DRAFT

DEVELOPMENT DOCUMENT FOR EFFLUENT LIMITATIONS GUIDELINES AND NEW SOURCE PERFORMANCE STANDARDS FOR THE

OIL AND GAS EXTRACTION POINT SOURCE CATEGORY

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

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PUBLICATION NOTICE

This is a draft development document for proposed effluent limitations guidelines and new source performance standards. As such, this report is subject to changes resulting from comments received during the period of public comments of the proposed regulations.

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for

EFFLUENT LIMITATIONS GUIDELINES

and

NEW SOURCE PERFORMANCE STANDARDS

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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 limitation guidelines, standards of performance, and pretreatment standards for the industry to implement Sections 304, 306, and 307 of the Federal Water Pollution Control Act of 1972, (PL 92-500). Guidelines and standards were developed for the overall oil and gas extraction industry, which was divided into 14 subcategories.

Effluent limitation guidelines contained herein set forth the degree of reduction of pollutants in effluents that is attainable through the application of best practicable control technology (BPCT), and the degree of reduction attainable through the application of best available technology (BAT) by existing point sources for July 1, 1977, and July 1, 1983, respectively. Standards of performance for new sources are based on the application of best available demonstration technology (BADT).

Annual costs for the oil and gas extraction industry for achieving BPCT by 1977 are estimated at $192,000,000.00. This preliminary cost estimate could be revised when more data for small facilities become available.

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

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SECTION I

CONCLUSIONS

EPA's Oil Extraction Task Force conducted a major study of the waste water treatment technology for the oil and gas extraction point source category. The study consisted of four phases: (1) literature survey, (2) field verification study, (3) data collection and analysis, and (4) data evaluation and documentation. The Task Force reached the following major conclusions:

. The most significant wastes generated by the oil and gas extraction category are production brines, drilling muds, and cuttings. Minor wastes include sanitary wastes and oil from deck drainage.

. Type of operation, waste characteristics, and location are the main factors affecting subcategorization of the industry for the purpose of establishing effluent limitations. Size of facility, climate, and volumes of waste generated have little influence on treatment technology.

. Oil and grease are the most important pollutants contained in wastes from brine production, deck drainage, drilling operations, and sand removal. Oil and grease require establishment of effluent limitations.

. Control and treatment technology for produced brine wastes have been developed which eliminates effluent discharges into surface waters. Current practice in the Gulf of Mexico and Coastal Alaska utilize technology which discharges treated brine waste into saline waters.

- Physical/chemical brine treatment systems consisting of equalization, chemical addition, and gas flotation are the best demonstrated technology for facilities located in the Gulf of Mexico and Coastal Alaska. The long term average for oil and grease is 27 mg/l for the exemplary treatment systems.

- Physical/chemical treatment followed by reinjection is the best demonstrated technology for control of produced brines in Coastal California and onshore areas.

- Control and treatment technology is subject to malfunctions which are caused by formation characteristics, improper operating procedures, equipment failure, or start-up problems. An effective program to investigate the causes of failure and take corrective action could eliminate the majority of the malfunctions and reduce the present high variability in effluent oil and grease concentrations.

- Equipment failure often results in untreated or partially treated brine discharges to surface waters. Minimal gravity separation systems on by pass lines are provided at some facilities to remove free oil.

- Oil and grease sampling and laboratory analytical procedures are not uniform throughout the industry, which causes considerable error in reports on performance of treatment systems.

. Application of best practicable and best available treatment technologies will result in little additional impact on air quality, solid waste disposal, and noise pollution control.

. The total cost to industry for application of best practicable control technology is estimated at $192,000,000.00.

SECTION II

RECOMMENDATIONS

Based on the finding and conclusion of the study of the control and treatment technology for the oil and gas extraction industry, the Task Force makes the following major recommendations:

- For the purpose of establishing effluent limitations, the industry be subcategorized as indicated in Table II-1.

- For the discharge technology subcategory, the best practicable control technology (BPCT) or end-of-pipe brine treatment be based upon physical/chemical technology consisting of equalization, chemical injection, and gas flotation.

- For the no discharge technology subcategory, the best practicable control technology be based upon physical/chemical treatment followed by reinjection.

- Effluent limitations for best practicable control technology for all subcategories be established in accordance with the values listed in Table II-2.

- Best available technology (BAT) for brine wastes be based upon physical/chemical treatment followed by reinjection, and effluent limitations be established in accordance with the values listed in Table II-3.

- New source performance standards be based upon best available technology, and effluent limitations be established in accordance with Table II-3.

- A program to investigate causes of failures and take corrective action programs be implemented to eliminate controllable malfunction and reduce high variability in effluent oil and grease concentrations.

- Standardized procedures for collecting, preserving, and analyzing samples be adopted throughout the industry to improve analysis of treatment systems performance, treatment system operating procedures, and process operations.

TABLE II-1

Industry Subcategorization

- Production Brine Wastes
  - No Discharge Technology
  - Discharge Technology (Gulf Coast and Coastal Alaska)
- Offshore
  - Deck Drainage
  - Drilling Muds
  - Drill Cuttings
  - Sanitary
    - Manned facilities with 10 or more people (M10)
    - Manned facilities with less than 10 people or intermittently manned (M9IM)
  - Physical/Chemical Treatment of Wells
  - Solids Removal
- Onshore
  - Drilling Muds
  - Drill Cuttings
  - Physical/Chemical Treatment of Wells
  - Solids Removal

TABLE II-2

Effluent Limitation - BPCT

Subcategory	Allowable Effluent Levels: Oil & Grease mg/l Daily Max.	Oil & Grease mg/l Monthly Max.	Chlorine Residual mg/l	Floating Solids	Other
Production Brine Waste	----	----	----	----	
No Discharge Technology	----	----	----	----	No discharge
Discharge Technology	85	57	----	----	
Offshore					
Deck Drainage	85	57	----	----	
Drilling Muds	None	None	----	----	
Drill Cuttings	None	None	----	----	
Sanitary					
M10	----	----	1.0 $\pm$ 40%	----	
M9IM	----	----	----	None	
Physical/Chemical Treatment of Wells	None	None	----	----	
Solids Removal	None	None	----	----	
Onshore					
Drilling Muds	----	----	----	----	No discharge
Drill Cuttings	----	----	----	----	No discharge
Physical/Chemical Treatment of Wells	----	----	----	----	No discharge
Solids Removal	----	----	----	----	No discharge

TABLE II-3

Effluent Limitation - BAT and New Source

SUBCATEGORY	Allowable Effluent Levels: Oil & Grease mg/l Daily Max.	Oil & Grease mg/l Monthly Max.	Chlorine Residual mg/l	Floating Solids	Other
Production Brine Waste	----	----	----	----	
No Discharge Technology	----	----	-----	----	No discharge
Discharge Technology	----	---	----	----	No discharge
Offshore					
Deck Drainage	----	----	----	----	No discharge
Drilling Muds	None	None	----	----	
Drill Cuttings	None	None	----	----	
Sanitary					
M10	----	----	1.0 ± 40%	----	
M91M	----	----	----	None	
Physical/Chemical Treatment of Wells	None	None	----	----	
Solids Removal	None	None	----	----	
Onshore					
Drilling Muds	----	----	----	----	No discharge
Drill Cuttings	----	----	----	----	No discharge
Physical/Chemical Treatment of Wells	----	----	----	----	No discharge
Solids Removal	----	----	----	---	No discharge

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 achievement by new sources of a Federal standard of performance providing for the control of the discharge of pollutants. 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, operation methods, and other alternatives.

The findings contained herein set forth effluent limitation 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 conducted in the initial exploratory phase of operations, or may be deep exploration seeking to to discover oil- or gas- bearing reservoirs.

Most wells are drilled today by rotary drilling methods. The basic components of this system consist of:

. 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.

. 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 III-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 III-2).

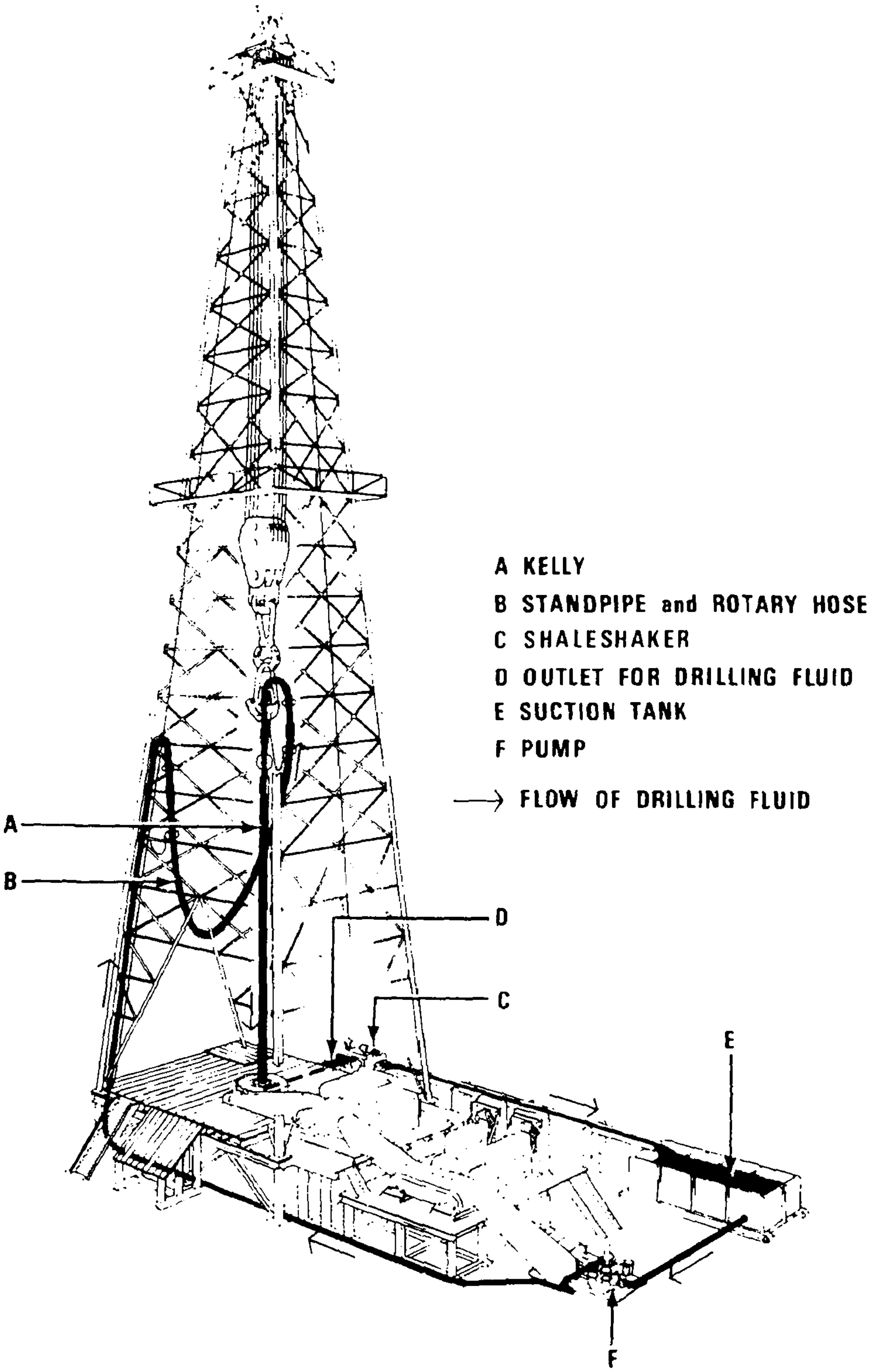


Fig. III-1 -- ROTARY DRILLING RIG

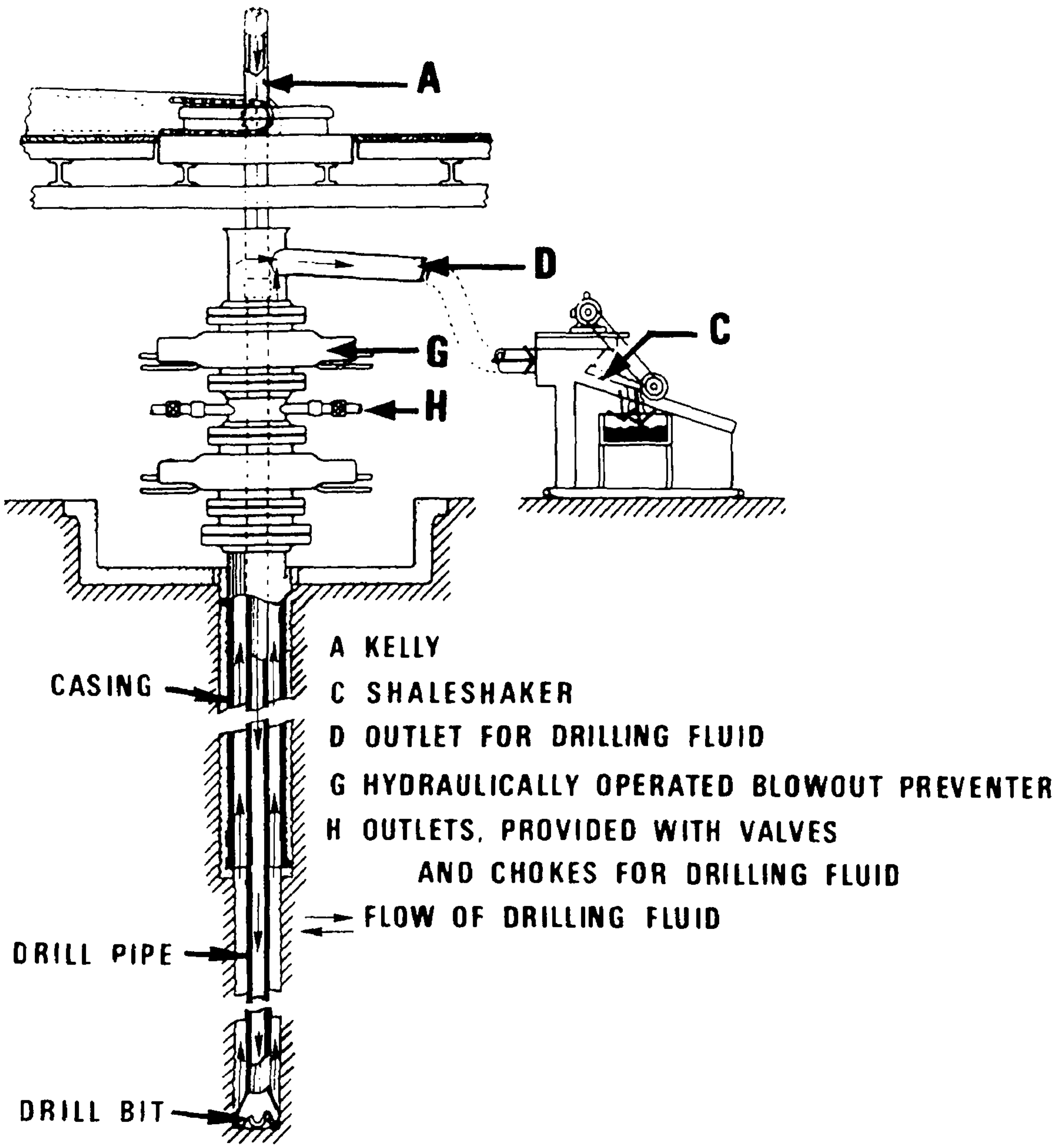


Fig. III-2 -- SHALESHAKER AND BLOWOUT PREVENTER

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 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 III-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 weighing 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 pipe, 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 the 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 have entered the hole from the formation (water, oil, or gas). When the mud arrives at the surface, cuttings, silt, and sand are removed by shale shakers, 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 cutting, 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 shale shakers and cyclone separators (desanders or desilters) usually go to an earthen (slush) pit adjacent to the rig. To dispose of this material, at the end of drilling operations, the pit is backfilled.

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 normally are 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 material.

These 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 III-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

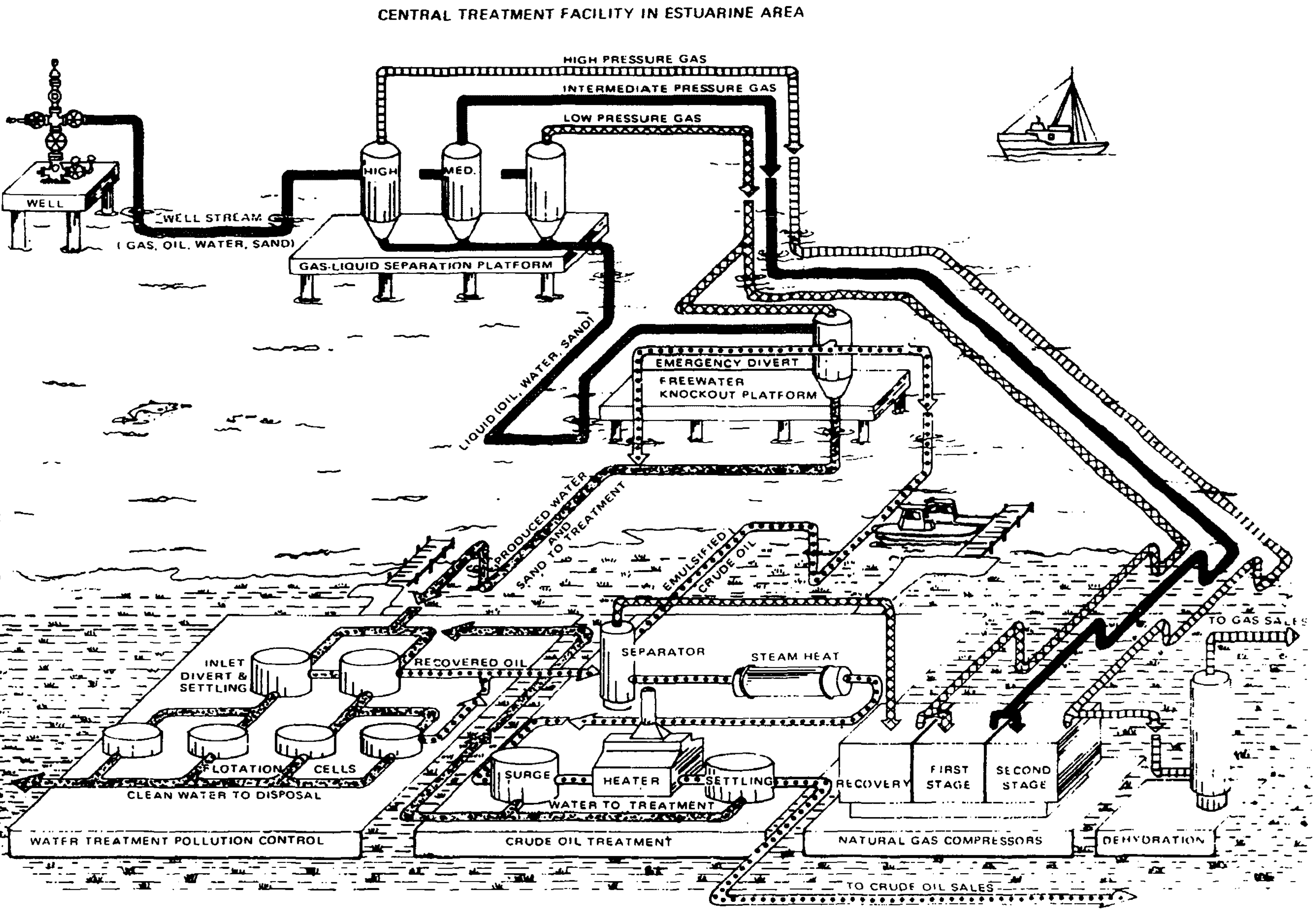
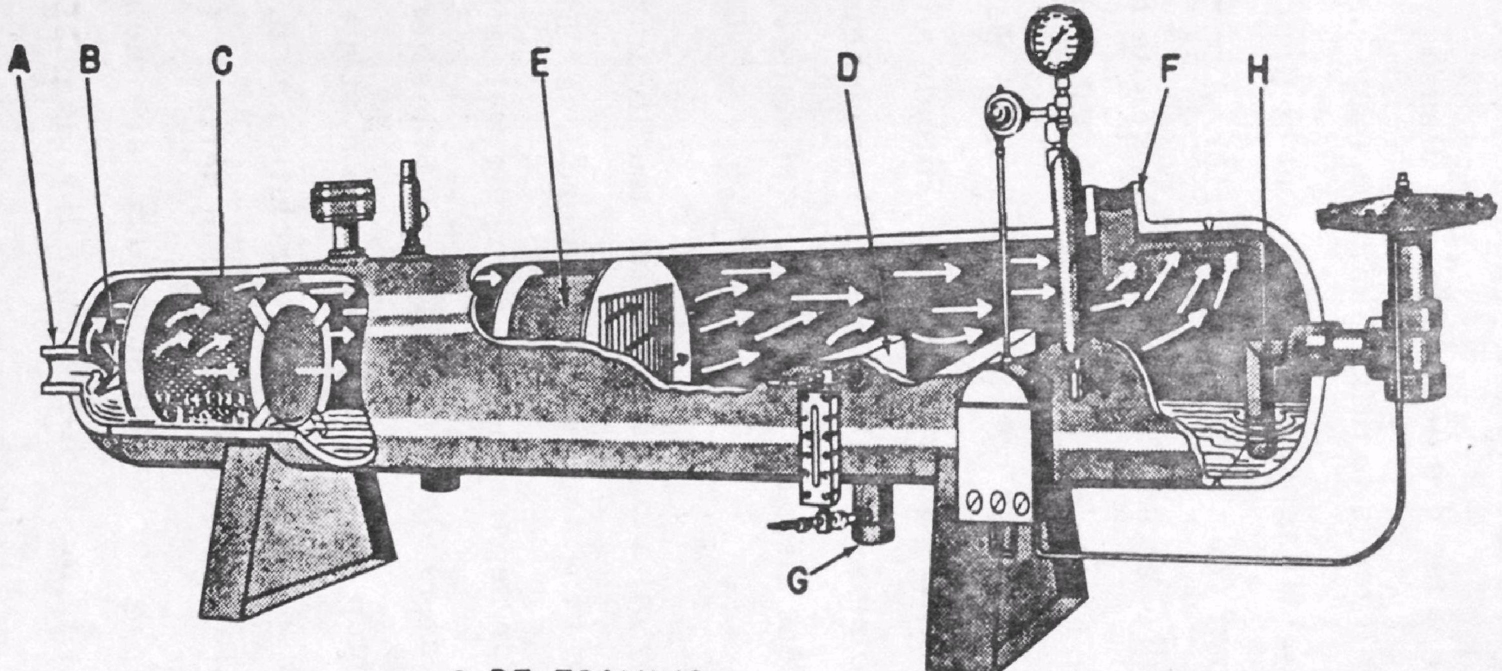


Fig. III-3 -- CENTRAL TREATMENT FACILITY IN ESTUARINE AREA be caused by various processes which tend to mix the oil and water vigorously together and cause droplets to form. Passage of the fluids into and up the well tends to mix them. Passage through well head chokes; through various pipes, headers, 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 III-4 shows a gas separator for separating gas from the well stream. 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



A-OIL AND GAS INLET

B-IMPACT ANGLE

C-DE-FOAMING ELEMENT

D-WAVE BREAKER AND SELECTOR PLATE

E-MIST EXTRACTOR

F-GAS OUTLET

G-DRAIN

H-OIL OUTLET (DUMP VALVE)

Fig. III-4 -- HORIZONTAL GAS SEPARATOR

oil from the brine. 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 III-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 1 percent) so as to be marketable. The brine or brine/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

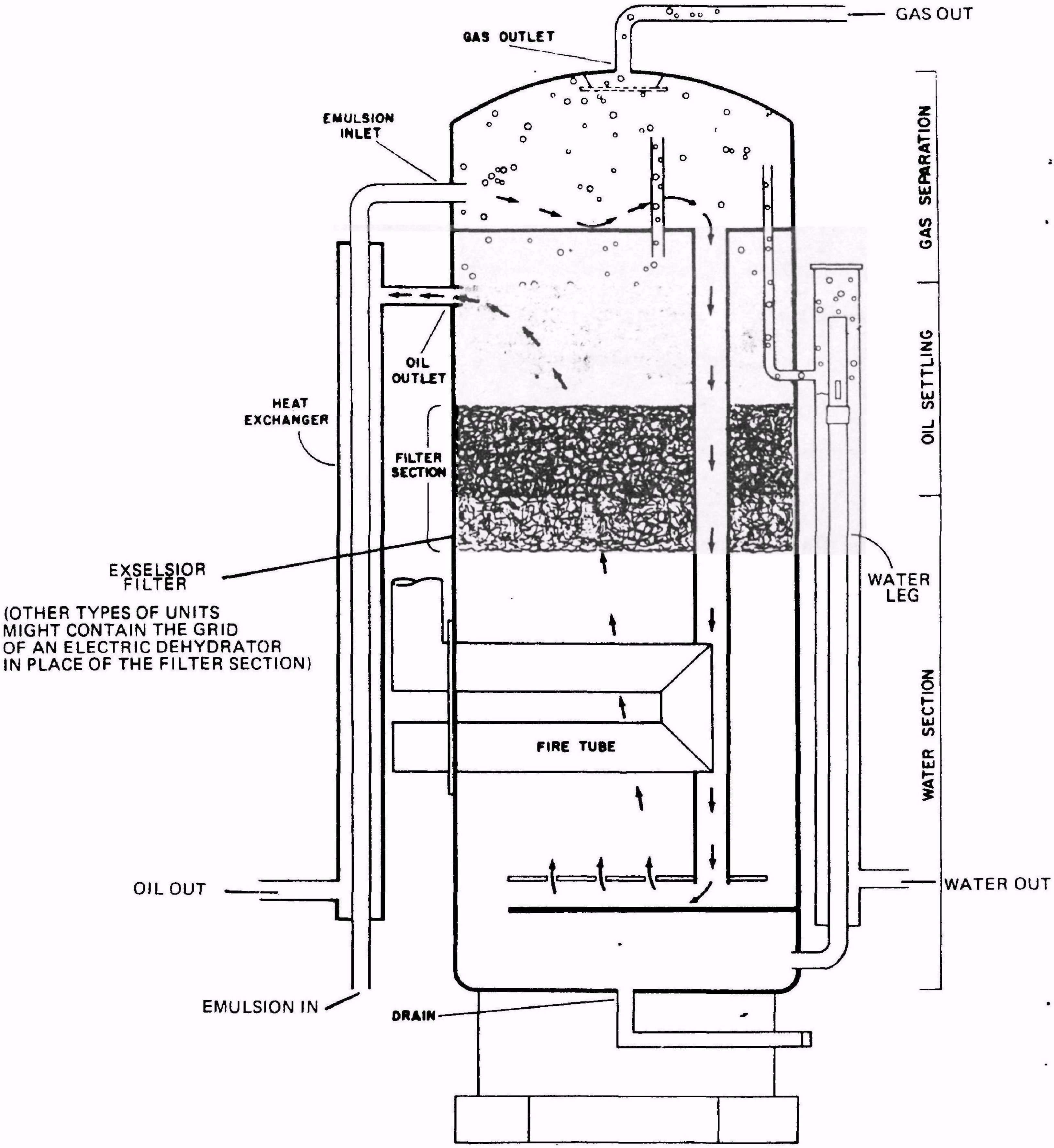


Fig. III-5 -- VERTICAL HEATER-TREATER

of treatment are necessary to remove sufficient oil from the brine 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 waste brine 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 surface disposal. (Brines 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, centrifuging, and separation by gas flotation are also used. In addition, combinations of two or more 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 brine waste to surface salt or brackish water bodies.

Several options are available in injection systems. Often water will be injected into a producing oil reservoir 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 wells and increase ultimate recovery. This process is one of several known as secondary recovery since it produces oil beyond that available by ordinary production methods. A successful waterflood project will increase the amount of oil being produced at a field. It will also increase brine production and thus effect the amount of waste water that must be treated. Pressure maintenance by water injection may also increase the amount of water produced and treated. Injection is also feasible solely as a disposal method. It is extensively used in all onshore production areas for disposal of waste brine and is used in California for disposal of brine from offshore facilities.

Evolution of Facilities

Early offshore development tended to place wells on individual structures, bringing the fluids ashore for separation and treatment (see Figure III-3). As the industry moved farther offshore, the wells still tended to be located on individual platforms but 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, including compressor stations for gas lift wells and sophisticated water treatment facilities for water flood projects.

Platform design reflects the operating environment. Cook Inlet platforms are enclosed as 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. Present platforms far removed from shore are practically independent production units.

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 shallower 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 so-called "tertiary recovery." The process usually involves injecting some substance into the oil reservoir to release or carry out 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:

- Thermal recovery.
- Miscible hydrocarbon.
- Carbon dioxide.
- Alcohols - soluble oil - micellar solutions.
- Chemical floods - surfactants.
- Gas - gas/water - inert gas.
- Gas repressuring - depletion.
- Polymers.
- 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 Services

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 contractor) is the largest. Drilling fluids and their disposal have already been discussed. Other services include completions, workovers, well acidizing, and well fracturing.

When the 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 or it may worsen with the passage of time, or both. 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 takes place as well as fracturing. The fluids also contain sand or some similar material that keeps the fractures 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 of 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.

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. The five largest oil-producing States in 1972 were: Texas, Louisiana, 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 producing States.

For 1973, domestic production was 9.2 million barrels-per-day (bpd) of oil and 1.7 million bpd of gas liquids, for a total production of 10.9 bpd down slightly from 1970, 1971, and 1972. (3) Total imports were 6.2 million bpd for 1973.

There are approximately half a million producing oil wells and 120,000 gas and condensate wells in the United States. Of the 30,000 new wells drilled each year, about 55 percent produce oil or gas.

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. Oil is produced from State waters in all three and from the OCS off the Gulf of Mexico and California. 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

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 depths as great 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.

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. Brine would be disposed of by subsurface injection ashore.

Additional lease sales have been proposed on the OCS off Santa Barbara and Southern California.

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 last five 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 brine and oil ashore for separation and treatment. Some platforms are producing increasing amounts of brine, 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 brines.

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

Industry Growth.

From 1960 to 1970, the Nation's demand for energy increased at an average rate of 4.3 percent. Table III-1 gives the projected national demands for oil and gas through 1985 and Table III-2 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 of 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 three areas in the Atlantic Coast (Georges Bank, Baltimore Canyon, and Georgia Embayment) plus 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.

TABLE III-1

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
% of Domestic Petroleum Demand that will be fulfilled by domestic supply	74.0	56.3	46.6
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
% of Domestic Gas Demand that will be fulfilled by domestic supply	96.0	85.5	80.7

TABLE III-2

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

1970	1971	1972	1973
1.58	1.69	1.67	1.59

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.

SECTION III

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SECTION IV

INDUSTRY SUBCATEOGRIZATION

Rationale of Subcategorization

SICs 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:

- Type of facility or operation.
- Facility's size, age, and waste volumes.
- Process technology.
- Climate.
- Waste water characteristics.
- Location of facility.

Field surveys, waste treatment technology, and effluent data indicate that the most important factors are the type of operations, waste water characteristics and location. The size of the facility, climate, and volumes of waste generated are significant with respect to operational practices but have less influence on waste treatment 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. Brine production may vary from less than one percent of the production fluids to 90 percent. High volumes of brines 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 are dependent upon the depth of the well, subsurface characteristics, recovery of drill muds, and recycling. Therefore industry subcategorization did 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 -- crude petroleum and natural gas production; oil and gas well field exploration and drilling; and oil and gas well completions and workover. Further subdivision can be made within each to reflect location -- offshore and on shore -- and any wastes requiring specific effluent limitations and standards. Since sanitary wastes for onshore operations normally do not result in any discharge and since deck drainage is not applicable to onshore operations, these subcategories are only applicable to offshore facilities. Considering location and wastes, the major groups are subcategorized as follows:

I Crude Petroleum and Natural Gas Production

A. Production Brine Waste

B. Deck Drainage - Offshore

C. Sanitary Waste - Offshore

II Oil and Gas Well Field Exploration and Drilling

A. Drilling Muds

B. Drill Cuttings

C. Sanitary Waste - Offshore

III Oil and Gas Well Completions and Workover

A. Chemical Treatment of Wells

B. Solids Removal

All six factors were then examined in detail to uncover additional relationships that would permit still further subcategorization.

Facility's Size, Age and Waste Volumes

Category I facilities differ little in the type of process or brine waste 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 brines to another facility for treatment and disposal. Comparable treatment technology has been developed for both large and small systems.

The types of treatment for sanitary wastes for large and small offshore facilities are different, as are facilities which are intermittently manned. For smaller and intermittent facilities, the waste may be incinerated or chemically treated, resulting in no discharges. 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 number of 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 brines 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 offshore, initial design should provide for the treatment system, the space required for equipment, platform loads, and energy requirements even though actual waste water treatment will not be required for a number of years. No further subcategorization is needed to account for production field age or brine produced since similar treatment technology is used regardless of the quantity of brine produced.

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 brine waste data showed no significant difference in oil content between the various process units; when high influent concentrations to the brine 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 different process systems.

Climate

Climate was considered because conditions in the production regions differ widely. All regions treat by gravity separation or 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 offshore 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.) for deck drainage are independent of rainfall. Proper operation and maintenance can reduce waste oil concentrations to minimal levels, thus reducing the effect of rainfall. No subcategorization is required to account for climate.

Waste Water Characteristics

Treatability and other characteristics of brine waste water are one of the most significant factors considered for subcategorization. Production waters high in total dissolved solids (TDS) cannot be discharged into fresh water; therefore, treatment technologies for onshore operations have been developed which result in no effluent discharge. Similarly, because of rigid State controls on specific brine components, treatment technology has been developed for use in California to eliminate discharges to saline waters as well as fresh water. The brine treatment systems for the Gulf Coast and Coastal Alaska differ from the California oil production areas since the technology was developed to meet requirements that permitted effluent discharges to saline waters.

The technology developed for each area has been primarily influenced by local regulatory requirements, but other factors associated with brine water treatability and cost effectiveness may also have had an effect. (1, 2, 3) Factors which may affect brine water treatability are:

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

. Concentration of suspended and settable solids.

. Fluctuation of flow rate and production method.

. Droplet sizes of the entrained oil emulsification.

. Other characteristics of the produced water.

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

Other factors that affect the type of treatment process selected are as follows:

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

. Proximity to shore.

. Type and depth of subsurface formations suitable for reinjection of brine waste.

If adequate land is available and the facility is relatively close to shore, more complex onshore treatment systems may be provided including: primary clarification, coagulation, secondary clarification, and filtration.

Based on the results of four field surveys, information provided by the oil industry, equipment manufacturers, chemical suppliers, and literature surveys, there is insufficient technical information to determine which of the above factors or combination of factors (if any) could be used to subcategorize the industry based on waste water treatability and other characteristics.

Initial information on performance levels for effluent discharges off the Texas and California coasts indicated that these systems are more efficient than those off the coast of Louisiana; however, field verification surveys indicated that the data was not comparable because of variations in analytical procedures. Effluent levels for similar treatment systems which had effluent discharges were found to be comparable for all areas.

An initial evaluation of brine treatability, treatment technology and related factors indicated that there may be no justification for sub-categorizing based upon discharge and no discharge technologies. However, upon further review of the complexity of the variables involved, it was concluded that existing treatment systems in the Gulf Coast and Coastal Alaska which have effluent discharges should be subcategorized to allow discharge technology; no further subcategorization based on brine characteristics is justified, however.

Discharges are permitted in inland areas where the brines are low in TDS and the water is used for beneficial purposes such as in stock watering and irrigation. These are exceptional cases and will be discussed in other sections of this report.

Facility Location

Location is a significant factor specifically with respect to areas where brine discharges are not permitted. The usual procedure in inland areas is to reinject the brine to the producing formation, which assists oil recovery, or to other subsurface formations for disposal only. Evaporation ponds are used in some inland areas, with the assumption that all brines 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 brines; 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 to allow discharges to be used for stock watering and other beneficial uses, subcategorization based on brine characteristics takes into account these location factors, and no further subdivision is needed.

For Categories II and III, 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. Categories II and III have been subcategorized to reflect the different technologies for onshore and offshore locations.

Another important consideration with respect to subcategorizing based on discharge and no discharge technology is the division between the two areas. Current practice allows discharges into salt water and excludes them from fresh water except for brines with low TDS. There are facilities that are located in areas where fresh and salt water interface or that have low TDS levels; therefore, the division between the different technologies has been established in accordance with the impact of brine discharges on the receiving water. Treatment technology which results in a discharge has been applicable if the effluent does not violate approved State Water Quality Standards, otherwise the no discharge technology has been required.

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

I Crude Petroleum and Natural Gas Production

- A. Production Brine Waste
  1. No Discharge Technology
  2. Discharge Technology (Gulf Coast & coastal Alaska)
- B. Deck Drainage - Offshore
- C. Sanitary Waste - Offshore
  - a. Facilities continuously manned with 10 or more people.
  - b. Facilities with less than 10 people or intermittently manned.

II Oil and Gas Well Field Exploration and Drilling

- A. Onshore
  1. Drilling Muds
  2. Drill Cuttings
- B. Offshore
  1. Drilling Muds
  2. Drill Cuttings
  3. Sanitary Waste

a. Facilities continuously manned with 10 or more people.

b. Facilities with less than 10 people or intermittently manned.

III Oil and Gas Well Completions and Workover

A. Onshore

1. Physical/Chemical Treatment of Wells

2. Solids Removal

B. Offshore

1. Physical/Chemical Treatment of Wells

2. Solids Removal

Description of Subcategories

Production Brine Waste

Production brine waste 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 production brine waste 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 early stages of production; in others, water is not produced until the producing formation has been significantly depleted; in still other types of oil- and gas- producing formations, water is never produced. (4)

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 materials discharged from toilets and urinals and domestic waste 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, weighing 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. Cuttings are separated from the drilling mud at the surface.

Physical/Chemical Treatment of Wells

Physical/chemical treatment of wells includes acidizing and hydraulic fracturing of the well to improve oil recovery. Hydraulic facturing 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 until the pressure is released. Chemical treatment of wells consists of pumping acid or chemicals down the well to remove formation damage and increase drainage in the permeable rock formations. (8)

Solids Removal

The 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 brine 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 brine water in excess of 10 million barrels-per-day. Approximately 17,000 wells have been drilled offshore in U.S. waters, and approximately 11,000 are producing oil or gas. Offshore Louisiana, the OCS alone produces approximately 420,000 barrels of brine water per day (2); by 1983, Louisiana coastal production will generate an estimated 2.54 million barrels of brine 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 heavy metals and other toxicants contained in drilling muds or formation fluids. (4)

Sanitary wastes are also produced during both drilling and production operations both onshore and offshore, but they are discussed and 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.

<u>Waste Constituents</u>

Production (Offshore)

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

The formation waters or brines 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 being chloride levels. Table V-1 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 brine 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 V-1, but it is reasonable to assume that actual analysis of the influent would show higher levels. 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 V-1

Averages of Constituents in

Produced Formation Water

-- Gulf of Mexico

<u>Influent</u>	
Oil and Grease	202 mg/l
<u>Effluent</u>	
Cadmium	0.0678 mg/l
Cyanide	0.01 mg/l
Chlorides	61,142 mg/l
Mercury	Trace
Total Organic Carbon	413 mg/l
Salinity	110,391 mg/l
API Gravity	33.6 degrees
Suspended Solids	73 mg/l

<u>Volumes</u>

Range - 250 to 200,000 bbls brine water/day

Average - 15,000 bbls brine water/day

Source: 25 discharges analyzed in 1974 EPA survey.

Industry data for offshore California describes a broader range of parameters (see Table V-2). Similar data were provided for offshore Texas (see Table V-3). Except as noted on the tables, all data are from effluents. Oil influent data for these two areas are listed on Table VII-10.

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

Production (Onshore)

In general, onshore production fluids are not given the broad scrutiny that offshore production fluids receive for possible toxicants and other pollutants. The primary reason is that the total dissolved solids (TDS) levels in the produced brines are too high to be discharged to surface fresh water streams. If discharge is prohibited, then the presence of pollutants other than TDS is moot.

In some arid areas of the United States, produced brine waters that are reasonably low in TDS are being used for livestock watering and irrigation. Some of these brines are reported to reach surface streams in these areas. Table V-4 describes brine water quality in terms of TDS, for a number of onshore oil production areas which utilize brine water for agricultural purposes.

TABLE V-2

Range of Constituents in Produced Formation Water -- Offshore California[a] (7)

Effluent Constituent	Range, mg/l	State of California Ocean Effluent Limits[b] mg/l
Arsenic	0.001 - 0.08	0.02
Cadmium	0.02 - 0.18	0.03
Total Chromium	0.02 - 0.04	0.01
Copper	0.05 - 0.116	0.3
Lead	0.0 - 0.28	0.2
Mercury	0.0005-0.002	0.002
Nickel	0.100 - 0.29	0.2
Silver	0.03	0.04
Zinc	0.05 - 3.2	0.5
Cyanide	0.0 - 0.004	0.2
Phenolic Comounds	0.35 - 2.10	1.0
BOD_5	370 - 1,920	
COD	340 - 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.

[b] Concentrations not to be exceeded more than 10% of time.

TABLE V-3

Range of Constituents

in Produced Formation Water

-- Offshore Texas (8)

Effluent Constituent	Range, mg/l [a]
Arsenic	*L0.01 - L0.02
Cadmium	L0.02 - 0.193
Total Chromium	L0.10 - 0.23
Copper	L0.10 - 0.38
Lead	L0.01 - 0.22
Mercury	L0.001 - 0.13
Nickel	L0.10 - 0.44
Silver	L0.01 - 0.10
Zinc	0.10 - 0.27
Cyanide	N. A.
Phenolic Compounds	53
BOD_5	126-342
COD	182-582
Chlorides	42,000 - 62,000
TDS	806-169,000
Suspended Solids	12 - 656

[a] L - less than

N.A. - not available

TABLE V-4

Ranges of Dissolved Constituents
for Selected Onshore Subsurface
Formation Water (9)

Location	Total Dissolved Solids, mg/l
Colorado	333-10,795
Montana	350-15,230
Utah	373-120,395
Wyoming	291-276,390

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, weighing, 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 V-5 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. No environmental surveys have been conducted to determine the spread, migration, or biological impact of these materials.

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 the 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 short term pollution problems due to 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.

TABLE V-5

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	
1,000-3500	16	623	545,000	Gelled sea water	700	81,500
2,500-10,000	12	915	790,000	Lime base	950	424,800

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, thus are the liquid phase. When muds are displaced from the well hole they also contain solids from the hole. There are two types of emulsified oil muds -oil emulsion muds, which are oil-in-water emulsions, and invert 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 weighing agents can also be added.

Sanitary Wastes

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 V-6 indicates typical waste flow for offshore facilities and vessels.

TABLE V-6

Raw Sanitary Wastes

No. of Men	Flow, gal/day	BOD_5, mg/l Avg.	BOD_5, mg/l Range	Suspended Solids, mg/l Avg.	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

Selected Parameters

Oil and grease from produced water, deck drainage, muds, cuttings, and sand removal, and residual chlorine and floating solids from sanitary sources have been selected as the pollutants for which effluent limitations will be established (see Table VI-1). The rationale for inclusion of these parameters are discussed below.

Parameters for Effluent Limitations

Oil and grease

Oil and grease (i. e., petroleum) have long been known to damage marine ecosystems; the harmful effects of petroleum have been recognized by international, national and state governments. (1, 2, 3) The harmful effects of petroleum include, but are not limited to, acute toxicity, coating and smothering, inhibition of photosynthesis, and interference with subtle life processes such as chemical communication. (4, 5)

Fecal Coliform - Chlorine Residual

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

TABLE VI-1

Selected Parameters

Category	Parameter
Production Brine Waste	
No Discharge	Not Applicable
Discharge	Oil and Grease
Offshore Installations	
Drilling Muds	Oil and Grease
Drill Cuttings	Oil and Grease
Workover	Oil and Grease
Sanitary	
Manned (over 10 people)	Chlorine Residual
Small, intermittent	Floating Solids
Onshore Installations	
Drilling Muds	Not Applicable
Drill Cuttings	Not Applicable
Workover	Not Applicable

The most direct methods to determine compliance with specified limits are to measure the fecal coliform levels in the effluent for seven days. This approach is very applicable to onshore installations; however, for offshore operations the logistics become complex, and simplified methods are desirable.

The two key factors that are related to fecal coliform levels in the effluent are suspended solids and chlorine residual. In general if suspended solids levels in the effluent are less than 150 milligrams per liter (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 determined on a daily basis is a reasonable control parameter.

It is considered desirable, however, that a 7-day 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 to form objectional deposits, float on the surface of the water, and produce objectionable odors. Floating solids have been selected as a control parameter for sanitary waste from small or intermittently manned offshore facilities.

For coastal areas where water quality criteria have been established other parameters may be selected to meet the requirement of a specific location.

Other Pollutants

Produced formation waters are known to contain toxic substances, constituents with substantial oxygen demand, and inorganic salts. Insufficient data exist to warrant comprehensive control of these parameters; however, restrictions on these parameters may be required as a result of water quality requirements as pointed out in Section V and below.

Formation 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 202 hectares (500 acres). Many estuarine areas fall into this category.

The proposed standards include limits for other water bodies based on dilution and mass emission parameters (see Table VI-2).

The harmful effects of these toxicants, which include direct toxicity to humans and other animals, biological concentration, sterility, mutagenicity, teratogenicity, and other lethal and sub-lethal 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 Wolf (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 .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.

Estuaries, excepting hypersaline lagoons, have salinities ranging from 1 to 35 parts per thousand (ppt). The average brine salinity

TABLE VI-2

A Comparison of Toxic Effluent Standards

and Surveyed Production Platforms For

Toxicants in Produced Formation Water

	307(a) Toxic Effluent Standards								Surveyed Production Platforms	
	Concentration, mg/l			Maximum pounds/day					Concentration, mg/l	
	low flow[a]	medium flow[b]	high flow[c]							
Toxicant	all waters	fresh tidal	fresh tidal	stream	lake	estuary	coastal		mean	range
Cadmium	0	0.004 0.032	0.040 0.320	12.96	10.8	86.4	102.6		0.068	0.50-.262
Mercury	0	0.002 0.010	0.020 0.100	1.62	1.35	27.0	32.4		-----	Traces
Cyanide	0	0.010 0.010	0.100 0.100	----	----	----	----		0.010	0.010

[a] less than 10 cfs.

[b] less than 10x waste stream.

[c] more than 10 cfs.

given in Table VI-2 would be approximately 110 ppt and would be characteristically devoid of oxygen and high in CO_2. It is feasible to expect this anoxic, hypersaline fluid, since it is more dense than the receiving water, to displace the estuarine bottom waters. This displacement increases density stratification, preventing aeration while simultaneously adding to the oxygen deficit and increasing the CO_2 of the bottom waters.

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, anomalous ion ratios, strange 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)

As seen from the above discussion of potential harm from produced formation 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 VI-3). 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 petroleum industry has developed a no discharge technology (reinjection of brine production water).

TABLE VI-3

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; and 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 the reduction or elimination of a waste stream or vary the character of the constituents and allow the end-of-pipe processes to be more efficient and cost effective. The two general 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 reinjection of waste brine water to increase reservoir pressures and utilization of treated production water for steam generation. An example of recycle systems is the conservation and reuse of drilling muds. An example of character change in a waste stream would be the substitution of a positive displacement pump for a high speed centrifugal pump, thereby reducing the amount of emulsified oil in the stream and so easing treatment, or substition of a downhole choke for a well head choke, thereby reducing the amount of emulsion created. (1)

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

Process Technology

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

Reinjection of produced brine 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.

Water treatment for injection at all installations is similar, both offshore and onshore. Existing injection systems vary from small units which treat 2,000 barrels per day of brine waste to large complexes which handle over 170,000. Waste brine reinjection systems for pressure 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).

Brine water treatment and injection systems are not limited by space availability but must be specifically designed to fit offshore platforms. Two limiting factors which affect brine water reinjection are insufficient quantity of produced brine water to meet the requirement for reservoir pressure maintenance and incompatibility between make-up sea water and produced water. The sea water currently injected into the producing formation in Cook Inlet is reported to be incompatible with produced brine 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 typical injection treatment units; additionally, water softeners are added to the system.

Also, changes in process technology have 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 brine to shore for processing and brine treatment.

Operation and Maintenance

In addition to the reuse of waste brine water, recycling of drilling muds, and reduction of waste loads in flows by other in-plant techniques, another 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:

. Elimination of deliberate dumping of waste crankcase oils into deck drainage collection system.

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

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

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

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

. Elimination of extreme loading of the waste brine water treatment system, when the process system malfunctions, by re-directing all production to shore for treatment. (3)

Good maintenance practice includes: an inspection of dump valves for sand cutting as a preventive measure, the use of dual sump pumps for pumping drainage into surge tanks, use of reliable chemical injection pumps for waste brine water treatment, and selection of the best combination of oil- and water-treating chemicals, and use of level alarms for initiating shut down during major system upsets.

Operation and maintenance of a waste brine water treatment system during start-up present special problems. One example on an offshore facility began with the oil process units upstream of the waste brine water treatment system. Two problems with the heater-treaters interfered with the water treatment system: insufficient heat in the treaters and malfunctioning level controls which caused heavy loading of the water treatment system. A change of the type of level controls and reduced production from wells contributing large volumes of water reduced the heating requirements and helped alleviate the problem during start-up of the waste brine water treatment unit. Further improvements were achieved by careful selection of the best chemical combinations for treating oil and waste brine water, and replacing chemical injection pumps and recycling pumps.

The preceding paragraph describes an actual case where a detailed failure analysis with corrective action ended an upset in the waste treatment system. Evaluation of operational practices, process and treatment equipment and correct chemical use is feasible and is an engineering technique that should be used to determine the causes of failures and upsets and to correct them.

The description of these operation and maintenance practices is not intended to advocate their universal application. The practices nevertheless indicate that good operations and maintenance on an oil/gas production facility can have substantial impact on the loads discharged to the waste treatment system and the efficiency of the system. Careful planning, good engineering, and a commitment 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 the 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; also 3-day studies were conducted in Texas and California to verify performance data. In addition, three field surveys were made to determine 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.

Variance in Analytical Results for Oil and Grease Concentrations

Effluent oil and grease values in brine waste 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, ultraviolet-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 VII-1 compares oil/grease concentrations of acidized and not acidized samples from facilities in California.

TABLE VII-1

Preparation of Analytical Samples

From California

Date of Effluent Sample	Oil & Grease Not Acidized mg/l	Oil & Grease Acidized mg/l
7-26-74	7.6	26.3
7-26-74	36.3	61.8

The values after pH adjustment are 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 extracted by halogenated hydrocarbon solvents.

Extraction of oil and grease from a sample is another critical step that can affect values. The extraction procedure usually depends on the analytical determinative step and the physical/chemical properties of the oil/grease in the sample. For example, petroleum ether extracts all crude oil constituents from a brine waste water sample except asphaltenes or bitumen. This limitation would affect the reported results of a sample containing high asphaltic constituents. Other extractants used in oil/grease determinations are trichlorotrifluroethane (Freon), hexane, carbon tetrachloride, and methylene chloride.

Reported oil/grease concentrations in waste water effluents were highly variable within and between geographical areas. There were no data to support that this variability was the result of the treatability of the waste stream or the treatment technology. Therefore, EPA undertook field verification studies to determine the reasons for the high variability of 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. Duplicate samples were provided to the oil/gas industry for independent laboratory analysis. Table VII-2 shows the results of two analytical methods (gravimetric and infrared) measuring Freon extractible oil/grease and comparing those determined values to petroleum ether extractables using the gravimetric method. This comparison study was conducted by the EPA Robert S. Kerr Research Laboratory (RSKRL) at Ada, Oklahoma. In addition, contract laboratories independently analyzed identical samples using extraction procedures and analytical methods as indicated in Table VII-3.

TABLE VII-2

Oil and Grease Data, Texas Coastal

Facility Identification	RSKRL, Ada, Okla. — Freon Extractibles Gravimetric Method: Influent	RSKRL, Ada, Okla. — Freon Extractibles Gravimetric Method: Effluent	RSKRL, Ada, Okla. — Freon Extractibles Infrared Method: Influent (mg/l)	RSKRL, Ada, Okla. — Freon Extractibles Infrared Method: Effluent	Contractor Lab — Freon Extractibles Gravimetric Method: Influent	Contractor Lab — Freon Extractibles Gravimetric Method: Effluent
T-1	32.0	126.0	45.0	154.0	2.0	5.0
T-2	372.0	242.0	314.0	197.0	178.0	145.0
T-3	643.0	52.0	695.0	62.0	685.0	10.0
T-4	1905.0	46.0	1736.0	51.0	968.0	6.0

TABLE VII-3

Oil and Grease Data, California Coastal

Facility Identification	RSKRL, Ada, Okla. — Freon Extractibles Gravimetric Method: Inf.[a]	RSKRL, Ada, Okla. — Freon Extractibles Gravimetric Method: Eff.[a]	RSKRL, Ada, Okla. — Freon Extractibles Infrared Method: Inf.	RSKRL, Ada, Okla. — Freon Extractibles Infrared Method: Eff. (mg/l)	RSKRL, Ada, Okla. — Pet. Ether Extractibles Gravimetric Method: Inf.	RSKRL, Ada, Okla. — Pet. Ether Extractibles Gravimetric Method: Eff.	Contractor Laboratory — Pet. Ether Extractibles Gravimetric Method: Inf.	Contractor Laboratory — Pet. Ether Extractibles Gravimetric Method: Eff.
C-1	106.0	22.3	126.0	16.0	76.0	5.0	79.0	3.1
C-2	359.6	42.2	473.0	39.0	241.0	27.0	508.0	3.6
C-3	167.6	46.1	197.0	35.0	141.0	7.0	189.1	11.2

[a] Inf. = Influent
Eff. = Effluent

The preceding tables indicate that there is slight variance in analytical results when EPA uses two different methods on the same sample. There is great variance on the same sample analyzed by the same method by EPA and contract laboratories. Therefore, the low oil and grease concentrations reported by Texas and California before the field sampling and analysis verification study appear to be more a function of the analytical techniques and the laboratory rather than an indication of treatability of the waste brine water and/or treatment equipment efficiency. This conclusion was validated by a separate statistical analysis of the data, which is contained in Supplement B to the Effluent Guideline Study. 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 oil/gas 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 VII-4 indicates types of treatment units, the performance observed during the survey, and long term performance based on historical data for each facility. Tables VII-5 and VII-6 indicate the comparative oil and grease concentration data for Texas and California offshore facilities and onshore treatment of offshore brine waste water treatment units.

TABLE VII-4

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[a]
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

[a] System malfunctioning during survey.

TABLE VII-5

Verification of Oil and Grease Data,

Texas Coastal

Facility Identification	RSKRL, Ada, Oklahoma — Freon Extractibles Gravimetric Method Influent	Effluent (mg/l)	Freon Extractibles Infrared Method 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 VII-6

Verification of Oil and Grease Data,

California Coastal

Facility Identification	RSKRL, Ada, Oklahoma					
	Freon Extractibles Gravimetric Method		Freon Extractibles Infrared Method		Petroleum Ether Extractibles Gravimetric Method	
	Influent	Effluent	Influent (mg/l)	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	1214.0	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[a]	6.0[a]
		24.2		15.0	59.0[a]	
		19.9		15.0	102.0[a]	

[a] Carbon tetrachloride extractibles.

End-Of-Pipe Technology: Waste Water Treatment (with Brine Discharge to Sea or Coastal Waters)

End-of-pipe control technology for offshore treatment of brine waste from petroleum 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 only of gravity separation pits without the addition of chemicals, while more complex systems may include surge tanks, clarifiers, coalescers, flotation units, chemical treatment, or reinjection.

Dissolved Gas Flotation

In a dissolved gas flotation unit tiny gas bubbles are dispersed 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 dissolved gas flotation systems are presently used in oil production: rotor/disperser systems and diffused gas systems. Rotor/disperser units use specially shaped rotating mixers or dispersers to disperse gas, from a blanket maintained over the surface of the liquid, in the form of fine bubbles throughout a tank containing the waste water. The resulting froth can be skimmed off at the surface. These units are normally arranged in a series of cells with a separate rotor for each cell. The waste water passes through each cell in series, being regassified and skimmed as it passes through each.

In the diffused gas system, either the entire waste water stream or a stream of recycled effluent is gassified by passing it through a centrifugal pump while gas is introduced in the pump suction. The stream is then passed into a contact tank at two to four atmospheres of pressure where the bubbles of the gassified stream are collapsed and go into solution. The gassified stream remains in the contact tank for a few minutes and is then passed through a valve or orifice into the bottom of the flotation unit, which is at or near atmospheric pressure. With the drop in the pressure on passing through the valve, gas bubbles in the gassified stream reform and, in passing through the body of waste water, attach themselves to any oil droplets in their path. The droplets with attached bubbles rise to the surface where they can be skimmed off. On production facilities it is usual practice to recycle the skimmed oily froth back through the production oil-water separating units.

Of the two types of systems, the rotor/disperser systems seem to remove a higher percentage of oil. The reason is not readily apparent -- perhaps it is because the system uses a series of cells, the waste stream being treated each time it passes through a cell. A flow diagram of the two typical flotation units is shown in Figure VII-1.

The addition of chemicals can increase the effectiveness of either type of dissolved gas flotation unit. Some chemicals used in brine water

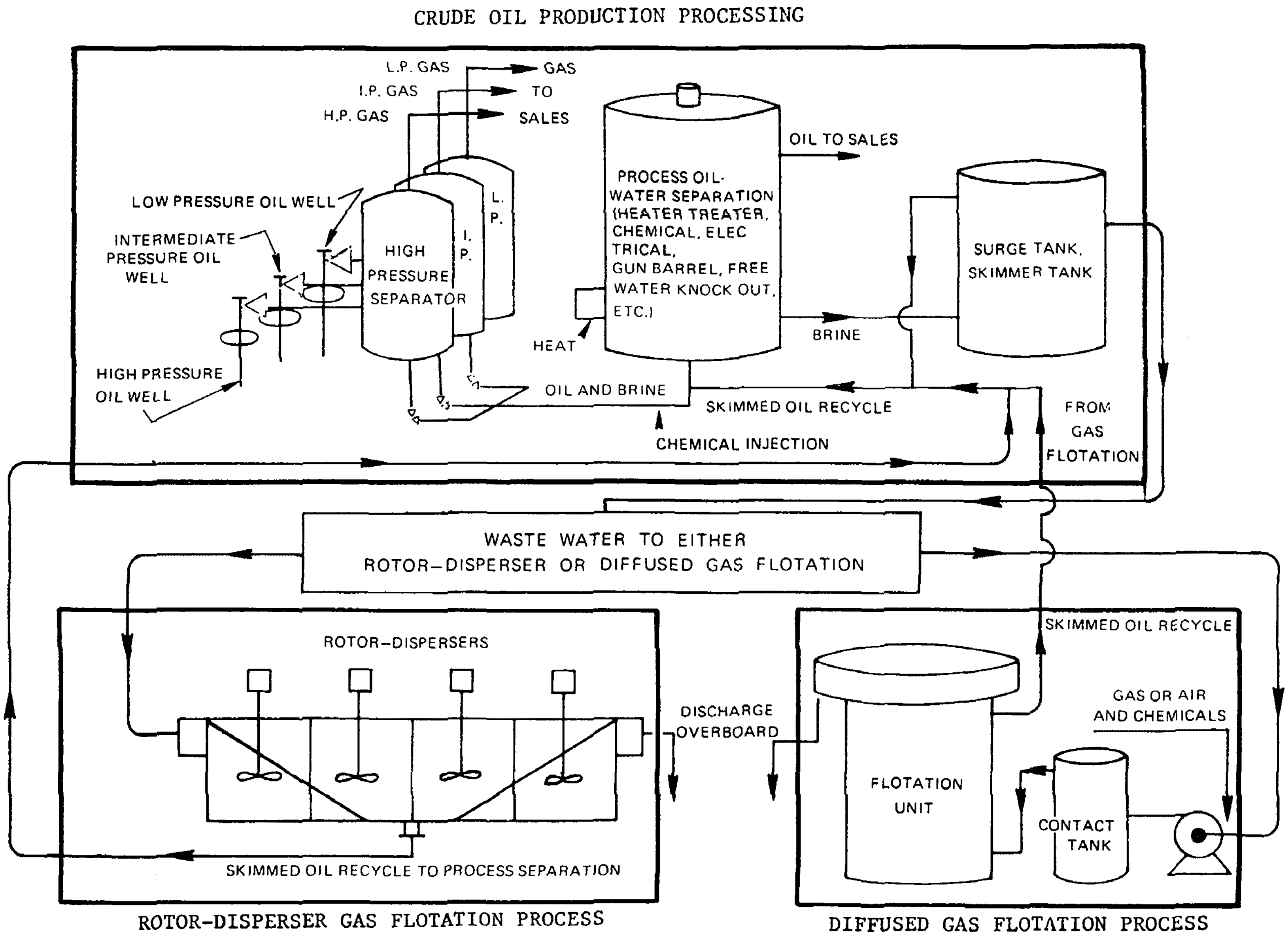


Fig. VII-1 -- **ROTOR-DISPERSER AND DIFFUSED GAS-FLOTATION PROCESSES FOR TREATMENT OF WASTE BRINE WATER** treatment increase the forces of attraction between the oil droplets and the gas bubbles. Others develop a floc which eases the capture of both oil droplets, gas bubbles, and fine suspended solids, 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 also 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 diffused 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. Four of the flotation units are preceded by surge tanks.

Information obtained during the field survey of onshore treatment systems for Cook Inlet produced brines indicated that one of the four onshore systems utilized a diffused air 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.

Field surveys on the West Coast found that physical/chemical treatment is the primary method of treating brine waste 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 injection 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.

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 top 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, but the principle of operation is the same.

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 to 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. Consequently, the oil content of effluents from these systems is generally higher than from gas flotation units or filter systems.

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 brine produced in offshore Louisiana waters. (4) Both the long-term performance data and the verification survey indicate that performance of these units was considerably lower than that of flotation units. In addition to the physical limitations of these coalescers' operation and maintenance, data indicated that the units require frequent cleaning to remove solids.

No plate coalescers are in use in Cook Inlet and none were reported to be in use on the West Coast.

Filter Systems (Loose or Fibrous Media Coalescers)

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

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

. 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 washing. Fibrous 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 gassifying and loosening the media bed.

The backwashing of filters presents several problems. Systems with automatic backwash cycles are available, but the valving and controls are complicated and need much maintenance. Disposal of dirty backwash water and contaminated filter elements present problems.

Measured by the amount of oil removed, filter performance has generally been good (provided that the units were 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.

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

On the West Coast and Cook Inlet, no filter systems are in use as the primary treatment method; however, filters are used for final treatment for brine 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 the majority of the oil and suspended particles. Backwashing is still required; however, these units, when used in series with other systems, perform well and are used extensively with reinjection systems.

Gravity Separation

The simplest form of treatment is gravity separation, where the waste brine is retained for a sufficient time for the oil and water to separate. Tanks, lagoons (often called pits), and, occasionally, barges are used as gravity separation vessels. Large volumes of storage to permit sufficient retention times are characteristic of these systems, and performance is dependent upon the characteristics of the waste water, brine volumes, and availability of space. While total gravity separation requires large containers and long retention times, any treatment system can benefit from storage, which provides the opportunity for some simple gravity separation and, more importantly, dampens out the production surges before the waste water enters the main phase of the treatment system.

About 75 percent of the systems on the Gulf Coast are simple 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 simple gravity system with the addition of chemicals produced an effluent of less than 15 mg/l during the verification survey.

Three of the onshore treatment systems in Cook Inlet use simple gravity separation, including various configurations of settling tanks, lagoons, and pits. No simple gravity systems were reported to be in use on the West Coast.

The four installations visited in the Texas verification study all use simple gravity separation tanks offshore and a combination of tanks and/or pits onshore.

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 to 20 percent with the addition of a polylectrolyte and a coagulating chemical could increase efficiencies 20 percent. (6)

Three basic types of chemicals are used for waste water treatment; however, many different formulations of these chemicals have been developed for specific application. The basic types of chemicals used to aid waste treatment offshore are as follows:

. 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.

. 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.

. 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:

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

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

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

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

A similar survey of offshore and related facilities in Cook Inlet, Alaska indicated that a facility uses coagulating agents and poly-electrolytes chemicals 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; oil and clay then 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 VII-7 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 VII-7

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

End-Of-Pipe Technology: Waste Water Treatment (with No Discharge of Brine to Sea or Coastal Waters)

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:

- Discharged to pits, ponds or reservoirs and evaporated.
- Injected into formations other than their place of origin.

In some of the Nation's arid and semiarid western and southwestern oil and gas producing areas, use of the first method is an acceptable, although limited, 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 by overland flow of water following precipitation. 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 natural 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 beneficial use by local farmers and ranchers by irrigating land and watering stock. A typical produced water system widely in use is shown in Figure VII-2. A cross section of the individual pit is shown in Figure VII-3.

A producing oil field in Nevada discharges brine 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.

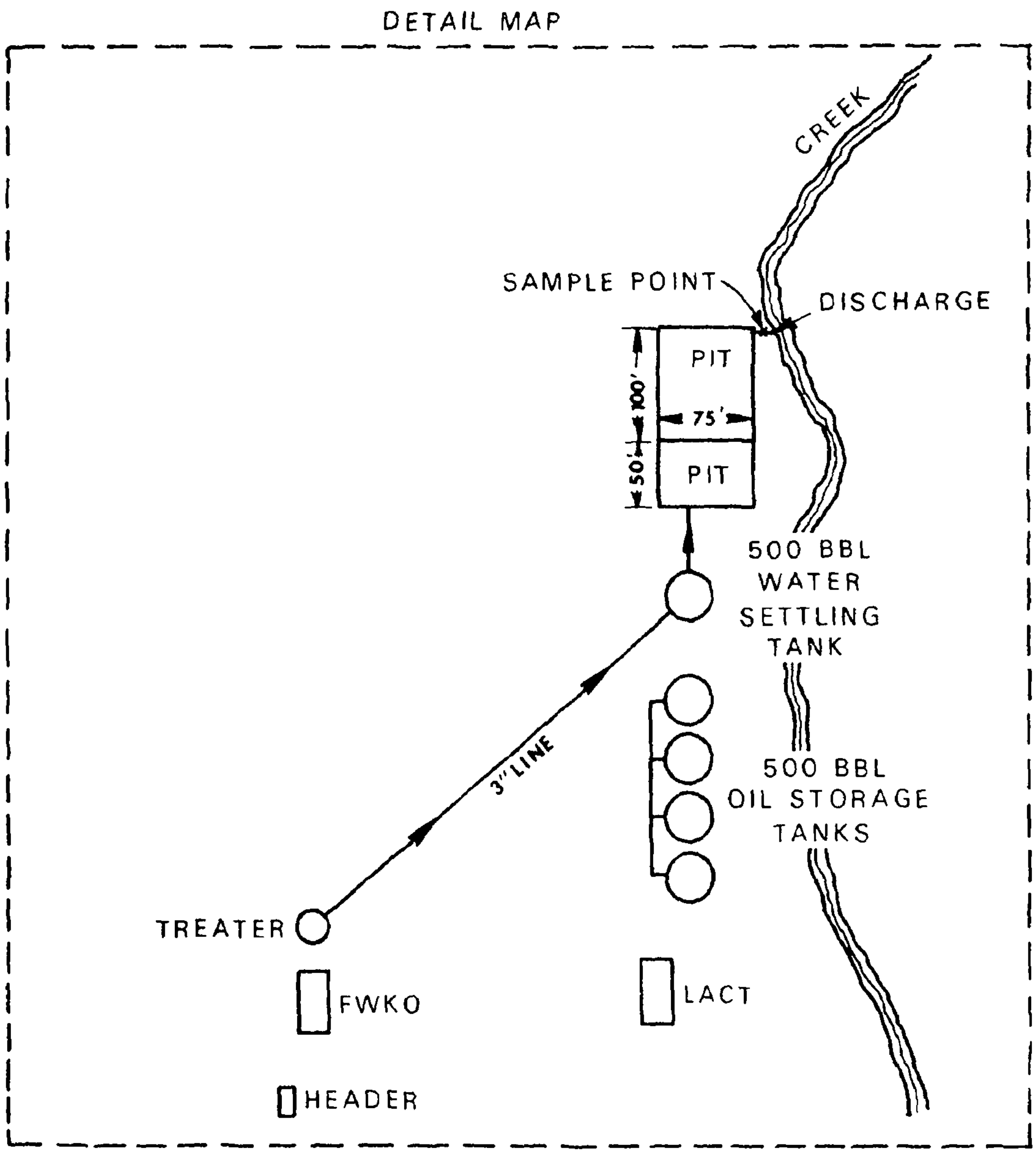
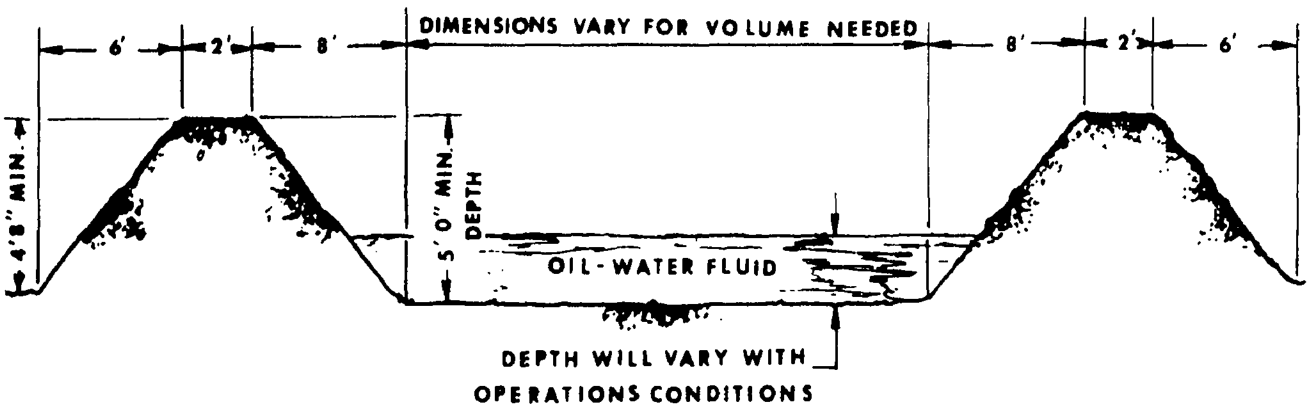


Fig. VII-31 -- ONSHORE PRODUCTION FACILITY WITH DISCHARGE TO SURFACE WATERS



NOTE

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

Fig. VII-3 -- TYPICAL CROSS SECTION UNLINED EARTHEN OIL-WATER PIT

Subsurface Disposal

Injection and disposal of oil field brines into the subsurface is practiced extensively by the petroleum industry throughout the United States. The term "disposal" as used here refers to injection of produced fluids, ordinarily into a formation foreign to their origin, for disposal only and playing no intentional part in secondary recovery systems. (Injection for pressure maintenance or secondary recovery refers to the emplacement of produced brines 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 minimal application of a corrosion inhibitor and bactericide; a sequestering agent may be added to waters having scaling tendencies. Brine composition and system characteristics determine the amount of chemical required.

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. (7)

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 corrosive dissolved gasses such as carbon dioxide, oxygen, hydrogen sulfide, organic and mineral acids, and dissolved salts. The basic action of the inhibitors is to temporarily "plate" 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 attack oil field injection and disposed systems and cause corrosion. These are:

- 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, that accelerates corrosion in the injection or disposal system.

- 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.

. 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.

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, beginning at the heater-treater or water knockout with approximately 100 ppm bactericide.

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, but they may also be developed by combining of waters containing moderately high to high concentrations of calcium, magnesium, barium, or strontium with waters containing high concentrations of biocarbonate, 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 VII-4. A typical producing well is also shown for comparison. Injection wells may be completed in a more complicated fashion with multiple strings of tubing, each injecting into a separate zone. 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 casing head, tubing head, and tubing to detect anomalies in pressure. Pressure may also be monitored by continuous clock recorders which are commonly equipped with alarms and automatic shutdown systems if a pipe ruptures. (8)

The brine injection well designed for pressure maintenance and secondary recovery purposes is completed in a manner identical to that of the disposal well. Treatment prior to injection may vary from that applied to the disposal well inasmuch as water injected into the reservoir sandface must be entirely free of suspended solids, bacterial slimes, sludges, and precipitates. (9)

Ordinarily, selection of injection wellsites poses few if any environmental problems. In many instances where injection is used for secondary recovery, the wellsite is fixed by the geometry of the waterflood configuration and cannot be altered.

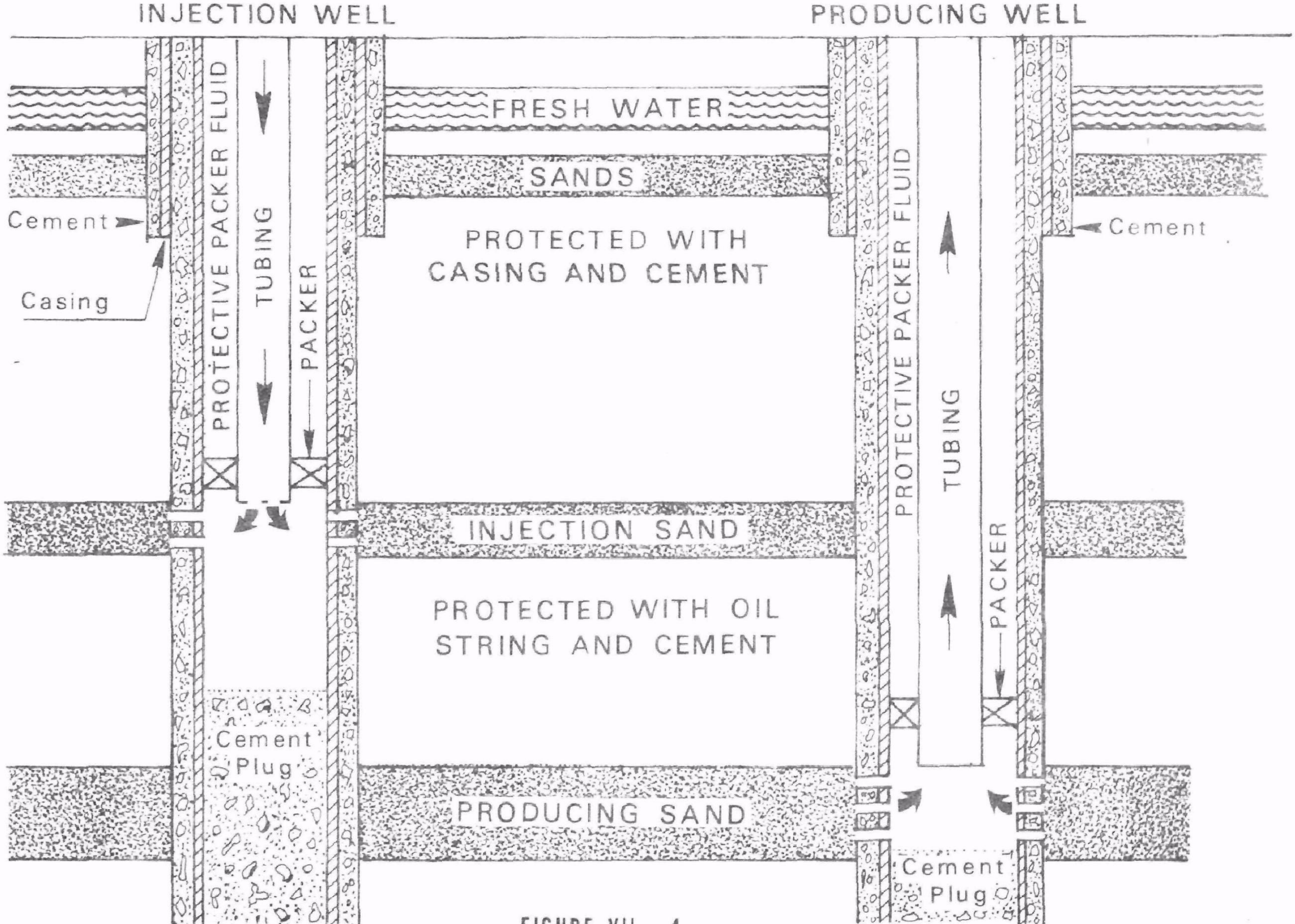


FIGURE VII - 4

TYPICAL COMPLETION OF AN INJECTION WELL AND A PRODUCING WELL

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

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 oil remaining after pretreatment); aeration facility if necessary to remove undesirable gasses such as hydrogen sulfide; 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 chemical house for storing and dispensing treatment chemicals.

In addition to the system described where no attempt is made to exclude air, there also exists a "closed" system. A closed system excludes air (and oxygen) from the water; its use is desirable because the water is less corrosive or requires less treatment to make it noncorrosive. The truly "closed" system is, for all practical purposes, 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 few instances the so-called "closed type" injection (or disposal) system is used where brines ordinarily have minimal corrosive characteristics; 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 salt 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 more desirable factors are:

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

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

. 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:

. How much reservoir volume is available?

. Is the receiving formation porous and permeable?

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

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

. What are the short-term and long-term environmental consequences of disposal? (10)

The geologic age of significant disposal and injection reservoirs throughout the nation ranges from relatively young rocks of the Cenozoic-Eocene period to older 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 at surface pressures in excess of 0.5 pounds per square inch gauge per foot of depth to the disposal zone, particularly in shallow wells, an alternate zone is usually sought.

It is necessary to be famililar 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 brine 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 germain 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 brine for disposal. Field investigations made in California were confined to OCS waters, with visits being made to five installations. All are disposal systems only -- none are used 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 brine in wells on the platform. Two were sending all fluid to shore, separating 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; however, the total fluids produced are presently greater than the capacity of the disposal system and 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.

Salt 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 or a cooperative association, or a joint interest group may operate a central treatment and 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.

End-of-Pipe Technology: Other Treatment Systems.

Treatment System By Pass

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; however, at smaller facilities and on offshore platforms only single units are usually provided. By pass practices (discharge to surface water) vary considerably from facility to facility. The following methods are currently practiced offshore:

- Discharge overboard without treatment.
- Discharge after removal of free oil in surge tank.
- Discharge to sunken pile with surface skimmer to remove free oil.

Offshore practices to avoid discharge to surface waters during upset conditions:

- Discharge of brine to oil pipeline for onshore treatment.
- Retention on the facility using available storage.
- Production shutdown.

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

Deck Drainage

Where deck drainage and deck washings are treated in the Gulf Coast, the waste water is treated by simple gravity separation, or it is transferred to the production brine treatment system and treated with the production brine. Platforms in the Cook Inlet and California offshore areas may pipe the deck drainage and deck washings along with produced fluids to shore for treatment; in Cook Inlet, these wastes may be treated on the platform.

Field investigations conducted on two platforms at Cook Inlet indicate that the most efficient system for treatment of deck drainage waste water in this area involves collecting oily deck drainage and deck wash water and feeding it to a surge tank, which provides gravity separation of oil, water, and solids. The water flows from the surge tank and is chemically treated with emulsion breaking and flocculating chemicals before the water passes through a gas flotation system. Limited data indicate an average effluent of 25 mg/l can be obtained from this system. The field investigations also found that deck drainage systems operate much better when crankcase oil is collected separately and when detergents are not used in washing the rigs. Also, the field visits noted the most difficult wastes to handle were the deck washings from drilling and workover operations using invert emulsion muds.

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 or in a water stream.

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. Excessive amounts of oil are carried overboard since oil that might cling to the sand particles has not been removed.

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.

Additional information is needed to determine the overall efficiencies of the sand-cleaning equipment, as there is limited information on the amount of oil that adheres to the sand particles. However, it has been established that 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, and 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 Operations (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.

Drilling muds perform many different functions and therefore must have differing physical and chemical properties satisfing the individual drilling requirements and well conditions. There are no differences in usage of drilling muds from one geographic area to another.

Both water based and oil muds are used. (11) 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 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 transfered to shore or contained in a closed liquid recovery system. (12)

Drilling Operations (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.

Field Services

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 produce 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 discreet waste source; however, their presence in the waste treatment system may cause upsets and 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 under "Drilling Operations (Offshore)." If water is used it will be moved through the production and treatment systems and disposed of.

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 fresh water; however, in some cases brackish water or sea 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. (5)

There are two alternatives to handling of sanitary wastes from offshore facilities. The waste can be treated at the offshore location or they may be retained and transported to shore facilities for treatment. Because of the high cost involved in retention and shore 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 compliments of men or on platforms which are intermittently manned. The incinerator 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 fuel and ignition which could result in a safety hazard at some locations. Some facilities have chemical toilets which require hauling of waste and also 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 are available for this facility; however, similar facilities located onshore obtain a mean effluent level of suspended solids of 17 mg/l.

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. (5)

The most common biological systems applied to offshore operations are aerobic digestion or extended aeration processes.

These systems usually include a comminutor which grinds the solids into fine particules, an aeration tank with air diffusers, gravity clarifier return sludge system, and disinfection 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 VII-8 have been recommended. Table VII-9 shows average effluent concentrations for various types of treatment units which are in use at offshore facilities in the coastal water of Louisiana.

TABLE VII-8

Per Capita Design Parameters

for Offshore Sanitary Wastes (13)

	Offshore Design
BOD_5	0.22 lb/day
Total Suspended Solids	0.15 lb/day
Flow	75 gal/day

TABLE VII-9

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

Table VII-10 indicates typical existing facilities, design capacity, and effluents for a particular company located in the Gulf Coast.

TABLE VII-10

Treatment Facilities for

Sanitary Wastes, Offshore Gulf Coast

No. of Men	Distance from Shore, miles	Water Depth, feet	Capacity, gallons/day	BOD_5, mg/l	Suspended Solids, mg/l
16	27	50	2,000	42	111
30	52	160	4,000	1	29
46	9	55	4,000	44	92
21	18	340	3,000	5	74
40	26	375	5,000	10	11

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 costs 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. The expected annual cost for existing plants in the oil and gas extraction industry to comply with BPCT effluent limitations by 1977 are estimated at $192,000.000. Estimated annual costs to comply with BAT effluent limitations and for new source will be published as an addendum to this report as soon as the computations are completed.

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 -- production brine with discharge, production brine reinjected, and sanitary wastes. The cost of brine treatment or disposal is significantly affected by availability of space; therefore, the cost analysis has been subdivided into two areas -- offshore brine disposal and onshore brine disposal. Of the other subcategories, deck drainage is considered to be treatable with the production brine water; water-based drilling muds are not presently treated, while oil-based muds are reused. In some instances, the production brine is transferred to shore along with the crude, while in others a variety of equipment has been installed on the platforms. Therefore, not all platforms will be required to add all of the treatment capabilities or incur all of the incremental costs indicated to bring their raw discharges into compliance with the effluent limitations. Existing brine treatment systems include a mix of sumps and sump piles, pits, tanks, plate coalescers, fibrous and loose media coalescers, flotation systems, and reinjection systems.

Offshore Brine Disposal

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

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

A_1 Gravity separation using tanks, then discharge to surface water.

A_2 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 equalization (surge tanks), desanders, and flotation, then discharge to surface water.

D Separation using filters, then discharge to surface water.

E 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 production brines based on these flow rates:

Small facility	5,000 bbls/day
Medium facility	10,000 bbls/day
Large facility	40,000 bbls/day

Where flow equalization was provided, surge tanks of these sizes were used:

Small facility	500 bbls
Medium facility	1,000 bbls
Large facility	3,000 bbls

The development of realistic cost estimates for the treatment of produced brines of necessity should be very generalized because of the nature of the problem. Costs have been developed for the systems identified based on the following assumptions:

All cost data were computed in terms of 1973 dollars corresponding to an Engineering News Record (ENR) construction cost index value of 1895 unless otherwise stated.

The annualized cost 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.

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

. 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.

. Option (b) assumes that, because of the high costs involved in building platforms, they have been built to minimum size needed for production. Therefore space is not generally available for brine 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)

. 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 on the basis of area at $350 per square foot.

In all three cases platform estimates are based on platforms being 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 five horsepower.

Operation and maintenance costs of components of the various systems are based on operating costs reported by the industry and correlated with capital costs of the equipment. (2) The resulting percentage of Investment Cost is shown in Table VII-1.

TABLE VIII-1

Operating Cost Factors

For Brine Treatment Facilities Offshore

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

[a] Excludes electrical power supply cost.

Energy and power for low demand is computed as 2 percent of the Investment Cost; on large requirements an electric power cost of 2-1/2 cents per kilowatt hour is assumed.

The annualized cost for the six alternative brine treatment methods for offshore installation of small, medium and large sizes are contained in Tables VIII-2, VIII-3, and VIII-4. Capital cost for options (a), (b), and (c) reflect equipment cost, installation and platform space costs.

Onshore Brine Disposal

The major source of waste water from onshore petroleum production is produced formation water. Produced formation water or oil field brine is sometimes used for pressure maintenance and water flooding to improve production. In areas where the water is not used for these purposes, it must be disposed of properly. Reinjection into a suitable underground formation is the generally accepted means. Treatment of the unwanted brine is generally held to the minimum that will permit the reinjection to function continuously. The typical system for reinjection 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.

When produced formation 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 reinjection equipment becomes a legitimate disposal cost.

TABLE VIII-2

Cost for Treating Brine on Offshore Installations

5,000-Barrel-Per-Day Flow Rate

(Thousands of 1973 dollars)

Treatment Technology	A_1	A_2	B	C	D	E
Capital Cost						
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 (Thousands of 1973 dollars)						
Capital & Depreciation						
Option (a)	9.4	4.2	17.6	262	14.8	902
Option (b)	290.8	11.0	54.8	84.6	31.4	1366
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	64.83	99.45	39.84	185.5
Cost of Brine Processed (1973 dollars/barrel)						
Option (a)	0.008	0.006	0.015	0.023	0.013	0.076
Option (b)	0.16	0.0098	0.036	0.054	0.022	0.102

TABLE VIII-3

Costs for Treating Brine on Offshore Installations

10,000-Barrel-Per-Day Flow Rate

(Thousands of 1973 dollars)

Treatment Technology	A_1	A_2	B	C	D	E
Capital Cost						
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 (Thousands of 1973 dollars)						
Capital & Depreciation						
Option (a)	12	6.2	29.6	41.2	21.6	112.6
Option (b)	428	13.6	97.6	325.2	51.8	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	114.5	348.7	64.1	457.8
Cost of Brine Processed (1973 dollars/barrel)						
Option (a)	0.005	0.004	0.013	0.018	0.009	0.048
Option (b)	0.117	0.006	0.031	0.096	0.018	0.125

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

TABLE VIII-4

Cost for Treating Brine on Offshore Installations
40,000-Barrel-Per-Day Flow Rate

(Thousands of 1973 dollars)

Treatment Technology	A_1[a]	A_2	B	C	D	E
Capital Cost						
Option (a)		60	355	448	170	907
Option (b)		98	1,780	1,913	230	2,354
Option (c)		102	880	1,254	369	1,585
Annualized Costs (Thousands of 1973 dollars)						
Capital & Depreciation						
Option (a)		12	71	89.6	34	181.4
Option (b)		20.4	356	382.6	73.8	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	93.1	578.5
Cost of Brine Processed (1973 dollars/barrel)						
Option (a)		0.002	0.0077	0.01	0.004	0.020
Option (b)		0.0028	0.027	0.030	0.006	0.040

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

The cost estimates for onshore disposal of produced formation water include a flow equalization tanks for 1,000, 5,000 and 10,000 barrels-per-day brine production, pumps are sized for these flow rates, 700 pounds per square inch pressure, and disposal wells for 3,000 foot depth. A maximum well capacity of 12,000 barrels-per-day was assumed. In addition, costs are determined for this system with a lined pond to provide standby capability for continuing production for seven days while pump repairs are being made or the reinjection well is being worked on (see Table VIII-5).

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).

Offshore Sanitary Wastes

Cost estimates for biological systems utilized on offshore platforms are of 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 per capita design parameters stated in Table VII-8 costs were developed for systems to serve 25 persons (2,000 gallons),

TABLE VIII-5

Estimated Costs for Onshore Disposal

of Produced Formation Water

by Shallow Well Injection With Lined Pond for Standby

(Thousands of 1973 dollars)

	Facility Size Barrels-Per-Day		
	1,000 BPD	5,000 BPD	10,000 BPD
Investment Costs:			
Equalization or Surge Tank	$ 3.5	$ 6.0	$ 8.0
High Pressure Pump	4.5	15.0	15.0
Well Completion	40.5	40.5	40.5
Pond	5.0	13.1	20.0
Total	$53.5	$74.6	$83.5
Annualized Costs:			
Capital	$ 2.5	$ 7.46	$ 8.35
Depreciation	2.5	7.46	8.35
O&M	5.0	6.71	7.52
Power	.5	3.0	6.0
Total Annual Costs	$20.5	$24.63	$30.22

TABLE VIII-6

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
Investment 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 & power	360	460	560

50 persons (4,000 gallons) and 75 persons (6,000 gallons). These costs are contained in Table VIII-6.

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.

SECTION VIII

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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>Production Brine Waste - Discharge Technology</u>

Gulf Coast and Coastal Alaska

For BPCT where discharge is permitted (in Gulf Coast and Coastal Alaska), the process control measures used include:

. Elimination of raw waste water discharged from free water knock-outs or other process equipment.

. Improved operations and maintenance on oil/water level control measures including sensors and dump valves.

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

The treatment consists of:

. Equalization (surge tanks, skimmer tanks).

. Solids removal (desanders).

. Chemical addition (feed pumps).

- Oil removal (dissolved gas flotation).

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 were determined using effluent data for oil and grease provided by the oil and gas producing industry, Department of the Interior (U.S. Geological Survey), and the States, 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 variability and data limitations for the various types of treatment which involve: flotation units, plate coalescers, and fibrous media/loose media filters.

The following additional information was obtained (this data on file in Effluent Guidelines Division): oil/gas industry reports; schematics, diagrams, and narratives of operation and maintenance for 25 selected producing facilities; Petroleum Systems Reliability Analysis Report; National Academy of Engineering's Outer Continental Shelf Technology Safety Report; reports of EPA field surveys; and literature surveys.

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 high 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 uncontrollable factors are:

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

. Suspended solids concentrations.

. Fluctuation of flow rate.

. Droplet sizes of the entrained oil.

. Degree of emulsification.

. Characteristics of the produced water.

The controllable factors are:

. Operator training.

. Sample collection and analysis methods.

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

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

. Non-compatible operations.

The major objective of the detailed data analysis was to reject inadequate treatment technology and select exemplary facilities utilizing a sound technical rationale. Initially, 138 treatment systems (94 in Coastal Louisiana, 36 in Coastal Texas, and 8 in Coastal Alaska) were evaluated. The treatment systems included gas flotation, plate coalescers, fibrous media filters, loose media filters, and simple 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. EPA could not verify effluent data provided by industry because of extreme variations in analytical procedures; therefore, all data were rejected for the 36 simple gravity systems located in Coastal Texas waters.

Ten of the 94 treatment systems in Coastal Louisiana had 10 or less data points; they were rejected. Statistical data on the oil effluent levels from the 84 remaining units were analyzed; in addition, the data collected from 25 selected facilities visited in the EPA verification study were analyzed. This analysis led to the conclusion that treatment efficiencies are significantly affected by operation and maintenance (O&M) procedures and factors associated with the producing geological formation. The variance in treatment efficiencies was reflected in the data for all types of treatment methods and within a facility treatment system. Both loose media and fibrous media filters are capable of producing low 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 ten data points were analyzed with respect to O&M reliability. A comparison analysis 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 are 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 brine constituents. When the parallel plate becomes plugged, frequent back washing, manual cleaning, or replacement of plates are required. According to the effluent data, the oil concentrations are highly variable, 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 other reports were available on nine of the units and each was evaluated to determine the acceptability of the data and the cause of significant effluent variations. A review of the design parameters for the various systems showed that the systems were designed for the maximum expected brine production. None was designed to handle overloads conditions which may occur during start-up, process malfunctions, or poor operating practices. Therefore, data were rejected when treatment units were installed (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 performed. Treatment data from some of the facilities analyzed were consistently 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. The causative factors relating to this situation are possibly 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; 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 evaluated, and 14 erratic high values were eliminated since they are a strong indication of errors in sample collection analysis.

Additional data were obtained for a number of the units from the oil companies and the Department of the Interior. Also additional data were extracted from the Brown & 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 was selected as potential exemplary 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, with one facility having 508 data points covering an 18-month period.

The EPA field survey included nine of the selected 28 gas flotation units in the Coastal Louisiana and the effluent data for seven systems fell within close proximity of the long term averages computed from the modified data. This was expected since none of the seven systems were experiencing malfunctions but were subject to formation fluctuations. Two systems were experiencing malfunctions and the effluent data fell outside the expected range for these units. The malfunctions were caused by operational and equipment problems which were correctable. 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 shape 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 were similar in the shape of their statistical 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; according to the test for distribution, the various units could be separated into three statistical groups -- five were in a high, 13 in a low, and nine in an average group. The means and 99 percent levels were calculated for the low, high, and total groups. The average group was of significance from both a technical and statistical point of view; therefore, rejecting all units except the low group was not considered to be valid. Similarly, no technical or statistical reason was found to justify rejecting or subcategorizing the high units; therefore, data from all 27 Louisiana Coastal units were included in determining the effluent limits for oil.

The data in Figure IX-1 represent a cumulative plot of the of the observed concentrations for the 27 Louisiana Coastal flotation units. The plot is essentially linear over the last 80 percent of the range, and the straight line represents a log normal distribution. Of the 2,286 samples, 99 percent have oil concentrations less than 85 mg/l.

A statistical analysis was also conducted to determine the normality, distribution, and variance for the one flotation unit in Coastal Alaska which treated produced brine waters. The average oil content in the effluent is approximately 15 mg/l. If the concentrations are assumed to be log normally distributed, it can be estimated from approximately 40 observed points that 99 percent of future samples will have oil concentrations less than about 75 mg/l. The operation of this unit appears very similar to the low group units for Coastal Louisiana. Figure IX-2 represents a plot of the Cook Inlet data and the best fit straight line (solid); this figure also shows, for comparison, the 27 Coastal Louisiana flotation units data (dot-dash line), and the plot of a flotation unit in the low group (dashed line). The first two curves converge at about the 99 percent level; however, at the 50 percent level, the Cook Inlet facility has a much better performance, with a median of 7 mg/l as compared to 23 mg/l for Coastal Louisiana facilities. The comparison of the Cook Inlet data to a Louisiana unit, in the low group, shows medians of 7 and 9 mg/l, respectively, and the Louisiana unit having a lower predicted 99 percent upper limit.

The statistical data base included data obtained from single grab samples and averaged daily samples. The majority of the data was from average daily samples; therefore, additional analysis based only on averaged data would have little effect on the long-term average but would result in a slight reduction of the daily maximum. Table IX-1 summarizes the results of the statistical analysis. The long-term average is the value that would be expected to be obtained if grab samples were collected four times each day for a period of 1-year and the analytical results averaged. The monthly maximum in the maximum value at the 99 percent level that would be expected if four grab samples were taken in a 24-hour period four times a month and the analytical results averaged. The daily value is the maximum value that would be expected at the 99 percent level if four grab samples were taken during a 24-hour period and the analytical results averaged. The monthly maximum value is dependent upon the number of averaged daily sample collected during a 1-month period.

TABLE IX-1

Statistical Results

Oil and Grease

	Long Term Average	Monthly Maximum (mg/l)	Concentration at 99% Level
Effluent Limitation	27	57	85

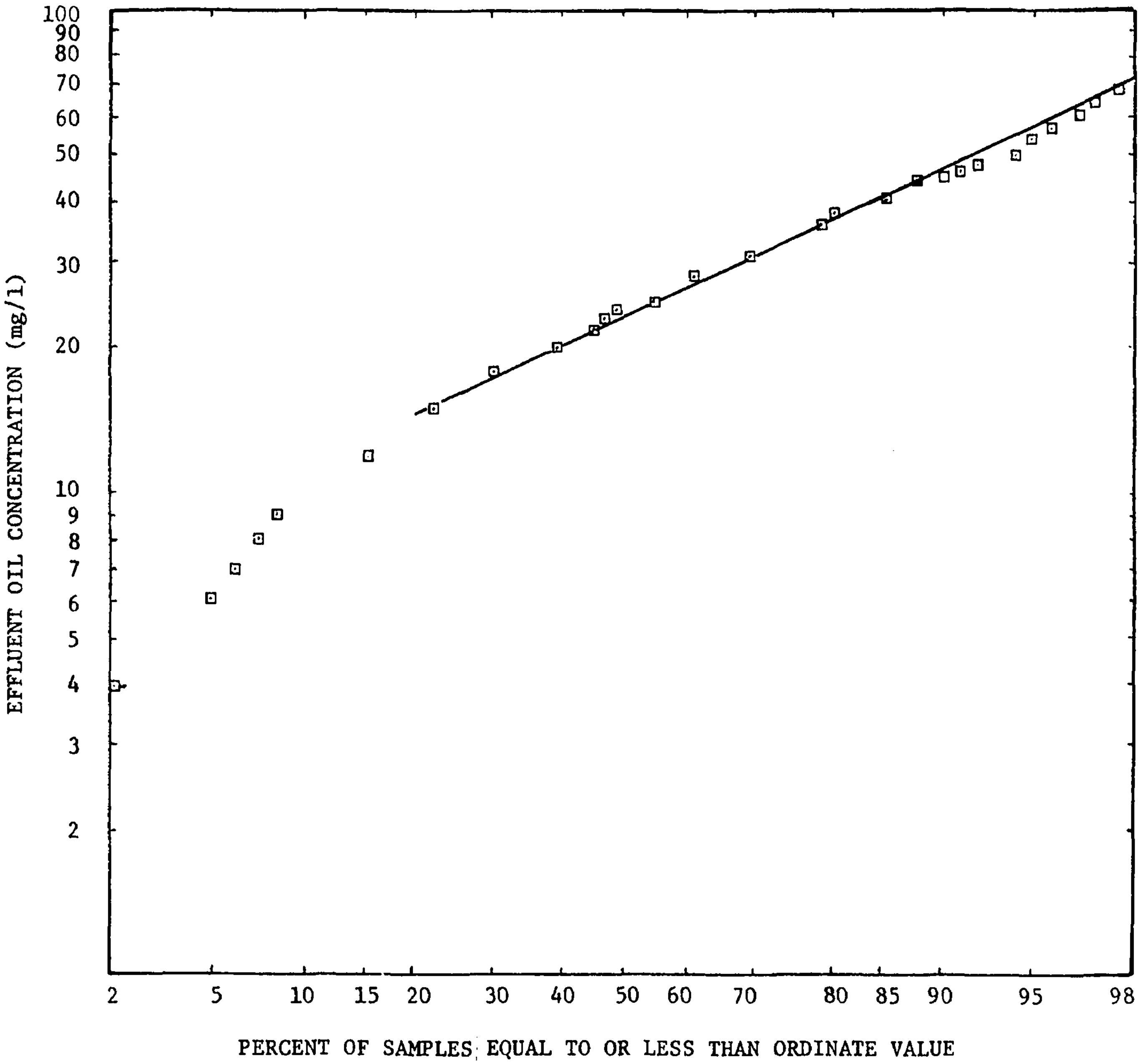

Fig. IX-1--Cumulative Plot of Effluent Concentrations of All Selected Flotation Units in the Louisiana Gulf Coast Area

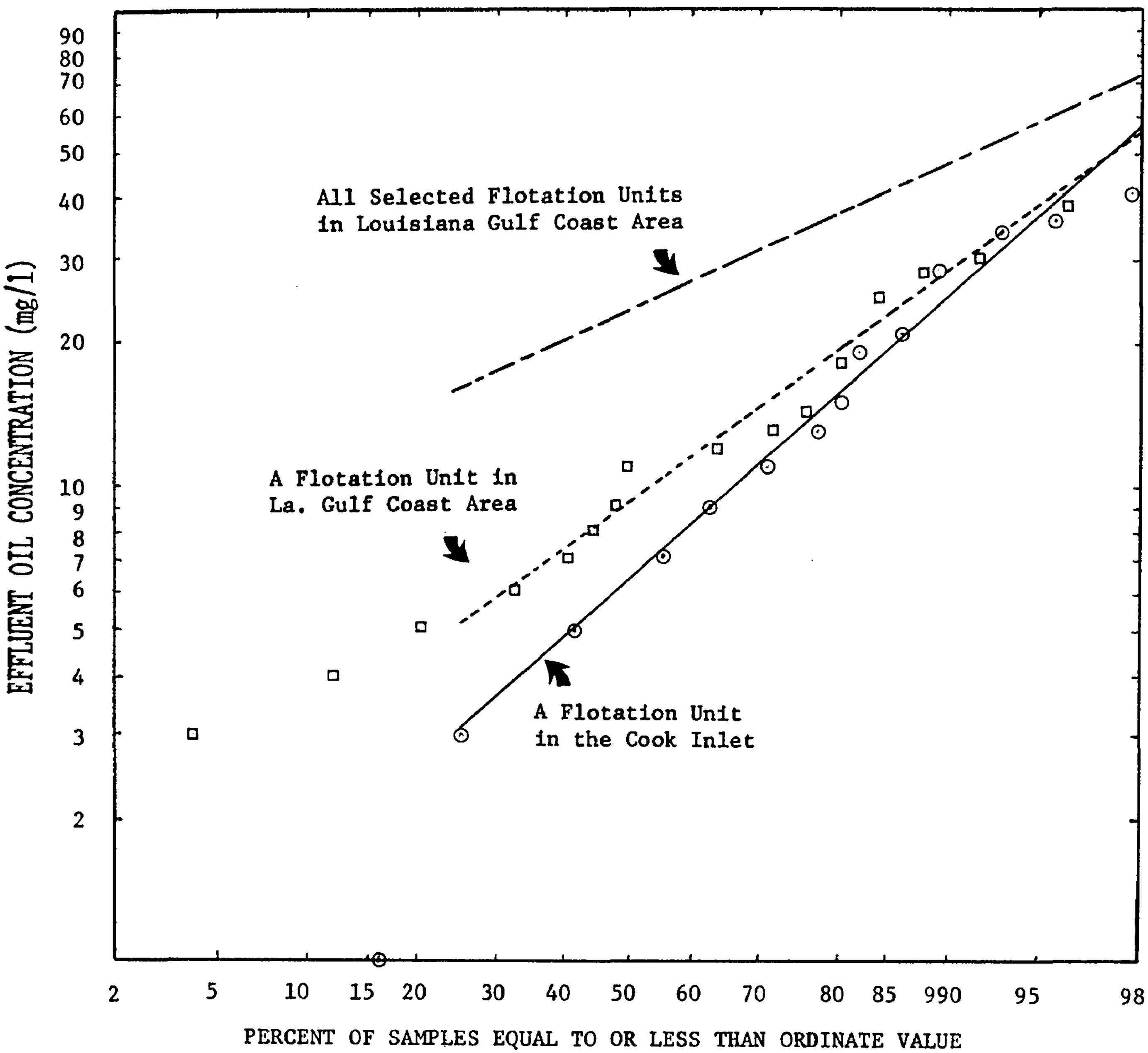

Fig. IX-2 -- All Selected Flotation Units in the Louisiana Gulf Coast Area Compared with Single Units in the Louisiana Coast Area and the Cook Inlet.

Production Brine Waste - No Discharge Technology

BPCT for production brine waste where no discharge is permitted consists of the process control measure of reinjecting produced brine water for reservoir pressure maintenance and for secondary recovery where it is compatible with reservoir characteristics.

The end-of-pipe treatment technology used consists of evaporation ponds, holding pits, and reinjection disposal wells. About 40 percent of the facilities with no discharge use end-of-pipe technology. Existing disposal systems were reviewed to select the exemplary technology for the purpose of establishing effluent limitations. Holding pits were found to be the least desirable because of frequent overflow, dike failure, infiltration of brine into fresh water aquifiers, and in proper O&M. 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 periods. Disposal well systems consisting of skim tanks, aeration facilities (if required), filtering system, backwash holding facilities, clear water accumulators, pumps, and wells provide the best method for disposal of produced brine. These systems are equally applicable to onshore and offshore operations and are the primary method used to dispose of produced brines on the California coast and in the inland areas.

BPCT end-of-pipe treatment consists of skim tanks, aeration facilities, filtering systems, backwash facilities, accumulators, pumps, and disposal well. Specific treatability and subsurface studies are required prior to application of a specific treatment and disposal system to an individual facility.

Procedure for Development of BPCT Effluent Limitations

Effluent limits for produced brine are based on the reinjection of produced brines and are applicable to all areas except for Coastal Louisiana and Coastal Alaska, where discharge technology has been permitted. In addition, there are two other exceptions where discharges are now permitted because low TDS waters are used to water livestock and because brines are discharged to a dry salt basin. BPCT and effluent limitations for these two areas are not proposed in this report because of insufficient information.

The attainable level for BPCT is <u>no discharge</u> of production water.

<u>Sanitary Wastes -- Offshore Manned Facilities With 10 or More People</u>

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 includes a comminutor, aeration tank, gravity clarifier, return sludge system, and disinfection contact chamber. Studies of specific treatability, operational performance, flow fluctuations and waste characteristics are required prior to application of a specific treatment system to an individual facility.

The effluent limitations were based on effluent data industry provides to the U.S. Geological Survey; the data were compared to the effluent levels achieved by similar systems and other units which treat domestic wastes. Chlorine residual, BOD, and suspended solids concentrations for the biological treatment systems were within the range of values which would meet fecal coliform requirement. The chlorine residuals for BPCT for offshore facilities are presented in Table IX-2. The value specified is the daily average and shall be maintained within the specified range.

TABLE IX-2

BPCT for Sanitary Wastes

Category	Chlorine Residual, mg/l
Oil and Gas Production	1.0 $\pm$ 40%
Exploration and Drilling	1.0 $\pm$ 40%

Sanitary Wastes -- Small Offshore Manned Facilities Operating Intermittently

BPCT for sanitary wastes from small offshore 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 chemical systems which may include chemical toilets, gas fired incinerators, electric incinerators or macerator-chlorinators. None of these systems has proved totally adequate to meet the requirement for this subcategory; therefore, the effluent limitations are based on the discharge technology which consist 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.

Deck Drainage

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

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

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

. Segregation of deck washings from drilling and workover operations.

. O&M practices to remove all free-oil wastes 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 involve 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.

BPCT for deck drainage is presented in Table IX-3.

TABLE IX-3

BPCT for Deck Drainage

Category	Oil and Grease Long-term Average (mg/l)	Oil and Grease Max. Daily (mg/l)
Oil and Gas Production	27	85
Exploration and Drilling	27	85

By Pass (Offshore Operations)

BPCT for by passing waste brine water treatment systems is necessary when equipment becomes inoperative or requires maintenance. Waste fluids must be controlled during by pass conditions to prevent discharges of raw wastes into surface waters. Control practices currently used in offshore operations are:

. Waste fluids are directed to onboard storage for temporary holding until the waste treatment unit returns to operation.

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

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

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

BPCT for by pass is presented in Table IX-4.

TABLE IX-4

BPCT For By Pass

Category	Oil and Grease
Offshore Oil and Gas Production	No discharge of free oil to surface waters[a]

[a] Except soluble oil components.

Drilling Muds

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

. Accessory circulating equipment such as shale shakers, agitators, desanders, desilters, mud centrifuge, degassers, and mud handling equipment.

. 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.

. 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 BPCT for offshore drilling muds is presented in Table IX-5 and BPCT for onshore is presented in Table IX-6.

TABLE IX-5

BPCT For Drilling Muds,

Offshore

Category	Oil and Grease
Natural & Water-Based Muds	None[a]
Oil-Based & Emulsion Muds	No discharge to surface water[b]

[a] Except for trace amounts of hydrocarbon-base pipe thread compound which will enter the mud system during drilling.

[b] All oil muds are to be transported to shore for reuse or disposal in an approved disposal site.

TABLE IX-6

BPCT For Drilling Muds,

Onshore

Category	Oil and Grease
Natural and Water-Based Muds	No discharge to surface waters.
Oil-Based and Emulsion Muds	No discharge to surface waters.

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 presented in Table IX-7, and for onshore drill cuttings are presented in Table IX-8.

TABLE IX-7

BPCT For Drill Cuttings,

Offshore

Category	Oil and Grease
Cuttings in Natural or Water-Based Mud	None[a]
Cuttings in Oil Muds	None[b]

[a] Except for trace amount of hydrocarbon base pipe thread compound which will enter the mud system during drilling.

[b] Cuttings may be collected and transported to shore for disposal in an approved disposal site.

TABLE IX-8

BPCT For Drill Cuttings,

Onshore

Category	Oil and Grease
Cuttings in Natural or Water-Based Mud	No discharge[a]
Cuttings in Oil Muds	No discharge[a]

[a] Cuttings may be disposed of in an approved disposal site.

Workover

Workover fluids other than Gulf waters, ocean waters, or water-based muds are recovered and reused. Materials not consumed during workovers and completions are returned to shore, if utilized offshore, or are returned to the service areas when used onshore.

The effluent limitations were determined using data supplied by industry and service companies serving the oil producing industry. The limitations are shown in Tables IX-9 and IX-10.

TABLE IX-9

BPCT For Workover and Completions, Offshore

Cateogry	Oil and Grease
Offshore Workover and Completion	None[a]

[a] Except for trace amounts of hydrocarbon base pipe thread compound which will enter the system during workover and completion operations.

TABLE IX-10

BPCT For Workover and Completions,

Onshore

Category	Oil and Grease
Onshore Workover and Completion	No discharge to surface waters.

Produced Sand

BPCT for produced sand is based on existing disposal methods used by the oil industry. The limitations for produced sand are presented in Table IX-11.

TABLE IX-11

BPCT For Produced Sand

Category	Oil and Grease
Offshore Oil/Gas Production	No discharge to surface waters.
Offshore Workover and Completion	" " " " "

SECTION X

EFFLUENT LIMITATIONS FOR BEST AVAILABLE TECHNOLOGY

Best available technology is defined as the very best control and treatment technology employed by a specific point source within the industrial category or subcategory. BAT that is readily transferable may be required of other industrial processes. These effluent limitations are to go into effect not later than July 1, 1983. BAT for all subcategories except brine production discharge technology and deck drainage is the same as BPCT. BAT for brine production wastes from the Gulf Coast and Coastal Alaska and for deck drainage is defined as no discharge technology. This may be accomplished through process or end-of-pipe treatments. This technology has been demonstrated both for inland and offshore production operations.

BAT process technology is based on control practices now practiced by some production facilities in the oil and gas production industry and consists of:

. Reinject produced brine water for reservoir pressure maintenance and secondary recovery operations where compatible with reservoir characteristics.

. Combine all deck drainage waste with production fluids and provide pretreatment in process units.

SECTION XI

NEW SOURCE PERFORMANCE STANDARDS

Recommended effluent limitations for new source performance standards are based on best available technology and effluent limitation for each of the subcategories.

SECTION XII

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Pollution Control Engineers

Rheem Superior

Shell Oil Company

Sun Oil Company

Texaco, Inc.

Tretolite Corporation

United States Filters

Union Oil Company

WEMCO

SECTION XIII

GLOSSARY AND ABBREVIATIONS

Acidize - To put acid in a well to dissolve limestone in a producing zone so that passages are formed 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 degree 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 at 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 (see Formation Pressure).

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 - Basic sediment and water measured with oil. Generally pipeline regulation limits the contents of 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 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 high specific gravity solids from a drilling fluid. Usually used on weighted muds to recover weight material 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. See "Desander - Cyclone."

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

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.

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.

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 tentions.

Coagulation - The combination or aggregation of semi-solid particles such as fats or protems 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 change from a liquid to a thickened curd-like state by chemical reaction. Also the combination of globules in an emulsion caused by molecular attraction of the surfaces.

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 separator, treaters, and other vessels for the purpose of draining, or "dumping" a batch of oil or water.

Emulsion - A substantially permanent heterogeneous 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 well bore.

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

Formation Pressure - See "Pore Pressure."

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 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.

Hydrocarbon - A compound consisting only of atoms of hydrogen and carbon.

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, when present in a petroleum product, prevents or retards undesirable changes taking place 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 - Normal permeability is 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 and the oil and gas production are controlled in such a manner 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 slate-like cleavage, sometimes containing (an oil-yielding substance).

Shale Shaker - Mechanical vibrating screen to separate drilled formation cuttings carried to 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.

Stock Tank - See "Flow Tank."

Stripper Well (Marginal Well) - A well which produces such 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 well is pressured without allowing vertical flow at top of 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.

TOC - Total Organic Carbon.

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

TDS - Total Dissolved Solids.

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 nearly producing wells.

Well Completion - In a potentially productive formation, the well must be completed 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 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.