wt. of Cuttings, pounds	Drilling mud	Vol of Mud components, bbl	Wt. of Mud components pounds
0-1,000	24	562	505,000	sea water & natural mud	variable	
1,000-3,500	16	623	545,000	Gelled sea water	700	81,500
3,500-10,000	12	915	790,000	Lime base	950	424,000

Table 14

Typical Raw Combined Sanitary and Domestic
Wastes from Offshore Facilities

No. of Men	Flow gal/day	BOD_5, mg/l Average	BOD_5, mg/l Range	Suspended Solids, mg/l Average	Suspended Solids, mg/l Range	Total Coliform (X 10)	Reference
76	5,500	460	270-770	195	14-543	10-180	(10)
66	1,060	875	----	1,025	-----	-----	(12)
67	1,875	460	----	620	-----	-----	(12)
42	2,155	225	-----	220	-----	-----	(12)
10-40	2,900	920	-----	---	-----	-----	(11)

SECTION V

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SECTION VI

SELECTION OF POLLUTANT PARAMETERS

Oil and grease from produced water, deck drainage, muds, cuttings, and produced sands and solids, and residual chlorine (as an indicator of fecal coliform) and floating solids from sanitary and domestic sources have been selected as the pollutants for which effluent limitations will be established. The rationale for inclusion of these parameters are discussed below.

Parameters for Effluent Limitations

Freon Extractables - Oil and Grease

No solvent is known which will directly dissolve only oil or grease, thus the manual "Metnods for the Chemical Analysis of Water and Wastes 1974" distributed by the Environmental Protection Agency states that their method for oil and grease determinations includes the freon extractable matter from waters.

In the oil and gas extraction industry, oils, greases, organic acids, various other hydrocarbons and some inorganic compounds, such as sulfur, will be included in the freon extraction procedures. The majority of material removed by the procedure from a produced water will, in most instances, be of a hydrocarbon nature. These hydrocarbons, predominately oil and grease type compounds, will make their presence felt in the COD, TOC, TOD, and usually the BOD tests where high test values will result. The oxygen demand potential of these freon extractables is only one of the detrimental effects exerted on water bodies by this class of compounds. Oil emulsions may adhere to the gills of fish or coat and destroy algae or other plankton. Depostion of oil in the bottom sediments can serve to inhibit normal benthic growths, thus interrupting the aquatic food chain. Soluble and emulsified materials ingested by fish may taint the flavor of the fisn flesh. Water soluble components may exert toxic action on fish. The water insoluble hydrocarbons and free floating emulsified oils in a waste water will affect stream ecology by interfering with oxygen transfer, by damaging the plumage and coats of water animals and fowls, and by contributing taste and toxicity problems. The effect of oil spills upon boats and shorelines and their production of oil slicks and iridenscence upon the surface of waters is well known.

Fecal Coliform (Chlorine Residual)

The concentration of fecal coliform bacteria can serve as an indication of the potential pathogencity of water resulting from the disposal of human wastes. Fecal coliform levels have been established to protect beneficial water use (recreation and shellfish propagation) in the coastal areas.

The most direct method to determine compliance with specified limits is to measure the fecal coliform levels in the effluent for a period representing a normal cycle of operations. This approach may be applicable to onshore installations; however, for offshore operations the logistics become complex, and simplified methods are desirable.

However, the presence of specific levels of suspended solids and chlorine residual in an effluent are indicative of corresponding levels of fecal coliforms. In general if suspended solids levels in the effluent are less than 150 mg/l and the chlorine residual is maintained at 1.0 mg/l, the fecal coliform level should be less than 200 per 100 ml. Properly operating biological treatment systems on offshore platforms have effluents containing less than 150 mg/l of suspended solids; therefore, chlorine residual is a reasonable control parameter.

It may be considered desirable, however, that a study of each sanitary treatment system be made at least once a year to measure influent and effluent biochemical oxygen demand, suspended solids, and fecal coliform. The purpose of the survey is to determine the treatment efficiencies, to evaluate operating procedures, and to adjust the system to obtain maximum treatment efficiencies and minimize chlorine usage.

Floating Solids

Marine waters should be capable of supporting indigenous life forms and should be free of substances attributable to discharges or wastes which will settle float on the water, and produce objectionable odors. Floating solids have been selected as a control parameters for domestic wastes and sanitary wastes from small or intermittently manned offshore facilities.

Other Pollutants

Some produced formation waters are known to contain heavy metals, toxic substances, constituents with substantial oxygen demand, and inorganic salts. Insufficient data exist to warrant comprehensive control of these parameters and there is no discharge technology now in use by the industry to remove these pollutants, although some concomitant reduction in oxygen demanding constituents may take place as a result of treatment not specifically designed for their removal.

Heavy Metals

Produced waters have been shown to contain cyanide cadmium, and mercury. Section 307(a)(1) of the Federal Water Pollution Control Act Amendments of 1972 requires a list of toxic pollutants and effluent standards or prohibitions for these substances. The proposed effluent standards for toxic pollutants state that there shall be no discharge of cyanide, cadmium, or mercury into streams, lakes or estuaries with a low flow less than or equal to 0.283 cubic meters per second (M^3/sec) (10 cubic feet per second) or into lakes with an area less than or equal to 200 hectares (500 acres). Many estuarine areas fall into this category.

The harmful effects of these toxicants, which include direct toxicity to humans and other animals, biological concentration, sterility, mutagenicity, teratogenicity, and other lethal and sublethal effects, have been well documented in the development of the Section 307(a)(1) proposed regulations.

Produced formation waters have also been shown to contain arsenic, chromium, copper, lead, nickel, silver, and zinc as pollutants. According to McKee and Wolfe (6), arsenic is toxic to aquatic life in concentrations as low as 1 mg/l. The toxicity of chromium is very much dependent upon environmental factors and has been shown to be as low as 0.016 mg/l for aquatic organisms. Copper is toxic to aquatic organisms in concentrations of less than 1 mg/l and is concentrated by plankton from their habitat by factors of 1,000 to 5,000 or more. Lead has been shown to be toxic to fish in concentrations as low as 0.1 mg/l, nickel at a concentration of 0.8 mg/l, and silver at a concentration of 0.0005 mg/l. Zinc was shown to be toxic to trout eggs and larvae at a concentration of 0.01 mg/l.

TDS

Dissolved solids in produced waters consist mainly of carbonates, chlorides, and sulfates. U.S. Public Health Service Drinking Waters Standards for total dissolved solids are set at 500 mg/l on the basis of taste thresholds. Many communities in the United States use water containing from 2,000 to 4,000 mg/l of dissolved solids. Such waters are not palatable and may have a laxative effect on certain people. However, the geographic location and availability of potable water will dictate acceptable standards. The following is a summary of a literature survey indicating the levels of dissolved solids which should not interfere with the indicated beneficial use:

Domestic Water Supply	1,000 mg/l
Irrigation	700 mg/l
Livestock Watering	2,500 mg/l
Freshwater Fish and Aquatic Life	2,000 mg/l

Estuaries are typically bilaminar systems, stratified to some degree, with each layer dependent upon the other for cycling of minerals, gases, and energy. The upper, low salinity, euphotic zone supports production of organic materials from sunlight and CO_2; it also produces oxygen in excess of respiration so that this upper layer is characteristically supersaturated with O_2 during the daylight hours. The bottom higher salinity layer functions as the catabolic side of the cycle, (microbial breakdown of organic material with subsequent O_2 utilization and CO_2 production). In a healthy estuarine system, these two layers are in precarious synchrony, and the alteration of density, minerals, gases, or organic material is capable of causing an imbalance in the system.

Apparently due to the stresses resulting from salinity shocks, anamalous ion ratios, strong buffer systems, high pH, and low oxygen solubility, few organisms are capable of adapting to brine-dominated systems. This results in low diversity of species, short food chains, and depressed trophic levels. (7)

Chlorides

Chloride ion is one of the major anions found in water and produces a salty taste at a concentration of about 250 mg/l. Concentrations of 1000 mg/l may be undetectable in waters which contain appreciable amounts of calcium and magnesium ions.

Some produced water associated with naturally occurring subsurface hydrocarbons may contain extremely high amounts of sodium chloride. These "so-called" connate brines developed because the particular geologic formation has not allowed the entrance of surface water for dilution. In the mid-continent region where these brines are found, they average 174,000 mg/l of dissolved solids.

The toxicity of chloride salts will depend upon the metal with which they are combined. Because of the rather high concentration of the anion necessary to initiate detrimental biological effects, the limit set upon the concentration of the metallic ion with which it may be tied, will automatically govern its concentration in effluents, in practically all forms except potassium, calcium, magnesium, and sodium.

Since sodium is by far the most common (sodium 75 percent, magnesium 15 percent and calcium 10 percent) the concentration of this salt will probably govern the amount of chlorides in waste streams.

It is extremely difficult to pinpoint the exact amount of sodium chloride salt necessary to result in toxicity in waters. Large concentrations have been proven toxic to sheep, swine, cattle, and poultry.

In swine fed diets of swill containing 1.5 to 2.0% salt by weight, poisoning symptoms can be induced if water intake is limited and other factors are met. The time interval necessary to accomplish this is still about one full day of feeding at this level.

Problems of corrosion, taste, and quality of water necessary for industrial or agricultural purposes occur at sodium chloride concentration levels below those at which toxic effects are experienced.

Oxygen Demand Parameters

Dissolved oxygen (DO) is a water quality constituent that, in appropriate concentrations, is essential not only to keep organisms living but also to sustain species reproduction, vigor, and the development of populations. Organisms undergo stress at reduced DO concentrations that make them less competitive and able to sustain their species within the aquatic environment. For example, reduced DO concentrations have been shown to interfere with fish population through delayed hatching of eggs, reduced size and vigor of embryos, production of deformities in young, interference with food digestion, acceleration of blood clotting, decreased tolerance to certain toxicants, reduced food efficiency and growth rate, and reduced maximum sustained swimming speed. Fish food organisms are likewise affected adversely in conditions with suppressed DO. Since all aerobic aquatic organisms need a certain amount of oxygen, the consequences of total lack of dissolved oxygen due to a high BOD can kill all inhabitants of the affected area.

Two oxygen demand parameters are discussed below: BOD5, and TOC.

Almost without exception, waste waters from oil and gas extraction exert a significant and sometimes major oxygen demand. The primary sources are soluble biodegradable hydrocarbons and inorganic sulfur compounds.

Biochemical Oxygen Demand (BOD)

Biochemical oxygen demand is a measure of the oxygen consuming capabilities of organic matter. The BOD does not in itself cause direct harm to a water system, but it does exert an indirect effect by depressing the oxygen content of the water. Sewage and other organic effluents during their processes of decomposition exert a BOD, which can have a catastrophic effect on the ecosystem by depleting the oxygen supply. Conditions are reached frequently where all of the oxygen is used and the continuing decay process causes the production of noxious gases such as hydrogen sulfide and methane. Water with a high BOD indicates the presence of decomposing organic matter and subsequent high bacterial counts that degrade its quality and potential uses.

If a high BOD is present, the quality of the water is usually visually degraded by the presence of decomposing materials and algae blooms due to the uptake of degraded materials that form the foodstuffs of the algal populations.

Total Organic Carbon (TOC)

Total organic carbon is a measure of the amount of carbon in the organic material in a wastewater sample. The TOC analyzer withdraws a small volume of sample and thermally oxidizes it at 150°C. The water vapor and carbon dioxides from the combustion chamber (where the water vapor is removed) is condensed and sent to an infrared analyzer, where the carbon dioxide is monitored. This carbon dioxide value corresponds to the total inorganic value. Another portion of the same sample is thermally oxidized at 950°C, which converts all the carbonaceous material to carbon dioxide; this carbon dioxide value corresponds to the total carbon value. TOC is determined by subtracting the inorganic carbon (carbonates and water vapor) from the total carbon value.

The recently developed automated carbon analyzer has provided rapid and simple means of determining organic carbon levels in waste water samples, enhancing the popularity of TOC as a fundamental measure of pollution. The organic carbon determination is free of many of the variables which plaque the BOD analyses, yielding more reliable and reproducible data.

Phenolic Compounds

Many phenolic compounds are more toxic than pure phenol; their toxicity varies with the combinations and general nature of total wastes. The effect of combinations of different phenolic compounds is cumulative.

Phenols and phenolic compounds are both acutely and chronically toxic to fish and other aquatic animals. Also, chlorophenols produce an unpleasant taste in fish flesh that destroys their recreational and commercial value.

It is necessary to limit phenolic compounds in raw water used for drinking water supplies, as conventional treatment methods used by water supply facilities do not remove phenols. The ingestion of concentrated solutions of phenols will result in severe pain, renal irritation, shock and possibly death.

Phenols also reduce the utility of water for certain industrial uses, notably food and beverage processing, where it creates unpleasant tastes and odors in the product.

As seen from the above discussion on the potential harm from produced water discharges, the effects of toxicants, high salinity, low dissolved oxygen, and high organic matter can combine to produce an ecological enigma.

The State of California, recognizing the potential impact of industrial wastes in the coastal areas, has adopted effluent limitations for ocean waters under its jurisdiction (see Table 15. They were arrived at by first applying safety factors to known toxicity levels and a consideration of control technology. This produced proposed standards which were subjected to the public hearing process, revised accordingly, and then declared. To meet the coastal water quality standards, the oil and gas extraction industry has developed a no discharge technology (reinjection of production water).

TABLE 15

Effluent Quality Requirements for

Ocean Waters of California

	Unit of measurement	Concentration not to be exceeded more than: 50% of time	10% of time
Arsenic	mg/l	0.01	0.02
Cadmium	mg/l	0.02	0.03
Total Chromium	mg/l	0.005	0.01
Copper	mg/l	0.2	0.3
Lead	mg/l	0.1	0.2
Mercury	mg/l	0.001	0.002
Nickel	mg/l	0.1	0.2
Silver	mg/l	0.02	0.04
Zinc	mg/l	0.3	0.5
Cyanide	mg/l	0.1	0.2
Phenolic Compounds	mg/l	0.5	1.0
Total Chlorine Residual	mg/l	1.0	2.0
Ammonia (expressed as nitrogen)	mg/l	40.0	60.0
Total Identifiable Chlorinated Hydrocarbons	mg/l	0.002	0.004
Toxicity Concentration	tu	1.5	2.0

Radioactivity not to exceed the limits specified in Title 17, Chapter 5, Subchapter 4, Group 3, Article 5, Section 30285 and 30287 of the California Administrative Code.

SECTION VI

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SECTION VII

CONTROL AND TREATMENT TECHNOLOGY

Petroleum production, drilling, and exploration wastes vary in quantity and quality from facility to facility. A wide range of control and treatment technologies has been developed to treat these wastes. The results of industry surveys indicate that techniques for in-process controls and end-of-pipe treatment are generally similar for each of the industry subcategories; however, local factors, discharge criteria, availability of space, and other factors influence the method of treatment.

In-plant Control/Treatment Techniques

In-plant control or treatment techniques are those practices which result in: 1) reduction or elimination of a waste stream; or 2) a change in the character of the constituents and allow the end-of-pipe processes to be more efficient and cost effective.

Reduction or Elimination of Waste Streams

The two types of in-plant techniques that reduce the waste load to the treatment system or to the environment are reuse and recycle of waste products. Examples of reuse are: 1) reinjection of produced water to increase reservoir pressures; and 2) utilization of treated production water (softened, if necessary) for steam generation. An example of a recycle system is the conservation and reuse of drilling muds.

Waste Character Change

Examples of character change in waste stream would be: 1) the substitution of a positive displacement pump for a high speed centrifugal pump; and 2) substitution of a downhole choke for a well head choke, thereby reducing the amount of emulsion created. (1)

Proper pretreatment and maintenance practices are also effective in reducing waste flows and improving treatment efficiencies. Return of deck drainage to the process units and elimination of waste crankcase oil from the deck drainage or produced water treatment systems are examples of good offshore pretreatment and maintenance practices.

Process Technology

The single most significant change in process technology is reinjection to the reservoir formation for secondary recovery and pressure maintenance. This is distinguished from injection for disposal purposes only, which is considered as end-of-pipe treatment. Waters used for secondary recovery and pressure maintenance should be free of suspended solids, bacterial slimes, oxygen, sludges, and precipitates. In some cases the quantity of produced water is insufficient to provide the needed water for a secondary recovery and pressure maintenance system. In this case, additional make-up water must be found, and wells or surface water (including sea water) may be used as a source of make-up water. There may be problems of compatability between produced water and make-up water. A typical reinjection water treatment facility consists of a surge tank, flotation cell, filters, retention tank, and injection pumps. (2)

Reinjection of produced water for secondary recovery and pressure maintenance is a very common practice onshore. It has been estimated that 60 percent of all onshore produced water is reinjected for secondary recovery.

Produced water treatment for reinjection is similar, both offshore and onshore. Existing reinjection systems vary from small units which treat less than 100 barrels per day of brine waste to large complexes which handle over 170,000 barrels per day. Produced water reinjection systems for presure maintenance and water flooding are less common in the Gulf Coast, and none are in use in Cook Inlet, Alaska (Cook Inlet water is treated and injected for water flooding, because of compatibility problems with the produced water).

Produced water treatment and reinjection systems are not generally limited by space availability but must be specifically designed to fit offshore platforms. Two limiting factors which affect produced water reinjection are insuffiecint quantities of produced water to meet the requirement for reservoir pressure maintenance and incompatibility between make-up sea water and produced water.

With the increasing oil demand, new ("tertiary") methods are being developed to recover greater amounts of oil from producing formations. The addition of steam or other fluids into the formation can improve ultimate recovery. A system which reuses produced water for steam generation is operating on the West Coast. The system consists of a typical reinjection treatment unit with water softeners added to the system.

Changes in process technology have also occurred in drilling operations. Environmental considerations and high cost of drilling muds have led to the development of special equipment and procedures to recycle and recondition both water based and oil based muds. With the system operating properly, mud losses are limited to deck splatter and the mud clinging to drill cuttings.

Pretreatment

The main pretreatment process which is applicable to offshore production systems is the return of deck drainage to the production process units to remove free oil prior to end-of-pipe treatment. This method of pretreatment is not applicable to facilities that flush drilling muds into the deck drainage system during rig wash down or to facilities that pipe all produced crude oil and water to shore for processing and brine treatment.

Operation and Maintenance

A key in-plant control is good operation and maintenance practices. Not only do they reduce waste flows and improve treatment efficiencies, but they also reduce the frequency and magnitude of systems upsets.

Some examples of good offshore operations are:

1. Separation of waste crankcase oils from deck drainage collection system.

2. Reduction of waste water treatment system upset from deck washdown by discriminant use of detergents.

3. Reduction of oil spillage through good prevention techniques such as drip pans and other collection methods.

4. Elimination of oil drainage from transfer pump bearings or seals by pumping into the crude oil processing system.

5. Reduction of oil gathered in the pig (pipeline scraper) traps by channeling oil back into the gathering line system instead of the sump system.

6. Elimination of extreme loading of the produced water treatment system, when the process system malfunctions, by redirecting all production to shore for treatment. (3)

Good maintenance practice includes: 1) inspection of dump valves for sand cutting as a preventive measure; 2) use of dual sump pumps for pumping drainage into surge tanks; 3) use of reliable chemical injection pumps for produced water treatment; 4) selection of the best combination of oil and water treating chemicals; and 5) use of level alarms for initiating shut down during major system upsets. Operation and maintenance of a produced water treatment system during start-up presents special problems. As an example, an offshore facility had two problems with the heater-treaters that caused problems with the water treatment system: 1) insufficient heat in the treaters; and 2) malfunctioning level controls which caused excessive oil loading. A change in the type of level controls and reduced production which lowered the heating requirements and helped alleviate the problem during start-up of the produced water treatment unit. Further improvements were achieved by careful selection of chemicals for treating oil and produced water, and the chemical injection and recylcing pumps were replaced.

The preceding paragraph describes an actual case where detailed failure analysis and corrective action ended an upset in the waste treatment system. Evaluation of operational practices, process and treatment equipment and correct chemical use is imperative for proper operation and in the prevention and detection of failures and upsets. The description of these operation and maintenance practices is not intended to advocate their universal application. Nevertheless, good operations and maintenance on an oil/gas production facility can have a substantial impact on the loads discharged to the waste treatment system and the efficiency of the system. Careful planning, good engineering, and a committment on the part of operating and management personnel are needed to ensure that the full benefits of good operation and maintenance are realized.

Analytical Techniques and Field Verification Studies

Data on the types of treatment equipment and performance of the systems in this report were provided by the industry. An early analysis of data indicated a need to both verify the information and determine current waste handling practices. EPA conducted a 3-week sampling verification study for facilities off the Louisiana Coast; and 3-day studies were conducted in Texas and California to verify performance data. In addition, three field surveys were made to determine the adequacy of laboratory analytical techniques, sample collection procedures, operation and maintenance procedures, and general practices for handling deck drainage. Similar field surveys were made of facilities located in Cook Inlet.

Performance verification studies were also conducted to identify the most efficient onshore facilities and to determine geographical and process differences based on crude oil residual separability and various produced water treatment processes.

Variance in Analytical Results for Oil and Grease Concentrations

Effluent oil and grease values in produced water recorded and reported by the oil and gas industry are usually determined by contracting laboratories using various analytical methods. Analytical methods presently in use include infrared, gravimetric, utlraviolet- fluorescence, and colorimetric. The method used by a contractor is usually governed by regulatory authority, the person in charge of the laboratory, the client, or some combination of these. For example, Department of the Interior, U. S. Geological Survey, Outer Continental Shelf Operating Order #8 (Gulf of Mexico area) dated October 30, 1970, specifies to Federal leasees that oil content values for effluents shall be determined and reported in accordance with the American Society for Testing and Materials Method D1340, "Oily Matter in Industrial Waste Water." A regional water quality board in California specifies APHA Standard Methods, 13th Edition, "Oil and Grease" Test No. 137 (Gravimetric). The U. S. Environmental Protection Agency lists the APHA Standard for oil and grease determination under the provisions of 40 CFR Part 136 "Guidelines Establishing Test Procedures for the Analysis of Pollutants." The manner in which the sample is prepared for analysis is equally critical. For example, Table 16 shows oil/grease concentrations of acidized and unacidized samples from facilities in California (both analyzed by the same method).

TABLE 16

Effect of Acidification on Oil and Grease Data

Date of Effluent Sample	Oil and Grease - mg/l Unacidized	Acidized
7-26-74	7.6	26.3
7-26-74	36.3	61.8

The values after pH adjustment were significantly higher than the samples that were not acidified. One explanation is that the acidification converts many of the water soluble organic acid salts to water insoluble acids that are then extractable by hydrocarbon solvents.

The solvent used for the extraction of oil and grease from a sample is another critical step that can affect analytical results. For example, petroleum ether extracts all crude oil constituents from a produced water sample except asphaltenes or bitumen. This limitation would affect the reported results of a sample containing high asphaltic constituents. Other solvents used in oil/grease determinations are trichlorotrifluroethane

(Freon), hexane, carbon tetrachloride, and methylene chloride, with each being somewhat selective in the hydrocarbon constituents extracted.

Reported oil/grease concentrations in waste water effluents from offshore facilities were highly variable within and between geographical areas. The available information did not show any discernible reason for this variability (difference in waste treatability or treatment technology). Therefore, EPA undertook field verification studies to determine the reasons for the low oil/grease concentration data in the coastal area of Texas and California as compared to Louisiana. These field studies included sampling for oil/grease in effluent waste water discharges and duplicate samples were provided to the industry for independent laboratory analysis. Tables 17 and 18 compare the results of two analytical methods (gravimetric and infrared) measuring Freon extractible oil/grease and those values determined by petroleum ether extraction using the gravimetric method. This study was conducted by the EPA Robert S. Kerr Research Laboratory (RSKRL) at Ada, Oklahoma.

Table 17

Oil and Grease Data - Texas Coastal
Analytical Procedure Study

Sample Identification	Oil and Grease - mg/l: RSKRL Freon Gravimetric	RSKRL Freon Infrared	INDUSTRY LABS Freon Gravimetric
T-1I	32	45	2
T-1E	126	154	5
T-2I	372	314	178
T-2E	242	197	145
T-3I	643	695	685
T-3E	52	62	10
T-4I	1905	1736	968
T-4E	46	51	6

Table 18

Oil and Grease Data - California Coastal
Analytical Procedure Study

Sample Identification	RSKRL Freon Gravimetric	RSKRL Freon Infrared	RSKRL Pet. Ether Gravimetric	INDUSTRY LABS Pet. Ether Gravimetric
C-1I	106	126	76	79
C-1E	22.3	16	5	3.1
C-2I	359.6	473	241	508
C-2E	42.2	39	27	3.6
C-3I	167.6	197	141	189.1
C-3E	46.1	35	7	11.2

1 - unacidified samples

I - influent

E - effluent

The preceding tables indicate that there was good correlation in analytical results when EPA uses two different methods on the same sample. There is no correlation between the same sample analyzed by the same method by EPA and the industry labs in Texas and California (EPA's results did correlate well to the contract labs during the Louisiana verification study). Therefore the low oil and grease concentrations reported by Texas and California appear to be more a function of the analytical techniques and the laboratory rather than an indication of treatibility of the waste water produced and/or treatment equipment efficiency. This conclusion was validated by a statistical analysis of the data, which is contained in Supplement B. The analysis indicated a high correlation with the results of the two analytical methods performed within the EPA laboratory and little or no correlation with the analytical results between the EPA and contractor laboratories.

Field Verification Studies

The EPA field verification study of coastal Louisiana facilities included sampling for oil/grease in effluent waste water discharges. Duplicate samples were provided to the oil/gas industry for independent laboratory analysis. The analytical results of this study, contained in Supplement B, verified the data collected over the years by Coastal Louisiana facilities. In addition, the study found a very high correlation between analytical results of contractor laboratories and the EPA laboratory.

The selection of facilities for the Gulf Coast verification study was based on a general cross section of the production industry and did not favor the more efficient systems. Table 19 indicates types of treatment units, the performance observed during the survey, and long term performance based on historical data for each facility. Tables 20 and 21 indicate the comparative oil and grease concentration data for Texas and California offshore facilities and onshore treatment of offshore produced water treatment units.

TABLE 19

Performance of Individual Units

Louisiana Coastal

Facility Identification	Long Term Mean Effluent Oil and Grease mg/l	EPA Survey Results Oil and Grease mg/l
Flotation Cells		
GFV01	22	23
GFV02	23	6
GFS03	31	25
GFS04	29	21
GFS05	32	32
GFT06	18	24
GFG07	24	148[1]
GFS08		30
GFT09	28	31
GFG10	18	13
Parallel Plate Coalescers		
GCC11	35	21
GCC12	66	78
GCM13	43	34
GCC14		52
GCG15	39	19
GCS16	39	56
GCC17	51	118
Loose Media Coalescers		
GLG23	25	12
GLT24	18	8
Simple Gravity Separators		
GPV18		13
GPT19		26
GPE20		19
GIM21		44
GTT22		63
GPE25		16

[1]System malfunctioning during survey.

TABLE 20

Texas Coastal Verification Data

Facility Identification	Freon Extractibles Gravimetric Method		Freon Extractibles Infrared Method	
	Oil and Grease - mg/l			
	Influent	Effluent	Influent	Effluent
T-1	32.0	126.0	45.0	154.0
	28.9	103.0	57.0	134.0
	830.0	116.0	1,230.0	232.0
	49.0	561.0	130.0	827.0
	199.0	141.0	300.0	304.0
	36.0	118.0	64.0	277.0
T-2	333.0	220.0	305.0	209.0
	372.0	242.0	314.0	197.0
	301.0	194.0	336.0	198.0
	327.0	185.0	351.0	204.0
	352.0	196.0	293.0	188.0
	286.0	220.0	312.0	237.0
T-3	1,250.0	13.0	1,350.0	55.0
	643.0	52.0	695.0	62.0
	1,626.0	45.0	1,635.0	60.0
	154.0	50.0	206.0	66.0
	667.0	55.0	1,242.0	81.0
	1,169.0	87.0	1,215.0	84.0
T-4	1,583.0	37.0	1,520.0	42.0
	921.0	9.0	1,578.0	9.0
	1,710.0	14.0	1,677.0	14.0
	1,844.0	24.0	1,780.0	27.0
	1,905.0	46.0	1,736.0	51.0
	1,007.0		1,884.0	

TABLE 21

Verification of Oil and Grease Data

California Coastal

RSKRL, Ada, Oklahoma

Facility Identification	Freon Extractibles, Gravimetric Method, mg/1		Freon Extractibles, Infrared Method, mg/1		Petroleum Ether Extractibles, Gravimetric Method, mg/1	
	Influent	Effluent	Influent	Effluent	Influent	Effluent
C-1	112.3	28.9	94.0	18.0		6.0
	97.4	43.1	101.0	18.0		
	110.7	26.0	122.0	18.0	90.0	
	106.1	22.3	126.0	16.0	76.0	5.0
C-2	359.6	42.2	437.0	39.0	241.0	27.0
	363.6	44.0	446.0	40.0	193.0	13.0
	215.6	53.5	323.0	54.0	172.0	19.0
	599.8	51.6	851.0	47.0	462.0	51.0
	881.1	55.4	1,214.0	53.0	611.0	14.0
C-3	165.6	54.0	188.0	39.0	83.0	23.0
	163.2	44.3	148.0	34.0	100.0	22.0
	202.2	51.7	206.0	37.0		71.0
	167.6	46.1	197.0	35.0	141.0	7.0
C-4	56.7	19.1	58.0	16.0	55.0[1]	6.0[1]
		24.2		15.0	59.0[1]	
		19.9		15.0	102.0[1]	

1. Carbon tetrachloride extractibles.

End-of-pipe control technology for offshore treatment of produced water from oil and gas production primarily consists of physical/chemical methods. The type of treatment system selected for a particular facility is dependent upon availability of space, waste characteristics, volumes of waste produced, existing discharge limitations, and other local factors. Simple treatment systems may consist of only gravity separation pits without the addition of chemicals, while more complex systems may include surge tanks, clarifiers, coalescers, flotation units, chemical treatment, or reinjection.

Gas Flotation

In a gas flotation unit gas bubbles are released into the body of waste water to be treated. As the bubbles rise through the liquid, they attach themselves to any oil droplet in their path, and the gas and oil rise to the surface where they may be skimmed off as a froth.

Two types of gas flotation systems are presently used in oil production: 1) Dispersed gas flotation - these units use specially shaped rotating mines or dispersers to form small gas bubbles which float to the surface with the contacted oil. The gas is drawn down into the water phase through the vortex created by the rotors, from a gas blanket maintained above the surface. The rising bubbles contact the oil droplets and come to the surface as a froth, which is then skimmed off. These units are normally arranged as a series of cells, each one operating as outlined above. The waste water flows from one cell to the next, with a net oil removal in each cell (some oil is recycled back into the water phase by the rotor action). 2) Dissolved gas flotation - these units differ from the dispersed gas flotation because the gas bubbles are created by a change in pressure which lowers the dissolved gas solubility, releasing tiny bubbles. A portion of the waste water stream is recycled back to the bottom of the cell after waste water has been gasified. This gasification is accomplished by passing the waste water through a pump to raise the pressure and then through a contact tank filled with gas. The waste water leaves the contact tank with a concentration of gas equivalent to the gas solubility at the elevated pressure. When the recycled (gasified) water is released in the bottom of the cell (at atmospheric pressure) the solubility of the gas decreases and the excess gas is released as microscopic bubbles. These bubbles then rise to the surface contacting the oil and bringing it to the surface where it is skimmed off. Dissolved gas flotation units are usually a single cell only.

On production facilities it is usual practice to recycle the skimmed oily froth back through the production oil-water separating units. A flow diagram of the two typical flotation units is shown in Figure 6.

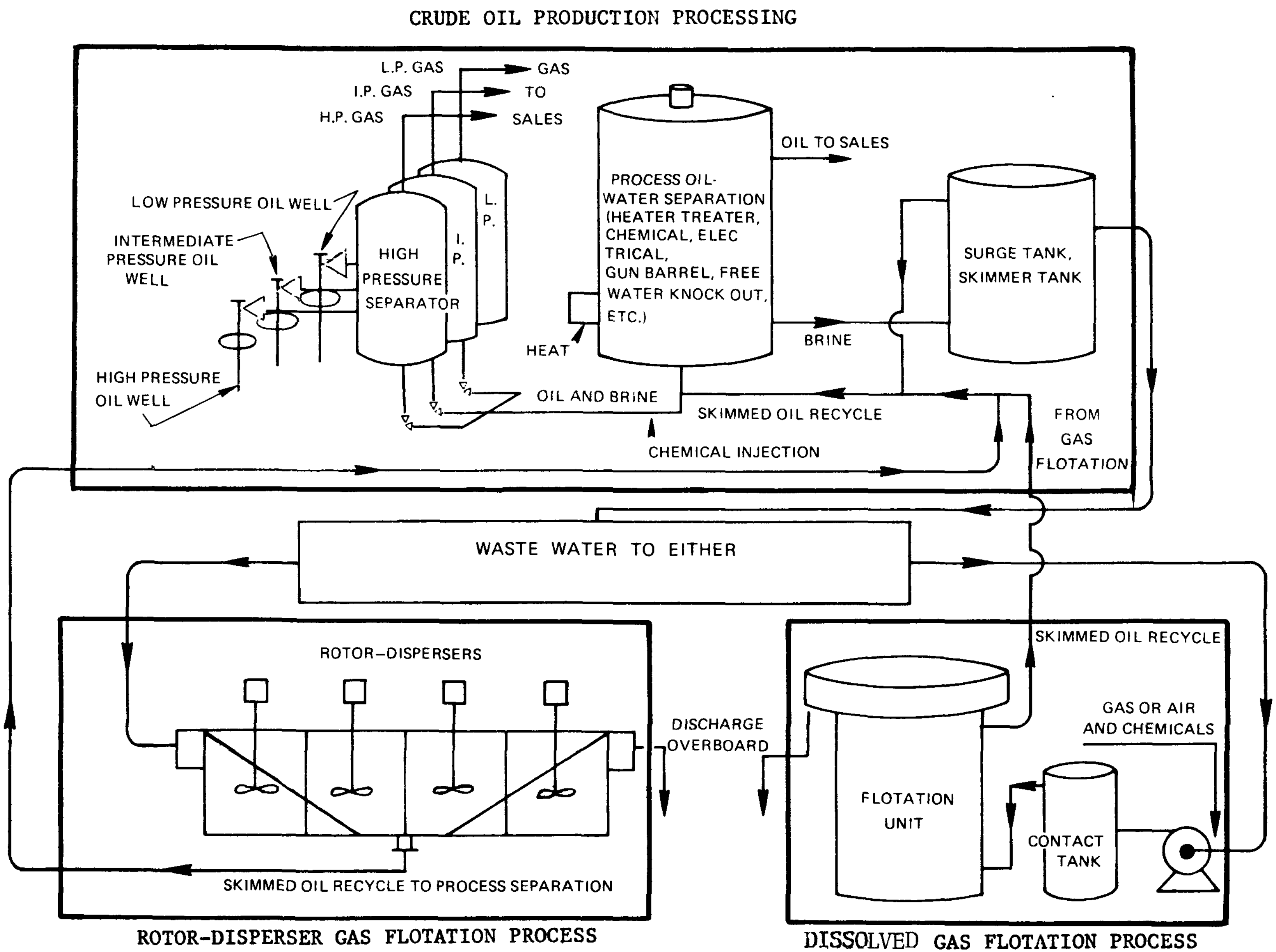


Fig. 6 -- ROTOR-DISPERSER AND DISSOLVED GAS FLOTATION PROCESSES FOR TREATMENT OF PRODUCED WATER

The addition of chemicals can increase the effectiveness of either type of gas flotation unit. Some chemicals increase the forces of attraction between the oil droplets and the gas bubbles. Others develop a floc which eases the capture of oil droplets, gas bubbles, and fine suspended solids, making treatment more effective.

In addition to the use of chemicals to increase the effectiveness of gas flotation systems, surge tanks upstream of the treatment unit also increase its effectiveness. The period of quiescence provided by the surge tank allows some gravity separation and coalescence to take place, and dampens out surges in flow from the process units. This provides a more constant hydraulic loading to the treatment unit, which, in turn, aids in the oil removal process.

The verification survey conducted on Coastal Louisiana facilities included 10 flotation systems which varied in design capacities from 5,000 to 290,000 barrels-per-day and included both rotor/disperser and dissolved gas units. The designs of waste treatment systems are basically the same for both offshore platform installations and onshore treatment complexes; however, parallel units are provided at two of the onshore installations, permitting greater flexibility in operations.

Information obtained during the field survey of onshore treatment systems for Cook Inlet indicated that one of the four onshore systems utilized a dissolved gas flotation system comparable to those used in the Gulf Coast. This system provides physical/chemical treatment and consists of a surge tank, chemical injection, and a dissolved air flotation unit. In addition, two of the Cook Inlet platforms use flotation cells for treatment of deck drain wastes.

Field surveys on the West Coast found that physical/chemical treatment is the primary method of treating produced water for either discharge to coastal waters or for reinjection and that flotation is the most widely used of the physical/chemical methods. On the West Coast, all treatment systems except one are located onshore and produced fluids are piped to these complexes. The majority of the waste water treatment systems have been converted to reinjection systems. However, some of those that still discharge are somewhat different from the systems in the Gulf Coast and Cook Inlet. One of the more complex onshore systems consists of pretreatment and grit settling, primary clarification, chemical addition (coagulating agent), chemical mixing, final clarification, aeration, chlorination, and air flotation. This system handles 50,000 barrels-per-day.

Surveys of onshore production facilities in California revealed induced gas flotation being used for treatment of produced water for recovery, disposal by reinjection and discharge. A total of seven units were observed, three of which were utilized ahead of sand filters and one unit was followed by a pond. The size range of the entire group was from 10,500 to 350,000 Bbl/day. Surge tanks normally preceded the flotation units with the floc going to a sump or being recycled.

In Wyoming two dispersed air flotation systems were observed, both of which discharge and reinjected for recovery the treated produced water. The system consisted of a skim tank, flotation unit, surge tank and in the case of the discharged stream, an earthen pond. The addition of chemicals was used to increase separation efficiency. The produced water treatment capacities of the two systems surveyed were 70,000 and 340,000 Bbl/day respectively.

Parallel Plate Coalescers

Parallel plate coalescers are gravity separators which contain a pack of parallel, tilted plates arranged so that oil droplets passing through the pack need only rise a short distance before striking the underside of the plates. Guided by the tilted plate, the droplet then rises, coalescing with other droplets until it reaches the tip of the pack where channels are provided to carry the oil away. In their overall operation, parallel plate coalescers are similar to API gravity oil water separators. The pack of parallel plates reduces the distance that oil droplets must rise in order to be separated; thus the unit is much more compact than an API separator. Suspended particles, which tend to sink, move down a short distance when they strike the upper surface of the plate; then they move down along the plate to the bottom of the unit where they are deposited as a sludge and can be periodically drawn off. Particles may become attached (scale) to the plate surface of the plate; then they move down along the plate surfaces, requiring periodic removal and cleaning of the plate pack.

Where stable emulsions are present, or where the oil droplets dispersed in the water are relatively small, they may not separate in passing through the unit.

The verification survey of Coastal Louisiana facilities included seven plate coalescer systems which had design capacities from 4,500 to 9,000 barrels-per-day. A recent survey indicated that approximately 10 percent of the units in this area were plate coalescers and they treated about 9 percent of the total volume of produced water in offshore Louisiana waters. (4) Both the long-term performance data and the verification survey indicated that performance of these units was considerably poorer than that of flotation units. In addition to the physical limitations, coalescers' operation and maintenance data indicated that the units require frequent cleaning to remove solids.

No plate coalescers are in use in Cook Inlet or California, either onshore or offshore.

Filter Systems (Loose or Fibrous Media Coalescers)

Another type of produced water treatment system is filters. They may be classified into two general classes based on the media through which the waste stream passes.

1. Fibrous media, such as fiberglass, usually in the form of a replacable element or cartridge.

2. Loose media filters, which normally use a bed of granular material such as sand, gravel, and/or crushed coal.

Some filters are designed so that some coalescing and oil removal take place continuously, but a considerable amount of the contaminants (oil and suspended fines) remain on the filter media. This eventually overloads the filter media, requiring its replacement or backwashing. Fibrcus media filters may be cleaned by special washing techniques or the elements may simply be disposed of and a new element used. Loose media filters are normally backwashed by forcing water through the bed with the normal direction of flow reversed, or by washing in the normal direction of flow after gasifying and loosening the media bed.

Filters which require backwashing present somewhat of a problem on platforms because the valving and controls need regular maintenance and disposal of the dirty backwash water may be difficult. Replacing filter media and contaminated filter elements also create disposal problems.

Measured by the amount of oil removed, filter performance has generally been good (provided that the units are backwashed sufficiently often); however, problems of excessive maintenance and disposal have caused the industry in the Gulf Coast to move away from this type of unit, and a number of them have been replaced with gas flotation systems.

The Gulf Coast survey information indicated that when filter systems are used there is no initial pretreatment of the waste other than surge tanks. Backwashing, disposal of solids, and complex instrumentation were reported as the main problems with these units.

On the West Coast and Cook Inlet, no filter systems are in use as the primary treatment method. Filters are however, used for final treatment in injection systems in California and several steps of filtration are used prior to sea water injection in Cook Inlet. On the West Coast, these units are preceded by a surge tank, flotation unit, and other treatment units which remove most of the oil and suspended particles. These units, when used in series with other systems, perform well.

In Wyoming a site was visited where approximately 6,600 Bbl/day was being treated by a mixed sand media pressure filter. Earthen ponds both preceded and followed the filter unit with backwash feed being pumped from the final pond and discharged to the primary pond.

Gravity Separation

The simplist form of treatment is gravity separation. The produced water is retained for a sufficient time for the oil and water to separate. Tanks, pits, and, occasionally, barges are used as gravity separation vessels. Large volumes of storage to permit sufficient retention times are characteristic of these systems. Performance is dependent upon the characteristics of the waste water, water volumes, and availability of space. While total gravity separation requires large containers and long retention times, any treatment system can benefit from quiescent retention prior to further treatment. This retention allows some gravity separation and dampens surges in volume and oil content.

About 75 percent of the systems on the Gulf Coast are gravity separation systems. The majority are located onshore and have limited application on offshore platforms because of space limitations. Properly designed, maintained, and operated systems can provide adequate treatment. A 30,000-barrel-per-day gravity system with the addition of chemicals produced an effluent of less than 15 mg/l during the verification survey.

Two of the onshore treatment systems in Cook Inlet use gravity separation with various configurations of settling tanks and pits. No gravity systems were reported to be in use on the West Coast. The four installations visited in the Texas verification study all use gravity separation tanks offshore and a combination of tanks and/or pits onshore.

The most prevalent treatment method for produced water encountered in the onshore field surveys of California, Wyoming, Texas, Louisiana and Pennsylvania onshore production sites were tanks and ponds when utilized as the single treatment process. As previously mentioned, tanks do not afford the retention times of ponds, but whether or not their primary function is separation they are effective in skimming readily removed free oil.

In California four sites were visited which utilized tankage as the single method of treatment prior to disposal by reinjection. The capacity of these systems to treat produced water ranged from 6,000-35,000 Bbl/day.

In Wyoming a total of 37 production facilities were visited which utilized either tanks or ponds as the method of treatment. Of the 23 sites using tanks for treatment ranging in produced water capacity from 920 to 34,000 Bbl/day, 11 were reinjecting for disposal and the remainder were reinjecting for secondary recovery purposes. Of the 14 sites using ponds for treatment, nine were discharging, two were reinjecting for recovery, while the remaining three both discharged and reinjected for recovery.

In Pennsylvania, where disposal by discharge is the rule rather than the exception, 11 sites were visited which utilized ponds for separation treatment ranging in capacity from 2-8,000 Bbl/day of produced water capacity.

Distillation

In California a site was visited which utilized produced water as boiler feedwater. The boiler was fired by field natural gas and discharged condensate to the local groundwater table. The steam was utilized to heat onsite crude storage tanks and the boiler blowdown containing oil and grease residue was hauled to a Class I (California Classification) landfill site. Reported daily fuel costs for the 150 Bbl/day facility are $70.

Chemical Treatment

The addition of chemicals to the waste water stream is an effective means to increase the efficiencies of treatment systems. Pilot studies for a large onshore treatment complex in the Gulf of Mexico indicated that addition of a coagulating agent could increase efficiencies approximately 15 percent and the addition of a polyelectrolyte and a coagulating chemical could increase efficiencies 20 percent. (5)

Three basic types of chemicals are used for waste water treatment and, many different formulations of these chemicals have been developed for specific applications. The basic types of chemicals used are:

1. Surface Active Agents - These chemicals modify the interfacial tensions between the gas, suspended solids, and liquid. They are also referred to as surfactants, foaming agents, demulsifiers, and emulsion breakers.

2. Coagulating Chemicals - Coagulating agents assist the formation of floc and improve the flotation or settling characteristics of the suspended particles. The most common coagulating agents are aluminum sulfate and ferrous sulfate.

3. Polyelectrolytes - These chemicals are long chain, high molecular weight polymers used to assist in removal of colloidal and extremely fine suspended solids.

The results of two EPA surveys of 33 offshore facilities using chemical treatment in the Gulf Coast disclosed the following:

1. Surface active agents and polyelectrolytes are the most commonly used chemicals for waste water treatment.

2. The chemicals are injected into the waste water upstream from the treatment unit and do not require premixing units.

3. Chemicals are used to improve the treatment efficiencies of flotation units, plate coalescers, and gravity systems.

4. Recovered oil, foam, floc, and suspended particles skimmed from the treatment units are returned to the process system.

A similar survey of facilities in Cook Inlet, Alaska indicated that a facility uses coagulating agents and polyelectrolytes to improve treatment efficiency. Recovered oil and floc are returned to the process system.

Chemical treatment procedures on the West Coast are similar to those used in the Gulf Coast and Cook Inlet. However, there are exceptions where refined clays and bentonites are added to the waste stream to absorb the oil and both are removed after addition of a high molecular weight nonionic polymer to promote flocculation. The oil, clay, and other suspended particles removed from the waste stream are not returned to the process system but are disposed of at approved land disposal sites. A 14,000-barrel-per-day treatment system using refined clay was reported to have generated 60 barrels-per-day of oily floc which required disposal in a State approved site. Selection of the proper chemical or combination of chemicals for a particular facility usually requires jar tests, pilot studies, and trial runs. Adjustments in chemicals used in the process separation systems may also require modification of chemicals or application rate in the waste stream. Other chemicals may also be added to reduce corrosion and bacterial growths which may interfere with both process and waste treatment systems.

Effectiveness of Treatment Systems

Table 22 gives the relative long term performance of existing waste water treatment systems. The general superiority of gas flotation units and loose media filters over the other systems is readily apparent. However, individual units of other types of treatment systems have produced comparable effluents.

TABLE 22

Performance of Various Treatment Systems

Louisiana Coastal

Type Treatment System	Mean Effluent, Oil and Grease mg/l	No. of Units in Data Base
Gas Flotation	27	27
Parallel Plate Coalescers	48	31
Filters		
Loose Media	21	15
Fibrous Media	38	7
Gravity Separation (4)		
Pits	35	31
Tanks	42	48

Table 23 gives the performance of existing produced water treatment systems over a 6-month to one and one-half year period of weekly and monthly sampling. The data has been divided into treatment systems according to State of location.

TABLE 23
Performance of Various Treatment Systems
Wyoming and Pennsylvania

State	Type of Treatment System	Mean Effluent Oil and Grease mg/l	No. of Units in Data Base
Wyoming	Ponds	8.2	6
	Gas Flotation	10.6	2
	Sand Filtration	12.5	1
Pennsylvania	Ponds	4.1	4

Zero Discharge Technologies

Water produced along with liquid or gaseous hydrocarbons may vary in quantity from a trace to as much as 98 percent of the total fluid production. Its quality may range from essentially fresh to solids-saturated brine. The no discharge control technology for the treatment of raw waste water after processing varies with the use or ultimate disposition of the water. The water may be:

1. Discharged to pits, ponds, or reservoirs and evaporated.

2. Injected into formations other than their place of origin.

Evaporation

In some arid and semiarid producing areas, use of evaporation is acceptable, although limited in its practice. The surface pit, pond, or reservoir can only be used where evaporation rates greatly exceed precipitation and the quantity of emplaced water is small. The pit or pond is ordinarily located on flat to very gently rolling ground and not within any natural drainage channel, so as to avoid danger of flooding. Pit facilities are normally lined with impervious materials to prevent seepage and subsequent damage to fresh surface and subsurface waters. Linings may range from reinforced cement grout to flexible plastic liners. Materials used are resistant to corrosive chemically-treated water and oily waste water. In areas where the natural soil and bedrock are high in bentonite, montmorillonite, and similar clay minerals which expand upon being wetted, no lining is normally applied and sealing depends on the natual swelling properties of the clays. All pits are normally enclosed to prohibit or impede access.

In much of the Rocky Mountain oil and gas producing area, the total dissolved solids of the produced waters are relatively low. These waters are discharged to pits and put to use for local farmers and ranchers by irrigating land and watering stock. A typical produced water system widely in use is shown in Figure 7. A cross section of the individual pit is shown in Figure 8.

A producing oil field in Nevada discharges produced water to a closed saline basin. The basin contains no known surface or subsurface fresh water and is normally dry. The field contains 13 wells and produces approximately 33 barrels of brine per well per day.

Subsurface Disposal

Injection and disposal of oil field produced water underground is practiced extensively by the petroleum industry throughout the

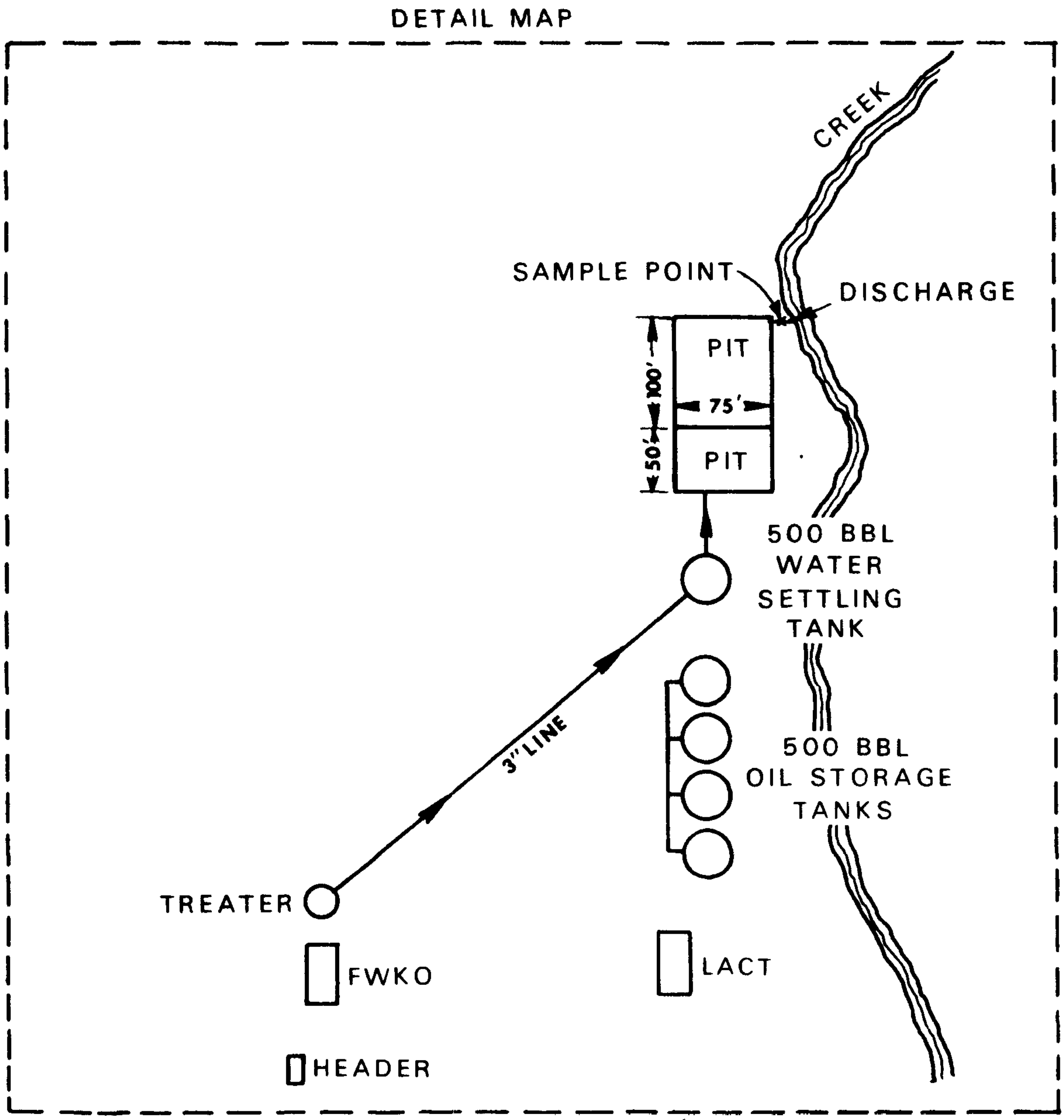
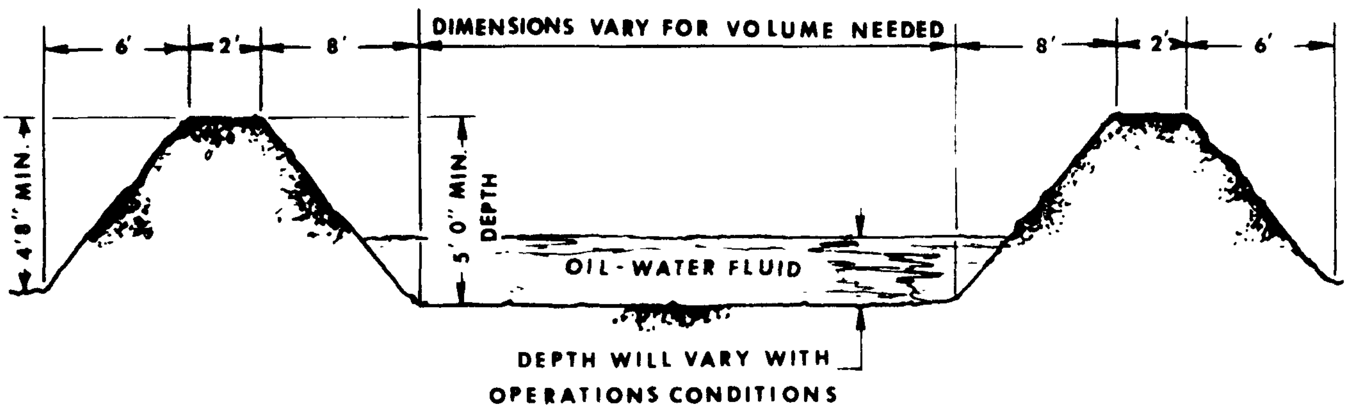


Fig. 7 -- ONSHORE PRODUCTION FACILITY WITH DISCHARGE TO SURFACE WATERS



NOTE

PITS ARE EQUIPPED WITH PIPE DRAINS FOR SKIMMING OPERATIONS TO OBTAIN OIL-FREE WATER DRAINAGE

Fig. 8 -- TYPICAL CROSS SECTION UNLINED EARTHEN OIL-WATER PIT

United States. The term "disposal" as used here refers to injection of produced fluids, ordinarily into a formation foreign to their origin. This injection is for disposal only and plays no intentional part in secondary recovery systems. (Injection for pressure maintenance or secondary recovery refers to the emplacement of produced fluids into the producing formation to stimulate recovery of additional hydrocarbons and is not considered end-of-pipe treatment.) Current industry practice is to apply minimal or no treatment to the water prior to disposal. If water destined for disposal requires treatment, it is usually confined to the application of a corrosion inhibitor and bactericide; a sequestering agent may be added to waters having scaling tendencies. The amount of treatment depends on the formation properties, water characteristics, and the availability and cost of storage and stand-by wells.

Corrosion is ordinarily caused by low pH, plus dissolved gasses. Bactericides serve to inhibit the development of sulfate-reducing and slime producing organisms. Chemicals and bactericides are frequently combined into a single commercial product and sold under various trade names. (6)

A wide range of stable, semipolar, surface-active organic compounds have been developed to control corrosion in oil field injection and disposal systems. The inhibitors are designed to provide a high degree of protection against dissolved gasses (carbon dioxide, oxygen, and hydrogen sulfide), organic and mineral acids, and dissolved salts. The basic action of the inhibitors is to temporarily "plant" or form a film on the metal surfaces to insulate the metal from the corrosive elements. The life of the film is a function of the volume and velocity of passing fluids. Inhibitors may be water soluble or dispersible in fresh water or brine. They may be introduced full strength or diluted. Treatment, usually in the range of 10 to 50 parts per million, may be continuous or intermittent (batch or slug). Effectiveness of corrosion inhibition is determined in several ways, including corrosion coupons, hydrogen probes, chemical analyses, and electrical resistivity measurements.

Three primary types of bacteria attach oil field injection and disposed systems and cause corrosion:

1. Anaerobic sulfate-reducing bacteria (Desulfovibrio--desulfuricans). These bacteria promote corrosion by removing hydrogen from metal surfaces, thereby causing pitting. The hydrogen then reduces sulfate ions present in the water, yielding highly corrosive hydrogen sulfide, which accelerates corrosion in the injection or disposal system.

2. Aerobic slime-forming bacteria. These may grow in great numbers on steel surfaces and serve to protect growths

of underlying sulfate-reducing bacteria. In extreme instances, great masses of cellular slime may be formed which may plug filters and sandface.

3. Aerobic bacteria that react with iron. Sphaerotilus and Gallionella convert soluble ferrous iron in injection water to insoluble hydrated ferric oxides, which in turn may plug filters and sandface. Oxygen entry into a system may also cause the formation of ferric oxide.

Treatment to combat bacterial attack ordinarily consists of applying either a continuous injection of 10 to 50 ppm concentration of a bactericide or batching once or twice a week.

Scale inhibitors are commonly used in the injection or disposal system to combat the development of carbonate and sulfates of calcium, magnesium, barium, or strontium. Scale solids precipitate as a result of changes in temperature, pressure, or pH. They may also be developed by combining of waters containing high concentrations of calcium, magnesium, barium, or strontium with waters containing high concentrations of bicarbonate, carbonate, or sulfate. Scale inhibitors are basically chemicals which chelate, complex, or otherwise inhibit or sequester the scale-forming cations.

The most widely used scale sequestrants are inorganic polymetaphosphates. Relatively small quantities of these chemicals will prevent the precipitation and deposition of calcium carbonate scale. Dimetallic phosphates or the so-called "controlled solubility" varieties are now widely used by the oil industry in scale control and are preferred over the polyphosphates.

The downhole completion of a typical injection well is shown in Figure 9. A producing well is shown for comparison. Injection wells may be completed in a complicated fashion with multiple strings of tubing, each injected into a separate zone. If the disposal well is equipped with a single tubing string, and injection takes place through tubing separated from casing by packer, the annular space between tubing and casing is filled with noncorrosive fluids such as low-solids water containing a combination corrosion inhibitor bactericide, or hydrocarbons such as kerosene and diesel oil. All surface casing is cemented to the ground surface to prevent contamination of fresh water and shallow ground water. Pressure gauges are installed on the casing head, tubing head, and tubing to detect anomalies in pressure. Pressure may also be monitored by continous clock recorders which are commonly equipped with alarms and automatic shutdown systems if a pipe ruptures.

The injection well designed for pressure maintenance and secondary recovery purposes is completed in a manner identical to

Casing and Cement Placement Necessary for Isolation of Injected Waters Underground.

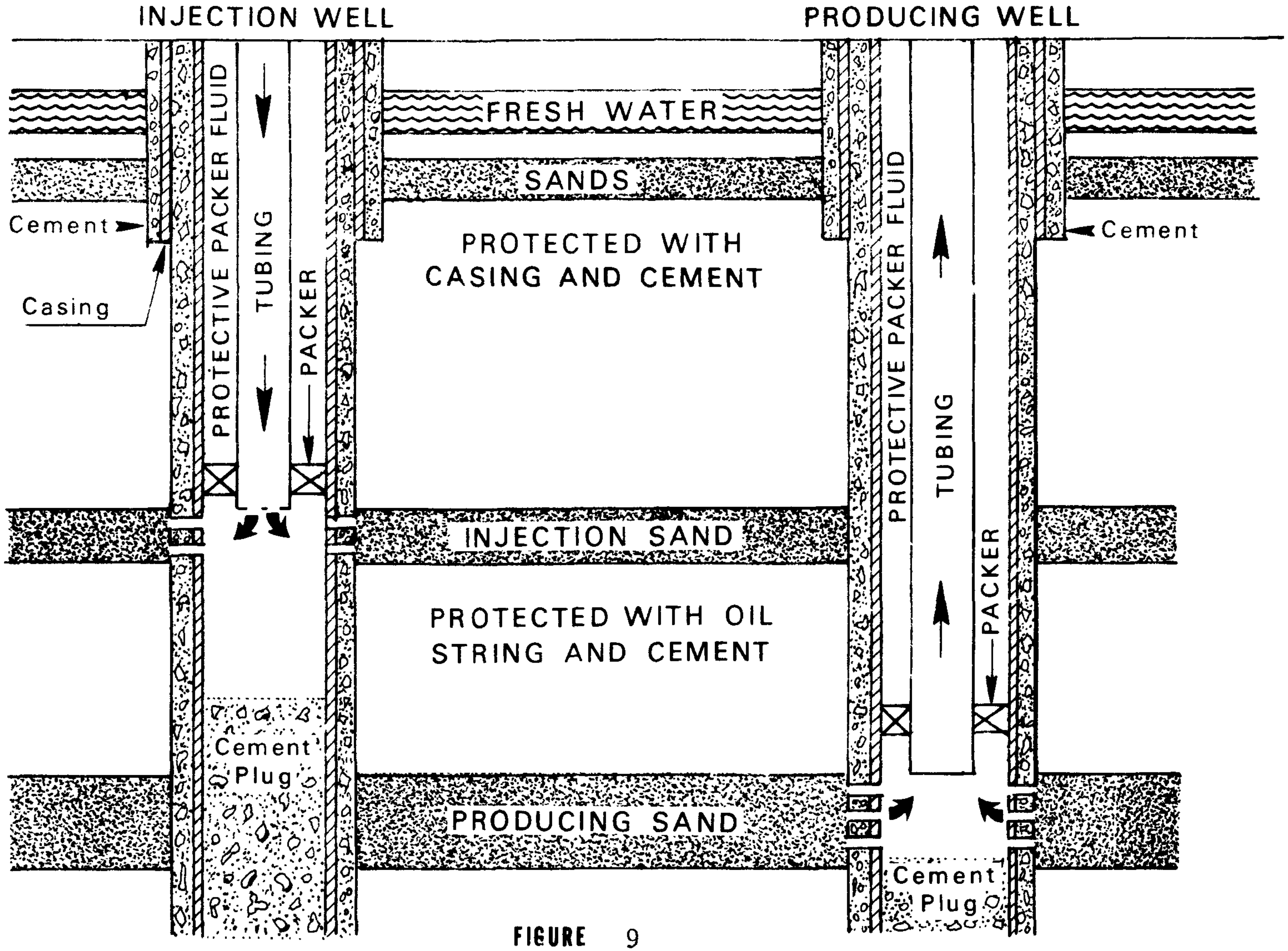


FIGURE 9

TYPICAL COMPLETION OF AN INJECTION WELL AND A PRODUCING WELL

that of the disposal well, except that injection is into the producing horizon. Treatment prior to injection may vary from that applied to the disposal well in as much as water injected into the reservoir sandface must be as free of suspended solids, bacterial slimes, sludges, and precipitates as is economically possible. Ordinarily, selection of injection well sites poses few if any environmental problems. In many instances where injection is used for secondary recovery, the well site is fixed by the geometry of the waterflood configuration and cannot be altered.

Water for injection into oil and gas reservoirs requires treatment facilities and processes which yield clear, sterile, and chemically stable water. A typical open injection water treatment system includes a skim pit or tank (steel or concrete equipped with over-and-under baffles to remove any vestiges of non-soluable material remaining after pretreatment); an aeration facility, if necessary to remove undesirable gasses such as hydrogen sulfide; a filtering system; seepage-proof backwash pit; accumulator tank (sometimes referred to as a clear well or clear water tank) to retain the finished water prior to injection; and a chemical house for storing and dispensing treatment chemicals.

In the system described above no attempt is made to exclude air. Closed systems, on the other hand, are designed to exclude air (oxygen). This is desirable because the water is less corrosive or requires less treatment to make it noncorrosive. The truly "closed" system is difficult to attain because of the many potential points of entry of air into the production system. Air, for example, can be introduced into the system on the downstroke of a pumping well through worn stuffing box packing or seals. In a few instances, closed injection (or disposal) system is used where product waters ordinarily have minimal corrosive characteristics. That is, where salt water is gathered from relatively few wells, fairly close together; where wells produce from a common reservoir; or where a one-owner operation is involved.

There are instances in which a closed input or produced water disposal system can be developed. In these systems all vapor space must be occupied by oxygen-free gas under pressure greater than atmospheric. If oxygen (air) enters the system, it is scavenged.

The "open" injection system has a much greater degree of operational flexibility than does the closed system. Among its more desirable factors are:

1. Wider range, type, and control of treatment methods.

2. Ability to handle greater quantities of water from different sources (diverse leases and fields) and differing formations.

3. Ability to properly treat waters of differing composition. This factor enables incompatible waters to be successfully combined and treated on the surface prior to injection.

Disposal Zone

The choice of a brine disposal zone is extremely important to the success of the injection program. Prior to planning a disposal program, detailed geologic and engineering evaluations are prepared by the production divisions of oil producing companies. Appraisal of the geologic reservoir must include the answers to questions such as:

1. How much reservoir volume is available?

2. Is the receiving formation porous and permeable?

3. What are the formation's physical and chemical properties?

4. What geological, geochemical and hydrologic controls govern the suitability of the formation for injection or disposal?

5. What are the short-term and long-term environmental consequences of disposal?

The geologic age of significant disposal and injection reservoirs throughout the nation, ranges from relatively young rocks of Cambro-Ordovician period. Depths of disposal zones oridinarily range from only a few hundred feet to several thousand. However, prudent operators usually consider it inadvisable to inject into formations above 1,000 feet, particularly where the receiving formation has low permeability and injection pressures must be high. If the desired daily average quantity of water cannot be disposed of, except at surface pressures which exceed 0.5 pounds per square inch surface guage pressure per foot of depth to the disposal zone, particularly in shallow wells, an alternate zone is usually sought.

It is necessary to be familiar with both the lithology and water chemistry of the receiving formation. If interstitial clays are present, their chemical composition and compatibility with the injected fluid must be determined. The fluids in the receiving zone must be compatible with those injected. Chemical analyses are performed on both to determine whether their combination will result in the formation of solids that may tend to plug the formation.

The petroleum industry recognizes that the most carefully selected injection equipment means nothing if the disposed water is not confined to the formation into which it is placed. Consequently, the injection area must be thoroughly investigated to determine any previously drilled holes. These include holes drilled for oil and gas tests, deep stratigraphic tests, and deep geophysical tests. If any exist, further information as to method of plugging and other technological data germane to the disposal project is assembled and evaluated.

On the California Coast there is a definite trend for all onshore process systems which handle offshore production fluids to reinject produced water for disposal. Field investigations made in California were confined to OCS waters, with visits being made to five installations. Each of these facilities were performing some subsurface disposal; none were injecting for secondary recovery or pressure maintenance. Four of these installations were sending all or part of the produced fluids to shore for treatment. All five installations were disposing of treated water in wells on the platform. Two were sending all fluids to shore, separating the oil and water, and then pumping the treated water back to the platforms for disposal. One installation was separating the oil and water on the platform and further treating the water so that it could be injected into disposal wells on the platform. Two of the platforms had been treating all fluids on the platform and injecting treated water. Since the total fluids produced are presently greater than the capacity of the disposal system, the excess treated water is being discharged overboard. Plans were being formulated to increase the capacity of the disposal system to return all produced water underground.

Produced water disposal is commonly handled on a cooperative or commercial basis, with the producing facility paying on a per-barrel basis. The disposal facility may be owned and operated by an individual, a cooperative association, or a joint interest group who may operate a central treatment or disposal system. The waste water may be trucked or piped to the facility for treatment and disposal. Two examples of cooperative systems are operating in the East Texas Field and the Signal Hill and Airport Fields at Long Beach, California.

Alternate Handling

During major breakdown and overhaul of waste treatment equipment, it is common practice to continue production and by pass the treatment units requiring repair. This does not create a serious problem at large onshore complexes where dual treatment units are available, but at smaller facilities and on offshore platforms there may not be an alternate unit to use. Alternate handling practices vary considerably from facility to facility. The following methods are currently practiced offshore:

1. Discharge overboard without treatment.

2. Discharge after removal of free oil in surge tank.

3. Discharge to a sunken pile with surface skimmer to remove free oil.

4. Discharge of produced water to oil pipeline for onshore treatment.

5. Retention on the facility using available storage.

6. Production shutdown.

The method used depends upon the design and system configuration for the paricular facility.

End-of-Pipe Technology for Wastes Other than Produced Water

Deck Drainage

Where deck drainage and deck washings are treated in the Gulf Coast, the water is treated by gravity separation, or transferred to the production water treatment system and treated with production water. Platforms in California pipe the deck drainage and deck washings along with produced fluids to shore for treatment. In Cook Inlet, these wastes are being treated on the platform.

Field investigations conducted on platforms at Cook Inlet indicate that the most efficient system for treatment of deck drainage waste water in this area is gas flotation. Limited data indicate an average effluent of 25 mg/l can be obtained from this system. The field investigations found that deck drainage systems operate much better when crankcase oil is collected separately and when detergents are not used in washing the rigs. The practice of allowing inverted emulsion muds to get into the deck drain system, during drilling or workovers, also seemed to adversely effect treatment.

Sand Removal

The fluids produced with oil and gas may contain small amounts of sand, which must be removed from lines and vessels. This may be accomplished by opening a series of valves in the vessel manifolds that create high fluid velocity around the valve. The sand is then flushed through a drain valve into a collector or a 55-gallon drum. Produced sand may also be removed in cyclone separators when it occurs in appreciable amounts.

The sand that has been removed is collected and taken to shore for disposal; or the oil is removed with a solvent wash and the sand is discharged to surface waters directly.

Field investigations have indicated that some Gulf Coast facilities have sand removal equipment that flushes the sand through the cyclone drain valves, and then the untreated sand is bled into the waste water and discharged overboard.

No sand problems have been indicated by the operators in the Cook Inlet area. Limited data indicate that California pipes most of the sand with produced fluids to shore where it is separated and sent to State approved disposal sites.

At least one system has been developed that will mechanically remove oil from produced sand. The sand washer systems consist of a bank of cyclone separators, a classifier vessel, followed by another cyclone. The water passes to an oil water separator, and the sand goes to the sand washer. After treatment, the sand is reported to have no trace of oil, and the highest oil concentration of the transferred water was less than 1 ppm of the total volume discharged. (6)

Drilling Muds and Drill Cuttings (Offshore)

Oil and gas drilling operations, including exploratory drilling, are accomplished offshore with the use of mobile drilling rigs. These drilling units are either self-propelled or towed units that are held over the drilling site by anchors or supported by the ocean floor. The wastes generated from drilling operations are drilling fluids or "muds" used in the drilling process, rock cuttings removed from the wellbore by the drilling fluids, and sanitary wastes from human activity.

Both water based and oil muds are used. (10) In-plant control techniques and drilling mud practices are affected by the type of mud used. Conventional mud handling equipment is used for water based muds. Some of the water based muds are discharged into the surface waters, with no special control measures other than routine conservation and safety practices. Operation and maintenance procedures on drilling rigs using water based muds are routine housekeeping practices associated with cleanliness and safety. A conventional drilling mud system for water based muds consists of a circulating system including pumps and pipes, mud pits, and accessory conditioning equipment (shale shakers, desanders, desilters, degassers).

In-plant control techniques for oil muds are much more restrictive. They are not discharged into surface waters. The in-plant practices include mud saving containers on board, in addition to the conventional mud handling system. Operations and maintenance practices on rigs using oil muds generally reflect spillage prevention and control measures, such as drill pipe and kelly wipers, and catchment pans.

Cuttings from drilling operations are disposed into surface waters when water based muds are used. However, cuttings from oil mud drilling are usually collected and transported to shore for disposal. Another method is to collect cuttings, clean them with a solvent water mixture, and subsequently dispose of the washed cuttings into the surface water body. After washing, the solvent water is transferred to shore or contained in a closed liquid recovery system. (11)

Drilling Muds and Drill Cuttings (Onshore)

With onshore drilling, the discharge from shale shakers, desilters, and desanders is placed in a large earthen pit. When drilling operations terminate, the pit is backfilled and graded over. Remaining muds, either oil or water based, are reclaimed.

Well Treatment

Acidizing and fracturing performed as part of remedial service work on old or new wells can produce wastes. Additionally, the liquids used to kill a well so that it can be serviced might create a disposal problem.

Spent acid and fracturing fluids usually move through the normal production system and through the waste water treatment systems. The fluids therefore do not appear as a discrete waste source. Their presence, however, in the waste treatment system may cause upsets and a higher oil content in the discharge water.

Liquids used to kill wells are normally drilling mud, water, or an oil such as diesel oil. If oil is used it is recovered because of its value, either by collecting it directly or by moving it through the production system. If the killing fluid is mud it will be collected for reuse or discharged as described earlier in this section. If water is used it will be moved through the production and treatment systems and disposed.

Sanitary (Offshore)

The volume and concentration of sanitary wastes vary widely with time, occupancy, platform characteristics, and operational situation. The waste water primarily contains body waste but, depending upon the sanitary system for the particular facility, other waste may be contained in the waste stream. Usually the toilets are flushed with water but, in some cases brackish or sea fresh water is used.

The concentrations of waste are significantly different from those for municipal domestic discharges, since the offshore operations require regimented work cycles which impact waste concentrations and cause fluctuation in flows. Waste flows have been found to fluctuate up to 300 percent of the daily average, and BOD concentrations have varied up to 400 percent. (12)

There are two alternatives to handling of sanitary wastes from offshore facilities. The wastes can be treated at the offshore location or they may be retained and transported to shore facilities for treatment. Offshore facilities usually treat waste at the source. The treatment systems presently in use may be categorized as physical/chemical and biological.

Physical/chemical treatment may consist of evaporation-incineration, maceration-chlorination, and chemical addition. With the exception of maceration-chlorination, these types of units are often used to treat wastes on facilities with small complements of men or which are intermittently manned. The incineration units may be either gas fired or electric. The electric units have been difficult to maintain because of salt water corrosion and heating coil failure. The gas units are not subject to these problems but create a potential source of ignition which could result in a safety hazard at some locations. Some facilities have chemical toilets which require hauling of waste and create odor and maintenance problems. Macerator-chlorinators have not been used offshore but would be applicable to provide minimal treatment for small and intermittently manned facilities. At this time, there does not appear to be a totally satisfactory system for small operations.

A much more complex physical/chemical system that has been installed at an offshore platform in Cook Inlet consists of: primary solids separation; chemical feed; coagulation; sedimentation; sand filtration; carbon adsorption; and disinfection. All solids and sludge are incinerated. Because of start-up difficulties, no data is available for this facility.

It has been reported that physical/chemical sewage treatment systems have performed well in testing on land, but offshore they have developed problems associated with the unique offshore environment including abnormal waste loadings and mechanical failure due to weather exposure. (12)

The most common biological system applied to offshore operations is aerobic digestion or extended aeration processes. These systems usually include: a comminutor which grinds the solids into fine particles; an aeration tank with air diffusers; a gravity clarifier return sludge system; and a tank. These biological waste treatment systems have proven to be technically and economically feasible means of waste treatment at offshore facilities which have more than ten occupants and are continuously manned.

Because of the special characteristics of sanitary waste generated by offshore operations, the design parameters in Table 24 have been recommended. Table 25 shows average effluent concentrations for various types of treatment units which are in use at offshore facilities in the coastal waters of Louisiana.

Domestic Wastes

Domestic wastes result from laundries, galleys, showers, etc. Since these wastes do not contain fecal coliform, which must be chlorinated, they must only be ground up so as not to cause floating solids on discharge. Traceration by a comminutor should be sufficient treatment.

TABLE 24

Design Requirements

for Offshore Sanitary Wastes (13)

Parameters	Design Requirement Per Capita Per Day
BOD_5	0.22 lb
Total Suspended Solids	0.15 lb
Flow	75 gal

TABLE 25

Average Effluents of Sanitary Treatment Systems

Louisiana Coastal (13)

Company	No. of Units	BOD_5 mg/l	Suspended Solids mg/l	Chlorine Residual mg/l
A	11	35	24	1.2
B	6	13	39	1.8
C	17	15	43	1.9
D	9	25	36	2.5
E	6	86	77	1.3

SECTION VII

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SECTION VIII

COST, ENERGY, AND NONWATER-QUALITY ASPECTS

This section will discuss the costs incurred in applying different levels of pollution control technology. The analysis will also describe energy requirements, nonwater-quality aspects and their magnitude, and unit costss for treatment at each level of technology. Treatment cost for small, medium, and large oil and gas producing facilities have been estimated for BPCT, BAT, and new sources end-of-pipe technologies. For existing facilities in the oil and gas extraction industry presently discharging formation water, the estimated capital cost required to comply with BPCT effluent limitation by 1977 is $147,307,000 and the annual costs for debt service, depreciation, operation and maintenance, and energy are $43,609,000.

Cost Analysis

Section IV discusses the major categories of industry operations or activities and identifies subcategories within each one. For purposes of cost analysis of end-of-pipe treatment three waste streams are considered -- produced water with discharge, produced water reinjected, and sanitary wastes (offshore). The cost of water treatment or disposal for produced water generated in the offshore and coastal subcategories is significantly affected by availability of space. The cost analysis has therefore been subdivided into two areas; offshore water disposal and onshore water disposal. The onshore water disposal has been further subdivided regionally. Deck drainage is considered to be treatable with the production water. Handling of drilling muds, well treatment wastes, and produced sands do not add any significant costs because the regulations requirements are common industry practice. In some instances offshore, the produced water is transferred to shore along with the crude, while in others the waste treatment system is installed on the platforms. Therefore, not all platforms will need to add all of the treatment equipment or incur all of the incremental costs indicated to bring their raw discharges into compliance with the effluent limitations. Existing water treatment systems include sumps and sump piles, pits, tanks, plate coalescers, fibrous and loose media coalescers, flotation systems and reinjection systems.

Offshore Produced Water Disposal

The systems currently used or needed for the treatment of process waste water (formation water) resulting from the production of oil and gas involve physical separation, sometimes aided by chemical application, prior to discharge. Shallow well injection has also been successfully used for disposal of produced wastes at onshore locations and at several offshore locations in California.

The methods examined for offshore use include the following arrangement of components:

A1 Gravity separation using tanks, then discharge to surface water.

A2 Gravity separation using plate coalescers, then discharge to surface water.

B Separation by coalescence, using flotation equipment, then discharge to surface water.

C Separation by coalescence, using flow equilization (surge tanks), desanders, and flotation, then discharge to surface water.

D Separation using filters, then discharge to surface water.

E1 Separation using flow equalization (surge tank) and filter with disposal by shallow well injection.

E2 Separation using flow equalization (surge tank) desanders and filters, with disposal by shallow well injection.

The data available for analysis suggest sizing treatment facilities for produced water based on these flow rates (barrels per day): 200, 1,000, 5,000, 10,000, 40,000. Where flow equalization is provided for the above systems, surge tanks of these sizes were used (barrels): 20, 100, 500, 1,000, 3,000, respectively.

Because of the nature of the problem, development of realistic cost estimates for the treatment of produced water should be very generalized. Costs have been developed for the systems identified based on the following assumptions:

1. All cost data were computed in terms of 1973 dollars corresponding to an Engineering News Record (ENR) construction cost index value of 1,895 unless otherwise stated.

2. The annualized costs for capital and depreciation are based on a loan rate of 15 percent which is equivalent to an annual average cost of 20 percent of the initial investment comprised of 10 percent for depreciation and 10 percent for average interest charges.

3. Costs will vary greatly depending upon platform space. Therefore, investment costs have been prepared for three options:

   a. Option (a) assumes that adequate platform space is available because existing requirements for waste treatment are contained in the offshore leases. (1) Therefore, no additional space will be needed. Rather, the space will be reused by facilities with more efficient removal capacity.

   b. Option (b) assumes that, because of the high costs involved in building platforms, they have been built to the minimum size needed for production. Therefore space is not generally available for water treatment equipment and ancillary facilities. Space is provided by cantilevered additions up to 1,000 square feet. Space requirements greater than this amount will require an auxiliary platform. (2)

   c. Option (c) is for new platforms being planned. The needed space would be provided as a basic part of the platform design and the costs apportioned at $350 per square foot.

In all three cases estimates are based on platforms located offshore in 200 feet of water. This depth is assumed to be an average for the period to 1983.

Where electric energy is required, generating equipment of adequate capacity for the treatment equipment is provided for all requirements exceeding 5 horsepower.

Operation and maintenance costs of components of the various systems are based on operating costs of the equipment. (2) The resulting percentage of investment cost is shown in Table 26.

TABLE 26

Operating Cost Offshore

Facility	Basis for Calculating Annual O & M Costs (Percentage of Investment
Tanks	11
Plate Coalescers	33
Flotation Systems[1]	11
Filters[1]	11
Subsurface Disposal[1]	9
Electrical Supply Facilities	10
Platforms	2

[1]Excludes electrical power supply cost.

Energy and power for low demand is computed as 2 percent of the investment cost. For high demands an electric power cost of 2-1/2 cents per kilowatt hour is assumed.

The capital costs and annualized costs for the six alternative produced water treatment systems, for offshore installation, are contained in Tables 27-31. Options (a), (b), and (c), as defined above, reflect equipment costs, installation, and the cost of platform space requirements.

Onshore Produced Water Disposal

The waste water treated onshore will result from either onshore production facilities or offshore produced water sent to shore for treatment. The costs for treatment of offshore wastes, which are sent to shore, treated and then discharged will be somewhat less than the costs quoted above. These lower costs result from cheaper construction costs onshore, no costs for platform space, lower O and M costs, etc. The costs shown here are for subsurface disposal onshore.

The typical system for injection for disposal only is a flow equalizing or surge tank, high pressure pumps, and a suitable well. Chemicals may be added to prevent corrosion or scale formation.

Table 27

Formation Water Treatment Equipment Costs
Offshore Installations

200 Barrels Per Day Flow Rate

EQUIPMENT COSTS (Thousands of 1974 dollars)

	A1	B	C	E1	E2
Capital Costs	59.3	69.7	87.1	348.7	400.5
Annualized Costs					
Capital	5.93	6.97	8.7	34.9	40.0
Depreciation	5.93	6.97	8.7	34.9	40.0
O & M	2.95	4.7	6.4	28.0	31.8
Energy	-	-	-	2.4	2.0
Total Annualized Costs	14.8	18.6	23.8	100.2	113.8
Cost of water disposal $/bbl	.20	.25	.33	1.37	1.55

Table 28

Formation Water Treatment Equipment Costs
Offshore Installations

1,000 Barrels Per Day Flow Rate

EQUIPMENT COSTS (Thousands of 1974 dollars)

	A1	B	C	E1	E2
Capital Costs	101	143	176.3	373.3	432.2
Annualized Costs					
Capital	10.1	14.3	17.6	37.3	43.2
Depreciation	10.1	14.3	17.6	37.3	43.2
O & M	6.7	11.6	14.3	29.7	38.0
Energy	-	1.5	1.5	3.3	4.4
Total Annualized Costs	26.9	41.7	51.0	107.6	128.8
Cost of water disposal $/bbl	.07	.114	.14	.30	.35

Table 29

Formation Water Treatment Equipment Costs
Offshore Installations

5,000 Barrels Per Day Flow Rate

(Thousands of 1973 dollars)

	A1	A2	B	C	D	E2
Capital Costs						
Option (a)	47	21	88	131	74	451
Option (b)	1,452	55	146	204	117	518
Option (c)	432	43	274	423	157	683
Annualized Costs						
Capital & Depreciation Option (a)	9.4	4.2	17.6	26.2	14.8	90.2
Option (b)	290.4	11.0	29.2	40.8	23.4	103.6
Operation & Maintenance	4.32	6.51	8.27	12.23	6.96	39.88
Energy	0.94	0.42	1.76	2.62	1.48	9.02
Total - Option (a)	14.66	11.13	27.63	41.05	23.24	139.1
Option (b)	295.66	17.93	39.23	55.65	31.84	152.5
Cost of Water Disposal - $/bbl						
Option (a)	0.008	0.006	0.015	0.023	0.013	0.076
Option (b)	0.16	0.0098	0.022	0.031	.017	0.084

Table 30

Formation Water Treatment Equipment Costs
Offshore Installations

10,000 Barrels Per Day Flow Rate

(Thousands of 1973 dollars)

	A1	A2	B	C	D	E2
Capital Costs						
Option (a)	60	31	148	206	108	563
Option (b)	2,140	68	228	1,626	161	1,972
Option (c)	a	66	488	708	259	979
Annualized Costs						
Capital & Depreciation Option (a)	12	6.2	29.6	41.2	21.6	112.6
Option (b)	428	13.6	45.6	325.2	32.2	394.4
Operation & Maintenance	5.52	8.28	13.91	19.33	10.12	52.14
Energy	1.20	0.62	2.96	4.12	2.16	11.26
Total - Option (a)	18.7	15.1	46.5	64.7	33.9	176
Option (b)	434.7	22.5	62.5	348.7	44.5	457.8
Cost of Water Disposal - $/bbl						
Option (a)	0.005	0.004	0.013	0.018	0.009	0.048
Option (b)	0.117	0.006	0.017	0.096	0.012	0.125

[a] Not considered to be a viable alternative because of large space requirement.

Table 31

Formation Water Treatment Equipment Costs
Offshore Installations

40,000 Barrels Per Day Flow Rate

(Thousands of 1973 dollars)

	A1	A2	B	C	D	E2
Capital Costs						
Option (a)	a	60	355	448	170	907
Option (b)	a	98	1,780	1,913	230	2,354
Option (c)	a	102	880	1,254	369	1,585
Annualized Costs						
Capital & Depreciation Option (a)		12	71	89.6	34	181.4
Option (b)		20.4	356	382.6	46.0	470.8
Operation & Maintenance		18.60	33.60	42.04	15.90	89.56
Energy		1.20	7.10	8.96	3.40	18.14
Total - Option (a)		31.8	111.7	140.6	53.3	289.1
Option (b)		40.2	396.7	433.6	65.3	578.5
Cost of Water Disposal - $/bbl						
Option (a)		0.002	0.0077	0.01	0.004	0.020
Option (b)		0.0028	0.027	0.030	.005	0.040

[a] No estimate made - method considered to be impractical because of large space requirements.

When produced water is treated and returned to the producing formation for secondary recovery, the costs should not be considered as a disposal cost, but rather as a necessary cost in production of oil. When produced water cannot be returned to the formation for secondary recovery or for water flooding, the costs for treating it and providing the injection equipment becomes a legitimate disposal cost.

Generalized cost estimates for onshore disposal of produced formation water were developed to include flow equalization tanks for 1,000, 5,000 and 10,000 barrels-per-day water production, pumps sized for these flow rates and 700 pounds per square inch pressure, and disposal wells of 3,000 foot depth. A maximum well capacity of 12,000 barrels-per-day was assumed. In addition, costs for this system include a lined pond to provide standby capability for continuing production for seven days while pump repairs are being made or the injection system is being worked on. The capital costs and annualized costs for these systems are contained in Tables 32 and 33.

Well completion costs are based on data contained in the Joint Association Survey of the U.S. Oil and Gas Producing Industry for 1972. (2) The costs are adjusted upwards by use of the ENR construction cost index using a value of 1895 for 1973. Energy (power) costs are computed at 2-1/2 cents per kilowatt hour. Operation and maintenance costs were computed at 9 percent of the capital cost based on an industry-sponsored report. (2)

Other costs for reinjecting produced formation water have been developed from field surveys conducted by the EPA during the first half of 1976. The sites surveyed were selected as being representative of reinjection disposal technology within the various states. The actual data, which can be found in Supplement B, was taken from data formats submitted by industry for the selected sites and is presented for the most part without major adjustment. In two cases, Pennsylvania and Texas/Louisiana nearshore platforms, field data was not available and engineering estimates were developed. The values for capital and operating costs shown in Tables 32 and 33 are from regression analysis of the field data.

TABLE 32
Capital Costs [1] for Onshore Disposal
by Reinjection of Produced Formation Water
From Field Surveys in Selected States
(Thousands of 1975 Dollars)

State	Description	# of Sites	Reinjection Capacity, bbl/day 10	100	1000	10,000
California	Land-based	6		74	146	280
Wyoming	Land-based	11		80	117	300
Texas and Louisiana	Land-based	14		40	140	375
Pennsylvania	Land-based Case I	(2), (4)	28	52	190	470
	Land-based Case II	(3), (4)	15	24	61	110
Texas	Nearshore Platforms	(4)		400	500	1600
Louisiana	Nearshore Platforms	(4)		400	470	1680

(1) Regression analysis data points.
(2) Production sites without existing reinjection facilities.
(3) Production sites presently reinjecting fresh water.
(4) Engineering estimates.

TABLE 33
Annual Operating(1) Costs for Onshore Disposal by Reinjection of Produced Formation Water From Field Surveys in Selected States
(Thousands of 1975 Dollars)

State	Description	# of Sites	Reinjection Capacity, bbl/day			
			10	100	1000	10,000
California	Land-based	6		5.6	15.5	52
Wyoming	Land-based	11		8.8	18.5	32
Texas and Louisiana	Land-based	14		12.5	25	50
Pennsylvania	Land-based Case I	(2),(4)	7.6	14	46	100
	Land-based Case II	(3),(4)	5	6.5	16.5	32
Texas	Nearshore Platforms	(4)		40	45	122
Louisiana	Nearshore Platforms	(4)		40	45	134

(1) Regression analysis data points excluding capital and depreciation charges.
(2) Production sites without existing reinjection facilities.
(3) Production sites presently reinjecting fresh water.
(4) Engineering estimates.

As an alternative to no discharge - reinjection technology, cost estimates were developed for discharge to navigable waters. The subcategories of production facilities selected for separate estimates were those described in Section IV, Industry Subcategorization. The treatment technology selected for each category was the most efficient type of treatment observed in general use during the 1976 field survey.

Treatment technology for the stripper well category was selected as a surge tank followed by chemical addition and ponds. The steel surge tank has 2-10 day storage. The three unlined ponds in series have a 5-foot operating depth and a retention time of 100-600 hours, depending upon the system's capacity. Annual costs consist of: operation at 1-3 hours per day, maintenance at 5% of constructed value, electrical power at 4¢ per kilowatt hour, chemical costs at 5 mils per barrel and capital plus depreciation at 20% of constructed value. The capital and operating costs for stripper well facilities in the size range 10-10,000 bbl/day are shown on Table 34.

Treatment technology for beneficial dischargers was selected as surge tank, skim basin, chemical feed and gas flotation followed by ponds. The surge tank has a 1-2 hour storage capacity and the skim basin is provided with an automatic skimming device. The gas flotation system uses induced air and the ponds have a 12-hour retention time. A standby pond of 48 hours retention time is also provided. Annual costs consist of: operation at 6-12 hours per day, maintenance at 8% of equipment constructed value, electrical costs at 4¢ per kilowatt hour and chemicals at 3 3/4 mils per barrel. The capital and operating costs for beneficial dischargers in the size range 5,000-100,000 bbl/day are shown on Table 35.

Treatment technology for the coastal platforms was selected as a surge tank followed by chemical feed and gas flotation. Additional platform space was assumed required to accommodate the treatment system. Design criteria and costing methods were patterned after the 1975 Brown and Root Report (3). The capital and operating costs so devised for coastal platforms are shown on Table 36. Details of cost estimating procedure for all categories is available in Supplement "B".

TABLE 34
Cost Estimates for Treatment in Ponds and
Disposal by Discharge for Stripper Well Facilities
(Thousands of 1976 Dollars)

	System Capacity Produced Water, Bbl/day						
Cost Item	10	50	100	500	1000	5000	10,000
Construction	12	19.6	24	30.1	36	65.7	90
Operation & Maintenance	5.6	7.5	8.7	13.8	18.8	38.1	53.2

TABLE 35
Cost Estimates for Treatment by Gas Flotation & Ponds & Discharge for Beneficial Dischargers
(Thousands of 1976 Dollars)

Cost Item	System Capacity Produced Water, Bbl/day 500	1000	5000	10,000	25,000	50,000	100,000
Construction	92	96	155	198	289	425	600
Operation & Maintenance	32	37	72	85	137	220	343

TABLE 36
Cost Estimates for Treatment by Gas Flotation & Discharge for Coastal Platforms
(Thousands of 1976 Dollars)

Cost Item	System Capacity Produced Water, Bbl/day 100	1000	5000	15,000	25,000
Construction	55	133	267	394	482
Operation & Maintenance	8	43	83	132	172

Offshore Sanitary Wastes

Cost estimates for biological systems utilized on offshore platforms are for the aerobic digestion process or extended aeration treatment plants. The estimates anticipate the use of a system including a comminuter to grind the solids into fine particles, an aeration tank with air diffusers, gravity clarifier return sludge system and a disinfection tank.

Based on the design requirements stated in Table 24 costs were developed for systems to serve 25 persons (2,000 gallons), 50 persons (4,000 gallons) and 75 persons (6,000 gallons). These costs are contained in Table 37.

Energy Requirements for Operating Flotation Systems

Table 38 presents several estimates of horsepower requirements of flotation systems for the three levels of production.

Actual installations will probably comprise a mix of manufacturers' units and the typical horsepower requirements will be some weighted average of the values in Table 38. For the purpose of estimating energy requirements, the average requirements are assumed to be 15, 25, and 60 horsepower for the 5,000, 10,000 and 40,000 bbls per day production levels. (The 118 Hp. figure for the 40,000 bbls per day unit was rejected as spurious - an incorrect linear extrapolation on a graph.)

Table 39 presents the calculations that translate these basic horsepower requirements into total energy requirements.

One way to evaluate the energy requirements of flotation systems is to compare their consumption with that of the oil production associated with their use. Water production rates do not vary regularly with crude oil production rates.

In some instances, the 5,000 bbl/day of produced water may be associated with a crude oil production of only 5,000 bbl/day. In other cases, crude production rates may be 50 to 100 times the rate of water production or vice versa. Given these variation and the variable products and costs of refining the crude oil, it would be a meaningless exercise to attempt to estimate the net BTU equivalent in terms of barrels of diesel oil for the oil production associated with the typical water flows. One can, however, usefully examine a range of possible levels of net production to get a general impression of the relative energy requirements of flotation systems. For example, it is reasonable to assume that the 5,000 bbl/day water production could be associated with a net energy production of anywhere from 50 to 50,000 bbl/day of diesel oil. Similarly the 10,000 and 40,000 bbl/day water flows could be associated with ranges of net diesel oil equivalent flows from 100 and 100,000 and 400 and 400,000 bbl/day, respectively. Table 40 presents a summary of the flotation systems' energy consumption data as compared to such associated oil production rates.

It is clear from Table 40 that the energy required for flotation relative to the net energy being produced is very small. Even in such a rare case as when water production is 100 times that of crude oil production, the flotation energy requirements amount to only 1.5 percent of the net energy being produced.

Nonwater-Quality Aspects

Evaluation of in-plant process control measures and waste treatment and disposal systems for best practicable control technology, best available technology, and new source performance standards indicates that there will be no significant impact on air quality. A minimal impact is expected, however, for solid waste disposal from offshore facilities. The collection, and subsequent transport to shore of oily sand, silt, and clays from the addition of desanding units, where appropriate, will generate a possible need for additional approved land disposal sites. There are no known radioactive substances used in the industry other than certain instruments such as well-logging instruments. Therefore, no radiation problems are expected. Noise levels will not be increased other than that which may be caused by the possible addition of power generating equipment on some offshore facilities.

TABLE 37

Estimated Treatment Plant Costs
For Sanitary Wastes For Offshore Locations
Package Extended Aeration Process
(Thousands of 1973 dollars)

	Treatment Plant Capacity (gallons/day)		
	2,000	4,000	6,000
Capital Cost	18,000	23,000	28,000
Total Annual Costs	6,010	7,660	9,360
capital	1,800	2,300	2,800
depreciation	1,800	2,300	2,800
operation & maintenance	2,050	2,600	3,200
energy and power	360	460	560

Table 38

Estimated Horsepower Requirements
for the Operation of
Flotation Treatment Systems

Level of Production bbl/day	Source				
	Brown & Root 1/ (Hp.)	WEMCO 2/ (Hp.)	NATCO 3/ (Hp.)	Rheem 4/ (Hp.)	Komlin 5/ Sanderson Engring Corp. (Hp.)
5,000	14	13	6	20	17-1/2
10,000	25	21	13	25	-
40,000	118	61	47	50	81-1/2

1/ Brown and Root. III-11

2/ Wemco Data Sheet, F8-D2, dated 4-19-73

3/ Letter dated June 12, 1974, from National Tank Com. to Mr. R. W. Thieme, OTA, EPA, plus telephone communication, Friday, July 19, 1974, with Mr. E. Cliff Hill, NATCO

4/ Telephone communication with Mr. Ken Sasseen, Rheem-Superior Corp., California.

5/ Telephone conversation with Mr. Arthur Albohn, Komline, 201-234-1000 July 24, 1974.

TABLE 39

Estimated Incremental Energy
Requirements Flotation Systems

5,000 bbl/day of water treated:

15 Hp. for 1 yr. = 3.35×10^8 BTU/yr.

1 bbl diesel oil = 6×10^6 BTU

15 Hp. - yr. = 55.8 bbl diesel oil/yr.

Assume 20% conversion efficiency, then 15Hp. - yr = 279 bbl diesel oil/yr.

10,000 bbl/day of water treated:
464 bbl diesel oil/yr.

40,000 bbl/day of water treated:
1115 bbl diesel oil/yr.

TABLE 40

Energy Requirements for Flotation Systems as Compared to Net Energy Production Associated with the Produced Water Flows

Produces Water Flow - bbl/day	Assumed Level of Net Energy Production in Diesel Oil Equivalents - bbl/day	Energy for Flotation Units Diesel Oil Equivalents - bbl/day
5,000	50 to 50,000	0.76
10,000	100 to 100,000	1.27
40,000	400 to 400,000	3.05

SECTION VIII

Bibliography

1. Offshore Operators Committee, Sheen Technical Subcommittee. 1974. "Determination of Best Practicable Control Technology Currently Available To Remove Oil From Water Produced With Oil and Gas." Prepared by Brown and Root, Inc., Houston, Texas.

2. Joint Association Survey of the U.S. Oil and Gas Producing Industry. 1973. "Drilling Costs and Expenditures for Exploration, Development and Production - 1972." American Petroleum Institute, Washington, D. C.

3. Offshore Operators Committee, Sheen Technical Subcommittee 1975 "Potential Impact of EPA Guidelines for Produced Water Discharges from the Offshore and Coastal Oil and Gas Extraction Industry," Prepared by Brown and Root, Inc., Houston, Texas.

SECTION IX

EFFLUENT LIMITATIONS FOR BEST PRACTICABLE CONTROL TECHNOLOGY

Based on the information contained in the previous sections of this report, effluent limitations commensurate with best practicable control technology (BPCT) currently available have been established for each subcategory. The limitations, which must be achieved not later than July 1, 1977, explicitly set numerical values for allowable pollutant discharges of oil/grease, chlorine residual and floating solids. BPCT is based on control measures and end-of-pipe technology widely used by industry.

<u>Produced Water Technology</u>

BPCTCA process control measures include the following:

1. Elimination of raw waste water discharged from free water knockouts or other process equipment.

2. Supervised operations and maintenance on oil/water level controls, including sensors and dump valves.

3. Redirection or treatment of waste water or oil discharges from safety valve and treatment unit by-pass lines.

BPCTCA end-of-pipe treatment can consists of some, or all of the following:

1. Equalization (surge tanks, skimmer tanks).
2. Solids removal desanders.
3. Chemical addition (feed pumps).
4. Oil and/or solids removal.
    a. Flotation.
    b. Filters.
    6. Plate coalescers.
    d. Ponds.
    e. Gravity Tanks.
5. Subsurface disposal.

Specific treatability studies are required prior to application of a specific treatment system to an individual facility.

Procedure for Development of BPCT Effluent Limitations

The effluent guidelines limitations for produced water were determined using effluent data for oil and grease. This data was provided by the oil and gas producing industry, Department of the Interior (U.S. Geological Survey), several States, EPA regional offices, as well as EPA data obtained during three field verification studies and four field surveys of operating platforms in the Gulf Coast; Cook Inlet, Alaska; and Coastal California.

The oil-grease effluent data were analyzed to assess average operating efficiency and variability for various types of treatment. The end-of-pipe technologies assessed for offshore and coastal facilities were; flotation units, plate coalescers, and fibrous media/loose media filters. For onshore facilities that discharge the end-of-pipe technologies assessed were; filters, flotation units, and ponds.

Information was also obtained from the industry that included schematics, diagrams, and narratives of operation and maintenance for 25 selected producing facilities.

A review of the effluent data showed a wide range of treatment efficiencies from facility to facility with similar treatment, variability between different treatment methods, and variability of effluent levels within an individual facility. Additional information was reviewed in detail to determine the reasons for these variations. It was concluded that treatment efficiency is affected by uncontrollable factors related to geological formation and controllable factors related to industry operations and analytical procedures. The factors considered uncontrollable by current technology are:

1. Physical and chemical properties of the crude oil, including solubility in water.

2. Suspended solids concentrations.

3. Fluctuations in flow rate.

4. Droplet sizes of the entrained oil (some control possible).

5. Degree of emulsification (some control possible).

6. Characteristics of the produced water.

The factors considered controllable are:

1. Operator training.

2. Sample collection and analysis methods.

3. Process equipment malfunction--for example in heater-treaters and their dump valves, chemical pumps and sump pumps.

4. Lack of proper equipment--for example, desanders or large tanks.

5. Noncompatible operations.

The major objective of the detailed data analysis was to reject inadequate treatment technology and select facilities utilizing a sound technical rationale.

Offshore and Coastal - Initially, 138 treatment systems (94 off Louisiana, 36 off Texas, and 8 off Alaska) were evaluated. The treatment systems included gas flotation, plate coalescers, fibrous media filters, loose media filters, and gravity separation.

EPA survey data show that the majority of the simple gravity systems produced highly variable effluents and were only minimally effective in removal of oil. The data from the 36 gravity systems in Coastal Texas were derived from extreme variations in analytical procedures. EPA attempts to verify this data failed and all of this data had to be rejected.

Ten of the 94 treatment systems off Louisiana had 10 or less data points; they were rejected. Data from the 84 remaining units were analyzed along with the data collected from 25 facilities visited in the EPA verification study. The variance in treatment efficiencies was reflected in the data for all types of treatment methods. Both loose media and fibrous media filters are capable of producing low average effluents, but because of O&M difficulties the units are being phased out.

The plate coalescer and gas flotation treatment units in Louisiana with greater than 10 data points were analyzed with respect to O&M reliability. A comparison was made to determine the effectiveness of physical separation of oil and ability to handle uncontrollable variation in raw waste characteristics. The treatment efficiencies of plate coalescers were significantly below those for gas flotation units. This is supported by an analysis of the design parameters for plate coalescers, which are similar to API gravity separators. A review of O&M records and findings from EPA field surveys indicate that these units are subject to plugging from solids, iron, and other produced water constituents. When the parallel plate becomes plugged, frequent back washing, manual cleaning, or replacement of plates is required. The effluent data showed highly variable oil concentrations which indicated that both controllable and uncontrollable factors significantly affected treatment efficiencies. Therefore, plate coalescers were eliminated from consideration.

The remaining 32 Louisiana treatment units were dissolved gas flotation systems with chemical treatment. Historical data and reports were available on nine of the units. Each was evaluated to determine the acceptability of the data and the causes of significant effluent variations. A review of the design parameters for the various systems showed that the systems were designed for the maximum expected water production. None was designed to handle overload conditions which may occur during start-up, process malfunctions, or poor operating practices. Data were rejected which followed unit installation (start-up), when chemical treatment rates were modified, and when significant equipment maintenance or other O&M procedures which affect normal efficiency of the treatment unit was being performed. Treatment data from some of the facilities analyzed were highly variable with no apparent explanation. In this case, all of the treatment data were accepted since it appeared highly unlikely that efficiency could be normalized with better O&M procedures. More likely the varibility seen is attributable to the geological formation. Units with influent data in excess of 200-300 mg/l were suspect, since historical data indicated that high influents could be attributed to dump valve malfunctions in the process units. These units were investigated, and if the causes of their high concentrations were found, they were rejected; otherwise they were accepted. Units without historical data, but which had variations similar to those which were rejected were evaluated and if the variations were judged to be caused by controllable malfunctions, they were eliminated. Three systems were rejected because of reported process and treatment malfunctions, six months of data were rejected from two other systems due to operational and start-up problems. For the remaining units, data points were eliminated since a strong indication of errors in sample collection and analysis.

Additional data were obtained for a number of the units from the oil companies, the Department of the Interior and the Brown and Root report. These data were screened and evaluated in a manner similar to that previously described. A total of 28 units, 27 off the Louisiana coast and one in Coastal Alaska were selected as potentially usable facilities. These facilities represent approximately 66 percent of the 41 facilities with the treatment technology to qualify as BPCT. Of the 28 units, 12 have in excess of 90 data points and one facility has 508 data points covering an 18-month period.

The EPA field survey included nine of the 28 selected gas flotation units off Louisiana. The results of the field survey supports the rationale used for selection of exemplary technology and establishing the data base for determining effluent limitations.

Upon completion of the technical evaluation of the data and units, a detailed statistical analysis was conducted to determine the form of the statistical distribution and to search for anomalous means or variances which might indicate a need to subcategorize based upon flow rates and space limitations. The initial review indicated that the selected units data were similar in distribution, and although the observed means and variances differed from unit to unit, no basis for further subcategorization was discovered.

The statistical analysis indicated that the data were log normally distributed over most of the data. The various units could be separated statistically into three groups: 1) five high; 2) 13 low; and 3) nine average. The means and 99 percent probability of occurance levels were calculated for the low, high, and total groups. Even though the group of 27 flotation units could be broken down further (into 3 subgroups), it was felt that at the current level of experience, with this technology, the entire industry could not be expected to achieve the same level of treatment as the very best units are now achieving. Therefore, data from all 27 Louisiana units were included in determining the effluent limits for oil.

Further analysis of the data base showed that some of the reported data were composites (4 grab samples taken in a 24 hour period, analyzed separately and the results averaged) and the rest were individual grab samples. It was determined that the grab samples had a higher variance than the composites and that the compositing technique would result in more representative results. The compositing would greatly decrease the effect of sampling and analytical variance, which is potentially significant in oil and grease monitoring.

The composited data were than analyzed separately and two different techniques were used on the grab samples analysis to simulate composite sampling.

A maximum monthly average was also calculated from the modified (composite) data base. To utilize all of the data, two different approaches were used to determine the monthly averages: 1) based on dates of observed values - this method averages a given number of samples (N) which are 30/N days apart, with the analysis being performed on these averages; 2) based on randomized observed values - this method divides the 2262 data points into 2262/N groups, each group containing N randomly selected points. The analysis is performed on the averages of each group.

The first method is free of assumptions, but is limited in data base since only 9 of the units had more than 2 data points per month. The second method is simple and utilizes all of the data, but ignores autocorrelation. Figure 10 is a plot of the results of these two methods being applied to the data base. As can be seen the plots begin separating at 4 samples per month because of the effects of autocorrelation.

The results of the above analyses are as follows:

1. Long term average (1 year) - 25 mg/l

2. Maximum monthly average (weekly sampling) - 48 mg/l

3. Maximum day (composited) - 72 mg/l

The data in Figure 11 represent a cumulative plot of the modified daily concentrations for the 27 Louisiana flotation units. The plot is essentially linear over the last 90 percent of the range, and the straight line represents a log normal distribution. Of the 2,262 samples, 99 percent have oil concentrations less than 72 mg/l.

A statistical analysis was also conducted to determine the distribution, and variance for the one flotation unit in Coastal Alaska which treated produced waters. The average oil content in the effluent is approximately 15 mg/l. The operation of this unit appears very similar to the low group units for Louisiana.

Beneficial Use - Data for this subcategory were collected from nine facilities in Wyoming representing filters, flotation and ponds as end-of-pipe technology. These facilities were visited by the technical contractor and were considered to have well run and well maintained operations. An analysis of the data from the individual units showed no significant difference between the three technologies used. In addition to this data, 292 data points which represented sampling done throughout Wyoming by Region 8 were analyzed.

Since there is no apparent difference in the first nine units, this data (160 points) were combined and analyzed. This data base has a mean of 10.0 and a daily maximum of 45 (both mg/l of oil and grease).

The Region VIII data base analysis showed a mean of 7.2 and a daily maximum of 45.

An additional analysis was run combining all the above data points (452 points) and this data base had a mean of 8.2 and a daily maximum of 44.

Figure 10

99th Percentile of Monthly Average Oil and Grease

Concentration vs.

Frequency Of Sampling Each Month

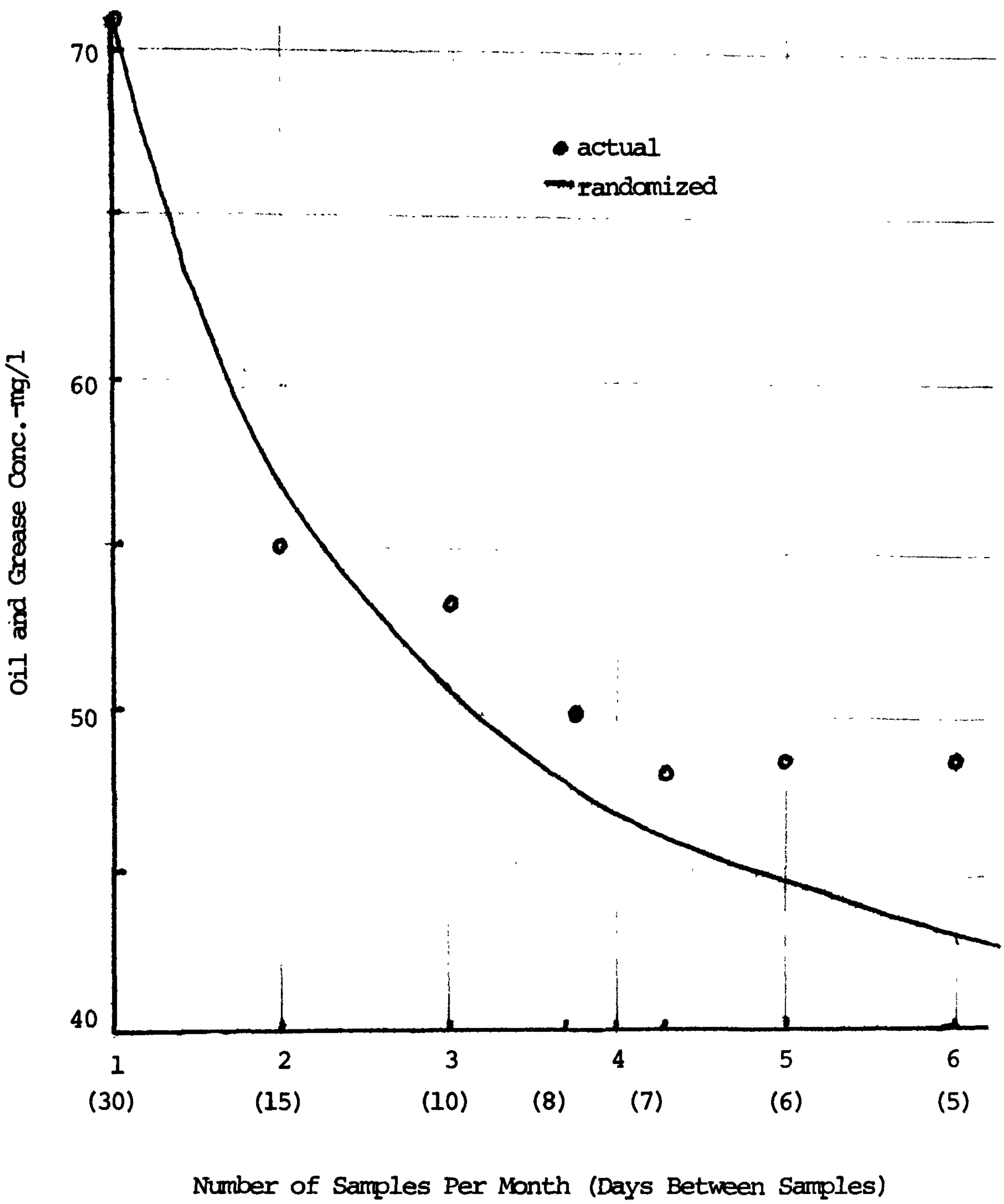

FIGURE 11

Cumulative Plot of Effluent Concentrations of All Selected Flotation Units in the Louisiana Gulf Coast Area

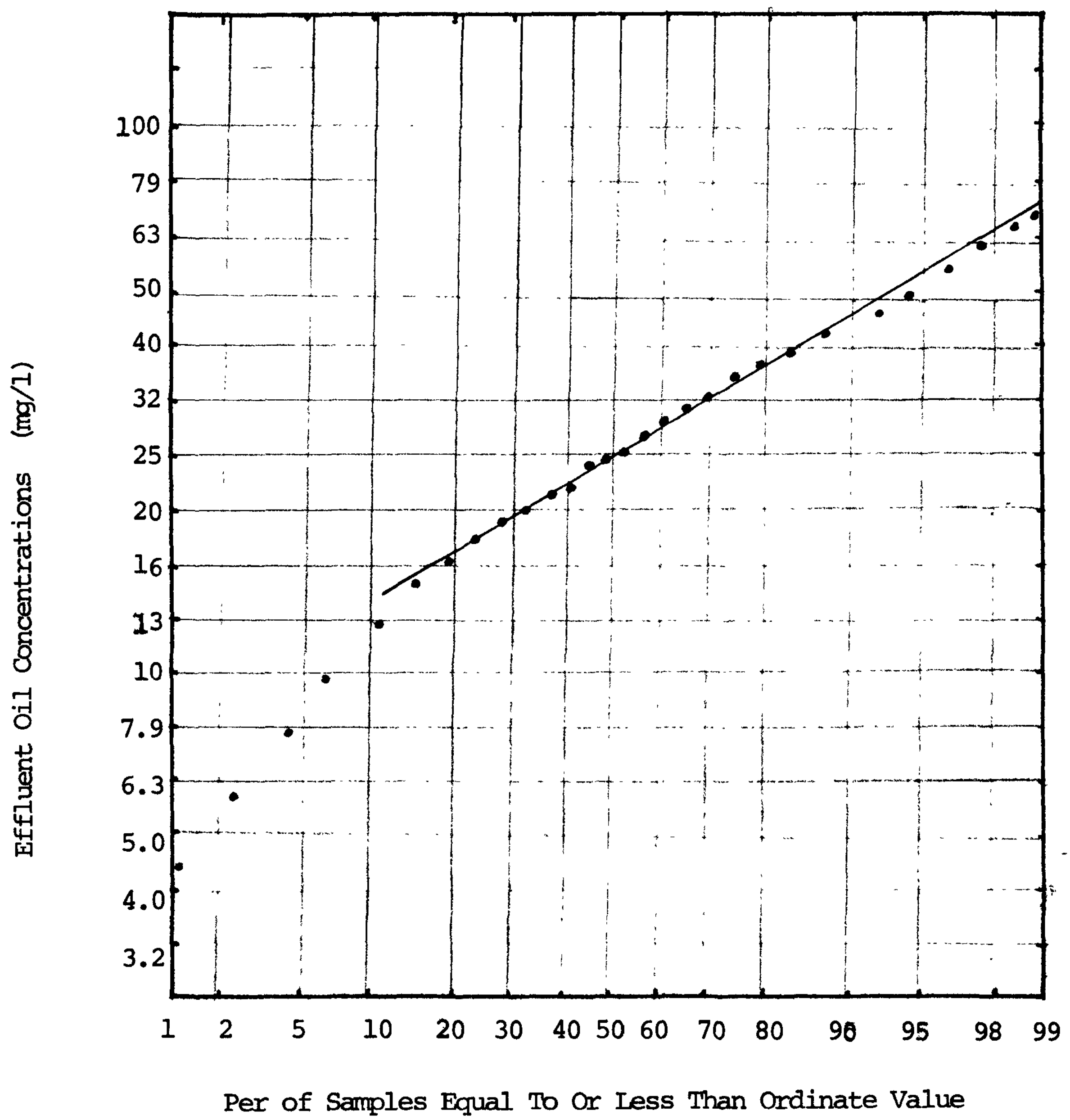

Figure 12 represents a cumulative plat of the combined data base. A slight modification was made to the analysis procedure described for the offshore data. In order to have the data form a straight line over the entire range, rather than the upper 80-90% of the range, a constant is added to each data point so that log (X+A) is plotted rather than log X. Since the affect of the constant A is more pronounced for smaller values of X the result is a straight line fit over the total range of data. Once the 99th percentile is determined for the distribution of X+A the constant is subtracted and the resulting value is the best fit to the distribution of X; this method is called the three parameter log normal analysis.

Sanitary Wastes -- Offshore and Coastal Manned Facilities With 10 or More People

BPCT for sanitary wastes from offshore manned facilities with 10 or more people is based on end-of-pipe technology consisting of biological waste treatment systems (extended aeration). The system may include a comminutor, aeration tank, gravity clarifier, return sludge system, and disinfection contact chamber or other equivalent system. Studies of treatability, operational performance, and flow fluctuations are required prior to application of a specific treatment system to an individual facility.

The effluent limitations were based on effluent data provided by industry to the U.S. Geological Survey. Chlorine residual, BOD, and suspended solids concentrations for the biological treatment systems were within the range of values which would meet fecal coliform requirements.

The only limitation being set on sanitary wastes is for chlorine residual. This requirement is set to control the fecal coliform level in this effluent. Limits on BOD or suspended solids for these wastes are not justified since the BOD and TSS content of the produced waters are likely to be several hundred times greater.

The limit for residual chlorine is greater than 1 mg/l, but as close to 1 mg/l as possible. The facilities for chlorination on offshore platforms are much less sophisticated then typical municipal treatment plants and the flows much more variable. Therefore, it is felt that the standard residual chlorine limit of 1 mg/l plus or minus 40 % is unrealistic. There has been no upper limit set because of a lack of valid data to be used to set such a limit.

BPCT for sanitary wastes from small offshore facilities and intermittently manned facilities is based on end-of-pipe technology currently used by the oil and gas production industry and by the boating industry. These devices are physical and

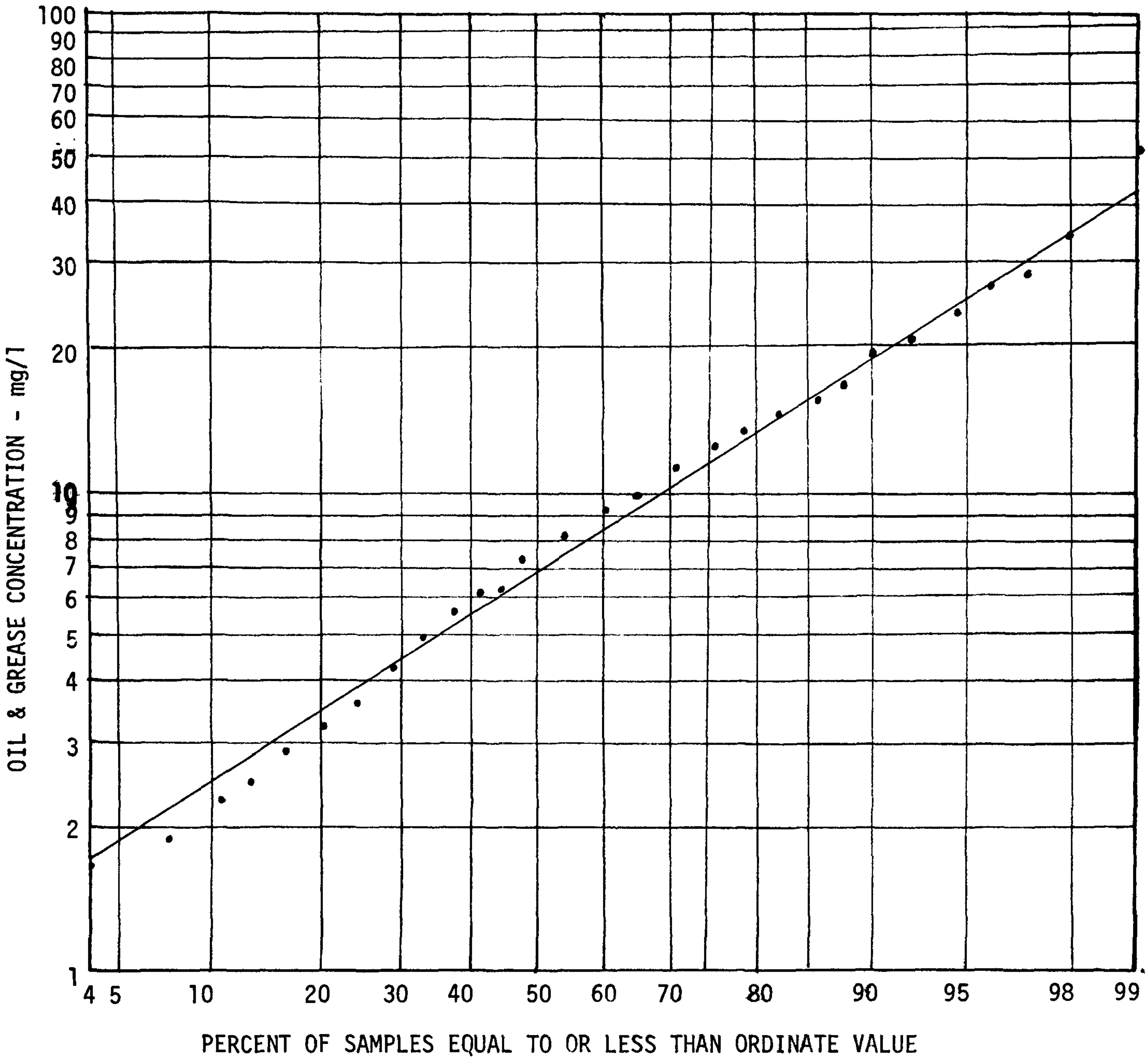

Fig. 12 - Cumulative Plot of Effluent Concentrations of All Wyoming Data (values are plotted as X + 1.3)

chemical systems which may include chemical toilets, gas fired incinerators, electric incinerators or macerator-chlorinators. None of these systems has proved totally adequate. Therefore, the effluent limitations are based on the discharge technology which consists of a macerator-chlorinator. For coastal and estuarine areas where stringent water quality standards are applicable, a higher level of waste treatment may be required.

The attainable level of treatment provided by BPCT is the reduction of waste such that there will be no floating solids.

Domestic Wastes - Offshore and Coastal

Since these wastes contain no fecal coliform, chlorination is unnecessary. Treatment, such as the use of macerators, is required to guarantee that this discharge will not result in any floating solids.

Deck Drainage - Offshore and Coastal

BPCT for deck drainage is based on control practices used within the oil producing industry and include the following:

1. Installation of oil separator tanks for collection of deck washings.

2. Minimizing of dumping of lubricating oils and oily wastes from leaks, drips and minor spillages to deck drainage collection systems.

3. Segregation of deck washings from drilling and workover operations.

4. O&M practices to remove all of the wastes possible prior to deck washings.

BPCT end-of-pipe treatment technology for deck drainage consists of treating this water with waste waters associated with oil and gas production. The combined systems may include pretreatment (solids removal and gravity separation) and further oil removal (chemical feed, surge tanks, gas flotation). The system should be used only to treat polluted waters. All storm water and deck washings from platform members containing no oily waste should be segregated as it increases the hydraulic loading on the treatment unit.

The limits for deck drainage are the same as for produced waters offshore.

Alternate Handling - Offshore and Coastal

Alternate handling of waste water may be necessary when equipment becomes inoperative or requires maintenance. Waste fluids must be controlled during these conditions to prevent discharges of raw wastes into surface waters. Control practices currently used in offshore and coastal operations are:

1. Waste fluids are temporarily stored onboard until the waste treatment unit returns to operation.

2. Waste fluids are directed to onshore treatment facilities through a pipeline.

3. Placing waste fluids in a barge for transfer to shore treatment.

4. Waste fluids are piped to a primary treatment unit (gravity separation) to remove free oil and discharged to surface waters.

Drilling Muds

BPCT for drilling muds includes control practices widely used in both offshore and onshore drilling operations:

1. Accessory circulating equipment such as shaleshakers, agitators, desanders, desilters, mud centrifuges, degassers, and mud handling equipment.

2. Mud saving and housekeeping equipment such as pipe and kelly wipers, mud saver sub, drill pipe pan, rotary table catch pan, and mud saver box.

3. Recycling of oil based muds.

BPCT end-of-pipe treatment technology is based on existing waste treatment processes currently used by the oil industry in drilling operations.

The limitations for offshore and coastal drilling muds are as follows:

1. Water based and natural muds shall contain no free oil when discharged.

2. Oil based and emulsion muds shall not be discharged to surface waters. These muds are to be transported to shore for reuse or disposal in an approved disposal site.

The limitations for onshore drilling muds are as follows:

1. The muds shall be discharged to surface waters. These muds are to be transported to and disposed of in an approved disposal site.

Drill Cuttings

BPCT for drill cuttings is based on existing treatment and disposal methods used by the oil industry.

The limitations for offshore drill cuttings are as follows:

1. Cuttings in natural or water based muds shall contain no free oil when discharged.

2. Cuttings in oil based or emulsion muds shall not be discharged to surface waters. Cuttings should be collected and transported to shore for disposal in an approved disposal site.

The limitation for onshore drill cuttings areas follows:

1. No drill cuttings shall be discharged to surface waters. These drill cuttings are to be transported to and disposed of in an approved disposal site.

Well Treatment

Workover fluids other than water, or water based muds are to be recovered and reused. Materials not consumed during workovers and completions are to be transported to and disposed of in an approved site.

The effluent limitations were determined using data supplied by industry and service companies serving the oil producing industry. The limitation for wastes from well treatment offshore is: well treatment wastes shall contain no free oil when discharged.

Section IX

Bibliography

1. Offshore Operators Committee, Sheen Technical Subcommittee. 1974. "Determination of Best Practicable Control Technology Currently Available to Remove Oil From Water Produced With Oil and Gas." Prepared by Brown and Root, Inc., Houston, Texas.

SECTION X

EFFLUENT LIMITATIONS FOR BEST AVAILABLE TECHNOLOGY ECONOMICALLY ACHIEVABLE

The application of best available technology economically achievable is defined as improved O&M practices and tighter control of the treatment process for the far offshore subcategory. BATEA for the near offshore and coastal subcategories are defined as subsurface disposal for produced waters. BATEA for the onshore, beneficial use, and stripper subcategories are the same as BPTCA. These effluent limitations are to go into effect no later than July 1, 1983.

The limitations for all subcategories are the same as BPTCA for drilling muds, drill cuttings, sanitary and domestic wastes, well treatment, and produced sands. Additionally the BATEA limitation for deck drainage in the near offshore subcategory is the same as for BPTCA.

<u>Near Offshore and Coastal Subcategories - Produced Water</u>

The BATEA limitations for produced water in the coastal and near offshore subcategories is no discharge to surface waters. This can be accomplished by reinjection or by end-of-pipe technologies such as, evaporation ponds and holding pits (when wastes are transferred to shore) or injection to disposal wells. About 40% of those producing facilities with no discharge use one of these end-of-pipe technologies.

Existing no discharge systems were reviewed to select the best technology for the purpose of establishing effluent limitations. Holding pits were found to be the least desirable because of frequent overflow, dike failure, and infiltration of salt water into fresh water aquifiers. If properly constructed and lined, evaporation lagoons may result in no discharge in arid and semiarid regions. However, erosion, flooding, and overflow may still occur during wet weather. Disposal well systems which may consist of skim tanks, aeration facilities, filtering systems, backwash holding facilities, clear water accumulators, pumps, and wells provide the best method for disposal of produced water. These systems are equally applicable to onshore and offshore operations and are the primary method used to dispose of produced water on the California coast and in the inland areas.

<u>Far Offshore Subcategory - Produced Water and Deck Drainage</u>

The BATEA limitations for produced water and deck drainage in the far offshore subcategory are based on the same end-of-pipe technology as used for BPTCA. It is expected that the industry will have gained sufficient experience in the reduction of raw waste loads and operation of end-of-pipe technologies to improve their operation by 1983. In order to define this level of discharge a statistical analysis was carried out on the data from the 27 flotation units, used to define BPTCA, to determine if any units were significantly better in effluent quality than the rest. A group of 10 flotation units were separated on that basis and their data analyzed. The resulting BATEA limitations for oil and grease are, 52 mg/l daily maximum (composited) and 30 mg/l maximum monthly average. Figure 13 is a cumulative plot of the effluent concentrations of these 10 selected flotation units.

When the BPTCA limitations were derived, it was concluded that they should be based on what was being achieved by all facilities using the BPTCA.

This conclusion was reached on the basis of industry experience. Since the industry will have, by 1983, 8 additional years of experience in waste abatement, there should be no significant problems in attaining effluent qualities now being met by many facilities.

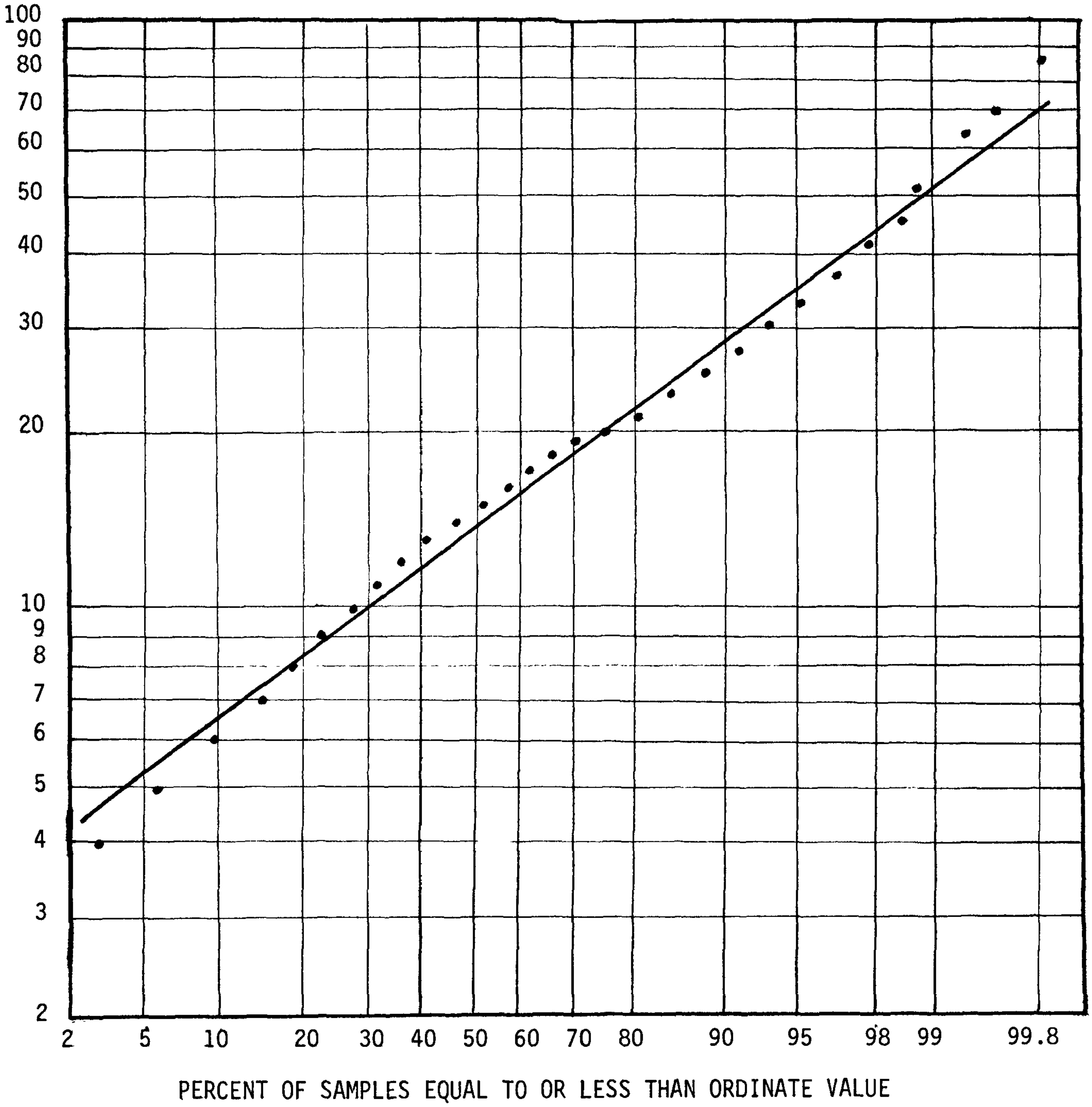

Fig. 13-Cumulative Plot of Effluent Concentrations of Ten Selected Flotation Units in the Louisiana Gulf Coast Area

SECTION XI

NEW SOURCE PERFORMANCE STANDARDS

The effluent limitations for new source performance standards are the same as the BATEA limitations for each subcategory. The facilities defined here will be built after this regulation is in affect. These facilities should therefore, be built with raw waste load reduction and waste treatability in mind. As a result, the number and magnitude of both preventable and unpreventable wastes should be minimized.

SECTION XII

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SECTION XIII

GLOSSARY AND ABBREVIATIONS

Acidize - To put acid in a well to dissolve limestone in a producing zone, forming passages through which oil or gas can enter the well bore.

Air/Gas Lift - Lifting of liquids by injection of air or gas directly into the well.

Annulus or Annular Space - The space between the drill stem and the wall of the hole or casing.

API - American Petroleum Institute.

API Gravity - Gravity (weight per unit of volume) of crude oil as measured by a system recommended by the API.

Attapulgite Clay - A colloidial, viscosity-building clay used principally in salt water muds. Attapulgite, a special fullers earth, is a hydrous magnesium aluminum silicate.

Back Pressure - Pressure resulting from restriction of full natural flow of oil or gas.

Barite - Barium sulfate. An additive used to weight drilling mud.

Barite Recovery Unit (Mud Centrifuge) - A means of removing less dense drilled solids from weighted drilling mud to conserve barite and maintain proper mud weight.

Barrel - 42 United States gallons at 60 degrees Fahrenheit.

Bentonite - An additive used to increase viscosity of drilling mud.

Blowcase - A pressure vessel used to propel fluids intermittently by pneumatic pressure.

Blowout - A wild and uncontrolled flow of subsurface formation fluids to the earth's surface.

Blowout Preventer (BOP) - A device to control formation pressures in a well by closing the annulus when pipe is suspended in the well or by closing the top of the casing at other times.

Bottom-Hole Pressure - Pressure at the bottom of a well.

Brackish Water - Water containing low concentrations of any soluble salts.

Brine - Water saturated with or containing a high concentration of common salt (sodium chloride): also any strong saline solution containing such other salts as calcium chloride, zinc chloride, calcium nitrate.

BS&W - Bottom Sediment and water carried with the oil. Generally, pipeline regulations limit BS&W to 1 percent of the volume of oil.

Casing - Large steel pipe used to "seal off" or "shut out" water and prevent caving of loose gravel formations when drilling a well. When the casings are set, drilling continues through and below the casing with a smaller bit. The overall length of this casing is called the string of casing. More than one string inside the other may be used in drilling the same well.

Centrifuge - A device for the mechanical separation of solids from a liquid. Usually used on weighted muds to recover the mud and discard solids. The centrifuge uses high-speed mechanical rotation to achieve this separation as distinguished from the cyclone-type separator in which the fluid energy alone provides the separating force. Also see "Desander - Cyclone."

Chemical-Electrical Treater - A vessel which utilizes surfactants, other chemicals and an electrical field to break oil-water emulsions.

Choke - A device with either a fixed or variable aperture used to release the flow of well fluids under controlled pressure.

Christmas Tree - Assembly of fittings and valves at the top of the casing of an oil well that controls the flow of oil from the well.

Circulate - The movement of fluid from the suction pit through pump, drill pipe, bit annular space in the hole and back again to the suction pit.

Closed-In - A well capable of producing oil or gas, but temporarily not producing.

Coagulation - The combination or aggregation of semi-solid particles such as fats or proteins to form a clot or mass. This can be brought about by addition of appropriate electrolytes. Mechanical agitation and removal of stabilizing ions, as in dialysis, also cause coagulation.

Coalescence - The union of two or more droplets of a liquid to form a larger droplet, brought about when the droplets approach one another close-by enough to overcome their individual surface tensions.

Condensate - Hydrocarbons which are in the gaseous state under reservoir conditions but which become liquid either in passage up the hole or at the surface.

Connate Water - Water that probably was laid down and entrapped with sedimentary deposits as distinguished from migratory waters that have flowed into deposits after they were laid down.

Crude Oil - A mixture of hydrocarbons that existed in liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities.

Cut Oil - Oil that contains water, also called wet oil.

Cuttings - Small pieces of formation that are the result of the chipping and/or crushing action of the bit.

Derrick and Substructure - Combined foundation and overhead structure to provide for hoisting and lowering necessary to drilling.

Desander - Cyclone - Equipment, usually cyclone type, for removing drilled sand from the drilling mud stream and from produced fluids.

Desilter - Equipment, normally cyclone type, for removing extremely fine drilled solids from the drilling mud stream.

Development Well - A well drilled for production from an established field or reservoir.

Disposal Well - A well through which water (usually salt water) is returned to subsurface formations.

Drill Pipe - Special pipe designed to withstand the torsion and tension loads encountered in drilling.

Drilling Mud - A suspension, generally aqueous, used in rotary drilling to clean and condition the hole and to counterbalance formation pressure; consists of various substances in a finely divided state, among which bentonite and barite are most common.

Dump Valve - A mechanically or pneumatically operated valve used on separators, treaters, and other vessels for the purpose of draining, or "dumping" a batch or oil or water.

Emulsion - A substantially permanent heterogenous mixture of two or more liquids which are not normally dissolved in each other, but which are held in suspension or dispersion, one in the other, by mechanical agitation or, more frequently, by adding small amounts of substances known as emulsifiers. Emulsions may be oil-in-water, or water-in-oil.

EPA - United States Environmental Protection Agency.

Field - The area around a group of producing wells.

Flocculation - The combination or aggregation of suspended solid particles in such a way that they form small clumps or tufts resembling wool.

Flowing Well - A well which produces oil or gas without any means of artificial lift.

Fluid Injection - Injection of gases or liquids into a reservoir to force oil toward and into producing wells. (See also "Water Flooding.")

Formation - Various subsurface geological strata penetrated by a well bore.

Formation Damage - Damage to the productivity of a well resulting from invasion of mud particles into the formation.

Fracturing - Application of excessive hydrostatic pressure which fractures the well bore (causing lost circulation of drilling fluids.)

Freewater Knockout - An oil/water separation tank at atmospheric pressure.

Gas Lift - A means of stimulating flow by aerating a fluid column with compressed gas.

Gas-Oil Ratio - Number of cubic feet of gas produced with a barrel of oil.

Gathering Line - A pipeline, usually of small diameter, used in gathering crude oil from the oil field to a point on a main pipeline.

Gun Barrel - An oil-water separation vessel.

Header - A section of pipe into which several sources, of oil such as well streams, are combined.

Heater-Treater - A vessel used to break oil water emulsion with heat.

Hydrogen Ion Concentration - A measure of the acidity or alkalinity of a solution, normally expressed as pH.

Hydrostatic Head - Pressure which exists in the well bore due to the weight of the column of drilling fluid; expressed in pounds per square inch (psi).

Inhibitor - An additive which prevents or retards undesirable changes in the product. Particularly, oxidation and corrosion; and sometimes paraffin formation.

Invert Oil (Emulsion Mud) - A water-in-oil emulsion where fresh or salt water is in dispersed phase and diesel, crude, or some other oil is the continuous phase. Water increases the viscosity and oil reduces the viscosity.

Kill a Well - To overcome pressure in a well by use of mud or water so that surface pressures are neutralized.

Location (Drill Site) - Place at which a well is to be or has been drilled.

Mud Pit - A steel or earthen tank which is part of the surface drilling mud system.

Mud Pump - A reciprocating, high pressure pump used for circulating drilling mud.

Multiple Completion - A well completion which provides for simultaneous production from separate zones.

OCS - Outer Continental Shelf.

Offshore - In this context, the submerged lands between shoreline and the edge of the continental shelf.

OHM - Oil and Hazardous Material.

Oil Well - A well completed for the production of crude oil from at least one oil zone or reservoir.

Onshore - Dry land, inland bodies and bays, and tidal zone.

OSMCD - Oil and Special Materials Control Division.

Paraffin - A heavy hydrocarbon sludge from crude oil.

Permeability - A measure of ability of rock to transmit a one-phase fluid under condition of laminar flow.

Pressure Maintenance - The amount of water or gas injected vs. the oil and gas production so that the reservoir pressure is maintained at a desired level.

Pump, Centrifugal - A pump whose propulsive effort is effectuated by a rapidly turning impeller.

Rank Wildcat - An exploratory well drilled in an area far enough removed from previously drilled wells to preclude extrapolation of expected hole conditions.

Reservoir - Each separate, unconnected body of producing formation.

Rotary Drilling - The method of drilling wells that depends on the rotation of a column of drill pipe with a bit at the bottom. A fluid is circulated to remove the cuttings.

Sand - A loose granular material, most often silica, resulting from the disintegration of rocks.

Separator - A vessel used to separate oil and gas by gravity.

Shale - Fine-grained clay rock with slatelike cleavage, sometimes containing an oil-yielding substance.

Shaleshaker - Mechanical vibrating screen to separate drilled formation cuttings carried to the surface with drilling mud.

Shut In - To close valves on a well so that it stops producing; said of a well on which the valves are closed.

Skimmer - A settling tank in which oil is permitted to rise to the top of the water and is then taken off.

Stripper Well (Marginal Well) - A well which produces such a small volume of oil that the gross income therefrom provides only a small margin of profit or, in many cases, does not even cover actual cost of production.

Stripping - Adding or removing pipe when a well is pressured without allowing vertical flow at the top of the well.

Tank - A bolted or welded atmospheric pressure container designed for receipt, storage, and discharge of oil or other liquid.

Tank Battery - A group of tanks to which crude oil flows from producing wells.

TDS - Total Disolved Solids.

TOC - Total Organic Carbon.

Total Depth (T.D.) - The greatest depth reached by the drill bit.

Treater - Equipment used to break an oil - water emulsion.

TSS - Total Suspended Solids.

USCG - United States Coast Guard.

USGS - United States Geological Survey.

Water Flooding - Water is injected under pressure into the formation via injection wells and the oil is displaced toward the producing wells.

Well Completion - In a potentially productive formation, the completion of a well in a manner to permit production of oil; the walls of the hole above the producing layer (and within it if necessary) must be supported against collapse and the entry into the well of fluids from formations other than the producing layer must be prevented. A string of casing is always run and cemented, at least to the top of the producing layer, for this purpose. Some geological formations require the use of additional techniques to "complete" a well such as casing the producing formation and using a "gun perforator" to make entry holes, the use of slotted pipes, consolidating sand layers with chemical treatment, and the use of surface-actuated underwater robots for offshore wells.

Well Head - Equipment used at the top of a well, including casing head, tubing head, hangers, and the Christmas Tree.

Wildcat Well - A well drilled to test formations nonproductive within a 1-mile radius of previously drilled wells. It is expected that probable hole conditions can be extrapolated from previous drilling experience data from that general area.

Wiper, Pipe-Kelly - A disc-shaped device with a center hole used to wipe off mud, oil or other liquid from drill pipe or tubing as it is pulled out of a well.

Work Over - To clean out or otherwise work on a well in order to increase or restore production.

Work Over Fluid - Any type of fluid used in the workover operation of a well.

TABLE 41

METRIC TABLE

CONVERSION TABLE

MULTIPLY (ENGLISH UNITS) by TO OBTAIN (METRIC UNITS)

ENGLISH UNIT	ABBREVIATION	CONVERSION	ABBREVIATION	METRIC UNIT
acre	ac	0.405	ha	hectares
acre - feet	ac ft	1233.5	cu m	cubic meters
British Thermal Unit	BTU	0.252	kg cal	kilogram - calories
British Thermal Unit/pound	BTU/lb	0.555	kg cal/kg	kilogram calories/kilogram
cubic feet/minute	cfm	0.028	cu m/min	cubic meters/minute
cubic feet/second	cfs	1.7	cu m/min	cubic meters/minute
cubic feet	cu ft	0.028	cu m	cubic meters
cubic feet	cu ft	28.32	l	liters
cubic inches	cu in	16.39	cu cm	cubic centimeters
degree Fahrenheit	°F	0.555(°F-32)*	°C	degree Centigrade
feet	ft	0.3048	m	meters
gallon	gal	3.785	l	liters
gallon/minute	gpm	0.0631	l/sec	liters/second
horsepower	hp	0.7457	kw	killowatts
inches	in	2.54	cm	centimeters
inches of mercury	in Hg	0.03342	atm	atmospheres
pounds	lb	0.454	kg	kilograms
million gallons/day	mgd	3,785	cu m/day	cubic meters/day
mile	mi	1.609	km	kilometer
pound/square inch (gauge)	psig	(0.06805 psig +1)*	atm	atmospheres (absolute)
square feet	sq ft	0.0929	sq m	square meters
square inches	sq in	6.452	sq cm	square centimeters
ton (short)	ton	0.907	kkg	metric ton (1000 kilograms)
yard	yd	0.9144	m	meter

* Actual conversion, not a multiplier

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