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ASSESSMENT OF OIL PRODUCTION VOLATILE ORGANIC COMPOUND SOURCES

by

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FOREWORD

The U.S. Environmental Protection Agency was created because of increasing public and government concern about the dangers of pollution to the health and welfare of the American people. Noxious air, foul water, and spoiled land are tragic testimonies to the deterioration of our natural environment. The complexity of that environment and the interplay of its components require a concentrated and integrated attack on the problem.

Research and development is that necessary first step in problem solution; it involves defining the problem, measuring its impact, and searching for solutions. The Municipal Environmental Research Laboratory develops new and improved technology and systems to prevent, treat, and manage wastewater and solid and hazardous waste pollutant discharges from municipal and community sources, to preserve and treat public drinking water supplies, and to minimize the adverse economic, social, health, and aesthetic effects of pollution. This publication is one of the products of that research and provides a most vital communications link between the researcher and the user community.

This report provides a description of oil and gas exploration drilling technology and drilling muds, and a rough estimate of volatile organic carbon emissions associated with drilling activities in the 48 contiguous states.

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ABSTRACT

Emissions of volatile organic compounds (VOC) from oil production in new fields were estimated, based on three types of information: (1) extent of new oil and gas fields (those that started production after 1974) in the contiguous 48 states, (2) drilling techniques used for oil and gas exploration and production wells (and their VOC potential), with specific emphasis on the drilling fluids, and (3) equipment and techniques for oil and gas production in new fields and their potential VOC sources.

The complete record obtained from Petroleum Data Systems (PDS) has been provided for post-1974 oil and gas production within the 48 contiguous states. Verification and updating of PDS has been accomplished for all but nine states. These data have been summarized with respect to the states and EPA Regions, whereas detailed information organized by state, county, field, etc. has been provided in Appendix A, bound under separate cover, which is on file with the U.S. EPA Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina.

An extensive description of oil and gas exploration and production drilling technology is presented. Emphasis has been placed on the makeup, use, and disposal of drilling fluids. A simple model for assessment of VOC emissions accompanying drilling is presented, along with an estimation of the potential VOC emissions associated with drilling activities.

As part of this effort, documentation in the form of 35-mm color slides with a sound tape containing a narrative description of each slide and a written transcript is presented (under separate cover) for current oil and gas production and drilling technology. This documentation was obtained from five oil- and gas-producing fields located in Texas, Oklahoma, Wyoming, Montana, and New Mexico. The slides, together with the narration and the transcript, which provide a brief description of the major process subsystems shown in each slide, are on file at the U.S. EPA Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina.

Quantification of the VOC emissions associated with oil and gas drilling and production technology was hampered by lack of data in several areas. Recommendations for further effort are presented so that the assessment of VOC potential emissions can be made by state, county, or field.

This report was submitted in fulfillment of Contract No. 68-03-2648 by the Environmental Monitoring & Services Center of Rockwell International under the sponsorship of the U.S. Environmental Protection Agency. This report covers the period from January 1980 to September 1980, and work was completed as of September 1980.

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ACKNOWLEDGMENT

The support and guidance provided by Leo McCarthy, serving as Project Officer for the U.S. Environmental Protection Agency, Oil & Hazardous Materials Spills Branch, Edison, New Jersey, and Dave Markwordt of the U.S. Environmental Protection Agency, Office of Air Quality Planning & Standards, Research Triangle Park, North Carolina, is greatly appreciated. The cooperation in this effort of Chevron USA, Shell Oil, Phillips Petroleum, and Exxon by allowing visits and photographic documentation of typical oil and gas fields discovered after December 1974 and of drilling rigs, is gratefully acknowledged. The contribution of consultants D.G. Wedding with regard to drilling technology and of Jay Simpson of O'Brien and Goin's Engineering, Inc. with regard to the drilling muds and completion and workover fluids section of this report is also gratefully acknowledged.

SECTION 1

INTRODUCTION

Rockwell International, through its Energy & Environmental Systems Division, Environmental Monitoring & Services Center (EMSC), has undertaken a study for the assessment of oil production volatile organic compounds (VOC) sources.

The program consists of a survey with the following tasks:

1. Determination of the new oil and gas fields in the 48 states that have started primary production after December 1974.

2. Determination of the VOC emission potential and techniques for drilling and gas exploration and production wells and the handling of drilling muds.

3. Documentation of equipment and techniques in use for the assessment and quantification (to the extent possible) of the potential VOC sources, including mud operations, waste oils, and fugitive emissions from operating equipment. Five areas defined by (1) above were visited.

This report addresses the objectives stated above. Current practices in well-drilling techniques, drilling and workover fluids, and well servicing and workover are discussed, and a survey of new fields is described. The survey data are used in conjunction with drilling information to define prospective VOC sources, and the VOC forecast is made. Appendices A and B are available under separate cover. Appendix A provides detailed data organized by state and county, and Appendix B is an annotated compilation of more than 300 color slides taken during this program of new field production and drilling sites in five states. Appendices A and B are on file at the U.S. EPA Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina.

SECTION 2

CONCLUSIONS

1. Drilling activity in 1980 will surpass the activity of the last several years, with an estimated 13,607 exploratory wells to be drilled.

2. Drilling has made many technological improvements in the past several decades, but the basic rotary method remains the one most often used.

3. VOC emissions from oil and gas exploration and production drilling are small, although several potential sources of VOC emissions (namely, entrained gas and oil in drilling fluids, emissions from oil-based muds, and the number of valves, flanges, etc. associated with fuel systems) are not well defined. The VOC emissions calculated using simple assumptions give less than 10 kg per well per day.

4. Reporting of state oil and gas production information is not uniform from state to state and not up to date.

5. The number of new fields reported give an order of magnitude estimate that can be useful, but the different definitions used by the individual states makes a direct comparison difficult. The collected information is adequate for use as a parameter and estimate of the VOC potential if a satisfactory model is developed for the VOC emission associated with an oil and gas well or field.

6. Additional data in several key areas are required to make an estimate of the VOC emissions associated with oil and gas well drilling and production. These areas are:

a. Drilling

- Emissions associated with mud degassing
- Emissions from oil-based muds
- The number of components within the fuel gas system for estimation of fugitive emissions

b. Oil and Gas Production

- A model of major subsystems (i.e., compressor) that will allow estimation of components to which emission factors currently developed can be applied.

SECTION 3

RECOMMENDATIONS

1. Measurements should be made to verify the magnitude of the estimated VOC emission values presented in this study.

2. Further effort should be devoted to defining more accurately a representative new oil and gas facility or site in terms of VOC emissions. This should include a survey of additional sites to establish one or more models for assessment of potential VOC emissions.

3. Component population estimates obtainable from photographic documentation provided in Appendix B of this report should be supplemented with stream composition data so that existing emission factors can be applied.

4. Oil and gas production data from new fields should be verified beyond the information presented in this report.

SECTION 4

CURRENT OIL/GAS WELL DRILLING TECHNIQUES

The well-drilling techniques and procedures now in use have evolved over a period of many decades. From the early oil wells drilled with cable tool drilling methods used in the drilling of water wells, the drilling technology has advanced to include complex modern rotary drilling equipment, blowout preventers, recirculating drilling fluids especially tailored with various additives, and well completion procedures. This section presents a brief review of the well-drilling techniques and equipment now in general use.

BASIC DRILLING PROCESSES

Rotary Drilling

The vast majority of oil and gas well drilling is done by the rotary method. In rotary drilling, a hole is gouged and cut through the various geological formations by specially designed bits attached to the bottom of a long string of steel pipe and rotated by means of a rotary table that turns the top pipe (the kelly) in the drill stem. The top pipe, or "kelly," has a square or hexagonal cross-section and fits into a four- or six-sided kelly bushing located in the rotary table. Drilling fluid, or drilling mud, is continually circulated down the drill pipe, or drilling string, through the bit and up and out of the hole through the annular space between the pipe and the borehole wall. The drilling mud serves to cool the bit, flush pieces of rock, or cuttings, away from the bit and out of the hole, provides hydrostatic pressure to prevent formation fluids or gases from migrating into the well bore and potentially blowing out, seals porous formations, and provides lubrication for the drill string and protection against corrosion.

Cable Tool Drilling

In cable tool drilling, the bit is attached to a cable and is repeatedly picked up and dropped to punch through the rock formations. At intervals the cable and bit are hauled out of the hole and a "bailer" or "sand pump" is run in and out of the hole to remove the cuttings. When the hole is cleaned out, the bit is again placed in the hole and the cycle is repeated until the desired depth or the prospective zone is encountered.

Cable tool drilling is cheap and simple, but the absence of drilling mud to provide a hydrostatic head in the hole can lead to uncontrolled release of formation gases and fluids where encountered under pressure. There are still areas of the U.S. where cable tool drilling is utilized.

Experimental Processes for Hole Forming

The increased cost of drilling has led the industry to invest large amounts of money in primary research facilities and expand their in-house research efforts to improve and speed up the drilling process and investigate innovative approaches to "making hole." For the next 5 years, however, it appears that no radical developments will occur in drilling technology. The changes will be evolutionary rather than revolutionary.

BASIC DRILLING EQUIPMENT - RIG COMPONENTS

A modern drilling rig accomplishes essentially four basic tasks: (1) producing and transmitting power, (2) hoisting equipment for the drilling string, casing and tubing, (3) rotating the drill string and bit, and (4) circulating drilling mud to remove cuttings and maintain a safe hydrostatic pressure in the well bore. The components included in a basic drilling rig will be discussed in terms of these four tasks.

Power System

Prime power sources for drilling rigs are almost always diesels, although some natural gas or liquefied gas engines are still used.

Power requirements for different drilling jobs may vary considerably, but most rigs require from 0.75 to 2.2 MW (1000 to 3000 HP), which is provided by two or more engines, depending on well depth and rig design. Shallow or moderate-depth drilling rigs will be provided with 0.37 to 0.75 MW (500 to 1000 HP) for hoisting the drill and for circulating the mud. Heavy-duty rigs for drilling 6100-m (20,000-ft) holes are usually in the 2.2-MW (3000-HP) class. Auxiliary power for lighting, etc., may require 0.075 to 0.37 MW (100 to 500 HP). A typical multi-engine setup with a mechanical rig is shown in Figure 1.

Until recently, the transmission of engine power to various tasks on a rig was invariably found to be performed mechanically via belts, pulleys, and chain drives. On modern rigs, however, diesel-electric units are installed. On mechanical rigs, diesel engines will be equipped with hydraulic couplings or torque converters to smooth out the power developed by the engine and mechanically linked by chains and pulleys (the compound, Figure 1). The compound delivers engine power to the rotary table, draw-works, and mud pumps.

Diesel-electric power, the method used to drive most operating rigs, eliminates the complicated, cumbersome mechanical drives. Diesel engines, located at convenient distances away from the rig (to reduce the noise level at the rig), drive electric generators which, in turn, produce electricity that is sent to electric switch and control gear (Figure 2). The electricity produced is used to power electric motors for the draw-works, rotary table, and mud pumps. Because of the improvements in electrical switch-gear, i.e., integrated circuits and chip circuitry, silicon-controlled rectifiers (SCR) are rapidly replacing the standard diesel-electric rig design. Improved power and torque curves are developed by the SCR conversion system.

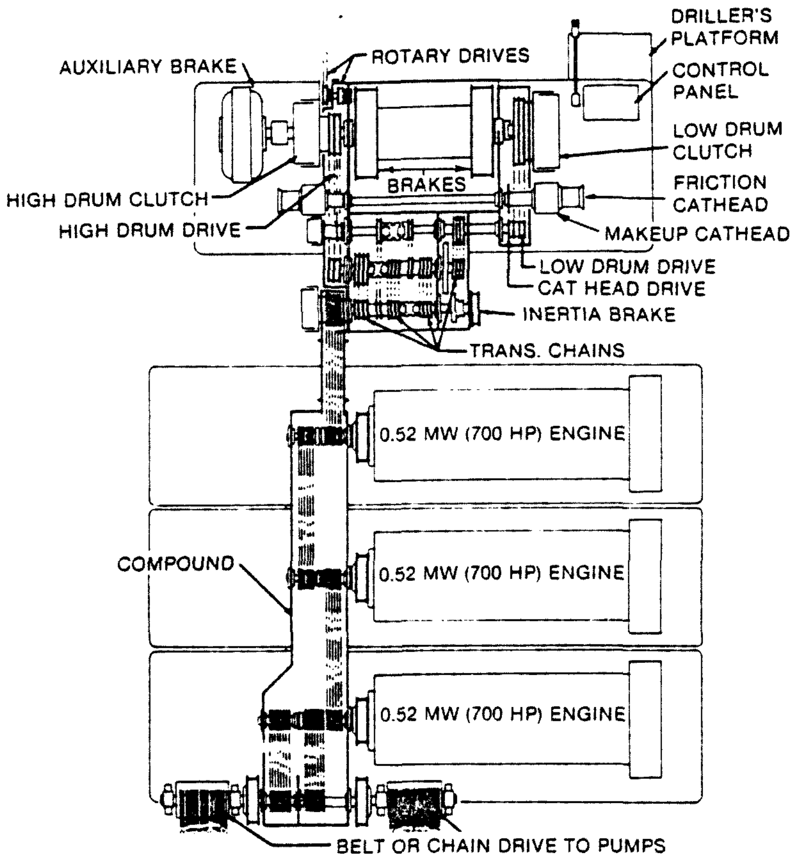


Figure 1. Multi-engine and chain drive transmission arrangement for a mechanical drilling rig.
(Courtesy Petroleum Extension Service (U. of T. at Austin))

Hoisting Equipment - The Draw-Works

An oil or gas well is drilled with a bit at the bottom of a long string of pipe, and drill collars. The total weight of this drill string is sometimes as much as 230,000 kg (about 500,000 lbs) for a deep well. During the drilling process the drill string must be hoisted out of the hole, disassembled and stacked in racks at the side of the derrick, then reassembled and replaced in the hole. This cycle is repeated many times to replace worn drill bits, run strings of casing into the well, test formations, take core samples, etc. This hoisting is done by the draw-works (Figure 3). Derricks and masts used to support the block and tackle system utilized for hoisting (the crown block and traveling block) are rated in various ways in terms of vertical load they can carry and the wind loading they can stand from the side. Derrick capacity may vary from 144,000 to 680,000 kg (250,000 to 1,500,000 lbs). Most derricks and masts can withstand a wind load of 160 to 210 km/hr (100 to 130 mph) with the racks full of pipe.

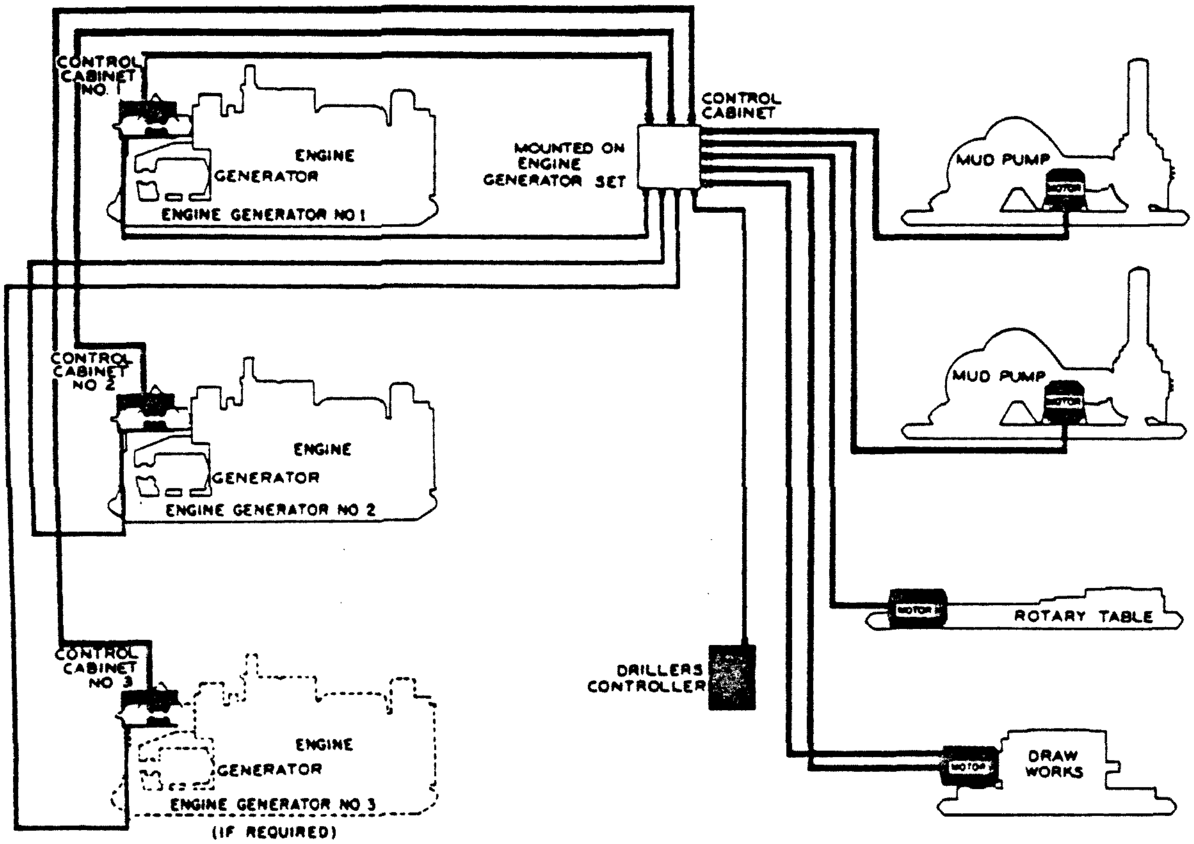


Figure 2. Diesel-electric system for power and transmission.
(Courtesy Petroleum Extension Service (U. of T. at Austin)

The draw-works shown in Figure 3 consists of a revolving drum (around which is wound the tough, flexible wire rope that is reeved over the sheaves of the crown and traveling blocks), a system of shafts, clutches, and chain and gear drives for speed and direction changes. The other end of the steel rope from the revolving drum is called the dead line and is fastened to a deadline anchor and an apparatus that measures the tension in the line. The draw-works also houses the main brake, which has the capacity to stop drum rotation, and an auxiliary hydraulic or electric brake to absorb the momentum created by a heavy load. The so-called catheads and catshafts that are part of the draw-works serve for smaller hoisting and pulling jobs on the rig and for operating pipe-handling tools.

Rotating Equipment

The rotary system (Figure 4) is comprised of the swivel assembly, the kelly, the rotary table, the drill string, and the bit. The swivel assembly sustains the weight of the kelly and drill string, permits its rotation, and affords a rotating pressure seal and passageway for drilling mud to be pumped down through the drill string.

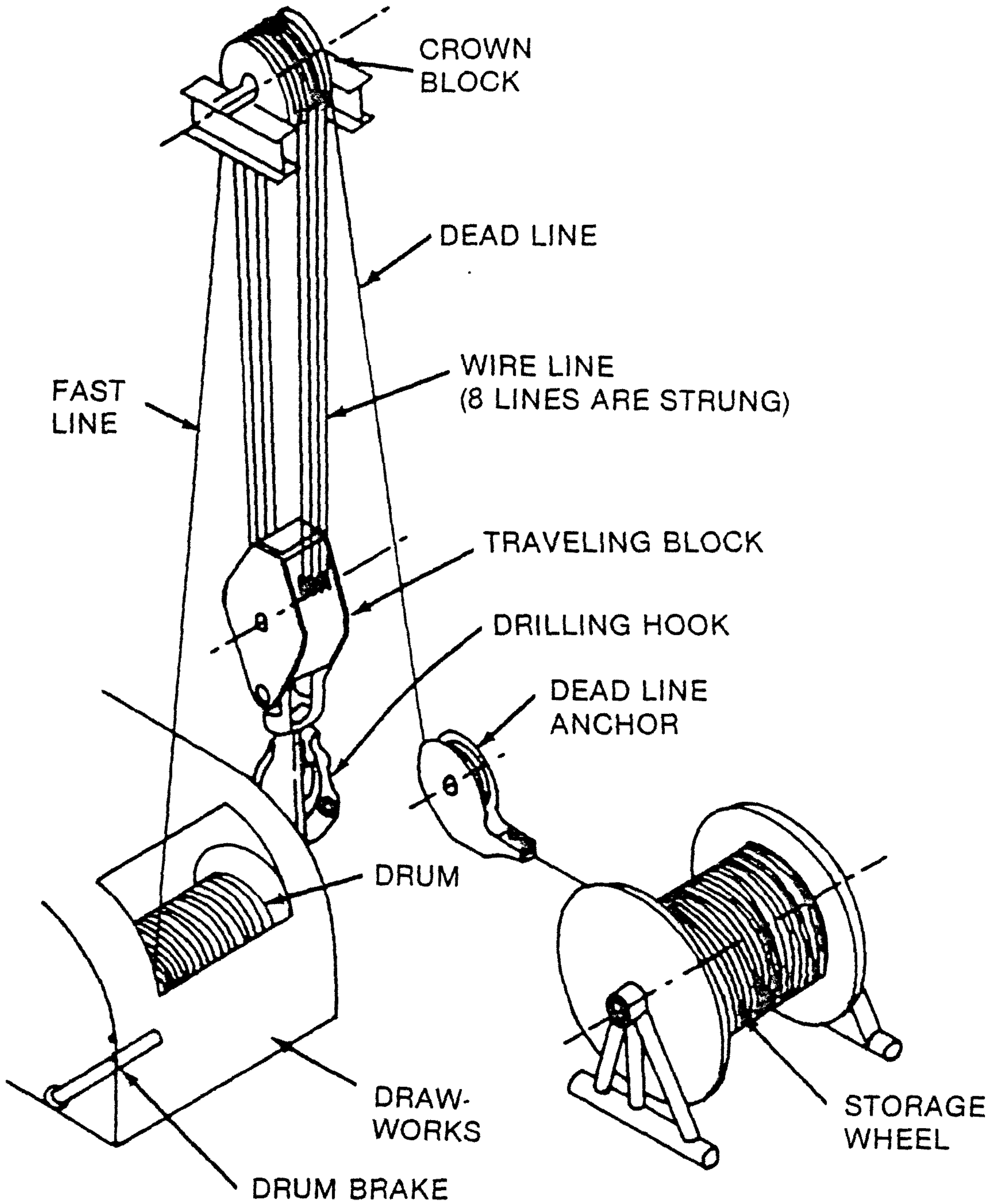


Figure 3. Rotary rig hoisting system.

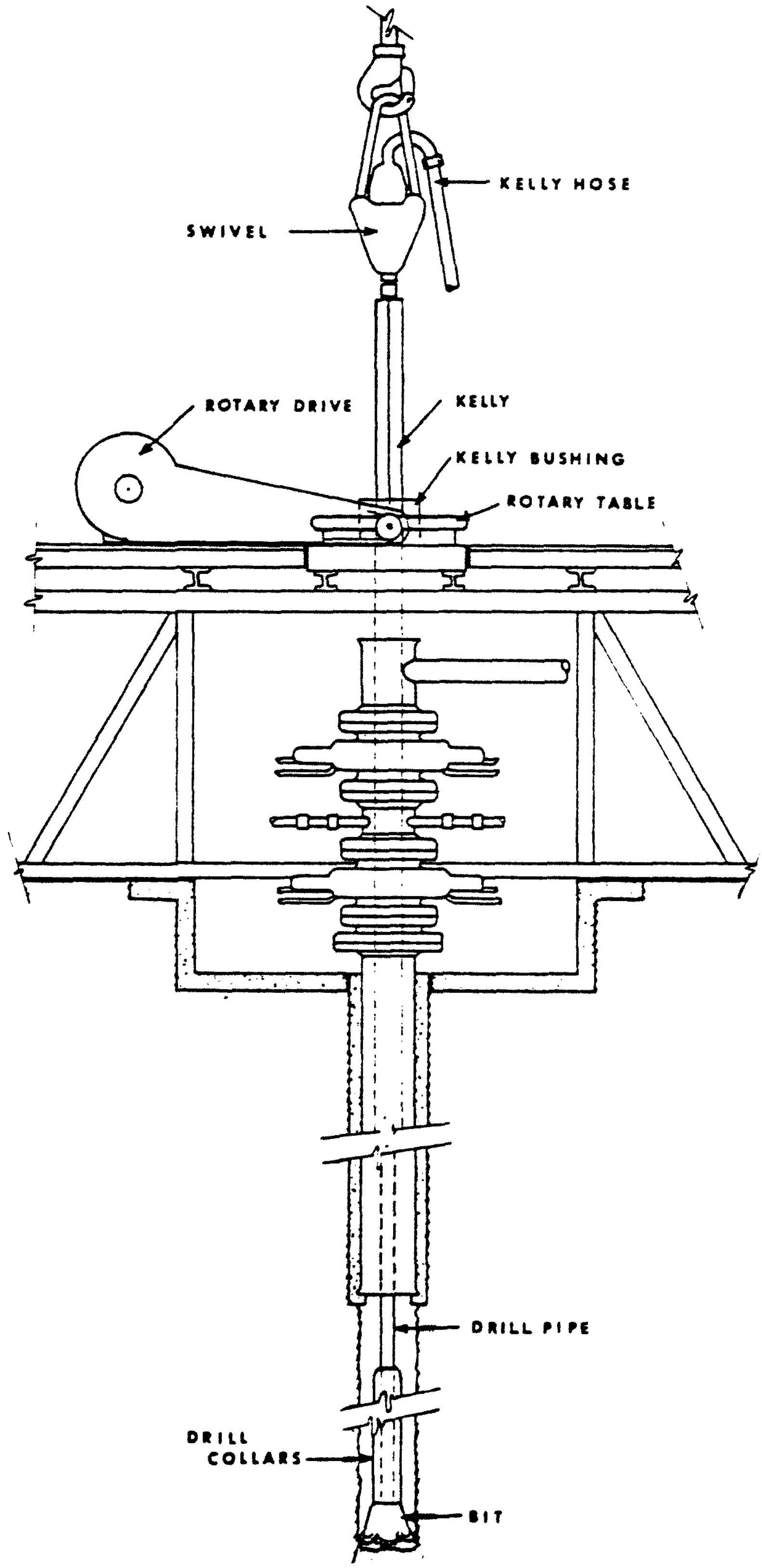


Figure 4. Rotary system.

The kelly transmits torque from the rotary table, via the kelly bushing, to the drill string and is free to move vertically throughout most of its length as the drilling deepens the hole. It is also the unit through which drilling mud is pumped down the string. Most kellys are about 12.2 m (40 ft) long. Above the kelly is the kelly cock, which can be used to shut off back flow in case of a blowout.

The rotary table is powered through a reduction gear driven by an electric motor or by chain drive through the draw-works from the diesel engines or other prime movers. A lock on the rotary table prevents it from turning when desired; the table can be locked when breaking out pipe without the use of backup tongs.

The drill string is composed of drill pipe and, near the base of the string, heavy thick-walled tubes called drill collars. A length of drill pipe is about 9.1 m (30 ft).

The drill string to be furnished by a contractor is often carefully specified in the drilling contract for a well. The operating company specifies size and strength of drill pipe to be used. Hole conditions will govern drill collar selection and number employed. Directional drilling or hole straightening will require additional modifications of the drill string to be made. Protectors for drill pipe and casing are made of rubber. Locked firmly around the pipe, they prevent metal-to-metal contact between the pipe and casing, thereby reducing wear.

The bits used for rotary drilling are primarily of the roller-cone type with three cones normally being used. Fewer and longer teeth are used on the cones of bits intended for softer formations, while harder formations may require shorter and harder teeth. For very hard formations, a bit will have cones fitted with tungsten carbide inserts. All bits have hardened steel nozzles through which drilling mud can be ejected downward at high velocity to flush away rock cuttings from the bit. Bits are designed to break, dislodge, or fragment formation material in such a way that the circulation of drilling mud will remove the cuttings. The several functions of a bit are accomplished simultaneously. Formations have many different characteristics and different bit types are available for drilling them at maximum rates and energy efficiency. Often, compromises are made when variable formations are drilled because of the time and expense involved in making a trip to change a bit.

Normally, the drilling string will be rotated at between 75 and 250 rpm under very high loads. After as few as 10 to 12 hours or as many as 150 hours of use, the bits must be pulled out of the hole and replaced because of either bearing or tooth wear.

Circulation System

The drilling mud circulation and treating system is depicted in Figure 5. Bulk storage of drilling fluid materials, pumps, and mud mixing equipment are placed at the start of the circulation system; working mud pits and reserve storage are at the other end. Between these two is the circulating system with

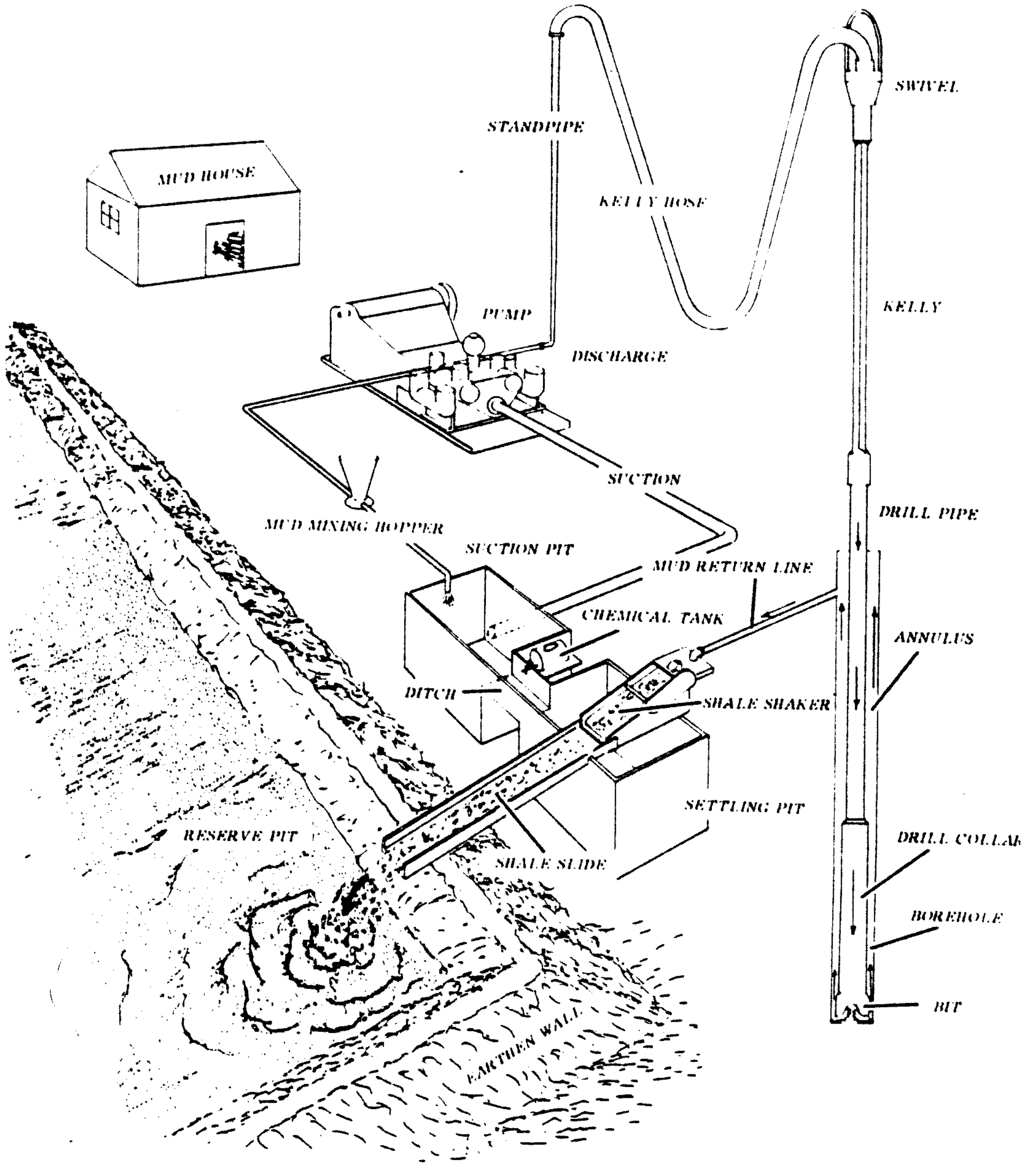


Figure 5. Rotary rig fluid circulation and mud treating system.

(1) auxiliary equipment for drilling fluid maintenance, and (2) equipment for well pressure control. Drilling mud is pumped under high pressure from a suction tank or a mud pit outside the derrick, up a standpipe, through the kelly hose and swivel to the drill string. After jetting from the bit and sweeping away the rock cuttings, the mud runs through the annulus formed by the drill string and the wall of the hole, through the blowout preventer stack (Figure 4) to the mud return line, then to a shale shaker for cuttings removal, and finally to a settling pit and temporary storage in a sump pit. Settling and sump pits are usually steel tanks. The so-called reserve pit is actually for waste material and excess water around the location.

The mud pump is a reciprocating, gear-driven, dual-piston type of very sturdy construction, capable of continuous service under heavy loads and capable of handling abrasive, sand-laden muds. Pumps rated at 0.75 MW (1000 HP) or more with working pressures of 17.2 to 20.7 MPa (2500 to 3000 lbs/in^2) are commonly used on deeper wells.

Exacting requirements related to maintenance of drilling mud necessitate some important auxiliaries. Mud pit agitators help maintain a uniform fluid mixture of mud materials. Other auxiliaries include (1) the cone-type desander and desilter for removing fine drilled solids that would otherwise not settle out, and (2) a vacuum degasser for quick release of entrained gas.

The basic equipment for well pressure control is located on the well casing beneath the rig floor in an assembly called blowout preventers (shown in Figure 4). The uppermost preventer is typically an annular type that can seal around the drill pipe or kelly. Two or three ram-type preventers may be provided in conjunction with the annular preventer. Other equipment in the blowout preventer "stack" permits connection of a line for mud return to the shale shaker, a line to fill up the hole when making a trip, a kill line to pump mud into the hole when needed to restore pressure balance, and lines to the choke fittings for relieving pressures in the well bore when a potential blowout situation exists.

A choke is a device to control pressure in the well bore through a control of flow from the well. It may be fixed, adjustable, or automatic. Drilling fluid and gas will be passed through a choke to a mud-gas separator that saves usable mud and pipes the gas to a safe distance from the rig.

FUELS FOR PRIME MOVERS

Over 90% of all rigs and support equipment are powered by internal combustion diesel engines. About 9% of the remaining drilling rigs are powered by natural gas or liquid petroleum gas (LPG). The remaining 1% of all rigs are totally electrically powered with an internal combustion engine system used as a standby in case of power failure. These rigs are equipped with their own substation transformer system so that they can tie into a high-voltage electrical system.

Diesel fuel for powering drilling rigs is stored in 18.9 to 37.8 m^3 (5,000 to 10,000 gallon) storage tanks located at a safe distance from the rig. Tank storage is in an approved tank equipped with a pressure containment filler and usually with a 1720-Pa (4-oz) pressure relief disk. The fuel is transferred to what is commonly called a "day tank" by periodically using a transfer pump located on the major fuel tank. A day tank is sized to furnish approximately 12 hours of fuel for each engine.

Natural gas is furnished from a field or from nearby gas transmission lines. A regulator system is installed for low-pressure distribution. Each engine will have a small-volume tank for starting and dehydration of the fuel prior to its use.

Butane and/or propane (LPG) is stored in large-volume pressure storage tanks and piped for usage throughout the power area with a low-pressure system for continuous feed.

DRILLING OPERATIONS

The basic operations involved in drilling a hole include: (1) keeping a sharp bit at the bottom of the hole, (2) adding new drill pipe as the hole deepens, (3) removing the drill string from the hole, replacing a worn bit, and running the string back down the hole, and (4) running and cementing casing.

Early in the drilling operation, a large-diameter pipe called conductor pipe is cemented into a hole bored by the rig or by a truck-mounted light-duty rig or, if the ground is soft, the conductor pipe is simply driven into place by a pile driver. Generally, a conductor pipe will extend 6.1 m (20 ft) into the ground, but for very soft ground it may be set at 30.5 m (100 ft) or deeper. The purpose of the conductor pipe is to prevent soft soil near the surface from caving in and endangering the rig foundation. After the conductor pipe is set in place and blowout preventers are installed, a large-diameter bit will be set on the drill string, lowered into the conductor pipe hole, and well drilling will begin on this "surface hole." After drilling has proceeded through the soft, sticky formations, sand and gravel beds and fresh water bearing formations (perhaps 152 to 1520 m [500 to 5000 ft]), the surface casing (steel pipe) is lowered into the hole and cemented to the bore hole wall. The surface casing seals off fresh water bearing formations (hence protecting them from contamination), and prevents loose shale, soft formations, sand or gravel from falling into the hole.

Following the installation of the surface casing, a smaller bit is installed and drilling will proceed to greater depths. Often during this intermediate stage of the drilling process, troublesome formations are encountered. These troublesome formations are those that contain high-pressure gas or liquid that could blow out unless handled very carefully with the recirculating drilling mud system, or that may cave into the hole. At some point, a smaller diameter casing string, the intermediate string, will be run into the hole and cemented. This intermediate string extends from the surface down through the surface casing string and to the bottom of the intermediate hole.

The final portion of the hole is drilled to the promising formation with a still smaller bit. The final casing is the oil or production string. An oil string is not run into the hole until the cuttings, an electric log survey, and other evidence from tests indicate that the well should produce oil or gas at an economical rate and in commercial quantities. Figure 6 depicts a cross-section of a well bore with the casings set in place.

WELL COMPLETION

If a decision is made to complete the well, production casing is set and cemented in the wall through the oil or gas bearing zone. The section of casing covering the producing zone is then perforated to permit the oil or gas to flow into the well (Figure 7). The perforations are usually made by igniting shaped charges set in a special device lowered into the well to the depth of the producing zone.

The oil or gas is not usually removed from the well through the production casing. Small-diameter tubing, which permits more efficient production than casing, is safer and can be removed if it becomes plugged or damaged. Tubing is run into the well with a packer that seals the annular space between the production casing and the tubing, normally when the well is capable of flowing naturally. The packer is located somewhat above the perforated casing and the producing zone, as shown in Figure 7. The packer serves to protect the upper portion of the casing from corrosion or pressure.

When the tubing string and the packer is set in place, a number of valves, a Christmas tree, will be installed at the top of the casing to control and direct the hydrocarbon flow. In Figure 7 this is labeled the "well head."

There are occasional problems with the oil/gas flowrate out of a formation because of low formation permeability. When this occurs, various procedures are initiated to open up the structure. If the formation can be easily attacked by acid, an acid mixture will be pumped into the formation to etch channels to increase the permeability and enhance oil/gas flowrates. Permeability can also be increased by pumping fluids into the formation under high pressure and fracturing it. Fracturing fluids will often contain small particulates that prop open the fractures after the pressure has been released.

AUXILIARY RIG EQUIPMENT

Drilling Mud Maintenance

The importance of drilling mud to the hole-making process has resulted in the development of equipment for mud maintenance. In addition to shale shakers which are intended to remove larger size cuttings before the mud enters the mud pits or storage tanks, desilters and desanders (hydrocyclones) can be mounted on the mud pits for the removal of fines as small as 25 microns. Decanting centrifuges are also being used more often to remove solids from the mud. These items are depicted in Figure 8 as part of a mud treatment system.

Drilling mud can at times pick up moderate amounts of formation gas during passage through an uncased portion of the hole. Since this entrained gas lowers the mud density anywhere from a few hundredths to several tenths kg per liter (a few tenths to several pounds per gallon), it must be removed before the mud is recirculated. Reportedly, many wells completed as oil wells will

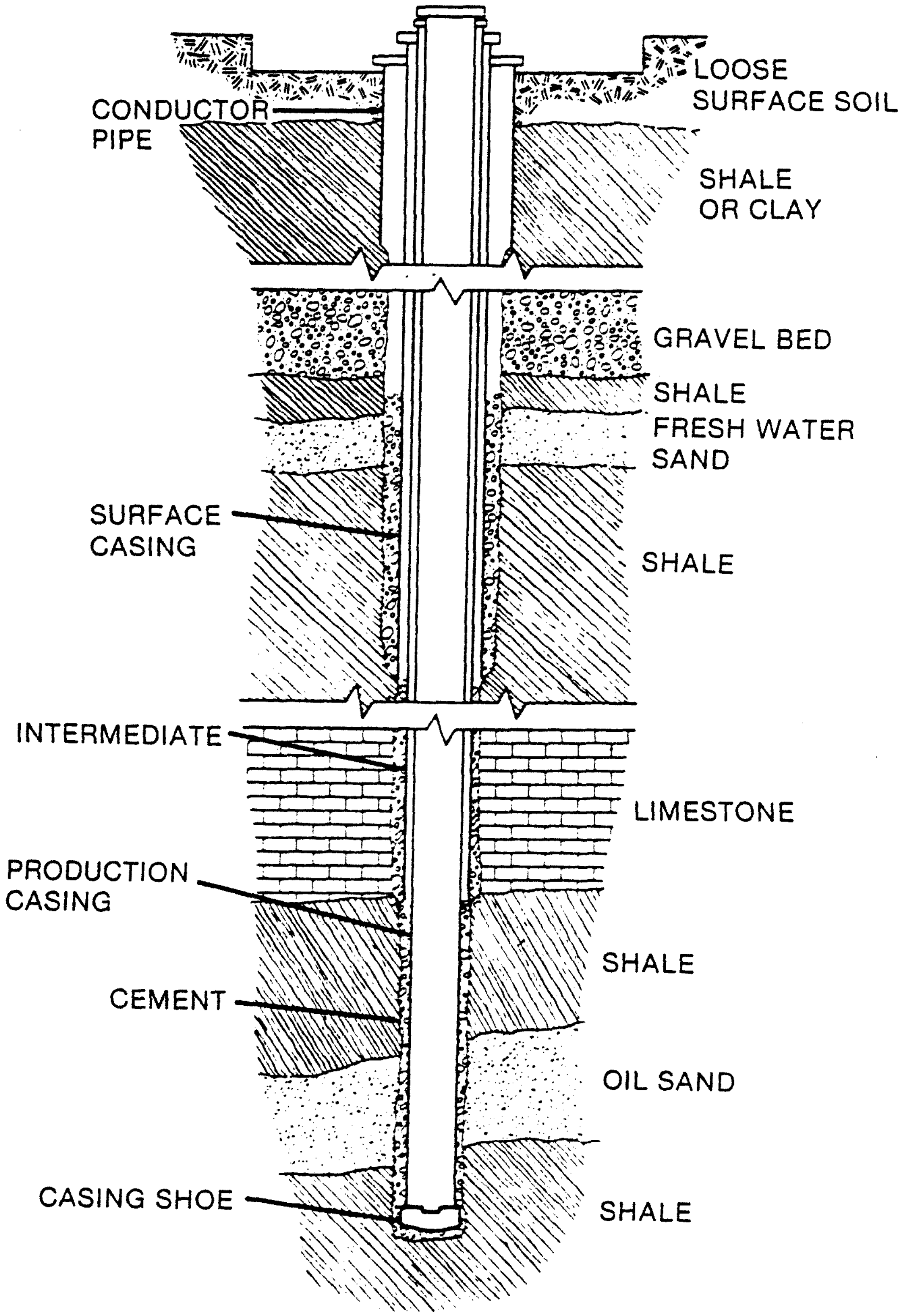


Figure 6. Casing strings and pipe used in an oil well.
(Courtesy Petroleum Extension Service (U. of T. at Austin))

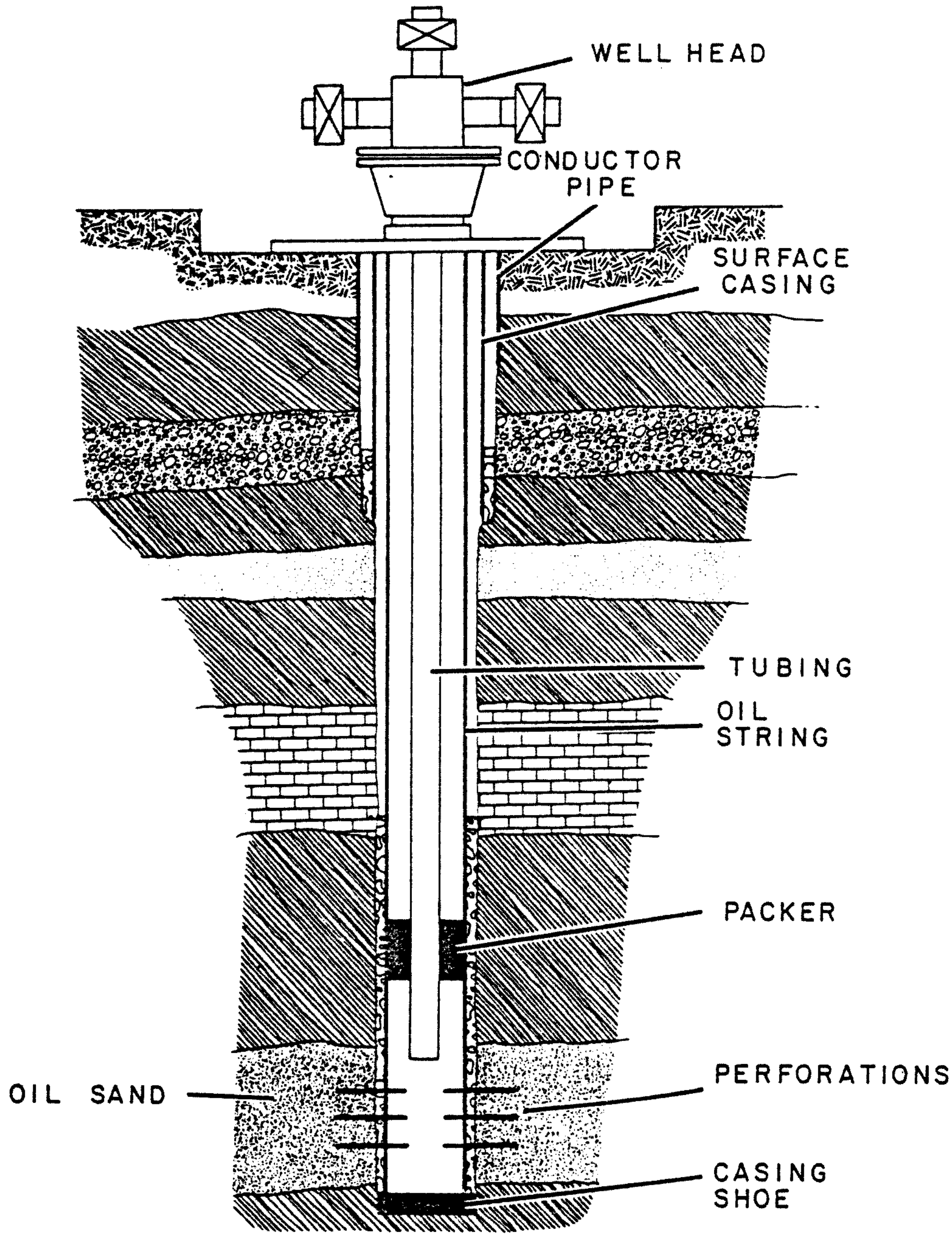
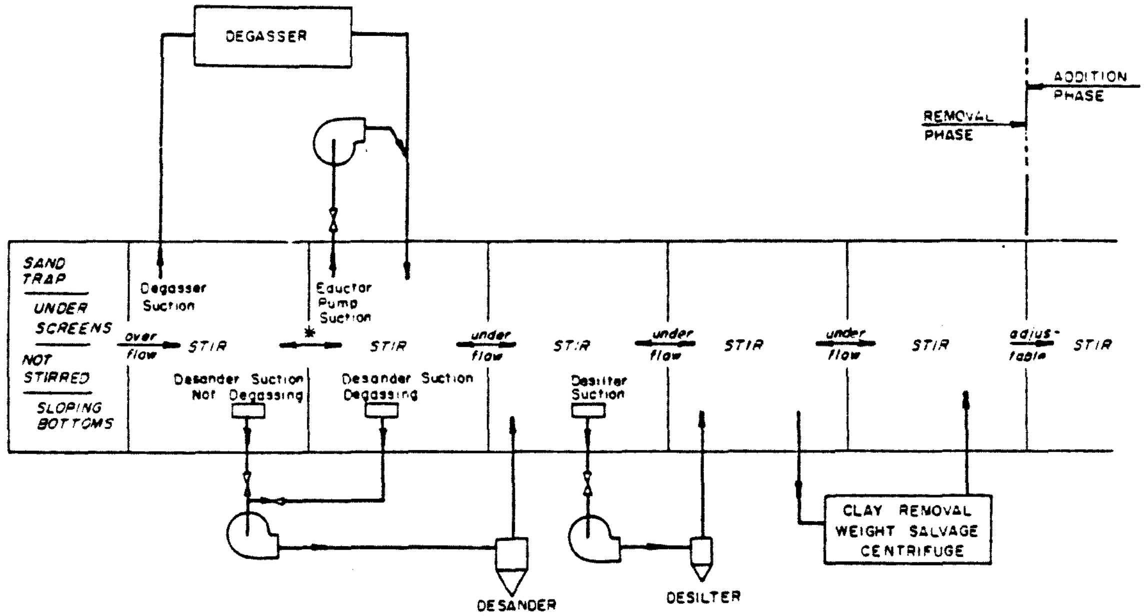


Figure 7. Typical well completion.
(Courtesy Petroleum Extension Service (U. of T. at Austin)



CONDITIONS:

<u>Drilling</u>: Single pump (under 3 m^3/min [800 gpm]) to holes. Medium-fast penetration rate.
<u>Centrifugal Pumps</u>: Single-purpose; feeding to single unit.
<u>Removal Equipment</u>: Screens, sand trap, degasser, desilter, centrifuge.

NOTE: *OVERFLOW when degassing; UNDERFLOW when not degassing.

Figure 8. Drilling mud maintenance system.

yield gas in the mud. Mud with gas bubbles must be watched carefully to avoid any possibility of blowout. Removal of gas from the mud is done with degassers, since normally the mud is too viscous to permit a large fraction of the bubbles to float to the surface in the mud tanks. The degassing method can consist of flowing the mud in thin layers where most gas bubbles will be moved close enough to the surface to emerge and break, or by spraying a thin sheet of the mud against a wall. Vacuum degassers will also flow the mud in thin sheets; the vacuum increases the bubble size and hence its buoyancy, which somewhat improves the possibility of the bubble surfacing and breaking. The vacuum pump serves to remove the natural gas-air mixture from the degasser to a remote location where the gas can be flared.

Another component of the mud recirculating system includes the mud hopper which is used to add solid materials to the mud stream to alter the mud properties in some desired manner. A mud house is used for storage of materials that might be required for mud treatment or maintenance.

Well Control

A bore hole filled with drilling mud provides a hydrostatic head to guard against the blowout of high-pressure formation fluids. Occasionally, formation fluids can enter the mud in sufficient quantities to cause a "kick." During a kick the level of mud in the pits or mud tanks may rise or mud may flow out of the well even with the pump off. When this occurs, the blowout preventers can be activated to close off the annular space between the drill pipe or kelly and the surface casing used for mud flow, and fluid control adjustments can then be made to eliminate the kick.

SECTION 5

DRILLING MUDS

The solid and liquid wastes generated in the process of drilling oil and gas wells depend to a large extent upon the type of drilling fluid used. There are, of course, other factors. Some of the more important other factors are:

- Types of formations drilled
- Types of bits used
- Drilling practices -- such as weight on bit and rotary speed
- Total drilling time
- Utilization of solids removal equipment

Consideration of such factors as these are part of the complex technology of drilling engineering. This discussion will be directed primarily toward the use of liquid drilling fluids, with reference to the other factors when they are of particular significance.

Gaseous wastes result from drilling with air or gas. When compared with use of liquid drilling fluids, however, drilling with air or gas is relatively insignificant and will not be included in this discussion.

The primary functions of the drilling mud are to:

- Control formation fluid pressures
- Transport drill cuttings to the surface
- Provide borehole stability
- Protect productive formations
- Protect against corrosion
- Cool and lubricate the bit and drill string

Drilling conditions vary so drastically that the industry utilizes dozens of different additives to allow the drilling mud to accomplish these purposes. Hundreds of products are listed in World Oil's fluids guide, but many of these are different trade names for the same material. Only a few of the materials would be present in a particular mud system at any given time.

DRILLING MUD COMPOSITION

The materials used in a drilling mud vary depending upon the mud type, with the weighting material as a major exception. At this time the weighting material used in all types of drilling muds (water-based, brine-based, or oil-based) is almost exclusively barite (mined $BaSO_4$). The characteristics that make barite desirable as a weighting material are:

- High specific gravity (API specification of 4.20 minimum)
- Moderate hardness (2.5 to 3.5 MOH)
- Low water solubility and chemical inertness
- Relatively low cost

There has been some small usage of certain iron oxide materials, either separately or as a blend with barite. Recently, ilmenite (iron titanate) has been introduced, but quantities used are still insignificant. Barite usage in drilling muds in the United States has been estimated at about 2.3 million tons* for 1978, including both land and marine operations. The concentration of barite in a drilling mud may vary from about 143 kg/m^3 (50 lb/bbl) for normal pressure formations to perhaps 1430 kg/m^3 (500 lb/bbl) for abnormally high pressure formations. In a weighted mud, therefore, the majority of the solid material will be the essentially inert barite.

Water-Based Muds

Most muds used for drilling on land have fresh water as the continuous liquid phase. The mud may consist simply of water and formation solids, but ordinarily commercial additives are utilized. Some of the commonly used classes of materials are described in the following paragraphs.

Clays--

Formation clays become incorporated in a fresh-water mud from shale formations drilled. Usually the quality of formation clays is such that mud viscosity increases excessively before providing the desired cuttings-carrying capacity, suspension of barite or filtration control. Commercial clays, therefore, are added to most fresh-water muds. Bentonite (montmorillonite mined in the Wyoming area) is used at concentrations of 14 to 86 kg/m^3 (5 to 30 lb/bbl). Commercial bentonite often contains 0.25 to 1 kg/ton (0.5 to 2.0 lb/ton) of a sodium polyacrylate polymer and 0.5 to 5 kg/ton (1 to 10 lb/ton) of soda ash to increase the efficiency. Bentonite is second to barite as to quantity used in drilling muds, with 885,000 tons reported for 1975 for the United States.

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* All ton designations not in parentheses are metric tons.

Dispersants--

Dispersants are added to water-based muds to lower viscosity, gel strength, and filtration rates. Chromelignosulfonates are the most widely used and rank third as to quantity of mud additives. U.S. consumption is about 68,000 tons/year. The chromelignosulfonates are manufactured from the lignin liquor obtained in the processing of paper pulp from wood. Hexavalent chromate in the form of sodium dichromate is reacted with the lignin, reduced to one trivalent state, and complexed with the lignin as cross-linking occurs. The final product is a weak organic acid. Typical concentrations of chromelignosulfonate in mud would be from 1.4 to 43 kg/m^3 (0.5 to 1.5 lb/bbl). Caustic soda is customarily added to the mud, along with the chromelignosulfonate to maintain an alkaline environment.

Lignite is widely used in fresh-water muds as a mild dispersant and to reduce filtration rates. U.S. drilling fluids consumption for 1979 is estimated as 54,000 tons. Drilling-mud-grade lignite is the mineral leonardite, a naturally occurring humic acid from the North Dakota area. Caustic soda is added with the lignite for treating mud. Typical concentrations of lignite in mud would be 2.9 to 29 kg/m^3 (1 to 10 lb/bbl). Chemically modified lignite products are also used, including causticized, oxidized, sulfonated, and sulfomethylated materials.

There is some usage of modified tannins as dispersants. Polyphosphates (used both as dispersants and in treating for calcium) are listed under inorganic chemicals.

Organic Polymers--

Various types of organic polymers are used to aid in hole-cleaning, barite suspension, and filtration control. Some of the products are made from natural polymers such as corn starch, potato starch, or guar gum. The more widely used products are synthetic polymers such as carboxymethyl cellulose, hydroxyethyl cellulose, xanthum gum, and polyacrylamides. These nontoxic products are added to muds at low concentrations (0.14 to 5.7 kg/m^3 [0.05 to 2 lb/bbl] being typical). An exception would be the starch materials used at concentrations of 5.7 to 29 kg/m^3 (2 to 10 lb/bbl). Starch consumption for 1977 is estimated at 13,600 tons, cellulosic derivatives at 11,300 tons, and other polymers at about 3,200 tons total.

Inorganic Chemicals--

Inorganic chemicals are added to muds for purposes such as controlling alkalinity, adjusting calcium ion concentration, scavenging oxygen and sulfide, and corrosion protection. For the most part, these chemicals react with other components of the mud and are neutralized, precipitated, or complexed. An example of neutralization would be caustic soda reacting with lignite to form sodium humate and water. Typical of precipitation would be soda ash reacting with calcium sulfate (incorporated while drilling gypsum) to form insoluble calcium carbonate. Sodium chromate added to a lignosulfonate mud being used at high temperature would be an example of complexing, with the chromate being reduced while cross-linking the thermally degraded chromelignosulfonate. Generally, chemicals of this type are not maintained in the mud at a selected concentration. Rather, they are added as needed for reaction, based on chemical analysis of the mud and filtrate. Some of the widely used chemicals, with approximate quantities used in 1977, are:

Sodium Hydroxide (caustic soda)	45,000 tons
Sodium Carbonate (soda ash)	18,000 tons
Calcium Hydroxide (lime)	9,000 tons
Sodium Chromate and Bichromate	3,600 tons
Phosphates	1,400 tons
Sodium Bicarbonate (bicarb)	450 tons
Calcium Sulfate (gyp)	450 tons
Sodium and Ammonium Bisulfite	140 tons
Basic Zinc Carbonate	90 tons

Surfactants--

Surfactants are used in water-base muds as lubricants, emulsifiers, corrosion inhibitors, detergents, and defoamers. Since these materials are film-formers (acting on solid surfaces and at liquid interfaces), the concentrations required are extremely low. The following indicates the types of surfactants and quantities used in 1977:

Fatty Acids and Soaps	4,500 tons
Ethoxylated Phenols	1,600 tons
Amine Derivatives	900 tons
Alcohols	Less than 9 tons

Lost Circulation Materials--

Lost circulation materials of a considerable variety are sometimes added to water-base muds to combat loss of mud to highly permeable or fractured formations. Mostly these are natural materials of a granular, fibrous, or plate-like structure. Walnut shells, cane fiber and mica are examples. Typical of the method of use would be to add a high concentration of sealing material (perhaps 86 kg/m^3 [30 lb/bbl]) to a small volume of mud (perhaps 47.7 m^3 [300 bbl]) and to spot that batch in the loss zone. Usage of lost circulation materials in 1977 is estimated at 18,000 tons.

Biocides--

Fresh-water drilling muds seldom require biocides. Occasionally, a biocide such as paraformaldehyde might be added at concentrations of perhaps 0.29 kg/m^3 (0.1 lb/bbl) to a mud containing xanthum gum. Generally, biocide usage would be limited to brine muds of intermediate salinity that contain pregelatized starch.

Salts--

Salts used to prepare brine-based muds are principally sodium chloride ($NaCl$) and potassium chloride (KCl). The $NaCl$ is available as a produced brine in certain localities. As such, it provides an inexpensive liquid phase for combatting shale hydration or limiting solution of salt formations to be drilled. In certain situations where formation pore pressure and permeability are low (such as deep drilling in the Permian Basin), $NaCl$ brine has sufficient density to serve as a clear-water drilling fluid. High-molecular-weight polymers are used to flocculate drilling solids, causing solids to settle in surface pits and allow the clean brine to be recirculated. Otherwise, $NaCl$ systems are customarily treated with clays, polymers, and barite. $NaCl$ concentration in the liquid phase is usually between 10 and 26% by weight (saturated). $NaCl$ used in drilling muds is estimated at 45,000 tons for 1977.

KCl--

KCl is used primarily to provide a mud to combat shale problems. Potassium has been found to alter the hydration and swelling of clays having an expandable lattice structure. Thus, KCl muds containing concentrations of 3 to 20% KCl have been found to provide borehole stability equal to or better than a saturated $NaCl$ mud. KCl usage is estimated at 4,500 tons for 1977.

Clays--

Clays of the bentonite type do not hydrate and disperse effectively in brine. This limitation can be overcome to some extent by prehydrating the bentonite in fresh water before adding it to the brine system. To avoid the inconvenience of prehydrating, salt-water clays are often used. Attapulgite from the Georgia-Florida area has a rod-like particle shape that provides cuttings-carrying capacity and aids in suspending barite in brine-based muds. Concentration in a typical mud would be 29 to 86 kg/m^3 (10 to 30 lb/bbl). Attapulgite usage for 1977 is estimated at 73,000 tons. There has been some use of sepiolite from California as a clay for brine-based muds.

Oils--

Oils are sometimes used in fresh-water mud to reduce drill string torque while drilling, to reduce drag when pulling the drill string, and to reduce shale balling of bits, drill collars, and stabilizers. The oil might be diesel oil, or vegetable oils (estimated at 450 tons for 1977) would be used where rapid biodegradability is considered necessary.

Asphaltic Materials--

Asphaltic materials are added to fresh-water muds to serve some of the same purposes as oil. Also, these materials are used to aid in combatting shale instability. Usage of both petroleum asphalts and gilsonite is estimated at 9,000 tons for 1977.

Example--

A typical water-based mud would be a lignosulfonate/lignite system having a composition such as:

Component	Concentration, kg/m^3 (lb/bbl)
Water	570 to 970 (200 to 340)
Bentonite	43 to 86 (15 to 30)
Lignosulfonate	5.7 to 29 (2 to 10)
Lignite	2.9 to 17 (1 to 6)
Sodium Hydroxide	2.9 to 14 (1 to 5)
Barite	0 to 1430 (0 to 500)

Brine-Based Muds

Most of the materials used in water-based muds might also be used in brine-based systems. The following are some of the aspects that are specific to brine systems.

Fibrous Materials--

Fibrous materials such as asbestos and shredded paper have had limited use in brine-based systems to provide a sweep to lift cuttings and sloughings from the well. While asbestos usage in 1977 is estimated at 9,000 tons, utilization of this type of product has since declined drastically.

Example--

A typical brine-based mud composition would be:

Component	Concentration, kg/m^3 (lb/bbl)
Water	860 to 986 (300 to 345)
Bentonite	0 to 29 (0 to 10)
Salt (NaCl, KCl)	29 to 290 (10 to 100)
NaOH or KOH	0.3 to 0.9 (0.1 to 0.3)
Polymer (CMC, Polyacrylamide)	1.4 to 5.7 (0.5 to 2)
Barite	0 to 860 (0 to 300)

Oil-Based Muds

Oil-based muds are used for special purposes, generally when water-based systems have been ineffective or excessively expensive. Oil-based muds have a high initial cost, are objectionable to crews when being used, and call for special handling because of environmental constraints. The following are some of the applications that justify the use of oil-based muds:

- Protecting productivity of shaly sands
- Drilling troublesome shales
- Drilling water-soluble formations
- Drilling deep, hot holes
- Preventing differential pressure sticking
- Combatting severe corrosion problems (high-pressure H_2S)
- Coring for connate water content, or where poorly consolidated

Oil-based muds are systems having oil as the continuous liquid phase and water as a dispersed, emulsified phase. In earlier years, emphasis was placed on the concentration of water in the mud, with the term "invert emulsion" used for muds containing water at more than 10% by volume. Today it is recognized that all commercial oil muds are prepared to contain a small amount of water and that water is always incorporated during use. No distinction, therefore, is warranted between oil-based and invert emulsion muds.

The oil used in oil-based muds is almost exclusively No. 2 diesel fuel, with No. 1 diesel fuel used in cold climates. On rare occasions, crude oil might be used to save transportation costs.

Salts are used to increase the salinity (lower the aqueous activity) of the emulsified water phase to obtain a sufficient oil mud osmotic force to prevent hydration of shale formations drilled. $CaCl_2$ is widely used for this purpose because aqueous activities can be obtained low enough to cope with shales having a high water demand. NaCl is used sometimes for the less stringent conditions.

Oil-dispersible clays are used in oil-based muds for viscosity and gel strength to lift drilled cuttings from the hole and to suspend weighting material. The clays (usually bentonite) are made oil-dispersible by reaction with quaternary ammonium compounds or other amine derivatives. Concentrations of 2.9 to 17 kg/m^3 (1 to 6 lb/bbl) are customarily used.

Emulsifiers and wetting agents are used to emulsify water and to preferentially oil-wet solids and metal surfaces. The most common surfactants used in oil-based muds are:

- Ca soaps of high-molecular-weight fatty acids
- Polyamides
- Alkylarylethoxylates
- Na salts of alkylaryl sulfonates

Concentrations of 5.7 to 14 kg/m^3 (2 to 5 lb/bbl) of one or more of the surfactants are used.

Asphaltic materials are often used in oil-based muds to augment the suspension provided by oil-dispersible clay and to provide low filtration rates. Air-blown asphalt at concentrations of 29 to 200 kg/m^3 (10 to 70 lb/bbl) might be used.

Oil-dispersible lignite is sometimes used for filtration control in oil-based muds. This type of product is made by dissolving lignite in water and then reacting it with amine derivatives. Oil-dispersible lignite is used at concentrations of 5.7 to 34 kg/m^3 (2 to 12 lb/bbl).

Lime (CaO or CaOH) is used in most oil-based muds to form calcium surfactants, to maintain an alkaline environment, and to react with acid gases such as CO_2 and H_2S that might be encountered. Typical concentrations would be 5.7 to 11.4 kg/m^3 (2 to 4 lb/bbl), with perhaps 29 kg/m^3 (10 lb/bbl) maintained if high-pressure H_2S formations are being drilled.

An example of a typical oil-based mud composition would be:

Component	Concentration, kg/m^3 (lb/bbl)
Diesel oil	430 to 630 (150 to 220)
Water	100 to 140 (35 to 50)
$CaCl_2$	43 to 71 (15 to 25)
Surfactant (soap, polyamide)	14 to 57 (5 to 20)
Filtrate reducer (amine lignite)	0 to 29 (0 to 10)
Gellant (amine clay)	5.7 to 11.4 (2 to 4)
Barite	0 to 1430 (0 to 500)

FACTORS AFFECTING TYPE OF DRILLING FLUID USED

A number of factors affect the type of drilling mud used. If conditions would permit, drilling with air or gas would probably provide the fastest rate of penetration. Conditions required are:

- Low formation pressures
- Strong, competent formations
- No highly permeable formation containing water or oil

There are not many situations where air or gas is sufficient as the drilling fluid. The next choice in terms of cost and drilling rate would be clear water or brine. Conditions for clear-water drilling are:

- Normal or subnormal formation pressures
- No highly permeable formations

- No extremely water-sensitive shale formations

Again, such conditions are uncommon. Usually, a liquid mud is needed. The choice of which type of liquid mud to use is based on consideration of a number of factors.

Formation Mineralogy

Often the composition of the formations to be drilled determines what type of mud can be used. Some formations may require a special mud to help avoid excessive hole enlargement. Others may dictate a certain mud to avoid hole size being reduced by buildup of filter cake or plastic deformation of the formation.

Another aspect is the effect of the formation on control of mud properties and ultimate mud maintenance costs. Some formations require special muds that can tolerate the formation solids without excessive treatment or loss of control of mud properties.

Shales--

The problems encountered when drilling through shale formations are hole enlargement and mud-making tendencies. Hydration of pressured shales containing swelling-type clays can also cause plastic flow and reduction of hole size. Muds that combat shale hydration are utilized to achieve borehole stability as well as minimize mud-making. In water-based muds, rate of shale hydration can be slowed by using adsorptive polymers and minimizing the use of dispersants. The salts in brine-based muds lessen the osmotic forces tending to hydrate shale. A brine/polymer mud, therefore, is more effective than a fresh-water system. If a potassium salt system is used, further help is obtained by limiting clay swelling. Hydration of shale can be eliminated by use of an oil-based mud having a high salinity in the dispersed water phase. Oil wetting of the shale prevents the initial surface hydration, and low aqueous activity of the water in the oil mud prevents subsequent osmotic hydration.

Sands--

Drilling through sand formations presents the problem of filtration and filter cake buildup. If the differential between mud hydrostatic pressure and formation pore pressure can be kept low, the main problem is reduction in hole size. Any of the mud types can be conditioned to have very low filtration rate to combat this problem. Bentonite, along with high concentrations of lignosulfonate and lignite, can serve the purpose in water-based muds. Polymers can be used in either water-based or brine-based muds. Lowest filtration rates of all can be obtained with oil-based muds.

High differential pressure creates a special problem in permeable sands. The drill string that becomes buried in the filter cake becomes subject to the differential pressure and tends to become stuck against the wall of the hole. Surfactants, oils and lubricants are used in water- or brine-based muds for help in combatting this problem. Differential pressure sticking is eliminated for all practical purposes by a low-filtrate oil-based mud because of the good lubricity of the extremely thin filter cake.

Carbonates--

Carbonates affect the selection of mud type primarily because of interest in obtaining improved rates of penetration. Low-solids, water-based, and brine-based muds are helpful. If other problems dictate an oil-based mud be used, low-colloid systems are now proving to provide greatly enhanced drilling rates.

Soluble Salts--

Soluble salts (usually NaCl) often dictate use of a brine-based mud to avoid excessive hole enlargement. Salt contamination of most water-based muds would also make control of mud properties very difficult. Hole enlargement in drilling salt formations can be eliminated by use of oil-based muds. Mud properties can be readily controlled if care is taken to utilize solids control equipment to screen the fine salt particles out of the mud.

Formation Pore Pressure

Selection of the type of mud to be used is affected by the formation pore pressures anticipated. Highly permeable formations having low pore pressures create a probability of loss of mud to the formation. Use of muds having a high cost per barrel (such as some brine polymer muds or oil-based muds) can become prohibitively expensive because of mud losses.

High formation pore pressures usually require high mud densities. Some nondispersive water-based or brine-based muds are difficult and expensive to control at mud densities much above 1.7 kg/liter (14 lb/gal).

Formation Fluids

Selection of the mud type also takes into consideration the type of formation fluids that are to be encountered. Usually, mud density will be adjusted to prevent formation fluids from entering the well. Fluids in the actual volume of formation drilled, however, will enter the mud system. Also, allowance must be made for some fluid entry due to fluctuations in mud pressure.

Salt water, like salt formations, can be a serious contaminant for many water-based muds. Lignosulfonate muds are often used to provide some tolerance for salt water. Low-solids polymer muds can be used with proper utilization of equipment to remove formation solids. Oil-based muds have considerable tolerance for salt water, but uncontrolled contamination would call for excessive oil dilution and maintenance treatment.

Hydrogen sulfide is more serious as a personnel hazard and cause of corrosive failure than as a mud contaminant. Formations containing H_2S at normal pressure can be handled by controlling mud alkalinity and using sulfide scavengers in water-based or brine-based muds. Oil-based muds are used to cope with formations containing H_2S at very high pressure. Personnel must still be protected from H_2S that reaches the surface, but high-strength steel is protected by the mud from sulfide stress cracking.

Contamination of a water-based or brine-based mud with carbon dioxide calls for lime and caustic soda for maintenance of alkalinity. Both mud properties and corrosion can become a problem if proper care is not taken. A lime mud (highly alkaline water-based system maintained with 5.7 to 14.3 kg/m^3 [2 to 5 lb/bbl] of free lime) provides good stability when coping with CO_2.

Petroleum oil or gas is not usually a serious contaminant of drilling mud. Most muds can tolerate small amounts of oil with no problem other than possible environmental considerations at time of disposal. Gas is usually separated by a gas separator and/or degasser. Gas separates quite readily from an oil-based mud. Some water-based muds (particularly the nondispersive systems) tend to entrap gas and may require treatment with a surfactant as a defoamer. Brine-based muds usually require use of defoamers to aid in release of gas.

Formation Temperature

An important factor in the selection of mud type is the anticipated formation temperature. Most of the organic additives used in brine-based muds degrade badly at temperatures in the range of 120°C to 150°C (250°F to 300°F). Upper limits for most water-based systems is somewhat higher, perhaps 150°C to 180°C (300°F to 350°F). The widely used lignosulfonates degrade in this range to form products that cause problems in control of rheology and filtration. Lignite degrades in this range, but the degradation products are less detrimental. If kept free of contamination from salt, cement, etc., a lignite system can have reasonable stability up to about 200°C (about 400°F).

A special aspect of thermal stability of aqueous muds is the reaction of hydroxyl with shale, sand, and clays in the presence of calcium to form cementitous material. The reaction is time/temperature-dependent. The longer an alkaline mud is used, and the higher the temperature, the more of the cementing material that is formed. A high-solids lime mud used at formation temperatures above 120°C (250°F) for several weeks, therefore, can be expected to gel excessively or solidify when left in the hole during trips.

Oil-based muds are generally used for stability when drilling formations having temperatures of 204°C to 288°C (400°F to 550°F).

Other Factors

Hole Deviation--

Hole deviation can be a factor in mud selection because of the need for good hole cleaning and lubricity. Borehole stability is needed to permit control of directional drilling. Muds will be selected, therefore, to control shale hydration and filter cake buildup. Lubricants may be added to the mud.

Economics and Logistics--

Brine-based muds may be used where there is an economical source of commercial brine. Oil-based muds are more likely to be used if local usage warrants installation of liquid mud plants for mixing and storing the muds. Polymer-treated muds sometimes are used because of drayage costs of greater quantities of bentonite tend to offset the lower cost per ton.

Governmental Regulations--

The choice of mud type is sometimes limited by governmental regulations. Use of brine-based and oil-based muds is prohibited in certain localities. Requirements for restoral of the drill site can also be a factor. Sometimes mud and cuttings must be removed from the drill site, favoring use of an inhibitive mud and good solids removal equipment.

FACTORS AFFECTING QUANTITIES OF MUD AND CUTTINGS GENERATED

Obviously, the minimum quantity of cuttings generated in a drilling operation will be determined by the diameter and depth of hole. The quantity of mud generated will be related to the hole dimensions, but other factors are also involved. Types of bits used, drilling practices, and total time of the drilling operation all affect the disintegration of cuttings and subsequent mud-making. To minimize quantities of mud, bit selection and drilling practices should be directed toward forming large-formation chips at a maximum rate of penetration, lifting the chips efficiently to the surface, and efficiently removing the chips from the mud. Time of use of the mud would be minimized to lessen attrition and disintegration of solids.

In practice, compromises must be made. Time must be allowed for logging and testing. Directional control may dictate controlling rate of penetration. For various reasons, quantities of mud and cuttings generated may vary widely for a given size and depth of hole.

Type of Formations Drilled

One factor over which the operator and contractor have no control is the types of formations to be drilled. As discussed previously, shales tend to hydrate and either erode or slough when drilled with aqueous muds. Unconsolidated sands also can cause hole enlargement and result in greater quantities of mud and solid waste. Water-soluble formations can cause hole enlargements and increased mud volume.

Even more important than the effect on hole volume is the effect that shale composition has on total mud volume generated. A soft shale containing swelling-type clays can yield perhaps 8.8 to 14 m^3 (50 to 80 barrels) of 15-cp mud per ton of solids when mechanically dispersed and fully hydrated in fresh water. A hard shale composed of non-swelling clays might yield only 0.88 m^3/ton (5 bbl/ton). In brine-based muds the yield of the soft shale would be drastically reduced, but there might be little change in the yield of the hard shale. Use of oil-based mud would result in yields of less than 5 bbl/ton for both the soft and hard shales.

Types of Mud Used

Selection of mud type is an option that the operator has to help control the volume of mud and cuttings formed. For minimizing hole enlargement and mud-making while drilling shale or salt formations, for example, the major mud types could be rated in the following order:

1. Oil-based mud (with salinity control)

2. Brine-based mud (with polymers)

3. Water-based mud (nondispersive with polymers)

4. Water-based mud

Solids Removal Equipment

Another option that can be utilized to lessen the volume of mud generated is utilization of mechanical means of solids separation. Shale shakers (vibrating screens) are used during all phases of most drilling operations. Screens can be used to separate drilled solids as fine as 140 microns.

For unweighted mud, desanders and desilters (hydrocyclones) are being used to remove solids as fine as about 25 microns. Various mud cleaners are available for use with weighted mud. The mud cleaner utilizes a hydrocyclone to recover most of the liquid phase of the mud. The solids discharge from the underflow of the cones is dropped onto a fine-mesh screen (120, 150, or 200 mesh) where the coarser drilled solids are removed. The barite particles are small enough to pass through the screen and be returned to the active mud system. The net effect is to remove drill solids as fine as 74 microns.

Decanting centrifuges are being used more frequently to remove solids from unweighted mud. The high-speed units can separate solids as fine as 2 microns. With weighted mud, decanting centrifuges are used to recover barite from mud that has accumulated excessive drilled solids and is to be discarded.

Effective utilization of a full suite of solids removal equipment can drastically reduce the volume of mud required to drill a well. In 1976 an experiment was conducted to determine if a well could be drilled with no liquid mud waste. Unweighted mud was used to drill to below 3050 m (10,000 ft) in Wyoming. The shales encountered were hard and nondispersive in the lightly treated fresh-water bentonite mud. By using all of the solids removal equipment continuously while drilling, all drilled solids were removed mechanically and the only liquid mud was that in the active system. Such complete success would not be expected under normal drilling conditions. (In the experiment, for example, drilling would be stopped if the solids removal equipment was not functioning.) Also, a similar attempt was not completely successful when soft swelling-type shales were drilled in South Louisiana. Mud volumes were reduced, but liquid waste mud was not eliminated.

Examples of volumes of mud and cuttings generated can be presented only to indicate some typical conditions. Actual quantities vary from the experimental well with no waste liquid mud to perhaps 16,000 m^3 (about 100,000 bbl) of waste for a very deep well. The following can be considered representative of three classes of well depth.

Shallow - 914 to 3050 m (3,000 to 10,000 ft)

Example: 31.1 cm (12-1/4-inch) hole drilled to 122 m (400 ft)

20.0 cm (7-7/8-inch) hole drilled to 1830 m (6000 ft)

Formation solids removed from 31.1-cm hole (30% washout):	15.9 m^3 (100 bbl)
Formation solids removed from 20.0-cm hole (30% washout):	95.4 m^3 (600 bbl)
Total liquid mud and surface water waste:	366 m^3 (2300 bbl)
Total	477 m^3 (3000 bbl)

Intermediate - 3050 to 4570 m (10,000 to 15,000 ft)

Example: 31.1-cm (12-1/4-inch) hole drilled to 914 m (3,000 ft)
21.6-cm (8-1/2-inch) hole drilled to 3660 m (12,000 ft)

Formation solids removed from 31.1-cm hole (30% washout):	127 m^3 (800 bbl)
Formation solids removed from 21.6-cm hole (20% washout):	143 m^3 (900 bbl)
Total liquid mud and surface water waste	3180 m^3 (20,000 bbl)
Total	3450 m^3 (21,700 bbl)

Deep - more than 4570 m (15,000 ft)

Example: 44.5-cm (17-1/2-inch) hole drilled to 1220 m (4,000 ft)
31.1-cm (12-1/4-inch) hole drilled to 3660 m (12,000 ft)
21.6-cm (8-1/2-inch) hole drilled to 4880 m (16,000 ft)

Formation solids removed from 44.5-cm hole (15% washout):	636 m^3 (4000 bbl)
Formation solids removed from 31.1-cm hole (10% washout):	238 m^3 (1500 bbl)
Formation solids removed from 21.6-cm hole (20% washout):	63.6 m^3 (400 bbl)
Total liquid mud and surface water waste	4770 m^3 (30,000 bbl)
Total	5708 m^3 (35,900 bbl)

DISPOSAL OF SOLID, LIQUID, AND GASEOUS WASTES PRODUCED IN DRILLING

On land, most drilling activities utilized an earthen reserve pit (or sump) to store drilling mud and cuttings during operations and for final disposal. The pit is customarily deeper near the rig to allow for settling of heavy mud solids. The reserve pit is sized according to the planned volume of mud and cuttings anticipated, as well as rainfall expected. Walls of the pit are usually high enough that 1 to 1.5 m (3 to 5 ft) of top soil can be backfilled over the mud and cuttings for disposal. In certain environmentally sensitive areas, government regulations require use of an impervious liner in the reserve pit. Waste mud and cuttings are usually hauled off the location to a disposal site, but sometimes they are covered over with the pit liner in place.

Water-based muds are customarily dewatered in the reserve pit and back-filled for disposal. Dewatering is often done by evaporation in dry climates. In other areas, flocculants may be mixed into the pit mud to help settle the solids. The clarified water is then pumped off.

In recent years, more attention has been given to landfarming techniques for disposal of water-based muds. The contents of the reserve pit are spread over the drilling location and incorporated into the soil using tilling equipment. Prior to such disposal, consideration should be given to the type of mud, the type of soil, and the type of plants to be grown. All of these are factors in whether the mud would be harmful or would enhance plant growth.

Brine-based muds usually are stored and disposed of in lined pits if the salinity is above 10% by weight. For lesser concentrations, the mud may be stored until diluted enough for disposal by other means.

Oil-based muds are customarily kept in steel mud tanks and are not discarded. If cuttings have been removed effectively by solids removal equipment, the oil-based mud is suitable for use for future drilling with little modification because shale solids do not hydrate and disperse in the oil. The oil-based mud usually is simply too valuable to be discarded. Cuttings coated with oil mud are discarded to an earthen pit sealed with bentonite or lined with plastic sheets to prevent seepage.

SECTION 6

COMPLETION AND WORKOVER FLUIDS

Often the fluid used to drill a well is also used for completion operations (such as perforating, testing, etc.). The same mud may be left in the well on the outside of the casing and in the casing-tubing annulus. Special completion fluids are used, however, particularly when the drilling mud solids would create problems of productivity damage, settling or solidification in the annulus, or corrosion.

Workover operations are often conducted with the same type of fluid left in the annulus of the well upon completion. This may be simply a drilling mud or it may be a low-solids system.

COMPOSITION

Solids-Free Systems

"Solids-free" systems are designed to avoid plugging of perforations by particles of weighting material and to avoid problems of settling when solids-laden mud is left in a well after completion.

Salts are used for two purposes in many completion fluids. One would be for clay inhibition, as in drilling fluids. The second would be to obtain the desired fluid density without use of solid weighting material. $NaCl$ and KCl are often used for inhibition as in drilling fluids. For density, $NaCl$ is used for fluids up to about 1.2 kg/liter (10 lb/gallon). Densities up to about 1.38 kg/liter (11.5 lb/gallon) are obtained with $CaCl_2$ alone or in combination with $NaCl$. $CaBr_2$ and $ZnBr_2$ can be used in combination to obtain densities in the range of 2.16 kg/liter (18 lb/gallon).

Organic polymers are used to give viscosity for lifting capacity and to aid in filtration control in the "solids-free" system. Hydroxyethyl cellulose and xanthum gum are two of the most commonly used. These materials are used at concentrations of 2.9 to 14.3 kg/m^3 (1 to 5 lb/bbl).

Calcium carbonate, sized to act as an effective agent on permeable sands, is used in these "solids-free" systems to allow a filter cake to start to form. A concentration of 28.6 kg/m^3 (10 lb/bbl) would be typical for this function. If the well is subsequently acidized, the calcium carbonate should dissolve enough to cause the filter cake to disintegrate.

Corrosion inhibitors, amine derivatives, are used in the salt systems at concentrations of 4.3 to 14.3 kg/m^3 (1.5 to 5 lb/bbl). At these concentrations the inhibitor also serves as a microbiostat to prevent degradation of the polymer components. Otherwise, paraformaldehyde might be used as a biocide.

A buffer, usually magnesium oxide, serves to stabilize the pH of the system and keep the polymers in an effective form. Concentrations of 0.3 to 1.4 kg/m^3 (0.1 to 0.5 lb/bbl) are typical.

Defoamers of various types (alkyl alcohols, sulfonated vegetable oils, etc.) are used to combat air and gas entrapment. Typical concentrations are in the 0.3 kg/m^3 (0.1 lb/bbl) range.

Solids-Laden Systems

These completion and workover fluids are water-based, brine-based, or oil-based systems equivalent to those used for drilling. The principal difference would be that a system might be freshly prepared to avoid the drilled formation solids that would have accumulated as extremely fine particles during the drilling operation. For densities up to about 1.5 kg/liter (12.5 lb/gallon), calcium carbonate often is used as an acid-soluble weighting material. There has been some minor usage of iron carbonate (siderite) for densities up to 1.68 kg/liter (14 lb/gallon).

DISPOSAL OF COMPLETION AND WORKOVER FLUIDS

In general, completion and workover fluids are disposed of in the same manner as the drilling fluids. One difference is that a significant amount of the completion fluid is usually left in the well, in the annulus between the tubing and the casing. The volume of completion fluid, therefore, is usually quite small relative to the volume of drilling mud in the reserve pit. Often a brine-based completion fluid is used in a well drilled with a water-based mud. When discarded to the reserve pit, the salinity of the completion fluid is drastically reduced because of the large dilution.

A disposal method not previously mentioned is that of pumping the waste down the well annulus and into a formation having sufficient porosity and permeability. This procedure is not always feasible and the practice is rather limited. Although drilling fluids could also be disposed of in this manner, it is more common with completion fluids because volumes are smaller and salinities are often higher.

ENVIRONMENTAL EFFECTS OF DRILLING, COMPLETION, AND WORKOVER WASTES

At a conference conducted by the EPA in Houston in 1975, there was much concern expressed by various groups about possible harmful effects on the environment from disposal of wastes from oil and gas drilling operations. Half a century of intensive drilling activity had resulted in no major impact on the environment, other than a few isolated examples of mishandling of brine. Nonetheless, relatively few studies had been made under controlled conditions.

The 1975 conference stimulated numerous research programs, many of which were reported on at a joint government/industry seminar in 1980. These studies indicated that the commonly used water-based muds and mud components are relatively nontoxic and not harmful to the environment when properly handled. Studies are continuing on long-term, sublethal effects that could be of importance in areas of prolonged concentrated drilling activity. For example, bioavailability and bioaccumulation of trace metals in drilling muds are subjects of on-going research. Such work may result in guidelines that could provide an added assurance that the environment is protected.

SECTION 7

OIL WELL SERVICING AND WORKOVER

With the passage of time, all oil or gas wells will develop production problems. These problems can be mechanical in nature such as the plugging of a tube with sand or the failure of a subsurface pump, or may be due to the depletion of the oil/gas reservoir. Perhaps the natural reservoir pressure has fallen to the point where the oil must be pumped out. In general, workover is a term applied to efforts to increase production from old wells.

SERVICE AND WORKOVER - RIG EQUIPMENT

Upon completion of well drilling activities the drilling rig is disassembled and moved to the next drill site. When well servicing or workover is required, special rigs must be employed.

Truck-Mounted Units

Light- to medium-duty servicing and workover can be handled with truck-mounted rigs. They are limited by the amount of structure that can be conveniently carried by truck and easily deployed above the wellhead and the amount of power available.

Two basic types of structures or masts are utilized, the double-pole masts and the structural mast. Pole masts are constructed of tubular members and are extended to their full length by wire-rope arrangements. Structural masts are constructed of angular steel elements and can carry heavier loads than pole masts. The telescoping structural mast is elevated by hydraulic devices and the upper section raised to full height by wire-line setups. The two sections are then mechanically locked together. Both types of masts require the use of guy lines for support.

Carrier Units

Heavy-duty servicing/workover often required by deeper wells necessitated the use of stronger, heavier, taller masts and wellhead clearance for the installation of blowout preventers. To meet these requirements, self-propelled carrier units were designed to fit the needed engine-hoist-mast combination. These units have capacities of 114,000 kg (250,000 lb) or more and can handle pipe in 9.14-m (30-ft), 18.3-m (60-ft), and even 27.4-m (90-ft) lengths. Many of the rigs can develop over 0.45 MW (600 HP).

Auxiliary Equipment

Well servicing/workover equipment includes (a) manually operated tubing or drill-pipe slips for medium-depth wells and air-operated equipment for heavier loads encountered in deeper wells, (b) hydraulically operated tongs, (c) a rotating head with a sealing arrangement for high-pressure fluid circulation and a small kelly to allow vertical movement of a pipe string during turning, and (d) mud-pumping apparatus.

REMEDIAL WELL WORK

The most common types of repairs to wells are swabbing and the repair of sucker-rod pumps, sucker-rods, production tubing, and packers. Normal wear of moving parts in downhole pumps, sucker rods and gas life equipment, age and corrosion, scale and paraffin deposits will make repairs necessary.

Swabbing

If the formation pressure is insufficient to overcome the hydrostatic pressure of the fluid in the tubing, a swab-cup arrangement is lowered into the well in a wireline from a truck-mounted hoist. The swab-cup raises the fluid to the surface. The removal of the fluid from tubing lowers the hydrostatic head on the formation and induces flow from the formation.

Pump Repair

When formation pressure is too low to bring oil to the surface, pumps must be used. There are two basic types of subsurface pumps, the tubing pump and the rod pump. The tubing pump is attached to the bottom of the tubing string. It is more difficult to service since the tubing must be extracted from the well to get at it. The tubing pump can handle larger volumes of fluid. The rod pump is more popular, since it is run in on the sucker rods and can be removed with them for repair.

Subsurface pumps are simple, rugged, and very reliable. Failure or impairment is often caused by sucker rod failure from corrosion, wear, and stress fatigue.

Production Tubing

A tubing string must be leak-free and capable of withstanding an internal pressure up to several tens of MPa (several thousand psi) and considerable external pressure. Leaks, when they occur, are usually caused by faulty or loose couplings, a hole or split caused by rod abrasion or working of the tubing as the well is pumped. Pressure testing of the tubing to check for leaks is easily done by truck-mounted oil-well servicing units with the tubing vertically mounted as it is made up in the string and run back into the hole.

Packers

Packers are used to seal off the space between the tubing and the oil string casing (Figure 7) and isolate the producing formation and its pressures from the casing higher up in the well. Repairing packers having worn sealing elements can be done by retrieving the packer. If the packer is nonretrievable (a type frequently used) it can be removed by drilling it out.

Blowout Prevention

While most wells requiring remedial work have a low formation pressure, service crews must always be alert to the hazard of a blowout. Gas sands from shallower depths that have been cased off may cause problems if casing failure occurs. Depleted sands at shallower depths have been used for gas storage and the pressure of the injected gas has sometimes built up to levels that would require a heavy fluid to contain the pressure.

Minimum requirements should include a rod blowout preventer that can be closed on the sucker rod in an emergency. Connections at the well head should be available for the pumping of mud or water into the well to overcome formation pressures. If pressure problems are expected, a blowout preventer should be installed before tubing is pulled.

WELL CLEANOUT AND WORKOVER

Completion, cleanout, or workover jobs comprise about half of the work for production rigs in the U.S. Because workover jobs can require the rotation of a drill pipe string and a means for circulating fluid, workover rigs must be capable of hoisting heavier loads than well-servicing rigs. As described earlier, these rigs will take on the appearance and function of regular drilling rigs.

Completion and Workover Fluids

The completion and workover fluids are normally either specially prepared mud or salt water. These mixtures and the various additives used to obtain desired properties are discussed in another section of this report.

Sand Cleanout

Sand cleanout is done with a macaroni rig which is essentially a 2.5-cm (1-inch) diameter pipe string fitted to a high-pressure pump for salt water circulation. If a packer has been fitted in the well or the tubing is obstructed, the tubing is pulled and cleared while the packer is either unseated or drilled out. The cleared tubing can then be used to circulate the fluid for flushing away the sand.

If sand has entered the annulus between the tubing and casing above a packer (through a hole in the casing or through open performations in an upper zone of a multiple completion well) in sufficient amount to prevent pulling the packer, the free portion of the tubing is cut off and pulled. A washover assembly is then run into the hole over the remaining tubing stub below the cutoff projecting upward from the packer. Circulation of fluid is then used for sand removal. Since the tubing is cut and removed, blowout preventers must be used. Rigs employing a washover assembly are larger and heavier since not only must the stuck tubing be pulled, but the much heavier washover unit must be run in and retrieved. Then, too, since the washover may involve turning the string, the rig should be equipped with a rotary.

Casing Repair

Well casing is subjected to corrosion, abrasion, high pressures and other forces that can sometimes cause holes and splits to develop. The presence of casing holes is usually indicated by shale or sand in the well when the tubing is pulled. A casing hole can be located by conducting a pressure test of the annular volume above a seal formed by a retrievable packer. The packer is then methodically lowered down the well and sealed at various depth intervals until the pressure test reveals a leak. When the hole is located, the casing can be repaired in several ways.

1. Squeeze cementing: A drillable plug or a packer is placed below the casing hole. Cement is then applied under sufficient hydraulic pressure to force it into the hole. After hardening, the cement drillable plug or packer is drilled out, leaving the cement plug in the hole of the casing wall.

2. Stressed steel liner patch: A corrugated steel liner tube is coated on the outer diameter surface with a layer of woven fiberglass cemented in place with epoxy resin. The corrugated patch is coated with additional epoxy and lowered to the desired location in the well, expanded with a special tool, and epoxied in place.

3. Upper string replacement: The upper portion of the casing string is removed down to the leak and rerun with an overshot tool.

4. Full liner: If steps 1, 2, and 3 are not possible, a complete string of smaller diameter pipe liner can be run in and cemented.

5. Casing roller: If the casing string has crimped or collapsed at one point, a casing roller, or swaging tool, can be used to open up the casing.

Sidetrack Drilling

Collapsed casing, nonretrievable junk in the well, or a desire to obtain a better location to drain a reservoir will call for sidetrack, or directional drilling. This is done by plugging back the casing at the desired depth, removing a section of casing above the plug, running in a whipstock (a long steel casing that uses an inclined plane to deflect the drilling tool), and drilling the new hole off to one side of the old well bottom.

Drilling Deeper

Deepening a well is usually done to facilitate the cleaning out of the existing producing zone rather than to find a deeper reservoir. After plugging existing perforations and pressure testing, the casing shoe is drilled out and the hole deepened. The well is logged, a liner or casing is run in, and the well is completed in much the same manner as a new well.

WELL STIMULATION

Oil-bearing formations are often poor producers because of low porosity and/or permeability and lack of fracturing. Well stimulation involves the opening up of low porosity, or dense reservoir rocks to permit oil to flow more rapidly to the collection zone at the well. Three methods of well stimulation have been developed over the years: explosives, acid stimulation, and hydraulic fracturing.

Explosives

The oldest of the stimulation techniques is explosive fracturing. After being considered obsolete for many years, there is a renewed interest in this technique. Experience has shown that explosive stimulation is more effective on certain types of tight formations than are acid or hydraulic techniques and that older wells stimulated with explosives or "shot" produced much longer than acidized or hydraulically fractured wells (A Primer of Oil Well Servicing and Workover, p. 58, 3rd Ed., Petroleum Extension Service, University of Texas, Austin, Texas, 1979).

Two basic methods of explosive stimulation are used. The detonation can be concentrated in the well or the explosive can be injected into an existing fracture system surrounding the well hole for dispersed detonation.

Acid Stimulation

Acid treatment serves to dissolve rock and thus enlarge channels and produce new networks of paths to induce greater flow of oil to the well. The acids used must result in soluble reaction products, should be relatively safe to handle, and economical. The rocks most often attacked with acids are limestone ($CaCO_3$) and dolomite (a mixture of $CaCO_3$ and $MgCO_3$).

Additives--

The effectiveness of oilfield acids can be improved by the use of various additives. Additives are available that will retard the rate of attack of the acid to prevent oil-acid emulsions and to permit easier flow of the acid into the formation interstices. Sequestering agents are added to the acid to control the reprecipitation of iron deposits stemming from iron oxide, sulfide and carbonate scale removed from oilwell tubing and casing by the acid. Finally, suspending agents are used in oilfield acids to keep fine clay and silt particles,that are often picked up by the acid during use, in suspension.

Acids--

Various acid formulations are available. Selecting the correct one involves detailed knowledge of the producing formation and its physical condition around the well. The acids used include hydrochloric acid, acetic acid, formic acid, sulfamic acid, and hydrofluoric acid.

Acetic acid is used to acidize limestone formations at high temperatures (greater than 120°C [250°F]). It is easily inhibited, will not cause either hydrogen embrittlement or stress corrosion in heat-treated steels, and will not attack chrome plating or aluminum. Formic acid can be easily inhibited and also can be used to treat high-temperature limestone formations, although not as effectively as acetic acid. Sulfamic acid is stronger than acetic or formic acid, but is not suitable for high-temperature use, and when mixed with water, forms very corrosive solutions that must be handled very carefully. Hydrochloric acid is generally considered to be the most efficient and economical means of treating limestone or dolomite formations. Hydrofluoric acid reacts with quartz particles (the main constituent of sandstone), silicates (glass and concrete), cast iron, and many organic materials. Hydrofluoric acid is poisonous and is handled with extreme caution.

Generally, the tendency of an acid to form sludges or emulsions increases with the concentration of the acid solution. Usually acids used in well treatment will range in strength from 3% to 28% by weight in water.

Placement--

Acid injection can be performed at rates sufficiently high to fracture the formation (the most common type of acid treatment) or the injection can be achieved at pressures low enough to avoid fracturing -- the so-called interstitial or matrix acidizing. The low-pressure technique should be considered when formation damage is present or whenever a water zone or gas cap is near and fracturing could result in excessive water or gas production with the oil.

In addition to producing new channels in a formation, acidizing can remove water blocks, emulsion blocks, and deposited solids from channels to increase or restore production.

Hydraulic Fracturing

Hydraulic fracturing has gained wide acceptance in the oil industry for the treatment of sandstone reservoirs to improve the flow of oil/gas. New wells may be fractured on completion to improve production and refractured when it is required to restore productivity.

To keep the fracture open or spread, the fracturing fluids will contain propping agents which are suspended particles that will be carried into the newly formed fractures and deposited therein. Sand, beads of aluminum, glass, plastics, and nutshells have all been used as propping agents. Fluids used for fracturing are often complex mixtures. A good fluid should have low-loss characteristics (nonpenetrating), the ability to carry the proppant into fractures, and low pumping friction loss. The fluids can be oil-based, water-based, and acid-based. The selection of the best fluid base depends on the chemical and physical nature of the formation and of the reservoir fluid. As stated in an earlier section, acid-based fluids are generally used with carbonate rocks, i.e., limestone and dolomites.

SECTION 8

SURVEY OF NEW OIL AND GAS FIELDS, 1975-1979

According to item 1. in the Introduction to this report, information was to be gathered for the "lower" or "conus" 48 states, onshore fields only, limiting data to fields that went into primary production after December 1974. Figure 9 was prepared to show the desired VOC Survey Data. Activity included telephone contacts with the following organizations:

1. American Association of Petroleum Geologists (AAPG), Tulsa, OK, and San Francisco, CA: They publish annual drilling statistics every August for the preceding calendar year, and, in more detail, prepare tapes that are sold through API. They do not appear to issue any production information. The August 1979 Bulletin with 1978 data was obtained.

2. American Petroleum Institute (API), Washington, DC: Furnish tapes of master wells, plus tapes of AAPG on exploratory wells. Tapes are incorporated in the PDS system (see 4. below).

3. Department of Energy (DOE) - Annual Survey of Oil and Gas Reserves (RAPS - Reserves and Production System), Norman, OK: Producers furnish annual data which are verified and then put on tape by the University of Oklahoma (subcontractor) and the tape is shipped to Washington, DC, for processing and incorporation into RAPS by DOE.

4. Petroleum Data System (PDS), Norman, OK: USGS-sponsored storage and retrieval system located at the University of Oklahoma. Includes most of State, API, and AAPG generated information and much of what is desired for this project.

5. Petroleum Information Corporation (PI), Denver, CO, and Houston, TX: Gathers nationwide data from states (except New England) on a weekly basis and maintains digital and hard copy files. Issues annual information sooner than others. Appears to have most information desired.

6. R&D Representatives of EPA Regions: These were requested to act as points of contact for the states in each Region. Cooperation was good throughout.

7. Interstate Oil Compact Commission, Oklahoma City, OK: An up-to-date directory of state oil and gas agencies was obtained.

1. Field Name and Operator(s) in Field
2. Formation/Reservoir
3. County
4. Primary Production Start Date (January 1975 or later)
5. Type of Field (oil, oil/gas, gas) and API Gravity (where applicable)
6. Well depth, feet
7. Producing Zone, feet (or least and greatest depth)
8. Number of wells as of recent date (state date)
   a. Producing
   b. Exploratory
   c. Abandoned
9. Annual Production for 1975, 1976, 1977, 1978, and 1979 of:
   a. Crude oil (bbl)
   b. Condensate (bbl)
   c. Nonassociated gas (million cu.ft.)
   d. Associated gas (million cu.ft.)
   e. Water (bbl)

Figure 9. List of drilling and production data to be acquired for each new field.

8. Oil and gas agencies or divisions of geology of all conus states. These agencies regulate oil and gas drilling and production and maintain records of various types. They issue annual (and sometimes monthly) reports, and these were requested for the years 1975-1979.

Further action was taken as follows:

PDS: A computer expert from Rockwell EMSC attended a PDS seminar in Tulsa on 11 December 1979. The seminar provided information on the files available at PDS and on methods of accessing to their data base. The PDS Users Guide was obtained. Table 1 shows a status report on their holdings, from which it is seen that information in the data base is incomplete. This means that more current information must be sought elsewhere. PDS is the most economical computer data bank, though, and a terminal hookup to their bank was made.

PI: A letter was written outlining our data requirements and a visit was made to PI's Houston facility. PI's cost estimate to furnish the desired data was, however, excessive compared with contract funding, so this route had to be abandoned.

Pursuant to the inquiries described above, it was decided to access the PDS data bank, obtain what information was available (see Table 1), and fill in the gaps from state files. Throughout, all the information listed on Figure 9 was sought.

The PDS compilation more or less contained the data listed in Figure 9, but "exploratory wells" were not listed. Instead, a listing of wells "capable of producing" was given. The states varied greatly in their publications. While oil and gas well drilling and production statistics are public records and open to inspection at the state capitals or other locations within the state, the printed reports disseminated were often incomplete or not in a form suitable for this study (e.g., production by county, not by field). Some of the largest oil/gas producing states (e.g., Oklahoma and New Mexico) issued no reports, but merely furnished information to API, PDS, or PI. Also, in many cases reporting was late by several years (see Table 1), representing the combination of delays ascribable to the state and the PDS.

Figure 10 is a map of the major oil/gas regions in the conus states. Figure 11 is a map of the U.S. EPA Regions. Statewide summations of new fields and wells were ordered in Table 2 by EPA Regions.

Twenty-one of the 48 states have no new fields, e.g., the New England states have no oil or gas exploration at all. In 18 of the states with new fields, state data were scanned, identified, edited and punched in as additions to the PDS computer compilation and appear in the printout of Appendix A. The limited scope of this project did not permit completion of such tasks for the nine remaining states with new fields; the PDS compilation and partially processed state data are preserved (indicated as "raw" data on Table 2). Table 2 shows that PDS and state data were available only for certain years.

TABLE 1. STATUS REPORT OF PETROLEUM DATA SYSTEM,

TEXS AND OILY DATA BASES, SEPTEMBER 14, 1979

State	Number of Records***	Production Years in Data Base
Alabama	82	1968-1977
Alaska	63	1972-1978
Arizona	15	1968-1977
Arkansas	838	1968-1977**
California	1,263	1968-1976
Colorado	1,085	1968-1974**
Florida	15	1968-1978
Illinois*	2,990	1968-1977
Indiana*	1,114	1968-1977
Kansas*	9,389	1968-1975**
Kentucky	2,725	1968-1975
Louisiana*	6,313	1968-1974**
Louisiana OCS*	261	1970-1976
Maryland	3	1973
Michigan	1,030	1968-1976
Mississippi	1,255	1968-1976
Missouri	8	1968-1976
Montana	556	1968-1977
Nebraska	672	1968-1977
Nevada	1	1968-1975
New Mexico	1,433	1968-1977**
New York	180	****-1972
North Dakota	180	1968-1974**
Ohio	1,314	****
Oklahoma	8,071	1968-1974**[A]
Pennsylvania	582	1968-1976
South Dakota	12	1968-1975
Tennessee	146	1970-1977
Texas	40,920	1968-1977
Utah	304	1968-1976**
West Virginia	297	1968-1973[B]
Wyoming	1,351	1968-1974

* Production is reported on "Field Record"
** To be added from Dwight's Energydata, Inc.
*** Each record contains oil production data for a different field.

A - Crude oil production - 1975

B - Cumulative production only

Texas - All annual production - 1977; cumulative crude oil production - 1977

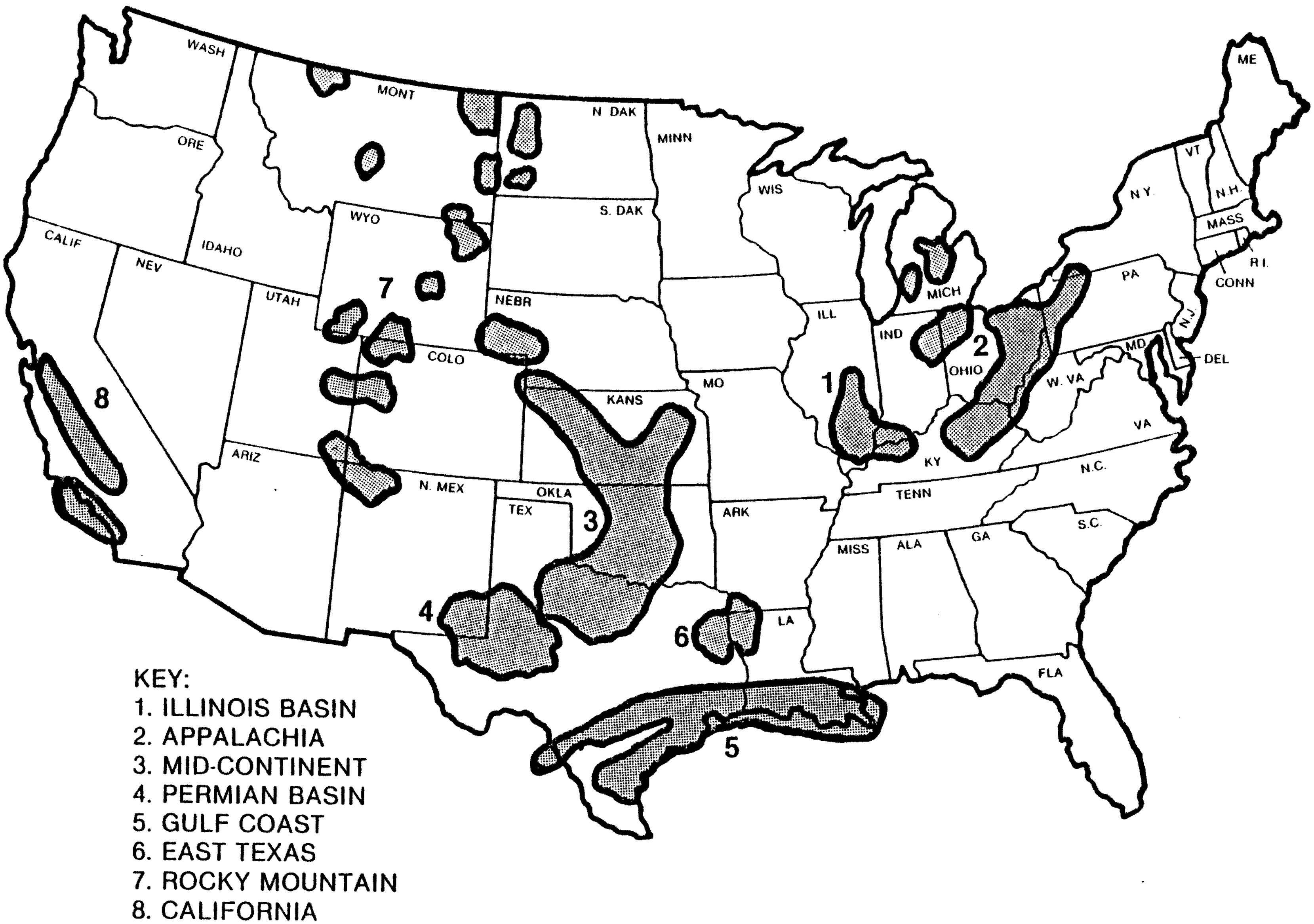

Figure 10. Major oil regions in continental U.S.

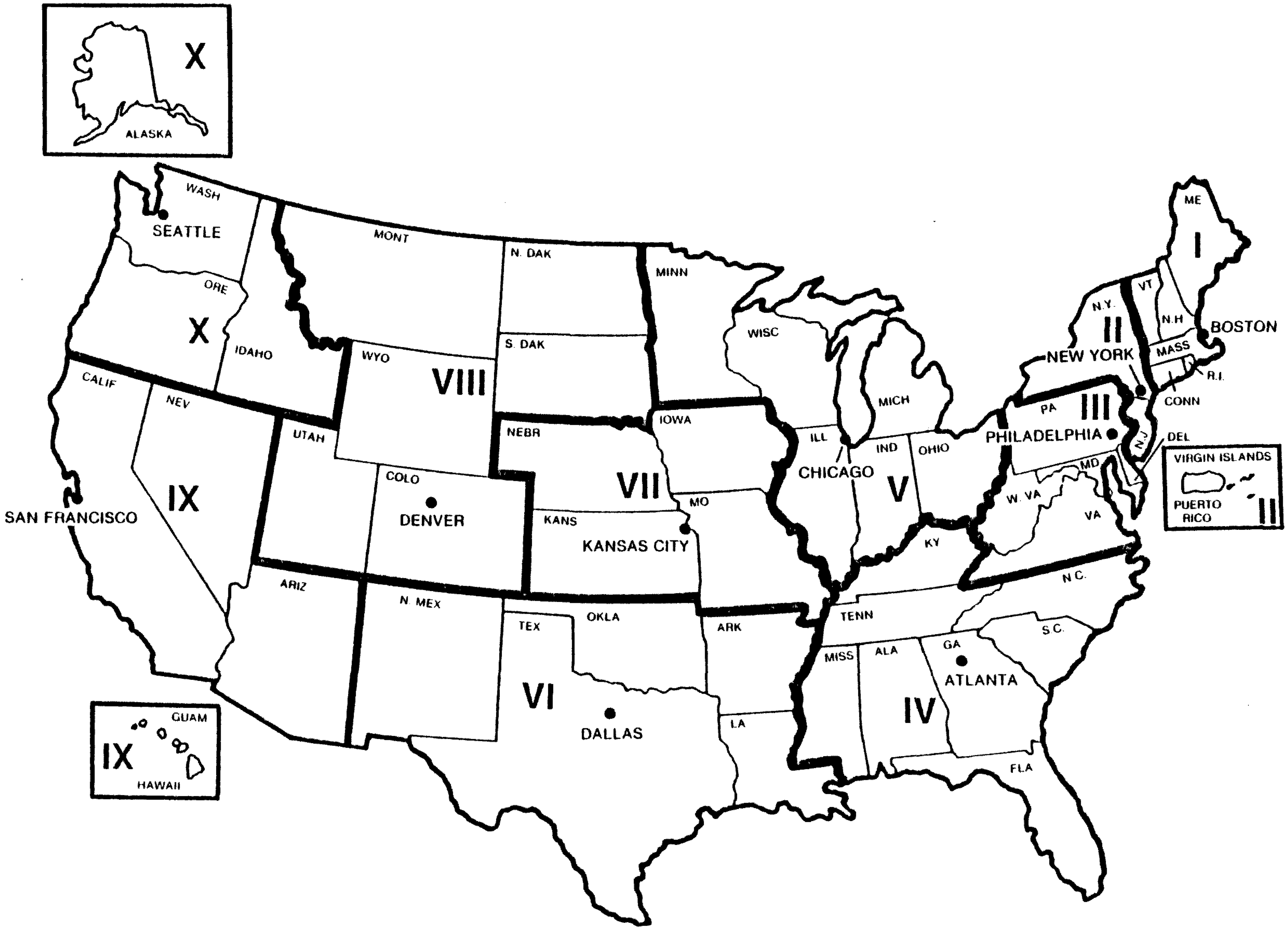

Figure 11. EPA Regional Offices - standard federal regions.

TABLE 2. REGIONAL AND STATEWIDE OVERVIEW OF NEW FIELD SURVEY AND DATA

EPA Region	Conus States	Data Years: PDS	Data Years: State	New Field Data: Printout	New Field Data: Raw Only*	No New Fields
I	CT					X
	MA					X
	ME					X
	NH					X
	RI					X
	VT					X
II	NJ					X
	NY					X
III	DE					X
	MD					X
	PA	76	-	✓		
	VA	-	75-78		✓	
	WV	-	75-79	✓		
IV	AL	75-77	77-79	✓		
	FL	-	75-79	✓		
	GA					X
	KY	75-76		✓		
	MS	75-76	75-78	✓		
	NC					X
	SC					X
	TN	75-77	75-78		✓	
V	IL	75-77	75-78	✓		
	IN	75-77	75-78	✓		
	MI	75-76	75-78	✓		
	MN					X
	OH	-	78-79			X
	WI					X
VI	AR	75-77	75-78	✓		
	LA	-	75-76	✓		
	NM	75-78	-		✓	
	OK	75	-		✓	
	TX	75-77	75-6,78	✓		
VII	IA					X
	KS	75	75-78		✓	
	MO					X
	NB	75-78	75-79		✓	

*Not worked up for printout.

(continued)

TABLE 2 (Continued)

EPA Region	Conus States	Data Years: PDS	Data Years: State	New Field Data: Printout	New Field Data: Raw Only	No New Fields
VIII	CO	75-76	75-76	✓		
	MT	75-77	75-78	✓		
	ND	-	75-79		✓	
	SD	75	75-79	✓		
	UT	-	74-78		✓	
	WY	75	75-78	✓		
IX	AZ	-	75-79			X
	CA	75-76	77-78		✓	
	NV	-	75-79	✓		
X	ID	-	75-79			X
	OR		75-79	✓		
	WA					X
	TOTAL CONUS STATES:			18	9	21

In terms of EPA Regions, there are no new fields in Regions I or II, whereas every state in Regions VI and VIII does have new fields. Regions IV, V, VII, IX, and X have some states with new fields and some without. It should be borne in mind that the definition of "field" varies with the state. For example, in Texas the term is frequently used for a single well, whereas in Ohio it is applied to formations that may be over 161 km (100 miles) in extent. Thus, Ohio, which has had recent drilling activity, is technically listed as not having new fields.

Statewide totals and averages are shown in Table 3 for the 18 states on the printout. In addition to total new fields and wells in new fields, average well depths and average pay (or producing) zone extent are listed where such data were given. The average pay zones are generally 15.2 m (50 ft) or less in extent. The average well depths vary from hundreds of meters (one or two thousand feet) to over 3660 m (12,000 ft). In the case of oil fields, average API gravity varies from 18 to 50.

Table 4 is a compilation of statewide new field production totals, in each of the 5 years of interest (1975 through 1979), separated into five categories (crude oil, associated gas, nonassociated gas, condensate, and water).

The information headings presented on a statewide basis (18 states) in Tables 3 and 4 appear on a fieldwide basis in the printout of Appendix A, alphabetically by state, within each state alphabetically by county, and within each county alphabetically by new field. Because of the mass of the printout (including Texas with over 4200 new fields), it has been placed between

TABLE 3. STATEWIDE NEW FIELD DATA: FIELDS, WELLS, DEPTHS, GRAVITY

State	New Fields			No. Wells in New Fields			Avg Depth, m (ft)	Avg Pay Zone, m (ft)	Avg API Gravity
	Total	Oil	Gas	Producing	CAPDG*	Shut In			
Alabama	23	11	21	102	0	0	3,014 (9,889)	5.2 (17)	40
Arkansas	62	50	18	2174	0	0	1,853 (6,078)	6.7 (22)	36
Colorado	107	58	57	138	0	11	1,734 (5,689)	9.1 (30)	38
Florida	4	4	1	3	0	3	3,934 (12,906)	4.9 (16)	31
Illinois	96	NG	NG	>151	(total wells)		1,352 (4,435)	NG	18
Indiana	1	1	0	0	2	0	344.4 (1,130)	NG	NG
Kentucky	18	>11	>3	>32	(total wells)		569.7 (1,869)	NG	NG
Louisiana	35	8	29	55	4	8	3,324 (10,906)	6.7 (22)	47
Michigan	141	>79	>28	169	22	1	1,623 (5,325)	NG	50
Mississippi	91	>62	>15	123	12	19	3,667 (12,030)	11.3 (37)	41
Montana	99	55	45	419	0	104	2,720 (8,924)	7.9 (26)	40
Nevada	1	1	0	14	0	0	1,246 (4,087)	NG	27
Oregon	1	0	1	5	0	0	833 (2,700)	183 (600) (sands)	NA
Pennsylvania	26	NG	NG	NG	NG	NG	1,165 (3,823)	NG	NG
So. Dakota	2	2	0	2	0	0	2,728 (8,950)	3.05 (10)	33
Texas	4208	>1408	>1922	6392	4303	0	2,276 (7,468)	NG	42
W. Virginia	21	0	21	21	0	0	1,095 (3,591)	4.6 (15)	NA
Wyoming	6	NG	NG	NG	NG	NG	2,880 (9,450)	18.6 (61)	24

* Capable of producing

NG = not given NA = not applicable

TABLE 4. STATEWIDE NEW FIELD PRODUCTION STATISTICS

Key:

TCRU	TNGS	TAGS	TCON	TWTR
TCRU75	TNGS75	TAGS75	TCON75	TWTR75
TCRU76	TNGS76	TAGS76	TCON76	TWTR76
TCRU77	TNGS77	TAGS77	TCON77	TWTR77
TCRU78	TNGS78	TAGS78	TCON78	TWTR78
TCRU79	TNGS79	TAGS79	TCON79	TWTR79

TCRU: Annual crude oil production, barrels (1 bbl = 0.159 m^3)

TNGS: Annual nonassociated gas production, million cu.ft. (million cu.ft. = 28,317 m^3)

TAGS: Annual associated gas production, million cu.ft. (million cu.ft. = 28,317 m^3)

TCON: Annual condensate production, barrels (1 bbl = 0.159 m^3)

TWTR: Annual water production, barrels (1 bbl = 0.159 m^3)

AL	150,524	81,499	152,647	NR	NR
	406,350	28,067	333,182	NR	259,323
	542,583	3,579,173	389,277	86,070	345,005
	965,433	12,213,688	774,968	372	NR
	949,586	12,066,875	666,085	268	NR
AR	80,743	NR	97,249	NR	NR
	573,727	NR	522,905	NR	NR
	1,212,083	548,621	1,247,681	NR	NR
	1,378,072	888,484	1,669,665	NR	NR
	NR	NR	NR	NR	NR
CO	155,242	806,745	128,133	1,844	NR
	406,260	4,355,247	424,902	24,953	NR
	2,219	NR	7,679	NR	NR
	NR	NR	NR	NR	NR
	NR	NR	NR	NR	NR
FL	NR	NR	NR	NR	NR
	NR	NR	574	NR	5,435
	130,286	NR	6,407	NR	79,472
	93,461	NR	5,718	NR	9,821
	121,948	NR	7,918	NR	57,756
IL	6,300	NR	NR	NR	NR
	47,300	NR	NR	NR	NR
	2,938,400	NR	NR	NR	NR
	NR	NR	NR	NR	NR
	NR	NR	NR	NR	NR
IN	1,365	NR	NR	NR	NR
	NR	NR	NR	NR	NR
	4,868	NR	NR	NR	NR
	NR	NR	NR	NR	NR
	NR	NR	NR	NR	NR

NR = no data reported.

(continued)

TABLE 4 (continued)

KY	95,415	NR	NR	NR	NR
	NR	NR	NR	NR	NR
	NR	NR	NR	NR	NR
	NR	NR	NR	NR	NR
	NR	NR	NR	NR	NR
LA	141,414	7,729,441	135,505	190,841	NR
	1,168,706	14,703,879	516,375	377,061	NR
	NR	NR	NR	NR	NR
	NR	NR	NR	NR	NR
	NR	NR	NR	NR	NR
MI	473,347	652,113	236,541	56,814	59,860
	2,822,236	7,613,651	2,375,440	325,206	467,930
	NR	NR	NR	NR	NR
	NR	NR	NR	NR	NR
	NR	NR	NR	NR	NR
MS	534,993	1,403,855	64,831	21,954	835,174
	1,451,989	4,764,596	850,445	126,453	3,605,531
	NR	NR	NR	NR	NR
	NR	NR	NR	NR	NR
	NR	NR	NR	NR	NR
MT	88,462	741,753	653,204	NR	NR
	687,213	2,481,750	738,373	NR	NR
	1,553,616	7,500,326	2,929,549	NR	NR
	2,036,765	8,565,412	5,722,375	NR	NR
	NR	NR	NR	NR	NR
NV	NR	NR	NR	NR	NR
	19,055	NR	NR	NR	NR
	548,226	NR	NR	NR	10,952
	1,084,523	NR	NR	NR	119,442
	1,160,804	NR	NR	NR	107,208
OR	NR	NR	NR	NR	NR
	NR	NR	NR	NR	NR
	NR	NR	NR	NR	NR
	NR	NR	NR	NR	NR
	NR	NR	15,160	NR	NR
PA	NR	NR	NR	NR	NR
	NR	39,043	NR	NR	NR
	NR	NR	NR	NR	NR
	NR	NR	NR	NR	NR
	NR	NR	NR	NR	NR

(continued)

TABLE 4 (Continued)

SD	30,216	NR	1,232	NR	NR
	NR	NR	NR	NR	NR
	NR	NR	NR	NR	NR
	NR	NR	NR	NR	NR
	NR	NR	NR	NR	NR
TX	4,575,848	168,752,960	475,899	1,015,566	NR
	16,078,350	376,611,104	6,864,836	2,958,835	NR
	24,482,236	646,636,032	36,059,528	6,148,281	NR
	NR	NR	NR	NR	NR
	NR	NR	NR	NR	NR

No production statistics were available for West Virginia or Wyoming.

separate covers. The time and effort allocated to this part of the program did not permit close scrutiny and correction of the many inaccuracies found in the printout as it came from PDS. For the present purpose, absolute verification of all items is not warranted. However, under the constraints mentioned above, the data do show those states with drilling activity and can be used for qualitative predictions.

SECTION 9

VOC EMISSIONS FROM OIL/GAS DRILLING OPERATIONS

A review of the literature on oil and gas well drilling practice published by the API (e.g., Baker, Ron, A Primer of Oil-Well Drilling, 4th Ed., Petroleum Extension Service, University of Texas, Austin, TX, 1979) and information supplied by drilling consultants indicates that there are three main sources of VOC associated with the drilling operation. These are:

1. Stored fuel for the drilling rig prime movers (usually diesel fuel)
2. Exhaust products from the prime movers (usually diesel engines)
3. Formation fluids, high-pressure, low-molecular-weight hydrocarbons and H_2S from unsealed "troublesome" formations

STORED FUEL AND ENGINE EMISSIONS

Estimates of VOC emissions from storage fuel tanks and prime movers associated with drilling operations have been specifically excluded from the scope of this effort. These VOC sources will be considered in studies conducted elsewhere.

FORMATION GASES, HYDROCARBONS

Many wells will have some gas in the drilling mud at times. Some wells, near completion, may send larger amounts of gas into the mud before drilling is completed and must be watched closely. High-pressure formation gases entering the bore hole during the drilling procedure will be entrained and, to a much lesser extent, dissolved in the drilling mud. If the entrainment rate is not severe enough to cause a kick (a rapid reduction in hydrostatic head that permits more high-pressure formation gases to enter the drilling mud, resulting in a further loss of hydrostatic pressure and a potential runaway, or blowout, situation), the entrained gases will be removed in the mud maintenance system by a degasser. Some gas bubbles will be removed from the drilling mud during processing by the shale shaker and during storage in the mud pits or tanks while awaiting recycling into the borehole. Ordinarily, however, drilling muds will be too viscous for gas bubbles to rise to the surface and break at an appreciable rate in the mud pits. While some formation gases entrained in the mud will be emitted to the atmosphere in the mud pits and should be taken into account, most of the gas will be extracted by the degasser.

If, during the well-drilling process, a kick does occur and it becomes necessary to activate the blowout preventers to shut off the drilling mud in the well bore, the gas can be bled off of the well annulus through the choke manifold and then flared to the atmosphere.

In summary, formation gas entering the mud will be removed in the shale shakers, degassers, the mud pits (reserve pit, settling pit, and suction pit), and the choke manifold (when necessary). Small quantities of gas will also be lost from valves, flanges, and other fittings in the mud recirculation system.

The probability of gas intrusion will vary according to the operation being conducted in the bore hole (i.e., drilling, tripping to change bits, running casing, cementing, well logging, and completing) and the formations that have been exposed. When the mud flow is stopped and the drill string is being hoisted from the hole (tripping), one is more likely to get gas intrusion, the so-called trip gas.

Unlike the VOC emissions from the on-site fuel storage facilities and the diesel engine exhaust, the emission of formation gases from the well via the drilling mud can vary greatly during the well boring process and, as indicated above, depending on the operation being conducted. VOC emission may be negligible until certain "troublesome" formations are penetrated. Even then, the amount of formation gas intrusion could depend on the skill of the drilling crew and the mud handler in plugging such a formation with ingredients added to the mud. Once such troublesome formations are sealed off with casing cemented in place, the VOC emission rate will again be small. The sporadic nature of the VOC emission problem from formation gases would indicate that some average gas entrainment rate in mud be obtained for troublesome formations specific to a certain oil/gas field or geological area. This rate could then be multiplied by an average formation exposure time to the mud before the zone is sealed off with well casing. Finally, this total gas leakage must be corrected to eliminate the fraction of the gas that is collected and burned. Presumably, this burned fraction will include gas removed from the drilling mud by the degasser and through the choke manifold.

FORMATION GAS, H_2S

Intrusion of H_2S into the mud is usually handled by chemical means. Iron sponge, a specially processed hematite that has extremely large surface area, can be suspended in the mud to react with H_2S to form insoluble iron sulfide. Zinc carbonate has been widely used in drilling muds in areas of high H_2S concentration. The reaction time of H_2S with the zinc carbonate is much faster than with iron sponge. Virtually all drilling muds are maintained at a high pH. Reactions of H_2S to form an alkaline sulfide are favored at pH above 10.5.

PROSPECTIVE VOC SOURCES

Estimates of VOC emission of hydrocarbon formation gases must include data on the number of oil and gas wells being drilled and the number of drilling rigs in operation. Current information on drilling activity in the U.S. has been reviewed and is summarized in the following subsections.

Drilling Activity

According to World Oil's 1980 forecast (World Oil, "U.S. Drilling Records Are Falling," p. 95, February 15, 1980), the number of oil and gas wells drilled in 1980 will increase sharply; the prediction was that 56,083* new wells would be drilled in the U.S. in 1980. This forecast, if verified, would make 1980 second only to 1956 in terms of holes drilled; it represents an 11.4% increase over the 50,332 wells drilled in 1979 and a 12.3% increase over the 49,831 wells drilled in 1978 (World Oil, loc. cit.). The data on total U.S. drilling activity since 1974 are given in Table 5, while data since 1956 are plotted in Figure 12 (World Oil, loc. cit.) along with information on how many of these wells were oil, gas, dry, and service wells.

As indicated in Table 5, only 31,121 wells (18,051 new oil and 13,070 new gas) drilled in 1979 were productive. It is these wells we would be concerned with as sources of VOC. Figure 12 shows the prediction of 35,001 producing wells for 1980, a 12.5% increase over 1979.

The number of exploratory wells drilled in 1979 was 11,658 (23.2% of the number of wells drilled in 1979), of which 3,055 were productive (1,236 oil and 1,819 gas) (World Oil, "More Wildcats Expected," p. 105, February 15, 1980). For 1980, it was predicted that 13,075 exploratory wells would be drilled (World Oil, loc. cit.). The data are given in Table 6 and are plotted in Figure 13. The category of "exploratory well" includes new field, new pool, deeper or shallower pool, outpost, and extension. Information on one of these categories, i.e., new field wildcats, was available and is presented in Table 7 and Figure 13 (World Oil, loc. cit.).

From the Oil and Gas Journal, actual U.S. well completions from January through July 1980 number 31,981, of which 13,652 are oil, 8,160 are gas, and 902 are service wells. This can be compared with 26,873 for the similar period of 1979. Using the ratio of well completions in 1980 and 1979 for this 7-month period (1.19) multiplied by the total well completions in 1979 to estimate the total number of well completions in 1980, one obtains 59,900. This estimate can be compared with the World Oil forecast of 56,083 new wells. It is quite apparent that drilling activity in the U.S. for 1980 will greatly exceed predictions made at the close of 1979.

Drilling Rigs

Data on the number of operating drilling rigs as a function of time are plotted in Figure 14. It can be seen that 1979 saw a decline in drilling activity; only 2,194 rigs were active. This decrease has been attributed to confusion over the Natural Gas Policy Act of 1978, a surplus of natural gas on the market, and a "wait and see" attitude by many operators regarding the government energy policy. However, an increase in natural gas prices and decontrol of some categories of crude oil in mid-1979 and the promise of total crude price decontrol in the near future spurred drilling activity near the

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* If Alaska, offshore Louisiana, and offshore Texas drilling are eliminated, the total number of new wells is predicted to be 54,861.

TABLE 5. TOTAL U.S. DRILLING

Year	Productive Wells: Oil	Productive Wells: Gas	Productive Wells: Dry	Service & Suspended*	Total Wells
1974	13,719	7,032	11,867	852	33,470
1975	16,626	7,437	13,203	1,121	38,387
1976	16,389	8,003	13,396	2,741	40,529
1977	17,876	9,836	14,198	4,196	46,106
1978	17,755	11,169	15,437	5,570	49,931
1979	18,051	13,070	14,947	4,264	50,332

* Most suspended wells will likely produce at some future date. No information is available regarding producing/nonproducing status.

end of the year. By January 28, 1980, 2,647 drilling rigs were reported to be active (Oil and Gas Journal, "Hughes Rig Count," p. 97, February 4, 1980). The all-time record high was set in May 1956 when an average of 2,899 units worked. World Oil's forecast issued in January 1980 was that an average of 2,525 rigs would be needed for 1980.

The cumulative average number of drilling rigs in operation in the U.S. as of 8 September 1980 is 2,788 compared with 2,070 on 10 September 1979 (Oil and Gas Journal, "U.S. Well Completions - July 1980 API Data," p. 178). This represents a 34.7% increase in rigs over 1979. It appears that drilling activity in 1980 will exceed the previous record year of 1956. The total number of well completions up through July 1980 is 19.0% ahead of the figures for 1979, while the total footage drilled is up only 16.8%.

MODEL FOR DRILLING OPERATIONS

An equation summing the total VOC emissions (E, kilograms per day) occurring during the drilling of an oil/gas well will consist of three general parts, or terms.

The first term of the equation will attempt to account for the VOC resulting from the oil contained in the volume of porous rock cut from a producing zone by the drill and flushed out of the well-bore by the drilling mud. Thus, this term of the equation will contain the volume of producing zone rock removed, multiplied by factors to account for the porosity of the rock, the density of the oil in the producing zone, and the fraction of the oil contained in the pores of the cuttings that can be considered as VOC (some of the oil will not readily volatilize, while the light hydrocarbons, methane, and ethane are not reactive enough to be considered as VOCs).

The second part of the equation to be considered when summing up the VOC losses will account for the rate of leakage of oil/gas from an oil-bearing zone into the drilling mud. As stated earlier, leakage of oil into the mud does not normally occur; the mud density is very carefully controlled so as to maintain a positive pressure on all formations likely to be encountered. The entrance of low-density fluid or gas bubbles into the drilling mud is highly undesirable since it could result in a "kick" and a possible blowout situation that would activate the blowout preventers and result in lost drilling time. Regardless of the precautions taken, leakage of formation fluids into the drilling mud does occasionally happen during exploratory drilling when unexpected high-pressure formations are encountered. Adjustments are rapidly made in the drilling mud density to quell the leakage problem. Leakage can also occur if the drill string is hoisted from the well-bore at too rapid a rate; a slight lowering of the hydrostatic head below the drill bit can be produced under these conditions (swabbing the hole). The occurrences described may have a low probability and may account for minor VOC emissions, but they should be considered and warrant inclusion in an equation describing the total VOC emissions.

The third and final term included in the total VOC summation expression is concerned with the emission from oil-based muds. The rate of evaporative loss of No. 2 diesel fuel (the usual liquid phase ingredient in oil-based mud) must depend on the mud tmperature at the mud-atmosphere interface, the total area of the mud-atmosphere interface, the wind velocity and other factors. This rate of loss would be multiplied by the length of time the oil-based mud was used. Oil-based muds are not often used and the inclusion of their VOC contribution is not meant to imply that the evaporative loss is excessive. The fraction of wells drilled using oil-based muds is quite small and a factor can be included in this VOC term to account for this usage.

An expression summarizing the total VOC emissions (E, kilograms per day) occurring during the drilling of an oil or gas well can be written as:

$$E = \left[\begin{pmatrix} \text{Volume of Hole} \\ \text{Drilled} \\ \text{m}^3 \end{pmatrix} \times \begin{pmatrix} \dfrac{\text{Producing Zone Interval}}{\text{Well Depth}} \\ \text{Fraction} \end{pmatrix} \times \begin{pmatrix} \text{Porosity of Pro-} \\ \text{ducing Zone} \\ \text{Cuttings, Fraction} \end{pmatrix} \right.$$

$$\left. \times \begin{pmatrix} \text{Density of Oil} \\ \text{in Producing Zone} \\ \text{kg/m}^3 \end{pmatrix} \times \begin{pmatrix} \text{Fraction of Oil} \\ \text{Considered VOC} \\ \text{Fraction} \end{pmatrix} \right] + \left[\begin{pmatrix} \text{Leakage of Oil/Gas} \\ \text{Into Drilling Mud} \\ \text{kg/day} \end{pmatrix} \right.$$

$$\left. \times \begin{pmatrix} \text{Average Producing} \\ \text{Zone Exposed Time} \\ \text{Days} \end{pmatrix} \right] + \left[\begin{pmatrix} \text{Fraction of Wells} \\ \text{Using Oil-Based Muds} \\ \text{Fraction} \end{pmatrix} \right.$$

$$\left. \times \begin{pmatrix} \text{Oil-Based Mud} \\ \text{Evaporation Rate} \\ \text{kg/day} \end{pmatrix} \times \begin{pmatrix} \text{Average Hole} \\ \text{Drilling Time} \\ \text{Days} \end{pmatrix} \right]$$

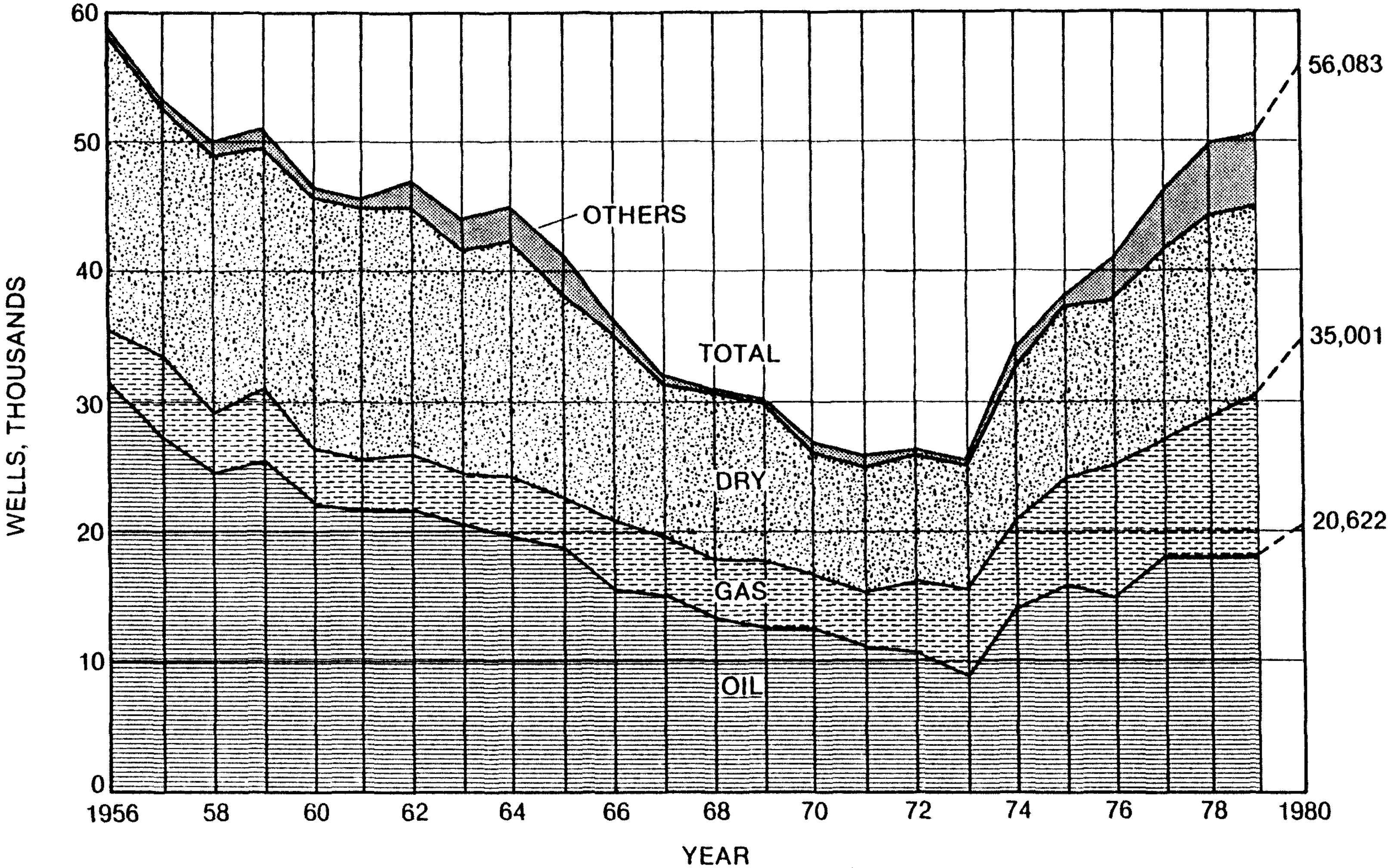

Figure 12. U.S. drilling activity since 1956.

TABLE 6. U.S. EXPLORATORY DRILLING*

Year	Productive Wells Oil	Productive Wells Gas	Productive Wells Total	Total Exploratory	Conus Avg Depth, m (ft)
1978	1,215	1,483	2,698	12,125	1,767 (5,798)
1979	1,236	1,819	3,055	11,658	1,809 (5,936)
1980 (predicted Jan.)				13,075	
(cum. July)	841	1,063	1,904	6,247	
(predicted July)				13,607	

* Includes new field wildcat tests, new pools, shallower pools, outpost, and extension.

TABLE 7. U.S. NEW FIELD EXPLORATORY WELL DRILLING (WILDCAT)

Year	Productive Wells Oil	Productive Wells Gas	Productive Wells Total	Total Wildcat*	Average Depth, m (ft)
1975	510	522	1032	7026	1778 (5834)
1976	508	530	1038	6438	1787 (5863)
1977	506	526	1032	7121	1838 (6031)
1978	516	501	1017	6779	1913 (6275)
1979	547	744	1291	7680	1895 (6217)

* 1976-1979 totals include suspended new field wildcat wells. It is presumed that most of these tests will ultimately be finalized as oil or gas discoveries because they were suspended.

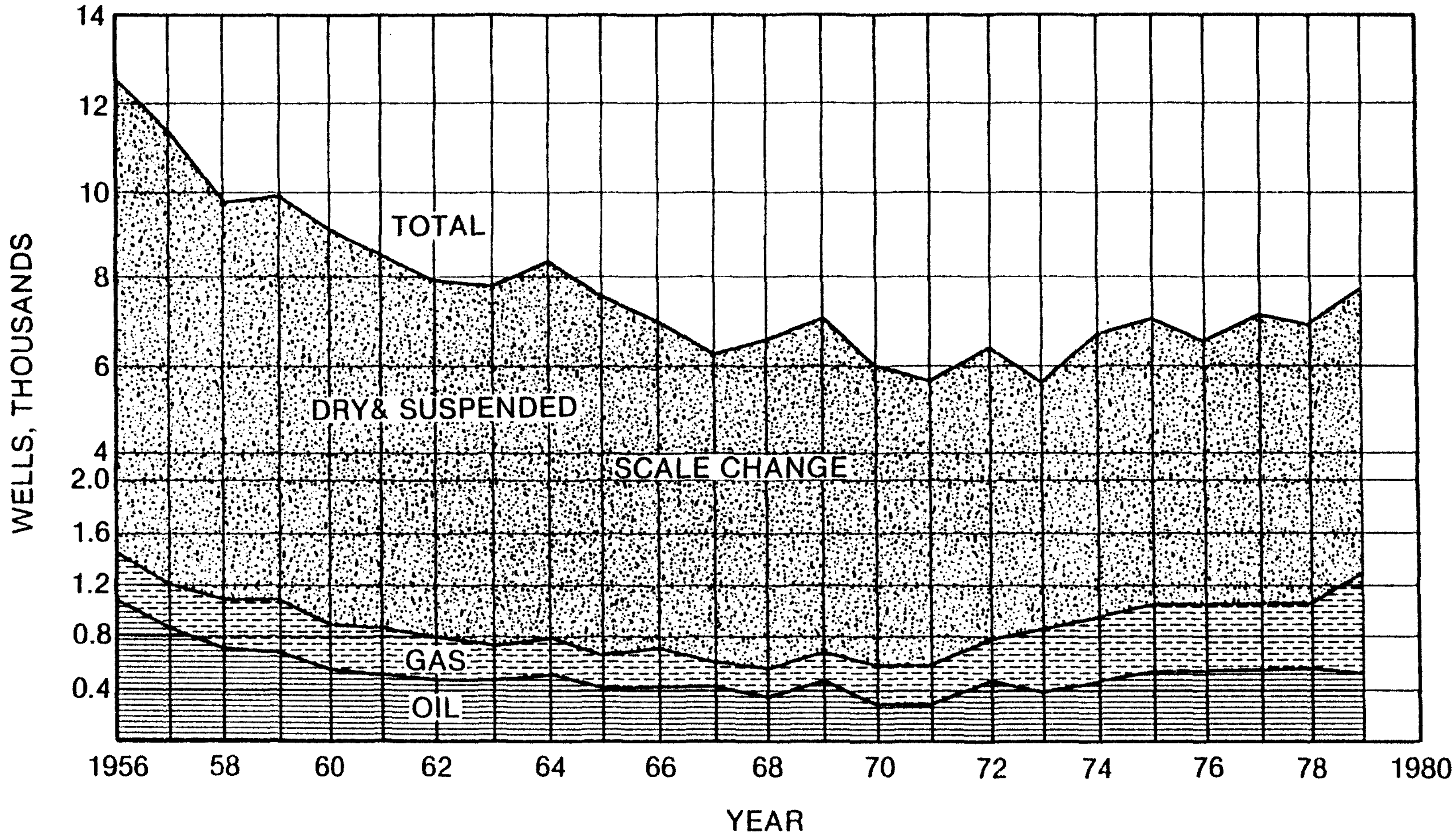

Figure 13. New field wildcatting since 1956.

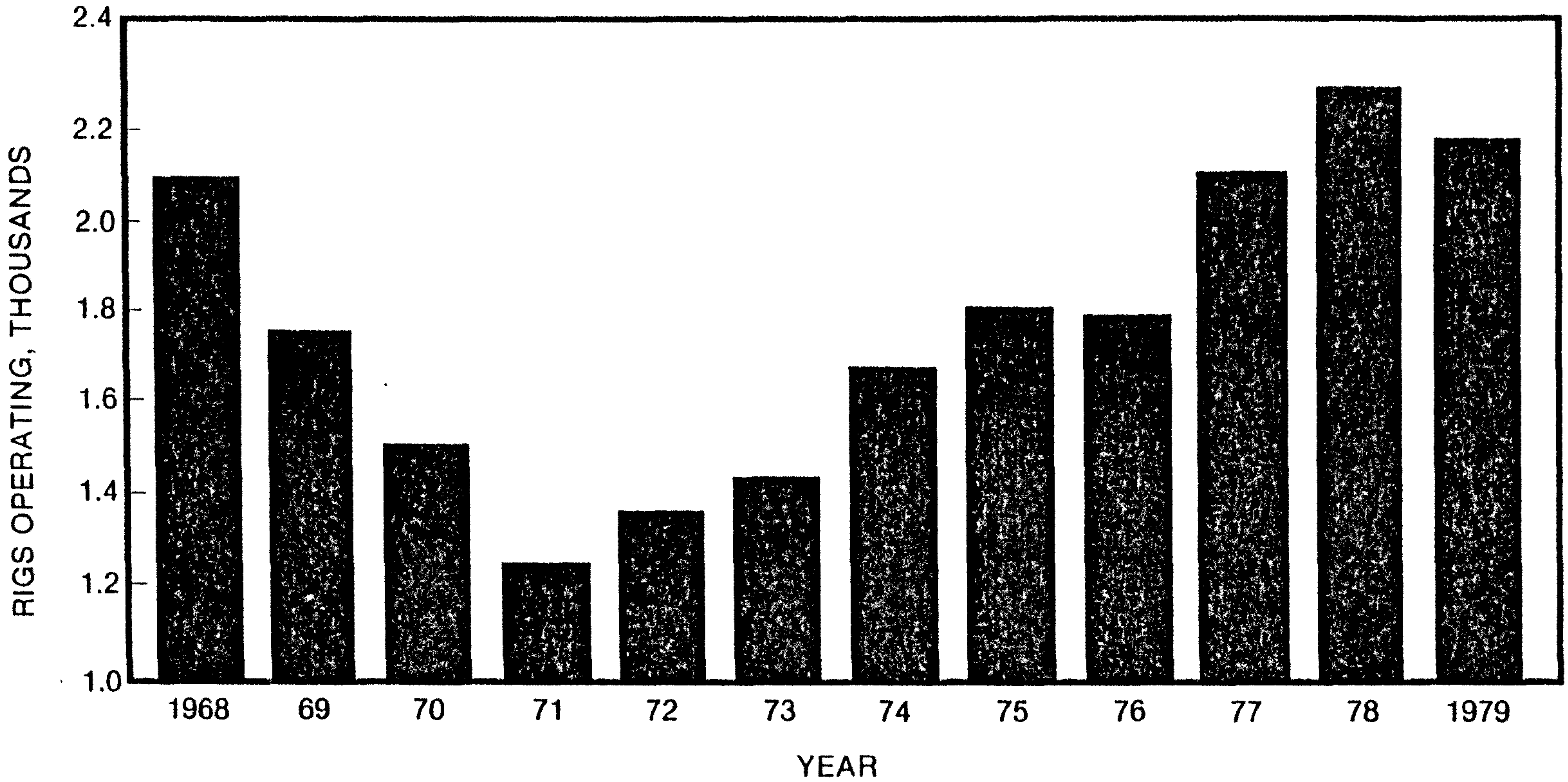

Figure 14. Drilling rig activity.

Terms involving stored fuel tank losses and unburned organics in prime mover exhaust products could be added to this general equation, but consideration of these items is not in the purview of this study.

Estimates of the *order of magnitude* of the VOC emissions occurring during the drilling of oil/gas wells (E) can be made by judicious utilization of new field information provided from PDS files referred to in Section 6 and Appendix A and the statistics on drilling activity such as those presented in Tables 5, 6, and 7. Values for some of the pertinent terms in the equation for E can be obtained from these data and estimates of other terms, such as the porosity of the producing formation (0.20 is a good estimate) and the density of the oil/gas in the producing zone (approximately 600 kg/m^3), can be made.

Using information given for 1979 on the total number of wells and footage drilled in the conus 48 states (excluding offshore drilling) and the average number of active drilling rigs for 1979, the following statistics were calculated:

Average well depth	1491 m (4893 ft)
Average depth drilled per day	117.3 m (385 ft)
Average well drilling time	14.7 days*
Average exploratory well depth	1809 m (5936 ft)
Average exploratory well drilling time	17.4 days*

New field data given in Table 3 provide values of average well depth and producing zone interval for many states. Values for five representative oil/gas-producing states are summarized in Table 8.

From the ratio of the producing zone interval to the average well depth (depth ratio, $\Delta m/m$) given in Table 8, it appears that for the five states shown, less than 1% of the total well drilling time is spent cutting through the producing zone. Assuming that the average well diameter is 0.23 meters and using a formation porosity and oil density of 0.2 and 600 kg/m^3, respectively, a value of 0.5 for the fraction of the oil in the rock that can be considered as VOC, and the depth ratio from Table 8, the values of the first bracketed quantity on the right-hand side of the equation for E have been calculated and appear in Table 9 under the column heading "VOC per Well." The well drilling time given in Table 9 is the result of dividing the average new field well depth for the state by the average depth drilled per rig-day (117.3 m [385 ft]). Dividing the VOC per well by the drilling time, an average VOC emission rate per day per producing well being drilled is obtained. If this number is multiplied by the rate at which new field wells are being brought into production in that state, the results would be the total state VOC emission rate from the producing zone cuttings. The average VOC emission rate per

* Assuming 2 days are required to relocate the drilling rig after a well drilling assignment.

TABLE 8. NEW FIELD DATA SUMMARY

State	Avg Well Depth, m (ft)	Producing Zone, Δ m (Δ ft)	$\frac{\text{Prod. Zone Interval}}{\text{Avg Well Depth}}$, $\left(\frac{\Delta m}{m}\right)$
Alabama	3014 (9887)	5.2 (17)	0.00172
Arkansas	1853 (6078)	6.7 (22)	0.00362
Colorado	1734 (5689)	9.1 (30)	0.00527
Louisiana	3324 (10906)	6.7 (22)	0.00202
Montana	2720 (8924)	7.9 (26)	0.00291

TABLE 9. ESTIMATED VOC EMISSIONS FROM NEW FIELD WELL DRILLING

State	VOC per Well (kg/well)	Average Well Drilling Time (days)	VOC Avg Rate per Well (kg/well/day)
Alabama	51.7	25.7	2.0
Arkansas	66.9	15.8	4.2
Colorado	91.5	14.8	6.2
Louisiana	67.0	28.3	2.4
Montana	78.8	23.2	3.4

day per producing well being drilled ranges from 2.0 kg/day for Alabama to 6.2 kg/day for Colorado.

The contribution of the second bracketed term to E cannot be calculated at present since the leakage rate of oil/gas from the producing zone into the drilling mud is unknown. The third bracketed term, which includes the contribution to E of diesel fuel oil evaporation losses from oil-based mud, is not often of significance since oil-based muds are used on only a small fraction of wells drilled.

MODEL FOR PRODUCTION OPERATIONS

The emissions here are primarily fugitive and the equipment components comprise valves, connections, pumps, compressors, meters, hatches, diaphragms, and pits. The following model is applicable:

$$\text{Emission Rate} = \sum \begin{pmatrix}\text{Component}\\ \text{Inventory}\end{pmatrix} \begin{pmatrix}\text{Emission Rate}\\ \text{per Component}\end{pmatrix}$$

kg/day	No. of components	kg/day/ component

The Emission Rates per Component for production operations have been developed by Rockwell under API sponsorship, to be issued as "Fugitive Hydrocarbon Emissions from Petroleum Production Operations" (two volumes) by W. S. Eaton, et al., 1980, by the API.

As part of this contract, sites in five new fields containing current oil and gas production and drilling equipment were visited. The five sites were located in the States of Montana, New Mexico, Oklahoma, Texas, and Wyoming. Visits to these sites were made to document by means of 35-mm color slides the equipment and equipment components currently in use for new oil and gas production and drilling. Appendix B contains a brief description of each of the total 300+ slides taken, with reference to the major equipment items appearing on each slide.

For more complete and effective information transfer, the actual 300+ slides and a sound tape containing a narrative description of each slide have been placed under separate cover as part of this report. They are part of Appendix B, which is on file at the U.S. EPA Office of Air Quality Planning and Standards, Research Triangle Park, NC.

Although the slides are representative of current oil and gas production and drilling technology, the sites were not selected to be representative of all new fields; however, they do reflect differences in current technology, geography, and production methods. The equipment shown on the slides cannot be considered that of a typical site or facility in a national sense. This would have required an extensive in-depth survey far beyond the scope of this project.

Application of the model to estimate VOC emissions from oil and gas production and drilling equipment requires the combination of (1) production survey information, and (2) the number of components, provided that these can be considered typical. Within the limited time and budget, we were unable to analyze the slides for the number of components with respect to a major parameter, such as a well, or with respect to a major process unit.

Once the numbers of components for truly typical production and drilling equipment on a nationwide basis have been identified, application of the new field production and drilling survey information developed on this program will lead directly to a meaningful estimation of VOC emissions associated with an EPA region, state, county, or field.

Petroleum production storage tank emissions will not be included as part of the production operation emission rates to be developed. The reason for this is to avoid duplication of effort, since the EPA is sponsoring such work with another contractor.

TECHNICAL REPORT DATA
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15. SUPPLEMENTARY NOTES

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16. ABSTRACT

An extensive description of oil and gas exploration and production drilling technology is presented. Emphasis has been placed on the makeup, use, and disposal of drilling fluids. A simple model for assessment of VOC emissions accompanying drilling is presented, along with an estimation of the potential VOC emissions associated with drilling activities.

Emissions of volatile organic compounds (VOC) from oil production in new fields were estimated, based on three types of information: [1] extent of new oil and gas fields (those that started production after 1974) in the contiguous 48 states; [2] drilling techniques used for oil and gas exploration and production wells (and their VOC potential), with specific emphasis on the drilling fluids; and [3] equipment and techniques for oil and gas production in new fields and their potential VOC sources.

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17. KEY WORDS AND DOCUMENT ANALYSIS

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Oil Fields Oil Wells Gases Gas Sampling Volatiles	Volatile Organics Air Pollution Drilling Fluids	13B

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