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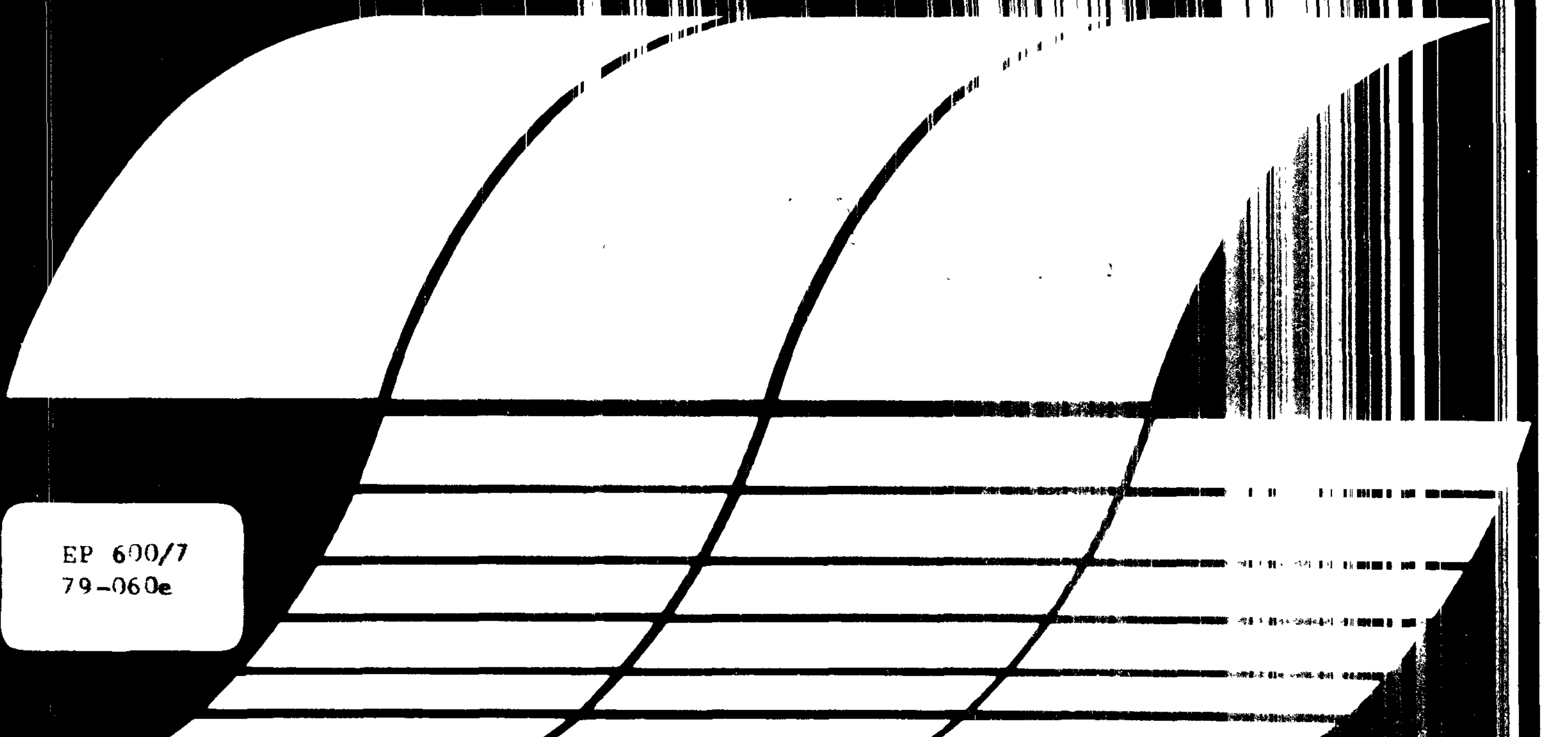
EPA

Energy from the West

Energy Resource Development Systems Report Volume V: Oil and Natural Gas

Interagency Energy/Environment R&D Program Report



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Energy From the West: Energy Resource Development Systems Report

Volume V: Oil and Natural Gas

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FORWARD

The production of electricity and fossil fuels inevitably impacts Man and his environment. The nature of these impacts must be thoroughly understood if balanced judgements concerning future energy development in the United States are to be made. The Office of Energy, Minerals and Industry (OEMI), in its role as coordinator of the Federal Energy/Environment Research and Development Program, is responsible for producing the information on health and ecological effects - and methods for mitigating the adverse effects - that is critical to developing the Nation's environmental and energy policy. OEMI's Integrated Assessment Program combines the results of research projects within the Energy/Environment Program with research on the socioeconomic and political/institutional aspects of energy development, and conducts policy - oriented studies to identify the tradeoffs among alternative energy technologies, development patterns, and impact mitigation measures.

The Integrated Assessment Program has supported several "technology assessments" in fulfilling its mission. Assessments have been supported which explore the impact of future energy development on both a nationwide and a regional scale. Current assessments include national assessments of future development of the electric utility industry and of advanced coal technologies (such as fluidized bed combustion). Also, the Program is conducting assessments concerned with multiple-resource development in two "energy resource areas":

- o Western coal states
- o Lower Ohio River Basin

This report, which describes the technologies likely to be used for developing six energy resources in eight western states, is one of three major reports produced by the "Technology Assessment of Western Energy Resource Development" study. (The other two reports are an impact analysis report and a policy analysis report.) The report is divided into six volumes. The first volume describes the study, the organization of this report and briefly outlines laws and regulations which affect the development of more than one of the six resources considered in the study. The remaining five volumes are resource specific and describe the resource base, the technological activities such as exploration, extraction and conversion for developing the resource, and resource specific laws and regulations. This report is both a compendium of information and a planning handbook. The descriptions of the various energy development technologies and the extensive compilations of technical baseline information are written to be easily understood by laypersons. Both professional planners and interested citizens should find it quite easy to use the information presented in this report to make general but useful comparisons of energy technologies and energy development alternatives, especially when this report is used in conjunction with the impact and policy analysis reports mentioned above.

Your review and comments on these reports are welcome. Such comments will help us to improve the usefulness of the products produced by our Integrated Assessment Program.

Steven R. Reznek

Acting Deputy Assistant Administrator
for Energy, Minerals and Industry

PREFACE

This Energy Resource Development System (ERDS) report has been prepared as part of "A Technology Assessment of Western Energy Resource Development" being conducted by an interdisciplinary research team from the Science and Public Policy Program (S&PP) of the University of Oklahoma for the Office of Energy, Minerals and Industry (OEMI), Office of Research and Development, U.S. Environmental Protection Agency (EPA). This study is one of several conducted under the Integrated Assessment Program established by OEMI in 1975. Recommended by an interagency task force, the purpose of the Program is to identify economically, environmentally, and socially acceptable energy development alternatives. The overall purposes of this particular study were to identify and analyze a broad range of consequences of energy resource development in the western U.S. and to evaluate and compare alternative courses of action for dealing with the problems and issues either raised or likely to be raised by development of these resources.

The Project Director was Irvin L.(Jack) White, Assistant Director of S&PP and Professor of Political Science at the University of Oklahoma. White is now Special Assistant to Dr. Stephen J. Gage, EPA's Assistant Administrator for Research and Development. R. Leon Leonard, now a senior scientist with Radian Corporation in Austin, Texas, was a Co-Director of the research team, Associate Professor of Aeronautical, Mechanical, and Nuclear Engineering and a Research Fellow in S&PP at the University of Oklahoma. Leonard was responsible for editing and managing the production of this report. EPA Project Officer was Steven E. Plotkin, Office of Energy, Minerals and Industry, Office of Research and Development. Plotkin is now with the Office of Technology Assessment. Other S&PP team members are: Michael A. Chartock, Assistant Professor of Zoology and Research Fellow in S&PP and the other Co-Director of the team; Steven C. Ballard, Assistant Professor of Political Science and Research Fellow in S&PP; Edward J. Malecki, Assistant Professor of Geography and Research Fellow in S&PP; Edward B. Rappaport, Visiting Assistant Professor of Economics and Research Fellow in S&PP; Frank J. Calzonetti, Research Associate (Geography) in S&PP; Timothy A. Hall, Research Associate (Political Science); Gary D. Miller, Graduate Research Assistant (Civil Engineering and Environmental Sciences); and Mark S. Eckert, Graduate Research Assistant (Geography).

Chapters 3-7 were prepared by the Radian Corporation, Austin, Texas, under subcontract to the University of Oklahoma. In each of these chapters, Radian is primarily responsible for the description of the resource base and the technologies and S&PP is primarily responsible for the description of laws and regulations. The Program Manager at Radian was C. Patrick Bartosh. Clinton E. Burklin was responsible for preparation of these five chapters. Other contributors at Radian were: William R. Hearn, Gary D. Jones, William J. Moltz, and Patrick J. Murin.

Additional assistance in the preparation of the ERDS report was provided by Martha W. Gilliland, Executive Director, Energy Policies Studies, Inc., El Paso, Texas; Rodney K. Freed, Attorney, Shawnee, Oklahoma; and Robert W. Rycroft, Assistant Professor of Political Science, University of Denver, Denver, Colorado.

ABSTRACT

This report describes the technologies likely to be used for development of coal, oil shale, uranium, oil, natural gas, and geothermal resources in eight western states (Arizona, Colorado, Montana, New Mexico, North Dakota, South Dakota, Utah, and Wyoming). It is part of a three-year "Technology Assessment of Western Energy Resource Development." The study examines the development of these energy resources in the eight states from the present to the year 2000. Other reports describe the analytic structure and conduct of the study, the impacts likely to result when these resources are developed, and analyze policy problems and issues likely to result from that development. The report is published in six volumes. Volume 1 describes the study, the technological activities such as exploration, extraction, and conversion for developing the resource, and laws and regulations which affect the development of more than one of the six resources considered in the study. The remaining five volumes are resource specific: Volume 2, Coal; Volume 3, Oil Shale; Volume 4, Uranium; Volume 5, Oil and Natural Gas; and Volume 6, Geothermal. Each of these volumes provides information on input materials and labor requirements, outputs, residuals, energy requirements, economic costs, and resource specific state and federal laws and regulations.

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CONVERSION FACTORS
ENGLISH UNITS/METRIC UNITS

To Convert From	To	Multiply By
acre-ft/yr	m^3/yr	1233.5
acre-ft/yr	gpm	0.6200
gpm	liters/min	3.785
acre	m^2	4046.9
Btu	Cal (gm)	252.0
Btu	joules	1054.4
tons	kg	907.18
lb	kg	0.4536
ft	m	0.3048
barrels	gal	42.0
bbls/day	gpm	0.02917
metric tons	kg	1000

ACKNOWLEDGEMENTS

Gary D. Jones and William R. Hearn of the Radian Corporation had primary responsibility for preparation of this volume of the Energy Resource Development Systems (ERDS) Report. The social controls sections were prepared by Rodney K. Freed of the Science and Public Policy Program at the University of Oklahoma. Mr. Freed is now an attorney in Shawnee, Oklahoma.

The research reported here could not have been completed without the assistance of a dedicated administrative support staff. At Radian Corporation, Mary Harris was responsible for typing of this volume, and at the University of Oklahoma, Janice Whinery, Assistant to the Director, coordinated assembly of the volumes of the ERDS Report.

Nancy Ballard, graphics arts consultant, designed the title page.

Steven E. Plotkin, EPA Project Officer, has provided continuing support and assistance in the preparation of this report.

The individuals listed below participated in the review of this volume of the ERDS Report and provided information for its preparation. Although these critiques were extremely helpful, none of these individuals is responsible for the content of this volume. This volume is the sole responsibility of the Science and Public Policy interdisciplinary research team and the Radian Corporation.

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CHAPTER 6

THE CRUDE OIL RESOURCE DEVELOPMENT SYSTEM

6.1 INTRODUCTION

6.1.1 Background

This document is one of several reports issued in support of a "Technology Assessment of Western Energy Resource Development," a project jointly conducted by the Science and Public Policy Program of the University of Oklahoma and Radian Corporation of Austin, Texas. The project is funded by the Office of Energy, Minerals, and Industry, Office of Research and Development, Environmental Protection Agency under Contract 68-01-1916. This document is issued as Chapter 6 of the "Energy Resource Development System" (ERDS) report. For each of six energy resources, the ERDS report describes the energy resource base, the technologies used to develop the resources, the inputs and outputs for each development technology, and the laws and regulations applying to the deployment and operation of each technology. Resources described in the ERDS report are: coal, oil shale, uranium, crude oil, natural gas, and geothermal energy.

Since its discovery in 1859, oil has been a significant factor in our national growth and development. Although it did not supplant coal as the primary energy source until the late 1940's, oil was important well before that, in large part because of its key role in the development and mass production of the automobile - and the fundamental changes in life style which followed.

In more recent times oil has become the base for many of our necessities, including medicinal drugs, clothing, fibers, plastic and rubber products, etc.; and it is a major substitute for other sources of energy. This end use flexibility makes oil a particularly valuable resource in all industrialized countries.

The oil industry has grown from a uniquely American business into a worldwide operation. Six of the 10 largest U.S. corporations are oil companies, and technologies developed to produce U.S. oil resources have been the basis for all free world oil development.

The U.S. was a net oil exporter until 1948, when U.S. consumption exceeded supply for the first time. Although the change from exporter to importer created a number of economic and political problems, dependence on oil imports will undoubtedly continue for the foreseeable future.

This chapter describes the technologies, inputs, outputs, laws, and regulations associated with the development of crude oil resources. There are five main sections to the chapter and they are briefly described below.

Section 6.2 describes the characteristics of the crude oil resource in the eight state region, discusses the quantity and location of the resources, and treats the ownership of the land and resource.

Sections 6.3 and 6.4 describe the development of crude oil from exploration to treatment of finished product and enhanced recovery techniques. For each activity the interactions of the resource itself with the attempt to produce the resource for man's use are described. When available, the inputs and outputs for each activity are presented. Inputs discussed include: manpower, materials and equipment, economics, water, land, and ancillary energy. The outputs are air emissions, water effluents, solid wastes, noise pollution, occupational safety and health, and odors. Laws and regulations affecting the activities are described.

Section 6.3 discusses the technologies, inputs and outputs, and social controls associated with crude oil exploration. Section 6.4 discusses the same items for conventional crude oil production and for enhanced oil recovery. Section 6.5 discusses the social controls for crude oil transportation.

It is important that the reader have a thorough understanding of this entire chapter before applying any of the contained information. Typical technologies were chosen for the basis of the data, and it is important to note that the parameters can vary greatly depending upon the specific basis chosen. The reader is advised to note any changes in bases between the different technologies in the chapter.

6.1.2 Summary

Tables 6-1 through 6-4 summarize the input requirements and outputs associated with development of the crude oil resources.

TABLE 6-1. SUMMARY OF IMPACTS ASSOCIATED WITH THE EXPLORATION FOR A 100,000 BARREL/DAY OIL FIELD

Inputs		
Manpower		
Materials and Equipment		
• Casing and tubing	6,250 Tons	5669 m. tons
• Rig-years	18	18
• Cement	18,000 Tons	16,327 m. tons
Economics[1]	$125,000,000	$125,000,000
Water (over life of exploration)	5.0×10^6 Barrels	7.95×10^5 m^3
Land	150 Acres	6.0×10^5 m^2
Ancillary Energy (total)	3.0×10^{12} Btu	3.1×10^{15} J.
Outputs		
Air Emissions		
• Particulates	80 lb/day	36 kg/day
• SO_2	168 lb/day	76 kg/day
• CO	1434 lb/day	650 kg/day
• Hydrocarbons	233 lb/day	105 kg/day
• Nitrogen Oxides	2329 lb/day	1056 kg/day
• Aldehydes	19 lb/day	8.6 kg/day
• Organic Acids	19 lb/day	8.6 kg/day
• CO_2	130,625 lb/day	59,240 kg/day
Water Effluents	Negligible	
Solid Wastes	Negligible	
Noise Pollution		
Occupational Health and Safety		
• Deaths	0.45/yr	
• Injuries	43/yr	
• Lost Time	7154 man-days/yr	

[1]1974 Dollars

TABLE 6-2. SUMMARY OF IMPACTS ASSOCIATED WITH THE DEVELOPMENT AND OPERATION OF A 100,000 BARREL/DAY OIL FIELD

Inputs		
Manpower		
• Construction	19,544 Man-years	19,544 Man-years
• Operation and Maintenance	6,143 Man-years	6,143 Man-years
Materials and Equipment		
• Pipe and Tubing	72,000 Tons	32,652 m. tons
• Pumps and Drives	8,000 Items	8000 Items
• Drill Rigs	12 Items	12 Items
• Ready-mix Concrete	20,000 Tons	9070 m. tons
Economics	$2,040 million	$2,040 million
Water		
• Waterflooding	2500-4100 acre-ft/yr	$3.1\text{-}5.0 \times 10^6$ m^3/yr
Land		
Ancillary Energy		
• Conventional	5.0×10^8 Btu/day	5.2×10^{11} J./day
• Waterflooding	3.5×10^8 Btu/day	3.7×10^{11} J./day
Outputs		
Air Emissions[1]		
• Particulates	3.1 ton/yr	2.8 m. tons/yr
• SO_x	190 ton/yr	172 m. tons/yr
• CO	11.4 ton/yr	10.3 m. tons/yr
• Total Organics	37.7 ton/yr	34.2 m. tons/yr
• NO_x	154 ton/yr	140 m. tons/yr
Water Effluents	Undetermined	
Solid Wastes	None	
Noise Pollution	--	

[1]For heater treaters only (oil production is 5% brine)

TABLE 6-3. SUMMARY OF IMPACTS ASSOCIATED WITH STEAM FLOODING

Inputs		
Manpower	2,000 Persons	2,000 Persons
Materials and Equipment	250-650 Items	250-650 Items
• Oil Field Boilers		
Economics		
Water		
Land		
Ancillary Energy		
Outputs		
Air Emissions		
• Particulates	860-2850 lb/day	390-1292 kg/day
• SO_2	24,000 lb/day	10,844 kg/day
• SO_3	300 lb/day	136 kg/day
• CO	500 lb/day	227 kg/day
• Hydrocarbon	260 lb/day	118 kg/day
• NO_x	740 lb/day	336 kg/day
Water Effluents		

TABLE 6-4. SUMMARY OF IMPACTS ASSOCIATED WITH CO_2 FLOODING

Inputs		
Manpower		
Materials and Equipment		
Economics[a]	\$13.5 x 10 /yr	\$13.5 x 10^6/yr
Water (life of field)	1.6-3.6 x 10^5 acre-ft	2.0-4.4 x 10^8 m^3/yr
Land	25-50 acres	1.0-2.0 x 10^5 m^2
Ancillary Energy	3.8 x 10^9 Btu/hr	4.0 x 10^{12} J./hr
Outputs		
Air Emissions		
• Particulates	290 lb/day	132 kg/day
• SO_2	8100 lb/day	3673 kg/day
• SO_3	110 lb/day	50 kg/day
• CO	170 lb/day	77 kg/day
• Hydrocarbon	84 lb/day	38 kg/day
• NO_x	2500 lb/day	1134 kg/day
Water Effluents		
Solid Wastes	Negligible	
Noise		
Occupational and Health Safety		
• Deaths	0.5	
• Injuries	43.8	
• Lost Time	7300 man-hours	

[a]1976 dollars

6.2 RESOURCE DESCRIPTION OF WESTERN CRUDE OIL

6.2.1 Reserves and Resources

The terms "reserves" and "resources" are often used in descriptions of the volume of petroleum deposits. In this chapter resources are the petroleum deposits that are ultimately recoverables with present or advanced technology. By this definition, resources include all the identified and yet-to-be discovered deposits whether they are economically recoverable or not. Reserves are economically recoverable resources that are identified on the basis of current geological evidence. "Proven reserves" are those reserves that are measured and marketable under current economic conditions.

6.2.2 Characteristics of the Resources

Crude oil is a naturally occurring oil consisting mostly of hydrocarbons, although oxygen, nitrogen, and sulfur-containing compounds are invariably present. It is usually found in sedimentary rock deposited in both freshwater and saltwater environments. Crude oil contains a number of organic compounds that are separated into various fuel and lubricating forms through refining processes. The refined products include gasoline, kerosene, distillate and residual fuel oils, lubricating oils, light hydrocarbon liquids, and others. An average heat content for crude oil is approximately 5.8 million Btu per barrel. The refined liquid petroleum products are characterized by their heat contents which range from 5.2 million Btu per bbl for gasoline to 6.3 million Btu per bbl for residual fuel oil.[1]

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[1]American Petroleum Institute. Petroleum Facts and Figures. Washington, D.C.: American Petroleum Institute, 1971, p. 589.

Crude oil is usually characterized by density. Most domestic crude oils range from 22°API (0.922 specific gravity) to 42°API (0.816 S.G.) with the average gravity near 35°API (0.850 S.G.).

The quality of a given crude may also be judged by its sulfur content. Crudes with more than 1 percent sulfur are usually considered sour. Domestic crudes vary greatly in sulfur content (0.3% - 3.0% by weight).

6.2.3 Quantity and Location of Western Oil Reserves

According to recent estimates, proven reserves in the eight western mountain states[1] account for approximately seven percent of the total U.S. reserves estimated to be about 34 billion barrels.[2,3,4] The ultimate recoverable production for these states is 21 percent of the total U.S., suggesting that the mountain states will probably play a larger role in supplying the country's fuel needs in the years to come.

Within the eight state region, crudes are produced primarily in a broad area stretching from the San Juan Basin in Northeast New Mexico to the Big Horn Basin in Wyoming and Montana. Figure 6-1 gives the location of various basinal areas that contain reservoirs. Table 6-5 shows reserve estimates of western crudes broken down by states, along with the cumulative productions

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[1]Arizona, Colorado, Utah, New Mexico, Wyoming, Montana, North Dakota, and South Dakota.

[2]U.S. Geological Survey. Geological Estimates of Undiscovered Recoverable Oil and Gas Reserves in the United States, Circular 725. Washington, D.C.: U.S. Geological Survey, 1975.

[3]FEA Lists Higher U.S. Reserves Figures, Oil and Gas Journal 73(27) July 7, 1975, p. 32.

[4]Gay, William F. Energy Statistics. A Supplement to the Summary of National Transportation Statistics, Final Report. Cambridge, Maryland: U.S. Department of Transportation, August 1975.

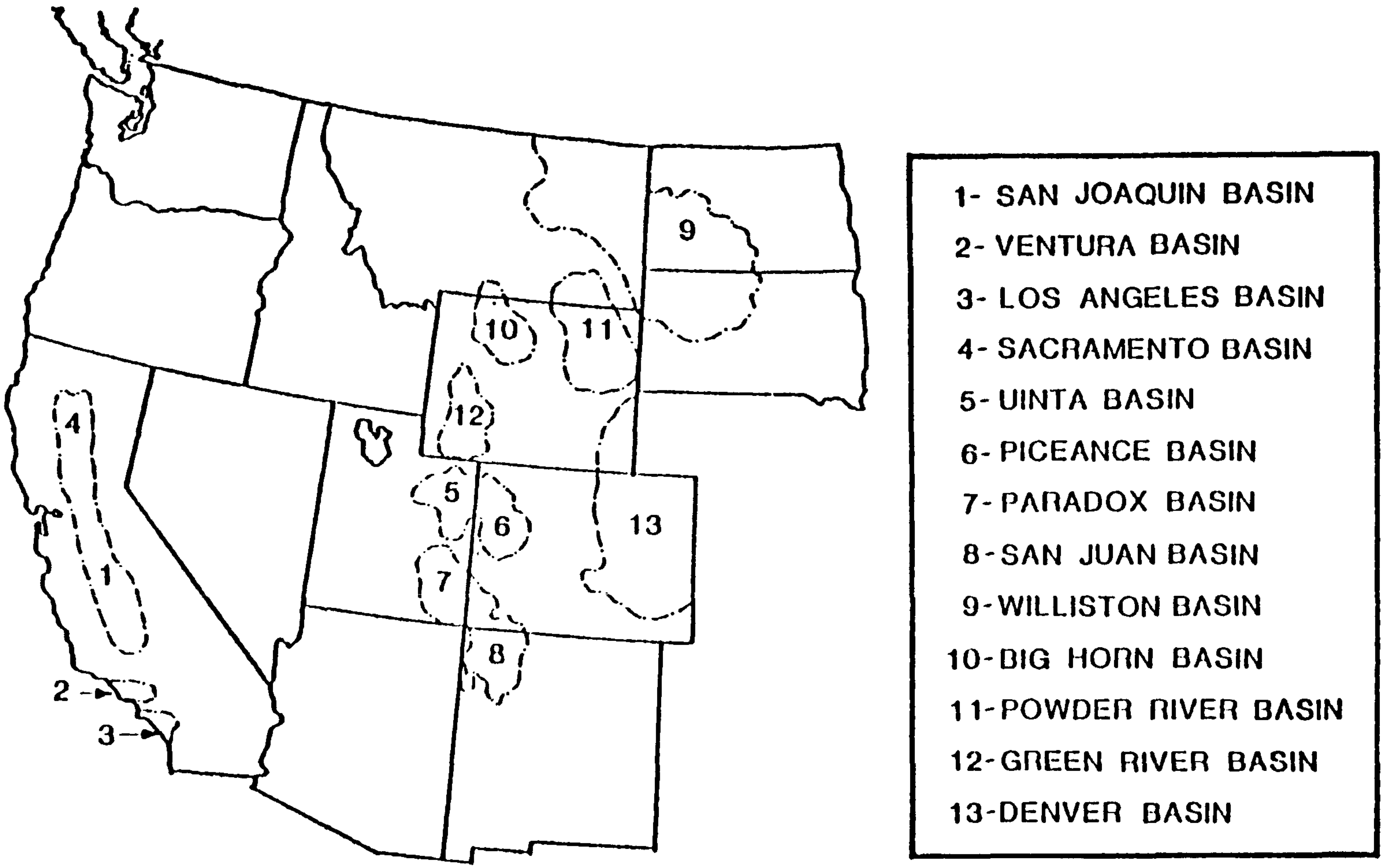

Figure 6-1. Locations of Major Crude Oil Deposits in the Western States.

Source: Landes, Kenneth K. Petroleum Geology of the United States. New York: Wiley-Interscience, 1970.

TABLE 6-5. WESTERN OIL RESERVE ESTIMATES[1]
(IN MILLIONS OF BARRELS)

State	API Proved Reserves[2]	USGS Identified But Not Proved Reserves	FEA Reserve Estimates[3]	API Cumulative Production[2]	USGS Ultimate Production[2]
Colorado	289	328	305	1,006	1,660
Montana	207	390	196	790	1,422
New Mexico	625	769	868	2,866	4,217
North Dakota	173	193	187	395	754
Utah	251	443	350	439	1,127
Wyoming	903	815	1,102	505	5,385
Total Western	2,448	2,938	3,008	6,001	34,565
Total U.S.	34,250	33,335	38,440	96,330	163,706
Ratio = $\frac{\text{Western}}{\text{U.S.}}$	0.07	0.09	0.08	0.06	0.21

[1]All figures come from reference (USGS, 1975)

[2]Based on API reports as of December 31, 1974.

[3]As quoted in Oil & Gas Journal, 1975 (July 7).

through 1972 and the ultimately producible quantities. The non-producing states are not entered in the table.

The average rotary-rig activities in the past ten years are listed by state in Table 6-6. The ratios given in the bottom line of the table indicate that the trend of rotary-rig operation in the western states has been roughly the same as that in the U.S. as a whole.

6.2.4 Ownership of Resources

Ownership of the western crude resources has not been identified at this time. Only federal ownership on a national level is known: 4 percent of onshore reserves and 8 percent of offshore resources.[1]

[1]Ford Foundation. Energy Policy Project. A Time to Choose: America's Energy Future. Cambridge, Massachusetts: Ballinger Publishing Co., 1974.

TABLE 6-6. AVERAGE ROTARY-RIG ACTIVITY IN THE WESTERN STATES[1]

State	Year									
	'76	'75	'74	'73	'72	'71	'70	'69	'68	'67
Colorado	38	42	46	42	35	30	25	23	17	16
Montana	28	27	24	19	20	17	17	31	34	22
New Mexico	54	71	79	62	55	47	40	64	68	56
Utah	19	26	42	38	34	17	12	12	12	15
Wyoming	87	107	107	70	60	45	71	81	56	44
Total Western[2]	226	273	298	231	204	156	165	211	187	153
Total U.S.	1,657	1,660	1,471	1,194	1,087	976	1,028	1,194	1,150	1,134
Ratio = $\frac{\text{Western}}{\text{U.S.}}$	0.14	0.16	0.20	0.19	0.19	0.16	0.16	0.18	0.16	0.13

[1]Source: Oil & Gas Journal, 1975 (January 27):109.

[2]The totals include negligible amounts of rotary-rig activities in other western states.

6.3 EXPLORATION

6.3.1 Technologies

Exploratory drilling for oil is done with a rotary drill bit connected to the surface by a length of pipe called a drill string. A series of sequential operations must be performed before the actual drilling proceeds, the first of which is site preparation. This involves clearing the land, digging pits to serve as holding ponds for circulating fluid (mud) and brine, and constructing the necessary access roads. Water must be made available at the site by completing water wells or installing water lines. The next step is bringing the drilling equipment to the site and "rigging up." Rigging up involves placing the drilling machinery in working position, then assembling and connecting the units which make up the drilling rig.

The three basic parts of the drilling rig are the hoisting system (Figure 6-2), the rotary system, and the fluid circulation system (Figure 6-3). The hoisting system is used to raise and lower the drill string and to regulate the weight on the drill bit by holding up the drill string. Hoisting systems at a deep well are capable of raising and lowering long drill strings which weigh up to 500,000 pounds.[1] The capacity of derricks supporting the hoist varies from 250,000 to 1,500,000 pounds.

The rotary system begins at the hook on the hoisting system which is attached to the rotary system by a swivel. The swivel

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[1]Petroleum Extension Service, University of Texas. A Primer of Oil Well Drilling, 3rd Edition. Austin, Texas: University of Texas, 1970.

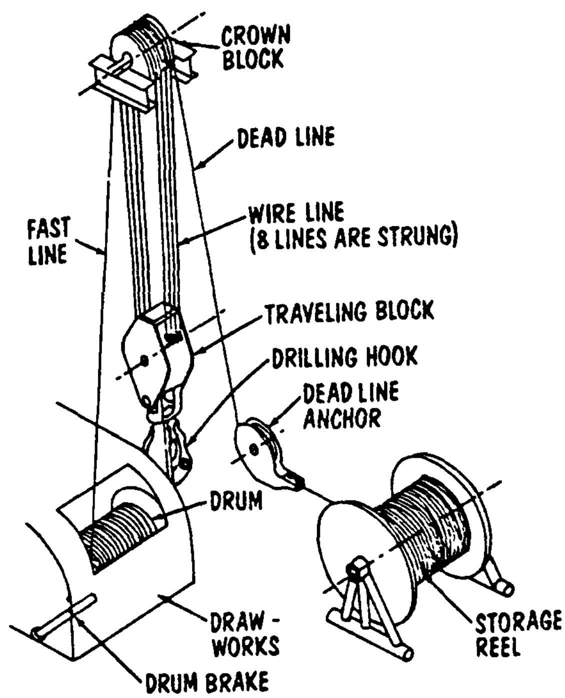

Figure 6-2. Rotary Rig Hoisting System.

Source: Petroleum Extension Service, University of Texas. A Primer of Oil Well Drilling, 3rd Edition. Austin, Texas: University of Texas, 1970.

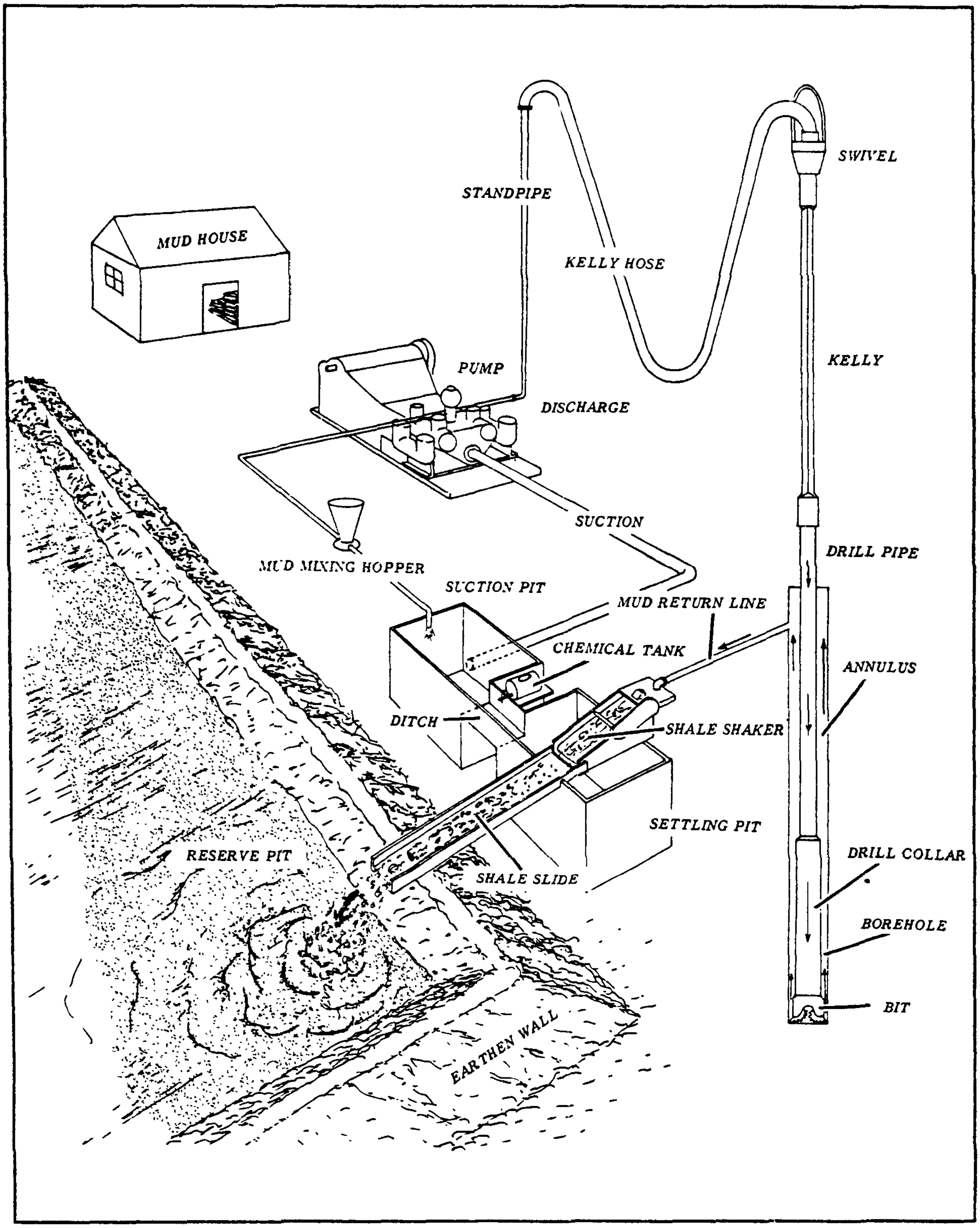

Figure 6-3. Rotary Rig Fluid Circulation and Mud Treating System.

Source: Petroleum Extension Service, University of Texas. A Primer of Oil Well Drilling, 3rd Edition. Austin, Texas: University of Texas, 1970.

sustains the weight of the drill string, affords a passageway for entry of the circulation fluid into the drill string and permits rotation of the drill string. The link between the swivel and the drill pipe, the kelly, is a square or octagonal shaft which fits through a square or octagonal hole in the rotary table and is connected to the drill pipe on the lower end and to the swivel on top. When the rotary table turns, it causes the kelly to rotate, which in turn causes the drill pipe and bit to rotate. The swivel, however, allows the hoist to remain stationary.

When the drill string needs lengthening, the drill string is raised by the hoist until the kelly is out of the hole. The kelly is then removed and the end of the drill pipe raised far enough to allow insertion of a new piece of drill pipe onto the top of the existing pipe. After the new pipe is inserted, the kelly is replaced and the entire assembly is lowered into the hole. To remove the entire drill string for bit changing, this process is reversed and the drill pipe is removed one piece at a time.

The fluid circulation system allows removal of the cuttings made by the bit and provides hydrostatic pressure to prevent a blowout. (A blowout is the unconstrained flow of liquids or gases from the well caused by high pressures in the penetrated reservoir.) The viscosity and density of the fluid must be maintained at a level sufficient to insure protection from blowouts. The circulated fluid, usually referred to as drilling mud, is a water-based slurry which contains a mixture of weighting material, clays, chemicals, and oil. Maintaining the quality and quantity of this drilling mud accounts for a major portion of both equipment and drilling costs.[1]

[1]Petroleum Extension Service, University of Texas. A Primer of Oil Well Drilling, 3rd Edition. Austin, Texas: University of Texas, 1970.

As shown in Figure 6-3, the drilling mud enters the drill pipe, flows out of the bit, entrains the cuttings, and rises in the annular space between the drill pipe and the hole wall. The cuttings are then removed from the mud and the mud is recirculated down through the drill pipe. The cuttings are periodically analyzed to determine the geological nature of the formations and to determine whether a zone capable of production has been located.

In addition to the drilling mud, a number of other safeguards are used to minimize the likelihood of a blowout. These include setting casing and installing blowout preventer (BOP) valves. Before the deep drilling is begun, a relatively shallow hole is made and casing is usually inserted. This short length of casing, usually 10 to 20 feet in length, is referred to as conductor pipe. It is cemented into the hole and the BOP valves attached. A BOP valve will seal off the annular space around the drill pipe to prevent the drilling fluid from being pushed from the hole. The valve can be closed by an automatic hydraulic system or manually.

The direction in which the hole is proceeding must also be monitored and controlled. As the drill string becomes very long, it becomes somewhat flexible, but gravity pulls the bit back in line if it begins to vary from a vertical attitude. This is known as the pendulum effect. The movement is monitored by a drift survey instrument positioned above the bit. If a non-vertical hole is desired, directional drilling is employed. This type of drilling requires special equipment for boring the hole and performing the directional survey for monitoring the course of the drilling.

Once the hole is drilled to the desired depth, an analysis of the production capabilities is required. If the well is deemed to be capable of profitable production, it is developed further. Developing activities are discussed in Section 6.4.

After the contractor has drilled the hole to final depth, taken electric logs, and evaluated potentially productive intervals, a decision will be made by the operating company whether to set casing or to plug the well. These decisions are sometimes difficult, for there may be considerable doubt that a well may produce enough oil or gas to pay for the casing and completion of operations. Completion costs can exceed $50,000 for even a moderate depth well.[1]

If the well is judged to be a dry hole, *i.e.*, not capable of producing oil or gas in commercial quantities, the well will be plugged before abandonment. Cost for plugging may be only a few thousand dollars; state regulatory authorities usually indicate the manner of plugging a well.

If the operating company decides to set casing, pipe will be hauled to the job, tested, and other preparations made to run it into the well. Before the casing is run, the bit is usually put back into the hole to check for possible bridging and settling of cuttings to bottom.

The operating company may elect to install centralizers and scratchers on the casing just prior to the running of

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Petroleum Extension Service, University of Texas. A Primer of Oil Well Drilling, 3rd Edition. Austin, Texas: University of Texas, 1970.

the casing. Their purpose is to obtain a good cement job, *i.e.*, to better restrict fluid movement behind the casing between formations, to support the casing, and prevent corrosion. A centralizer secured around the casing prevents the pipe from touching the hole wall so that the cement sheath around the pipe will be uniform. Scratchers are moved during the cementing operations to scratch the mud cake off the wall of the hole so that the cement will make a better bond with the formation. The movement of the casing and the presence of the centralizers and scratchers lessen the chance that the cement will channel between the casing and wall of the hole. A diagram of a well with the casing installed is shown in Figure 6-4.

The drilling portion of the oil well operations is complete when the hole has been drilled to its final depth and the casing has been set. Further operations to allow production from the well are discussed in Section 6.4 on production.

6.3.2 Input Requirements

The inputs required for drilling the wells which will ultimately produce 100,000 barrels per day of crude oil are discussed in this section. Exploratory drilling means searching for the geologic strata containing petroleum in sufficient quantities to justify recovery. Once the oil is found, developmental wells are drilled to recover the maximum amount of oil over the life of the field. Other recovery techniques must also be considered in planning a developmental well program.

As a basis for the inputs for this field, 400 producing wells, each rated at 250 barrels/day, will supply the crude oil.

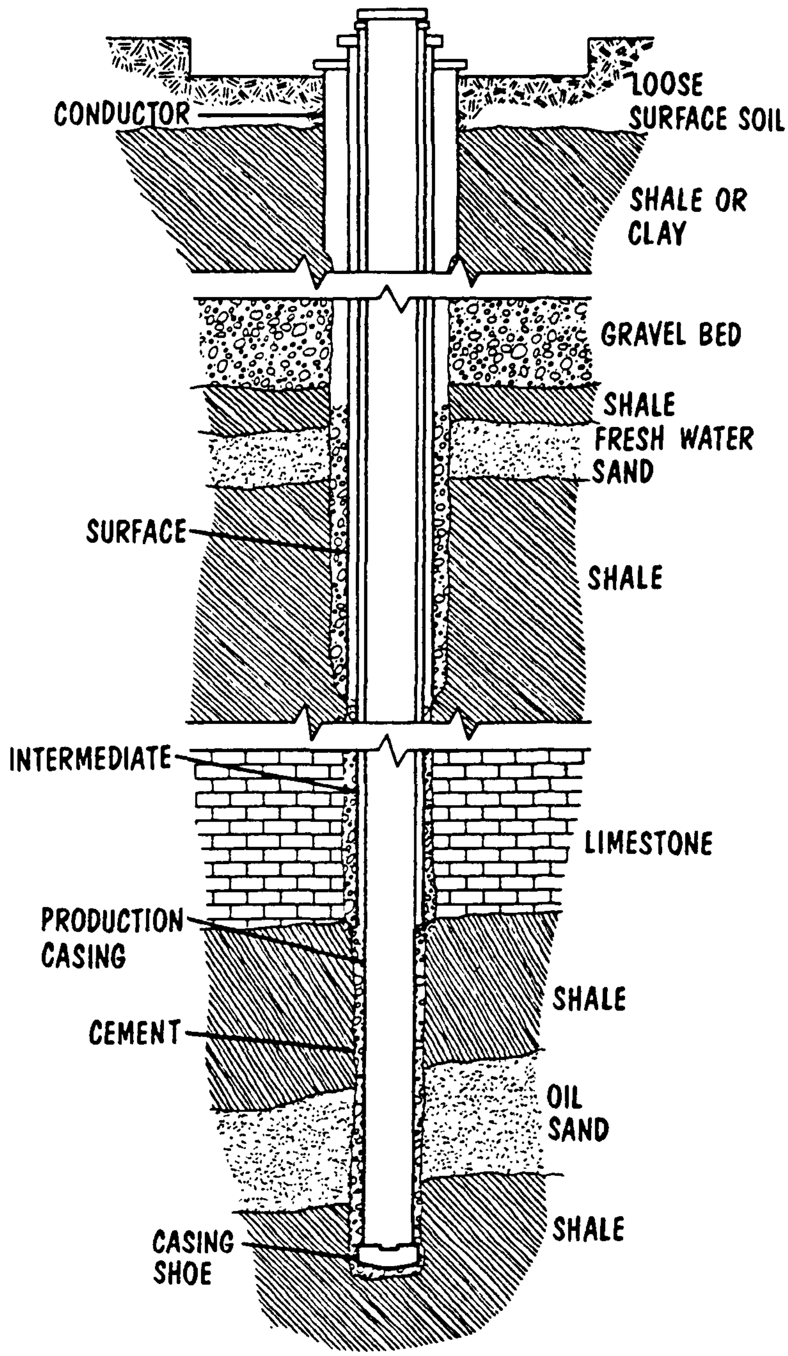

Figure 6-4. Casing Strings and Pipe Used in an Oil Well.

Source: Petroleum Extension Service, University of Texas. A Primer of Oil Well Drilling, 3rd Edition. Austin, Texas: University of Texas, 1970.

Three hundred dry holes will have been drilled by the end of the seven year time frame of this project.

6.3.2a Manpower Requirements

The Bechtel Corporation[1] has estimated manpower required for developing and producing a domestic oil field and gathering system. The total manpower requirements for developing the example field are included in Section 6.4.3.2a.

6.3.2b Materials and Equipment

The Federal Energy Administration has estimated the major material requirements for both dry holes and producing holes.[2] The estimates per well and for a field producing 100,000 BPD are shown in Table 6-7.

6.3.2c Economics

Only the costs incurred with the drilling operation are considered in this section. Drilling costs vary greatly with location, depth, and nature of the local substrata, but by using average costs for drilling in the western U.S. at 5,000-10,000 foot depths, a total cost of approximately $125 million is derived.[3]

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[1] Carasso, M., *et al.* Energy Supply Model, Computer Tape. San Francisco, California: Bechtel Corporation, 1975.

[2] Federal Energy Administration, Interagency Task Force on Natural Gas. Project Independence Blueprint, Final Task Force Report, Natural Gas. Washington, D.C.: Federal Energy Administration, November 1974.

[3] *Ibid.*

TABLE 6-7. MATERIALS AND EQUIPMENT REQUIRED FOR A 100,000 BPD OILFIELD

	300 Dry Holes	Requirements for 400 Successful Holes	Total
Casing and Tubing (Tons)	6,250	15,200	21,450
Surface and Sub-surface Equipment (Tons)	---	30,800	30,800
Number of Rig-Years (6 Year Duration)	18	24	42
Steel Tonnage Per Rig (Tons)	250	250	---
Cement (Tons)*	18,000	24,000	42,000

*Assuming each well is 5,000 feet deep.

Source: Federal Energy Administration, Interagency Task Force on Natural Gas. Project Independence Blueprint, Final Task Force Report, Natural Gas. Washington, D.C.: Federal Energy Administration. November, 1974.

6.3.2d Water Requirements

Drilling fluid make-up is the major requirement for fresh water at a drilling site. Between 200 and 500 barrels per day are needed for a conventional drilling rig.[1] Approximately 7500 barrels are required for the drilling of one well; about 5,000,000 barrels are consumed over the life of the drilling project.

6.3.2e Land Requirements

About 2 acres of land are cleared and used around a typical exploratory well.[2] After drilling is complete, some of this land is retained for workover rig purposes, and can be sodded or surfaced as local conditions dictate. Any area not needed for workover can be restored to its original condition. About 150 acres are used permanently for drilling locations and roads for the exploration wells (300 dry holes). Land associated with producing wells is included in Section 6.4.2e.

6.3.2f Ancillary Energy

Most energy required for drilling oil wells is provided by diesel fuel. Energy is used to operate the drilling equipment, generate an electrical system in remote areas, and operate mobile vehicles around the drilling site. The quantity depends on well depth, rig size, time on the well, and type of geologic formation drilled.

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[1]Federal Power Commission. National Gas Survey, Vol. II. Washington, D.C.: Federal Power Commission, 1974, pp. 73-75.

[2]*Ibid.*

The consumption of diesel fuel varies from 900 to 1800 gallons per day.[1] Total fuel consumption for the entire drilling program is approximately 20 million gallons, or the energy equivalent of 3.0×10^{12} Btu.

6.3.3 Outputs

The outputs associated with the exploratory phase of crude oil production are discussed in the following sections.

6.3.3a Air Emissions

The large internal combustion engines used to power the drilling equipment are the major source of air emissions during exploratory and developmental drilling. Table 6-8 contains emission factors, air emission per rig, and entire oil field emissions averaged over the seven years in which drilling takes place. Drilling will be more intensive near the middle of the period, and emissions will be somewhat greater than the average.

6.3.3b Water Effluents

A negligible amount of water used in the drilling operation is lost to the surroundings due to the circulating mud system being closed. Some water may escape from the well by mechanical failure or human error, and some water from the holding pond may seep into the ground water. This loss is considered minimal.

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[1]Federal Power Commission. National Gas Survey, Vol. II. Washington, D.C.: Federal Power Commission, 1974, pp. 73-75.

[2]Environmental Protection Agency. Compilation of Air Pollution Emission Factors, 2nd Edition with Supplements, AP-42. Research Triangle Park, North Carolina: Environmental Protection Agency, April 1977.

TABLE 6-8. AIR EMISSIONS FROM DRILLING RIGS

Type of Emission	Emission Factors $lbs/10^3$ Gal of Diesel Fuel	Individual Rig Emissions lb/day	Oil Field Emissions lb/day
Particulates	13	17	80
Sulfur Oxides as SO_2	27	36	168
CO	225	308	1,434
Hydrocarbons	37	50	233
Nitrogen Oxides	370	500	2,329
Aldehydes (as HCHO)	3	4	19
Organic Acids	3	4	19
CO_2	20,775	28,046	130,625

Source: Environmental Protection Agency. Compilation of Air Pollution Emission Factors, 2nd Edition with Supplements, AP-42. Research Triangle Park, North Carolina: Environmental Protection Agency, April 1977.

Drainage patterns of surface waters and rain runoff may be disturbed by the construction of roads into the area of a drilling rig. This disturbance may cause increased turbidity and suspended solids in the fresh water and erosion.

6.3.3c Solid Wastes

Exploratory drilling brings drill cuttings from the hole to the surface. These cuttings are mixed with the mud containing additives such as barite, bentonite, and phosphate. They will dry in the reserve pit and are plowed into the native soil when drilling is complete. Although some soils may be improved by the addition of these compounds,[1] they will have an adverse effect in most instances.

6.3.3d Noise Pollution

Associated with drilling activities, there is a substantial noise level which may be annoying to wildlife or nearby residents. In congested areas, such as Southern California, some drilling rigs have been soundproofed, and purchased electricity has replaced internal combustion engines. These solutions seemed to prevent a disturbance to the environment.

6.3.3e Occupational Health and Safety

Occupational health and safety data are obtained from information for oil and gas production.[2] Values for deaths,

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[1]Federal Power Commission. National Gas Survey, Vol. II. Washington, D.C.: Federal Power Commission, 1974, pp. 73-75.

[2]Battelle Columbus and Pacific Northwest Laboratories. Environmental Considerations in Future Energy Growth. Columbus, Ohio: Battelle Columbus and Pacific Northwest Laboratories, 1973.

injuries, and working time lost are presented in multiples of 10^6 Btu. Scaling this information for 100,000 bbl/day oil production, the results are as follows: 0.45 deaths/year, 43 injuries/year, and 7,154 man-days/year are expected to be lost.

6.3.3f Odor

There are no odor problems associated with the drilling of oil wells.

6.3.4 Social Controls

6.3.4.1 Oil Exploration Regulation

Exploration for oil or gas is usually controlled by statute and regulation at the level of government having control over the land proper. Federal and Indian land is regulated by federal laws and regulations and state laws apply usually to state and private lands. The discussion below will be divided into those categories. In most cases the state law on exploration will have limited application to private lands.

6.3.4.1a Exploration on Federal Lands

The oil and gas sections of the Mineral Leasing Act of 1920[1] allow the Secretary of the Interior to lease the lands for development. If the lands are in a known geologic structure (KGS) of a producing oil and gas field, only a competitive (by bidding)

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[1]Mineral Leasing Act of 1920, 30 W.S.C.A. §§ 223-228 (1970). The Mineral Leasing Act of 1920 is the main source for this regulation although other sources of federal control are discussed in Chapter 2 (e.g., The Acquired Lands Act of 1947, 30 U.S.C.A. §§ 351-359 (1970)).

lease is allowed.[1] The exploration of "unknown" lands was previously regulated by a permitting process administrered by the Bureau of Land Management (BLM), but the present regulation allows a non-competitive lease for such lands.[2] Leases issued for exploration can be for between 640 and 2,500 acres.[3] Even the "unknown" lease must contain a royalty provision equal to that of the KGS for 12½ percent.[4] The terms of the lease can also include specifications for conservation and environmental protection.[5] The exploring developer who does not want to lease lands even under the non-competitive provision may still explore public lands, but only if he files a notice of intent with the U.S. Geological Survey (U.S.G.S.).[6]

6.3.2.1b Exploration on Indian Lands

Under the Omnibus Mineral Leasing Act of 1938, the leasing of unallotted or tribal and ceded lands for mining purposes is authorized.[7] The only provision for exploration with the statutory framework seems to be lease itself.[8]

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[1] 30 U.S.C.A. § 226 (b) (1970).

[2] 30 U.S.C.A. § 226 (c) (1970).

[3] 43 C.F.R. § 3110. 1-3 (1972).

[4] 30 U.S.C.A. § 226 (c) (1970).

[5] 30 U.S.C.A. § 226 (j) (1970). See also Section 6.4.4.1a below for a more detailed discussion.

[6] 43 C.F.R. 3045.1-1 (1972).

[7] Omnibus Mineral Leasing Act of 1938 and subsequent amendments codified as 25 U.S.C.A. §§ 396-401 (1970).

[8] But see Proposed Regulations - 25 C.F.R. Part 177, as discussed by Simonds, Jerome H. "The Acquisition of Rights to Prospect for and Mine Coal from Tribal and Allotted Indian Lands," pp. 159-162, in Rocky Mountain Mineral Law Foundation. Rocky Mountain Mineral Law Institute: Proceedings of the Twenty First Annual Institute, July 17-19, 1975. Albany, N.Y.: Matthew Bender, 1975, where prospecting permits are included.

Because the later section (6.3.4.2b) on leasing explains the recent changes in leasing procedures, the exploration will not be discussed here but should be viewed as a part of the leasing procedure described there.

6.3.4.1c Exploration on State Lands

Exploration for oil on state lands is generally controlled by the terms of the lease. Only Colorado allows for a separate permit for oil exploration outside the lease. A developer in the remaining seven states must obtain a lease under the appropriate statute and perform any necessary exploration within that lease (leasing of state lands for oil development is discussed in Section 6.3.4.2c). Arizona has a system which allows exploration on "unknown lands" under a lease; whereas the state's "known lands" must be competitively leased. In summary the general rule in the western states is to allow a non-competitive lease (to allow exploration) of unknown lands and to require a competitive (without exploration) lease of known lands.

Under the above described system, a preference to the discoverer is built into the lease since the royalty provisions, etc., are specified prior to a "discovery." Once the initial lease expires (although this would be rare since all states save Colorado build in the term "continues as long as producing" into their leases) or once an area is not considered unknown, then there is only a preference to re-lease in New Mexico.

Table 6-9 summarizes the exploration procedures in the eight states and Tables 6-10 through 6-17 give a detailed explanation for each state.

TABLE 6-9. SUMMARY OF STATE LAND EXPLORATION PERMITS

	Method of Exploration		Term of Permit or Lease	Preference Given to Explorer/ Discoveror	Additional Permits May Be Required[4]
	Separate Permit	Exploration Within Lease			
AZ		X[1]	5 Years[3]		X
CO	X[2]		60 Days Extensions available.	Upon Expiration of permit the holder may be required to lease.	
MT		X	10 Years[3]		X
NM		X	5 Years[3] Renewable.	Preference is given to previous lessee to re-lease.	
ND		X	5 Years[3]		
SD		X	10 Years[3]		
UT		X	10 Years[3]		X
WY		X[5]	10 Years[3]		

[1]Exploration for oil in Arizona on state lands is only available on "unknown lands"; the remaining "known" lands must be leased competitively.

[2]Although this is a permit type of exploration, many of the requirements, (e.g., posting of notice on site) of claim filing method are retained.

[3]Continues for "so long as producing."

[4]For example: Intent to drill, explosive use, open mine, etc.

[5]Wyoming statutes do not provide for exploration for oil on state lands, but presumably the lease holder could explore as needed.

TABLE 6-10. ARIZONA OIL EXPLORATION PERMIT[a]

Item	Statutes	Summary
Agency	§ 27-553	State Land Department, State Land Commissioner
Special Requirements[b]	§ 27-513	All wells in state require a drilling permit at a fee of $25 from commissioner
Fees	§ 27-555	$25
Rental	§ 27-555	$1.25 per acre per year for a maximum of 2,560 acres
Royalty	§ 27-555	12 1/2%
Duration	§ 27-555	Five years and so long as producing
Bond		
Discretionary Actions		
Other Information		

[a]Arizona Revised Statutes Annotated, 1956.

[b]The second item in each table indicates special requirements for issuing the permit. A blank in this category reflects a necessity of filing an application with a minimum of information to include the applicant's name, address, and location of the land involved.

TABLE 6-11. COLORADO OIL EXPLORATION PERMIT[a]

Item	Statutes	Summary
Agency	§ 36-1-140	State Board of Land Commissioners
Special Requirements[b]	§ 36-1-140	1. Discovery. 2. Posting of notice of discovery on site. 3. Notify board within ten days of discovery
Fees		
Rental		
Royalty		
Duration	§ 36-1-140	Sixty days, but extension possible.
Bond		
Discretionary Actions		
Other Information	§ 36-1-140	At expiration of permit the locator may be required to lease upon agreed-to-terms

[a]Colorado Revised Statutes, 1973.

[b]The second item in each table indicates special requirements for issuing the permit. A blank in this category reflects a necessity of filing an application with a minimum of information to include the applicant's name, address, and location of the land involved.

TABLE 6-12. MONTANA OIL EXPLORATION PERMIT[a]

Item	Statutes	Summary
Agency	§ 81-1701	State Board of Land Commissioners
Special Requirements[b]	§ 69-33	See Chapter 2 for Montana Geophysical Exploration Permit
Fees	§ 81-108	Set by State Land Department
Rental	§ 81-1702 § 81-1702.1	Minimum of $1.50 per acre, but not Less than $100 per year per lease. Maximum area of 640 acres per lease and per person.
Royalty	§ 81-1704	12 1/2 percent
Duration	§ 81-1702	10 years and so long as producing.
Bond		
Discretionary Actions		
Other Information	§ 81-1715	Competitive re-lease of producing lands.
	§ 81-1702.2	Delay drilling penalty shall be $1.25 per acre per year.
	§ 81-2612	If there is a conflict between coal, oil, gas, or geothermal developers on state lands, the first issued lease has priority, but the board may amend to fit the situation

[a]Revised Codes of Montana, 1974.

[b]The second item in each table indicates special requirements for issuing the permit. A blank in this category reflects a necessity of filing an application with a minimum of information to include the applicant's name, address, and location of the land involved.

TABLE 6-13. NEW MEXICO OIL EXPLORATION PERMIT[a]

Item	Statutes	Summary
Agency	§ 7-11-1	Commissioner of Public Lands
Special Requirements[b]	§ 65-3-11	The Oil Conservation Commission has authority to require bond of $10,000 to insure plugging, conservation of oil and gas resources
Fees	§ 7-11-1	The Commissioner may set terms and fees
Rental	§ 7-11-9 § 7-11-3	Not more than 6400 acres per lease at not less than $100 per year for primary term or not less than 5¢ per acre nor more than $1.00 per acre during secondary term
Royalty	§ 7-11-3.4	Not less than 1/8 nor more than 1/6, also the Commissioner may cancel secondary term (possible in kind royalty)
Duration	§ 7-11-3	5 years primary and so long thereafter as producing with one 5 year extension possible
Bond		
Discretionary Actions	§ 7-11-3.4	Cancellation of secondary term
Other Information	§ 7-11-63	Preference to previous lessee on re-lease
	§ 7-11-10	Certain lands herein specified can only be leased by competitive bids

[a]New Mexico Statutes, 1953.

[b]The second item in each table indicates special requirements for issuing the permit. A blank in this category reflects a necessity of filing an application with a minimum of information to include the applicant's name, address, and location of the land involved.

TABLE 6-14. NORTH DAKOTA OIL EXPLORATION PERMIT[a]

Item	Statutes	Summary
Agency	§ 38-09-14	Any department or agency of the state
Requirements[b]	§ 38-08-04	Industrial commission requires a bond for repair of surface and charges $25.00 for a drilling permit. Permittee (without bond) required to file notice of intent to drill with county register of deeds
Fees		
Rental	§ 38-09-18	Not less than 25¢ per acre per year
Royalty	§ 38-09-18	Not less than 1/8 of lessor's interest
Duration	§ 38-09-18	Not less than 5 years and for so long as producing
Bond	§ 38-15-03	The industrial commission may require a bond to satisfy conflicts between mining or oil and gas developers on same land
Discretionary Actions		
Other Information	§ 38-09-14	The procedure above is for exploration. Leasing must be competitive bid (38-09-15)
	§ 38-09-20	Any county, city, etc., may also lease their lands for oil and gas and they have the authority to establish their leasing regulations

[a]North Dakota Century Code, 1960 (as amended).

[b]The second item in each table indicates special requirements for issuing the permit. A blank in this category reflects a necessity of filing an application with a minimum of information to include the applicant's name, address, and location of the land involved.

TABLE 6-15. SOUTH DAKOTA OIL EXPLORATION PERMIT[a]

Item	Statutes	Summary
Agency	§ 5-7-1	Commissioner of School and Public Lands
Special Requirements[b]	§ 5-7-2	This lease goes to the highest bidder in oral bids
Fees	§ 5-7-27	The Board of School and Public Lands may set reasonable fees
Rental	§ 5-7-24	Not less than 10¢ per acre per year
Royalty	§ 5-7-24	Royalty shall be 1/8 of production
Duration	§ 5-7-23	Not more than ten years and for so long as producing
Bond		
Discretionary Actions	§ 5-7-22	Commissioner may withhold lands from lease if in best interests of state
Other Information	§ 45-9-4 § 45-9-15	A permit to drill from the State Oil and Gas Board for a fee of $100. A bond required from $5,000 to $20,000 for restoration (discretionary)
	§ 45-7A-3	This section may additionally require a report of any exploratory well sent to the Department of Natural Resources (confidential). Also, that all such wells be capped, sealed, or plugged
	§ 5-7-6	Exempts oil and gas from the provisions concerning mineral prospecting and leasing (see Coal Exploration and Leasing for South Dakota § § 5-7-3 to 5-7-17)
	§ 5-7-2	Specifically allows for prospecting and production in the lease

[a]South Dakota Compiled Laws, 1967.

[b]The second item in each table indicates special requirements for issuing the permit. A blank in this category reflects a necessity of filing an application with a minimum of information to include the applicant's name, address, and location of the land involved.

TABLE 6-16. UTAH OIL EXPLORATION PERMIT[a]

Item	Statutes	Summary
Agency	§ 65-1-18	State Land Board
Special Requirements[b]	§ 40-6-5	The Board of Oil, Gas and Mining has the authority to require: security (for plugging), notice of intent to drill, cont'd; and filing of a well log (for any drilling)
Fees	§ 65-1-24	15¢ per acre
Rental	§ 65-1-18	Not less than 50¢ per acre per year nor more than $1.00 per acre per year
Royalty	§ 65-1-18	Not more than 12 1/2 percent of gross
Duration	§ 65-1-18	Not less than ten years and for so long as producing
Bond	§ 65-1-90	Required only to reinstate lease after failure to pay for damage to surface
Discretionary Actions	§ 65-1-90	Amount of bond in item no. 7 above
Other Information	§ 65-1-45	Newly acquired lands and lands with an expiring lease must be let through competitive bids, all other leased to first applicant

[a]Utah Code Annotated, 1953.

[b]The second item in each table indicates special requirements for issuing the permit. A blank in this category reflects a necessity of filing an application with a minimum of information to include the applicant's name, address, and location of the land involved.

TABLE 6-17. WYOMING OIL EXPLORATION PERMIT[a]

Item	Statutes	Summary
Agency	§ 36-74	Board of Land Commissioners, Commissioner of Public Lands
Special Requirements[b]		
Fees	§ 36-42	Fee for filing a lease application is $15
Rental		
Royalty	§ 36-74	Not less than 5 percent of gross
Duration	§ 36-74	A primary term of 10 years and to continue so long as production realized
Bond		
Discretionary Actions		
Other Information	§ 36-74	The agency above has authority to set rates and terms in its rules and regulations within the confines of specific statutes noted above
	§ 36-79	This section allows the counties, cities, and school districts to lease their lands (if owned in fee) for oil or gas production
	§ 36-34	For a fee of $10 you can be put on the mailing list of lands open to file upon (appears to be non-competitive)

[a]Wyoming Statutes of 1957.

[b]The second item in each table indicates special requirements for issuing the permit. A blank in this category reflects a necessity of filing an application with a minimum of information to include the applicant's name, address, and location of the land involved.

6.3.4.2 Leasing

After exploration, the procedures for obtaining leases vary according to the ownership status of the land and what is known about the mineral deposits of the proposed tract. These procedures will be discussed in the following order: federal laws governing development, federal lease types, Indian lands and state lands.

6.3.4.2a Leasing on Federal Lands

Since the federal laws applicable to the leasing of oil lands are primarily the same ones applicable to coal, gas, and oil shale, they were discussed in Chapter 2. The following discussion will note the key provisions applicable only to oil.

Two types of leases may be issued, depending upon what is known about the mineral deposits of the proposed lease section. A competitive lease has a publicly announced invitation to bid and the bidder with the highest bonus bid is awarded the lease. Lands of known geological structure (KGS, lands whose mineral characteristics are known or can be reasonably estimated) must be submitted to competitive bidding.[1] A prospecting permit may be issued or a non-competitive lease may be awarded for lands whose mineral characteristics have not been determined.[2] A

[1]43 C.F.R., 3120.1-3120.4-2.

[2]Section 3, a, 1, Order No. 2948, U.S. Department of Interior, Division of Responsibility Between Bureau of Land Management and Geological Survey for Administration of Mineral Leasing Laws - (Onshore) in U.S. Congress, Senate, Committee on Interior and Insular Affairs, Federal Leasing and Disposal Policies, Hearings, 92nd Congress, 2nd Session, June 19, 1972, p. 175-176; 43 C.F.R. 3110.1-2112.5-2.

prospecting permit grants the holder authority to explore the land covered and preferential rights on possible leases. The non-competitive lease is entered into by the BLM and the leasee, and conditions are negotiated between the two parties.

A minimum bonus (cash deposit) is required for competitive bids on federal onshore lands. The minimum is discretionary and is determined through an evaluation made by the Geological Survey. This is used to indicate whether or not the high bid received represents an estimation of the fair market value of the tract leased. Non-competitive leases for oil and gas bearing lands are issued without a bonus.

Differences also exist in the time limitations applicable for the two lease types. Competitive leases are issued for five years and non-competitive leases are for ten years. In both cases the lease may be continued after the initial period if oil or gas is being produced in paying quantities. (This standard has not been specifically defined.) If drilling operations are underway at the lease's expiration it may be extended for two years and thereafter, if producing, may be continued as with the original lease.[1]

Non-competitive leases for either public or acquired lands must lie within a six-mile square or an area not exceeding six surveyed sections in length or width. The lease may not be for an area of less than 640 acres or more than 2,560. Exceptions may be granted if the lands are in an approved unit or cooperative plan or the land is surrounded by lands which are

[1]Federal Leasing and Disposal Policies, p. 122.

not available for leasing. Competitive leases, on the other hand, may not exceed 640 acres and should be as compact as possible.[1]

Total acreage limitations also exist. No individual association or corporation may hold more than 264,080 acres in any single state; of that figure, no more than 200,000 acres may be held under option. The computations are made separately for public domain and acquired lands; neither category can be applied to the other to determine total acreage held.

The lease agreements obligate the developer to pay rentals on the land and royalties on the production. Rental rates for non-competitive leases are not less than $0.50 per year per acre. For competitive leases the rate is not less than $2.00 per year per acre.[2] Royalty rates differ for oil and gas wells. For oil wells the rate begins at 12.5 percent if average production is under 110 barrels per day and advances up a scale to 25 percent for wells producing over 400 barrels per day. For gas wells the rate is 12.5 percent if average production is less than 5,000,000 cubic feet per day and is 16.5 percent if production exceeds that level. These rates apply to both public domain and acquired lands.

6.3.4.2b Leasing on Indian Lands

Procedures for acquiring Indian lands are generally the same as those for federal lands, although Indian authorities do have

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[1] Landman's Legal Handbook, p. 33-34; 43 C.F.R. 3123.1 and 43 C.F.R. 3122.1, 3124.1

[2] 43 C.F.R. 3103.3-4 (i).

veto power over leasing decisions. Indian lands are administered in a cooperative trusteeship. Although Indian lands are not an integral part of the public domain, neither do the Indians have complete legal title. Indian lands are divided into two principal categories: allotted where title has been partially transferred to individual Indian landowners; and tribal where the lands are collectively owned.

The Bureau of Indian Affairs (BIA) acts as a trustee, both for individual Indians and tribes on reservations. The stated goal is to protect Indian interests from overzealous government policies and to provide assistance and service in granting permits and making leases. Both the federal government and the Indian tribes have veto power over a lease.

The Omnibus Mineral Leasing Act of 1938 authorized the leasing of unallotted or tribal and ceded lands for mining purposes.[1] Under this Act, the tribal council or other authorized spokesman for the tribe may, with the approval of the Secretary of the Interior, enter into a lease not to exceed ten years "and so long thereafter as minerals are produced in paying quantities."[2]

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[1] Omnibus Mineral Leasing Act of 1938, 25 U.S.C. 396, 52 Stat.

[2] Unallotted or tribal lands are held in trust by the federal government for an entire tribe; allotted lands are held in trust for individual Indians; and ceded lands are those which were ceded to the federal government and settled by non-Indians while the tribe retained the mineral rights. Authorization to lease allotted lands was legislated in 1909 (Indian Department Appropriations Act of 1909, 25 U.S.C. 396, 35 Stat. 783). While there are differences because in one case lands are held in common and in the other by individuals, the regulations and procedures for allotted lands discussed here are essentially the same. Regulations implementing the Act are contained in Title 25, Code of Federal Regulations, Part 171 (25 C.F.R. Part 171).

Current regulations require competitive bidding on oil and gas leases unless the Commissioner of Indian Affairs grants the tribe written permission to negotiate for a lease.[1] Lease size is limited to 2,560 acres unless the Commissioner finds that larger acreage is in the interest of the tribe and required ".... to permit the establishment or construction of thermal electric power plants or other industrial facilities on or near the reservation."[2]

Rents and royalties are also established by regulation: for oil and gas the rent is $1.25 per acre per year and the minimum royalty is 12.5 percent of the value of all oil and gas actually produced.[3]

Regulations require diligent development. In the case of oil and gas, the regulation simply states that lessees are to exercise diligence in drilling and operating wells.[4] There is also a conservation requirement for oil and gas.[5]

Under the current system, leasing is the sole mechanism emphasized in the regulations and the initiative for minerals development (for example, in initiating a lease sale) is with the Secretary of the Interior. The theme throughout the regulations is one of management by the federal trustee for

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[1]25 C.F.R. 171.2 and 171.3.

[2]C.F.R. 171.9.

[3]25 C.F.R. 171.14 and 171.15.

[4]25 C.F.R. 171.14.

[5]25 C.F.R. 171.19 and 171.21. Other regulations cover assignment (transfer) of leases, penalties, prospecting permits, inspection, prior approval for starting operations, and cancellations. 26 C.F.R. 171.18, 171.19, 171.20, 171.25, and 171.27.

Indians. As noted earlier, many individual Indians and Indian tribes wish to have a more active role in managing their own affairs. Some tribes have, in fact, departed from current regulations and dealt directly with energy companies without the prior approval of the Secretary of the Interior.[1]

Some tribes have shown considerable interest in alternatives to leasing. The Jicarilla Apaches, for example, are preparing a proposal for joint ventures in oil and gas resource development.[2] Other alternatives being discussed are modified leases (with variable rather than fixed royalty, for example), production sharing agreements, and service contracts.

6.3.4.2c Leasing on State Lands

Leasing of state lands is controlled by statute in seven of the eight states. Colorado controls its state lands through agency regulation. For a general discussion of leasing procedures see Chapter 2; the following paragraphs will note the special provisions. Because the statutes written to control oil have been on the books longer than for other resources they are generally more specific. Hence, an oil developer in the western states will usually find an established procedure for leasing state lands.

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[1]For example, the Navajos dealt directly with Exxon in negotiating a uranium lease in 1972. Although bypassing the Secretary violates existing regulations, such an agreement would be valid if he subsequently approved it. Although the purpose of these so-called "joint ventures" is to secure a competitive advantage in the leasing market, it appears that this one agreement has had little effect on competition for resources. See U.S. Federal Trade Commission, Bureau of Competition, Report to the Federal Trade Commission on Mineral Leasing on Indian Lands. Washington: Federal Trade Commission, 1975, pp. 163-171.

[2]The tribal council considers the standard lease to be unacceptable, and does not intend to use it in the future.

In all states, responsibility for managing and leasing state lands and minerals is located in a single state agency, except for oil and gas in North Dakota where each state agency may lease land it controls. The administrative head of the agency may be authorized to accept or reject prospecting and lease applications. It is not unusual, however, for leasing approval to require the consent of more than one state agency.

If the state lands are known to contain commercially valuable oil reserves, they will usually be leased competitively. If they are unknown lands, the procedure varies from competitive to first-come-first-served. The terms of leases are usually 5 or 10 years while production of oil keeps the lease in operation indefinitely.

Generally, the leases are required by statutes to set specific rental and royalty rates, although some states allow discretion (e.g., New Mexico and Colorado) or some states set a maximum or minimum level for the rates.

Table 6-18 summarizes the key terms for the eight states and Tables 6-19 through 6-27 show the detailed statutory requirements.

TABLE 6-18. SUMMARY OF TERMS FOR OIL LEASES ON STATE LANDS

	Duration of Lease	Preference to Lease Giver	Must Lease be Issued Under Competitive Bid
AZ	5 years (continues while producing)		Yes, for lands of known commercial value
CO	Not specified by statute		Not specified by statute.
MT	10 years (continues while producing)		Yes, for re-lease of producing lands.
NM	5 years (continues while producing)[1]	To previous lessee	Yes, for lands within a statutorily described geographic region.
ND	5 years (continues while producing)		Yes
SD	10 years (continues while producing)		Yes
UT	10 years (continues while producing)		Yes, for newly acquired lands and for lands with an expiring lease
WY	10 years (continues while producing)		Not specified, but state has mailing list of lands available.

[1]New Mexico also allows for one, 5-year extension on the lease if not producing.

TABLE 6-19. ARIZONA OIL LEASE FEATURES (UNKNOWN LANDS)[a]

Item	Statutes	Summary
Agency	§ 27-553	State Land Department, State Land Commissioner
Requirements		
Fees	§ 27-555	$25
Rental	§ 27-555	$1.25 per acre per year for a maximum of 2,560 acres
Royalty	§ 27-555	12 1/2 percent
Duration	§ 27-555	Five years and so long as producing
Bond		
Other Information	§ 27-513	All wells in state require a drilling permit at a fee of $25 from commissioner

[a]Arizona Revised Statutes Annotated, 1956.

TABLE 6-20. ARIZONA OIL LEASE FEATURES (KNOWN LANDS)[a]

Item	Statutes	Summary
Agency	§ 27-553	State Land Department, State Land Commissioner
Requirements	§ 27-556	Must be leased by competitive bids
Fees		
Rental	§ 27-556	$1.00 per acre per year for a minimum of 160 acres and a maximum of 1,280 acres
Royalty	§ 27-556	12 1/2 percent
Duration	§ 27-556	Five years and so long as producing
Bond		
Other Information	§ 27-513	All wells in state require a drilling permit at a fee of $25 from commissioner

[a]Arizona Revised Statutes Annotated, 1956.

TABLE 6-21. COLORADO OIL LEASE FEATURES[a]

Item	Statutes	Summary
Agency	§ 36-1-113	State Board of Land Commissioners
Requirements		
Fees	§ 36-1-112	Application - $.50 Lease - $1.00 Lease Service Fee - $5.00
Rental	§ 36-1-114	Board may adjust rentals to get maximum revenue
Royalty		
Duration		
Bond		
Other Information		

[a]Colorado Revised Statutes, 1973.

TABLE 6-22. MONTANA OIL LEASE FEATURES[a]

Item	Statutes	Summary
Agency	§ 81-1701	State Board of Land Commissioners
Requirements		
Fees	§ 81-108	Set by state Land Department
Rental	§ 81-1702	Minimum of $1.50 per acre, but not less than $100 per year per lease. Maximum area of 640 acres per lease and per person
Royalty	§ 81-1704	12 1/2 percent minimum
Duration	§ 81-1702	10 years and so long as producing
Bond		
Other Information	§ 69-33	Geophysical Exploration Permit may be required (see Chapter 2)
	§ 81-1715	Competitive re-lease of producing lands
	§ 81-1702.2	Delay drilling penalty shall be $1.25 per acre per year
	§ 81-2612	If there is a conflict between coal, oil, gas, or geothermal developers on state lands, the first issued lease has priority, but the board may amend to fit the situation

[a]Revised Codes of Montana, 1947.

TABLE 6-23. NEW MEXICO OIL LEASE FEATURES[a]

Item	Statutes	Summary
Agency	§ 7-11-1	Commissioner of Public Lands
Requirements		
Fees	§ 7-11-1	The commissioner may set terms and fees
Rental	§ 7-11-9	Not more than 6400 acres per lease at not less than $100 per year for primary term or not less than 5¢ per acre nor more than $1.00 per acre during secondary term
Royalty	§ 7-11-3.4	Not less than 1/8 nor more than 1/1 also the commissioner may cancel secondary term
Duration	§ 7-11-3	5 years primary and so long thereafter as producing with one 5 year extension possible
Bond		
Other Information	§ 65-3-11	The Oil Conservation Commission has authority to require bond of $10,000 to insure plugging, conservation, etc., of oil and gas resources
	§ 7-11-63	Preference to previous lessee on re-lease
	§ 7-11-10	Certain lands herein specified can only be leased by competitive bids

[a]New Mexico Statutes, 1953.

TABLE 6-24. NORTH DAKOTA OIL LEASE FEATURES[a]

Item	Statutes	Summary
Agency	§ 38-09-14	Any department or agency of the state
Requirements		
Fees		
Rental	§ 38-09-18	Not less than 25¢ per acre per year
Royalty	§ 38-09-18	Not less than 1/8 of lessor's interest
Duration	§ 38-09-18	Not less than 5 years and for so long as producing
Bond	§ 38-15-03	The industrial commission may require a bond to satisfy conflicts between mining or oil and gas developers on same land
Other Information	§ 38-08-04	Industrial commission requires a bond for repair of surface and charges $25 for a drilling permit. Permittee cont'd (without bond) required to file notice of intent to drill with county register of deeds
	§ 38-09-14	The procedure above is for both exploration and production. Leasing must be competitively bid (38-09-15)
	§ 38-09-20	Any county, city, etc. may also lease their lands for oil and gas and they have the authority to establish their leasing regulations

[a]North Dakota Century Code, 1960 (as amended).

TABLE 6-25. SOUTH DAKOTA OIL LEASE FEATURES[a]

Item	Statutes	Summary
Agency	§ 5-7-1	Commissioner of School and Public Lands
Requirements	§ 5-7-2	This lease goes to the highest bidder in oral bids. Allows for prospecting and/or production within the lease
Fees	§ 5-7-27	The Board of School and Public Lands may set reasonable fees
Rental	§ 5-7-24	Not less than 10¢ per acre per year
Royalty	§ 5-7-24	Royalty shall be 1/8
Duration	§ 5-7-23	Not more than ten years and for so long as producing
Bond		
Other Information	§ 5-7-22	Commissioner may withhold lands from lease if in best interests of state
	§ 45-9-4	A permit to drill from the State Oil and Gas Board for
	§ 45-9-15	a fee of $100. A bond required from $5,000 to $20,000 for restoration (discretionary)
	§ 45-7A-3 § 45-7A-2	This section may additionally require a report of any exploratory well sent to the Department of Natural Resources (confidential). Also that all such wells be capped, sealed, or plugged.
	§ 5-7-6	Exempts oil and gas from the provisions concerning mineral prospecting and leasing (see Coal Exploration and Leasing for South Dakota § § 5-7-3 to 5-7-17)

[a]South Dakota Compiled Laws, 1967.

TABLE 6-26. UTAH OIL LEASE FEATURES[a]

Item	Statutes	Summary
Agency	§ 65-1-18	State Land Board
Requirements		
Fees	§ 65-1-24	15¢ per acre
Rental	§ 65-1-18	Not less than 50¢ per acre per year nor more than $1.00 per acre per year
Royalty	§ 65-1-18	Not more than 12 1/2 percent of gross
Duration	§ 65-1-18	Not less than ten years and for so long as producing
Bond	§ 65-1-90	Required only to reinstate lease after failure to pay for damage to surface
Other Information	§ 65-1-90	Amount of bond in item no. 7 above
	§ 40-6-5	The Board of Oil, Gas and Mining has the authority to require: security (for plugging), notice of intent to drill, and filing of a well log (for any drilling)
	§ 65-1-45	Newly acquired lands and lands with an expiring lease must be let through competitive bids, all other leased to first applicant

[a]Utah Code Annotated, 1953.

TABLE 6-27. WYOMING OIL LEASE FEATURES[a]

Item	Statutes	Summary
Agency	§ 36-74	Board of Land Commissioners, Commissioner of Public Lands
Requirements		
Fees	§ 36-42	Fee for filing a lease application is $15
Rental		
Royalty	§ 36-74	Not less than 5 percent of gross
Duration	§ 36-74	A primary term of 10 years and to continue so long as production realized
Bond		
Other Information	§ 36-74	The agency above has authority to set rates and terms in its rules and regulations within the confines of specific statutes noted above.
	§ 36-79	This section allows the counties, cities, and school districts to lease their lands (if owned in fee) for oil or gas production.
	§ 36-34	For a fee of $10 you can be put on the mailing list of lands open to file upon (appears to be non-competitive)

[a]Wyoming Statutes of 1957.

6.4 CRUDE OIL PRODUCTION

6.4.1 Conventional Production Technologies

The crude oil development technologies discussed in this section are grouped into four categories: development drilling, completion, processing, and improved recovery.

Development Drilling

Once oil is discovered by exploratory drilling, the well is tested to determine the possible oil flow rate and size of the reservoir. If the reserves calculated from these data and other geological information are large enough to warrant commercial production, the reservoir is developed. Development includes drilling a number of wells to drain the reservoir as efficiently as possible, completing these wells so that flow occurs and can be controlled, installing field processing equipment, and installing gathering pipelines.

Development drilling is carried out in the same manner as exploratory drilling, except that the spacing of wells and location of the bottoms of the holes are more carefully controlled. Once the development well is drilled, casing is set in a manner similar to that discussed in Section 6.3.1.

Completion

Well completion encompasses all those activities required for preparing the well for production. The four basic types of completion are open hole, liner, perforated casing, and multizone.

Open hole completion is used when the production zone is firm and not in danger of caving. It involves setting the casing to a depth just above the production zone and leaving the bottom open. An example of this is shown in Figure 6-5. Liner completion is accomplished by setting a screen liner opposite the producing layer to hold the sand or shale from caving.

The third type of completion, perforated casing, accounts for over 95 percent of all completions.[1] It is accomplished by putting holes in the casing at the production zone. This is done by either using a perforating gun which fires steel bullets through the casing or by using a jet type perforator which blasts holes in the casing with a high temperature, high velocity gas generated by a shaped charge explosive. An example of a perforated casing completion is shown in Figure 6-6. The fourth type of completion, multizone completion, produces two or more separate zones simultaneously through the same wellbore without mixing the fluids. This type completion is used not only to permit separate monitoring of the wells, but is also made compulsory by many state regulations.

Another aspect of the completion process is installing the production tubing. Production tubing is the pipe string inside the casing through which the produced fluids flow to the surface. The diameter of this pipe is small, relative to the casing diameter. The annular space between the tubing and the casing is blocked off above the producing zone by packers to force the fluid into the tubing. In the case of a multicompletion well, the annular space is blocked off both above and below the producing zone. Tubing and packers are shown in Figure 6-6.

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[1]Petroleum Extension Service, University of Texas. A Primer of Oil Well Drilling, 3rd Edition. Austin, Texas: University of Texas, 1970.

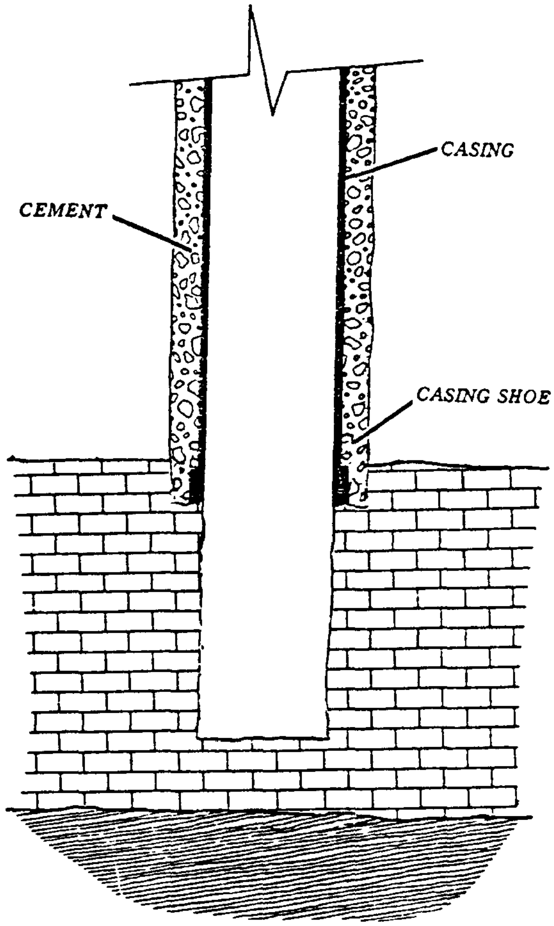

Figure 6-5. Open-Hole Completion.

Source: Petroleum Extension Service, University of Texas. A Primer of Oilwell Drilling, 3rd ed. Austin, TX: University of Texas, Petroleum Extension Service, 1970.

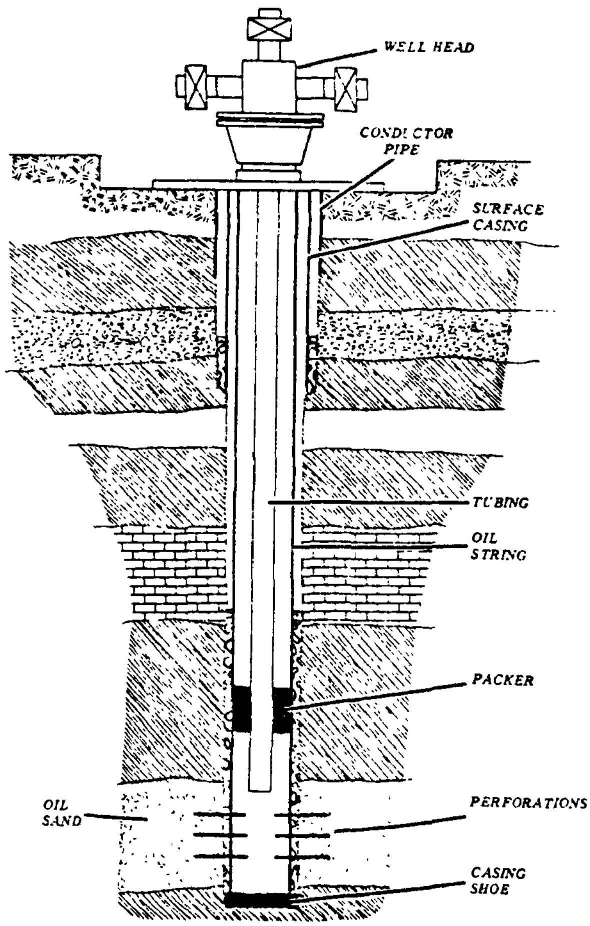

Figure 6-6. Perforated Casing Completion.

Source: Petroleum Extension Service, University of Texas. A Primer of Oilwell Drilling, 3rd ed. Austin, TX: University of Texas, Petroleum Extension Service, 1970.

At the wellhead, the tubing is attached to a series of valves which regulate the flow of oil from the well. These valves are known as the "Christmas tree." In those wells where there is danger of wellhead damage (such as in seismically active areas), a valve is placed near the bottom of the production tubing string. This downhole safety valve, commonly called a Storm Choke (the trade name for one brand), is designed to close when the flow through the valve exceeds a set limit. Recent modifications have made these valves much more reliable than earlier versions, which were responsible for some serious accidents.

Once the well has been completed, the crude oil is forced into the well by either of two reservoir forces: depletion drive or water drive.[1] Depletion drive causes the oil movement when the reservoir is closed; that is, the hydrocarbons are not in contact with a large body of water-bearing sand. Expansion of the hydrocarbons and other reservoir materials that occurs as the fluid is removed furnishes the energy to force the crude oil into the well. This depletion drive in an oil reservoir can be of two types: solution-gas drive and gas-cap drive.[2] In the solution-gas drive, a gas is dissolved in the oil providing pressure. In the gas-cap drive, the oil reservoir has a pocket of gas trapped above it. This pressurized gas forces the movement of the oil.

In a reservoir with water drive, the oil is in contact with a large body of water. The water is free to move into the reservoir and displace the hydrocarbons as they are withdrawn; thus, the reservoir pressure remains essentially constant. Since the water in this type drive has a greater displacement efficiency

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[1] Petroleum Extension Service, University of Texas. Field Handling of Natural Gas, 3rd Edition. Austin, Texas: University of Texas, 1972.

[2] *Ibid.*

than the gas in the depletion drive reservoirs, the oil recovery from a water drive reservoir is usually significantly higher than from either of the depletion drives. Optimistic recovery from a depletion drive may be 50-60 percent of the oil in place, whereas recovery from a water drive may be around 75 percent.[1] An example of a water drive reservoir is shown in Figure 6-7.

Production

Once the oil is in the well it must be brought to the wellhead. This is accomplished by one of three methods: natural flow (if reservoir pressure is great enough), plunger lift, or gas lift. Natural flow is the process by which either the depletion or water drive is sufficient to push the oil to the surface. Natural flow involves no prime mover and hence generates no emissions and effluents other than fugitive losses characteristic of hydrocarbons in the crude oil.

Plunger lift, which includes the sucker-rod or submersible pump, and gas lift will require a prime mover for either pumping or compressing. A list of available prime movers is shown in Table 6-28. The electric motor is the most convenient, and it is emission free. Electricity may not be available, however, in which case internal combustion-type engines are used. Common fuels used in internal combustion-type engines are natural gas, refinery gas, liquified petroleum gases (butane and propane), diesel fuel, and light fuel oils. Direct well natural gas which contains heavier hydrocarbons or gases which contain over two percent sulfur are not suitable.[2] Most fuels require some

[1]Petroleum Extension Service, University of Texas. Field Handling of Natural Gas, 3rd Edition. Austin, Texas: University of Texas, 1972.

[2]Frick, Thomas C. and R. William Taylor, Editors. Petroleum Production Handbook, 2 Vols. New York: McGraw-Hill, 1962.

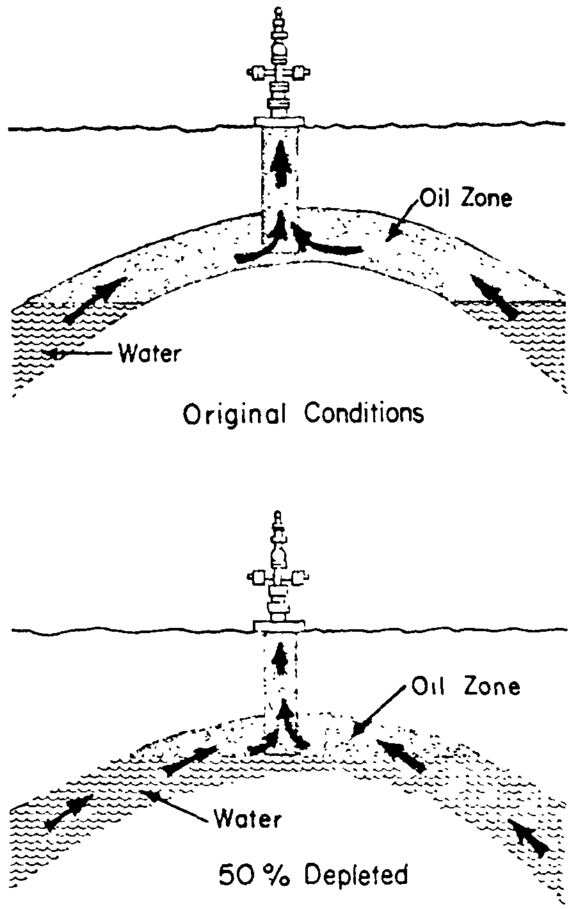

Figure 6-7. Water-Drive Reservoir.

Source: Petroleum Extension Service, University of Texas. Field handling of natural gas, 3rd ed. Austin, TX: University of Texas, Petroleum Extension Service, 1972.

TABLE 6-28. CLASSIFICATION OF PRIME MOVERS

1. Slow-speed* single-or twin-cylinder two-cycle gas engines.

2. Slow-speed single cylinder four-cycle gas engines.

3. High-speed** multiple-cylinder four-cycle gas engines.

4. Slow-speed diesel or oil-burning engines.

5. High-speed diesel engines.

6. Electric motors.

*Slow-speed is 750 rpm or less.

**High-speed is 750 rpm or greater.

Source: Frick, Thomas C. and R. William Taylor, eds. Petroleum Production Handbook, 2 vols. NY: McGraw-Hill, 1962.

type of on-site storage. The operations which are performed subsequent to wellhead production are discussed in the processing section.

Processing

Before the oil can be delivered for refining it must be processed to remove undesired components. An overall view of the processing options is shown in Figure 6-8. First, the oil from the wellheads is brought together to a central oil-water-gas separation facility by a gathering system consisting of piping from the wellheads and a central collection manifold. The simplest gathering system is a direct flow system where oil from the wells is merely piped to a common manifold and then on to the separation facility. This system works for wells with essentially equal producing pressures. If pressures are not equal, a gathering system which provides for pressure reduction before entering the manifold is employed. If the wells are producing heavy crudes, and especially if steam injection is being used, the gathering system may have to be heated by some means such as steam tracing to keep liquids flowing in the lines.

The brine and oil from the oil field is usually in an emulsion form. This emulsion must be broken and the brine content in the crude reduced to an acceptable level of about two weight percent. This operation consists of destabilizing the film between the oil and water droplets, coalescence of the oil droplets, and gravitational separation of the oil and water phases. The four methods used in dehydrating emulsions are 1) heating, 2) chemical treating, 3) electricity, and 4) gravity settling.

The application of heat to break emulsions is usually an auxiliary process to speed up separation. A heater is usually

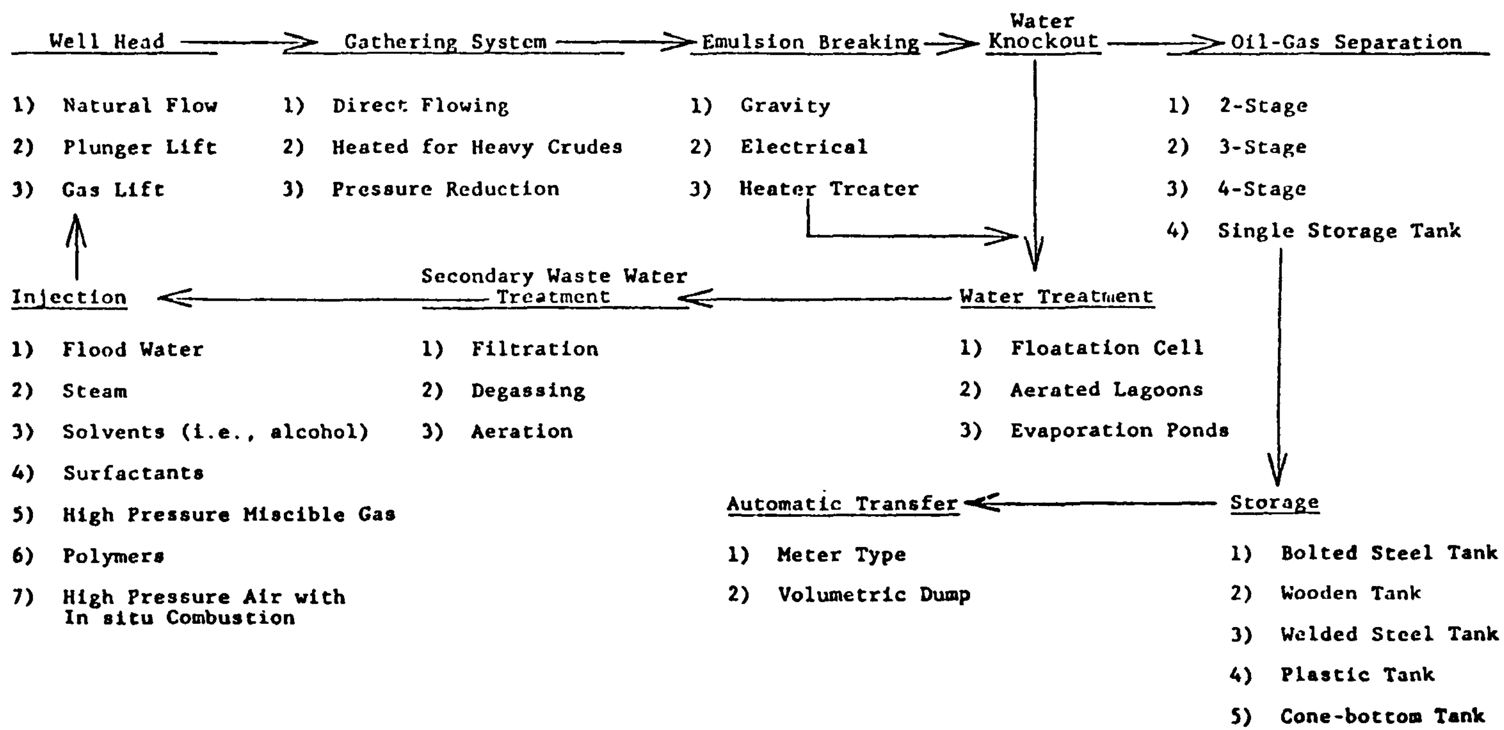

Figure 6-8. Oil Production Operation Options.

Source: Cavanaugh, E. D., et al. Atmospheric Environmental Problem Definition of Facilities for Extraction, On-Site Processing, and Transportation of Fuel Resources. Contract No. 68-02-1319, Task 19. Austin, Texas: Radian Corporation, July 1975.

used as an integral part of a single vessel in which heating and treating are both accomplished.[1] It is sometimes necessary to use separate heaters in the treatment of certain emulsions, but this is seldom done.

Chemical treatment is accomplished by the deactivation of the emulsifying agent that surrounds the dispersed water droplets. The emulsion breaking chemical is soluble in oil and surface active (work on the surfaces of the water droplets and cause them to break). Separation is enhanced by the addition of heat and is completed in some type of gravity settler.

Electricity is often an effective means of breaking an oil-water emulsion. The crude oil is usually pre-heated and subjected to a high voltage, alternating circuit electric field which increases the random motion of the polar water molecules. The droplets collide with each other with enough force to coalesce into larger and larger droplets until gravity causes a separation. The use of electricity means less preheat and therefore less fuel consumption. An electrostatic treater is shown in Figure 6-9.

Gravity settling is usually performed in a wash tank. The wash tank has three parts: 1) a bulk separator for free gas, 2) a bulk separator for free water, and 3) a quiescent tank for settling of suspended solids and water droplets. The bulk gas separator is usually a gas "boot" located in the inlet line to the wash tank. The bulk separator for free water is the lower

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[1]Petroleum Extension Service, University of Texas. Treating Oil Field Emulsions, 3rd Edition. Austin, Texas: University of Texas, 1974.

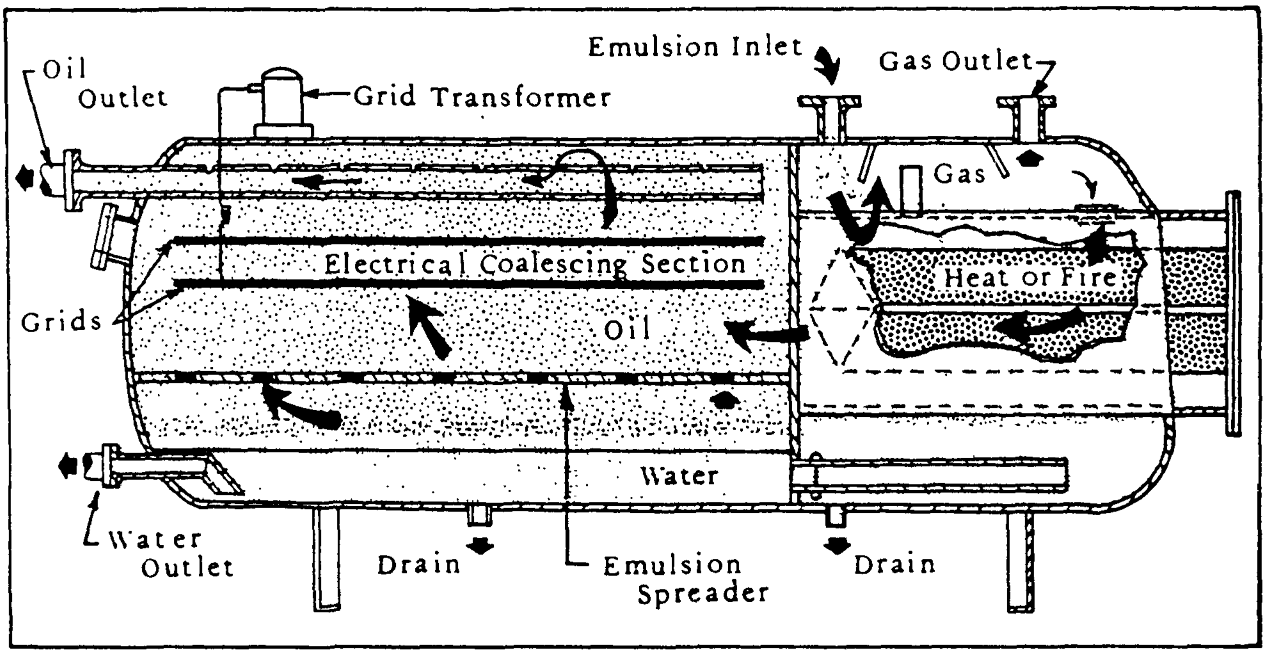


Figure 6-9. Cutaway of Electrostatic Treater.

Source: Petroleum Extension Service, University of Texas. Treating Oil Field Emulsions, 3rd ed. Austin Texas: University of Texas, 1974.

section of the wash tank, while the quiescent tank for settling of suspended solids and water droplets is the upper section. A wash tank may be used as a knock-out tank before or after a heater treater, chemical dehydrator or electrical dehydrator.

A heater treater combines all the various emulsion breaking features in one vessel. There are many different kinds of heater treaters and the selection of the right one for any given set of conditions is a complex engineering decision. A typical vertical heater treater is shown in Figure 6-10.

After the brine has been removed to an acceptable level, the oil and gas are separated. Oil and gas separators are classified as to the number of stages, the shape, and the number of phases separated. The number of stages is determined by the pressure of the incoming oil and gas mixture. For high-pressure fluids a greater number of stages will be required. Very low-pressure crudes may be routed directly to a storage tank which is considered as one stage of oil and gas separation.

Separators are horizontal, vertical, or spherical. The shape is determined by the oil-to-gas ratio. Horizontal separators are used for high oil-to-gas ratios, and vertical separators for low ratios. Spherical separators are used for intermediate ratios. All three types of separators are shown in Figure 6-11. Separators are either two- or three-phase units. In two-phase units only oil and gas are separated, while in three-phase units, oil, gas, and water are separated. The gases recovered can be segregated by pressure or by "wetness" ("wet" gases are those containing condensable hydrocarbons). The recovered gas is piped to a gas treating plant for further sweetening and purification. In remote areas, the off-gas may be reinjected or flared.

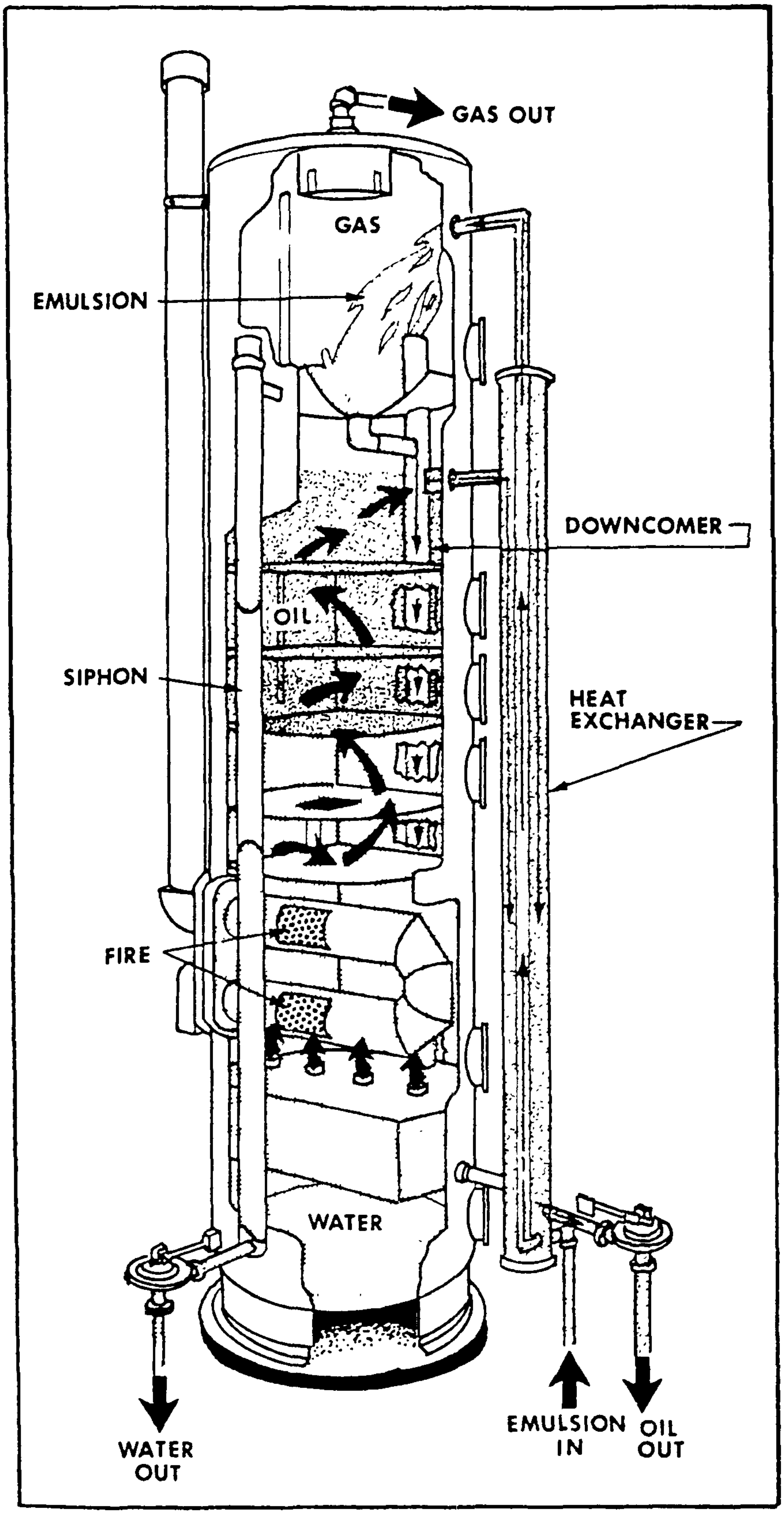
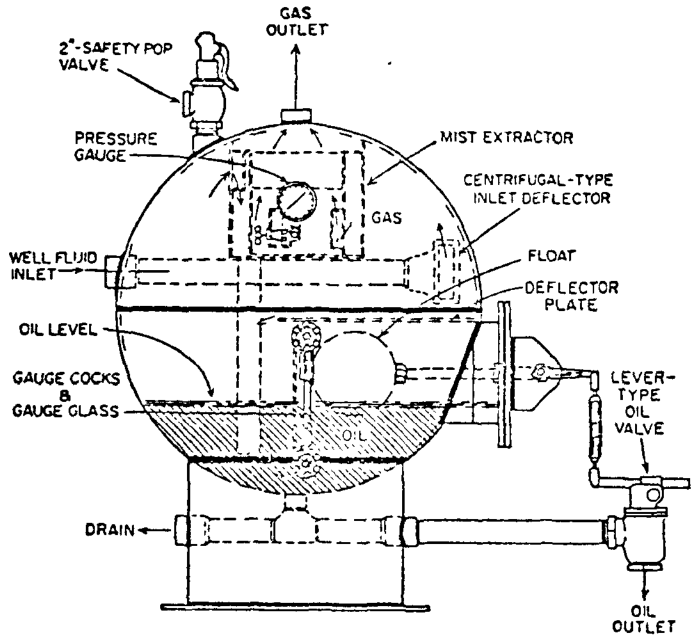
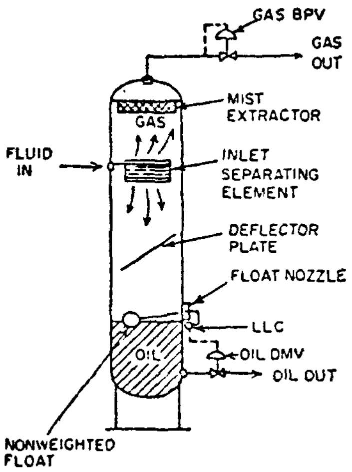


Figure 6-10. Cutaway of Vertical Heater Treater.

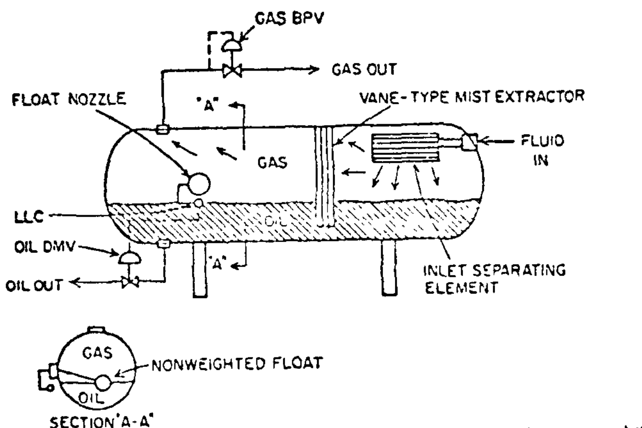
Source: Petroleum Extension Service, University of Texas, Treating Oil Field Emulsions, 3rd ed. Austin, TX: University of Texas, 1974.



Schematic diagram of typical spherical two-phase oil and gas separator with *float-operated lever-type oil control valve.*



Schematic diagram of typical vertical two-phase oil and gas *separator.*



Schematic diagram of typical horizontal two-phase oil and gas separator.

Figure 6-11. Oil-Gas Separators.

Source: Frick, Thomas C. and R. William Taylor, ed. Petroleum Production Handbook, 2 vols. N.Y.: McGraw-Hill, 1962.

The final dehydrated and gasified crude is held in surge or storage tanks to await shipment via pipeline, train, barge, or tank truck. The most common storage tank is the bolted steel tank. It can be easily transported, dismantled, and repaired. Other types of tanks are wooden, welded steel, plastic, and cone-bottom tanks. A tank battery should contain at least two tanks and usually have a capacity equal to four days' production.[1]

With the increase in value of lighter hydrocarbons, the recovery of these hydrocarbons has become economically feasible. Installation of floating roof tanks or some type of floating covers reduces hydrocarbon emissions from tanks. Vapor recovery systems can also be used to recover vapors but are more expensive than floating roofs. Vapor recovery systems have the advantage of being able to recover vapors from other sources such as dehydration or loading facilities. A schematic flowsheet for a typical vapor recovery system is shown in Figure 6-12.[2]

If the crude is to be transported by pipeline, the crude from the storage tanks is transferred by a lease automatic custody transfer (LACT) system. There are two types of transfer units: the meter type and the volumetric dump. In the meter type the oil is deaerated and then run through a metering system to determine the volume. The volumetric dump determines the oil volume by alternately filling and dumping calibrated tanks.

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[1]Frick, Thomas C. and R. William Taylor, editors. Petroleum Production Handbook, 2 Vols. New York: McGraw-Hill, 1962.

[2]Cavanaugh, E. C., et al. Atmospheric Environmental Problem Definition of Facilities for Extraction, On-Site Processing, and Transportation of Fuel Resources. Austin, Texas: Radian Corporation, July 1975.

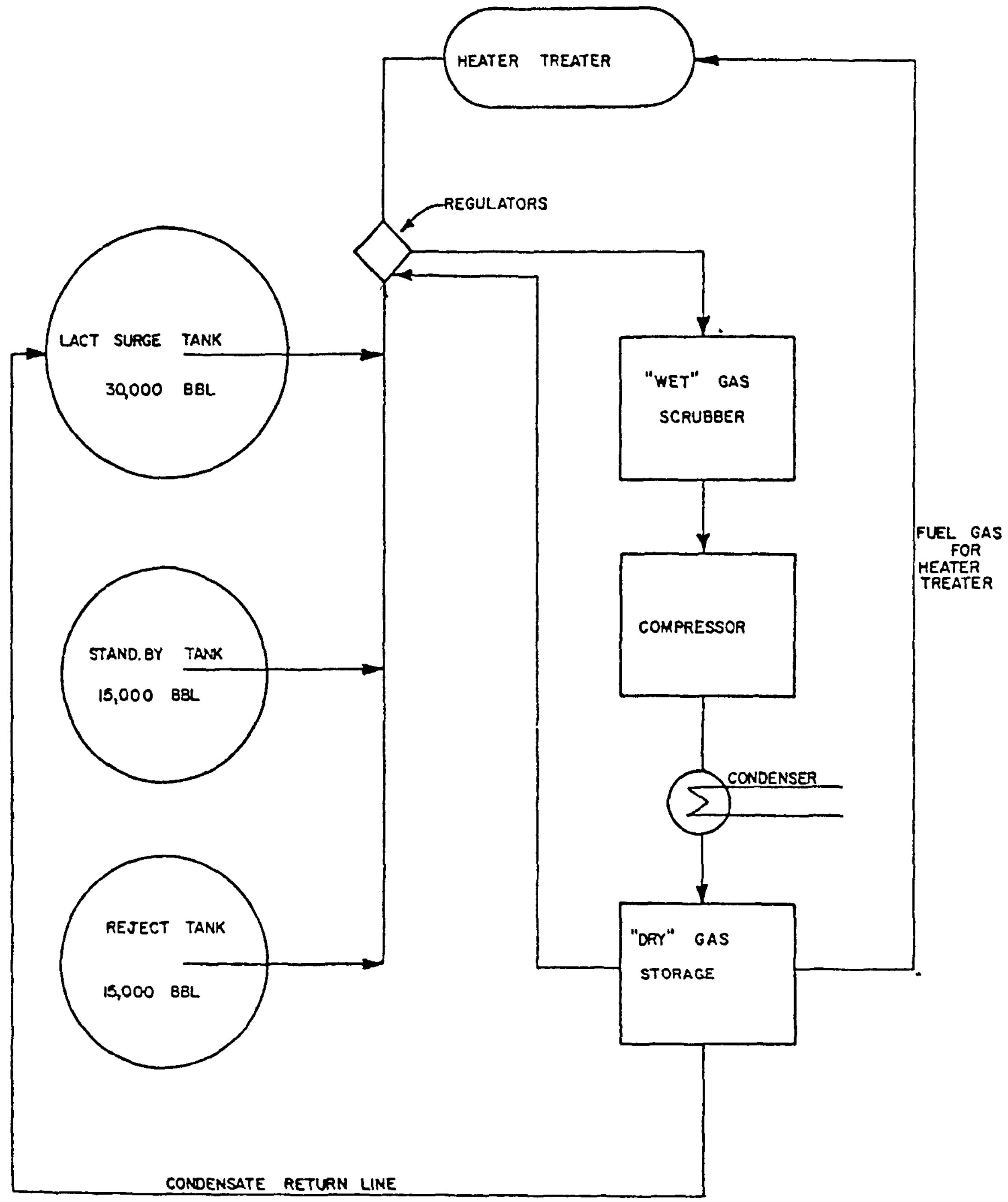

Figure 6-12. Vapor Recovery System.

Source: Cavanaugh, E.C., et al. Atmospheric environmental problem definition of facilities for extraction, on-site processing, and transportation of fuel resources. Austin, TX: Radian Corporation, July 1975.

Both units also automatically sample the crude for residual basic sediment, water content, and oil gravity.[1]

The water from the dehydrator, knock-out tanks, and three phase separators, if used, must be further treated before being discharged as wastewater or reinjected back into the well as steam injectors or water flooding. The flotation cell type wastewater treater is a commonly used primary water treating facility. This system involves air or gas injection upstream of the main wastewater process dump. The air and the chemical coagulants, if required, are thoroughly mixed inside the pump. The discharge flow from the pump enters the retention tank where air is dissolved under 2-3 atmospheres of pressure. As the wastewater enters the flotation cell, the pressure is released to atmospheric pressure and the air comes out of solution. Small sludge and oil particles become flotable on the bubbles or foam and pass to the top where the rotating skimming arm sweeps the oil sludge into a compartment for removal. The same drive shaft also rotates a bottom grit scraper arm for the separate removal of settleable solids to the grit collecting box.

Other possible wastewater treatment methods include sedimentation followed by aeration, aerated lagoons, or evaporation ponds. The type system employed is determined primarily by the ultimate use of the wastewater.

If the treated water is to be further used for either steam generation or water flooding, it must be filtered to remove the suspended solids. A sand filter or a diatomaceous earth filter may be used. The solids concentration must be lowered as much as possible to eliminate particulate buildup in the injection well.

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[1]Chilingar, George V. and Beeson, Carrol M. Surface Operations in Petroleum Production. New York: American Elsevier, 1969.

The wastewater must often also be treated for removal of dissolved H_2S. This can be accomplished by one of the following methods: 1) aeration, 2) vacuum degassing, 3) countercurrent gas stripping, or 4) chemical treatment.[1]

Improved Recovery

When the natural flow of the crude oil into the well has diminished, additional oil may be recovered by the use of various improved recovery techniques. These techniques are of two general types: secondary recovery and tertiary recovery. Secondary recovery techniques are those which improve recovery by augmenting the natural reservoir energy.[2] Waterflooding, a secondary recovery method, is discussed in this section. Two tertiary recovery techniques are discussed in greater detail in later sections.

The most common type of secondary recovery is waterflooding. As was discussed earlier, the natural reservoir drive is caused by pressure on the reservoir from expansion of gases (depletion drive). After this pressure has decreased, due to removal of the crude, it is replaced by a similar pressure induced by injected water. Each well which will continue to produce oil is encircled by injection wells. These can either be existing wells which will be converted from producing to injection or newly drilled wells specifically for injection. Water is then injected into the reservoir through the injection wells. As the water

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[1]Chilingar, George V. and Beeson, Carrol M. Surface Operations in Petroleum Production. New York: American Elsevier, 1969.

[2]Thermal Recovery Handbook, Reprint. Oil and Gas Journal. Tulsa, Oklahoma: Petroleum Publishing, 1966.

flows through the reservoir it pushes the oil out of the pore spaces where it had been trapped and into the producing well. Generally, waterflooding requires injection of several barrels of water for each barrel of oil recovered, the amount dependent on the nature of the reservoir. A typical waterflooding system is shown in Figure 6-13.

Present oil field recovery practices usually employ a recovery technique, like waterflooding, followed by an enhanced method such as steam injection or CO_2 miscible, the two techniques discussed later. In the future it may become economically feasible to incorporate enhanced recovery methods earlier in the life of an oil field.

6.4.1.1 Input Requirements

For the following analysis, a total crude oil production of 100,000 barrels per day was chosen. The site of this operation is assumed to be in Rio Blanco County, Colorado. Each well is assumed to produce 250 BPD of crude oil requiring a total of 400 wells. The construction of the 100,000 BPD facility is scheduled to last seven years. All 400 wells are scheduled to be on line by the end of the seventh year.

The module for oil production is based on one gathering system fed by several oil wells. The wellheads are the plunger lift type equipped with primer movers which operate on electricity. From the gathering system, the oil-brine emulsion is fed into a water knock-out tank. To enhance the oil-water separation in the knock-out tanks, the oil-brine emulsion is pretreated in a heater treater which destabilizes the emulsion. The light

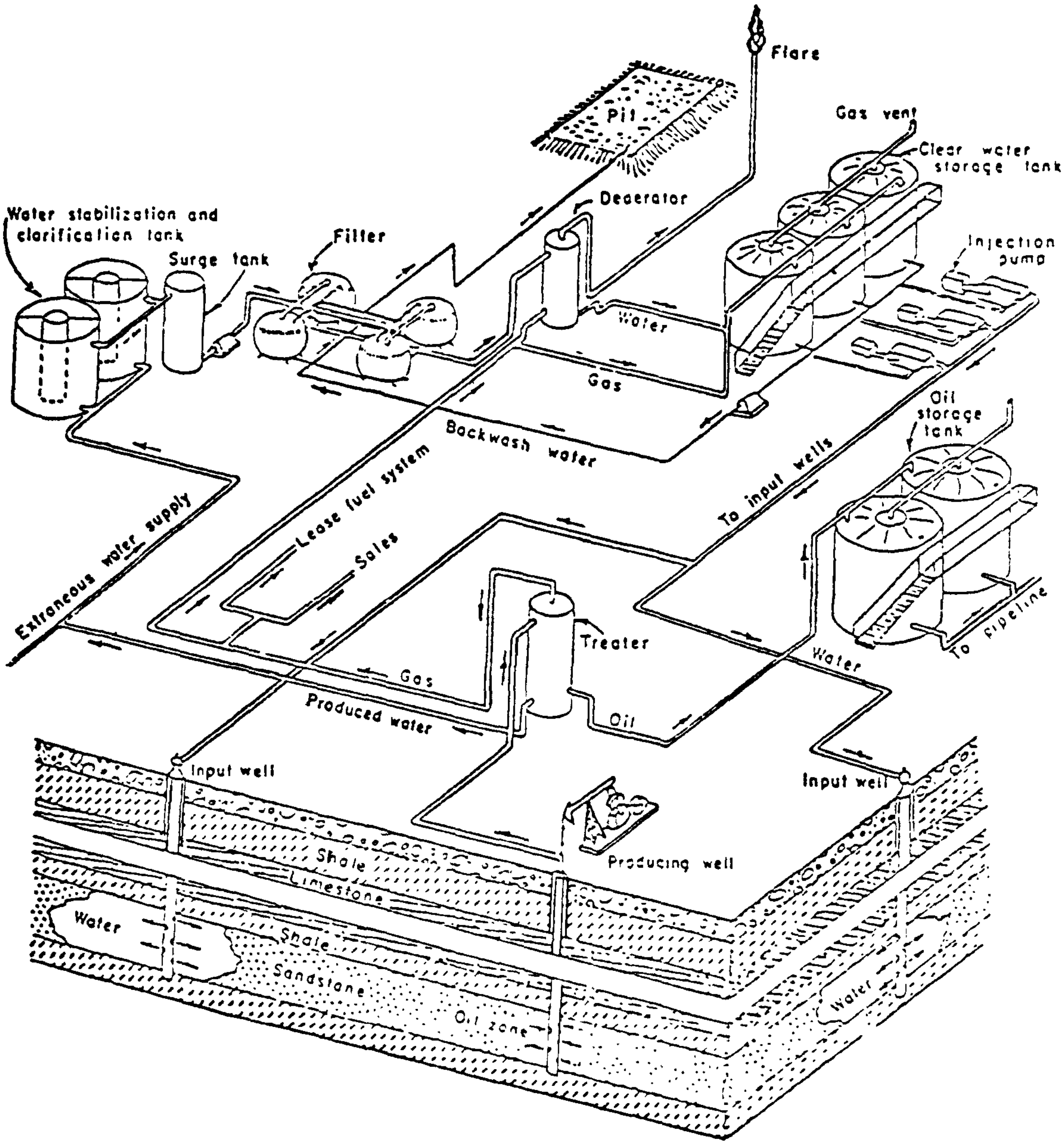

Figure 6-13. Waterflood Secondary Recovery System.

Source: U.S. Bureau of Mines. Potential Oil Recovery by Waterflooding Reservoirs Being Produced by Primary Methods, I.C. 8455.' Washington, D.C.: Bureau of Mines, 1970.

hydrocarbon gases are then removed in an oil-gas separation section consisting of three spherical separation tanks operating at progressively decreasing pressures. The released gas is sent directly to a gas treating plant.

The brine from the emulsion breaking system is combined with the brine from the water knock-out tank and run through a flotation cell wastewater treater. The flotation cell treater removes sludge, grit, and oil particles from the wastewater. The treated water is used for either steam generation or water flooding. It must be filtered to remove the suspended solids. The solids concentration is lowered as much as possible to eliminate particulate buildup in the injection well. A sand filter is normally used for this purpose. The water is also treated for removal of dissolved H_2S, which contributes to corrosion in the pipes and machinery, and which is an atmospheric emission problem. H_2S removal from the wastewater is usually accomplished by countercurrent stripping, with the offgas being routed along with the associated gas to a nearby gas treating plant.[1]

The storage facility for crude oil from the separation unit is equipped with a vapor recovery system. The vapor recovery system is also tied in with the heater treater to capture any vapor emissions from that unit. The crude oil is transferred from the storage tanks to the pipeline by a lease automatic custody transfer pumping system. This unit also automatically

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[1]Chilingar, George V. and Carrol M. Beeson. Surface Operations in Petroleum Production. New York: American Elsevier, 1969.

samples the crude for analysis of sediment, water content and oil gravity.

In addition to the descriptions of primary production the injection system for waterflooding consists of a central high-pressure water pump and a distribution system. Waterflooding, where described, is based on 10 percent of the total production (10,000 bpd).

The flow sheet for this oil production operation is shown in Figure 6-14.

6.4.1.1a Manpower Requirements

Construction

The construction of the 100,000 bpd oil producting facility is scheduled to take 7 years. The required manpower for this construction is shown in Table 6-29.[1] Manpower is required for drilling the 400 wells and the 300 dry holes, as well as for the construction of gathering, separation, and reinjection facilities. Each well produces 250 barrels per day. A great deal of engineering manpower is required to make all the construction possible.

Operation and Maintenance

The schedule of required manpower for operation and maintenance of the 100,000 bpd crude oil operation is shown in

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[1]Carasso, M., et al. Energy Supply Model, Computer Tape. San Francisco, California: Bechtel Corporation, 1975.

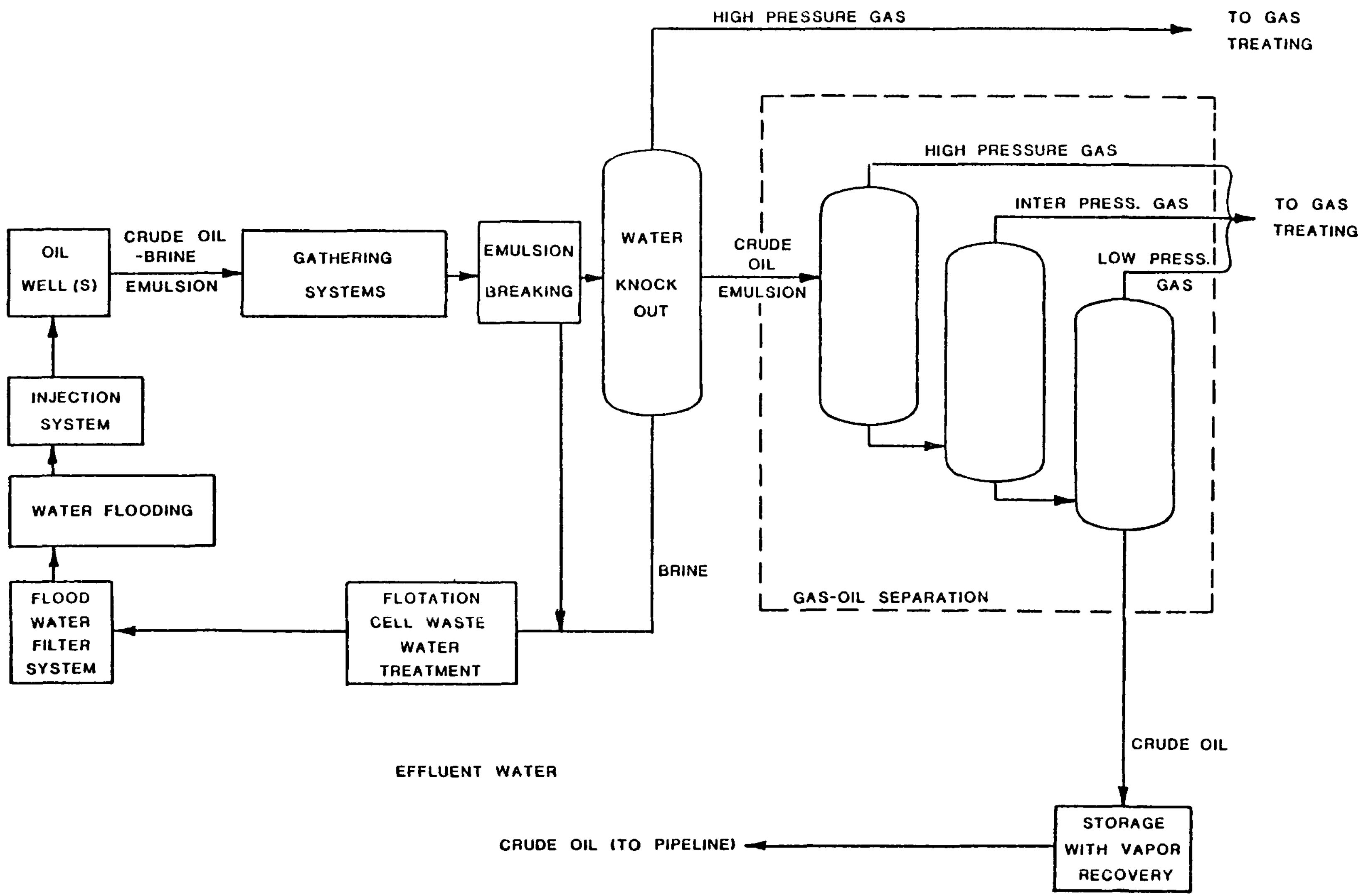

Figure 6-14. Crude Oil Production.

Source: Cavanaugh, E.C., et al. Atmospheric environmental problem definition of facilities for extraction, on site-processing, and transportation of fuel resources. Austin, TX: Radian Corporation, July 1975.

TABLE 6-29. SCHEDULE OF MANPOWER RESOURCES (MAN-YEARS) REQUIRED FOR CONSTRUCTION OF ONSHORE OIL PRODUCTION (100,000 bpd)

Resources	Year 1	2	3	4	5	6	7
Civil Engineers	3	14	21	21	21	17	7
Electrical Engineers	3	14	21	21	21	17	7
Mechanical Engineers	7	28	42	42	42	35	14
Geological Engineers	28	111	167	167	167	139	56
Petroleum Engineers	28	111	167	167	167	139	56
Total Engineers	69	278	417	417	417	347	139
Total Designers & Draftsmen	21	83	125	125	125	104	42
Total Supervisors & Managers	21	83	125	125	125	104	42
Total Technical	111	444	667	667	667	556	222
Total Non-Technical (Non-Manual)	17	73	125	125	125	108	50
Pipefitters	21	111	208	208	208	187	97
Pipefitters/Welders	17	89	167	167	167	150	78
Electricians	4	22	42	42	42	37	19
Operating Engineers	58	311	583	583	583	525	272
Other Major Skills	175	933	1750	1750	1750	1575	817
Total Major Skills	275	1467	2750	2750	2750	2475	1283
Other Craftsmen	17	89	167	167	167	150	78
Total Craftsmen	292	1556	2917	2917	2917	2525	1361
Total Teamsters & Laborers	14	97	208	208	208	194	111
GRAND TOTALS	434	2170	3917	3917	3917	3483	1744

Table 6-30.[1] The tabulated data do not indicate that operations begin during construction year 4 and that required manpower increases in subsequent years as more wells start producing. The manpower shown for the seventh year represents requirements for the full 100,000 bpd production and should remain relatively constant in the subsequent years.

6.4.1.1b Materials and Equipment

A schedule of the needed materials and equipment for the seven years of construction is shown in Table 6-31.

6.4.1.1c Economics

Construction

The total capital cost of the seven year construction project is estimated at $2,040 million (third quarter 1974 dollars). This estimate excludes owner's costs (land costs, interest during construction, etc.). A schedule of these construction costs is shown in Table 6-32.[2]

Operation and Maintenance

The estimated annual operation and maintenance costs.starting in year 4, when the first wells become operational, are

[1]Carasso, M., et al. Energy Supply Model, Computer Tape. San Francisco, California: Bechtel Corporation, 1975.

[2]*Ibid.*

TABLE 6-30. SCHEDULE OF MANPOWER RESOURCES (MAN-YEARS) REQUIRED FOR OPERATION AND MAINTENANCE OF ONSHORE OIL PRODUCTION (100,000 bpd)

Resources	Year 1	2	3	4	5
Civil Engineers	3	6	9	12	16
Electrical Engineers	2	3	5	6	8
Mechanical Engineers	5	0	14	19	24
Geological Engineers	19	38	57	76	94
Petroleum Engineers	19	38	57	76	94
Total Engineers	47	94	142	189	236
Total Designers & Draftsmen	16	32	47	63	79
Total Supervisors & Managers	19	38	57	76	94
Total Technical	82	164	246	327	409
Total Non-Technical (Non-Manual)	13	25	38	50	63
Pipefitters	24	47	71	94	118
Pipefitters/Welders	19	38	57	76	94
Electricians	5	9	14	19	24
Other Operators	47	94	142	189	236
Other Major Skills	8	16	24	32	40
Total Major Skills	102	205	307	409	512
Other Craftsmen	158	315	473	630	788
Total Craftsmen	260	520	780	1040	1300
Total Teamsters & Laborers	55	110	165	22	276
GRAND TOTALS	410	819	1229	1637	2048

Source: Carasso, M., et al. Energy Supply Model, Computer Tape. San Francisco, California: Bechtel Corporation, 1975.

TABLE 6-31. SCHEDULE OF SELECTED MAJOR MATERIALS AND EQUIPMENT REQUIRED FOR CONSTRUCTION OF ONSHORE OIL PRODUCTION (100,000 bpd)

Resources	Year 1	2	3	4	5	6	7	Total
Refined Products (Tons)	14,000	74,667	140,000	140,000	140,000	126,000	65,333	700,000
Ready Mixed Concrete (Tons)	400	2,133	4,000	4,000	4,000	3,600	1,867	20,000
Pipe & Tubing (less than 24% D) (Tons)	1,440	7,680	14,400	14,400	14,400	12,960	6,720	72,000
Oil Country Tubular Goods (Tons)	11,200	59,733	112,000	112,000	112,000	100,800	52,267	560,000
Reinforcing Bars (Tons)	80	427	800	800	800	720	373	4,000
Drill Rigs (Item-Years)	14	77	144	144	144	130	67	720
Pumps & Drives (100 HP) (Items)	160	853	1,600	1,600	1,600	1,440	747	8,000
Pumps & Drives (100 HP) (Tons)	64	341	640	640	640	576	299	3,200

Source: Carasso, M., et al. Energy Supply Model, Computer Tape. San Francisco: Bechtel, 1975.

TABLE 6-32. SCHEDULE OF CAPITAL RESOURCES (MILLION DOLLARS, THIRD QUARTER 1974) REQUIRED FOR CONSTRUCTION OF ONSHORE OIL PRODUCTION (100,000 bpd)

Resources	Year 1	2	3	4	5	6	7	Total
Wood Products	0	1	2	2	2	1	1	8
Chemicals and Allied Products	1	8	15	15	15	13	7	74
Petroleum Products	1	6	12	12	12	10	5	58
Stone & Clay Products	1	6	10	10	10	9	5	52
Primary Iron & Steel Products	7	38	71	71	71	64	33	356
Primary Non-Ferrous Metals	0	0	1	1	1	1	0	4
Fabricated Structural Products	0	0	1	1	1	1	0	4
Other Fabricated Products	1	7	13	13	13	12	6	64
Materials Subtotal	12	66	124	124	124	112	58	620
Construction, Mining & Oil Field Equip.	11	57	107	107	107	96	50	536
Gas Welding Sets & Metalworking Equip.	0	0	1	1	1	1	0	3
Electric Welding Sets	0	0	0	0	0	0	0	2
General Industry Equipment	1	4	8	8	8	7	4	40
Instrumentation & Controls	0	1	2	2	2	1	1	8
Electrical Equipment	0	1	2	2	2	1	1	8
Fabricated Plate Products	1	4	7	7	7	6	3	36
Miscellaneous	3	16	30	30	30	27	14	148
Equipment Subtotal	16	83	156	156	156	140	73	780
Construction Capital Cost Total*	41	218	408	408	408	367	190	2,040

*Construction capital cost total includes materials and equipment subtotals above plus other (Construction labor, overhead, profit, etc.) costs. It excludes owner's costs (land costs, interest during construction, etc.)

Source: Carasso, M., et al. Energy Supply Model, Computer Tape. San Francisco, California: Bechtel Corporation, 1975.

are shown in Table 6-33 to be $18 million.[1] This cost should represent the cost of operation and maintenance for the life of the field and remain fairly constant in 1974 dollars.

6.4.1.1d Water Requirements

The facility considered in this report will have no water requirement if waterflooding is not used. Since the produced oil contains a significant quantity of brine (connate water) and there are no significant uses of water in primary production, there will be an excess of water and a disposal problem (see Section 6.4.1.2b), but no water needs. Water needed in the drilling process for the drilling mud was discussed in Section 6.3.2b.

If waterflooding is used to a significant extent as a recovery technique, there is definitely a need for additional water. A case study has been developed to show the requirements for the example 100,000 barrel per day field. The total additional water requirement has been calculated as a function of the connate water (brine) produced with the crude oil. Table 6-34 reports water requirements for crudes containing 10%, 20%, and 30% free water. Although these values are in the range which might be expected from these assumptions, they are subject to wide variation and are used as inputs to a water balance only to show possible water needs. The water balance assumed that all water produced with the crude oil is treated and used as make-up in the waterflood program.

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[1] Carasso, M., et al. Energy Supply Model, Computer Tape, San Francisco, California: Bechtel Corporation, 1975.

TABLE 6-33. SCHEDULE OF MATERIALS AND EQUIPMENT RESOURCES (MILLION DOLLARS, THIRD QUARTER 1974) REQUIRED FOR OPERATION AND MAINTENANCE OF ONSHORE OIL PRODUCTION (100,000 bpd)

Resources	Cost ($ million)
Metal Products	3
Non-Electrical Machinery	2
Electrical Equipment	1
Transportation Equipment	5
Instruments and Controls	1
Miscellaneous	6
GRAND TOTAL	18

Basis: 400 wells producing 250 bpd each.

TABLE 6-34. WATER REQUIREMENTS FOR SECONDARY RECOVERY

	Case I	Case II	Case III
Water in crude, vol %	10	20	30
Waterflood injection rate,[1] bbl H_2O/bbl oil recovered	10	10	10
Water production, bbl/day	11,000	25,000	43,000
Additional water requirement acre-ft/yr	4,175	3,520	2,675

[1] Chilingar, George V. and Beeson, Carrol M. Surface Operations in Petroleum Production. New York: American Elsevier, 1969.

6.4.1.1e Land Usage

Total permanent land usage for an oil field with a capacity of 100,000 barrels per day is approximately 2000 acres. This assumes five acres per well for cleared area around producing well, pipeline right-of-ways, separation facilities, and roads.[1] Another estimate of the amount of land required for the oil production is 0.06 acres per 10^6 Btu/hr.[2] For a crude oil heat content of 5.6×10^6 Btu, 1400 acres would be required for the 100,000 bpd operation. The reservoir is estimated to be 20 square miles with assumptions for depth of formation, nature of formation, life of field, etc. This is an average well spacing of 32 acres.

6.4.1.1f Ancillary Energy

Energy in the example 100,000 bpd oil field is consumed in two major areas: the heater treaters and the prime movers of the oil. Table 6-35 lists energy requirements for a typical heater treater system of a field this size as a function of the amount of brine produced with the crude oil. Electricity powers the plunger pumps at the wellhead as well as other miscellaneous pumps. Assuming a value of 20 hp for the average electric motor, a daily power consumption of approximately 150,000 kilowatt-hr is realized. Converted to heat equivalents, this energy is about 500 million Btu/day.

[1]Federal Power Commission. National Gas Survey, Vol. II. Washington, D.C.: Federal Power Commission, 1974, pp. 73-75.

[2]Battelle Columbus and Pacific Northwest Laboratories. Environmental Considerations in Future Energy Growth. Columbus, Ohio: Battelle Columbus and Pacific Northwest Laboratories, 1973.

TABLE 6-35. HEATER TREATER ENERGY REQUIREMENTS*

Brine Vol %	Heat Requirements (Btu/day)	Fuel Gas Requirement (scf/day)
5	3.67×10^{9}	3.67×10^{6}
50	1.88×10^{10}	1.88×10^{7}
85	4.20×10^{10}	4.20×10^{7}

Basis: 100,000 bpd crude oil production.

*Scaled up from values reported for 1000 bpd production.

Source: Cavanaugh, E. C., et al. Atmospheric Environmental Problem Definition of Facilities for Extraction, On Site Processing, and Transportation of Fuel Resources. Contract No. 68-02-1319, Task 19. Austin, TX: Radian Corporation, July 1975.

If improved recovery techniques are used in addition to the primary production, there are additional ancillary energy needs for the large waterflooding pumping system required. It is assumed that 10 gallons of injection water are required per gallon of oil recovered.[1] The injection rate for 10,000 bbl/day crude oil production should be about 3000 gpm. The injection pressure required is around 1500 psig. From these data it was determined that the module would require a 4000 hp pumping system. The pump was assumed to have a diesel drive which consumes 1920 gallons of diesel fuel per day. The total energy required is 3.4×10^{8} Btu/day.

6.4.1.2 Outputs

The outputs described below are based on a total production of 100,000 bpd of crude oil. The process design and other parameters are the same as those described in Section 6.4.1.1 for the Input Requirements. The operations considered here have a total crude oil output of 100,000 barrels per day. The crude oil produced for these operations in Rifle, Colorado, is assumed to be identical to the crude produced from the Rangely field in Rio Blanco County, Colorado. The detailed analysis of this crude oil is shown in Table 6-36. For a heat content of 5.6×10^{6} Btu/bbl, the energy output of the production facility is 5.6×10^{11} Btu/day.

6.4.1.2a Air Emissions

The air pollutants from the 100,000 bbl/day primary production operation are emitted from the following sources:

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[1]Chilingar, George V. and Beeson, Carrol M. Surface Operations in Petroleum Production. New York: American Elsevier, 1969.

TABLE 6-36. CRUDE OIL ANALYSIS - RANGELY FIELD, RIO BLANCO COUNTY, COLORADO

Tests	
Gravity, °API	34.8
Gravity, Specific	0.851
Viscosity, SUS @ 100°F	48.0
Pour Point, °F	+10
Color	Greenish black
Sulfur, wt %	0.56

Source: McKinney, C. M., E. P. Ferrero, and W. J. Wenger. Analyses of Crude Oil from 546 Important Oilfields in the United States, R.I. 6819. Washington, D.C.: Bureau of Mines, 1966.

burning of fuel (natural gas) in heater treater, crude oil storate tanks, fugitive losses from various sources, and intermittent flaring due to unusual conditions. The use of waterflooding requires an extensive pumping system whose diesel engines produce additional emissions. Table 6-37 presents a summary of most emissions from the crude oil production module.

The heater treaters associated with the separation equipment contain a direct-fired heater which burns a natural gas with about 2000 ppm total sulfur. The crude emulsion is preheated by the exit crude oil, and the treater is operated at 210°F. The emission factors for fuel gas combustion are given in Table 6-38. The heat requirements are given in Section 6.4.1.1f.

TABLE 6-37. AIR EMISSIONS - 100,000 BPD PRIMARY PRODUCTION

	Particulates		SO_x		CO		Total Organics		NO_x	
	lb/hr	ton/yr[1]	lb/hr	ton/yr[1]	lb/hr	ton/yr[1]	lb/hr	ton/yr[1]	lb/hr	ton/yr[1]
Heater Treater										
5% brine	3.0	13.1	43.3	190	2.6	11.4	8.6	37.7	35.2	154
50% brine	15.7	68.8	223	977	13.3	58.3	22.7	99.4	179	784
85% brine	35.0	153	496	2,170	29.7	130	50.7	222	403	1,770
Crude Storage	-	-	-	-	-	-	30.5	134	-	-
Wastewater Separators[2]	-	-	-	-	-	-	32.9	144	-	-
Pumps[2]	-	-	-	-	-	-	307	1,344	-	-
Compressors[2]	-	-	-	-	-	-	15.8	69.2	-	-
Relief Valves[2]	-	-	-	-	-	-	32.9	144	-	-
Pipeline Valves[2]	-	-	-	-	-	-	48.3	212	-	-
Miscellaneous Flaring	0.084	736	0.308	2,700	0.011	92.0	0.018	153	0.14	1,230

[1]Based on 8,760 hr/yr.

[2]Scaled up from values reported in Source shown below for 1000 bpd crude oil production.

Source: Cavanaugh, E. C., et al. Atmospheric Environmental Problem Definition of Facilities for Extraction, On-site Processing, and Transportation of Fuel Resources. Contract No. 68-02-1319, Task 19. Austin, TX: Radian Corporation, July 1975.

TABLE 6-38. AIR EMISSION FACTORS FOR THE COMBUSTION OF NATURAL GAS AND FUEL OIL

	Natural Gas lb/1000 scf	Fuel Oil lb/1000 bbl
Particulates	0.02	970
Sulfur Oxides (as SO_2)	2 S_g*	6,729 S_o**
CO	0.017	0.168
Hydrocarbons	0.027	126
Nitrogen Oxides (as NO_2)	0.23	1,680
Aldehydes (as HCHO)	0.003	42

* S_g is the sulfur concentration in the fuel gas (lb/1000 ft^3).
**S_o is the sulfur weight fraction in the fuel oil.

Source: Cavanaugh, E.C., et al. Atmospheric Environmental Problem Definition of Facilities for Extraction, On-Site Processing, and Transportation of Fuel Resources. Contract No. 68-02-1319, Task 19. Austin, TX: Radian Corporation, July 1975.

Fugitive and miscellaneous emission factors are shown in Table 6-35. These are emissions from wastewater separation, seals, and valves. Also miscellaneous flaring is estimated to occur at the rate of 2 x 10^{-5} bbl flared/bbl oil produced.[1]

Two assumptions for storage emissions are the use of floating roof tanks and storage of six days production. Using the UPA emission factor for storage of 0.029 lb/day-10^3 gal,[2] a hydrocarbon emission of 30.5 lb/hr is calculated.

The primary source of additional emissions from waterflooding is the sizable water injection pump system. The injection rate of 10 bbl water/bbl oil recovered for the 10,000 bbl additional production is 3000 gallons/min. It is determined from this rate that a pumping system requiring 4000 horsepower consuming 1920 gallons of diesel fuel daily is needed. Table 6-40 presents the waterflooding contribution to the total emissions.

6.4.1.2b Water Effluents

The amount of water effluent from an oil field depends on the percent water produced with the crude oil and on the extent that water is used in secondary recovery techniques. Many fields have no effluent due to the reinjection into the formation

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[1] Battelle Columbus and Pacific Northwest Labs. Environmental Considerations in Future Energy Growth. Columbus, Ohio: Battelle Columbus and Pacific Northwest Labs., 1973.

[2] Environmental Protection Agency. Compilation of Air Pollution Emission Factors, 2nd Edition with Supplements, AP-42 Research Triangle Park, North Carolina: Environmental Protection Agency, April 1977.

TABLE 6-39. MISCELLANEOUS OIL PRODUCTION EMISSION FACTORS

	Hydrocarbon Emissions	
	tons/day*	$lb/10^3$ bbl
Wastewater Separation	0.2	7.9
Pump Seals	1.9	73.8
Compression Seals	0.1	3.8
Relief Valves	0.2	7.9
Pipeline Valves	0.3	11.6

*Based on a production rate of 50,600 bbl/day.

Source: MSA Research Corporation. Hydrocarbon Pollutant Systems Study, Vol. 1, Stationary Sources, Effects and Control. PB-219-073, APTD 1499. Evans City, PA: MSA Research Corporation, 1972.

TABLE 6-40. WATERFLOOD OPERATION CONTRIBUTION TO TOTAL EMISSIONS

Emission	lbs/day
Particulates	25
SO_x	52
CO	432
Hydrocarbons	77
NO_x	710
CO_2	41,150

Source: Cavanaugh, E. C., et al. Atmospheric Environmental Problem Definition of Facilities for Extraction, On-Site Processing, and Transportation of Fuel Resources.

TABLE 6-41. WATER POLLUTANTS FROM OIL EXTRACTION (Ton/10^6 bbl oil produced)

Source	Pollutant									
	Acids	Bases	PO_4	NO_3	Total Dissolved Solids	Suspended Solids	Organics	BOD	COD	Thermal (Btu's/10^{12})
Hittman[1]	U	N/A	N/A	N/A	U	N/A	0.84	N/A	U	0
Battelle[2]	U	N/C	N/C	N/C	17,360	0	22.4	N/C	N/C	0
Teknekron[3]	U	N/C	N/C	N/C	U	N/C	4.5	N/C	N/C	N/C

N/A = not applicable

N/C = not considered

U = unknown

Sources: [1]Hittman Associates, Inc. Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use, Final Report: Vol. I, 1974; Vol. II, 1975. Columbia, MD: Hittman Associates, Inc., 1974 and 1975.

[2]Battelle Columbus and Pacific Northwest Laboratories. Environmental Considerations in Future Energy Growth, Vol. I: Fuel/Energy Systems: Technical Summaries and Associated Environmental Burdens. For the Office of Research and Development, Environmnetal Protection Agency. Columbus, OH: Battelle Columbus Laboratories, 1975.

[3]Teknekron, Inc. Fuel Cycles for Electrical Power Generation, Phase I: Towards Comprehensive Standards: The Electric Power Case. Report for the Office of Research and Monitoring, Environmental Protection Agency. Berkeley, CA: Teknekron, 1973.

of all water produced; however, some fields will have a net effluent which will impact the surface water system locally. Table 6-41 presents available data on the quantity of pollutants from an oil production operation.

6.4.1.2c Solid Wastes

No appreciable solid wastes are produced by the example oil field.

6.4.1.2d Noise

Several pieces of equipment in the oil field are potential emitters of significant noise levels. These include control valves and pump engines. Most noise would be centered around central storage areas and waterflood injection pumping facilities. Perceptible noise should not be heard outside the boundaries of the facility.

6.4.1.2e Occupational Health and Safety

The information for this section is included in Section 6.3.3e.

6.4.1.2f Odor

Odor may be a problem around the oil-gas separators and the storage tanks where fugitive emissions from leaks, valves, flanges, etc. may occur. If the crude contains appreciable sulfur compounds (H_2S, mercaptans) odor problems are more likely. Good housekeeping practice is the best safeguard against odor.

6.4.2 Enhanced Oil Recovery

Enhanced oil recovery is generally defined as fluid injection techniques other than natural gas and waterflooding that augment a reservoir's ability to produce oil. Enhanced oil recovery differs from primary and secondary oil recovery in that the recovery technique is aimed at altering the forces trapping the oil in the porous rock. Secondary recovery maintains the pressure driving forces extant during primary recovery. Like primary and secondary recovery, enhanced oil recovery also mobilizes oil by means of a hydrodynamic pressure gradient that will be described in the following paragraphs.

Following a waterflood, the oil remaining in the reservoir exists as dispersed oil droplets or globules in water. The amount of oil remaining after a waterflood is generally 50 to 65 percent of the original-oil-in-place (OOIP). The oil droplets are trapped within the pores and channels of the formation and held in place by both capillary and viscous forces.

If the interfacial tension between the oil and water is reduced sufficiently, then the forces due to water pressures will overcome the capillary forces and move the oil droplet. In the situation where oil is trapped by viscous forces, reducing the oil viscosity will allow the droplet to flow at a lower water pressure. Once droplets move by either of these methods, they coalesce with other droplets and form an oil bank that moves through the reservoir.

There are two enhanced recovery techniques which are currently being used on full scale operations. The most successful method to date, steam flooding, utilizes the viscosity reduction principle. The other technique is CO_2 miscible flooding which displaces oil by eliminating the oil/water interfacial tension. This technique is discussed in Section 6.4.3. Other enhanced recovery techniques are currently being developed; however, these two methods have been the most successful to date.

These two recovery methods will be discussed with regard to the technology involved, raw material and equipment regulations, and pollutant emissions. Since enhanced oil recovery is currently at the early stages of commercialization, there are only a limited number of projects from which data are available. Some of these data are highly site specific and therefore difficult to represent with a "typical value". In this report, every attempt has been made to present data which is representative of the processes involved. Calculations were made on a consistent basis throughout the sections and existing data were converted to this basis. However, due to site-to-site variations and future technological innovations, it may be difficult to apply the data presented herein on a general basis. Calculations for both steam flooding and CO_2 flooding were made using the same basic assumptions.

The inputs and outputs sections contain several calculated values based on a hypothetical "example reservoir". This was done to put the input and output quantities on a consistent basis. It is assumed that the rate of oil production can be represented by some average number. This was assumed to be 100,000 bbl/day. It is also assumed that oil will be produced at this average rate for 5 years. Assumptions that pertain to the reservoir are

Reservoir Pore Volume = 2.85×10^9 Bbls
(Volume of the formation that is filled with gas and liquid)

Porosity = 30%
(Fraction of the formation that is filled with gas and liquid)

Initial Oil Saturation = 0.64
(64% of pore volume is oil)

Average Thickness = 100 ft.

Surface Land Area = 19.1 square miles

Literature values indicate the first two assumptions are typical values for real fields.[1]

A recovery efficiency of 40 percent was assumed for the waterflood and a literature source showed 10 percent to be an average recovery efficiency for enhanced recovery techniques.[2] These literature values and assumptions can be used to calculate the following values for the oil contained in the example reservoir.

	Initial	After Waterflood	After Enhanced Recovery Method
Oil Saturation, bbls/acre-ft	1500	900	750
Oil Saturation, relative	0.64	0.41	0.32
BBls of Oil in the Reservoir	1.83×10^9	1.10×10^9	9.15×10^8
Recovery Efficiency, % of OOIP	---	40	10

6.4.2.1 Steam Flooding

6.4.2.1.1 Technologies

Steam flooding or steam displacement comes under the category of thermal displacement in which there are two other displacement techniques. These other techniques are cyclic steam injection and

[1]Devanney, J. W., et al. "The Estimated Recovery Potential of Conventional Source Domestic Crude Oil," EPA Contract No. 68-01-2445, May 1975.

[2]*Ibid.*

in-situ combustion. Steam flooding is currently the most suitable technique of the three since it has a better oil recovery efficiency than cyclic steam injection and has been more commercially developed than in-situ combustion. Steam flooding lowers the viscosity of the oil and allows it to flow at a lower pressure. Oil viscosity is very sensitive to temperature. Generally speaking, the kinematic viscosity will decrease exponentially as the temperature is increased linearly. For example, at 300°F a 15°API oil will have a viscosity similar to that of a 30°API oil at normal reservoir temperatures.[1] Crude oils are generally referred to as being a certain gravity rather than viscosity. This terminology will be used in subsequent discussions of viscosity.

Not all reservoirs are amenable to steam flooding. The reservoir characteristics necessary for a successful steam flood have been reported to be:

- low API gravity crude oil (10-20° API)
- high permeability (>500 md)
- shallow depth (<3000 ft)

Most of the reservoirs suitable for steam flooding are in California, Texas, and Louisiana. However, there are several field tests being conducted in Wyoming as can be seen in Figure 6-15.

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[1]Devanney, J. W., et al. The Estimated Recovery Potential of Conventional Source Domestic Crude Oil, EPA Contract No. 68-01-2445. May 1975.

[2]*Ibid.*

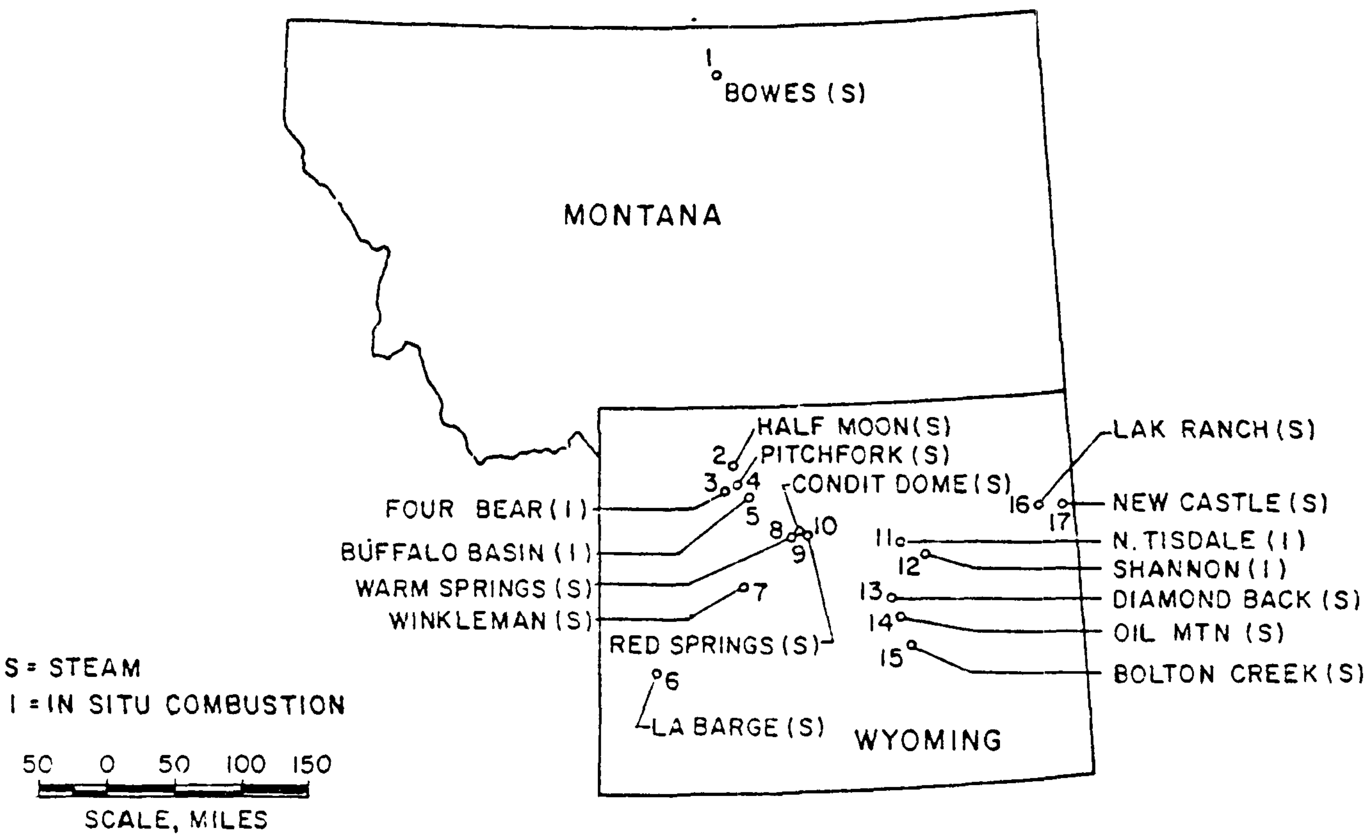

Figure 6-15. Sites of Thermal Recovery Field Tests in Montana and Wyoming.

In a typical steam flooding operation, surface water is passed through a boiler where it is heated to a sufficient pressure to allow it to enter the reservoir. The steam is saturated at this pressure and is generally about 70 to 80% quality.[1] After entering the reservoir, the steam condenses due to heat loss through conduction into the formation rock and fluids. It is this latent heat of vaporization that is primarily responsible for increasing the temperature of the surrounding oil and water. At the increased temperature, the viscosity of the oil is reduced sufficiently to allow it to be displaced. As the frontal edge of the steam flood passes through the reservoir, the oil and water cool allowing the viscosity to increase. However, the oil saturation[2] at this frontal edge has been increased by the oil that was displaced initially. The cooler water is still capable of displacing the oil at this increased saturation and what oil is left trapped is mobilized by the hot water following the frontal edge. Figure 6-16 is a schematic of the steam flooding process.

Typically, a steam flood will displace 10 percent of the OOIP over and above that produced by a waterflood. Steam can be introduced into the reservoir either before a waterflood has been conducted or before. If, in the future, steam flooding becomes well established technology it will probably be used prior to waterflooding. This would allow more oil to be produced with less total water. In either case, the costs and equipment required for steam flooding are similar to those for waterflooding with the addition of water treatment and steam generation facilities. It is necessary to install steam generators at or near the injection wells. An oil field will require several generators to provide the steam requirements. The types of generators in

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[1]Steam quality is defined as the weight fraction of vapor.

[2]Oil saturation is defined as the fraction of the reservoir pore volume that contains oil.

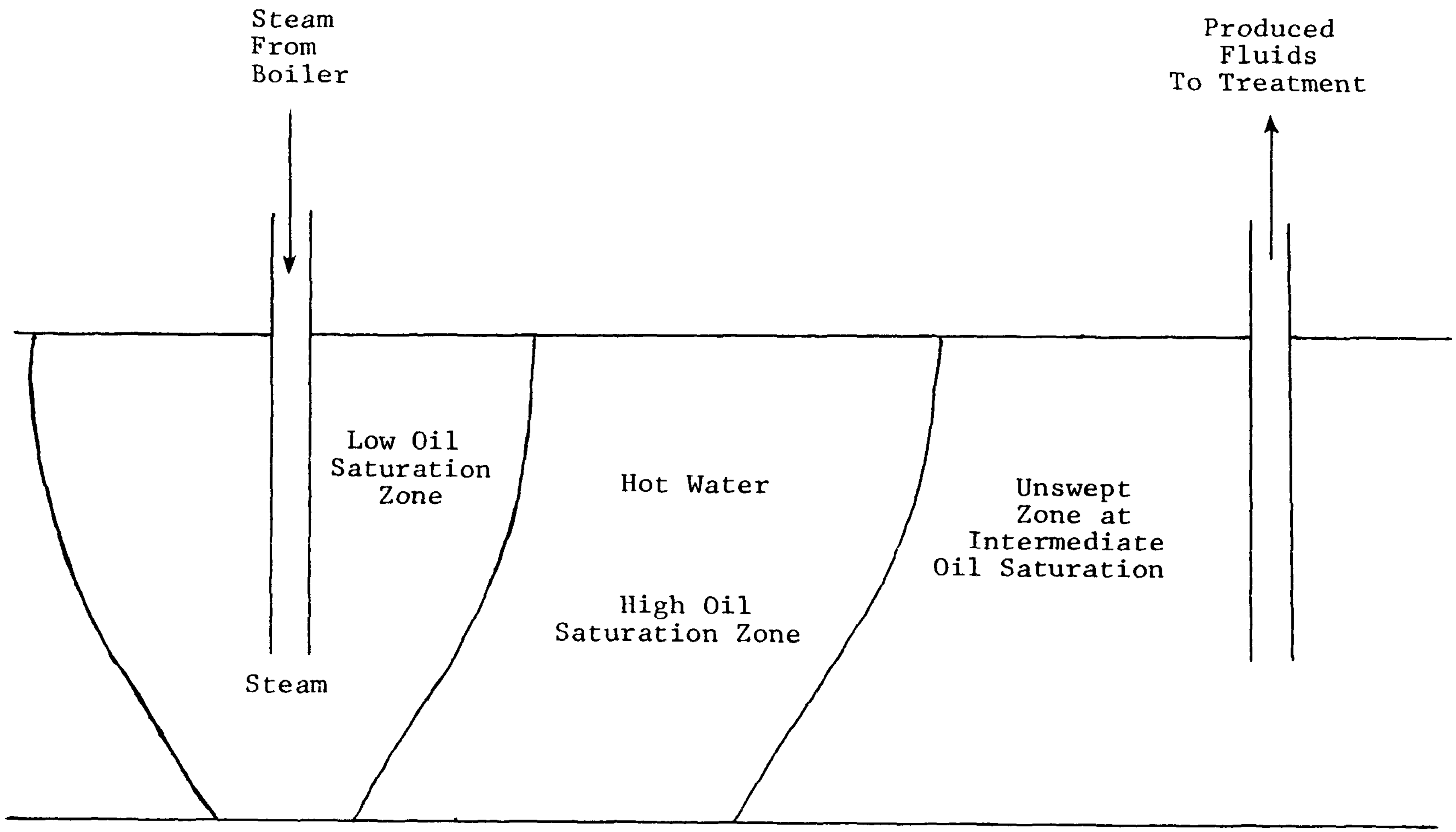

Figure 6-16. Schematic of Steam Flooding Operation.

use today are package boilers with capacities ranging from 20 to 50 million Btu/hr. They are fired with oil produced from the field. Generally, about 30 percent of the oil produced by a steam flood is consumed by the steam generators.

A 25 million Btu/hr steam generator will require 1000 barrel raw and treated water tanks. Water treatment is required for the boiler feed water to prevent tube scaling and the size of the treatment equipment will depend on the quality of the available water. The water produced by the well will also require treatment whether it is to be reinjected or discharged. Water reinjection will require less total surface water, but probably will also require a higher level of water treatment than surface water.

At the production wells, the operations are similar to those of waterflooding. The produced gas/oil/water mix is processed to separate the phases and break the emulsion. The degassed, dewatered oil is sent to storage tanks and the water is sent to the water treatment section prior to discharge or reinjection.

6.4.2.1.2 Inputs

6.4.2.1.2.a Manpower Requirements

Manpower will be required to install boilers and feed water treatment facilities. Steam flooding has not been applied extensively enough to date for accurate quantitative estimates to be made. It is likely that construction manpower requirements will be similar to those for waterflooding. A first approximation might be 4000 total man-years for 2-3 years.

The manpower requirements for operation of a steam-flooding operation will be only slightly higher than those for water flooding. These were indicated in the section on conventional recovery to be about 2000 man-years/year. For a steam flood, the operating manpower requirement is estimated to be 2000 man-years/year for 5 years.

6.4.2.1.2.b Materials and Equipment

Essentially, the materials and equipment necessary for a waterflooding operation will also be required for steam flooding. An exception would be the high pressure pumps used to inject water which would be replaced by steam injection equipment. The water supply, production, treating, and storage equipment associated with waterflooding will be necessary for a steam flood. In addition, feed water treatment and steam generation equipment will be necessary.

Consider the steam generation equipment first. Package steam boilers with capacities ranging from 20 x 10^6 to 50 x 10^6 Btu/hr are most common. Larger boilers, up to 250 x 10^6 Btu/hr, are available, but create the problem of losing a large portion of the generating capacity when a single unit goes down. The smaller units allow a single boiler to go out of service without significantly affecting the overall steam capacity. The boilers are essentially smaller versions of watertube boilers used in steam generation for electrical production. The boilers are designed to operate on crude oil and produce steam of a suitable quality for injection. Generally, the steam quality is 80 percent. A typical oil field boiler is shown in Figure 6-17. There are several boilers distributed over the oil field, each serving one or more injection wells.

By making a few assumptions the boiler density in an oilfield can be calculated. The assumptions are:

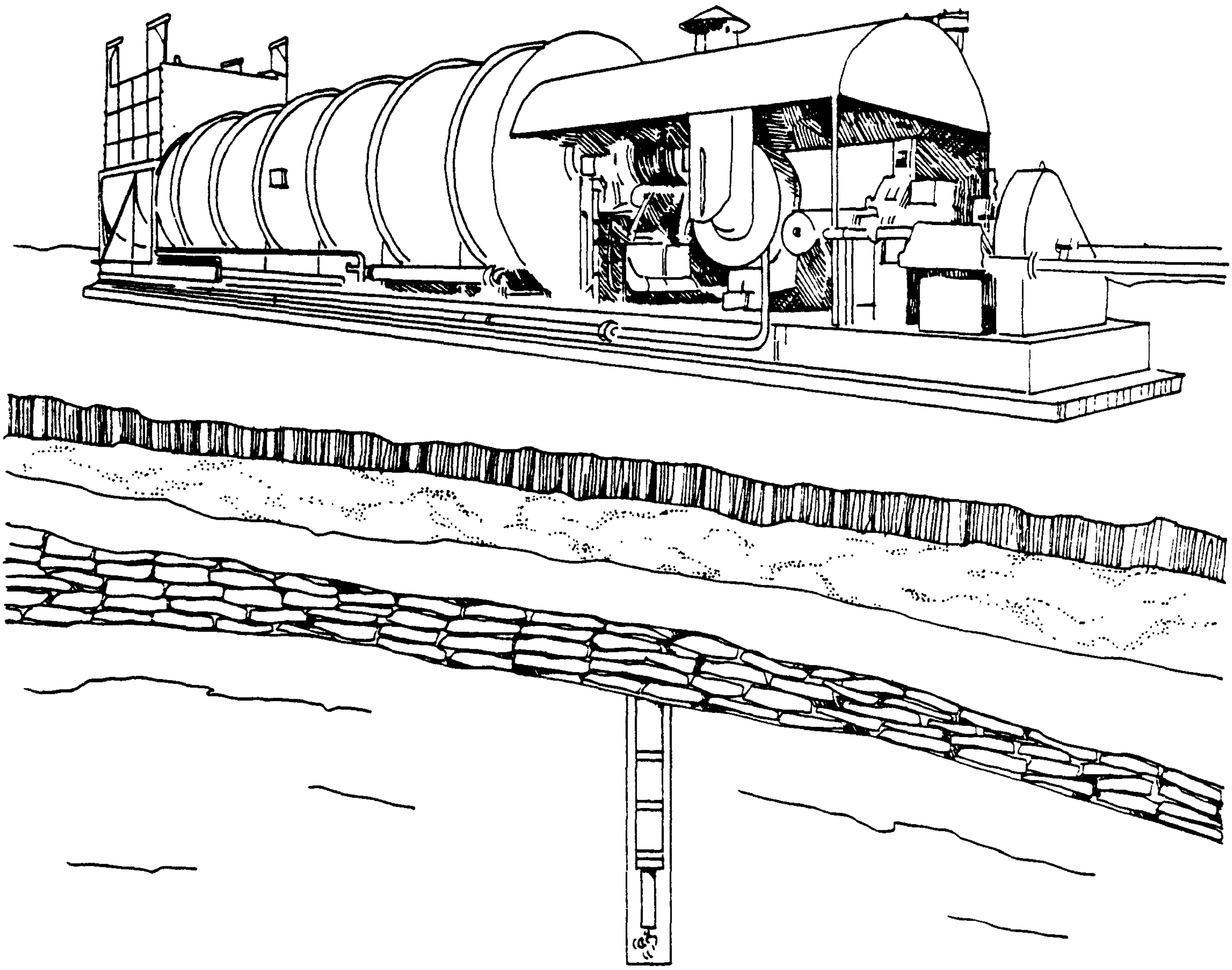

Figure 6-17. Oil Field Steam Generator.

- 2000 psia steam
- 1 bbl of oil produces 45 barrels of steam
- one bbl of oil burned for each 3.33 bbl produced[1]
- oil saturation - 900 bbl/acre-ft
- recovery efficienty 10 percent
- steam injection rate = 2500 bbl/acre-ft/year[2]

These values indicate a steam requirement of 1×10^6 Btu/hr per acre or 1 boiler for every 20 to 50 acres. For the example reservoir this amounts to a total from 250 to 650 boilers with the actual number depending on boiler size.

Water used for steam generation must be used to prevent scale formation on the boiler tubes. Water treatment facilities will probably consist of softening equipment and ion exchange equipment. An estimated 120 gal/hr/acre of water treatment capacity is required (equivalent to 5 bbl H_2O/bbl oil produced). Additional water treatment facilities may be required if water produced with the oil is either discharged or reinjected.

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[1]In this, and all other references to steam volume in this section, the indicated volume will be the actual volume occupied by 80 percent quality steam at 2000 psia.

[2]This assumption is slightly higher than values used typically for analyses of steam flooding. This is due to the fact that recent articles have indicated that steam floods have not been as productive as was originally anticipated.

6.4.2.1.2.c Economics

The economics of steam flooding are tied to the price of crude oil. In the previous section it was assumed that 3.33 bbls of oil will be produced for each bbl burned. Since about 30 percent of the oil produced is consumed by steam generation the cost of the steam is strongly related to the price of crude oil. As the price of crude rises, the process becomes more economical. This can be seen in the following analysis.

There are three major costs associated with steam flooding: flooding costs, steam generation costs, and fuel costs. Flooding costs are the typical combination of costs involved in operating a steam flood. These include well workover, well maintenance and fluid distribution. They range from $0.50 to $1.50 per barrel of oil produced.[1] The capital and operating costs of the steam generation equipment are also important. These are generally $0.013 to $0.020 per bbl of steam and include the cost of the steam generator, boiler maintenance, and water treatment.[2] Finally, there is the cost of the oil burned in the steam generator. Since this is a variable, two cases are considered here: $3 per bbl and $10 per bbl. Of course, the cost of the oil produced is going to be affected by the amount of steam injected. Table 6-42 shows the cost of producing a barrel of oil as a function of fuel costs, flooding costs and steam:oil ratio (bbl/bbl). The values presented in the table reflect the fact that oil burned in steam generation must be subtracted from the amount produced in order to indicate the real cost per standard tank barrel. These costs are plotted as a function of steam:oil ratio in Figures 6-18 and 6-19.

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[1]Devanney, J. W., et al. The Estimated Recovery Potential of Conventional Source Domestic Crude Oil, EPA Contract No. 68-01-2445. May 1975.

[2]*Ibid.*

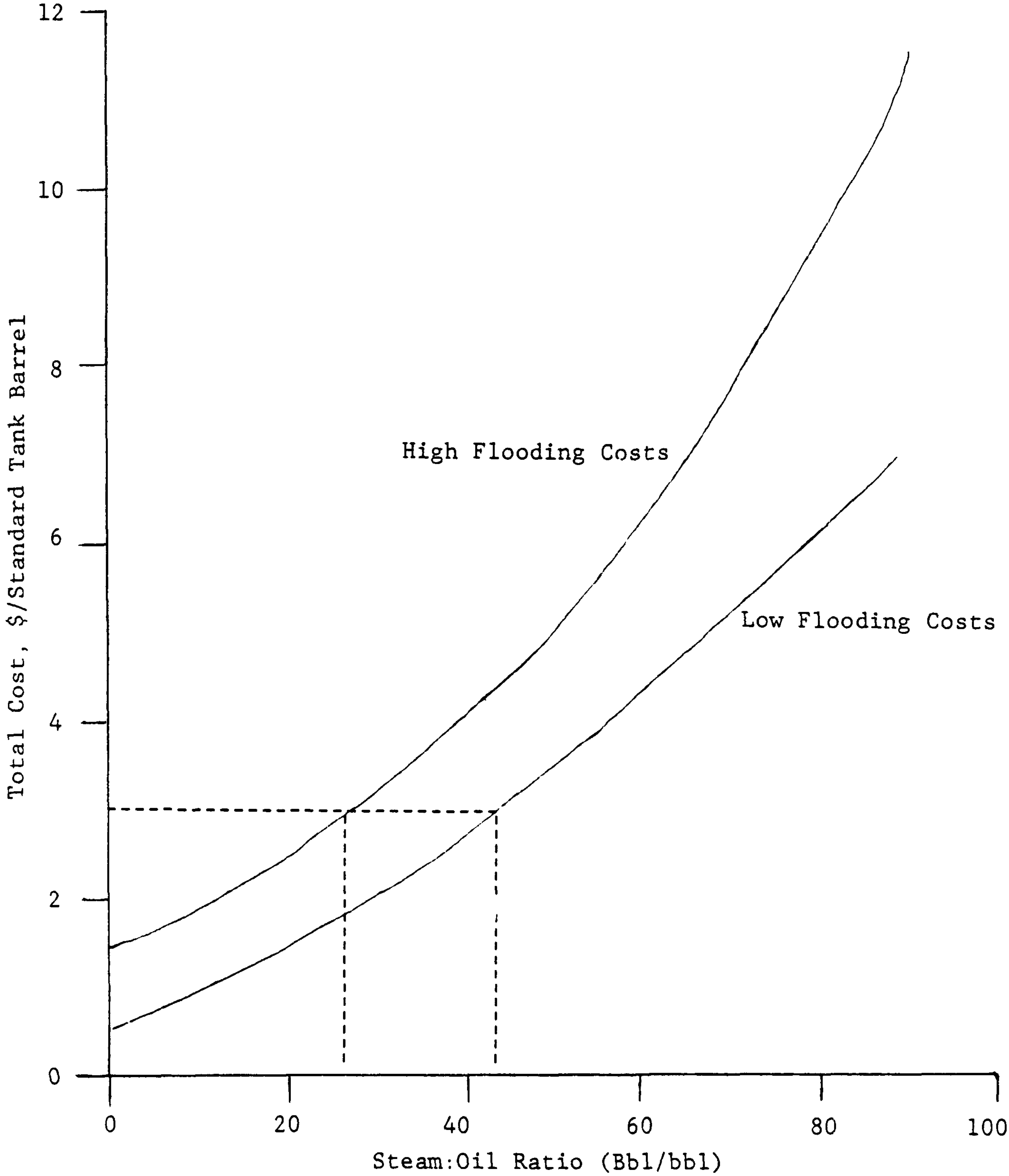

Figure 6-18. Cost/Standard Tank Barrel of Oil For Steam Flooding.
Basis: Price of Oil = $3/Bbl

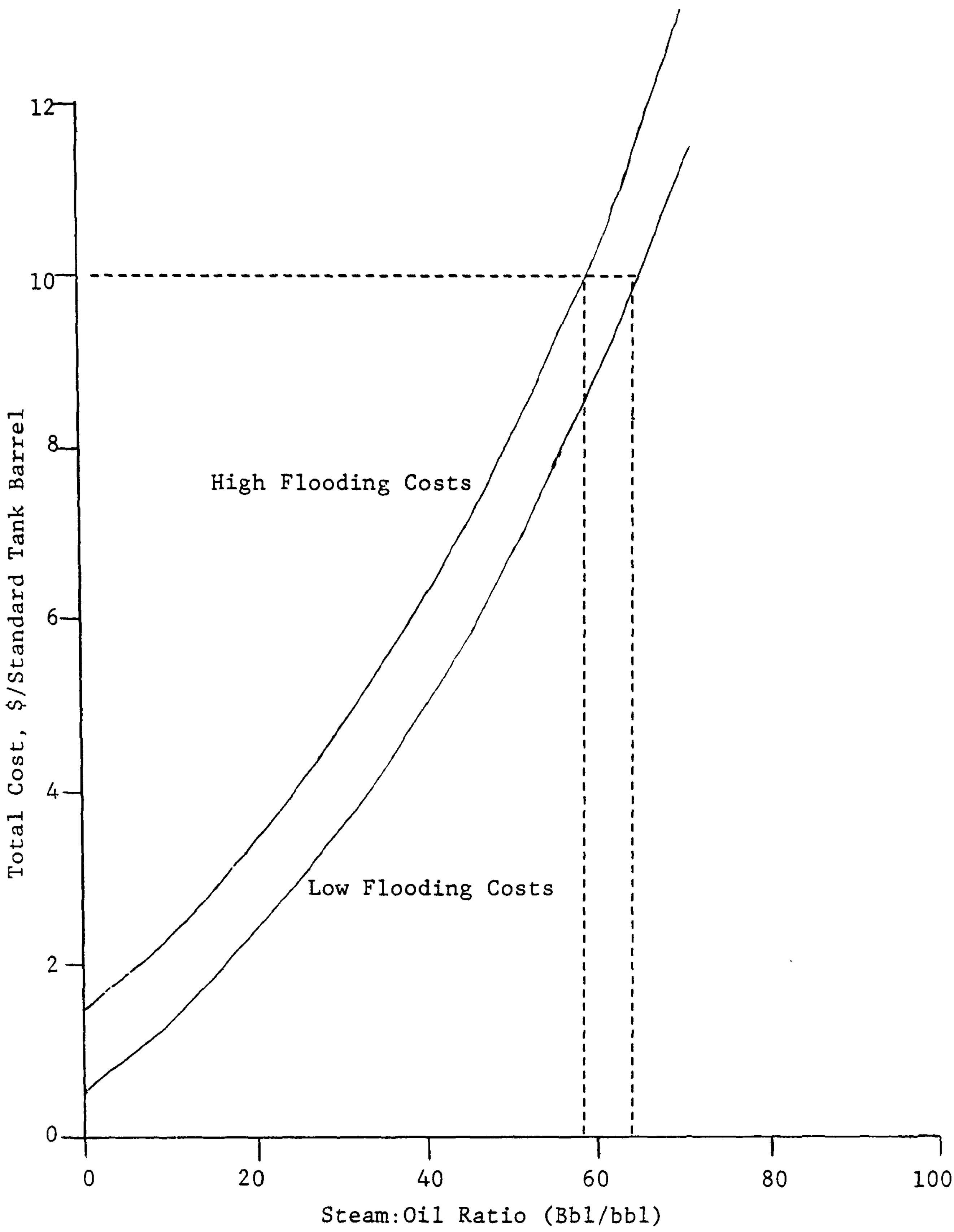

Figure 6-19. Cost/Standard Tank Barrel of Oil For Steam Flooding.
Basis: Price of Oil = $10/Bbl

Figure 6-18 considers oil at $3/bbl while Figure 6-19 is based on the price of oil being $10/bbl. It can be seen from the figures that the breakeven steam:oil ratio in the $3/bbl case is about 26 to 44 bbl/bbl. With $10/bbl oil the breakeven ratio is about 58 to 64 bbl/bbl indicating that steam flooding is more profitable at higher crude prices. In addition, higher crude prices allow a more rigorous recovery operation to be conducted since higher steam:oil ratios may be economically applied.

TABLE 6-42. COST OF OIL RECOVERED BY STEAM FLOODING

Fuel Cost $/bbl	Flooding Costs $/bbl produced	Total Cost per Standard Tank Barrel[1] at Various Steam:Oil Ratios (Bbl/bbl)			
		30	50	70	90
3	0.50	1.99	3.45	5.61	9.11
3	1.50	3.24	4.96	7.50	11.61
10	0.50	3.68	6.81	11.45	18.94
10	1.50	4.92	8.30	13.28	21.35

6.4.2.1.2.d Water Requirements

The water requirement can also be calculated from the steam injection rate and a feedwater requirement of 120 gal/hr/acre is indicated. This results in a feed water requirement of about 5 bbl of water per bbl oil produced. This value is consistent with recent estimates of water requirements of 1 to 6 bbl of water per bbl of oil.[2] The actual quantity of water used will depend on the steam:oil ratio required for a successful displacement. Therefore,

[1] A "Standard Tank Barrel" refers to oil that has production and oil field treating operations. Due to losses in these operations only part of bbl that is produced appears in the product tank.

[2] U.S. Congress, Office of Technology Assessment. Enhanced Recovery of Oil and Devonian Gas. June 1977.

water usage for steam generation can vary from field to field. It is possible to treat produced water and use it to produce steam. Produced water requires more treatment than surface water and, for this reason, would probably not be used unless shortages of surface water existed. For the example reservoir, without reinjection of produced water, the total water requirement would be 9×10^8 bbl for the 1.85×10^8 bbls of oil produced by the steam flood.

Water requirements for uses other than steam generation are assumed to be small in comparison to those for steam generation. For this reason, ancillary water requirements were not quantified.

6.4.2.1.2e Land Usage

Land usage in steam flooding will be similar to that necessary for waterflooding. This will include areas for steam generators, water treatment, fluid distribution, and product treatment. The steam generators will be distributed over the entire oil field to allow injection at various locations with a minimum of high pressure piping. Water and product treatment will most likely be performed at single locations rather than using several smaller units.

Land usage will be affected by the disposal technique used to handle the produced water. One option is to treat the water sufficiently to allow discharge. Alternatively, produced water can be treated less rigorously and sent to an evaporation pond. Use of evaporation ponds will require more land area than treatment and discharge. The applicability and size of evaporation ponds will depend upon the environmental conditions existing at each oil field location but over the range of evaporation rates typical in the west will be between 20 and 80 acres/Mbbl evaporated/day).

6.4.2.1.2f Ancillary Energy

Steam flooding is a very energy intensive process primarily due to the high energy requirements of steam generation. Ancillary energy requirements other than steam generation will be similar to those of waterflooding. Most of these are associated with the heater treaters. On the basis of waterflood heater treater requirements and the production values presented in the previous sections, the energy requirements are about 10^5 Btu/hr per reservoir acre. This is about 10% of the steam generation energy requirements.

6.4.2.1.3 Outputs

The example reservoir described at the beginning of the inputs section will also be used as a basis for calculations in this section.

6.4.2.1.3a Air Emissions

Air emissions of criteria pollutants will come primarily from the boilers and heater treaters. There will also be some fugitive emissions from well heads, oil/water separators, valves, pumps, and storage tanks.

Air emissions from steam generators have been reported in the literature[1,2] and these are presented in Table 6-43. Several assumptions were made in order to arrive at the numbers shown in the table. A fuel sulfur content of 1.23 wt % was assumed. This

[1]Devanney, J. W., et al. The Estimated Recovery Potential of Conventional Source Domestic Crude Oil, EPA Contract 68-01-2445. May 1975.

[2]U.S. Congress, Office of Technology Assessment. Enhanced Recovery of Oil and Devonian Gas. June 1977.

is a typical value for Wyoming crudes. Published values for NO_x were used; however, NO_x emissions can vary with the nitrogen content of the fuel. As discussed in previous sections, this value can vary. Higher steam:oil ratios will result in increased emission rates.

It is also possible to estimate trace metal emissions. Table 6-44 shows values for California, Louisiana and Texas crudes. If Wyoming crudes are assumed to be similar, these values would represent guidelines for trace metal emissions.

Specific data for fugitive emissions from steam flooding operations have not been developed yet. Fugitive emission data for similar sources in a waterflood operation will probably be approximately the same and are available. Oil produced from a steam flood is at a higher temperature which increases the vapor pressure of volatile components. However, crudes recovered by steam flooding are generally high boiling mixtures. These two facts have offsetting effects on the vapor pressure of the crude. For this reason, fugitive emission factors for steam flooding are assumed to be similar to those for water-flooding. Table 6-45 shows estimated fugitive emissions for an average system. The values presented in the table were calculated from those in the literature source to make them consistent with the data used elsewhere in this section. These emissions can be significantly reduced with a strict equipment maintenance and housekeeping program. A study by MRI[1] indicated that fugitive emissions can be as low as two orders of magnitude less for a highly maintained operation than for an operation that receives average maintenance.

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[1]Hundly, J. B. Total Hydrocarbon Emission Measurements of Values and Compressors at Arco's Ellwood Facility. January 21, 1076, p. 14.

TABLE 6-43. AIR EMISSIONS FROM STEAM GENERATORS

Pollutant	lb / 1000 Gal Oil Burned	lb[c] / 1000 Bbl Steam Generated	lb[d] / 1000 Bbl Oil Produced
Particulate	7-23	1.9-6.3	86-285
SO_2 [a]	193	52.6	2400
SO_3 [a]	2.5	0.68	30
CO	4	1.1	50
HC (as CH_4)	2	0.55	26
NO_x (as NO_2)[b]	60	16	74

[a]Assumes 1.23 wt % sulfur in fuel.

[b]NO_x is highly dependent upon the fuel nitrogen content.

[c]Basis: 80% quality, 2000 psia steam.

[d]Basis: 45 bbls of steam per bbl of oil produced.

Source: Environmental Protection Agency, Compilation of Air Pollutant Emission Factors, 2nd ed, with supplements. AP-42. Research Triangle Park, N.C., Feb. 1972, April 1973, July 1973, Sept. 1973, July 1974, Jan. 1975, Dec. 1975, Feb. 1976, April 1977.

TABLE 6-44. TRACE METAL EMISSIONS FROM STEAM FLOODING

Trace Metal	ppm[a]	lb / 1000 Gal Oil Burned	lb[b] / 1000 Bbl Steam Generated	lb[c] / 1000 Bbl Oil Produced
Antimony	<0.022	<0.015	<0.0041	<0.18
Arsenic	<0.059	<0.024	<0.0066	<0.30
Barium	<0.097	<0.072	<0.020	<0.90
Manganese	0.032	0.0095	0.0026	0.12
Nickel	3.9-77	1.2-24	0.33-6.6	15-300
Tin	0.70	0.45	0.12	5.4
Vanadium	1.5-4.8	0.41-13	0.11-3.5	5.0-165

[a] Averages based on Texas, Louisiana and California crude.

[b] Basis: 80% quality, 2000 psia steam.

[c] Basis: 30 bbl of steam per bbl of oil produced.

Source: Magee, E. M., et al. Potential Pollutants in Fossil Fuels, EPA Report No. EPA-R2-73-249. June 1973.

TABLE 6-45. ESTIMATED FUGITIVE EMISSIONS FROM STEAM FLOODING

Source	lb / 1000 Gal Oil Burned	lb / 1000 Bbl Steam Generated[a]	lb / 1000 Bbl Oil Produced[b]
Storage Tanks	0.40	0.11	3.4
Wastewater Separators	0.80	0.22	6.8
Pumps	7.6	2.1	65
Compressors	0.40	0.11	3.4
Relief Valves	0.80	0.22	6.8
Pipeline Valves	1.2	0.33	10

[a]Basis: 80% quality, 2000 psia steam.

[b]Basis: 30 bbl of steam per bbl oil produced.

Source: Cavanaugh, E. C., et al. Atmospheric Pollution Potential from Fossil Fuel Resource Extraction, On-Site Processing and Transportation, Final Report. EPA Contract No. 68-02-1319. Austin, Tex.: Radian Corp., 1972.

6.4.2.1.3b Water Effluents

Currently, water effluents from commercial steam flooding operations have not been quantified. This is due to the technology being in the early stages of development. Data are available for waterflooding operations and it is assumed here that they are similar to those for steam flooding.

There are two major pollutants in water produced from an oilfield: salts and hydrocarbons. Reservoir fluids generally contain from 5 to 50 wt % of brine. The actual concentration will vary among different formations. Hydrocarbon effluents were estimated from data from studies by Teknekron[1] and Battelle[2] to be about 9 to 45 lbs per 1000 bbl of oil produced. On the basis of 5 bbl of water used per bbl of oil produced, calculations show that 1.8 to 9 lbs of hydrocarbons per bbl of water used. Hydrocarbon concentrations could be higher in water produced by a steam flood due to the higher temperature increasing the hydrocarbon solubility.

6.4.2.1.3c Solid Effluents

There are two potential solid effluents from a steam flood. One is the sludge that is produced during wastewater treatment operations. A second potential effluent would be sludge from an SO_2 scrubber if these are used to treat the boiler flue gas. The latter is a potential effluent. SO_2 scrubbers can be used but are only required for steam flooding boilers greater than

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[1]Teknekron, Inc. Fuel Cycles for Electrical Power Generation. Phase I: Towards Comprehensive Standards: The Electric Power Case, report for the Office of Research and Monitoring, Environmental Protection Agency. Berkeley, Calif: Teknekron, 1973.

[2]Battelle Columbus and Pacific Northwest Laboratories. Environmental Considerations in Future Energy Growth, Vol. 1: Fuel/Energy Systems: Technical Summaries and Associated Environmental Burdens, for the Office of Research and Development, Environmental Protection Agency. Columbus, Ohio: Battelle Columbus Laboratories, 1975.

250 million Btu per hour heat input with high sulfur fuel.[1,2] The quantities of sludge produced in each case will be highly process and site specific.

6.4.2.1.3d Noise

No data were found describing noise associated with steam flooding. It is assumed that the steam generators will produce more noise than waterflooding equipment. The flow of high pressure steam in the boiler and injection equipment would be the major source of noise.

6.4.2.1.3e Occupational Health and Safety

Figures on occupational health and safety appear in Table 6-26. These values are based on published data that are tabulated for oilfield operations on an incidents-per-million-Btu basis.

TABLE 6-46. OCCUPATIONAL HEALTH AND SAFETY DATA FOR OIL PRODUCTION OPERATIONS

Type of Incident	Occurance per 1000 bbls produced[a]
Deaths	1.2×10^{-5}
Nonfatal Injuries	1.2×10^{-3}
Man-days Lost	2.0×10^{-1}

[a]Calculated based on 5.6×10^6 Btu/bbl of oil

Source: Batell Columbus & Pacific Northwest Labs, Environmental Considerations in Future Energy Growth, EPA No. 68-01-0470, Columbus, OH, 1973.

[1]40 CFR 60.40 New Source Performance Standards for Fossil-Fired Steam Generators.

[2]40 CFE 60.43 Where discharge into the atmosphere of sulfur dioxide in excess of 0.80 pounds per million Btu heat input, maximum 2 hour average, when liquid fossil fuel is burned.

6.4.2.2 CO_2 Miscible Flooding

6.4.2.2.1 Technologies

Flooding with CO_2 displaces trapped oil by eliminating the interface between the oil droplets and the displacing fluid and produces a miscible flood. In addition, there are several other effects of CO_2 on the oil. CO_2 also

- reduces the oil viscosity
- swells the oil thereby increasing the pressure
- increases the bulk and relative permeability.

All of these effects aid in displacing oil, although miscibility is the most important.

CO_2 is injected into the reservoir as a slug of about 15 to 30 percent of the total pure volume which is followed by water. When the CO_2 slug contacts the oil there is transfer of oil components into the CO_2 phase. This transfer creates the miscible zone between the two phases. The water drive then pushes both phases through the reservoir.

In practice, CO_2 flooding can only be applied to reservoirs that exhibit the following characteristics:[1]

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[1]Devanney, J. W., et al. "The Estimated Recovery Potential of Conventional Source Domestic Crude Oil," EPA Contract No. 68-01-2445, May 1975.

- API gravity = 32° to 42°
- Depth = 4500 to 9000 ft.
- Permeability = 2 to 10 millidarcies

CO_2 miscibility is favored by the high gravity crudes and deep formations that are necessary to keep the CO_2 in liquid form.

There are several injection techniques that can be used with a CO_2 flood; however, the most promising technique involves injecting a CO_2 slug followed by alternate water and CO_2 injection.[1] In this method, a 5 percent pore volume slug is injected initially. Then water and CO_2 are alternatively injected until the cumulative amount of CO_2 injected has reached 15 to 30 percent pore volume, after which water is injected continuously. This method gives the best mobility and thereby reduces the chances of premature water breakthrough at the production wells. Breakthrough occurs at the drivewater channels through the CO_2 slugs and appears at the producing wells. The overall best performance is with undipping reservoirs where gravity reduces the extent of fingering by the drive water.

In a previously waterflooded reservoir, a CO_2 flood will typically recover about 10 percent of the original-oil-in-place (OOIP).[2] When used before waterflooding, a CO_2 flood would be expected to recover 50 percent of the OOIP rather than the 40 percent that is typical of a waterflood. If CO_2 flooding

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[1]Herbeck, E. F., et al. Petroleum Engineer, May 1976, pp. 114-120.

[2]Devanney, J. W., et al. "The Estimated Recovery Potential of Conventional Source Domestic Crude Oil," EPA Contract No. 68-01-2445, May 1975.

becomes an established, economical technology in the future, it is likely to be applied prior to waterflooding.

6.4.2.2.2 Inputs

6.4.2.2.2a Manpower Requirements

Accurate data on manpower requirements for CO_2 flooding are not currently available. It is assumed that they will be similar to those for waterflooding, but for a fewer number of years. The magnitude and type of manpower resources necessary for CO_2 supply will depend on the CO_2 source. There are two potential sources of CO_2: geologic and chemical by-products. Use of geologic sources of CO_2 will require manpower for exploration, production and transportation. Once a suitable formation is discovered, a production facility must be constructed and operated. A pipeline to transport the high pressure CO_2 to the oil field will also have to be built and operated. Where the source of CO_2 is a relatively pure by-product of a chemical process, manpower will be required for construction and operation of both a compression facility and a pipeline to the oil field.

Construction manpower requirements are assumed to be 4000 man-years/year for 2-3 years. Operational manpower requirements are estimated at 2000 man-years/year for 5 years.

6.4.2.2.2b Materials and Equipment

A CO_2 flood will use much of the injection, production, and treatment equipment that is available from waterflooding operations. This is discussed in detail in a previous section where conventional recovery techniques are considered. This section will consider the additional material and equipment requirements necessary for a CO_2 flood.

The most significant material requirement is the CO_2 which amounts to 30 percent of the reservoir pore volume. For the example reservoir, this is equivalent to 10^{12} standard cubic feet. The other major material requirement is water which is discussed in a separate section.

Additional equipment requirements for a CO_2 flood will be a function of the type of source. With a geologic source equipment will be necessary for production and transportation of the CO_2. Production will involve drilling wells 15,000 or more feet deep and high pressure production equipment. Since geologic production of CO_2 is not a commonly practiced technology, it is not possible to accurately estimate specific equipment requirements. Transportation to the oil field will involve construction of a high pressure pipeline (>3000 psia) between the source and the injection points. The high pressure pipeline is required by the fact that CO_2 is most economically transported as a liquid.

Chemical process sources will involve compression equipment necessary to take the CO_2 from atmospheric pressure to greater than 3000 psia. This is necessary to be installed at the source since pipeline economics favor transportation of liquid CO_2.[1] The actual pressure requirement will be 3000 psia plus the pressure drop occurring in the pipeline. If it is assumed that the CO_2 is supplied over 2½ years, then the compressor requirement will be equal to or greater than 1.1×10^5 horsepower. Longer transportation distances will require more compression.

[1]Devanney, J. W., et al. "The Estimated Recovery Potential of Conventional Source Domestic Crude Oil," EPA Contract No. 68-01-2445, May 1975.

As mentioned before, a high pressure pipeline between the source and the injection points will also be necessary.

6.4.2.2.2c Economics

There are three major cost components that affect the cost of oil produced by CO_2 flooding. These are:[1]

Flooding Costs = $0.50 to 1.50/bbl recovered

Compression Costs = $0.87/bbl recovered

CO_2 Transportation Costs = function of distance.

These costs have been calculated from literature data and put on a per-bbl-recovered basis. CO_2 transportation costs, as indicated, are a function of distance and are potentially the the largest single factor that will determine the cost of oil produced by a CO_2 flood. Table 6-47 shows the individual and cumulative costs as a function of distance between the CO_2 source and the oil field. The cumulative costs are plotted as a function of transportation distance in Figure 6-20. The cumulative costs do not include the purchase price of the CO_2 since this cost will probably be highly variable and specific to each application. The price of bulk liquid CO_2 has averaged $60-$80/ton from 1974 to present.

6.4.3.2d Water Requirements

No value for the water required for a CO_2 flood was found in the literature consulted; however, it is possible to make some

[1]Devanney, J. W., et al. "The Estimated Recovery Potential of Conventional Source Domestic Crude Oil," EPA Contract No. 68-01-2445, May 1976.

TABLE 6-47. COSTS ASSOCIATED WITH CO_2 FLOODING

Miles Between CO_2 Source and Reservoir	CO_2 Transportation Costs	Flooding Costs	Compression Costs	Total Cost Exclusive of Purchase Price of CO_2
0	$0.50	$0.50-1.50	$0.87	$1.87-2.87
100	1.75	0.50-1.50	0.87	3.12-4.12
200	1.83	0.50-1.50	0.87	3.20-4.20
500	3.84	0.50-1.50	0.87	5.21-6.21
1000	7.66	0.50-1.50	0.87	9.00-10.00

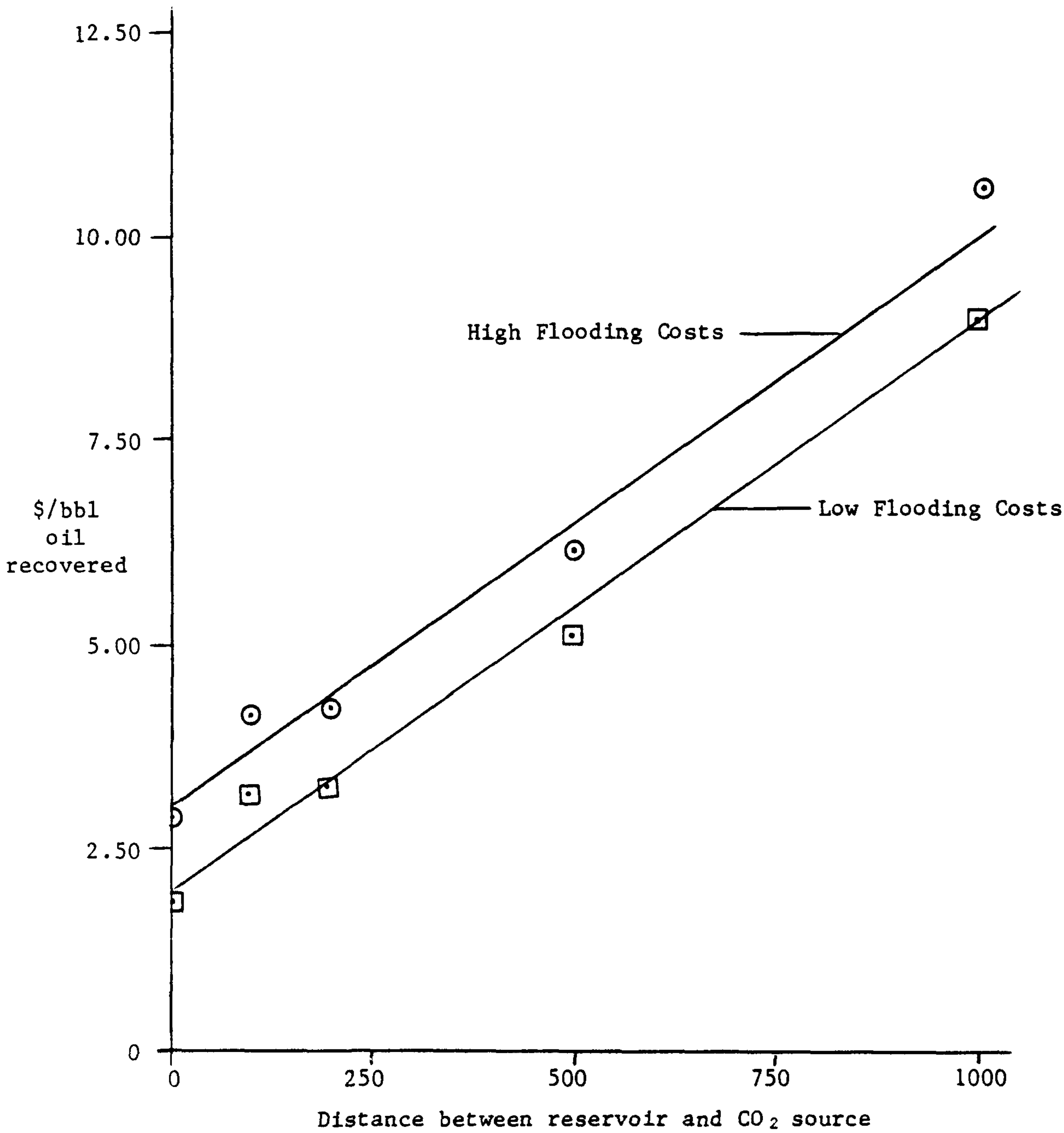

Figure 6-20. Costs of Oil Recovered by CO_2 Miscible Flooding
(Exclusive of Purchase Price of CO_2)

assumptions. Assuming that water is injected sufficient to complete one to two sweeps through the reservoir, then the total water usage for the flood is 50 to 100 percent of the reservoir pore volume. For the example reservoir, this translates into 7 to 15 bbls of H_2O per bbl of oil recovered or 4000 to 8600 acre-ft total. There may be other water requirements associated with CO_2 flooding; however, they are assumed to be minor in comparision.

6.4.2.2.2e Land Usage

Land usage in the oil field will be the same for CO_2 flooding as for waterflooding. For the example reservoir, 20 square miles will be required. This will vary with the reservoir characteristics. Injection and production wells will be placed at intervals over the land area. Part of the land will be used for oil storage and water treatment facilities.

Off-site there may be land requirements for CO_2 production if a geologic source is used. If a chemical process source is chosen, then some land will be required to accomodate the compression equipment. Land will also be necessary to construct the pipeline between the source and the reservoir.

6.4.2.2.2f Ancillary Energy

Ancillary energy for off-site operations will be required for either production of CO_2 from geologic formations or compression of CO_2 for transportation and injection. Estimates of energy requirements for production of CO_2 from geologic formations are not available. Compression of CO_2 from atmospheric pressure to 3000 psi requires about 0.015 bbl of oil per 1000 scf. This is equivalent to 3.8×10^9 Btu/hr for the example reservoir using the assumptions presented in previous sections. Using a crude oil heating value of 5.6×10^6 Btu/bbl, about 8 percent of the produced energy is lost to CO_2 compression.

Heater treaters, if they can be considered as an ancillary energy requirement, consume about 10^5 Btu per bbl of oil recovered.[1] This translates to 2 percent of the produced energy.

6.4.2.2.3 Outputs

As in the input section, the example reservoir is the basis of several of the values shown in the discussion of outputs.

6.4.2.2.3a Air Emissions

Since CO_2 flooding does not involve high fuel combustion rates, it is expected that the air quality impact will be less than with thermal recovery. The primary air pollution impact of a CO_2 flood will be from hydrocarbons and H_2S that have been absorbed by the CO_2.[2] CO_2 may also be emitted. The actual quantities emitted cannot be determined since no detailed concentration data currently exists. In Section 6.4.2.2.2f on ancillary energy requirements, crude oil consumption due to CO_2 compression and heater treater operation amounted to 10 percent

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[1]Cavanaugh, E. C., et al. Atomospheric Environmental Problem Definition of Facilities for Extraction, On Site Processing, and Transportation of Fuel Resources, Contract No. 68-02-1319, Task 19. Austin, Texas: Radian Corporation, July 1975.

[2]U.S. Congress, Office of Technology Assessment. "Enhanced Recovery of Oil and Devonian Gas," June 1977.

of the total volume produced. Table 6-48 shows major pollutant emissions assuming 10 percent of the produced oil is burned. Table 6-49 shows trace metal emissions calculated using the same assumption.

As stated above it is impossible to estimate the amount of fugitive emissions attributable to absorption into the CO_2 phase. There are also emissions associated with other oil production operations such as treating, transfer and storage. Emission factors for these operations exist and are presented in Table 6-50.

6.4.2.2.3b Water Effluents

The primary impacts of effluent water quality will be from dissolved CO_2, hydrocarbons, and salts. Published data describing typical dissolved CO_2 concentrations and treatment techniques were not found. The range of possible CO_2 concentrations can be calculated. CO_2 in contact with water at 3000 psia will give a dissolved CO_2 concentration of about 5 wt percent. At the wellhead the concentration will be on the order of 1 wt percent. Water at equilibrium with the atmosphere will have a dissolved CO_2 concentration of about 10^{-4} wt percent. The actual concentration of CO_2 in the effluent water will be somewhere between these two values. Water treatment by aeration or lime addition may be necessary to remove the CO_2.

Hydrocarbon effluents in the water can be estimated using published data.[1,2] These data indicate that hydrocarbon emissions

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[1] Teknekron, Inc. Fuel Cycles for Electrical Power Generation, Phase I: Towards Comprehensive Standards: The Electric Power Case, Report for the Office of Research and Monitoring, Environmental Protection Agency. Berkeley, California: Teknekron, 1973.

[2] Battelle Columbus and Pacific Northwest Laboratories. Environmental Considerations in Future Energy Growth, Vol. 1: Fuel/Energy Systems: Technical Summaries and Associated Environmental Burdens, for the Office of Research and Development, Environmental Protection Agency. Columbus, Ohio: Battelle Columbus Laboratories 1975.

TABLE 6-48. AIR EMISSIONS OF MAJOR POLLUTANTS FOR CO_2 FLOODING OPERATIONS (ASSUMES 10% OF PRODUCED OIL IS BURNED)

Pollutant	lb[c] / 1000 gal oil burned	lb / 1000 bbl recovered
Particulate	7-23	29-27
SO_2[a]	193	810
SO_3[a]	2.5	11
CO	4	17
HC (as CH_4)	2	8.4
NO_x (as NO_2)[b]	60	250

[a]Assumes 1.23% S in fuel.

[b]NO_x is highly dependent upon fuel N content.

[c]Average values based on data from:

Sources: U.S. Congress, Office of Technology Assessment. "Enhanced Recovery of Oil and Devonian Gas." June 1977.

Environmental Protection Agency. Compilation of Air Pollutant Emissions Factors, 2nd ed., with supplements. AP-42. Research Triangle Park, NC, Feb. 1972, April 1973, July 1973, Sept. 1973, July 1974, Jan. 1975, Dec. 1975, Feb. 1976, April 1977.

TABLE 6-49. TRACE METAL EMISSIONS FOR CO_2 FLOODING OPERATIONS (ASSUMES 10% OF PRODUCED OIL IS BURNED)

Trace Metal	ppm[a]	$\frac{\text{lb}}{\text{1000 gal oil burned}}$	$\frac{\text{lb}}{\text{1000 bbl recovered}}$
Antimony	<0.022	<0.015	<0.063
Arsenic	<0.059	<0.024	<0.10
Barium	<0.097	<0.072	<0.30
Manganese	0.032	0.0095	0.040
Nickel	3.9-77	1.2-2.4	5.0-100
Tin	0.70	0.45	1.9
Vanadium	1.5-4.8	0.41-13	1.7-55

[a] Averages based on Texas, Lousiana, and California crudes.

Source: Magee, E. M., et al. Potential Pollutants in Fossil Fuels, Environmental Protection Agency Report No. EPA-R2-73-249, June 1973.

TABLE 6-50. FUGITIVE EMISSION FACTORS FOR CO_2 FLOODING OPERATIONS

Source	lb hydrocarbons/ 1000 bbl oil produced
Storage Tanks	3.9
Wastewater Separators	7.9
Pumps	74.
Compressors	3.8
Relief Valves	7.9
Pipeline Valves	11.6
Diesel Pump for Waterflooding	7.1
Miscellaneous Flaring & Fires	0.76

Source: Cavanaugh, E. C., et al. Atmospheric Pollution Potential from Fossil Fuel Resource Extraction, On-Site Processing and Transportation. Final Report. Radian Corp., Austin, Tex. EPA Contract 68-02-1319. 1972.

Burklin, C. E., et al. Control of Hydrocarbon Emissions from Petroleum Liquids. Final Report. Radian Corp., Austin, Tex. EPA Contract 68-02-1319. 1975.

in the effluent water are about 0.01 lb per 1000 bbls of oil produced. Using the assumed water usage rate of 7-15 bbls H_2O per bbl oil, the concentration of hydrocarbons in the water can be estimated to be 10^{-7} wt percent.

Salt concentration will vary as a function of the reservoir rock type and perhaps other factors. Typically, salt concentrations in the range of 5 to 50 wt percent are encountered.

6.4.2.2.2c Solid Effluents

Solid effluents resulting from CO_2 flooding operations were not found in the literature. Most likely, the only solid effluents will be from water treatment processes where pollutants are removed as a solid. If evaporation or aeration ponds are used, there may be some salt precipitation as water evaporates.

6.4.2.2.3d Noise

The major potential source of noise will be the CO_2 compression facility that is necessary with certain CO_2 sources.

6.4.2.2.3e Occupational Health and Safety

Figures on occupational health and safety appear in Table 6-46. These values are based on published data that are tabulated for oilfield operations on an incidents-per-million-Btu basis.

6.4.3 Production Social Controls

6.4.3.1 Federal

The following sections will discuss the oil production social controls at the federal level to include statutes and regulations. A majority of the controls at the federal level are broadly applicable and effect energy development whether on private or public land; whereas a few controls, which are noted, are applicable only to development on the public domain.

6.4.3.1.1 Conservation on the Public Domain[1]

As discussed in Chapter 2 the primary statutory control over oil and gas leasing on the public domain is the Mineral Leasing Act of 1920 (MLA).[2] Oil (and gas) production operations are regulated by the USGS under MLA also and subsequently issued regulations.[3] The regulatory scheme is directed at controlling the wasteful extraction of resources.[4] Pursuant to such regulation, the BLM in concert with the USGS is authorized to approve cooperative or unit plan agreements and joint operating contracts for federal lessees when such action is necessary to prevent waste.[5]

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[1]Conservation as used here means both the efforts to conserve the resource and to protect the environment. Also note these controls are only applicable to federal lands.

[2]30 U.S.C. § 181 *et seq.*(1970).

[3]30 U.S.C. § 226 (1970); 30 C.F.R. Part 221 (1974).

[4]Dolgin, Ernie L. and Thomas G. P. Guilbent, eds. Federal Environmental Law. St. Paul, Minn.: West, 1974, p. 936.

[5]Shapiro, Michael E. "Energy Development on the Public Domain: Federal/State Cooperation and Conflict Regarding Environmental Land Use Control." Natural Resources Lawyer. Vol. 9, 1976: 401. Note the statutory authority stems from 30 U.S.C.A. § 226 (j) (1970) and regulations are found at 43 C.F.R. subpart 3105 (1974). For complete discussion of federal unitization see: Churchill, D. O. "Federal Unitization" pp. 223-256, in Rocky Mountain Mineral Law Institute: Proceedings of the Twenty-First Annual Institute. July 17-19, 1975. Albany, N.Y.: Matthew Bender, 1975.

Since the Secretary is given full discretion to refuse to accept an offer for an oil and gas lease,[1] the BLM under his authority has rejected leases on environmentally sensitive areas. The BLM may also impose conditions on lease.[2] As can be gathered from the above there are no specific statutes protecting the public domain from environmental harm.[3]

Other controls exist at the federal level but will be primarily discussed in Section 6.4.3.2.1 (State Conservation Laws). Controls in this area include "market demand prorationing" and were passed by some states and approved by Congress in 1935 as the Interstate Oil Compact.[4] Basically the Act allows the states to limit oil production to prevent prices that would be low enough to allow physical waste of oil. Recently, with the peaking of domestic oil production and respective high prices, the prorationing controls have lost most of their effect on oil production.[5]

The Secretary of the Interior is required to keep his regulations on oil and gas leasing in line with similar provisions in state laws where the leased land is located. Court cases interpreting this question have tended toward narrow interpretation of the state's rights. For example, the Interior

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[1] 30 U.S.C.A. § 226 (a) (1970).

[2] Shapiro, Michael E. "Energy Development on the Public Domain: Federal/State Cooperation and Conflict Regarding Environmental Land Use Control." Natural Resources Lawyer. Vol. 9, 1976: 401. Note the statutory authority stems from 30 U.S.C.A. § 226 (j) (1970) and regulations are found at 43 C.F.R. subpart 3105 (1974). For complete discussion of federal unitization see: Churchill, D. O. "Federal Unitization" pp. 223-256, in Rocky Mountain Mineral Law Institute: Proceedings of the Twenty-First Annual Institute. July 17-19, 1975. Albany, N.Y.: Matthew Bender, 1975.

[3] But see Chapter 2 for a discussion of NEPA's application.

[4] 49 Stat. 20 (1935).

[5] Dolgin, Ernie L. and Thomas G. P. Gilbert, eds. Federal Environmental Law. St. Paul, Minn. West, 1974 p. 943.

Board of Land Appeals (within Department of Interior) has disapproved a communication agreement affecting federal oil and gas leases which had been previously approved by a state oil and gas commission under state conservation statutes.[1] The same problem occurs in attempting to pool Indian land with private land under state laws. At least one case has held the state laws are ineffective to force such pooling.[2]

6.4.3.1.2 Air Pollution

Although new source performance standards have been written for "Storage Vessels for Petroleum Liquids," it appears that petroleum storage at the drilling or production facility is not covered.[3] Also, the federal NSPS for steam generators have a threshold of 250 million BTU's per hour and even steam injection on a large scale would not approach that limit.[4]

6.4.3.1.3 Water Effluent Controls

6.4.3.1.3a Surface Water

Effluent guidelines have been promulgated for oil and gas extraction point sources.[5] EPA, under court order, published the regulations without a comment period and made the guidelines

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[1]Shapiro, Michael E. "Energy Development on the Public Domain: Federal/State Cooperation and Conflict Regarding Environmental Land Use Control." Natural Resources Lawyer, Vol. 9, 1976:418.

[2]Assimiboine and Sioux Tribes of Fort Peck Indian Reservation, Montana v. Calvert Exploration Co., 233 F. Supp. 909 (D. Mont:1965).

[3]40 C.F.R. 60.110 (b) (1975), see generally 40 C.F.R. 60.110 for the NSPS for petroleum storage.

[4]40 C.F.R. 60.40 as revised by 41 Fed. Reg. 51397, Nov. 22, 1976.

[5]41 Fed. Reg. 44942-44952, Oct. 13, 1976, to be codified at 40 C.F.R. § 435 (1977).

effective immediately.[1] The regulations are classified interim and comments will be taken prior to promulgation of final regulations.

Interim regulations address the following categories of oil and gas development: onshore, beneficial use, and stripper. The onshore sub-category is all those categories not coastal, not beneficial use and not stripper; therefore, the one applicable to most western energy development. Table 6-51 will summarize the effluent guidelines.

6.4.3.1.3.b Underground Water

Underground disposal of brine (injection wells) has historically been controlled by state law and these same laws deal with injection for secondary recovery. Recently, however, the federal government, more specifically EPA, has moved into the field.

Authority for EPA comes from various sources and there is potential for challenge under each of them.[2] The primary basis for EPA jurisdiction is the Safe Drinking Water Act.[3] Congress, when passing the Pact, included a comprehensive state-federal system of regulation over underground injection.

Under SDWA, the states must establish a permit program of rules governing such injection prior to December 1977.[4] The EPA

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[1] NRDC v. Train, (CV. No. 1609-73, D.C. Cir.) requiring the regulations to be promulgated by September 1, 1976.

[2] Eckert, Allan W. "EPA Jurisdiction over Well Injection Under the Federal Water Pollution Control Act," Natural Resources Lawyer, Vol. 9, 1976: pp. 455-465.

[3] Safe Drinking Water Act, P.L. 93-523, 88 Stat. 660, 42 U.S.C.A. § 300 (f) *et seq.*, amending 42 U.S.C.A. § 201 (1970).

[4] Safe Drinking Water Act, § 1421 (b), 42 U.S.C.A. § (Supp. 1976).

TABLE 6-51. SUMMARY OF OIL AND GAS EXTRACTION EFFLUENT GUIDELINES

Type of Regulation	Sub-Categories Onshore	Beneficial Use[2]	Stripper[3]
Interim BPT	No discharge of pollutants	No discharge of pollutants[1]	Not issued
Proposed BAT (New Sources)	No discharge of pollutants	No discharge of pollutants[1]	Not issued
Pre-treatment[4] for new sources	Not more than 100 mg/l of oil and grease	Not more than 100 mg/l of oil and grease	Not issued

Source: 41 Fed. Reg. 44942-44952 (October 13, 1976).

[1]Additional limit of notmore than 45 mg/l of oil and gas in the discharged water.

[2]That category wherein the effluent is applied to livestock or other agricultural uses.

[3]Those wells producing less than 10 barrels of oil per day.

[4]Those sources discharging into publicly owned treatment works.

administrator must approve the program or develop his own for that state.[1] Not all states will be included initially but all eventually will be included.

Potential problems from holding seepage conflicting with SDWA has been covered in Chapter 2 and is applicable to the surface pond storage of brine, as may also be the case with state solid waste laws.

Oil production is not free from controls other than those noted here; for example, there are comprehensive federal laws within FWPCA controlling oil spills on land as discussed in Chapter 2.

6.4.3.2 State

State laws affecting the production of oil are aimed primarily at operations on private lands with some variations for oil production on state laws which also affect federal land and will be noted below. Topics discussed herein are conservation, injection, air emissions, and plugging.

6.4.3.2.1 State Conservation Laws and Regulations

State conservation laws started with Indiana's law of 1893 which made it illegal to allow a well to flow freely for more than two days after striking oil. The U.S. Supreme Court upheld the law, stating that the law was proper as one way to protect the right of others to produce from the pool (common source of supply), because waste reduced the amount that could be produced

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[1] SDWA, § 1422, 42 U.S.C.A. §

from the common supply, and the wasteful acts of one could result in "the annihilation of the rights of the remainder."[1]

The state laws within the category are those for spacing, compulsory pooling, and compulsory unitization. The spacing statutes exist in all eight states and allow for administrative determination of the number of acres per well. These vary from no more than one well per 20, 40, 80, and 160 acres for oil and 320 and 640 or larger for gas wells.

Pooling is generally defined as the means used to bring together small tracts of land sufficient for the granting of a well permit under applicable spacing rules and must be distinguished from unitization which is the joint operation of all or some part of the reservoir.[2] Unitization is suggested in the primary stages of development but is nearly mandatory in secondary recovery operations. All eight of the states in this study have enacted compulsory pooling laws allowing the majority lessee to drill on a spacing unit. The other lessees and lessors may not hinder but are allowed to share in costs and profits.[3]

All states in this study area have statutory authorization for voluntary unitization except New Mexico.[4] The states went further to encourage unitization when it became apparent that the

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[1]Ohio Oil Co. v. State of Indiana, 1977 U.S. 190 (1960).

[2]Williams and Meyers, Oil and Gas Law, Vol. 6, § 901, 1964: p. 2.

[3]Williams and Meyers, Oil and Gas Law, Vol. 6, § 901, 1964: p. 20.

[4]Id. § 911, p. 94.

maximum recovery of hydrocarbons from a reservoir would require the production of the formation as a unit. Under specified circumstances six of the eight states statutorily provide for compulsory unitization (with New Mexico and South Dakota being the exceptions).[1]

Although the unitization statutes vary, the following findings are generally necessary as prerequisites to the administrative order to unitize:[2]

(1) Unit operation is reasonably necessary.
(2) The proposed method is feasible.
(3) The cost of unitization will not exceed the estimated additional revenues.
(4) The proposed operation is for the common good and is fair and equitable.
(5) The plan has been approved by the specified percentage of owners.

6.4.3.2.2 Injection

State injection laws have not been included here since the recently promulgated federal regulations on the subject include a mechanism for revision of state injection programs (see Section 6.4.4.1.3.b).

6.4.3.2.3 Air Pollution

(See Section 7.4.4.2.b, State Laws Concerning Storage of Oil or Gas and Flaring).

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[1] Id. § 912, p. 98.

[2] Id. § 913.4, p. 112.

6.4.3.2.4 Plugging and Sealing

Vary by state but usually require sealing the bore hole so that zones of production do not mingle and that oils and brines do not migrate to the fresh water strata. For summary by state see Section 7.4.4.2.d and Table 7-12.

6.5 TRANSPORTATION

6.5.1 Social Controls

Transportation social controls were covered generally in Chapter 2, including rail, highway and electric, hence this section will be devoted to an analysis of those controls affecting only oil and more specifically oil pipeline problems.

6.5.1.1 Federal

Federal regulation of oil pipelines has been discussed in Chapter 2, Transportation, but some factors deserve mention here. Previously discussed were DOT safety regulations for pipelines, ICC rate regulation, and rights-of-way on public and private lands. Factors or controls at the federal level noted before are FWPCA oil spill regulations and Corps permits when crossing streams or bodies of water.

6.5.1.1.1 Oil Spills

Section 311 of FWPCA holds owners and operators of oil pipelines responsible for "harmful" oil spills into the navigable waters of the U.S.[1] Liability extends to the cost of removal of the oil and/or to penalties. Regulations specify and it has been upheld in court that the amount of spill is harmful if it is enough to cause a sheen on the waters.[2] It appears that EPA has delegated their authority to the DOT for control of the above.

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[1]See Section 2.9.1 for definition of Navigable Waters.

[2]40 C.F.R. § 110.3 (1972), upheld in U.S. v Boyd, 491F.2d 1163 (9th Cir. 1973).

CHAPTER 7

THE NATURAL GAS RESOURCE DEVELOPMENT SYSTEM

CHAPTER 7

THE NATURAL OIL RESOURCE DEVELOPMENT SYSTEM

7.1 INTRODUCTION

7.1.1 Background

The first recorded use of natural gas in the U.S. was in Fredonia, New York in 1821. Early usage tended to be localized and many utilities distributed gas manufactured from coal. In 1947, a major change in the character of the industry occurred when natural gas from the Southwest reached the East Coast through two converted liquid pipelines, the "big inch" (crude oil) and the "little inch" (refined crude oil products). Since then, the consumption of natural gas in all end-use classifications (residential, commercial, industrial, and power generation) has increased rapidly. This growth has resulted from several factors, including: the development of new markets; replacement of coal as a fuel for providing space and industrial process heat; use in making petrochemicals and fertilizers; and the strong demand for low-sulfur fuels that emerged in the mid-1960's.

As a result of these expanded end uses, total gas utility mains increased from 218,000 miles in 1945[1] to 980,000 miles in 1975.[2] The high-pressure natural gas transmission network was

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[1]Zareski, J.K. "The Gas Supplies of the United States - Present and Future." Pollution Control and Energy Needs, Advances in Chemistry Series No. 127. New York, New York: American Chemical Society. 1973.

[2]American Gas Association, Department of Statistics. Gas Facts, 1975 data. Arlington, Virginia: American Gas Association, 1976, p. 29.

extended into all the lower 48 states and, by 1975, included 261,000 miles of pipe and 12.0 million horsepower of compression.

All phases of development and utilization of gas resources are provided by private industry and fall within three fairly well-defined segments: supply, transmission, and distribution. Although large corporations dominate the individual segments, the industry is not characterized by vertical integration from the gas field to the consumer. For the most part, the gas industry consists of transmission companies that buy their gas from the oil industry and distribution companies that sell the gas to the ultimate consumers.

This chapter describes the technologies, inputs, outputs, laws, and regulations associated with the development of natural gas resources. There are five main sections to the chapter and they are briefly described below.

Section 7.2 describes the characteristics of the natural gas resources found in the eight-state region and also discusses the quantity and location of the resource.

Section 7.3 discusses the technologies, inputs and outputs, and social controls associated with exploration for natural gas. Section 7.4 discusses the same items for convention natural gas production and field processing. Section 7.5 discusses the technologies and social controls for transportation of natural gas.

It is important that the reader have a thorough understanding of this entire chapter before applying any of the contained information. Typical technologies were chosen for the basis of the data, and it is important to note that the parameters can vary greatly depending upon the specific basis chosen. The reader is advised to note any changes in bases between the different technologies in the chapter.

7.1.2 Summary

Tables 7-1 and 7-2 summarize the input requirements and outputs associated with the development of the resource.

TABLE 7-1. SUMMARY OF IMPACTS ASSOCIATED WITH EXPLORATION FOR A 250,000,000 CUBIC FEET/DAY GAS FIELD

Inputs		
Manpower	see Table 7-8	
Materials and Equipment		
• Casing and Tubing	4548 tons	4126 m. tons
• Rig-Years	9	9
• Cement	8960 tons	8128 m. tons
Economics	25×10^6 dollars	25×10^6 dollars
Water (lifetime of project)	10^6 barrels	15,350 m^3
Land	30 acres	121,407 m^2
Ancillary Energy	5.2×10^{11} Btu	5.4×10^{14} J.
Outputs		
Air Emissions		
• Particulates	24 lbs/day	10.9 kg/day
• SO_2	50 lbs/day	22.7 kg/day
• CO	431 lbs/day	195.5 kg/day
• Hydrocarbons	70 lbs/day	31.7 kg/day
• Nitrogen Oxides	700 lbs/day	317.4 kg/day
• Aldehydes	6 lbs/day	2.72 kg/day
• Organic Acids	6 lbs/day	2.72 kg/day
• CO_2	39,265 lbs/day	17,807 kg/day
Water Effluents	negligible	
Solid Wastes	66,000 ft	1869 m^3
Noise Pollution	variable	
Occupational Health and Safety		
deaths	0.2/year	
injuries	19/year	
lost time	3200 man-days/year	

TABLE 7-2. SUMMARY OF IMPACTS ASSOCIATED WITH THE PRODUCTION FOR A 250,000,000 CUBIC FOOT/DAY NATURAL GAS FIELD

<u>Inputs</u>		
Manpower	See Table 7-8, 9	
Materials and Equipment		
• Refined Products	128,650 tons	116,708 m. tons
• Cement	75,000 tons	68,038 m. tons
• Pipe and Tubing	15,000 tons	13,608 m. tons
• Heat Exchangers	83,000 ft^2 of surface	7710 m^2 of surface
Economics	400 million dollars	
Waters	380 acre ft/yr	468,730 m^3/yr
Land	850 acres	3.44×10^6 m^2
Ancillary Energy	3% of gas produced	
<u>Outputs</u>		
Air Emissions		
• Particulates	50 lb/day	22.7 kg/day
• SO_2	11,233 lb/day	5095 kg/day
• NO_x	15,741 lb/day	7140 kg/day
• HC	19 lb/day	8.6 kg/day
• CO	47.5 lb/day	21.5 kg/day
• Triethylene glycol	240 lb/day	108.8 kg/day
Water Effluents		negligible
Solid Wastes		none
Noise Pollution		no data
Occupational Health and Safety		See Table 7-1
Odor		no data

7.2 RESOURCE DESCRIPTION OF WESTERN NATURAL GAS

7.2.1 Characteristics of the Resource

Natural gas is a degradation product resulting from the decomposition of buried organic matter. It is found in recent sediments deposited in both fresh water and salt water environments, in ancient sedimentary rocks, in subsurface aquifers, in fine fractures in coal seams, and even in metamorphic rocks. As of 1975, there were approximately 131,000 wells producing gas from such formations.[1] The determining factor in classifying a well with respect to type of production is the ratio of oil/gas produced. The different states have statutes defining an oil or gas well, and most are similar to Texas law. It defines an oil well as "... any well which produces one (1) barrel or more of crude petroleum oil to each one hundred thousand (100,000) cubic feet of natural gas."[2]

Unprocessed natural gas is a mixture of hydrocarbons with methane as the major component. The mixture also includes ethane (C_2H_6), propane (C_3H_8), butane (C_4H_{10}), and some heavier hydrocarbons. Most of the ethane and heavier hydrocarbons are removed through liquefaction and are sold as separate products for a multitude of uses. Other components found in natural gas are water, hydrogen sulfide, nitrogen, carbon dioxide, and others, which for the most part are removed during gas processing. The heat content of dry natural gas in the U.S. averages 1,032 Btu per cubic foot measured at 14.7 psia and 60°F.[3]

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[1]American Gas Association, Department of Statistics. Gas Facts, 1975 Data. Arlington, Virginia: American Gas Association. 1976, p. 29.

[2]Processes Research, Inc. Industrial Planning and Research. Screening Report. Crude Oil and Natural Gas Production Processes. Final Report. Cincinnati, Ohio: Processes Research, Inc. 1972.

[3]American Petroleum Institute. Petroleum Facts and Figures. Washington, D.C.: American Petroleum Institute. 1971.

However, the heat content as well as the composition of unprocessed natural gas varies considerably with different wells as illustrated in Figure 7-1.[1]

Natural gas may also be classified in terms of the level of association with crude oil in its natural occurrence underground. Nonassociated gas is gas occurring by itself in reservoirs, while associated gas is produced along with crude oil. Natural gas may also exist in a dissolved state in crude oil. In deep reservoirs (*e.g.*, 15,000 feet or deeper), crude oil may exist in a gaseous state (called gas condensate) due to the high temperatures.

7.2.2 Quantity and Location of the Resources

Total proved gas reserves for the western regions as of December, 1975, have been estimated to be 19.6 trillion cubic feet (tcf).[2] The figure for the entire U.S., onshore and offshore, is 228 tcf. This total figure has been dropping each year since the peak year of 1967 which saw proven reserves of approximately 290 tcf. Since that time the annual consumption has far outstripped the discovery rate for natural gas. In terms of recoverable, but yet-to-be-discovered resources the western region has a potential of 56 tcf compared to 484 tcf for on and offshore U.S.[3]

Table 7-3 presents a breakdown of proven and ultimate reserves of natural gas by states. It is seen in the table that the natural gas reserves in the western states account for only

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[1] Federal Power Commission. National Gas Survey, Vol. I. Washington, D.C.: Federal Power Commission. 1974. Chapter 2.

[2] American Gas Association, Department of Statistics. Gas Facts. 1975 Data. Arlington, Virginia: American Gas Association. 1976, p. 29.

[3] U.S. Geological Survey. Geological Estimates of Undiscovered Recoverable Oil and Gas Resources in the United States, Circular 725. Washington, D.C.: U.S. Geological Survey. 1975.

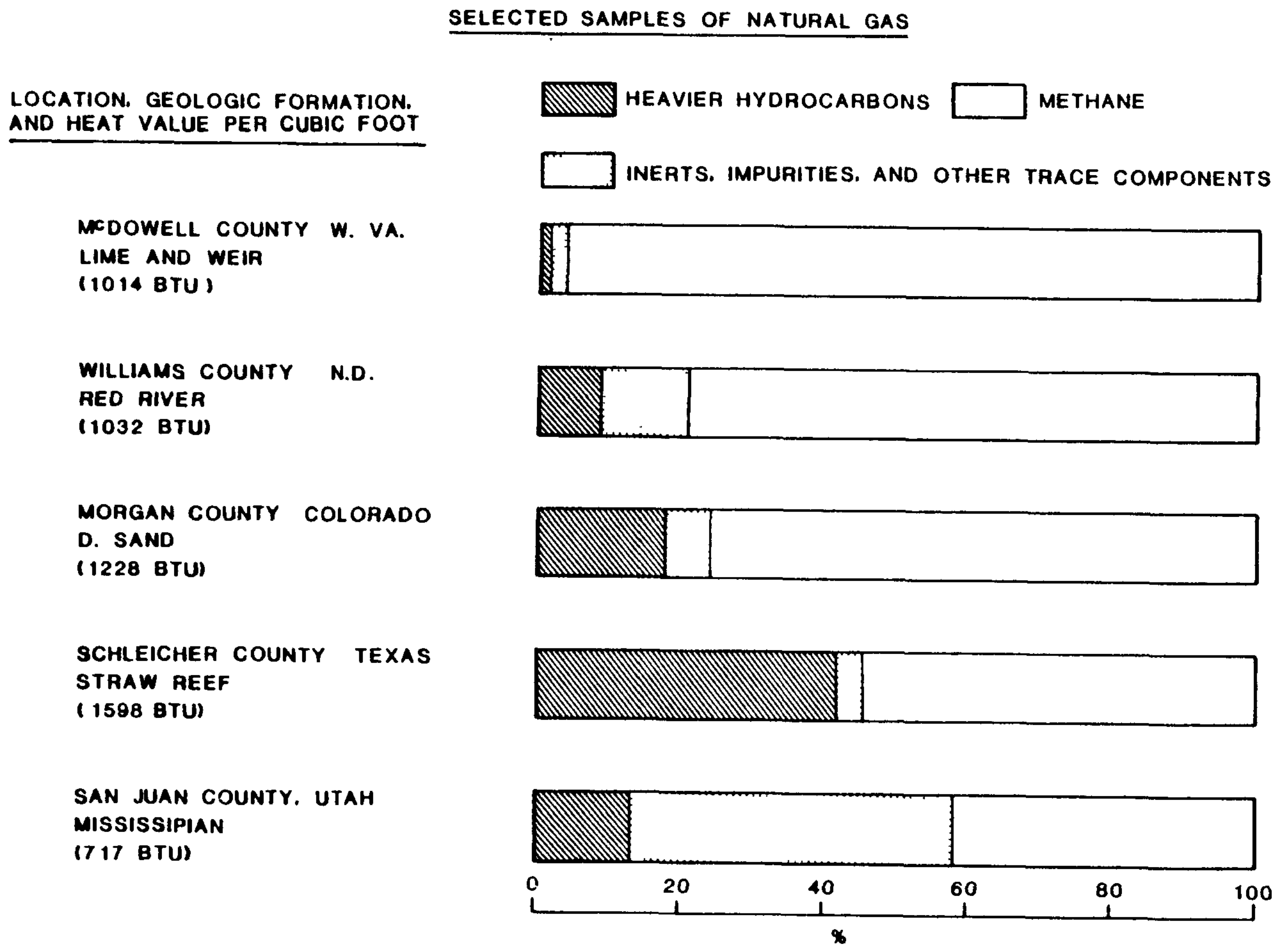

Figure 7-1. Selected Samples of Natural Gas.

Source: Federal Power Commission. National Gas Survey, Vol. I. Washington, D.C.: Federal Power Commission. 1974. Chapter 2.

TABLE 7-3. WESTERN NATURAL GAS RESERVE ESTIMATES[1]
(In billions of cubic feet)

	AGA Proved Reserves[3]	USGS Identified But Not Proved	AGA Cumulative Production[2]	USGS Ultimate Production[2]
Colorado	1,893	1,344	2,233	5,232
Montana	930	577	1,371	3,012
New Mexico	11,759	6,364	23,134	41,833
North Dakota	417	368	658	1,467
Utah	917	876	979	2,877
Wyoming	3,703	3,412	6,296	13,797
Total Western	19,619	12,941	34,677	68,218
Total U.S.	228,200	202,548	436,896	904,576
Ratio = $\frac{\text{Western}}{\text{U.S.}}$	0.09	0.09	0.08	0.08

[1]U.S. Geological Survey. Geological Estimates of Undiscovered Recoverable Oil and Gas Resources in the United States. Circular 725. Washington, D.C.: U.S. Geological Survey. 1975.

[2]Based on American Gas Association reports as of December 31, 1972.

[3]Based on American Gas Association reports as of December 31, 1975.

about ten percent of the whole U.S. reserves. Table 7-4 presents the production record for the western states for a ten year period.

7.2.3 Ownership of Resources

No data has been collected on the ownership of the western natural gas resources. On a national level six percent of onshore reserves are federally owned,[1] but the figure is considered somewhat higher for the western U.S.

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[1]Ford Foundation. Energy Policy Project. A Time to Choose: America's Energy Future. Cambridge, Massachusetts: Ballinger Publishing Co., 1974.

TABLE 7-4. MARKETED PRODUCTION OF NATURAL GAS[1]

(Million Cubic Feet per Day)

State	1976[3]	1975	1974	1973	1972	1971	1970	1969	1968	1967
Colorado	488	470	396	377	320	297	290	325	332	320
Montana	108	112	150	154	92	90	117	113	53	71
New Mexico	3,361	3,335	3,410	3,339	3,323	3,199	3,121	3,118	3,181	2,925
Utah	163	152	138	117	108	116	117	128	126	134
Wyoming	651	866	895	980	1,025	1,044	927	832	679	658
Total Western[2]	4,771	4,935	4,989	4,967	4,868	4,746	4,572	4,516	4,371	4,108
Total U.S.	54,210	55,092	59,180	62,048	61,562	61,625	60,057	56,708	52,792	49,784
Ratio = $\frac{\text{Western}}{\text{U.S.}}$	0.09	0.09	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08

[1]Lange, D., "There's an Upbeat to Journal's Forecast of Oil Activity in 1977." Oil and Gas Journal. 75(5), Jan. 31, 1977. p. 118.

[2]North Dakota was not included in total.

[3]Preliminary

7.3 EXPLORATION

7.3.1 Technologies

The technologies used in gas well drilling are essentially the same as in oil well drilling. The reader is referred to Section 6.3.1 for a description of exploration drilling.

7.3.2 Input Requirements

The inputs associated with drilling the gas wells which will ultimately produce 250 MM scfd are discussed in this section. With respect to drilling operations, there are two types of gas wells, exploratory and developmental. Exploratory drilling means searching for the geologic strata containing petroleum in sufficient quantities to justify recovery. Once the natural gas is found, developmental wells are drilled in strategic areas which will produce the maximum amount of product over the life of the gas field.

As a basis for the inputs, a gas field was designed consisting of 83 wells each producing 3 MM scfd. For the example field, the assumption is made that for every 10 producing wells 8 additional dry holes will have been drilled. Both operations, a total of 149 wells, and construction of gathering and processing facilities are scheduled for a 5 year program.

7.3.2.1 Manpower Requirements

The Bechtel Corporation has estimated the manpower required to develop and produce a domestic gas field.[1] The total manpower

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[1]Carasso, M., et. al. The Energy Supply Model, computer tape. San Francisco, California: Bechtel Corporation. 1975.

requirements for developing the example field and also for constructing gathering and processing facilities are found in Section 7.4.2.1.

7.3.2.2 Materials and Equipment

Major equipment requirements for development and production of a 250 MM scfd gas field includes casing, tubing, drilling rigs/associated equipment, and cement. The data in Table 7-5 is a compilation of material requirements estimated by the Federal Energy Administration.[1] The average depth of the wells drilled in this study is approximately 5000 ft. If wells are to be drilled into "tight gas" formations found in some areas of Colorado, Wyoming, and Utah at depths greater than 10,000 ft., the materials requirements will be somewhat larger.

7.3.2.3 Economics

Assuming the costs of developing this example gas field are represented by drilling costs along, the development phase of the gas field will cost approximately $25 million before the first gas is recovered. Drilling costs vary widely depending on the depth, location, and the nature of the geologic substrata. The cost data are derived from cost per foot drilled in the western U.S. using 1974 dollars.[2]

7.3.2.4 Water Requirements

The freshwater requirements for a drilling well are almost exclusively for use in the drilling mud. A conventional drilling

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[1] Federal Energy Administration, Interagency Task Force on Natural Gas. Project Independence Blueprint, Final Task Force Report, Natural Gas. Washington, D.C.: Federal Energy Administration. November, 1974.

[2] *Ibid.*

TABLE 7-5. MATERIALS AND EQUIPMENT REQUIRED FOR A 250 MM scfd NATURAL GAS FIELD

	Requirements for 66 Dry Holes	Requirements for 83 Successful Holes	Total
Casing & Tubing (tons)	1394	3154	4548
Surface & Subsurface Equipment (tons)	-	6391	6391
Number of rigs-year (5 year duration)	4	5	9
Steel tonnage per rig (tons)	250	250	-
Cement (tons)*	3980	4980	8960

*Assuming each well is 5000' deep

Source: Federal Energy Administration, Interagency Task Force on Natural Gas. Project Independence Blueprint, Final Task Force Report, Natural Gas. Washington, D.C.: Federal Energy Administration. November, 1974.

rig consumes from 200 to 500 barrels per day of water.[1] For a 14 to 21 day stay at a drilling site, from 5000 to 7500 barrels are used per rig. The total consumption over the drilling phase of this project is approximately 1,000,000 barrels of water.

7.3.2.5 Land Requirements

Two acres of land are cleared and used around a typical exploratory well.[2] Some of this land is retained for workover purposes after the drilling is completed and can be sodded or surfaced as local conditions dictate. Any area not needed for a workover rig can be restored to its original condition. Permanent land usage for the exploratory drilling phases (66 dry wells) is about 30 acres for drilling sites and roads. Land associated with the producing wells is accounted for in the production section.

7.3.2.6 Ancillary Energy

Energy required for drilling oil and gas wells varies with rig size, type of formation drilled, well depth, and the time on the well. Diesel fuel and natural gas are used as fuel. Diesel fuel is normally used in internal combustion engines for drilling exploratory wells.

The consumption of diesel fuel per rig varies from 900 to 1800 gallons per day.[3] Total fuel used for drilling purposes

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[1] Federal Power Commission. National Gas Survey, Vol. II. Washington, D.C.: Federal Power Commission. 1974, pg. 73-75.

[2] *Ibid.*

[3] *Ibid.*

during the 5 year program will be approximately 3.5 million gallons (5.2×10^{11} Btu) of diesel fuel.

7.3.3 Outputs

The outputs associated with the exploratory phase of natural gas production are discussed in the following sections.

7.3.3.1 Air Emissions

The large internal combustion engines used to power the drilling equipment are the major source of air emissions during exploration. Table 7-6 is a tabulation of emissions factors, air emissions per rig, and air emission for the entire gas field averaged over the five-year development period. Sometimes drilling is more intense than these average figures and the emissions are somewhat higher. Periodically, usually near the completion of drilling, wells are tested to evaluate the ultimate producibility of the well. Some gas is brought to the surface and is usually burned. By-products are emitted to the atmosphere. This burning is very infrequent, and there is no data on the quantity of emission.

7.3.3.2 Water Effluents

During normal exploration drilling operations, loss of pollutants to fresh water is negligible. The largest use of water is the circulating drilling mud which is a closed system allowing for no water effluent except for mechanical failure or human error.

Drainage patterns of surface waters and rain runoff may be disturbed by the construction of roads into exploration areas.

TABLE 7-6. AIR EMISSION FROM DRILLING RIGS

Pollutant	$lb/10^3$ gal of diesel fuel	Individual Rig Emission lb/day	Gas Field Emission lb/day
Particulates	13	17	24
Sulfur Oxides as SO_2	27	36	50
CO	225	308	431
Hydrocarbons	37	50	70
Nitrogen Oxides	370	500	700
Aldehydes (as HCHO)	3	4	6
Organic Acids	3	4	6
CO_2	20,775	28,046	39,265

Source: Environmental Protection Agency. Compilation of Air Pollution Emission Factors, 2nd edition with supplements. AP-142. Research Triangle Park, North Carolina: Environmental Protection Agency. April, 1977.

This disturbance may cause increased turbidity and suspended solids in the fresh water. Erosion may also be a possible result.

7.3.3.3 Solid Wastes

Exploratory drilling brings drill cuttings from the well to the surface. These cuttings are mixed with the drilling mud which contains additives such as barite bentonite, inert clays, and phosphate. They will dry in the reserve pit and are plowed into the native soil when drilling is complete. Although some soils may be improved by the addition of these compounds[1], these materials will have an adverse effect in most instances.

7.3.3.4 Noise Pollution

Associated with drilling activities there is a substantial noise level which may be annoying to wildlife or nearby residents. This has occurred most often in Southern California. The rigs are soundproofed, and purchased electric power replaces internal combustion drilling equipment. These solutions seemed to prevent a disturbance to the environment.

7.3.3.5 Occupational Health and Safety

Data on injuries, deaths, and man-days lost for the natural gas exploration, producing, and processing of a 250 MM scfd field are taken directly from Battelle.[2] These numbers are converted from Battelle's basis of producing 10^6 Btu of natural

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[1]Federal Power Commission. National Gas Survey, Vol. II. Washington, D.C.: Federal Power Commission. 1974, p. 73-75.

[2]Battelle-Columbus and Pacific Northwest Labs. Environmental Considerations in Future Energy Growth. Columbus, Ohio: Battelle-Columbus and Pacific Northwest Labs. 1973.

gas to a basis of production of 250 MM scfd of natural gas. The results are as follows: 0.2 deaths/year, 19 injuries/year, and 3200 man-days/year are expected to be lost.

7.3.3.6 Odor

There are no odor problems associated with drilling of gas wells.

7.3.4 Social Controls

Social controls for natural gas development are not substantively different from oil development controls in most areas. Specifically the controls over exploration and leasing are so similar that the sections below will refer the reader to the respective sections in Chapter 6.

7.3.4.1 Exploration Permits; see 6.3.4.1.
7.3.4.1.a Exploration Permits on Federal Land; see 6.3.4.1.a.
7.3.4.1.b Exploration Permits on Indian Land; see 6.3.4.1.b.
7.3.4.1.c Exploration Permits on State Land; see 6.3.4.1.c.
7.3.4.2 Leasing; see 6.3.4.2.
7.3.4.2.a Leasing on Federal Land; see 6.3.4.3.a.
7.3.4.2.b Leasing on Indian Land; see 6.3.4.2.b.
7.3.4.2.c Leasing on State Land; see 6.3.4.2.c.

Utah does allow a variation in rental on its state lands for shut-in gas as opposed to normal oil and gas rental. The statute provides for double the rent in such situations requiring rates to be between $1.00 and $2.00 per acre.[1]

[1]Utah Code Annotated. §65-1-18 (1953).

7.4 NATURAL GAS PRODUCTION

7.4.1 Technologies

Natural gas production technologies discussed in this section are grouped in three general categories: development drilling, well completion, and processing.

7.4.1.1 Development Drilling

Once gas is discovered by exploratory drilling, the well is tested to determine the possible gas flow rate and size of the reservoir. If the reserves calculated from these data and other geological information are large enough to warrant commercial production, the reservoir is developed. Development includes drilling a number of wells to drain the reservoir as efficiently as possible, completing these wells so that flow occurs and can be controlled, installing field processing equipment, and installing transportation pipelines.

Development drilling is similar to exploratory drilling, except that the spacing of wells and location of the bottoms of the holes are more carefully controlled. Once the development well is drilled, casing is set in a manner similar to that discussed in Section 6.4.1.

7.4.1.2 Completion

Well completion encompasses all those activities required to prepare the well for production. A discussion of well completion is found in Section 6.4.1. Oil wells and gas wells are completed in a similar manner.

7.4.1.3 Natural Gas Processing

As pointed out in the introductory section, wells are classified as gas wells or oil wells depending on the ratio of oil/gas produced. In this section, only those operations involved in producing natural gas from basically pure gas reservoirs are discussed. Gases extracted from different producing fields have widely varying compositions. Most field gases contain some undesirable compounds such as CO_2, H_2S, H_2O, and combined sulfur compounds which must be removed prior to sales. Typical processing facilities for upgrading the gas to market specifications are described. These facilities include field separation, compression, and natural gas plants.

The processing method selected for a particular gas depends on factors such as its type and composition, the geographic location of the source, and the proximity of natural gas transmission lines. For example, different processing methods may be used for similar gas produced from onshore and offshore wells. Also, some processing may be done to make the gas suitable for pipeline transmission or sales, while other processing is done to recover valuable products, including a wide range of hydrocarbon liquids.

7.4.1.3.a Field Separation

Two basic types of fields exist from which gas is produced. One is the "dry" gas field in which no hydrocarbons heavier than methane and ethane are produced and the only processing required is dehydration and acid-gas removal. The other type is the "wet" or "condensate" field where a clear hydrocarbon condensate is produced with the gas. Separation of these heavier hydrocarbons is a necessary step in achieving acceptable natural gas specifications. This operation is often accomplished in the field.

Generally, fluids from gas wells are first treated to remove water and sand, then passed through a single separator or a sequence of separators, depending on the composition and the nature of the produced fluids. Both water and water vapor must be removed from the gas to prevent formation of hydrates (solid snow-like compounds of water and methane). Hydrates form as the result of the cooling which accompanies gas expansion and can plug wellhead valves, metering equipment, and pipelines. If formation of hydrates is a problem in a particular field, the produced fluids may be heated at the wellheads prior to flow into any gas processing equipment to deter hydrate formation before treatment.

Normally, the stream produced from a gas reservoir is separated in a single stage by passing it through a free water knockout separator to remove water and sand and then through a low-pressure separator to split the gas and condensate streams. The separation of associated gas and condensates may also be done in several stages to increase the recovery of liquid hydrocarbons. In the three-stage separation process shown in Figure 7-2, the first stage (a high-pressure separator) separates the liquid hydrocarbons from the gas by expanding the stream of well fluids. Liquid from the first stage separator is partially vaporized in the second stage (an intermediate-pressure separator) and additional gas is recovered. The remaining liquid then passes to the third stage (a low-pressure separator) for additional vaporization and gas removal. The liquid remaining after the third separation stage is transferred to storage. Three-stage separation is frequently hard to justify economically and is not as commonly used for gas wells as two-stage separation.

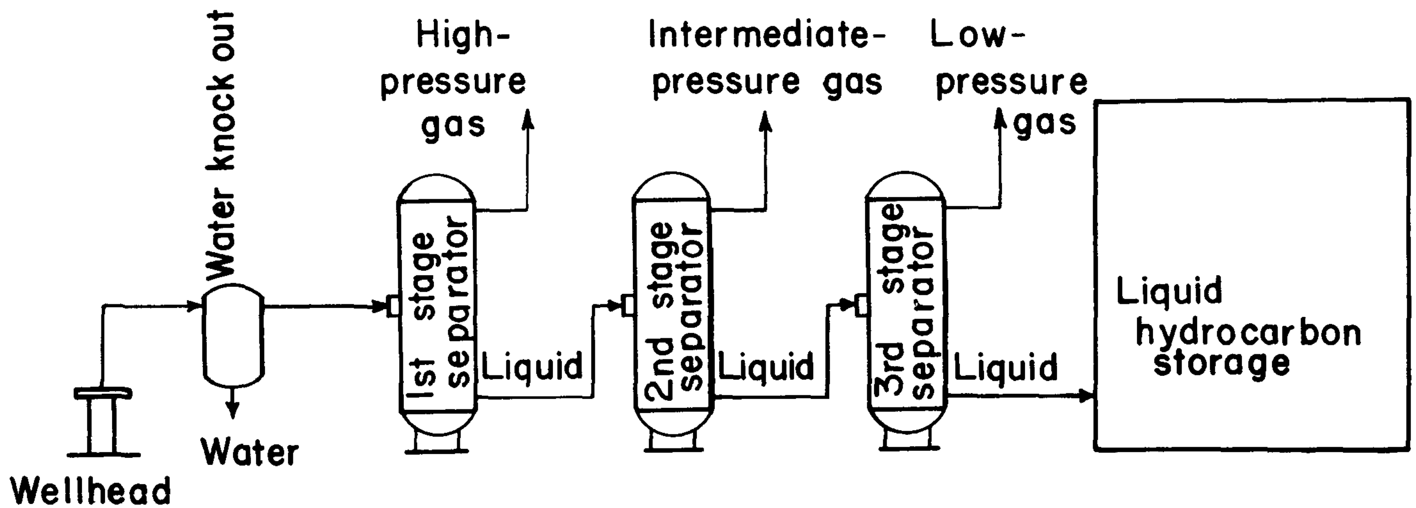

Figure 7-2. Three-Stage Wellhead Separation Unit.

Source: Adapted from Handbook of Natural Gas Engineering, by D. L. Katz et al. Copyright 1959. Used with permission of McGraw-Hill Book Company.

7.4.1.3.b Compression

Since pressures are normally high in the early production life of a gas reservoir, compression to transmit the gas through the gathering system and into the high-pressure transmission line may be needed only in later reservoir stages. In oil-gas reservoirs, however, compression is required throughout the life of the reservoirs to repressure gases that have been processed through low-pressure separators. Thus, depending on the type and stage of the reservoir, a range of compressor facilities from individual wellhead compressors to a central compressor station may be required. Individual wellhead compressors are flexible, whereas a central compressor station is economical.

7.4.1.3.c Natural Gas Plants

The partially dehydrated, raw natural gas is sent to a gas processing plant which is usually located near the field. Here the field gas is processed to meet sales specifications of utility gas distributors and transmission companies. Some typical specifications are as follows:[1]

(1) A hydrogen sulfide content of less than 0.25 grains per 100 cubic feet (about 4 ppm) and a total sulfur content of less than 3 grains per 100 cubic feet are usually required.

(2) Water and hydrocarbon dew point temperatures may range from as high as 50°F in the south to as low as 0°F in cold areas.

[1]Chilingar, George V. and Carrol M. Beeson. Surface Operations in Petroleum Production. New York: American Elsevier, 1969.

(3) Air content is usually limited to 1 to 5% by volume.

(4) Carbon dioxide is usually limited to 1 to 5% by volume.

(5) Gross heating value range is specified. A minimum might be 1000 Btu per standard cubic foot. Often gas is sold on a Btu basis with a penalty or credit for each 50 Btu per cubic foot change in heating value above or below some base value.

The processing plant has three distinct sections: (1) acid gas removal usually followed by a Claus sulfur recovery plant; (2) gas dehydration; and (3) heavy hydrocarbon separation. A typical arrangement of these processes is shown in Figure 7-3. The following sections describe more fully these gas plant operations.

Acid Gas Removal

Over thirty methods are available for the removal of acid gas constituents, carbon dioxide, and hydrogen sulfide. Methods developed range from the simple water-wash techniques to the molecular sieve removal methods. Most acid gas removal procedures used in gas plants are characterized by the processes listed in Table 7-7.

A frequently used method for separation of acid gas is by absorption with an amine solution. The basic flow is shown in Figure 7-4. Other common treating absorbents are aqueous solutions of the ethanol amines or alkali carbonates. In these

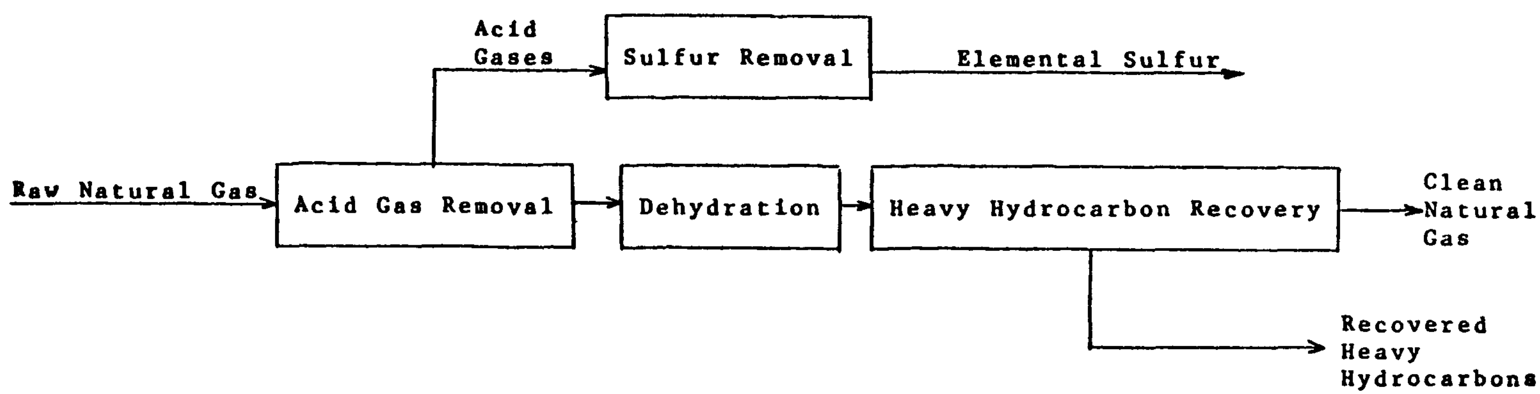

Figure 7-3. Natural Gas Processing Plant.

TABLE 7-7. AVAILABLE GAS TREATING PROCESSES[1,2]

Chemical Solvents	
	Amines - Monoethanolamine, diethanolamine, trietholamine, diglycolamine, diisopropylamine
	Activated hot potassium carbonate - Benfield, Catacarb, Lurgi, Vetrocoke
	Others - Alkazid, ammonia, copper liquor, Scott, Stretford, tripotassium phosphate
	Lesser Known - Ferrox, Konox, Manchester, Seaboard, Sulfox, Thylox, sodium phenolate
Physical Solvents	
	Fluor solvent, Purisol, Rectisol, Selexol, Sulfinol, water
Solid Bed	
	Activated carbon, iron oxide, molecular sieves, zinc oxide
Other	
	Distillation

[1] Tennyson, R.N. and Schaff, R.P., "Guidelines can help choose proper process for gas-treating plants" Oil and Gas Journal 75 (2): p 79.

[2] Only a partial list. New technologies are being developed at all times.

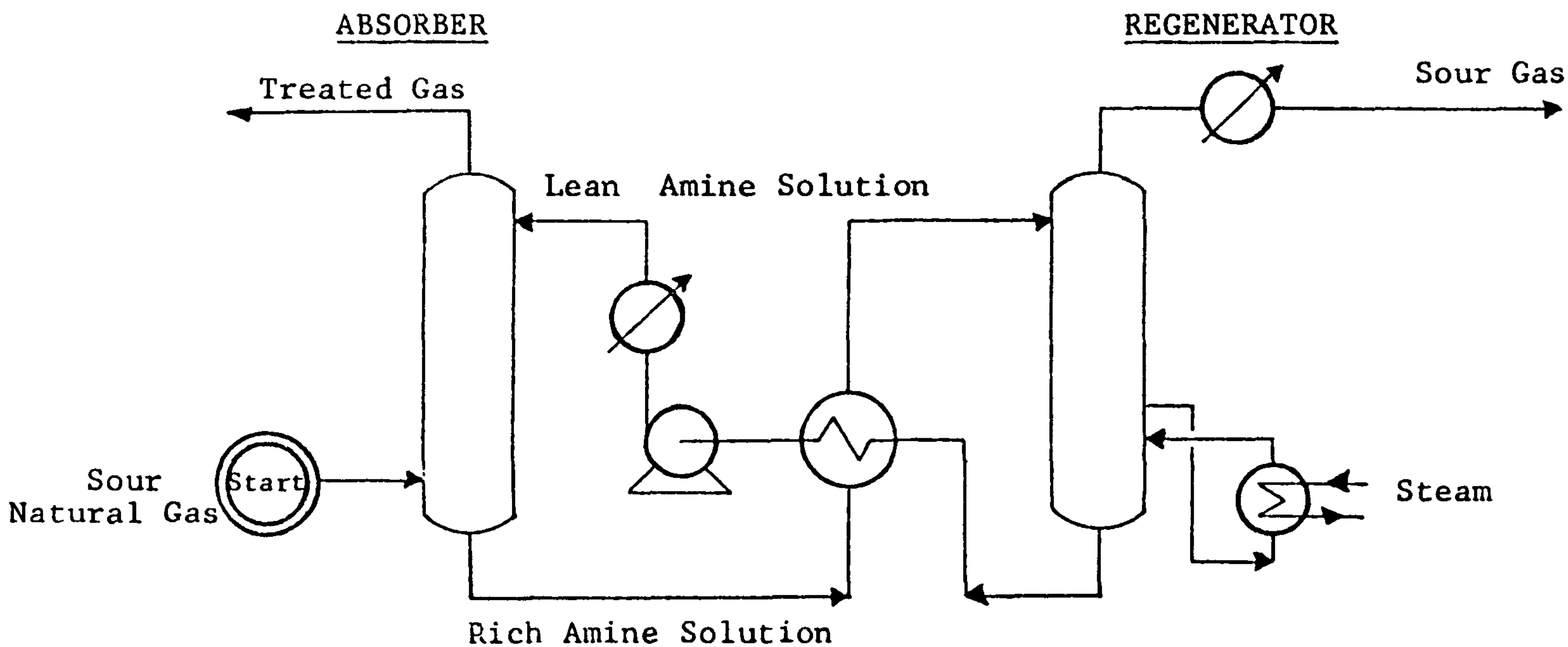

Figure 7-4. Typical Amine Treating Unit.

processes the sour natural gas is passed countercurrent to a stream of the absorbent solution in a packed or tray tower. The H_2S and CO_2 are absorbed by the solution, sweetening the gas. After leaving the absorber, the rich solution enters a regenerator where the acid gases are stripped from the solution usually by heating, but also by pressure reduction in flash vessels, or by an inert gas stripping. The regenerated solution is then pumped back to the absorber where a new cycle begins. The H_2S rich stream is usually routed to a Claus unit.

Molecular sieves are dry bed absorbers. This technology has been receiving increasing attention in the gas industry. Advantages of molecular sieves include simplified operation, reliability, and a wide range of cleanup capabilities. The molecular sieve can be used for removal of all polar contaminants present in the gas, including water vapor, sulfur- and oxygen-bearing compounds.

Sulfur Recovery Plant

In a sulfur recovery plant the H_2S removed in the acid gas removal unit is normally converted into more disposable by-products such as elemental sulfur. The most commonly used process is the Claus process shown in Figure 7-5.

In the reaction furnace, one third of the H_2S is combusted with a substoichiometric air supply to form SO_2.[1] Some sulfur is formed here and removed, while the rest of the gases pass to a series of two or three catalytic converters. In these converters unreacted H_2S combines with the SO_2 formed in the reaction furnace, producing elemental sulfur which is then

[1]Petroleum Extension Service, University of Texas. Plant Processing of Natural Gas. Austin, Texas: University of Texas. 1974.

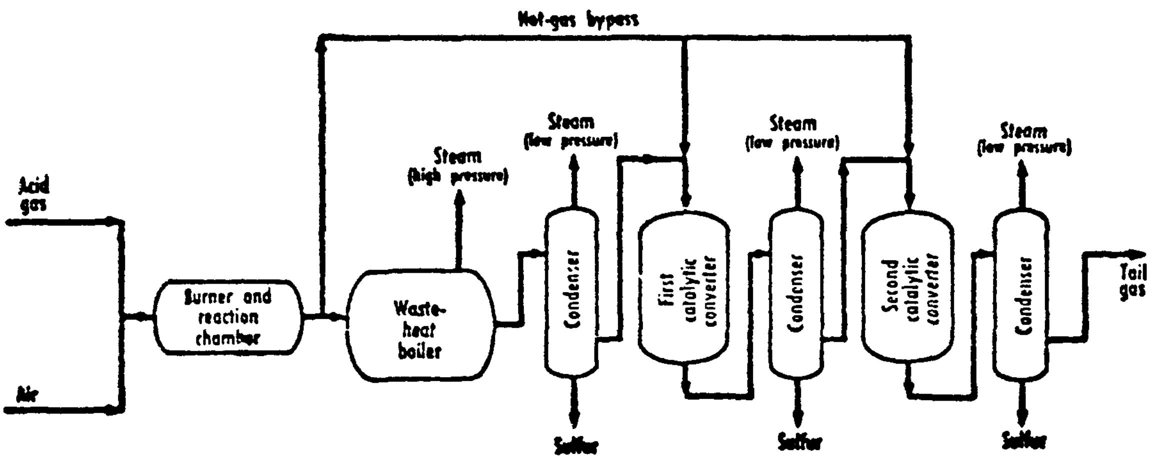

Figure 7-5. Claus Sulfur Recovery Unit.

removed by condensation from the process. Efficiencies for the unit range from 80 to 98 weight percent sulfur recovery. An overall control efficiency of 96.0 percent may be achieved with a three-stage Claus unit.[1] Efficiencies attainable are dependent on the H_2S concentration in the feed, the quality of the catalyst used, and the number of catalytic stages.

Dehydration

Water is the most common impurity in natural gas. Its removal is accomplished by dehydration with a dry desiccant or glycol solution. Desiccants commonly used are activated alumina, silica gel, and molecular sieves. Figure 7-6 shows a typical two-bed solid adsorbent treater used for dehydration. While one desiccant bed is removing water from process gas, the other is being regenerated by heat and then cooled. Frequently a three-bed system is installed. One unit is adsorbing, one is being heated or regenerated, and the third is being cooled.

Another gas dehydrating method involves contacting the wet gas with hygroscopic substances such as diethylene glycol (DEG) and triethylene glycol (TEG). These chemicals are efficient drying media, chemically stable and readily available at a moderate cost.

A typical glycol dehydration plant is presented in Figure 7-7. Water vapor is continuously absorbed from the wet gas stream by countercurrent contact with a glycol solution. The dried gas passes out the top of the column. Wet glycol passes to a regenerator section where the glycol is dehydrated by air stripping and sent back to the absorber.

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[1]Thoem, T., and J. Dale. "The Effect of the Clean Air Act Amendments on the Field Processing Units." Twenty-Eighth Annual Gas Conditioning Conference, Norman, Oklahoma: March 7, 1978.

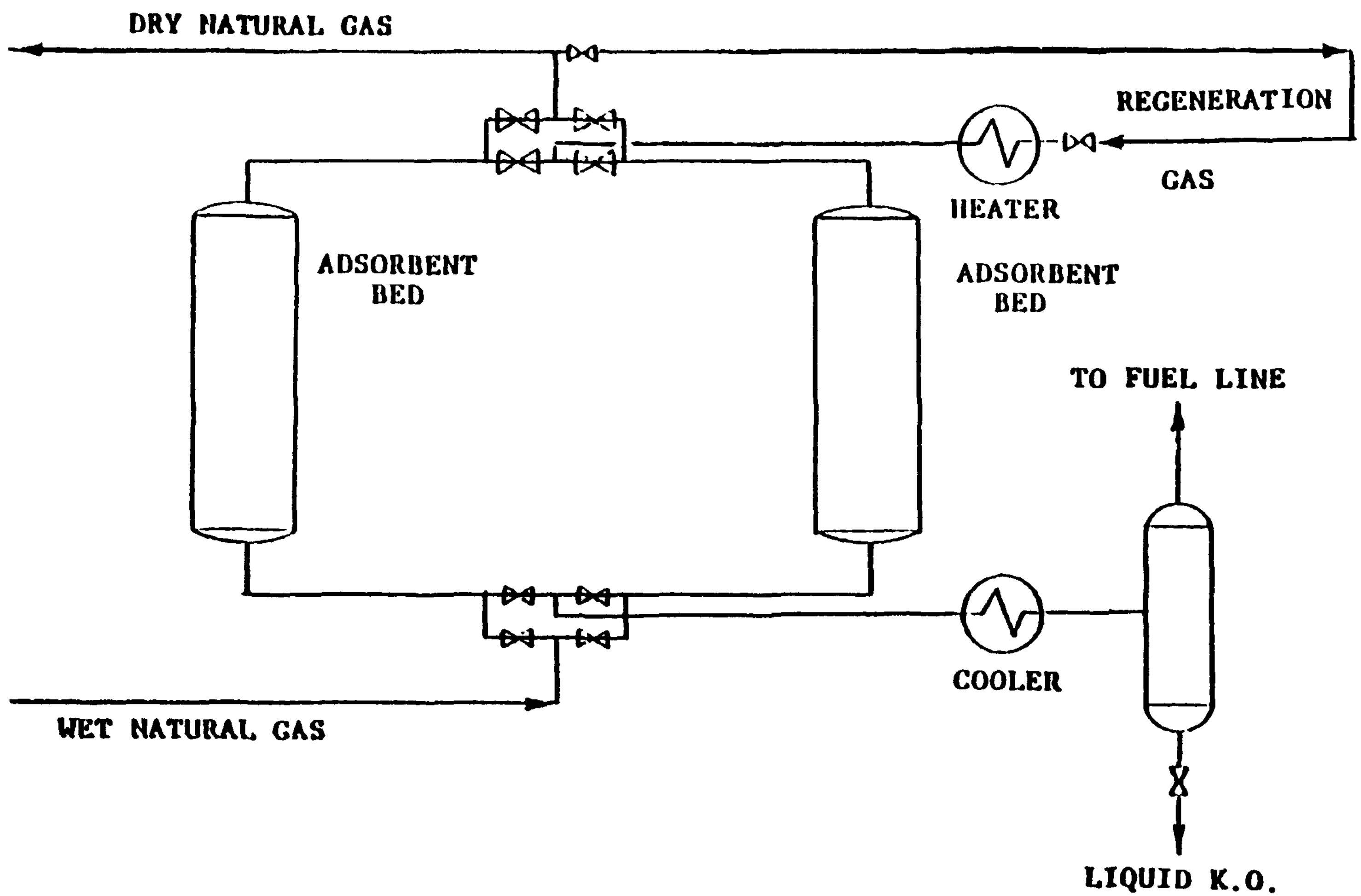

Figure 7-6. Two Bed Solid Adsorbent Treater.

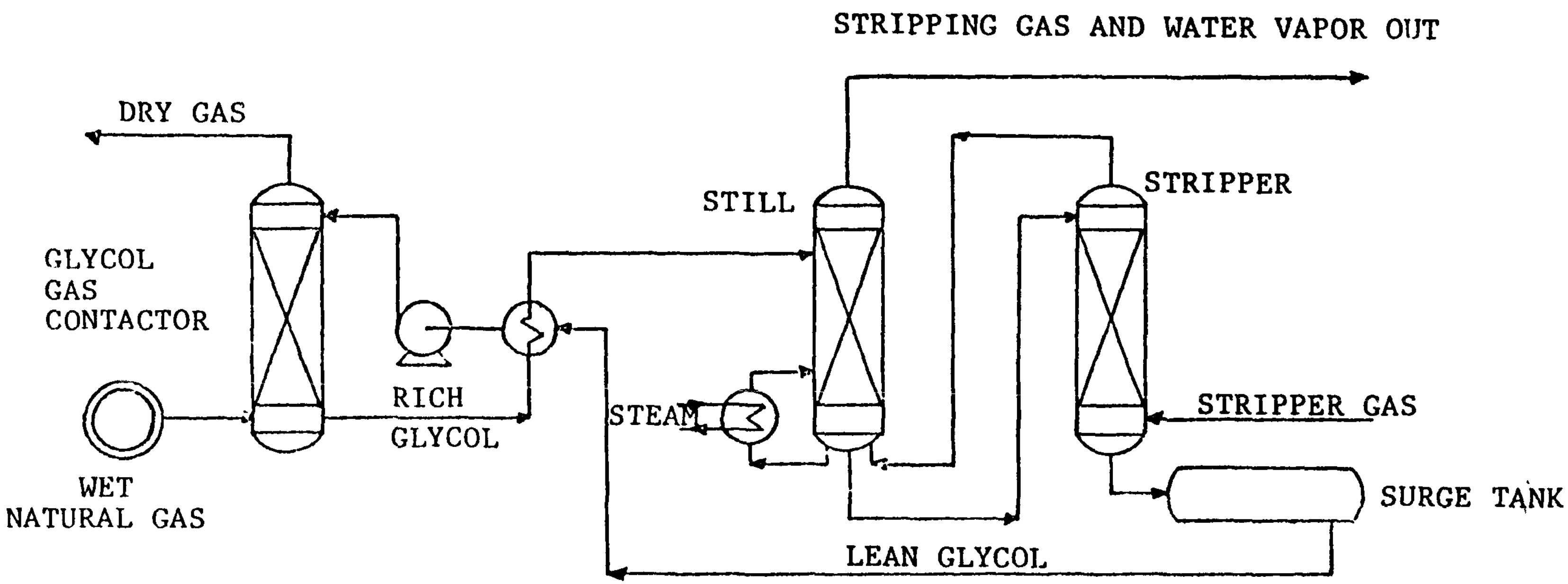

Figure 7-7. Typical Glycol Dehydration Unit.

The gas stream may also be dried by glycol injection.[1] Lean glycol is injected upstream of a gas chiller. The glycol mixes with the condensed water and keeps it from freezing. The stream enters a glycol separator in which the dry gas passes overhead and the glycol-water mixture leaves from the bottom of the vessel to be regenerated. This process further reduces the danger of hydrate formation, and enables the gas to meet the minimum water specification for sales.

Heavy Hydrocarbon Stripping

Several processes are currently used in the United States to achieve heavy hydrocarbon separation from the natural gas. These processes involve various combinations of absorption, refrigeration, compression, adsorption, fractionation, cryogenic separation, and turboexpansion. With the exception of the fractionation process, heavy hydrocarbon stripping processes are usually identified by the method used to separate ethane and heavier hydrocarbons from the raw natural gas feed. Brief descriptions of commonly used separation processes are given in this section. Included are absorption, refrigerated absorption, refrigeration, compression, and adsorption.[2]

In an absorption process the wet field gas is contacted with an absorber oil in a packed or bubble tray column. Propane and heavier hydrocarbons are absorbed by the oil while most of the ethane and methane pass through the absorber. The enriched

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[1] Petroleum Extension Service, University of Texas. Plant Processing of Natural Gas. Austin, Texas: University of Texas. 1974.

[2] Process Research, Inc., Industrial Planning and Research. Screening Report, Crude Oil and Natural Gas Production Processes. Final Report. Cincinnati, Ohio: Processes Research, Inc., 1972.

absorber oil is routed to a stripper where the propane and other hydrocarbons are separated from the absorption oil. The gas stream of propane and heavier hydrocarbons goes to a stabilizer tower where any methane and ethane are removed overhead and recycled. The bottoms product is usually routed to a series of distillation columns which separate the propane, butane, and natural gasoline for sales.

The natural gas feed to a refrigerated absorption process must be dehydrated to a -40°F dew point. An absorption oil cooled to -40°F or cooler removes all hydrocarbons heavier than methane from the natural gas. The heavier products are usually separated by distillation and sold separately.

In the refrigeration process, molecular sieve beds are used to remove as much water as possible. The dry gas is cooled to -35°F (-37°C) and then to -135°F (-93°C) with liquid hydrocarbons being condensed in each stage. The condensed liquids are then separated by distillation; and the gas, essentially methane, is ready for transmission.

A compression process uses two stages of compression, each followed by cooling and gas-liquid separation, to produce a "wet" natural gas product (still containing some heavy hydrocarbons) and natural gasoline. Less than 3% of the gas processing plants in the United States are using compression only for gas separation.

The adsorption system usually consists of two or three activated carbon beds which alternatively adsorb all hydrocarbons except methane. The regeneration is effected by steam which removes the adsorbed hydrocarbons as vapor. These are condensed, separated from the water, and usually distilled into separate products. Approximately 12 percent of the existing natural gas plants in the United States use an adsorptive process.

7.4.2 Input Requirements

Input requirements have been estimated for a 250 MM scfd natural gas production facility. The site of the gas field is assumed to be Rio Blanco county in western Colorado. The input requirements have been calculated for some production facilities, gathering facilities, and a natural gas plant. Inputs examined include manpower, materials and equipment, economics, water, land, and ancillary energy. The following discussions outline and quantify the above input requirements.

7.4.2.1 Manpower Requirements

The construction of a 250 MM scfd gas production collection, and processing facility is scheduled to take five years. The required manpower for this construction has been estimated by Bechtel[1] and is shown in Table 7-8. This data is based on the construction of 83 producing wells each capable of supplying 3 MM scfd of natural gas and the construction of 66 dry holes. Bechtel assumes that 8 out of every 18 wells will be unsuccessful. These figures also include the manpower required to design and construct a natural gas plant to prepare the gas for transmission.

Estimates for the number of men required to operate the 83 wells and natural gas plant have also been made.[2] These are shown in Table 7-9.

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[1]Carasso, M., et. al. The Energy Supply Model, computer tape. San Francisco, California: Bechtel Corporation, 1975.

[2]Ibid.

TABLE 7-8. SCHEDULE OF MANPOWER RESOURCES (MAN-YEARS) REQUIRED FOR CONSTRUCTION OF ONSHORE GAS PRODUCTION FACILITIES TO PRODUCE 250 MMscfd NATURAL GAS

Skill	Number Required				
	Year 1	Year 2	Year 3	Year 4	Year 5
Civil Engineers	0	1	5	10	6
Electrical Engineers	0	1	5	10	6
Mechanical Engineers	0	2	10	19	12
Geological Engineers	1	9	38	78	48
Petroleum Engineers	1	9	38	78	48
Total Engineers	1	21	95	195	119
Total Designers & Draftsmen	0	6	29	58	36
Total Supervisors & Managers	0	6	29	58	36
Total Technical	2	34	153	311	191
Total Non-Tech (Non-Manual)	0	5	25	56	43
Pipefitters	0	7	37	89	84
Pipefitter/Welders	0	6	29	71	67
Electricians	0	1	7	18	17
Operating Engineers	1	20	103	248	234
Other Major Skills	3	59	308	744	702
Total Major Skills	5	92	485	1168	1103
Other Craftsmen	0	6	29	71	67
Total Craftsmen	5	98	514	1239	1170
Total Teamsters & Laborers	0	7	37	89	84
GRAND TOTAL	7	143	729	1695	1488

Source: Carasso, M., et.al. The Energy Supply Model, computer tape. San Francisco, California: Bechtel Corporation, 1975.

TABLE 7-9. MANPOWER RESOURCES (MAN-YEARS) REQUIRED FOR OPERATION AND MAINTENANCE OF A 250 MMscfd ONSHORE GAS PRODUCTION FACILITY

Skill	Number Required
Chemical Engineers	2
Civil Engineers	9
Electrical Engineers	2
Mechanical Engineers	9
Geological Engineers	76
Petroleum Engineers	76
Total Engineers	174
Total Designers & Draftsmen	54
Total Supervisors & Managers	36
Total Other Technical	0
Total Technical	264
Total Non-Tech (Non-Manual)	52
Pipefitters	19
Pipefitter/Welders	16
Electricians	3
Operators	19
Other Major Skills	6
Total Major Skills	63
Other Craftsmen	348
Total Craftsmen	411
Total Teamsters & Laborers	63
GRAND TOTAL	790

Source: Carasso, M., et.al. The Energy Supply Model, computer tape. San Francisco, California: Bechtel Corporation, 1975.

7.4.2.2 Materials and Equipment

Bechtel has also estimated the total materials required for construction of a gathering network and a natural gas plant large enough to produce 250 MM scfd. These estimates are shown in Table 7-10.

7.4.2.3 Economics

Bechtel Corporation estimates a total capital requirement of $400 million (3rd quarter, 1974 dollars) for the drilling and development of the gas wells, construction of gathering facilities, and construction and operation of a 250 MM scfd gas processing plant.[1] This includes a large number of contingency items. Manpower for conceptual planning and construction costs for equipment and materials used in development are included in the total cost. The total cost also includes $25 million for gas well drilling expenses previously listed in Section 7.3.2.3.

The uncertainty of the resource data estimates vary widely. Some are classified as accurate; other estimates are only "rough approximations."[2] The cost data should be used for estimation purposes only.

7.4.2.4 Water Requirements

Water will be used to cool the compressed gases and process streams much as in any other hydrocarbon process industry. The major use will be for makeup water for an evaporative cooling tower. Other water requirements, will be minor. Total water

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[1]Carasso, M., et. al. The Energy Supply Model, computer tape. San Francisco, California: Bechtel Corporation, 1975.

[2]Carasso, M., et. al. Energy Supply Model, Vol. I. San Francisco, California: Bechtel Corporation, 1975. p. 6-29.

TABLE 7-10. SELECTED MAJOR MATERIALS AND EQUIPMENT REQUIRED FOR CONSTRUCTION OF ONSHORE GAS PRODUCTION REQUIRED TO SUPPLY 250 MMscfd OF PIPELINE QUALITY GAS

Resources	Quantity
Refined Products (Tons)	128,650
Cement (Tons)	75,000
Ready Mixed Concrete (Tons)	4,150
Pipe & Tubing (Less than 24 inch) (Tons)	15,000
Oil Country Tubular Goods (Tons)	103,750
Reinforcing Bars (Tons)	830
Heat Exchangers (1000 sq. ft. surface)	83

Source: Carasso, M., et. al. The Energy Supply Model, computer tape. San Francisco, California: Bechtel Corporation, 1975.

requirements have been estimated and converted to a plant size capable of producing 250 MMscfd of natural gas. Water requirements for this size plant are estimated to be 380 acre-ft/year.

7.4.2.5 Land Requirements

Approximately 850 acres are required for a gas field and processing plant with a capacity of 250 MMscfd. Assumptions used for this data were a total of seven acres per well for cleared area around producing wells, pipeline right-of-ways, and roads and 250 acres for plant site.[1] Many land owners consider the land usage a significant land improvement allowing better access for farming and grazing. In wilderness areas, wildlife frequently use these roads and right-of-ways as better access to forage.

7.4.2.6 Ancillary Energy

Energy requirements for producing, gathering, maintaining deliverability, and processing natural gas are net almost exclusively by using a portion of the product gas as fuel. An estimate of the fuel required expressed in terms of total gas handled is 3%.[2] In areas where electric power is readily available and cheap, purchased electricity may be attractive.

7.4.3 Outputs

Outputs potentially associated with a natural gas plant include air emissions, water effluents, solid wastes, noise pollution, and occupational health and safety aspects. Each of these will be examined individually.

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[1] Federal Power Commission: National Gas Survey, Vol. II. Washington, D.C.: Federal Power Commission, 1974. p. 73-75.

[2] Ibid.

7.4.3.1 Air Emissions

Table 7-11 contains air emission rates from the various sources within the gas field and processing plant. The emission factors were scaled to a facility processing 250 MM scfd.[1]

There are several emission sources in the gas production/process model. Fugitive hydrocarbons and combustion products result from booster compressors in the field maintaining deliverability of the natural gas to the processing plant. At the plant, air emissions result from fuel combustion in the glycol dehydration unit, acid gas removal unit, and the refrigerated absorption unit. SO_2 is emitted from Claus plants and gas flaring. Miscellaneous fugitive hydrocarbon leaks from valves, flanges, and equipment seals account for a great deal of the hydrocarbon emission.[2]

7.4.3.2 Water Effluents

No water streams leave a processing plant; thus, water pollution from such a facility is negligible. Rain or storm water runoff may pick up a small amount of liquid hydrocarbon resulting from spills, human error, or equipment failure, but not data is available on this subject.

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[1]Environmental Protection Agency. Compilation of Air Pollution Emission Factors, 2nd edition with supplements. AP-42. Research Triangle Park, North Carolina: Environmental Protection Agency. April, 1977.

[2]Cavanaugh, E.C., et. al. Atmospheric Pollution Potential from Fossil Fuel Resource Extraction, On-Site Processing, and Transportation. EPA Contract No. 68-02-1319. Austin, Texas: Radian Corporation. March, 1976.

TABLE 7-11. AIR EMISSIONS FROM 250 MM SCFD PRODUCTION/PROCESSING FACILITY (LB/DAY)

Pollutant	Gas Well Compressor	Acid Gas Removal Unit	Glycol Dehydrator	Refrigerated Absorption	Flare	Total
Particulates	-	9	4.5	31.5	5	50
SO_2	3,840	0.3	0.15	1.0	7,392	11,233
NO_x	15,600	60	29	21	31	15,741
HC	10	1.5	0.5	5	2	19
CO	-	8.5	4.0	30	5.5	47.5
Triethylene Glycol	-	-	240	-	-	240

Source: Cavanaugh, E.C., et. al. Atmospheric Pollution Potential from Fossil Fuel Resource Extraction, On-Site Processing, and Transportation. EPA Contract No. 68-02-1319. Austin, Texas: Radian Corporation, March 1976.

7.4.3.3 Solid Wastes

There are no significant solid wastes generated by the natural gas processing facility.

7.4.3.4 Noise Pollution

Several pieces of equipment used in gathering systems and processing plants are potential sources of high noise levels. These include control valves, engines, compressors, and turbines. However, noise control is required in plants to meet Occupational Safety and Health (OSHA) standards. Normally the local area around a plant or production facility has very few noise pollution problems. Noise suppression programs have reduced noise from gas flow through meters and regulations and also from compressors and auxiliary equipment.[1]

7.4.3.5 Occupational Health and Safety

The information for this section is included in Section 7.3.3.5.

7.4.3.6 Odor

A producing well usually has no associated odor problems because the odor-causing compounds (H_2S, mercaptans, and others) are fairly dilute and any gas leak will be easily dissipated below the odor threshold for these impurities in air. At the plant where more concentrated streams of these compounds are found, odor does present a pollution problem. Good housekeeping practice and preventive maintenance are the best safeguards against odor.

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[1]Federal Power Commission. Natural Gas Survey, Vol. II. Washington, D.C.: Federal Power Commission. 1974. p. 73-75.

7.4.4 Production Social Controls

Some of the social controls for oil production are applicable to natural gas production and will be noted below in the specific sections; where controls are applicable only to gas production, they will be described in detail. As with oil controls, some federal lands (public or acquired) and others (e.g., FPC rate regulation)[1] apply to gas production irrespective of place of production. Likewise some state laws apply to some production and not to other production.

7.4.4.1 Federal Laws and Regulations

7.4.4.1.a Conservation of the Public Domain

Conservation laws applicable to gas production on the public domain are identical to those for oil production and are described in Section 6.4.2.1.1 of Chapter 6. However, variations may occur. For example, the federal laws were written to allow some state regulation for conservation on the public domain lands within that state; hence the state has some input into the spacing of wells which is different for oil than gas. Recent court decisions have modified this by saying - although the state may set the "conservation tone" the federal agency must give its approval of the arrangement.[2]

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[1]Although there is no doubt the rate regulation affects production and therefore deserves discussion here, certain factors make it better to discuss it in the transportation sections. One such factor, for example, is the interstate/instrastate determination, by the FPC. Such a determination, inherently a transportation question, also sets the pre-determined rate. See Section 7.5.2.1.1.

[2]E.g., Texas Oil and Gas Corp. v. Phillips Petroleum Co., 277 F. Supp. 366 (W.D. Okla. 1967), *affirmed per curiam*, 406 F. 2d1303 (10th Cir.), *cert denied*, 396 U.S. 829 (1969). See also, Sharpiro, Mickael E. "Energy Development on the Public Domain: Federal/State Cooperation and Conflict Regarding Environmental Land Use Control." Natural Resources Lawyer, Vol. 9 (No. 3, 1976), pp. 429-31.

7.4.4.1.b Air Quality - Federal

Federal air pollution laws and regulations affecting gas production are not significantly different from those affecting oil production. As noted in Chapter 6, the NSPS that have been promulgated address only petroleum refineries and liquid petroleum storage facilities.[1] NSPS are being prepared for crude oil and natural gas field processing units which will place limits on hydrogen sulfide content of any gaseous fuel burned at a field processing facility, on sulfur dioxide or total reduced sulfur emissions of sulfur recovery facilities, and on hydrocarbon emissions on petroleum storage vessels.[2] Until those NSPS are promulgated, gas production facilities are only bound by federal ambient standards as discussed in Chapter 6, or state laws and regulations as discussed in Section 7.4.4.2.b.

7.4.4.1.c Water Quality - Federal

Water effluents from gas production are either injected into underground formations or held in storage ponds. As noted in Section 6.4.2.1.3, the applicable laws have been identified in the water quality section of Chapter 2 as to surface and underground regulation. Additionally in Section 6.4.4.1.c it was noted that EPA was moving into the area under the Safe Drinking Water Act of 1974.[3] Proposed regulations have been published and will be summarized below for only the oil and gas operations subpart.[4]

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[1]See Section 6.4.4.1.b Air Pollution; also note that Petroleum Refineries are not included in these ERDS and that the storage facilities NSPS specifically exempt production or drilling facilities (40 C.F.R. 60.110(b) and 60.110 (h)).

[2]Thoem, T. and Dale, J., "The Effect of the Clean Air Act Amendments on Field Processing Units," Twenty-Eighth Annual Gas Conditioning Conference, Norman, Oklahoma: March 7, 1978.

[3]Safe Drinking Water Act of 1974, 1421, 1422, and 1450, 42 U.S.C.A. (Supp. 1976).

[4]41 Federal Register 36730 (Aug. 31, 1976).

As with the prior environmental laws (e.g., the FWPCA or CAA), those regulations under SDWA list minimums for state injection control programs and make provisions for turning the enforcement over to the state. More specifically as to oil and gas, the SDWA prohibits EPA from regulating injection (i.e., either disposal or secondary and tertiary recovery) where such regulation will interfere with oil or gas production, unless such regulation is essential to protection of drinking water sources.[1] However, EPA's proposed regulations require first that the discharger (injector) prove his oil or gas operation is interfered with before the Administrator prove his regulations are essential.[2]

Generally the proposed oil and gas regulations allow for:

(1) Existing injection wells to be controlled by existing rules for 5 years if no endangerment

(2) New injection wells to be controlled by permits

(3) Public notice and hearing on permits

(4) New well aquifers, other wells, pressures, soils, etc.

The comment period on the proposed regulations was extended until Jan. 14, 1977.[3]

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[1] Federal Register, Vol. 41 (August 31, 1976), p. 36731.

[2] *Ibid.*

[3] Federal Register, Vol. 41 (November 19. 1976), p. 50701.

7.4.4.2 State Laws and Regulations

7.4.4.2.a Conservation

State conservation laws attempting to protect the supplies of natural gas by requiring efficient production techniques have not been as strongly supported in the courts as have similar laws for oil production. Essentially the state regulation of natural gas pricing for conservation purposes has lost when brought to court and has been opposed by the broad powers given the FPC over natural gas pricing. The line of cases and authorities dispute how far the states can go to regulate natural gas production but it appears to be only as long as it does not affect price.

States can at a minimum regulate the production of natural gas from gas fields by a process called "ratable taking". In this process each producer in a common zone is required to hold his production to a percentage of the maximum possible production, based on his ownership, structure, and natural flow. (Still to be answered are the state laws on this question. It may not be of value since it only restricts the producers in an area from taking more than their share, but does not change total production from zone. In fact the law is designed to get maximum total production from the zones.)

7.4.4.2.b State Air Quality Laws

Although in Section 7.4.4.1.2 Air Quality Federal, it was states that the New Source Performance Standards (i.e., for Petroleum Refineries) were not applicable to the production technologies described, some of the states have modified the standards to make them applicable. The states are allowed to do such under the provisions of the Act.[1] Treatment of the specific air pollution problems of natural gas production has been attampted by various methods in states. Below are recorded the states' laws and regulations on natural gas flaring. Equipment used in gas recovery operations (e.g., high horsepower pumps) are regulated for air pollution no differently than other engines and such regulations can be found in Chapter 2.

Generally under their respective air pollution laws and regulations each state prohibits open burning. But each state also provides for various exemptions from those regulations. Sometimes the flaring of natural gas at production facilities is authorized, sometimes prohibited, and sometimes required. Unless noted specifically the regulations described below apply generally to any natural gas flaring whether as a by-product of oil production or of gas production. Most gas flaring occurs as a by-product of oil production.

The following table summarizes and divides the state regulations into two categories - the general and specific incineration bans. Although Montana and Colorado have a ban on the incineration of wastes, the more specific regulations detailing the limitation have varied probable controls and are recorded (Table 7-12).

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[1]See Chapter 2, Section 2.8.3.a. The reader is reminded again that all aspects of the Clean Air Act as described in Chapter 2, Section 2.8 must be complied with (e.g., ambient air standards, etc.) and that this section will only point out the specifics of each state's laws that are aimed directly at the air pollution problems caused by natural gas production.

TABLE 7-12. STATE REGULATION OF NATURAL GAS FLARING

State	General Incineration			Specific Limitation		Reference Air Quality Regulations
	Ban	Exception[a]	Required	Standard	Exception	
Arizona	x	x[b]		No. 1 Ringlemann		R9-3-303 Eff: 10-1-75
Colorado				20% Opacity	x[c]	Reg. No. 1 Eff: 4-22-76
Montana				Less than .10 grains of parti- *culates/cu. ft. gas*		Reg. 16-2.14 (1) 5-1420, *Eff*: 9-5-75
New Mexico	x	x[d]		No. 1.5 Ringlemann	x[d]	Reg. 401.A Amended 5-26-71
North Dakota	x	x[e]		No. 1 Ringlemann		R23-25-03.210 Eff: 12-15-73
South Dakota	x	x[f]	x[f]	No. 1 Ringlemann		Reg. Part 3-1 Eff: 7-10-72
Utah	x	x[g]		No. 1 Ringelmann		Reg. 2.2.2 Revised 7-9-75
Wyoming			x[h]	20% Opacity		Reg. Sec. 14a *Amended*: 1-31-75

[a] The standards for the exception vary and are recorded in footnotes.

(Continued)

TABLE 7-12. STATE REGULATION OF NATURAL GAS FLARING (Cont'd)

[b] Although Arizona bans open burning, the regulations are directed at only open outdoor fires and exempt all burning taking place where the wastes are directed through a flue (R9-3-107B, Eff: 10-1-75). But as noted in the table above the flue effluents must be less than No. 1 on the Ringelmann Chart.

[c] Colorado's regulations set the 20 percent opacity but also grants safety or smokeless flares for the combustion of waste gases only an exception from the permit requirements. In addition to the exception for flares, Colorado allows an exception from permits for natural gas-fired indirect heat exchangers used as separators and known heater treaters when used in oil and gas field operations when sweet gas is burned (Reg. No1 II E.2(j)).

[d] Allows an exception from both the incineration ban and the Ringelmann Standard for oil and gas production operations, including compressor stations, if necessary to avoid a serious hazard to safety (Reg. 301.B.2.).

[e] Prior approval of the Department of Health for an exception the open burning ban is allowed for removal of hazardous material if no other means is practical (R23-25-04), Sec. 4.203). Also approval under Sec. 4.203 exempts the source from permit requirements (R23-25-01, Sec. 1.093(1)e).

[f] Under S.D. Reg. Part 4.2.8 hydrocarbon wastes maybe burned if there is no other practical way to dispose of or recover them and if the ambient air of a community is not affected. Also under Reg. Part 4.2.9 waste hydrocarbons must be burned by using atmospheric flares.

[g] Utah Regs. authorize as permissible burning without a permit the properly operated industrial flares for the combustion of flammable gases (Reg. 2.1.3(d).

New Mexico has some very specific air quality regulations which deserve extra attention in addition to those already described. For the gas resource, the regulations listed in Section 6.4.4.2.c are also applicable where the gas is produced together with oil. The only regulations in New Mexico applicable to gas production alone are those for Natural Gas Processing Plants - Sulfur Emission Limitations.

In summary those regulations require new natural gas processing plants to comply with the following:[1]

> G. No person owning or operating a new natural gas processing plant that is governed by a sulfur emission limitation of an Air Quality Control Regulation shall permit, cause, suffer or allow gas coming off any off-gas sweetening regeneration unit or other sulfur releasing unit to be sent to a facility other than the natural gas processing plant for the purpose of sulfur recovery or disposal:
>
> 1. unless all the gas coming off the gas sweetening regeneration unit or other sulfur releasing unit is sent to the facilities other than the natural gas processing plant, except mercaptan gas, and the amount of sulfur in the off-gas stream from fuel burning equipment does not exceed the quantity of sulfur that would exist if the sulfur content of the gas used for fuel was 10 grains of sulfur per 100 standard cubic of fuel gas; or
>
> 2. unless only a portion of the gas coming off the gas sweetening regeneration unit or other sulfur releasing unit is sent to the facility other than the natural gas processing plant, and:
>
> (a) if the natural gas processing plant is a new natural gas processing plant that releases an average of five or more tons a day but less than twenty tons a day of sulfur in plant processes, sulfur emissions from the new natural gas processing plant do not exceed 10 pounds of sulfur for every 100 pounds of sulfur that are released in plant processes but not

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[1]New Mexico Air Quality Regs., #621. as reprinted in BNA, State Air Laws, pp. 72-77, May 23, 1975.

sent for sulfur recovery or disposal to another facility; or

(b) if the natural gas processing plant is a new natural gas processing plant that releases an average of twenty tons a day or greater of sulfur in plant processes, sulfur emissions from the new natural gas processing plant do not exceed 2 pounds of sulfur for every 100 pounds of sulfur in plant processes but not sent for sulfur recovery or disposal to another facility.

H. No person owning or operating a natural gas processing plant shall permit, cause, suffer or allow sulfur compounds to be emitted to the atmosphere unless the sulfur compound emission is from a stack of a sufficient physical height to prevent concentrations of sulfur compounds near ground level equal to any state or federal ambient air standard.

1. The necessary physical stack height shall be determined by the following graph. (Table 7-13).

I. No person owning or operating a new natural gas processing plant that releases an average of five or more tons a day and less than twenty tons a day of sulfur in plant processes shall permit, cause, suffer or allow sulfur emissions to the atmosphere in excess of 10 pounds of sulfur for every 100 pounds of sulfur released in plant processes.

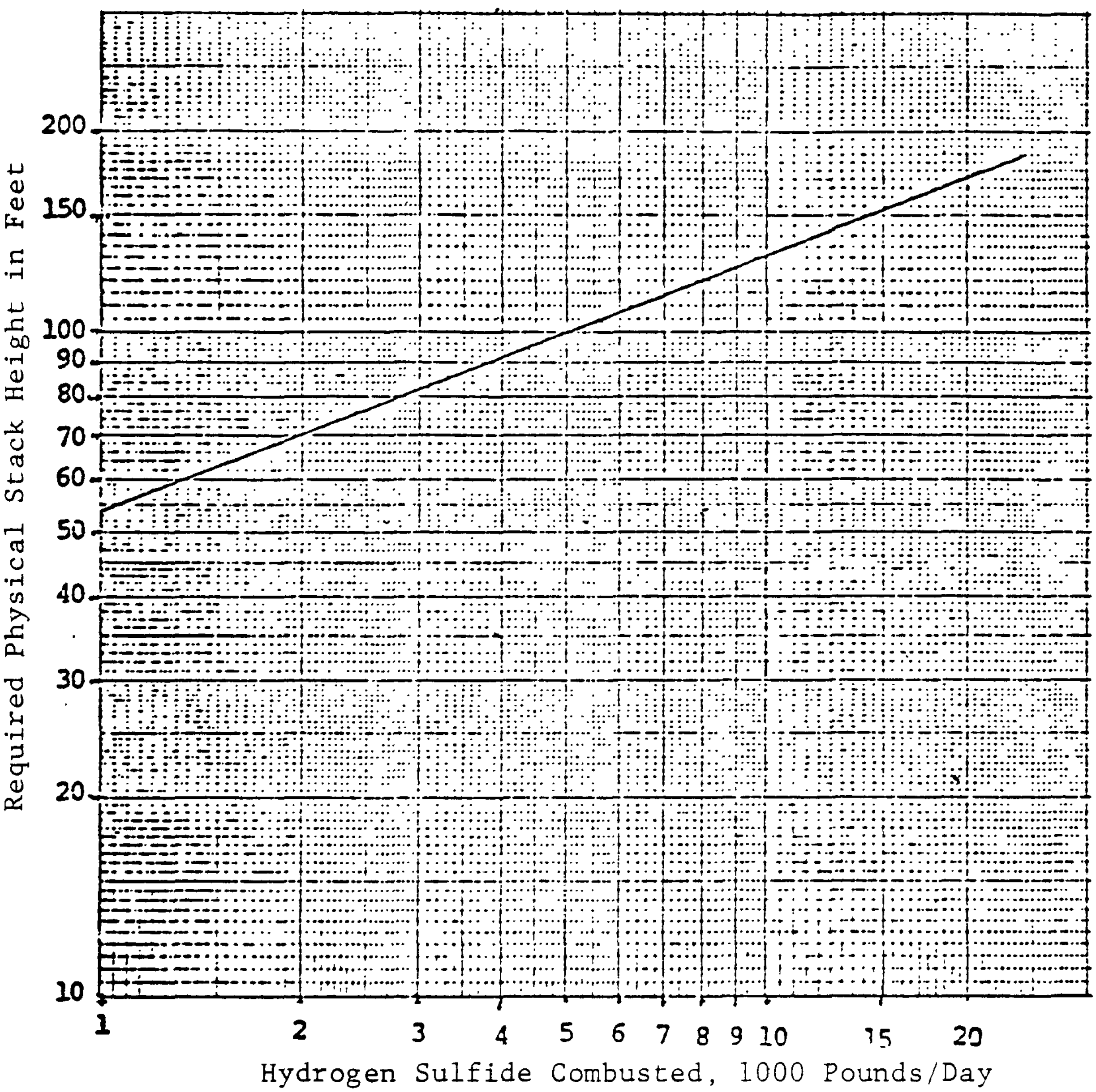
J. No person owning or operating a new natural gas processing plant that releases an average of 50 tons a day or greater of sulfur in plant processes shall permit, cause, suffer or allow sulfur emissions to the atmosphere in excess of 2 pounds of sulfur for every 100 pounds of sulfur released in plant processes.

L. To aid the department in determining compliance with this section, the owner or operator of a natural gas processing plant to which this section applies shall submit to the department quarterly reports in the months of January, April, July, and October of each year containing the following information:

1. the sulfur content of feedstock entering the natural gas processing plant determined no less frequently than three times per week and no more frequently than once every twenty-four hours;

2. the sulfur content of all fuel burned in the plant and the amount of each type of fuel burned determined no less frequently than quarterly;

TABLE 7-13. REQUIRED STACK HEIGHT FOR GAS PROCESSING PLANTS IN NEW MEXICO



Source: New Mexico Air Quality Regulations #621. As reprinted in BNA, State Air Laws, p. 75, May 23, 1975.

3. the sulfur content of the products produced by the natural gas processing plant determined no less frequently than weekly;

4. the sulfur content of the inlet and outlet gas stream or streams of the sulfur recovery plant determined no less frequently than quarterly; and

5. the weight of the recovered sulfur determined no less frequently than weekly.

If it appears necessary, the department may require reports on a more frequent basis, but no more frequently than monthly. The department may, upon the request of the owner or operator of a natural gas processing plant, alter the sampling periods specified in this subsection.

The above is not a complete discussion of controls over gas production since a large portion of the regulations are written for the production of oil and gas together. Therefore a production facility producing both oil and gas would have to comply with air quality regulations associated with both.

7.4.4.2.c State Water Quality Laws

Water effluents are controlled by both federal and state laws and as described in Section 7.4.4.1.c, new injection regulations are being written to modify and expand the present state laws. At this time the present state laws are not described (again see Section 7.4.4.1.c). The federal minimum regulations took effect in December 1977. It is possible that because the initial regulations are aimed selectively at the states having greater injection problems perhaps not all of the eight western states will initially be brought under the new underground injection program.[1]

[1]Determination of which states have not yet been made, but the criteria include reliance on underground sources for drinking water and magnitude of the injection operations in the state. 41 Fed. Reg. 36731 (Aug. 31, 1976).

7.4.4.2.d Miscellaneous State Laws Affecting Production

There are numerous state laws affecting oil and gas operations (Table 7-14). The laws have various purposes but generally reflect a states' concern over protecting the public interest (e.g., in preventing pollution of a drinking water source) or in protection of the correlative rights of other resource producers (e.g., regulating the oil and gas ratio to prevent rapid dissipation of reservoir pressure). The states which have statutory duties are listed in Table 7-14.

7.5 TRANSPORTATION OF NATURAL GAS

7.5.1 Technologies

Transportation of natural gas throughout the nation's gas system, from field to market, is accomplished primarily by pipelines. Pipelines collect the gas from individual wells and deliver it to a processing plant or treating facility. This is called the field and gathering system, and was discussed in Section 7.4 with the production and processing technologies. After processing, the salable natural gas is compressed and moved in relatively large lines in a network which covers the entire country. Compressors placed along the length of the pipelines provide the driving force to keep the gas moving. Smaller pipeline branches provide the means of delivery to the ultimate consumer whether industries, business, or residences.

Total natural gas pipeline mileage in the United States at the end of 1975 was 980,000 miles with approximately two-thirds of the mileage being used as the smaller distribution mains to consumers. Total mileage in the eight mountain states is

TABLE 7-14. OIL AND GAS STATUTORY DUTIES

State	Plugging			Casing Required	Regulations Promulgated	
	Required	Required	Special Requirements		For Oil/Gas Ratio	For Secondary Recovery
Arizona	x			x	x	x
Colorado	x	x	x[a]	x	x	x[b]
Montana	x			x	x	x
North Dakota	x	x		x	x	x
New Mexico	x			x	x	x
South Dakota	x			x	x	x
Utah	x			x		
Wyoming	x			x	x	x[b]

[a] Colorado has special additional statutory requirements for plugging wells in a coal field.

[b] This state has regulations alone on secondary recovery as opposed to the others listed which also have statutes on the subject.

Source: Summers, W.L. Summers' Oil and Gas, 2nd ed., Vol 1, 1976 supplement. Kansas City, Mo.: Vernon Law Book Co., 1954, Sections 72, 73, and 76.

approximately 81,000 miles,[1] about eight percent of the U.S. mileage.

Transmission lines are usually 24, 30, 36, and 42-inch diameter systems with the 30-inch being the most popular. Maintenance of the 750 psig pressure, the usual operating pressure of a long distance line, is performed by compression stations spaced strategically along the length of the line. Average spacing for compressor station of 50 to 75 miles.[2] Compressors are driven by gas engines, gas turbines, and electric power. The size of compressor stations varies widely, but most of the new construction in stations ranges from 2,500 to 10,000 horsepower.[3]

Energy consumption for a compressor station system averages 4.1 percent of the throughput of the stations.[4] Most of the fuel is natural gas, although more and more electrically powered stations are being installed.

7.5.2 Social Controls

Pipeline social controls for gas are the same as those oil concerning such subjects as rights-of-way and are discussed in Chapter 6. There are variations though between oil and gas when

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[1] American Gas Association, Department of Statistics. Gas Facts, 1975 Data. Arlington, Virginia: American Gas Association. 1976. p. 29.

[2] Cavanaugh, E.C., et. al. Atmospheric Pollution Potential from Fossil Fuel Resource Extraction, On-Site Processing, and Transportation. EPA Contract No. 68-02-1319. Austin, Texas: Radian Corporation. March, 1976.

[3] Congram, G.E. "U.S. Pipeline Investment Expands by $4.26 Billion," Oil and Gas Journal, 75 (34), p. 78.

[4] Battelle-Columbus and Pacific Northwest Labs. Environmental Considerations in Future Energy Growth. Columbus, Ohio: Battelle-Columbus and Pacific Northwest Labs. 1973.

describing the controls over rate setting and safety and those will be described below.

7.5.2.1 Federal Laws and Regulations

7.5.2.1.a Federal Power Commission (FPC)

Natural gas pipelines operating in interstate commerce are required to obtain a license from the Federal Power Commission.[1] Naturally the right-of-way must be obtained from the proper authority, for example from the Secretary of Interior for public domain lands. A complete discussion of right-of-way procedures is located in Section 2.14.

A primary function of the FPC for natural gas regulation is the interstate/intrastate price rate determination. The FPC derives authority for such action from the Natural Gas Act, wherein the FPC was given the power to regulate the wellhead price of natural gas dedicated to interstate commerce to protect consumers.[2] Other functions of the FPC are regulating the profits and prices of natural gas pipeline companies and coordinating planning among firms engaged in interstate electric power transmission.[3]

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[1]Natural Gas Act of 1938, § 7, 15 U.S.C.A. § 717 (f) (19). A Corps of Engineers permit is also required if the pipeline crosses navigable waters - permits are discussed in Section ________ .

[2]Dolgin and Guilbert, Federal Environmental Law, West, St. Paul: 1974 p. 942. See Phillips Petroleum Co. v. Wisconsin, 347 U.S. 672 (1954) wherein the U.S. Supreme Court held such authority for the FPC existed.

[3]Breyer, Stephen G., and Mactvoy, Paul W. Energy Regulation by Federal Power Commission, Brookings Institute, Washington, 1974: p. 4.

The regulation of a natural gas pipeline company by the FPC begins with the issuance of a certificate of public convenience and necessity to the company allowing it to provide service into a new market area. The FPC must determine the sufficiency of the demand for the proposed service and the ability of the company to provide the service. If the certificate is granted, then prices to be charged are reviewed and differences of opinion between the company and the FPC pipeline division are settled by a hearing examiner. Pricing appeals may be taken to the FPC itself and then to the federal courts.[1]

Natural gas production regulation started with the U.S. Supreme Court ruling in 1954 that the FPC had authority to set prices charged by producers on sales to interstate pipeline.[2] Initial attempts at rate setting were frustrated when cost of service determinations varied widely; subsequently the FPC adopted an area-wide average cost basis for price setting and was upheld in the Permian Basin Area Cases.[3] Under this system the regulation is in the form of a ceiling price for an area of production. Unfortunately the varied situations (i.e., higher costs for some exploration) and long time delay in area-wide price hearings has resulted in a continued and growing use of cerfiticates issued to individual producers.[4] Again, it should be noted that intrastate gas sales are exempt from FPC regulation but that such a determination will only come into play where the natural gas consumer would be a utility buying within a state hence possibly buying at unregulated prices.

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[1]Breyer, Stephen G., and Mactvoy, Paul W. Energy Regulation by Federal Power Commission, Brookings Institute, Washington, 1974: p. 5.

[2]Phillips Petroleum Company v. Wisconsin, 347 &.S. 672(1954).

[3]390 U.S. 747 (1968).

[4]Breyer, *op.cit.* p. 9.

7.5.2.1.b Department of Transportation

Under the provisions of the Natural Gas Pipeline Safety Act of 1968,[1] natural gas pipelines must comply with the regulations promulgated by the Department of Transportation's Office of Pipeline Safety (OPS).[2]

[1]Natural Gas Pipeline Safety Act of 1968, 82 Stat. 720 42. U.S.C.A. 1671 *et seq*. (1970).

[2]Dolgin and Guilbert, *Federal Environmental Law*, West, St. Paul: 1974 p. 972.

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