MINING FOR PETROLEUM: FEASIBILITY STUDY

PREPARED FOR

UNITED STATES DEPARTMENT OF THE INTERIOR
BUREAU OF MINES

BY

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FINAL REPORT

ON

CONTRACT NO. JO275002
"TECHNICAL AND ECONOMIC FEASIBILITY STUDY
OF OIL MINING"

JULY 1978

50272-101

REPORT DOCUMENTATION PAGE	1. REPORT NO. BuMines OFR 56-79	2.	3. Recipient's Accession No. PB297133

4. Title and Subtitle
Mining for Petroleum: Feasibility Study

5. Report Date
July 1, 1978

6.

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8. Performing Organization Rept. No.

9. Performing Organization Name and Address
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10. Project/Task/Work Unit No.

11. Contract(C) or Grant(G) No.
(C) J0275002
(G)

12. Sponsoring Organization Name and Address
Office of the Assistant Director--Mining
Bureau of Mines
U.S. Department of the Interior
Washington, D.C. 20241

13. Type of Report & Period Covered
Contract research,
March 1977--July 1978

14.

15. Supplementary Notes
Approved by the Director of the Bureau of Mines for placement on open file, June 8, 1979.

16. Abstract (Limit: 200 words)
Two potential modified in situ methods are described for recovering the 68 pct "unrecoverable" hydrocarbons in oil reservoirs. For the 300 billion barrels of conventional light crude a drip drainage system is suggested by mining underneath a reservoir and producing from below by controlled gravity flow. For the 200 billion barrels of heavy or viscous oil and tar sands deposits, a flip flop process is described using surface flooding with hot water saturated with surfactant and weighting additives. Mining engineering description of shafts and tunnels required are included as is a discussion of the tunnel proximity to a reservoir. Petroleum engineering flow equations to describe production rates and candidate reserve areas of the United States are described.

17. Document Analysis a. Descriptors
Gravity drainage
Gravity redistribution
Conventional oil
Viscous oil
Tar sands
Heavy oil
Oil sands
Petroleum mining
Modified in situ
Oil economics
Flip flop
Drip drainage

b. Identifiers/Open-Ended Terms

c. COSATI Field/Group 08I, 11H

18. Availability Statement	19. Security Class (This Report)	21.
Release unlimited by NTIS.	20. Security Class (This Page)	22. Price PC A16 MF A01

1

ANSI-Z39.18) See Instructions on Reverse OPTIONAL FORM 272 (4-77) (Formerly NTIS-35) Department of Commerce

FOREWORD

This report was prepared by Energy Development Consultants, Inc. (EDC), 9725 E. Hampden Ave., Suite 302, Denver, Colorado 80231 under USBM Contract Number JØ 275002. The contract was initiated under the Advancing Oil Shale Mining Technology Program. It was administered under the technical direction of the Twin Cities Mining Research Center with Mr. Richard Dick acting as the Technical Project Officer. Mrs. Darlene Wilson was the contract administrator for the Bureau of Mines.

This report is a summary of the work recently completed as part of this contract during the period March 1977 to July 1978. This report was submitted by the authors on July 31, 1978.

ACKNOWLEDGEMENTS

The investigative team of this report wish to express our gratitude to the Technical Project Officer, Mr. Richard A. Dick, for his continued guidance and support throughout this study. In addition, we wish to thank the staffs of both the Twin Cities Mining Research Center and the Denver Mining Research Center of the U.S. Bureau of Mines for their prompt replies to our requests for information and assistance.

We also wish to thank the following companies and their respective staffs for their prompt and courteous assistance in furnishing data necessary for the completion of this project.

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SECTION I

EXECUTIVE SUMMARY

1.1 GENERAL

In 1932 the Bureau published Bulletin 351, "Mining Petroleum by Underground Methods". It is the purpose of this report to update the conclusions of Bulletin 351.

The investigating team concludes that in situ production methods are now technically, environmentally and economically viable. This supports the keystone conclusion of the 1932 study that extractive mining methods should not be used as a primary method of oil recovery from an oil field. The economics of handling large volumes of rock plus the flammable and toxic gases inevitably emitted from open reservoir rock expose workers to health and safety risk and are restraints to handling oil bearing rock unnecessarily. Thus, our conclusion is that the historical mission of the mining engineer must change in oil mining from providing the total underground technology to a primary role of providing and maintaining access or proximity to target reservoirs. The petroleum engineer then becomes the on-going key technologist for the completion and operating life phases of the petroleum recovery project.

This report considers only in situ recovery methods*, that is mining technology is used primarily, but not exclusively, to gain undisturbed access to the proximity of oil bearing zones but the integrity of the deposit itself would not be changed by mining, oil bearing ore would not be removed and the seal of deep underground target formations and the competence of the rock above or below the formation would be protected. However, in the case of viscous oil targets, it is the objective to remove or expose the surface of a formation so that it may be produced in situ.

The study describes two processes that can be used to produce presently unrecoverable reserves for two types of petroleum deposits - the 300 billion barrels of conventional light (above 25° API) crudes and the 200± billion barrels of heavy or viscous oils and tar sands.

For the light conventional crudes a gravity drainage mechanism is applied after shafting through and tunneling under a reservoir. With close proximity gained below, many short wells are drilled upward into the formation under sealed pressure control. Petroleum engineering technology is applied to controlled flow gravity methods without the current economic constraints of high

*A companion study on oil mining contracted by the U.S. Bureau of Mines concurrent to this study considers the technical and economic feasibility of extractive or in-seam mining. The resulting report, titled "Oil Mining - A Technical and Economic Feasibility Study of Oil Production by Mining Methods", evaluates surface, underground and in situ petroleum recovery.

cost surface wells, limiting density of wells, maximum well flows and limiting to small well diameters. Likewise, the historic above ground technical constraints of having to flow upwards against the force of gravity, utilizing only contained formation energies and operating only within the radial flow regime are no longer limitations. Then, gravity will be the paramount mechanism used to produce oil although other internal energies, such as capillary forces and the contained formation energy of water drive or gas pressure may be used as supportive producing forces.

To recover conventional light crudes a Drip Drainage method of controlled gravity production will increase recovery from the current 32% (average) of the original oil in place to additionally capture 80-95% of the remaining 68% as long as:

1. Formation temperature, which is related to depth, does not exceed worker comfort levels. This limit changes by geographical location but is in the range of 4000-8000 feet making a good portion of the 300 billion barrels of "unrecoverable" conventional oil in the United States immediately available to recovery.

2. Competent rock lies below a target reservoir. This should occur in many or most of the cases in nature, however geologic data of formations underlying reservoirs is generally lacking.

The depth and rock competence requirements confirm conclusions of the 1932 study. However, gravity drainage of reservoirs from below requires further development of four additional generic mechanical technologies. First is to adapt the wide experience in pressure control from a downward to an overhead or overhanging orientation. Second is to adapt existing overhead and angled drilling technology to the constraints of a small underground room. Third, more adequate pressure control blocking technology for tunnels and drifts should be developed to isolate sectors of underground workings into drilling room chambers. Fourth, petroleum engineering technology must be applied to plug pressure zones prior to drilling the access shafts. Beyond this, lab experiments to prove production rates and conditions must be provided. With these data, for which some studies are currently in progress, a first demonstration can be established.

To recover viscous or heavy oil or tar sands deposits Flip Flop methods have been devised to remove up to 80% of the in place oil by hot water soaking using surfactant and weighting additives. Flip Flop places a hot water pond immediately on top of an oil deposit. Hot water is heavier than oil and will cause alteration of oil viscosity so the oil will rise to the top of the pond where it can be recovered. Most heavy oils are in shallow deposits easily accessible by surface mining. However, for deeper deposits, cavern jetting to expose the deposit surface is suggested by adapting work currently in development at the Twin Cities Mining Research Center of the Bureau of Mines. Little technology need be added to this concept prior to demonstration testing.

Environmental concerns in mining for petroleum are considered to be minimal except for the risk of mechanical failures of pressure control devices allowing leaking of reservoir gas into mine openings. Surface disturbance and environmental concerns should be very small and the major environmental concerns are expected to be to underground worker health and safety in a potentially hazardous environment due to proximity to toxic gases and its attendant risk of mechanical or human failures.

Economics for a commercial operation of gravity drainage are developed in detail within the report and indicate that even for a poor reservoir current oil prices are at adequate levels. The economics for heavy viscous oil by Flip Flop have not been detailed but are judged attractive. However, in order to call forth industry risk capital for first demonstration projects, a 20%± rate of return may be required and some government cost sharing needed to establish the two or more demonstration projects to test the processes described.

As a result of our study, four patent disclosures have been assigned to the U.S. Government.

1.2 CONCLUSIONS

1. Tertiary recovery holds little promise that a significant fraction of reserves currently termed "unrecoverable" can be captured.

2. Mining for Petroleum (modified in situ) that is, gaining close access to oil bearing formations by mining technology and then utilizing this proximity to apply proven petroleum engineering technology for additional in situ recovery is

- Technically feasible
- Environmentally acceptable
- Economically viable.

3. Two processes, or variations, can be used to produce "unrecoverable" oil

- Drip Drainage for conventional hydrocarbons
- Flip Flop for viscous, heavy oil or tar sands hydrocarbons.

4. Recovery factors can be substantially increased to obtain more of the original oil in place

- from 0-25% to 60-90% for viscous oils by Flip Flop
- from 32% to 80-95% for conventional oils by Drip Drainage.

5. Recovery volumes of currently "unrecoverable" oil are in the range of

- 150-200 billion barrels of conventional oil to 8000' in depth
- 150-200 billion barrels of viscous, heavy oil and oil from tar sand deposits.

6. Technology development is required for adapting existing knowledge in the areas of

Drip Drainage

- upward (and angled) drilling of short small diameter holes from underground rooms
- pressure control in an overhanging orientation
- underground room chamber isolation.
- drilling large shafts through pressured reservoirs

Flip Flop

- cavern jetting or underground drilling of caverns (underground mining only).

7. Data development is required to practically apply at demonstration level the processes described in combination with known technology

- oil/water interchange rate for Flip Flop
- oil/water/gas redistribution rate in produced reservoirs for Drip Drainage
- rate of production by Drip Drainage against variables of reservoir rock and fluid properties
- high pressure fluid jetting rates of underground rock for Flip Flop caverns.

8. Demonstration projects by industry should be governmentally encouraged for

- Flip Flop
- Drip Drainage.

9. Economics of mining for petroleum underground by Drip Drainage indicate an oil price between $12.50 and $15.25 per barrel is required for a conservative prospect depending upon the rate of return required to call forth industry risk capital for a demonstration. This oil price may or may not be sufficient to trigger industry but would certainly be sufficient should government cost sharing be added. For surface Flip Flop, the economics are somewhat more improved but industry probably cannot develop this process independently. For underground Flip Flop high technical risks exist and government support certainly will be required to test its viability.

10. Conservation of a great national resource, national security and the balance of payments dictate that every encouragement be given by government to recovering the 68% of "unrecoverable" oil presently existing in depleted reservoirs of the U.S.

11. Environmental concerns will be limited primarily to the area of isolating a pressured reservoir from underground mine workings to protect worker safety and health.

SECTION 2

HISTORY OF PETROLEUM MINING

2.1 INTRODUCTION

Mining for petroleum may constitute one of the greatest challenges to engineers in the entire mining industry today, because only about 1/3 of the petroleum is extracted from its reservoir by conventional methods. There are large numbers of petroleum reservoirs in the U.S. that still contain over 2/3 of their original oil. It is this oil that is the primary target for mining for petroleum.

A number of foreign countries have investigated and conducted successful mining operations in depleted oil zones. Germany, for example, attempted to increase its supplies of petroleum by underground mining methods during World War I (1914-1918). In 1935, German oil mining was carried out on a more commercial basis. For many years, France successfully and economically recovered oil by mining zones that would not produce by conventional wells. More recently, the USSR has undertaken the mining of oil in the Yarega Field which is presently producing 1.5 million barrels annually.

Although foreign countries are experiencing some success in recovering oil by underground mining methods, little research has been performed in the United States regarding oil mining. The study of the methods used in foreign countries alone is not sufficient to evaluate the practicality of oil mining in the United States, because reservoir and geologic characteristics vary so greatly that no one method can be applied to all reservoirs.

In 1932, the U.S. Bureau of Mines published Bulletin 351 which concluded that under certain conditions oil mining might be preferred over conventional recovery methods. This conclusion was based on studies begun in 1923 by George S. Rice, Chief Mining Engineer, U.S. Bureau of Mines, of oil mining methods employed in Europe at oil sand mines at Pechelbronn, Alsace, France, and Wietze, Hannover, Germany. Later studies, in varying detail, were conducted by Uren, Sack, Bruderer and Louis, and Robertson Research International Limited.

In the past 45 years since the publication of Bulletin 351, tremendous technical advances have been made in mining and petroleum technology and designs. In light of these technical advances, it is essential to reassess the 1932 USBM study and to detail present day mining technology and equipment that could be used economically to mine petroleum in the United States. However mining technology alone cannot be unilaterally considered without understanding the mechanics of the oil reservoir itself. Therefore the mining engineer must first determine from petroleum engineering technology what is mechanically required for increasing ultimate recovery and must be reactive to those reservoir technology constraints.

2.2 PETROLEUM MINING, A CENTURIES OLD PRACTICE

The first oil mining, petroleum, asphalt and other bitumens were mined in the Sinai peninsula, the valley of the Euphrates and in Persia prior to 5000 B.C. The Hoover's, in their translation of Agricolas' De Re Metallica wrote, "Bitumen was used by the Egyptians for embalming from prehistoric times, i.e. prior to 5000 B.C., the term "mummy" arising from the Persian word for bitumen, mumiai....The Hebrew word sift for pitch or bitumen does occur as the cement used for Moses' bulrúsh cradle (Exodus II-3) and Moses is generally accounted about 1300 B.C...Herodotus (484-424 B.C.)....in referring to a well at Arderrica, a place about 40 miles from ancient Susa in Persia, describes the manner in which bitumen, salt and oil are recovered. Pliny in writing of the same operation mentions production of a "bituminous liquid-like oil which is burned in lamps." Mining was accomplished by shafts or wells sunk on the oil seep, followed by bailing with buckets or other containers. The brine-bitumen mix was then heated and partially evaporated in the sun to crystallize the salt out and float the liquid bitumen to the water surface. Later shafts were sunk deeper and short drifts were driven into the oil sands to establish better drainage. These methods were subsequently practiced in Romania, France, Germany, Burma and elsewhere.

In addition to these early beginnings it should be noted that rock [illegible] asphalt, tar sands, and asphalt lakes in the new world were occasionally mined by surface techniques at an early date. Columbus, who discovered the island of Trinidad off the coast of Venezuela on his third voyage, is said to have calked his ships with asphalt from Pitch Lake in 1498. Sir Walter Raleigh reported his observations of the same bitumen deposit following his visit in 1595. The ship's crews broke the crusted surface of the lake with picks and carried the tar to the beach to calk their ships. It was so mined and used by buccaneers, merchant and navy men alike for about three centuries.

Asphalt street paving in the United States began in 1870 with pavement in front of the City Hall, Newark, N.J. In 1876 the Congress directed that Pennsylvania Ave., in the District of Columbia be surfaced with asphalt. By 1903 about 42 million square yards of streets had been paved with asphalt in the United States. Such work in coastal cities usually utilized asphalt from Trinidads' Pitch Lake or the Bermudez Lake in Venezuela, but natural occurrences of asphalt impregnated rock, which occur in Alabama, Texas, Missouri, Arkansas, California, New Mexico, Oklahoma, Utah, and some other states were also used for local and nearby paving projects. About 10 million tons of asphalt were mined and exported from Trinidad, and the asphalt from Bermudez Lake in eastern Venezuela was actively mined between 1891 and 1931. Neither is currently worked, because modern oil refinery asphalt products are made to specifications and the plants are located nearer the demand. Present exports of asphalt from Trinidad and Venezuela are almost if not wholly the product of the local area refineries.

2.2.1 The Developing Petroleum Industry

World production of petroleum expanded tremendously in the 19th century as industry developed newly discovered oil fields utilizing the well drilling and allied techniques developed so extensively in the United States following the initial Drake well in 1859. By about 1880, oil seeps, springs and tar sands had lost their significance as a raw material source, except for local use in primitive situations.

By 1860 the United States was the leading world oil producer with market production of 500,000 barrels. The first petroleum refinery in Pennsylvania was built in 1860 about a mile from the Drake well. Pipelines, pumping stations, and railway tank cars followed almost immediately and by 1869 the first oil tanker, the Charles of Antwerp was regularly crossing the Atlantic. Throughout this period, the petroleum products primarily were used for illumination and lubricants, and gas was used for illumination. In 1874, the Russian government converted its Caspian fleet to the use of residual oil as boiler fuel.

From those beginnings the industry increased until today, world crude oil production approximates 56 million barrels per day and that of the United States almost 9 million, all of which essentially is produced from drilled wells. Although it has long been known that oil fields cannot be exhausted by boreholes alone, experts have questioned the economic feasibility of tapping the oil beds by mining. Today, the increasingly higher prices of petroleum together with the increasing expense of oil well drilling has brought the concept of mining for petroleum within the range of practical economics. An additional factor presently being considered is that new oil fields are becoming much more difficult and expensive to find and it has been suggested that the world demand for petroleum will outstrip the world supply of petroleum by the late 1980s or early 1990s.

2.3 PETROLEUM MINING IN THE UNITED STATES

Until the 1970s, the prices for petroleum and petroleum products were so low that a petroleum mining venture was not economically feasible. A number of attempts at petroleum mining ventures have been made over the years but the bountiful supply of petroleum from wells made most of these ventures unprofitable. Today the status of our foreign petroleum dependency and the expense and inability to find and develop large new fields make petroleum mining much more attractive.

2.3.1 Early Attempts at Mining for Petroleum

An early reference to the method of producing oil in the United States by shaft sinking appears in a report by the Geological Survey of Ohio, which states, "Among the novel features of the work at Macksburgs in 1865 was the sinking of a shaft by the Moorhead Oil Co., on the Rayley farm, for the purpose of obtaining the Dutton vein of lubricating oil. A well was first drilled down to the vein which yielded a little oil with a large quantity of water. The owners then conceived the idea of putting down a shaft into which it was supposed the oil would flow in great quantity. The work was finally completed at great cost, but no more oil was obtained from the shaft than the well had yielded. Another company, which held a lease on the adjoining land, contemplated digging a trench to the depth of the Dutton vein across his leasehold, but abandoned the project after the completion of the shaft."

"A large sum of money was also expended by the Boston Petroleum Co. in sinking a shaft for shallow oil on Eight-Mile Run in Newport Township."

In 1866, according to Prof. L.C. Uren, a series of 31 oil-drainage tunnels was driven into the oil sands of Sulphur Mountain in Ventura County, California, by the Union Oil Co., of California. One of these tunnels was driven to a total length of 1,900 feet. It had a slight inclination above the horizontal to facilitate drainage. The oil sands were penetrated and the oil drained from them for many years.

In the vicinity of Newport Beach, Orange County, California, an inclined shaft, dip 45^{o}, was sunk 505 feet to a heavy, viscous oil sand. A drift about 30 feet long was made into the oil sand at the bottom of the shaft, and a large steel coil was placed in the sump to heat the oil in the surrounding oil sand. The plan at first was successful, but the production dropped rapidly.

About 1902, in southwest Colorado near the Utah line, a few miles north of Fruita on Whiskey Creek, a drift was driven into a shallow syncline to drain a light oil. According to an informal report in 1922 it was producing 50 barrels per day, but in 1927 the production had dropped to 1½ barrels of asphaltic oil per day, accompanied by 10 or 15 barrels of water.

Another mine, in the same area about 8 miles south of Dragon Station, Utah, at Urado, Rio Blanco County, on the Uintah Railway, 1.5 miles east of the Colorado-Utah border, was operated by the Urado Co. which also operated an oil well and a small refinery. It produced lubricating oils of high quality which were sold in the Uinta Valley region.

The plant was capable of producing between 5 and 10 barrels per day. A well 505 feet deep was sunk in beds that lie at a horizon below the oil shales of the Green River formation, possibly in the upper beds of the Wasatch. Drilling was suggested by the presence of an oil spring. The beds are nearly flat or dip 2 degrees to 3 degrees northwest. Oil was present in the three sands penetrated.

A tunnel 375 feet long was driven in the upper sand. This tunnel was bulkheaded a short distance in. It was reported that the oil sand forms a shallow syncline. There was little or no gas pressure and no gas was encountered in driving the tunnel. The oil sand and the oil lie in shallow sags which are 4 to 5 feet in depth. Oil came into the sags from the southeast and issued at the portal of the tunnel.

The possibility of recovering oil by underground mining in Pennsylvania became a live subject in 1939. In most of the Pennsylvania fields the gas pressure had been so dissipated that only small quantities of oil are produced per well. Much of the oil still remains in the sands. This oil was of superior quality and commanded a price double that of most western oils. The oil sands lie at comparatively shallow depths.

Apparently the promoters of the Pennsylvania Rock Oil Co., who drilled the first successful oil well in 1859, contemplated the recovery of oil from the Titusville area by trenching and possibly mining, and it was not until 1856 that they decided to drill a well, having noted the oil found in brine wells as Tarentum. Mining was attempted even after production from wells had reached a considerable quantity.

Three shafts were sunk in 1865 about 1 mile north of Greg, Ohio, in an area where shallow wells were very small and short-lived. Only small quantities of oil were recovered.

In 1864, an 8 x 12 foot shaft was sunk to a depth of 165 feet near Tidioute, Pa., on the site of a well that had produced about 4 barrels of oil per day. The oil sand was encountered at a depth of 152 feet and was 5 feet thick, coarse and pebbly. Several holes 10 to 40 feet deep were drilled down from the base of the shaft, some of which produced water but no oil. Only about 4 barrels of oil per day were recovered from seepage from the wells. An attempt also was made to mine the first oil sand near Petroleum Center, Pa.

At Ravenna, Estill County, Ky., a shaft sunk 130 feet to an oil-bearing limestone produced 2 to 3 barrels of oil per day. The project was not a commercial success.

Near Jacksboro, Texas, where the oil sands are a few inches to about

8 feet in thickness, tunnels were driven in two directions on top of a thin limestone cap and small holes were drilled into the sand with 2 inch perforated pipe connected to the sump. The project apparently was not successful. A shaft 99 feet deep in the Electra, Texas, field reputedly yielded 40 barrels per day.

The general interest of the petroleum industry in the United States in the possible use of underground oil mining methods for depleted fields was aroused by the publication in 1920 of a series of papers by Paul de Chambrier, Strasbourg, Germany describing the oil sands of Pechelbronn and the application of underground mining in that field. Oil trade journals in this country published brief abstracts of these and subsequent French papers, including also some German journal articles relative to the mining methods employed at Pechelbronn and Wietze.

Further interest was stimulated in 1922 by a visit of Dr. E. Middendorf and B. Szilasi, directors of the Deutsch Erdol Aktiengesellschaft (later a subsidiary of the Deutsche Petroleum Aktiengesellschaft). It was this company, which had extensive experience in coal and lignite mining and distillation methods in various parts of Germany, that started oil mining at Pechelbronn (France) and Wietze (Germany). Its representatives, as experienced engineers, had come to this country to try to interest American petroleum companies in adopting their underground methods. They also conferred with the U.S. Bureau of Mines, which was concerned from the standpoints of better oil recovery technology and of conservation on both public and private oil lands.

Although the suggestions of the German engineers were not adopted, their visit crystallized interest in the problem, and various American petroleum engineers and geologists from time to time have proposed systems of mining which varied to a greater or lesser extent from the European methods.

2.3.2 Petroleum Mining in Ohio

In Morgan County, Ohio there have been several attempts to recover oil from the shallow First Cow Run sand in Morgan County by drilling horizontal holes either into the outcrop or into the sand face that has been exposed by excavation. The engineering achievements involved in these projects were notable, but the companies failed in each case because of high operating costs and small production rates.

In Morgan County, the first horizontal hole was drilled near the village of Malta in Section 32 of Malta township by the Ohio Level Well Co. under the direction of Mr. Leo Ranney. This well was drilled in 1937, 802 feet into the outcrop in the Cow Run sand along Havener Run on the Dion Birney farm. This sand is 28 feet thick consisting of two pay streaks separated by a hard fine grained impermeable zone. The upper pay zone is 4 feet thick and occurs 3 feet down from the top of the sand. The lower pay zone includes the total thickness of 14 feet of the lower part of the sand. Discovered in the 1860s, the hydrocarbon reservoir had been subjected to both vacuum and pressure recovery techniques. Until this attempt at horizontal drilling, the reservoir had not been operated since 1930, a lapse of some 7 years. A core was taken from a well drilled approximately 700 feet from the outcrop and 40 feet from the horizontal well. A summary of Parke Dickey's report of the project is as follows:

"The sand showed a porosity for the upper pay of about 16% and an oil saturation of 16%. The lower pay showed porosity up to 20% and oil saturation of 17.5%. The permeability of both pays was high and quite uniform, ranging from 150 to 750 millidarcies. Oil content was quite low, and was estimated as 4,200 barrels per acre for the 18¼ feet of pay sand."

A horizontal well was drilled in the upper pay zone almost level for 802 feet. This well was entered later and a hole branching off at 630 feet was drilled to 953 feet. The branch hole was thought to have descended 8 to 9 feet and to have finished in the lower pay zone. The horizontal well was drilled with a conventional diamond drilling machine with a rotatable hydraulic unit having a two-foot feed, powered by a 25 horsepower gasoline engine. The hole was 2 5/8 inches in diameter. The average rate of drilling on the first hole was 40 feet per shift, approximately 5 feet per hour. At times the drill advanced at the rate of about 15 feet per hour and occasionally at the rate of 1 foot per minute or 60 feet per hour.

Gas and oil spouted from the hole three times during drilling which was probably due to penetrating pockets of pressure within the sand which were sealed off by some means from the rest of the reservoir. Upon completion, the hole was shot with 1,150 pounds of 80% high-velocity gelatin formed in 2 inch sticks. After shooting, the well blew for about 20 minutes and an estimated several hundred barrels of oil flowed out. Unfortunately, this oil, which was confined behind the dam, was lost during a washout of the creek.

The well completion consisted of three feet of casing cemented into the rock and tubing run to 940 feet, the last 10 feet of the tubing having been perforated. During production, a vacuum was applied to the tubing which removed the oil collected in the far end of the hole. Vacuum then was applied to the casing which removed the oil from the first reach of the well. The well is reported to have produced 9½ barrels of petroleum in 7 hours after standing for two weeks before the well was shot.

After completing tests on the horizontal well, Ranney and the Ohio Level Well Company in 1939 decided to dig a pit through the First Cow Run sand to expose a fresh surface of the sand. This pit was located about 500 yards upstream from the horizontal well and in construction was 30 feet deep and 30 feet in diameter with concrete walls that were one foot thick. They had planned to drill horizontal holes radially from the pit into the sand, then after three holes had been drilled and were producing a few barrels of oil per day the company was dissolved because of financial difficulty.

Blakson Oil Company of Charleston, West Virginia made the last attempt at horizontal drilling in Morgan County in 1945. From cores taken from the First Cow Run sand, the sand averaged 20 feet in thickness with the lower 10 feet containing hydrocarbons. A rectangular shaft, 6 x 8 feet at the top and widening to a 20 foot square room at the bottom was sunk to a depth of 113 feet through the sand. A hoisting cage was used to lower workmen down the shaft. The first two horizontal holes, of a planned array of 24 holes, were successfully completed and had a combined production of 12 to 14 barrels of oil per day after being shot along the entire length. The expense of the operation at this point became so great that the Blakson Oil Company was forced to abandon the project. Local men operated the wells for a few years but it since has been shut down.

2.3.3 Petroleum Mining in Pennsylvania

In the early 1940s, a horizontal drilling method was used by the Venango Development Corp. in a hydrocarbon formation underlying 400 acres in the Franklin oil field in the Sugar Creek Township, Venango County, Pennsylvania. This method, which was developed on two previous projects in Ohio, consisted of sinking a shaft to the bottom of an oil sand and drilling holes in a horizontal plane radiating outward from the chamber in a pattern similiar to that of the spokes of a wheel. Mr. Leo Ranney, whose patents will be discussed later, served as technical advisor to the Venango Corporation. The Franklin oil field is located in the northcentral and northeast portions of the Franklin quadrangle in Pennsylvania and contains four pools: Franklin, Sugar Creek, Miles and Oak Forest School. The Franklin pool reportedly has produced more oil than the other three pools combined. The first Venango sand is the oil producing formation, which is a part of the Venango group of the Conewango series of Upper Devonian age.

A circular shaft sunk to a depth of 370 feet and 10 feet in diameter was excavated and lined with concrete from the surface to the top of the hydrocarbon bearing formation. After completion the inside diameter of the shaft was 8 feet. The concrete lining had a minimum thickness of 12 inches but averaged 14 inches in thickness. The shaft collar was made of concrete with an outside diameter of 14 feet that extended a few feet below the surface and provided the foundation for the wooden head frames used while sinking the shaft. After the shaft was completed, it was equipped with an emergency escapeway ladder and guidebraces, and a steel head frame was erected.

A service chamber was constructed at a depth of 200 feet below the top of the shaft. This was a rectangular chamber 8 feet wide by 12 feet long by 8 feet high and was lined with concrete. Upon completion of the shaft a 27 foot diameter work chamber was excavated in the hydrocarbon bearing formation. The work chamber for the shaft was eccentric in plan to permit the maximum freedom of action. The inside wall of the 8 foot shaft is tangent to the inside wall of the 27 foot diameter work chamber. The roof of the work chamber was 370 feet below the surface and the base was at a depth of 388 feet below the surface. A plan, elevation and section view of the shaft and chambers is shown in Figure 1.

The work chamber was lined with concrete 18 inches thick. Three rows of portholes 6 inches in diameter, 24 to a row, were cast into the concrete walls of the chamber 391.3, 407.0, and 419.5 feet below the collar of the shaft

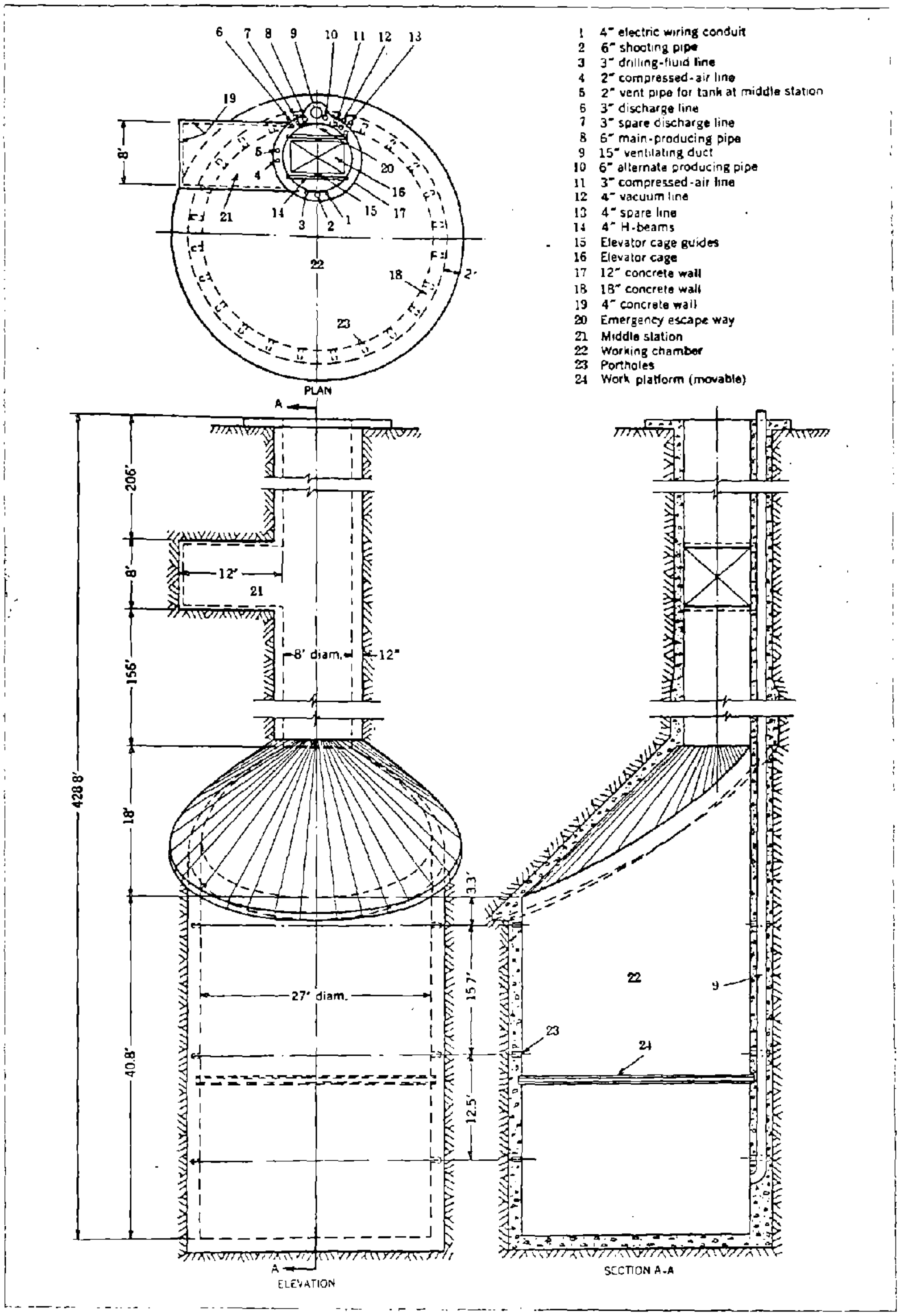

Figure 1. Plan, elevation and section view of shaft and chambers of the Venango Development Corp.'s horizontal oil-well drilling project, Franklin, Pa. (USBM R.I. 3779).

through which the horizontal holes were drilled. Each porthole was fitted with a 6 by 18 inch standard pipe nipple with four 1 3/8 inch O.D. by 8 inch inserts welded onto the outside surface. The ends of the inserts were placed flush with the end of the 6 x 18 inch pipe nipples at the inside of the work chamber. Each insert was threaded on the inside to receive a 1 inch diameter bolt. Recesses were cut in the walls of the chamber in which H-beams could be placed for supporting a removable fireproofed wooden floor.

Horizontal drilling began with an inclination upward of about 1 inch in 10 feet. The drilling plan was to alternate drilling in opposing holes first on one side of the shaft and then the same drill stem handling to drill the hole on the opposite side of the shaft. The first two holes drilled were 2,255 feet and 2,334 feet in length. Upon completion these holes were loaded with 80% high velocity gelatin dynamite from 400 feet away from the shaft wall to total length then detonated simultaneously.

The shaft was started on May 4, 1942, and the shaft excavation, work chamber and concrete lining was completed on November 15, 1942. No production records could be found to indicate any degree of success for the project.

2.3.4 Petroleum Mining in Kansas

In 1943, Thomas and Thomas, mining operators of St. Louis, Missouri developed the first petroleum mining project in Kansas. This mine was located on some abondoned leases on the Hugh Whiteford farm in Miami County, about 4 miles north of LaCygne, Kansas. Accurate production records for this pool are not available but the pool is reported to have produced about 600 barrels per acre.

The mining methods used in Kansas are similar to those used in Ohio and Pennsylvania. A shaft 7 x 7 feet was sunk to a depth of 230 feet. Two sixteen feet square stations were excavated and cribbed at the bottom of the shaft to serve as working rooms from which to drill horizontal holes into the hydrocarbon formation. Fourteen horizontal holes were drilled in a radial pattern from the shaft, with a total footage of more than 7,000 feet. The hole diameters were 3 3/4 inches, 3 7/8 inches and 4¼ inches. The length of the holes ranged from 350 feet to 700 feet. All the horizontal holes were drilled into the oil sand about 8 or 9 feet below a black limestone caprock. Core drilling equipment was used to drill the horizontal holes. Tubing either 3 or 3½ inches in diameter was cemented into each hole. A small tank served as a sump from which the oil was pumped to the surface, while each pipe was equipped with a valve for selective control. The crude oil is reported to have been 29 to 31° gravity and that initially 25 to 50 barrels per day of the crude oil was produced from the shaft.

2.3.5 Petroleum Mining in Texas

The Jacksboro field is a small structural dome about 75 miles northwest of Fort Worth. The pay zone is a lens of sand in the Strawn Formation which is overlain by a cap rock of hard limestone about 18 inches thick. The cap changes to a conglomerate in some places, a facies change. The producing sand lies at an average depth of 100 feet. The overburden principally is blue shale. A hard conglomerate underlies the producing sand and is 6 to 14 inches in thickness. Verified information is unavailable, however, the sand is thought to have a maximum thickness of 21 feet. About 100 wells were drilled in the field, but no records of value were left. Normally the wells were drilled to the bottom of the sand and cased with the bottom joint perforated. In some cases, however, the wells were drilled through the underlying bed and occasionally into water. Whatever gas or pressure originally existed in this hydrocarbon reservoir has since been dissipated through the early wells. Where the mining venture was located there is no ground water located above the pay zone. The entire field covers less than 250 acres.

A small shaft was sunk in about 1920 to a point 20 feet below where the sand should have been, but the sandstone had pinched out at this point. A tunnel was driven to relocate the sand but instead entered the cap rock which dipped toward the shaft at an angle of 45°. This work was stopped at this point because no more funds were available.

About two years later Mr. Leo Ranney undertook to continue this mining venture. The main tunnel was driven above the cap rock 100 feet long in length and 9 wells were drilled from the tunnel into the pay zone. The wells were spaced 8 to 10 feet apart. These wells, cased and cemented, were connected to a common 2 inch header pipe which extended to the foot of the shaft where a pump discharged the produced oil and water to storage at the ground surface. Commercially the mine was not a success because the field was so small and contained only a small volume of hydrocarbons. This venture enabled Ranney to develop a plan for a system of underground mining for oil covered in his patent specifications. Early oil mining patents will be discussed later.

2.3.6 Petroleum Mining in Wyoming

Continental Oil Company opened its North Tisdale Unit Lakota-Gravity Drainage Project in the summer of 1977. It is located in Johnson County and the objective is to produce the Lakota Formation by gravity drainage. Continental has submitted applications to the USGS, USBLM and state agencies and constructed an inclined shaft from an adit in the side of a hill. The formation has about 200' overburden and the mine will intersect and expose the formation itself.

Typical formations such as the Lakota contain 30° API oil from a consolidated sand of ∿ 20% porosity and oil saturations of perhaps 40-50%.

Information at the point of publishing this report is limited, however, we understand the project at this time has not progressed sufficiently for the mined formation to have been placed on production.

2.3.7 Petroleum Mine Plans in California

Getty Oil Company has tentative plans to start an open pit pilot operation that would tap a deposit of 421 million barrels of in place hydrocarbons on 1,780 acres of Getty owned land in the McKittrich field in California. Diatomaceous sediments containing hydrocarbons extend from the surface to about 400 feet in depth. In the same area oil deposits currently being produced lie at depths of 1500 to 2000 feet. It has been estimated that the Getty property contains 627 million tons of hydrocarbon bearing sediments with an average grade of 28.188 gallons of crude oil per ton. According to Getty, "no oil has been produced from the diatomite deposit on the Getty property, because it would not respond to the usual oil field production techniques. To date no extraction process has been applied commercially to the production of oil from hydrocarbon impregnated diatomaceous sediments. It now appears that certain of the techniques devised to exploit oil shale or tar sand deposits can be modified for application to diatomite oil deposits." Getty engineers believe the deposit can be mined "with an overburden-to-oil-bearing-sediments ratio of approximately 0.8:1"..

If successful, data from the Getty pilot plant would be used to design a full scale plant that could begin operating in the mid 1980s or earlier. If commercial operations are undertaken, Getty said it would abandon 60% of the present producing wells on their property but that the wells would be redrilled after the mining operation was completed. The wells to be abandoned produced an average of 5,158 barrels of oil per day in June 1976.

2.3.8 Petroleum Mining Prospects in Utah

At this writing, the only project publicized in Utah is a 3 year extension to a cooperative agreement between Sohio Petroleum Company and the Energy Research and Development Administration being conducted by the Laramie Energy Research Center. This cooperative agreement allows for a coordinated effort for investigating in situ extraction methods for recovering hydrocarbons from oil sands. Under the original agreement Sohio has provided 10 acres of land in the northeast Asphalt Ridge oil sands deposit in northeastern Utah. About 5 miles west of Vernal, Utah, the experimental site is just off the northwest edge of the Asphalt Ridge oil sands deposit which has been estimated to contain more than 1 billion barrels of hydrocarbons. Including the Asphalt Ridge deposit, there are about 30 billion barrels of bitumen awaiting recovery in Utah. Until now present technology has not proved economically attractive for recovering the hydrocarbons from the tar sands and heavy oil deposits in Utah.

2.3.9 Discussion

Although there are some 383 known viscous oil fields in the United States, there are no known large heavy oil mining projects in operation. Over the years there have been several projects undertaken but these have not proved economically viable. With the increased demand for hydrocarbon and hydrocarbon products and the increased prices of these products, the heavy oil deposits in the U.S. can now be considered as potential economic prospects. If a typical heavy oil deposit has 30% porosity, 40% oil saturation and a $12 per barrel value, the deposit then contains material worth $3.60 per metric ton of rock. The mining and processing costs for an oil sand, one which does not require crude oil upgrading facilities, probably are sufficiently low to provide an attractive economic opportunity for hydrocarbon recovery.

In a heavy oil deposit, the saturation distribution of hydrocarbons would be much more uniform and continuous than an ore deposit of hard rock minerals. This factor suggests that the dilution with waste rock would be minimal and that the ore recovery efficiency from a well designed pit could be very high. The recovery efficiency of a well engineered and designed extraction process could be high also, perhaps in the range of 85%.

The most aesthetically and environmentally acceptable method of extracting the hydrocarbons from heavy oil deposits would be a successful in situ process. One such process for the in situ mining of heavy oil deposits is described in a later section of this report.

2.4 PETROLEUM MINING IN FRANCE

The mining methods and technology used both in Franch and in Germany are well documented and illustrated in U.S. Bureau of Mines Bulletin 351 entitled, *Mining Petroleum by Underground Methods*, by George S. Rice. A literature search to update the material of Bulletin 351 for France and Germany has not been successful. For this reason the mining technology used in France and Germany for mining for petroleum is summarized from Bulletin 351. For more specific information, the reader is referred to this 1932 Bureau of Mines publication.

2.4.1 Oil Field Location and Description

The Pechelbronn oil field is located in the Rhine Valley, approximately 30 miles north of Strasbourg, Alsace, and is about 4 miles wide and 12 miles long. According to French geologists, the oil bearing formation in the Pechelbronn field occurs in Oligocene marls deposited during tertiary time. The hydrocarbon formation is situated in a large sunken monoclinal block of a former anticlinal structure, which lies in the wide valley of the Rhine River between the Black Forest hills on the east and the Vosges Mountains on the west. A series of sand beds are interbedded with the marls and range from 0 to 30 feet thick. The sands are lenslike and are not continuous over a large area. The structure of the area is highly complex because the beds are intersected by many faults.

In shallow workings, the petroleum is thick asphaltic oil with an average density of 0.970. At intermediate depths the oil is paraffin based and its density is 0.945. The deepest oil also is a paraffin base with a density of 0.880. Because the geology in the area is so complex, the physical characteristics of the oil do not depend on depth alone.

2.4.2 Mining System

A system of drainage levels and inclined crosscuts characterize the mine workings in the Pechelbronn field, which divide the oil sand layers into rectangular blocks ranging from 100-150 feet wide and 150-300 feet long. The oil was extracted from the sand either by natural drainage or drainage augmented by compressed air. The local mining officials reported that extraction by drainage aided by air pressure was so nearly complete that other special methods such as the introduction of hot water would not significantly improve the recovery.

The main haulage raise and airway galleries located near the shafts were lined with brick. Steel rail girders were used extensively for roof support. The steel girders were spaced close enough to use cement blocks for lagging. The secondary slopes and inclined crosscuts were wood-timbered post and collar sets installed on approximately three foot centers as the heading was advanced. Intermediate sets were required when the roof was weak and heavy. The lagging installed over the timber sets consisted of small poles placed tightly together.

When the mines first opened in 1917-1918, the top of the marl stratum that underlies the hydrocarbon zone served as the floor of the respective gallery or level. A shallow ditch was cut along the downdip side of the gallery to transport the drained fluids. Where the sand was thin the roof of the gallery would penetrate into the overlying marl formation. Accumulations of oil on the floor in haulageways made travel difficult and was a fire hazard. In 1922 the drainage galleries were placed vertically higher so that the floor was just above the richer oil zone of the sand. The transport ditch then had to be cut deeper so the full thickness of the pay zone could be drained. The floor of the gallery was planked but oil still accumulated on the floor.

In 1925, the drainage gallery arrangements were changed. The change was necessary because in the previously constructed workings which were driven into the pay zone the marl roof rested heavily on the timbers causing many of them to bend, creating a potentially dangerous situation. To reduce or eliminate this hazard, levels and inclines were driven in the marl stratum above the pay zone, usually leaving a layer of marl as a floor over the sand. Collection pits were sunk 33 feet apart on one side of the gallery and extended down through the oil sand and a foot or so below it. These pits were drained periodically using suction pumps. These pits were lined with plank and ranged from 20 to 30 square inches in cross section. Pit depth generally was 6 to 8 feet depending on the thickness of the marl stratum and the thickness of the pay zone. For safety purposes, the pits were covered to prevent anyone from falling in, to lessen the diffusion of gas into the passageway and to reduce the fire hazard. Fortunately, little gas was entrained in the oil.

Exploratory bore holes were drilled up and down from the gallery at 66 foot intervals. These holes were drilled with a pneumatic drill equipped with auger bit on hollow rods, were 2" in diameter and usually not cased or lined. The holes were drilled 50-66 feet long, vertically up or down, horizontal or at some angle with the working face. If one of the drill holes encountered oil, it was then cased and connected to the nearest pit or sump. A packer was used to prevent fluids from escaping around the casing. A few of the bore holes were drilled as much as 300 feet long and occasionally encountered a different oil sand than the one in which the gallery was being driven. The long exploratory holes were drilled using heavy portable equipment driven by compressed air.

Galleries of three different sizes were used: 1) main levels, with two mine car tracks, which had a width inside of the timbers of 8 feet at the bottom, 6'1" at the top and 6'6" high, 2) secondary galleries, with one mine-car track and, where necessary a ventilating pipe, were 7' wide at the bottom, 4'9" wide at the top and 6'6" high, and 3) temporary or exploratory galleries or levels of inclines were 5'6" wide at the bottom, 6'6" wide at the top and 6'1" high.

Headings were driven in the Pechelbronn mines with hand held pneumatic equipment. In 1923, when headings were driven within the sand, considerable care was taken to prevent striking glancing blows which might cause sparks and ignite gas that might be coming out of the oil. Miners made vertical cuts at each corner of the face and horizontally at the top to install the next timber set. When the timber was set in place and the lagging inserted, the miners then cut away the middle body of marl with the pneumatic equipment, using a sweeping motion. When the face was squared and the exploratory holes were drilled, the mining cycle was completed. For the timber sets round timber was used which consisted of the usual two legs and a crossbar or collar. The sets were installed 3'3" apart and were lagged at the top with round poles. This timbering method was used in relatively weak formations in mine workings in any country.

2.4.3 Petroleum Production

In the 1800s, early oil production at Pechelbronn was carried out in underground drifts and in shallow pits in the outcrops of the oil sands. Then in 1888, following the completion of a flowing well, all underground mining was abandoned for about 25 years. In 1914, the annual production of oil from wells in the Pechelbronn field had risen to 343,000 barrels, but by 1916 had fallen off to 291,000 barrels. The drop in production by the Pechelbronn wells led to consideration of increasing oil production at Pechelbronn by underground mining. In 1916 shaft number 1 was started in the shallow northern part of the field in what later proved to be the richest oil bearing area yet discovered in the field. This shaft, sunk to a level of 495 feet from the surface, was circular and 13 feet in diameter. The upper portion of the shaft was lined with brick and the lower part with concrete. During 1917 underground developments were pushed and 40,000 barrels were produced from the mine. The following year (1918) production was increased to 127,000 barrels. Two other shafts were started in 1918 located south of the No. 1 Clemenceau shaft, but the mining developments were not pushed until secondary or escapeway shafts were sunk for each mine. These were later called the LaBel and Daniel Mieg mines. Production of oil in 1918 from the three mines was 134,000 barrels, nearly all of which came from the Clemenceau mine. In that year about 500 wells were in operation which produced about 254,000 barrels. In 1919, underground fires and gas explosions occurred which prompted authorities in the mining department of the province to require the sinking of second shafts for emergency escapeways and to improve ventilation in addition to other safety precautions. The production from wells and mines decreased slightly in 1919 to about 212,000 barrels and 119,000 barrels respectively. In 1920 production from the wells increased to 294,000 barrels but production from the mines fell to 90,000 barrels. There was little change from production in 1921.

The free flowing oil in the vicinity of the shafts had apparently been drained. For this reason, it was decided to adopt the system of rapid gallery driving to enter new drainage areas on a continuous basis. After an initial trial, the systematic underground mining had been adopted as an appropriate method. It included prior drilling to probe the territory to be mined, both as a safety measure to avoid outbursts of gas and oil under high pressure and as a guide to future planning. No reports are available on oil production based on unit volume or area of oil sand. In papers published before 1921 the Clemenceau mine reportedly yielded 23 barrels of crude oil per foot in the period 1917 to August 1919.

The rapidly decreasing rate of production from the peak of production in 1919 confirmed that making prior assumptions of production on the basis of unit area of sands was unsatisfactory. Mine operators concluded that the only way to estimate production, although admittedly unsatisfactory, was to base production on unit lengths of gallery, rather than on area of volume of sand. At the time, it could not be determined how far oil would drain laterally into the working levels under the various conditions of permeability of the sand. It was suggested, however, an average of about 1500 barrels of oil was obtained per acre of oil sand by mining, following extraction by drainage. If the producing sand, for example, at Pechelbronn averaged 3 feet in thickness, the production per acre was approximately 6.4% by volume of oil sand. An increasing number of galleries had been driven annually in an effort to maintain production.

2.4.4 Production Statistics

In the first three years, production of oil from the Clemenceau mine had been at the rate of nearly 84 barrels per 3.3 feet of drainage gallery. By 1921 production had dropped to less than 56 barrels per 3.3 ft. This led management to adopt a plan of rapid gallery development. In the first four years, for example, approximately 2,835 feet of gallery had been driven annually. In 1921, 8,931 feet was driven and in 1922, 14,546 feet. The amount per year increased steadily until an all time high of 23,618 feet was achieved in 1927. Initially, these increases in entry development stimulated annual oil production. However, the yield steadily decreased from 112 barrels per 3.3 feet in 1919 to 10 barrels per 3.3 feet or about 3 barrels per foot in 1928. The average yield per 3.3 feet of length of headings in the Clemenceau mine, from its beginning in 1917 to 1928, was 26.9 barrels, equal to 8.1 barrels per linear foot. The total footage driven was 153,759 (29.1 miles). The statistics of production are shown in Figures 2, 3 and 4 and Table 1.

Either decreasingly leaner oil sands were encountered in the headings or the 1925 change in the drainage method was not as successful as the method previously used. Tests, however, made by cutting into the oil sand after draining by the present methods indicated that little oil remained.

In 1923, the Clemenceau mine produced 197,000 barrels of oil. Four hundred and eighty men were employed underground per 24-hour day on a 6½ hour shift. In the United States the standard miners daily shift was eight hours. The Pechelbronn arrangement produced less than a 6-hour shift. The work done per day by the 480 underground employees was approximately equivalent to that performed by 360 manshifts per eight hours. There were 120 men employed on the surface on an 8-hour basis, making a total per 24 hours of 480 manshifts. Assuming that production was on a 300 day per year basis in 1923, the daily production was equal to 1.4 barrels per 8 hour manshift.

In 1928, there were 814 underground employees in the three Pechelbronn mines, also on a 6-hour basis, equivalent to 610 shifts of 8 hours. There were 218 surface employees on an 8-hour basis, making a total of 828 shifts per 8 hours. The three mines produced 791 barrels per day. On a 300-day per year shift basis, this is equivalent to 0.98 barrels per 8-hour manshift. Based on these figures, 30% less was produced per manshift in 1928 than in 1923.

Table 1. Yearly production of oil from mines in France. USBM Bull. 351, p. 35.

Year	Clemenceau		Le Bel		Daniel Mieg		Total	
	Metric Tons	42 Gallon Barrels	Metric Tons	42 Gallon Barrels	Metric Tons	42 Gallon Barrels	Metric Tons	42 Gallon Barrels
1917	7,787	55,000	-----	-----	-----	-----	7,787	55,000
1918	18,220	128,000	744	5,000	210	1,400	19,174	134,000
1919	14,098	99,000	2,431	17,000	426	3,000	16,955	119,000
1920	11,816	83,000	719	5,000	350	2,400	12,885	90,000
1921	9,497	66,000	2,065	14,000	188	1,300	11,750	82,000
1922	20,367	143,000	4,392	31,000	200	1,400	24,959	175,000
1923	28,205	197,000	8,940	63,000	324	2,300	37,469	262,000
1924	25,235	177,000	10,308	73,000	2,970	21,000	38,513	270,000
1925	14,217	100,000	7,296	51,000	4,983	35,000	26,496	185,000
1926	10,478	73,000	6,795	48,000	6,520	46,000	23,793	167,000
1927	10,499	73,000	12,095	85,000	6,884	48,000	29,478	206,000
1928	9,691	68,000	17,078	120,000	7,217	51,000	33,986	238,000
Total	180,110	-------	72,863	-------	30,272	------	283,245	-------

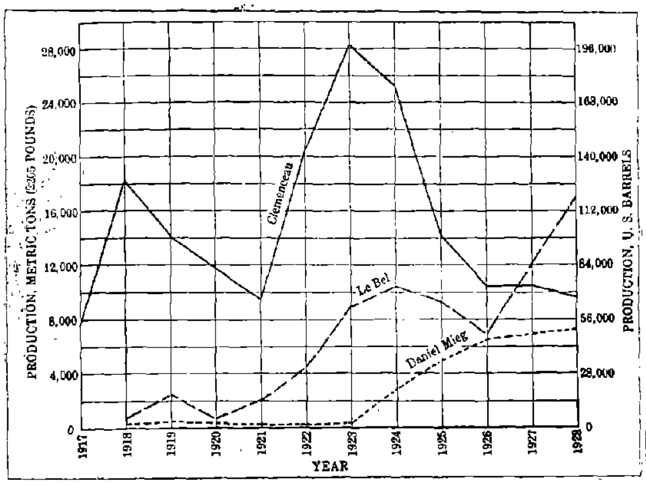

Figure 2. Curve of annual production of each mine in France (USBM Bull. 351, p. 35).

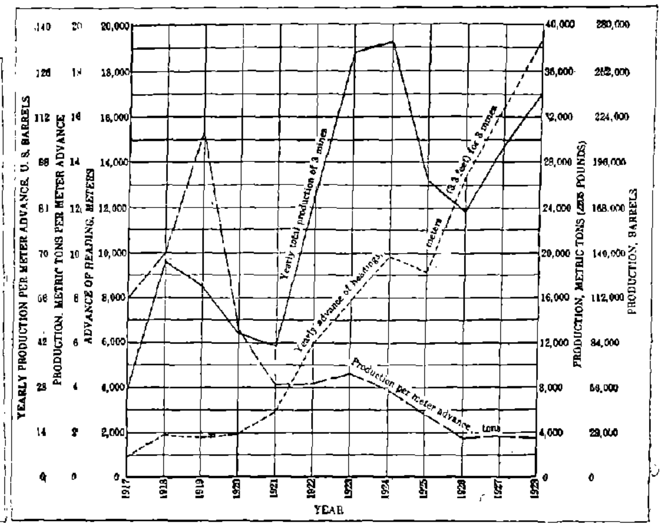

Figure 3. Curves of total annual production in relation to heading advance (USBM Bull. 351, p. 36).

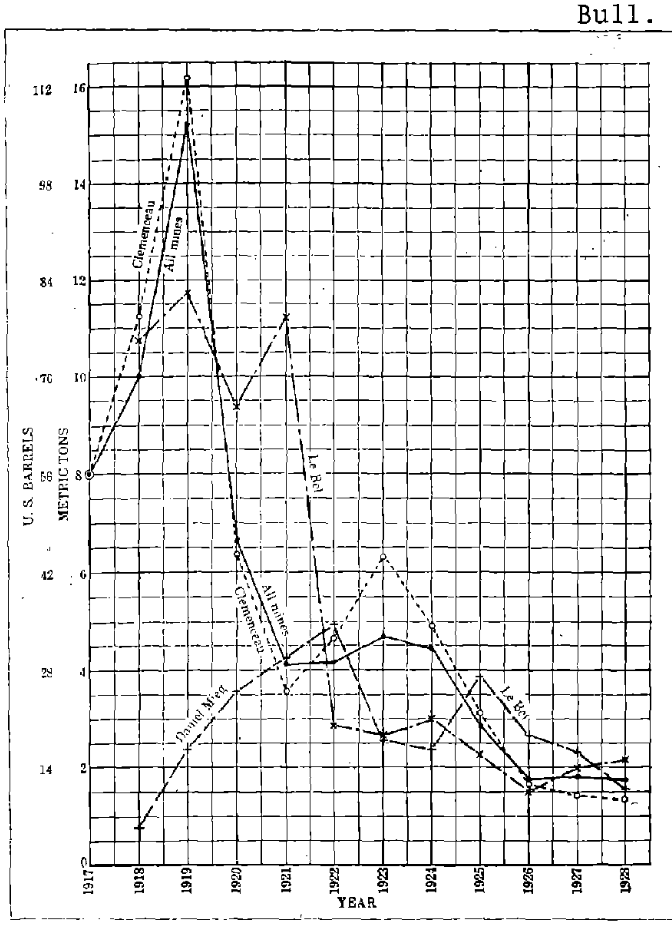

Figure 4. Annual production of each Pechelbronn mine, combined output and annual production per meter of heading advance (USBM Bull. 351, p. 37).

2.5 PETROLEUM MINING IN GERMANY

2.5.1 Oil Field Location and Description

At Hanover, Germany, the Wietze mine is in the largest of four small oil fields on the flanks of salt domes that contain potash salts of Permian Age. These salt domes were thrust up through sedimentary layers of Triassic, Jurassic and Cretaceous Ages. The oil bearing zones are in six horizons and are beds of sand, sandstone or clay sand in the Upper and Lower Jurassic and the base of the Lower Cretaceous Period. These sedimentary beds lie at steep angles at the flanks of the salt domes. The geologic units containing the hydrocarbon material are covered unconformably by the Upper Cretaceous, Tertiary and alluvial sediments. The porosity of the hydrocarbon beds varies widely. The oil bearing strata in the Wietze field is about 200 ft. thick and contains four pay zones separated by clay beds.

2.5.2 Mining System

Rice reported in Bulletin 351 that the Wietze mine was developed by sinking two vertical shafts about 842 feet deep which intersected the four oil sand beds. One shaft served as the main hoisting shaft which was downcast for ventilation. The air came back up the other shaft which was equipped with a large ventilating fan at the surface. Two main landings were constructed at depths of 733 and 812 feet. From these landings the main crosscut levels crossed the four oil sand beds. Branch levels were turned into the intersection of each bed both to the right and to the left. Inclined passageways for rope haulage were constructed up and down the dip of the formation. From these passageways secondary or sublevels were developed. This development plan divided each bed within the mine area into blocks or panels and provided haulageways and drainage channels for the oil.

In a manner similar to coal mine ventilation, the layout of the mine passageways also served for coursing the air. The passageways outlined blocks that were extremely irregular because the strike of the beds changed direction frequently as the result of numerous faults and folds. The blocks were shaped as irregular trapezoids approximately 100' x 200' in size. When the Wietze mine was started, the arrangement for drainage was similar to that used at the Pechelbronn mines in 1917-1918 except as modified by the difference in the character of the beds. The Wietze beds were much thicker and the roof and floor were much softer than at Pechelbronn. In general, the porosity of the Wietze sands was higher than at Pechelbronn with the exception of the number 4 bed where sand is extremely fine. Where the oil sands were thick and rich, forepoling (Figure 5) was required in driving headings. The usual methods of timbering drifts were employed, with timber sets spaced about 3.3 ft. apart. In permanent or semi-permanent drifts, steel rail girders were used for cross bars, with the flange placed upward and the head down. In passageways, the head was placed against the lagging and the flange was cut away on either side of the post so that the web could be inserted in its slot cut in the top of the wood post.

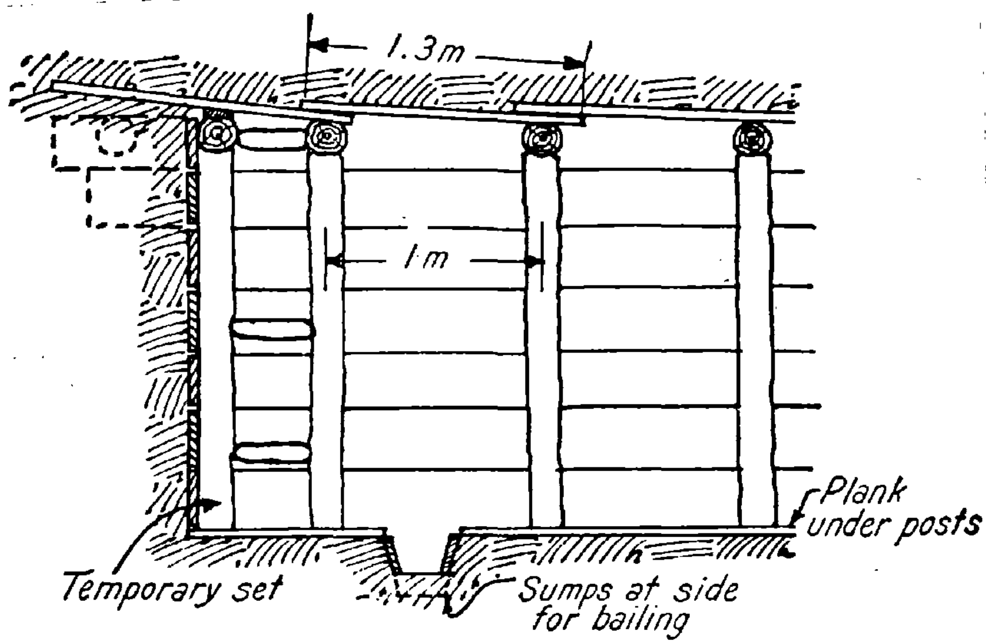

Figure 5. Forepoling required in the Wietze mine in soft sand (USBM Bull. 351, p. 57).

2.5.3 Petroleum Production

Drainage troughs or launders (Figure 6) extended along the raise side of the headings. Drain holes were drilled periodically into the pay zone along the entry. Other holes were drilled upward into other sands. The crude oil from these holes ran into troughs or soaks. There was little free gas in the oil and the production mechanism was gravity drainage. Special troughs were constructed in certain areas to act as oil-water separators.

Initially, the fluid was drained from the main levels by open ditches. In more permanent levels which had circular or elliptical brick linings the space below the mine track was used as the drainage ditch. Later, pipe and tubing was used for drainage. Small sumps in the headings collected oil which was bailed into the side ditches. From a principal sump in each heading, oil was pumped by compressed air through a pipeline to one primary sump location near the main shafts. The oil was pumped to the surface by a deep well pump through a drill hole that extended from the surface to the primary sump.

Because the sand in the No. 4 bed was so tight the fluid would not drain, a longwall mining method was developed. The longwall face, about 200 feet long was parallel with the pitch of the bed. The oil sand was compacted but not cemented, making excavation relatively easy. The loose sand was shoveled onto a canvas or rubber belt conveyor located parallel to the longwall face. The oil sand was conveyed to the rise end of the face and dumped

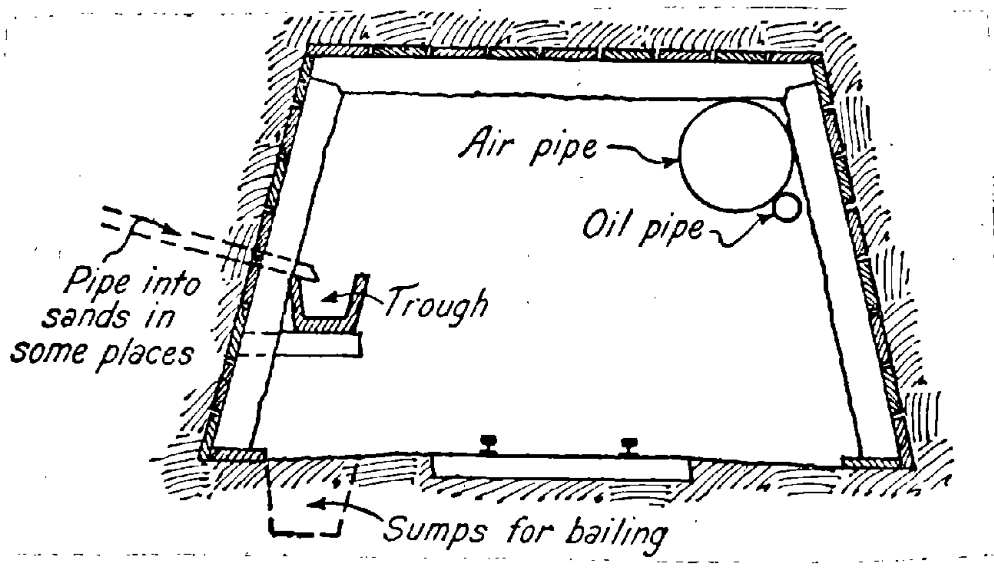

Figure 6. Cross section of heading of an oil-draining gallery at the Wietze mine (USBM Bull. 351, p. 57).

onto a conveyor belt located in a sublevel extending along the upper edge of that block of oil sand. This conveyor moved the sand to a winze or blind shaft where it was discharged onto another belt located in the main 812 ft. level for loading into mine cars. By endless rope the cars were then hauled to the main shaft and there hoisted to the head house. Here the sand was dumped into a hopper and subsequently into closed tanks, ready for surface separation and processing.

Officials of the mine reported that 30% of the original oil content in beds 1, 2 and 3 was obtained by surface wells and 60% of the remainder or 42% of the original content was obtained by underground gallery drainage. The mine also was experimenting with mining and hoisting a certain amount of oil sand to the surface and washing it with hot soda solution to recover the oil. Part of this sand was obtained from headings developed for drainage in three of the beds, but the bulk of the sand came from excavating the fine sand by a semi-longwall face working in No. 4 bed. The total output of oil sand hoisted to the surface per day from all sources was 250-300 metric tons which yielded 210-245 barrels of crude oil by the washing method. The underground drainage method used for the other three beds produced 455 to 490 barrels of crude oil daily for a total of some 700 barrels daily from the entire mine.

2.5.4 Production Statistics

The Wietze mine was opened in 1919. Annual combined production from both wells and mines in the Hanover field had increased to 667,000 barrels by 1926 and in 1927 the output was 678,000 barrels. In 1928, production fell to 644,000 barrels but in 1929 rose to about 721,000 barrels. Nearly one half the total annual German production for 1929 came from the Wietze-Steinforde field. The annual production of the Wietze mine was not published, but it was reported to have produced about 189,000 barrels of oil, 56% of the Wietze-Steinforde field production in 1929.

Mine management reported in 1929 that an average of 0.847 barrels of crude oil were produced per manshift from the oil sand excavated from the longwall face. They also disclosed that 1.869 barrels per manshift was produced from the mine, including oil from the mined oil sand and drainage.

There was an average of 301 men working underground and 142 working on the surface in 1929. The average wage of the underground worker was approximately $1.58 per shift and approximately $1.51 for the surface worker. The approximate average for all employees was $1.55. Production per month was about 4,200 barrels of mined oil and 13,300 barrels of drained oil, making a total of 17,500 barrels. Underground accidents in German oil mines are listed in Table 2.

According to Wietze mine management, about 8 to 10 barrels per foot of drained oil was recovered in newly driven galleries. Additionally, after drainage, about 3 to 5 barrels per foot were obtained from the relatively small amount of sand excavated in driving headings.

Estimated cost of producing oil in the Wietze-Steinforde oil field near Hanover, Germany, from 1919 to 1929 was $3.45 per barrel, a figure close to the cost of producing a barrel of oil in the Pechelbronn oil field in France. The higher cost included mining by the drainage method as well as actually mining the oil sand and washing it on the surface. The latter practice increased the average cost per barrel considerably. Drained oil was produced at a cost of $2.10 per barrel and mined oil sand at a cost of $4.50 per barrel. If only drained oil was produced, total cost per barrel would be less than $3.00. Germany's petroleum resources were limited and, in the interest of conservation, all oil possible was recovered regardless of cost.

Table 2. Record of underground accidents in oil mining in Germany (USBM Bull. 351, p. 65).

Location and conditions surrounding accidents	Number of persons killed or injured											
	1928				1929				1930			
	Total	Fatal	Injuries, weeks: Over 13	Injuries, weeks: 4 to 13	Total	Fatal	Injuries, weeks: Over 13	Injuries, weeks: 4 to 13	Total	Fatal	Injuries, weeks: Over 13	Injuries, weeks: 4 to 13
Falls of rock:												
In blind shafts and inclined headings	4		1						1			1
In level gangways	4			2	7			4	4		1	1
At working face	2			2	14			11	9		2	3
Mining tools and machinery	2			1	3							
In main shafts:												
Ascending or descending ladders	1		1						1			
In haulage	4		1	2	4			1	3			2
In blind shafts and inclined headings:												
By falling									2		1	
By haulage	4	1		2	3			2	7		2	1
Miscellaneous	6			5	6			4	18		1	10
In level gangways:												
While traveling	3				6			3	4			2
Haulage by machinery	34		3	3	27			11	12		1	6
Haulage by hand	39		1	12	19			8	24		2	12
Miscellaneous	22			8	22			8	27		1	11
At the working face, general	10		1	1	12			4	9			1
Caused by natural gas	1			1								
Other causes:												
By machinery and mechanical arrangements	1											
Miscellaneous	1				1			1				
Total injured and killed	138	1	8	30	124	0	0	57	121	0	11	50
Per thousand employed	367.0	2.7	21.3	103.7	323.8			148.8	200.2		26.4	119.9

1 The Wietze mine is the only oil mine in the Clausthal district. Figures in table abstracted and compiled from statistics appearing in Zeitschrift für das Berg-, Hütten-, und Salinenwesen im preussischen Staate (Berlin) for the years 1928, 1929, and 1930.

2.6 PETROLEUM MINING IN RUSSIA

Early in 1976, Russia released reports that it had developed the world's first thermal-mining methods employing underground mining techniques, drilling from underground stations and injecting steam from subsurface stations to reduce oil viscosity so that high viscosity crude could be pumped to the surface. The technique reportedly is economical, recovering up to 60% of in place oil at an operating cost of $5.82 per barrel. The process has been in commercial use since 1972 in the Yarega oil field near Ukhta, Komi Autonomous Soviet Socialist Republic, approximately 755 miles northeast of Moscow. Operating at a depth of 650 feet, the process is expected to recover up to 60% of the reserve compared to only 2% recovery by conventional methods. Resource Sciences Corp., Tulsa, Oklahoma, is the licensing agent for the process in the United States.

Although not a totally new approach, as discussed in the French and German sections of this report access to the reservoir is gained by sinking shafts 60 to 100 feet above the reservoir. Drifts are then driven out along the reservoir and incline production galleries then developed into the pay zone.

From the production galleries, some 250 production boreholes 600 to 800 feet deep are extended outward and upward into the reservoir. At the steam injection galleries, located at the main working level, borehole or steam injection wells are drilled downward and upward at these locations. Steam is then injected at 75 to 120 psi into the boreholes at rates varying from several kilograms per hour to 4 or 5 tons per hour.

Combined oil and water collected underground is advanced by open gutters, and pumped to a central underground storage facility where oil is separated from the water and finally pumped to the surface.

Resources Sciences Corp. reports that the technology is based on the following appropriate combinations:

1. Intense heating of the reservoir-(600 to 1,000 square feet per injection well).
2. Low injection pressure (not over 75 psig).
3. Optimum distribution of production wells.
4. Favorable geology and mine construction.
5. Recycling of heated water appropriately placed in the reservoir after recovery from production.
6. Use of chemical additives (surfactants).
7. Effective utilization of natural fractures in the reservoirs.
8. Cyclic injection of steam based on a preprogrammed plan of operations.
9. Knowledge of fluid and heat flow parameters of the reservoir.

2.6.1 Undersea Petroleum Mining

Russia also reportedly plans to recover heavy viscous oil from undersea mines at its old Baku area offshore fields in Azerbaijian, as well as develop new fields in the Caspian Sea.

As to offshore drilling, depending on the distance of the field from shore and on water depth, two methods of reaching the reservoir can be utilized: 1) by a mine shaft located onshore or on an offshore bank or island. In this instance, the main shaft diameter can vary from 11.5 to 26 feet, and 2) by a main shaft located offshore. The latter technique presently is used for oil fields lying farther from shore but in water depths less than 328 to 492 feet. It calls for a vertical all-purpose structure of reinforced concrete 138 feet in diameter and tall or long enough to rest on the ocean floor. Prefabricated onshore, this structure is floated horizontally and towed to its offshore location in the center of the oil field where it is flooded and positioned in its proper location. Mining takes place within the concrete structure.

2.7 TAR SANDS TECHNOLOGY

Although the production of oil from tar sand deposits in Canada and the United States has not been too economically successful, independent companies and governments are spending large sums of money and devoting considerable time to develop economical mining systems and processes to recover the huge oil reserves locked up in these deposits.

With regard to mining these deposits, all operations to date have used surface mining methods, with some attempts being made to recover the oil by in situ methods. Nearly all attempts at recovering oil from tar sand deposits have been carried out in Canada. The methods employed are worth noting, as regards to oil mining, especially since Getty Oil Co. has recently announced plans to surface mine oil sands in California.

2.7.1 Mining Tar Sands in Canada

The largest and most significant surface mining operations now producing oil are located in the Athabasca tar sands located in the province of Alberta, Canada. These sands underlie about 19,000 square miles and are estimated to contain 895 billion barrels of proven, in place crude bitumen of about 8°API gravity. The bitumen-bearing sands are of Mesozoic Age, deposited on eroded Paleozoic sediments and are in turn covered by Cretaceous sediments, glacial drift and muskeg to depths ranging from 0 to 2,000 feet. Of the 12,013,000 acres of known tar sands, about 490,000 acres containing about 74 billion barrels of bitumen, are covered by overburden up to 150 feet thick. When mined and processed, this amount of bitumen will yield 27 billion barrels of pipeline grade crude.

Fort McMurray, about 240 miles northeast of Edmonton, is near the east central edge of the Athabasca deposit which has a maximum north-south extent of about 160 miles and a width of about 80 miles. The portion of the deposit within a 60 mile radius of Ft. McMurray is the area with overburden thickness of 0-150 feet. It is the first area being developed and is where 90% of the existing acreage of tar sand leases are located.

The tar sands consist of rounded or sub-angular quartz grains packed to a void volume of about 35%. Normally, a water film coats the sand grains and the wetted particles are covered with a film of bitumen that partially fills the voids. The remaining void space is filled with water and occasional small volumes of gas. The sand deposit also contains lenses of clay, and other fines which occupy part of the void space in the tar sands. Bitumen content ranges from 0% to 17% by weight. A bitumen content of 6% is considered the cutoff point for calculating reserves, but other factors such as strip ratio and position in the sand formation may cause the cutoff point to vary.

2.7.1.1 Great Canadian Oil Sands, Ltd.

The ore body on one of the leases of the Great Canadian Oil Sands, Ltd. (GCOS) averages 130 feet in thickness within present pit limits. The overburden is up to 235 feet thick, but averages 53 feet in thickness. Cutoff grade is 8% bitumen, but average bitumen content of mined sand is slightly over 12% dry weight. The weight percentage of minus 325 mesh "lines" in sand averages about 16%. A Shell Oil lease on which four ore bodies have been delineated shows similar characteristics. Using 6% as the cutoff grade, the deposits contain 11.5% dry weight of bitumen over a thickness of 135 feet. Average overburden thickness of 32 feet, combined with an average center zone reject thickness of 20 feet, gives a waste to ore ratio of 0.38:1, while the average fines content is 14.3% of the mineral component of the mined tar sand. The bitumen content decreases as fines content increases, whereas water content generally increases with increased fines content.

All surface mining in the Athabasca region faces difficulties in equipment operation and maintenance. In the winter the frozen tar sand is tough, hard and extremely abrasive causing extreme wear on bucket teeth and intense stress on all mechanical structural parts. In the summer the floors of the bench yield to the weight of the massive equipment. Tar accumulates on all surfaces in both seasons and organic compounds in the tar attack rubber tires causing high maintenance cost.

Despite these difficulties, the GCOS plant went on stream in 1967, but design level of output was not achieved until late 1970. During 1972 and 1973 average production was more than 50,000 barrels per calendar day.

The mining operation of GCOS consists of clearing muskeg, overburden removal, oil mining and transportation, as well as construction of retaining dikes. All vegetation must be cleared separately so as to exclude it from the earthwork dikes. The underlying muskeg, up to 20 feet thick, must be ditched and drained and cut into huge blocks which are moved in the winter as frozen blocks in 150 ton end dump trucks to disposal areas encircled by earth retaining walls. The lease agreements require that all spoil material and waste be stored on the lease. Eighty percent of the overburden is used to build high dams inside the pit to contain future mill tailings. These dams are up to 300 feet high with slopes of 2.5:1 and contain impervious clay cores. Bulldozers, frontend loaders and 150 ton trucks are used in stripping and dam building. Mining tar sands to produce 55,000 barrels per calendar day of product requires mining and processing 140,000 tons per day of oil sand and removal of about 70,000 tons per day of overburden. Two large German made bucket wheel excavators, operating one above the other on separate benches dig the oil sand and transfer the broken material on articulated conveyors to face conveyors which in turn discharge onto other conveyor systems leading to the extraction plant. Isolated portions of the oil sand are mined with a smaller bucket wheel, discharging into trucks that haul to the trunk conveyor system. The two large bucket wheels each weigh about 1,800 tons and are supported and moved on six tracks. Each is electrically powered, and has a 33 foot diameter digging wheel mounted on a boom. The wheel which requires about 1,400 horsepower has an average output of about 5,000 tons per hour. The mining system is capital intensive but not labor intensive. Each large bucket wheel, for example, employs only eight men per shift.

2.7.1.2 Syncrude Canada Ltd.

Syncrude Canada, Ltd. utilizes walking draglines with 75 to 90 cubic yard buckets to strip overburden, excavate oil sand and remove the center reject material occurring in the oil sand bed. Waste materials will be cast into previously mined areas using the draglines. Plant grade oil sand will be stockpiled on the surface when excavated and picked up as needed by bucket wheel reclaimers, assisted by frontend loaders. It then will be transferred by belt conveyor systems to the extraction plant. When at projected output of 125,000 barrels per calendar day of crude oil, Syncrude will have to move about 92 million tons of oil sand and 45 million tons of overburden and submarginal oil sand per year.

2.7.1.3 Shell Canada Ltd.

Shell Canada Ltd. and Shell Explorer Ltd., with a design capacity of 100,000 barrels per calendar day of product, will require about 75 million tons of plant feed annually, or 225,000 tons of ore daily, and the removal of some 85,000 tons of waste. Shell plans to strip overburden and waste and to mine oil sand, utilizing four walking draglines with 75 to 90 cubic yard buckets. Waste and overburden is to be backcast into mined out areas once they are available. Ore will be stockpiled on the surface and then reclaimed as required by bucket-wheel reclaimers and frontend loaders. A conveyor system then will move the ore to railway cars for shipment to the processing plant.

2.7.2 In Situ Research

The Alberta Energy Resources Conservation Board (AERCB) estimates that there are 74 billion barrels of crude bitumen in the Athabasca oil sands deposit in areas having 150 feet or less overburden. This represents but 8% of the total 895 billion barrels of reserves estimated by AERCB for the total area as shown in Table 3.

The remaining 92% of the in place bitumen lies at depths of 150 to 2,500 feet. Not only does the added depth present a very substantial constraint on surface mining but the crude bitumen per acre is so much less that costs would be prohibitive except for in situ techniques now being researched by several of the lease holders. An economic in situ process would eliminate the costly bulk materials handling and also would have the further advantage of eliminating many of the environmental problems attached to the extreme surface disturbance associated with clearing the spruce, tamarack and other vegetation, stripping muskeg, placement of dikes up to 300 feet high, and

Table 3. Estimated In Place Reserves of Crude Bitumen (AERCB).

Deposit	Overburden Depth Interval, (ft)	Areal Extent, (M acres)	Crude Bitumen, (10^9 bbls)	Crude Bitumen, (bbls/acre)
Athabasca	0-150	490	74	151,020
Athabasca	150-2000	5,260	552	104,943
Buffalo Head Hills	500-2500	159	1	6,289
Peace River	1000-2500	1,180	50	42,373
Wabasca A	250-2000	764	30	39,267
Wabasca B	1000-2500	1,000	24	24,000
Cold Lake	1000-2000	3,160	164	51,899
Totals		12,013	895	74,503

huge tailings impoundments that are required in processing hundreds of millions of tons of tar sands.

In situ processes presently under study include the following: Amoco Canada has developed a combination fire flood-water flood (COFCAW) process. Forward combustion is used to heat a portion of the reservoir to 1,500°F, after which air and water are injected into the formation. The water disperses the local high temperature and results in a larger volume of the sand being heated to about 200°F. The bitumen then becomes more mobile and responds to air and water drive pressures, permitting recovery through production wells. Working in a formation thickness of 120 feet, the field test is reported to have been satisfactory.

Shell Canada, Ltd. tested an emulsion process in field trials in 1957-1962 on the assumption that water with a suitable surfactant would yield a bitumen-in-water emulsion (20-30% bitumen) with a viscosity approaching that of water. Field tests between 1957 and 1959 used a proprietary non-ionic surfactant in water and those in 1960-1962 tested the use of NaOH (sodium hydroxide) in water combined with a steamdrive technique. Shell also successfully experimented with formation of horizontal fractures to establish flow between injection and production wells.

Imperial Oil, Ltd. was producing about 1,500 barrels per day of crude bitumen from 23 shallow wells using steam injection in the Cold Lake deposit. Shell also tested steam injection on a site in the Peace River oil sands. Gulf Oil, Canada, was given approval in January, 1975 by the AERCB to recover 50 barrels per day of bitumen from the Wabasca deposit by steam drive.

The advantages, disadvantages and costs of these various techniques are being carefully evaluated by both the concerned corporations and by the Alberta Energy Resources Conservation Board, which issues the leases and is concerned with recoveries and the overall economics of maintaining viable technology to the advantage of the province.

2.7.3 Economic Summary

The capital costs, percentage cost range of major capital cost items and the estimated cost per barrel of synthetic crude for the surface mining-processing plants as of the end of 1974 presented in the January 1975 issue of Mining Engineering are given below.

Table 4. Capital Cost Comparisons, Canadian tar sands projects (Mining Engineering, Jan. 1975)

Project Name	Capacity in bpd	On-Site Cost In $ Millions	Total Project Cost In $ Millions	Total $ Cost Per bped of Capacity
GCOS	50,000	180	260	5200
Syncrude	125,000	800	900	7200
Shell	100,000	510	710	7100
Petrofina	122,500	*NA	830	7000

*Not Available

Table 5. Canadian tar sands, percentage cost range of major capital cost items (Mining Engineering, Jan. 1975)

Item	Percent of Total
Mining and Materials Handling	20-25
Extraction and Dehydration	10-15
Bitumen Upgrading	25-30
Utilities	20-25
Offsites	10-15
Preproduction and Start-up	5-10

Table 6. Estimated Total Cost per Barrel of Product (Mining Engineering, Jan., 1975)

Grade % Bit	Product Bbl Per Ton	Dollars per bbl of product with Cost per ton of material moved at: 25¢	30¢	35¢	40%
10.1	0.4225	1.21	1.46	1.70	1.94
10.50	0.4436	1.16	1.39	1.62	1.85
11.00	0.4643	1.10	1.32	1.54	1.76
11.50	0.4859	1.05	1.26	1.48	1.69

The corporations involved have invested tremendous sums in capital, operating costs and royalties and have had the further disadvantage that they had to pioneer new technology and applications as well as possibly placing tailings and waste materials in a temporary location, pending the development of a mined area to which they could later be moved. They have had the advantage that the areas now being mined and produced have the least cover and the most bitumen per acre.

Atlantic Richfield withdrew from its 30% interest in the Syncrude project in 1974 because of "the deteriorating economics of the project caused by the rapid inflationary increases in capital and operating costs." At about the same time, the GCOS was reported to have a cumulative loss of $80.2 million since beginning production in 1967. To what degree the effects of inflationary costs have been offset by improved product prices are unknown.

2.8 EARLY PATENTS ON PETROLEUM MINING

Use of underground methods, such as shaft sinking in 1865 in Ohio and tunneling in 1866 in California, was the natural trend in this country as well as abroad before well drilling methods were developed. This is indicated by Patent 50903, which was issued to Paul Casamajor, of New York City, November 14, 1865. The process is described as follows:

"An oil well composed of a main shaft which terminates at a suitable distance above the rock containing the oil, and from which galleries extend in a horizontal or oblique direction, in combination with drillholes sunk from said galleries in a vertical or oblique direction substantially in the manner and for the purpose set forth."

It was not until after descriptions of the successful use of mining methods in France and Germany for oil fields more or less depleted by wells from the surface were published that many patents were issued. One of the first important foreign patents after 1920 was that of Adolph Ehrat, Zurich, Switzerland, granted by France, August, 1921. He was given British Patent 175116, February, 1922. This patent is similar in principle to the Casamajor patent, but the plans and specifications indicate a more complete project. Shafts sunk to or through the oil bearing strata were proposed, and horizontal galleries were to be driven either above, or preferably below, the oil bearing strata. From these galleries vertical holes were to be drilled extending up or down, as the case might be, into the oil sand. The holes were to be cased and the casing connected to pipe lines extending to the surface, with the idea that the oil and gas could thus be taken out of the strata without entering the mine passages except as confined in pipelines.

Gotfried Schneiders, Berlin, Germany, received United States Patent 1418097, May, 1922. Application for a German patent was claimed to have been filed January 15, 1917. It proposes the use of a protective cylindrical metal shield to be placed in each heading in the oil sand, the shield to be forced ahead, as in tunneling through silt or water bearing ground. Evidently it is designed with the expectation of use in unconsolidated oil sand. The specifications indicate further that through valve openings in the vertical diaphragm of the shield, boreholes are to be drilled into the sand horizontally or slanting for long distances to the oil and gas. The holes are to be cased with perforated pipe to permit oil to enter and collect in a sump in an excavation between the shield diaphragm and the unmined sand. After the oil and gas pressure has been relieved by drainage into pipelines extending through the shield diaphragm and thence to the surface, miners enter by a manhole in the shield diaphragm into a space ahead and excavate so the shield can be again pushed forward.

Paul de Chambrier, former general manager of the Pechelbronn Mining Co., obtained United States Patent 1506920, September, 1924, on an oil mining and drainage system. His claims cover a scheme of galleries in the oil sand, with open ditches and sumps. The specifications included practically all the methods used at Pechelbronn until 1924.

John L. Rich received United States Patent 1507717, September 9, 1924. The method consists essentially of putting down two shafts; an operating and an air shaft, to a tight stratum above the oil sand and driving tunnels in that stratum around rectangular blocks 165 by 330 feet or other dimensions; at regular intervals in the tunnels on the long sides of the block, boring large vertical holes or sinking pits through the oil sand; then drilling horizontal holes by diamond drills or other means from one tunnel, at the top of each vertical hole or pit, to the opposite tunnel. Endless wire ropes with sand feed are put through these horizontal holes and down into the vertical holes on each side, passing around a sheave at the bottom of each vertical hole and up to the tunnel level, then to some driving mechanism. The endless wire rope would be used to saw slits down through the oil sand, using sand for an abrasive, following a method now employed extensively in sawing long vertical cuts in large stone quarries. The slits in the oil sand would then form channels for the flow of oil into the pits and to collecting galleries where the oil would be pumped to the surface. The Rich patent specifications also include the application of gases and fluids under pressure through wells drilled inside of the blocks surrounded by the channel galleries.

R.L. Wright was granted United States Patent 1520737, December, 1924. The specifications include boring holes -- 5 feet in diameter -- to serve as shafts, from the surface through the oil sand and enlarging to provide a chamber at the bottom with place for a sump and a pump, the borehole "shaft" and the chamber to have a tight concrete lining. From the chamber holes would be drilled radially and diagonally upward to pass through the oil sand and thus provide means of drainage into the oil sump in the chamber.

Leo Ranney of New York received United States Patents 1634235 and 1634236 June 28, 1927 (on improvements of prior applications-serial 683703, filed December 31, 1923, and serial 711596, filed May 7, 1924). The specifications include sinking shafts to or through oil sands and driving tunnels around blocks and drilling wells from the tunnels at frequent intervals --10 feet--up or down, as the case may be, to reach the oil sand. These wells were to have casings tightly cemented in them, each with suitable valves and connections to a pipeline system extending through the mine passages. Ranney suggests that the tunnels might be driven around 40-acre tracts; and if the wells are placed at 10-foot intervals 528 wells would surround each 40-acre tract, and three-fourths of the oil in it will have to flow through an average distance of only 165 feet of sand to reach the drainage outlet. In a paper, Ranney gave details of his proposed method, which would prevent gas and oil from entering the tunnels. He suggests the use of steam or dry heat in the sands to expel the oil and also proposes that the process may make use of various other means of explusion of oil from the sand, such as gravity, gas, and hydrostatic pressure. Although he does not recommend that the process be used in any oil sand until gas pressure has been greatly diminished he believes that, since the tunnels will be in tight ground or below cap rock and any cracks may be sealed by cementation, there will not be a hazard from gas. However he agrees that the tunnels are to be well ventilated.

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SECTION 3

PETROLEUM ENGINEERING TECHNOLOGY

3.1 INTRODUCTION

The Petroleum Industry began in 1859 in Pennsylvania when the Drake well was drilled purposely to find liquid petroleum. The industry grew slowly and it was not until 1901, with the discovery of the Spindletop field in Texas, that the world was convinced there was more petroleum than could ever be consumed. The birth of the automobile industry created a growing demand for petroleum products and accelerated growth in the petroleum industry.

Because world demand for petroleum was far smaller than production, the oil reservoirs found prior to 1940 were produced using only the natural energies of the reservoir. In the late '30s waterflooding and gas injection were initiated in some petroleum reservoirs in Pennsylvania and New York that had been depleted of their natural energies. These reservoirs usually had been depleted to pressures less than 100 psi and were waterflooded at pressures of 400 to 800 psi.

After World War II the petroleum industry began using more engineering techniques to develop petroleum reservoirs, resulting in pressure maintenance by water and/or gas injection at an early stage in the productive life of a reservoir. These projects were initiated at reservoir pressures usually in excess of 500 psi (pounds per square inch) and many times were increased to pressures as high as 4000 psi. The oil remaining in these reservoirs however, still contains considerable gas in solution.

In the late '50s, it was evident that finding new petroleum was becoming more difficult and more expensive. The world demand for petroleum had grown at an unpredicted rate and it became evident that the world petroleum productive capacity would soon fall short of demand. As a result, new recovery processes--fireflooding, steam stimulation, steam flooding and miscible flooding--were initiated in an effort to increase the recovery from existing reservoirs and to produce from reservoirs not producible by natural forces. These techniques were expensive and in some cases did not achieve the desired degree of success. At the present time the only process still being used with consistent success is steam stimulation and steam flooding for those reservoirs with low gravity, high viscosity oil.

In the mid '60s, the industry began to investigate the possibilities of tertiary recovery in reservoirs that had been water flooded in the mid '40s. Tertiary projects, utilizing caustics, surfactants, special emulsions and polymers, were initiated on an experimental basis. At the present time the Federal government, through the Department of Energy (DOE), and the petroleum industry are continuing to investigate tertiary recovery processes. Currently, none of these techniques are a universal economic success.

3.2 NATURE AND OCCURRENCE OF PETROLEUM

A key to unlocking the origin of petroleum is to note the environmental conditions of petroleum accumulations as they exist today. Crude oils are complex mixtures of many different hydrocarbons and impurities and no two reservoirs contain crude oil of exactly the same composition and in the same physical state. In geological terms, petroleum is not a mineral because it varies so widely in composition. It can however be called an organic mineraloid, although the terms mineral fuels and fossil fuels have become widely accepted.

Generally, petroleum occurs in sediments which are chiefly marine in origin. In terms of fossil fuels, the fossil organic matter had to be buried quickly and in some manner protected from decay. Continental, or non marine, sediments therefore would not be a likely source bed for petroleum because continental sediments are subjected to oxidation and other weathering agents. Petroleum source beds are more likely to be of marine origin. Organic material is constantly settling to the bottom of seas along with the silt, clay and other water transported materials. The sea bottom generally is undisturbed, sediment is continually being deposited and usually there is not enough oxygen to support decay and disintegration of organic matter.

Petroleum has been found in sediments ranging in age from Precambrian to Pleistocene, although occurrences in the Precambrian and Pleistocene rocks are infrequent and anomalous. Petroleum existing in the older sediments indicates that it can be preserved and protected from decay or other destruction over long periods of geologic time.

Insoluble organic matter has been found to be nearly universal in the sediments. It took modern analytical technology to discover that organic matter soluble in organic solvents also occurs almost universally. Analytical investigators have reported concentrations of the soluble petroleum hydrocarbons in the sediments ranging from 10 to 50 barrels per acrefoot. More commonly, the sediments contain less than 10 bbls/acrefoot. Living organisms contain many of the same hydrocarbons.

The presence of porphyrins indicates that the origin of petroleum is probably a low temperature phenomenon. Porphyrins are destroyed at temperatures above 392^{o}F (200^{o}C). Reservoir temperatures rarely exceed 225^{o}F, although temperatures up to 300^{o}F occur in some deep reservoirs. In most areas, reservoir temperatures are a function of depth and the local temperature gradient.

Porphyrins are derivations of chlorophyll and are easily oxidized and decomposed when exposed to the atmosphere. This suggests that petroleum is formed under anaerobic or reducing conditions. The oxygen content of petroleum is usually less than two percent by weight, which also suggests a reducing environment.

Petroleum hydrocarbons occur in nature as solids, liquids and gases. The solid and liquid (and semi-solid) hydrocarbons are of primary interest in this study. Solid hydrocarbons exist as asphaltic bitumens (tar sands) and kerogen (oil shale). Semi-solid hydrocarbons are usually referred to as heavy or viscous oils and usually are found at low temperatures and pressures.

3.2.1 Origin, Migration and Accumulation of Petroleum

In general, an accumulation of petroleum requires a source bed, a transporting formation and a reservoir trap. It is generally accepted that marine, organic shales and clays are the most common source beds for petroleum. Prerequisites for a reservoir are that the host material must be porous and permeable and that it must be contained or sealed in some manner to prevent escape of the hydrocarbons. A permeable carrier bed, then, is required for the hydrocarbons to migrate from the source bed to the reservoir. A special carrier bed is not required where the reservoir is in contact with the source bed and acts as the carrier formation. The major liquid petroleum producing regions in the U.S. are shown in Figure 7. Areas containing shallow oil fields are shown in Figure 8.

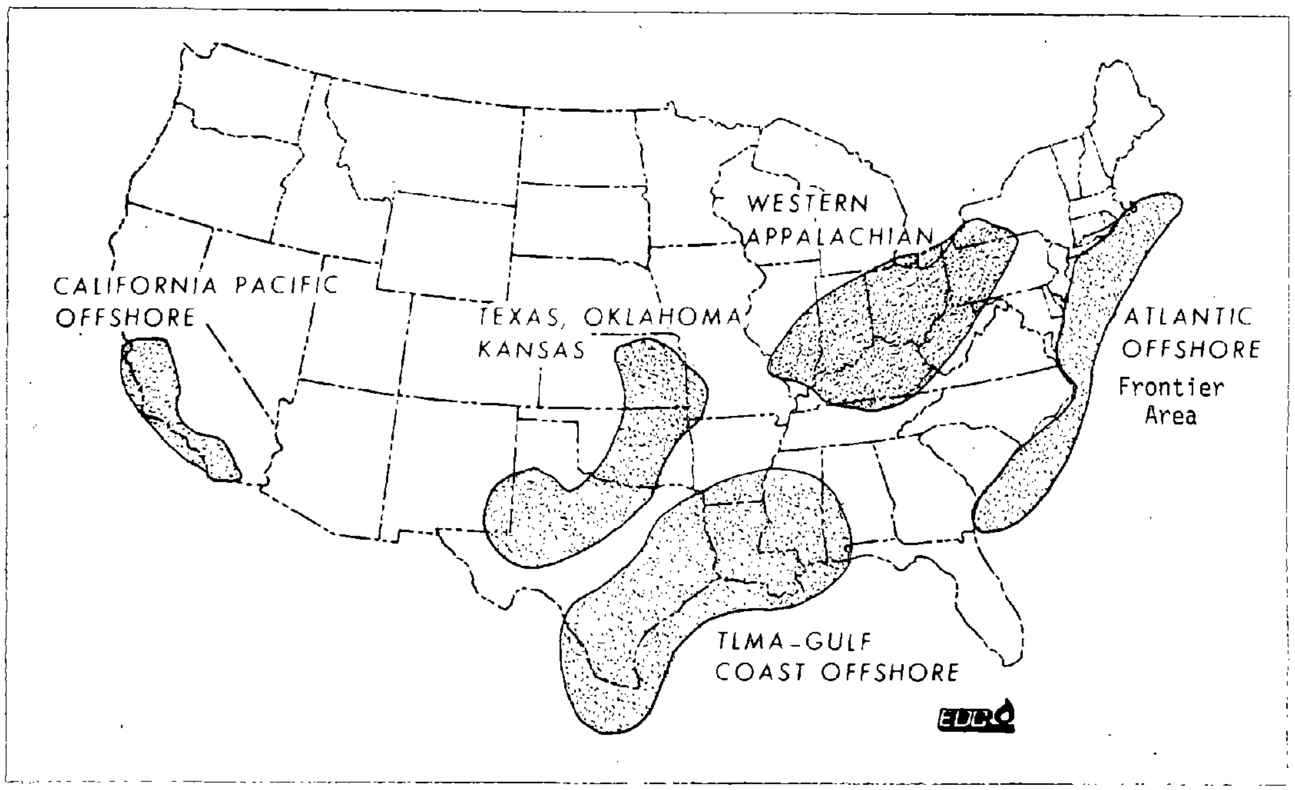
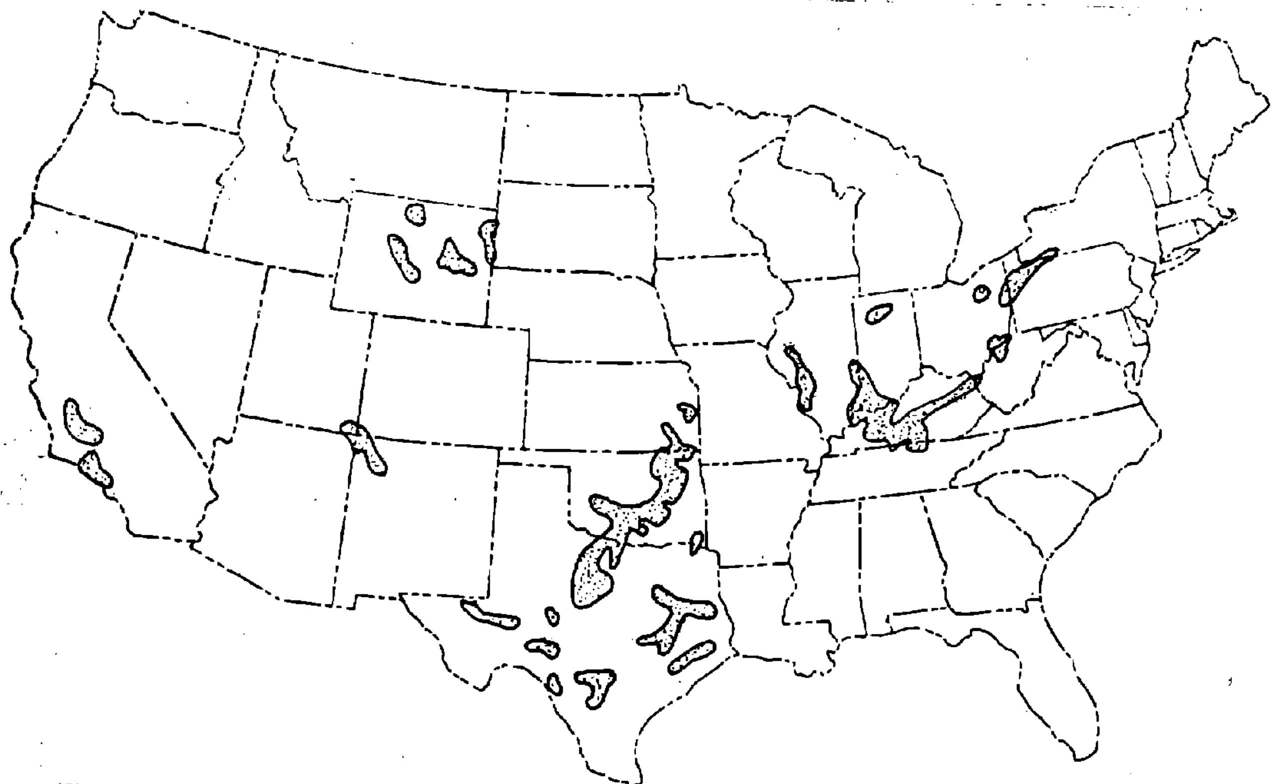


Figure 7. Map showing the four major petroleum regions in the United States (plus the major frontier area).



Source: Ball Brothers
USBM Monograph 12

Figure 8. Map showing the locations of shallow oil fields in the U.S.

Primary migration is the movement of petroleum from its source bed into a reservoir. Secondary migration is the concentration and accumulation of petroleum into oil and gas pools. The comprehensive mechanisms that cause primary migration are still subject to theory and study. The simplest and therefore the most probable theory of primary migration is that the oil and gas trapped in the water is squeezed out of the marine, organic shales and clays during the rock-forming process called diagenesis. After the diagenetic process, a lesser amount of the contained oil may be removed by groundwater circulation.

The major forces causing secondary migration and accumulation of oil and gas into a pool are capillarity and gravity. For capillary migration, the capillary pressure of the oil-water interface at a pore must be less than the displacement pressure imposed by gravity.

Vertical segregation is the result of gravitational forces that cause less dense fluids to rise to the surface of a more dense fluid. A fluid or a solid immersed in another fluid is bouyed by a force equal to the weight of fluid displaced. In a reservoir that contains water, gas and oil, the gas is found above the oil and the water is found below, as shown in Figure 9.

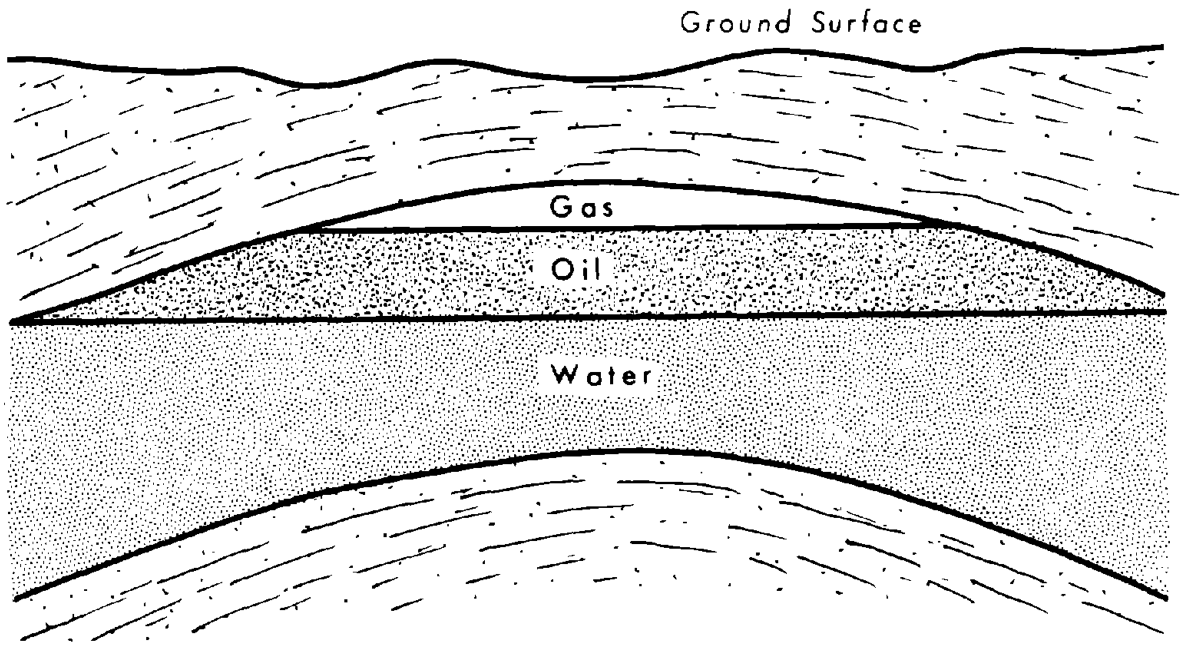


Figure 9. The position of fluids in a hydrocarbon reservoir containing gas, oil and water.

3.2.2 Traps

The requirements for the accumulation of oil into a pool are: 1) a source bed, 2) permeable carrier bed, 3) porous and permeable reservoir, and 4) some means of containment called a trap to restrict the upward movement of the oil and gas. Fundamentally, reservoir traps can be classified as structural or stratigraphic. Structural traps, as shown in Figure 10 are those due to tectonic forces that create folds and faults in the sediments. Domes, anticlines and displacement faults are examples of structural traps. Piercement domes due to salt plugs are another type of structural trap.

Stratigraphic traps, shown in Figure 11 are more a depositional feature such as a lateral change in permeability due to a change in lithology (a facies change) such as from sand to clay. Buried stream channels and organic reefs are also best termed stratigraphic traps.

The volume of reservoir available for oil and gas accumulation depends on the amount of closure of the trap. In a dome or anticline, the rock overlying the reservoir can be thought of in terms of an inverted bowl. Oil and gas can accumulate under the inverted bowl until it is filled and the gas and oil trying to enter passes under the edges of the bowl. The volume of a reservoir is dependent on how much of the reservoir is contained by an impervious cap that prevents the oil and gas from escaping and by the vertical closure of the structure.

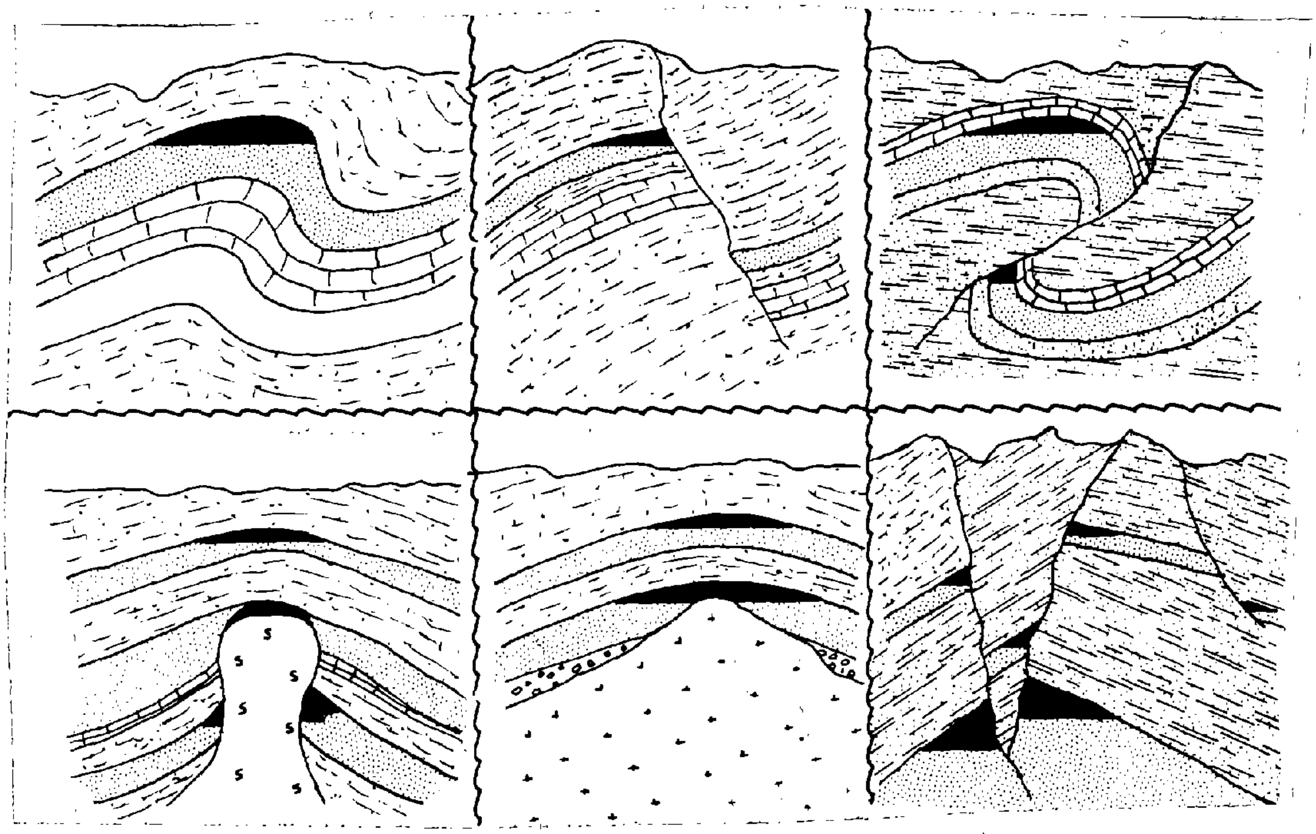


Figure 10. Common types of structural traps.

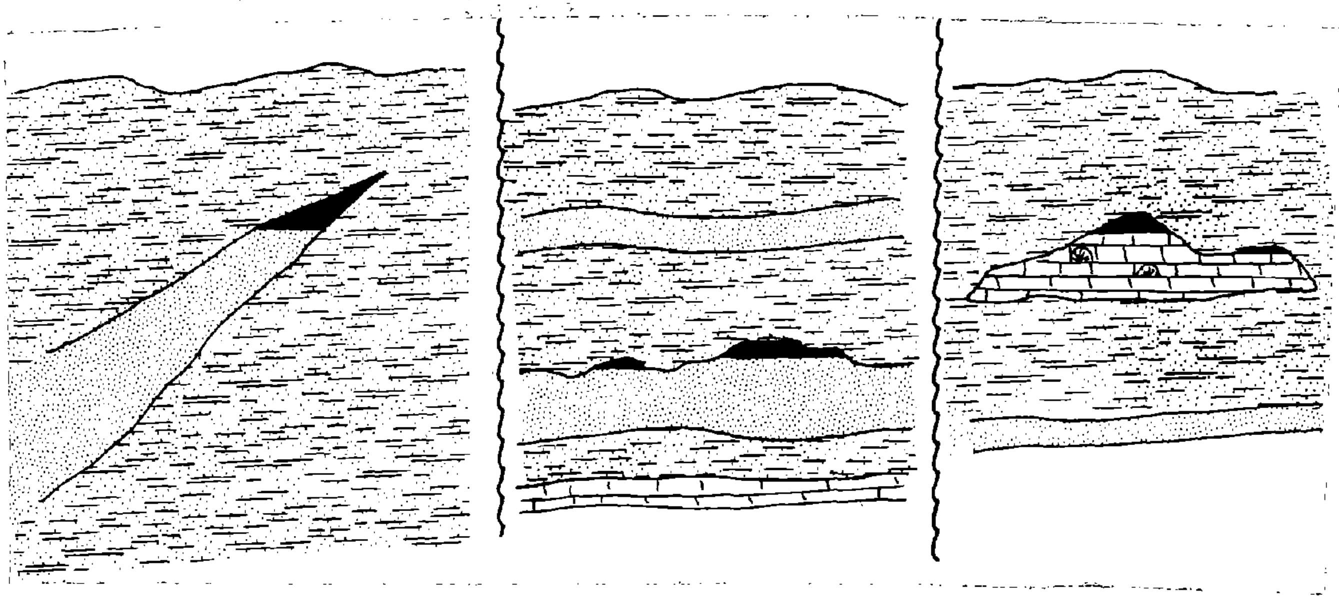


Figure 11. Common types of stratigraphic traps.

Containment traps may occur as combination traps, shown in Figure 12 with both structural and stratigraphic features and all traps and oil pools may be subject to alteration by tectonic forces due to stresses within the earth's crust.

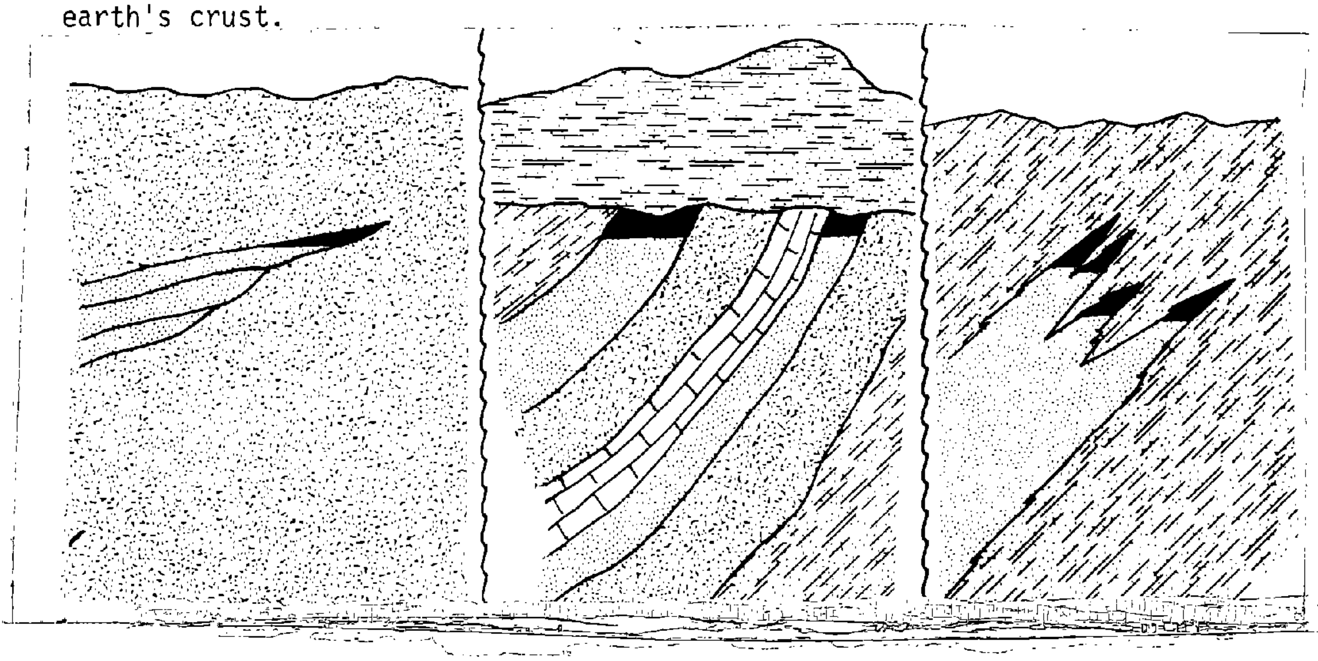


Figure 12. Common types of combination traps.

3.2.3 Drives

Potential energy within a reservoir can be measured in terms of pressure and the expansibility of the contained fluids. Fluid pressure in a reservoir may be caused by any of the following phenomena:

1. Hydraulic pressure of a column of water (ground water).
2. Overburden pressure (weight of the overlying rock).
3. Tectonic activity after fluid accumulation.
4. Osmotic pressure.
5. Cementation or precipitation of solids within the reservoir rock and other chemical or biochemical reactions.
6. Changes in barometric pressure and tide.
7. Earthquakes.

The first three are perhaps the most significant sources of reservoir pressure. The hydraulic pressure due to a column of fresh water 100 feet high is about 43.3 psi. The total head of water against a pool of oil and gas may be several thousand feet at between 390-480 psi per thousand feet of head.

In a hydraulically closed reservoir filled with fluid, the pressure within the reservoir may be partially a result of the fluid having to support part of the weight of the overlying rocks. Overburden pressure is approximately 100 psi per 100 feet of overburden, or 1,000 psi per 1,000 feet of depth. Hydraulically sealed reservoirs cannot discharge the contained fluids as fast as the formation is buried and hence the overburden load can not be transferred to the solid particles of the formation.

Osmotic pressure due to clays acting as semi-permeable membranes is a source of reservoir pressure. Osmotic pressures develop across clay beds whenever a marked contrast in dissolved salt concentrations in water exists on both sides of the clay. The direction of movement is toward the more saline side, thus increasing the liquid volume in the formation.

The effect of cementation or precipitation of solids within the reservoir is that of reducing the volume available for the reservoir fluids. Changes in barometric pressure simply are changes in the weight or density of air pressing on the overburden. In relation to overburden weight, the change in air density is generally insignificant in all but the very near surface situation. The change due to tides is usually even less significant.

Reservoirs that contain gas, oil and/or water under hydrostatic or hydrodynamic pressure are said to be normally pressured. Reservoirs under a pressure greater than would be obtained with a water gradient of 0.465 psi/ft. are usually classified as abnormally pressured.

Petroleum reservoirs are classified according to the sources of energy which will be utilized during the production process. There are basically four general classifications: 1) solution gas drive, 2) solution gas-gas cap drive, 3) solution gas-water drive, 4) combination drive which is a combination of both two and three.

A solution gas drive is one in which the gas originally contained was a liquid in the heavier hydrocarbon phase. It is evolved as the pressure is reduced within the reservoir. The expansibility of the in-place liquids in evolved gas are then used to displace the petroleum to the producing well.

Solution gas-gas cap drive is one in which, on discovery, there are discrete volumetric areas in which petroleum hydrocarbons exist in a liquid and gaseous state. The energy from the evolved gas out of the original liquid and the expansive energy of the original free gas are utilized to produce hydrocarbons through the well.

A solution gas-water drive reservoir is one in which a significant volume of water lies underneath or peripheral to the hydrocarbon accumulation. The small energy available from the expansion of the water upon reduction in pressure is utilized, in addition to the larger evolution of gas energy from the original liquid hydrocarbon, to displace the hydrocarbon material to the producing wells.

A combination system is one in which a distinct petroleum gas phase is present, as well as a distinct petroleum liquid phase and a significant accumulation of water similiar to that of combination of the gas cap-solution gas and solution gas-water drive type reservoir. The energy from all of these systems, which is obtained by a reduction in pressure, is used to produce the hydrocarbons.

Gas reservoirs also can be classified in the same way as oil reservoirs. They are also sub-classified as to the behavior that the hydrocarbon will undergo with a pressure reduction. The two general classifications for gas reservoirs are: 1) volumetric, and 2) gas with a water drive.

A volumetric reservoir simply is one where the only major energy used for production purposes is the hydrocarbon itself.

A gas reservoir with water influx is one in which significant energy is obtained from the contiguous accumulation of water, as well as the expansion of the entrapped hydrocarbon gas.

Sub-classification of gas reservoirs is a function of the phase behavior of the original gaseous material. As the pressure is reduced upon the hydrocarbon accumulation, two classifications are made: 1) a single-phase gas reservoir, 2) condensate gas reservoir.

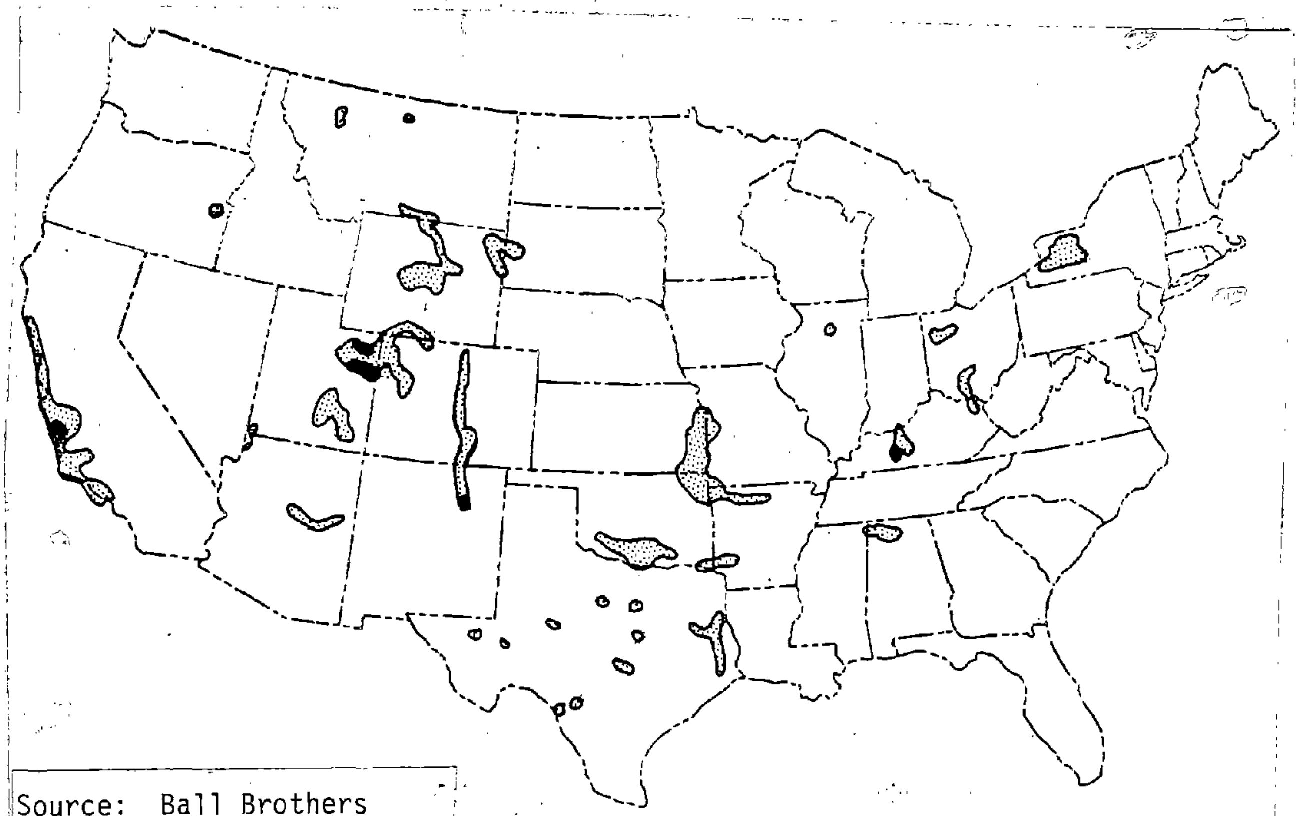
A single-phase gas reservoir is one in which the hydrocarbon composition and temperature of the reservoir are such that, regardless of what pressure the fluids are reduced to, the hydrocarbon material remains in a gaseous state in the ground.

A condensate reservoir is one in which the hydrocarbon is originally in a gaseous state. A composition of materials and reservoir temperature are such that, as the pressure is reduced, some of the gas is condensed into a liquid form. This condensation normally is referred to as "retrograde" because it is anticipated, with normal materials, that as the pressure is reduced they would vaporize instead of condensing.

3.2.4 Solid Petroleum

Reservoirs that contain heavy, non-flowing oil, or asphaltic hydrocarbons (tar), could at one time have been a conventional, pressured liquid oil with gas in solution. Because of natural tectonic forces or by becoming over pressured, the reservoir cap becomes cracked and broken, allowing the gas and the lighter oil fractions to escape. As a result of the gas fractions escaping the reservoir, the viscosity of the remaining liquid increases which retards the ability of the fluid to move. Regions in the U.S. that contain petroliferous rock are shown in Figure 13.

Another natural phenomenon affecting conventional reservoirs is erosion. As the vertical depth from the surface to the reservoir is diminished by



Source: Ball Brothers
USBM Monograph 12

Figure 13. Regions in the U.S. that contain petroliferous rock.

erosion, the pressure is reduced and gas comes out of solution. If the gas is allowed to escape the trap, the remaining oil will be more viscous. After the reservoir is exposed by erosion, the reservoir becomes an inspissated (drying up) deposit. Exposure at the surface permits the hydrocarbon near the surface to oxidize, leaving only the very heaviest or asphaltic portion of the original fluid in what is commonly called a tar sand.

Solid hydrocarbons disseminated in nonreservoir rocks were probably deposited and formed with the sediment. The hydrocarbons may have been a part of the sedimentary source material or they may have been formed by diagenetic forces after deposition on organic material deposited with the sediment.

3.2.5 Exploration

In the early days of petroleum exploration, geologists learned that petroleum was often discovered in structurally high areas of anticlines and domes. Because most structural features such as domes and anticlines are easily seen at the ground surface, geology became the primary exploration tool. Soon, everyone was looking for surface expressions of structural features to lease and drill. As the use of petroleum and petroleum products increased, more and more petroleum was needed to supply the new demands. As surface structural features became harder to find, wells were drilled below existing fields in an attempt to locate deeper sources of oil. These deep tests were often successful. The demand for oil, however, continued to increase. In addition, existing oil supplies appeared finite and limited. To make matters worse, geologists could not find new oil prospects from surface indications.

Geologists realized that there were probably vast reserves of undiscovered oil in traps not visible by surface features. Stratigraphic traps are not indicated by surface features. Nature could easily hide structural features by erosion and subsequent unconformable deposition of new sediments. New techniques had to be discovered.

During the early beginning of the oil industry, wells were drilled with churn drills (cable tools). Simple in operation and inexpensive to build and maintain, these drilling rigs were slow and limited to relatively shallow depths. Usually a churn-drilled hole started with a very large diameter hole and, when the walls of the hole began caving faster than the material could be removed, casing was run into the hole. A smaller bit was then used to again drill until the hole sluffed or caved in faster than the bailer could remove the solids. At this time, a nominal size smaller casing was run into the hole. A well that may have been started 3 feet in diameter could end up at total depth with 4-inch casing, with every nominal pipe diameter between 36 inches and 4 inches represented in the hole. Eventually the cost of casing would make the cost of well construction prohibitive. With oil being discovered at greater depths, the economic depth limits of the cable tool method of drilling were being reached and new techniques had to be discovered.

From this point on, drilling technology and the techniques of petroleum exploration progressed in parallel because one was necessary for the other. A deep oil prospect was worthless if the drilling technology was not there to reach it and bring it into production. Unfortunately, there have been no definite characteristics of petroleum buried underground yet discovered that is measurable at the surface. The two major technological developments that occurred to propel the infant oil industry to what it is today are geophysics and rotary drilling.

Seismographs, a geophysical technique, may look below the surface in two ways. For shallow work, seismic refraction of vibrational waves are used. For deep structures, seismic reflection of the vibrational waves are used. In both methods, a shock wave is initiated and the time of travel of the wave from its source to its arrival at a geophone (an instrument designed to identify the arrival of the shock wave) is measured.

In seismic refraction, the induced shock wave travels downward until a more solid strata is encountered, the wave then is refracted, that is it travels along the harder strata until it reaches the vicinity of the geophone. The wave then travels back to the geophone. A timer is started at the moment the shock is induced and is stopped upon the arrival of the primary wave by the geophone. By taking a number of measurements at various spacings, the geophysicist can determine whether or not the harder stratum is flat lying or lies on a slope or is faulted. Because this is a shallow depth technique, the shock wave can be induced using a hammer and steel plate, dropping a heavy weight or with small amounts of an explosive.

For deep lying strata, seismic reflection is used in which the induced wave travels downward and eventually bounces off a hard strata and is reflected directly back to a geophone at the ground surface. Again, a number of measurements are taken from various spacings. For many years the initial shock was induced by explosives placed at the bottom of 100-to 500-feet deep drill holes. Now, in many applications the waves are induced by sonic generators at the ground surface. The analysis of seismic records have also become extremely sophisticated by the application of modern computers. With these techniques, it is possible to look below the ground surface and find deep-lying structural traps that may contain petroleum.

The first tool of production, as it has always been, is the last tool of exploration--the drilling equipment. Since a characteristic of underground petroleum cannot be measured directly, discovery of a petroleum reservoir by biological and geophysical methods is indirect or inferred. To prove an inferred discovery, a hole must be drilled into the zone of inferrence to see if it, indeed, does contain oil and if the accumulation is of sufficient quantity and character to be an economical prospect. About the time seismic prospecting took the industry beyond the depth churn drills could effectively handle, rotary drilling equipment began to develop.

Modern drilling rigs in use today are capable of drilling over 30,000 feet on land, ice or over water. The development and engineering of the modern rotary tables, pumps and rotary drill bits, made deep drilling possible.

Surface casing is still used to hold unconsolidated material and to isolate fresh water zones from the well. Intermediate strings of casing are no longer required. The hydrostatic pressure of the drilling fluid and the present science of mud control keep the walls of the hole from sloughing and maintain hole gauge. Rotary drilling equipment has a much higher initial cost than percussion equipment, but the rotary drills much faster and deeper than the old cable tool.

Even with modern, sophisticated and ultra scientific geophysical and drilling techniques and equipment, world demand for oil is outstripping production. Predictions are that a world oil shortage situation will occur in the late 1980s. World petroleum available for consumption again seems very finite and limited. It is time for another technological breakthrough.

Today's petroleum technology indicates that only about 30-35% of the original oil in place is being produced. Sixty-five to 70% of the original oil in place is left in the ground, economically unrecoverable by present technology. The next technological breakthrough probably will be to merge petroleum engineering and mining to recover most or all of the remaining 65-70% from known oil accumulations.

3.2.6 Reservoir Characteristics

The analysis of a petroleum reservoir requires a variety of types of data and rather complex engineering computations. An outline of procedure for processing petroleum engineering data is given in Figure 14. The data for reservoir analysis is divided into two parts: 1) reservoir fluid and production data and 2) formation evaluation data. In the figure, the sources of data are shown along with the general data reduction processes required for proper engineering analysis.

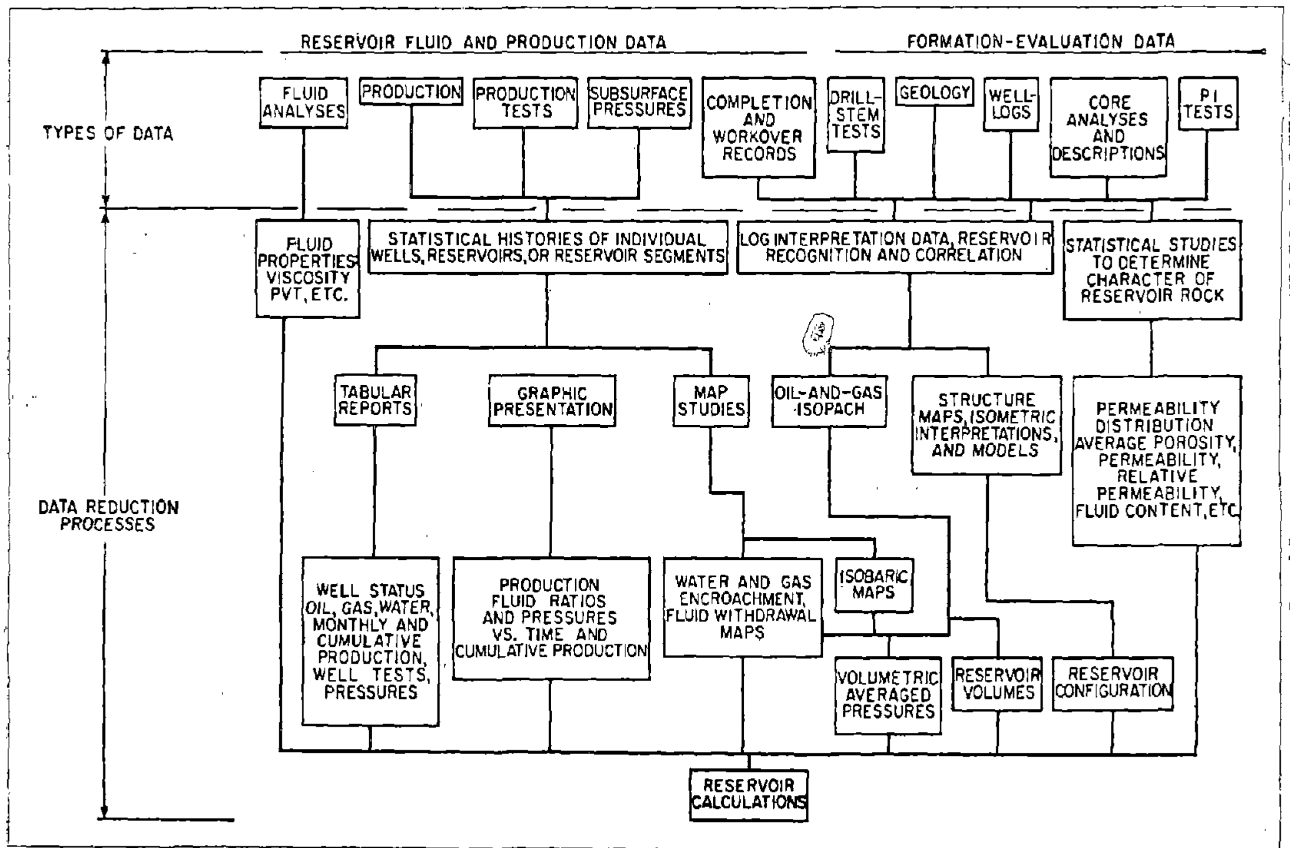


Figure 14. Processing procedure for petroleum engineering data. (Amyx, Bass & Whiting p. 474). Petroleum Reservoir Engineering

Geological and geophysical data from every drill hole penetrating the reservoir are necessary to determine the physical dimensions and shape of the reservoir. Maps are drawn to show the stratigraphy and structure of the reservoir. These data are also used in correlating the information obtained in seismic investigations.

Once the shape and extent of the reservoir is defined, the character of the reservoir and contained fluid must be determined. All these data must be obtained through the drill hole, that is, the oil well. As previously stated, a petroleum reservoir must be both porous and permeable. Porosity is defined as the volume of void space contained in bulk unit volume of reservoir material and is usually expressed as a percentage of the total volume. Porosity is a characteristic of the reservoir rock that formed either during deposition or afterward due to some geological process. This void space contains the oil, water and/or gas.

Permeability is a measure of how well a fluid will move through the formation under an imposed pressure drop. If a porous reservoir is to be permeable, the pores or void spaces must be interconnected and be of sufficient size for oil to move. For example, some shale is very porous, but nearly impermeable, whereas an unconsolidated sand of constant grain size is both porous and permeable.

The term Darcy (millidarcy) as a measure of the magnitude of permeability is derived from early experiments by Henry Darcy in 1856. Darcy studied the flow of water through sand filters and derived an empirical formula (Darcy's law) for laminar flow of water (100% saturation) that contained a proportionality constant, K. Later investigators extended Darcy's law to other fluids and found that the constant, K, could be written in terms of k/μ, where k represents a proportionally constant for the flow system and μ represents the viscosity of the fluid. API code 27 presents the generalized form of Darcy's law as follows:

$$V_s = -\frac{k}{\mu}\left[\frac{dP}{ds} \pm \frac{\rho g}{1.0133}\ \frac{dz}{ds} \times 10^{-6}\right] \qquad (1)$$

Here, s = distance in direction of flow and it is always positive, cm

V_s = volume flux across a unit area of the porous medium in unit time along flow path s, cm/sec

z = vertical coordinate, considered positive downward, cm

ρ = density of the fluid, gm/cc

g = acceleration of gravity, 980.665 cm/sec

dP/ds = pressure gradient along s at the point to which V_s refers, atm/cm

μ = viscosity of the fluid, centipoises

k = permeability of the medium, darcys

1.0133×10^6 = dynes/(sq cm) (atm)

A millidarcy is 10^{-3} darcy. A darcy is defined as follows: A porous medium has a permeability of one darcy when a single-phase fluid of one centipoise viscosity that completely fills the voids of the medium will flow through it under conditions of viscous flow at a rate of 1 cubic centimeter per second per square centimeter cross-sectional area under a pressure or equivalent hydraulic gradient of 1 atmosphere per centimeter (Amyx, Bass and Whiting, p 70).

Complex flow systems found in nature due to multi-phase flow (two fluids, water and oil, or gas and oil) often make analysis using Darcy's law nearly impossible. Fortunately, Darcy's law is comparable to Ohm's law for electrical conductance and Fourier's equation for heat conduction. The additional equations from the flow of electricity for heat are used in many of today's reservoir engineering calculations.

Mathematical derivations of the numerous parameters and equations are left to textbooks written specifically for this purpose. Derivations and mathematical treatments appear in this report only as required to define a particular principle.

3.3 CONVENTIONAL OIL RECOVERY METHODS

3.3.1 The Oil Well

All oil fields are produced through holes drilled from the land or water surface and cased with steel pipe 2.5 to 9.875 inches in diameter. There are three general methods for completing an oil well: 1) open hole, 2) cased and perforated, and 3) screened.

In the open hole completion, the well is cased to the top of the producing formation. The producing formation thus is drilled through but not cased. This technique was widely used during the period from 1859 to 1945. Since then, this method has been used only for structurally strong (competent) producing strata, such as limestone or well-cemented sandstones. In less competent formations, the exposed formation tends to slough off and cave-in, filling the hole and ruining the well. An open hole completion is illustrated in Figure 15a.

In the cased and perforated completion as shown in Figure 15b casing is run the full length of the well and generally cemented in place. The casing is perforated at selected intervals within the producing formation with special tools. This is the most common completion method used today. It is used in all types of geologic formations, consolidated and unconsolidated, and permits better production control, easier abandonment and ready conversion to secondary and tertiary recovery processes.

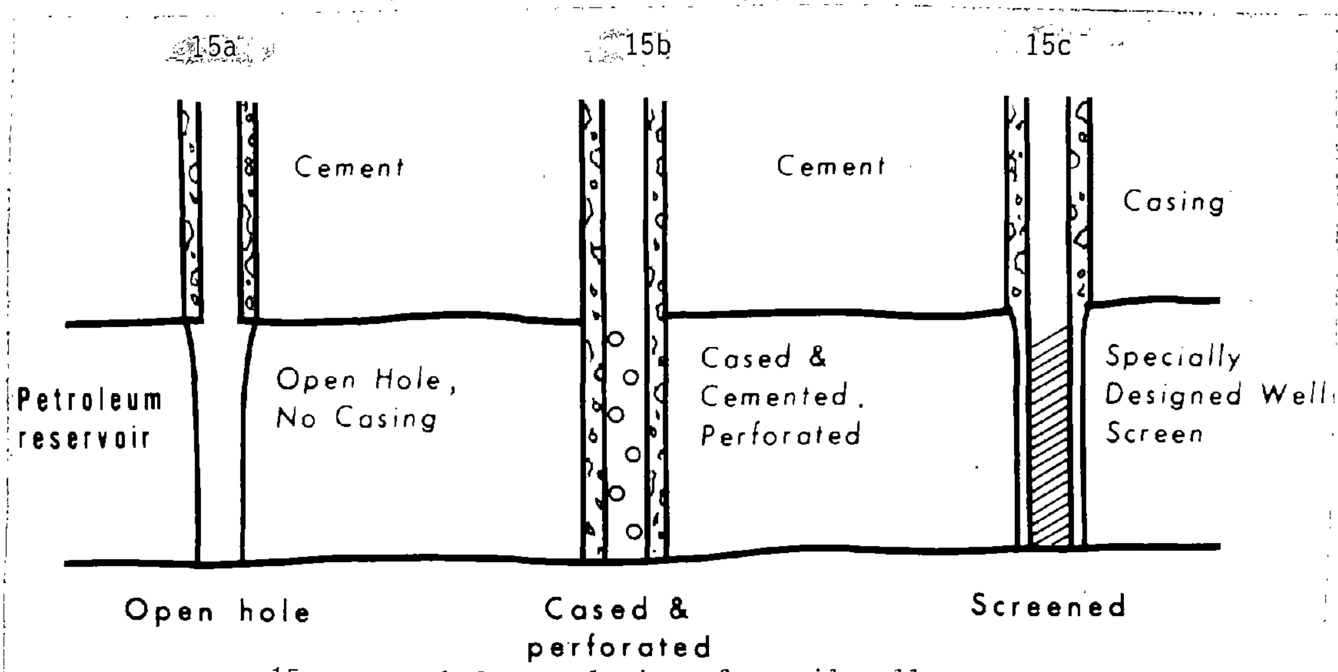


Figure 15a. Open hole completion of an oil well.
15b. Cased and perforated completion of an oil well.
15c. Screened completion of an oil well.

When the screened completion method is used, the well is cased from the surface down to the top of the producing formation. A slotted screen (pipe) is installed, extending from the bottom of the casing down through the productive zone. Unconsolidated reservoir material may be held back by a 'gravel pack' hydraulically placed between the outside of the screen and the walls of the producing formation. The screened completion method, illustrated in Figure 15c used extensively in California and the Gulf Coast region of the U.S., is only used in unconsolidated formations. Production problems are inherent with this method resulting in lower ultimate oil recovery than with the other completion methods.

To increase the efficiency of an oil well, it is usually subjected to some method of stimulation. The objective is to increase the permeability of the producing formation around the well bore. The most common methods are hydraulic fracturing, acidizing, and blasting.

In hydraulic fracturing, fluids are pumped into the producing formation under high pressure to induce fractures within the formation. Sand is then added to the pumped fluids to hold the fractures open. This procedure is commonly used in cased and perforated wells penetrating a low permeability sandstone or limestone.

In acidizing, a solution of acid is pumped into the formation, often under high pressure to dissolve some of the rock in the vicinity of the well bore. This procedure is commonly used in cased and perforated wells penetrating either a limestone or a tight, lime-cemented sandstone. In some cases acid is used as the carrier fluid in hydraulic fracturing.

To shoot a well, a quantity of high explosives is detonated in the well bore in the producing interval. This technique is not widely used today. Often, shooting a well causes more problems than it solves and it must be done in an uncased hole. This, perhaps, was the first major attempt at well stimulation to improve oil production efficiency, but since has been all but replaced by hydraulic fracturing and acidizing.

3.3.2 Primary Recovery

Primary production, as the term suggests, is the first method of producing oil from a well. If the pressure on the fluid in the reservoir (reservoir energy) is great enough, the oil will flow into the well and up to the surface. In this case, no pumping equipment is required. If the reservoir energy is not sufficient to force the oil to the surface then the well must be pumped. In either case, nothing is added to the reservoir to increase or maintain the reservoir energy nor to sweep the oil toward the well. The rate of production from a flowing well tends to decline as the natural reservoir energy is expended. When a flowing well is no longer producing at an efficient rate, a pump is installed.

The most commonly recognized oil-well pump is the reciprocating or plunger pumping equipment (also called a sucker-rod pump). This equipment is easily recognized by the 'horse head' beam-type pumping jacks seen while driving through most oil fields. Electrically powered centrifugal pumps and submersible pumps (both pump and motor are in the well at the bottom of the tubing) have proven their production capabilities in numerous applications throughout the industry. Gas or air lift is another method of bringing oil from the bottom of the well to the ground surface. Various mechanical devices (special valves, plunger lifts, intermitters, and other devices) have been invented to lift oil to the surface with gas. Gas lift is used where ample gas supplies are available at a reasonable cost.

While naturally flowing wells are sought after by all producers, only about 70% of the more than 500,000 wells in the U.S. were naturally flowing at the end of 1977. Primary oil production amounted to about half of the U.S. production in 1976. The National Petroleum Council estimates that less than 10% will come from primary production from known fields by the year 2000.

3.3.2.1 Problems and Limitations

The major problem and limitation with primary production is that only 10 to 15% of the in-place oil is recovered. It is for this reason that secondary recovery techniques have been developed and extensive research is in progress on tertiary recovery technology. Secondary and tertiary recovery technology are discussed later under their appropriate headings.

For maximum efficient and economic recovery, oil cannot be produced at the maximum rate it will flow into the borehole. The permeability of an oil reservoir is variable and if produced too rapidly, much of the oil will be left in the less permeable zones as illustrated in Figure 16.

Another problem that occurs when an oil well is produced too rapidly is that of coning. The hydraulic conductivity of a reservoir is greater for water or gas than for oil. It is easier for gas and water to move than it is for oil. As oil is removed from the well, the overlying gas and the underlying water form a cone around the well encroaching on the oil zone, as shown in Figure 17. Once the gas and water have reached the well bore, the oil production rapidly declines and soon the well must be abandoned.

The oil industry is intensively regulated to prevent unnecessary waste of oil and gas and for the maximum economic recovery of oil. For this reason the spacing of the wells are also regulated. Oil well spacings of 320, 160, 80 and 40 acres are quite common. Well spacing problems are especially troublesome when there are several different lease owners in one field. The most effective way to deal with the divided ownership problem is to unitize the field. Unitization is discussed later.

If the field is unitized and the reservoir characteristics permit, primary production can be increased by in-fill drilling. If the current spacing is 80 acres, more wells may be drilled to reduce the spacing to 40 acres. In-fill drilling is limited by economics because of the expenses of drilling, completing and producing oil wells. The hydrocarbon reservoir

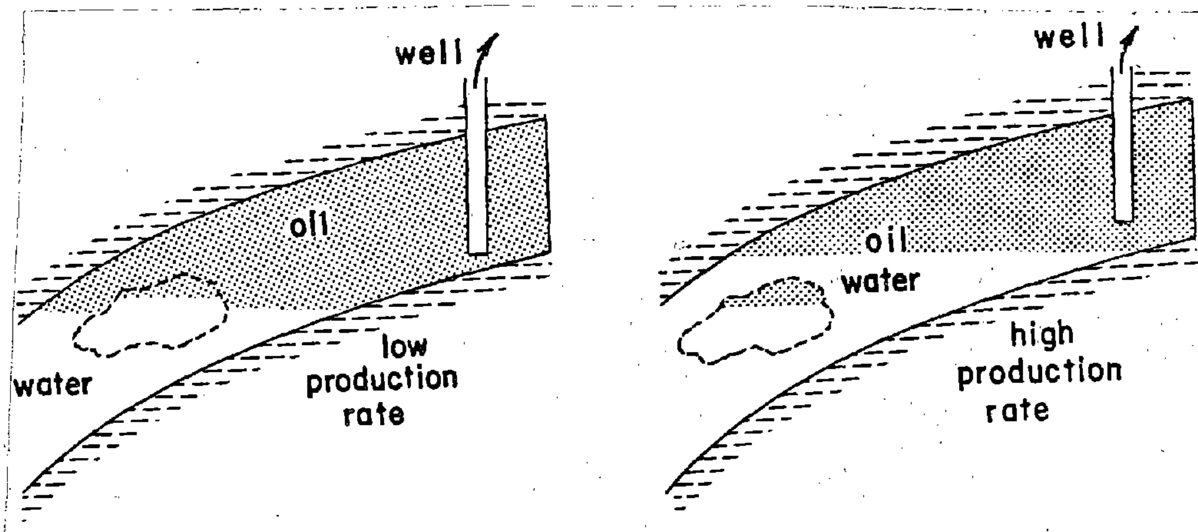


Figure 16. The effects of production rate on ultimate hydrocarbon recovery.

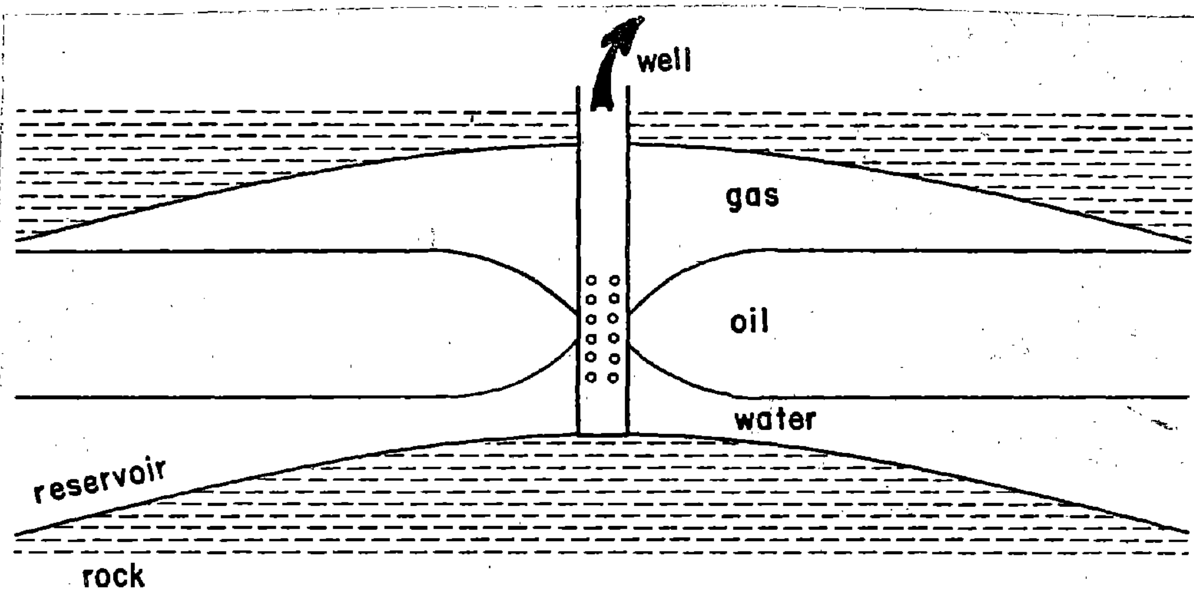


Figure 17. The effect of coning on petroleum recovery.

must be carefully analyzed to determine if in-fill drilling will add new reserves or if existing reserves will be produced more rapidly.

Water disposal problems have been a part of the oil industry ever since it began. The water associated with oil is generally highly saline, and not useable as a domestic or commercial source of water. The normal methods of disposing of the saline water are as follows: 1) pump it back into the formation, 2) pump it into another deep-lying saline formation, 3) hold the water in sealed ponds at the surface and let the water evaporate, and 4) in very few cases, treat the water.

3.3.3 Secondary Recovery

Available reservoir fluid energy tends to decline over the producing life of a reservoir. A need to sustain or increase that energy exists if ultimate recovery is to be improved. Reservoir pressure decline adversely affects oil production in two ways. First, it diminishes the force which drives oil into the well bore. Second, and more important, a decline in reservoir pressure soon causes some of the gas held in solution to be released as discrete gas bubbles in the pore spaces of the reservoir rock. This impedes the flow of oil toward the well while increasing the flow of gas and accelerating the depletion of reservoir fluid energy.

There are two main objectives in secondary crude oil production. One is to supplement the depleted reservoir energy pressure by injecting a fluid such as water or a gas. The second objective is to sweep the crude oil from the injection well toward and into the production well. When water is used the process is called a water flood; with gas, a gas flood.

Thermal floods, using steam and controlled in place combustion, is used as a secondary or tertiary recovery system. A prime objective of thermal floods is to reduce the viscosity of the crude oil so it will flow more readily with existing energy into the production well. Tertiary techniques are usually variationsof secondary methods with a goal of improving the "sweeping" action of the invading fluid.

By careful planning and extensive reservoir analyses, production wells can be converted into injection wells to reduce the extra drilling costs of secondary or tertiary recovery. Table 7 gives approsimate incremental costs of new injection well equipment in dollars per injection well.

Table 7. Approximate incremental costs of New Injection Equipment.*
($ per injection well)

State/District	Geographic Unit	Depth Category (feet) 0-2,500	2,500-5,000	5,000-10,000	10,000-15,000
California	1-4	$25,000	$30,000	$35,000	$35,000
All Other	5-19	18,600	22,700	26,800	26,800

*Incremental costs for reservoirs currently under primary recovery, i.e., those with no current secondary or tertiary development. Includes water supply and surface injection equipment.

Source: Bureau of Mines, IC-8562 (1970 costs) updated to 1975. Lewin and Associates.

3.3.3.1 Waterflooding

Secondary recovery by water flooding began when a leak in a make-shift packer allowed water from a shallow horizon to flow down and into the oil formation. Oil production declined in this well, but increased in the surrounding wells. John Carll is credited with having the first substantiated hypothesis that water moving through an oil sand increased oil recovery. He reached this conclusion in 1880 after five years of study of production operations in western Pennsylvania oil fields. Incidentally, Carll's work also confirmed the theory that oil does not occur in underground lakes or pools, and that oil sands lie in lens-shaped masses and not in continuous belts.

Early operators who believed that linking water sands with oil sands increased ultimate oil recovery designed "circle floods." The water sand was linked with the oil sand in one well and adjacent wells were produced in a basically radial pattern. When the produced wells flooded out, they were then used as "injectors" and the project expanded outward.

Operators however proceeded slowly. Until about 1920 it was illegal in most states to introduce water into the oil zone. The next major change occurred late in the 1920s with the application of pressured, rather than gravity-flow water injection. The legal acceptance and wider application of water injection led to solid theoretical and experimental work that elevated it from a field operation to an engineering practice. The experiences culminated in the early 1940s with the advent of the high-pressure floods begun early in the life of the pool before much drawdown had occurred. Only cased and perforated wells can be readily converted to injection wells for secondary or tertiary techniques. The effectiveness of water injection and its cost per unit barrel of oil produced depends on depth, geographic location, water availability, water quality, oil properties, reservoir rock properties and type of formation. Water injection is initiated in a reservoir when the additional oil recovered will yield at least a 15% internal rate of return on investment.

The amount of oil produced by waterflooding is about the same as for primary oil production, about 16% of the original oil in place. In the early part of a water flood, production rates increase from 50% to 400%. Waterflooding currently is the principal secondary oil recovery method and accounts for about half the U.S. daily oil production.

3.3.3.2 Gas Flooding

Another common secondary recovery technique is the injection of gas, either structurally high or in a pattern. Prior to 1973 most of the gas injection projects used natural gas produced from the reservoir itself or purchased from some outside source. Since 1973, the higher cost of natural gas has caused new gas injection projects to change to carbon dioxide, nitrogen or flue gas. Gas injection is preferrable to water injection in most reservoirs that have significant structural features. The initiation of gas injection is based on the same economic principles applied to waterflooding.

3.3.3.3 Miscible Fluid Displacement

The injection of fluids that will mix (miscible) with the in place oil is a secondary recovery method. To meet the ultimate objective of enhanced recovery -- the reach for the elusive 100% recovery -- the invading fluid must be completely miscible with the reservoir oil, leaving no residual oil in the invaded region. Even if the oil in place at the start of the project is residual to a waterflood, the miscibility will cause the oil to form a bank and flow ahead of the invading fluid. An unfavorable facet of this process is that the invading fluid also displaces the formation water and thus causes a lengthy period of water production either ahead of or along with the produced oil.

There are only a few fluids which are completely miscible with both oil and water and reasonable enough in cost to be considered for use in this process. Three fluids have been tried: alcohol, hydrocarbon gases and carbon dioxide. In the past, mixtures of alcohols, usually propyl and butyl alcohols, were used, but the higher molecular weight alcohols lose their water solubility and the lower alcohols, ethyl and methyl, are not miscible with many of the crude oils. The miscible fluid currently considered most promising is carbon dioxide (CO_2). Typically, as pressurized CO_2 begins to appear at the producing well, it is recovered, "cleaned" of impurities and reinjected.

The basic concept of miscible flooding was proposed in 1927, however little field development took place until about 1960. At the present time research is being conducted with emulsions and micro-cellular emulsions which are miscible with the oil. Field tests of some of these fluids are being sponsored by DOE as of this writing. None have proven that they can recover oil for less than $15/barrel. Figure 18 illustrates the process of gas miscible flooding.

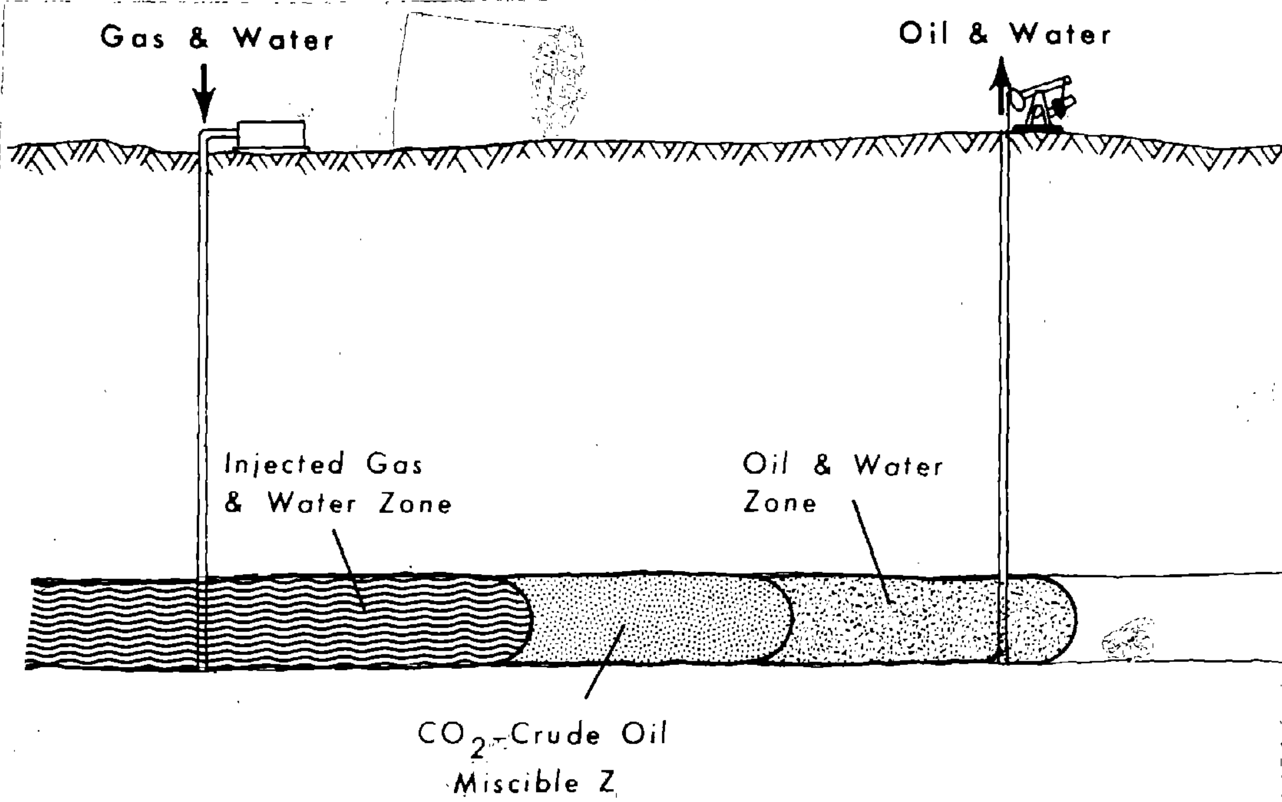


Figure 18. The gas miscible flooding process.

3.3.4 Tertiary Recovery

Tertiary recovery techniques are designed to improve the sweep efficiency of the injected fluid or to lower the viscosity of the crude oil. Some of the techniques discussed below are used in some cases for secondary oil recovery. Others are still highly experimental.

3.3.4.1 Surfactant/Polymer Flooding.

The use of surfactants in the displacing fluid (Figure 19) is the most recent and potentially most promising method for stripping the oil from the rock. The displacement, while not truly miscible, is at such low interfacial tensions that virtually all of the contacted oil is displaced.

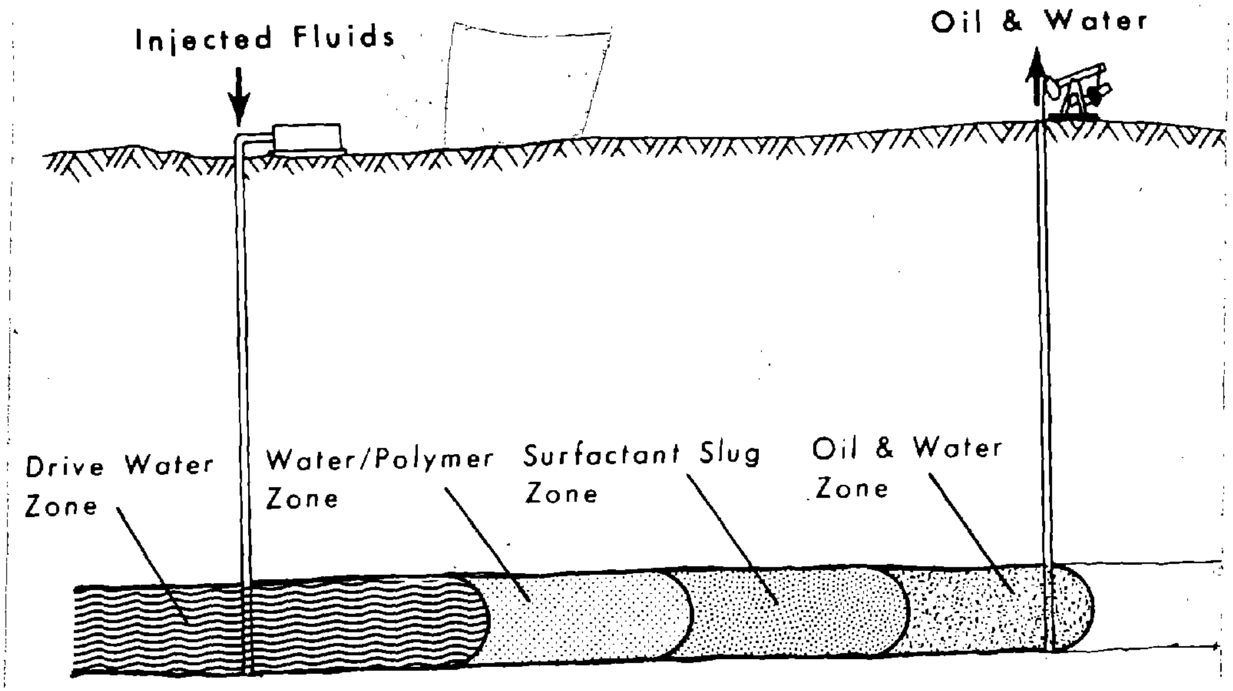


Figure 19. The surfactant/polymer flooding process.

The injected water is treated with a surfactant to reduce the surface tension and increase the wetting forces of the injected fluid compared to any hydrocarbon or water which might be indigenous to a reservoir system. Many different types of surfactants are being tested. The primary reason for the continued search is to reduce the surfactant absorption onto the surface of the matrix material. Because of the expense of the surfactant it is normally injected as a slug and followed by a polymer water system. The thickened or viscous water is used to increase the sweep efficiency of the surfactant material.

3.3.4.2 Micellar/Polymer Flooding

Another popular flooding system is one in which the initial displacement slug is a micellar solution which generally is created by emulsifing alcohol and water with a sulfonate as the emulsifing agent. In most cases this micellar solution is miscible with the in-place water and the residual hydrocarbons. In theory, it should displace all of the formation water and the hydrocarbon content. This micellar solution is injected as a slug and is usually followed by a polymer treated water which in turn is followed by untreated water. Hence the process involves two slugs of injected material followed by water and is very difficult to control. This difficulty in control of the areal sweep and the necessity of producing large volumes of formation water has made the micellar/polymer system very expensive. The micellar/polymer flooding process moves underground similar to the surfactant/

polymer process illustrated in Figure 19.

3.3.4.3 Polymer Flooding

This process employs an additive to the initial injection water to increase the viscosity of the displacing fluid. The influence of this thickened water on the efficiency of oil displacement is minimal at best since the thickened water pushes the connate water to form the actual displacing fluid. It does however cause the reservoir conformance (the fraction of the reservoir swept by the invading fluid) to be increased. It therefore follows that this process is most advantageous in reservoirs where the conformance will be poor either because of adverse viscosity conditions or because of differences in the reservoir permeability. Thickened water can be used alone or it may be used as a following agent for any fluid injection system.

3.3.4.4 Steam Injection

Steam injection or steam flood involves the injection of steam into a group of outlying wells to push oil toward the production wells. In this process the heat is forced into the perimeters of the reservoir to reduce the oil viscosity and permit the hot water to displace the oil. To ensure high rates of production at the wellhead, steam flooding projects are typically conducted jointly with cyclic steam injection in the production wells.

Tests in the 1960s in the San Joaquin Valley, particularly the Kern River Field, demonstrated the effectiveness of this method. Steam drive is now a major factor in California oil production, with much of new field development concentrating on the use of steam drive. Side benefits might include in-place distillation of the oil. Some experts see steam drive as the most universally applicable technique. The major drawback is the amount of energy required relative to the amount produced. The steam drive process is illustrated in Figure 20.

3.3.4.5 Hot Water and Steam Flooding

Hot water and steam flooding are now being utilized as a secondary recovery process. The behavior of these systems is essentially the same as waterflooding but heat is added to reduce the viscosity of the oil thus increasing the displacement efficiency. This process is more capital intensive than waterflooding or gas injection and has a higher operating cost. Heat plus water is usually used in reservoirs which have an in-place oil viscosity of greater than 100 centipoises. Again, the same economic conditions apply to the steam and hot water process as with any other secondary project.

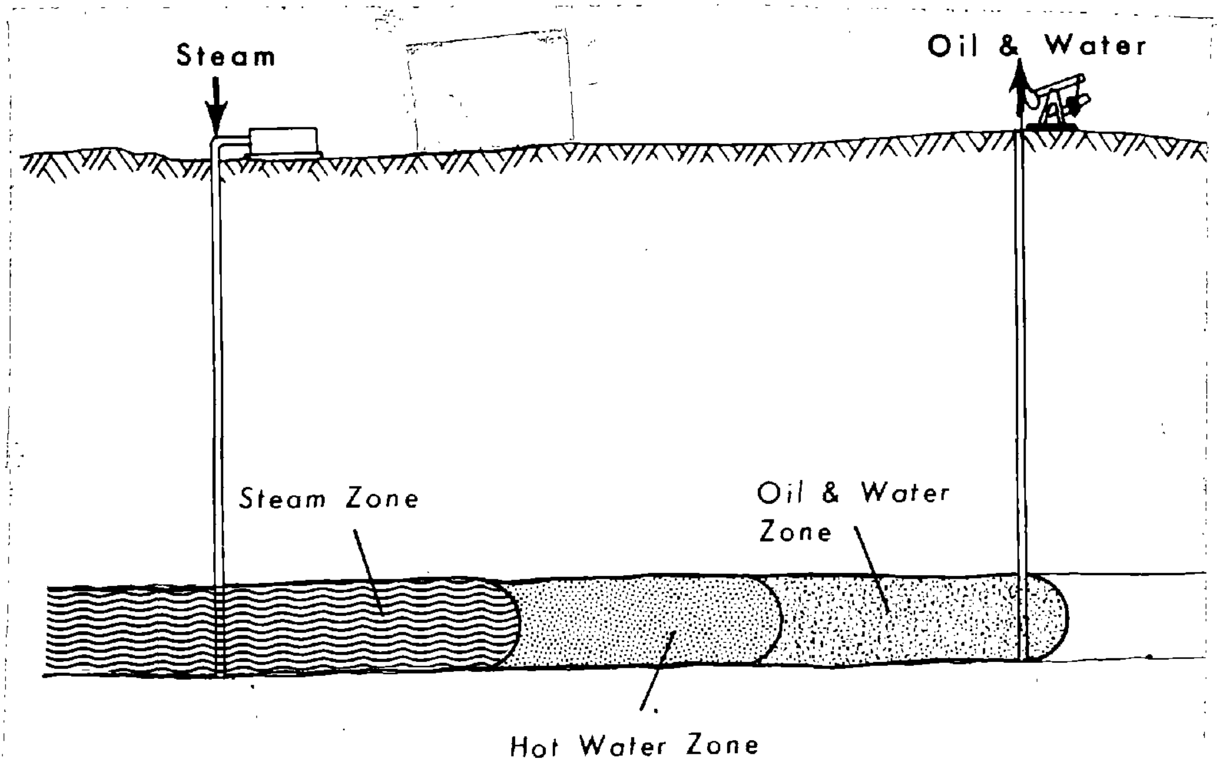


Figure 20. The steam injection process.

3.3.4.6 Cyclic Steam Injection

Cyclic steam injection, called huff and puff, is the most commonly applied thermal recovery process. Steam is injected directly into the reservoir through the production wells to heat the surrounding area. The condensation and cooling of the steam heats the reservoir rock and oil, reducing the oil viscosity and thus increasing production rates. Then steam injection is stopped and the heated oil is produced from these same wells. After the hot oil production has ended, a new cycle may be initiated. The time period of the cycles are on the order of six to 12 months or longer. These reservoirs are usually shallow and the producing wells are drilled on very close spacing because the heat does not penetrate far from the wells.

The effectiveness of steam in recovering heavy oils was forseen in 1917. The first field tests were conducted in the 1920s and the 1930s, first in Venezuela and then in California by Shell Oil Co. Initial use of cyclic steam, from 1930-1950, was to remove paraffin from the wellbore. Use of cyclic steam gained prominence in the early 1960s in California with Shell Oil Co.'s success. Cyclic steam injection is now a reliable economic, secondary and tertiary recovery technique. Figure 21 illustrates the 'huff and puff' technique of cyclic steam injection.

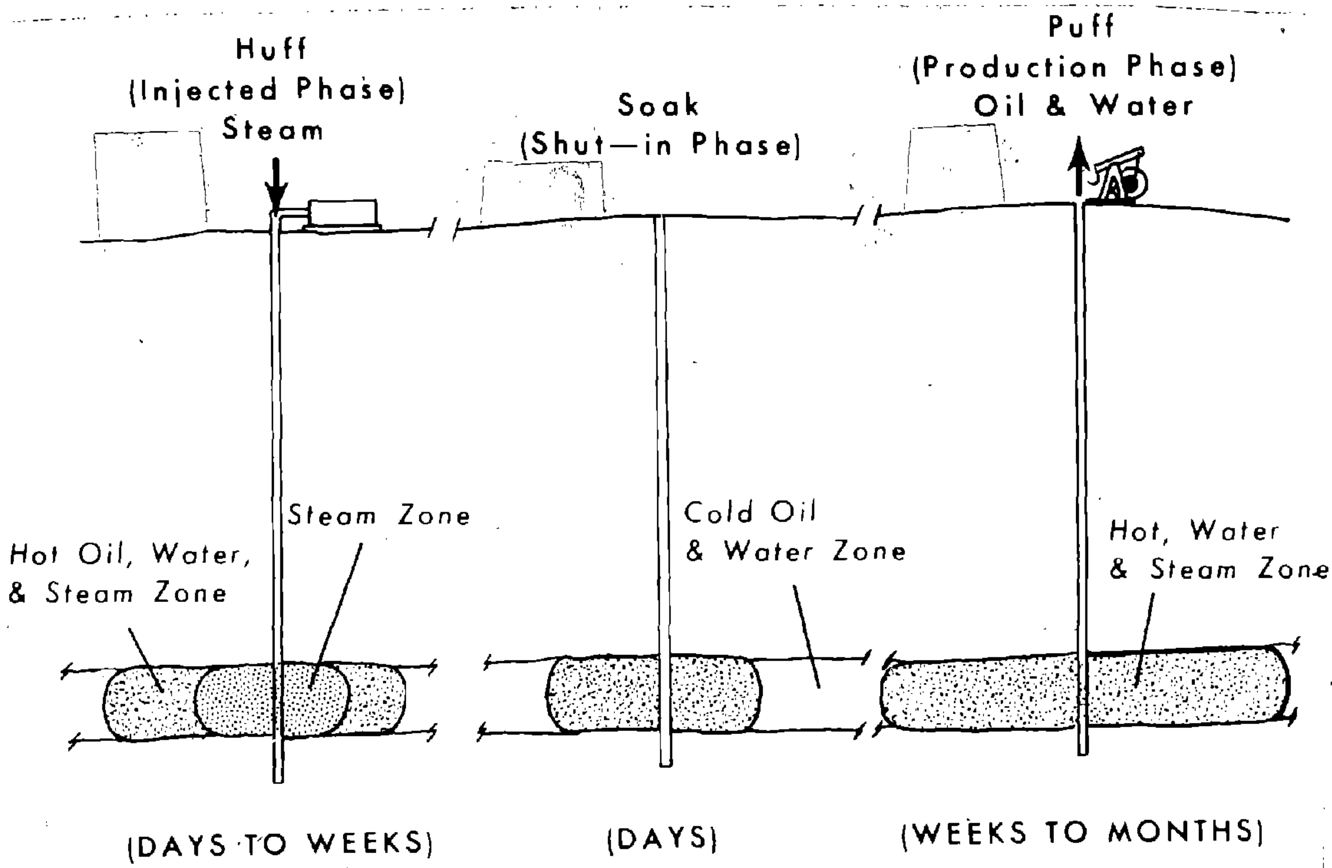


Figure 21. Cyclic steam injection (Huff & Puff).

3.3.4.7 In-Situ Combustion

One method of controlling heat in a combustion front is with the injection of air. By controlling the rate of air, the amount of oil burned (and therefore heat generated) is kept within desired limits. The hot combustion gases thus generated flow toward production wells pushing or carrying the oil as they pass. In some cases, cyclic steam injection may be used in conjunction with projects of this type to increase oil recovery rates.

Typically, air is injected into the reservoir to create a gas saturation high enough to allow the large air flows necessary to sustain combustion. When the air flow is large enough, spontaneous combustion may take place or a downhole heater is used in the injection well to initiate the combustion. The temperature of the combustion should be maintained at about 900^{O}F. and the burning oil front should proceed slowly through the reservoir. Higher rates of air injection tend to burn excessive amounts of oil in the reservoirs and may cause the burning front to override the oil.

Although the temperatures can be controlled by changing the air injection rate, a more recently developed method accomplished this by injecting air and water. Referred to as the "COFCAW" (combination of forward combustion and water), this method cools the combustion zone by vaporizing the water and the resulting hot vapor helps to move the heat through the reservoir ahead of the combustion front. This process is still economically unproven or unsuccessful in U.S. fields outside California's San Joaquin Valley.

In-situ combustion had its start in the early 1900s when underground combustion was accidentally started from air injection being used to sweep oil toward producing wells. An increase in production and well temperature was noted but neither factor was attributed to a subsurface fire at the time. Only much later was spontaneous combustion acknowledged as the cause of these effects.

Russia did the first cognizant work in subsurface combustion. They ignited a shallow oil reservoir by feeding glowing charcoal into the well with injected air. The resulting increased production was reported in 1935. The first English translation of the report appeared in 1938.

First mention of in-situ combustion in the U.S. was a 1923 patent granted to F.A. Howard (Standard Development Co.). The first test was conducted by Magnolia Petroleum and reported in 1953. The test produced only 80 barrels of oil but demonstrated the feasibility of in-situ combustion.

Early in-situ combustion pilots in the U.S. were generally discouraging. Recent efforts show improved results, but in-situ combustion continues to be a high risk technique. Figure 22 illustrates the wet combustion process.

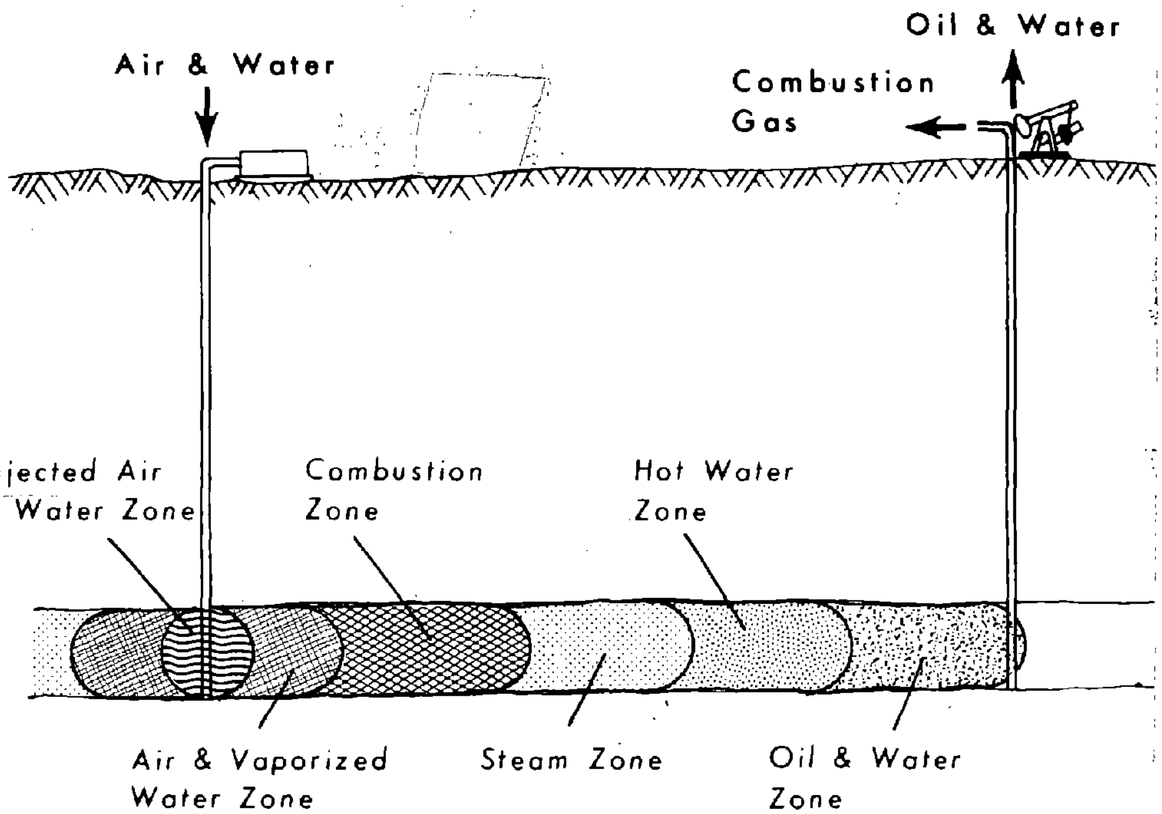


Figure 22. In-Situ wet combustion process.

3.3.5 Potential of Secondary and Tertiary Recovery

Many studies have been made of the volume of oil that could be recovered from existing reservoirs. A summary of these studies is presented in Table 8. While these separate estimates vary, it appears that most of the agencies expect tertiary recovery to gain somewhere between 13 and 51 billion barrels of the 300 billion "unrecoverable" reserves.

Table 8. Potential of Secondary and Tertiary Recovery

		Potential EOR Recovery (Bbls)	Production in 1985 (Mbls/Day)
NPC Study			
$5	(1976 $'s)	2.2	0.3
$10	(1976 $'s)	7.2	0.4
$15	(1976 $'s)	13.2	0.9
$20	(1976 $'s)	20.5	1.5
$25	(1976 $'s)	24.0	1.7
GURC			
$10	(1974 $'s)	18-36	1.1
$15	(1974 $'s)	51-76	---
FEA/PIR			
Business as Usual, $11		---	1.8
Accelerated Development, $11		---	2.3
EPA			
$8-12	(1975 $'s)	7	---
$12-16	(1975 $'s)	16	---
FEA/Energy Outlook			
$12		---	0.9
FEA (3 States)			
Upper Bound, $11.28	(1975 $'s)	30.5	2
Lower Bound, $11.28	(1975 $'s)	15.6	1

From only the NPC study portion of the above table a breakdown of the recovery potential into the three current tertiary recovery modes provides added detail of where increased recoveries are expected to be obtained as indicated in the following Table 9.

Table 9. Ultimate Hydrocarbon Recovery*

Price Per Barrel, $	Steam	CO_2 Miscible, Billions of Barrels	Chemical
5	2.5	0	0
10	4.25	2.50	1.25
15	4.50	5.75	2.75
20	7.00	6.00	7.65
25	7.50	7.88	9.38

*"Enhanced Oil Recovery", National Petroleum Council, 1976. These projections were based on 1976 dollars and a 10% internal rate of return.

At best the slightly less than 25 billion barrels at $25/barrel is a small fraction of the "300 billion barrels remaining in currently known reservoirs that cannot be produced by conventional primary and secondary methods". (JPT, May 1977, p. 519)

As shown in Table 10 the first barrels of crude oil produced will be the most easily recovered and thus the cheapest, with the investment and injection costs of producing each additional barrel rising as the supply of less costly oil is depleted.

Table 10. Average EOR Investment Costs

	Lower Bound Case	Upper Bound Case	Technically Recoverable Case
Total Field Development, Equipment, & Injection Cost ($ Billion)	67.4	151.7	278.3
Total Reserves (Billion Barrels)	15.6	30.5	43.3
Average Investment ($ per Barrel)	$ 4.30	$ 5.00	$ 6.40

Source: Lewin and Associates Enhanced Oil Recovery

While the average undiscounted investment cost rises nearly 50%--from $4.30 to $6.40 per barrel--from the lower bound case to the technically recoverable case, when one considers the incremental investment costs, this capital requirement effect becomes even more dramatic, as shown in Table 11.

Table 11. Incremental EOR Investment Costs

	Upper Bound Case	Technically Recoverable Case
Incremental Addition to Reserves (Billion Barrels):		
Over Lower Bound Reserves of 15.6	14.9	-
Over Upper Bound Reserves of 30.5	-	12.8
Incremental Investment Required ($ Billion)		
Over Lower Bound Investment of $67.4	84.3	-
Over Upper Bound Investment of $155.7	-	126.6
Average Incremental Investment Cost ($/Barrel)	$ 5.70	$ 9.90

Source: Lewin and Associates Enhanced Oil Recovery

The capital requirements for start-up and injection materials in tertiary oil production are given in Table 12.

Table 12. Capital Requirements for Tertiary Oil Production. Start-Up and Injection Material Costs. Field Development Injection (A) and Equipment Costs (B) ($ Billions).

	Lower Bound Case		Upper Bound Case		Technically Recoverable Case	
	(A)	(B)	(A)	(B)	(A)	(B)
Steam	5.2	29.3	11.5	48.1	24.5	74.9
In Situ	0.5	2.5	0.9	3.5	1.5	6.1
CO_2	2.2	13.1	8.2	39.2	30.3	76.7
Surfactant/ Polymer	2.5	12.1	7.6	32.7	13.6	47.9
Polymer	*	*	*	*	1.8	0.9
Total	10.4	57.0	28.2	123.5	71.8	206.5
Total Field Dev't Equip. & Injection	64.4		151.7		278.3	

Source: Lewin and Associates Enhanced Oil Recovery

3.4 UNITIZATION

Early production practices tended to waste energy by producing more gas than was necessary and then since there was no market for it flaring (burning) the gas at the well. Later, the importance of gas for energy was recognized and now every attempt to conserve gas is made until all the available oil has been produced.

Indiana was the first state to recognize that gas must not be wasted, and enacted a law (1893) to insure that it was not. The statute was violated and subsequent litigation went to the Supreme Court. The Court unanimously upheld the Indiana statute and an opinion written by Chief Justice Edward D. White set forth three conservation principles upon which subsequent legislation is based:

1) All the owners of property in a reservoir have a common interest in the available reservoir energy. Waste of energy by one owner deprives the others of their products.
2) The state has the right to prevent waste of any of the reservoir products.
3) The public has an interest in conservation sufficient to justify legislation to protect its interests.

The most efficient way to produce a reservoir is for one operator to produce the entire reservoir (unit).

Unitization is the merger of all interests of a reservoir into a unit, the assignment of individual interests in respect to the entire unit for purposes of costs and benefits, and the designation of an operator to represent all the interest holders. The principle of Unit Operation is based, for the most part, on voluntary cooperation of all interested parties. The advantages of unit operations are as follows:

1) Increases flowing life of the wells.
2) Increases recovery of hydrocarbons.
3) Retards decline in rate of production.
4) Permits shutting in of high gas-oil ratio (GOR) wells (inefficient producers).
5) Reduces development and operating expense.

There are two basic types of unitization agreements. The Unit Agreement that must be joined by everyone having an economic interest - the royalty, mineral and working interests owners - and must be approved by the State Oil and Gas Commission. A majority of the working and interest owners must approve the plan before the Commission can approve and initiate compulsory unitization.[1]

[1] Laws for individual states differ slightly concerning the minimum percentage of working and royalty interest owners that must agree to the unit plan before compulsory unitization may be initiated. Percentages are listed for some states in subsequent pages.

The other type of unitization agreement is the Unit Operating Agreement, (voluntary unitization) which needs only to be agreed upon by the working interest owners, and filed with, but not approved by, the Oil and Gas Commission. In some cases the royalty interest may be partially unitized or not unitized at all.

There are two subdivisions of the Unit Operating Agreement commonly in use, as published by the Rocky Mountain Mineral Law Foundation. These are the divided and the undivided types.

In the divided type, working interest owners share costs and benefits attributed to the specific tract of land within the participating area in which they have the interest. Royalty costs of specific acreage are paid for by the working interest owner of that specific area.

In the undivided type, costs and benefits are shared by the working interest owners according to fixed percentages agreed upon by the interest holders, determined by a participation formula.

The basic principle upon which most equitable allocations are based was stated by the American Petroleum Institute in 1931. It states:

> "that it (API board) endorses and believes...the principle that each owner of the surface is entitled only to his equitable and ratable share of the recoverable oil and gas energy in the common pool in the proportion which the recoverable reserves underlying his land bear to the recoverable reserves in the pool."[2]

Some of the factors on which participation formulas are based for working interest owners are:

- -Number of wells, current and cumulative production
- -Consolidation of leases having the same ownership
- -Productive sand volume
- -Productive acreage
- -Estimated oil reserves
- -Total acreage
- -Number of wells and current production
- -Acreage and number of wells
- -Allowable (production)
- -Allowable and potential (production)
- -Number of wells, bottom hole pressure, acreage, and sand thickness
- -Cumulative production, number of wells, volume oil and gas sands and current production
- -Number of wells, productive acre-feet, and productive acreage

[2] "Progress Report on Standards of Allocations," p.3

Some of the factors on which royalty interests are allocated are:[3]

- -Interests already under same ownership
- -Current income
- -Productive sand volume
- -Productive acreage
- -Estimated reserves
- -Past production
- -Number of wells, current production and cumulative production
- -Allowable (production)
- -Cumulative production, number of wells, volume of oil and gas sands and current production
- -Number of wells, bottom hole pressure, acreage and sand thickness

By these factors alone or by combinations of them in varying proportions, a suitable allocation can be agreed upon by the royalty and working interest owners. Some of the most widely used formulas are based equally on acreage and number of wells or by a combination in different proportions of each.[4]

Regional migration causes special problems when trying to reach a reasonable allocation agreement. In its report of Standards of Allocation of Oil Production Within Pools and Among Pools, the Committee on Well Spacing and Allocation of Production and its Legal Advisory Committee states:

> "The producing life of a property depends partly upon structural position and its effect on regional migration...Clearly, the structural position must be taken into account because of its effect upon ultimate recovery and drainage...For instance, properties which, because of structural position and regional migration, would not have the opportunity to produce the amount of recoverable oil originally in place if the pool allowable should be based upon relative reserves, should be given higher allowable than the properties which, because of the restriction on the pool allowable are benefited by regional migration..."

In the case of Mining for Petroleum such a solution would not apply. The mining process could not be selective as to tracts of land under specific ownership, mining will have to be done on a field under a Unit Agreement. In this case, there would be no restriction on the location where mining would

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[3]When royalty interests are unitized under state laws, it must be on the same basis as is used for working interests.

[4]For a discussion of the different formulas and the frequency of use in Texas, see Conservation in the Production of Petroleum by Eric W. Zimmerman, 1937 through 1948, pp. 332-334.

be most appropriate and reservoir fluid migration would not be a legal problem.

Since the method by which the allocations for a specific field were determined are suitable for either the conventional petroleum reserve or mining process, the interests need not to be changed. In some states, the percentage of participation is fixed when the field is unitized and cannot be changed.

Another problem that might be encountered when mining for petroleum is the case of limited unitization with respect for formations. If the field is unitized before exploratory drilling, the agreement includes all formations under the unitized land, but if the field is unitized prior to secondary recovery, the agreement usually includes only a single productive formation.

Currently, Oklahoma has a forced unitization agreement which requires a minimum of 63% of the working interest and 63% of the royalty interest in order that the unit may be formed. Louisiana also has a forced unitization agreement which may be dictated by the State Conservation Commission or by 75% of the working and royalty interest ownerships. Arkansas has a forced unitization agreement requiring 75% of the working interest and 75% of the royalty interest prior to consumation of the unit.

The evolution of the various conservation departments in states such as California, Illinois, Kansas, New Mexico, etc. can be obtained from the book Conservation in the Production of Petroleum by Eric W. Zimmerman. The evolution of conservation for each state gives an idea of the political situation in that state and how this political condition will affect Mining for Petroleum. It is advisable to select states which have unitization laws for the first oil mining test or to select a site wherein the field is already unitized.

The percentage of working and royalty interests required by the various states is given in Table 13. An example of a unit operating agreement is included as Appendix C.

Table 13. Statutory Unitization by State.

State	% of W.I. and R.I. needed to invoke statutory unitization	Comments
Alaska	62½	
Arizona	63	
Arkansas	75	Adopted in 1975. Statute does not say on what basis the 75% should be based. Once drilling interests are approved by

Table 13 (continued)

State	% of W.I. and R.I. needed to invoke statutory unitization	Comments
		the Commission, thereafter they are fixed.
California	65	Adopted in 1975. Assembly bill stated that unitization may involve more than one pool, or it may involve just a portion of a pool. In 1974, there were 301 fully unitized and 55 partially unitized fields.
Colorado	80	
Illinois	75	Adopted in 1969.
Kansas	75	Adopted in 1969. Unitization act requires one contiguous field and interconnecting zones.
Kentucky	75	Adopted in 1974.
Missouri	75	Adopted in 1975. Based on approval of royalty interest owners.
Montana	80	Adopted in 1969.
Nebraska	75	
Nevada	62½	
New Mexico	75	Adopted in 1975.
North Dakota	80	Does not permit approval of unitization if it does not consist of the entire pool.
Oklahoma	63	Based only upon surface acreage.
Oregon	75	
South Dakota	75	
Texas		All unitization is completely voluntary.
Utah	80	Adopted in 1969.
Wyoming	80	Adopted in 1975.

3.5 RESERVOIR CONSTRAINTS TO MINING

3.5.1 Types of Reservoirs Suitable To A Mining Process

Reservoirs which may be candidates for a mining recovery process can be classified in two broad general areas.

1) depleted
2) virgin

The depleted category probably is the most prevalent and contains the greatest volume of potentially recoverable petroleum. If considered world wide, this assumption would probably be false because tar sands, oil shale and viscous crude reservoirs are still in the virgin state and probably contain the greatest amount of petroleum potentially recoverable by the mining process.

3.5.1.1 Depleted Reservoirs

The depleted reservoirs can be classified into two general categories: those which have undergone some type of secondary recovery process and those which have only been primarily depleted. The former category probably contains the greatest amount of remaining petroleum because they represent the greatest number of petroleum reservoirs. Numerous primary depleted reservoirs exist that contain viscous crude oil. Some of these reservoirs have undergone steam stimulation but not a secondary recovery process. The U.S. volume of oil remaining in these reservoirs is probably in excess of 200 billion barrels (primary depleted) and 300 billion barrels (secondary processes).

The depleted systems which have undergone secondary recovery processes were flooded in the late '30s and early '40s and are located at relatively shallow depths at low pressures. Some of these reservoirs were placed on a vacuum during World War II and hence would contain only small amounts of gas in solution in the oil. As a result only small amounts of any gas remain in the reservoir to be utilized as a displacing fluid. The other type of reservoirs which have undergone secondary recovery will have been flooded at pressures in excess of 500 psi and will have considerable gas in solution and possibly free gas to assist in the removal of fluids from the formation. These depleted reservoirs will probably contain oil having the following properties.

Viscosity - 1 to 10 centipoises
Gravity - greater than 25° API
Pressures - less than 300 psi
Gas in Solution - between 10 and 800 std. cu. ft. per reservoir barrel
Oil Saturation - between 10% and 40% of the pore space
Porosity - between 15% and 30%

Whether these reservoirs can be economically produced by a mining process will be a function of the product of the formation thickness, formation porosity and residual oil saturation, as shown below:

OIL IN PLACE = AREA X THICKNESS X POROSITY X OIL SATURATION

Factors of depth and mineability of formations above or below the oil zone itself will be major factors in the economics and technical feasibility of any such process.

The reservoirs which have undergone primary depletion only, with or without steam stimulation, will normally contain a much higher percentage of in-place oil at the time any mining process may be initiated. These reservoirs will normally contain a more viscous oil, be at relatively low pressures, and at relatively shallow depths. These reservoirs are represented by the higher viscosity oil reservoirs in California, Venezuela and Canada. They are presently being produced but with great difficulty. There is probably over 500 billion barrels of oil in this class of reservoirs in the world.

3.5.1.2 Virgin Reservoirs

Virgin reservoirs which might be susceptible to underground mining are represented by the known tar sands and the very viscous oil deposits throughout the world. It is known that very extensive reserves of petroleum exist in these deposits in the U.S., Canada and South America--some 1,000 billion barrels. These virgin deposits are susceptible to both strip mining and to underground recovery.

The tar sands which are being produced in Canada by strip mining have been exposed to conventional petroleum recovery mechanisms with very little success. The petroleum of these tar sands changes into a very viscous oil with depth and have not been treated with combinations of known recovery technology to make them productive. They have been overlooked as a potential source of petroleum production primarily because of the quality of the petroleum and their location. In many cases these reservoirs represent a petroleum deposit which is directly mineable. As the depth of these deposits increases, the contained petroleum is less viscous and has gas in solution so that removal of the petroleum containing formation is not feasible.

3.5.2 Conditions For Mineable Petroleum Deposits

Certain conditions must be present to mine petroleum. The formation must contain sufficient petroleum to make it economically feasible and the formations above and below the hydrocarbon reservoir must be competent enough to permit the driving of tunnels within that formation. These two conditions are not met by all of the petroleum producing formations within the country. In the multi-sand fields in the Gulf of Mexico and in the salt dome areas of Louisiana and Texas, the confining zones above and below producing formations are not thick enough or strong enough to allow the construction of mine workings.

Some of the most productive zones susceptible to mining are the thick limestone reservoirs which themselves are competent and which have over- and under-lying competent formations. These limestone reservoirs are fairly prevalent in the Appalachian states, West Texas, and New Mexico and contain large quantities of hydrocarbon material. The recovery from these limestone systems, whether by primary or secondary methods, is usually small. These formations have not behaved as existing engineering theory predicted, so a tremendous amount of oil is still present in most of these limestone formations.

The characteristics of depleted and virgin reservoirs are shown in Figure 23.

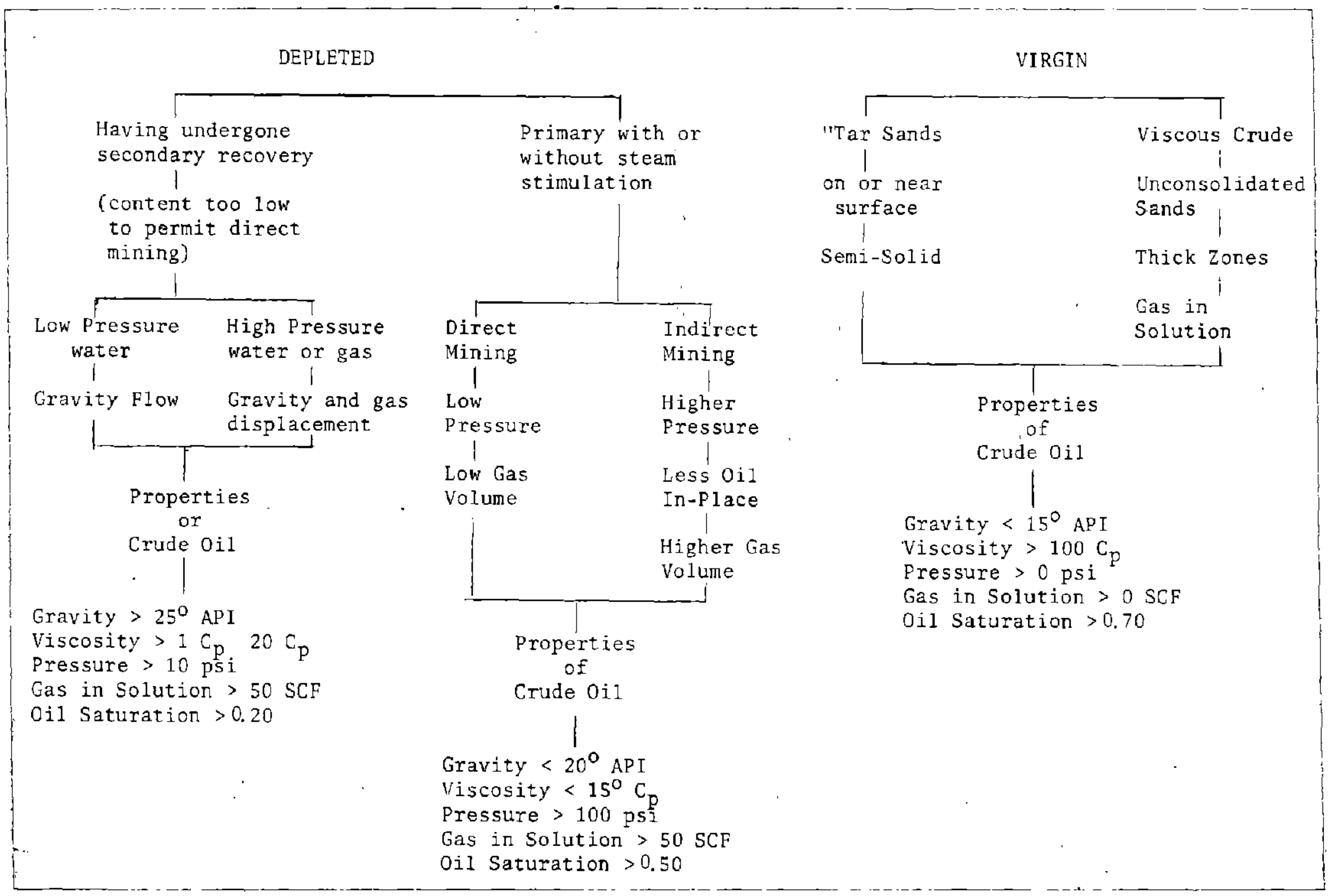

Figure 23. Characteristics of depleted and virgin reservoirs.

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SECTION 4

MINING ENGINEERING TECHNOLOGY

4.1 INTRODUCTION

Section 3, Petroleum Engineering Technology, was included to provide mining engineers an outline of current petroleum technology. This section is included to provide petroleum engineers an outline of current mining technology. Both sections are important because mining for petroleum will require the expertise of both professional disciplines.

Mining for petroleum will be performed using one of two basic techniques. One technique is to mine the hydrocarbon as an ore, that is, to remove the hydrocarbon and the reservoir material together and separate the hydrocarbon from the rock in a surface facility. The other method is to use mining technology to get close to a hydrocarbon reservoir then use petroleum technology to extract the hydrocarbon leaving the reservoir rock in place. This second method can be termed in-situ mining.

To extract the reservoir material as petroleum ore, the reservoir would first have to be degasified and pressure depleted. Costly ventilation techniques will have to be used, gas warning devices installed in every part of the mine and elaborate safety equipment and procedures would have to be followed. The ore even degasified and well ventilated would be flammable and the mine floor probably would become slippery and hazardous. Much more material would necessarily be taken from the mine when mining the ore rather than in mining for access. This would create handling and disposal problems as the materials would have to be processed on the surface and stored somewhere on the surface. Surface processing would be difficult. Degasifying the ore would leave only the heaviest fraction of the hydrocarbon in the rock which would create the same expensive problems as with the Canadian tar sands. Finally, mining the reservoir material would preclude the use of any of the modern petroleum engineering recovery techniques, and the use of any of the natural reservoir energies, thus severely limiting the amount and types of applicable production technology.

After considering environmental trade offs, mine and mine worker safety and the wealth of petroleum reservoir engineering technology, the project team decided to emphasize the use of in situ mining methods and to combine the most efficient and cost effective technology from both disciplines.* The in situ mining methods developed by the project team are described in Section 5, Mining for Petroleum.

This section is only a brief review of mining technology. For more detailed discussions of specific aspects of mining, the reader is referred to specialized mining texts and handbooks such as the SME Mining Engineering Handbood and the Handbook of Mining Engineering by Peele (see references).

*A companion study on oil mining contracted by the U.S. Bureau of Mines concurrent to this study considers the technical and economic feasibility of extractive or in-seam mining.

4.2 PETROLEUM MINE PLANNING AND DEVELOPMENT

As for any resource, the development of a petroleum mine requires proper planning in design and management. In the case of hydrocarbon resources, preliminary resource definition and geology are of prime importance because the physical nature of hydrocarbon resources ranges from the solid bitumens and tar sands through heavy, viscous oils to light, thin liquid (conventional) petroleum.

Geology is important in the mining phase of gaining close access to the reservoir. The rock characteristics of the formations above and below the reservoir will influence the level selected for development entries.

4.2.1 Economic Feasibility

The first step before developing a mine is usually a general review of the economic feasibility of the mining venture. In brief, there must be an adequate amount of resource obtainable by current technology, marketable at current prices to make the venture profitable. The economic analysis must take into account the logistics of necessary men and supplies, surface facilities, transport of product, applicable technology and other factors.

If a general analysis shows the venture to be economically feasible and profitable, the management probably will proceed to more detailed studies based on field acquisition of data.

4.2.2 Field Acquisition of Data

For detailed mine planning and design, the physical nature and occurrence of the resource must be defined to a high degree of confidence. Information to be compiled includes data common to both mining and petroleum, some will be specifically for the mining aspect and some specifically for the petroleum reservoir engineering aspect.

If a petroleum mining venture is planned for a reservoir that has been produced conventionally, a wealth of physical information on the reservoir and its geologic setting will already be available, making the initial feasibility study more easily accomplished. More information, however, will be required about the physical nature of the geologic strata above and below the reservoir.

Geological information with respect to stratigraphy and structure is a requirement of both disciplines. A geological investigation should include surface geological maps, cross sections showing structure, isopachous (thickness) maps showing the shape of the reservoir and adjacent formation, and isopachous maps showing the thickness and areal extent of the zone of hydrocarbon saturation. The stratigraphy, the relationship of one formation with another, generally is correlated from drill hole and core hole data. The geologic structure also can be defined with drill hole data, but much greater confidence can be placed on the structural evaluation if seismograph data correlated with the drill holes are also used.

As in petroleum engineering much data for mine planning and design comes from drill holes and core holes. In drill holes, borehole geophysical logs provide much information on the geology and on the physical nature of the geologic strata. In petroleum reservoir engineering, logs that are commonly run include: self potential, resistivity, gamma density, gamma-gamma, neutron caliper and sonic velocity logs. Borehole logging for mining information will include: P & S wave logs, gamma density and caliper logs. In conventional petroleum development, cores are taken of the reservoir material to determine oil saturation, water saturation and other physical aspects of the reservoir itself. For mine planning and design additional core information will be required not only on the reservoir but on the adjacent formations where tunnel workings will be located. Additional tests on the core must be performed to determine the following parameters: 1) compressive strength, 2) tensile strength, 3) permeability of all samples, 4) hardness, 5) abrasivity, 6) RQD, 7) Youngs modulus and 8) Poisson's ratio. An additional test on the core will include a jet curfing test to determine the efficiency of water jet drilling anc cutting on the strata. As important to mining as for petroleum, the reservoir pressures and temperatures and oil characteristics can be determined by logs, cores and samples taken from the drill hole.

To summarize, the information to be collected will include, but not be limited to, the following:

1. Geological maps and cross sections
2. Drill hole data; logs, correlations, drill stem tests (DSTs), etc.
3. Seismic data and correlation maps
4. Reservoir analysis results
5. Character of the oil
6. Physical nature of the overburden, the reservoir and the underlying formation
7. Geographical location
8. Location with respect to transportation, cities and towns, water resources, power facilities, etc.

4.2.3 Mine Management, Systems Engineering

The tools of systems engineering are valuable in the development, conduct and control of any complex project. The objectives of systems engineering are to map, structure, and schedule the program management and the functional tasks involved in mine development. The final product system should be open ended and flexible to allow the additions of unforseen but necessary subtask elements and to easily make minor changes in organization and structure.

4.2.3.1 Work Breakdown Structure (WBS) and WBS Dictionary

The first major task of systems engineering should be to list and identify all major tasks involved in the oil mining process. After the major functional elements have been identified and defined, each major element should be broken into subtasks and lesser subtasks as required for scheduling, cost control management. After all the task and subtask elements have been identified, a WBS dictionary should be developed to define in detail each element. Each element should be described in terms of technology involved, equipment, manpower needs, time required for accomplishment and its relation to the critical path flow of work.

4.2.3.2 Logic Network

After the Work Breakdown Structure has been developed the second step of systems engineering will be to construct a logic network to facilitate planning. A logic network diagram will show each task element in relation to the other tasks involved and to the program as a whole. The general flow of the tasks and the general order of timing should be illustrated using this technique.

4.2.3.3 Critical Path Method (CPM)

The relationship of one task element to another defines whether and where a task is placed on the critical path. Some tasks cannot begin until others are completed. A series of these interdependent tasks represent a critical path in the work flow. These elements require special attention because when delays occur in critical path elements the whole project schedule and costs can be affected. On the other hand, if problems or delays occur in independent noncritical elements, the total project schedule and costs are not likely to be significantly affected.

The critical path method was developed by the E.I. du Pont deNemours Co. as a computer approach to project scheduling. Using CPM, a comprehensive project schedule is developed based on a previously constructed logic network. The input information includes (1) the sequence of task activities, (2) duration of the activities and (3) starting times of the activities. CPM takes into account project time, the element missing from a network diagram. The critical nature of each task, once assigned arbitrarily, is determined by its position in the framework of the network diagram. The network position of the task is determined by the professional, scientist or engineer familiar with and experienced in the work of that task and related elements.

4.2.3.4 Performance, Evaluation and Review Technique (PERT)

The Performance Evaluation and Review Technique (PERT) was developed in the Navy Polaris program to fulfill the following objectives:

1. To appraise the validity of existing plans in terms of meeting program objectives.
2. To measure progress achieved versus program objectives.
3. To measure the potential for meeting program objectives.

PERT is a management system based on the objectives listed above and which aids management in the following ways:

1. Increases the consistancy and orderliness in project evaluation and planning.
2. Is an automatic means of identifying potential problem areas.
3. Provides operational flexibility for a project by allowing for a simulation of various schedules.
4. Provides rapid handling and analyses of integrated information, which is the source of systems flexibility for correcting errors or making systems changes.

As with CPM, PERT is based on the project plan mapped as a logic network, which in turn, was developed from the Work Breakdown Structure. These management tools are invaluable in controlling and managing complex projects.

4.2.3.5 Estimating Costs

Project time is taken into account with both CPM, and PERT. With each activity defined as to performing sequence, start time and duration, costs of each activity can be incorporated into the CPM and PERT charts. The costs of activities that start some time after the project has begun can be escalated to allow for inflation and other costs of money.

4.3 SURFACE MINING

Physical extraction of hydrocarbon ore by surface mining methods currently is being conducted on a large scale in Canada. The extensive Alberta oil sands are water wet which aids in separating the hydrocarbon from the host rock. In the U.S., much of the reservoir material containing similar hydrocarbons is oil wet which makes the separation process much more difficult.

Open pit and strip mining are the two fundamental methods of surface mining. The choice of mining method and the mine configuration is dependent upon the size, shape and resource concentration of the ore body and on the topographic features of the ground surface. Open pit mining generally is used for ore bodies of limited lateral extent, but are relatively thick vertically. Open pit methods are common for near surface ore bodies or copper and iron. Problems basic to open pit mining include waste disposal, slope stability and dust control.

Strip mining commonly is used for thin near surface ore bodies such as coal that may extend laterally a great distance. Overburden and waste disposal is handled by dumping the overburden and waste rock back into the mined out strips. Dust control commonly is accomplished by wetting the area with water. The extensive Canadian projects of mining the Alberta oil sands and the Athabasca tar sands have shown that ore extraction surface mining of hydrocarbons is only a marginally economic venture.

In a later section of this report an in situ surface mining process is described for extracting hydrocarbons from tar sands and heavy oil deposits. For in situ mining, the overburden is stripped off a portion of the hydrocarbon formation, but the reservoir material is not removed. The hydrocarbons are extracted and the reservoir rock is left in place.

Equipment common to surface mining includes various types of excavators, and haulage equipment. Excavating equipment includes power shovels, drag lines, scrapers and bucket-wheel excavators. Haulage equipment includes such choices as bulldozers, scrapers, trucks, trains and conveyors. The cost of stripping in open pit mining has remained fairly constant because of increased productivity due to improved technology. The cost of underground mining, however, has risen steadily. More than 90% of the metal produced in the U.S. today originates in open pits.

4.4 UNDERGROUND MINING

There are many complex mining systems and combinations of mining methods in use for physically extracting the various kinds of ore under different geological settings. Because the emphasis of this report is on in situ petroleum mining, the mining methods and equipment described below is for gaining close access to the reservoir.

4.4.1 Shaft Sinking Technology

In this section, two kinds of shaft sinking methods will be discussed. One is shaft sinking by conventional methods and the other is shaft sinking using drilling and boring equipment. Both vertical shafts and sloped openings are discussed.

4.4.1.1 Conventional Shaft Sinking

In conventional shaft sinking, the sinking cycle consists of three operations: 1) drilling and blasting, 2) mucking, and 3) installing concrete lining and support. Equipment selection for these operations is important if low sinking costs and high rates of advance are to be achieved. As a general rule, it is less expensive to install a permanent head frame and hoist initially and use this equipment for the shaft sinking operation.

It is important to achieve the highest rate of advance, consistent with maintaining shaft stability. Full-face shaft advances generally are preferred with mechanical type mucking because it offers rapid advance. However, bench shaft rounds are also used, especially when water is present, to provide a bench on which to work and allow water to drain to a lower bench. Shot holes usually are drilled using conventional air drilling equipment. In large diameter shafts, mechanized multiple drill jumbos (Figure 24) can be used to great advantage. A number of different mechanical muckers are available to remove muck from the shaft bottom after blasting.

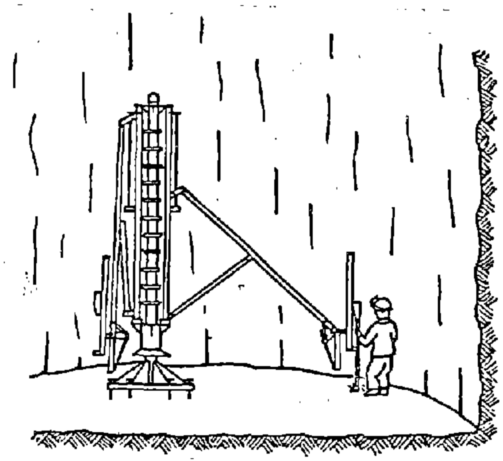

Figure 24. Illustration of a simple shaft drill jumbo. (RETC Proceedings, 1976, p. 106).

4.4.1.1.1 Mechanical Muckers

The relatively inexpensive Riddell mucker (Figure 25) is readily adaptable in restricted areas. It also operates successfully in shafts where water is a problem with other types of muckers. It consists of a traveling crane located above the shaft bottom, a clamshell attached to the crane and a hoist bucket. The clamshell loads the muck into the bucket which is then hoisted to the surface.

The Cryderman mucker (Figure 25) is designed to operate above the shaft bottom with the operator located in a control compartment. A hydraulically operated, boom mounted clamshell loads muck into buckets for hoisting to the surface. The equipment and the mucker is raised or lowered by a special tugger hoist.

Mobile clamshells are used in shallow shafts. Under ideal conditions they can be used to sink shafts rapidly and at minimum cost.

Track mounted muckers (Figure 25) often are used in shafts 18 feet in diameter or larger. They are equipped with a hydraulically operated scoop or bucket. They cannot, however, operate in shafts containing large amounts of water.

A catus grab (Figure 25) is a traveling crane-type unit mounted above the shaft bottom. Attached to the hoist is a specially designed grabbing device designed to fill the largest size bucket used during shaft sinking.

In the Grants, New Mexico, uranium belt, one company is sinking two concrete lined shafts, 14 feet and 24 feet in diameter to a depth of 3,300 feet, using the Cryderman mucker. The benching system is used to advance the shafts. Crews work half the bottom at a time, providing a sump at the lower side. The crews, using hand held sinkers, drill blast holes 8 feet deep. In the 24-foot production shaft, two Cryderman shaft muckers hang from a four deck Galloway working platform. When the shaft has been advanced to the depth for a concrete pour, then Galloway working platform is lowered into position to handle the forms. The intervals between raw rock and concrete lining carrys from 2½ to 20 feet depending on rock conditions. The forms are suspended from hanging rods screwed to the last cement pour. Refrigeration plants, rated at 100 tons, will be used underground to cool the mine air, because rock temperatures at the 3,300 feet ore levels will be 135°F.

If conventional methods are used to sink shafts for petroleum mining, the location of the shaft may not be the optimum point. Using conventional shaft sinking technology it would be difficult to sink the shaft through a pressured petroleum reservoir. For this reason, for petroleum mining the shafts may be sunk using drilling methods in which there are no men underground. Using drilling methods, any suddenly encountered pressurized fluids can be controlled and do not constitute a hazard to the workers. Once drilled, the shaft can be cased or cemented, and if the objective is to go to a level below the reservoir, the men can be hoisted down the shaft in safety once the shaft is completed.

4.4.1.1.2 Inclined Shafts

Various kinds of loading machines are used for sinking an inclined shaft. Methods of removing the muck from the incline include muck cars and belt conveyors and rubber-tired and crawler-mounted diesel units. Special units, such as modified extensible belts used with loading machines have advanced a 9 x 18 feet opening 4 to 10 feet per 8 hour shift. For steeper inclined shafts, a track mounted grab type machine is available. For any system, a bail and disposal system is necessary on the surface.

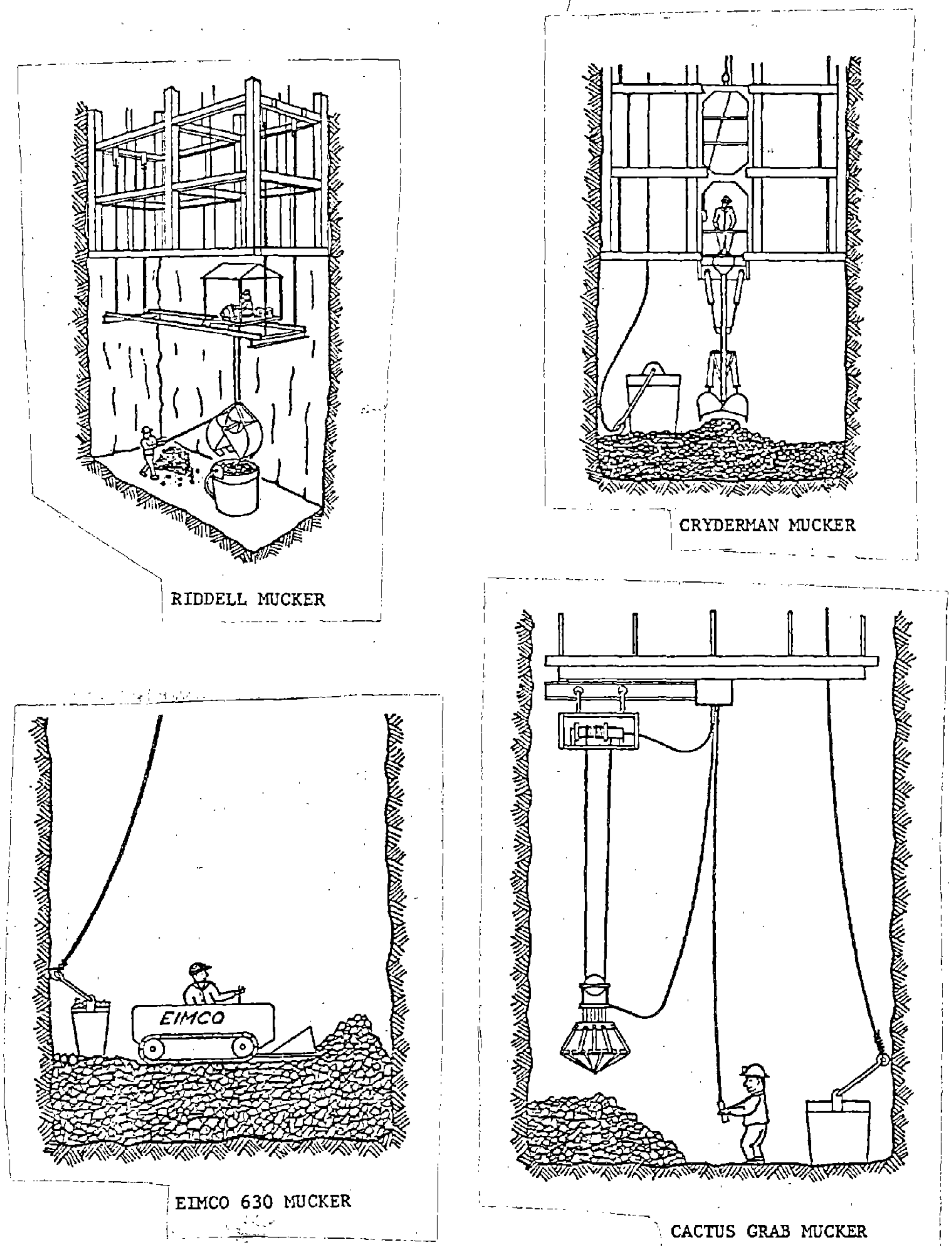

Figure 25. Various types of mechanical shaft muckers. (RETC Proceedings, 1976, pp. 107-109).

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Today, inclines and main entries often are designed for belt conveyors which dictate that the preferred slope be >17°. A two-compartment entry with an arched roof, and a belt compartment over a men/materials track provides a special advantage in weak rock. The over/under section pattern permits a narrower span and the arched roof, bolted and gunited or concreted, provides even greater stability.

Machine loading also is desirable in raising inclined shafts and airways up to approximately 20°. The preferred transportation system is the conveyor belt up to the point where the material will begin to run on sheet metal. The material will begin to run on bottom rock on inclines of 35-40°, and above 45° checks are required.

4.4.1.2 Shaft Drilling Technology

Conventional drilling rigs, such as used in the oil fields, have been beefed up and modified to permit drilling a 7 foot diameter shaft to depth of 6000 feet or more. Drilling a shaft from the surface in this manner is called blind-hole drilling. Often in this situation a small diameter hole is drilled to the desired depth then the hole is successively reamed in increments until it reaches the desired diameter. If a shaft and tunnel workings already exist then a small pilot hole can be drilled from the surface to a mine tunnel and the hole upreamed by assembling the bit inside the tunnels, drilling upwards, and removing the cuttings as they fall down into the tunnel. This is called upreaming. Another term for upreaming is raise boring. There are variations of this technique which will be discussed later.

4.4.1.3 Blind-Hole Drilling

The use of the rotary drill to sink blind shafts offers many advantages over other shaft sinking methods. A diagram of conventional blind-hole rotary drilling equipment is shown in Figure 26. All operations, for example, are controlled at the surface therefore eliminating the need for workers in the shaft. Drilling through water bearing formations is carried on routinely without interruption. The sidewall caving problems resulting from hydrostatic pressure exerted on walls of the hole by groundwater are overcome using drilling methods.

Unlike conventional oil well drilling, reverse circulation is used in blind-hole drilling. The hole is kept full of a mud mixture while the cuttings are drawn up through the drill stem. Using modern mud control technology and because no blasting is required in the shaft, the shaft wall is not fractured or damaged resulting in a smooth stable wall. The number of men required to operate blind-hole drilling equipment is 4-7 men per shift depending on the depth and size of the shaft. At present disadvantages of rotary drilling include limited hole diameter, prohibitive costs in drilling very hard formations and high capital cost of the equipment, some 4-5 million dollars.

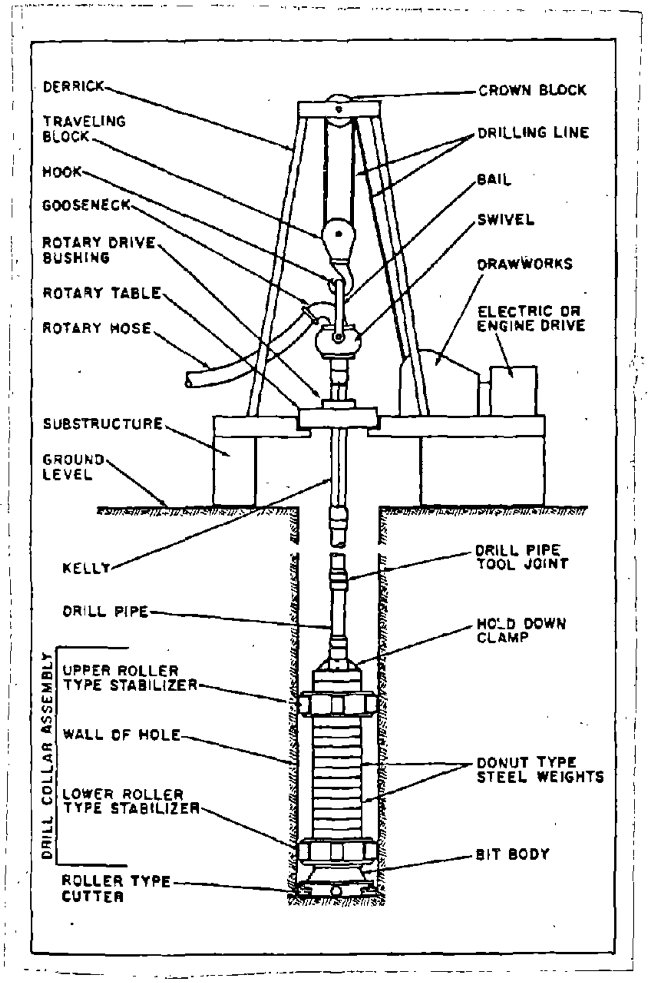


Figure 26. Diagram of conventional blind-hole rotary drilling equipment (SME Mining Engineering Handbook, p. 10-31).

4.4.1.4 Upreaming and Raise Boring

With the availability of shafts and tunnel workings, upreaming or raise boring has advantages. The cuttings fall to the bottom of the hole into the tunnel and there loaded into the materials handling facilities and removed. Methods of raise boring or shaft drilling by downreaming and upreaming are illustrated in Figure 27.

Raise boring is a widely used method for mechanically excavating shafts. The application of raise boring equipment should have wide use in mining for petroleum because at least two shafts will be required in such a mine development. Raise boring was accomplished with good results in two very difficult Australian assignments in hard and extremely abrasive rock. In the first assignment, Robert's Union Corp., operating a diesel driven Ingersoll-Rand RMB-7 borer with RBH-6 head and cutters, completed 1,021 feet of a 6 foot diameter exhaust raise in 12½ working days. The raise is located in an extremely abrasive fine grained quartzite and sandstone formation with a compressive strength of 25,000 to 58,000 psi. Average penetration rate was approximately 5 feet per hour in spite of blocky ground conditions. The raise was backreamed in a single pass. After the head was removed from the raise borer, only two cutters had to be replaced.

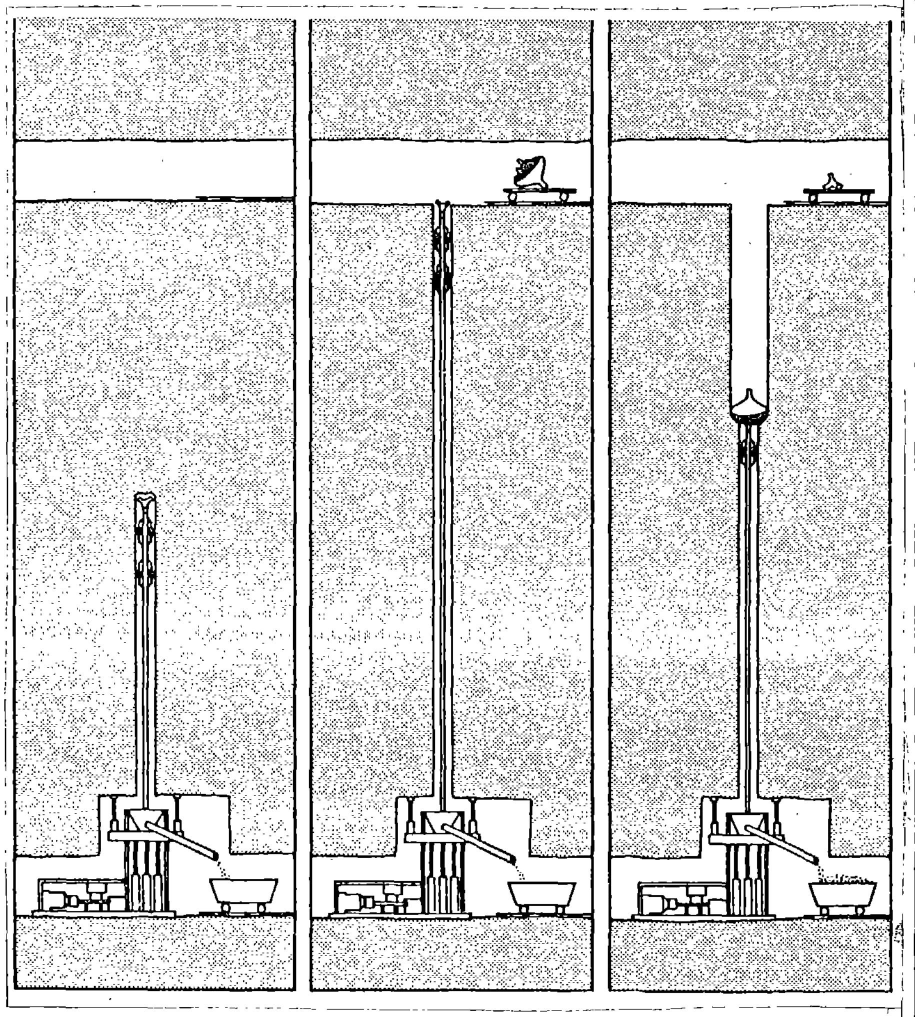
The second raise was completed in 292 hours including delays, rod handling time, and servicing. Teton Exploration Drilling Co. upreamed two 16 foot diameter airshafts 1500 feet at a coal mine in Alabama early in 1977. The first shaft was completed in the period from Sept. 20, 1976 to Jan 18, 1977. The procedure was to downdrill a 13 7/8" pilot hole to the mine workings and upream to a diameter of 16 feet.

4.4.2 Shaft Linings

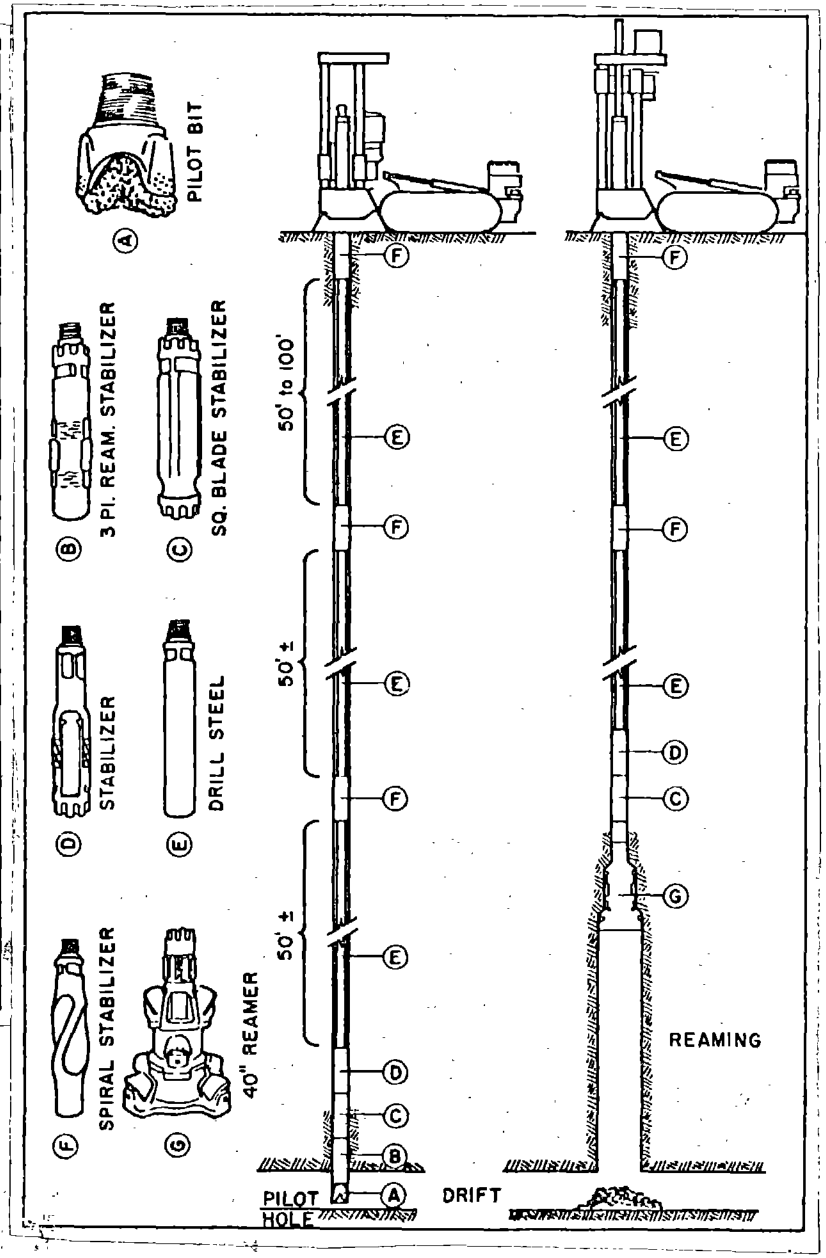
Nearly all deep shafts today are circular in section and lined with concrete. High sinking rates, better ground support, better air flow, lower maintainance costs and greater air and gas sealing ability are among the advantages of circular shafts. Oval, square or rectangular shafts are generally lined with steel or less often with timber sets. Steel sets usually are packed with wood lagging placed in the web of the steel.

In using conventional mining methods, the shaft lining operation may have a great impact on the rate of advance. The overall drilling and shooting, mucking and lining cycles demand a high degree of coordination. A delay in any part of the cycle will delay the rest of the cycle. The development of the curb ring, a closure ring on the bottom of shaft lining slip form that permits the shaft lining cycle to take place concurrently with the sinking cycle and is the biggest improvement in conventional shaft sinking technology in recent years.

In sinking shafts with drilling equipment, the shaft can be lined with steel or concrete after it has been sunk to its total depth. The U.S. Bureau of Mines, for example, drilled and cased an 8 foot diameter shaft in the



RAISE BORING AND DOWN REAMING



RAISE BORING BY UPREAMING

Figure 27. Methods of raise boring or shaft drilling by down reaming and upreaming (SME Mining Engineering Handbook, p. 10-94 & 10-95).

Piceance Creek Basin of Colorado. A 10 foot diameter hole was drilled to a depth of 2,371 feet and subsequently cased with 8 foot diameter steel casing which was cemented in place.

4.4.2.1 Technology Suitable for Petroleum Mining

The shaft sinking technology best suited for mining for petroleum probably is drilling. The optimum locations for a shaft may be through the center of a petroleum reservoir if reservoir pressures can be controlled using the blind hole drilling equipment. Once the shaft has been lined and cemented it would be safe for miners to enter and to create levels below or above the reservoir as the situation permits.

4.4.3 Tunneling Technology

For underground in situ mining of petroleum, the purpose of tunneling will be to provide access to a reservoir and not actually mine any of the hydrocarbon reservoir. Tunneling equipment used for petroleum mining probably will be the newest mechanized continuous miners. It is desirable to use an alternative to the conventional drilling, blasting and mucking methods.

4.4.3.1 Drill-Blast-Muck (DBM) Tunneling

The cyclic nature of the three operations involved in conventional drill-blast-muck systems using explosives is the greatest drawback to this system of mining. Daily advance by this method is approximately 35 feet per day depending upon the number of units to be driven because of the cyclic nature. First, holes must be drilled into the face of the tunnel, then these holes are loaded with explosives, the mining area evacuated then the explosives detonated. When the dust clears the miners come back in and remove the broken rock.

Equipment basic to DBM tunneling is based on a mobile loading machine, a face drill, roof drill and bolter, and the necessary transportation and haulage units. Options for hauling include railroad cars, load-haul-dump units, standard conveyors and extensible belts. Hydraulic and pneumatic transport systems technology is developing rapidly and is a worthwhile consideration for mining for petroleum.

Conventional DBM mining is highly flexible and has been applied to practically all types of mining. A sufficient supply of muck and efficient materials handling system are key factors for efficient machine loading. The basic rule is that as soon as the loading machine is finished in one place, muck should be available for loading in another.

To increase the rate of advance and efficiency in cutting entries, the U.S. Bureau of Mines has sponsored three research contracts on the development of continuous drill-blast-muck systems. The objective is to increase the efficiency by changing the frequency of the cycles or performing some of the operations simultaneously while still taking advantage of inexpensive chemical explosives.

One of the three research projects may have a potential of overcoming the cyclic barrier. This system incorporates a continuous drill and blast tunneler which controls the geometry of the face. In addition to blasting efficiency, the control face geometry forces flyrock into a tangential trajectory, which simplifies shielding requirements. The machine advances the face in a helical spiral. The head of the spiral is approximately equal to 1/2 the tunnel width and the holes are fired singly to minimize undesirable blast effects. The main design feature of the tunneling machine is the head assembly, which is mounted on a main shaft to permit rotational and longitudinal motion relative to the machine frame. The front end assembly consists of the drills, shield, and explosive loading pods which rotate with the shaft. While this technology has not been perfected, it may show promise. The mucking operation for this system has yet to be developed but it will provide complete remote operation with television monitoring.

The drilling equipment used in the drill-blast-muck mining system generally is air or water circulation units which may either be hand held or machine mounted with the capability of drilling in nearly any direction from a given point.

A wide variety of explosives are available for fragmenting or blasting the rock. The type of explosive and velocity of the explosive reaction required is determined by the characteristics of the rock. A slow burning powder, for example, usually is used in moving overburden or coal. In harder materials, explosives with a higher velocity is normally used. The placement of the holes in the tunnel heading is also determined by the rock characteristics. The type of explosive and the drilling pattern is subject to careful and deliberate study and experimentation to find the most efficient and economic combinations.

4.4.3.2 Tunnel Boring

Mechanical boring technology has developed rapidly in the last few years and is taking over a larger percentage of the tunnel work being performed today. Limitations still remain in their application in regard to rock hardness, machine design limitations and adverse geological conditions. In addition, tunnel borers are capital intensive. Under favorable conditions tunnel borers provide for rapid excavation which is an important factor in mining. One recent development in tunnel machine design is a unit that can bore crosscuts off the main tunnel, retreat back into the tunnel and continue boring. This machine was designed with sufficient thrust to bore an 11 foot diameter tunnel through quartzite rock averaging about 30,000 psi compressive strength.

Another version of a tunneling machine is a boom type unit that makes circular tunnels in which shield protection is required. The boom is mounted on a turret that permits excavation of the tunnel profile. A gathering-arm loader built into the leading shield places broken material on an internal chain conveyor.

An 18 foot diameter Caldwell tunnel borer was recently modified for use in eastern coal mines. The machine was used to bore an 18 foot diameter, 6,000 foot long entry, split horizontally, with a nonflammable partition to provide intake and return air ways. The machine was equipped with 35 - 18 inch diameter disk cutters mounted on a rotating wheel to cut the rock. Two roof bolters mounted near the cutter head allowed the installation of 5 foot resin grouted roof bolts. The shotcrete machines lined the complete entry with 2 to 4 inch thick sprayed concrete. A belt conveyor system transported the muck to mine cars 200 feet behind the face.

4.4.3.3 Continuous Mining

Under favorable conditions continuous miners generally provide good penetration rates and versatility. There are a number of types of continuous miners available each with its own rock limitations and limitations as to machine height and width. One of the first continuous miners was the ripper miner which has been used for some 20 years and is still used extensively. This machine has good maneuverability and may be adapted to a wide range of conditions.

A full face borer is a thick-seam miner which provides material from the entire face as it advances. High rates of advance can be obtained with the full face borer, resulting in smooth uniform entries or headings.

A milling miner, also referred to as oscillating-head miner, is a unit that combines some of the advantages of the borer and the ripper miner. The mining plan for using the milling miner generally calls for two side by side cuts. The first cut is as wide as the machine head and the second is cut wide enough to produce the designed width of the entry. Under favorable conditions high rates of penetration can be obtained with good maneuverability.

Boom-type continuous miners consist of a four major component system; a fully articulated boom and cutter, muck gathering and loading devices, mobile undercarriage, and a power control system.

The basic considerations in developing a continuous mining plan include the following: 1) a layout that insures continuous or nearly continuous transportation availability. The belt conveyor provides the maximum in continuity, but as in conventional mining the difficulties in using belts including moving and extention, have kept the shuttle car and other mobile units such as load-haul-dumps in the forefront as the principle materials loading and handling facility. It should be pointed out, however, that technical advances are rapidly developing the conveyor design that may eliminate many of the disadvantages of current conveyors. The use of conveyors behind mining machines probably will increase in the next few years. Extensible, bridge, mobile and other more recently designed units are more suitable for face application.

2) An efficient mine plan is one that holds equipment moves to a minimum and keeps transport distance to a minimum when such moves must be made.

3) The mining plan must insure the adequate ventilation of the working face and control of any dust or gas problems. The method of ventilating faces may have considerable influence on the number of machine moves.

4.4.3.4 Technology Suitable for Petroleum Mining

Because of the potential for gas problems or other flammable material in mining for petroleum it would be advantageous to use equipment or a mining system other than the drill-blast-mucking system. In many cases the geologic strata either underlying or overlying the hydrocarbon reservoir will probably be shale or other suitable medium for continuous mining equipment.

4.4.3.5 Crosscuts

Crosscuts or drifts generally are smaller tunnels cut perpendicular to the main entries or tunnels. Crosscuts will be used for drilling stations to connect the main tunnels and to provide access to a wider area of the reservoir. Since the crosscuts are generally somewhat smaller than the main tunnels smaller mining equipment necessarily is used. Again, it would be wise to stay away from the drill-blast-muck system of tunneling. Small mechanical boring machines and continuous miners have been developed to penetrate medium to hard formations therefore reducing costs for crosscuts and sublevel development.

4.4.3.6 Ground Support

Ground support techniques and materials technology have advanced steadily in the past few years. Mining greater depths, demands for greater extraction rates and new mining methods and systems have created additional problems. Both government and industry have responded to these support difficulities by developing more efficient roof hazard monitoring/detection systems and increasing the use of resin rock anchors, sponsoring research in pre-reinforcing and backfilling technology, improving shotcrete systems and by increasing the use of computers in the design simulation control of ground support.

When openings are cut underground, the equilibrium of the stresses is upset. For this reason some type of roof support generally is required to prevent roof collapse and walls falling that would endanger life and equipment thereby interrupting the operations. The rock is sometimes strong enough to support itself, however, man-made structures and devices usually are installed to insure stable roof and wall conditions. Recent legislation concerning surface subsidence places additional responsibility on the effectiveness of the support mechanisms.

Support varies with the objective and with the character of the material. Temporary protection of the immediate roof will require one type of support while another type would be more suitable for permanent openings in bad roof conditions or caved ground. Weathering resulting from changes in temperature and moisture content of the ventilating air may require the sealing of the roof which is another type of support.

In mining for petroleum, ground support and control will be necessary in the main entries, the side entries and drifts and also in the drill stations and chambers. The life of these openings will be determined by the character of the hydrocarbon reservoir and the time required to recover the resource.

The ground support methods and materials should match the expected life of the opening. If a tunnel requires access for a life to ten years, the material used should last at least that 10 year period. There may be situations where the economics warrant the use of less expensive materials and replacing this ground support at the required interval.

Wood or mine timbers was perhaps the first material used for ground control for mining. The use of wood is perhaps uniquely suitable for mines containing acid mine water seepage. The acid mine waters attack concrete lining and steel more than wood. As a rule of thumb, untreated wood has a mine life of 3 years in comparison to treated wood with cresote or other tar which will last approximately 10 years.

Support by completely lining a tunnel roof, walls and floor is limited to special situations. These situations include: soft section of roof near the outcrop in a permanent drift opening, or other soft or broken areas such as under streams and valleys; and permanent long-lived openings on shaft or slope bottoms. Reinforced concrete is heavy duty lining and also provides for sealing.

Sealing, with some support, is provided by sprayed on sand-cement mixtures, but the support is minimal when the coating is only a quarter to a half inch thick. Though not strictly a lining or coating, grouting has been used to strengthen the roof in sections of permanent openings under stream beds where the overburden is thin and the top is fragmented. Grouting is simply injecting cement into the rock through drill holes. After the cement has set it tends to seal the area from seepage and at the same time it strengthens the roof rock.

Steel liner plates are also used to provide sealing with considerable support. The steel liner plates are relatively easy to install using a concrete footwall as a starting point.

Piers and abutment supports usually are found at points where openings fork in two or more directions and any location where resistance to roof movement is necessary. These supports may be of concrete with or without reinforcement or cinder blocks, brick or masonry.

Where overburden weight is substantial and the roof rock is badly fractured and there is possibly of movement in the ground in which the opening is made, regular yielding arches or rings may be installed. These are used extensively in the United States, particularly under heavy cover. Three basic types of arch supports are available. Each has its specific application to various ground conditions and their costs vary widely.

Rigid arches are designed to support a given load without yielding. Their resistance to the movement of the surrounding ground is greater than the forces from the surrounding strata. The rigid arch usually is constructed from an H or I shaped section. The size and weight of the section are determined by the pressure from the surrounding ground to be supported and the desired or required spacing of the arch sets. Of the several basic types of arches, the two most common types are the continuous rib and the rib and post. In mines with squeezing walls or a swelling floor, full circle or invert strut type arches are recommended to prevent the inflow from the squeezing of the ground from all directions. Yieldable arch segments are formed from U-shaped steel sections that can be fabricated and assembled in the shape and size that will best fit the opening it is to support. It is designed so the maximum strength develops from the section about both neutral axes. This enables the section to resist forces from all directions. Yieldable arches serve the same functions as rigid arches, but their use is often confined to areas with live loads or squeezing ground conditions which would destroy a rigid arch. Yielding arches require more labor to install than do rigid arches. Some of the more common arch shapes and the loads for which they are designed include the following: 1) Three segment symmetrical arch with leg segments toed in are used where ground pressure is predominately vertical. 2) Three segment symmetrical arch with leg segments toed out are used to resist vertical as well as lateral ground pressures. 3) Symmetrical rings are used to resist ground pressures from all directions.

Timbering is probably the most widely used form of ground support. The most common configuration is the three piece set, a cross bar supported by legs at each end. Wood generally is the material used, however the set may also be made of steel or may consist of wooden legs and a steel bar. If steel legs are used, they should be set on concrete piers or low footwalls for maximum stability especially in more permanent openings. Two piece sets are an alternative to the three piece sets under certain conditions. For example, in pitching beds one end of the bar is hitched into bedrock and the other is held on a leg. To eliminate the leg and its hazards, bars may be installed in holes either cut or drilled into the rib. Hitch holes may be provided for each individual bar. As an alternative, holes may be drilled some distance to accomodate pins. Steel bars are then laid on these pins and the regular bars placed on the stringers.

Lagging support is used where the tunnel roof or walls tend to crumble and cave into the tunnel. Lagging consists of boards or timbers placed on top of the timber sets or on the sides effectively covering the roof or walls of the tunnel. In long lived openings, lagging should be treated just as with the main timbers. Lagging provides some support but its major function is to hold loose roof and wall material in place. Lagging has wide use in permanent support, especially in openings where the spacing can be cut down, as in air ways, manways and belt headings or where the roof needs some support.

The widest application of temporary supports is in the active working area which includes the working face. The major objectives of temporary support include 1) protecting men, and 2) keeping the workings open. The majority of roof falls causing fatalities occur in the immediate face area past the last permanent support, and are a result of human failure, primarily the failure to install proper support.

In conventional mining, the first form of face support is the safety post or safety lag, including the hydraulic types. The latter has the advantage of being easier to install and remove to permit machines to pass. The use of cross bars helps to keep support close to the working face while at the same time being out of the way. Specially shaped aluminum alloy beams have been added to the list of cross bar type supports. These are supported by either screw or hydraulic jacks. An older form of support consists of steel beams welded to screw jacks on skids, permitting the bars to be dropped and skidded diagonally ahead under the cross bars still in place.

4.4.3.7 Roof Bolting

Roof bolting, a self descriptive term, simply refers to inserting a long rod into the wall or roof of the tunnel securing it in place by some means and putting a washer and nut on to hold the walls or roof together. The long rod called a roof bolt can be made of steel, various alloys or resins. The primary advantage of roof bolts is that of providing good rib support with full head room. In many cases it is possible by modifying the face cycle, to install the roof bolts as the muck is loaded. In addition to independent bolting units, many continuous miners are equipped with dual bolters.

Normally, suspension is only part of the effect of roof bolting. By tensioning the bolt and clamping the several members of the group together friction is set up between them. This increases the outer fiber resistance to bending and consequently makes each member a stronger beam. The net effect of friction and suspension together varies with specific conditions including the bedding sequence and bolt tension. The need for tensioning emphasizes the need for adequate bolt anchorage, in turn involving drilling and bolting methods. A series of formulae are available designed to determine what reinforcing is necessary. The theoretical pattern is checked by experimental tests in the mine roof followed by any necessary adjustment.

4.4.3.8 Roof Trusses

Roof trusses create a stress pattern by putting zones of the roof in compression, thus providing support. Roof trusses are commonly made of high strength steel rods which are designed for a tension of 14,000 pounds or more. This method has its greatest potential in areas of poor rock which must remain open for extended periods, such as track and belt headings.

In one test at a Pennsylvania mine, roof trusses were superior to H beams set on 4" steel pipes. Other advantages of this support include 1) elimination of legs posts and other vertical supports, 2) less obstruction along the roof line, and 3) trusses are easier to handle than beams or timber.

4.4.3.9 Technology Suitable to Petroleum Mining

The techniques and equipment used in ground control and in tunneling must be designed for the strata that is normally adjacent to a petroleum reservoir. If a petroleum mine, for example, is to have a life of 20 years the ground support must be well designed and planned so that the mine will remain open and safe for that duration.

4.4.4 Materials Handling

Haulage is one of the major obstacles to higher production and productivity in mines today. Men, materials and equipment must enter through the shaft openings and all the waste and ore must be taken out of the shaft. The use of two shafts, necessary for safety and ventilation reasons, does alleviate the problem somewhat. The problem, however, still remains in making the most efficient use of the mine entries, the tunnels and drifts in transporting men, materials and equipment to the tunnel face and the waste materials out. The use of mine cars and track is perhaps the oldest mechanized means of haulage in a mine and is still in wide use today. There have been, however, major advances in haulage technology such as using rubber tired load-haul-dump units, conveyor belts and slurry pipeline transport systems. For any haulage system, the objective is to make waste and ore rock removal as continuous and efficient as possible, keeping loading machines continuously busy, providing for adequate maintenance, keeping down-time or nonuse of equipment to a minimum.

4.4.4.1 Track Haulage

The simplest form of track layout for car or trip loading is the tail-track system. The track can merely be extended down the heading or it can be turned right or left then turned back in U-turn fashion into an adjacent heading. A major disadvantage is that the equipment must come out the same way it goes in which causes a loss of time unless a changing track or system is nearby. Sidetrack or loop-track systems provide access from both ends, thereby permitting most rapid possible trip changes. If properly set up there is little time loss. The sidetrack may be in the same heading as the main track.

Complete loading of trips without the need for operators or attendants has been achieved in mining. Underground stations currently include facilities for automatically diverting the muck from one car to another, controlling the hoist that moves the trip, and starting and stopping the belts. The problem of switching muck from one car to the next in continuous trip loading is met in several ways. One way is to overlap mine cars. Where muck flow is not too great, the means of preventing spillage during car change includes a simple plate or chute to catch that muck during the change. Larger rates of muck flow usually require power or some other type of equipment for a quick change. Power equipment includes the short reversible conveyor mounted transversely under the head of the main belt. Equipment without power includes a "pants chute" with a flop gate to divert the muck stream from one car to the next.

4.4.4.2 Mobile Haulage Units

Although battery powered tractor/trailer combinations and battery powered front end loaders are becoming more popular, shuttle cars remain as the common face haulage units. There are various types of shuttle cars depending on their design for capacity, mining conditions and power source. The electric wheel shuttle car features better traction on wet rough floors and can turn its wheels at a 45^{o} angle. Articulated six wheel shuttle cars permit increased capacity and extra wide tires provide increased traction. Alternating current and torque converter cars not only offer advantages of simplicity and low operating and maintenance costs, but facilitate alternating current use. The maximum length of shuttle car haul is approximately 500 feet with two cars per face unit. For more efficient use of men and equipment time, the trend is to keep the maximum travel distance under 400 feet where possible. Haulage roads must be kept clear of obstructions and kept as smooth as possible to promote efficiency and eliminate wear and tear on equipment.

It is common practice to install transport conveyors or elevators capable of taking maximum shuttle car discharge. These units are designed to feed the belt at the proper rate. Conveyors may be of the belt or chain type with or without hopper and with or without two speed controls. Recently developed units, using either one or two chains, provide differential feeding by employing a constricted discharge and a broad receiving end to accept the material at the full shuttle car discharge rate. Special transfer units include breakers to reduce maximum lump size. Wheel mounted surge hoppers or cars are another transfer device providing similar advantages in addition to portability.

4.4.4.3 Battery Powered Tractors

A wide range of battery powered tractors in combination with rubber tire cars are available for use in conventional mines. The tractors are powerful enough to pull one or more cars or trailers. The majority of the trailers in use today are of the end dumping type, although some side dumps are also in service. New units on the market use a hydraulically operated discharge system which also has the advantage of a variable discharge rate.

Recently developed battery powered articulated front end loaders offer several advantages, such as the flexibility to handle cleaning and supply duties. These units usually incorporate a variable discharge rate which in some cases eliminates the need for belt feeders.

4.4.4.4 Conveyor Systems

The bridge conveyor is used behind face loading or mining equipment. An extensible belt conveyor that can be extended and retracted easily has also been developed for this purpose. Conveyor systems commonly rely on a series of conveyors which may or may not be coupled together with the aim of reducing or eliminating delays in haulage due to inserting or removing conveyor units. In many applications, the mine face equipment may be followed by a single mobil bridge conveyor unit relaying the muck to rubber tire trailers. On the other hand, the conveyor systems may involve a bridge conveyor (or two bridges in tandem), bridge carrier and chain conveyor feeding to a belt.

4.4.4.5 Hydraulic Transport

A number of slurry transport systems have been developed and are being constantly improved. All slurry systems include a device that injects a high pressure stream of liquid into settled or compacted dry materials transforming them into a slurry to pump and pipeline handling. Systems developed by Marconaflo have been installed in mines, replacing loaders, scrapers, drag lines, tracks and conveyors. Slurry technology currently is being researched for various applications such as mining uranium and this technology should be considered in developing mine access entries for mining for petroleum.

4.4.4.6 Water Handling

Water handling procedures have been developed in both the mining industry and the petroleum industry for many years. Mine tunnels are designed to permit seepage to flow to a storage area where it is then pumped to the surface for disposal or to some other appropriate area. Water handling practices in the petroleum industry are outlined in the Appendix B. Water diversion practices in mining include constructing diversion ditches around the shaft openings, sealing stream beds at troublesome points, grouting or cementing underground to seal off stream channels, and constructing dams.

It is neither possible nor practical in most instances to totally prevent water from entering the mine. Some provisions must be made for handling the underground inflow. It may be possible to lay out the mine so that workings advance on a slight incline also assisting haulage as well as the drainage.

The drainage system must be operated and maintained with minimum expen-iture of service labor. The pumps and drainage equipment must give long troublefree service, pipelines must last and there should be minimal relocation of pumps. Controls for pumps range from simple float switches to elaborate fully automatic systems for the larger stations. Modern pumps can be made of special alloys or lined with coatings which will increase the life of the pump if handling corrosive water.

Water handling technology is well advanced and is not prone to special problems in underground mining. In mining for petroleum, the water associated with the hydrocarbon must be considered in design. The handling of hydrocarbon related water is also highly developed technology and will present no unique problems.

4.4.5 Ventilation

Ventilation will be extremely important in mining for petroleum. The development openings will be close to the hydrocarbon reservoir so extra care is necessary to prevent the accumulation of toxic, suffocating or explosive gases. In-situ mining for petroleum as emphasized in this report will only expose limited rock surfaces in the development openings. If the hydrocarbon reservoir were mined as ore as in conventional mining it would be much greater danger due to toxic, suffocating, or flammable gases. Prior to mining, the following parameters should be measured in order to estimate the inflow of the gases into the development opening: 1) gas pressure, 2) permeability of the rock, 3) rate of water inflow and the content of hydrocarbons and toxic gases in the water. The geological conditions such as fault zones have to be mapped accurately and caution must be exercised prior to mining these particular areas to avoid the sudden inflow of large quantity of fluids.

In discussion with technical personnel at the Mine Safety and Health Administration, the general opinion is that mining for petroleum logically would be treated in a manner similar to coal mining. Most of the regulations that apply to gassy mines would apply to mining for petroleum.

4.4.5.1 Ventilation Layout and Planning

Depending on the geometry of the hydrocarbon reservoir, the ventilation layout may be similar to that used in coal mines and to some metal mines. Two distinct subjects must be emphasized in mining for petroleum. One, to construct and use as many ventilation raises as is practically and economically possible to increase the air flow and reduce air resistance. Second, to develop modular ventilation sections such that they can be closed individually in case of mine fire or other reasons without affecting the entire mine. It is anticipated that an exhaust system with axial flow plans will be used for an underground oil mining operation. Two main shafts, one for intake and the other for exhaust air will be required.

4.4.5.2 Face Ventilation, Probe Drilling and Gas Drainage

The fresh working face is the most critical area where gas and other hydrocarbons can accumulate. Fresh rock surfaces are constantly being exposed at the working face and the gas contained in the rock tends to have a higher pressure and flow rate at the initial stage. The working face must be well ventilated at all times with continuous monitoring of gas concentration. Mining machines should be equipped with automatic shut-offs if the concentrations get too high. Ventilation at the working face can be accomplished using various arrangements, tubing and fans, such as 1) with a blowing auxillary fan, 2) with an exhaust fan, 3) with a combination of exhaust and blower fans, 4) with a machine mounted diffuser fan and exhaust auxiliary fan, 5) with machine mounted dust collector and exhaust fan.

Probe drilling in advance of the tunnel heading is always prudent if fracturing,shear or fault zones are anticipated from the geological data. In mining for petroleum it would be a sound practice to use probe drilling as a routine procedure to avoid suddenly encountering zones of pressure or toxic or otherwise dangerous gases. If significant amounts of gas inflow continuously at the working face, drainage holes can easily be drilled from the face or sidewall to drain the gas and pipe it to storage or for use.

4.4.5.3 Temperature Control

Due to the natural geothermal gradient, a temperature of about 140°F will be reached within depths of 6,000-7,000 feet. For temperatures above 140°F cooling of the mine through the ventilation air will become much more expensive. For shallow oil mining, temperature control probably can be achieved by using ordinary ventilation. At great depths, however, additional thermal control procedures will be necessary. Currently two types of methods are being employed, 1) the use of a refrigerator plant and 2) the use of cold service water. Most high temperature mines are using refrigerator plants to cool the mine workings. Cooling the ventilation air using cold water has recently been successfully employed in the South Africa gold mines. This method has proven to be effective. Using a supply of cold water for temperature control may be preferable because of its simplicity and favorable economics.

4.4.5.4 Controlling Leakage

Fugitive air is an expensive occurrence in todays mines. Surveys of some mines show up to 80% of the air moving through the fan never reaches the working faces. The air leaks through poor stoppings, around doors and back into the returns without moving near many of the active sections. Even in mines where ventilation is given more serious consideration, leakage may short circuit 30% or more of the incoming air supply. The fugitive air problem must be carefully controlled and monitored in a mine system for petroleum.

Sealing points of excessive leakage is the common way of overcoming these problems. For example, cinder blocks differ in permeability and it has been shown cinder block stoppings can be made more air tight by applying a coat of plaster. A coat of paint over the plaster provides still a tighter seal. One company seals stoppings by mixing portland cement with the slurry in a wet rock duster, then applying the mixture to the stoppings as in conventional wet rock dusting. Another method of reducing leakage is to achieve one way or unidirectional flow, thus reducing leakage opportunities by eliminating side by side intakes and returns which are separated by porous stoppings or other leakage control devices. Air shafts or other openings to the surface may be used as new fan locations for additional intake openings to get the one way flow.

New federal regulations are in effect concerning gas detection and control, air quality and quantity and escapeways. Consideration must be given to these legal aspects before designing a ventilation system.

Computers contribute greatly to efficient underground ventilation systems. For example, the Mine Environmental Simulations (MINES) program is user-oriented software that can compute the time-dependent air flow, temperature, humidity, long-term wall heat flux, and mechanical cooling or heating requirements for underground mines. This program, developed by Brinckerhoff, Quade, and Douglas, Inc., can also simulate emergency conditions, such as tunnel fires, and provide estimates of temperatures and the amount of mechanical ventilation required to exhaust both smoke and heat to maintain any prespecified conditions.

This computer program has three main components: 1) an aerodynamic subprogram that provides precise estimates of air flows and velocities throughout the tunnel network resulting from any configuration of ventilation shafts, fan location, fan capacities, and tunnel sizes. 2) A temperature-humidity subprogram that computes the environmental conditions resulting from all sources of sensible and latent heat addition and removal (e.g., heat released by underground equipment), as well as exchange of air with the above ground atmosphere and heat transfer across the surrounding tunnel walls. 3) A deep heat-sink subprogram that computes the effects of long term addition by the surrounding earth as a function of the thermal characteristics of the earth and the velocity dependent transfer of heat between air in the tunnel and the tunnel walls.

The MINES program is an ancillary product of a three year R&D project sponsored by the Transit Development Corporation and partially funded by the U.S. Department of Transportation. Portions of the program have already been validated in a scale model tunnel system and in full scale field tests.

4.4.6 Health and Safety

The view that mining is a highly dangerous occupation is gradually on the decline. Statistics make it so. Government and industry research devoted to improving health and safety condition in mines has produced many ideas, devices and systems to reduce hazardous conditions which have produced immediate and long term improvements on the overall health and safety of both underground and surface mining operations. A serious thrust has been made to improve health and safety in the mining industry with the passage of the Coal Mine Health and Safety Act of 1969 and the passage of the more recent act of 1977. While the government has placed the burden on the mining industry, it has fulfilled its responsibility relating to mine health and safety, all of which is a plus for the future of mining for oil.

The Bureau of Mines is concerned about the health and safety of miners and is focusing attention on such factors as respirable dust, mine gases, methane removal, noise limitations and adequate lighting.

Operating under a research budget of some $30 million, the Bureau has increased its support of health and safety in research and development programs. In fiscal year 1975, the Bureau spent more than $4.5 million for research in metal and nonmetal health and safety, with the largest expenditures going for industrial-type hazards (24%), fire and explosion prevention (16.3%), ground control (14.6%), radiation (18.8%), and respirable dust (8.3%). Much of this research was done in cooperation with private industry.

A few successes, with and without government funding, are as follows:

1. A new fire detection and control system for shafts has been developed by FMC Corp.
2. A microseismic rockburst detection system was engineered by Hecla Mining Co.
3. An inflatable mine plug for emergency closure of corridors has been developed by ILC Industries.
4. Collins Radio and Westinghouse Electric have jointly produced a directional antenna system for locating trapped miners.
5. A mobile rescue unit consisting of a steel cage, winch, and truck combination is offered by Pitman Mfg. Co.
6. An infrared heat-sensing device for detecting loose rock, crevices, and hot spots, is available from Hughes Aircraft Co.
7. Short-duration self-contained breathing apparatus have been developed by Lockheed, Dragerwerk AG, and Mine Safety Appliances.
8. St. Joe Minerals has reduced the noise of pneumatic drills through the use of ultrahigh molecular weight polyethylene bushings and mufflers.

4.4.6.1 New Mine Health and Safety Act of 1977

With the passage of the new mine health and safety act of 1977, many changes will be implemented. Full details of the act as it relates to mining are not certain at this time. Changes are in the making. It will be some time before complete details and rules and regulations are established. While at present, they will apply to metal and nonmetallic mines and coal mines, they also will be applicable to oil mining. It is too early to quantify the effect of the new law on oil mining.

4.4.6.2 New Technology in Health and Safety

Research and development of new equipment and techniques for protecting miners has brought forth many improvements in mine health and safety. All aspects of the field appear to be covered.

4.4.6.3 Respirable Dust Control

Research on the control of dust includes methods to determine which combinations of continuous mining machine parameters produce the least respirable dust. Bureau of Mines laboratory studies show that formation of airborne respirable dust is reduced drastically as the bit's depth of cut increases. A drum-type microminer 10 x 5 x 5 feet in size, with a 30 inch diameter drum is capable of sump and sheer rates of up to 10 inches per second and drum speed of 1 to 180 revolutions per minute. Tests with this miner show that bit speed as well as depth of cut greatly affects dust generation. Slower rotations and deeper cuts reduce dust. This has been demonstrated on full-scale mining machines.

A secondary ventilation system has been tested on an auger machine. For this application, a high efficiency dust collector is used rather than a duct to the return air.

Laboratory work is in progress on the capture of airborne dust by water sprays, and also on the spreading of water drops and wetting of the surface to be mined. A full-scale simulated mine entry with mock up of a continuous miner with water sprays has been constructed at the Pittsburgh Mining and Safety Research Center. This is being used to determine the best location for spray nozzles for capture of airborne dust near the face. Location of water sprays at the cutting bit ("wethead" concept) has proven to be the best technique of reducing dust with sprays.

Other current research regarding the suppression of dust include water infusion, foam, canopy air curtain and improved dust sampling.

4.4.6.4 Toxic Gas Control

Rapid detection of toxic gases in underground mines shows great promise. Standard instrumentation employed in mines today consists of flame safety lamps, hand-held methanometers and machine mounted methane monitors. For gases other than methane and for oxygen deficiency, the principal instrumentation is a length of stain tube. New instrumentation for detecting these and other types of gases include automatic length of stain, carbon monoxide meters, and oxide of nitrogen detectors which include electro-chemical and nondespersive adsorption techniques.

4.4.6.5 Noise Control

Noise control technology is advancing along several lines, including control at the source, and personal ear protection and measurement. Results of on-going research will protect the hearing of miners and improve productivity.

In Bureau of Mines noise research, retrofit methods have been developed to reduce noise of pneumatic drills used in roof bolting operations and noise of loading and continuous mining machines.

4.4.6.6 Mine Lighting

Studies by the Bureau of Mines and the National Bureau of Standards have established 0.06 foot-lamberts as the minimum light required in the working places in underground mines.

On April 1, 1976, the form and substance of the new illumination standards, which were to be promulgated on October 1, 1976, were published in the Federal Register. The new standards contain a number of modifications of originally proposed standards, the principal ones being lighting required only while self-propelled mining equipment is operated in a working place, illumination levels to be determined only by measurement of surface brightness, and standardization of light measuring procedures provided.

4.4.6.7 Discussion

While this is only a sampling of the health and safety rules and regulations to be imposed on the mining industry, it is an indication of the regulations that pertain to an oil mining industry. There is no doubt that the metal and nonmetal mining industry will meet these requirements. The oil mining industry must also meet these requirements. Explosive gases and roof control are likely to be the most serious problems in oil mining.

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SECTION 5

MINING FOR PETROLEUM

5.1 INTRODUCTION

The petroleum mining methods described in this section resulted from combining the most current technologies of petroleum and mining engineering. Methods and techniques are described for mining conventional liquid hydrocarbon reservoirs and for heavy, viscous oil and tar sands. In general, petroleum technology is used for the extraction of the hydrocarbon from its reservoir and mining technology is used for close access to the reservoir. One of the techniques, however, primarily is a mining engineering technique, but the crude production can be calculated using petroleum engineering theory.

Basically, two processes are described, one for conventional liquid hydrocarbon reservoirs and one for heavy oil and tar sands. Each process has several mining applications depending upon the depth, configuration and other physical and chemical properties of the reservoir. Drip Drainage is the name given to the basic process for mining for petroleum from a conventional petroleum reservoir, and Open Surface Flotation (nicknamed Flip-Flop) is the term for the process described for heavy oil and tar sands. Because conventional petroleum reservoirs contain the hydrocarbons compatible with existing refining, processing and consumer facilities, the gravity drainage process and its various applications will be discussed first. Flip-Flop, the process for producing heavy oil and tar sands, and its various applications will be discussed second.

5.1.1 Project Definition

No attempt was made in this study to design a mine or mine workings for any particular hydrocarbon reservoir or for any selected geographical area. The objectives of this study were to review USBM Bulletin 351 (Mining Petroleum by Underground Methods, George S. Rice, 1932, 159 pp).and to develop technically and economically feasible concepts for mining for petroleum. The project team for this study includes ability in petroleum engineering, mining engineering, geology, the environment and economics.

The project team, after careful study of available technology and of the problems involved, decided not to concentrate on processes that involve removing reservoir material as 'ore' and also decided not to emphasize surface mining methods. Mining processes that remove reservoir materials were given no consideration for the following reasons:

1. Other Studies. Concurrent studies by other engineering companies under contract are involved in investigations of the technical and economic feasibility of extractive mining of petroleum.

2. Petroleum Technology. Mining the reservoir material would preclude the use of any modern petroleum engineering recovery technology and the use of any of the naturally occurring reservoir energies for crude oil extraction.

3. Processing. Surface processing of the reservoir material would be similar to the expense and problems of processing tar sands. In degasifying the reservoir, only the heaviest fraction of the original hydrocarbons would remain in the "ore". The heavier remaining oil fractions are then more difficult to remove from the rock.

4. Environmental. There would be more environmental disturbance (in land area, process emissions and waste disposal) by removing the reservoir material and extracting the crude oil at the surface than in mining only for access to and extracting the crude oil in-place. In addition to the surface facilities for crude oil extraction and the storage or disposal of waste, there would be a much greater probability of a significant amount of surface subsidence.

5. Economics. The economics of mining in-situ should have a much better rate of return since rock does not have to be handled to processing plants and the need for waste rock disposal is eliminated. The capital and labor intensive sand separation plant is not required, thus improving project economics substantially.

Surface ore extraction mining methods have not been emphasized in this report because surface mining feasibility and economics is straightforward and relatively simple after a location has been chosen. One of the applications discussed in this section begins as a surface mining technique, however, it is an in-situ process.

The petroleum mining processes and applications were subjected to the following four questions:

1. Is it within the scope of current technology?
2. Is it safe for surface and underground workers?
3. It is environmentally sound?
4. Is it economical?

The processes and equipment are within the realm of current technology, however, some engineering modifications may be necessary. Safety of the underground workers is vital to the success of petroleum mining. Special underground safety techniques may be required, but not as elaborate as in mining out the reservoir material. The environmental objectives were to minimize disturbance both at the surface and underground, to minimize or eliminate surface processing and emissions, and to make the best possible use of existing facilities. Economic objectives were to design processes as simply as possible to minimize the required amount of capital equipment, to minimize operating costs and to use existing equipment whereever possible.

5.2 PETROLEUM MINING TARGETS

Nearly any liquid, viscous or solid hydrocarbon reserve is a potential petroleum mining target for the two processes developed by the project team. For liquid hydrocarbons the logical initial targets are the shallower depleted or nearly depleted oil fields. For initial demonstration and development the choice of a shallow reserve will cut shaft costs and would significantly cut the initial development time. For heavy oil and tar sands any surface exposure or near surface occurrence of adequate size will be amenable to the surface process described in this report. For heavy oil and tar sands reserves at depth, the overburden ratio must conform to certain mining constraints. For deeper heavy oil deposits, cavern jetting or other technology must be further developed.

5.2.1 Conventional Liquid Petroleum

The major constraints in mining for liquid petroleum by Drip Drainage will be the physical competency and thickness of the rock strata immediately above and below the reservoir and the temperature of the mine workings.

Temperatures of mine workings are a function not only of depth but of geothermal gradient for the site specific geographical area of the United States. Geothermal gradients (the rise in temperature with depth) vary markedly over the U.S. In areas of substantial oil reserves in the lower 48 the "hot" areas are the Texas-Louisiana Coast and the southwestern California Los Angeles-San Joaquin Valley deposits. Mining (at depth-not surface mining) in these areas will produce high mine operating temperatures in the range of 140^{o}F at depths of around 4000'. There are "cool" areas containing large petroleum deposits such as those located in the Permian Basin of West Texas-New Mexico. A mine in some of these locations can be operated at around 7000' before a 140^{o}F temperature limitation is reached. Because mine operating temperatures and the human working environment are a limitation, the geothermal gradient in "cool" areas will make available to conventional mining sizable reserves at greater depths. Figure 28 is an isotherm map of the United States which generally indicates the "cool" and "hot" areas and represents the temperature limitations to mining before excessive ventilation costs (above 140^{o}F) are encountered. Reservoir targets below the 140^{o}F isotherm are available to mining for petroleum if the value of the petroleum reserve is sufficient to overcome the costs associated with added ventilation and larger shafts and tunnels required to accommodate higher air flows. The geothermal gradient therefore is not an absolute or technical barrier to mining at lower depths but is a limitation because of economics. As greater mining depths are projected, earth pressure increases requiring smaller tunnel diameters to accommodate the overburden stresses. Since the two factors, added ventilation requiring larger tunnels and overburden pressure requiring smaller tunnels work against each other there is a practical depth limit to mining for petroleum. Each case will be calculated separately by the petroleum and mining industries as the depth limit can be modified by refrigeration, tunnel bracing, or other costly mechanical means if the economic petroleum target is sufficiently

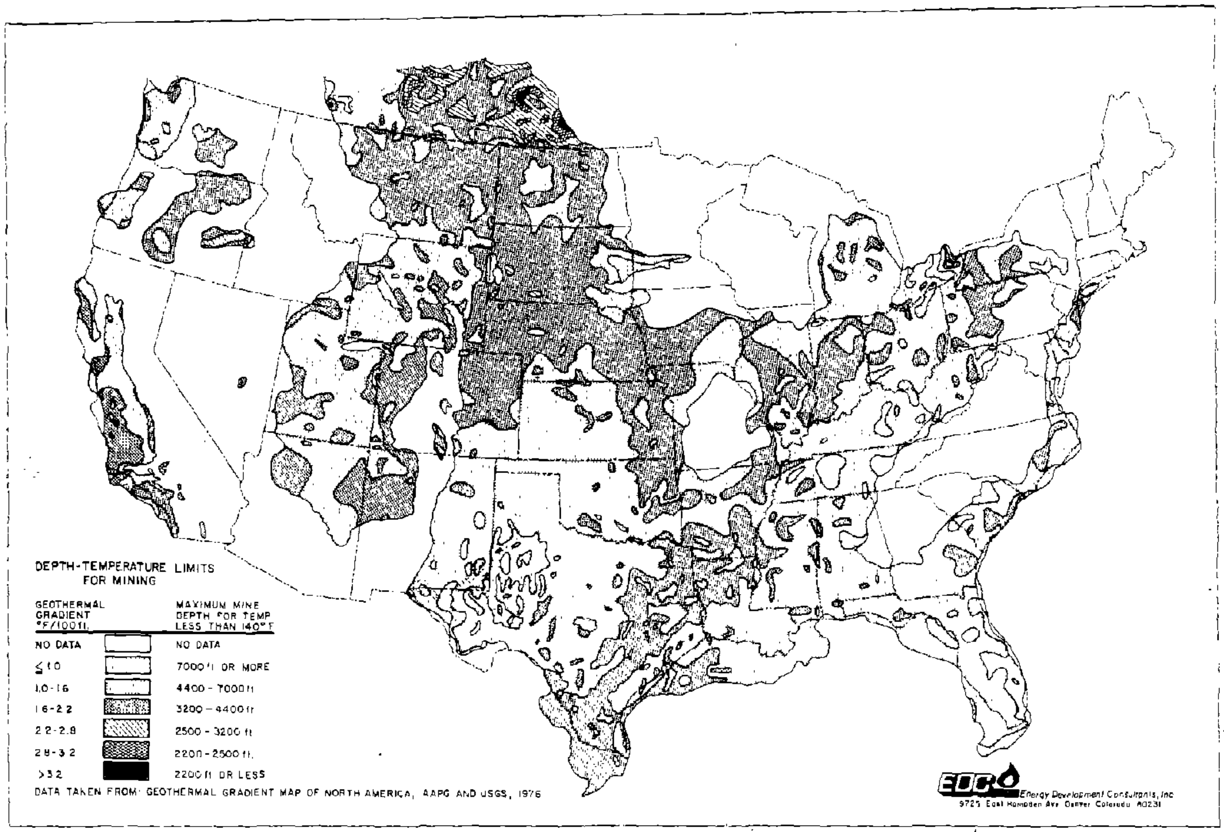

Figure 28. Isotherm map of the United States.

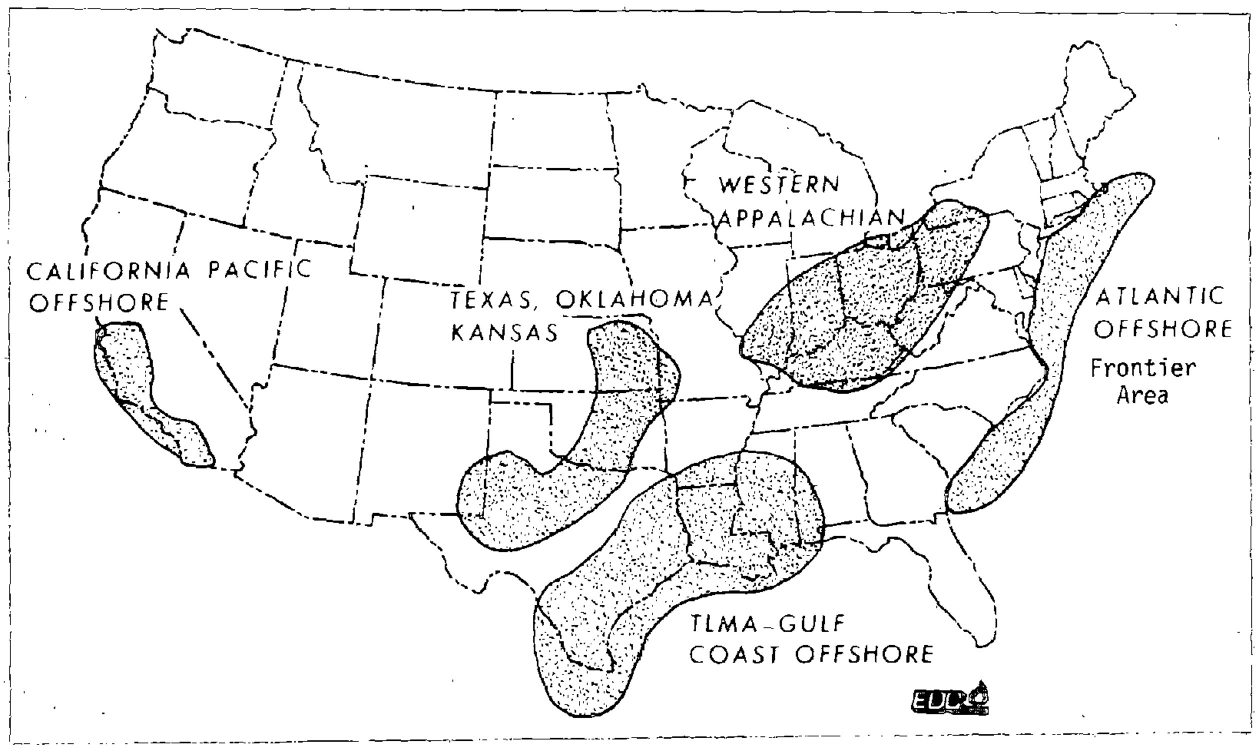

Figure 29. Major oil producing regions of the United States (plus the major frontier area).

attractive. As the free market price of oil rises additional reserves will be economically brought into the viable range of mining for petroleum.

Mining for petroleum may be thought of as a tertiary petroleum recovery method but could be used as a primary or secondary recovery process. As a tertiary technique, the mining target is the approximate 2/3 of oil in place which is currently unrecoverable by conventional primary and secondary methods. Underground mining for petroleum can be used upon primary depletion, replacing conventional secondary methods, thereby adding its 10-15% of oil in place to the mining target. In certain situations, mining for petroleum by underground methods could be economically effective bypassing all conventional production methods including primary production development by surface wells. There are a great number of large depleted fields in the United States.

The magnitude of the potential of mining for petroleum is partially indicated by Table 14, which is a listing of the largest U.S. oil fields in descending order of the amount of "unrecoverable" oil remaining in place. Half of these 40 largest fields can be categorized into two very specific types and locations of reservoirs: West Texas-New Mexico Permian Basin San Andres (about 4000') geothermally "cool" conventional oil and California San Joaquin Valley shallow viscous oil. Therefore, this chapter addresses two methods of recovery by mining for petroleum: one method for each of these large reserve categories. For the remaining 20 fields listed in Table 14, at least one of the two methods described herein is a potential recovery method. Therefore, we feel that mining for petroleum has a very broad potential to recover a large percentage of the 300 billion "unrecoverable" oil in the U.S.

Figure 29 shows the major oil producing regions in the United States and Figure 30 shows the location of U.S. shallow oil fields, the most likely initial target of mining for petroleum.

The estimates within this report are exclusive of presently undiscovered conventional oil which, according to USGS Circular 725, approximates 80-100 billion barrels of recoverable original oil in place. Since current technology recovers only 32%, then a remaining undiscovered 160-200 billion barrels in the future could be available to recovery by methods described herein. Most of this undiscovered oil, however, is at sufficient depth that reservoir access is not possible with current mining technology or it is offshore where mining would be very costly.

5.2.2 Heavy Oil and Tar Sands

A significant portion of U.S. hydrocarbon reserves are locked in heavy oil and tar sands. While not as great as liquid petroleum, heavy oil and tar sands reserves are still several times the 30 billion remaining producible reserves attributed in the U.S. There are few profitable commercial ventures in the U.S. for extracting these hydrocarbons although much research is being conducted. Figure 31 shows the location of documented petroliferous rock in the U.S. There is a great deal of undocumented heavy, viscous oil in the United States.

Table 14

Largest U.S. Oilfields (1000's Barrels)
Source: API (As of Dec. 31, 1976)

Field	Location	Est Cumulative Prod	Remaining Proved Reserves	Original OIP	Unrecoverable Reserves By Present Tech	Unrecoverable As % OIP
Prudhoe Bay	AK	3170	9396830	23800000	14400000	60.5
Spraberry	WTNM	431091	103537	8598550	8063922	93.8
Wilmington	CA (LA)	1807458	677542	9693100	7208100	74.4
Huntington	CA (LA)			6000000	4940000	82.3
Panhandle	**WTNM**			**6060000**	**4651000**	**76.7**
Midway Sunset	***CA (SJ)***			***6185000***	***4554500***	***73.6***
Coalinga	***CA (SJ)***			***4505000***	***3801000***	***84.4***
Wasson	**WTNM**			**4747792**	**3230327**	**68.0**
Kern River	***CA (SJ)***			***4062000***	***3082000***	***75.9***
Ventura	CA (Coast)			3500000	2600000	74.3
McElroy	**WTNM**			**2544015**	**2033900**	**79.9**
Yates	WTNM			4000000	2000000	50.0
Elk Hills	CA (SJ)			2815321	1793141	63.7
Sho-Vel-Tum	OK			3100000	1722558	55.6
Eunice	**WTNM**			**2000260**	**1621445**	**81.8**
Goldsmith	**WTNM**			**1823130**	**1208923**	**66.3**
Belridge South	***CA (SJ)***			***1400000***	***1905000***	***78.2***
Vacuum	**WTNM**			**1425426**	**1069808**	**75.1**
San Ardo	CA (Coast)			1450000	1050000	72.4
H. Glasscock	**WTNM**			1421100	**1035839**	**72.9**
Rangley	CO			1681575	955577	56.8
Bay Marchand	LA (S)			1569073	952851	61.0
Fullerton	**WTNM**			**1322570**	**948359**	**71.7**
Sooner Trend	OK			1202778	922448	76.7
Slaughter	**WTNM**			**1810000**	**864000**	**47.7**
Salt Creek	WY			1478980	846885	57.3
Kelly-Snyder	**WTNM**			**2160886**	**827814**	**38.3**
McArthur River	AK			1336000	825001	61.8
Cowden North	**WTNM**			**1208750**	**762650**	**63.1**
McKittrick	***CA (SJ)***			***992900***	***731275***	***73.7***
Golden Trend	OK			1170000	715345	61.1
Levelland	**WTNM**			**1012000**	**659200**	**65.1**
Seminole	**WTNM**			**1008800**	**597200**	**59.2**
Healdton	OK			940000	594491	63.2
Oregon Basin	WY			905600	572429	63.2
Cailou Island	LA (S)			1218993	539973	44.3
Hobbs	**WTNM**			**815024**	**537001**	**65.9**
Elk Basin	WY—MT			1058705	535515	50.6
Dos Cuadras	CA (Coast)			750000	535000	71.3
Foster	**WTNM**			**755000**	**521750**	**69.1**

Bold print are West Texas-New Mexico "cool" area oil fields available to gravity drainage mining for petroleum.

Bold italic print are shallow California heavy oil deposits available for Flip Flop mining for petroleum.

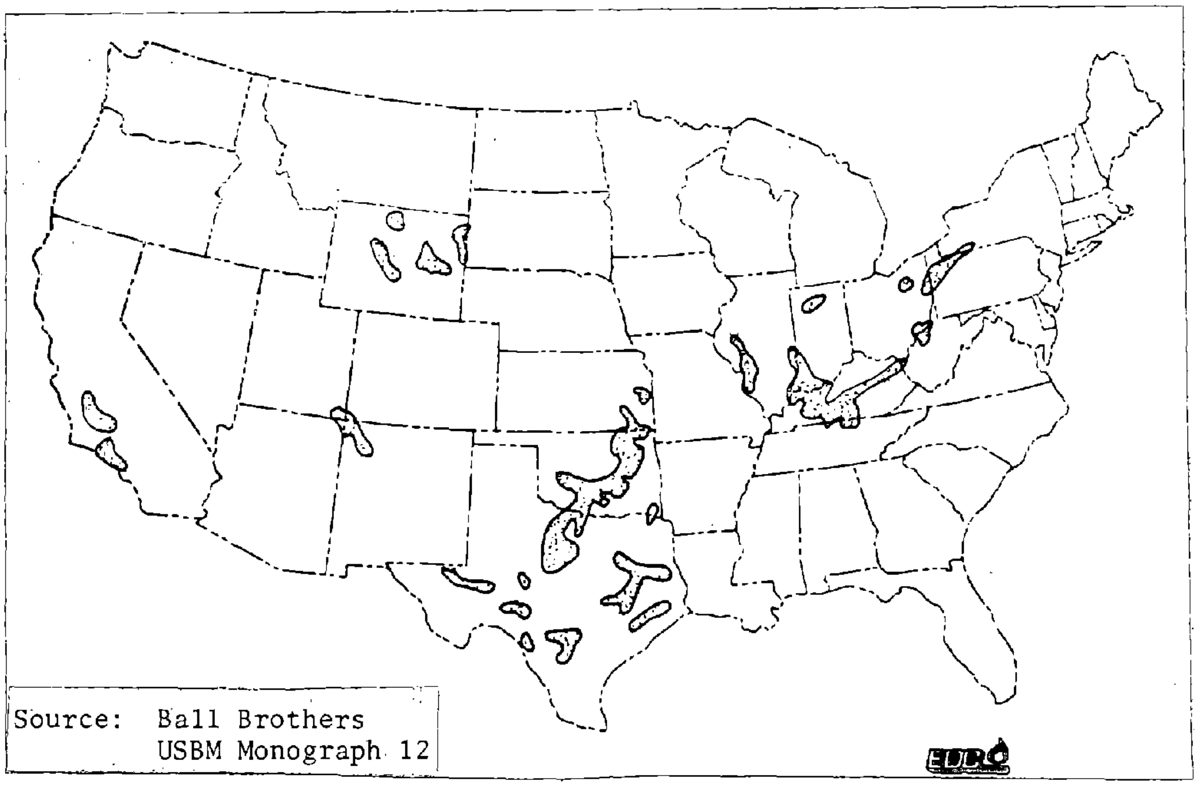

Figure 30. Location of shallow U.S. oil fields.

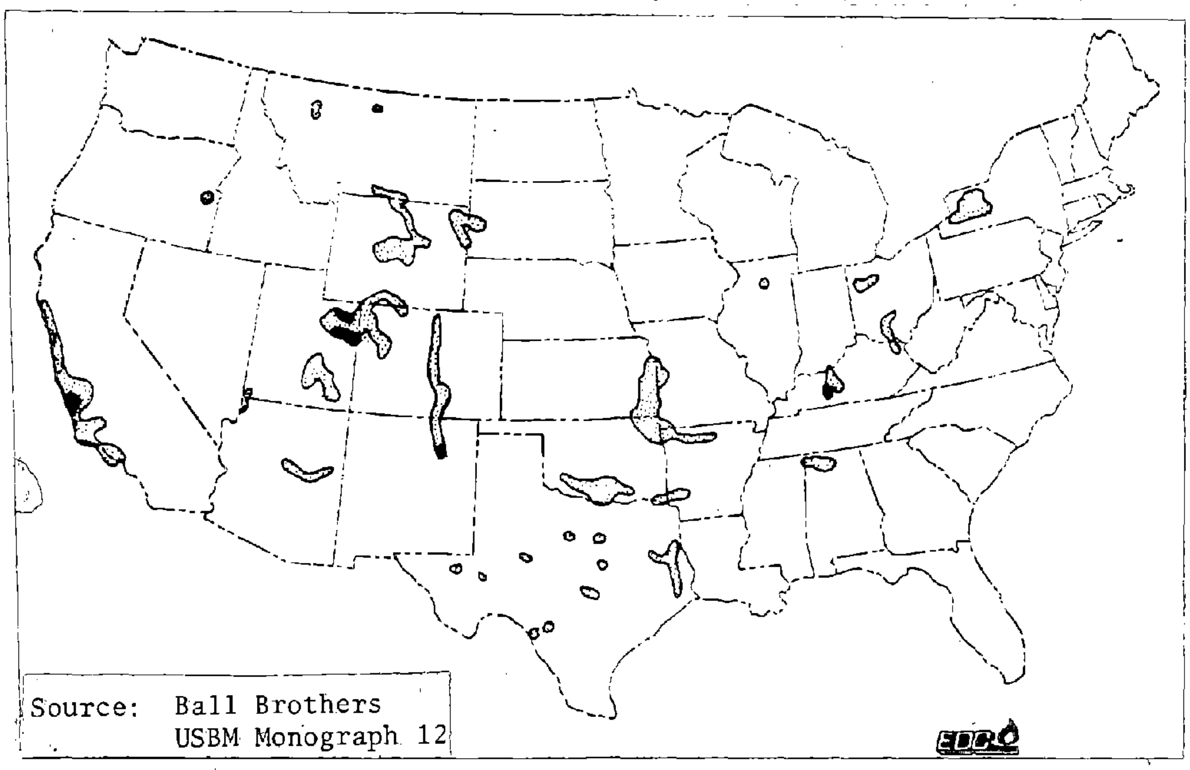

Figure 31. Location of petroliferous rock in the U.S.

5.3 MINING FOR CONVENTIONAL LIQUID PETROLEUM

There are many oil reservoirs within the continental United States which have been pressure depleted, depleted by gas driven secondary recovery or water flooded. These reservoirs still contain approximately 70% of the oil orginally in place. Of course, this residual oil in place varies with the different reservoirs and the only ones to which mining presently would apply probably would be those with residual oil contents in excess of 50%. The oil remaining in most of these reservoirs will have a viscosity of probably less than 10 centipoises and a solution gas content of less than 500 cu.feet per barrel. The remaining reservoir pressure would probably be less than 2,000 psi and the depth would be less than 4,000 feet.

The mining/production processes will be one of two types: 1) to recover all the fluid within the reservoir, that is gas, oil and water, 2) to recover only the oil and whatever gas is in solution in that oil. The selection of the mining/production process will be a function of the reservoir, the condition in which it has been abandoned and the auxiliary types of energies which might be involved.

5.3.1 Reservoir Forces

For purposes of this discussion, natural reservoir energies may be separated into (1) forces acting on the reservoir, and (2) forces acting within the reservoir. The forces acting on a conventional reservoir can be measured in terms of pressure, pounds per square inch (psi). These forces include (1) the hydraulic pressure due to the weight of a column of water (water drive), (2) the weight of the overburden (overburden pressure), (3) entrapped gas cap pressures and entrained gas (gas drive) and (4) other less important pressure sources such as those due to temperature change.

The forces acting within the reservoir include those of capillarity and bouyancy forces due to gravity. The effects of these forces cannot be measured in terms of hydraulic reservoir pressure. The effect of capillarity is a primary force in the migration and accumulation of crude oil and bouyancy causes the separation of gas, oil and water.

In primary crude oil production, wells are completed so that only the forces acting upon the reservoir that are measurable in terms of pressure are used. In many cases, the forces acting on the reservoir are great enough that if a well is drilled into the reservoir oil will flow at the surface. In other cases, the oil must be pumped from the well by mechanical means. As oil is produced from a reservoir, the reservoir pressure declines resulting in a decline of oil production. At some point the well becomes marginally economic and secondary production techniques are initiated.

There are two main objectives in secondary crude oil production. One objective is to supplement the depleted reservoir energy pressure by injecting under pressure a fluid such as water or gas. The second objective is to sweep the crude oil from the injection well toward and into the production well. When water is used the process is called a water flood, with gas, a gas flood. Thermal floods using steam and controlled in-place combustion are also used. Thermal floods reduce the viscosity of the crude oil by heat so it will flow more easily into the production well. Tertiary techniques are usually variations of secondary methods with a goal of improving the "sweeping" action of the invading fluid.

5.3.2 The Gravity Drainage Process

In the process of gravity drainage extraction of liquid crude oil, the wells will be so completed that only the forces acting within the reservoir are used. The forces acting on the reservoir are left intact, perhaps maintained or increased. A large number of closely spaced wells can be drilled into a reservoir from an underlying tunnel more economically than the same number of wells from the surface. In addition, only one pumping system is required in underground drainage, whereas at the surface each well must have a pumping system. The objective of using a large number of wells is to produce each well slowly so that the gas-oil and water-oil interfaces move toward each other efficiently. By maintaining the reservoir pressures because of forces acting on the reservoir, it is then assured that the oil production is being provided by the internal forces due to gravity (the bouyancy effect) and capillarity. Although the production rate of each well will be low in gravity drainage, and the oil interfaces will move very slowly, production will be over a large area thereby providing an economical volume of oil extraction. After conventional production has ceased, up to 90% of the oil remaining in place may be recoverable by gravity drainage extraction.

Gravity drainage of petroleum from an underlying mine tunnel is illustrated as Figure 32. In the illustration, each well penetrating the reservoir has its own pressure gage and valve and is hooked to a common header pipe drainage to a single sump. Only one pumping system for all the wells is necessary to transport the crude oil to the surface. A computer system probably would be used to control individual wells flows and pressures.

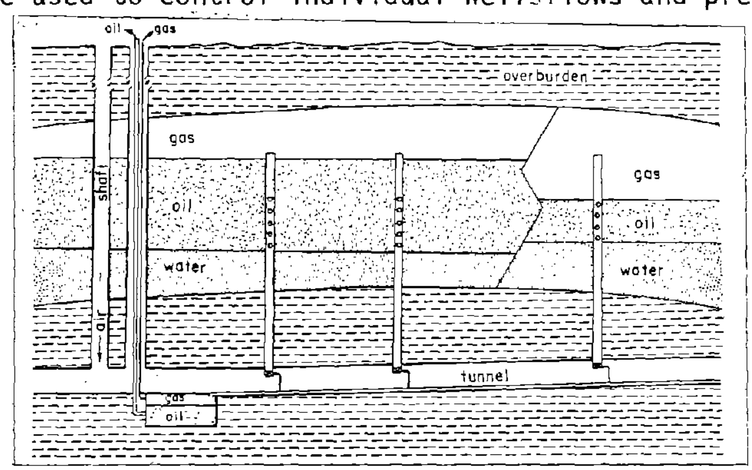

Figure 32. Gravity drainage of petroleum from an underlying mine tunnel.

5.3.3 Water Flooded Reservoirs; Fluid Distribution

There are many fluid distribution systems possible in an oil reservoir that has undergone waterflooding. In fact, one might find several of the fluid distribution systems in a single reservoir. Some of the possible fluid distributions are:

1. Water and low residual oil saturation occupying the lower parts of the formation and original (high) oil saturation in the upper parts;
2. One hundred percent water in some part of the lower section of the formation with water and oil in capillary equilibrium in the upper parts of the formation;
3. Some of the areal region having a dispersed oil and water saturation throughout the vertical height and other parts of the areal region with original oil saturation throughout the vertical height; and,
4. A dispersed oil and water saturation throughout the vertical height and areal region.

Fluid distribution 1 would be obtained using Dietz's method of calculating oil displacement by water. Fluid distribution 2 is the result of fluid redistribution by gravitational separation after the cessation of water injection and is time dependent. The resulting fluid locations are essentially the same as in distribution 1. Fluid distribution 3 would be calculated using the Frontal Advance theory in conjunction with areal coverage prediction procedures. Fluid distribution 4 results from the application of the Frontal Advance method only.

5.3.4 Gas Driven or Solution Gas Drive Reservoirs; Fluid Distribution

There are two possible fluid distributions in a gas driven or solution gas drive reservoir that are predictable under current petroleum theory. These distributions are as follows:

1. A high oil saturation in the structurally lower parts of the reservoir and a very high gas saturation in the upper part of the structure.
2. A uniform saturation of oil and gas throughout the entire reservoir.

In the first distribution, the oil and gas are distributed in accordance with gravity and capillary forces. Generally, this is the same as finding a gas reservoir with a thin oil column. Under the conditions of the second fluid distribution, the reservoir permeability with respect to the oil is so low that the reservoir essentially cannot be produced. This type reservoir could be produced by mining the rock as 'ore'.

5.3.5 Waterflooded Reservoirs; Fluid Distribution Flow Characteristics

In the case of fluid distributions 1 and 2, wherein the upper section of the formation has a very high oil saturation, well completions would be designed to produce only from the region of high oil saturation. In this type completion, if one were to take whatever fluids could be produced utilizing all the energies the equations for flow would be given below:

Radial Flow

$$Q_r = \frac{Kh_o}{\mu_o} \frac{(P_r - P_w)}{\ln(.472\ r_e/r_w)} \tag{2}$$

Linear or Slot Flow

$$Q_l = \frac{\overline{K}h_oW}{\mu_o} \frac{(P_l - P_w)}{L} \tag{3}$$

where:

Q_r and Q_l, volumetric flow rate for radial and linear or slot flow, respectively, ft^3/hr

K and $\overline{K}$, proportionality constants including permeability to oil

h_o, height of oil saturated formation, ft

P_r and P_l, formation pressure mid-way between producing surfaces, $\#/in^2$

P_w, back pressure at producing surface, $\#/in^2$

r_e and L, half the distance between producing wells or surfaces, ft.

r_w, radius of a producing well, ft

W, length of a linear producing surface, ft

μ_o, oil viscosity, cp

By utilizing all the pressure within a system for production purposes one would expect to produce oil, water and gas in the process. If the reservoir were under an active water drive one would anticipate that relatively large volumes of water would be handled. In addition, the reservoir would eventually be pressure depleted with the possibility of limited subsidence. Regardless of whether or not the total energy within the system is used for production purposes the production process would eventually reduce itself to the gravity drainage flow system which will be discussed later.

In the case of fluid distribution 3 one would be required to complete all producing surfaces within the region of the highest oil saturation. In this case the flow equations would be the same as for distributions 1 and 2 except that the height of the oil zone (h_o) would be the total thickness of the formation instead of a partial thickness wherein the oil saturation was at a maximum.

For fluid distribution number 4, one would have little choice of selectively completing wells to prevent the production of the water within the formation. In fact, if fluid distribution 4 does exist, such a reservoir would represent a poor prospect for in situ petroleum mining processes.

5.3.6 Gas Drive or Solution Gas Driven Reservoirs; Fluid Distribution Flow Characteristics

Based on the two gas-oil distributions previously discussed, the first fluid distribution is the most significant. With this distribution, the mining development would be in regions containing very high oil saturation. If well completions in this region are properly located the reservoir can be depleted by utilizing both the gas energy at first and gravity drainage production in later stages. If not completed properly, the gas energy will be rapidly (and inefficiently) depleted and the majority of the oil will then have to be recovered using only gravity drainage.

The equations describing the fluid flow for gas-oil systems are identical to those for a water-oil system wherein fluid distributions 1 and 2 for the water-oil system are utilized. Both the total energy equation and the gravity drainage equation are the same.

If gas-oil distribution 2 exists the equations for flow would be as follows:

Total Energy: Radial

$$Q_r = \frac{Kk_{ro}h_t}{\mu_o} \frac{(P_r - P_w)}{\ln(.472\, r_e/r_w)} \tag{4}$$

Linear

$$Q_l = \frac{Kk_{ro}h_t}{\mu_o} \frac{(P_l - P_w)}{L} \tag{5}$$

where:

Q_r and Q_l, volumetric flow rate for radial and linear or slot flow respectively, ft^3/hr

k_{ro}, oil fraction of the total permeability

h_t, total formation thickness, ft

Gravity Only: Linear

$$Q_o = \frac{1.1407 \times 10^{-4}}{2} \frac{k_o W}{\mu_o} \frac{\gamma_o h^2 (y^2 - x^2)}{L} \quad (6)$$

where:

Q_o, volumetric flow rate gravity drainage, ft³/hr

k_o, oil permeability, md

W, length of slot, ft

γ_o, specific gravity oil, fraction

h, saturated thickness, ft

y, portion of total height that contributes to gravity flow, fraction

x, portion of height h through which fluid flows into slot, fraction

L, total length of flow, ft

Radial

$$Q = 7.1659 \times 10^{-4} \frac{k_o}{\mu_o} \frac{h_o^2 \gamma_o (y^2 - x^2)}{\ln(.472 r_e/r_w)} \quad (7)$$

where:

r_e, radius of outer drainage boundary, ft

r_w, radius of drain hole, ft

5.3.7 Gravity Redistribution of Reservoir Fluids

The fluids in an untapped petroleum reservoir under equilibrium conditions are separated by density according to natural laws. If the reservoir is disturbed, such as by primary and secondary production, the fluids, by the same natural laws, will redistribute themselves in time in an attempt to reach to and then maintain equilibrium. The equations below represent this redistrubution process and their derivations will be found in Appendix G.

when $S_w = \frac{1}{(ah_w + 1)^{1/2}}$ (8)

$$ah_wS_{wm} + 2\,(ah_w + 1)^{1/2} = aS_{wi}h_t + 2(ah_t + 1)^{1/2} \quad (9)$$

and when $S_w = \frac{1}{(ah_w + 1)}$ (10)

$$ah_wS_{wm} - \ln(ah_w + 1) = aS_{wi}h_t - \ln(ah_t + 1) \quad (11)$$

and when $S_w = \frac{1}{(ah_w + 1)^2}$ (12)

$$ah_wS_{wm} + \frac{1}{(ah_w + 1)} = aS_{wi}h_t = \frac{1}{(ah_t + 1)} \quad (13)$$

or when $S_w = \frac{1}{(ah_w)^2 + 1}$ (14)

$$ah_wS_{wm} - \tan^{-1}(ah_w) = aS_{wi}h_t - \tan^{-1}(ah_t) \quad (15)$$

The value of h_w determines the height above the bottom of the formation which would only produce water.

where:

S_w, water saturation, fraction

S_{wi}, initial average water saturation over the total liquid saturated thickness, fraction

S_{wm}, maximum water waturation obtainable by capillary redistribution (usually 100% as a first try), fraction

a, difference in liquid specific gravities, $(\gamma_w - \gamma_o) \times .433$, fraction

h_w, height to which S_{wi} applies, ft

h_t, total height of liquid saturated zone, ft

5.3.8 Gravity Flow into Drainage Hole (Well) or Slot

One would hope that fluid distribution 2 (waterflooded reservoir) would be found most often. For this fluid distribution approximate flow equations can be derived for gravity flow of oil into a drainage hole or slot. Based on a fluid distribution as shown in Figure 33 the flow into a slot can be represented by equation 16.

$$\frac{Q_o}{W} = \frac{1.1407}{2} \cdot 10^{-4} \frac{k_o}{\mu_o} \cdot \frac{\gamma_o h^2}{L} \cdot (y^2 - x^2) \qquad (16)$$

where:

W, is the length of the slot, ft

Q_o, is the oil flow rate, ft^3/hr

k_o, is the oil permeability, md

h, is the height of the oil column, ft

x, is the height of h through which the fluid flows into the slot, fraction

y, is the total height which contributes to gravity flow, fraction

γ_o, is the specific gravity of the oil, fraction

μ_o, is the oil viscosity, cp

L, is the total flow length, ft

The variables k_o, μ_o, γ_o, and h are controlled by the reservoir selected for development. In a waterflooded reservoir very little can be done to alter their in-situ value. The variable L is controlled by the frequency or spacing of the slots or wells placed within the reservoir, hence is a function of the mine design.

The variables y and x are controlled by the manner of completion in the slot such that the reservoir can be controlled so as to produce at the maximum drainage rate.

Based on a controllable factor, Equation 16 can be rearranged such that

$$\frac{Q_o}{W} \frac{\mu_o}{k_o} \frac{8776.55}{\gamma_o} = \frac{(y^2 - x^2) \quad h^2}{L} \qquad (17)$$

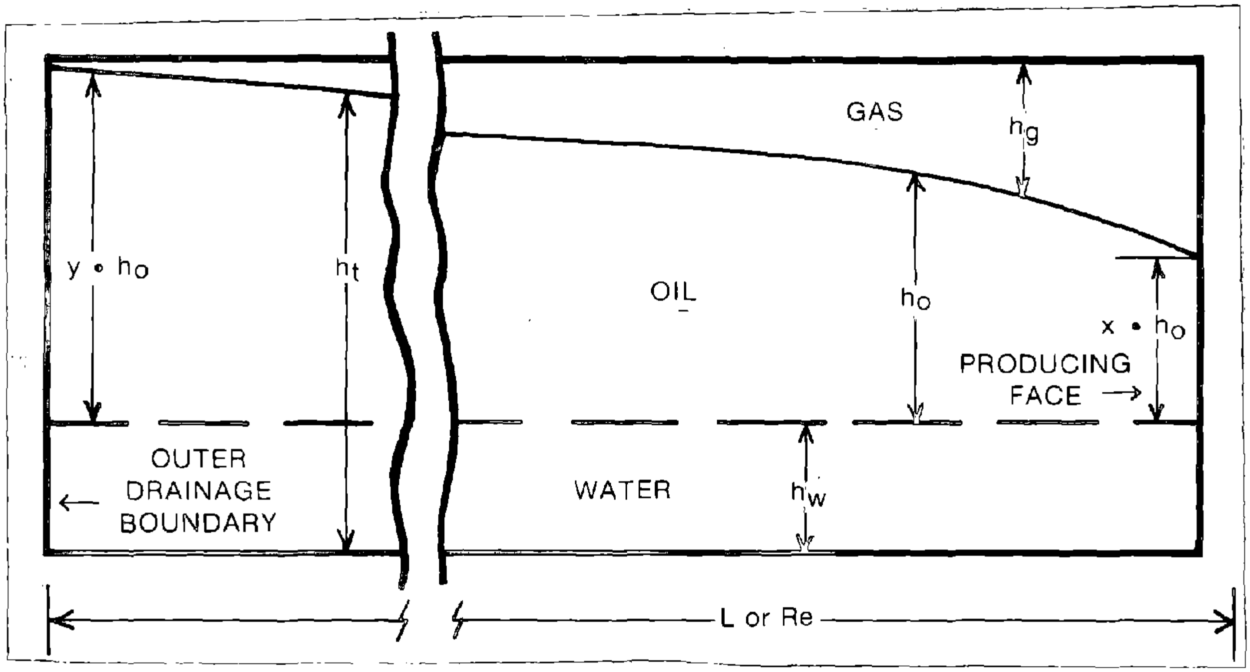

Figure 33. Fluid drainage configuration.

From Equation 17 it is seen that the rate of production for a given reservoir is inversely proportional to the distance between the slots. This inverse proportionality creates an economic relationship between the time cost of money and capital cost of construction. The greater the capital cost, the shorter the time required to recover the petroleum.

Again using fluid distribution 2, the flow into a radial bore hole would be given by Equation 18.

$$Q = 7.1659\,(10^{-4})\,\frac{k_o}{\mu_o}\;\frac{h^2\,\gamma_o\,(y^2 - x^2)}{\ln\,(.472\; r_e/r_w)} \tag{18}$$

where:

r_e, is the outer drainage boundary, ft

r_w, is the radius of the drain hole, ft

and all other terms are as previously defined.

Equation 18 can be rearranged to illustrate the effect of in place factors and design criteria on a particular reservoir as shown in Equation 19.

$$\frac{1395.5 \quad Q \quad \mu_o}{k_o \quad \gamma_o} = \frac{h^2 \quad (y^2 - x^2)}{\ln(.472 \; r_e/r_w)} \qquad (19)$$

5.3.9 Petroleum Mine Design Considerations

Production of a reservoir by gravity drainage may be done by means of wells or slots and also by exposing and fracturing selected portions of the underside of the reservoir. In order to choose the most economical mining method and to properly design the mine workings, a predevelopment phase will be necessary to collect and evaluate all relevant information. Here, mining and petroleum are interrelated and information collection and evaluation techniques must be taken from both disciplines.

If a reservoir is chosen that has been depleted by conventional primary and secondary recovery methods, much of the petroleum engineering will already have been done. For example, the reservoir pressure, temperature, oil and rock characteristics and geologic configuration will have been determined previously as a result of conventional oil exploration and production. Much more information, however, will be necessary to design a mine. Additional current information on the reservoir will be required as well as more specific information relative to the geological strata both overlying and underlying the reservoir.

The geology of the overburden, the reservoir and the underlying strata will have to be mapped in detail and must include stratigraphy, structure and lithology. This information should be obtained from drill hole data and correlated seismic profiles. This information will be necessary to choose the proper shaft location.

To determine the competency and stability of the rock to design mine entries and workings, coreholes will necessarily be drilled to obtain samples for a variety of rock mechanics tests. Parameters to be determined from the cores include:

- -RQD
- -Young Modulus of Elasticity
- -Poisson's Ratio
- -Compressive strength
- -Tensile strength
- -Permeability
- -Hardness
- -Abrasivity
- -Jet Kerfing Test
- -Joint and fracture orientation
- -Stress field analysis

The results of the new core analysis will not only aid in the design of the tunnel size and openings, but will also aid in designing the proper direction of the tunnels. For example, the stress field analysis is performed to determine whether the strata is in tension or compression by the earth's internal forces and the direction of these stresses. Optimum tunnel orientation is in the direction of the stress. If a tunnel is driven in a direction normal (perpendicular) to an internal compressive force, the tunnel will have a tendency to squeeze, or to become narrower, and perhaps subject to spalling of the tunnel walls.

Additional borehole logs must also be taken. Important to mine design is the P wave log and the conventional density and caliper logs.

Additional reservoir and reservoir fluids analysis will have to be performed to determine fluid character and distribution and if the reservoir is nearing equilibrium or needs additional time for gravity to do its work. Where possible, the rate of gravity redistribution should be determined.

If mining is for close access to the hydrocarbon reservoir and production is to be by means of wells, there are several possibilities for the design of the mine workings. In any event, two shafts must be put down for mine personnel safety and for adequate mine ventilation. Tunnels, then, can be driven (1) above the reservoir, (2) alongside the reservoir, (3) under the reservoir, or (4) some combination of the first three. It has already been decided for purposes of this report not to tunnel into the reservoir.

5.3.9.1 Shafts

Large vertical shafts sunk from the surface are generally the means through which underground openings can be excavated. These shafts are one means of access to offer an outlet for removal of excavated rock, provide sufficient opening for equipment, provide for ventilation, and allow for the removal of oil and gas products during later production. These requirements plus geologic conditions and oil reservoir dimensions will determine the shaft size. It is expected that access shafts may range from 8-20' in diameter.

The initial shaft would be blind hole, that is, opening downward into virgin formation. Later shafts may also be blind hole or may be up-reamed from existing tunnels. Up-reaming is much faster and cheaper than downward blind hole drilling if reservoir conditions such as areal pressure blocking can be accomplished. Once the shaft location has been selected exploratory holes in the immediate area will be drilled to gain complete geologic conditions, aquifer, gas and oil zone delineation as to pressure, volume, depth and thickness. Guard wells may or may not be desired to block flows or freezing of fluid zones can be done.

The conventional method of shaft sinking involves installation of a firm and substantial concrete collar at the shaft opening. A headframe is erected over the shaft opening for hoisting equipment support. Thereafter, the normal drilling, blasting and mucking (DBM) and concrete lining sequentially proceeds.

During the sinking cycle, even though exploration holes might have been drilled before the shaft began, probe holes would still be drilled in advance when approaching a potential pressured zone. There are no contemporary cases of shafts having been sunk through pressured oil reservoirs, but they have been driven through high pressure water zones successfully and similar control techniques could be used in advancing through gas and oil pressured reservoirs.

Upon approaching a pressured zone a concrete floor plug is poured in the shaft floor. Probe holes are then drilled downward and outward and are fitted with conventional blow out heads. These probe holes would be used to inject blocking materials into a pressured formation in advance of the shaft. Usually, advances are made in 20-50 feet increments through pressured zones. Through pressured zones the concrete shaft lining is usually thickened or reinforced. Alternately, steel casing can be run and cemented in place. Mining shafts for oil would be classified under gassy mine procedures therefore shafts would be limited to 1% methane (hydrocarbon) content in the air.

Drilling as opposed to DBM has only recently (since 1976) been applied in sinking shafts, mainly in sedimentary formations. To date no large shafts have been sunk by drilling to depths of 3000-4000'. Rigs of sufficient size exist for such drilling and the limitation appears to be the exceptional drill pipe that would be required which is presently not manufactured. To date a 7' shaft has been sunk at Amchitka, Alaska to 6100+ feet, a 16' shaft to 800 feet by Kerr-McGee in New Mexico and a 10' shaft to 2400' for the USBM in Western Colorado. These indicate actual experience and need of the specific targets but do not indicate limits of mechanical capability.

Containing or controlling underground pressures such as those provided from water flows, oil reservoirs or gas pockets that are encountered in the drilling of wells is a normal petroleum problem. However, the technology exists only for small diameter petroleum wells (less than 1½' diameter) and not for the large diameter shafts (8-20' diameter) which would be required of mining for petroleum. Shafts or wells drilled by rotary means will normally have the hole filled with a fluid that is sufficiently weighted with additives (or mud) to provide a pressure greater than any expected to be encountered. Mud shelf technology can provide fluid weighting material in the range of 22#/gal (Barite) to 30#/gal (Galena). Pressure to be encountered cannot be greater than the earths ability to contain it, that is, overburden pressure. Since earth (or rock) overburden runs in a rule of thumb range equivalent to 19.0 to 19.5 #/gal, current mud fluid weighting technology will contain any pressure that can possibly be encountered in drilling large diameter shafts. For an example, a fluid weight using 22#/gal mud in a 3000' shaft is expressed

Pressure (psi) = .052 (factor) x Mud Weight (#/gal) x Depth (ft), or,

Bottom Hole Mud Pressure = .052 x 22 #/gal x 3000 ft. = 3430 psi.

Earth or rock overburden runs about 1.1 psi/ft (in West Texas) so that at 3000' depth no greater than 3300 psi could be encountered in the most exceptional circumstances and oil reservoirs at that depth usually are of much lesser pressure.

The petroleum industry always works with an emergency safety mechanism (a blow out preventer or BOP) at the surface to shut in wells. If the mud becomes diluted with gas, oil, or water, and thus inadverently lightened, the BOP is an essential last tier containment mechanism. Such devices are not presently developed for drilling shafts of the diameters envisioned in this report. The problem of designing a back-up control device or BOP for large diameter shafts is substantial and may be impossible. The forces acting on holes multiply by the square of the diameter. Thus a 1½' or 18" hole which is containing 3000 psi of pressure has exerted on it a total blow out force of 3/4 million pounds whereas the same pressure on an 8' diameter shaft would produce 20 times that force.

Fluid weighting of a rotary drilled shaft with mud does not provide absolute control of pressures to be encountered and thus back up systems such as BOP's are essential safety devices to minimize the risk of a blowout that will cause attendant worker exposure and very substantial economic loss in order to regain control. Mud weight can be overcalculated for safety and control to the point where formations will break down by fracturing the rock and then will rapidly absorb the fluid. Once absorbed, the fluid head is lost but the pressure remains and a blowout occurs. The amount of pressure to be encountered is not usually known with absolute assurance nor is the head pressure at which zones will break down and thief the fluid. Thus the safety band of exactly proper mud weight is narrow due to the unknowns on both the upper and lower limits of control. It is the analyses of this type of risk for shaft pressure control and the many other risks to petroleum development that will determine at what rate of return level (or even whether) industry will come forth to demonstrate mining for petroleum.

One alternative to designing the required massive BOP's may be for petroleum engineering technology to provide methods to block anticipated pressure back within the reservoir rock or sand (in situ) with a sufficient design assurance so that large shafts could then be sunk through the pressure neutralized locations. This can be done with combinations of materials (cement, mud, gels), techniques (fracturing, acidizing, directional jet shooting) and wells (various guard wells sunk in a peripheral pattern around a shaft location). Such a system would provide a multi-tier control of pressure:

1. formation in situ block of pressure
2. guard well monitor of pressure
3. guard well bleed off of pressure
4. shaft mud weight
5. shaft mud caking on formation walls
6. guard well mud fluid injection in case of shaft fluid blow out

Whether such a system will provide sufficient safety control is presently unknown.

5.3.10 Tunneling

Circular openings offer the best shape to resist underground rock stresses. Tunnels and drifts would best be done by a continuous boring machine or a boom-type continuous miner and tunneling machine. The continuous boring machines have outstanding performance records in driving openings up to 35 feet in diameter. For 10-15 foot drifts, penetration rates of 8-10 feet per hour can be expected at a cost of around $300 per foot. The boom type continuous miner cannot be used where unconfined rock compressive strength is above 18,000 psi, therefore, in specific hard rock locations such as West Texas limestone, the continuous boring machine probably will be used to advance horizontal mine openings.

5.3.11 Pressure Control (Probe Drilling)

Pressure control and blow out prevention has been dealt with in the petroleum industry for many years. In conventional underground mining, however, a requirement for pressure controls has not been needed and thus not developed. In the extraction of oil from its reservoir, the safety of underground personnel will depend upon fail-safe design of pressure control devices. Even a depleted oil reservoir may contain pressures of 500 psi or more due to secondary pressure maintenance programs.

In tunneling above, below or alongside a conventional petroleum reservoir, there is always the possibility of encountering a random zone of pressure containing gas, oil or water. For this reason, probe drilling along the tunnel headings will be necessary using pressure control technology.

The control of suddenly encountered pressures during drilling, illustrated in Figure 34, is current conventional petroleum technology. The process is begun by drilling a large diameter hole to a specified depth; then casing is installed and cemented. This casing is called surface casing. A blowout preventer (BOP) is then mounted securely to the top of the casing. If sudden pressure is encountered, the BOP is closed around the drill stem

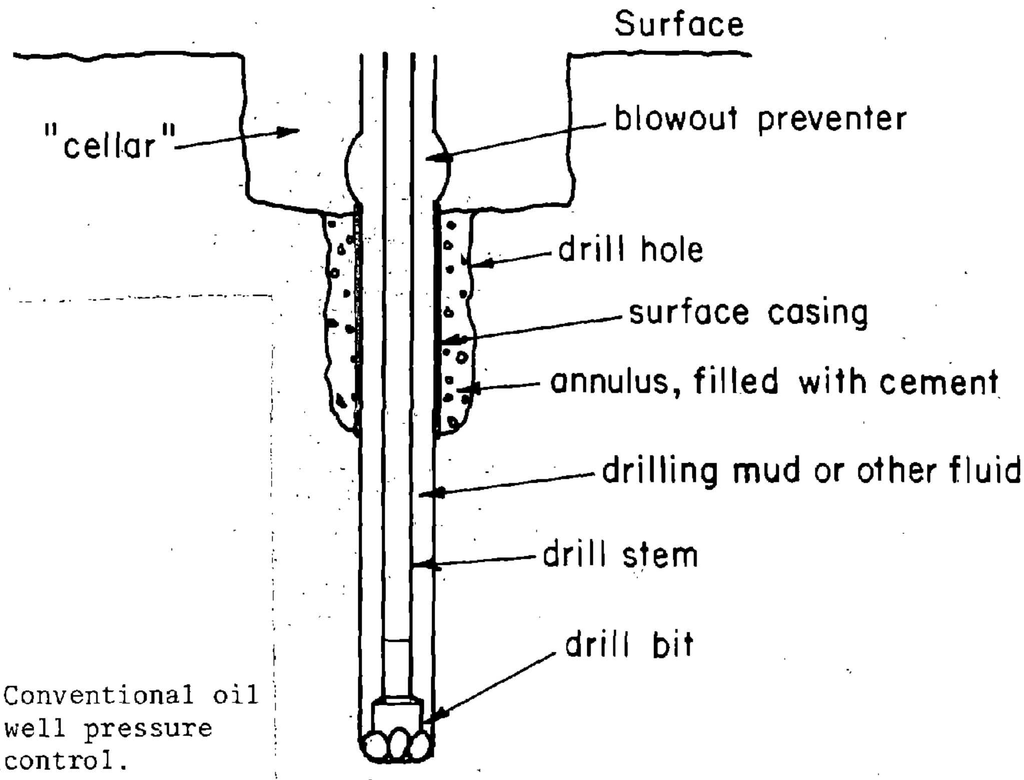

Figure 34. Conventional oil well pressure control.

thereby preventing the borehole fluids from 'blowing out', which is hazardous to both men and equipment.

After a zone of pressure has been encountered and the initial pressure bled off and stabilized, another method must be used so that drilling can be resumed. This pressure is controlled by mud weight, or the hydrostatic pressure due to a column of drilling fluid. Special muds can be added to the drilling fluids to add weight. In fact, this is the primary method of pressure control in drilling an oil or gas well. The BOP is a secondary or emergency method of pressure control, a back-up system.

The surface casing serves two equally important purposes. One purpose is to seal out all freshwater aquifers to prevent the mixing of potable and nonpotable groundwaters. The other purpose, in conjunction with the BOP, is to prevent the drilling fluids from being ejected from the hole if sudden high pressure is encountered.

The drilling fluid, or mud, serves at least three important functions: to stabilize the borehole walls, to carry out the drill cuttings, and for primary pressure control.

In an underground situation, drilling horizontally or vertically upwards, the "surface" casing becomes the primary means of pressure control and loses the function of sealing out potable water. The drilling fluid, in this case, loses its capability of controlling pressure, because this is a function of the vertical height of the fluid column against the zone of pressure.

In drilling from a mine tunnel, the 'surface' casing becomes the primary means of controlling suddenly encountered pressure. For this reason, if the pressures to be encountered are unknown or cannot be accurately calculated, the method of pressure control drilling where the surface casing is cemented in should be used. Where the maximum pressures that may be encountered are known or can be calculated, the use of cement may not be necessary.

The equipment for pressure control drilling is standard in the petroleum industry and is readily available. From a mine tunnel, short drill stem and a hydraulic turret drill must be used. Figure 35 illustrates the equipment less the drilling rig needed to control suddenly encountered pressure while drilling from underground. As on the surface, a first string of casing commonly called surface casing is placed as shown in the figure. An intermediate string of casing is cemented in place; the first string is primarily a cement form to prevent any leaking into the tunnel. The blow out prevention equipment and reverse circulating head are mounted on the cemented-in casing. With this combination of equipment, residual reservoir pressure can be controlled during drilling and while adding or removing drill-stem from the hole. This method should be used for drilling the production wells.

The borehole equipment for pressure control drilling without the use of cement is the same as that illustrated in Figure 35. Rather than cementing in the surface casing, one or more packers are used to provide a seal between the surface casing and the bore hole. The number of packers used will depend on the pressure to be encountered. Packers of many different kinds are used throughout the petroleum industry and can withstand considerable pressure. Packer design and engineering is standard shelf technology, so this application will not be difficult. Once the surface casing is installed and the packers set, the same arrangement of blow out preventers as before is mounted on the casing and drilling can begin. This method can be used for probe drilling in advance of the tunnel headings.

5.3.11.1 Casing Set with Cement (Probe Drilling)

Cement will hold casing in place against pressure more securely than the use of packers. Cemented casing, however, has the following disadvantages:

1. Time is required for the cement to set before drilling can begin. If just a few holes were needed this time delay probably would be insignificant. Where numerous holes are required, the time delay could be very costly.

2. After probe holes have been drilled ahead in tunnel driving, the cemented casing would make driving the tunnel ahead difficult if not impossible with modern tunnel boring equipment.

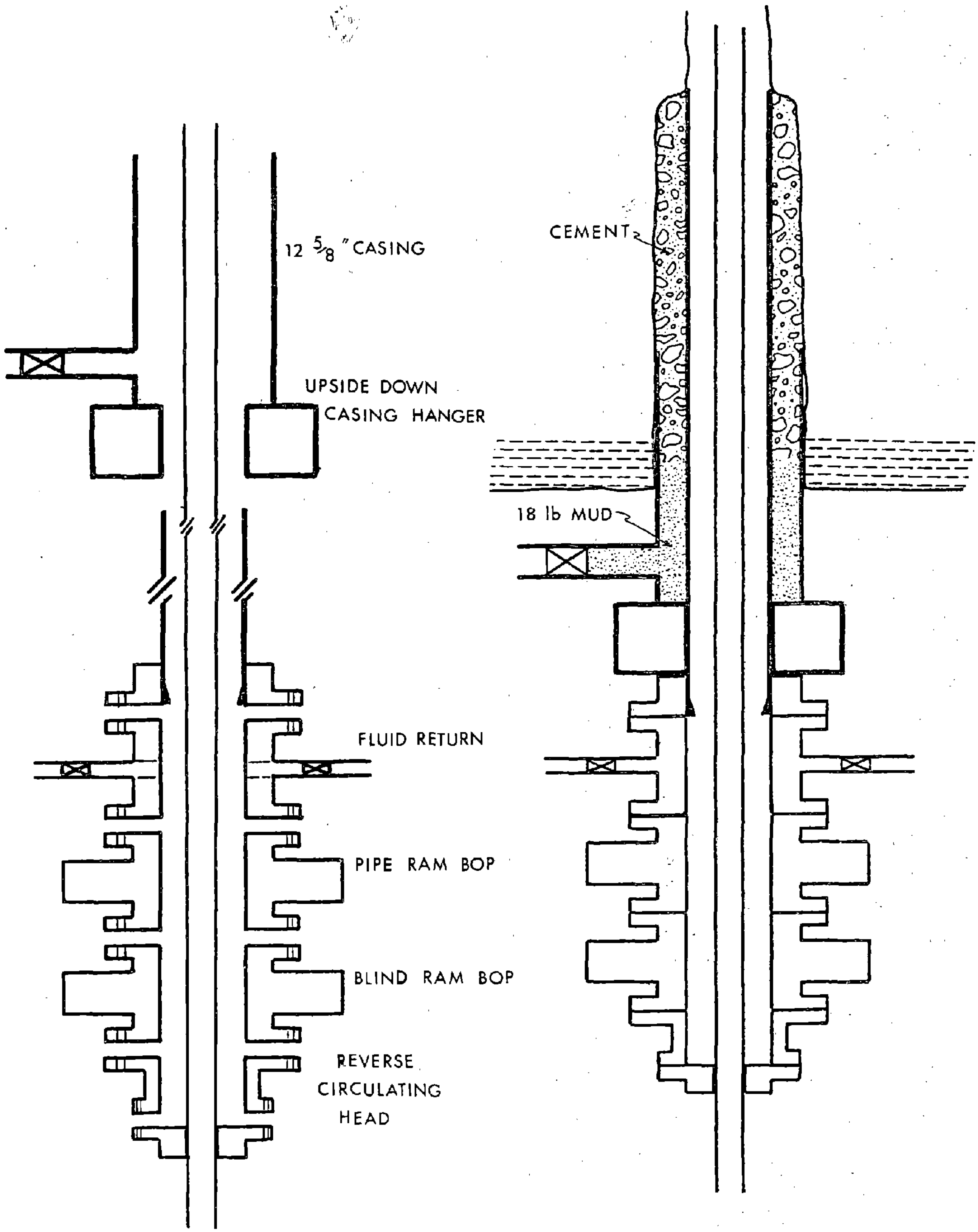

Figure 35. Equipment necessary for control of pressure while drilling from underground.

3. The surface casing could not be pulled and used again.

4. The lost time and safety hazards of wrestling cement and cementing equipment through the mine workings.

5.3.11.2 Casing Set with Packers (Probe Drilling)

By using packers rather than cement, the time required for cement to set is eliminated. For long hole probe drilling ahead of a tunnel when the hole is completed the surface casing is easily removed, it is no longer an obstruction to tunnel boring machines or other equipment. The surface casing and packers can be used over and over and there is no extra equipment and materials to further clutter a probably already overcrowded tunnel.

The decision to use packers in probe drilling of tunnels rather than cement should be made based on rock characteristics and geologic structure and stratigraphy.

5.3.12 Well Production from Tunnels Beneath the Reservoir

Completing wells from a level of drifts beneath the reservoir is the most economical application of gravity drainage. In this case, only one pumping system is required rather than the need for installing a pump in each well as is necessary in wells drilled from the surface. Figure 36 is the same as the figure used to illustrate gravity drainage and also illustrates crude oil production by wells from an underlying tunnel.

When wells are drilled from beneath the producing formation in an oil-water system the developer has two options for completion. The casing may be set totally through the formation as illustrated in Figure 37 and the region opposite the oil saturation perforated to permit production. If the operator chooses, he may only set the casing through the water saturated zone and then use a jet slotting process to wash out or drill slots in the oil saturated zone to increase the productivity of the individual well.

If the hydrocarbon system is a gas-oil system then the completion procedure is slightly changed from that shown in Figure 37. In this case the oil would be at the bottom of the zone and two completion options are again possible. The first completion would be to eliminate the third string of casing and simply drill through the formation which is highly saturated with oil and leave the zone uncased. The well could then be produced in this fashion or it could be slotted to increase the productivity of the well.

The second technique would be to drill through the oil saturated zone, use the third string of casing, and perforate for production purposes. This completion gives the greatest control and permits future changes in operational techniques.

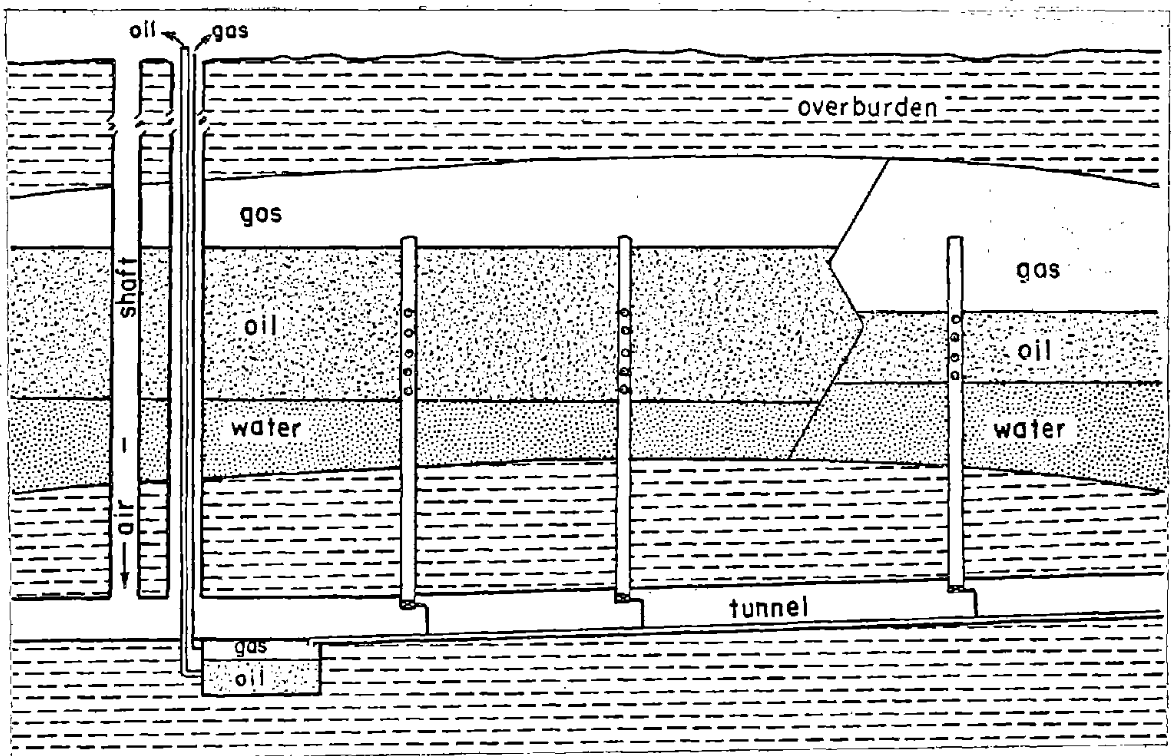

Figure 36. Crude oil production by wells drilled from a tunnel underlying the reservoir.

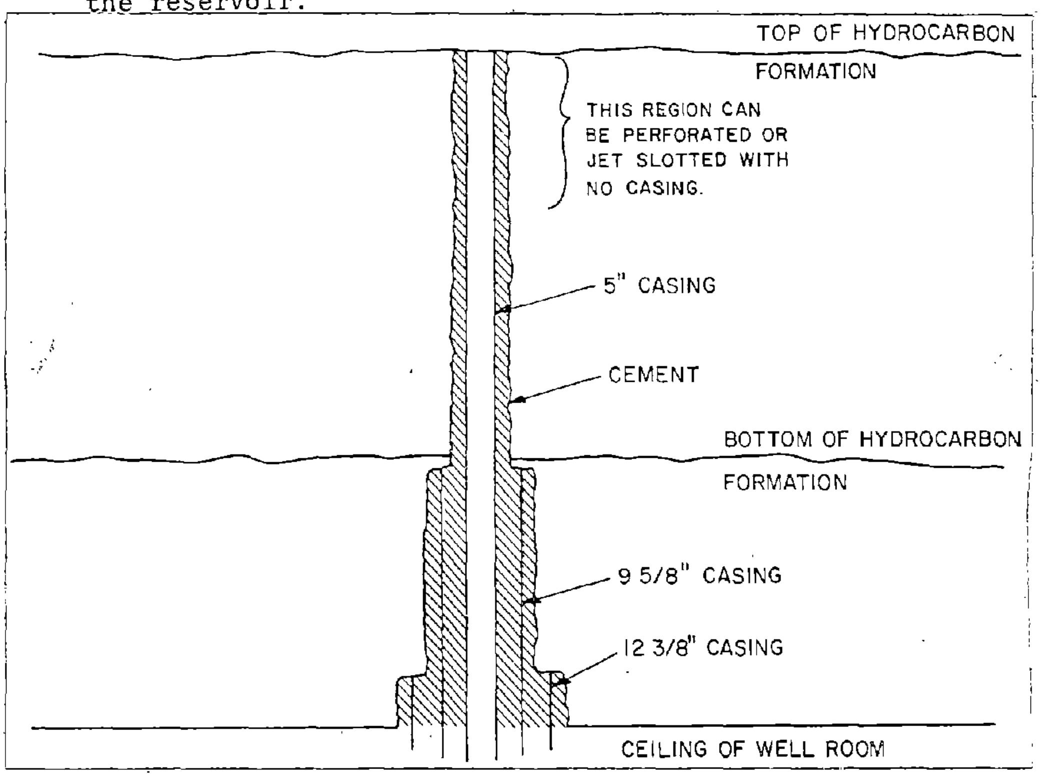

Figure 37. A potential well completion technique for use in tunnels underlying the reservoir.

5.3.12.1 Tunnel Proximity to a Reservoir

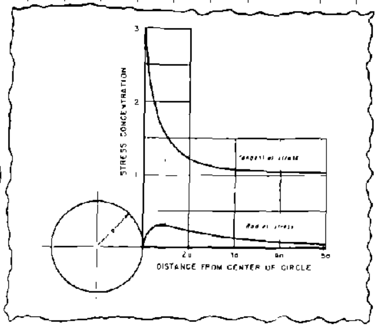

Figure 38. Horizontal stress for circular hole in unidirectional stress field (USBM RI 4192)

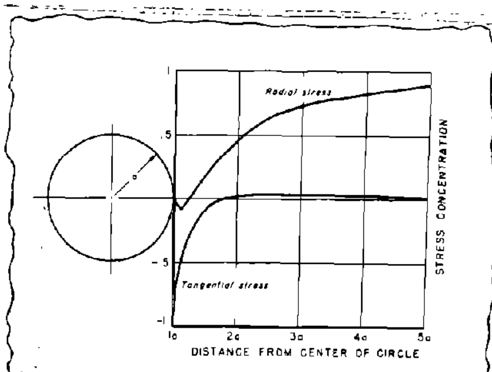

Figure 39. Vertical stress for circular hole in unidirectional stress field (USBM RI 4192)

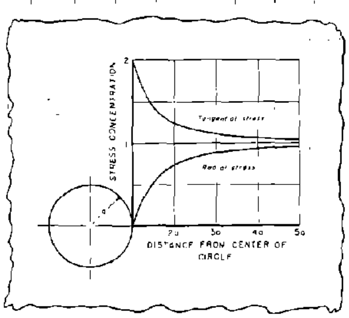

Figure 40. Horizontal stress for circular hole in hydrostatic stress field (USBM RI 4192)

For a stress field acting on a single underground tunnel of great length areal distribution of stress is defined along the horizontal and vertical axes normal to the axis of the tunnel. As shown in Figure 38 and 39 the radial and tangential stresses for unidirectional stress (shallow depth) asymptotically approach unity and zero depending upon which orientation is being considered. These stresses stablize approximately to zero and unity within a standoff distance of 1-2 tunnel diameters. For a hydrostatic stress, uniform in all directions, the tangential and radial stresses asymptotically stabilize at even less than two tunnel diameters as shown in Figure 40. These illustrations indicate that tunneling in close proximity to a reservoir, perhaps within two to three tunnel diameters, is acceptable even at depths of 3-4000 feet with high safety factor from a rock mechanics standpoint. From the reservoir delineation viewpoint, however, the petroleum engineer may have some difficulty in picking clean upper and lower reservoir limits.

Later sections describe an economic evaluation of mining for petroleum and it will be found that the study team chose a standoff distance of over three tunnel diameters based upon the graphs depicted here. For those petroleum engineers desiring to become more acquainted with the derivation of these stress calculations for circular tunnels or for more detail on the stresses upon alternate tunnel configurations see Appendix F or the referenced USBM RI4192 authored by Wilbur Duvall. Obviously the circular configuration will provide maximum hoop strength capacity and also would be consistent with a continuous tunnel boring machine configuration.

5.3.13 Well Production from Tunnels Driven Above the Reservoir

If the rock underlying the reservoir is not competent enough to support mine workings, tunnels can be driven above the reservoir. In this application of gravity drainage, a pump must be installed in each well, but much smaller pumps than would be needed from the ground surface, since the lift height is minimal equaling perhaps 100'± as opposed to several thousand feet.

The casing string which might be installed when completing a well from above the formation is illustrated in Figure 41. It should be noted that if it is a gas-oil system the well must penetrate below the formation by at least 30 feet to permit maximum productivity from the well. Basically, the casing strings are the same as in the case of drilling from beneath the hydrocarbon formation.

If the hydrocarbon system contains oil and gas there basically is only one type completion that can be used. This completion requires drilling through the formation and beyond by at least 30 feet and having the formation cased and perforated. The extra 30 feet will be the reservoir (sump) from which the oil draining from the reserve will be pumped.

Developing a gas-oil system from above with slots would be difficult and probably would not permit adequate control of the completion.

If the hydrocarbon system is oil and water, it is again necessary to drill at least a 30 foot sump depth below the oil-water contact. The well would then be cased, cemented and perforated in the zone of oil saturation. Again developing a slotted system in an open hole would be difficult to control. It could be done by setting the second string of casing at the very top of the formation and then drilling into the producing zone to a depth equal to the oil-water contact. The zone could then be slotted, but the well would not produce at maximum efficiency and it would also produce water.

5.3.14 Well Production from Tunnels Driven Alongside the Reservoir

Horizontal wells drilled into a petroleum reservoir from tunnels driven alongside is another application for gravity drainage. If the horizontal wells are drilled on a slight incline, the oil produced would drain out by gravity, eliminating the need for a pump in each well. This application could be more economical than drilling from overlying tunnels if the areal extent of the reservoir can be reached by the horizontal drilling.

5.3.15 Well Production from Tunneling Combinations

Applying gravity drainage for petroleum extraction using tunnels at various levels above, below and alongside the reservoir may have its advantages. For example, Figure 42 illustrates the use of tunnels both overlying and underlying the reservoir. The wells drilled from the lower tunnel are

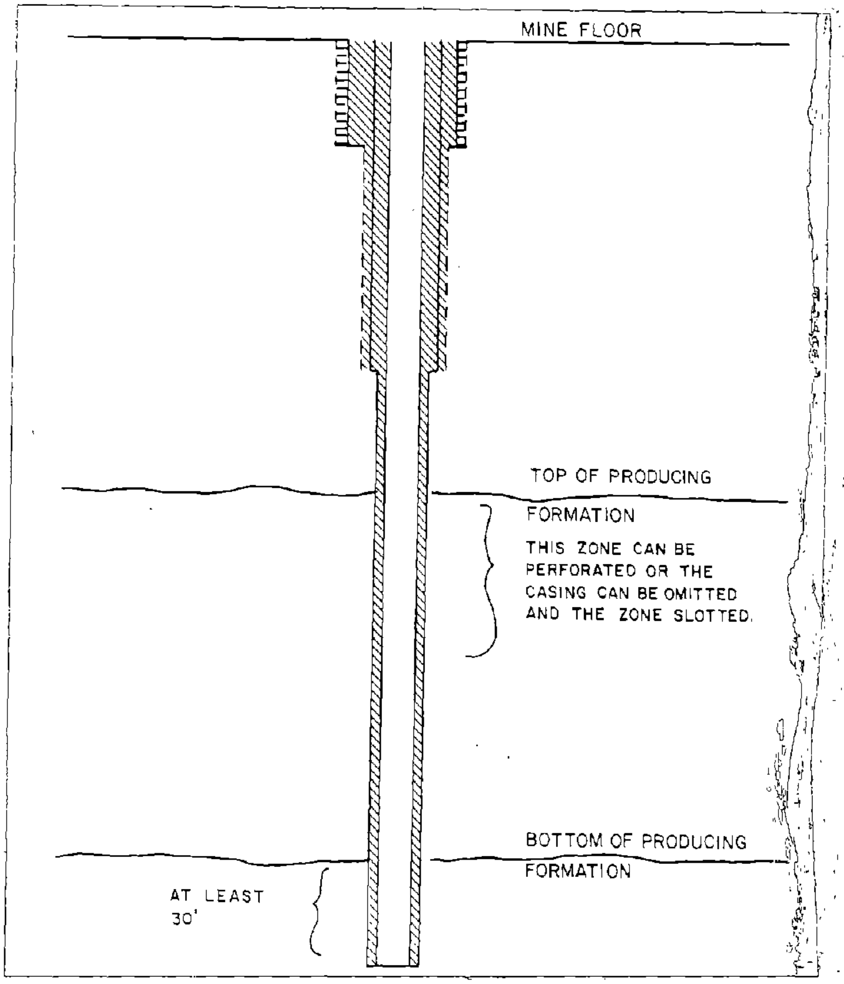

Figure 41. A potential well completion technique for use in tunnels above the reservoir.

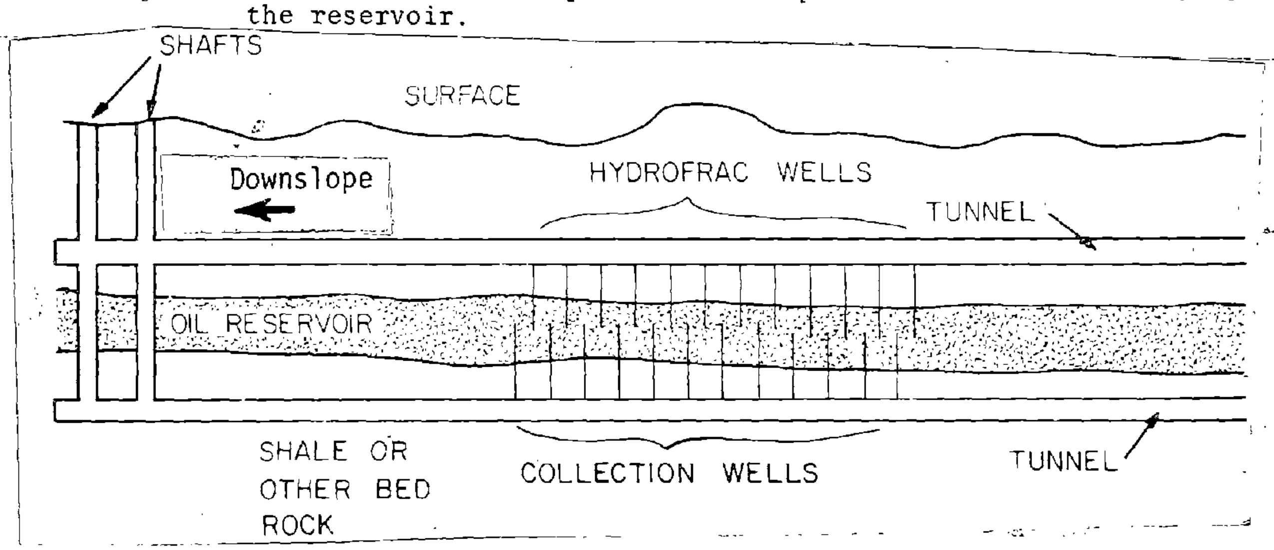

Figure 42. Reservoir maintenance and well production from two levels of tunnels, one level above the reservoir and one level below.

used for crude oil production while the wells drilled from the upper tunnel can be used for reservoir pressure maintenance, sweeping fluid injection or steam injection.

By using several levels of tunnels, oil fields containing several pay zones could be produced. Production from each pay zone would be used to pay back shaft costs, while each pay zone additionally would have to be large enough to pay back the costs of its own level of tunnels and drifts plus the desired rates of return.

5.3.16 Special Cases

Only a brief discussion of three special cases is given because in mine design each reservoir will be a special case with its own unique problems and solutions.

5.3.16.1 Horizontal Drilling from Shaft

Drilling horizontal wells from the bottom of a shaft has been used on a number of occasions in the U.S. This method may be useful where the reservoir is shallow and a number of shafts can be sunk economically on a spacing appropriate to develop the reservoir. In deep lying reservoirs this use of shafts probably will not be economical. One of the problems is that when the horizontal wells from the shaft have been completed, the shaft no longer can serve any other useful purpose. Much better use of the shaft can be made by the use of tunnels which gain access to more of the reservoir.

5.3.16.2 Inclined Stratigraphic Traps

A petroleum reservoir that structurally is an inclined stratigraphic trap can be produced by applying a combination of at least two levels of tunnels. Two shafts are drilled, as usual, but one shaft is driven in an up-dip location and the other is sunk down-dip. A level of drifts can be driven under or over the trap and wells can be drilled either along the tunnel or on an incline from one tunnel to the other, parallel to and within the trap.

5.3.16.3 Salt Piercement Domes

The nature and occurrence of salt plugs has created a special assortment of stratigraphic traps that have been prolific producers of petroleum. In a salt dome, the shafts would be sunk within the salt deposit. The competency of the rock in the vicinity of the reservoir will dictate whether a tunnel or a combination of tunnels can be used or if production must be taken by horizontal holes drilled from the tunnel connecting the shafts.

5.3.17 Oil Production by Means Other Than Wells

To increase the fractured permeability of the reservoir, three methods for substantially fracturing the reservoir and allowing fluids to drain through the tunnels to a common collection point are fracture caving, modified fracture caving and collapsed slot (tunnel).

This discussion is included for completeness of the report, however, the applicability is limited to very unique situations. Generally, massively fracturing an oil formation by caving or collapsing will destroy efficient formation sweep mechanisms to recover oil and very little production will result. Before seriously considering caving or collapsing petroleum formations design engineers would be well advised to counsel specifically with petroleum engineering technologists about the anticipated recovery results.

5.3.17.1 Fracture Caving

Fracture caving is an underground mining technique, essentially similar to block caving, to extensively fracture an oil formation. This increases the overall permeability of the producing zone. The oil is collected in an underlying tunnel where it drains to a collection for transport to the surface. The caving must be done on 'retreat', which means that fracture caving is initiated at the most remote point of the tunnel workings, sequentially caving on retreat toward the surface openings.

In conventional petroleum production by means of wells, techniques for fracturing the producing zone in the vicinity of the well bore have been used for years. One of two techniques is commonly used. The first method is to lower a measured quantity of explosives down the well bore to a selected point within the producing zone and detonate it. The second method, which is more commonly used, is called 'hydrofracing'. Hydrofracing is a method of fracturing the producing formation by injecting fluids into the production zone under high pressure. In this method, a propping agent such as sand usually is injected to hold the fractures open.

The presumed advantage of fracture caving is that most or all of the producing formation can be fractured rather than only a limited circumference around a well bore. Also, only one fluid pumping system is required rather than having to install a pump in each well.

While the mining techniques used to induce the required degree of fracturing will vary with different reservoirs and reservoir characteristics, the intent in fracture caving remains the same, that is, to increase the permeability of the reservoir and to extract the crude oil from underneath its reservoir.

As usual, two shafts must be either drilled or sunk by conventional means. For the fracture caving technique, the shafts should penetrate the production zone, and be completed at a predetermined depth below the reservoir. The placement of the shafts will depend on the configuration of the reservoir and its physical character. Upon completion of the shafts, drifts are driven in various directions below the reservoir. Petroleum production can begin only after the tunnel workings have been completed.

Two levels of tunnels underlying the reservoir will be required for a reservoir that is difficult to fracture as is shown in Figure 43. The lower level workings are for petroleum collection and distribution lines and for primary underground access. The upper level tunnels are used as a point of departure for cutting out expansion chambers for later fracturing. Pillars of adequate dimension are left in the rooms at this point of development. The rooms are necessary to provide a space for just enough caving to induce the desired fracturing. The formation just under the producing zone is the area that is collapsed. Predrilled conduits connect the upper and lower levels so the oil can drain into the lower level and on to a sump and the main pumping station. Figure 44 illustrates the production phase of fracture caving.

5.3.17.2 Modified Fracture Caving

For a reservoir moderately difficult to fracture, explosives probably will be the primary means of inducing fracture and rock breakage. It may prove desirable to use hydrofracing techniques in conjunction with the explosives. As illustrated in Figure 45 the tunnels and workings would be on one primary level underlying the reservoir. A blind hole raise drill would be used to provide access and drilling stations somewhat closer to the reservoir. From each drilling station, fans of holes are drilled up into the reservoir and loaded with explosives. The space or chamber for each drilling station serves as an expansion chamber for the expansion of the fractured rock to create more permeability within the reservoir. After the area has been evacuated and sealed, the explosives are detonated. Limited crude oil then drains from the reservoir into a pipeline in the main tunnel and flows from there to a pumping station for transport to the surface.

5.3.17.3 Collapsed Slot (Tunnel)

After tunnels have been completed beneath the reservoir, the formation could be collapsed into the drift so that the drift becomes the production system. A sketch of this type of producing system is illustrated in Figure 46. The flow equations for a collapsed slot producing system would be those indicated as linear, where all the pressure within the system is utilized for production.

The collapsed slot would not permit the selective production of oil. All the reservoir fluids would be produced. This type completion would deplete all the pressure within the formation and as a result, could subject the area to some degree of subsidence. Once the formation is collapsed, the operation cannot be altered in the future. Access to the drifts would no longer be possible and if by any chance plugging of the drift or flow system occurred, the entire operation within that drift would have to be abandoned.

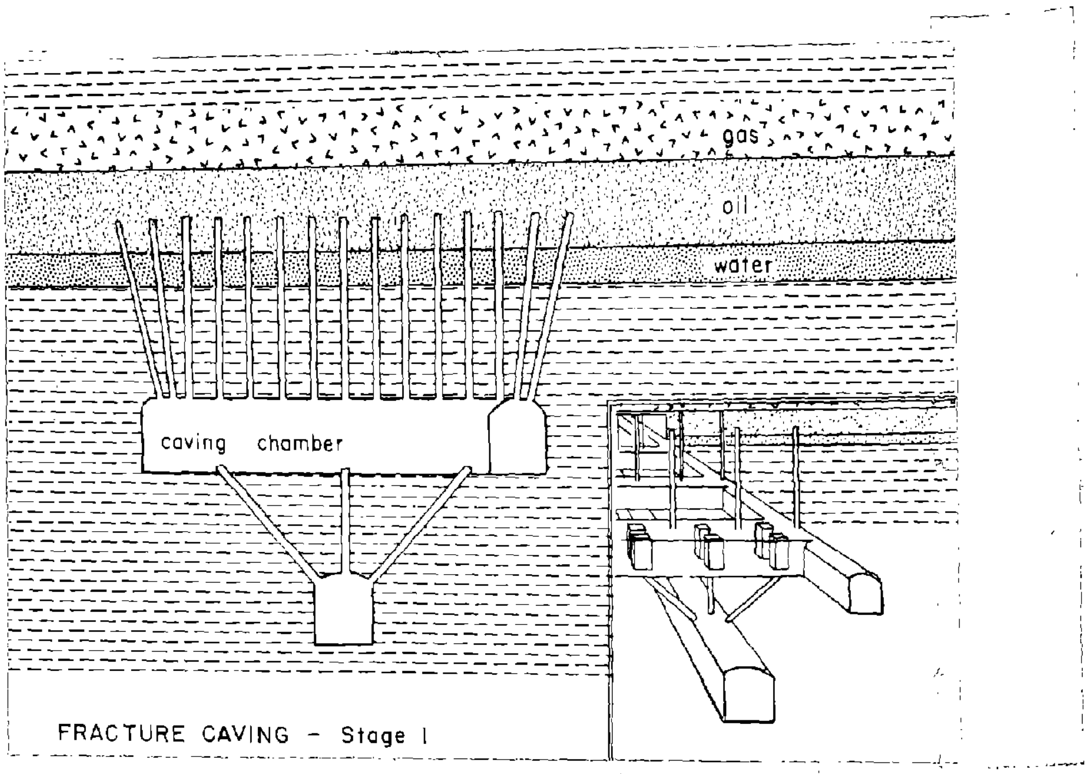

Figure 43. End view and perspective of mine workings for fracture caving.

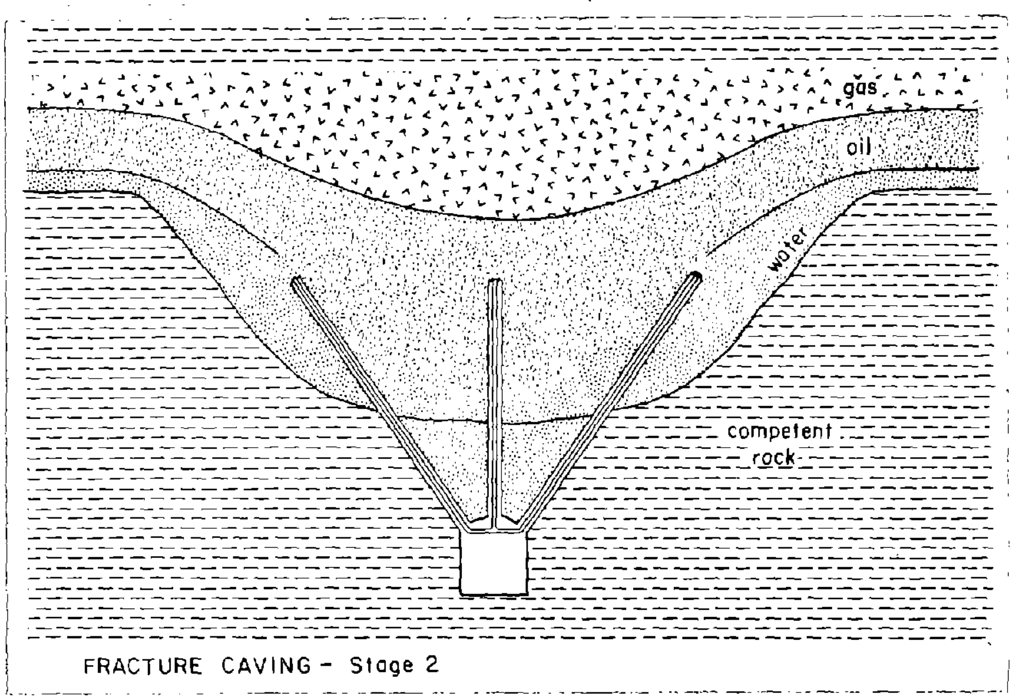

Figure 44. After fracturing; production phase for fracture caving.

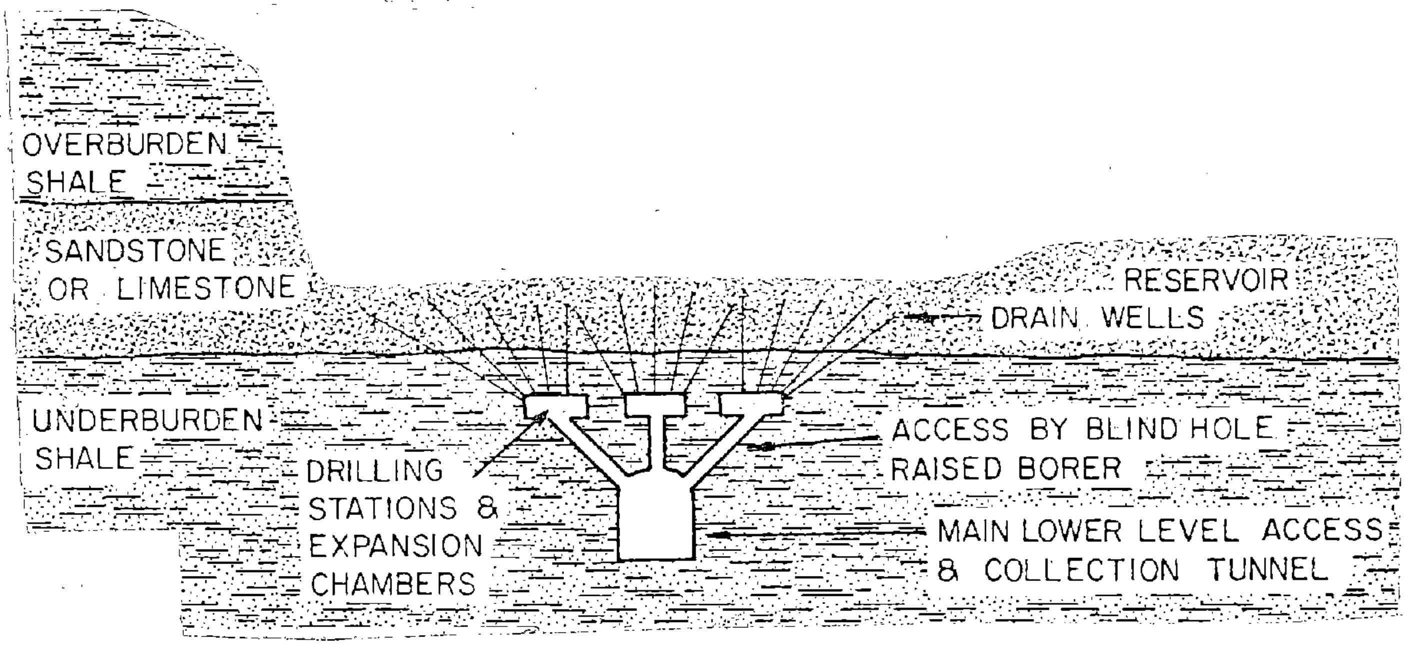

Figure 45. End view of workings for modified fracture caving.

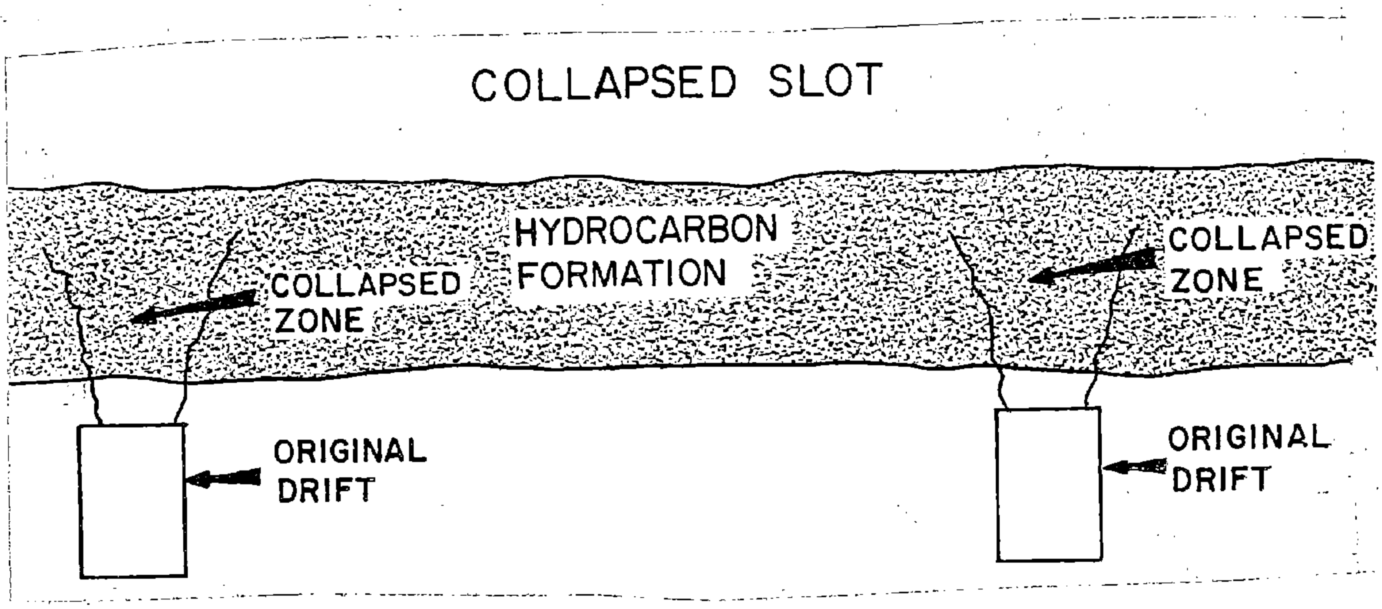

Figure 46. End view of collapsed slot production system.

5.3.17.4 Offshore Applications

In Great Britain, a feasibility study is in progress on the development of offshore oil fields by tunnels and underground excavations. The basic purpose of this project, under the direction of Dr. E.L.J. Potts, Newcastle University, is to investigate the feasibility of replacing sea bed production platforms by drilling rigs positioned in underground caverns and connected to the mainland by tunnels. This idea is illustrated in Figure 47.

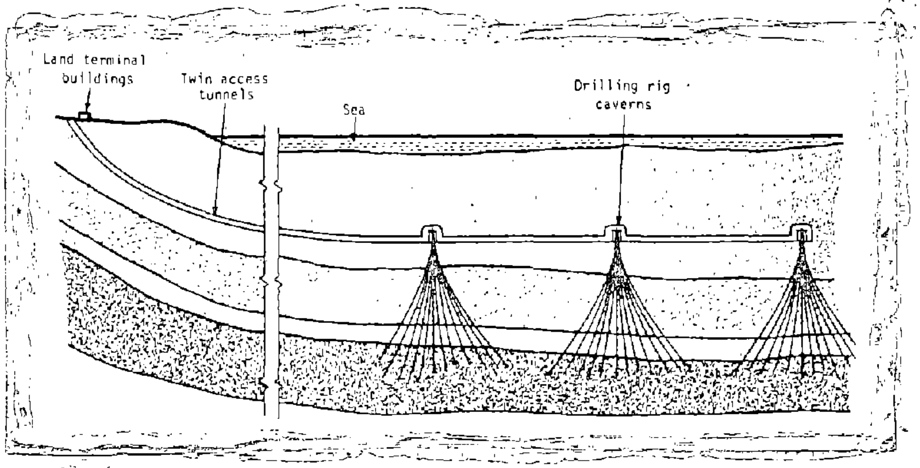

Figure 47. Proposed scheme for the establishment of oil production platforms in underground caverns and connected to the surface by tunnels.

The idea presented above may not be advantageous. Historically, production from above by using conventional primary and secondary methods can expect to extract an average 32% of the crude oil in place. Production from below by the gravity drainage process would extract significantly more of the reserve - 70-95% of the oil in place.

All of the techniques and applications described in this report for gravity drainage extraction of petroleum are applicable to offshore reserves. Where the reserves are too far from shore to make long inclined shore entries economically feasible, offshore production platforms can be converted to serve as supports for necessary shafts. This is within the realm of current technology adaptation.

5.3.18 Environmental Considerations

5.3.18.1 Disposal and Stabilization of Wastes

Excavation of shafts and tunnels during the mining process results in waste rock which must be stored or disposed of at the ground surface. The days are gone when the spoils could be dumped in a heap near the mine shaft as an eyesore for future generations and a source of air and water pollution for untold years. Air, water, and esthetics must be conserved not only for the present but also against reasonable future contingencies, either natural or man-made.

Mine spoils need to be disposed of in a manner which will assure physical stabilization. This means appropriate slope stability for the pile not only against gravity but also earthquake forces. Since return of the spoils to the mine excavations is seldom economic, the spoil pile must be designed as a permanent structure whose outline will blend into the landscape. Straight, even lines in the pile need to be avoided. The approximate volume of waste to be handled per square mile of underground mining for petroleum is listed in Table 15. Here, spoils would be returned to the mine because of environmental requirements as opposet to being economic.

Table 15. Approximate volume of waste rock after mining depletion of the reservoir.

ONE SQUARE MILE OF DEVELOPMENT

Amount	Item	Size	Yd^3 solid	Yd^3 @ 30% Void	Yd^3 Ultimately Backfilled
6,000'	Shafts	15' dia.	39,270	56,100	39,270
12,320'	Tunnels	15' dia.	80,634	115,191	80,634
45,760'	Drifts	10' dia.	133,110	190,158	133,110
77	Rooms	20'x20'x 20'	22,815	32,593	22,815
4	Rooms	10'x20'x 20'	593	847	593
12,150'	Wells	8 5/8" dia.	183	261	---
76,608'	Wells	8.63" dia.	1,153	1,647	---
88,064'	Wells	8.63" dia.	1,324	1,893	---
			279,082	398,690	276,422

Original waste rock mined	=	398,690	
Backfilled into old workings	=	276,422	
Ultimate surface disposal	=	122,268	$Yd^3/mile^2$

5.3.18.2 Reclamation

Stabilization of a spoil pile against air and water erosion can be accomplished by proper revegetation of its surfaces. For this to be performed effeciently within a reasonable length of time, top soiling is necessary. Topsoil and overburden can be stripped from the surface of the disposal site, stockpiled, and used to provide a plant growth medium on the surface of the mine wastes.

Vegetation must be planned to match the natural landscape, provide a permanent cover compatible with the local ecosystem, and be self-sustaining after the initial period of care. Sufficient topsoil with probable nutrient additives is needed to accomplish this result. Below about 10 inches of precipitation per year, revegetation becomes more difficult.

5.3.18.3 Isolation of Toxic and Hazardous Substances

The possibility exists that the mine spoils will contain toxic and hazardous substances which could oxidize and leach into groundwater (e.g., excess boron), or could be taken up by plants to poison grazing animals (e.g., selenium). Analyses of the mine spoils for such materials prior to permanent disposal plans plus burial under sufficient overburden and topsoil normally will solve most problems.

The Federal Surface Mining Control and Reclamation Act of 1977 (PL 95-87) presently applies only to coal mines. However, Section 709 authorizes a study of further laws for other types of mining. Rules to be promulgated under the Federal Resource Conservation and Recovery Act of 1976 (PL 94-580) may, in the future, include mine spoils under the classifications of toxic and hazardous wastes.

Few states regulate hard-rock mining and reclamation of lands disturbed by such activities. Colorado is one of the few states which does have a Mined Land Reclamation Act (Article 32 of Title 34, CRS 1973, as amended) which covers all kinds of mining operations and which legislates reclamation.

U.S. Forest Service lands and Public Domain lands are covered by rules (or proposed rules) regulating reclamation of spoils from all mining operations.

5.3.18.4 Mine Tunnels; Subsidence

Although coal mines are well known for the surface subsidence effects when old underground workings collapse, subsidence is not nearly so common in hardrock mines. This is because hardrock tunnels tend to be deeper and to leave less extensive cavities than coal mines. Because subsidence from this cause is extreme, sudden, and local, it can cause extensive and expensive surface damage. Due to the relatively restricted nature of the tunnels proposed for petroleum mining, proper mine abandonment plans should reduce to almost zero the possibility of surface subsidence from tunnel collapse.

5.3.18.5 Dewatering

The removal of oil and associated waters from geologic formations is known to cause surface subsidence. Examples can be found in the Long Beach area of California and the Texas City area of the Gulf Coast. Such subsidence is usually gradual, and evenly distributed on the surface in contrast to the catastrophic failure of old mine workings. Difficulty does occur when such subsidence occurs in coastal areas with consequent flooding of land previously above the high tide mark. Such subsidence can be controlled by reinjection of waters into the formation to replace the liquids withdrawn.

Most states have water laws regulating subsurface aquifers. Before withdrawal of underground water, plans must be approved by the State Engineer.

5.3.18.6 Water Disposal

All petroleum has some quantity of water associated with it in the geologic formation. These waters usually are quite high in salt content. Separation of oil field brines from the petroleum and its subsequent disposal is a long standing occurrence to the oil industry and one which has been successfully solved in numerous ways. Appendix B, "Disposal of Oil Field Brines and Elements of Water Treatment" is an extended treatment of the subject.

Water usually is separated from oil using settling tanks although heat, chemical additions, centrifuges and other means sometimes are employed. It is important to the transportation, processing, and refining of petroleum that as much water as possible be removed at the production site.

5.3.18.7 Disposal Methods

For reasons clearly outlined in Appendix B, treatment of oil field brines to the point that they can be discharged into natural bodies of water is prohibitively expensive. Evaporation is too slow and still leaves the problem of disposing of the salt. Normally, for the last 20-30 years, the only acceptable water disposal method is reinjection into the reservoir or into an underlying saline aquifer.

The discharge of foreign substances into the natural waters of the nation is regulated by the Federal Environmental Protection Agency and the individual states under the National Pollution Discharge Elimination System and associated rules by authority of the Federal Water Pollution Control Act as Amended 1977 (PL 95-12).

5.3.18.8 Discussion

At this stage of the concept of mining for petroleum, environmental problems are difficult to foresee clearly. However, they cannot be too different from those clearly defined in normal oil production and mining operations. It appears that the environmental problems are slightly greater than normal pumped well oil production but far less than area strip coal mining. The single major problem will be underground worker safety.

5.3.19 Economics of Gravity Drainage

The concept of mining for petroleum in the final analysis must be economic. The process must be competetive with coal, in fill drilling, tertiary recovery of petroleum and alternate (synthetic) sources of liquid energy. The major cost, as would be expected, is the mining program with the cost of drill holes second.

For the purpsoe of this study an oil reservoir was selected whose lower surface was at 2950 feet and the mining was done 50 feet below this surface. For cost calculations the following values were used:

15 foot shaft	$4,000/ft. max., $2,000/ft. avg.
15 foot tunnel	$500/ft., max., $400/ft. avg.
10 foot drift	$400/ft., max., $325/ft. avg.
Drill holes	$35/ft.
Drill chambers	$30.375/cubic yard
Piping	4" - $8/ft., 6" - $13/ft., 8" - $18/ft.

Based on these values, development costs are presented in Table 16 for a mine layout of 640 acres as shown in Figure 48. The mine development is such that a drainhole is located every 220 feet within the oil reservoir. The cost of developing a mine for a 100 foot thick oil reservoir is shown to be a maximum of $57,317,010 with a projected average of $40,650,010. The cost for a 200 foot thick reservoir is slightly higher because of the drill holes and production equipment, $59,959,710 maximum and $43,292,710 on an average.

To further determine the economics of the process, the following set of reservoir properties were selected: permeability to oil of 10 millidarcies, oil viscosity of 2 centipoises, thicknesses of 100 and 200 feet, porosity of 20 percent, oil saturation of 50 percent, recoveries of 50 and 70 percent, well bore radius of .26 feet, and drainage radius of 110 feet.

The petroleum engineer will recognize that 100' and 200' oil column reservoirs are common occurrences certainly in Texas, New Mexico and Louisiana among other oil producing states. The San Andres pay of the Permian Basin of West Texas and New Mexico (see Table 14) with over 100 individual fields has oil columns all in excess of 100' and many over 200'. In both Texas and Louisiana there are a great many multiple sands or pays that gross over 300' where all pays could be operated from a single gravity drainage mine network.

These reservoir properties were selected on the conservative side to present a reasonable evaluation. Based on these reservoir properties the oil in place and potential recoveries were calculated and are presented in Table 17. The projected minimum recovery of 50% resulted in ultimate production of 22,569,000 and 45,137,000 barrels for the 100 foot and 200 foot thick reservoirs respectively.

Using the flow equations presented in earlier paragraphs (see Section 5.3.8), a production performance was predicted for the 100 foot and 200 foot thick reservoirs. These projections are presented in Tables 18 and 19. The 100 foot thick reseroivr recovered 20,311,854 barrels of oil in 12,893 days. The 200 foot thick reservoir recovered 40,623,709 barrels of oil in 6,428 days.

Based on the projected oil recovery values and the calculated mining cost, the capital expenditure per barrel of future oil was determined. The results of these calculations are presented in Table 20. The maximum capital cost per barrel was $2.54 whereas the minimum capital investment per barrel was $0.95.

A discounted cash flow (BFIT) has been calculated which is shown in Table 21. Using the maximum cost case (worst case) and the lower production recovery and rates of the 100' reservoir, a payout time of 3.3 years and a project rate of return of about 35% BFIT is indicated.

An AFIT run was also made on the worst case and is represented by Tables 22 through 24. These data would indicate that an oil selling price of $12.50-15.25/bbl is required depending upon whether a 15% or 20% AFIT rate of return (DCF) was required to call out the high risk capital for this type of demonstration.

These economic analyses would indicate that the gravity drainage process is competitive with other alternate energy sources.

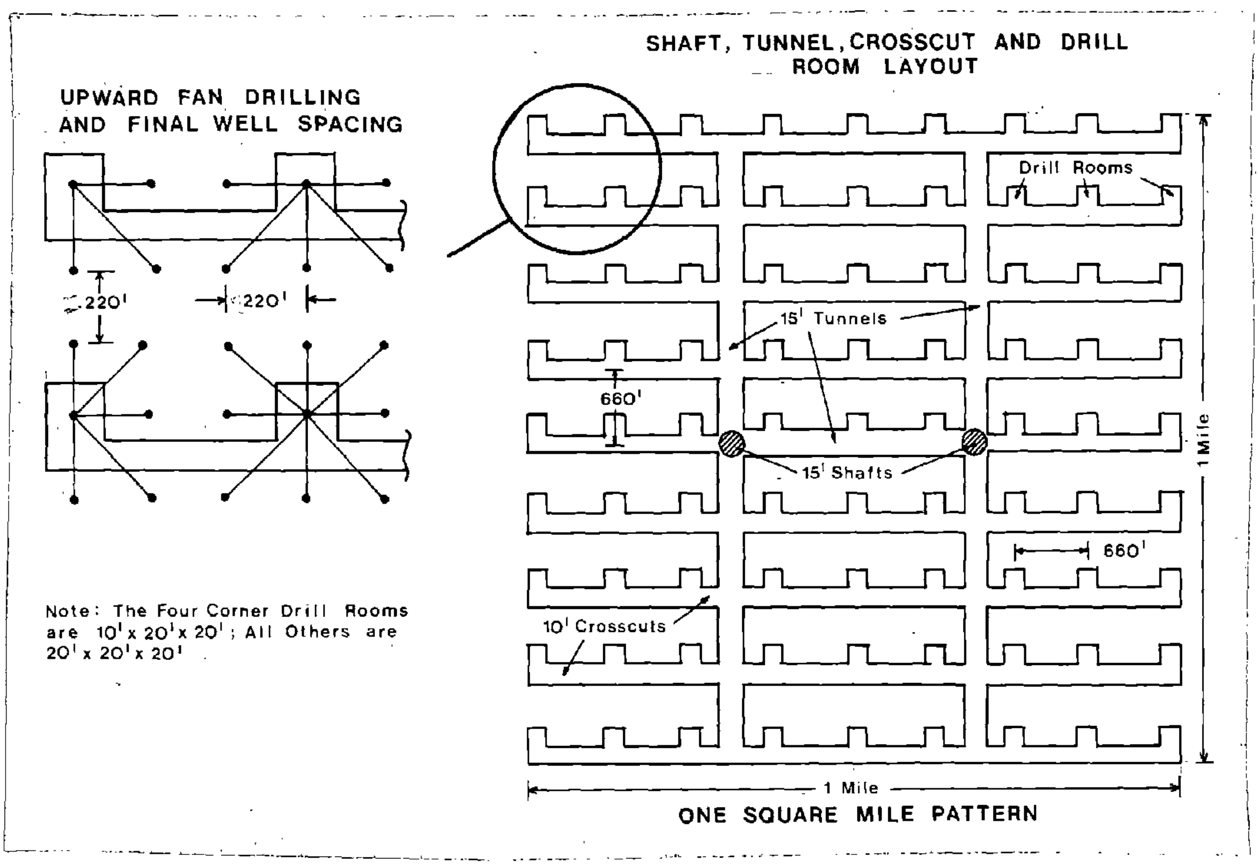

Figure 48. Shaft, tunnel, drift and drilling room layout for gravity drainage.

Table 16. Projected mining costs for a 640 acre oil reservoir which bottoms at 2,950 feet with 220 foot well spacing.

Operation		Cost Maximum $	Cost Average $
Two 3,000' shafts - 15' dia.		24,000,000	12,000,000
12,320 ft. of 15' tunnels		6,160,000	4,928,000
45,760 of 10' drifts		18,304,000	14,872,000
Drill Rooms			
77 - 20' x 20' x 20' rooms		693,000	693,000
4 - 10' x 20' x 20' rooms		18,000	18,000
Drill Holes			
Producing Formation 100 ft. thick			
81 - 150 ft. holes	(12,150 ft.)	425,250	425,250
288 - 266 ft. holes	(76,608 ft.)	2,681,280	2,681,280
256 - 344 ft. holes	(88,064 ft.)	3,082,240	3,082,240
Total 625	(176,822 ft.)	6,188,770	6,188,770
Producing Formation 200 ft. thick			
81 - 250 ft. holes	(20,250 ft.)	708,750	708,750
288 - 333 ft. holes	(95,904 ft.)	3,356,640	3,356,640
256 - 398 ft. holes	(101,888 ft.)	3,566,080	3,566,080
Total 625	218,042 ft.)	7,631,470	7,631,470
Piping in Mine			
45,760 ft. of 4"		366,080	366,080
12,320 ft. of 6"		160,160	160,160
Separation and Pumping Equipment			
14,000 Bbls per day		600,000	600,000
55,000 Bbls per day		1,800,000	1,800,000
Piping to Surface			
4,000' of 6"		52,000	52,000
4,000' of 8"		72,000	72,000
Total 8,000'		124,000	124,000
Surface Equipment		700,000	700,000
Total Cost for 100 ft. formation		57,317,010	40,650,010
Total Cost for 200 ft. formation		59,959,710	43,292,710

Table 17. Potential recoverable oil and income from gravity drainage systems

$\phi = 0.20$, $S_o = 0.50$, Area = 640 acres, $B_o = 1.1$, Royalty = 0.125

Thickness	Oil in Place S.T. Bbls	Potential Recovery 50% Bbls	Potential Recovery 70% Bbls	Potential Operators Gross Income, $15.25/bbl 50% $	Potential Operators Gross Income, $15.25/bbl 70% $
100	45,137,454	22,568,727	31,596,218	301,151,451	421,612,031
200	90,274,908	45,137,454	63,192,435	602,302,902	843,224,062

Table 18. Projected production for gravity drainage, 100' Reservoir

$\phi = .20$, $h = 100$ ft., $r_e = 110$ ft., $r_w = .26$ ft., $\gamma = .0.8$, $k_o = 10$ md, $\mu_o = 2.0$ cp
50% Recovery, $S_o = .50$

y*	x*	Q Bbls/Day/Hole	Rate/Sq. Mile Bbls/day	Total Recovery Bbls	Incremental Days	Total Elasped Time Days
1.0	0	22.03	13,769	0	0	0
0.9	0	17.84	11,150	2,256,873	181	181
0.8	0	14.12	8,824	4,513,745	226	407
0.7	0	10.78	6,738	6,770,618	290	697
0.6	0	7.91	4,947	9,027,491	386	1,083
0.5	0	5.52	3,449	11,284,364	538	1,621
0.4	0	3.51	2,193	13,541,236	800	2,421
0.3	0	1.84	1,150	15,798,109	1,350	3,771
0.2	0	0.90	562	18,054,982	2,637	6,408
0.1	0	0.21	134	20,311,854	6,485	12,893

*For definition of y and x, refer to Section 5.3.8

Table 19. Projected production for gravity drainage, 200' Reservoir

ϕ = .20, h = 200 ft., r_e = 110 ft., r_w = .26 ft., γ = 0.8, k_o = 10 md, μ_o = 2.0 cp, 50 % Recovery, S_o = 0.50

y*	x*	Q Bbls/Day/Hole	Rate/Sq. Mile Bbls/day	Total Recovery Bbls	Incremental Days	Total Elasped Time Days
1.0	0	88.13	55,080	0	0	0
0.9	0	71.40	44,626	4,513,745	91	91
0.8	0	56.39	35,241	9,027,491	113	204
0.7	0	43.17	26,979	13,541,236	145	349
0.6	0	31.74	19,840	18,054,982	193	542
0.5	0	22.03	13,770	22,568,727	289	831
0.4	0	14.12	8,824	27,082,472	400	1,231
0.3	0	7.91	4,947	31,596,218	656	1,887
0.2	0	3.51	2,193	36,109,963	1,264	3,151
0.1	0	0.90	562	40,623,709	3,277	6,428

*For definition of y and x, refer to Section 5.3.8

Table 20. Development cost per unit.

Thickness Feet	Development Cost Maximum	50% Recovery Recoverable Oil Bbls	50% Recovery $/bbl	70% Recovery Recoverable Oil Bbls	70% Recovery $/bbl
100	57,317,010	22,568,727	2.54	31,596,218	1.81
200	59,959,710	45,137,454	1.33	63,192,435	0.95

Table 21. Generalized Cash Flow (BFIT). 100' Oil Reservoir (worst case) 50% Recovery (worst case) Maximum Cost (worst case). One square mile only.

Maximum capital cost case ($65 million)[1], 2 year construction, production is in years 3-20 (production years 1-18 are cost years 3-20; ignore production years 19-35), operating cost @ $.25/bbl, 12.5% royalty, $15.25/bbl.

(Dollars & Barrels in Millions)

Time Year	Capital[1] Costs $	Operating Costs $	7/8 Prod Bbl	7/8 Prod Income $	Σ Year $	Pay-out $	Discount[5] 15% Factor	PW15 $	Discount 35% Factor	PW35 $
0-1	(30.0)				(30.0)	(30.0)	.9286	(27.9)	.8438	(25.3)
1-2	(30.0)				(30.0)	(60.0)	.7993	(24.0)	.5946	(17.8)
2-3	(5.0)	(1.0)	3.53	53.8	47.8	(12.2)	.6879	33.9	.4190	20.0
3-4		(0.8)	2.68	40.9	40.1	27.9	.5921	23.7	.2953	11.8
4-5		(0.5)	1.78	27.1	26.6		.5096	13.6	.2081	5.5
5-10		(1.3)	4.60	70.2	68.9		.3323	22.9	.0820	5.6
10-15		(0.6)	1.97	30.0	29.4		.1570	4.6	.0143	0.4
15-20		(0.5)	1.05±	16.0	15.5		.0742	1.2	.0025	0.0+
20[2]	(65.0)	(4.7)	15.61[3]	238.0[4]	168.3			+48.0		+0.2

ALL BFIT:

PROJECT ROR (DCF) $\cong$ 35%
PW 15 $\cong$ \$50MM
PAYOUT TIME $\cong$ 3.5 Years
INCOME/INVESTMENT $\cong$ 238.0 - 4.7/65.0 $\cong$ 3.6

[1] Approximately $8 million has been added to costs shown in previous tables as a 15% contingency factor.

[2] Two construction plus 18 production years.

[3] Equals 17.9 million barrels on a 8/8 basis, 18 years cumulative production.

[4] Value of gas production ignored (worst case).

[5] All discount factors are from Interest Tables for Determining Rate of Return, J.C. Gregory; using factors "uniformly over individual years", i.e.,

$$\text{Factor} = \frac{e^{rt} - 1}{r \cdot t \cdot e^{rt}}$$

Table 22. Depreciation Schedule (sum of years-digit method).

Time	Capital	Σ Digits	Yrs. Left	Depr. Factor	Depr. Base	This Yrs. Depr.	Undepr. Cap Bal.
Yr.	$	Factor	Yrs.	Factor	$	$	$
0-1	(30.0)	210	20	.095	30.0	2.85	27.15
1-2	(30.0)	190	19	.100	57.15	5.72	51.43
2-3	(5.0)	171	18	.105	56.43	5.93	50.50
3-4		171	17	.099	56.43	5.59	44.91
4-5		171	16	.094	56.43	5.30	39.61
5-6		171	15	.088	56.43	4.97	34.70
6-7		171	14	.082	56.43	4.63	30.01
7-8		171	13	.076	56.43	4.29	25.72
8-9		171	12	.070	56.43	3.95	21.77
9-10		171	11	.064	56.43	3.61	18.18
10-11		171	10	.058	56.43	3.27	14.89
11-12		171	9	.053	56.43	2.99	11.90
12-13		171	8	.047	56.43	2.65	9.25
13-14		171	7	.041	56.43	2.31	6.64
14-15		171	6	.035	56.43	1.98	4.96
15-16		171	5	.029	56.43	1.64	3.32
16-17		171	4	.023	56.43	1.30	2.02
17-18		171	3	.018	56.43	1.02	1.00
18-19		171	2	.012	56.43	.67	0.33
19-20		171	1	.006	56.43	.33	0.00

The economics herein are developed in 1978 constant dollars, all equity, maximum capital cost as opposed to average cost, with discount rates being infinite series and with a 15% contingency factor laid on top of maximum costing. The analysis herein does not include pre-development costs such as design engineering development, second level economics, site specific sub-reservoir coring, logging and analyses, guard wells for shafts through the reservoir, if required, or major changes or additions that might be required to surface metering, storage and transportation facilities. These costs could accumulate to or exceed $8 million which is equal to and could wipe out the contingency factor overlaid within the economic calculations of Tables 21 through 24.

The reader will also be aware that the pattern developed in Figure 48 will really drain an area 5500 feet on a side as opposed to 5280 feet; if the outer boundary drill rooms were utilized to their fullest capability with an additional outer row of directional wells, the tunnel and drift arrangement of Figure 48 would drain, for an infinite pattern case, an area 5940 feet on a side as opposed to 5280 feet.

Table 23. Generalized Cash Flow (AFIT) 100' Reservoir (worst case) 50% Recovery ($12.50/bbl Trial)
(All numbers are in millions.)

Time Yr.	7/8 Prod Income $	Operating Costs $	BFIT Income $	Depr. Costs $	Taxable Income $	48% Tax $	AFIT Income $	Capital Outlay $	Cash Flow $	Discount 15% Factor	For Req'd PW15 $
0-1	0	0	0	(2.85)	CF	0	0	(30.0)	(30.0)	.9286	(27.9)
1-2	0	0	0	(5.72)	CF	0	0	(30.0)	(30.0)	.7993	(24.0)
2-3	44.1	(1.0)	43.1	(5.93)	28.6	(13.7)	29.4	(5.0)	24.4	.6879	16.8
3-4	33.5	(0.8)	32.7	(5.59)	27.1	(13.0)	19.7	0	19.7	.5921	11.7
4-5	22.2	(0.5)	21.7	(5.30)	16.4	(7.9)	13.8	0	13.8	.5096	7.0
5-10	57.5	(1.3)	56.2	(21.45)	34.8	(16.7)	39.5	0	39.5	.3323	13.1
10-15	24.6	(0.6)	24.0	(13.20)	10.8	(5.2)	18.8	0	18.8	.1570	3.0
15-20	13.1	(0.5)	12.6	(4.96)	7.6	(3.6)	9.0	0	9.0	.0742	0.7
20	195.0	(4.7)	190.3	(65.0)	125.3	(60.1)	130.2	(65.0)	65.2		+ 0.4

Table 24. Generalized Cash Flow (AFIT) 100' Reservoir (worst case) 50% Recovery ($15.25/bbl Trial)
(All numbers are in millions.)

Time Yr.	7/8 Prod Income $	Operating Costs $	BFIT Income $	Depr. Costs $	Taxable Income $	48% Tax $	AFIT Income $	Capital Outlay $	Cash Flow $	Discount 20% Factor	For Req'd PW20 $
0-1	0	0	0	(2.85)	CF	0	0	(30.0)	(30.0)	.9063	(27.2)
1-2	0	0	0	(5.72)	CF	0	0	(30.0)	(30.0)	.7421	(22.3)
2-3	53.8	(1.0)	52.8	(5.93)	38.3	(18.4)	34.4	(5.0)	29.4	.6075	17.9
3-4	40.9	(0.8)	40.1	(5.59)	34.5	(16.6)	23.5	0	23.5	.4974	11.7
4-5	27.1	(0.5)	26.6	(5.30)	21.3	(10.2)	16.4	0	16.4	.4072	6.7
5-10	70.2	(1.3)	68.9	(21.45)	47.5	(22.8)	46.1	0	46.1	.2325	10.7
10-15	30.0	(0.6)	29.4	(13.20)	16.2	(7.8)	21.6	0	21.6	.0855	1.8
15-20	16.0	(0.5)	15.5	(4.96)	10.5	(5.0)	10.4	0	10.4	.0315	0.3
20	238.0	(4.7)	233.3	(65.0)	168.3	(80.8)	152.4	(65.0)	87.4		- 0.4

5.3.20 Conclusions for Project Viability

As in all petroleum projects, the viability depends upon successfully defining two independent constituent parts, the first being performance of the mechanical factors and second the performance of the flow theory involved. In Drip Drainage the study team concludes that the flow mechanisms are well proven (although not fully demonstrated with data) in theory starting at Muskat and concluding with theory within this report. Simultaneous to the completion of this report a timely supporting article was published in the May 1978 Journal of Petroleum Technology authored by Dykstra. Therefore the conclusion herein is that there is the highest assurance level probability that ultimate recoveries of conventional petroleum can be raised from the current average of 32% to the 80-90% range which represents 150-200 billion barrels (5-7 times current U.S. reserves) utilizing controlled gravity drainage theory.

Addressing the mechanical ability to access proximity (primarily underneath) of reservoirs in order to apply and capture these added reserves, there are the following mechanical elements which must be addressed:

1. Large shafts in the range of 8-20' diameter, depending upon mining requirements of muck removal, ventilation due to bottom hole temperature and equipment access limitations, will have to be installed by blasting, drilling or raise boring. The technology for establishing these shafts is well demonstrated and poses no unique problems (including encountering water flows) except for shafts through pressured gas and oil reservoirs.

2. Shafts through pressured reservoirs have not been experienced widely. Because the target reservoirs are so diverse as to pressure level, residence depth, gross volume, rate of exposed production, rock or sand qualities of permeability, porosity and saturation and the fluid flow characteristics of the gas and fluid, it is not possible to design a general method of isolating these reservoirs from shaft operations. This is recognized in the economic evaluation where costs of tunnels, drifts, drill holes, drill chambers and piping was estimated for a maximum versus average case within a rather narrow band. Without the unknown of penetrating pressured reservoirs shafting experience in the same narrow range of $1800-2400/ft. could be predicted. The study has recognized however that the mining engineer, prior to sinking a shaft through a known or potential oil reservoir, will have to rely on petroleum engineering technology to first isolate reservoir(s) from the shaft. For certain reservoirs this may be relatively simple requiring only a proper mud program or fracturing and cementing a formation beyond the anticipated shaft diameter. In other cases, and this is probably to be expected frequently, other means may have to be designed such as drilling circumferential guard wells prior to sinking the original shaft. Whatever the reservoir conditions dictate, however, the economic cases illustrated in earlier sub-sections should be valid. While drilling through pressured reservoirs poses engineering problems, they do not appear to be disqualifying technically or economically.

3. Tunnelling closely underneath without creating fractures into the reservoir can be accomplished by boring machines as opposed to blasting and

probing ahead for gas can be accomplished, if required, to eliminate surprises.

4. Drilling room chambers can be established in side rooms off of main tunnels or drifts by Alpine miners or low level blasting.

5. Pressure locks for isolating drilling chambers or remote control drilling of upward wells is within the existing technology adaption range. Whether required or not depends upon risk analyses of overhanging pressure control mechanisms and fail safe backup equipment.

6. Drilling upward and angled wells is shelf technology with equipment built of modular construction so it can be dismantled for access through narrow shafts, tunnels, drifts and cross cuts and re-assembled inside drilling room chambers.

7. Overhanging pressure control to isolate reservoir oil, gas and water from the mine while drilling and throughout the operating life is technology readily adapted by engineering re-design of existing equipment. Of course, because of the possibility of mechanical or human failures full back-up systems will be required and only those service and manufacturing companies with a full range and wealth of field experience will probably be used.

The conclusion is that Drip Drainage flow theory is proven and that there are no disqualifying mechanical (mining or equipment design) limitations to oil mining.

5.4 MINING OF HEAVY OIL AND TAR SANDS

As indicated earlier in this report, large quantities of U.S. petroleum reserves are located close to the surface in what is commonly referred to as tar sands or heavy, viscous oil sands. At the present time, this petroleum is being produced, if at all, through conventionally completed oil wells and stimulated with steam. In the case of the Athabasca Tar Sands the solid containing the hydrocarbon is being mined and processed at the surface. Recovery efficiencies of these deposits is very low and/or costs of recovery are very high.

The major difficulities in recovering this heavy hydrocarbon through conventional wells are: 1) the formation generally is unconsolidated sand and hence the solid particles tend to flow toward the well with the hydrocarbon, 2) the heating material has to be injected into the formation through a well which causes a difficulty of proper placement to gain the greatest efficiency from the injected hot substance, and 3) a large portion of the heating material is produced back with the hydrocarbon thereby wasting a large amount of the heat.

Present techniques of completing these oil wells require that special sand control methods (gravel pack) be used to prevent the influx of solids into the producing well. These methods reduce the producing capabilities of the wells. It is the purpose of this section to describe an in-situ mining method which is a combination of mining technology and petroleum production technology as a possible solution for the recovery of hydrocarbons from these types of formations.

5.4.1 The Flip Flop Process

For hydrocarbon formations which are close to the surface, either strip mining of the overburden or trenching can be used to uncover the surface of the heavy oil or tar sand. The formation itself should not be mined. After the surface is exposed, special dams for containing both oil and water in ponds are installed on the surface of the formation. Then, the following oil recovery procedure is applied: 1) cover the exposed oil containing surface with hot brine to a height of approximately 3 feet. This brine should contain a surfactant, both anonic and catonic such as Adafoam, 3M's X-35 or X-37, or any other surface tension reducer, which will cause the sand grains to become "water wet". 2) Place steam pipes on the surface of the formation so the brine soak can be maintained at its maximum temperature. These pipes will also be used to add additional water to maintain an approximate 3 foot height. 3) The hot brine will conduct its heat to the oil, reducing the oil viscosity and density such that a gravitational head differential will develop causing the brine to flow down into the formation and force the oil up and out. This interchange of position of brine and oil (Flip Flop) will be accelerated by a surfactant agent within the brine by creating a differential capillary pressure force between the two liquids. There are thus two forces acting: gravitational and capillary. If the right agent is selected, the capillary force will represent the major component of the two forces for the removal of the oil. 4) Water (or brine) is continually added to the surface of the sand while oil is removed from the top of the restricting (or skimming) vessels until all the oil has been removed from the top 6 to 10 feet of the formation. This treatment is necessary to stabilize the surface so that oil may flow through this region without moving (or floating) the sand itself. The wetting characteristics of this water will create a minimum connate water saturation (about 35%) which, in turn will help to retain the sand grains and keep them from moving when the oil is produced through them to the surface. 5) Drive pipes with perforated sections at the lead ends can now be driven to the bottom of the hydrocarbon containing formation. They can be driven at angles underneath an area which has not been trenched or which has not had its overburden removed and can also be driven straight down beneath the section which has been exposed. 6) A 60 to 70 percent quality steam with a surfactant is injected into the pipes and may be injected under considerable pressure. 7) If the formation is thick (over 50 feet) the drive pipes will have to be driven to different depths to increase the amount of heat placed within the formation and also to reduce the distance over which the pressure gradient for moving the hydrocarbon must be applied. Low quality steam may be injected at different levels alternately so that the oil is constantly being replaced by brine and the sand can stabilize itself during the process of production. 8) Steam condenses to water and transmits heat into the formation and hydrocarbon. As the steam condenses to water, it also becomes heavier than the oil so that it tends to flow toward the bottom of the formation and the oil tends to rise to the top. In addition to this gravitational movement the wetting agent within the water will create a capillary pressure which will also have a tendency to drive the oil to the exposed surface.

5.4.2 Flow Theory

The initial heat application for stabilizing the top 6 to 10 feet of the section depends on heat being transmitted by conduction as well as mass transport. The surfactant in the water will cause a set of adhesive forces to try to "suck" the water downward into the sand in the smallest pores. This action (imbition) creates a pressure gradient in the oil system such that the oil is forced to flow out the largest pores. Once water has penetrated into the smallest pores, additional force is applied because of the density difference in the oil and water. At this point the flow is represented by Equation 20.

$$Q_o = \frac{KA}{\mu_o}\left[\frac{\dfrac{(\rho_w - \rho_o)\,(h)}{144} + P_c}{h}\right] \tag{20}$$

where:

Q_o, is the volumetric flow rate, ft^3/hr

K, is some proportional function including permeability. In the imbition process this function has not been totally defined but appears to decrease with time

μ_o, is the viscosity which decreases as the oil is heated, centipoises

ρ_w, is the density of the hot water and increases as the water cools, #/cu. ft.

ρ_o, is the density of the oil which decreases as the oil is heated, #/cu. ft.

h, is the depth from which oil is flowing to the exposed surface, ft.

P_c, is the capillary pressure caused by the surfactant, psi

A, is the cross sectional area of the flow surface, sq. ft.

The process should continue until the top 6 to 10 feet have reached about a 35% water saturation. The surface bed should then permit oil flow without sand movement.

The second phase of the recovery process is to inject heat in the form of steam into the system, thus generating a bottom water drive with both imposed potential forces and gravity forcing the oil to the exposed surface. The flow equation for the recovery of the remaining oil is given by Equation 21.

$$Q_p = \frac{KA}{\mu_o} \left[\frac{P_i + P_c + \dfrac{(\rho_w - \rho_o)(h)}{144}}{h} \right] \tag{21}$$

where:

P_i, is the pressure of steam injection, psi

h, is the depth from the exposed surface of injection, ft.

and the other terms are as previously defined.

The "Flip-Flop" recovery process as discussed herein may be applied when the surface of the formation safely can be exposed, i.e., the oil does not evolve free gas upon exposure to atmospheric pressure. The process also can be used, with modifications, when free gas will be produced.

5.4.3 Development for Production

It will be unnecessary to expose the total surface of the producing formation. Instead, depending upon the permeability of the formation and the ability to reduce the viscosity of the in-place hydrocarbon, there are several possibilities that exist. Four of these possibilities are illustrated in Figure 49. The most probable initial development pattern will be the one illustrated as mode 2. This development pattern requires the exposure of one acre of the producing formation for every nine acres from which oil will be extracted. The maximum distance any hydrocarbon has to travel in order to be produced is 7,467 feet. But, over 80% of the oil that will be produced only has to travel a maximum of 5,280 feet. Another mode of operation for initial development is either modes 1 or 3. Mode 1 would probably be preferable because it permits itself to be expanded to mode 4 in case accelerated production is required. In the case of mode 1 the maximum distance any droplet of oil has to travel is 3,734 feet. But 88% of the recoverable oil has to travel less than 2,640 feet. These distances of travel and the development intensity are identical for mode 3. Both of these modes of operation require the exposure of one acre of the formation for every 4 acres to be produced. Mode 4 is the most intensely developed of all systems. 100% of the recoverable oil has to travel less than 2,640 feet.

It is unlikely that mode 4 will ever be used in a normally viscous oil sand. This method may be desirable in the case of a tar sand wherein the viscosity remains relatively high even after the heating process. In all likelihood, either mode 2 or mode 3 will be the probable pattern. There is also the possibility of expanding mode 2 into a mode 3 type operation.

5.4.4 Flip Flop; Surface Application

Once the surface of the formation is exposed, then the actual production operations will be initiated utilizing a phase 1 and phase 2. Phase 1 will be the period in which the top 6 to 10 feet of the exposed surface of the formation is stabilized such that as oil flows upward through the zone, the sand particles do not move.

The general operational procedure is illustrated in Figure 50, wherein a container is placed on the surface of the formation with steam pipes laid in contact with the surface formation and this container is filled with a hot brine solution. Steam is continually added to maintain the temperature of the water and the oil that floats to the surface is removed from an oil sump within the container and pumped to oil storage at the surface of the ground.

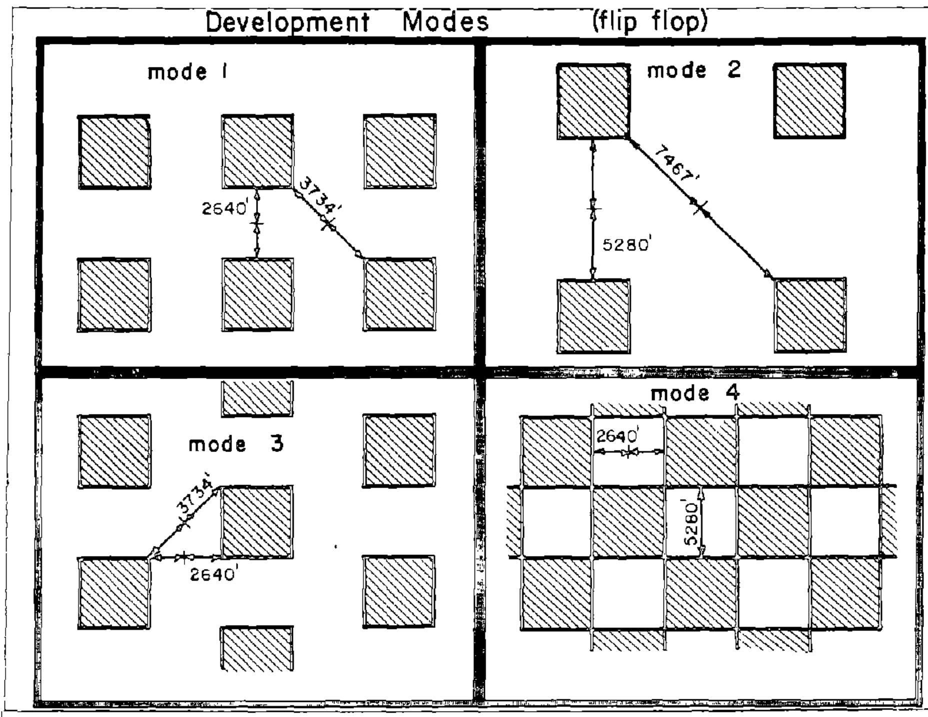

Figure 49. Development modes for the surface application of Flip Flop.

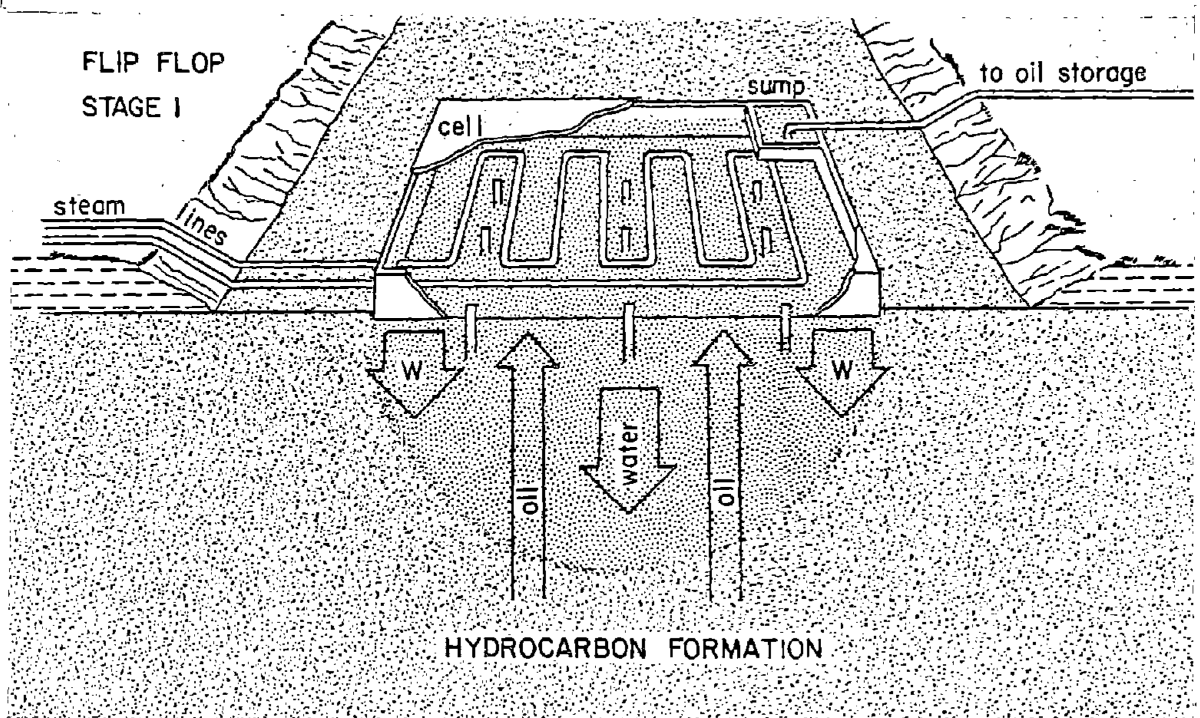

Figure 50. Stage 1, stabilization configuration for the surface application of the Flip Flop process.

In phase 2, steam pipes are driven from the surface of the formation down into the formation either vertically or at various angles as shown in Figure 51. The degree of the angles and the number of drive pipes will be a function of the thickness of the formation and the ability to inject fluid into the formation. It is noted that no attempt is made to maintain the exposed surface of the formation at an elevated temperature. This section of the formation has now been stabilized and only heated oil will be passing through to be collected in the sump.

Figure 52 shows in some detail the container that will be placed on top of the formation. This container can be made from fiberglass utilizing drive pipe or legs to hold the frame in place. The steam pipes could be built as an integral part of the container, but probably should be built separately. If the steam pipes were built separately, from the container body, they can be removed after the stabilization period and the same container can be used for both phase 1 and phase 2 of the operation. The oil collector indicated in Figure 52 should be built as an integral part of the container. The container has not been shown with all the necessary piping hardware required to remove the oil from the system. Such detail was not desired at this stage.

5.4.5 Flip Flop; Underground Application

In many cases, the surface of the hydrocarbon containing formation cannot be exposed to the atmosphere because the fluid contained is under a natural pressure and would flood an excavation. A second reason, less dangerous but more difficult perhaps to control, is that during the heating and stabilizing process some hydrocarbons will yield considerable volumes of flammable hydrocarbon gases which will make the operational control procedures more difficult. A third reason for not exposing the reservoir is that the overburden thickness may be too great to be economical.

When the surface formation cannot be exposed it becomes necessary to develop the hydrocarbon containing formation in a different fashion. Two techniques have been devised which differ only in the method of obtaining access to the formation. In the first technique, all access to the formation is from the surface of the ground, whereas in the second technique, access to the formation is obtained from underground rooms or tunnels which reduce some of the vertical drilling. As in previous cases, the selection of the technique will be a function of the depth of the formation and the costs of providing access.

A general illustration, Figure 53 indicates the two possible techniques. The first technique is conventionally drilling a single hole to the top of the reservoir. The top of the formation is then jetted to form a cavern approximately 5 feet in height and 40 feet in diameter. By special drilling techniques a hole is then drilled through the producing formation so that steam may be injected into the bottom of the formation.

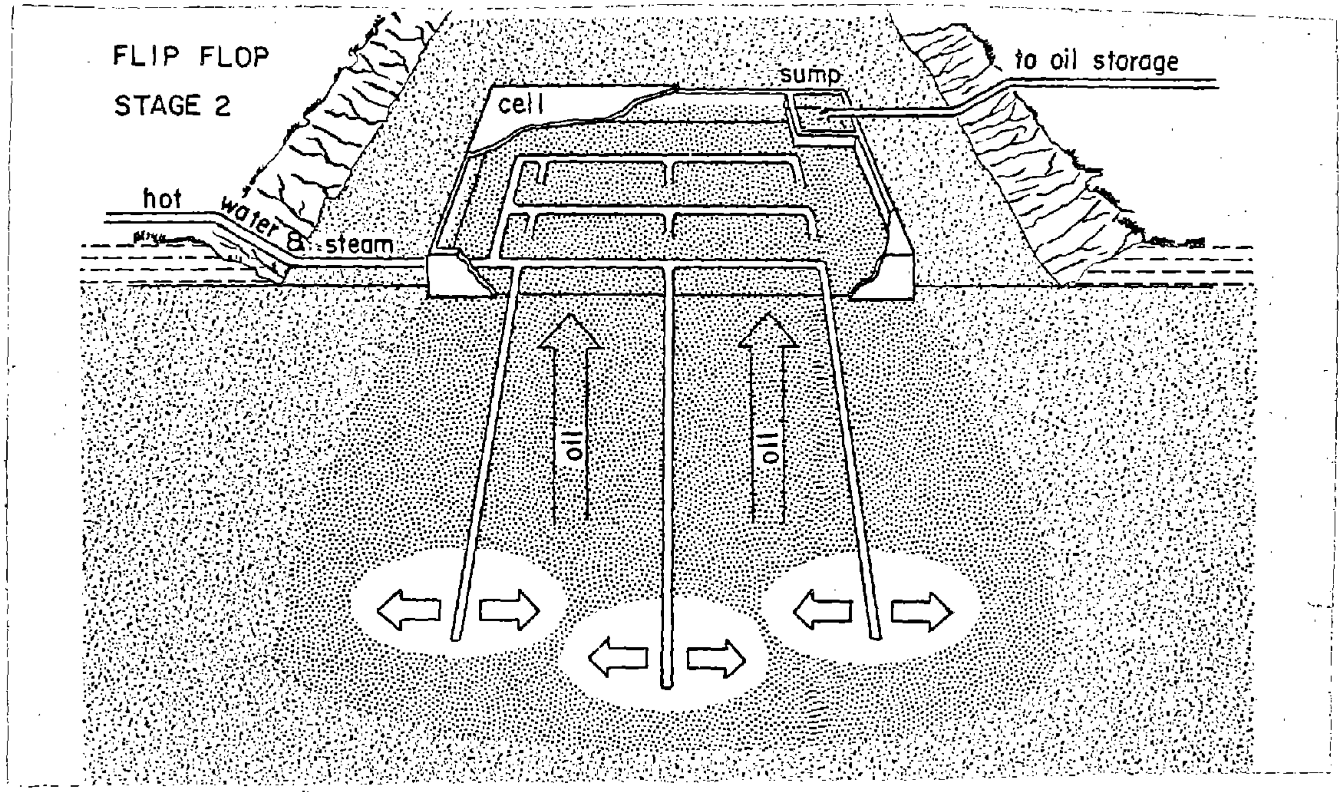

Figure 51. Stage 2, steam injection and oil production phase for surface application of the Flip Flop process.

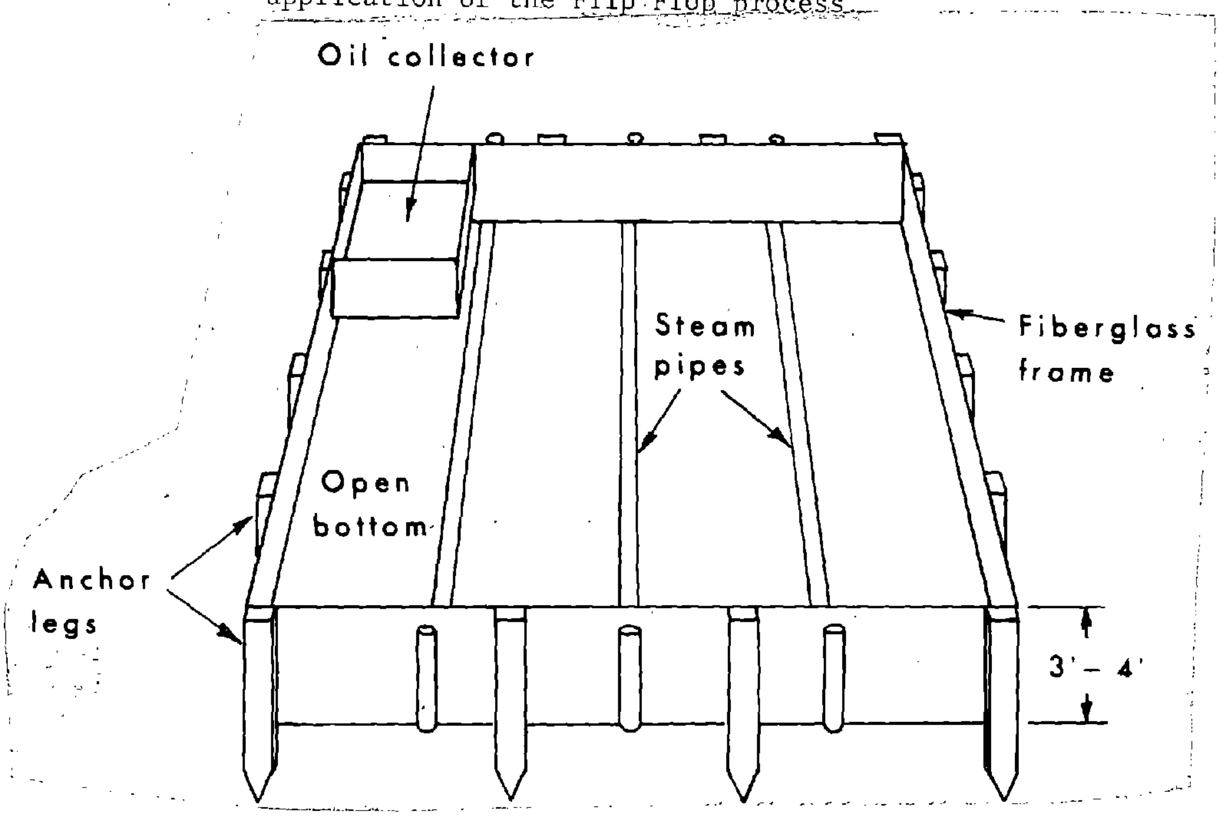

Figure 52. Sketch of the surface dam used for the initial phase of the Flip Flop process.

The technique of initiating and stabilizing the jetted cavern is slightly different from that used at the surface. The hole and cavern are both filled with extremely hot water with the necessary surfactants. Steam is injected in the bottom of the drilled hole and the hot fluids are permitted to migrate up to the cavern to maintain a constant availability of hot water in the region to be stabilized. This process is continued until the region around the cavern has been satisfactorily treated so the oil will flow upward without movement of the sand and destruction of the cavern. The oil released is pumped from the initial wellbore to the surface for processing and to reduce the pressure head on the hydrocarbon system.

Also illustrated in Figure 53 is a similar technique except that additional steam injection holes have been drilled through the formation. This procedure would increase the area that could be drained with any one drill hole from the surface, but it would require a much larger diameter hole from the surface to the top of the formation. The choice of these two types of completions will be determined by economics and will be a function of the viscosity of the crude oil, formation thickness, formation permeability and depth to the top of the formation.

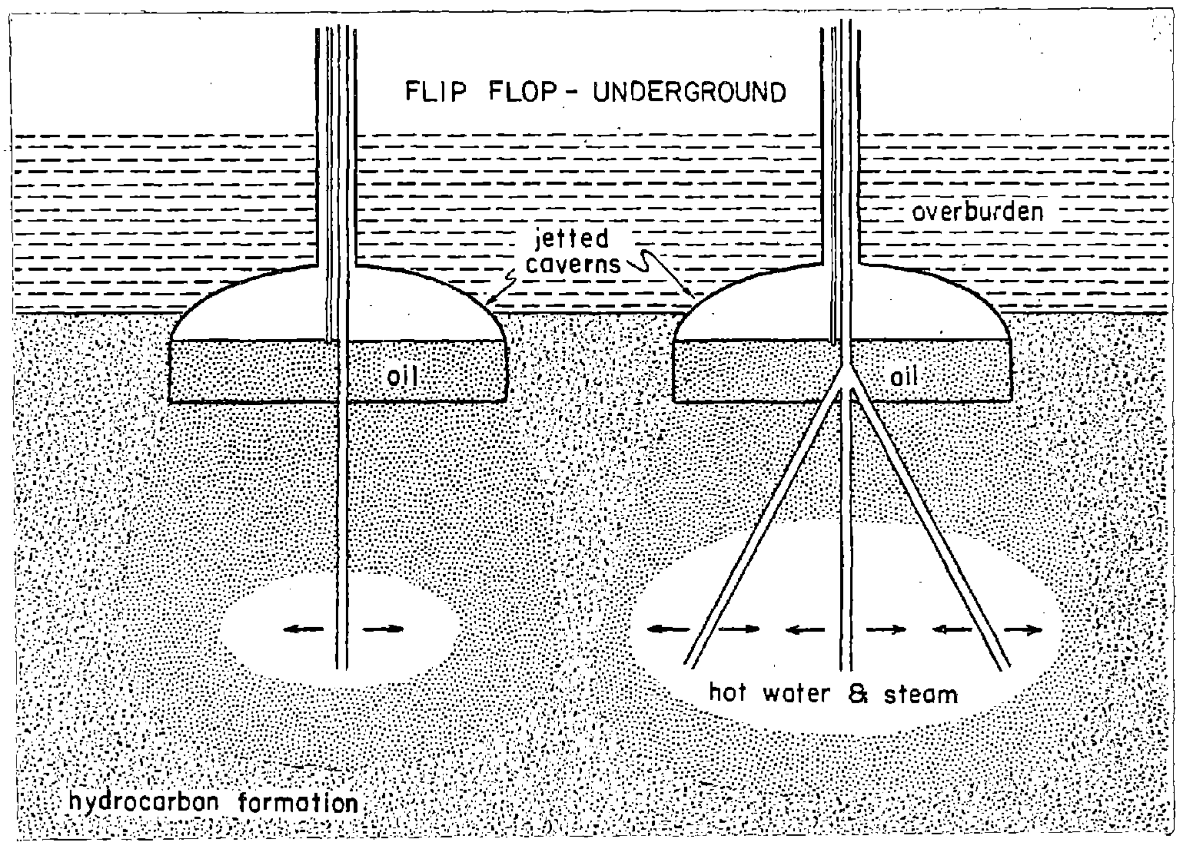

Figure 53. Two configurations for the underground application of Flip Flop.

5.4.6 Production Facilities

An indicated procedure for developing one of these production facilities would be as follows:

1. Prepare drill site.
2. Drill a 13 3/8" hole to the top of the formation.
3. Run and cement 9 5/8" casing from on top of formation.
4. Jet the cavern 40 feet in diameter and approximately 5 feet in height.
5. Hang 5½" casing from the drill floor to the bottom of the cavern, this casing should be hung off-center to permit later running of material.
6. Drill a 4½" hole coring through the 5½" casing to the bottom of the hydrocarbon containing formation.
7. Run 2 7/8" tubing to the bottom of the producing formation and cement to the bottom of the jet cavern.
8. Pull the 5½" casing that encloses the 2 7/8" tubing.
9. Run the 2 7/8" production string to just above the cavern with an electric down-hole centrifical pump attached to the bottom of the tubing string.

Extremely hot water can then be injected through the producing string to fill the cavern. A perforating gun is then run in the 2 7/8" tubing and it is perforated at whatever intervals are selected for steam injection. The number of intervals perforated will be a function of the thickness of the formation. A 60% quality steam can then be injected through the injection string so that it will exit from the perforated intervals, will heat the oil, condense to water, and force the hydrocarbon to flow toward the jetted cavern.

The number of wells required to drain any specified volume will be a function primarily of the initial reservoir pressure and the viscosity reduction which can be obtained by the injection of steam. No attempt has been made to apply economics to this type of system at the present time, but the technology is presently available and in some cases existing petroleum producing wells in areas which are undergoing steam stimulation could utilize this process.

5.4.7 An Underground Alternative

The same general production facility technique could be used with an underground mining process. Where the heavy oil is deep, the drilling could be initiated from entries and drifts developed just above the reservoir as shown in Figure 54.

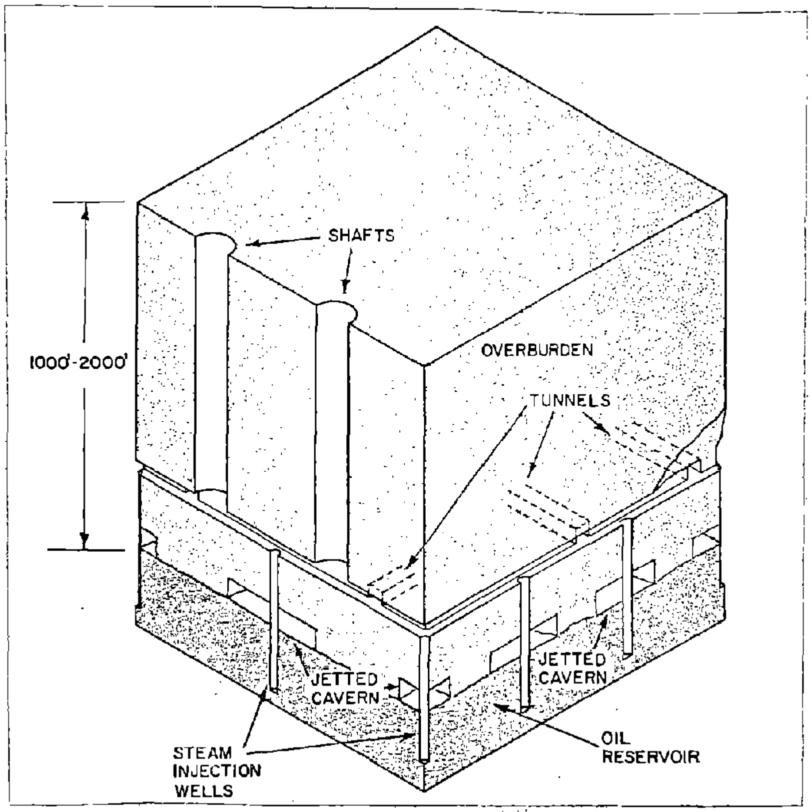

Figure 54. - Underground mining process for Flip Flop recovery.

5.4.8 Conventional, But Dead Oil

The Flip Flop process applies to the extraction of conventional, but "dead" oil. A conventional petroleum reservoir that only contains liquid petroleum, with no gas or water, and is under little or no overburden or other pressure is said to contain "dead" oil. Usually, little or no oil can be produced by conventional primary methods.

5.4.9 Environmental Considerations

Since a Flip Flop process is primarily used to extract dead oil, i.e., not containing associated gas or water, certain of the environmental problems normally associated with oil production do not exist. Water used in the process can be recycled and, instead of a problem of brine disposal, sufficient make up water will be needed to replenish that lost in escaped steam and by evaporative cooling.

Reclamation of mined overburden may not offer the same difficulties since the trenches probably will have to be back filled. Thus, spoil piles are generally avoided.

Surface subsidence may present a problem depending on whether the heavy oil only fills rock or sand voids or whether the heavy oil actually occupies a supporting fraction of the geologic formation. However, such subsidence will be gradual rather than catastrophic and should present a minimum of problems.

It would appear at this conceptual stage of the Flip Flop process that such a process may offer fewer inherent environmental problems than the more conventional oil mining.

5.4.10 Economics of Flip Flop

The economics of the Flip Flop process depends on many more petroleum engineering variables than the gravity drainage production system. One must specify the temperature expansibility of the oil, change in viscosity with temperature, the pore size distribution of the sand, the wettability of the sand and many other factors. Interchange rate of fluids under these variable conditions have not been totally documented in the literature and for each case some laboratory data will have to be derived. Because of the variables involved and need for confirming data on specific deposits, economics must be calculated for each case individually.

However, it is anticipated generally that the capital development cost would be approximately 10% of the gravity drainage process. The oil recovery factors should be as good, or nearly so, as the gravity process. Operating cost for the Flip Flop process probably will be higher than for gravity drainage. The magnitude of the operating cost will not be defined until some laboratory experiments are performed to determine oil/water exchange rates.

5.4.11 Conclusions for Project Viability

In order to address viability of a Flip Flop process an evaluation of flow theory and the mechanical factors results in different conclusions than those for a Drip Drainage project. For surface Flip Flop, the study team concludes that the mechanical factors pose no unique questions in any of required elements and that all are shelf technology. However the reservoir theory of maintaining a stabilization bed whose residual water saturation tension characteristics will allow flow of non-viscous crude must be demonstrated under laboratory and field conditions and thus poses economic viability risks.

The mechanical factors which are all well demonstrated are:

1. Exposure of the producing surface by mining technology

2. Flooding the surface with

3. Hot water for viscosity modification which can easily be controlled including

4. Brine additives to enhance density interchange and also including

5. Surfactants for capillary improvement

6. Soaking time in order for the Phase I interchange to take place

7. Bed depth of 6-10' to provide a sufficient stabilization thickness and

8. Residual water saturation of approximately 35% to provide optimum interfacial tension for maximum bed stability.

The conclusion is that Flip Flop flow theory has some risk to find a proper balance of the inter-relation of the forces of nature but that there are no unknowns associated with the mechancial factors of project performance.

Relating to deeper underground deposits technology development will be required of projects where underground flooding chambers must be developed.

5.5 RESEARCH, DEMONSTRATION AND DEVELOPMENT

5.5.1 Technology Transfer

Given the U.S. dependency on foreign oil, the lack of success in finding large new oil fields, and the nearly 2/3 of the original oil that remains in known reservoirs unrecoverable by conventional means, government and industry should be made aware of a petroleum mining alternative. The targets for mining for petroleum are the approximately 300 billion barrels left in known liquid hydrocarbon reserves and the approximately 200+ billion barrels locked in U.S. heavy oil and tar sands.

Technology transfer sessions consisting of a comprehensive slide presentation, an adequate question and answer period and appropriate hand outs and press releases would bring the petroleum mining alternative to public awareness and provide impetus for industry participation in demonstration and development projects. Suggested primary targets for technology transfer sessions are listed as follows:

CITY	FACILITY
Washington, D.C.	Federal Facility
Denver, CO	CSM (Green Center)
Houston, TX	Petroleum Club
Los Angeles, CA	Petroleum Club
Tulsa, OK	Petroleum Club
PA/OH/W. VA/etc.	Unknown

5.5.2 Economics and Pricing

Petroleum produced by mining should sell at the Free Market Price to make demonstrations of mining for petroleum more economically viable and attractive. The oil pricing structure, however, is complex and should be related to the cost development of the mining alternative.

The economics of petroleum mine design and development also should be defined more accurately than could be handled in this report as should processing, transportation and marketing of the petroleum.

5.5.3 Logistics

A logistics study would relate the location of resources to processing and refining facilities and to the major petroleum markets. It should be determined whether or not existing transportation facilities can handle the inflow of labor, materials and equipment and the transport of the resource to market.

5.5.4 Sociological

In major target areas for petroleum mining, social and socioeconomic studies can be performed to facilitate community planning, to determine the availability of a labor force and transportation facilities and to aid in an informational public relations effort.

5.5.5 Environmental

Environmental impacts from petroleum mining appear to be minimal. Nonetheless, environmental programs will more than likely be required before the development of a petroleum mine. In major target areas, or in a chosen site specific area, a preliminary environmental study compiling all existing information can be performed. A public relations effort and technology transfer meetings should be conducted for the various local citizens and environmental groups to develop acceptable environmental standards and to work out any foreseeable problems.

5.5.6 Applications of Gravity Theory

Selected secondary and tertiary recovery technology probably will be used to maximize production of petroleum by gravity drainage. Selection of the best recovery technology to use will begin with comparative calculations based on applying gravity drainage theory. Conventional radial flow theory does not directly apply to mining for petroleum, however, linear theory applies. One subject of these computations would be injection rate versus gravity drainage recovery efficiency.

5.5.7 Rate of Fluids Redistribution

Laboratory and field experiments can be performed to determine the rate of reservoir fluid redistribution in a depleted reservoir after cessation of production. It is a fact that after reservoirs have been disturbed by the various recovery techniques, the remaining fluids do redistribute themselves to reach equilibrium according to the natural laws. The results of laboratory and field experiments would materially aid in determining proper rates of gravity flow and the efficiency of gravity drainage extraction by various classes of reservoirs.

5.5.8 Literature Review

A literature search of reports and publications pertaining to major or primary petroleum mining target areas should be performed to compile all readily available data. This would help to prevent unnecessarily duplicating previous laboratory tests and field work. Rock properties and other physical information will be necessary for the reservoir, the geologic strata overlying the reservoir and the strata underlying the reservoir. Reserve base versus depth for U.S. reserves should also be compiled. Potentially mineable reserves should be compiled along with their physical character.

5.5.9 Laboratory Tests - Other

A number of laboratory tests should be performed to determine the various rock properties such as permeability, consolidation (induration) and resistance to the various kinds of stress. The internal forces on reservoir material due to the application of heat should be measured. For the Flip Flop process, lab determinations of the rate of Flip Flop at various temperatures with an array of hydrocarbons should be performed.

5.5.10 Resource Characterization

A field program should be planned and conducted to gather information on primary target areas. During conventional oil exploration little note is taken of the physical properties and character of the geologic units both overlying and underlying the reservoir. Some of this information could probably be obtained from geolograph records of drilling rates. In any case, core holes will have to be drilled to obtain samples for the rock mechanics testing required for mine design.

5.5.11 Shaft Drilling

Controlling gas, oil or water pressure during drilling is a highly refined art in the conventional petroleum industry. Fortunately, the reservoir pressures to be encountered during shaft drilling operations will be known and therefore can be taken into account. A study should be made of the mud control technology, whether a blowout could occur or pose any hazard, and if blowouts could occur how current technology should be applied to prevent or handle them.

5.5.12 Main Entry and Drifting Technology

Current tunnel boring and driving equipment is getting bigger and more efficient. Some study is needed in adapting the equipment to making short turns to side entries and for rapidly backing out of a tunneling position. The study should include drilling and reaming equipment.

5.5.13 Development of Drilling Stations

Numerous drilling stations will be required for a petroleum mine. Methods and equipment used to cut drilling stations should be fast, safe and efficient. Roof and wall stability are of prime importance, so attention must be given to the size and shape of the drilling station. Isolation of drilling stations from other tunnel workings should be studied.

5.5.14 Water Jet Drilling

Although water jet drilling is developing technology, tests should be performed aimed at increasing its efficiency, because numerous holes will have to be drilled in an underground petroleum mine.

5.5.15 Water Jet Slotting

To increase the efficiency of the application of gravity drainage for petroleum extraction, the use of a water jet to slot a drill hole in various directions from its center needs to be demonstrated. The stability of slots in various directions should be evaluated.

5.5.16 Water Jet Cavern Cutting

This, again, is developing technology and is of prime importance to the underground application of the Flip Flop process for heavy oil and tar sands. In this demonstration special attention must be given to the tool design for maximum efficiency and to the necessary on site equipment. The shape of the cavern should be related to the stability of the cavern.

5.5.17 Pressure Control Drilling

Technology exists for the control of pressures suddenly encountered during drilling. In a petroleum mine, pressure control drilling will be used for at least two applications. One is to drill the holes or wells into the petroleum reservoir from the mine tunnel, and second, to probe ahead of a tunnel to insure the safety of the tunnel driving laborers. The second application has been termed probe drilling.

A pressure control drilling demonstration should include the following factors:

1. Setting "surface" casing with cement.
2. Setting "surface" casing with packers (hydraulic, mechanical, etc.)
3. Adaptation of blow out prevention equipment.
4. Use of a turret drill to drill in any direction; up, down, or horizontally.
5. Use of short, flush-jointed drill stem.
6. Proper choice of bits or water jet technology.
7. Adaptation of reverse circulating head.

Well construction and design should be evaluated along with rapid and safe procedure for probe drilling.

5.5.18 Flip Flop Process, Surface Application

The Flip Flop process, developed by Energy Development Consultants, Inc., is a process for producing hydrocarbons from heavy oil and tar sands. The reserve selected for this demonstration should be exposed at the ground surface. The first phase of the demonstration should include the literature review, laboratory test and field data acquisition necessary for designing and planning the surface application demonstration. The second phase, of course, is to conduct and document the demonstration.

5.5.19 Flip Flop Process, Underground Application

The reserve base selected for the underground application of the Flip Flop process should lie at some depth below the surface. The overburden rock should be competent enough for cutting a stable cavern with water jet technology. The development of the demonstration should be performed in two phases as described above in the surface application.

5.5.20 Gravity Drainage by Means of Wells

A conventional liquid petroleum reservoir should be chosen that is large enough to support moving to commercial production after the demonstration. Two shafts will have to be drilled, so choosing a reservoir at a shallow depth would conserve demonstration funds. At least two working levels might be developed, a level under the reservoir and a level over the reservoir, so the various drilling combinations and recovery techniques can be demonstrated.

5.5.21 Gravity Drainage by Caving Methods

More study is needed of the potential, if any, of fracture caving, modified fracture caving and collapsed slot as mining methods applications of petroleum extraction by gravity drainage. Fracture caving is a modification of block caving methods. By exposing portions of the underside of the reservoir and inducing a controlled amount of caving, the intent is to fracture the reservoir making it more permeable. In collapsed slot or modified fracture caving, the reservoir is fractured and caved into a tunnel cut for this purpose. Again, two shafts are necessary and several modifications of fracture caving can be demonstrated.

5.5.22 Systems Engineering

The tools of systems engineering are invaluable in the development, conduct and control of any complex project. The objectives of systems engineering would be to map, structure, and schedule the program management and the functional tasks involved to complete two demonstrations, one for the gravity drainage process and one for the Flip Flop process. The final product system should be open-ended and flexible to allow the additions of unforseen but necessary subtask elements and to easily make minor changes in organization and structure.

5.5.22.1 General Demonstration Systems Structure

In a general manner, the systems engineering of the demonstrations will follow the outline of the flow chart illustrated in Figure 55. In the illustration, a demonstration project is broken into two phases, the first phase being a data compilation, evaluation and interpretation leading to the second phase which is the actual demonstration. In reality, the flow outline does not take into account work that has already been completed. Perhaps a more logical phasing from conception to a completed demonstration would be as follows:

Phase 1. A technical and economic study of oil mining (this report).

Phase 2. A technical and economic site-specific study of oil mining.

Phase 3. A field data acquisition and evaluation program coupled with systems refinement (Objective: To collect the specific field data required to conduct the demonstrations).

Phase 4a. Conduct field demonstration of drip drainage process.

Phase 4b. Conduct field demonstration of Flip Flop process.

Phase 5a. Move drip drainage demonstration to commercial development.

Phase 5b. Move Flip Flop demonstration to commercial development

The phasing of the demonstrations apparently diverge. This is because the two processes involve two different hydrocarbon targets. There should be no problem in developing the systems engineering for each process in parallel, if the same technical project team that developed both processes inputs the technical aspects concerning each process.

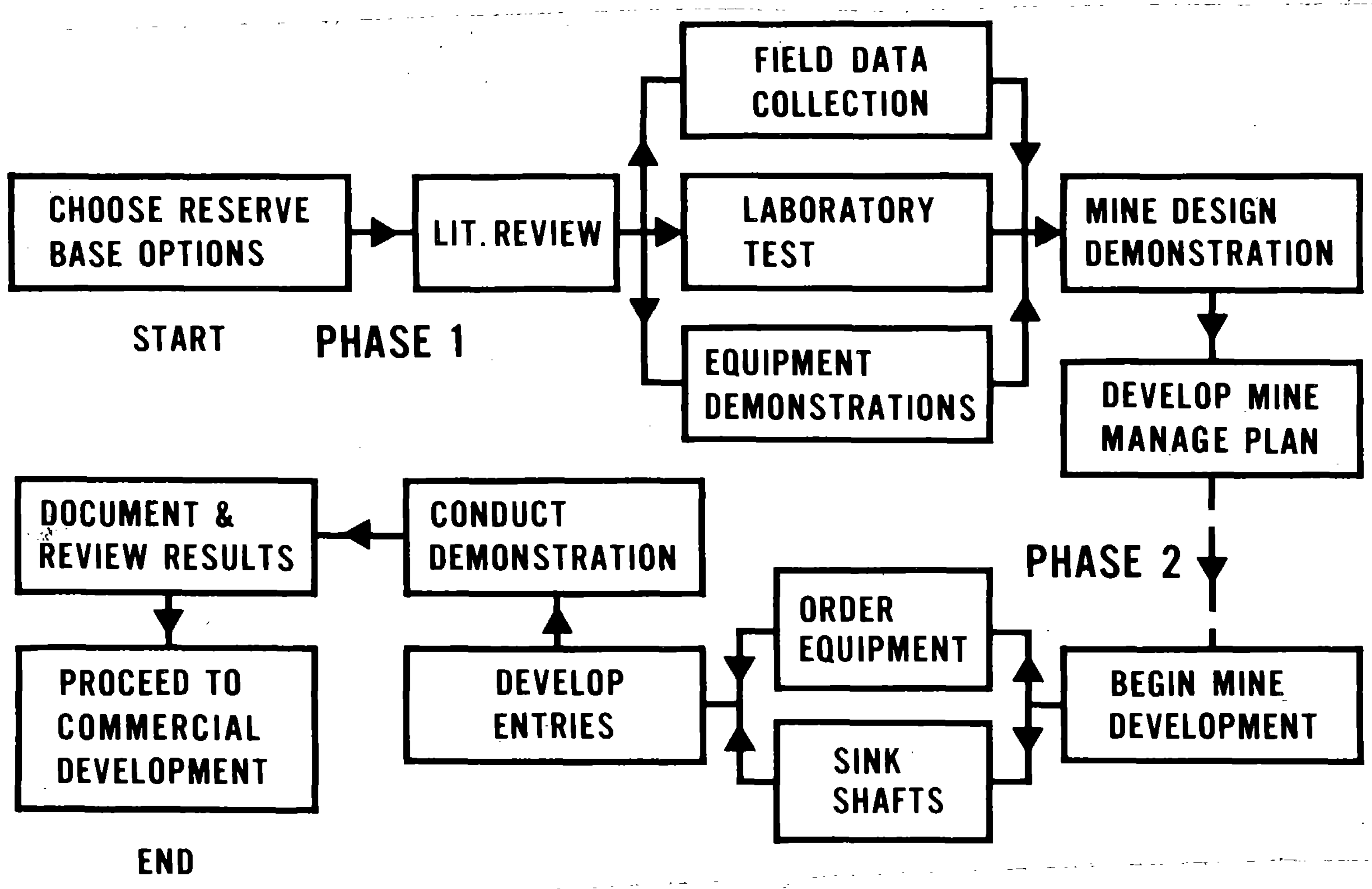

Figure 55. General flow chart for an oil mining demonstration.

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APPENDIX A

GENERAL ECONOMICS OF PETROLEUM AND OIL MINING

A.1 ECONOMIC ASPECTS OF THE OIL MINING ALTERNATIVE

A.1.1 Introduction

In 1960, a group of oil producing nations formed the Organization of Petroleum Exporting Countries (OPEC). Membership in OPEC has expanded since its formation. Members on July 1, 1978 were: Algeria, Ecuador, Gabon, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, U.A. Emirates, and Venezuela. According to their own Statutes, the primary purpose was "...the coordination and unification of the petroleum policies of Member Countries and the determination of the best means for safeguarding their interests, individually and collectively." In other words, the OPEC group had decided to control their own oil destiny. The emergence of OPEC and that organization's subsequent oil price and supply manipulations has demonstrated the importance and vulnerability of the United States' energy sector. With our large dependence on foreign oil, the U.S. is susceptible to both political and physical oil supply shortages. We do not control our oil destiny.

Oil mining is a currently untapped procedure that could have substantial impact on the U.S. energy destiny. The cost of the petroleum resource obtained by this method is not higher; it is competitive with other energy alternatives. Oil mining has the economic advantage of yielding a product that is already useful in domestic energy-consuming processes. In addition, there already exists a petroleum transportation, processing, and distribution system. Oil mining must be considered for a place in the future supply of U.S. domestic energy. Oil mining alternatives would have a positive effect on balance of payments as well as domestic employment and income. The concept of oil mining is still in a preliminary stage. A great deal of additional work, especially detailed cost studies, mine design, and pilot plant operation will be necessary before the economic viability of the concept is proven.

A.1.2 Oil as a Non-Renewable Resource

Like any other product of value, petroleum has certain physical and economic characteristics that places limits on its production and pricing. The first, and perhaps most important factor, is the depletability of petroleum resources. Oil is found only in certain geologic environments. Its formation takes place over millions of years, so there is no immediate replacement for that which is produced and consumed. As a result, world oil supplies are diminishing irretrievably as petroleum production continues. Sooner or later, nations or districts that derive important income from oil revenues must adjust to a declining production base. Recognizing that there is a finite limit to petroleum reserves in any geographical area, a producer (corporate or state) must decide on a rate of production that will maximize its benefit from the resource. In many cases, this optimal production rate will be less than the maximum rate possible. Not only are slower rates likely to increase the total recoverable resources, but they may be necessary in order to assure a district of an evenly-spaced, long lived economic base. Developing countries are especially anxious to achieve a production rate that will bring in much needed foreign exchange without swamping the local economy with funds.

Another characteristic of the petroleum resource is the geographical limitation placed on its extraction. An oil field located in Alaska must be produced in Alaska. However, from a market price point of view, oil is oil, regardless of its point of origin. Hence, a low-cost producer sells at the same price as a high-cost producer and obtains a substantial profit advantage. In remote areas, offshore oil fields, or fields where very deep drilling is required, oil reserves must be substantial to justify production at current prices.

Under perfect conditions a mineral commodity is priced according to its supply and demand. In an ideal situation, where commodity production may be quickly expanded or contracted to match consumption, the price of a resource such as oil is determined by a worldwide supply and demand function. A fundamental assumption of the supply/demand model is that consumers, when faced with rising prices, will reduce their consumption until equilibrium is once again achieved. If, for any reason, consumers do not correspondingly reduce their demand as prices increase, this economic mechanism will not stabilize prices. During a time of shortage, should people not reduce consumption significantly as the price is increased, supply cannot meet the demand and the price could rise almost without bound. In these situations, the producer of the resource is in a powerful position since there are few market pressures to control the price he charges for his product. A characteristic of fuels is inelasticity in demand with respect to price. A tight supply-demand situation is likely to promote drastic increases in price. There are few or no substitutes for oil, and with many products crude petroleum is a small component of total cost. Thus prices go up, demand does not diminish proportionally, and the resulting impact on the balance of payments can be catastrophic.

The 1973 oil crisis and subsequent price increases were not totally unpredictable. The future potential of such events re-occurring are high. Some of the factors that contributed to the dramatic 1973 price increases and the embargo include cost, supply, demand, and political trends of the pre-embargo years. These factors, in combination with the economic characteristics of oil as a non-renewable resource, are worthy of further discussion.

A.1.3 Energy, Oil and the U.S. Economy

The bulk of the oil consumed in the U.S. is used for energy. In 1974 approximately 85% of the United States' petroleum consumption went to energy use. The bulk of the remainder went to industrial and chemical products.

such as plastics and food packaging. Since energy is the most important use for petroleum, it is within this sector that the future of overall oil supply and demand rests. In 1978 oil made up 48% of the United States' energy supply.

Table 25. 1978 U.S. energy consumption pattern. (Exxon, USA Energy Outlook, May 1978).

	Percent of Total Mid-1978 U.S. Energy Consumption
Oil	48%
Gas	27%
Coal	18%
Nuclear	3%
Other	4%

Of the United States energy that is supplied by oil, the major portion goes to transportation. This is a significant fact, because other fuels are not readily capable of substituting into this important sector of petroleum consumption.

The level of future petroleum demand for energy will depend on several factors. First, the growth of the U.S. population and the U.S. economy. Second, the ability of substitutes to replace petroleum in a wide variety of energy applications. Use of these alternatives is especially dependent on the price and effectiveness of the alternatives versus oil. Third, the speed at which the technology associated with the potential substitutes may be developed and implemented. Fourth, the degree to which the consuming public may or may not be reduced to a lower living standard. Many other events could also affect the future level of U.S. energy consumption, including U.S. military involvements, foreign cartel actions, the magnitude of energy research funding, artificial restraints on nuclear energy development, regulation affecting the speed and extent of mined energy sources such as coal, and others. It may well be that a factor presently considered minor will be a major determinant of future energy consumption. If nothing else, the 1973 oil boycott has taught the U.S. not to be complacent in energy matters.

Historical data shows that there is a close, consistent correlation between U.S. domestic energy consumption and Gross National Product. Surprisingly, the level of energy consumption as expressed in terms of living standard is no greater in the U.S. than in Western Europe and Japan, areas often considered more frugal than the United States. From 1955 to 1975, U.S. energy use remained consistently between 11-12 million barrels of oil equivalent per billion 1970 dollars of GNP. In 1970, the U.S. consumed 32% of world energy and accounted for 31% of the world's GNP. The implications of the close correlation between U.S. GNP and energy consumption are clear. First, any national move away from energy use, without prior economic preparation, could result in a drop in national income. Second, unless the structure of the U.S. economy is changed, future disturbances in the U.S. energy supply will have a corresponding affect on the economy. The first of these implications is difficult to verify, for energy consumption decreases and economic recession are so interrelated that the affects of energy shortages on GNP are debatable. The Chase Manhattan (September 1976) reports that there is no indication that we could produce a billion dollars of GNP with any less energy and the trends of U.S. energy per unit of GNP certainly corroborate this. The second implication, that the economy must be adversely affected by energy shortages or real price increases, has already been demonstrated in 1973 and 1974.

If the United States is not as wasteful of energy as we sometimes believe, the potential of conservation must be approached cautiously. There is certainly energy waste in the United States economic system, but if our energy consumption is comparable to worldwide demand on a GNP basis, then the waste is probably not as great nor as extraneous to the economy as we believe. An unplanned move to reduce our trade imbalance through conservation, could have an unexpected impact on the economy. To illustrate this, consider the different possibilities that could come out of an unprepared conservation effort. Total U.S. income is proportional to the national consumption less imports. If U.S. citizens suddenly cut gas consumption by 10%, these consumers are likely to spend the additional savings in other economic sectors, increasing profits and opening up employment opportunities in industry unrelated to gas consumption. Simultaneously, a number of filling station owners and attendants, tourist-related businessmen, longshoremen and others related to oil importation, and other operating in the gasoline sector will lose their jobs. Imports would be reduced somewhat as less petroleum is used, reducing the outflow of funds from the U.S.

If labor resources were interchangeable and would flow instantaneously from sector to sector, such a conservation move could improve the economy by decreasing imports. In a real-world imperfect economy the affects of such conservation measures is less clear. Small businessmen catering to tourists, filling station owners and attendants, and dockworkers will not necessarily be employable in the newly favored industries. If these people accept lower-paying jobs or unemployment their incomes will drop. The expenditures made by the consumer could place too much demand on selected industries, resulting in inflationary rather than real growth. Eventually the slow-moving economic factors could readjust themselves, but the timing and certainty of such a readjustment would be virtually impossible to calculate. The situation is so complex that a prediction of the change in magnitude and direction of consumption, hence national income, is impossible. There is no reason to believe that lessening imports will compensate for the potential losses in domestic consumption.

Future moves toward conservation or the development of alternative sources of U.S. energy should be well planned. The effects of a changing energy industry will be best controlled if the programs are implemented over as long a time period as energy supply and demand permits. To ignore the importance of conservation and alternative energy source development would be foolish, for such a near-sighted approach ignores the very real risk of our present energy path. However, a sudden unplanned emotional jump into an alternative energy or conservation program could result in very real damage to the U.S. economy. The more slowly we can perform the necessary changes to our energy program, the more we can prepare for and absorb the economic displacement that will result. Oil mining could provide the buffer between the present energy system and the system of the future.

A.1.4. Political and Economic Events Prior to the 1973 Oil Crisis

Table 26 shows that prior to 1973, oil prices had not increased significantly for many years. Oil was not only an inexpensive energy resource, but held an esteemed position in the growing manufacturing/chemical industries. As a result, U.S. petroleum demand had expanded steadily. As with any mineral commodity, low-cost occurrences were developed first.

Table 26. U.S. crude oil price and demand, 1964-1972. (Pre-Arab embargo)

Year	US Price Actual Price	US Price Constant (1967)	US Constant Dollar Price Change from Previous Year	US Demand (mil. bbls.)	Demand Change from Previous Year
1964	$2.88	$3.11	-2.3%	4,034	+2.9%
1965	2.86	3.03	-2.6%	4,202	+4.2%
1966	2.88	2.97	-2.0%	4,411	+5.0%
1967	2.92	2.92	-1.7%	4,585	+3.9%
1968	2.94	2.83	-3.1%	4,902	+6.9%
1969	3.09	2.83	0	5,160	+5.3%
1970	3.18	2.77	-2.12%	5,365	+4.0%
1971	3.39	2.82	+1.8%	5,553	+3.5%
1972	3.39	2.73	-3.2%	5,990	+7.9%

Despite the usefulness of petroleum, low foreign prices discouraged development of U.S. oil reserves. Production of oil fields continued, draining low cost U.S. reserves. New oil supplies were not so readily discovered and exploited. This fact combined with unattractive prices to decrease the relative amount of petroleum exploration and development that was carried out within the U.S. During this pre-1973 period U.S. production leveled off. U.S. consumption was bouyed along by rising GNP and stable prices.

Demand increases were steady and outpaced prices, which actually declined when measured on a real basis. Rising U.S. demand, combined with leveling U.S. oil supplies, necessitated increased U.S. imports of oil. This is shown in Table 27.

Table 27. U.S. oil import requirements, 1964-1972. (Pre-Arab embargo)

Year	US Production	US Demand	Import Requirement Demand Production	% Demand Met By Imports
1964	2,796,822	3,613,558	816,736	23
1965	2,848,514	3,749,286	900,772	24
1966	3,027,763	3,966,925	939,162	24
1967	3,215,742	4,141,743	926,001	25
1968	3,329,042	4,368,411	1,039,369	24
1969	3,371,751	4,527,302	1,155,551	26
1970	3,517,450	4,765,512	1,248,062	26
1971	3,453,914	4,886,794	1,432,880	29
1972	3,455,368	5,190,682	1,735,314	33

Values are shown in thousands of barrels. Total demand includes crude oil, condensate, and natural gas liquids (Petroleum Institute, 1975).

Not only were physical factors leading the U.S. to the 1973 energy crisis, but political signs were also pointing in that direction. The first modern oil-related problem was the 1956-57 Suez oil emergency. Nasser-led Egypt, backed by Soviet money and aid, nationalized the Suez Canal. For three months the canal was closed, and the U.S. established a committee to investigate alternate oil supply and transportation routes. In 1956 the U.S. produced 81% of its petroleum demand.

Throughout the 1960s OPEC countries gradually renegotiated agreements with the foreign companies which owned and controlled most of their production. In general, the new regulations directed more sizeable revenues to the host countries, and required local participation in petroleum projects. State-owned oil companies were established to work with the foreign firms. Much of this activity proceeded quietly, causing little alarm within the U.S. populace. Gasoline prices, probably the average American's most frequent contact with oil product economics, remained fairly stable.

In 1967, the U.S. had another brush with mideast oil politics. As in 1956, the Arab nations involved in the oil boycott were engaged in hostilities with Israel. The rapidly deteriorating military situation prompted certain Arab nations to attempt a boycott as an application of economic pressure against nations deemed pro-Israel. The boycott was evidently a result of the war, not a carefully planned course of action. In 1967, the U.S. was producing 70% of its petroleum demand.

A.1.5 The 1973 Oil Crisis

On October 15, 1973, OPEC really awakened the world to its existence by raising the price of "marker" (Saudi Arabian light No. 34 crude) from $3.01 to $5.12 per barrel. Market panic bidding pushed the prices even higher, with spot prices going as high as $20.00 per barrel, and finally OPEC responded to the situation by a further increase to $11.65. Subsequent posted increases have inflated this price to a July, 1977 level of around $13.50. (Prices vary somewhat depending on oil quality and source.) Recent estimates place the mid-1978 cost of OPEC oil, including transportation to the U.S., at $14.57 per barrel.

In addition to the 1973 oil price hikes, the U.S. found itself facing another politically-induced mideast oil embargo. When the embargo occurred, the U.S. was only producing 62% of its oil supply. The immediate affect was a temporary petroleum shortage in the U.S., possibly affecting oil supply 12-15 percent. U.S. car sales dropped, and spotty oil product shortages placed considerable inconveniences on the U.S. public. Gasoline lines were also a nuisance. The psychological reaction to the shortage may have been as significant a factor in reducing supplies as the embargo itself.

A1.6 Lingering Effects of the 1973 Oil Crisis

Certain effects of the 1973 embargo and the accompanying oil price increases have been long-lasting. One of the most significant of these is the realization by growing numbers of American officials and laymen that our energy resources, oil in particular, are not of infinite supply.

Economic consequences of rising oil prices and the 1973 embargo include balance of payment problems, world asset redistribution, U.S. domestic asset redistribution, inflation, recession, and the costs of conversion to alternate resources. Each of these is important, and justifies further discussion.

As of mid-1978, the balance of payment problems facing the U.S. are of mounting concern. The steadily rising dependency of the United States on foreign imported oil, combined with oil price increases, has created a tremendous drain of U.S. dollars to oversea oil producers. Between 1970 and 1976 U.S. imports, shown in Table 28, not only increased dramatically but shifted heavily in favor of the oil exporting nations.

Table 28. U.S. imports of crude materials and fuels.
(Millions of Dollars)

Year	Fuel and Crude Materials Imports	Total Imports	Total Imports from Petro. Exporting Countries	Fuel and Crude Materials % Total Imports	Imports from Petroleum Exporters % Total Imports
1970	$ 6,542	$ 39,952	$ 2,516	16%	6%
1971	7,268	45,563	3,060	16%	7%
1972	8,838	55,583	3,729	16%	7%
1973	13,446	69,476	6,309	19%	9%
1974	31,842	100,251	20,488	34%	20%
1975	32,596	96,116	21,417	24%	22%
1976*	37,700	119,220	28,600	32%	24%

*Estimate, based on 11 months data

Source: Economics Report of the President, January 1977.

A2 THE IMPACT OF U.S. OIL EXPENDITURES

A2.1 U.S. Trade Imbalance

The significance of the U.S. oil expenditures has become more and more apparent in recent months. Until late 1975, the spiraling U.S. foreign trade bill was offset by equally impressive export increases. Then, in early 1976, the U.S. began to register substantial trade deficits. Aided by slumping U.S. grain sales, slight monthly deficits starting in Feburary 1976 had mushroomed to a $2.8 billion dollar deficit in June, 1977. The mounting trade deficits resulted in the decline of the dollar against other major industrial currencies.

By mid-1977, the dollar had declined 1.9% against the Japanese yen, and 2.9% against the German mark. The impact of more 1978 declines are being felt around the world, and they could well result in a straining of relations between the U.S. and other major industrial nations. As the dollar falls, foreign products became more expensive relative to American goods. This ultimately increases the flow of American exports and reduces the amount of imports flowing into the U.S. This situation is very unpopular with the other major industrial nations that are involved in trade with the U.S.

Otmar Emminger, quoted in <u>Business Week</u>, August 8, 1977: "The U.S. deficit is mainly due to the enormous increase in the oil deficit of the United States and also to a large increase in the trade deficit vis-a-vis Japan."

Emminger's concern was that the United States, facing an estimated 1977 deficit of $25 billion, would try to recoup some of this loss by reducing imports from Europe. If successful, this would slow European economic growth. This slowdown could become worldwide if OPEC, responding to the devalued dollars they receive, further increased the price of oil. The situation was judged critical enough that, on July 11, the Bank of Japan began buying dollars to slow the currency's decline. Germany, depending on exports for 25% of the GNP, also began dollar purchases. There seems to be no question that the ongoing cause of the deficit is oil expenditures. Emminger considers extravagant use of oil by the U.S. the major problem, and he is not alone. It has been calculated that 70% of the 1976 U.S. movement into deficit was caused by oil imports. If it were not for an estimated 1977 foreign oil bill of $45 billion, the U.S. would have a large trade surplus of $20 billion for the year. The total 1977 trade deficit was $26.7 billion.

The resolution of the U.S. trade imbalance will not be simple. Already, Japan, Germany and other industrialized nations have expressed discomfort at U.S. efforts to reduce the outflow of funds. From the point of view of the United States, the outflow represents money lost from the economy; unless the leak is plugged, national incomes could drop. There is no doubt that the political tensions created in this type of situation could become increasingly acute. The United States cannot continue to operate in a large trade-deficit situation indefinitely without a major economic readjustment taking place.

A.2.2 Inflation

Inflation has also been a result of the OPEC price hikes, although the precise inflationary contribution is debatable. The Department of Energy (old FEA) estimates that a .4% increase in the Wholesale Price Index would result from a 15% increase in oil costs. Assuming a comparable price/inflation sensitivity can be projected back to 1973, the OPEC increases since that year could have cost the world approximately 10% in total inflation. U.S. prices have increased over 40% since 1972. By this estimate, oil increases have amounted to almost ¼ of the total inflation bill.

Not all observers credit OPEC price increases with that much inflationary impact. A smaller figure is developed in World Oil (Merklein, 1974), who estimated the total inflationary impact of the 1973/1974 price hikes at 2.4%. By extrapolation, price hikes since then would have brought this value up to approximately 3% by 1978. Although there is a tremendous difference between these and the many other fuel-related inflation estimates that exist, there is total agreement that oil price increases have contributed significantly to world inflationary problems. The impact of oil-based inflation is perhaps better illustrated by noting that just 1% of inflation cost the United States GNP $16.9 billion in real-dollar value in the year 1976.

A.2.3 Oil Induced Recession

In 1974 the world was plunged into a recession, an economic slump from which some nations still have not recovered. The degree to which this economic recession was oil-induced is, much like the inflationary affects, controversial. In 1974 and 1975, the United States experienced a drop in real gross national product, breaking a long established trend of growth as shown in Table 29.

Table 29. U.S. GNP, both actual and constant values, 1972. (Millions of Dollars)

Year	Actual U.S. GNP	U.S. GNP Constant 1972 Dollar	Oil Revenues Sent to Oil Exporting Countries
1970	$ 982.4	$ 1075.3	$ 6,542
1971	1063.4	1107.5	7,268
1972	1171.1	1171.1	8,838
1973	1306.6	1235.0	13,446
1974	1413.2	1214.0	31,842
1975	1516.3	1191.7	32,596
1976	1692.4	1265.0	37,700

The domestic GNP and the 1970-1976 U.S. foreign oil bill. Economic recession is apparent in the constant-dollar column. Note the correlation between the U.S. recession and the heavy foreign oil debt (Economic Report of the President, January 1977).

If the OPEC price increases were not the cause of the world recession, they undoubtedly were a significant contributing factor. One publication (Business Week, Jan. 10, 1977) estimated that OPEC pricing induced a $550 billion world output loss over three years. During the same period, lesser developed countries saw their external debt swell by $170 billion.

A2.4 Cartelization of Other (non-oil) Commodities

Business Week placed the cartel's impact on the 1977 U.S. economy at a loss of $75 billion in GNP, $90 billion in disposable income, and 3 million jobs. These figures are the total losses accumulated from three years of oil price increases. The United States and the rest of the free world had little choice about the timing of the OPEC price hikes. At a time when world economies could least afford it, they had to absorb a drastic increase in world oil prices.

Lesser developed countries (LDCs) that could hardly afford sudden high petroleum bills were severely hit by high oil prices and recession. Undeveloped countries throughout the world depend on the oil exporting countries for petroleum. However, in many cases these LDCs have little foreign exchange to help pay for or absorb high oil-related debts. In their desperation to rebalance serious foreign exchange problems, these countries have formed cartels that now involve many assorted products. They often depend on a few raw materials for the bulk of their exports. As a consequence, OPEC-type price agreements have sprung up for many commodity products. The OPEC example is a major factor in the activities of these cartels. As a result, the industrialized nations, including the United States, have not only paid directly for the price increases of their own oil imports, but indirectly have paid toward the oil debts incurred by poorer nations.

One example of a non-oil cartel with some power is one formed by the buaxite producers. This organization has initiated a number of substantial bauxite price hikes. Jamaica, prompted by OPEC's success and by a rapidly accelerating energy bill, adversely affected U.S. industry by raising bauxite prices.

An important economic effect of oil revenue flowing into the oil exporting countries is the redistribution of international money holdings. Even without 1977 oil price increases, oil revenue was drainaing into OPEC at a rate of $100 billion/year. The United States paid $34.6 billion to foreign nations for petroleum and related products in 1976, most of which went to OPEC, and in 1977 this figure rose to $43.8 billion.

A2.5 Shifts in Wealth and Power

The economic power gained by the recipients of these funds is enormous. In late 1974 it was calculated that OPEC's expected income could buy the entire Fortune 500 list of America's largest corporations in only 6 years. Many oil exporting countries do not have the internal economic structure to absorb this money, and must invest it internationally. This has the benefit of recycling some of the money back to where it originated. However, such massive revenues provide the oil exporting nations with economic ammunition to use in international political and financial dealings. Certain OPEC nations, opposed to the state of Israel, boycotted international companies that dealt with their foe. The 1973 U.S. oil embargo was similarly induced. This transfer of wealth, and the associated transfer of power, has been described by the Chase Manhattan Bank as the major cause of long term damage being done to the oil importing nations.

Not only are international monetary balances being upset rapidly by high oil prices, but U.S. domestic money is also susceptible to redistribution. Certain states and local areas that have long depended on oil production for a substantial economic base are finding that their reserves are declining. Industries previously attracted to the area by cheap, available petroleum may shift to other areas. An example is Louisiana, a state long dependent on petroleum and gas resources for internal use and state revenues. In the early 1970s declining production and long-term out-of-state commitments caused an "energy gap" between in-state supply and demand. Louisiana is now forced to change both its tax-base structure and its energy sources. In the case of Louisiana, alternate or imported fuel sources and increased personal taxes will probably have to fill the energy and economic gaps. The expected energy demand in Louisiana showing the energy gap is illustrated in Figure 56. Increased recovery from previously exploited fields could significantly improve Louisiana's internal energy situation.

Another sector of America's domestic economy that is especially hurt by increasing foreign importation is the independent gasoline refiners and marketers who are less capable of obtaining alternate supplies. This was demonstrated by the 1973 petroleum shortage. As further emphasis is placed on foreign petroleum development, the independents are likely to have continuing problems obtaining supplies. Despite various forms of government protection, many weaker operations closed in 1974.

Gas retailers were particularly hurt during 1973 and 1974. The petroleum product shortages resulted in lower sales, forcing many to eliminate extra services. The sudden increase of gasoline prices caused many consumers to go to cheaper "self serve" stations, resulting in a shift industry-wide away from the more employee-intensive "full service" outlets.

A.2.6 Indirect Impacts

Certain fuel-dependent industries were also seriously affected in 1974. The U.S. automotive sales slump was certainly deepened by the threat of gasoline shortage or spiraling prices. The airline companies are especially affected by fuel price increases. In 1976, the Air Transport Association of America estimated that a 20% OPEC crude oil price increase (equal to an increase of \$2.40/barrel) would cost the airlines \$1/2 billion dollars, a figure that would exceed their entire 1977 profits.

U.S. governmental regulations attempt to de-emphasize the selective effects of fuel price increases. As yet, no legislation has eliminated the inherently selective impact of increasingly costly petroleum. Poorer citizens must sacrifice more than the wealthy in order to pay their portion of rising energy costs. Companies with substantial petroleum inputs face higher risks of recession, lost profits and layoffs. These problems are compounded for the United States by their lack of control over the timing of OPEC price increases.

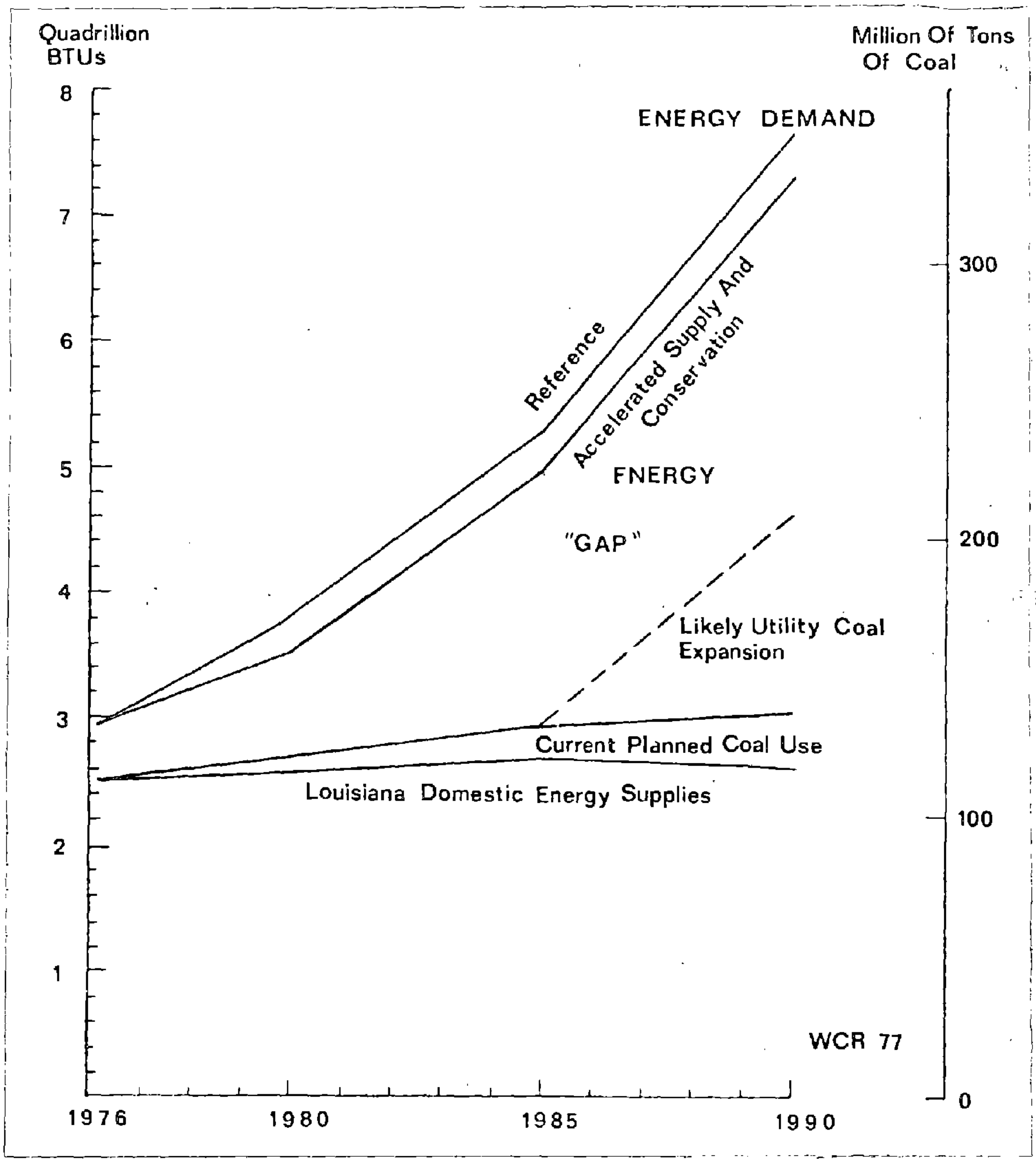


Figure 56. Expected energy demand in Louisiana showing the energy gap.

A.3 U.S. PETROLEUM SUPPLY AND DEMAND TRENDS 1973-1977

Since 1973 the United States petroleum demand has risen despite a brief slump. The 1973 OPEC increases combined with overall world recession to temporarily depress petroleum consumption. Projected U.S. 1977 consumption estimates indicate that petroleum demand shown in Table 30 is again increasing at rates typical of the pre-embargo years.

Table 30. U.S. petroleum demand, production, and import figures, 1972-1977. (Millions of Barrels)*

Year	U.S. Demand	U.S. Production	Imports	% Demand Imported
1972	5,990	4,094	1,735	29%
1973	6,297	3,995	2,283	36%
1974	6,073	3,818	2,231	37%
1975	5,947	3,648	2,199	37%
1976	6,158	3,520	2,638	43%
1977	6,457	3,553	2,904	45%

*Figures from World Oil, Feb. 15, 1977. 1977 values are estimates. The projected U.S. production increase in 1977 reflects the initial arrival of Prudhoe Bay (Alaska) oil.

Production includes natural gas liquids. Due to miscellaneous inputs, production plus imports do not necessarily equal total U.S. demand. The combined effects of the 1973 oil price increase and the 1974 world recession are apparent in the demand figures. Years 1972, 1973 are based on Bureau of Mines data Years 1974, 1975 are based on data from the Petroleum Institute.

The United States is now importing around 50% of its oil, and the certainty of this supply is of paramount importance. These suppliers include relatively recent exporters to the U.S. as well as a number of traditional ones. However, there is little reason to believe that the United States' traditional oil suppliers may be depended upon in a time of crisis. Unquestionably, all of the suppliers of U.S. oil imports are going to work in their own interest first. Venezuela, long a source of U.S. imports, was an original force in OPEC's formation. Although OPEC is often thought of as an Arab cartel, it is a fact that non-Arab Iran is a price "hawk" compared to the more moderate Saudi Arabia. Canada, long considered the United States' staunchest ally, has already reduced its exports to the U.S. in order to preserve its own fuel supplies. In the event of future oil pinches, history has shown that the U.S. cannot depend on the goodwill of any of her oil suppliers.

Table 31. U.S. sources of petroleum imports, % of Total U.S. Imports.

Source of Import	Last 3 Months 1977	First 9 Months 1976	12 Months 1975	12 Months 1973
Saudi Arabia	14%	23%	17%	14%
Nigeria	12%	19%	18%	14%
Indonesia	6%	10%	9%	6%
Venezuela	7%	4%	10%	11%
Canada	6%	8%	15%	31%
Iran	6%	6%	7%	7%
Others*	49%	30%	24%	17%

*Including Algeria, Libya, United Arab Emirates, Trinidad and Mexico. (Economic Report of the President, 1976 plus 1977 data from DOE)

Simultaneously, total imports of petroleum are increasing both in real terms and as a percentage of U.S. consumption. Future projections indicate a further drift to dependency on OPEC nations, especially Arab, for petroleum imports.

A.3.1 U.S. Supplies in the World Setting

The United States has long been a nation with large petroleum resources. Recently, significant world-wide exploration has combined with high U.S. production rates to reduce the importance of the United States as a holder of world reserves as shown in Table 32.

Table 32. U.S. and World petroleum reserve status. (Millions of Barrels) Source: API

Year End	U.S. Recoverable Petroleum Reserves	World Recoverable Petroleum Reserves	U.S. % of World Reserves
1949	22,028	68,197	32.3%
1959	31,614	290,035	10.9%
1969	29,710	530,534	5.6%
1974	34,196	712,418	4.8%
1975	32,682	657,921	5.0%
1976	30,942	640,090	4.8%
1977	29,486	645,805	4.6%

The dramatic decline of the relative importance of United States reserves is accompanied by an increasing dependence of the U.S. on world oil production. Perhaps another consideration of world petroleum distribution is the amount found with the so called central economy nations, especially the U.S.S.R. As of 1976, the central economy countries held 16% of the world's petroleum reserves, as compared to 5% for the U.S. The U.S.S.R. is currently self-sufficient in petroleum and ranks as the world's largest producer. Strategically, there is no doubt that the Soviet Union is in a more solid position in respect to oil than is the United States. Even though some projections indicate that the USSR may soon have to import oil, they certainly are far from demanding the amount of foreign oil that the U.S. is already consuming. For strategic reasons the relative superiority of the USSR over the United States in terms of petroleum is a matter of some concern.

A.3.2 Increasing Costs of Exploration and Development

Both world and U.S. reserves appear to be declining despite increased exploration for new supplies. Cost increases characterize all areas of petroleum exploitation, including exploration, drilling, and capital expense. Drilling costs are rising substantially as oil wells move offshore and go to greater depths. Since 1960, the average cost per well has risen from approximately $55,000 to $155,000 in 1974 (See Figure 57). The National Consumer Price Index (CPI) rose from 76.3 to 127.0 during the same period, a substantially smaller increase.

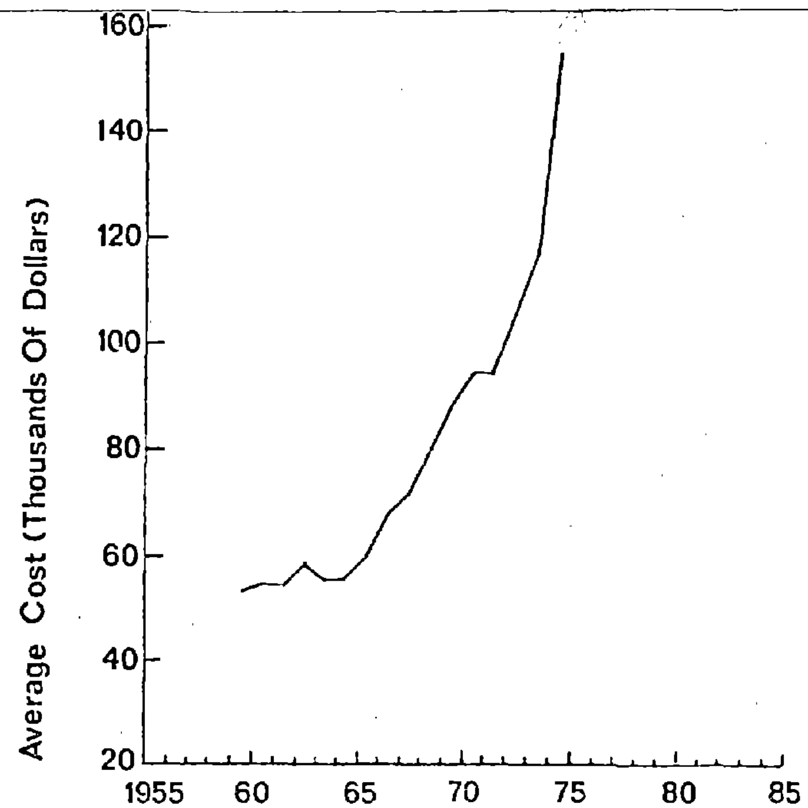


Figure 57. Cost of average well drilled in the U.S. 1960-1974. (Larue, 1975).

During the same 1960-1974 period, profits and drilling declined in the United States. The declining constant-dollar price of oil drove oil company return of investment down to a minimum in the early 1970s. The price jump initiated by OPEC brought the industry return on investment back to the 10-15% range required for heightened drilling levels. This is shown in Figure 58.

The rising costs of developing new oil in the United States are becoming a major factor in the economics of secondary oil recovery and alternative energy sources. Calculations show that the total cost of oil in 1973 was \$8.75 per barrel, based on a 15% DCF-ROR. This figure was up from \$4 just ten years previously, and climbed an incredible 45% to \$12.75 in 1974.

Data published by the Chase Manhattan Bank shows similar cost increases in the exploration/land acquisition phase of petroleum exploitation as shown in Table 33.

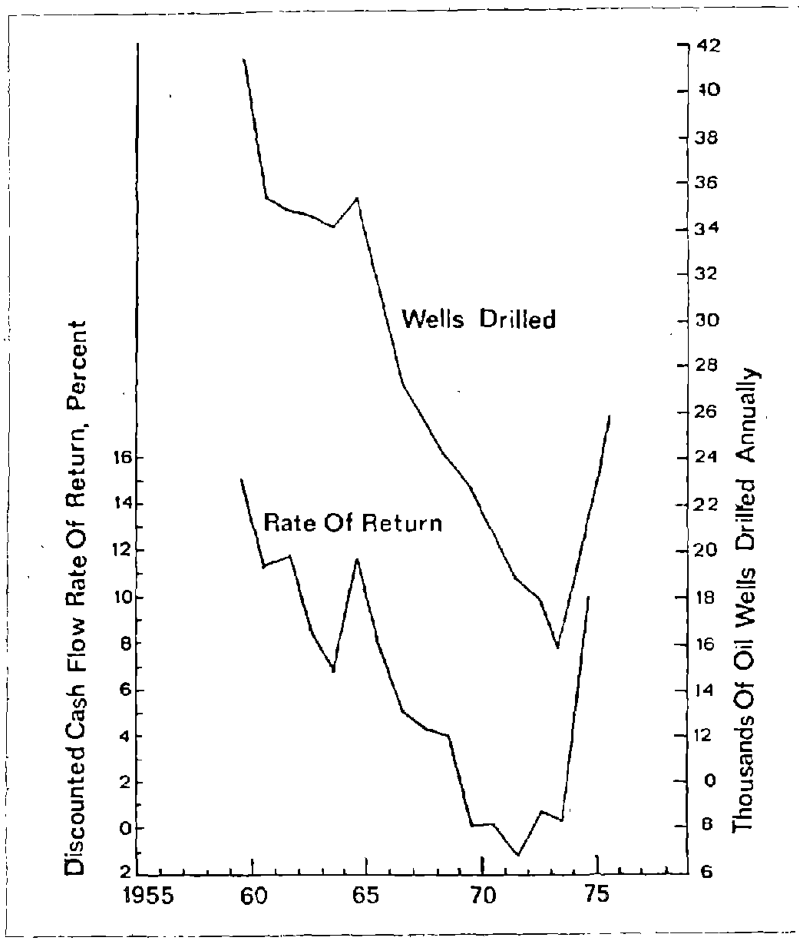


Figure 58. U.S. oil industry return on investment and wells drilled 1960-1975. Wells drilled do not include Prudhoe Bay, Alaska. 1975 data is projected (Larue, 1975).

Courtesy of Laru, John D., The Rising Cost of New U.S. Oil Reserves, 1959-1975.

Table 33. U.S. geological, geophysical, and lease rental expenses vs. U.S. oil production.

Year	U.S. Geological Geophysical and Lease Expenses	U.S. Petroleum Production	Expense Per Barrel of Production	Expense Per Barrel of Added Reserves
1950	$ 300	2,156	$ 0.14	$0.12
1955	625	2,766	0.23	0.22
1960	625	2,915	0.21	0.26
1965	610	3,291	0.19	0.20
1966	650	3,496	0.19	0.22
1967	615	4,730	0.16	0.21
1968	715	3,879	0.18	0.29
1969	725	3,952	0.18	0.34
1970	665	4.123	0.16	0.05*
1971	715	4,072	0.18	0.31
1972	740	4,094	0.18	0.47
1973	850	3,995	0.21	0.40
1974	1,130	3,819	0.30	0.57

*Low 1970 value represents large addition of Alaskan oil reserves. The expense/barrel of production is shown as a relative indication of costs, although it must be noted that exploration expenses incurred in any one year may not result in production until some future date. The expense per barrel of reserves added to the U.S. supply is a more significant figure. Expense values are in millions of dollars; production is in millions of barrels (derived from American Pertoleum Institute, 1975, and the Chase Manhattan Bank, 1975).

A.3.3 Future Projections of Petroleum Supply and Demand

There are a large number of future projections for petroleum supply and demand. The projections vary widely depending on the assumptions used in each model.

A.3.3.1 Future Supply

The primary factors controlling future oil supplies are petroleum prices, new petroleum discoveries, improvements in oil recovery technology and methods and the economics of producing petroleum from presently untapped sources such as oil shales. Table 34 lists estimates of reserves and undiscovered petroleum resources.

Table 34. Reserves and undiscovered petroleum resources.
(Billions of Barrels)

Region	Reserves: Demonstrated: Measured	Reserves: Demonstrated: Indicated	Reserves: Inferred	Resources: Undiscovered Statistical Mean	Resources: Recoverable 95%-5% Range
Economic Resources*					
Lower-48 Onshore	21.1	4.3	14.2	44	29-64
Lower-48 Offshore	3.1	0.4	2.6	18**	11-28
Alaska Offshore	0.2	0	0.1	15	3-31
Alaska Onshore	9.9	***	6.1	12	6-19
Subtotal-Economic	34.3	4.7	23.0	89	50-127
Sub-Economic	120	***	20	57	44-111

*Economic at pre-embargo prices.
**Adjusted for resources at water depths greater than 200 meters.
***Negligible

Measured, indicated, and inferred reserves are located in known areas. Resources are speculative, but based on geological potential and known discovery patterns. The 95%-5% confidence range lists the barrels of petroleum as yet undiscovered, for which there is a 95% and a 5% chance of recovery (F.E.A., 1976; originally in U.S.G.S. P.P. No. 725).

Under present economic conditions (new crude oil is currently bringing about $12.50/barrel) the known U.S. petroleum reserve is 30 billion barrels recoverable. Depending on future price trends and the number of discoveries in presently untested areas, the ultimate U.S. reserve picture will range from 135-223 billion barrels. Recent trends of discovery do not encourage much optimism. Accelerated exploration on the outer continental shelf (OCS) has not yielded the reserves expected. The OCS has been considered the best prospect for significant future U.S. oil discoveries.

Another potential source of future U.S. reserves is Alaska. Recent estimates place the 1985 producing potential of Alaska between .70 and 1.8 billion barrels per year. This is a significant contribution but is far from enough to offset U.S. supply deficits. Long-run Alaskan production rates are still uncertain, but probably will not exceed the near-term projections.

Worldwide, exportable oil reserves will become increasingly concentrated in a few geographical areas. As of 1975, world estimates in placed 23% of the total oil reserves in Saudi Arabia, and more than 50% in the mideast. OPEC holds almost 2/3 of the oil presently considered recoverable.

As important to future oil economics as reserve distribution is the general lack of oil in most countries that have high petroleum demand. Of the world's more industrialized nations, only the U.S.S.R. and Canada are currently self-sufficient in oil. Great Britain, because of extensive reserve development in the North Sea, will soon join that category. France, Italy, and Japan are in an opposite situation, with domestic production accounting for a very low percentage of their demand.

The growing number of nations that require imported oil, combined with a shrinking number of nations that have the production capacity or reserves to export, raises a potentially dim picture of the world supply situation. The more oil these exporting nations sell, the more influence they will exert on the world market place. Since OPEC nations have most of the "excess" reserves worldwide, under the present level of Saudi Arabian oil production, there could be a world oil deficiency by 1981. This shortage could appear as late as 1989 if Saudi production is increased to approximately double the current rate. The level at which Saudi Arabia will hold its production is still undetermined, but with increasing Arab awareness toward the importance of long-term revenues, there is little question that some quota will be established.

An MIT study places a global oil shortage as probable in 1984, with the shortfall occurring in 1998 if Saudi Arabia production is at the maximum possible level. Further complicating the situation are recent projections that the Soviet Union, once thought to be in a long-term state of oil self-sufficiency, may have to begin importing oil in the near future.

There is a high potential of a future worldwide oil shortage. When this occurs, the degree to which the U.S. is dependent on imports is going to have an important effect on our ability to absorb oil price increases or supply reductions. Oil mining, as a contributor of additional domestic petroleum, will be a factor in reducing U.S. foreign oil dependency. The oil resources obtained by this method would be largely unexploitable otherwise. This "bonus" petroleum previously not considered part of the U.S. oil reserve, would allow us time to better and more securely transfer the U.S. sources of energy away from petroleum and into suitable, long-term alternatives.

A.3.3.2 Future Demand

While future U.S. supplies appear to be limited, future U.S. demand for petroleum will almost certainly increase for some years to come. World demand for oil is likely to increase even faster, accelerating the international competition for oil. Before any attempt is made to quantify future oil demand, a discussion of the factors controlling that demand is appropriate. The major determinants of future oil consumption, both in the U.S. and worldwide, are levels of economic development, conservation efforts, growth in energy demand, growth in petroleum demand versus alternatives, and the speed at which alternative resources and new petroleum are developed. A major item underlying all those factors is the future of oil prices.

Worldwide, demand for oil is almost certain to increase, barring major unforseen economic change. The potential for conservation to reduce world petroleum consumption is not as great as it is within the United States. Most places in the world have long faced high oil prices, which encourages conservation. Technological improvements in industry and transportation will contribute to lower world-wide conservation, but the overall population growth and economic development will more than compensate for any reductions in oil usage. There are many estimates of future worldwide and U.S. petroleum demand. Two of these are shown in Tables 35 and 36.

Table 35. Oil Demand.
(Millions of Barrels/Year)*

	1974 Actual	2000 Probable	Average Annaul 1974-2000 Growth
USA	6,059	10,293	2.1%
Rest of World	14,892	35,588	3.4%
World Total	20,951	45,881	3.1%
Total Energy Demand	44,238	110,267	3.6%

*Projection by James Voss of Caltec Corporation. Assumptions: World economic growth will average 3.6% from 1974 to 2000; conservation and increasingly efficient use of energy reduced the potential energy growth from 3.7% to 3.6%. Oil will be the dominant energy source until 2000, although alternatives will be a much more important energy factor by that year (World Oil, May, 1977).

Table 36. U.S. and world petroleum demand, 1973-2000.
(Millions of Barrels)

	1973 Actual	Probable Demand 1985	Probable Demand 2000	Probable Average Annual Growth 1973-2000
USA	6,298	8,600	11,400	2.2%
Rest of World	14,726	22,000	31,000	2.8%
World Total	21,024	30,600	42,400	2.6%

Factors considered in the derivation of these figures include inflation, improved exploration and development technology, and conservation. High prices for petroleum are expected to dampen useage growth rates. Recognizing the many uncertainties, the forecast acknowledged that Yr2000 U.S. oil consumption could be as low as 8,700 MBBLS and as high as 12,000 MBBLS (USBM, 1975).

The Caltec Petroleum Corporation year 2000 estimated U.S. consumption of 10,293 million barrels compares favorably to the U.S.B.M. estimate of 11,400 million barrels. A total U.S. demand of 8,500 and 11,000 million barrels of oil in 1985 and 2000 appears to be reasonable.

The U.S.B.M. estimates that between 1974 and 2000, the U.S. will consume 240,000 million barrels of oil, approximately seven times the 1974 U.S. reserve estimate. For the world as a whole, estimated 1974-2000 cumulative oil consumption of 858,000 million barrels exceeded the total world reserve estimate by some 140,000 million barrels. If additional oil reserves or alternatives to petroleum are not found, a major future economic disturbance must occur in the international market place. There seems to be no question that future U.S. oil demand will continue to outstrip U.S. production. This gap will be filled by imports in the short run. Over the long run, this shortfall of U.S. production may be overcome by oil imports, alternative energy sources, and presently uneconomic domestic sources of petroleum. There would be many benefits of a U.S. oil mining industry. Some of these advantages are a result of the costs that will be avoided by deferring rapid development of other energy sources. These were discussed briefly in the previous section.

A.4 BENEFITS FROM OIL MINING

One major asset of oil mining would be the great improvement in the U.S. petroleum reserve outlook. Present United States petroleum reserves, that oil recoverable through conventional primary and secondary techniques, totals 20 billion barrels for the "lower 48" states and 30 billion barrels for the entire U.S.

Even with projected tertiary recovery techniques, these reserves will not be greatly increased. Under present projections, not including the potential of oil mining, a tremendous quantity of petroleum remains untouched in the ground. Conventional and secondary oil production in the lower 48 states will only extract an average of 31% of the oil in place. A study of the three major oil producing states, Texas, Louisiana, and California, indicates that enhanced oil recovery (EOR) methods could produce another 8% of the original oil under good price conditions. With the present oil production techniques, and without EOR, the U.S. will leave some 278 billion barrels of petroleum unrecovered in the lower 48 states. This oil would be the target for oil mining industry in the contiguous states. Alaskan oil would swell this potential target to 300 billion barrels, an amount 10 times the present U.S. oil reserve. If EOR techniques were applied before the petroleum was mined, the mining recovery methods would still have a resource target containing about 60% of the total oil discovered in the United States.

The reserve targets shown in Table 37 include petroleum found in a tremendously wide variety of environments. Much of this petroleum may never be recoverable by mining. However, the magnitude of the petroleum resources that could be accessible to oil mining is too huge to ignore.

Table 37. Potential oil mining target.

	Oil Produced	Proven Reserves Recoverable by Primary, Secondary Techniques	Oil Remaining In Place Target for Tertiary Recovery EOR or Oil Mining	Oil-In-Place
Texas Louisiana California	63	19	177	259
Lower 48 States	101	22	278	401
Total U.S.	106	34	300	440

Potential oil target for oil mining is currently 300 billion barrels. The three largest oil producing states contain the majority of the United States' large oil fields and reservoirs. Data is in billions of barrels (Lewin and Associates, 1976, and USBM, 1974). These figures are for conventional light crude only and do not include viscous or heavy oil or tar sands deposits.

A.4.1 Identified Reservoirs

There are several important advantages to be gained by exploiting this potential oil resource. The 300 billion barrels lie in places of known geological occurrence. Of the 60,000 known oil reservoirs, approximately 350 of them accounted for more than 60% of the total United States production to date. Seventy-five per cent of the recoverable petroleum reserves and 63% of the presently known domestic oil also lies within these reservoirs. These sizeable, known oil occurrences provide the most promise for oil mining. Their size provides the economic advantages of large-scale operations.

The extensive development already done on these fields will provide many cost advantages to the oil-mining operations.

A.4.2 Existing Development and Small Exploration Costs

First, exploration costs will be relatively small. These fields are already known, and considerable data on reservoir depth and configuration already exists. In 1974, the total U.S. petroleum industry expenses for geology, geophysics and lease rentals was $1.13 billion. However, the 300 billion barrels of oil that have been listed as a potential target for oil mining are already defined by previous exploration. Further detailed exploration work will certainly be required prior to a mining effort. However, the virtual elimination of the expenses that are required for a regional exploration program represents a cost savings for oil mining or EOR programs.

There is an economic and an environmental advantage to using an already existing transportation mechanism. In 1975, 220,000 miles of pipelines carried petroleum to some 284 refineries in 41 states. When an oil field is abandoned, the remaining useful in-place life of the pipelines and facilities is lost. Tertiary enhanced oil recovery or oil mining would maintain the usefulness of such facilities, rather than building the extensive transportation, storage, and refining infrastructure needed for coal or uranium operations on previously unexploited sites. This would represent a cost savings to both the operating company and ultimately to the consumer.

Tertiary oil recovery and oil mining also could help maintain the revenues in a region otherwise facing a decline in oil production. This decline in oil production will ultimately affect an area of any size, whether it be a district, state, or the entire U.S. Many portions of the United States are presently in this situation, as is the nation as a whole.

A.4.3 Stabilization of U.S. Petroleum Prices

Revenues from oil mining could well be a stabilizing influence on U.S. petroleum prices. This in turn would stabilize the petroleum-related economy, which is a huge segment of the U.S. economy.

The stability of U.S. oil supplies should help the small, full-service station maintain a place in the retail gas market. The 1973 oil price increases, foreign nationalizations of U.S. petroleum-related assets, and U.S. government regulations all seriously affected the retail gasoline market. In 1973, there were 226,000 filling stations in the United States. By 1977, the changing economic conditions had reduced this to 180,000. The shift of gas stations from full-service to self-service has been dramatic. In 1974, 8% of the stations were self-serve. By mid-1977, this had swollen to 50%. The implications regarding employment are correspondingly large, considering both the reductions in the number of outlets and in the number of employees per outlet. The future might well see automatic credit card stations, manned by no one.

The oil refineries in the U.S. are major employers, with over 154,000 workers in 1974. Oil mining will help guarantee the future petroleum supplies demanded in the oil refining industry.

By extending the life of the oil transportation system, oil mining will help maintain employment in the large petroleum extraction portion of the industry. Petroleum and natural gas extraction employed 335,700 people in 1974. As oil producing districts face declining production, they will also see a loss of related jobs. The indirect loss of employment might well be more significant than the direct loss, since local oil royalty recipients will see the end of their payments. Since some of these monies would have been spent locally, the termination of those royalties amounts to a local monetary loss. Oil mining will provide direct employment by continuing the petroleum transportation system, and indirect employment through the multiplied effects of oil royalty and wage payments spent in the local area.

Oil mining has the potential to reduce U.S. balance of payment deficits. The oil so produced would be used to offset petroleum imports.

Further inflationary pressure can be better controlled if the level of U.S. oil importation is reduced. The magnitude of a boycott-induced recession would be minimized in a like manner. Energy costs may rise as higher cost petroleum is produced domestically, but these increases are far more predictable than sudden OPEC price postings or supply shutoffs.

The possibility of a future U.S. oil supply shortfall, regardless of oil importation, is considerable. This may occur even if U.S. petroleum alternatives are rapidly developed. Oil mining would help offset a future energy deficiency by producing additional internal crude supplies.

Oil mining could help reduce the amount of petroleum produced from other sources. This includes imports, coal liquefaction, and other less effective methods of secondary or tertiary oil production, or high cost oil produced by conventional techniques.

Government officials are so worried about the possibility of future oil shortages that they have established a government emergency oil pool. This reserve, which should reach 500 million barrels by 1980, will cost nearly

$9 billion dollars. The amount of oil in the pool could ultimately reach 1.0 billion barrels by 1983 if present government policy is followed. This reserve, coupled with industrial stocks and strict rationing, could last for more than three months even if all mideast imports were cut off.

For a short-term emergency, only a readily available oil supply would provide a buffer for the United States. In the event of a long-lasting shortage, federally sponsored previously prepared oil mines could begin production rapidly. Prepared oil mines could begin production rapidly enough to help offset the long-run economic damage that could otherwise occur. Such oil mines would be pre-developed to the maximum extent possible without drawing production. The pipeline transportation system would already be in existence, so should the need arise petroleum production could commence in a short time. Such properties would comprise part of the U.S. strategic oil reserve and as such would provide an increased measure of national security.

Oil mining could forestall a crisis and thus provide time for conversion to non-petroleum energy sources such as gas, coal, nuclear power, solar, wind, geothermal energy, and several others. As the United States eventually converts to other energy sources, oil mining will help ease the associated economic impact by delaying the rate at which such conversion must take place.

A.5 ENERGY ALTERNATIVES: AN ECONOMIC COMPARISON

A.5.1 Introduction

Mining oil is feasible, but is also relatively untested in the United States in the light of modern technology. In order to be practical, oil mining must have economic equivalence or advantage over competing energy sources. The economics associated with oil mining go much further than a cost per barrel of oil obtained. Oil mining in the U.S. would carry with it certain economic and socio-economic advantages that may not be characteristic of competing alternatives. At the same time, other alternative energy or oil sources carry certain economic and socio-economic costs that are not present, or have less impact, with oil mining. The economic marketplace will be the primary determining factor in the composition of future U.S. energy and industrial inputs. The complete economics picture is not restricted to the cost per unit produced, however. It may well be that the consuming nations, industries, and agencies will prefer a higher-cost traditional energy source, such as petroleum, to a lower cost alternative that would require a retooling of their energy consuming processes. The capital cost of such retooling may well offset small, down-the-road cost savings of energy input.

Consider the cost of converting a business from $14/barrel oil to coal power. The company requires a 12% return to justify an investment, and estimates that for the next 20 years their oil costs will be $56,000/year, including equipment upkeep. It is calculated that the energy-equivalent coal fuel could be obtained for $40,000/year. How much could the company afford to pay for the required equipment conversion? Using discounted cash flow techniques, one finds that the most the company can afford to pay is $119,510. Should their cost of conversion be any higher than this, they would not be able to justify conversion to the cheaper fuel source.

This simplified example illustrates that caution must be used when comparing the economics of the various energy alternatives available to the U.S. The amount of capital already committed to certain energy supplies makes instant conversion to any other source impossible. The future projected increase in oil demand certainly reflects this fact.

A.5.2 Assumptions and Definitions

The future costs required to produce a selected number of competing energy resources are discussed in this section. This information was taken from a report prepared by the Stanford Research Institute for federal agencies. The energy sources compared in this section include domestic crude oil, domestic natural gas, shale oil, coal, nuclear fuel and imported crude oil.

Marginal cost, as used in the following figures, is defined as the minimum price at which a producer would be willing to obtain and sell a particular mineral resource. The supply information that is used is the expected U.S. cumulative production of the materials starting July 1, 1975.

As the producer is required to extract more and more resource, the increasingly unfavorable material that must be obtained is reflected in the increased marginal cost. A cost line that is asymptotic upwards shows that a physical production limit is being reached; the mineral is depleted. A relatively horizontal cost curve indicates that the resource is relatively abundant compared to expected future consumption of the energy source, hence no supply barriers are encountered. All of the marginal cost curves demonstrate a price to volume relationship for at least 50 years from the 1975 starting point.

The marginal cost curves are sensitive to and depend upon a variety of assumptions. The ultimate reserve quantities of the various resources are implicit in the cost figures. The marginal cost figures which are the minimum prices at which a producer will obtain and sell the resources are based on the following assumptions:

1. Cost values are expressed in constant July 1, 1975 costs.
2. Cost curves reflect long-run marginal costs.
3. Curves assume constant July 1, 1975 technology.
4. Marginal cost excludes lease bonus payments.
5. Marginal cost curves assume a normal supply and demand balance will remain in all secondary industries.
6. Demand will neither increase or decrease rapidly.
7. Marginal costs will increase because a resource tends to be obtained in order of decreasing economic attractiveness.
8. The slope (steepness) of the marginal cost curve reflects scarcity.

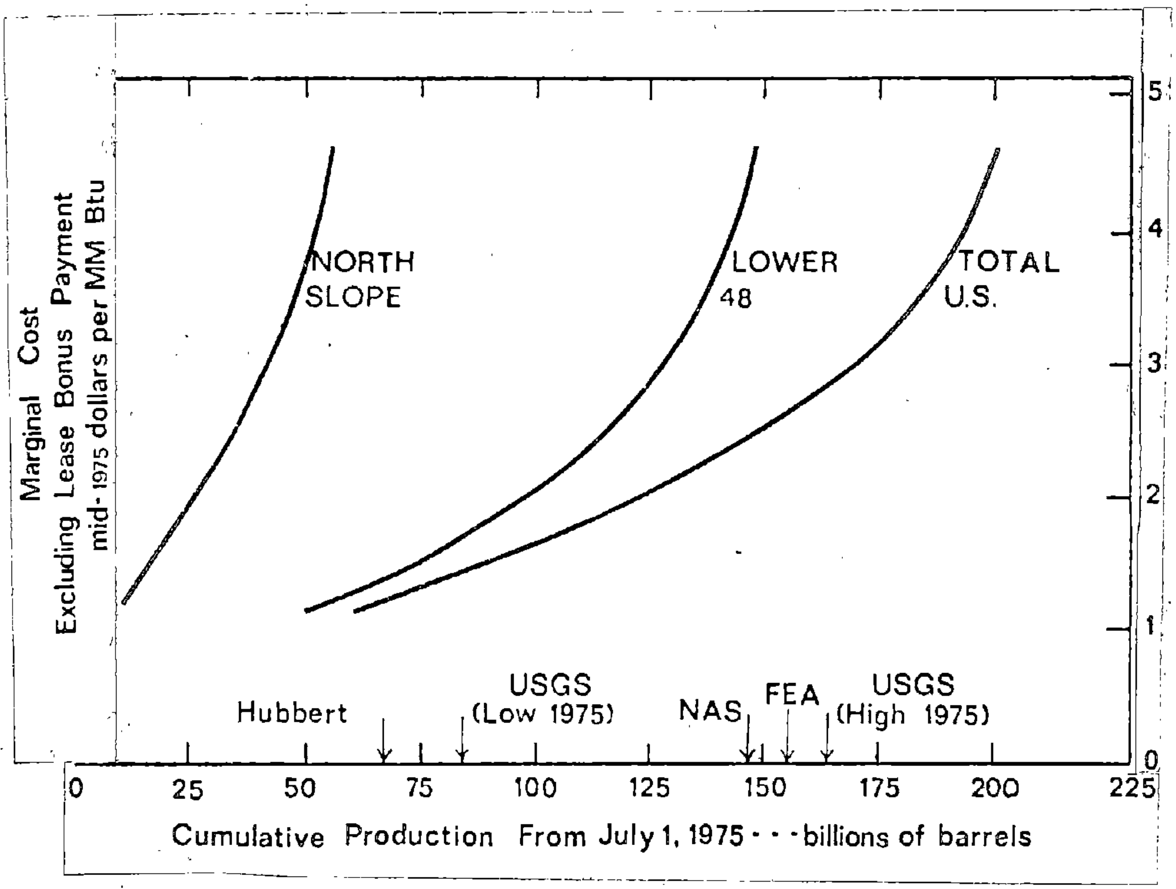
Long run costs will be the primary focus of this section. The order of extraction of deposits is accounted for in the marginal cost curve. Also included in the cost figures are:

1. Royalties (taken at a standard minimum)
2. Exploration costs, including unsuccessful drilling
3. Development costs
4. Production costs
5. Ad valorem or production taxes
6. Capital costs
7. Secondary material costs
8. Depletion allowance
9. Investment tax cridits
10. Utility costs
11. Depletion of the resources
12. Overhead
13. Income tax
14. Liquids credits (for natural gas)
15. Discount rate = 15%

For further details on the derivation of these cost figures, see Stanford Research Institute, 1976.

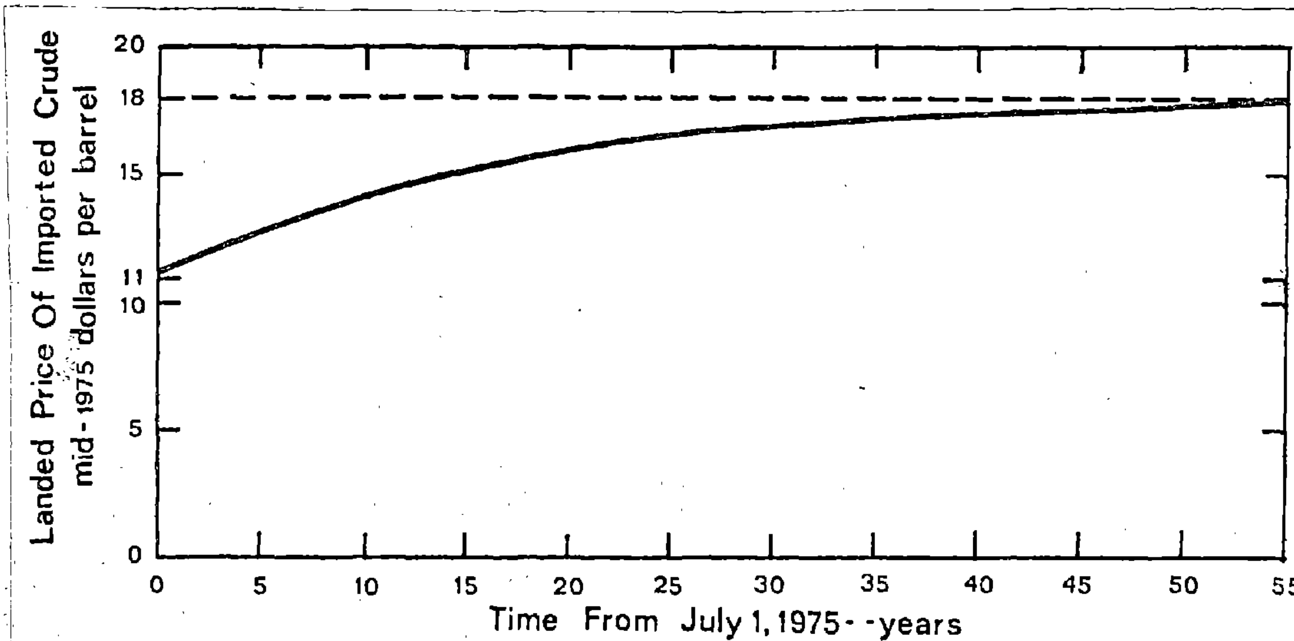
A.5.3 Domestic Crude Oil

World import prices to the U.S. are approximately \$14.50/barrel, although much of the oil produced in the U.S. is cheaper due to regulation. New oil being developed within the U.S. will command a price comparable to that fixed by OPEC. On August 12, 1977, the U.S. government decided that Alaskan production would be sold at the highest possible price, that being paid for imported oil. At the time, this was $14.60/barrel. At the same time, U.S. old oil (from wells which began producing prior to 1971) sold for $5.17 and new oil sold for $10.94. These prices were to be raised to $5.24 and $11.71, respectively, by November 1977. The old oil supply in the U.S. will continue to decline, so all future oil discoveries or imports will be brought in at prices comparable to that set by world markets. In the long run the U.S. will depend on mid-east supplies for the bulk of their oil imports. Imports are expected to supply about 50% of total consumption until at least 1985. The marginal cost curve for domestic crude oil is shown in Figure 59. The import price in terms of mid-1975 dollars is shown in Figure 60.



(Source: SRI 1976)

Figure 59. Domestic crude oil marginal cost curve



(Source: SRI, 1976)

Figure 60. Price of imported crude oil, mid-1975 dollars

A.5.4 Domestic Natural Gas

Natural gas supplied 30% of the United States 1974 energy requirements, but this share is expected to decline. Engineering and Mining Journal, April, 1974 estimated that natural gas will only supply 25% of the total U.S. demand in 1985 and 18% in the year 2000. The Federal Energy Administration (FEA) was more optimistic in terms of total production, at least for 1985. The FEA report did not estimate year 2000 gas production.

The declining relative importance of natural gas must be compensated for by other energy sources. Where used for electrical generation; oil, coal, nuclear, and synthetic gas are all potential substitutes. Where used in an individual application, electrical energy is likely to be substituted for natural gas.

The potential supply of natural gas is large, but higher costs will be required for future development of this resource. As shown in Figure 61, the difference between the well cost for proved and potential gas reserves is almost a factor of seven.

Marginal cost curves for U.S. domestic natural gas appear in Figure 62 by region and for total U.S. gas production.

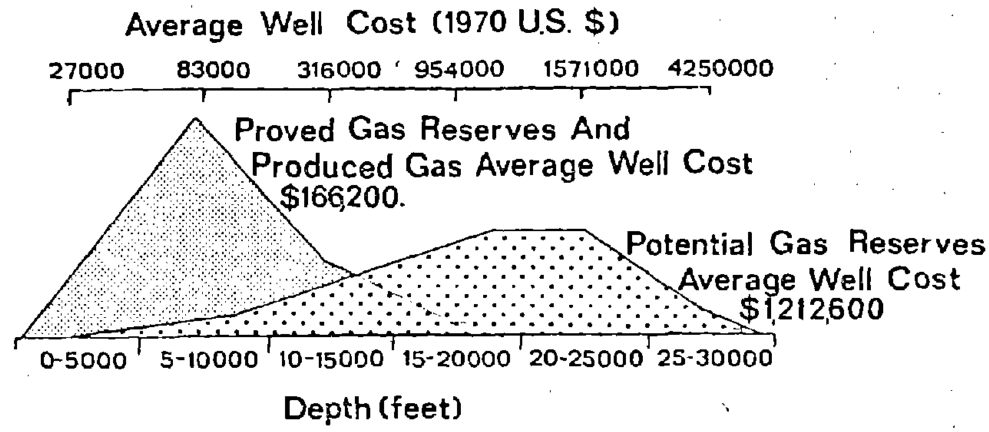
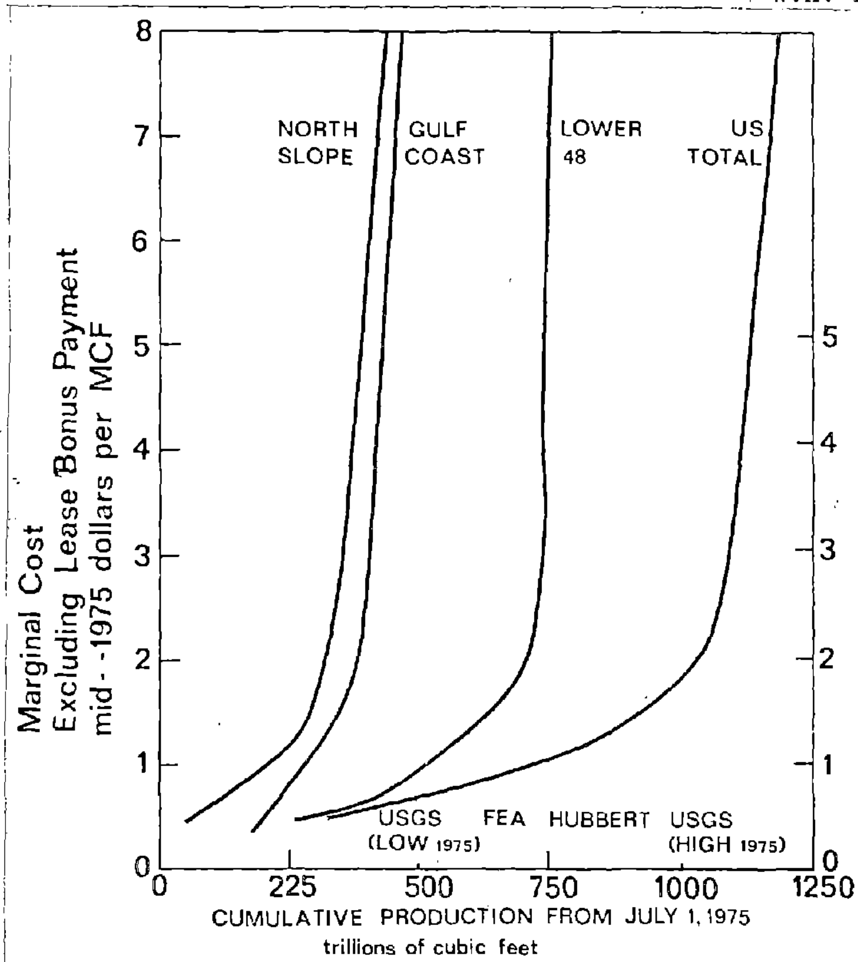


Figure 61. Potential and proven natural gas reserves in Texas. Average well cost for proven reserves is $166,200; for potential gas, $1,212,600 (Cook, 1976). Man, Energy, Society W.H. Freeman and Co.



(Source: SRI, 1976)

Figure 62. Marginal cost curves for U.S. domestic natural gas, by region and total

A.5.5 Coal

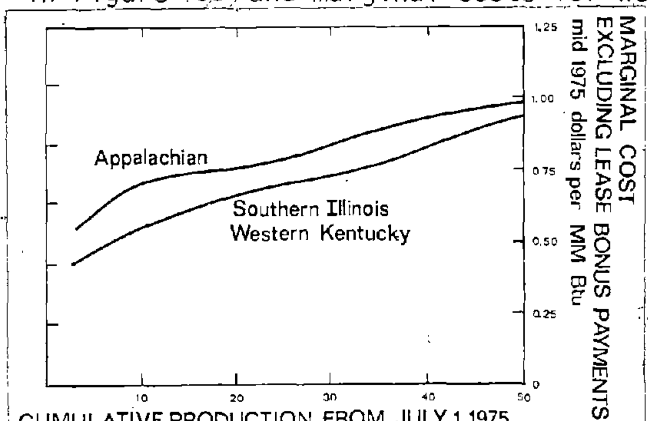
Both the supply and the cost of coal make it the most promising source of new energy between now and the year 2000. The technology needed to utilize coal resources is well defined, both from the physical and the economic viewpoint. The information available on potential energy alternatives such as oil shale, solar, wind, geothermal, and nuclear power is not nearly so complete. The U.S. coal reserve base is extensive, and will not be depleted in the near future. The very gradual increase in the marginal cost of coal reflects the slow requirement for more expensive reserve exploitation.

The total marginal cost (see Section A.5.2) of western coal is almost the same as the cost for Eastern coal. The components of the costs for the two regions is different, with Western coal being much more transportation intensive.

Table 38. Northeast U.S. industrial region electricity costs.

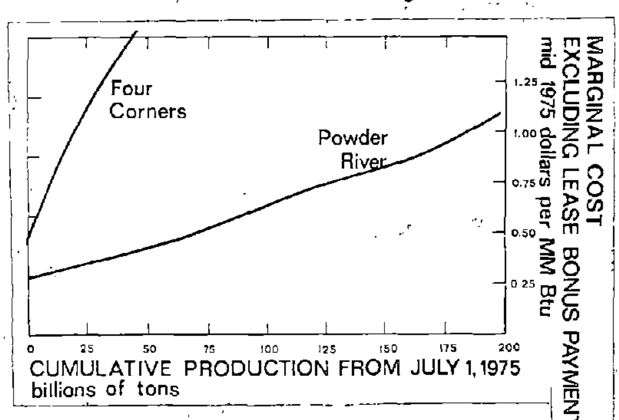
	Western Coal	Percentage of Total Cost	Eastern Coal	Percentage of Total Cost
Cost of Resources	$ 2.22	37%	$3.14	49%
Cost of Transportation	1.62	27%	0.37	6%
Cost of Power Generation	2.12	36%	2.93	45%
Total Cost of Electricity	$ 5.96	100%	$6.44	100%

The thick, strippable western coal seams are cheaply mined, but the production is costly to ship to market areas. Eastern coal, much of it mined underground, is expensive to produce but accessible to markets. High-sulfur eastern coal is more costly to use in power generation due to the required desulfurization process. Marginal costs for eastern coal is shown in Figure 63 and marginal costs for western coal is shown in Figure 64.



(SRI, 1976)

Figure 63. Marginal costs for eastern coal



(SRI, 1976)

Figure 64. Marginal costs for western coal

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A.5.5.1 Fuels From Coal

A great deal of research has tested the potential of synthetic manufacture of oil and gas from such resources as coal, oil shale, and tar sands. Coal gasification and liquefaction is feasible, but costly. Several types of gas can be made from coal. These include coke oven gas, water gas, producer gas (made without water), and coal gas. The energy conversion efficiency of most plant-based coal gasification processes runs from 60-90%.

Another potential conversion product from coal is a crude oil known as syncrude. Liquid fuels as a product of coal are more difficult and expensive to make. A plant that produces syncrude or synthetic natural gas will probably also produce lower BTU product as well. The cost of synthetic crude is high. Initial capital expenses will range from $.5 to $1.0 billion dollars. Synthetic fuels will have to sell for $12 to $30 per barrel of oil equivalent to justify an investment. The high capital development cost limits the number of companies that could enter the industry.

Some work has been done to judge the potential of in-situ coal gasification, a technique that has the advantage of eliminating a great many mining and handling costs, plus reducing the amount of capital and labor needed for the process. The gas produced underground is low BTU, and cannot be economically transported. Plants using the gas would have to be located near the site. To be economical, the selling price for synthetic fuels will have to range from $12 to $30 per barrel of oil equivalent. To develop a synthetic fuel industry capable of producing the fuel equivalent of one million barrels per day by 1985, the FEA estimates that a total investment of $19 to $22 billion will be required by 1984. This would apply to development in all phases of synthetic fuel production, including both coal and oil shale.

A.5.6 Oil Shale

The oil shale formations of Colorado, Wyoming and Utah contain 80 billion barrels of oil equivalent that is potentially recoverable under projected economic conditions. As yet, only the highest grade material has been considered for exploitation. No profitable oil shale production has occurred in the U.S., although oil shales have been mined elsewhere in the world. Since no major production has occurred, the economics of oil shale is still in question. The marginal cost of oil developed from raw shales is shown in Figure 65.

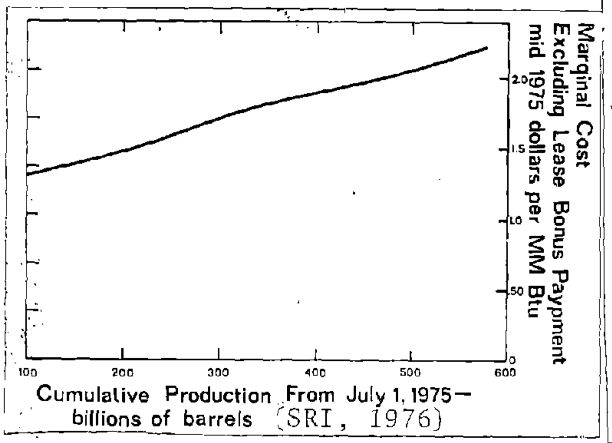

Figure 65. Marginal cost of oil develop from raw shales

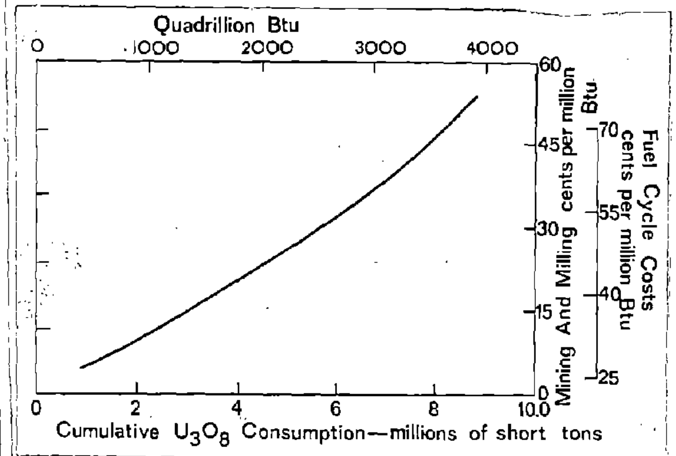

Figure 66. Marginal cost of nuclear fuel.

A.5.7 Uranium

Uranium has been a growing source of energy for a number of years. In 1974 uranium provided 2% of the United States energy consumption. The importance of uranium as an energy source should continue to grow between now and the year 2000, but the magnitude of this growth is still in question. The economics of other energy sources will have an important effect on the future of uranium as a U.S. energy source, especially since nuclear energy is not in favor among many environmental groups and individual citizens.

The U.S. has considerable amounts of uranium, but many of the reserves are available only at high cost. Prices for uranium, U_3O_8, were approximately $40 per pound for the first half of 1977. On May, 1978 the spot price for one pound of U_3O_8 was listed as $44.00 for immediate delivery.

There is no question that uranium will remain economically competitive with other fuel sources and the potential of fusion reactors is also promising. The future of breeder reactors and other nuclear plants in the total U.S. energy picture hinges more on the social costs than the economic ones. The rate of development of conventional nuclear power will also be tied directly to the negative aspects of such growth. The risk of a nuclear plant disaster is a major fear commonly held by the public. Transfer and disposal of nuclear wastes also are stumbling blocks to increased nuclear development.

If nuclear power is not developed at the rates estimated, the resulting loss must be filled by other energy alternatives. This includes the use of oil, and oil mining then could be an important addition to projected U.S. petroleum supplies. The marginal cost of nuclear fuel is shown in Figure 66.

A.5.8 Marginal Cost Comparison

In Figure 67, the marginal cost curves are shown on one chart for a graphical comparison of domestic crude oil, North Slope natural gas, lower 48 states' natural gas, domestic coal, domestic shale oil and domestic nuclear fuel.

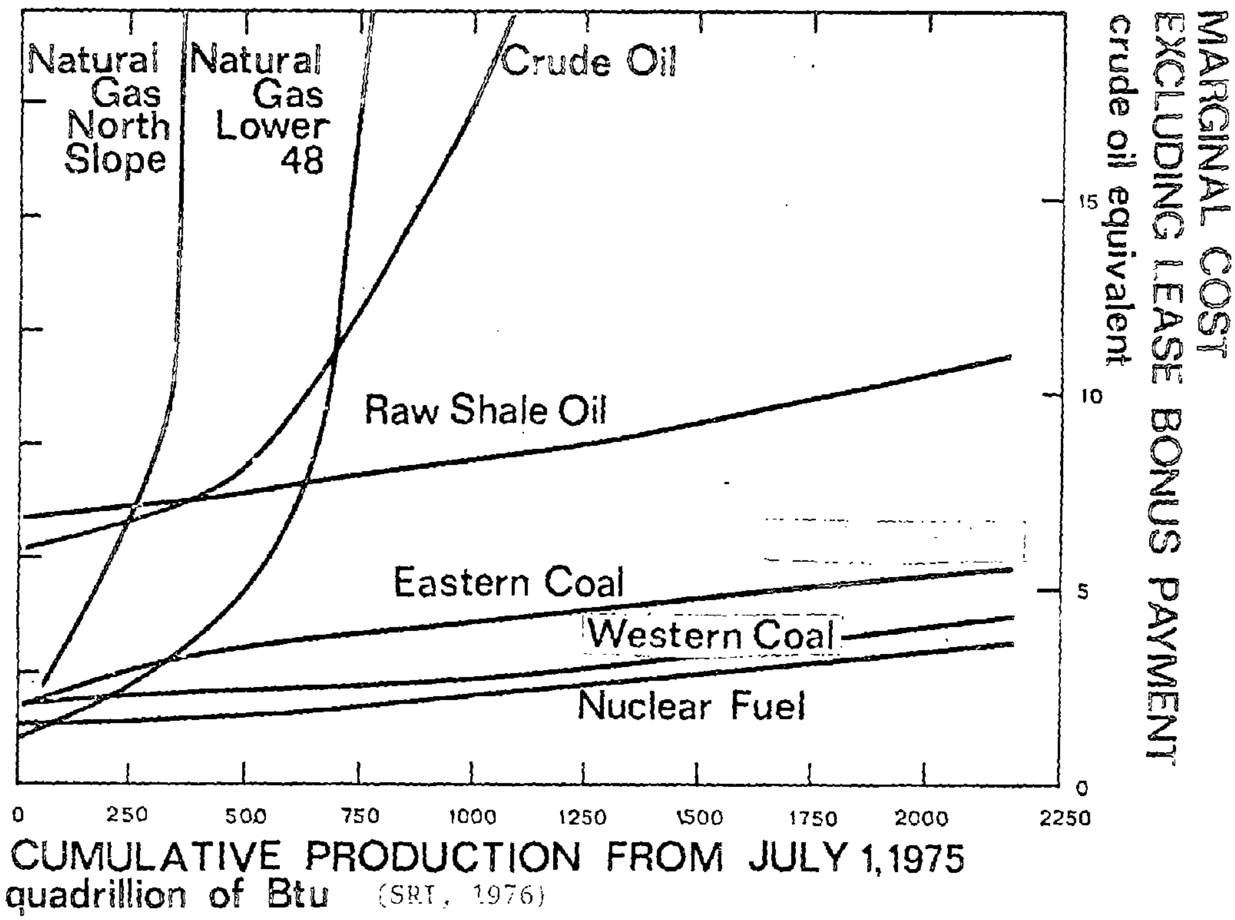

Figure 67. Marginal costs of domestic crude oil, North Slope natural gas, lower 48 natural gas, domestic coal, domestic shale oil and domestic nuclear fuel

A.6 CONCLUSIONS

Oil mining could be a viable and beneficial U.S. industry. Petroleum is a commodity in demand that presently is in short domestic supply. The social and environmental impact of an oil mining industry will be less severe than the impact of coal mining and utilization. Oil mining carries little of the uncertainty associated with the use of uranium. Economically, the costs of currently major energy alternatives are tabulated below.

Table 39. Costs of major energy alternatives and oil mining. (Dollars per Million BTUs)

	1977	1985	2000
Crude Oil (Domestic)	\$2.05	\$2.50	\$2.80
Natural Gas	1.50	2.00	3.00
Imported Oil	2.10	2.45	2.80
Uranium	0.30	0.31	0.35
Coal	0.60	0.70	0.85
Oil Mining	1.40-2.70	---	---

The cost per million BTU's of alternative energy sources. All values are in constant 1975 dollars. Figures assume "expected" energy development predicted by the Stanford Research Institute (1976). Minemouth or wellhead prices are given except for uranium, where fuel cycle cost is used.

Oil mining in 1977 costs ranges from \$1.40 - \$2.70 per million BTU's and is thus competitive with the major energy sources. The economics are certainly enhanced on a national scale when other benefits of oil mining, such as a reduction in foreign oil dependency, are taken into account. As with all energy sources, oil mining has a number of both costs and benefits. The development of a future oil mining industry in the United States will depend upon the further definition of all the social, technical, and economic factors that are associated with the concept. The specific economics of mining for petroleum are discussed further in Section 5.

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HYDROCARBON RESERVOIRS, CASE HISTORIES AND DISPOSAL METHODS

PART TWO

The Container and The Fluid

Oil and gas accumulations occur in underground "traps" formed by stratigraphic and structural features. They usually occur in the more porous and permeable portions of beds, which are mainly sands, sandstones, limestones, and dolomites, in the intergrandular openings, or in openings due to joints, fractures, and solution activity. A "reservoir" is that portion of a trap which contains oil and/or gas as a single hydraulically-connected system.

Many hydrocarbon reservoirs are hydraulically connected to various volumes of water-bearing rocks called "aquifers." Most petroleum reservoirs are located in large sedimentary basins and share a common aquifer, and the production of fluid from one reservoir often causes the pressure to decline in other reservoirs by fluid communication through the aquifer. In some cases the entire trap is filled with oil or gas, and in this case the trap and the reservoir are the same. However, in other situations the aquifers may be so large compared with the reservoirs they adjoin as to appear infinite for all practical purposes, and range down to those so small as to be negligible in their effect on reservoir performance. The aquifer itself may be entirely bounded by impermeable rock so that the reservoir and aquifer together form a closed or volumetric unit. On the other hand the aquifer may outcrop at one or more places where it may be replenished by surface waters. Finally, an aquifer may be essentially horizontal with the reservoir it adjoins, or it may rise, as at the edge of structural basins, considerably above the reservoir so as to provide some artesian-type flow of water to the reservoir.

In response to a pressure drop in the reservoir, the aquifer reacts to offset or retard pressure decline by providing a source of water influx or encroachment by: (a) expansion of the water; although it is slightly compressible, nevertheless, in many of the deep reservoirs the expansion of compressed water provides an important source of energy for the production of oil and gas; (b) expansion of other known or unknown hydrocarbon accumulations in the aquifer rock; (c) compressibility of the aquifer rock; and/or (d) artesian flow, where the aquifer rises to a level above the reservoir, whether it outcrops or not, and wheather or not the outcrop is replenished by surface water.

From an analytical point of view the aquifer may be considered an independent unit which supplies water to a reservoir in response only to the time variations in the "boundary pressure," i.e., the average pressure at the oil-water or gas-water contact. The boundary pressure will generally be higher than the average reservoir pressure; however, in some studies no distinction is made between the two, the average reservoir pressure being used for the average boundary pressure.

While the term "oil reservoir" implies that the rock structure in question is definitely oil bearing and oil productive, the oil phase itself in general will not comprise the exclusive fluid content of the void space. All oil- and gas-bearing rock contain a water phase and all samples of oil-productive formations thus far brought to the surface and analyzed have been found to contain some water, that is presumably indigenous to the rock immediately prior to exploitation. The amount of this water - usually termed "connate" or "interstitial" water - has been found to range from about 2 percent to more than 50 percent of the total pore space. The finer the pore channels between the mineral grains of the rock, the larger the percentage of pore space that will be filled with water throughout the oil and gas zones. Where clay or adsorptive minerals are present, comparatively large quantities of water are found. Very little, if any, of the water held by capillary forces throughout the reservoir is produced into the wells. Although connate water may well be considered as universally associated with the oil itself, there may be exceptions in the case of oil masses trapped in actual fissures or cavernous voids, though it will obviously be very difficult to obtain conclusive data on this point.

Formation waters have mineral-content compositions that are often characteristic of the geologic stratum and may be used to locate the source of waters being produced from a well. They have also served to clarify the geological histories of oil accumulations. While in some cases the oil field waters appear to be similar to ocean waters, there are large variations among the compositions of brines from oil-bearing rocks. Reservoir water may be fresh, brackish, or saline, but it is usually saline (see table 4). The total salinity may reach approximately 25 percent by weight of solids, or about seven times that of sea water. The greatest part of these solids is commonly sodium chloride, but lesser amounts of other constituents are also present. A few instances have been reported in which sodium chloride comprises slightly more than 99 percent of the total solids in the water. Chloride concentrations generally range

TABLE 4

ANALYSES OF OIL-FIELD BRINES
(In ppm)

Field	Formation	Cl	SO_4	CO_3	HCO_3	Na	K*	Ca	Mg	Miscellaneous	Total
Sharon, Pa.	Berea Sand	6,740	0	0	250	3,440		700	160	-------------	11,290
Evans City, Pa.	3d Venango Sand	88,820	180	0	40	38,660		13,790	2,220	-------------	143,710
Bell Run, W. Va.	Salt Sand	64,930	0	0	90	30,450		7,580	1,620	-------------	104,670
Kawkawlin, Mich.	Dundee Limestone	161,200	155	--	60	66,280	--	25,740	4,670	-------------	258,105
Reed City, Mich.	Marston Dolomite	156,225	265	--	20	59,080	--	28,440	5,155	-------------	249,185
Seminole, Oklahoma	Wilcox Sand	89,990	515	--	65	44,020	--	9,460	1,990	-------------	146,040
Glenn, Okla.	Arbuckle Limestone	101,715	120	--	60	50,345	--	10,160	2,120	-------------	164,520
Burbank, Okla.	Bartlesville Sand	107,895	--	--	35	50,000	--	14,340	1,875	-------------	174,145
Nikkel, Kans.	Hunton Limestone	76,797	207	--	61	40,284	--	5,440	1,790	-------------	124,579
East Texas, Tex.	Woodbine Sand	40,958	278	--	569	24,540		1,388	282	-------------	67,649
Yates, Tex.	San Andres Dolomite	2,518	2,135	251		1,624	--	587	288	Si:18;Fe,Al:24	7,445
Monument, N. Mex.	Grayburg Limestone	6,630	160	--	1,740	3,735	--	515	365	-------------	13,145
Shelby, Mont.	Madison Limestone	1,179	659	71	1,270	1,322	--	143	66	-------------	3,388
Frannie Dome, Wyo.	Tensleep Sand	27	2,303	0	691	51	--	760	240	-------------	4,022
Grass Creek, Wyo.	Frontier Sand	256	6	1,211	--	1,087	--	5	2	-------------	2,565
Fruitvale, Calif.	Fairhaven Sand	245	11	60	2,235	1,024		8	10	-------------	3,593
Edison, Calif.	Upper Duff Sand	79	4	29	648	299	--	17	1	-------------	962
Ventura Ave., Calif.	Pico-Re-petto Sand	14,212	59	--	1,846	8,607	--	729	242	NH_3:66;Si:170; Fe,Al:160	26,091
Bay City, Mich.	Salina Dolomite	403,207	0	--	1,208	21	21,362	206,300	7,300	Br:3,500	642,798
Ocean waters (mean)	--------	19,410	2,700	70	--	10,710	390	420	1,300	-------------	35,000

*In most brine analyses Na and K are determined together and reported as Na. For those cases, however, where the alkali content was listed as Na + K, the values are tabulated between the Na and K columns. A similar uncertainty obtains in the case of some of the reported values of CO_3 and HCO_3 concentrations.

from about 5,000 ppm* to more than 400,000 ppm, the average being about 50,000 ppm (see table 4). Comparatively, salt water from the ocean contains about half as much chloride, and water from streams, rivers, lakes, and from springs and wells usually contains less than 100 ppm of chloride. The U. S. Public Health Service considers water exceeding 250 ppm in chloride content to be unsatisfactory for public water supply; however, it is not uncommon that water containing 500 ppm of chloride to be used for domestic purposes, and in some arid areas of the world animals may consume, for short periods of time, water containing as much as 2,000 ppm of chloride and 15,000 ppm of dissolved solids. Many brines are characterized by high contents of lithium, bromide, and chloride; however, some water produced from oil fields is comparatively low in these minerals, in fact, in a few fields relatively fresh water is produced with the oil. Unfortunately, a barrel of brine discharging from an oil well containing 50,000 ppm of chloride (the average) will raise the chloride content of 200 barrels of fresh water containing no chloride above the maximum permissible chloride content for drinking water. In general the chemical nature of the solids depends upon the make-up of the ancient sea within which the sediments were deposited and upon later geological changes. The salinity may have been reduced through dilution with fresh water, concentrated by evaporation of the water, or altered chemically by bacterical action.

Three Phase Reservoirs

All producing oil reservoirs contain gas in solution in the oil. And in many reservoirs the total gas content exceeds that which can be held in equilibrium in solution in the oil at the prevailing initial reservoir temperature and pressure. The excess generally overlies the oil-saturated section as "gas caps." The gross content of an oil reservoir is thus initially a composite of at least two and often three fluid phases. They must all be recognized as integral parts of a common system. The mutual interactions and reactions of three fluid phases to the entry - artificial or natural - of similar extraneous fluids give rise to the inherent complexity of the oil-producing system.

The fluids in petroleum reservoirs have all been subjected to the forces of gravity, as evidenced by the relative positions of the fluids, i.e. gas on top, oil underlying the gas, and water underlying the oil. Owing to long periods of time involved in the petroleum accumulation and migration process, it is generally assumed that the reservoir fluids are in equilibrium. If the reservoir fluids are in equilibrium then the gas-oil and oil-water contacts should be essentially horizontal. Although it is difficult to determine precisely the reservoir fluid contacts, best available data indicate that in most reservoirs the fluid contacts actually are essentially horizontal. Hubbert (1955) has presented a somewhat different theory called the "hydrodynamic theory of oil accumulation," which postulates that tilted oil-water contacts may be expected as a result of the oil-accumulation process. Hubbert cites several examples to substantiate his theory. It is interesting to note that as early as 1939 a similar theory was postulated for the accumulation of oil in the Langham Sand reservoir in the Amelia Field of Jefferson County, Texas.

The Water-drive Reservoir

Production from most reservoirs is accomplished as a result of a combination of several forces. For the purpose of this paper, the discussion will be limited to a water-drive reservoir. The performance of water-drive reservoirs is typified by a slight decline in pressure, very little change in producing gas-oil ratios, and a steady increase in the volume of water produced per well. The first water production comes from those wells near the water-oil contact. As the reservoir is depleted, the water-oil contact moves up structure. Eventually water is produced from all wells in the reservoir.

In reservoirs where water underlies the entire oil zone, as in some dome-type structures, the water surface may rise uniformly from the base to the top of the structure, floating the oil to the wells higher on structure as the reservoir is produced. Water may also encroach laterally through the most permeable streaks to be produced in the high-structure wells, or it may encroach in a combination of these two ways.

Some control on water production can be accomplished by selective recompletion of wells. Zones that produce water can be plugged off, and zones not previously flooded can be opened. If wells are produced at excessive rates, the water will find channels toward the well opening and much of the oil will be left behind. Oil may ride the top of the water and be "coned off," or the oil in the relatively impermeable streaks may be "bypassed" and leave large quantities of oil unrecoverable.

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* parts per million

Recovery of oil from water-drive reservoirs depends upon the amount of water coning or bypassing. Under ideal reservoir conditions, as much as 85 percent of the oil content may be recovered from zones through which the water passes. But the total recovery depends upon the character of the reservoir rock, on the oil itself, and on the nature of the production controls designed to prevent excessive bypassing. Estimates of such recoveries usually range from 40 to 70 percent of the initial oil in place. A water-drive reservoir produced at rates that permit only a slight drop in pressure generally realizes the greatest ultimate recovery. Instances occur where it is necessary to create a rather large pressure differential before the water-drive becomes an active force in recovery of the oil.

SPECIFIC EXAMPLES OF OIL FIELD POLLUTION

To illustrate the many facets associated with brine production and disposal within a single field a cross section through a series of sample locations has been chosen in an effort to present typical situations that might be encountered in all areas of the country. For this purpose the authors have selected the Citronelle Field in Mobile County, Alabama and the Pollard Field in Escambia County, Alabama. This choice was made because of the familiarity of the senior author with this area and the belief that it will appropriately illustrate some aspects presented in this paper, but it should not be construed as an effort to focus any particular attention to the oil and gas industry in Alabama.

The Texas Water Commission publication, "Investigation of Ground-Water Contamination, P. H. D., Hackberry, and Stone Oil Fields, Garza County, Texas," by Burnitt and Crouch (1964), is an excellent example of the type of studies that many state agencies and regulatory bodies are currently undertaking.

Citronelle Field, Alabama

The Citronelle Field is located in north Mobile County and fringes the eastern margin of the Mississippi salt basin. Oil is produced from the Rodessa formation of early Cretaceous age at depths ranging from 10,650 feet to 11,600 feet. The oil pool underlies the town of Citronelle, which is located on a prominent surface feature, a flat top ridge that is capped by the Citronelle formation of Pliocene age and consists of deposits of sand, gravel and clay having an aggregate thickness of about 50 feet. It is underlain uncomformably by deposits of Miocene age, consisting of sandstone, sand and clay. The formations dip generally southward at about 10 feet per mile. Ground water in the Citronelle formation is under water-table conditions and water yields are adequate for domestic use. In parts of the area, relatively impermeable clays at shallow depths prevent the downward percolation of water. In areas where the impermeable layer intersects the valley slope, ground water discharges by means of springs and by seeps. There is at present little use of shallow ground water from the Citronelle formation. The Citronelle municipal water system, which supplies approximately 600 outlets, obtains water from wells tapping the Miocene sands at depths of 600 to 750 feet (figure 4). Permeable sands of the Miocene that crop out in the vicinity of Citronelle form the recharge area for artesian aquifers tapped by wells to the south and southwest. The Citronelle oil field is drained by streams and creeks that form tributaries to the Mobile River and Pascagoula Bay.

The Citronelle Field was discovered in August 1955 by oil productive completion in the Rodessa sand section from 10,868 to 11,414 feet in the Zach Brooks Drilling Company, Donovan Well No. 1 (figure 5). Drilling proceeded rapidly considering the relative great depths. By June 1957, 100 wells were producing 400,000 barrels per month, or an average of 4,000 barrels per well per month. In January 1961, 261 wells produced 527,056 barrels, or an average of 2,000 barrels per well per month.

Early in the life of the field rapid bottom hole pressure decline, production decline, and an almost total absence of water production indicated that the reservoir was under a depletion drive. This prompted a group of owners to form an operators committee to undertake studies as to a means for increasing recovery of oil from the field, and if it were determined that the field should be unitized, the manner and method of such unitization should be approached. The operators committee selected a consulting engineering firm, Core Laboratories, Inc., of Dallas, Texas, to make the necessary engineering and geological subcommittee of the operators committee. Core Lab analyzed and examined data on the 4,014 feet of core samples from 56 wells within the proposed unit area. Based on the core analyses, the field produces from sand averaging 11.1 milidarcies in permeability and 9.7 percent in porosity. The Core Lab report was submitted and adopted by the operators committee with the result that a concerted effort was launched to unitize the field at the earliest possible data.

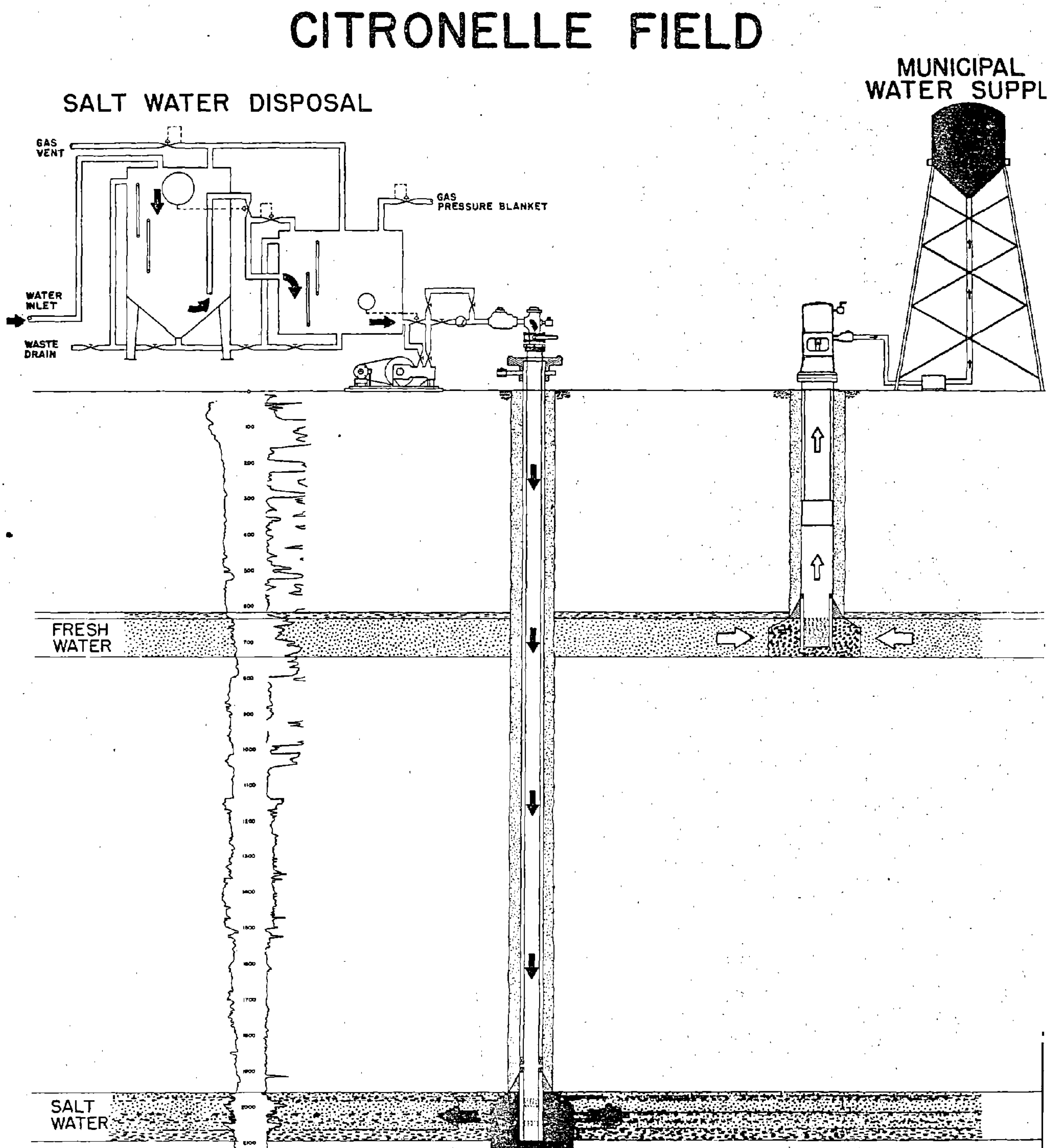
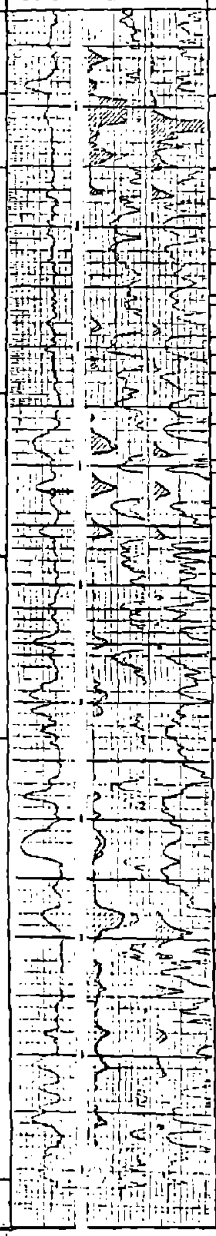


Figure 4. - Salt Water Disposal Practice Followed in Citronelle Field Mobile County, Alabama.



FLOOD GROUP	ELECTRIC LOG DONOVAN NO.1 A-25-5	SAND NO.	K (md)	Ø (%)	CW (%)
FERRY LAKE ANHYDRITE					
IV		2	2.04	8.34	55.9
		3	1.34	[illegible]	62.8
		4	1.30	7.47	66.3
		5	1.45	[illegible]	64.5
		6	1.86	7.72	58.7
		7	2.53	8.67	53.0
		8	2.53	8.38	62.4
		9	1.49	8.53	53.0
		10	2.99	9.50	50.5
		11	3.50	8.34	[illegible]
III		12	4.85	10.79	45.8
		14	29.88	12.57	40.3
		15	15.94	12.37	40.8
		16	67.4	12.07	44.6
		17	12.40	9.60	43.3
		18	10.49	10.03	46.2
II		19A	1.76	7.89	58.2
		19B	1.72	7.82	58.3
		20A	8.43	9.46	55.4
		20B	1.46	7.45	60.2
		20C	[illegible]	[illegible]	70.3
		21	2.00	8.23	56.4
		22	2.33	8.93	56.4
		24	4.85	12.71	42.4
I					
		32	4.90	8.73	53.5
		34A	0.77	8.65	65.8
		34B	0.84	6.38	63.8
		36	8.17	9.67	49.5
		38	4.38	9.84	48.8
		40	8.38	10.09	45.3
		42	10.15	9.62	50.4
		43	8.33	8.19	54.2
			11.14 md	9.71 %	50.7 %

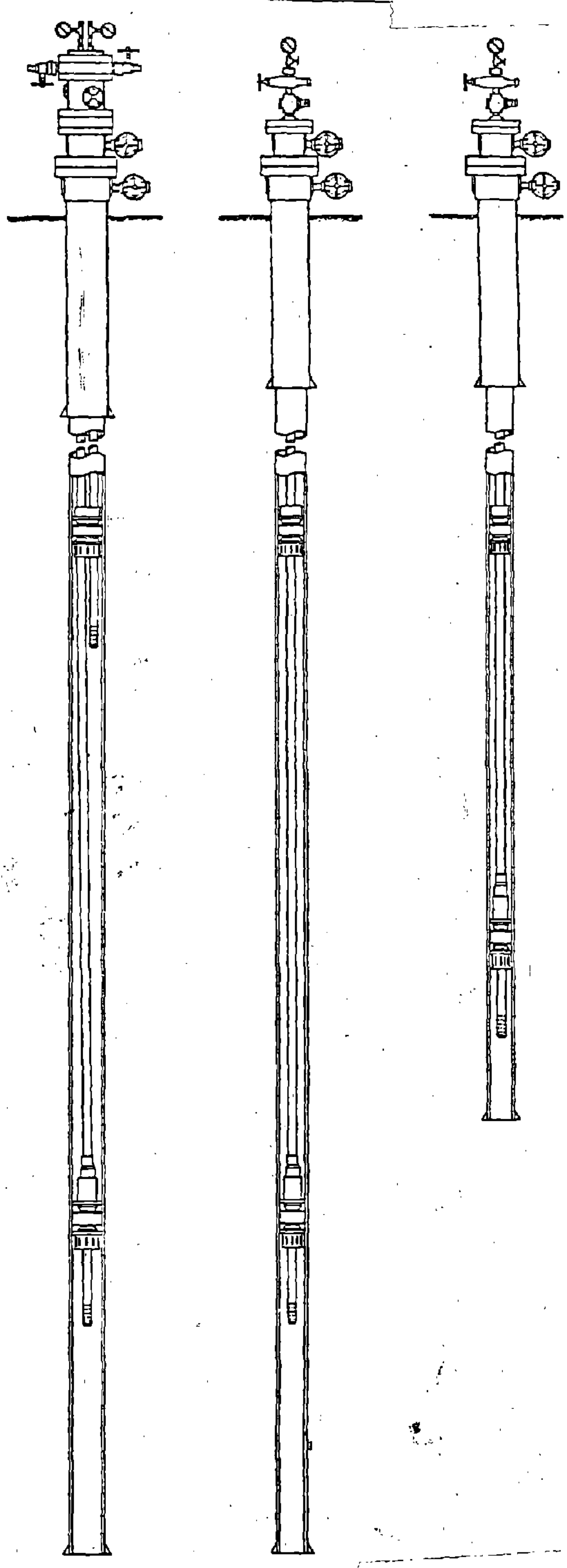


Figure 5. - Citronelle Producing Sand Properties and Well Completions.

The State Oil and Gas Board heard and approved the petition for unitization of the Citronelle Field and water injection was commenced shortly thereafter. Within two months each of the 15 wells that offset directly and diagonally the two injection wells had increased in production coincident with injection. Bottom hole pressure tests were also taken on offset wells at the beginning of each injection operation, and revealed substantial increases in pressure as a result of injection.

For the purpose of the pilot flood the municipal water supply was found to be the most compatible and economical source of fluid available for injection. The unit management is presently purchasing approximately 400,000 barrels of fresh water per month from the City of Citronelle. Since this and the public usage almost equals the total capacity of the present system (figure 4), other sources of water must be made available if the secondary recovery program is placed on a full scale basis. Several alternatives have been proposed, including use of brine produced from a shallow Wilcox sand, dilution of fresh water and brine, and recycling produced water. The latter will be a necessity in view of the steadily increasing water production.

As the water flood program takes in other sand groups, a great degree of success will depend largely on selective zone isolation in both injectors and producers. This is a mechanical situation involving the effective bond between the casing, cement and bore hole. Corrosion and deterioration of subsurface well equipment will also play an important role. This is of importance since increasing injection pressures to more than 6,500 psi (pounds per square inch) at the sand face in the less permeable sands and increasing pressure differentials between subjacent partially depleted oil sands and the salt water sands at virgin pressure will develop. An efficient field-wide injection plan will require application of improved logging, remedial processes, and testing devices, such as cement bond, salinity logs, radioactivity tracer, flow meter, and other surveys, and squeeze cementing to achieve resolution of this problem.

A corrosion problem presented itself prior to secondary recovery operations. One well began to make a tremendous amount of salt water and had to be temporarily abandoned. Ten thousand feet of salt water stood on the face of the producing zone for several months. A diagonal offset well began to increase its oil production. The normal production decline curve of the offset well was sharply reversed and showed a steady improvement for approximately 10 months. The abandoned well was reworked and several casing leaks were located and squeeze cemented. The diagonal offset well resumed its normal production decline curve. In effect, the two wells had initiated a water flood on their own accord. If the stimulated production had not been detected and remedial work performed, the owner of the abandoned well would have suffered great loss. The situation could have been reversed and it could have been a salt water sand repressurizing a fresh water sand and the ultimate loss of water resources.

This emphasizes the need for proper surface casing, cementing, and abandoning producers and wildcat wells. During the early stages of development at Citronelle, 1,800 feet of surface casing was set and cemented to the surface (figure 5). As more information was obtained concerning the fresh water-salt water interface, this requirement was reduced to 1,400 feet of casing cemented to the surface. In many areas of the country, surface casing requirements are inflexible, and, as such, present an economic block to drillers operating on limited funds. As more information is obtained concerning the depth to the fresh water-salt water contact, the controlling agency should adopt realistic rules to live by. This can only be accomplished by an agency that is aware of the many complex physical and chemical relationships that exist between rocks, ground water, oil and gas, and by an understanding of the ultimate effect that these relationships have on fluid reservoirs.

We must be vitally concerned with the introduction of foreign substances into the rock fluid system in terms of the well-being of future generations; therefore, an agency must be prepared to forecast the migration paths that a contaminating substance will take over long periods of time if we are to completely safeguard water supplies for the future and derive the maximum benefit from brine disposal practices.

During the early life of the field, salt water production was at a minimum of 2 percent or less. The isolated cases of excessive salt water production could usually be solved by successful zone isolation. During this period the most popular method of disposal was by the use of waste pits. A centrally located large waste disposal pit was constructed for the reception of drilling mud, tank bottoms and other deleterious substances associated with drilling and production. The drilling mud effectively sealed this pit for a number of years. Later in the life of the field, the pit was used for salt water disposal. Due to the areal extent of this large pit and its proximity to the town's water supply it was deemed necessary to establish observation wells peripheral to the area in question. Samples were periodically examined and indicated that the brines were not permeating the entire ground water reservoir, but were moving laterally in a relatively thin zone above a less permeable bed of clay and limonitic hardpan. This lateral movement terminates as springs and seeps that eventually feed the streams and creeks in the area. Insomuch as the Citronelle area is in the recharge area for artesian aquifers farther south, brines from the Citronelle area, if allowed to excape, could be expected subsequently to cause deterioration in the quality of the water from the wells further south.

It is futile to think that evaporation pits work to any degree of success. In the first place most of them are far too limited in surface area for evaporation to have much effect. Again evaporation and rainfall so nearly compensate each other in some areas that a few cloudy days in summer months, to say nothing of winter months, would mean a gain in volume. To make it still more difficult, the steady input to a non-leaking pit would certainly spell disaster and result in spillage. Evaporation in another sense cannot contribute to the solution of the problem, because only water vapor is lifted from the pond, thereby reducing the volume of water but leaving a more concentrated brine and finally a residue of solids. For instance, if the daily brine production at Citronelle was 100 percent evaporated, the water containing 150, 000 ppm of dissolved solids would leave a residue of 2, 600 tons to dispose of at the end of each month. Solar evaporation depends upon several unstable factors such as air temperature, temperature of water surface, wind movement, and humidity. It is obvious that only a few days of each year could be expected when all evaporation factors would bear such favorable aspect to each other as to be conducive to high evaporation rates. The average rainfall for the Citronelle area has been as high as 61 inches, of which 27 to 30 inches per year normally appears as runoff. The remainder is lost through evapo-transpiration or as recharge to the ground-water reservoir. The high rainfall and associated high humidity would preclude the possibility of a successful evaporation pit operation in the Citronelle area. Observation wells around any salt water pit will quickly dispel the thought that the pond is watertight. It has been proved conclusively that all earthen ponds leak to some degree and those constructed in porous soils to an alarming extent. The leaks occur most readily at the contact between the earthfill and the original ground, or directly through the new embankment; however, the most insidious is the downward infiltration of the impounded mineral waste. Certain pollution quickly follows this infiltration in the many instances where no impervious stratum interposes between the surface and the first fresh ground water. It is obvious, however, that should there be an impervious stratum, the time of pollution is extended only until the water moves downdip, or until a salt water aquifer is built up above one of fresh water - a situation that is almost impossible to remedy. In view of these facts and the increase of salt water production from 2 percent to approximately 18 percent, the State Oil and Gas Board had no alternative but to order discontinuance of all waste pits at Citronelle. This order has resulted in the construction of a disposal well (figure 4) and the construction of lined pits and the use of coated galvanized tanks. These pits and tanks are used in preparation, collection, and storage of salt water prior to subsurface injection. It is imperative that the field must be capable of handling the estimated increases and large volumes of water associated with the waterflood project. The results of the pilot injection program have proved beyond doubt the economic feasibility of waterflooding the more permeable sands in the Citronelle reservoir. It is estimated that the entire field has approximately 700 million barrels. Primary recovery would claim 105 million barrels. Pilot flood results have doubled this estimate to 210 million barrels. These figures compare closely with the national average.

At the beginning of 1963 we had discovered a cumulative total of about 350 billion barrels of oil in place. This includes all crude oil produced and all known reserves. Of this amount, we have produced by January 1963, a cumulative total of 71 billion barrels according to API records. This means that in all oil field ever found, there still remains some 279 billion barrels of oil in the ground. At a demand rate of 3 billion barrels per year this would be enough to last almost 90 years if we could produce all of it.

In 1930 we could recover, by methods applied then, only 15 percent of the oil found. Thirty years later, methods were developed that doubled recovery efficiency to 30 percent. If the overall recovery efficiency was raised another 5 percent our proved recoverable reserves would increase by 12 1/2 billion barrels, bringing our total recoverable crude oil reserves to 43. 8 billion barrels rather than 31. 4 billion as estimated by the API at the beginning of 1963. Recovery efficiency curves indicate that efficiency will double again in the next thirty years to 60 percent.

The utility of water and the problem of proper disposal will increase in similar proportions. Thermal techniques utilizing steam injections would certainly require an abundance of water with a minimum of impurities; therefore, if secondary recovery projects such as Citronelle and similar projects throughout the United States are to reach their ultimate goal, and if technological advances are to increase our recovery efficiency, we must diligently protect the substance that will yield these effects.

We have been discussing a stiuation where man has used fresh water to artifically stimulate production and, in so doing, has increased equipment deterioration, the problem of obtaining a large quantity of fresh water, and the problem of additional brine production. We shall now turn our attention to a field where these problems are natural in that the reservoir energy is derived from a water-drive.

Pollard Field, Alabama

Pollard Field is located in Escambia County, Alabama, in the southwestern part of the state. The wells drilled in the Pollard Field penetrated the south-southwestward dipping Tertiary and Cretaceous sediments of the Gulf Coastal homacline; undifferentiated post-Miocene deposits overlie these sediments and conceal the structural evidence of the field. The structure is a west-northwest trending graben bounded on the north and on the south by the north Pollard and Pollard faults. Closure in excess of 150 feet and drag of 40 feet or more of the Tuscaloosa beds both on a downthrown and upthrown side of the Pollard fault form the trap of oil accumulation. Production is from the basal sand of the Upper Tuscaloosa on the downthrown side of the fault, and from the Pilot and Massive sands in the Lower Tuscaloosa on the upthrown side.

Erosion of the undifferentiated post-Miocene deposits resulted in a gently rolling topography with surface elevations ranging from 75 feet in the swamp bottom of the Little Escambia Creek, which divides the field, to over 200 feet on the eastern and western portions. Drainage is southward into the Escambia River, which empties into Pensacola Bay 30 miles to the south.

Initially, the productive area of 738 acres contained 35 producing wells. In January 1964 there were 29 producing wells. The field had produced 8, 387, 676 barrels of oil through December 1963. Salt water production has increased to approximately 95 percent of produced fluids. The absence of free gas, low gas-oil ratios, small decreases in bottom hole pressures, and the continued increase in water production gave early indication that an active water drive was the reservoir energy. During the development stages drilling, completion, and production difficulties were seldom encountered. Several years after the field development was completed, corrosion and increased salt water production were the basis of the most serious production problems at Pollard. An attempt to store brine in waste pits resulted in tree kill that affected several small areas.

In 1958, a problem of salt water encroachment in a shallow ground water aquifer used for a source of domestic water was reported in the northwestern part of the field. This water supply was abandoned and an alternate supply was obtained. In 1962, salt water encroachment was again noticed in a domestic water supply by a local landowner. As a result of this and other complaints pertaining to brine contamination, a study was conceived to obtain information to aid in the future planning and protection of water resources and determination of proper conservation practices. This included the identification of water problems related to oil field development in all areas of the state, determination of source, severity, approximate areal extent, and probable future movements of contaminants in both ground and surface waters. Because of the large quantity of water being produced and the history of past complaints, the Pollard area received the most concentrated program of study.

Water supplies for all municipal, industrial, agricultural and stock use in and near the Pollard Oil Field in Alabama are obtained from wells tapping beds of Tertiary and Quaternary age. These beds crop in and underlie parts of the oil field area and consist chiefly of thin to massive beds of sand, clay, silt, gravelly sand, and sandy clay. The deposits are also lithologically similar to the rocks underlying much of the Gulf and Atlantic Coastal Plain areas.

The permeable sand and gravel beds that crop out in and underlie the Pollard Field at relatively shallow depths are subject to contamination where a source of pollution is available (figure 6). Beds in which water-table conditions exist are estimated to have an average thickness of about 50 feet in the area. They are underlain by relatively impermeable beds of clay that prevent the downward movement of water. The clay also acts as a confining bed for water that occurs under artesian conditions in underlying aquifers (figure 6).

Natural water in aquifers underlying Pollard Oil Field is generally of good quality, but, locally, it may have a high iron content. Chemical analyses of water samples collected from 815 wells tapping these aquifers throughout Escambia County, in which Pollard Field is located, indicate that the water is low in dissolved solids and generally has a chloride content of less than 15 ppm and a hardness of less than 25 ppm.

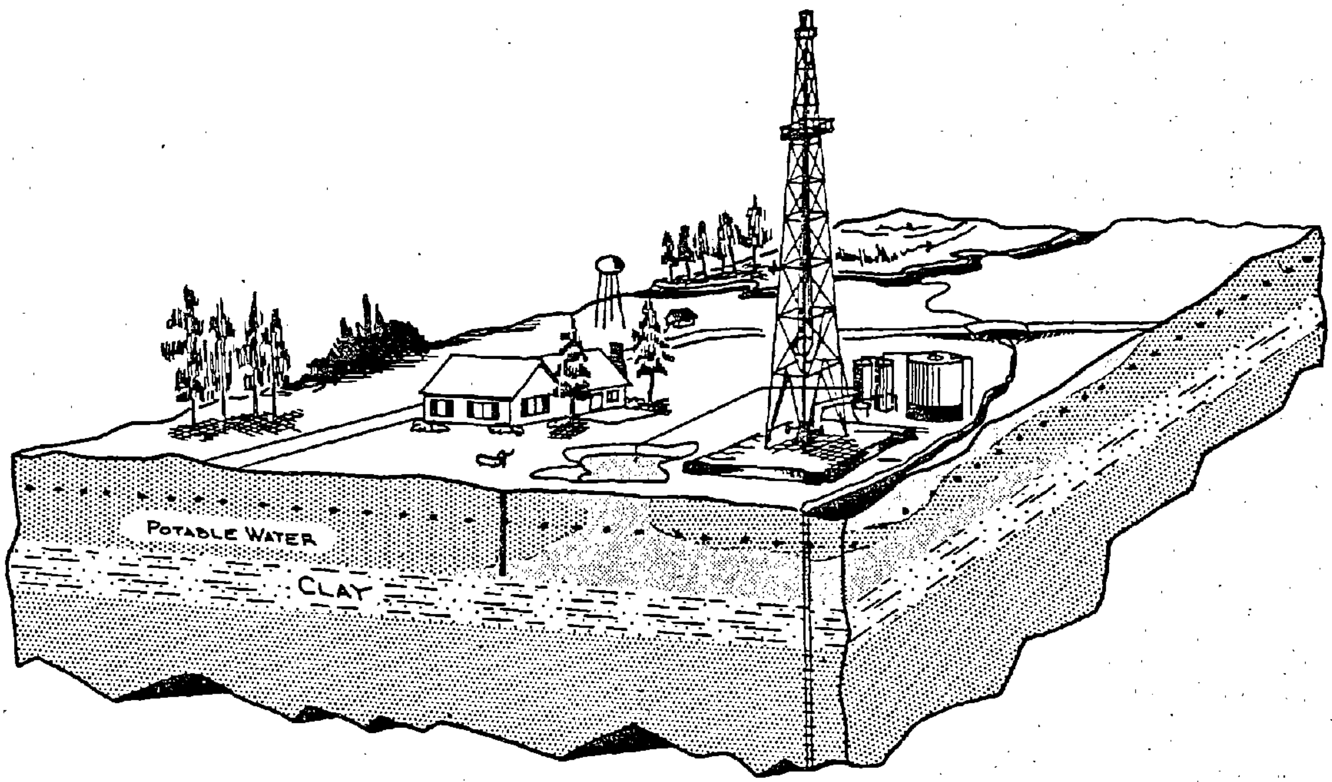


Figure 6. - Diagram showing possible means of contamination of ground-water supplies in oil field area.

The total area in the Pollard Oil Field affected by contamination is estimated at 400 acres. The sources of contamination in the field are waste-disposal installations and pipeline leaks.

Brines and other oil field wastes in the Pollard Field are disposed of by injection and "so-called" evaporation pits. Brine is separated from the oil at the treater plants and pumped through pipelines to a disposal well. These wells are constructed to resist corrosion from the brines and are screened or perforated opposite a sand below the fresh water-salt water interface. There are three active disposal wells in the Pollard Field.

Wastes flushed periodically from the treater plants, brines rejected at the disposal wells, or wastes discharged from producing wells are disposed of in "evaporation pits" that are of earthen construction. Hydrologically, these pits might be more aptly described as "infiltration ponds." Oil that accumulates in the pits is skimmed or burned off and the brine is left to evaporate, although a large part of the brine percolates downward to the ground-water reservoir (figure 6). There are eight large pits and twenty small pits associated with individual wells in the Pollard Field.

Contamination of ground water is seldom recognized until the contaminant pollutes a source of water supply or has an effect on vegetative growth. It is possible that months or years may pass after a contaminant is first introduced into the ground-water reservoir before it is recognized as a problem.

Figure 7 shows the location of the wells in, and adjacent to, an area of salt water encroachment in the Pollard Field and the chemical character of water from these wells. Well W-147 obtained water from sand at a depth of 55 feet, but is was abandoned in 1955 because of the high chloride content of the water. Well W-148 was drilled in 1959 to a depth of 40 feet as a source of water supply for domestic and stock use. Water from this well became salty in October 1961, and in March 1962 the chloride content was 4,160 ppm. The well was abandoned in April 1962, and well W-146, drilled to replace it, obtained water of good quality at a depth of 45 feet. Five partial chemical analyses of water collected from well W-146, from May 1962 to March 1963, indicate that contaminated water did not migrate to the well during that period. The chloride content of water from observation well W-146-1 has increased from 52 ppm in

Source	Depth (feet)	Date	Chloride (ppm)	Hardness (ppm)	pH	Temperature (°F)
W-69	60	1-23-56	11	24		
Do		2-19-63	7	10	6.4	51
Do.		3-13-63	10	14	5.5	
W-72	57	2-14-56	7	9	5.0	
Do.		3-21-62	14	8		
Do.		5-16-62	15	10	6.0	
Do.		10-12-62	45	5	5.7	
W-73	52	1-24-56	14	8		
Do		2-19-63	7	8	5.8	56
Do		3-13-63	8	5	5.5	
W-74	72	12-29-55	36	29		
Do		2-19-63	27	48	6.6	47
W-146	45	5-16-62	4.8	7	6.4	69
Do		6-13-62	5	6	6.7	69
Do.		10-12-62	4.8	7	6.4	
Do.		2-18-63	7.8	5	6.6	68
Do		3-13-63	8.0	6	6.0	
W-146-1	33-35	6-14-62	40	18	6.1	70
Do.	38-40	6-14-62	13	5	7	
Do	41.6-43.6	6-15-62	52	20	6.6	
Do.	41.6-43.6	10-12-62	76	34	6.7	
Do	41.6-43.6	2-18-63	54	45	7.1	66
Do.		3-13-63	148	62	7.2	73
W-146-2	42.5-44.5	6-14-62	1,100	346	4.6	70
Do.	47.8-49.8	6-15-62	1,240	396	5.5	
Do.	53.1-55.1	6-15-62	2,510	833	4.6	
Do	58.5-60.5	6-15-62	3,220	1,230	6.2	
Do	58.5-60.5	10-12-62	2,480	446	6.8	
Do.		2-18-63	3,900	1,340	6.2	66
Do		3-13-63	10,800	4,320	6.9	71
W-148	40	2-21-62	4,160	1,390		
W-149	23.5	2-18-63	5,250	1,980	6.9	73
* Do.		2-18-63	11,050	3,000	7.2	82
Do.		2-19-63	7,800	3,350	6.8	81
Do		3-13-63	11,800	4,250	7.4	80
W-150	23.5	2-19-63	38,900	14,800	6.5	82
* Do.		2-19-63	40,500	15,000	6.1	82
Do.		3-13-63	28,500	10,800	5.5	81
* Do.		3-13-63	29,500	10,900	5.6	81
W-151	10.6-12.6	2-19-63	480	136	4.8	70
Do	13.5-15.5	2-19-63	1,400	474	6.1	71
Do	16.3-18.3	2-19-63	18,400	4,580	6.9	74.5
Do.		2-20-63	9,610	3,840	6.8	74.5
Do.		3-13-63	8,250	3,000	7.2	73

* Sample after ½ hour pumping at ±1 gpm.

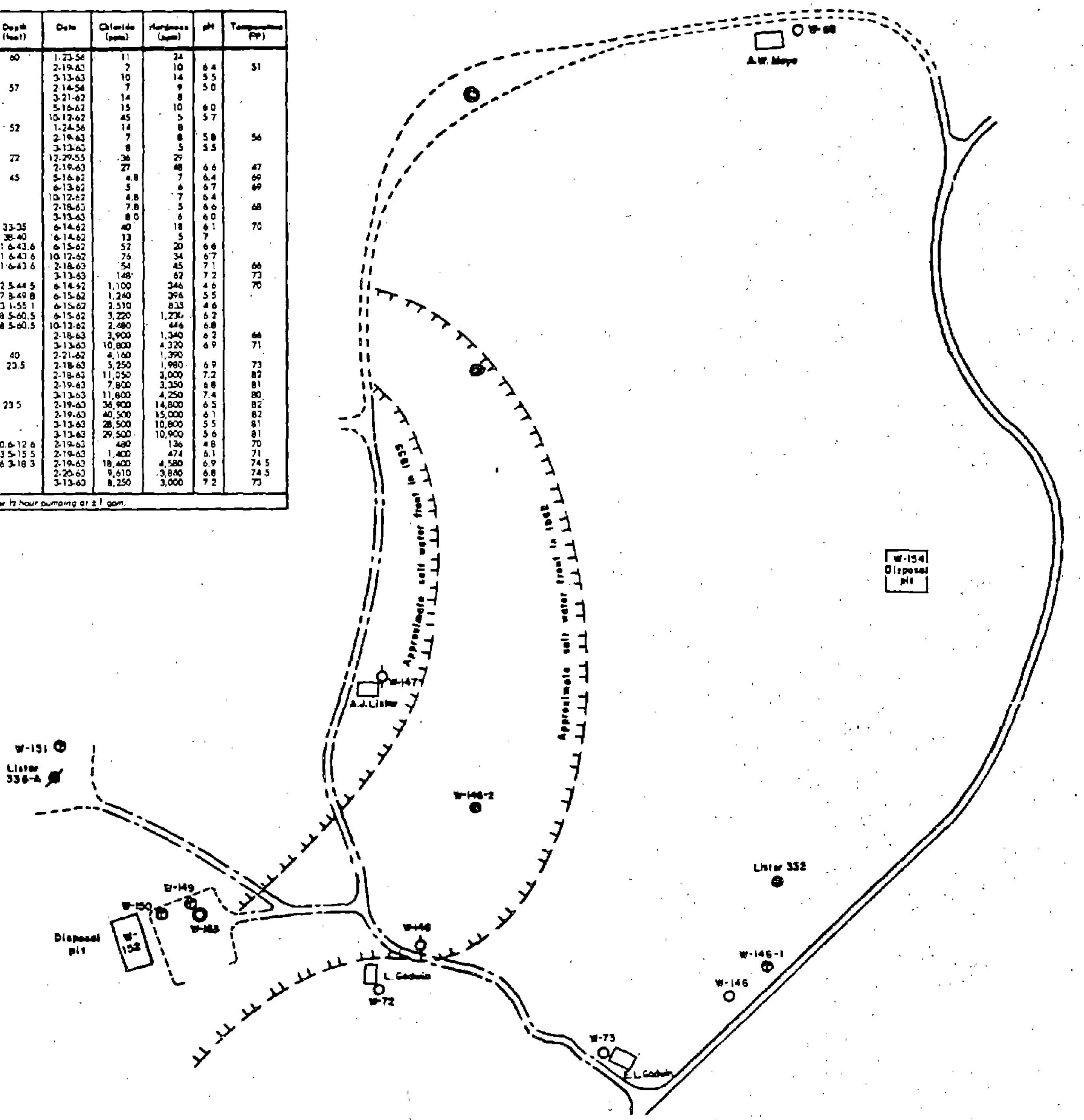


Figure 7. - Wells and disposal pits in and in close proximity to area of salt water encroachment, Pollard Oil Field, Escambia County, Ala.

June 1962 to 436 ppm in November 1963. It is estimated the salt water front will have migrated to well 146 in 1964.

Several test wells were installed to aid in delineating the extent of salt water encroachment and in determining the source of the salt water. The results of observations made in these wells and in wells drilled prior to 1955 indicate:

1. The area of contamination has enlarged considerably since 1955. The approximate locations of the salt water front in 1955 and 1962 are shown in figure 7.
2. One source of the contamination is pit W-152.

Disposal pit W-152 is constructed in an area underlain by sand, gravel and clay. The sides of the pit are of earthen construction, and they are approximately 7 feet high. The approximate dimensions of the pit are as follows: depth - 17 ft, width - 35 ft, and length - 90 ft. The bottom of the pit is about 7 feet above the water table. Because the pit is constructed in a material that is permeable, the seepage loss is probably high.

The temperature of water obtained from a test well near the pit was 82° F., immediately following completion of the well, and the chloride concentration was 36,900 ppm. The normal temperature of the ground water in uncontaminated aquifers in the area at depths of less than 50 feet is about 65° F.

A loss of about 23,000 gallons of brine from pit W-152 during the period 4:00 p.m. on February 19 to 7:30 a.m. on February 20, 1963, was attributed to seepage to the ground-water reservoir (figure 8).

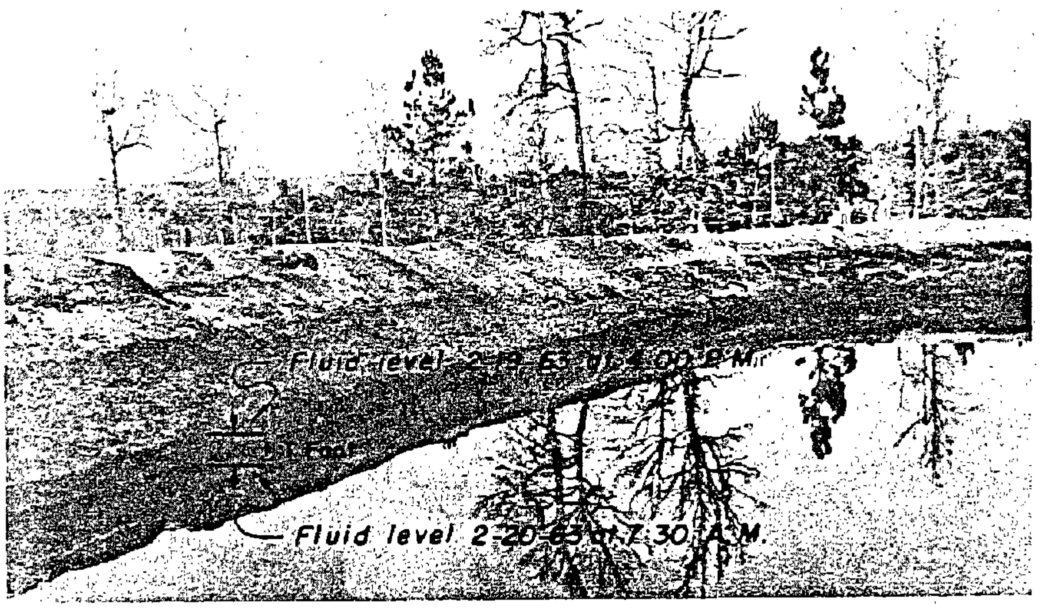


Figure 8. - Drop in fluid level in "evaporation pit".

Another problem associated with contamination in the vicinity of pit W-152 is tree kill. The dashed line in figure 9 shows, in part, the approximate limit of tree kill associated with the discharge of water high in chloride content. The source of brine responsible is partly from seepage loss from a pit, partly from ground water high in chloride content discharged through seeps (figure 9), and partly from leaks in pipelines. Salt water that is being discharged through the seeps in the vicinity drains northward to a creek, but the flow of the creek at this point probably is sufficient to dilute the contamination during most periods. The leak in the pipeline (figure 9) was discharging at the rate of about 2 gpm (gallons per minute) on February 19, 1963.

Changes in the ground-water quality in the area of contamination since the development of the Pollard Oil Field are as follows:

1. The chloride concentration of ground water above the first clay layer in the area of encroachment has increased; chloride concentration increased also with depth.

Site	Chloride (ppm)	Specific Conductance (micromhos at 25° C)
W-152	91,800	140,000
1	Field determination	1,800
2	8,080	24,700
3	12,900	32,300
4	11,600	30,000
5	14,800	35,900
6	20,000	48,200
7	18,100	44,300
8	16,400	40,700
9	16,800	39,300
10	15,100	37,600
11	3,500	10,700

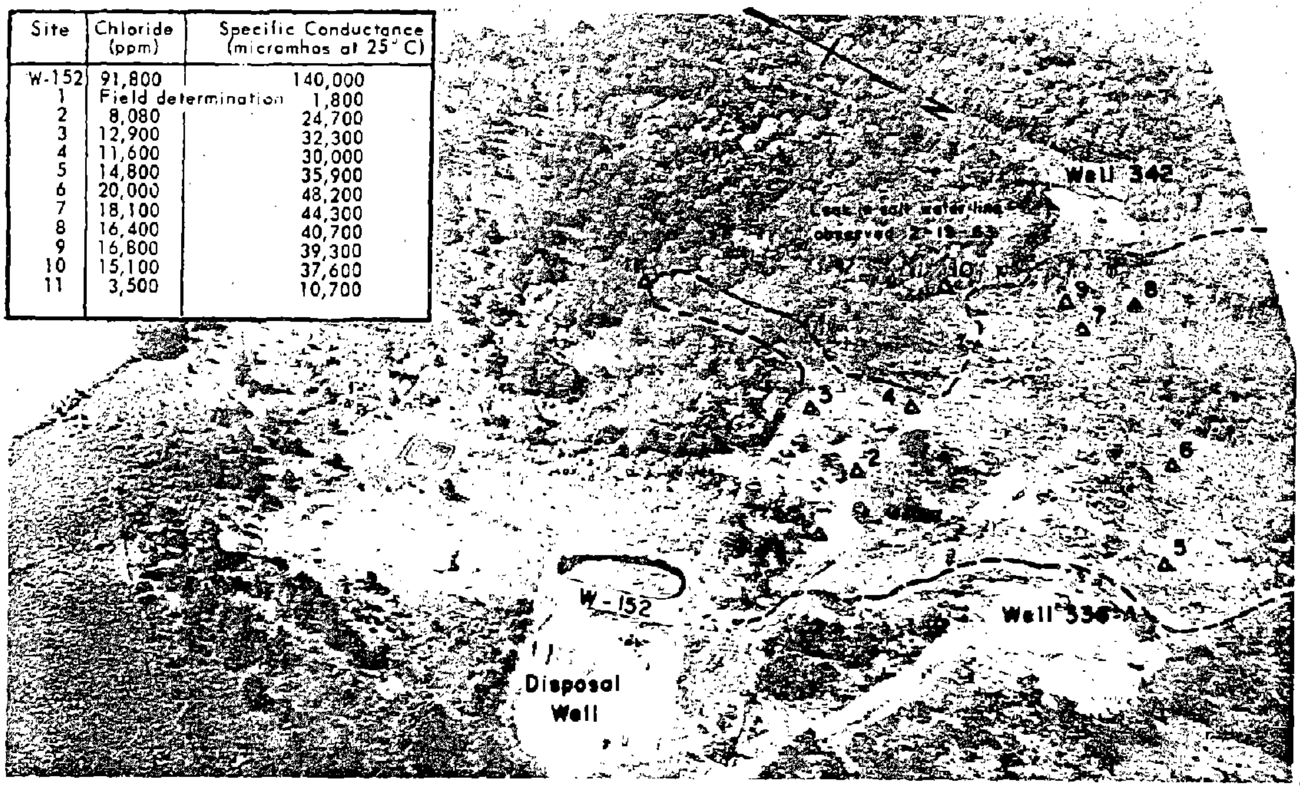


Figure 9. - Tree kill in vicinity of pit W-152 and locations of seeps.

2. The chloride concentration in the area of contamination has increased with time. The chloride concentration of water from one of the observation wells increased from 3,220 ppm in June 1962 to 10,800 ppm in March 1963.

3. The rate of movement of water with high chloride content increases with increases in the rate of withdrawal from wells.

4. Ground-water mounds caused by seepage loss from pits have affected the movement of water locally.

In Pollard and similar fields producing from water-drive reservoirs, it is imperative that brine disposal be done at a minimum cost. Obviously a well producing a high percentage of salt water could not be profitable if the cost and volume of brine disposed therefrom were high. It is just as obvious that evaporation pits will not handle the quantity of water in a proper manner; therefore, the only alternative is proper subsurface disposal. Another drastic alternative would be to abandon the property and leave the recoverable oil in the ground. Since stripper production constitutes a large percentage of the total domestic production, this, indeed, would be a very drastic step. It would also include economic complexities greater than we are able to cope with; for instance, who can judge what the value of potable water in any location in the United States will be forty years from now, and who can say that the oil is presently the most important when a saturated petroleum market exists. These problems will have to be resolved if Pollard and similar fields and marginal stripper fields are to survive.

One problem that has occurred several times in the history of oil and gas production is where a high pressure oil or gas sand has recharged fresh water aquifers. A comprehensive report on a case of this nature in Harris County, Texas, was covered by Rose and Alexander, (1945), in a paper titled "Relation of Phenomenal Rise of Water Levels to a Defective Gas Well, Harris County, Texas."

The water levels in wells throughout the Houston district, Texas, had declined due to the large increase in the rate of pumping in the Houston and Pasadena areas. An outstanding exception to this downward trend of water levels occurred in several wells north and northwest of Houston which had a sharp upward trend. The area in which rise was noted is about 25 miles long and 10 miles wide. About 50 water wells in northern Harris County were investigated - several water wells in, and near, the Bammel Gas Field that theretofore had been pumped were flowing and the water level in most of the wells within a range of several miles had risen sharply. Within a few days five water wells in the field started to crater. It was soon discovered that one of the gas wells in the field had developed a leak in the casing at approximately 600 feet below the surface and was discharging gas into the water-bearing sands. A detailed study was made by the U. S. Geological Survey, Texas State Board of Water Engineers, and the Oil and Gas Division of the Railroad Commission of Texas. This study resulted in a report that concluded that the discharge of gas from the defective well in the Bammel Gas Field into the water-bearing sand had caused a phenomenal rise of the water levels in many of the water wells in the area north and northwest of Houston. As a result of this leakage, five water wells in the Bammel Field had cratered and several wells in the field had produced some gas with water. It is estimated that the gas had traveled about 2,400 feet from the defective well. It was believed, however, that complete displacement of the water and unwatering of the sands had occurred only to the limited extent, perhaps principally in the upper part of each sand; and that in the upper part of the sand, gas had moved more than 2,400 feet and that a part of the displacement had taken place by diffusion. The experience gained from the study of the defective well in the Bammel Field shows that serious damage may be done to the municipal and privately-owned wells if gas wells become defective, and the gas is discharged into the water-bearing sands.

DISPOSAL METHODS

Most of the oil-producing regions have legislation controlling the disposal of oil field brines to provide adequate protection for surface vegetation of all types, soils, surface and subsurface water, and mineral fuels and mineral resources. Both state agencies and the petroleum industry have spent large sums to study the occurrence and availability of water resources in oil field areas and for the determination of the best methods to separate, treat, and dispose of produced brines.

Common Disposal Methods

Some of the more common means of salt-water disposal which prevent pollution of fresh-water strata and surface streams and avoid contaminating land and killing vegetation include: (1) disposal into seepage sumps; (2) controlled disposal into streams; (3) collection and evaporation in surface pits; (4) injection into salt-water-bearing formations; and (5) piping to ocean or other salt-water body.

Seepage Sumps. In certain areas, where approved by applicable regulatory bodies, salt water may be disposed into seepage sumps located on outcrops of steeply dipping marine formations that do not contain fresh water.

Streams. The controlled dilution and disposal of brines into streams and surface waters has been allowed in some areas during periods of high stream flow or surface water runoff. The increasing development of our surface water supplies for regional or urban use definitely limits this practice. The danger of undesirable concentrations of dissolved salts increases during periods of low water flow. This can result in concentrations dangerous to aquatic plant and animal life and render waters unfit for irrigation or other human use during periods of greatest need.

The water resources and recreational value of our fresh water streams and lakes becomes an increasingly important factor as our population growth continues and the development of additional recreational facilities becomes necessary or desirable. Surface disposal should not be permitted when these values are endangered or threatened.

Surface Pits. The use of evaporation pits, surface pits, retention pits, brine-storage pits, and impounding basins of earthen construction is common practice in many areas. In the warmer and more arid areas of the country, evaporation from such open pits, if the water surface is free of oil film, may be considerable; and under such conditions, large earthen pits could handle significant quantities of salt water. However, in many areas, the average annual rainfall equals or exceeds the evaporation rate. For this reason, together with contamination risk from seepage and overflow of pits and their recognized inadequacy to handle the ever-increasing production of salt water, the use of such surface pits is now largely restricted to impounding relatively small quantities of brine. Seepage into underground fresh-water aquifers and lateral migration into natural stream courses create a serious contamination or pollution hazard. The use of surface pits of earthen construction as seepage basins for the disposal of very small volumes of brine or saline waters has often been approved for temporary or semi-permanent use. The volume of brine involved may be insufficient to create an undesirable or hazardous condition that warrants the construction of a costly subsurface disposal system. These surface pits remain a continuing source of contamination, as even small volumes can add up to a considerable quantity over an extended period of time. Surface pits are useful in skimming off oily waste while permitting gradual seepage and dilution of waste waters. The use of such pits should be strictly limited and should be discontinued as soon as proper facilities can be provided.

Piping to Ocean or Other Salt-Water Body. Where an oil field is located fairly near an ocean, gulf bay, or other large salt-water body, the transportation (usually through pipelines) of salt water thereto is sometimes the most practical disposal method. Some of the factors that would determine the feasibility of this method --- relative to other means --- would be: (1) the distance between the oil field and the salt-water body; (2) the nature of the land over which the pipeline, canal, etc. would be located; (3) the volume of brine to be handled; and (4) restrictions of regulatory bodies controlling such disposal.

Injection into Salt-Water-Bearing Formation. In many circumstances this is the most feasible means of disposal. Hence it is the method most widely used in the United States of disposing of large volumes of oil field brine. For highest receptivity per well, lowest injection pressure, and lowest cost of maintaining maximum well receptivity, the disposal formation should preferably be either a highly permeable limestone or dolomite having a relatively low static fluid level (i.e., bottom-hole pressure) and wide areal extent. The basic advantage of limestone or dolomite formations is that their permeability, and hence receptivity, can be fairly readily maintained by periodic injection of hydrochloric acid into the disposal well.

If, however, suitable limestone or dolomite is not present in the area, a sandstone having comparable porosity, permeability, and volume (area and thickness) is generally the next best disposal formation prospect. Also, some conglomerates and gravels afford worthwhile disposal capacities.

Other Potential Disposal Methods. Disposal of oil field brines by evaporation in heated vessels has been used to a very limited extent. However, the corrosion and scaling problem and cost of this method are considerable. If these problems can be largely overcome, the evaporation method of disposal might have widespread application.

There has also been considerable development work in recent years on desalting of brines by electrolysis and other methods. Although this technique is yet too expensive and otherwise not now commercially feasible for handling large volumes of high dissolved solids content salt water, it seems to offer considerable eventual promise as another means of disposing of oil field brine.

Beneficial Uses. By-product recovery is the utopian aspect of industrial-waste disposal and treatment, the one phase of the entire problem which may lead to economic gain. Many consultants deprecate this approach to the solution of waste problems. Their attitudes are based mainly on statistics concerning the low percentage of successful by-products developed from waste salvage. The search for by-products should be encouraged, however, if only because it provides management with a clearer insight into processing and waste problems. Obviously any use of waste materials eliminates at least some of the waste which eventually must be disposed of. There are many expamples of positive results from adapting waste-treatment procedures to by-product recovery.

Among these are metal-plating industries, paper mills, sewage plants, distilleries, packing houses and slaughterhouses, dairy industry, and sugar industry. There are many companies that are in business primarily to develop by-products from other plants' waste products. With the multiple constituents contained in oil field brine, there should be many ways in which the oil industry could turn waste into a usable product. It is already being used for utility on waterflood projects and in some instances bromine production. Although the problem of waste disposal usually persists despite the utilization of waste for by-products, it is greatly lessened by this practice.

*SUBSURFACE DISPOSAL

The return of brines to suitable subsurface formations below the last known fresh-water aquifers is the most satisfactory method for the disposal of oil field brines. One disadvantage to this method has been the popular practice of using old wells for subsurface disposal. The requirement outlined in the section on selection of disposal wells should be utilized for successful subsurface disposal. Brines can be returned to the aquifer associated with the parent producing reservoir or to one of the nonproducing saline aquifers normally present in a producing region. One or more of these nonproducing saline aquifers are usually approved by regulatory agencies as suitable for brine-disposal use. The disposal of brine by injection into subsurface aquifers can be accomplished by several types of well completions. As this method is universally accepted as the best for disposing of brines, some specific guidelines are listed for the implementation of this type of disposal system.

Planning For Subsurface Salt-water Disposal

Several initial stages of planning should be completed before designing any salt-water disposal system. These stages in their logical order are:

1. Predict the total amount and maximum rate of water production which must be disposed of by the system.
2. Select a suitable disposal formation and disposal well or wells.
3. Determine if the gathering system will operate under gravity head or if pressure will be required.
4. Determine whether an open or a closed water-treating system is necessary.
5. Secure the necessary permits from the state regulatory body, royalty and/or landowners, and offset operators.

The first step in planning for the design of a salt-water disposal system is to construct a curve of estimated rate of future water production for the area to be served. This task becomes easier as the producing properties become older. The rate and period of water production and disposal will be influenced by the following:

1. Extent of water drive present in oil reservoir.
2. Capacity of present and future producing equipment.
3. Number of producing wells to be served.
4. Expected life of operation.

If the oil reservoir is producing under the influence of an active water drive, the percentage of water production from each well will increase throughout the life of the well until a minimum economic oil-production rate is reached. The water-production rate at that time will be dependent upon the producing capacity of the formation and the capacity of the artificial-lift equipment on the well. Thus, for design purposes, the maximum water-production rate will be the sum of the producing capacity of the lift equipment installed on the wells to be served. In reality, the water-production rate will hardly ever be that high. It is very seldom that all of the wells in a field reach their maximum water-production rate at the same time. Usually, several wells will be watered out and abandoned before others approach their maximum water-production rate. Again, other wells will never produce at the maximum capacity of their lift equipment because of reservoir producing-capacity limitations.

Where there is a limited water drive in the producing reservoir, the water-production rate will frequently increase to some maximum and then decrease before the economic limit is reached. Thus,

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* The following section is abstracted from American Petroleum Institute Vol. III, "Subsurface Salt-Water Disposal." For a thorough discussion on this subject, the reader is referred to this report.

the problem of estimating the water-production rate from each well is directly related to determing the extent of the water drive in the reservoir.

Where it is necessary to install a disposal system in the life of the reservoir, a comparison with nearby older reservoirs in the same formation is the most reliable way of estimating the extent of a water drive.

After the maximum water-production rate of any one well has been estimated, it is then necessary to estimate how many of the wells to be served will be producing water at the same time. This will be dependent upon the direction of water encroachment within the reservoir. If there is a bottom-water drive, the wells will normally go to water in an order which is proportional to the distance they are completed above the water table. If there is an edge-water or side-water encroachment, the wells closest to the encroachment will produce water first.

After the available data have been analyzed as suggested, a curve of future water production vs. time for any or all parts of the reservoir may be constructed. This curve can be used to design the disposal system from the gathering lines through to the injection well. Although the curve may not be exactly accurate, it will usually suffice to indicate the magnitude of water production at various times.

Selection of Disposal Formation

A suitable disposal formation is the very heart of a good disposal system. If water can be disposed of by gravity or with a vacuum on the injection well head throughout the life of the project, operating expenses will be much less than if injection pressures are required. For the average system the additional cost of operating injection pumps is approximately one cent per barrel of water. This cost amounts to $100, 000 for a system that disposes of 10, 000, 000 barrels of water during its life. Economics such as these dictate that all available formations should be screened carefully before selecting one.

The three primary requirements for a good disposal formation are:

1. High permeability and porosity.

2. Large areal extent.

3. Low reservoir pressure.

It is necessary for a disposal formation to have a high permeability so that injection pressures will be at a minimum. Injection pressure is also related to the formation thickness.

Formation Factors Important to Subsurface Brine Disposal

The permeabilities and thicknesses of the various formations available for disposal purposes can be determined or estimated by one or more of the following: core analysis, examination of bit cuttings, drill-stem test data, electric logs, driller's logs, and analogy with the characteristics of the same formation in other nearby areas.

The native permeability of the disposal formation can be increased in many cases by one of the several stimulation techniques now available to the industry. The most common of these are acidizing and fracturing.

A formation must have a large areal extent before it can be used for disposal purposes for any length of time. The reason for this is that the fluids within the disposal formation must be compressed to make room for the incoming fluids. As the fluids within the formation are almost always water and as water is very slightly compressible, there must be a large amount of freely connected pore space to allow for compression of the water. If the pore space is not large enough, the reservoir water pressure will soon rise to a point where further injection is impracticable.

Connate water at normal bottom-hole pressures has a compressibility factor 3×10^{-6} unit volumes per psi. Thus, if the disposal formation pressure cannot be increased over 500 psi from its initial pressure and 10, 000, 000 barrels of water are expected to be injected into the formation throughout the life of the system, then the formation must contain at least 6, 670, 000, 000 barrels of water in place. This would be equivalent to a formation 50 feet thick, with a porosity of 25 percent and an areal extent of 68,600 acres.

An estimate of the areal extent of a formation is best made through a subsurface geological study of the area.

If it is possible to inject water into the aquifer of some oil- or gas-producing horizon, then the size of the disposal formation is not too important. Under these circumstances the injected water would displace water from the aquifer into the producing reservoir from which fluids are being produced. Thus the pressure in the aquifer would only increase in proportion to the amount that water injection exceeds fluid withdrawals.

Other things being equal, the formation with the lowest reservoir pressure should be chosen for disposal purposes.

The best disposal formations will generally be the pressure-depleted aquifers of older producing reservoirs.

SELECTION OF DISPOSAL WELLS

After determining future water-production rates and selecting the best available disposal formation, the next step in planning for a disposal system is to select a disposal well. A salt-water disposal well can be created either by drilling a new well or by converting an existing well or dry hole. The choice between the two is strictly a matter of economics. Not only must initial costs be considered, but also expected future operating costs.

All existing wells should be carefully screened, as normally it is much more economical to convert existing wells than to drill new ones. The most likely candidates for conversion will be dry holes and abandoned producers. Sometimes it will be best to convert a producing well.

When selecting a disposal well, the surface topography in the area should be considered. If possible, the disposal well should be located so that as many water-gathering lines as possible will be operating under a gravity head. A surface topography map of the area to be served will be useful in selecting the tentative locations of the gathering lines, water-collection points, and disposal wells to obtain maximum advantage of the surface elevations. After locating the lines on the map, the elevation of the various junctions can be determined for use in hydraulic-flow equations. The solution of these equations will show whether or not a pressure system is required.

Newly Drilled Well

The advantages of a well drilled specifically for disposal purposes are that an optimum location may be selected - both topographically and geologically - to take advantage of all available hydraulic head in delivering water to the well, and to dispose into an area of optimum porosity and permeability. Also, the surface or protection casing strings may be sized to accommodate the required size casing and tubing strings. Desired casing weights and grades may also be used. Special cementing practices may also be employed on newly drilled disposal wells, such as cementing, circulating cement the entire length of the long string, or placing corrosion-resistant material above the cement behind the casing.

The principal disadvantage of drilling a new well is the cost. The disposal capacity of a new well will not be known until the well has been drilled and tested. If the capacity is not sufficient, one or possibly more additional wells may be required.

Abandoned Dry Hole

The economic advantages of using a dry hole without casing are that the well can usually be obtained for a fraction of the actual drilling cost. If production casing has been installed, the well may be obtained for the salvage value of the casing. With some additional expense, the well may be deepened, and, if necessary, logged, cored, or tested to determine the nature and disposal quality of the proposed disposal zone.

The disadvantages are that the well may not be favorably located topographically. The surface casing may not be sufficiently large to permit running the proper size casing. If production casing is in the well, it may not be large enough for the required disposal capacity.

The casing may have to be stage-cemented or cement-circulated, an additional expense, if desired.

Abandoned Producing Well

The advantages of converting an abandoned producing well for disposal purposes are approximately the same as those of using a dry hole that has been cased as discussed. If regulations permit disposing into the abandoned producing zone, the disposal capacity of the well may be increased over a newly drilled or perforated zone because of established drainage patterns formed during the producing life of the well.

The disadvantages are also approximately the same as those of a cased dry hole. Also, the casing in the well may be corroded or badly worn, which may result in early failure and cause considerable expense to repair or possibly result in the loss of the well. The casing may not be large enough for the proper size tubing or for deepening and installing a liner, if necessary.

Annular-space Disposal Wells

The use of saline aquifers exposed to the annulus in the uncased intervals between casing strings for the disposal of brines is a common practice. Under proper conditions, this system may provide satisfactory disposal facilities for an individual well or lease where small volumes of brine are produced. The use of an annulus for disposal may preclude normal rework operations in the event of casing failure, which can lead to serious contamination of unapproved aquifers, including that caused by migration between aquifers. This method of disposal frequently requires the injection of brine under increasing pressure with respect to time. This can be the result of the accumulation of formation cavings, drilling mud, pipe scale, or other plugging agents either trapped in the annulus or introduced with injected water. An associated pressure buildup in the injection reservoir may be due to such unfavorable geological and physical characteristics of the rock unit, such as low porosity and permeability, a thin porosity zone, and discontinuity or lenticularity of the injection reservoir. Annulus disposal can provide a temporary solution to a disposal problem while more adequate and permanent facilities are being developed.

SECURING OF PERMITS

It is usually advisable to secure the necessary permits before completing a full-scale design of the disposal system. This is because it may not be possible to obtain permission to use the well which has been selected as the best disposal well. Sometimes it is also difficult to obtain rights-of-way which would permit construction of the best possible system. In these cases it is necessary to design the system to the available rights-of-way and disposal-well sites.

In most instances it is necessary to obtain permits to dispose of salt water from the land and/or royalty owners, offset operators, and state regulatory bodies. A simple contract is the most common instrument of agreement used between the operator and land or royalty owners.

In most states, permission must be obtained from some state regulatory body to dispose of salt water in underground formations. Applications for permission are heard before the regulatory bodies in some states and are handled by correspondence in the others. Generally, it is necessary to submit the following type of information with the applications:

1. Location of disposal.
2. Name, depth, and intervals of subsurface formation to be used for disposal purposes.
3. Size, weight, and depth of all casing strings in well and amount of cement behind casing.
4. Approximate amount of water to be disposed.
5. Expected wellhead pressures to be encountered.

6. Well log if available.

7. Depth of fresh or usable water in immediate area.

8. Names and addresses of offset operators and royalty owners.

Based on the foregoing information and other available data or testimony, the regulatory body must satisfy itself that the disposal of salt water as intended will not pollute fresh or usable water, or damage nearby oil and gas reservoirs.

If there are any objections from offset operators that cannot be settled by the operators, they are usually heard and settled before the state regulatory body.

APPENDIX B PART II

ELEMENTS OF WATER TREATMENT

As a general rule of thumb, surface water contains much suspended matter but relatively low concentrations of dissolved solids. Conversely, groundwater generally contains little suspended matter, but higher concentrations of dissolved solids. There are many local exceptions to this rule which are dependent on the topography, climate and geologic setting.

The purpose of water treatment is to improve the bacterial, physical, and chemical quality of the supply. The final use to be made of the water determines, to a large degree, how much treatment is justified. For example, if the supply is to be used for agricultural purposes only, irrigation or livestock, bacterial contamination and turbidity are of relatively little consequence. "Hard" water can be desirable for irrigation, but is a nuisance for laundering clothes. Water for municipal supplies is expected to be more than merely clear and bacteria free. The demand is for water that is soft free from taste and odors, non-corrosive and non-discoloring.

Factors in selecting specific water treatments include the characteristics of the raw water, initial and operating costs, space limitations, future rate of expansion, desired effluent quality and the availability of skilled operating personnel. Treatment of water involves suspended or colloidal particles and dissolved material, which may be either organic or inorganic. The chief concern in treating water containing organic material is that of killing any pathogenic organisms; usually bacteria. Treatment of oil field brines indicates that the treatment primarily will be desalination. Two additional problems can be anticipated in the mining of an oil reservoir. One, the process of mining will add suspended matter as turbidity in the water, and two, some oil and oil products will be contained in the brine because they are in mutual contact in the same reservoir.

Conventional Treatment Methods

Sedimentation

If turbid water is let into a basin and allowed to remain quiet, much of the suspended matter is removed by Plain sedimentation. This is a first step commonly used in surface water purification. Long storage (weeks or months) of surface water in this manner will greatly reduce turbidity and bacterial count, but this method is neither economical nor dependably safe.

Today, treatment of water may begin by using presedimentation basins for a period of 3 to 8 hours to allow the courser material to settle out.

Flocculation

Plain sedimentation is not practical for treating muddy water carrying clay and colloidal particles. To accelerate the settling velocity of the tiny particles, artificial means are used to flocculate, or bring together in loose clusters, all the suspended particles. Chemicals, called coagulants, are added to the water to form chemical flocs that adsorb, entrap and otherwise assemble suspended particles into larger masses. The floc results from chemical reaction of the coagulant with the alkalinity of the water. It forms as a fragile, cloudly, gelatinous mass. The chemicals most commonly used are aluminum sulfate, ferrous sulfate and ferric chloride.

Coagulation proceeds in three basic stages:

1. Neutralization of the negative charges on the suspended clay particles.
2. Clustering or flocculation of the particles.
3. Surface adsorption of particles on the large surface area provided by the floc.

Clarification

After the coagulants have been mixed with it, the water is passed to a settling basin called a clarifier. Here, the water is held long enough for the heavy flocculated material to settle out. The smaller and lightest fraction remains in suspension and is removed in the next step, filtration.

Contact units, also known as upward flow units, combine mixing, flocculation and clarification in the same structure, thereby conserving space and usually decreasing investment cost. Because the incoming water is in intimate contact with both the added and previously coagulated chemicals, the continuous formation of new floc particles is accelerated.

Filtration

When water flows through sand or other porous media, most of the suspended and colloidal impurities are left behind in the pores or on the surface of the porous medium. This process is called filtration.

Natural filtration is an active, important and effective process of self-purification of groundwater, which is characteristically free of bacteria and other suspended material.

The slow sand filter was first used in Great Britain early in the nineteenth century. Characteristic features of the slow sand filter are:

1. Direct feed of raw water without chemical pretreatment.
2. Slow rate of filtration.
3. Mechanical cleaning of sandbed by scraping and removal of about

one inch of sand when clogging occurs.

The rapid sand filter has largely replaced the slow sand filter in the U.S. because of its greater adaptability to more turbid waters. Essential characteristics of the rapid sand filter include:

1. High rate of filtration (approx. 30 times the slow sand filter).
2. Careful pretreatment of the water before filtration.
3. Cleaning the filter by backwashing rather than mechanical removal.

Both gravity and pressure types of rapid sand filters are widely used.

A diatomite filter is a specialized type of rapid filter. Rather than sand, water is passed through a layer of diatomaceous earth. Diatomaceous earth is mined from deposits of the remains of tiny water plants called diatoms. The particles of diatomite are tiny shells composed of nearly pure silica, the skeletons of dead diatoms. Diatomite filtration removes amoebic cysts and certain other organisms which are not always removed by sand filters and which are not easily killed by chlorination.

Diatomite filters are normally pressure filters, but they can be open-type, operated by the vacuum produced by pump suction.

Disinfection

Disinfection of water means killing all the potentially dangerous or pathogenic organisms that may be present. Common chemicals used to disinfect water include chlorine, ozone, iodine and potassium permanganate. Disinfection is also done by boiling, pasterization, and by exposure to ultraviolet light.

Chlorination is by far the most common means for disinfecting water. Chlorine offers several advantages for water treatment. It is low in cost, reliable and fairly easy to handle. A slight chlorine residual in the water after purification acts as a tracer indicating the presence of a disinfecting agent at any point in the system.

Adding chlorine to pure water forms hypochlorous acid and hydrochloric acid. It is the hypochlorous acid that provides the principal disinfecting and oxidizing properties of chlorine solutions.

Chlorine that reacts with organic matter and dissolved minerals such as iron, manganese and hydrogen sulfide has no further disinfecting powers. This amount of chlorine taken up by chemical reaction is called the chlorine demand of the water. The total dosage of chlorine must be enough to satisfy the chlorine demand plus the amount needed for disinfection. The amount of chlorine left over for disinfection is called residual chlorine.

Ultraviolet Light

Clear water can be disinfected by exposing thin layers of water to ultraviolet light. The germicidal effect of ultraviolet rays depends on the intensity of the light and the time of exposure. At low intensity, the exposure time may be 24 hours; at high intensity, it can be as short as one second.

Ultraviolet light is produced by passing electric current through a fused quartz lamp containing mercury vapor. The fused quartz is transparent to ultraviolet rays.

Boiling and Pasteurization

The use of heat is perhaps the oldest and best understood method of disinfection. Disinfection is accomplished by bringing the water temperature up to 161°F and holding it for 15 seconds. Tests show that this process kills both disease-causing bacteria and other organisms such as amoebic cysts, worms, and viruses which are more resistant to disinfection by chlorine than are the bacteria.

Based on pilot units, the cost of water pasteurization on a household scale has been estimated at $1 per 1,000 gallons. This figure is high compared with chemical disinfection, but pasteurization is simple, reliable and requires little or not attention by the homeowner.

Ozone

Ozone can disinfect water because of its powerful oxidizing action. This method is used in several European countries. Ozone has an unstable molecular configuration containing 3 atoms of oxygen rather than the usual stable oxygen molecule containing 2 atoms of oxygen. Upon being mixed with water, ozone loses one oxygen atom, which is the mechanism for killing bacteria by oxidation.

Ozone is formed by high voltage electrical discharge in dry air. Thorough mixing is necessary because ozone is only slightly soluble in water. Ozone treatment also reduces odors, color, and tastes that may be present.

Treatment with ozone is reported to cost about double that of chlorination.

Disinfection in Tropical Regions

Besides the usual water-borne diseases found in temperate climates, those in tropical regions include amoebic dysentery, fluke diseases, guinea worm infestation and filariasis. The carriers of these diseases are found in surface water sources, are larger than bacteria, and are more resistant to chlorination. Water disinfection in tropical regions is usually done by combining several methods.

Aeration of Water

Aeration of water is the process of exposing water to air and produces two results: (1) the water can dissolve a maximum of oxygen, and (2) it can release other gases that may be in solution. Methods of aeration include spraying water into the air, allowing to to cascade over steps, trickling it through beds of coarse coke or stone and bubbling air through it.

Aeration can remove dissolved gases such as hydrogen sulfide, methane, carbon dioxide and chlorine, thereby reducing tastes, odors and the corrossiveness of the water. This process aids in the removal of iron and manganese, which, after oxidation, precipates as hydroxides.

Activiated Carbon

Activated carbon or charcoal is widely used for removing tastes, odors and color from water. This treatment takes place by a process called adsorption.* Where relatively large quantities of water are being treated, activate carbon is added to the water in the form of powder. Filters containing activated carbon in granular form are particularly suited to industrial systems.

Ion Exchange

The process of ion exchange is the exchange of ions contained in the structure of a solid with different ions disseminated in a solution. Ion exchange is a commonly used method of "softening" water. Calcium and magnesium are the major hardness forming elements. The hardness is generally exhibited by the insoluble precipitates formed while washing, which form a scum on the container being used.

Certain granular materials, called zeolites, exchange ions in their structure for other ions in the water. When "hard" water percolates through a bed of zeolite which has sodium ions attached, the ions of calcium and magnesium are exchanged for ions of sodium, making the water "soft". Some "hard" waters already contain much sodium and adding more sodium by ion exchange can create an unpleasant affect in drinking water. It is sometimes called "Montezuma's Revenge".

Only those compounds that ionize in water can take part in ion exchange processes. Mineral acids, bases and salts ionize, or dissociate, to the

*NOTE: Adsorption: Adsorption is the adhesion of molecules of gases, of ions, or of molecules in solutions to the surfaces of solid bodies with which they are in contact.

full extent of their solubility, and ordinary table salt is an example.

Ion exchange is used not only to exchange one dissolved salt for another, but is also used to extract all dissolved minerals and produce nearly pure water that exceeds the quality of distilled water. Demineralization results from passing the water through beds of two different types of ion-exchange resins. One type of resin will remove all the positive-charged metallic ions, or cations, and the other type of resin removes all the negatively charged ions such as chloride and sulfate.

APPENDIX B PART III

DESALINIZATION

The U.S. Geological Survey classifies the degree of salinity of mineralized water as follows:

Dissolved solids, ppm	Classification
1,000- 3,000	Slightly saline
3,000-10,000	Moderately saline
10,000-35,000	Very saline
More than 35,000	Brine

NOTE: Brackish water generally is considered to contain from 1,000 to 3,000 mg/l (ppm) of total dissolved solids.

Desalination by Ion Exchange

Costs are very high for ion-exchange treatment of water containing more than 2,500 mg/l dissolved solids. Total cost of reducing dissolved solids from 2,500 mg/l to 500 mg/l (acceptable by U.S. Public Health Drinking Water Standards) in a plant producing 100,000 gallons of fresh water per day is reported to be $1.00 per 1000 gallons. If the dissolved solids of the raw water are 2,000 mg/l, the cost is reported to be $.81 per 1000 gallons.

This process is prohibitively expensive for use on sea water; however, it is well adapted for use on water with salt content less than 1000 mg/l, where costs of $100 to $200 per acre foot have been estimated.

Desalination by Distillation

The distillation methods being studied and in use include the following:

1. Multiple-effect evaporation
2. Vapor-compression distillation
3. Flash-type distillation
4. Long-tube vertical distillation
5. Evaporation by immiscible-liquid heat transfer
6. Evaporation in solar stills

The formation of scale on heated metal surfaces is one of the major stumbling blocks in distillization units and in the cost of the process.

A two-stage vapor compression plant has been built at Roswell, New Mexico, that was designed to produce 1,000,000 gallons per day (770 gpm) of frest water. The well water being treated contains more than 24,000 mg/l dissolved solids, with hardness of over 3,000 mg/l. Process problems related to pretreatment of the feed water to avoid scale formation has caused much trouble.

In 1970, minimum cost of desalination by distillation was about $300/acre foot (approx. $1.00/1000 gal.). Estimates are that costs can be reduced to about $100/acre foot with large dual-purpose plants, which generate high-pressure steam for electrical power and low pressure steam for evaporation operation.

Solar stills have been used for limited production in areas having abundant sunshine throughout the year. However, large scale production by solar stills does not appear economically feasible within the near future.

Electrodialysis Process

In this process, an electric current is passed through the water in a special chamber that contains two special plastic membranes. The membranes divide the chamber into three compartments. One membrane will only allow negatively charged ions such as chloride or sulfate to pass through, while the other membrane will only allow positively charged ions such as sodium to calcium, to pass through.

The positive electrode, which attracts negative ions, is placed behind the appropriate membrane and the negative electrode, which attracts positive ions, is placed behind the other membrane. As a result, the water in the compartments containing the electrodes becomes concentrated while the water in the center compartment has lost its ions and is therefore partly demineralized. The membranes then prevent the circulation and remixing of the water. The freshened water in the middle compartment is then piped to the point of use.

The town of Webster, South Dakota, used the electrodialysis process for treating its municipal water supply. The groundwater at Webster, about 250 feet deep, contains about 1,500 mg/l dissolved solids, which contains about 900 mg/l of hardness and 700 mg/l sulfate. The plant reduced the dissolved solids to about 500 mg/l. Originally designed to produce 250,000 gallons per day, the plant capacity has been increased to 320,000 gallons per day. The town uses an average of 150,000 gallons per day at a cost of about $1.18 per 1,000 gallons.

At Buckeye, Arizona, an electrodialysis plant treats well water containing about 2,100 mg/l dissolved solids at a cost of about $.63 per 1,000 gallons This plant is designed for peak production of 650,000 gallons per day, while average use is about 200,000 gallons per day.

Comparing the difference of the cost of treated water between Buckeye and Webster illustrates the effect of the different kinds of dissolved minerals on the cost of creating by electrodialysis.

The waste from an electrodialysis plant generally varies from 20 to 50 percent of the volume of water treated. At Webster, volume of waste can be 70,000 gallons, which constitutes a major disposal problem.

The city of Coalinga, California, formerly imported drinking water by rail car at a cost of more than $200 per acre foot. It now treats brackish well water (2,000 mg/l) by electrodialysis at a cost of less than $400/acre foot. In the process about half the feed water is wasted.

Cost of salt removal by this method is proportional to the amount of salt in the water.

Freezing Process

Two freezing methods to purify water are being tried. In one method, sea water is let into a high vacuum chamber. In the vacuum some of the water vaporizes which causes cooling of the remainder to a temperature low enough to produce fresh water ice crystals. The vapor, like steam is free of salt, and is condensed and recovered in addition to the ice.

Another method called the direct refrigerant process, freezes ice crystals of fresh water by evaporating a refrigerant, such as isobutane, directly in the sea water.

In both methods, the ice-brine mixture is drawn off and passed through a washer where the ice crystals are washed free of brine. This is the most troublesome portion of the process. Fresh water is used for the washing which then mixes with the brine thereby lowering the overall efficiency of the process.

A vacuum-freezing plant is in operation at Eilat, Israel, which can produce about 240,000 gallons per day of water containing about 300 mg/l dissolved solids. The raw water feed is from a series of shallow wells in a beach of the Red Sea. The sea water, containing about 3,000 mg/l dissolved solids, is naturally filtered of particulate matter as it passed through the beach sand into the wells.

Reverse Osmosis

The process of reverse osmosis is an effective way to remove nearly all the dissolved solids from mine effluent. Because reverse osmosis is a concentrating process, a potential exists for the recovery of valuable heavy metals.

Osmosis is the flow through a semi-permeable membrane from a dilute solution to a more concentrated solution. If pressure is applied to the concentrated solution greater than osmotic pressure, then the flow is reversed, that is, from the concentrated solution to the dilute solution. Water can be demineralized using this method by choosing a membrane filter that will only pass near-pure water, leaving nearly all other ions on the concentrated side. Once the osmotic pressure is exceeded, the rate of flow through the membrane is roughly proportional to the applied pressure.

The basic reverse osmosis system for treating acid mine effluent consists of the following:

1. Filtration to remove particulate matter
2. pH adjustment
3. Disinfection (using ultraviolet light)
4. A high pressure pump (usually 400-600 psig)
5. A reverse osmosis membrane package
6. Post treatment depending on the desired water use:
    a. pH adjustment (neutralization)
    b. further filtering or conditioning (Fe, Mn, etc.)
    c. Chlorination
    d. Carbonation (another pH adjustment)

The removal of specific ions by reverse osmosis is based upon the ability of the membrane to reject those ions and on the concentration of the ions in the raw water. There are three membrane configurations currently available, spiral wound, tubular and hollow fine fiber. Typical ion rejections by these three types of membranes are shown in Table 6.

Table 41. Typical Rejections by Reverse Osmosis Systems[(a)]

Systems	pH	Cond.[(b)]	Acidity	Ca	Mg	Total Fe	FeII	Al	SO_2	Mn
Sprial Wound[(c)]										
Feed Water	3.1	2070	460	260	170	77	64	12	1340	43
Product	4.4	17	38	0.4	0.3	0.4	0.3	0.2	0.9	0.5
Rejection (%) (d)	---	99.2	91.7	99.8	99.8	99.8	99.8	99.2	99.9	98.8
Tubular[(c)]										
Feed Water	3.4	1050	250	125	92	78	61	12	660	14
Product	4.2	46	46	2.2	1.4	0.9	1.0	1.0	4.4	0.3
Rejection (%) (d)	---	95.6	81.6	98.2	98.5	98.8	98.4	91.7	99.3	97.8
Hollow Fiber[(c)]										
Feed Water	3.4	1020	210	150	115	110	71	15	940	14
Product	4.3	32	32	1.2	1.4	1.2	0.8	0.8	4.6	0.1
Rejection (%) (d)	---	96.9	84.8	99.2	98.8	98.9	98.9	94.7	99.5	99.1

(a) All units are mg/l except pH.
(b) Cond. -- Specific conductance (micromhos/cm).
(c) 75 percent recovery.
(d) Rejection = 100 (Feed concentration - Product concentration)/Feed concentration.

Water Recovery Problems

The concentrations of the constituents on the brine side of the system should not exceed the saturation limits because anything that precipitates will foul the membranes. Field tests of treating mine effluent that iron and calcium sulphate are two major causes of fouling the membranes. Means have been found to minimize the iron problem (pH adjustment; chlorination), but the results of 13 studies at four different mine drainage sites indicated that the limiting factor in high-recovery reverse osmosis operation was the precipitation of calcium sulfate.

Membrane life has a significant affect on the cost of water treatment. To date, the longest mine effluent treatment time on a single set of modules is as follows:

1. Spiral modules - 4400 hours
2. Hollow fiber modules - 2670 hours
3. Tubular Modules - 807 hours

No loss of ion rejection capability was noted in any of the above tests.

Pressures as high as 1,500 psi are used. Flow rates depend on the initial salinity and have varied from 20 gpd/sq. ft. (gallons per day per square foot) for sea water to 30 gpd/sq. ft. for brackish waters.

Total System Approach

The design of a complete reverse osmosis system must begin with a definition of the quality of the final product. This definition is necessary to design the proper post-membrane treatment that may be required. Provisions must also be made for brine treatment and disposal.

A pilot unit at Coalingua, California, produces 5,000 gallons of fresh water per day by reverse osmosis. The raw water contains about 2,500 mg/l dissolved solids. (Note - no further data in this reference)

Cost Estimate

Current estimates of cost per 1,000 gallons of product water vary between \$0.35-\$1.50 depending on the plant size, water quality, disposal techniques, and desired quality of product.

General Discussion: Munincipal water treatment

In the United States and Canada there are over 1,000 water utilities having raw water with total dissolved solids in the 1,000 to 3,000 mg/l range. It is likely that the first wide spread application of desalting will be on brackish water. Ocean water, desalinized, generally has to be pumped for considerable distances to the place of use, further adding to the cost of the freshened water.

Selection of Water Treatment Method

The type of treatment required depends on the physical, chemical, and biological characteristics of the water. Water from deep wells, for example, is usually free of pathogenic bacteria, and no purification is necessary. Most well waters are hard; and, softening, together with removal of iron and manganese, may be desirable. Well waters are generally quite clear so there is no need for turbidity removal. If there is possibility of pollution, chlorination is advisable.

The relatively high turbidity of river water usually requires chemical coagulation and filtration. The turbidity of river water varies considerably throughout the year. It may be high during floods but low at other times. Some plants treating river water may have facilities for adding coagulants but use them only during floods. Storage in reservoirs will reduce the need for sedimentation. Many cities have also taken steps to reduce erosion in the watersheds tributary to their water source in order to minimize the requirements for clarification. Most surface waters are subject to contamination, and disinfection is usually essential.

Table 42. Energy Requirements for Six Desalting Processes *

	Energy required (per 1000 gal of product water)			
	1964 technology		Estimate for 1980 technology[1]	
Processes	Btu x 10^{-3}	kw-hr	Btu x 10^{-3}	kw-hr
Processes using heat				
Multistage flash distillation	1020	300	610	180
Long-tube vertical distillation(LTV)	1020	300	610	180
Processes using electricity[2]				
Electrodialysis(brackish water only)	250	25	150	15
Vapor compression distillation	610	60	360	35
Freezing	610	60	360	35
Reverse osmosis	510	50	310	30

*W.S. Gillam & W.H. McCoy, Desalination Research and Water Resources in K.S. Spiegler (ed.), *Principles of Desalination*, Academic Press, New York, 1966.
[1]The estimated 1980 energy requirements are for high-efficiency processes and are not applicable to processes using low-cost energy.
[2]The energy values given for the "electrical" processes are the thermal energies for the appropriate electrical power generation at 33% plant efficiency.

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APPENDIX C

UNIT AGREEMENT EXAMPLE

UNIT AGREEMENT*

SEMINOLE-SAN ANDRES UNIT
GAINES COUNTY, TEXAS

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*Obtained from the Railroad Commission of Texas, Austin, Texas.

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UNIT AGREEMENT

SEMINOLE-SAN ANDRES UNIT

GAINES COUNTY, TEXAS

THIS AGREEMENT, entered into as of the 1st day of May, 1968, by the parties who have signed the original of this instrument, a counterpart thereof, or other instrument agreeing to be bound by the provisions hereof;

W I T N E S S E T H:

WHEREAS, in the interest of the public welfare and to promote conservation and increase the ultimate recovery of oil, gas, and associated minerals from the Seminole (San Andres) Field, in Gaines County, State of Texas, and to protect the rights of the owners of interests therein, it is deemed necessary and desirable to enter into this agreement, in conformity with Texas Laws 1949, Chapter 259, designated as Article 6008b of Vernon's Civil Statutes of Texas, to unitize the Oil and Gas Rights in and to the Unitized Formation in order to conduct a secondary recovery, pressure maintenance, or other recovery program as herein provided;

NOW, THEREFORE, in consideration of the premises and of the mutual agreements herein contained, it is agreed as follows:

ARTICLE 1

DEFINITIONS

As used in this agreement, the terms herein contained shall have the following meaning:

1.1 Unit Area means the lands described by Tracts in Exhibit A as to which this agreement becomes effective or to which it may be extended as herein provided.

1.2 Unitized Formation means that subsurface portion of the Unit Area lying between the top of the San Andres formation and 2,000 feet subsea. The top of the San Andres formation is identified as the point at 4,624 feet (elevation of 1,266 feet subsea) as shown on the Schlumberger logs of the Amerada T.S. Riley Well No. 11, located 1,650 feet from the South line and 950 feet from the East line of Section 229, Block G.W.T. RR Survey, Gaines County Texas.

1.3 Unitized Substances means all oil, gas, gaseous substances, sulphur contained in gas, condensate, distillate, and all associated and constituent liquid or liquefiable hydrocarbons within or produced from the Unitized Formation.

1.4 Working Interest means an interest in Unitized Substances by virtue of a lease, operating agreement, fee title, or otherwise, including a carried interest, which interest is chargeable with and obligated to pay or bear, either in cash or out of production or otherwise, all or a portion of the cost of drilling, developing, producing, and operating the Unitized Formation.

1.5 Royalty Interest means a right to or interest in any portion of the Unitized Substances or proceeds thereof other than a Working Interest.

1.6 Royalty Owner means a party hereto who owns a Royalty Interest.

1.7 Working Interest Owner means a party hereto who owns a Working Interest. The owner of oil and gas rights that are free of lease or other instrument conveying the Working Interest to another shall be regarded as a Working Interest Owner to the extent of seven-eights (7/8) of his interest in Unitized Substances, and as a Royalty Owner with respect to his remaining one-eighth (1/8) interest therein.

1.8 Tract means each parcel of land described as such and given a Tract number in Exhibit A.

1.9 Unit Operating Agreement means the agreement entitled "Unit Operating Agreement, Seminole-San Andres Unit, Gaines County, Texas," of the same effective date as the effective date of this agreement, and which is entered into by Working Interest Owners.

1.10 Unit Operator means the Working Interest Owner designated by Working Interest Owners under the Unit Operating Agreement to develop and operate the Unitized Formation, acting as operator and not as a Working Interest Owner.

1.11 Tract Participation means the percentage shown in Exhibit A for allocating Unitized Substances to a Tract under this agreement.

1.12 Unit Participation of each Working Interest Owner means the sum of the percentages obtained by multiplying the Working Interest of such Working Interest Owner in each Tract by the Tract Participation of such Tract.

1.13 Phase I means the period of time beginning on the effective date hereof and continuing to 7:00 a.m. of the first day of the calendar month next following the date on which 45,000,000 barrels of oil have been produced and saved after January 1, 1968 from the Unitized Formation underlying the Unit Area dated May 1, 1968 and as determined from the oil production reports required by and submitted to the Railroad Commission of Texas.

1.14 Phase II means the remainder of the term of this agreement after the end of Phase I.

1.15 Outside Substances means all substances obtained from any source other than the Unitized Formation and which are injected into the Unitized Formation.

1.16 Oil and Gas Rights means the right to explore, develop, and operate lands within the Unit Area for the production of Unitized Substances, or to share in the production so obtained or the proceeds thereof.

1.17 Unit Operations means all operations conducted by Working Interest Owners or Unit Operator pursuant to this agreement and the Unit Operating Agreement for or on account of the development and operation of the Unitized Formation for the production of Unitized Substances.

1.18 Unit Equipment means all personal property, lease and well equipment, plants, and other facilities and equipment taken over or otherwise acquired for the joint account for use in Unit Operations.

1.19 Unit Expense means all cost, expense, or indebtedness incurred by Working Interest Owners or Unit Operator pursuant to this agreement and the Unit Operating Agreement for or on account of Unit Operations.

1.20 Unless the context otherwise clearly indicates, words used in the singular include the plural, the plural include the singular, and the neuter gender include the masculine and the feminine.

ARTICLE 2

EXHIBITS

2.1 Exhibits.* Attached hereto is the following exhibit which are incorporated herein by reference:

> 2.1.1 Exhibit A is a schedule that describes each Tract in the Unit Area and shows its Tract Participation.

2.2 Reference to Exhibits. When reference herein is made to an exhibit, the reference is to the Exhibit as originally attached or, if revised, to the latest revision.

2.3 Exhibits Considered Correct. An exhibit shall be considered to be correct until revised as herein provided.

2.4 Correcting Errors. The shapes and descriptions of the respective Tracts have been established by using the best information available. If it subsequently appears that any Tract, because of diverse royalty or working interest ownership on the effective date hereof, should be divided into more than one Tract, or that any mechanical miscalculation has been made, Unit Operator, with the approval of Working Interest Owners, may correct the mistake by revising the exhibits to conform to the facts. The revision shall not include any re-evaluation of engineering or geological interpretations used in determining Tract Participation. Each such revision of an exhibit shall be effect at 7:00 a.m. on the first day of the calendar month next following the filing for record of the revised exhibit or on such other date as may be determined by Working Interest Owners and set forth in the revised exhibit.

* Exhibit B, a map of the unitized area included in the original, is omitted herein.

2.5 Filing Revised Exhibits. If an exhibit is revised pursuant to this agreement, Unit Operator shall certify and file the revised exhibit for record in the County in which this agreement is filed.

ARTICLE 3

CREATION AND EFFECT OF UNIT

3.1 Oil and Gas Rights Unitized. Subject to the provisions of this agreement, all Oil and Gas Rights of Royalty Owners in and to the lands described in Exhibit A, and all Oil and Gas Rights of Working Interest Owners in and to said lands, are hereby unitized insofar as the respective Oil and Gas Rights pertain to the Unitized Formation, so that operations may be conducted as if the Unitized Formation had been included in a single lease executed by all Royalty Owners, as lessors, in favor of all Working Interest Owners, as lessees, and as if the lease had been subject to all of the provisions of this agreement.

3.2 Personal Property Excepted. All lease and well equipment, materials, and other facilities heretofore or hereafter placed by any of the Working Interest Owners on the lands covered hereby shall be deemed to be and shall remain personal property belonging to and may be removed by the Working Interest Owners. The rights and interests therein as among Working Interest Owners are covered by the Unit Operating Agreement.

3.3 Amendment of Leases and Other Agreements. The provisions of the various leases, agreements, division and transfer orders, or other instruments covering the respective Tracts or the production therefrom are amended to the extent necessary to make them conform to the provisions of this agreement, but otherwise shall remain in effect.

3.4 Continuation of Leases and Term Royalties. Operations, including drilling operations, conducted with respect to the Unitized Formation on any part of the Unit Area, or production from any part of the Unitized Formation, except for the purpose of determining payments to Royalty Owners, shall be considered as operations upon or production from each Tract, and such operations or production shall continue in effect each lease or term royalty interest as to all lands covered thereby just as if such operations had been conducted and a well had been drilled on and was producing from each Tract.

3.5 Titles Unaffected by Unitization. Nothing herein shall be construed to result in the transfer of title to the Oil and Gas Rights by any party hereto to any other party or to Unit Operator. The intention is to provide for cooperative development and operation of the Tracts and for the sharing of Unitized Substances as herein provided.

3.6 Injection Rights. Royalty Owners hereby grant unto Working Interest Owners the right to inject into the Unitized Formation any substances in whatever amounts Working Interest Owners deem expedient for Unit Operations, including the right to drill and maintain injection wells on the Unit Area and to use producing or abandoned oil or gas wells for such purposes.

3.7 Development Obligation. Nothing herein shall relieve Working Interest Owners from the obligation to develop reasonably as a whole the lands and leases committed hereto.

ARTICLE 4

PLAN OF OPERATIONS

4.1 Unit Operator. Working Interest Owners are, as of the effective date of this agreement, entering into the Unit Operating Agreement, designating Amerada Petroleum Corporation as Unit Operator. Unit Operator shall have the exclusive right to conduct Unit Operations. The operations shall conform to the provisions of this agreement and the Unit Operating Agreement. If there is any conflict between such agreements, this agreement shall govern.

4.2 Operating Methods. To the end that the quantity of Unitized Substances ultimately recoverable may be increased and waste prevented, Working Interest Owners shall, with diligence and in accordance with good engineering and production practices, within a reasonable time after this agreement becomes effective, commence secondary recovery operations by means of the injection of water, gas, and other substances, or any of them, into the Unitized Formation.

4.3 Change of Operating Methods. Nothing herein shall prevent Working Interest Owners from discontinuing or changing in whole or in part any method of operations which, in their opinion, is no longer in accord with good engineering or production practices. Other methods of operation may be conducted or changes may be made by Working Interest Owners from time to time if determined by them to be feasible, necessary, or desirable to increase the ultimate recovery of Unitized Substances.

ARTICLE 5

TRACT PARTICIPATION

5.1 Tract Participation. The Tract Participation of each Tract is shown in Exhibit A. The Tract Participations were determined with the following formulas:

5.1.1 Phase I Tract Participation is equal to that proportion expressed as a percentage that the adjusted current oil production from each Tract during the period from December 1, 1966 through May 31, 1967 bears to the total adjusted current oil production from all the Tracts during said period.

5.1.2 Phase II Tract Participation is equal to the sum of fifty percent (50%) of the proportion expressed as a percentage that the total equivalent net acre feet of the Tract bears to the total equivalent net acre feet of all Tracts plus fifty percent (50%) of the proportion expressed as a percentage that the ultimate primary recovery from each Tract bears to the total ultimate primary recovery from all Tracts.

5.2 Relative Tract Participations. If the Unit Area is enlarged or reduced, the revised Tract Participations of the Tracts remaining in the Unit Area and which were within the Unit Area prior to the enlargement or reduction shall remain in the same ratio one to another.

ARTICLE 6

ALLOCATION OF UNITIZED SUBSTANCES

6.1 Allocation to Tracts. All Unitized Substances produced and saved shall be allocated to the several Tracts in accordance with the respective Tract Participations effective during the period that the Unitized Substances were produced. The amount of Unitized Substances allocated to each Tract, regardless of whether it is more or less than the actual production of Unitized Substances from the well or wells, if any, on such Tract, shall be deemed for all purposes to have been produced from such Tract.

6.2 Distribution Within Tracts. The Unitized Substances allocated to each Tract shall be distributed among, or accounted for to, the parties entitled to share in the production from such Tract in the same manner, in the same proportions, and upon the same conditions as they would have participated and shared in the production from such Tract, or in the proceeds thereof, had this agreement not been entered into, and with the same legal effect. If any Oil and Gas Rights in a Tract are now or hereafter become divided and owned in severalty as to different parts of the Tract, the owners of the divided interests, in the absence of an agreement providing for a different division, shall share in the Unitized Substances allocated to the Tract, or in the proceeds thereof, in proportion to the surface acreage of their respective parts of the Tract.

6.3 Taking Unitized Substances in Kind. The Unitized Substances allocated to each Tract shall be delivered in kind to the respective parties entitled thereto by virtue of the ownership of Oil and Gas Rights therein or by purchase from such owners. Such parties shall have the right to construct, maintain, and operate within the Unit Area all necessary facilities for that purpose, provided that they are so constructed, maintained, and operated as not to interfere with Unit Operations. Any extra expenditures incurred by Unit Operator by reason of the delivery in kind of any portion of the Unitized Substances shall be borne by the receiving party. If a Royalty Owner has the right to take in kind a share of Unitized Substances and fails to do so, the Working Interest Owner whose Working Interest is subject to such Royalty Interest shall be entitled to take in kind such share of the Unitized Substances.

6.4 Failure to Take in Kind. If any party fails to take in kind or separately dispose of its share of Unitized Substances, Unit Operator shall have the right, for the time being and subject to revocation at will by the party owning the share, to purchase for its own account or sell to others such share; provided that, all contracts of sale by Unit Operator of any other pary's share of Unitized Substances shall be only for such reasonable periods of time as are consistent with the minimum needs of the industry under the circumstances, but in no event shall any such contract be for a period in excess of one year. The proceeds of the Unitized Substances so disposed of by Unit Operator shall be paid to the party entitled thereto. Notwithstanding any other provisions herein to the contrary, Unit Operator shall not make a sale into interstate commerce, as such term is defined in the Natural Gas Act, of any Working Interest Owner's share of gas production without first giving such Working Interest Owner at least sixty (60) days' notice of such intended sale.

6.5 Responsibility for Royalty Settlements. Any party receiving in kind or separately disposing of all or part of the Unitized Substances allocated to any Tract or receiving the proceeds therefrom shall be responsible for the payment thereof to the persons entitled thereto, and shall indemnify all parties hereto, including Unit Operator, against any liability for all royalties, overriding royalties, production payments, and all other payments chargeable against or payable out of such Unitized Substances or the proceeds therefrom. If the amount of production accruing to any Royalty Interest in a Tract, by the terms of the instrument reserving or creating it, depends on the per well production from such Tract during any period of time, then, for the purposes of computing the quantity of Unitized Substances accruing to such Royalty Interest during such period of time, there shall be deemed located on such Tract that percentage of the total number of usable wells in the Unit completed in the Unitized Formation at the beginning of such period, either as producing or injection wells, which is equal to the Tract Participation of such Tract, and the quantity of Unitized Substances allocated to such Tract, as provided in Section 6.1, shall be deemed to have been produced in equal proportions from the wells deemed located on such Tract.

6.6 Royalty on Outside Substances. No payments shall be due or payable to Royalty Owners on Outside Substances.

> 6.6.1 If gas is the Outside Substance injected, seventy-five percent (75%) of any gas subsequently produced from the Unitized Formation and sold, or used for other than Unit Operations, shall be deemed to be the Outside Substance so injected until the total volume thereof equals the total volume of the Outside Substances so injected.

> 6.6.2 If Liquid Petroleum Gas (LPG) is the Outside Substance injected, ten percent (10%) of all Unitized Substances produced from the Unitized Formation subsequent to two years after the initial injection of such LPG into the Unitized Formation shall be deemed Outside Substance so injected until the total value thereof equals the total cost of Outside Substances so injected.

ARTICLE 7

PRODUCTION AS OF THE EFFECTIVE DATE

7.1 Oil in Lease Tanks. Unit Operator shall gauge all lease and other tanks within the Unit Area to ascertain the amount of merchantable oil produced from the Unitized Formation in such tanks, above the pipe line connections, as of 7:00 a.m. on the effective date hereof. The oil that is a part of the prior allowable of the wells from which it was produced shall remain the property of the parties entitled thereto the same as if the Unit had not been formed. Any such oil not promptly removed may be sold by the Unit Operator for the account of the parties entitled thereto, subject to the payment of all royalties, overriding royalties, production payments, and all other payments under the provisions of the applicable lease or other contracts. The oil that is in excess of the prior allowable of the wells from which it was produced shall be regarded as Unitized Substances produced after the effective date hereof.

7.2 Overproduction. If, as of the effective date hereof, any Tract is overproduced with respect to the allowable of the wells on that Tract and the amount of overproduction has been sold or otherwise disposed of, such overproduction shall be regarded as a part of the Unitized Substances produced after the effective date hereof and shall be charged to such Tract as having been delivered to the parties entitled to Unitized Substances allocated to such Tract.

ARTICLE 8

USE OF LOSS OF UNITIZED SUBSTANCES

8.1 Use of Unitized Substances. Working Interest Owners may use as much of the Unitized Substances as they deem necessary for Unit Operations, including but not limited to the injection thereof into the Unitized Formation.

8.2 Royalty Payments. No royalty, overriding royalty, production, or other payments shall be payable upon, or with respect to, Unitized Substances used or consumed in Unit Operations, or which otherwise may be lost or consumed in the production, handling, treating, transportation, or storing of Unitized Substances.

ARTICLE 9

TRACTS TO BE INCLUDED IN UNIT

9.1 Qualification of Tracts. On and after the effective date hereof and until the enlargement or reduction thereof, the Unit Area shall be composed of the Tracts listed in Exhibit A that corner or have a common boundary (Tracts separated only by a public highway or a railroad right of way shall be considered to have a common boundary), and that otherwise qualify as follows:

> 9.1.1 Each Tract as to which Working Interest Owners owning one hundred percent (100%) of the Working Interest have become parties to this agreement and as to which Royalty Owners owning seventy-five percent (75%) or more of the Royalty Interest have become parties to this agreement.

9.1.2 Each Tract as to which Working Interest Owners owning one hundred percent (100%) of the Working Interest have become parties to this agreement, and as to which Royalty Owners owning less than seventy-five percent (75%) of the Royalty Interest have become parties to this agreement, and as to which the Working Interest Owners in such Tract have executed and delivered an indemnity agreement or obligated themselves to execute and deliver an indemnity agreement indemnifying and agreeing to hold harmless the other Working Interest Owners in the Unit Area, their successors and assigns, against a portion of all claims and demands that may be made by nonsubscribing owners of Royalty Interest in such Tract on account of the inclusion of the Tract in the Unit Area. The portion of such claims and demands covered by the indemnity shall, as to each such Tract, be the fraction thereof in which the numerator is the difference between the percentage of the Royalty Interest signed and seventy-five percent (75%) of the Royalty Interest in the Tract; and the denominator is the difference between the percentage of the Royalty Interest signed and one hundred percent (100%) of the Royalty Interest in the Tract.

9.1.3 Each Tract as to which Working Interest Owners owning less than one hundred percent (100%) of the Working Interest have become parties to this agreement, regardless of the percentage of Royalty Interest therein that is committed hereto; and as to which (a) the Working Interest Owners, including the Working Interest Owner who operates the Tract, owning a total of ninety percent (90%) or more of the Working Interest in such Tract who have become parties to this agreement, have joined in a request for inclusion of such Tract in the Unit Area, and have executed and delivered or have obligated themselves to execute and deliver an indemnity agreement indemnifying and agreeing to hold harmless the other Working Interest Owners in the Unit Area, their successors and assigns, against all claims and demands that may be made by the owners of Working Interests in such Tract who are not parties to this agreement, and which arise out of the inclusion of the Tract in the Unit Area; and as to which (b) eighty percent (80%) or more of the combined voting interest of Working Interest Owners in all Tracts that meet the requirements of Sections 9.1.1 and 9.1.2 have voted in favor of the inclusion of such Tract and to accept the indemnity agreement. For the purpose of this Section 9.1.3, the voting interest of each Working Interest Owner shall be equal to the ratio that its Phase I Unit Participation attributable to Tracts that qualify under Sections 9.1.1 and 9.1.2 bears to the total Phase I Unit Participation of all Working Interest Owners attributable to all Tracts that qualify under Sections 9.1.1 and 9.1.2. Upon the inclusion of such a Tract in the Unit Area, the Unit Participation that would have been attributed to the nonsubscribing owners of the Working Interest in such Tract, had they become parties to this agreement and the Unit Operating Agreement, shall be attributed to the Working Interest Owners in such Tract who have executed indemnity agreements in proportion to their respective Working Interests in the Tract.

9.1.4 Each Tract, regardless of the percentage of Working Interest or Royalty Interest therein that has been committed hereto, as to which (a) the Working Interest Owner who operates the Tract has become a party to this agreement and (b) Working Interest Owners having eighty percent (80%) of the combined voting interest of Working Interest Owners in all Tracts that meet the requirements of Sections 9.1.1, 9.1.2, or 9.1.3 vote in favor of the inclusion of such Tract. For the purpose of this Section 9.1.4, the voting interest of a Working Interest Owner shall be equal to the ratio that its Phase I Unit Participation attributable to Tracts that qualify under Sections 9.1.1, 9.1.2, or 9.1.3 bears to the total Phase I Unit Participation of all Working Interest Owners attributable to all Tracts that qualify under Section 9.1.1, 9.1.2 or 9.1.3. In the case of the inclusion of a Tract in the Unit Area under the provisions of this Section 9.1.4 in which Tract there are nonsubscribing owners of Working Interest, the Unit Participation which would have been assigned to such nonsubscribing owners of Working Interest had they signed or ratified this agreement shall be alloted to all Working Interest Owners in proportion to their then effective Unit Participation; provided that the Working Interest Owners shall be fully liable and responsible in the same proportion to the nonsubscribing owners of Working Interest in the accounting for production from such Tract and all other matters pertaining to the separate operation of such Tract insofar as the nonsubscribing owners are concerned. If a Tract is included in the Unit Area under the provisions of this Section 9.1.4, all Working Interest Owners shall bear in proportion to their then effective Unit Participation all claims and demands that may be made by the nonsubscribing owners of Working Interest or Royalty Interest on account of the inclusion of the Tract in the Unit Area.

9.2 Subsequent Commitment of Interest to Unit. After the effective date of this agreement, the commitment of any interest in any Tract within the Unit Area shall be upon such terms as may be negotiated by Working Interest Owners and the owner of such interest.

9.3 Acquisition of Interest. If any party bound by this agreement acquires an uncommitted interest in any Tract within the Unit Area, such interest shall, upon approval of the Working Interest Owners, be subject to this agreement and, where the interest acquired is a Working Interest, shall also be subject to the Unit Operating Agreement.

9.4 Revision of Exhibits. If any of the Tracts described in Exhibit A fail to qualify for inclusion in the Unit Area, Unit Operator shall recompute, using the original basis of computation, the Tract Participation of each of the qualifying Tracts, and shall revise Exhibit A accordingly. The revised exhibits shall be effective as of the effective date hereof.

ARTICLE 10

TITLES

10.1 Removal of Tract from Unit Area. If a Tract ceases to have sufficient Working Interest Owners or Royalty Owners committed to this agreement to meet the conditions of Article 9 because of failure of title of any party hereto, such Tract shall be removed from the Unit Area effective as of the first day of the calendar month in which the failure of title is finally determined; however, the Tract shall not be removed from the Unit Area if, within ninety (90) days of the date of final determination of the failure of title, the Tract requalifies under a Section of Article 9.

10.2 Revision of Exhibits. If a Tract is removed from the Unit Area because of the failure of title, Unit Operator, subject to Section 5.2, shall recompute the Tract Participation of each of the Tracts remaining in the Unit Area and shall revise Exhibit A accordingly. The revised exhibit shall be effective as of the first day of the calendar month in which such failure of title is finally determined.

10.3 Working Interest Titles. If title to a Working Interest fails, the rights and obligations of Working Interest Owners by reason of the failure of title shall be governed by the Unit Operating Agreement.

10.4 Royalty Owner Titles. If title to a Royalty Interest fails, but the Tract to which it relates is not removed from the Unit Area, the party whose title failed shall not be entitled to share hereunder with respect to such interest.

10.5 Production Where Title is in Dispute. If the title or right of any party claiming the right to receive in kind all or any portion of the Unitized Substances allocated to a Tract is in dispute, Unit Operator at the discretion of Working Interest Owners shall either:

(a) require that the party to whom such Unitized Substances are delivered or to whom the proceeds thereof are paid, furnish security for the proper accounting therefor to the rightful owner if the title or right of such party fails in whole or in part, or

(b) withhold and market the portion of Unitized Substances with respect to which title or right is in dispute, and impound the proceeds thereof until such time as the title or right thereto is established by a final judgment of a court of competent jurisdiction or otherwise to the satisfaction of Working Interest Owners, whereupon the proceeds so impounded shall be paid to the party rightfully entitled thereto.

10.6 Payment of Taxes to Protect Title. Should any party hereto fail to pay when due any ad valorem tax on real or personal property, which failure might result in a loss of title to any interest in the Unit Area, Unit Operator may pay the same and discharge any tax liens arising from non-payment. Working Interest Owners shall reimburse Unit Operator for any amount so paid and Unit Operator shall withhold and distribute among the Working Interest Owners, in proportion to their contribution toward such payment, an amount sufficient to defray the cost of such payment out of any sums due to the deliquent taxpayer or taxpayers as proceeds from the sale of any Unitized Substances.

ARTICLE 11

EASEMENTS OR USE OF SURFACE

11.1 Grant of Easements. The parties hereto, to the extent of their rights and interests, hereby grant to Working Interest Owners the right to use as much of the surface of the land within the Unit Area as may reasonably be necessary for Unit Operations; provided that, nothing herein shall be construed as leasing or otherwise conveying to Working Interest Owners a site for a water, gas injection, processing or other plant, or camp site.

11.2 Use of Water. Working Interest Owners shall have free use of water from the Unit Area for Unit Operations, except water from any well, lake, pond, or irrigation ditch of a Royalty Owner, provided water injected into the Unitized Formation may not be obtained under this grant from an underground source above 400 feet below the surface.

11.3 Surface Damages. Working Interest Owners, to the extent provided in the lease agreement, shall pay the owner for damages to growing crops, timber, fences, improvements, and structures on the Unit Area the result from Unit Operations.

ARTICLE 12

ENLARGEMENTS OF UNIT AREA

12.1 Enlargements of Unit Area. The Unit Area may be enlarged to include acreage reasonably proved to be productive, upon such terms as determined and approved by Working Interest Owners that own a combined Phase I or Phase II Unit Participation, whichever is in effect at the time, of at least ninety percent (90%); and subject to but not limited to the following conditions:

12.1.1 The acreage shall qualify under a Section of Article 9.

12.1.2 The participation to be allocated to the acreage shall be fair and reasonable, considering all available information.

12.1.3 There shall be no retroactive allocation or adjustment of the Unit Expense or of interests in the Unitized Substances produced, or proceeds thereof; however, this limitation shall not prevent an adjustment of investment by reason of the enlargement.

12.2 Determination of Tract Participation. Unit Operator, subject to Section 5.2, shall determine the Tract Participation of each Tract within the Unit Area as enlarged, and shall revise Exhibit A accordingly.

12.3 Effective Date. The effective date of any enlargement of the Unit Area shall be 7:00 a.m. on the first day of the calendar month following compliance with conditions for enlargement as specified by Working Interest Owners, approval of the enlargement by the appropriate governmental authority, if required, and the filing for record of revised Exhibit A in the records of the County in which this agreement is recorded.

ARTICLE 13

CHANGE OF TITLE

13.1 Covenant Running With the Land. This agreement shall extend to, be binding upon, and inure to the benefit of, the respective heirs, devisees, legal representatives, successors, and assigns of the parties hereto, and shall constitute a covenant running with the lands, leases, and interests covered hereby.

13.2 Notice of Transfer. Any conveyance of all or any part of any interest owned by any party hereto with respect to any Tract shall be made expressly subject to this agreement. No change of title shall be binding on the Unit Operator, or upon any party hereto other than the party so transferring, until the first day of the calendar month next succeeding the date of receipt by Unit Operator of a photocopy or a certified copy of the recorded instrument evidencing such change in ownership.

13.3 Waiver of Rights to Partition. Each party hereto covenants that, during the existence of this agreement, it will not resort to any action to partition the Unit Area or the Unit Equipment, and to that extent waives the benefits of all laws authorizing such partition.

ARTICLE 14

RELATIONSHIP OF PARTIES

14.1 No Partnership. The duties, obligations, and liabilities of the parties hereto are intended to be several and not joint or collective. This agreement is not intended to create, and shall not be construed to create, an association or trust, or to impose a partnership duty, obligation, or liability with regard to any one or more of the parties hereto. Each party hereto shall be individually responsible for its own obligations as herein provided.

14.2 No Sharing of Market. This agreement is not intended to provide, and shall not be construed to provide, directly or indirectly, for any cooperative refining, joint sale, or marketing of Unitized Substances.

14.3 Royalty Owners Free of Costs. This agreement is not intended to impose, and shall not be construed to impose, upon any Royalty Owner any obligation to pay for Unit Expense unless such Royalty Owner is otherwise so obligated.

14.4 Information to Royalty Owners. Each Royalty Owner shall be entitled to all information in possession of Unit Operator to which such Royalty Owner is entitled by an existing agreement with any Working Interest Owner.

ARTICLE 15

LAWS AND REGULATIONS

15.1 Laws and Regulations. This agreement shall be subject to the conservation laws of the State of Texas; to the valid rules, regulations, and orders of the Railroad Commission of Texas; and to all other applicable federal, state, and municipal laws, rules, regulations and orders.

ARTICLE 16

FORCE MAJEURE

16.1 Force Majeure. All obligations imposed by this agreement on each party, except for the payment of money, shall be suspended while compliance is prevented, in whole or in part, by a strike, fire, war, civil disturbance, act of God; by federal, state, or municipal laws; by any rule, regulation, or order of a governmental agency; by inability to secure materials; or by any other cause or causes beyond reasonable control of the party. No party shall be required against its will to adjust or settle any labor dispute. Neither this agreement nor any lease or other instrument subject hereto shall be terminated by reason of suspension of Unit Operations due to any one or more of the causes set forth in this Article.

ARTICLE 17

EFFECTIVE DATE

17.1 Effective Date. This agreement shall become binding upon each party as of the date such party signs the instrument by which it becomes a party hereto, and, unless sooner terminated as provided in Section 17.2, shall become effective as to qualified Tracts at the time and date as determined and approved by ninety percent (90%) of the combined voting interest of the Working Interest Owners, only after Tracts comprising eighty-five percent (85%) or more of the Phase I Unit Participation for the Unit Area as shown on the original Exhibit A have qualified under the provisions of Article 9; at least one counterpart of this agreement has been filed for record by the Unit Operator in Gaines County, Texas; and this agreement has been approved by the Railroad Commission of the State of Texas. For the purpose of this Section 17.1, the voting interest of each Working Interest Owner shall be equal to the ratio that its Phase I Unit Participation attributable to Tracts that qualify under the provisions of Article 9 bears to the total Phase I Unit Participation of all Working Interest Owners attributable to all Tracts that qualify under the provisions of Article 9.

17.2 Ipso Facto Termination. If the requirements of Section 17.1 are not accomplished on or before November 1, 1968, this agreement shall ipso facto terminate on that date (hereinafter called "termination date") and thereafter be of no further effect, unless prior thereto Working Interest Owners owning a combined Phase I Unit Participation of at least sixty-five percent (65%) have become parties to this agreement and have decided to extend the termination date for a period not to exceed six (6) months. If the termination date is so extended and the requirements of Section 17.1 are not accomplished on or before the extended termination date, this agreement shall ipso facto terminate on the extended termination date and thereafter be of no further effect. For the purpose of this section, Phase I Unit Participation shall be as shown on the original Exhibit C attached to the Unit Operating Agreement.

ARTICLE 18

TERM

18.1 Term. The term of this agreement shall be for the time that the Unitized Substances are produced in paying quantities and as long thereafter as Unit Operations are conducted without a cessation of more than ninety (90) consecutive days, unless sooner terminated by Working Interest Owners in the manner herein provided.

18.2 Termination by Working Interest Owners. This agreement may be terminated by Working Interest Owners having a combined Phase II Unit Participation of at least eighty percent (85%) whenever such Working Interest Owners determine that Unit Operations are no longer profitable or feasible.

18.3 Effect of Termination. Upon termination of this agreement, the further development and operation of the Unitized Formation as a unit shall be abandoned, Unit Operations shall cease, and thereafter the parties shall be governed by the provisions of the leases and other instruments affecting the separate Tracts.

18.4 Salvaging Equipment Upon Termination. If not otherwise granted by the leases or other instruments affecting each Tract unitized under this agreement, Royalty Owners hereby grant Working Interest Owners a period of six (6) months after the date of termination of this agreement within which to salvage and remove Unit Equipment.

ARTICLE 19

EXECUTION

19.1 Original, Counterpart, or Other Instrument. A person may become a party to this agreement by signing the original of this instrument, a counterpart thereof, or other instrument agreeing to be bound by the provisions hereof. The signing of any such instrument shall have the same effect as if all the parties had signed the same instrument.

19.2 Joinder in Dual Capacity. Execution as herein provided by any party as either a Working Interest Owner or a Royalty Owner shall commit all interests that may be owned or controlled by such party.

ARTICLE 20

CREATION OF A NEW INTEREST

20.1 Creation of a New Interest. In the event any Working Interest Owner shall, after executing this agreement, create an overriding royalty, production payment, net proceeds, carried interest, or any other interest out of its Working Interest then subject to this agreement, such carved-out interest shall be subject to the terms and provisions of this agreement, specifically including, but without limitation, Section 21.3 hereof entitled "Lien of Unit Operator." In the event the Working Interest Owner creating such carved-out interest (a) fails to pay any costs or expenses chargeable to such Working Interest Owner under this agreement and the production of Unitized Substances accruing to the credit of such Working Interest Owner is insufficient for that purpose, or (b) withdraws from this agreement under the terms and provisions of Article 17 of the Unit Operating Agreement, the carved-out interest shall be chargeable with a pro rata portion of all costs and expenses incurred hereunder, the same as though such carved-out interest were a Working Interest, and Unit Operator shall have the right to enforce against such carved-out interest the lien and all other rights granted in Section 21.3 for the purpose of collecting the costs and expenses chargeable to said carved-out interest.

ARTICLE 21

GENERAL

21.1 Amendments Affecting Working Interest Owners. Amendments hereto relating wholly to Working Interest Owners may be made if signed by all Working Interest Owners.

21.2 Action by Working Interest Owners. Any action or approval required by Working Interest Owners hereunder shall be in accordance with the provisions of the Unit Operating Agreement.

21.3 Lien of Unit Operator. Unit Operator shall have a lien upon the interests of Working Interest Owners in the Unit Area to the extent provided in the Unit Operating Agreement.

IN WITNESS WHEREOF, the parties hereto have executed this agreement on the dates opposite their respective signatures.

Date: ______________________________ AMERADA PETROLEUM CORPORATION

ATTEST:

______________________________ By ______________________________

Assistant Secretary Vice President

STATE OF OKLAHOMA)
) SS
COUNTY OF TUSLA)

Before me, the undersigned authority, on this day personally appeared ______________________________, known to me to be the person whose name is subscribed to the foregoing instrument as ______________________ Vice President of AMERADA PETROLEUM CORPORATION, and acknowledged to me that he executed the same for the purposes and consideration therein expressed, in the capacity therein stated, and as the act and deed of said Corporation.

GIVEN UNDER MY HAND AND SEAL OF OFFICE on this the ______ day of ___________________________, 1968.

My commission expires:

____

____
Notary Public in and for the State of Oklahoma.

STATE OF ___________________________)
) SS
COUNTY OF ___________________________)

Before me, the undersigned authority, on this day personally appeared ______________________________, known to me to be the person whose name is subscribed to the foregoing instrument as ____________________ Vice President of ____, and acknowledged to me that he executed the same for the purposes and consideration therein expressed, in the capacity therein stated, and as the act and deed of said Corporation.

GIVEN UNDER MY HAND AND SEAL OF OFFICE on this the __________ day of ______________________________, 1968.

My commission expires:

____

____
Notary Public in and for ______________ County, ___________________.

EXHIBIT A

Attached to and made a part of the
UNIT AGREEMENT
for the

SEMINOLE (SAN ANDRES) UNIT
Gaines County, Texas

TRACT DESCRIPTION

Block G, W. T. Railway
Company Survey

Tract No.	Operator	Tract Name	Section		Tract Participation Per Cent Phase I	Phase II
1	Mallard	Oil Development Company	267:	S/2 SW/4	0.39214	0.06589
2	Amerada	I.E. Auten	267:	That part of the SE/4 lying southwest of the Lovington-Seminole Highway	0.52226	0.35407
3	Henderson and McMillian	Fred Turner, Jr.	267:	S/2 of 158.5 acres desc. as beg. at the SE/c of Sec. 267; th.N. 26^{0} W. 2131.4 varas to N. Line of said Sec.; th. E. to NE/c of said Sec.; th.S. to place of beg.	0.26130	0.09196
4	Amerada	J.L. Sawyer	248:	SW/4	0.65291	0.44226
5	Amerada	J.L. Lawyer "A"	248:	SE/4	0.70623	0.58997
6	Amerada	Northrup & Carr	233:	SW/4 & S/2 SE/4	0.31600	0.30626

EXHIBIT A

SEMINOLE (SAN ANDRES) UNIT
Gaines County, Texas

T R A C T   D E S C R I P T I O N

Block G, W. T. Railway
Company Survey

Tract No.	Operator	Tract Name	Section	Tract Participation Per Cent Phase I	Phase II
7	Atlantic Richfield	T.S. Riley "D"	283: E/2 & E/2 SW/4 & SE/4 NW/4	1.93690	1.19726
8	Amerada	J.L. Tippitt	266: NW/4 NW/4	0.32910	0.20990
9	General American	Tippitt "B"	266: NW/4 except 40 acres in the form of a square out of NW/4	0.70008	0.93915
10	General American	Tippitt "A"	266: S/2 & W/2 NW/4	3.17175	3.65130
11	Atlantic Richfield	J.L. Tippitt	266: E/2 NE/4	0.69121	0.66414
12	Atlantic Richfield	T.S. Riley "A"	249: W/2 NW/4	0.70193	0.69892
13	Atlantic Richfield	T.S. Riley "C"	249: E/2 NW/4 & NE/4	2.12980	2.31720
14	Amerada	T.S. Riley "A"	249: S/2	2.75962	3.23638
15	Amerada	Laura E.Blakemore	232: N/2	2.67687	2.16346
16	Texas Pacific	Laura E.Blakemore	232: S/2	2.46836	2.66033

EXHIBIT A

SEMINOLE (SAN ANDRES) UNIT
Gaines County, Texas

TRACT DESCRIPTION

Block G, W. T. Railway
Company Survey

Tract No.	Operator	Tract Name	Section	Tract-Participation Per Cent Phase I	Phase II
17	General American	Crain	216: W. 41 acres	0.40465	0.26339
18	General American	Crain "A"	216: E. 300 acres of N/2	0.39373	0.22758
19	Amerada	Glen Crain	216: E. 300 acres of S/2	1.78839	1.03540
20	J.G. McMillian et al	S.R. Simpson	284: NW/4 NE/4 & SE/4 NE/4	0.08891	0.06355
21	General American	Brand	284: NE/4 NE/4	0.20355	0.18239
22	Mobil	H & J Section 265	265: All	3.20919	3.70149
23	Marathon	Ida M. Tippitt	250: W/2	2.81790	3.13547
24	Amerada	D.F. Lamb	250: NE/4	1.42820	1.65112
25	Texas Pacific	Ora McMurtrey	250: N/2 SE/4	0.50639	0.75066
26	Texas Pacific	R.L. Champion Oil Company	250: S/2 SE/4	0.60747	0.75424
27	Amerada	Mathews "A"	231: N/2	2.80342	2.95858
28	Humble	Florence Mathews	231: S/2	2.49476	3.06536

EXHIBIT A

SEMINOLE (SAN ANDRES) UNIT
Gaines County, Texas

TRACT DESCRIPTION

Block G, W. T. Railway
Company Survey

Tract No.	Operator	Tract Name	Section	Tract Participation Per Cent Phase I	Tract Participation Per Cent Phase II
29	Mobil	H & J Section 217	217: All	3.86395	3.08102
30	Henderson and McMillian	Otis Parker	264: N/2 NE/4 & SE/4 NE/4	0.44275	0.25164
31	Mobil	H & J Section 251	251: N/2 & N/2 S/2 & S/2 SE/4 & SE/4 SW/4	3.54993	3.83321
32	Marathon	Katie I. Gibbs	230: W/2	2.74745	3.42792
33	Amerada	Nettie Hahn	230: NE/4	1.42311	1.68789
34	Texas Pacific	T.H. Hahn	230: SE/4	1.11564	1.63978
35	Amerada	Walter Turlin	218: All	5.26040	5.04779
36	Atlantic Richfield	T.S. Riley "E"	197: NW/4	0.24145	0.11898
37	Amerada	T.S. Riley "B"	197: S/2	0.91116	0.53702
38	Amerada	Mary E. Coffey	252: E/2	1.66972	1.64991
39	Atlantic Richfield	T.S. Riley "B"	229: N/2	2.94954	3.57880

EXHIBIT A

SEMINOLE (SAN ANDRES) UNIT
Gaines County, Texas

TRACT DESCRIPTION

Block G, W. T. Railway
Company Survey

Tract No.	Operator	Tract Name	Section		Tract Participation Per Cent Phase I	Phase II
40	Amerada	Thomas S. Riley	229:	S/2	2.98269	3.63534
41	Mobil	H & J Section 219	All		4.96980	6.31309
42	Skelly	J.B. Robertson	196:	NW/4	1.18166	0.95649
43	Amerada	R.W. Robertson et al	196:	E/2 & SW/4	3.13583	2.04778
44	Amerada	R.J. Riley et al	187:	NW/4	-0-	0.03039
45	Amerada	T.S. Riley "C"	187:	NW/4 SW/4	0.11259	0.02743
46	Amerada	Riley	187:	NE/4 SW/4 & SW/4 SW/4	-0-	0.00972
47	Mobil	H & J Section 253	253:	NE/4 NE/4	-0-	0.00818
48	Amerada	S.J. Averitt "A"	228:	W/2 NW/4	0.29364	0.25183
49	Marathon	S.J. Averitt	228:	W/2 E/2 & E/2 NW/4 & NE/4 SW/4	1.44256	1.71104
50	General American	Averitt	228:	NE/4 NE/4	0.36939	0.50218
51	Amerada	S.J. Averitt	228:	S/2 E/2 E/2 & 0.5-acre along W. line of S/2 E/2 & SE/4 NE/4 & 0.25-acre along W.line of SE/4 NE/4	0.84687	1.03247

EXHIBIT A

SEMINOLE (SAN ANDRES) UNIT
Gaines County, Texas

TRACTS DESCRIPTION

Block G, W. T. Railway
Company Survey

Tract No.	Operator	Tract Name	Section	Tract Participation Per Cent Phase I	Phase II
52	Shell	M.J. Mann	220: N/W 4	1.35530	1.75848
53	Amerada	S.F. Mann Account #2	220: E/2	2.81334	3.46276
54	Skelly	S.F. Mann	220: SW/4	1.40227	1.53105
55	Mobil	H & J Section 195	195: All	3.66279	3.55304
56	Amerada	W.C. Malone "A"	188: W/2 NW/4 & NE/4 SW/4	0.11828	0.06970
57	Amerada	W.C. Malone "B"	188: SE/4 NW/4 & SE/4	0.40947	0.10470
58	Continental-Emsco	Humble Oil & Refining Co.	188: SW/4 NE/4	0.04412	0.00759
59	Amerada	Mrs. M.A. Brown	188: W/2 SW/4	0.14917	0.09793
60	Amerada	W.C. Malone	188: SE/4 SW/4	0.06245	0.08081
61	Tenneco	James B. Riley	227: E/2 NE/4	0.09135	0.05171
62	Mobil	H & J Section 221	221: N/2 & N/2 S/2 & S/2 SE/4 & SE/4 SW/4	2.60973	2.41708
63	Harry W. Bass, Jr. Trust et al	Emma J. Austin	194: W/2	1.82431	2.07765

EXHIBIT A

SEMINOLE (SAN ANDRES) UNIT
Gaines County, Texas

TRACT DESCRIPTION

Block G, W. T. Railway
Company Survey

Tract No.	Operator	Tract Name	Section	Tract Participation Per Cent Phase I	Phase II
64	Amerada	Amma J. Austin	194: E/2	2.60490	1.87398
65	Mobil	H & J Section 189	189: All of those lots and parcels in NW/4, Scrip 78, dated Ocbober 6, 1879, known as the Russel Addition and designated as Blocks 1 thru 5 and 18 thru 27 and 40 thru 49 and 62 thru 71 and E/2 of Blocks 39, 50, 61 & 72	0.43693	0.31027
66	Amerada	Unknown	189: Lots 7 thru 12, Block 72, Russell Addition to the town of Seminole	-0-	0.00306
67	Amerada	Unknown	189: Lots 7 thru 12, Block 61, Russell Addition to the town of Seminole	-0-	0.00347
68	Amerada	Unknown	189: Lots 7 thru 12, Block 50, Russell Addition to the town of Seminole	-0-	0.00300

EXHIBIT A

SEMINOLE (SAN ANDRES) UNIT
Gaines County, Texas

T R A C T D E S C R I P T I O N

Block G, W. T. Railway
Company Survey

Tract No.	Operator	Tract Name	Section	Tract Participation Per Cent Phase I	Tract Participation Per Cent Phase II
69	Continental-Emsco	Seminole 189-3	189: All of Blocks 6, 7, 16, 17, and 28 of the Russell Addn to the town of Seminole; and all the following in the original town of Seminole: Lots 4, 5, 6, 7, 8, & 9 in Block 47; Lots 1 thru 9, and E. 60' of Lots 10, 11, & 12 in Block 59; Lots 4 thru 9, Block 60; Lots 3 to 12, incl. in Block 62 except Lot 8; Lots 1, 2, & 5 in Block 69, all of Block 70 & all of Block 71	0.07277	0.02238
70	Mabee	Riley Estate	189: All of Blocks 8, 9, 14, 15, 29, 30, 31, 36, 37, 38, 51, 52, 53, 58, 59, 60, 73, 74 & 75, and W/2 of Block 39, all in Russell Subdivision in the town of Seminole	0.28154	0.19173
71	Amerada	Unknown	189: Lot 8, Block 62 & Lots 3 & 4, Block 69 of the original town of Seminole	-0-	0.00014

EXHIBIT A

SEMINOLE (SAN ANDRES) UNIT
Gaines County, Texas

TRACT DESCRIPTION

Block G, W. T. Railway
Company Survey

Tract No.	Operator	Tract Name	Section	Tract Participation Per Cent Phase I	Phase II
72	Mabee	Lindsey	189: All of Blocks 10, 11, 12 13, 32, 33, 34, 35, 54, 55, 56, 57, 76, 77 of Russell Addition to the town of Seminole	0.38507	0.23732
73	Tenneco	F.A. Andrews	222: N/2 NE/4	0.25309	0.16261
74	Tenneco	W.L. Pickens	222: S/2 NE/4	0.07032	0.03190
75	Mobil	H & J Section 193	193: All	2.81923	1.72316
76	Mabee	Austin	190: NW/4	0.88146	0.59830
77	Tenneco	Emma Austin "B"	190: W/2 NE/4	0.25825	0.15202
78	Humble	Emma Austin	190: Blk. 23 Lots 1-16 Blk. 24 Lots 1-8 Blk. 25 Lots 5-8 Blk. 27 Lots 1-12 Blk. 28 E/part Lot 10 & Lots 11 & 12 Blk. 35 Lots 1 & 2 & E/part of Lot 3 Blk. 36 Lots 3-6 Blk. 37 Lots 1-8	-0-	0.02586

EXHIBIT A

SEMINOLE (SAN ANDRES) UNIT
Gaines County, Texas

TRACT DESCRIPTION

Block G, W. T. Railway
Company Survey

Tract No.	Operator	Tract Name	Section	Tract Participation Per Cent Phase I	Phase II
78 (Cont)	Humble	Emma Austin	190: Blk. 38 Lots 1-4 Blk. 39 Lots 5-8 Blk. 40 Lots 9-16 Blk. 41 Lots 7-12 Blk 42 E/part Lot 10 & Lots 11 & 12 Also E/6.75 acres out of 13 acre tract off south end of tract known as "College Ground" Blk 25 Lots 1-4 Blk. 28 Lots 1 & 2 & E/ part Lot 3 Blk. 35 Lots 11 & 12 & E/ part Lot 10 Blk. 36 Lot 1 Blk. 35 Lots 7-12 Blk. 37 Lots 9-16 Blk. 38 Lots 5-8 Blk. 39 Lots 1-4 Blk. 40 Lots 1-8 Blk. 41 Lots 1-6 Blk. 42 Lots 1 & 2 & E/ part of Lot 3		

EXHIBIT A

SEMINOLE (SAN ANDRES) UNIT
Gaines County, Texas

TRACT DESCRIPTION

Block G, W. T. Railway
Company Survey

Tract No.	Operator	Tract Name	Section	Tract Participation Per Cent Phase I	Tract Participation Per Cent Phase II
79	Amerada	Unknown	190: Lots 1 thru 16, Block 26 Austin Miller Addition to the town of Seminole	-0-	0.00149
80	Amerada	Unknown	190: Lot 2, Block 36 of Austin Miller Addition to the town of Seminole	-0-	0.00014
81	Tenneco	Emma Austin "C"	190: SW/4	0.56883	0.38770
82	Tenneco	Emma Austin "A"	190: SE/4	0.12807	0.22739
83	Amerada	Carr et al	161: SW/4 NW/4 & W/2 SW/4	-0-	0.01437
84	American Petrofina	Argo Hyde	192: NE/4	0.02381	0.02959
85	Mibil	H & J Section 191	191: N/2 N/2	-0-	0.03004
				100.00000	100.00000

AGREEMENT TO BECOME A PARTY TO
UNIT AGREEMENT AND UNIT OPERATING AGREEMENT
SEMINOLE-SAN ANDRES UNIT, GAINES COUNTY, TEXAS

KNOW ALL MEN BY THESE PRESENTS:

WHEREAS, the undersigned owner (whether one or more) of Royalty Interests hereby acknowledges receipt of a true copy of the "Unit Agreement, Seminole-San Andres Unit, Gaines County, Texas", dated May 1, 1968, hereinafter referred to as the Unit Agreement, and the undersigned owner (whether one or more) or Working Interests hereby acknowledges receipt of a true copy of said Unit Agreement, and a true copy of the "Unit Operating Agreement, Seminole-San Andres Unit, Gaines County, Texas", dated May 1, 1968, hereinafter referred to as the Unit Operating Agreement; and

WHEREAS, Exhibit A attached to the Unit Agreement, identify the Tracts which may become a part of the Unit Area as Initially constituted, depending upon whether such Tracts qualify for inclusion therein as provided in said agreement; and

WHEREAS, the undersigned represents that it is a Royalty Owner or Working Interest Owner, or both, as defined in the Unit Agreement, in one or more of the Tracts identified by said Exhibit;

NOW, THEREFORE, the undersigned owner of Royalty Interests desires to and does hereby agree to become a party to the Unit Agreement, and the undersigned owner of Working Interests, or the owner of both Working Interests and Royalty Interests, desires to and does hereby agree to become a party to both the Unit Agreement and the Unit Operating Agreement, with respect to all of its interest in all of the Tracts identified by said Exhibit.

IN WITNESS WHEREOF, each of the undersigned parties has executed this instrument on the date set forth below opposite its signature.

Date:____________________ ________________________

Date:____________________ ________________________

Date:____________________ ________________________

Date:____________________

Attest:

____________________ By: ____________________
Secretary President

STATE OF ____________________)
) SS: (Individual)
COUNTY OF ____________________)

BEFORE ME, the undersigned authority, on this day personally appeared ______________________________, known to me to be the person whose name is subscribed to the foregoing instrument, and acknowledged to me that he (or she) executed the same for the purposes and consideration therein expressed and in the capacity therein stated.

GIVEN UNDER MY HAND AND SEAL OF OFFICE this _____ day of _____________, 196__.

____
NOTARY PUBLIC in and for
_______________ County, _____________

STATE OF ____________________)
) SS: (Husband and Wife)
COUNTY OF ____________________)

BEFORE ME, the undersigned authority, on this day personally appeared ______________________________ and wife ______________________________, known to me to be the persons whose names are subscribed to the foregoing instrument, and acknowledged to me that they executed the same for the purposes and consideration therein expressed. And the said ______________________________, wife of ______________________________, having been examined by me privily and apart from her husband, and having the same fully explained to her, she, the said ______________________________, acknowledged such instrument to be her act and deed and declared that she had willingly signed the same for the purposes and consideration therein expressed and that whe did not wish to retract it.

GIVEN UNDER MY HAND AND SEAL OF OFFICE this the ____ day of ________________, 196__.

____
NOTARY PUBLIC in and for
_______________ County, _____________

STATE OF ____________________)
) SS: (Corporate)
COUNTY OF ____________________)

BEFORE ME, THE undersigned authority, on this day personally appeared ______________________________, known to me to be the person who executed the foregoing instrument as ______________________________ of ____________________ same for the purposes and consideration therein expressed, as the act and deed of said Corporation, and in the capacity therein stated.

GIVEN UNDER MY HAND AND SEAL OF OFFICE this ____ day of _______________ 196 _.

____
NOTARY PUBLIC in and for
_______________ County, _____________

APPENDIX D

ENVIRONMENTAL CONSTRAINTS

Outline

I. Introduction: a brief history of the environmental movement as it relates to the mining and oil industries.
II. Description and purpose of proposed action
III. Description of existing environment
    A. Location
    B. Legal description
    C. Baseline environmental studies
        1. Human environment
            a. Cultural resources
                1. Identify known cultural resources in the area of interest.
                    a. Historical and archelogical sites
                    b. Areas of ecological, scientific, geologic or aesthetic significance
                    c. Areas of ethnic importance
                2. Prepare a discussion of cultural overview of the area, including prehistorical as well as historical patterns
                3. Because a complete survey of cultural resources is rarely taken for an area, it is necessary to further identify potential cultural resources
                4. Determine significance of known and potential cultural resources relative to local, regional, and national concern
            b. Socioeconomic setting
                1. Describe socioeconomic setting
                    a. General characteristics and trends in population for state, county and city
                    b. Migrational trends in study area
                    c. Population characteristics in study area, including distributions by age, sex, ethnic groups, educational level, and family size
                    d. Economic history for state, county, and city
                    e. Employment and unemployment patterns in study area, including occupational distribution and location and availability of work force
                    f. Income levels and trends for study area
                    g. Land-use patterns and controls for study area
                    h. Land values in study area
                    i. Tax levels and patterns in study area, including land taxes, sales taxes, and income taxes
                    j. Housing characteristics in study area, including types of housing and occupancy levels and age and condition of housing
                    k. Health and social services in study area including manpower, law enforcement, fire protection, water supply, waste-water treatment facilities, solid waste collection and disposal, and utilities

l. Public and private educational resources in study area, including K-12, junior colleges, and universities
m. Transportation systems in study area, including highway, rail, air, and waterway
n. Community attitudes and life-styles
o. Community cohesion, including organized groups
p. Tourism and recreational opportunities in study area
q. Religious patterns and characteristics in the study area
r. Areas of unique significance such as cemeteries or religious camps

2. Physical environment
   a. Air quality
      1. Describe or determine existing air quality levels in the area
      2. Present historical trends in air quality
      3. Examine the frequency distribution and median and mean concentrations for each gaseous or particulate air pollutant that has an ambient air quality standard
      4. Determine air pollution dispersion potential for the area by aggregating information on parameters such as mixing height, inversion height, annual wind speeds, high air pollution potential advisories, and episode-days
      5. Summarize basic meteorological data for the area to include monthly summaries of precipitation, temperature, wind speed and direction, solar radiation, relative humidity, etc.
         a. Present data in graphical form of monthly, seasonal, or annual patterns of the various parameters
      6. Document unique meteorological phenomena
      7. Identify major point source of air pollution in the area and indicate the types and quantities of pollutants emitted as well as specific location
   b. Noise levels
      1. Determine existing noise levels for the project area
         a. May involve field measurements or determination of land use patterns
   c. Water quality
      1. Water quality parameters
         a. Physical parameters
            i. Color-true (dissolved) or apparent (filterable)
            ii. Odor
            iii. Solids content-suspended or dissolved, turbidity, conductivity, settleability
            iv. Oil or grease
            v. Aeration
            vi. Temperature and stratification
         b. Chemical parameters
            i. Organic

(a) BOD
(b) COD
(c) TOD
(d) Total organic carbon

ii. Inorganic

(a) Salinity
(b) Hardness
(c) pH
(d) Acidity
(e) Alkalinity
(f) Levels of iron, manganese, chlorides, sulfates, sulfides, heavy metals, nitrogen (organic, ammonia, nitrite, nitrate), phosphorous, etc.

c. Bacteriological parameters
   i. Coliforms
   ii. Fecal coliforms
   iii. Specific pathogens
   iv. Viruses

2. Determine existing water quantity and quality levels for the surface watercourses in the area (drainage basin)
   a. Examine frequency and mean data for both water quantity and quality
   b. Consider historical trends of water quality
   c. Examine flow characteristics
3. Document unique pollution problems that have occurred or are existing in local surface watercourses
4. Identify major local uses of surface water
5. Describe groundwater quantity and quality in the area, noting depth of groundwater table and direction of groundwater flow
6. Identify major local uses of groundwater
7. Delineate historical trends for groundwater depletion and pollution
8. Assemble summary of key meteorological parameters for the area, noting particularly the monthly averages of precipitation, evaporation, and temperature
9. Summarize the waste load allocation study for the particular surface watercourses in the area

d. Land
   1. Describe land in terms of stratigraphy, soil characteristics, land forms and mineral resources
   2. Determine the existence of faults, fracture zones, folds or similiar structures which might yield under the pressure of mining facilities and equipment
   3. Locate porous formations and surface and underground watercourses
   4. Determine present land use and land use controls

3. Biological Environment
   a. Prepare description of the flora and fauna

1. Describe community types and their geological distribution, and develop species descriptions for each community type

b. Identify rare and endangered species and discuss relevant characteristics of each species

1. Breeding and nesting requirements
2. Life-cycle features
3. Other unique requirements that may be important

c. Discuss past and current management practices as related to floral and faunal species, as well as special activities associated with protected species

1. Examples include

a. Spraying for pest control
b. Introducing new species
c. Controlled burning
d. Stocking water bodies with fish species
e. Limiting hunting seasons in terms of time and number of animals harvested

d. Describe natural succession as it relates to the alteration of communities with time, i.e., describing what the environment will become if proposed action were not implemented

IV. Potential beneficial and detrimental impacts and mitigation methods

A. Human environment

1. Cultural resources

a. Delineate possible impacts on known and potential cultural resources in the area of interest. Impacts should be determined for preconstruction, construction, operation, and postoperation phases
b. Develop measures to avoid adverse impacts
c. Develop procedures that will be used during the construction phase if previously unidentified cultural resources are uncovered

2. Socioeconomic setting

a. Identify critical environmental concerns relative to the socioeconomic factors described above

1. Examples include

a. Locations where water and waste-water treatments may be operated in excess of design capacity
b. Locations where existing school systems will be overcrowded

b. Develop measures to avoid adverse impacts

3. Health and safety of employees

a. Define applicable local, state, and federal regulations

1. Underground and surface mining laws
2. Possible crushing operations, etc.
3. Use of explosives
4. Building codes
5. Electrical codes

b. Develop safety and accident prevention programs

1. Special concerns

- a. Airborne contaminants
- b. Noise control
- c. Explosives
  - i. Storage
  - ii. Transportation
  - iii. Use
- d. Gassy mine environment
- e. Electrical facilities
  - i. Cables and power lines
  - ii. Grounding
  - iii. Lightning protection
  - iv. Electrical equipment
- f. Machinery and equipment
- g. First aid and medical facilities
- h. Health and sanitation
- i. Signs and posters
- j. Personal protection and life-saving equipment
- k. Protection of the public
- l. Toxicology studies

c. Fire prevention and control
- 1. Applicable local, state, and federal regulations
- 2. Construction
- 3. Mining
- 4. Processing and storage facilities
- 5. Mobile equipment
- 6. Offices, warehouses and shops
- 7. Fuel storage

B. Physical environment
- 1. Air quality
  - a. Identify air pollutants (chemical and dust) emitted during preconstruction, construction, operation, and postoperation phases and determine quantity
    - 1. Examples include
      - a. Construction of
        - i. Access roads
        - ii. Mine site
        - iii. Disposal areas
        - iv. Support facilities
        - v. Burning control
        - vi. Control vehicles and equipment
      - b. Operation or mining
        - i. On-site power generation systems
        - ii. Exhaust ventilation
        - iii. Development and processing
        - iv. Storage facilities for products and waste material
        - v. Burning of waste petroleum and chemical products
      - c. Postoperation (abandoned mines)
        - i. Natural weathering of waste piles, etc. resultant dispersion of weathered particles by air currents

            ii. Air pollutants include inert particulates, toxic particulates, and gases

   b. Procure local, state, or federal ambient air quality standards and emission standards
      1. Determine if each phase must be within standards or if the standard applies to overall operation
   c. Determine increase in regional and local emissions inventory for each pollutant as result of all phases of action
   d. Consider cummulative effects of pollutant emissions from all nonpoint and point sources in the air basin
   e. Calculate the ground level concentrations of air pollutants under varied meteorological conditions
   f. Compare the calculated air quality levels with the applicable ambient air standards to assess impact
   g. If ambient air or emission standards are exceeded
      1. Determine the significance or importance of calculated air quality levels
      2. Consider mitigation or control measures
         a. Dust control techniques
            i. Periodic sprinkling or application of calcium chloride or waste oil
            ii. Tree screening of dust before it reaches nearby communities

2. Noise levels
   a. Define noise and give noise levels encountered in our everyday environment
   b. Identify sources of noise and determine the noise levels during preconstruction, construction, operation, and post-operation phases
      1. Employee exposure
      2. Public exposure
   c. Obtain applicable noise standards and criteria for the area
      1. Determine the role of federal and state governments
         a. EPA
         b. OSHA
         c. MESA
      2. Discuss basis of noise standards
         a. Physiological
         b. Psychological
   d. Compare predicted noise levels with applicable standards or criteria in order to assess impact
   e. If standards or criteria are exceeded, consider noise abatement methods to minimize impact
   f. Prepare program to monitor employee exposure

3. Water quality
   a. Consumptive requirements
      1. Determine total annual consumptive requirements
         a. Determine requirements for rock drills, townsites, etc.
      2. Determine availability of water to meet above requirements
         a. Determine if water may be obtained from existing sources - wells (artesian and non-artesian) constant

flow streams or reservoirs

b. Determine agricultural, industrial or municipal competition for water
c. Determine if available water is chemically suitable for consumptive requirements

3. If availability of water is insufficient to meet consumptive needs
   a. It may be necessary to transport water by pipeline
   b. It may be necessary to retreat and reuse water

b. Impacts of water quality
   1. Definition of water pollution (point source and nonpoint source)
      a. Physical
      b. Chemical
   2. Identify and determine levels of pollutants emitted during preconstruction, construction, operation, and postoperation phases
   3. Obtain relevant water quality standards for local surface watercourses and groundwater supplies. Specify applicability of effluent standards and required treatment technology and state whether the receiving stream is water-quality limited or effluent limited. Consider time schedules required for attaining applicable water quality standards
      a. Water quality standards vary from state to state, river basin to river basin, and various segments within river basins
      b. State standards may include consideration of present and potential beneficial uses of water
   4. Determine mesoscale impacts by calculating estimated daily quantities of water pollutants during construction, operation and postoperation phases and comparing these to existing waste loads in the drainage area
   5. Determine microscale impacts during construction, operation, and postoperation phases by calculating specific downstream concentrations resulting from conservation pollutants (pollutants not biologically degraded or physically lost from water phase); dissolved concentrations resulting from biological degradation of nonconservative (organic pollutants); and temperatures resulting from thermal discharge. Compare with applicable water quality standards to assess impact.
   6. Consider construction phase impacts in terms of following factors
      a. Time period of construction and resultant time period of decreased water quality. Specify stream discharges and quality variations that would be anticipated
      b. Anticipated distance downstream of decreased water quality
      c. Implications of decreased water quality relative to downstream water users

d. Specific construction specifications directed toward pollutant minimization

7. Consider operation phase impacts in terms of following factors
   a. Frequency distribution of decreased quality and quantity
   b. Effects of sedimentation on the stream bottom ecosystem
   c. Fate of nutrients by incorporation into biomass
   d. Reconcentration of metals, pesticides, or radionuclides into the food web
   e. Chemical precipitation or oxidation-reduction of inorganic chemicals
   f. Anticipated distance downstream of decreased water quality and the implications for water users and related raw water quality requirements
   g. General effects of any water quality changes on the stream ecosystem
   h. Unique water quality changes that occur as a result of water impoundment and thermal stratification
8. Examples of potential impacts resulting from construction, operation and postoperation phases
   a. Direct loss of wetlands, marshes, etc. (loss of land and/or productivity)
   b. Loss of stream fishery - through loss of fish runs
   c. Loss of recreation potential
   d. Change in rate of eutrophication
   e. Change in flow characteristics
   f. Change in water quality for downstream agricultural, industrial, recreational, or municipal users
   g. Change in groundwater recharge
   h. Change in aesthetic characteristics
   i. Adverse effests on wildlife and vegetation
      i. Loss of habitat
      ii. Loss of nutrients
      iii. Biomagnification of pollutant in food web
   j. Streams flowing in and around storage and waste piles accelerate weathering and erosion and, thereby increase discharge of pollutant
   k. Increase sedimentation
   l. Redissolving of previously precipitated pollutants by chemical or biological mechanisms and re-entering aquatic ecosystem
   m. Salinization of water resources
   n. Groundwater pollution
9. Water quality may also be adversely affected by
   a. Spillage or discharge of harmful materials into the water supply through accidental or continuous low-level discharge of oil
      i. Pipeline spills due to accidental punctures, cracked welds, and leaded from corrosion

        b. Spillage of salt water produced with the oil
        c. Spillage of other harmful materials, such as chemicals or solid waste
        d. Blowout
            i. Sudden or violent uncontrolled escape of gas, oil, or water from the well and subsequent contamination of aquifers used for drinking and other consumptive purposes
        e. Mine seepage by brine waters
        f. Produced brines pumped out with oil
    10. If water quality of effluent standards are exceeded, consider mitigation or control measures
        i. Inflitration control of water flowing into or through storage and waste piles
        a. Surface blankets such as soil sealants, synthetic membranes, and clay blankets which form an impermeable barrier on the surface of piles
            i. Surface water diversion of existing watercourses
            ii. Groundwaer diversion
            iii. Diversion of polluted discharge
            iv. Erosion prevention (see IC-4)
            v. Backfilling mine with inert materials
            vi. Sedimentation basins
            vii. Deep well disposal, reinjection into groundwater squifers
            viii. Monitoring of surface and groundwater watercourses
            ix. Water treatment, if mitigation methods are only partially successful, for process needs and fire protection or potable water
            x. Evaporation ponds
            xi. Use of water for dust control
            xii. Control of surface runoff with retention dams and collection ditches

4. Land [illegible]
    a. Determing the size of the operation and land area needed for mine facilities accounting for distance between buildings for fire protection and for improving access and conveying or material
        1. On-site power plant
        2. Water reservoir and treatment
        3. Machine shops
        4. Main office
        5. Medical facilities
        6. Disposal area for mine wastes
        7. Disposal area for nonprocess solid waste
        8. Facilities for storage, loading, shipping
        9. Access roads, turnarounds for equipment
        10. Parking space for employees
        11. Provision for future expansion
        12. In wooded areas, sufficient land must be cleared around plant to prevent forest fire

13. If located far from town, housing and meal facilities for visitors, top management and maintenance personnel
14. Space for townsite, schools, recreation facilities, etc.

b. Determine land related impacts
   1. Land pollution resulting from spillage of oil, brine or chemicals
      a. Soil sterilization
      b. Adverse effects on vegetation and crops and wildlife
   2. Impact of oil operations on alternative uses of land
   3. Subsidence
   4. Areas cleared of vegetation and storage and waste piles subject to increase weathering and erosion
   5. Changing existing and form characteristics through construction of access roads, build-up of storage and waste piles, etc.

c. Land rehibilitation, erosion control and subsidence control
   1. Land reclamation
      a. Considerations
         i. Mining
         ii. Access roads
         iii. Transmission lines
         iv. Pipelines
         v. Etc.
      b. Land reclamation process
         i. Site selection and preparation (shaping and grading) considerations
            a-Erosion control
            b-Aesthetics
            c-Species to be planted
            d-Method chosen to construct artificial soil profile
         ii. Revegetation
            a-Success to depend upon terrain, stoniness, toxicity, moisture the microclimate of the site, and the species of vegetation
            b-Re-establish vegetation to support same kinds and number of fauna
            c-Consideration of existing revegetation technology
   2. Erosion control
      a. Determine material soze and classification
      b. Slope and surface treatment
         i. Physical stabilization
            a-Use of rock or soil borrowed from nearby areas
         ii. Chemical stabilization
            a-Formation of impermeable crust
         iii. Vegetative stabilization
      c. Facilities to drain water into erosion resistant areas or into specially designed channels

3. Subsidence Control
    a. Determine likely areas and estimate extent
    b. Prevention or mitigation measures
        i. Filling mined areas with materials of various kinds for strata support
    c. Establish monitoring system

5. Waste Disposal
    a. Procure applicable local, state, and federal regulations
    b. Determine sources, composition and quantities of waste material created by each phase of proposed action
        1. Process wastes
            a. Water, gas, and oil treatment wastes
            b. Overburden
            c. Waste piles
            d. Brine
            e. Etc.
        2. Nonprocess wastes
            a. Community waste such as sewage and garbage
                i. Average person produces 10 pounds of waste per day
            b. Windblown material
            c. Paper, wood, metal, etc.
    c. Waste disposal and treatment
        1. In areas of very thick sedimentary material, it may be possible to pump obnoxious waste material into deeply buried porous formations already containing deleterious brines
        2. Areas used for mine waste disposal may require installation of a blanket base of impervious material, such as clay, to prevent groundwater contamination by deleterious materials seeping through surface soils
        3. Prevent dumping of sewage into streams
            a. Modern sewage contains chemicals which natural biochemical action can not break down
        4. Water can be treated for reuse and for use in waste disposal plants
6. Oil and hazardous material control
    a. Procure applicable local, state, and federal regulations
        1. Facility design
            a. Transportation of liquids (pipeline)
            b. Disposal and storage of pesticides and pesticide containers
            c. Oil pollution prevention
            d. Water pollution control
            e. Reporting spills of oil and other hazardous material
    b. Storage and handling
        1. Nontransportation related facilities
        2. Transportation related facilities
    c. Biological environment
        1. Predict the impacts of the proposed action on the biological environment. Quantify where possible and

qualitatively discuss implications.

a. Examples include
   1. Effects on resiliency and fitness of ecosystem types (lowland forest, grassland, marsh, stream, etc.)
   2. Effects on total standing crop of organic matter
   3. Effects on annual plant productivity
   4. Effects on mulch or litter removal as related to top soil stripping
   5. Effects on animal production
   6. Effects on sediment load carried by stream
   7. Effects on aquatic macroinvertebrate population
   8. Effects on drift rate of aquatic macroinvertebrates
   9. Effects on population density of fish
   10. Effects of sediment load on fish spawning
   11. Effects on species diversity of the aquatic biota
   12. Effects on undesirable proliferation of biota
   13. Effects on localized survival of rare plants and animal species
   14. Effects on habitat carrying capacity of both aquatic and terrestrial systems

2. Assess predicted impacts in terms of their magnitude and importance. Summarize the critical impacts
3. Determine possible causes of detrimental effects on the biologic environment
   a. Continuous low-level discharge of materials or noise
   b. Accidental discharge of oil, brine, or other toxic materials
   c. Occasional or temporary discharge of materials o-disruption of environmental quality (e.g., noise and vibrations of construction equipment)

V. Identification of "any adverse environmental effects which cannot be avoided should the proposal be implemented" (no new information is included in this section)

VI. Discussion of "alternatives to the proposed action"
   A. One alternative action is "no-action"
   B. Discuss points delineated in Sed. IV. for each alternative

VII. Description of "the relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity"

VIII. Discussion of "any irreversible and irretrievable commitments of resources which would be involved in the proposed action should it be implemented"
   A. Examples include
      1. Changes in land usage
      2. Loss of cultural features
      3. Loss of habitat

IX. Discussion of how proposed action may conform or conflict with the objectives and specific terms of any federal, state, or local land-use matters, either approved or proposed. In addition, land-use plans developed in response to the requirements of the Clean Air Act or the Federal Water Pollution Control Act Amendments of 1972 should also be specified

X. Discussion of growth inducing impacts
XI. Indication of what other interests and considerations of federal policy are thought to offset the adverse environmental effects of the proposed action
XII. Discussion of problems and objections raised by reviewers

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APPENDIX E

SAFETY REGULATIONS*

In that the explosive danger is from gas and not dust, the development and mining should be goverened by the Safety Regulations for Non-Metallic Mines rather than coal mines.

Title 30 Mineral Resources

Part 57 - Health and Safety Standards Metal and Non-Metallic Mines.

To avoid one of the main hazards a strong effort should be made to design a mining system without explosives, using shaft, tunnel and raise boring machines supplemented by pneumatic or hydraulic drilling of drainage bore holes.

The following safety regulations are those that apply to gassy mines and do not include regulation that apply to all metal and non-metal mines.

57.6	Explosives
57.7	Drilling
57.8	Rotary Jet Piercing
57.9	Loading, Hauling and Dumping
57.10	Aerial Tramway
57.11	Travelways and Escapeways
57.12	Electricity
57.13	Compressed air & boilers
57.14	Use of Equipment
57.15	Materials storage and handlings
57.17	Illumination
57.18	Safety Programs
57.19	Man hoisting

All of the above are also important for our project, and should be enforced.

Section 57.21-1 Gassy Mine

A mine shall be deemed gassy, and thereafter operated as a gassy mine if:

a) The state in which the mine is located classifies the mine as gassy; or
b) flammable gas emanating from the ore body or the strata surrounding the ore body has been ignited in the mine; or
c) a concentration of 0.25 percent or more, by air analysis of flammable

*PL 95-164 that was effective March 1978 modifies this material somewhat and periodic revisions to Federal and State regulations can be anticipated in the future.

gas emanating only from the ore body has been detected not less than 12 inches from the back, face or ribs in any open workings; or

d) the mine is connected to a gassy mine. (The petroleum reservoir can be considered a gassy "ore body").

57.21-2(M)* Flammable gases detected while dewatering mines and similar operations shall not be used to class a mine gassy.

Fire Prevention and Control

57.21-10(M) Men shall not smoke or carry smoking materials, matches or lighters underground. The operator shall institute a reasonable program to ensure that persons entering the mine do not carry smoking materials, matches or lighters.

57.21-11(M) Except when necessary for welding or cutting, open flames shall not be used in other than fresh air or in places where flammable gases are present or may enter the air current.

57.21-12(M) Welding or cutting with arc or flame underground in other than fresh air or in places where flammable gases are present or may enter the air current shall be under the direct supervision of a qualified person who shall test for flammable gases before and frequently during such operations.

57.21-13(M) Welding or cutting shall not be performed in atmospheres containing more than 60 percent of flammable gases.

Ventilation

51.21-20(M) Main fans shall be

a. installed on the surface

b. powered electrically from a circuit independent of the mine power circuit. Internal combustion engines shall be used only for standby power, or where electrical power is not available.

c. installed in fireproof housing provided with fireproof air ducts.

d. offset not less than 15 feet from the nearest side of the mine opening and equipped with ample means of pressure relief unless:

1. the opening is not in direct line with forces, which would come out of the mine should an explosion occur; and

2. another opening not less than 15 feet nor more than 100 feet from the fan opening is equipped with a weak wall stopping or explosion doors in direct line with forces which would come out of the mine should an explosion occur.

e. installed to permit prompt reversal of air flow.

f. attended constantly or provided with automatic devices to give alarm when the fans slow or stop. Such devices shall be places so they will be seen or heard by responsible persons.

* M - Mandatory

57.21-21 Main fans should be:

a. operated continuously except when the mine is shut down for an extended period.

b. provided with pressure gages

c. inspected daily and records kept of such inspections and of fan maintenance

57.12-22 Air Intake

The main intake and return air currents in mines should be in separate shafts, slopes or drifts.

57.12-23(M) When single shafts are used for intake and return the curtain wall or partition shall be constructed of reinforced concrete or equivalent and provided with pressure relief devices.

57.21-24(M) When main fan fails or stops and ventilation is not restored in a reasonable time, action shall be taken to cut off the power to area affected and to withdraw all men from such area.

57.21-25 When there has been a failure of ventilation and ventilation has been restored in a reasonable time, all places where flammable gas may have accumulated should be examined by a qualified person and determined to be free of flammable gas before power is restored.

57.21-26(M) When ventilation is not restored in a reasonable time, all men shall be removed from the areas affected, and after ventilation has been restored, the areas affected shall be examined by qualified persons for gas and other hazards and made safe before power is restored and before men other than the examiners and other authorized persons return to the areas affected.

57.21-27(M) When main fan or fans have been shut down with all men out of the mine, no person, other than those qualified to examine the mine, or other authorized persons, shall go underground until the fans have been started and the mine examined for gas and other hazards and declared safe.

57.21-28(M) Booster fans shall be:

a. operated by permissable drive units maintained in permissible condition

b. operated only in air containing not more than 1.0 percent flammable gas.

57.21-29(M) A booster fan shall be:

a. equipped with an automatic devise to give alarm when the fan slows or stops, or equipped with a devise that automatically cuts off the power in the area affected if the fans slow and stop.

b. provided with air locks, the doors of which open automatically if the fans stop.

57.21-30(M) Auxiliary fans shall be:

a. operated by permissible drive units maintained in permissible condition.

b. operated only in air containing not more than 1.0 percent flammable gas.

57.21-31 Auxiliary fans should be inspected by competent persons at least twice each shift.

57.21-32(M) Men shall be withdrawn from areas affected by auxiliary or booster fans when such fans slow down or stop.

57.21-33(M) The volume and velocity of the current of air coursed through all active areas shall be sufficient to dilute and carry away flammable gases, smoke, and fumes.

57.21-34(M) The quantity of air coursed through the last open cross cut in pairs or sets of entries or through other ventilation openings nearest the face, shall be at least 6000 cubic feet per minute (CFM).

57.21-35(M) At least once each week a qualified person shall measure the volume of air entering the main intakes and leaving the main returns, the volume of the intake and return of each split, and the volume through the last open crosscuts or other ventilation openings nearest the active faces. Records of such measurements shall be kept in a book on the surface.

57.21-36 Permanently installed battery charging and charging and transformer stations should be ventilated by separate split of air conducted directly to return-air courses.

57.21-37 Electrically operated pumps, compressors and portable substations should be in intake air.

57.21-38(M) Changes in ventilation that materially affect the main air currents or any split thereof and may affect the safety of persons in the mine shall be made only when the mine is idle. Only those persons engaged in making such changes shall be permitted in the mine during the change. Power shall be removed from the areas affected by the change before work starts and not restored until the effect of the change has been ascertained and the affected areas determined to be safe by a qualified person.

57.21-39(M) If flammable gas in excess of 1.0 percent by volume is detected in the air not less than 12 inches from the back face, and rib of an underground working place, or in air returning from a working place or places adjustments shall be made in the ventilation immediately so that the concentration of flammable gas in such air is reduced to 1.0 percent or less.

57.21-40(M) If 1.5 percent or higher concentration of flammable gas is detected in air returning from underground working place or places, the men shall be withdrawn and the power cut off to the portion of the mine endangered by such flammable gas until the concentration of such gas is reduced to 1.0 percent or less.

57.21-41(M) Air that has passed by an opening of any unsealed abandoned area and contain 0.25 percent or more flammable gas shall not be used to ventilate working areas. Examinations of such air shall be conducted during the pre-shift examination required by 57.21-59 (Examination by a "fire-boss" or other qualified person using the proper instruments).

57.21-42(M) Air that has passed through an abandoned panel or area which is inaccessible or unsafe for inspection shall not be used to ventilate any working place in such mine. No air which has been used to ventilate an area from which the pillars have been removed shall be used to ventilate any working place in such mine, except that such air, if it does not contain 0.25 volume per centum or more of methane, may be used to ventilate enough advancing working places immediately adjacent to the line of retreat to maintain an orderly sequence of pillar recovery on a set of entries.

(The above section applys mainly to room and pillar methods of mining, which we will probably not use.)

57.21-43(M) Abandoned areas shall be sealed or ventilated; areas that are not sealed shall be barricaded and posted against unauthorized entry.

57.21-44(M) Seals shall be of substantial construction. Exposed surfaces shall be made of fire-resistent material or, if the commodity mined is combustible, seals shall be made of incombustible material.

57.21-45(M) One or more seals of every sealed area shall be fitted with a pipe and a valve or cap to permit sampling of the atmosphere and measurement of the pressure behind the seals.

57.21-46(M) Cross-cuts shall be made at intervals not in excess of 100 feet between entries and between rooms. (Do not believe this would apply to development).

57.21-47 Cross-cuts should be closed where necessary to provide adequate face ventilation.

57.21-48(M) Line brattice or other suitable devices shall be installed from last open cross-cut to a point near the face of every active underground working place, unless the Secretary or his authorized representative permits an exception to this requirement. (This probably applies to multiple entry systems.)

57.21-49 Brattice cloth should be of flame resistant material.

57.21-50(M) Damaged brattices shall be repaired promptly.

57.21-51 Cross-cuts should be provided where practicable, at or near the faces of entries and rooms before they are abandoned.

57.21-52(M) Entries or rooms shall not be started beyond the last open cross-cut, except that room necks and entries not to exceed 18 feet in depth may be turned off entries beyond the last open cross-cuts if such room necks or entries are kept free of accumulation of flammable gas by use of line brattice or other adequate means. (The 18 ft. would apply to off set stations we may use for drilling drain holes.)

57.21-53(M) Stoppings in cross-cuts between intake and return airways, on entries other than room entries should be built of solid, substantial materials; exposed surfaces should be made of fire resistant materials or, if the material mined is combustible, stoppings should be made of incombustible material. (The safest way would be to have two shafts one downcast and connected by our tunnels to an upcast shaft, where petroleum pumps, water pumps, battern charges, etc. would be located in the shaft station.

57.21.54 Stoopings should be reasonably air tight.

57.21-55(M) The main ventilation shall be so arranged by means of air locks, overcasts, or undercasts that the passage of trips or persons does not cause interruptions of air currents. Where air locks are impractible, single doors may be used if they are attended constantly while the area of the mine affected by the doors is being worked, unless they are operated mechanically or are self closing.

57.21-56(M) Air locks must be ventilated sufficiently to prevent accumulation of flammable gas inside the locks.

57.21-57(M) Doors shall be kept closed except when men or equipment are passing through the doorways.

57.21-58 Overcasts and undercasts should be:

a. constructed lightly of incombustible material
b. of sufficient strength to withstand possible falls from the back
c. kept clear of obstructions.

57.21-59(M) Pre-shift examinations shall be made of all working areas by qualified persons within 3 hours before any workmen other than examiners enter the mine.

57.21-60 None

57.21-61(M) Only qualified examiners and persons authorized to correct dangerous conditions shall enter places or areas where danger signs are posted.

57.21-62(M) Danger signs shall not be removed until the dangerous conditions have been corrected.

57.21-63,64 None

57.21-65 Examinations for dangerous conditions including tests for flammable gas with a device approved by the Secretary should be made at least once a week, and at intervals of not more than 7 days by the mine foreman or other designated mine official, except during weeks in which the mine is idle for an entire week. The foreman or other designated mine offical should:

a. Examine and make tests
    1. in the return of each split where it enters the main return
    2. on accessible pillar falls
    3. at seals
    4. in main return
    5. in at least one entry of each intake and return airway in its entiréty
    6. on idle workings
    7. in abandoned workings, in so far as conditions permit
b. mark his initials and date at the places examined
c. report dangerous conditions promptly to the mine operator or other designated persons
d. record the results of his examination with ink or indelible pencil in a book kept for that purpose at a designated place on the surface of the mine.

57.21-66 The mine foreman or other designated mine official should read and countersign promptly the reports of daily and weekly examinations by qualified persons and should take prompt action to have dangerous conditions corrected.

Equipment

57.21-76(M) Diesel-powered equipment shall not be taken into or operated in places where flammable gas exceeds 1.0% at any point not less than 12 inches from the back, face or rib.

57.21-77(M) Trolley wires and trolley feeder wires shall be on the intake air and shall not extend beyond the first open cross-cut or other ventilation opening. Such wires shall be dept at least 150 feet from pillar workings.

57.21-78(M) Only permissible equipment maintained in permissible conditions shall be used beyond the last open cross-cut in places where dangerous quantities of flammable gases are present or may enter the air current.

57.21-79(M) Only permissible distribution boxes shall be used in working places and other places where dangerous quantities of flammable gas may be present or may enter the air current.

57.21-80 None

57.21-81(M) No electric equipment shall be taken into or operated in places where flammable gas can be detected in the amount of 1.0% or more at any point not less than 12 inches from the back, face, and rib.

Illumination

57.21-90(M) Only permissible electric lamps shall be used for portable illumination underground.

Explosives

57.21-95(M) Explosives not designated as permissible by the Bureau of Mines or the Mining Enforcement and Safety Administration shall not be used in any underground gassy mine until MESA and State Inspector of Mines have given written approval for each specific explosive to be used.

57.21-96(M) MESA and State Inspector of Mines in granting approval referred to in standard 57.21-95 shall provide the operator with a written list of conditions for using the specific explosive covered by the approval and adapted to the mining operation.

57.21-97(M) Blasts in gassy mines shall be initiated electrically, and multiple shot blasts shall be initiated only with millisecond delay detonators. Permissible blasting units capacity suitable for the number of holes in the round to be blasted shall be used unless the round is fired from the surface when all men are out of the mine.

57.21-98(M) Boreholes shall be stemmed as prescribed for the explosives used.

57.21-99(M) Examination for gas shall be made immediately before and after firing each shot or round.

57.21-100(M) Shots or rounds shall not be fired in places where flammable gas can be detected with a permissible flame safety lamp or where 1.0% or more of flammable gas can be detected by any other Bureau of Mines or MESA approved device or method, at a point not less than 12 inches from the back, face and rib.

57.21-101 Shots and rounds should be fired by qualified persons.

Metal & Non-Metal Federal Mandatory Standard with State Codes

Utah - July 1976

Gilsonite Mines

Section 8 - Duty of Mine Inspectors

21 - Ventilation - Gilsonite Mines

A. Provide and maintain a constant and adequate supply of pure air to the working faces of all mines.

B. The main ventilating fan shall be placed on the outside of the mine and shall be of sufficient capacity to provide the required air.

C. All fans shall be of fireproof material.

D. Placed at least 15 feet to one side of mine opening.

E. Temporary fan or fans for small mines may be installed which do not meet the requirements of this section may be installed if permission is secured from the commission.

F. Motors of fans shall be explosion proof or at least (50 ft.) away from collar of the mine.

G. Fans not operated continuously, shall be started at least 30 min. before the mine inspector enters the mine.

H. The ventilation current shall be conducted and circulated to the face of each working place throughout the entire mine in sufficient quantities to dilute, render harmless and sweep away all dust and noxious or dangerous gases to the extent that all working places and traveling roads shall be in a safe condition for working and traveling therein.

I. Worked out or abandoned areas shall be kept free of dangerous gases. If impossible to keep the entire mine free from dangerous accumulations of standing gases, the Industrial Commission shall be notified immediately.

J. All doors used in ventilation shall be hung and adjusted to close automatically. Main doors regulating the principal air currents shall be in pairs to act as an air lock.

K. Worked out areas will be sealed or posted with danger signs and so ventilated as to prevent an accumulation of dangerous gases.

L. Contaminated air from worked-out areas shall be conducted directly to the main airway without passing through any working sections.

<u>Section 22 - Gassy Mines - Including Gilsonite</u>

Same as 57.21-1 schedule 30

<u>Fire Prevention and Control</u>

Same as 57.21-10

<u>Section 46 - Explosives</u>

Additional Rules for Gilsonite Mines

A. Only competent and experienced persons designated by mine management shall be permitted to handle explosives and to blasting. Except herein provided, the man who does the blasting shall hold either a mine foreman's, a mine examiner's or a shot finer's certificate. In non-gassy mines where less than six men are employed, the man who does the blasting, if not certified, shall have passed an oral examination given by the state mine inspector.

B. Persons who assist in charging, stemming or wiring shall be under the direct supervision of the man who does the blasting.

C. No blasting shall be done where there is a showing of <u>methane</u> gas or an accumulation of flammable dust until after either or both have been cleared.

D. Unconfined shots, mud caps, or plaster shots are strictly prohibited in the mine.

E. The blasting of rock in gilsonite mines will be permitted only when using permissible powder. All shots shall be fired electrically after all men are out of the mine.

F. The area around and adjacent to the place where blasting is to be done shall be either wet down throughly or well rock-dusted to prevent the ignition of the dry gilsonite dust that may be raised in suspension in the air. Under these conditions millisecond delay caps shall be used.

G. In charging holes for blasting only wooden tamping poles shall be used.

H. Holes shall be stemmed to the collar with clay or other non-combustible material.

I. After the firing of shots, the place shall be examined for dangerous or unsafe conditions, and if such exists the place shall be made safe before any other work is done therein.

J. When misfires occur with electric detonators, a working period of at least fifteen minutes shall elapse before anyone returns to examine the electtic connections. Before returning to the shot, the blasting cable shall be disconnected from the source of power and short circuited.

<u>Section 69 - Hoisting - Gilsonite Mine Shaft without Guides</u>

We will not be using shafts without guides.

<u>Section 78 - Electrical Power - Gilsonite Mines</u>

A. Electrical Equipment

1. All electrical face equipment used in a gilsonite mine shall be permissible.

2. In gassy mines, permissible junction or distribution boxes shall be used for making multiple power connections in working places or other places where methane may occur.

3. Electric equipment shall not be taken into or operated in any place where methane can be detected with flame safety lamp at any point not less

than 12 inches from the roof, face, or rib.

4. The operators of electrically powered face equipment shall remain with their machines while they are in operation. When leaving the machine or the working place, they shall see the power is cut off from the trailing cable.

5. In gassy mines, if electric sparks or arcs are produced by face equipment or cables, the machine shall be stopped, the occurrence reported to a mine official, and the machine shall not be restarted until the defect has been corrected.

6. Electric drills or other electrically operated rotating tools intended to be held in the hands shall have the electric switch constructed so as to break the circuit when the hand releases the switch or shall be equipped with properly adjusted friction or safety clutches.

7. Post mounted drills shall be equipped with automatic stop control safety switches or shall be equipped with properly adjusted friction or safety slutches.

8. Electric power for face equipment shall be limited to 650 volts between conductors and the ground. If higher voltage is desired, permission shall be from the Industrial Commission of Utah.

B. Trailing Cables

1. Trailing cables purchased after the effective date of these order for use underground shall meet the U.S. Bureau of Mines or MESA requirements for flame resistant cables.

2. Trailing cables shall be provided with suitable short-circuit protection and means of disconnecting power from the cable.

3. Temporary splices in trailing cables shall be made electrically efficient, mechanically strong and well insulated. The number of temporary splices in trailing cables should be limited to five. No splice shall be permitted in drag cables less than 25 feet from the machine.

4. Trailing cables or hand cables having exposed wires or splices that heat or spark under load shall not be used.

C. Permanent splices in trailing cables are made as follows:

1. Mechanically strong with adequate electrical conductivity and flexibility.

2. Effectively insulated and sealed so as to exclude moisture.

3. The finished splice shall be vulcanized or otherwise heated with suitable materials to provide flame resistant properties and good bonding to

outer jacket.

D. Care shall be used to protect trailing cables from avoidable mechanical damage.

Section 83 - Gilsonite Mines

A. Approaching Old Workings - Impounding Water

1. Whenever any working place in a gilsonite mine approaches within fifty (50) feet of abandoned workings in such mine as shown by surveys made and certified by a competent engineer or surveyor; or within 200 feet of any other abandoned working of such mine, which cannot be inspected and which may contain dangerous accumulations of water or gas, or within 200 feet of any workings on adjacent mine, borehole or boreholes shall be drilled to a distance of at least 25 feet in advance of the working place. Such boreholes shall be drilled sufficiently close to each other to insure that the advancing face will not accidently hole through in such openings.

2. It shall be unlawful to impound water underground in any section of the mine above where men working without permission of the mine inspectors.

3. Any dangerous accumulations of water in a mine shall be reported to the Industrial Commission immediately.

Safety

Mining involves unavoidable and calculated risks, as in all facets of life. It is most important then that men employed in mining be schooled in the hazards and develop fully the ability to evaluate and minimize risks. The environment of underground mining often is harsh and strange compared to the more natural surface conditions man has learned to cope with as a part of established life patterns. The miner, therefore, must adapt to unusual situations and conditions and must develop a mental attitude permitting acceptance to change.

The mining method adopted will undoubtly include:

Shafts - Drilled or conventional
Ventilation; men and material handling; hoisting broken rock; transportation of slurries or liquid.

Stations - a) Large underground stations so large tunneling equipment can be used.
b) Pump stations for water, rock slurry, and petroleum, electrical sub-stations, repair facilities, crushing or breaking room, first aid facilities.

Tunnels - (Major work) - Boring with moles, jet assisted fragmentation, hydraulic mining.

Roof Support - Chemical sealants, rock bolts, steel segment, shot crete.

Drilling Rooms - Conventional = Special mechanical rock breaking equipment with multiheads and booms.

Raises or Drain Holes - Bored, or drilled with air or hydraulic percussion drills.

Transportation - Rock haulage by rail conveyor, load haul dump units, slurry pumping.

Ventilation - Surface, underground booster fans, air conditioning.

Surface - Head frames, hoist building office facilities, water purification plant, change rooms, waste rock storage, oil storage, etc.

In view of the many possible mining methods, the safety regulations must be extensive, and enforced by well trained and competent, personnel.

It is rather certain that gas and water will be encountered or seep into the travelways and working areas from the petroleum sands or reservoir.

A special set of safety and operating regulations will have to be developed from existing Federal and State regulations plus our own emphasis on preventive safety with fool proof ventilation for gas dispersement, standby sumps and pumps for water and petroleum and equipment to assure a comfortable and health environment.

Industrial Hygiene (SME-ME-HB 3.8)

Most occupational illness arises from inhalation of air borne particles or toxic gases.

Dusts - Quanity and size of dust in the ambient air must be continually monitored. Threshold Limit Values (TLV) for contaminant dusts are established by the American Converence of Governmental Industrial Hygienist.

a. Gases

Contaminant gases in respired air may be toxic or inert. Inert gases in high concentration act primarily as asphyxiants, replacing and reducing the oxygen content below minimum acceptable levels. Acetylene, helium, methane, nitrogen, carbon dioxide.

Illness producing gases

Oxides of Carbon - Blasting - diesel engines

Oxides of Nitrogen - Blasting - diesel engines

Hydrogen sulfide - natural
Welding gases
Paint vapors

Awareness of the potential hazards of toxic and/or explosive gases is the key to adequate provisions for employee protection.

b. Skin Diseases

Oils - remove fats from skin
Acids & Bases - destroy tissues
Water solution - soften tissues

c. Potable Water

If the industrial water is not potable water, then potable must be available in sanitary containers convient to the working area.

d. Sewage Collection

Mobile sanitary closets shall be provided as required.

Personal Protective Equipment (SME-ME-HB 3.10)

a. Head Protection

1. Hard hats must meet the requirements of the job.

b. Eye & Face Protection

1. Safety Glasses - Eye spectacles of high impact strength and non-shattering properties, sturdy frames, plain or optically corrected lenses shall be required.

2. Goggles - Lightweight plastic lenses or screens, that practically inclose the eye, for protection from fine material being air borne at high velocity.

3. Face Shields - Lightweight plastic visors for stopping low-impact material. Safety glasses are worn beneath the shield.

4. Helmets - Essentially a complete head enclosure, for welding, sand blasting. Safety glasses can be worn beneath the helmet.

c. Hearing Protection

1. Reduce noise at source with mufflers and other devices
2. Ear plugs
3. Ear muffs

d. Hand, foot and leg protection

1. Hand gloves
2. Shoes and boots are required to have steel caps over the toe
3. Metatarsal guards for certain work
4. Aprons or chaps for leg protection on very special application

e. Protective Clothing

1. Ordinary clothing provides sufficient for most jobs, should be sufficiently tight fitting to minimize catching on objects or in machinery.
2. Special protective clothing will be provided as required.

f. Respiratory Equipment

1. It is imperative that the devices be matched to the hazards that wearers are well-instructed in their proper use and limitations.
2. All underground men will carry "Self-Rescurers".

Mine Disasters (SME-ME-HB 3.11)

Despite the rarity of major disasters, awareness of the possibility and adequate preplanning provides adequate planning.

First - It leads to a more complete elimination of conditions that could lead to a disaster.
Second - In case one should occur, the advance planning can reduce loss of life and property damage.

a. Early Warning Devices

1. Sensors may react to smoke, heat, carbon monoxide, explosive gases, dust levels or other physical or chemical indicators of possible disaster conditions.

b. Positive Personnel Warning Systems

A warning to underground employees of a possible or actual disaster implies mandatory and immediate evacuation of the mine or resort to pre-establish refuge areas.

Communication systems are mandatory in coal mines normally meaning telephones and should be mandatory in mining for petroleum thus permitting verbal transmissions of warning.

Stench in the compressed air lines is often used, but it is doubtful if we will have compressed air throughout the mine.

Blinking lights in the actual working area, would be satisfactory.

Sound devices such as sirens, whistles or bells have been used for emergency signals, but are limited to relatively small areas.

c. Evacuation Methods

1. Alternative means of escape should be available to men evacuating working areas upon receipt of warning. The escape route should be in intake air.
2. All routes must be clearly marked.
3. Maps showing these routes must be posted where they can be seen by the miners. Maps should show direction of normal ventilation flow, established refuge areas, firefighting equipment, emergency bratticing material.

d. Procedure Plans for Employees

1. All mine and management employees must receive early and continuing instruction in procedures.

e. Communications

1. Good communications very necessary.

f. Personal Protective Devices

1. Toxic gases and oxygen deficiency are primary concern of underground fires and explosions. Carbon monoxide is the most common and deadly. Concentrations as low as 400 to 550 ppm of air may be fatal.
2. Refuse chambers supplied with air, lights and water are necessary.
3. Strategic supplies for constructing seals across dead end openings.
4. Self rescuers - mandatory.

g. Ventilation

The flow of air in an underground mine after a fire or explosion should be changed or altered only by authorized persons. In general such changes can be made only with the approval of state and federal representatives at the sight. Reversal is one of the possible changes.

h. Fire Fighting and Rescue Crews

Recommended crews of five men with another complete crew and equipment for back up. Two to four hour self contained breathing apparatus are necessary, plus other special devices supplied from compressed air, and chemically generated oxygen.

i. Inundations

Preventive measures involve engineering studies to determine the minimum safe thickness of competent rock which must be maintained between the tunnels and reservoir. Headings should be proceeded by a small hole for early detection of water or to permit drainage at a controlled weight.

j. Mine Fire Fighting

1. Initial stages usually can be attacked successfully with water, chemicals, foam.
2. Intense fire extinguished by indirect methods such as: Seating to exclude oxygen, introducing inert gases such as nitrogen and carbon dioxide, flooding the mine with water, slimes, sand.
3. Shaft fires most frequent, so should be concrete lined, with steel guides.
4. Fire hoses should be located in all shaft station, repair shops, etc.

1974 Rapid Excavation and Tunnel Conference
San Francisco, CA June 24-27, 1974
Editors Harry C. Pattison & Elio D'Appolonia
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9 - Safety - page 483

Chairman E.B. Waggoner

1. Noise Control

Public Exposure - Sound Level

Exposure/Day (hours)	Sound Level in dba
8	90
6	92
4	95
3	97
2	100
1½	102
1	105
½	110
¼ or less	115

Tunneling Safety - Regulations & Rewards
Robert Vergie - page 495

1. Compentent safety representative
2. Safety meeting with entire crew once a week
3. Dust control equipment on tunneling maching
4. Insulate hydraulic lines on tunneling machines to protect workers from burns.
5. Inspections regularly
6. Shaft cable weekly inspection
7. Gassy tunnels - tested prior to the shift and at least hourly during actual operation.
8. Continuous automatic monitoring may even be required
9. Employee conducting tests must be certified by the Division of Industries
10. Emergency plan - electrical control, etc.
11. Check in and check out system
12. Self Rescuer carried by each miner. Used for escape purposes only because it does not sustain life in an atmosphere containing deficient oxygen. Protection against smoke, carbon monoxide for about 30 minutes.
13. Approved self rescuing equipment for each crew member at the heading must be available. Air tanks should be present on haulage equipment.
14. If a tunnel has been classified gassy or extra-hazardous, at least one rescue team should be maintained on the surface within 30 minutes travel time of the job.
15. Escape route or refuge chamber within 1000 feet of portal. This chamber must have an independent air supply and communication system.
16. Fans for tunnel ventilation are to located at the surface. They must be reversible from a single switch at the portal or shaft.
17. A "kill" button capable of cutting off all equipment has to be maintained in any gassy tunnel, and the power must be cut whenever gas or

vapor levels reach 10 percent of the lower explosive limit.

Gas Explosions and Fires in Tunnels - A chemical viewpoint
Jerome F. Thoms - University of Colorado RETC - Vol. I Ch. 39

Methane is the classical hydrocarbon encountered in mines whose presence is generally due to bacterial decomposition of organic debris. The higher hydrocarbons are more likely to be found during tunneling when petroleum products either natural or man made.

Fires may be defined as rapid gas phase oxidations accompanied by rapid evaluation of light and heat.

Explosions may be defined as uncontrolled fires. The rapidly expanding gasses exceed the speed of sound and generate percussive forces.

Ignition Sources - Fig. 12 (text)
a) arc, b) spark, c) flame, d) heat

Gases

C_1	Methane	CH_4	non-toxic - cannot be detected
C_2	Ethane		Requires 20,000 ppm for detection
C_3	Propane		Requires 10,000 ppm for detection
C_4	Butane	C_4H_{10}	
C_5	Pentane		
C_6	Hexane	C_6H_{14}	constituent of gasoline solvent
C_7	Heptane		
C_8	Octane	C_8H_{18}	normal hydrocarbon in petroleum
C_9	Nonace		
C_{10}	Decane		

Explosive Limits of Readily Volatile Hydrocarbons Concentration Fig. 3 page 506

1. C_1 to C_4 are gaseous hydrocarbons.
2. C_4 to C_{18} are liquid hydrocarbons.
3. Volatility decreases with chain length hydrocarbons C_{12} and less classed as very volatile.
4. All volatile hydrocarbons have characteristic odors with the exception of methane which is odorless.
5. Carbon petroleum products contain a wide array of hydrocarbons. Hard to identify a petroleum product by smell.
6. Threshold odor values (TOV) methane cannot be detected at any concentration. Ethane requires a concentration of over 20,000 ppm to be detected. Propane can be detected at 10,000 ppm. The higher hydrocarbons are more easily detected.
7. Threshold Limit Values (TLV). This is the concentration selected by industrial health and safety groups as a permissible working level for prolonged exposure. It is interesting to note tha TLV values can be exceeded at concentration less than odor perceptable.

Explosive Limits of Various Mixtures of Hydrocarbons - Fig. 3
Determination of the Lower Explosive Limits - Explosion Meter - Fig. 4
Figure 5 - Density of hydrocarbons is a significant property.

a. Methane gas will raise to the crown and must be proved there

b. Others are heavier than air will cling to the walls and settle to the bottom. For proper ventilation and dilution it is necessary that large volume of air be brought in intimate and trubulent contact with suspect hazardous faces, crowns, inverts, and walls.

Figure 6 - Schematic of Air Ventilation System
Figure 7 - Typical Air Pump Performance Curve
Figure 8 - Booster Pump
Figure 9 - Reach of Pressure System and Suction System
Figure 10 - Capture Velocity (general rule of thumb is 100 ft. per min.)

It is essential to move supply of air through the gas mixture above a critical pickup or capline velocity to carry the misture to exhaust.

Figure 11 - Portable Ventilation Systems to provide localized turbulence for mixing of gasses with air.

Figure 12 - Recommendation to minimize the hazards of fire. Summary.

Figure 12A - Advantage and disadvantages of pressure type and suction type ventilation are summarized.

Chapter 40 - Blasting Techniques and Safeguards using electric detonators.
Sources of extraneous electricity - Lighting, Electrostatic induction, Electromagnetic induction, Stray ground currents, Radio Transmission.

The State of the Art in Percussion Drill Noise Abatement
A.W. Wallace, Staff Engineer
Gardner-Denver Company

It is obvious there is a great deal of confusion about noise regulations, how to measure noise and how various governmental agencies fit into the picture. A short discussion of these factors may clear up some of the confustion.

What is Noise and How is it Measured?

The human ear detects sound or noise by sensing pressure waves in the air as they act upon the ear. The intensity or power of the sound is related to the amount of pressure in these waves and the frequency or pitch of the sound is associated with the wavelength of these waves. The human ear can detect only a certain range of frequency and it senses some frequencies better than others.

Noise is measured in terms of decibles which is abbreviated db. The name originiated from the combination of two words: "Deci" for ten, and "Bel" for the logarithmic sound pressure scale named for Alexander Graham Bell. The decibel, then is a measure of the power level of sound and this in turn, is related to the pressure level of the sound waves. Now, since the human ear hears some frequencies better than others, we usually try to measure sound on a scale that interprets the sound like a human ear. On sound meters this standard is the A scale so that when we read the meter, we read decibels on the A scale, and we read decibels on the A scale, and this is abbreviated dbA. The scientific definition of the noise measurement reading "dbA" is rather complex, but the important thing to remember is that it is a measure of the sound pressure level and that it is a measurement of sound as the ear would perceive it.

Another important thing to realize about the dbA is that since it is a complex physical measurement with a mathematical interpretation, it is often difficult to relate dbA readings with noise levels that you hear. This is particularly true when one tries to relate a change in noise level with a change in dbA. For example, cutting the sound power in half reduces the dbA reading by only 3. A good muffler design is a rock drill will reduce the dbA level by about 10. Surprisingly, a 10 dbA muffler is reducing the sound power output of the rock drill by about 90%.

Another characteristic of the dbA reading is that one has to specify exactly where it is taken in relation to the noise source in order for it to be meaningful. After you are back a certain distance from a rock drill the dbA level will drop off 6 db each time you double the distance. Thus, if the sound level of a rock drill reads 112 dbA at 3 feet, you might expect a reading in the neighborhood of 100 at 12 feet since you have doubled the distance

Presented at the Twelfth Annual Intermountain Minerals Conference, Intermountain Rocky Mountain Section, AIME. August 5, 1976 Vail, Colorado

from the drill twice. (In order for this to be exactly true the source must be a point source in space.)

To relate decibel readings to our everyday environment, we can note that:

A Quiet Business Office	50 dbA
Normal Conversation	65 dbA
An Auto at 20'	75 dbA
Inside an Auto in City Traffic	85 dbA
50' from a High Powered Rock Drill	90 dbA
20' from a Subway Train	90 dbA
Inside a Subway Car	95 dbA

Note that in almost all cases, it is necessary to specify where the dbA level exists in order for it to be meaningful.

Governmental Agencies

Most of todays noise regulations have Federal laws as their basis. However, there are indications that State agencies in many cases are supplementing Federal agencies in carrying out noise regulations.

In general, the EPA (Environmental Protection Agency) is concerned about noise created in our environment and other governmental agencies like OSHA and MESA are concerned with the noise exposure that an individual employee is subjected to.

The EPA is the governmental agency which implements the Noise Control Act of 1972 that was passed by the United States Congress on October 18, 1972. One of their main activities with regard to noise, is to identify products as major sources of noise in our environment and set noise control regulations on them. In carrying out this charge, the EPA set noise limits for portable compressors on December 31, 1975. This regulation states that within 24 months the noise limit of portable compressors smaller than 250 cfm cannot exceed 76 dbA at 7 meeters and in 30 months this limit cannot be exceeded for larger compressors. Meeting this noise limit is the responsibility of the machinery manufacturers. At the present time the EPA is also studying rock drills. It is expected that sometime in the near future the EPA will identify them as a major noise source and subsequently they will set noise control limits for rock drills. Again, the rock drill manufacturer will be responsible for meeting these regulations. In setting a regulation, the EPA has to determine reasonable test methods and then determine reasonable noise limits. Thus, it will take them sometime to set the regulations on the rock drills, but you can be assured it will be here before we know it.

OSHA, the Occupational Health and Safety Administration, is part of the U.S. Department of Labor. With regard to noise, they are primarily concerned that an employee is not exposed to noise levels that will do permanent damage to his hearing. Meeting this requirement is the responsibility of the employer. I am sure that you are familiar with the noise exposure limits for an employee without ear protection. He can be exposed eight hours to noise only if the sound level is less than 90 dbA. This time exposure is cut in half with each 5 dbA increase in noise level; thus, at 95 dbA he can only be exposed for four hours, 100 - 2 hours, at 105 - 1 hour, 110 - ½ hour and only for 15 minutes at 115 dbA or less. There has been some talk about shifting this scale down 5 dbA and setting the time exposure beginning at 85 dbA; but these are the present regulations. OSHA is primarily concerned with industrial workers but this includes many of our customers using rock drill products in contracting work.

MESA, the Mining Enforcement and Safety Administration of the Bureau of Mines, is primarily concerned with the safety of workers in mines. MESA currently follows the same noise level exposure limits as OSHA. As far as we can determine, however, MESA is much more active in finding ways to attentuate the noise emitted by rock drill products that are currently being used in mines. They have found some very good ways to muffle existing drills.

Public concern about rock drill noise resulted in initial basic research efforts in:

- identifying the sources of noise
- developing techniques of control

The market at this time (1950s) only occasionally demanded drills having noise control devices. Sales were for mounted drifters where the exhaust port had been fitted with a threaded connection, which permitted piping away the exhaust. This simple solution is, with a few refinements, being used today. It is well suited to surface drill rigs, and ring-drilling, or other relatively stationary underground applications. The hose carries the oil-laden fog away with the exhaust, yielding another benefit in improved working conditions. Another potential market exists for the handheld drills. Mufflers for these present a challenge; in that the operators can't tolerate another hole, and mufflers cannot add significantly to the weight.

Our first efforts involved attaching a simple resonator to the drill body.

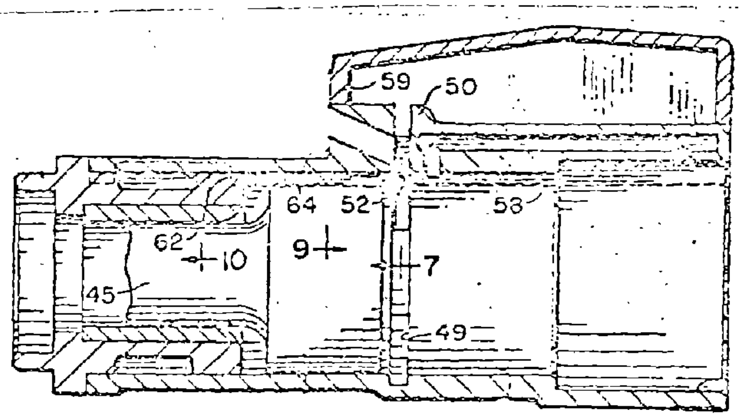

Figure 74. Single resonating chamber.

These simple models provided an insertion loss of 5 db.

The next element of the noise justifying study involved concentrating on the shock wave generated by each burst of air coming out of the exhaust port.

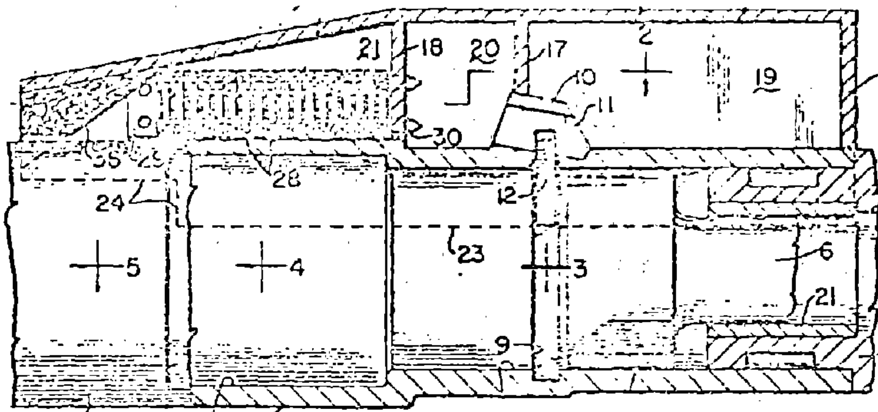

Figure 75. Double resonating chamber

This is a much more complicated device, involving two resonating chambers, a set of orifices, and then a treated bend in the passage. The spaced orifices behave like the silencer on a gun - dissipating that initial sharp edge of the exhaust burst. The system provided 9-12 db in noise reduction. Production of a stoper, a a family of feed leg drills resulted. Many people expressed interest in a conversion kit - for the drills they were using. To satisfy this need, a wide variety of detachable mufflers were developed...

A lightweight detachable fiberglass model was made available for both stopers and feed legs. It weighed 1½ to 2 lbs., reduced noise about 10 db, and wouldn't freeze.

A more durable cast aluminum detachable version was offered which removed 6-8 db.

A rubber model was also developed for feed legs and stopers, and found to offer 6-8 db. It would handle ice nicely, was lighter, and more durable.

A paving breaker version was given extensive study - and utilized the same accoustical circuit. This involves two rubber jackets with carefully sized interconnecting passages. It provides 8 db insertion loss, weighs 7½ lbs., handles water and physical abuse. The large sales potential justified the rather substantial tooling costs. Other rubber versions utilizing the simple resonating cavity became available.

With the creation of OSHA and MESA, the marketing situation supported renewed emphasis on the integral muffler.

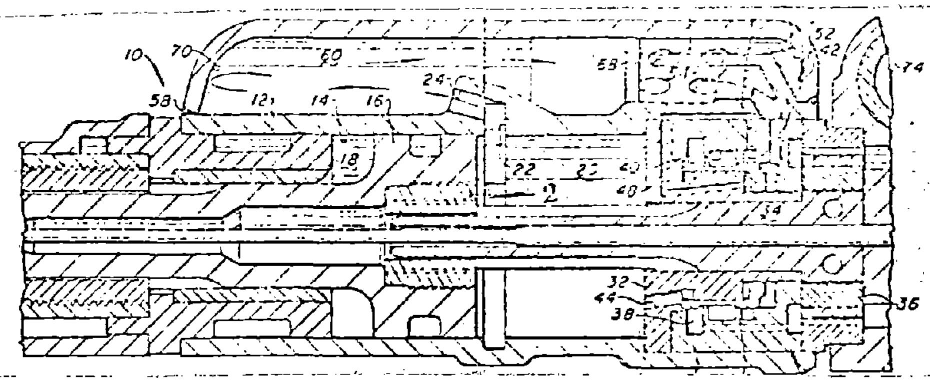

Figure 76. Refined resonating chamber

The current acoustical technique is shown here, where the basic resonating chambers have been carefully modified to accommodate a wider latitude of moisture in the air line. Further refinements which will accommodate even more water, while providing a healthy insertion loss.

Water is a restraint which challenges the designer. The cooling of the air's expansion process produces temperatures which freeze any moisture carried in the air. This material accumulates in the exhaust port region, threatening to plug the openings.

One of the early problem areas occurred in drills with the piped away exhaust. The connection at the drill was notorious for freezing.

A rubber line elbow was developed which has enough space around the sleeve to permit the rubber to vibrate, breaking up the ice.

A further improvement was made in the hose itself.

By using a double-walled hose, the vibrating surface of the inner inlet hose radiates much less noise to the atmosphere. By plugging the end of the inner hose, and turing the perforations, a double expansion chamber, reactive muffler results. This device can be applied to many drifters with treaded exhaust, and can reduce noise levels by as much as 12 db.

Of course, all new drills incorporate built-in mufflers. Our current development techniques include the use of a unique computer program which combines the best proportions in moisture handling ability and noise reduction. Some of our newest samples are a family of valveless drifters.

The present state-of-the-art then, has been confined to treatment of the principal offender - the exhaust noise.

The other sources; the drill rod, and mechanical noise of the drill, constitute a greater challenge.

The drill rod, because of its relatively great exposed length - provides a significant surface for noise radiation. Also note, the rod is transmitting all of the power that the drill is producing.

Let us examine the possibilities of reducing the noise radiated by this exposed rod.

- -Obviously, you can improve the set-up by - keeping sharp bits and maintaining good alignment. This reduces reflected shock waves within the drill rod. (Sharp bits can reduce noise levels by as much as 2½ db in certain instances.)
- -The proposed use of shielding materials to damper surface vibrations has revealed several detrimental problem areas: high manufacturing costs, difficulty in cleaning the hole if the treatment is not full length and high damage rate to the sleeve if it is full length.

While showing some promise, efforts made in this area thus far, haven't resulted in significant adoption by mining and construction operators.

Because the noise radiated by the drill rod originates at such a large surface - it is usually more significant than the radiated mechanical noise from the drill body. The specific configuration of the body - and the job application dictates whether surface treatment is justifiable.

The state of the art then - is that in 1976, the most dominant noise source has been controlled, and either integral or retrofit devices have been made available for the majority of rock drills. Secondary sources involve more complex treatments which have not resulted in practical solutions to date.

At this point, I'd like to diverge a bit - and talk about perspective. It is appropriate that we weave in a little of the Centennial-Bicentennial subject, because there's another important anniversary, especially important to us. July 4 was our Nation's Bicentennail, August 1 is our State's Centennial, and July 1 was the centennial of the Hoosac Tunnel.

The Hoosac was the first major tunnel drilled in this country, it required 21 years to complete the 4 3/4 mile bore. It is significant to the mining and construction world because of the payoff in tools to our industry:

- -Nitroglycerin was proven safe and a successful blasting agent.
- -Electric detonation was also.
- -The rock drill, which....started on the job as an imported item - required a lot of back-up (200 machines to keep 16 going). It was refined by men like Burleigh, Ingersoll and Sargent. At the completion of the Hoosac, through the American inventive genius, the rock drill emerged as a reliable, practical tool for drilling in rock.

It took 25 years more before drills found their way into the mines. Iler and Shaw, of Denver, devised the air leg on a percussion hammer drill, and made stoper drills available to the Cripple Creek mines in 1903.

- -They'd drill about an inch a minute.
- -The bit edge, forged on the rod would dull in a foot or two and have

Underground Mine Standard 57.2 Definitions

Abandoned mine - means all work has stopped on the mine premises and an office with a responsible person in charge is no longer maintained at the mine.

Abandoned workings - means deserted mine areas in which further work is not intended.

Active workings - means areas at, in, or around a mine or plant were men work or travel.

American Table of Distances - the current edition of "The American Table of Distance for Storage of Explosives" published by the Institute of Makers of Explosives.

Approved - tested and accepted for specific purpose by a nationally recognized agency.

Authorized person - a person approved or assigned by mine management to perform a specific type of duty or duties or to be at a specific location or locations in the mine.

Auxilary fan - a fan used to deliver air to a working place off the main air stream; generally used with ventilation tubing.

Barricaded - obstructed to prevent the passage of persons, vehicles, or flying materials.

Berm - a pile or mound of material capable of restraining a vehicle.

Blasting Agent - any material consisting of a mixture of fuel and oxidizer. a) is used or intended for blasting, b) is not classed as an explosive by the Department of Transportation, c) contains no ingredient classed as an explosive by the Department of Transportation, d) cannot be detonated by a No. 8 blasting cap when tested as recommended in Bureau of Mines Information Circular 8179.

Blasting Area - the area near blasting operations in which concussion or flying material can reasonable be expected to cause injury.

Blasting cap - a detonator containing a charge of detonating compound, which is ignited by electric current or the spark of a fuse. Used in detonating explosives.

Blasting circuit - electric circuits used to fire electric detonators or to ignite an igniter cord by means of an electric starter.

Blasting switch - a switch used to connect a power source to a blasting circuit.

to be reforged for sharpening.

-The process required a dozen drill rods to complete a round. But the idea caught - and the industry started changing.

Rock drills were fairly common in mines by the time of our depression in the 1930s. Then, detachable bits became available, and handling of all of that steel was over. By the time of WW2, tungsten carbide became available. You could drill one or more holes in a cut without having to change bits! Deep holes became practical, and new mining methods - like block caving - became possible.

This, then, carries us through the first 75 of the 100 years since the Hoosac.

After WW2, many drifters were still being sold on 2 foot steel shells with hand crank feeding. The largest drills would cut hard granite at the rate of a foot a minute (for 1½ inch bit). Today's valveless drill will punch a 4½ inch hole down in the same rock at over 2 feet per minute.

While it uses ten times the amount of air, it is removing rock 16½ times faster than it did 25 years ago!

We, in 1976, can't hope to forecast exactly what conditions will be like in the next 25 years - but we do have some clues:

-Working conditions will be better - but legislation, such as within the control of agencies like OSHA and MESA, will guarantee that.

-We will be drilling holes faster, with less cost - if we don't, as a nation, we'll loose our competitive position in the world market.

100 years ago, Leadville was about to boom, and the mining industry was about to explode our new state into a new, more powerful economy.

In comparison, today, both our State and our technology is expanding at a much faster rate. We, in drilling holes, are capable of focusing so much energy on a small spot of rock that just the mechanical losses produce objectional noise levels. While today, we're striving to control this form of energy loss, there's no question that in the exciting world of tomorrow, noise challenges will be met while we maintain our positions in both the world market, and in our standard of living.

Booster fan - a fan installed in the main stream or split off the main stream to increase air flow through a section or sections of the mine.

Capped fuse - a length of safety fuse to which a detonator has been attached.

Capped primer - a package or cartridge of explosives and which contains a detonator.

Combustible - capable of being ignited and consumed by fire.

Company official - a member of the company supervisory or technical staff.

Competent person - a person having abilities and experience that fully qualify him to perform the duty to which he is assigned.

Detonating cord - or detonating fuse means a flexible cord containing a core of high explosive.

Detonator - a device containing a small detonating charge that is used for detonating an explosive, including, but not limited to blasting caps, exploders, electric detonators, and delay electric blasting caps.

Distribution box - a portable apparatus with an enclosure through which an electric circuit is carried to one or more cables from a single incoming feed line; each cable circuit being connected through individual overcurrent protective devices.

Electric blasting cap - a blasting cap designed for and capable of being initiated by means of an electric current.

Electrical grounding - to connect with the ground to make the earth part of the circuit.

Employee - a person who works for wages or salary in the service of an employer.

Employer - a person or organization which hires one or more persons to work for wages or salary.

Escapeway - a passageway by which persons may leave a mine.

Explosive - a chemical compound mixture, or device, the primary or common purpose of which is function by explosion. Explosives include, but are not limited to black powder, dynamite, nitroglycerin, fulminate, ammonium nitrate when mixed with hydrocarbon or other blasting agents.

Face or bank - that part of any mine where excavating is progressing or was last done.

Flammable - capable of being easily ignited and of burning rapidly.

Flash point - the minimum temperature at which sufficient vapor is released by a liquid or solid to form a flamable vapor-air mixture at an atmospheric pressure.

Highway - any public street, public allys or public road.

High potential - more than 650 volts.

Hoist - a power-driven windlass or drum used for raising ore, rock or other material from a mine, and for lowering or raising men and material.

Ignitor cord - a fuse, cordlike in appearance, which burns progressively along its length with an external flame at the zone of burning, and is used for lighting a series of safety fires in the desired sequence.

Lay - a distance parallel to the axis of the rope in which a strand makes one complete turn about the axis of the rope.

Low potential - means 650 volts or less.

Main fan - a fan that controls the entire airflow of the mine, or the airflow of one or two major air circuits.

Major electrical installation - an assemblage of stationary electrical equipment for the generation, transmission, distribution or conversion of electrical power.

Man-trip - a trip on which men are transported to and from the work area.

Mill - any ore mill, sampling works, concentrator, and crushing, grinding or screening plant used to process mine ore.

Mine opening - any opening or entrance from the surface into the mine.

Misfire - the complete or partial failure of a blasting charge to explode as planned.

Overburden - material of any nature, consolidated or unconsolidated that overlies a deposit of useful materials or ores that are to be mined.

Permissible - a machine, material, apparatus, or device which has been investigated, tested and approved by the Bureau of Mines or MESA and is maintained in permissible condition.

Potable - fit for drinking.

Powder chest - a substantial non-conductive portable container equipped with a lid and used at blasting sites for explosives other than blasting agents.

Primer or Booster - a package or cartridge of explosive which is designed specially to transmit detonation to other explosives and which does not contain a detonator.

Reverse-current protection - a method or device used on direct-current circuits or equipment to prevent the flow of current in a reverse direction.

Roll protection - a framework, safety canopy or similar protection for the operator when equipment overturns.

Safety can - an approved container of not over 5 gallons capacity, having a spring-closing lid and spout cover.

Safety fuse - a train of power inclosed in cotton, jute yarn and waterproofing compound which in turn sets off the explosive charge after it is ignited.

Safety switch - sectionalizing switch that also provides shunt protection in blasting circuits between the blasting switch and the shot area.

Scaling - removal of insecure material from a face or high wall.

Secondary safety connection - a second connection between a conveyance and rope, intended to prevent the conveyance from running away by falling in the event the primary connection fails.

Shaft - a vertical or inclined shaft, mine opening used for access; also a incline or winze.

Stray current - that portion of a total electric current that flows through paths other than the intended circuit.

Substantial construction - construction of such strength, material, and workmanship that the object will withstand all reasonable shock, wear, and usage to which it will be subjected.

Suitable - that which fits, and has qualities or qualifications to meet given purpose, occasion, condition, function, or circumstance.

Travel way - a passage, walk or way regularly used and designeate dor persons to go from one place to another.

Trip light - a light displayed on the opposite end of a train from the locomotive or engine.

Wet drilling - the continuous application of water through the central hole of hollow dull steel to the bottom of the drill hole.

Working place - any place in or about a mine where work is being performed.

Information Sources for securing Federal & State Safety Regulations

Federal

a. Mining Enforcement and Safety Administration
   1. General Information - MESA
      1457 Ammons Lakewood, CO   234-2293
   2. Coal Mine Health & Safety
      1457 Ammons   Lakewood, CO   (303) 234-2293
   3. Metal & Non-Metal Safety
      Rocky Mtn. Dist.
      603 Miller Co.   Lakewood, CO
   4. Technical Support Center - Denver Federal Center
      Safety - Denver Federal Center
      Box 25367   Denver, CO 80225   (303) 234-2276
      Richard Kline - Health Technology
      Donald Hutchins - Safety Technology
      Richard A. Fisher - Explosives   (303) 234-5382

b. Occupational Safety and Health Adm.   (OSHA)
      Assistant Regional Director
      9161 Stout   (303) 837-3883
      Denver Area Office
      8327 W. Colfax   Denver, CO   (303) 234-4471

c. Publications
      Code of Federal Regulations
      Title 30 Mineral Resources 1976
      GPO Bookstore
      Federal Bldg. Rm. 1421
      20th & Stout   Denver, CO   (303) 837-3964
      Out of stock - 5/16/77
      On order for 5 weeks

State Regulations

The 10 most productive crude petroleum producing states, except Alaska were selected as the states with the most potential for mining petroleum. Pennsylvania although a small producer has a different type of crude and has been added to the list. Ref. USBM Yearbook 1974 - Preprint

The following States Safety Agencies can be contacted and will furnish available state regulations concerning mining.

1. Texas
   Texas Industrial Board - Walton Bldg. - Austin
   Occupational Safety - Walter Martin - Director (512) 458-7111
   No State mining regulations - depend on MESA & OSHA

2. Louisiana
   Curtis Luttrel, Commissioner of Labor
   P.O. Box Baton Rouge, LA (504) 389-5314
   No State mining regulations - depend on MESA & OSHA

3. California
   California Division Industrial Safety Mining Industry
   455 Golden Gate Ave.
   San Francisco, CA 94101
   Samuel Alexander (415) 557-0603
   Tom Carroll Act. covering gassy mines & tunnels
   Documents & Publications - Ordering Dept.
   P.O. Box 1015
   Horth Highland, CA 95660

4. Oklahoma
   Department of Mines
   Ward Padget, Chief Mine Inspector
   117 Capital Bldg.
   Oklahoma City, OK 73105 (405) 521-3859

5. Wyoming
   State Inspector of Mines
   Mariano Tierantoni - Chief
   Tom Avery-Asst.
   Box 1094
   Rock Springs, WY 82901 (307) 362-5222

6. New Mexico
   Chief Inspector of Mines
   State of New Mexico
   2340 Menaul NE Suite 106
   Albuquerque, NM 87101
   Joe de Longacre-Chief (505) 842-3055
   Data Co. - Mailing & Printing
   1712 Lomas Blvd. NE
   Albuquerque, NM 87106

7. Kansas

Human Resources - Department of Labor
Industrial Safety
401 Topeka Ave.
Topeka, KS 66603
M. Johnston - Director (913) 296-7475
State government repealed all state mining laws MESA & OSHA

8. Mississippi

Workmen's Compensation Commission
Pearl & President St.
Box 651
Jackson, MS 39201
John A. Craig-Director (601) 354-7496

9. Utah

Safety Division
State Industrial Commission
350 East 5th South
Salt Lake City, UT 84111
Carlyle Grawniang-Chief (801) 533-6411

10. Colorado

Bureau of Mines
1313 Sherman
Denver, CO 80203
Norman R. Blake-Director (303) 892-3401

11. Pennsylvania

Department of Environmental Resources
P.O. 2063
Harrisburg, PA 17120 (717) 787-4805

Federal Regulations

1. Title 30 - 1976 - not in stock at GPO Store Federal Bldg., 19th & Stout, Denver 837-3964

2. Exerpts from - Code of Federal Regulations
   Title 30 - Mineral Resources
   Revised as of July 1, 1975
   Parts 15 - Explosive & related articles
         16 - Stemming Devices
         17 - Blasting Devices
         18 - Electric Motor Driven Mine Equipment & Accessories
         70 - Mandatory Health Standards Underground coal Mines
              Dust Standards
         71 - Surface work areas of underground mines
          b - Dust Standards
         74 - Coal Mine Dust Personal Sampler Units
         75 - Certified Persons - Ventilation - Trailing Cables - Fire Protection - Fire Suppression Devices - Emergency Shelters - Communications
       75.1 - Qualified of Certified Persons
              Tests for Methane - Air Flow - Hoist Engineer - Electrical
       75.2 - Roof - Back Support Program - Plans
       75.3 - Ventilation
              Main Fans - Criteria
              Air quality, quanity & velocity
              Harmful quantitites of noxious gases
              Location of air measurement
              Velocity of air
              Gases other than methane
              Monitors - maintenance
              Methane - on and after Dec. 31, 1970, a methane detector approved by the Secretary shall be used for such tests, and a supplemental testing device.
       75.4 - Abatement of Dust
              Rock dusting coal mines
       75.5 - Electrical Equipment - 22 pages
    75-1100 - Fire protection
              Automatic fire sensors
              Extinguishing agents on equipment
    75-1200 - Maps
              Active workings
              Entries, air courses, escapewyas
              Producing or abandoned oil and gas wells located within 500 ft.
              Scale - not less than 100 or more than 500 ft. to the inch.
    75-1300 - Blasting & Explosives
    75-1400 - Hoisting
              Man Trips
       1403 - General Criteria

75-1500 - Emergency Shelters
75-1600 - Communications
75-1700 - Oil and Gas Wells - Location
1704 - Escapeways
75-1713 - First Aid Training
1714 - Self Rescue Device
1720 - Protective Clothing
77 - Mandatory Safety Standards, surface coal mines, and surface work areas of underground mines
77-800 - High Voltage
Fire protection
80 - Notification, Investigation, Reports and Records of Accidents
81 - Procedure for Identification of Representatives of Miners at Mines
82 - Notification of Legal Identity
90 - General
Health - x-rays
100 - Civil Penalties

3. Code of Federal Regulations - Title 30 Mineral Resources Revised July 1, 1974 - Same as No. 2

Federal Register OSHA
Department of Labor

1. Occupational Safety and Health Administration
Construction Safety and Health Regulations
June 24, 1974 Volume 39 - Number 122 - Part II

1926-250 - Materials Handling & Storage
1926-300 - Tools - Hand & Power
1926-550 - Cranes & Derricks
1926-650 - Escavations, Trenching and Shoring
1926-800 - Tunnels-Shafts-Caisons-Cutter dams

1. General Industry
OSHA 2206 (Revised January 1976) Classification wood used for ladders trestles
Text 590 pages - Index 58 pages

3. All About OSHA
Program & Policy Series April 1976 (Revised)
OSHA - 2056
Explanation in broad terms the provisions of the Occupational Safety and Health Act of 1970.

APPENDIX F

FORMULAS AND DERIVATIONS

For the phenomenon of the redistribution of the reservoir fluids by the forces due to gravity, these equations have been derived for a horizontal formation. If the formation dips, these equations are not valid. These equations assume that the fluids are uniformly distributed throughout the vertical thickness during the displacing process and reaches capillary equilibrium after the displacing process ceases.

Beginning with the following equation:

$$S_{wi}h_t\phi = \phi h_w S_{wm} + \phi \int_{h_w}^{h_t} S_w \, dh \qquad (22)$$

If $S_w = \frac{1}{P_c+1} = \frac{1}{h\ (\gamma_w - \gamma_o)\ .433 + 1} = \frac{1}{ah\ + 1}$ (23)

then $$S_{wi}h_t\phi = \phi h_w S_{wm} + \frac{\phi}{a} \int_{h_w}^{h_t} \left[\frac{1}{(ah\ + 1)} \ dh_o \right] \qquad (24)$$

$$S_{wi}h_t\phi = \phi h_w S_{wm} + \phi \frac{1}{a} \left[\ln(ah_t + 1) - \ln(ah_w + 1) \right] \qquad (25)$$

where:

S_w, water saturation, fraction

S_{wi}, initial average water saturation over the total liquid saturated thickness, fraction

S_{wm}, maximum water waturation obtainable by capillary redistribution (usually 100% as a first try), fraction

a, difference in liquid specific gravities, $(\gamma_w - \gamma_o)$x.433, fraction

h_w, height to which S_{wi} applies, ft

h_t, total height of liquid saturated zone, ft

ϕ, porosity, fraction

If $S_w = \frac{1}{(P_c + 1)^2} = \frac{1}{(ah\ + 1)^2}$ (26)

$$\text{then}\quad S_{wi}h_t\phi = \phi h_w S_{wm} + \phi\,\frac{1}{a}\,(-1)\left[\frac{1}{(ah_t + 1)} - \frac{1}{(ah_w + 1)}\right] \tag{27}$$

$$\text{or}\quad S_{wi}h_t = h_w S_{wm} - \frac{1}{a}\left[\frac{1}{(ah_t + 1)} - \frac{1}{(ah_o + 1)}\right] \tag{28}$$

$$\text{If,}\quad S_w = \frac{1}{(P_c + 1)^{\frac{1}{2}}} = \frac{1}{(ah + 1)^{\frac{1}{2}}} \tag{29}$$

$$\text{then}\quad S_{wi}h_t = h_w S_{wm} - \frac{2}{a}\left[(ah_t + 1)^{\frac{1}{2}} - (ah_w + 1)^{\frac{1}{2}}\right] \tag{30}$$

Solving for h_w becomes trial and error, such that:

<u>when</u>
$$S_w = \frac{1}{(ah + 1)^{\frac{1}{2}}} \tag{31}$$

$$ah_w S_{wm} + 2\,(ah_w + 1)^{\frac{1}{2}} = aS_{wi}h_t + 2(ah_t + 1)^{\frac{1}{2}} \tag{32}$$

<u>and when</u>
$$S_w = \frac{1}{(ah + 1)} \tag{33}$$

$$ah_w S_{wm} - \ln(ah_w + 1) = aS_{wi}h_t - \ln(ah_t + 1) \tag{34}$$

<u>and when</u>
$$S_w = \frac{1}{(ah + 1)^2} \tag{35}$$

$$ah_w S_{wm} + \frac{1}{(ah_w + 1)} = aS_{wi}h_t = \frac{1}{(ah_t + 1)} \tag{36}$$

<u>or when</u>
$$S_w = \frac{1}{(ah)^2 + 1} \tag{37}$$

$$ah_w S_{wm} - \tan^{-1}(ah_w) = aS_{wi}h_t - \tan^{-1}(ah_t) \tag{38}$$

The value of h_w determines the height above the bottom of the formation which would only produde water.

TUNNEL PROXIMITY TO A RESERVOIR*

UNIDIRECTIONAL STRESS FIELD

In the following treatment the stress concentrations (that is, the stress at any point divided by the average applied stress) around single openings in a unidirectional stress field are determined. The types of openings considered are ellipses, ovaloids, and rectangles. By varying the height-to-width ratio of each, the effect of changing the shape of the opening is shown. As previously pointed out, this case corresponds in mining to a single long opening (such as a drift) situated at a comparatively shallow depth.

Elliptical Openings

If the opening is an ellipse having one axis vertical and parallel to the stress field then the maximum stress concentration is given by,

$$f_{max} = \frac{(\sigma\theta)\ max}{S} = (1 + 2\frac{w}{h}); \tag{39}$$

where f =stress concentration,

$\sigma\theta$ =tangential stress,

S =average applied stress,

w =width or horizontal axis of ellipse,

h =height or vertical axis of ellipse.

The maximum stress occurs on the boundary of the ellipse at the end of the horizontal axis and is tangent to the boundary. The stress at this point is a compression when the applied stress is a compression. To show the effect of the height-to-width ratio on the maximum stress concentration around the ellipse, the equation is shown graphically in the Figure 2 of page F-4 together with some maximum stress concentration values determined photoelastically. As the height-to-width ratio increases, the maximum stress concentration decreases and approaches unity for large values of h/w; as the height-to-width ratio decreases, the maximum stress concentration increases without limit. When h/w equals unity the ellipse becomes a circle and the maximum stress concentration is 3.

The tangential stress produced on the boundary at the ends of the vertical axis is equal in magnitude but of opposite sign to the applied stress and is independent of the height-to-width ratio. Thus, if the applied stress is a compression, this stress is a tension. In unidirectional stress fields, therefore, failure may occur in the roof rather than the side walls for the tensile strength of most rock is only a small fraction, averaging about ¼ of its compressive strength. Evidence of this type of failure has been observed in this laboratory.

*USBM RI4192, March 1948, Duvall, W.I.

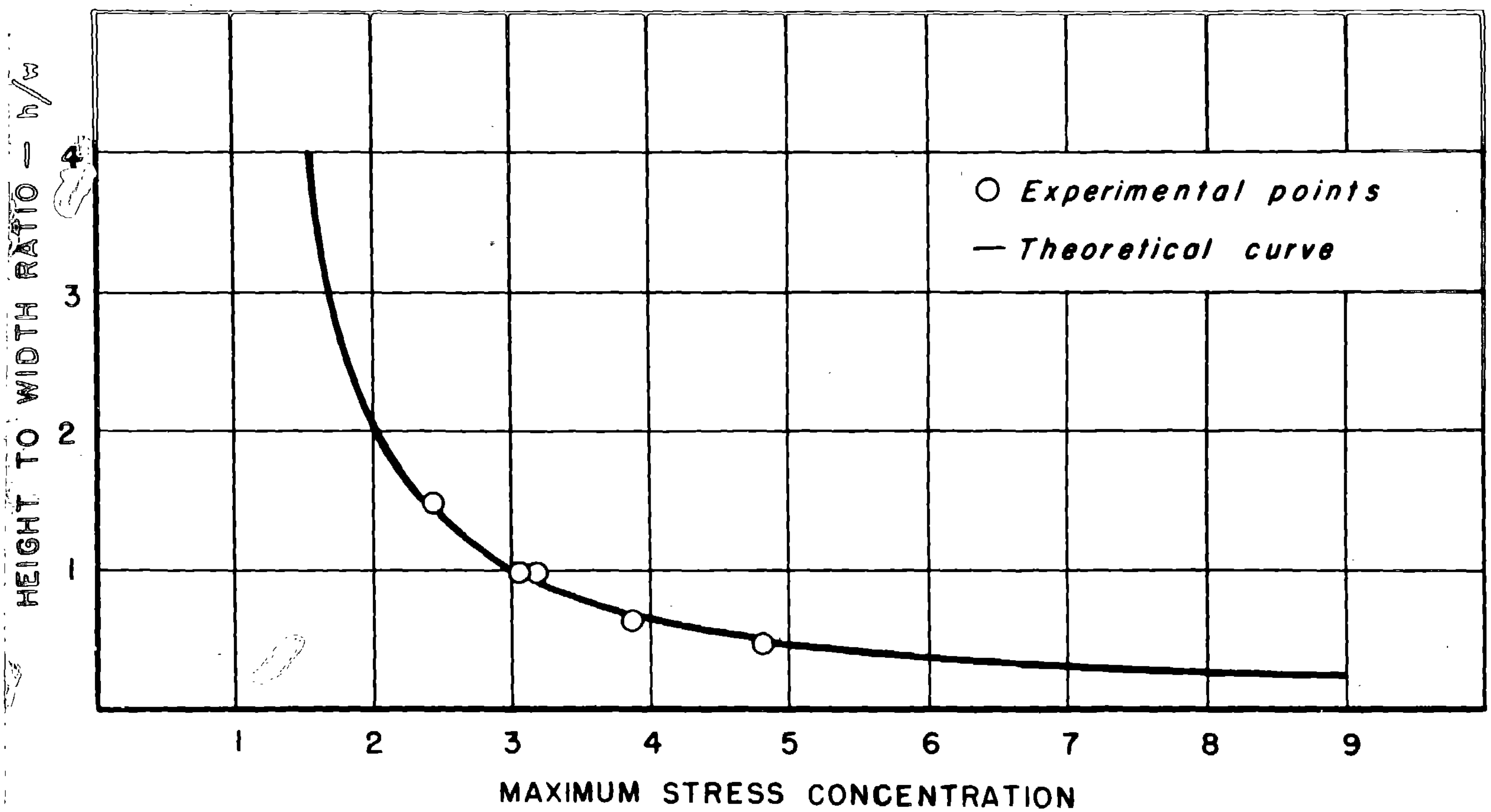

Figure 77 — MAXIMUM STRESS CONCENTRATION AS A FUNCTION OF HEIGHT TO WIDTH RATIO FOR ELLIPTICAL OPENING — UNIDIRECTIONAL STRESS FIELD.

Areal Distribution of Stresses

The stress concentration produced around an opening in an infinitely wide plate subjected to a unidirectional stress field is entirely local to the area surrounding the opening. To illustrate this point, the analytical results for the case of a circular opening are given. These data are shown in curve form in the figures in the text. From the curves it is seen that virtually all of the stress concentration has disappeared at a distance of 1 diameter from the boundary of the opening. For engineering purposes, it may be assumed that, if two openings are removed 2 diameters from each other, there is little or no effect of one opening on the other.

HYDROSTATIC STRESS FIELD

In the following treatment, the stress concentrations around single openings in a two-dimensional stress field are determined. A two-dimensional stress field is obtained from the principle of superposition by adding vectorially the stresses at any point produced by two perpendicular, unidirectional stress fields. The types of openings considered are ellipses, ovaloids, and squares. As previously pointed out, this corresponds in mining to a single long opening at a greath depth.

Elliptical Openings

The maximum and minimum stress concentrations occurring around an elliptical opening in an infinitely wide plate subjected to a uniform compression in all directions are given by:

$$f_{max} = \frac{(\sigma\beta)max}{S} = 2\frac{a}{b}, \tag{40}$$

and

$$f_{min} = \frac{(\sigma\beta)min}{S} = 2\frac{b}{a}; \tag{41}$$

where:

f = stress concentration,

$\sigma\beta$ = tangential stress,

S = average applied stress,

a = major axis of ellipse,

b = minor axis of ellipse.

The maximum stress occurs at the ends of the major axis tangent to the boundary of the ellipse and is a compression if the applied stress is a compression. The minimum stress occurs at the end of the minor axis tangent to the boundary and is a compression if the applied stress is compression. The stresses on the boundary of the hole at any other point lie between these two values and are determined by the location of the point in question. When the ellipse degenerates into a circle - that is, when a equals b - then the stress concentration around the boundary is constant and has the value of 2. Curves showing the relation between the maximum and minimum stress concentration and the ratio of the minor axis to the major axis are given in RI4192. From these curves, it is apparent that as the minor to major axis ratio becomes small, the maximum stress concentration increases. Thus, to minimize the stress concentration openings should be circular.

CONCLUSIONS

Considering the results of this investigation as applied to the mining of long single openings in underground mines where the rock formations approach a homogenous elastic medium, the following general conclusions are made in RI4192 although much of the data is not included in this appendix:

1. Where the conditions underground are such that the applied stress is a compression in the vertical direction, an opening should be mined so that it resembles an ellipse with its major axis vertical if a minimum of stress concentration is desired. Furthermore, the larger the ratio of the major axis to the minor axis the smaller the stress concentration. Other shaped openings, such as an ovaloid or rectangle with rounded corners, give higher stress concentration than the ellipse when the height-to-width ratio is greater than unity. If mining conditions are such that it is desired to mine an opening whose height-to-width ratio is less than unity, the preferred shape is a rectangle with rounded corners rather than an ovaloid or an ellipse. The two important factors that cause high stress concentration around openings in a unidirectional stress field are a height-to-width ratio less than unity and sharp corners on the horizontal axis of the opening. RI4192 shows three different shaped openings having a height-to-width ratio greater than unity and three having a height-to-width ratio less than unity. These openings are labeled in order (A to F) of their their preference for use in a unidirectional stress field.

2. There is produced a tensile stress in the floor and roof of openings underground where the applied stress field is a compression in the vertical direction. This stress, which is tangent to the boundary and approximately equal in magnitude to the applied stress, in many instances may cause roof failures.

3. Where the conditions underground are such that the applied stress field is hydrostatic, an opening should be mined so that it is circular in order to obtain a minimum of stress concentration. However, if mining conditions are such that openings other than those having a ratio of axes equal to unity are desired, the opening should be mined to resemble an ovaloid to reduce stress concentrations to a minimum. The two important factors that contribute to high stress concentration around openings underground in a hydrostatic stress field are a height-to-width ratio other than unity and sharp corners anywhere on the boundary. RI4192 shows two different shaped openings having a height-to-width ratio equal to unity and two having a height-to-width ratio different from unity. These openings are labeled (A to D) in order of their preference for use in a hydrostatic stress field.

4. For either stress field the stress concentration produced around single openings is negligible at a distance of one diameter from the boundary of the opening. This fact should be useful in determining the spacing between two openings in order that one opening will not affect the other.

APPENDIX G

ADDENDUM TO ECONOMICS OF GRAVITY DRAINAGE

Subsequent to publication of this report the authors reviewed the economic case for gravity drainage, Section 5.3.19, and calculated discounted cash flow economics for an additional case, a 200' oil column reservoir. The calculations AFIT are included herein as is Figure G-1; the Project Rate of Return is plotted against potential oil price.

Table G-1. Projected production by gravity drainage by time for 200' Oil Reservoir. (All Barrels in Millions)

(From Table 19 - Convert from Days to Years)

Proj. Yrs.	Prod. Yrs.		Cum. 8/8 Prod.	Term 8/8 Prod.	Term 7/8 Prod.
0-1	Construction		0	0	0
1-2	Construction		0	0	0
2-3	0-1	(365)	13.915	13.95	12.176
3-4	1-2	(730)	20.994	7.079	6.745
4-5	2-3	(1095)	25.548	4.554	3.985
5-10	3-8	(2920)	35.285	9.737	8.520
10-15	8-13	(4745)	38.306	3.021	2.643
15-19.6	13-17.6	(6428)	40.624	2.318	2.028

Table G-2. Generalized Cash Flow (BFIT). 200' Oil Reservoir, 50% Recovery, Maximum Cost, One Square Mile Only. (Dollars and Barrels in Millions)

Yrs.	Cap.	@$.25/Bbl Opr.	BFIT Income $5/bbl	$10/bbl	$15/bbl	$20/bbl
0-1	(30.0)		(30.0)	(30.0)	(30.0)	(30.0)
1-2	(30.0)		(30.0)	(30.0)	(30.0)	(30.0)
2-3	(5.0)	(3.044)	52.836	113.716	174.596	235.476
3-4		(1.686)	32.039	65.764	99.489	133.214
4-5		(.996)	18.929	38.854	58.779	78.704
5-10		(2.130)	40.470	83.070	125.670	168.270
10-15		(.661)	12.544	25.769	38.984	52.199
15-17.6		(.507)	9.633	19.773	29.913	40.053