PD-WAA 029

DOE/FE/60457-1

UNCERTAINTIES IN INDUSTRIAL COAL-BASED ENERGY AND FEEDSTOCK UTILIZATION PATTERNS

FINAL REPORT

March 1985

Prepared for:
U.S. Department of Energy
Assistant Secretary for Fossil Energy
Office of Planning & Environment

Under Contract No. DE-AC01-84FE60457

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DOE/FE/60457-1
Dist. Category UC-90j

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Under Contract No. DE-AC01-84FE60457

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ABSTRACT

UNCERTAINTIES IN INDUSTRIAL COAL-BASED ENERGY FEEDSTOCK UTILIZATION

The use of coal in United States industry has not reached the levels anticipated in many of the projections of the past ten years. This report presents an analysis of factors affecting the use of coal in the three highly energy intensive U.S. industries of chemical manufacturing, oil refining, and steel production. The analysis focuses on the outlook for expanded use of coal in each of these three industries and specifically addresses the following issues and factors for each industry.

- energy and feedstock utilization patterns
- traditional coal uses and current use of coal
- candidate new uses for coal
- state of growth for each industry
- favorable conditions for coal use
- uncertainties and obstacles for coal use
- attitude of industry toward the use of coal
- projected time frames for utilization of coal and specific coal technologies
- attractive coal-related research and development candidates

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SECTION 1

SUMMARY AND CONCLUSIONS

The outlook for coal use in the chemical, oil refining, and steel industries varies dramatically for each industry. Currently in the United States, about 55% of the required energy in the steel industry is met with coal, which is the traditional energy source for that industry. Of the three industries addressed in this report the steel industry uses far more coal than oil refining and chemicals combined. About 11 percent of energy required in the chemicals industry (not feedstocks) is met by coal, whereas only a fraction of a percent of refining energy requirements are met by coal. Direct coal consumption for these industries is illustrated in Table 1-1 for the year 1983. Not included is the additional coal which is used in the generation of purchased electricity.

Table 1-1

ESTIMATED COAL CONSUMPTION -- 1983

Industry	Million Tons	% of Total Energy Used*
Steel	37	55
Chemicals	13	11
Oil Refining	0.3	0.2

* Electric power at 10,000 Btu/kWh

A complex variety of factors will influence future coal use in these three highly energy intensive industries. Moreover, the effects will likely differ significantly for each industry.

The Steel Industry

Of the three industries addressed in the analysis by far the most dramatic conclusions were reached for the steel industry. The near-to-intermediate-term potential exists for substantially increased use of coal in that industry together with the greatly expanded application of new and emerging coal-based steel making technology.

The U.S. steel industry has traditionally been the dominant force in coal utilization by the industrial sector. That dominance has recently diminished with the sharp decline in U.S. steel production. The expanded use of coal is needed for the integrated steel mills to be competitive and for the scrap-based mini mills to expand significantly. For the near-term, integrated steel mills will regain some profitability due to import restrictions. However, this profitability will be sufficient only to generate enough capital for investments in steel finishing (continuous casting). In the meantime, operation of the existing aging iron-making facilities will lead to a coke supply crisis. Continuous iron/steel making technology based on low cost, abundant domestic steam coal needs to be developed to ensure the viability of U.S. integrated steel mills. This new technology is an attractive alternative to batch operation coke ovens, blast furnaces and basic oxygen furnaces which use higher cost metallurgical coal.

Specific conclusions regarding the steel industry are as follows:

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- Several continuous iron/steel making technologies are currently under development that can be based on low-cost steam coal. The KR process appears to be the leader.

- The continued long-term growth and profitability of mini mills could be restricted by the high price and limited availability of high quality scrap. The best alternative appears to be coal gasification integrated with the conventional Midrex direct reduced iron (DRI) process. The leading coal gasification process for this application appears to be the Sumitomo/KHD process because the hot raw gas is sulfur free and is about 95% reducing gas (H_2 + CO). Therefore the hot raw gas can be fed directly to the DRI reactor.

- The biggest obstacles to growth in coal use by the U.S. steel industry are:

  - fluctuating U.S. steel demand
  - steel imports
  - increased mini mill steel production that is not based on coal

- The biggest uncertainties to growth in coal use by the U.S. steel industry are:

  - low profitability that limits investment capital
  - slow acceptance of technology change by U.S. integrated steel mills

- The most favorable conditions for growth of coal use by the U.S. steel industry would be:

  - increased steel demand
  - reduced steel imports
  - a shortage of high quality scrap, thus creating a market for steam-coal-based DRI

The Chemical Industry

Only modest increases are expected in coal use in the chemical industry at current gas and coal prices. The increases are also limited by the small number of new plants and units being built as well as by continuing energy conservation. It is believed that no dramatic change will occur until at least beyond 1990, perhaps beyond 1995. The current gas surplus will eventually be worked off after substantial oil price increases resume. Gas price increases will then make coal attractive. Coal will then dominate the chemical industry purchased fuel market for steam and internally generated electricity. Many of the new coal-fired boilers are expected to use fluidized bed combustion with sulfur capture. Later, as economics and technology allow, coal will be increasingly used for direct fired heaters and as feedstock.

Specific conclusions regarding the chemical industry are as follows:

- o The chemical industry is mature and cyclic, but is still growing at a moderate rate.

- o The chemical industry makes a myriad of products with differing values, production rates, growth rates, and energy intensities. Consequently, factors affecting coal use differ greatly from one plant to another.

- o The principal obstacles to the growth of coal use in the U.S. chemical industry are:

  - economics - not enough difference between gas/oil prices and coal prices
  - high investment required for coal use, particularly for environmental controls
  - lack of growth in fuel use in the chemical industry due to increasing energy conservation

- o The largest uncertainties in coal use in the chemical industry are:

  - gas/oil prices
  - environmental regulations
  - future governmental regulations/tax laws/PURPA

- o The most favorable conditions for coal use in the chemical industry appear to be:

  - high priced gas and oil
  - large fuel usage, growing production rates, and fuel costs representing a large fraction of operating costs
  - increased electricity rates forcing consideration of in-plant generation/PURPA

The Oil Refining Industry

Only a small amount of coal has been traditionally used in the oil refining industry. Furthermore, the level of refinery activity has had no influence on whether or not coal was used as a fuel. However, the use of coal will likely spread in refineries as the real price of oil and natural gas increases. Fuel gas, produced in the course of refining, will continue to be the mainstay of refinery fuel requirements, and coal will not likely make major inroads into this use before the end of the century. Depressed growth will be the biggest hindrance to the growth of coal in refining. Coal uses in refining will likely be restricted to fuel uses, mainly replacement of natural gas and in meeting electric power needs until the year 2000.

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Specific conclusions regarding the oil refining industry are as follows:

- o The oil refining industry is mature and changing slowly to meet:
  - changing levels of product demand
  - declining feedstock quality
  - economics-induced energy conservation goals
- o The industry is consolidating; only limited refinery growth is projected through the 1990s.
- o Coal should come into use in refining on a very limited basis in the 1990s. Depressed growth in the refining industry will be the biggest obstacle to the use of coal in refining. Other major obstacles are lack of experience in using coal, lagging development of new coal utilization technologies, low industry profitability, and increasing energy conservation.
- o The best opportunities for coal over the near or intermediate term will be in fired boilers (both conventional and fluidized bed). The use of fluidized bed combustion should expand significantly by the late-1990s.
- o Coke is the cheapest form of solid fuel available to the refiner. Its use will lead coal in refining applications.
- o Major uncertainties regarding the future use of coal in refining are oil prices and natural gas prices, changes in refinery requirements, changes in refined product markets, environmental requirements and taxation.
- o Experience in the production and use of coke will be a major favorable condition for using coal in a refinery. Other important favorable conditions will be attractive cogeneration options and proximity to both rail and barge transportation.

Research and Development Opportunities

A variety of good opportunities for research and development are available for coal-based technologies. These are summarized as follows, along with main industry of application, not necessarily in order of priority:

- o integrated direct iron ore reduction with coal gasification (steel)
- o continuous steam coal based iron/steel making processes (steel)
- o fluidized bed combustion for process heat (oil refining and chemicals)
- o high value fuels directly from synthesis gas (oil refining)

- synthesis gas based chemicals (chemicals)
- staged slagging combustion for radiant heat (oil refining and chemicals)
- light aromatics from hydropyrolysis (oil refining and chemicals)
- improved coal gasification for synthesis gas (all three industries)
- hot gas clean-up technology (all three industries)
- improved use of coke oven, blast furnace and basic oxygen furnace gas (steel)
- gas treating and gas separation technology (all three industries)

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SECTION 2

INTRODUCTION AND BACKGROUND

The dramatic increases in oil and natural gas prices during the 1970s led to the widespread perception that industrial use of coal in the United States would increase significantly. Coal use in the electric utility industry did increase and plans for expanded coal use in that industry are being implemented. However, coal use in other industries did not increase as expected.

The object of the analysis documented in this report was to help shed light on why coal use in conventional industry did not expand significantly as a result of the oil and gas price increases of the 1970s. The analysis focused on traditional, current, and projected future fuel and energy use in the three most energy intensive U.S. industries:

- chemical manufacturing
- oil refining
- steel production

The analysis addressed the outlook for current and new coal-based utilization technologies concurrent with increasing coal use in these three industries. Regarding the expanded use of coal in industry, the analysis also addressed major related issues including favorable conditions for coal use, uncertainties and obstacles, and industry attitudes. Perceptions were developed for coal utilization time frames in the three industries together with what appear to be the most attractive candidates for continued research and development potentially leading to increased coal use.

Section 3 of the report provides necessary background for the chemical, oil refining, and steel industries, and Section 4 presents a brief discussion of world oil price projections and the likely effect of different pricing levels on U.S. industry coal use. Section 5 presents necessary status and background information for coal-based technologies.

The heart of the report is in Sections 6, 7, and 8, which present assessments of coal use in each of the three industries individually. Section 9 is a related section which addresses uncertainties for coal use common to all three industries.

SECTION 3

BACKGROUND FOR THE CHEMICAL, OIL REFINING, AND STEEL INDUSTRIES

Industry Selection

This study of industrial coal use focused on three major segments of industry: chemicals manufacturing, oil refining, and steel production. These industries are all undergoing changes and difficulties of differing degrees. They are all large fuel users that were affected greatly by the rising fuel prices of the 1970s. These industries appear to have the greatest potential for expanded coal use.

These three industries targeted in this project have differing degrees of experience with coal. The steel industry has traditionally relied primarily on coal for both fuel and process needs. The chemical industry has long experience with coal, but until recent years was switching away from coal to gas, oil, and purchased electricity. The oil refining industry, processing petroleum, has very little experience with coal use. It is anticipated that the three industries will accordingly approach coal use in different manners.

The three targeted industries have all been considering expanded coal use over the past several years. Illustrative cases of coal use decisions in the three targeted industries are among several summarized in a recent book [1]. The analysis in this project examines the coal use potential of these industries and applies the results to identify the most applicable technology development alternatives.

Fuel and Energy Utilization Patterns

The total energy used and coal used as fuel in the three target industries in 1983 are shown in Table 3-1. Table 3-1 is useful in comparing the three industries, but the assumptions behind the listed values are complex. In the chemical and oil refining industries considerable additional fuel material is used as feedstock.

Table 3-1

ENERGY USED[a] IN THE CHEMICAL, OIL REFINING AND STEEL INDUSTRIES, 1983

Industry	Total Energy Used[a] Trillions Btu	Coal Used as Fuel Trillions Btu
Chemicals	2,814[b]	318
Oil Refining	2,535[b]	7
Steel	1,760	960

a) Purchased electricity is calculated at 10,000 Btu/kWh. About 53% of electricty generated in United States in 1983 was generated from coal.
b) Feedstocks are excluded.

Sources: Reference 2 and 3 and SFA Pacific analysis

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Natural gas is the principal fuel used in the chemical industry. It is used for steam and electricity generation and for fired heaters. It is also used as a feedstock as are petroleum products and refinery by-product streams. The fuel and feedstock uses in Table 3-1 were separated by subtracting the energy equivalent of the feedstock from total hydrocarbons purchased. A certain amount of inaccuracy is expected in the data due to incorrect identification of feedstock amounts.

The refining industry relies heavily on captive fuel as well as natural gas. Feedstock is primarily crude oil (including natural gas liquids), although a significant quantity of natural gas is used as feedstock for refinery hydrogen. The refinery hydrogen feedstock is included in the fuel use value in Table 3-1. Refinery fuels are used for direct heating, to generate electricity, and to generate steam.

The steel industry uses large amounts of hydrocarbons as reducing agents and lesser amounts directly as fuel. By-product gases from the reduction process are used extensively as fuel. For example, about 60% of the fuel value of the metallurgical coal is effectively used as fuel. The remainder is that consumed in the reduction process. Only about 6% of the coal used in the steel industry is burned directly as steam coal.

Since the gas supply limitations in the mid-1970s and ensuing price increases, all industries have attempted to reduce natural gas usage. The ability of the steel industry to reduce natural gas consumption, primarily used in ingot casting is limited unless the investment is made in continuous casting. However, significant reductions in natural gas fuel usage have been made in the chemical and refining industries. Natural gas fuel consumption by the chemical industry decreased from 1.7 quads (quadrillion Btu) in 1972 to 1.1 quads in 1983 even as industry production was increasing. Natural gas usage by the refining industry decreased from 0.95 quads in 1972 to 0.56 quads in 1983 with a small overall increase in the amount of crude oil refined. Much of the remaining natural gas usage is as hydrogen feedstock.

Purchased electricity has decreased modestly in the chemicals and refining industries over the last few years after increasing through the 1970s. Rising electricity prices are primarily responsible for this decrease.

Another factor is increased cogeneration encouraged by Public Utilities Regulatory Policies Act (PURPA) incentives. PURPA gives qualifying facilities (cogenerators and small power producing facilities) the right to sell electric power to utilities at avoided cost, which is usually the highest-cost utility-produced power. The law also exempts qualifying facilities from regulation as public utilities.

The trend toward decreasing purchased electricity is expected to continue in the chemicals and refining industries. More electricity will be used, but much of it will be generated internally. Purchased electricity per ton of steel produced has steadily increased, probably due to the growth of mini mills.

Petroleum based fuel use has decreased sharply in the past several years in both the chemical and steel industries in response to the large increase in prices. The use of petroleum fuels in the refining industry, as would be expected, has decreased only modestly.

Coal use (steam coal in the steel industry) has increased in all three industries because of the wide price differential between coal and gas or oil. However, the increase of coal use has not been dramatic, apparently because of the investment required and other obstacles.

Feedstock Component Use Patterns

"Feedstock" is a term used loosely for starting material or raw material. In fact, one company's product may be another company's feedstock. "Feedstock" is a term used widely in the petrochemical and refining industries but seldom used in the inorganic chemical and steel industries.

For purposes of this report feedstock refers to hydrocarbons that may be used as a fuel or as a process starting material. Feedstock use is distinquished from fuel use because of the vastly different chemical and physical requirements of the two uses.

The feedstocks that dominate petrochemicals include natural gas (including the methane), natural gas liquids (excluding the methane), paraffinic petroleum liquids, and aromatic petroleum liquids. "Dry" natural gas (high methane contents) is the usual syngas feedstock in the United States. Natural gas liquids, as well as light refinery hydrocarbons and gas oils, are the usual olefins (ethylene) plant feedstocks.

Olefins plants produce ethylene, propylene, butadiene and butylenes that are "starting" chemicals for entire lines of C_2, C_3, C_4, and other derivatives. Highly aromatic hydrocarbon streams from refineries are sources for benzene, toluene, xylenes, and naphthalenes which serve as starting materials for separate families of chemical derivatives.

Many olefins plants were converted to wide feedstock flexibility during the natural gas shortages of the mid 1970s. However, the natural gas surplus of recent years has had a profound effect on olefins plant feedstocks. As seen in Table 3-2, ethane and propane feedstocks expanded at the expense of heavy feedstocks. However, heavy liquids (naphthas, raffinates, and gas oils) are expected to increase greatly as feedstocks by 1990. Coal as a chemical feedstock is currently confined to one syngas chemical unit.

Table 3-2

OLEFINS PLANT FEEDSTOCKS
(percentages of total used)

Feedstock	1978	1982	1990(projected)
Ethane	49	52	38
Propane	15	24	17
Butane	2	1	2
Refinery gases	2	1	1
Heavy liquids	32	22	42

Source: Reference 4

Feedstock considerations for the refining industry mostly relate to crude oil characteristics. The trend for several years, now delayed by the "oil glut", has been toward heavier, "dirty" crude oils. Consequently, many large refineries have been modified to include more hydroprocessing and coking capacity. Natural gas used for hydrogen production in refineries is really a feedstock but is not thought of as such. It is in this use that coal "feedstock" could first enter refineries as the price of natural gas greatly increases.

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Metallurgical coal is, in effect, a feedstock for integrated steel mills. Integrated steel production has declined in the United States even as mini mills based on steel scrap and electricity have prospered. A revitalization of the integrated steel industry will require coal based energy technology. The coal used can be metallurgical coal in conventional coke ovens, steam coal in developing continuous iron making processes, or in coal gasification. Furthermore, there is the potential for coal gasification-based reduced iron ore as an alternative feedstock to scrap in mini mills.

Traditional Uses of Coal

The availability of abundant cheap coal was a big factor in the industrialization of the United States. Coal was especially important to the steel, rail, and chemical industries. The availability of petroleum led to the replacement of coal-based chemicals by the petrochemical industry. Diesel fuel displaced coal as a railroad locomotive fuel, leaving coal with mainly steel and electric power markets. Certain industries retained existing coal-fired boilers, but many of these were switching to cheap natural gas in the 1960s.

Even the oil embargo of 1973-74 with the large resulting oil price increase only slowed the process of industry switching from coal to gas or oil. The second round of oil price increases began in 1978-80 and came on the heels of a severe gas shortage. The renewed price increases resulted in new laws concerning fuel use and convinced many companies to attempt to decrease oil and gas usage. Replacement of gas or oil with coal was given high priority, especially by companies with equipment already capable of burning coal. However, economically induced energy conservation was the easier option in most cases since it often involved little or no investment. By 1981 industry had already made large reduction in fuel usage and the reduction was continuing.

The option of switching fuels from gas or oil to coal has turned out to be more difficult than energy conservation. The major difficulties with switching to coal include environmental restrictions and the significant investment often required. In addition, coal applications are usually limited to the generation of steam for power production or low/medium level heating. The use of coal in direct fired heaters is not a commercial technology. The use of coal as feedstock is also limited by technology and economics.

The use of coal to generate steam would have wide application in the chemical industry because of the large amount of low level steam used. Low level steam is used in a wide variety of heating and process applications. The chemical industry is a large user of electric power. Internally generated power from coal is often attractive given the widespread increases in electricity rates.

The oil refining industry uses little coal at present although power generation and medium/high level steam uses both present sizable potential applications. An additional obstacle to coal use in refining is the integration of internally generated fuel streams such as refinery gas. The usage of internally generated petroleum coke may actually be helpful in introducing coal because of the similarity of coke-using facilities to those needed for coal. However, a large amount of natural gas is also used by refineries both as a fuel and as a hydrogen feedstock. The main motivation for coal use in refineries, therefore, is the difference in price between natural gas and coal, currently about $1/million Btu.

The steel industry currently is a large user of coal, but mainly metallurgical coal. In addition, there is a lesser requirement for steam coal. The current usage of natural gas, LPG, and oil is still several times that of steam coal in the steel industry. Therefore, there is still considerable opportunity for coal to displace petroleum and natural gas in the steel industry.

Environmental Considerations

A major impediment in the burning of coal in industry is the high level of undesirable emissions. Coal contains significant (often high) amounts of sulfur and ash. The sulfur content of the coal is almost all emitted in the flue gas as sulfur dioxide. Some of the ash is also entrained in the flue gas as fly ash. In addition, the properties of coal make it more difficult to control the emission of nitrogen oxides than is the case with oil or gas.

Fly ash emissions can be controlled with moderate expense with various particulate control equipment. Nitrogen oxides emissions levels from industrial burners are not of major concern in most regions of the country. However, sulfur dioxide emission control is expensive, requires space, and is labor intensive. Most industrial users are confident that flue gas desulfurization processes can be applied to industrial coal burning, but the cost adversely affects the economics of coal use.

In "non-attainment" areas of the country pollution offsets may have to be purchased in order to burn coal. The permitting process itself is often time-consuming and an impediment to coal use. Adding potential negative publicity to increased costs and time delays can result in a close decision being decided against coal use.

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SECTION 4

WORLD OIL PRICE PROJECTIONS

The overwhelming factor that will determine how much additional coal will be used in U.S. industry in the future is its price (and cost of use) relative to competing fuels. The principal competition is and will continue to be petroleum-based fuels and natural gas.

For purposes of having general bounding scenarios, the analysis of this report has used the "high", "middle", and "low" world oil price projections developed by the Energy Information Administration and published in May 1984 in their Annual Energy Outlook 1983 [Reference 1]. These projections are shown in Figure 4-1. The background for these projected price scenarios is presented in Appendix B for world oil, coal, and natural gas.

The middle world oil price forecast assumed that the real price of oil (in 1983 dollars) delivered to the United States will decrease from $29.35 in 1983 to $25.56 per barrel in 1986, and then increase to $50.49 by 1995. In other words, prices are assumed to rise at an average annual rate of 3.2 percent between 1983 and 1990, and 6.6 percent between 1990 and 1995. In the low world oil price case the cost of imported oil is assumed to decline to $22.28 per barrel in 1986 and then subsequently increase to $26.54 per barrel by 1995.

In the low world oil price scenario total primary energy consumption is projected to be about 4.0 percent higher than in the midprice case in 1995. In the high world oil price case, total primary energy consumption would be about 3.9 percent lower in 1995 compared to the midprice case.

Total oil consumption in 1995 is projected at about 9.4 percent lower in the high world oil price case than in the middle world oil price case, while domestic oil production in the high world oil price case is about 19 percent higher than in the middle world oil price case.

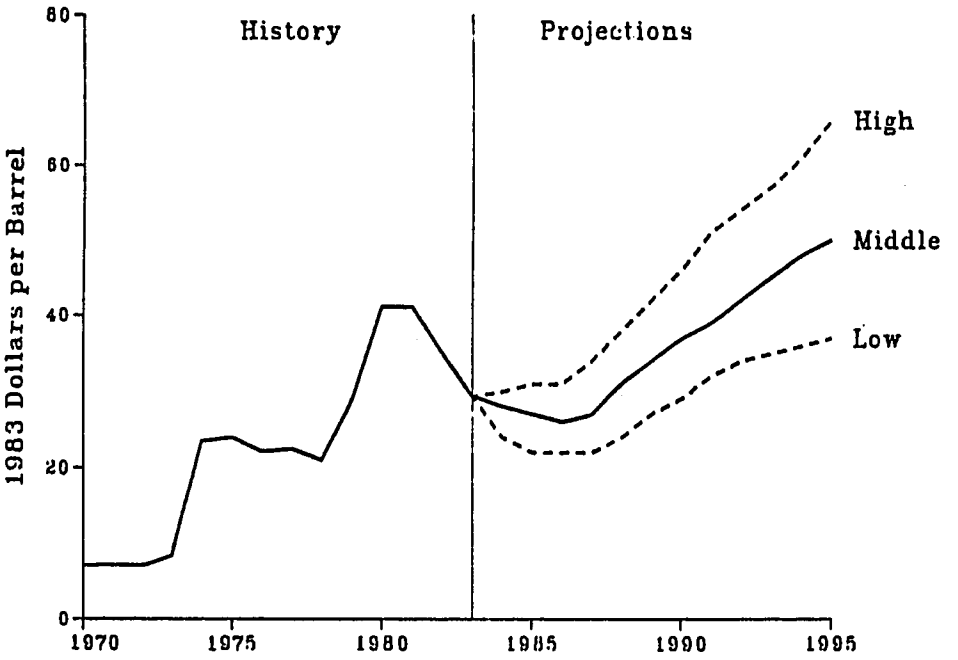
Since 1981 OPEC has seen inflation-adjusted oil prices decline appreciably due to weakened demand. Early in 1983 OPEC reduced the price for benchmark Arabian Light to $29 per barrel from $34 per barrel. Since then the pricing structure has further weakened and marginal oil supplies of equivalent crudes were being moved on the spot market at $26 and $27 per barrel (first quarter 1985). It should be noted that the price of oil has increased in most countries in the past two years due to the strong U.S. dollar.

The "high" scenario would likely bring about the rapid switching of oil and natural gas to coal in the United States, whereas the "low" scenario would likely lead to very limited new use of coal where incremental investment for fuel switching would be necessary.

1. Annual Energy Outlook 1983, Energy Information Administration, U.S. Department of Energy, May 1984.

Figure 4-1

WORLD OIL PRICE PROJECTIONS, 1970 to 1995



Source: Reference 1

Note: Prices reflect the average landed price of crude oil in the United States.

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SECTION 5

COAL-BASED TECHNOLOGIES

Introduction

There are numerous coal technologies in various stages of development. For convenience, coal technologies have been divided into four generic technology groupings as follows:

- o Direct Combustion
- o Gasification
- o Liquefaction
- o Electricity Generation

Each of the generic technologies have specific applications for the oil, chemical and steel industries. The discussion of technologies is kept necessarily brief since the major emphasis of this analysis is on the overall outlook for the three industries addressed. The discussion in this section of the report assumes that the reader has a reasonable level of understanding of coal utilization technologies.

The principal application for direct coal combustion is of course generation of steam for direct process use, indirect heating, or shaft power. All three industries of interest have large energy requirements for this application. Another potential important application for direct combustion is high temperature process heating which is at too high a level for use of steam as the heat transfer medium. The oil and chemical industries each have a number of processes requiring high temperature radiant heat transfer, e.g., steam methane reforming and pyrolysis furnaces. The development of fluidized bed combustion and slagging combustors could make the use of direct combustion possible for these applications.

The principal application for coal gasification is generation of fuel gas as a replacement for natural gas or fuel oil. All three industries currently have large fuel-related natural gas and oil requirements. Another potentially important application for coal gasification is the generation of synthesis gas (H_2 and CO). The oil industry has large requirements for H_2 while the chemical industry produces substantial amounts of chemicals from synthesis gas. There is also a large potential for coal-derived synthesis gas in the steel industry as the reducing agent in converting iron ore into steel.

The principal application for coal liquefaction (direct, indirect and pyrolysis) is generation of liquid fuels by the oil industry as a supplement or replacement for crude-oil-derived liquid fuels. Coal liquefaction processes also have the potential for production of liquid chemicals for the chemical industry, such as benzene and phenolic-based chemicals from direct liquefaction and pyrolysis or alcohols and olefins from indirect liquefaction.

The electric utility industry supplies the oil, chemical and steel industries with a significant amount of electricity. However, the industrial electricity consumers are now beginning to seriously consider generating more of their own electricity because of increasing prices charged by electric utilities and incentives under PURPA. The sharp increase in electricity prices of the past few years is due to a complex variety of factors including: outrageous costs of new nuclear plants, impact of environmental regulation on coal-based power generation, and continued use of large amounts of natural gas and oil-based power generation by utilities.

Direct Combustion

There are several commercial and developmental technologies for direct combustion of coal including the following:

- o conventional pulverized combustion
- o conventional stoker-fired combustion
- o atmospheric fluidized bed combustion (AFBC)
- o coal water mixtures (CWM)
- o slagging combustors
- o pressurized fluidized bed combustion (PFBC)

Coal gasification / combined cycle power generation -

Conventional pulverized combustion is the dominant technology for coal utilization. However, pulverized combustion is generally restricted to industrial applications having large steam or power requirements and high load factors due to the large capital investments required for pulverized coal boilers. Potential requirements of flue gas desulfurization (FGD) also add to the cost for industrial use of pulverized coal combustion. Industrial environmental standards are sometimes less stringent than utility standards and may permit use of only low sulfur coal without FGD in many situations. Sulfur emissions standards for industrial applications have not yet been established by EPA. This creates uncertainty for potential users.

AFBC is now commercial and has excellent potential for increasing industrial utilization of coal. AFBC appears to be more economical than pulverized combustion at small scale. Furthermore, AFBC has very good feed fuel flexibility as a fluidized bed system can use fuel such as wood wastes, petroleum coke or even coal cleaning plant refuse. AFBC also has potential for process heat since the heat transfer coefficient to tubes filled with process liquids or gases is very high. The key issue still to be resolved before AFBC is broadly accepted by industry is sulfur capture (required Ca/S ratio for specific removal) and potential spent absorbent disposal problems. Most industrial interest in AFBC is focused on recirculating FBC designs due to the better carbon conversion and lower Ca/S ratio relative to a bubbling bed FBC.

Coal water mixtures (CWM) could have potential to replace oil in existing industrial boilers. However, this technology suffers from large potential boiler derating and environmental limitations. Furthermore, the potential cost of CWM could be high due to requirements of premium coals and chemical additives to produce high slurry concentrations. An interesting alternative to CWM appears to be pre-dried and pulverized coal.

The development of two-stage slagging combustors could also have potential for replacing oil or natural gas in existing industrial boilers. Furthermore, slagging combustors could have potential of replacing oil or natural gas in large radiant type process heaters. However, much development is still required. The key issues are the ability to operate at large scale, long term demonstration to verify ash removal efficiency, and life cycle of the first stage combustion/gasifier.

PFBC has many of the same potential advantages as AFBC plus higher efficiency. However, current development efforts for PFBC have been less successful and it is questionable if it ever will be commercialized. Key technical issues are similar to AFBC plus the problems of high pressure solids handling and hot gas clean-up.

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Gasification

There are a large number of coal gasification processes, each having its own distinctive characteristics. However, essentially all gasification processes can be separated into the three classic (or generic) types of reactors:

- o Moving-bed or counter-current reactors (generally most efficient)
- o Fluidized-bed or back-mixed reactors
- o Entrained-flow or plug-flow reactors (generally least efficient)

Figure 5-1 shows the three generic types of coal gasification reactors together with temperature profiles and location of the coal, steam and oxidant (air or oxygen) inputs and the coal gas and ash outputs.

Considering the types of gasification reactors on a generic basis is useful in understanding the fundamentals of coal gasification. Many individual process characteristics are common to all of the different gasifier designs related to a particular generic reactor type. Table 5-1 summarizes the most important characteristics of each generic type of gasification reactor.

It is also useful to distinguish coal gasification processes by state of technology development. Coal gasification processes can be characterized as commercial, near-commercial or advanced.

Commercial systems are defined as those with existing commercial operating units and which require no further scale-up or demonstration except when testing of specific coals is necessary. This category includes 5 systems:

- o Gas producers
- o Lurgi (dry ash)
- o Winkler
- o Koppers-Totzek
- o Texaco

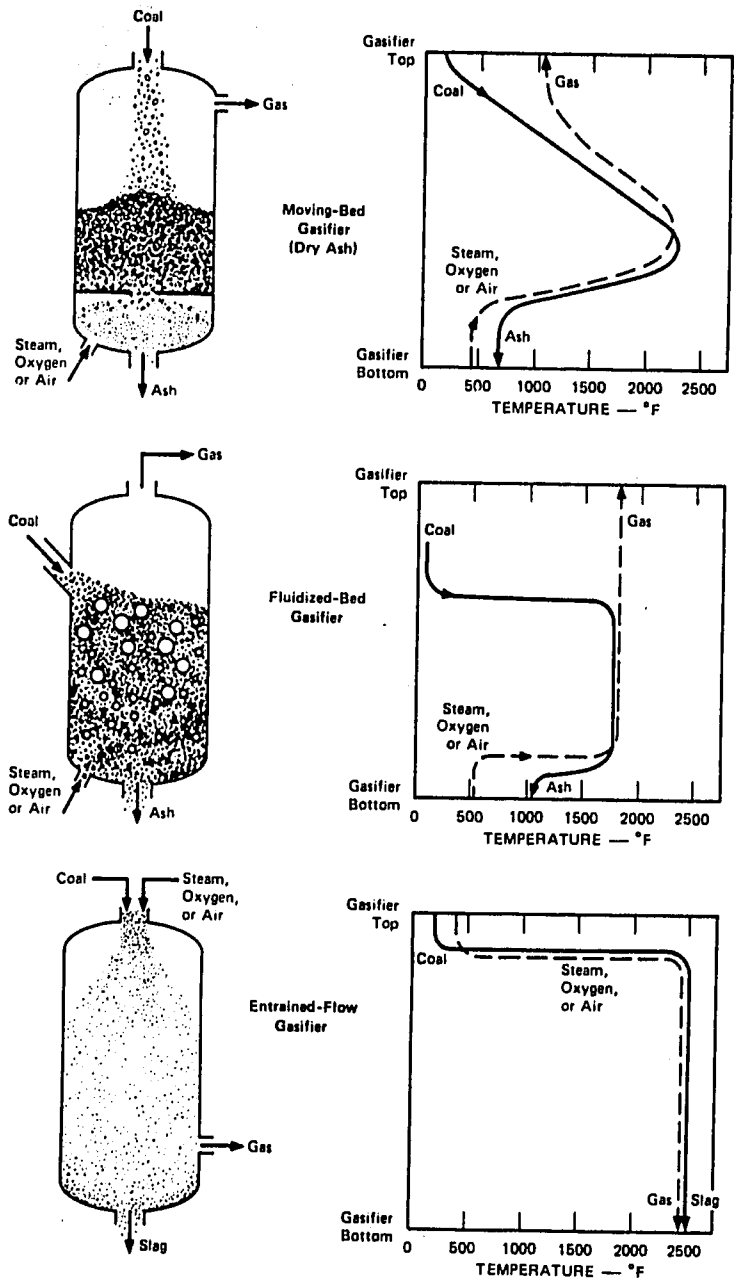
Gas producers are marketed by several companies and various names. They are all moving-bed gasifiers which are air blown and operate at near atmospheric pressure. The Lurgi is a moving-bed gasifier which is oxygen blown and operated at 300-450 psig pressure.

The Winkler process is a fluidized-bed gasifier which is oxygen blown and operated at near atmospheric pressure. The Koppers-Totzek (also known as K-T or GKT) process is an entrained-flow gasifier which is also oxygen blown and operates at near atmospheric pressure.

The Texaco process is the first new commercial coal gasification technology in over 40 years. Three commercial plants (2 operating and 1 under construction) use the Texaco process to produce chemicals from H_2 and CO. A fourth plant is the first large-scale demonstration of integrated coal gasification combined cycle electric power generation (Cool Water). The Texaco process is an entrained-flow gasifier which is oxygen blown and operates at 600-1200 psig pressure. The process differs from most gasifiers by the use of a coal/water slurry feed system.

Figure 5-1

GENERIC COAL GASIFICATION REACTORS



Source: Reference [1]

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Table 5-1

IMPORTANT CHARACTERISTICS OF GENERIC TYPES OF GASIFICATION REACTORS

Ash Conditions	MOVING-BED		FLUIDIZED-BED		ENTRAINED-FLOW
	Dry Ash	Slagging	Dry Ash	Agglomerating	Slagging
Feed Coal Characteristics					
Size	Coarse (-2 inch)	Coarse (-2 inch)	Crushed (-¼ inch)	Crushed (-¼ inch)	Pulverized (-100 mesh)
Acceptability of Fines	Limited	Better than dry ash	Good	Better	Unlimited
Acceptability of Caking Coal	Yes (with modifications)	Yes (with modifications)	Possibly	Yes	Yes
Preferred Coal Rank	Low	High	Low	Any	Any
Operating Characteristics					
Exit Gas Temperature	Low (800°F-1200°F)	Low (800°F-1200°F)	Moderate (1700°F-1900°F)	Moderate (1700°F-1900°F)	High 2300°F)
Oxidant Requirement	Low	Low	Moderate	Moderate	High
Steam Requirement	High	Low	Moderate	Moderate	Low
Key Distinguishing Characteristics	Hydrocarbon liquids in the raw gas		Large char recycle		Large amount of sensible heat energy in the hot raw gas
Key Technical Issue	Utilization of fines & hydrocarbon liquids		Carbon conversion		Raw gas cooling

Source: Reference 1

Near-commercial technology is defined as a process which has been successfully operated at a large-scale pilot plant and for which a near-commercial size demonstration unit is currently operating or under construction. The following coal gasification processes meet these criteria:

- o British Gas Corporation (BGC)/Lurgi Slagger
- o Dow
- o HTW
- o Kilngas
- o Sumitomo/KHD

The BGC/Lurgi and Kilngas are moving-bed processes. HTW (High Temperature Winkler) is a fluidized bed process. The Dow gasifier is a entrained-flow gasifier which is fed with slurry. It differs from the Texaco process by use of a proprietary feed system and raw gas cooler which makes it effective for low rank coals. The Sumitomo/KHD gasifier is like an entrained-flow process except the reaction takes place in a bath of molten iron similar to a pressurized continuous basic oxygen furnace.

There are a large number of advanced coal gasification processes under development. However, many have been operated only at bench scale or in small pilot plants. Important advanced processes which have been successfully operated at large pilot plant scale or have been operated in small pilot plants but for which developers plan to build large-scale pilots in the near future include:

- o CGT
- o HKV
- o Shell
- o U-Gas
- o VEW
- o KRW (Westinghouse)

The CGT, HKV, U-Gas and KRW are all fluidized-bed gasification processes while the Shell and VEW are entrained flow processes.

Liquefaction

Coal liquefaction processes can be separated into three classic (or generic) types of processes:

- o direct
- o indirect
- o pyrolysis

Direct coal liquefaction involves the hydrogenation of coal/recycle oil slurries with high pressure hydrogen at temperatures of 700-900°F and 30-60 minutes residence time. Interest in direct coal liquefaction in the U.S. has declined since successful completion and termination of large scale pilot plant testing of the H-Coal and Exxon Donor Solvent (EDS) processes. However, pilot plant testing and consideration of large-scale demonstration plants continues in West Germany and Japan. Most of the current interest in direct coal liquefaction focuses on use of two stage processes. Coal is liquefied to produce an extract at relatively mild conditions in the first stage followed by hydrogenation of the extract in the second stage at more severe conditions. This modification reduces the hydrogen demand while increasing the

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liquid yield. A key drawback with two-stage direct liquefaction processes is that the principal product are heavy distillate liquids (600-900°F) which have limited uses. Futhermore, these liquids require expensive upgrading because of the hydrogen content and high nitrogen and oxygen contents.

Indirect coal liquefaction involves first gasifying coal and purifying/shifting the coal gas into synthesis gas (H_2 and CO). The synthesis gas is then reacted over catalyst into liquids. The key issues in indirect liquefaction are coal gasification economics, liquid yield, selectivity and catalyst deactivation. Much of the current interest in indirect liquefaction involves developing better catalysts and improved synthesis gas reactors such as slurry-phase and fluidized bed processes.

Pyrolysis processes involve heating coal to produce fuel gas, pyrolysis liquids and char. Hydropyrolysis involves doing the pyrolysis in the presence of high-pressure hydrogen, which improves the quality of the liquids. The key issue with pyrolysis or hydropyrolysis is that the primary product is char, not liquids; therefore, effective char utilization is essential. The increased use of fluidized bed combustion could improve the potential for pyrolysis/hydropyrolysis processes as FBC boilers can easily burn char.

Electricity Generation

Alternative coal technologies for electricity generation include the following:

- o direct combustion/steam generation
- o coal gasification combined cycle (CGCC)
- o fuel cells
- o magnethydrodynamics (MHD)

Direct coal combustion technologies such as pulverized-coal boilers, FBC, CWM and slagging combustors have previously been discussed in the section entitled Direct Combustion.

CGCC is becoming a commercial reality due to the success of the Cool Water demonstration plant. This 100 MW (net) plant located near Barstow, California is based on integration of the Texaco coal gasification process and General Electric combined cycle. The plant began operation in mid-1984 and has been operating very well while meeting the following stringent environmental emissions levels:

- o sulfur dioxide - less than 0.035 lbs/million Btu coal (over 97% reduction)
- o nitrogen oxides - less than 0.065 lbs/million Btu coal (less than 27 ppm NOx)
- o particulates - less than 0.005 lbs/million Btu coal

A second large scale (155 MW net) CGCC plant is under construction at Plaquemine, Louisiana, based on the Dow coal gasification process and existing Westinghouse combined cycle. The key issues for CGCC are its ability to easily meet stringent environmental requirements and its economic advantage over direct coal combustion due to the greater ability of CGCC to be constructed in stages.

Fuel cell technology based on coal-derived synthesis gas (H_2 + CO) is less developed than CGCC. Currently, phosphoric acid fuel cells are being tested at a relatively small (4.5 MW) scale. However, phosphoric acid fuel cells convert only H_2 to electricity, not CO. Converting coal or other fuels such as

natural gas to pure H_2 is relatively expensive compared with converting them to synthesis gas (mixed H_2 and CO). The more advanced molten carbonate fuel cells are required to convert H_2 and CO to electricity. The development of molten carbonate fuel cells will be required before coal gasification based fuel cells have a significant potential.

The development of coal-based MHD electricity is tenuous. The development has had limited success, and technology is a long way from integrated commercial-scale operation.

References

1. D.R. Simbeck, et al, SFA Pacific, Coal Gasification Systems, A Guide to Status, Applications and Economics," Electric Power Research Institute, Report No. AP-3109, Palo Alto, CA, June 1983.

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SECTION 6

CHEMICAL INDUSTRY ASSESSMENT

Conclusions

The chemical industry in recent years has changed from a growth industry into a mature industry. The industry is under profit pressure from increased feedstock and fuel costs and depressed or stagnant product prices. Increased competition from foreign chemical producers is showing signs of limiting the U.S. chemical industry's traditionally large export sales.

In the current environment coal must compete as a fuel and feedstock on strictly economic grounds. Coal is cheaper than competing fuels, but often requires significant investment to use. The principal conclusions reached in this analysis of coal use in the chemical industry are as follows:

- o A much larger price differential between coal and natural gas will be required to increase coal use by the chemical industry significantly. The current $1/million Btu differential must rise to at least $3/million Btu (and probably much greater) to stimulate coal use.

- o Coal use in the chemical industry is likely to increase slowly at current natural gas prices. No dramatic increase in coal use is expected until about 1995.

- o Coal use is most likely to be expanded for chemical production that:
  - is a large consumer of steam and power
  - is being expanded to meet a growing market
  - is located near a coal mine or on a navigable waterway to minimize coal transportation cost.

- o The new use of coal by the chemical industry will be, as is the case now, almost totally for steam and power.

- o Internal generation of electric power is increasingly economical in chemical plants due to PURPA and the large increases in electricity rates by some utilities.

- o Technology is not a major limitation on coal use for steam and power although economical means of meeting emissions requirements would be useful.

- o New technology is needed to allow the use of coal in direct fired heating applications, for example, in reformers and cracking furnaces.

- o The use of coal as a chemical feedstock is widely believed to be uneconomical under current conditions although one pioneer unit has commercialized the Texaco gasifier as a means of producing synthesis gas from bituminous coal.

- Additional technologies for gasification of low rank coal and for coal liquefaction will be required for coal to be a practical chemical feedstock even when oil price increases resume.

- Syngas chemistry and catalysis is a promising area for technology development.

Industry Definition

The chemical industry consists of a wide variety of manufacturing operations transforming materials via chemical reactions into valuable salable products. The manufacturing operations include chemical reactions which are induced to proceed by mixing, heating, pressurizing, or passing over a catalyst. Crude reaction products typically must be separated by operations including distillation, drying, absorption, extraction, filtration, or evaporation. Polymeric products are typically formed by additional mechanical operations such as extrusion. In addition, air separation plants producing nitrogen, oxygen and rare gases via cryogenic distillation are also classified as chemical plants.

The chemical industry is identified by the Department of Commerce as "Chemicals and Allied Products" with SIC Code 28. A great variety of products are included under this code including industrial inorganic chemicals, plastic materials and synthesis, drugs, soaps, cleaners, and toilet goods, paints and allied products, industrial organic chemicals, agriculture chemicals, and miscellaneous chemical products.

In this report the entire SIC Code 28 industry is included when reference is made to the chemical industry. Generalizations concerning the industry, however, are especially applicable to those parts most likely to use coal as a fuel.

Characteristics of the U.S. Chemical Industry

The U.S. chemical industry has been a major growth industry since World War II. In particular, the development of new man-made polymeric materials has resulted in a wide variety of uses as fibers, films, elastomers, and structural parts. New pharmaceutical products have revolutionized medicine. New specialty chemicals have found numerous applications in agriculture and across industry. As a consequence the chemical industry has become quite sensitive to the business cycle.

Historically, U.S. chemical producers have had access to inexpensive natural gas which helped keep production costs low. However, in recent years the basic "building block" organic chemicals have increased in cost to produce in the United States primarily due to the large increase in fuel and feedstock costs. In particular, ethylene and co-produced olefins have increased greatly in cost primarily because of the increased price of natural gas liquids in the United States. Similarly, the cost of synthesis gas chemicals, principally ammonia and methanol, has greatly increased due to natural gas price increases. Many foreign producers that have low cost natural gas available can now produce these basic chemicals more cheaply than they can be produced in the United States. It is widely believed that most new basic chemical capacity will be built in natural gas surplus countries.

U.S. chemical producers still supplied about 20% of the world chemical market in 1983 and ran a positive trade balance of $9 billion [1]. The industry had a profit margin of 4.3% in 1983 down from 6 to 10% in the 1970s. Return on stockholders' equity was 8.8% in 1983 down from values usually in the teens in the 1970s. The U.S. chemical industry earned a profit of $3 billion in 1983 in the middle of its typical

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range of $2 to $4 billion over the past ten years. In short, the U.S. chemical industry is becoming a mature industry growing at a reduced rate and reduced profitability.

Industry Structure by Products Made

The fifty chemicals produced in the largest amounts in the United States in 1983 are listed in Table 6-1. The diversity of the major chemicals is apparent from this table. The prices shown are illustrative only; specific prices depend on a variety of factors including product purity, volume of sale, transportation cost, and many other factors. The prices do show the approximate economic importance of the various products.

The variation of ten selected chemicals over the past ten years is shown in Table 6-2. The dependence of sales volume on the economic cycle is apparent. The annual growth rage of these typical chemicals appears to average about 2 to 3 percent.

The most important economic characteristic of the production of any particular chemical is the value that is added to the starting material. Basic chemicals by definition begin with a raw material that is not classified as a chemical product. Chemical derivatives, on the other hand, are classified as those made from another chemical product.

There is great diversity in the chemical reactions used industrially to produce the various chemicals. For example, ethylene is produced by pyrolysis of a hydrocarbon exposed for a short time to a high temperature. Hundreds of separate chemical reactions have been identified as occurring during the complex pyrolysis process. For example, ethylene may be formed from propane by the simple reaction: $C_3H_8 \rightarrow C_2H_4 + CH_4$. But ethylene may also be formed in a variety of secondary reactions. Ethylene may also be destroyed by conversion to secondary, less desirable products.

As a chemical starting material ethylene is converted into many chemical products and intermediates, such as polyethylene, ethylene oxide, ethylene glycol, and vinyl acetate to name some examples. In this work it was not necessary to perform a detailed accounting of the large variety of individual chemicals produced.

An important classification of chemical products is as organic chemicals and inorganic chemicals. Organic chemicals are those based on carbon chemistry and inorganic chemicals include all others. Organic chemicals are almost always derived in one or more steps from hydrocarbons or from biological materials. Hydrocarbons are usually the starting material of choice. Multi-carbon hydrocarbons including gas liquids, LPGs, and gas oils are used as raw materials for ethylene and co-produced chemicals. Natural gas itself, primarily single carbon methane, can be used as a carbon monoxide/hydrogen "syngas" feedstock. Inorganic chemical raw materials include minerals, air and water.

Capacity-Product Price Relationships

The chemical industry in the United States since World War II has been perceived by many companies as an attractive growth field. Consequently, companies have built chemical plants to the extent that there has frequently been a much greater capacity than needed to supply the demand for chemicals. The intense competition, common in a free market, has cycled between overcapacity with low prices and undercapacity with increased prices. In general, the overall trend has been toward lower prices and profits as the industry

Table 6-1

LEADING CHEMICALS PRODUCED IN THE UNTIED STATES
(production rates in billions of pounds per year)

Rank 1983		Billions of lb 1983	Billions of lb 1982	Typical Price $/lb
1	Sulfuric acid	69.45	65.36	0.03
2	Nitrogen	42.03	35.07	0.04
3	Lime	28.80	28.15	0.02
4	Oxygen	28.73	28.81	0.04
5	Ethylene	28.59	24.50	0.17
6	Ammonia	27.37	31.56	0.07
7	Sodium hydroxide	20.46	18.77	0.20
8	Chlorine	19.92	18.35	0.10
9	Phosphoric acid	19.90	16.52	0.30
10	Sodium carbonate	16.93	15.64	0.04
11	Nitric acid	14.75	14.78	0.14
12	Propylene	13.98	12.54	0.20
13	Ammonium nitrate	13.24	14.18	0.75
14	Urea	11.54	13.04	0.10
15	Ethylene dichloride	11.25	7.62	0.17
16	Benzene	9.48	7.75	0.17
17	Ethybenzene	7.86	6.66	0.22
18	Carbon dioxide	7.15	7.36	0.04
19	Toluene	7.12	5.18	0.20
20	Styrene	6.99	5.94	0.35
21	Vinyl chloride	6.95	4.90	0.21
22	Methanol	6.62	7.56	0.06
23	Terephthalic acid	5.69	4.84	0.40
24	Ethylene oxide	5.58	4.99	0.35
25	Xylene	5.57	4.74	0.16
26	Formaldehyde	5.40	4.82	0.09
27	Hydrochloric acid	5.22	4.92	0.03
28	Ethylene glycol	4.46	4.31	0.17
29	p-Xylene	4.11	3.21	0.22
30	Ammonium sulfate	3.94	3.54	0.04
31	Cumene	3.30	2.74	0.23
32	Potash	2.87	3.93	0.18
33	Acetic acid	2.79	2.75	0.25
34	Phenol	2.61	2.02	0.36
35	Carbon black	2.50	2.30	0.30
36	Butadiene	2.31	1.92	0.32
37	Aluminum sulfate	2.29	2.37	0.12
38	Acrylonitrile	2.15	2.04	0.45
39	Vinyl acetate	1.96	1.88	0.39
40	Calcium chloride	1.88	1.75	0.08
41	Acetone	1.87	1.69	0.23
42	Sodium sulfate	1.71	1.73	0.05
43	Cyclohexane	1.69	1.28	0.20
44	Propylene oxide	1.58	1.48	0.48
45	Titanium dioxide	1.51	1.31	0.69
46	Sodium silicate	1.45	1.33	0.15
47	Adipic acid	1.42	1.20	0.57
48	Sodium tripolyphosphate	1.34	1.30	0.40
49	Isopropyl alcohol	1.21	1.38	0.33
50	Ethanol	1.10	1.02	0.25

Source: Reference 1 and SFA Pacific

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Table 6-2

PRODUCTION OF SELECTED CHEMICAL PRODUCTS 1973 - 1983
(millions of pounds annually)

	Growth %/yr	1983	1982	1981	1980	1979	1978	1977	1976	1975	1974	1973
Acrylonitrile	5	2,146	2,035	1,997	1,830	2,018	1,752	1,646	1,518	1,215	1,412	1,354
Caprolactan	4	979	793	928	905	945	919	867	780	713	668	656
Chlorine gas	0	9,960	9,176	10,763	11,421	12,291	11,052	10,573	10,378	9,167	10,753	10,402
Ethylene	3	28,586	24,501	29,418	28,667	29,904	25,955	25,172	22,475	20,499	23,891	22,329
Ethylene oxide	3	5,575	4,987	4,937	5,220	5,665	5,012	4,364	4,184	4,467	4,200	4,167
Methanol	-1	6,624	7,555	8,577	7,153	7,367	6,443	6,453	6,242	5,176	6,878	7,064
Polyester fibers	2	3,544	3,169	4,176	3,989	4,178	3,800	3,642	3,340	2,995	2,926	2,888
Styrene monomer	2	6,987	5,942	6,679	6,856	7,484	7,186	6,867	6,301	4,673	5,956	5,975
Sulfuric acid	1	34,725	32,680	40,742	44,158	43,204	41,314	38,337	34,878	32,360	33,926	31,949
Urea	5	5,770	6,518	8,062	7,830	7,000	6,273	5,072	4,498	3,799	3,789	3,543

Source: Reference [1]

matures. Consequently, chemical companies have concentrated on controlling costs, the only short term way of improving profits.

Energy and feedstock costs have become the two greatest costs of producing chemicals in the past 12 years. Numerous changes have been made in operations to reduce these costs. Frequently, new investment is required to achieve cost savings, as is usually needed to switch to coal as fuel.

Classification of Principal Product Groups

For purposes of this analysis the following groups of products are considered:

- o ethylene and co-products
- o organic derivatives
- o syngas chemicals
- o polymers
- o fertilizers
- o inorganic chemicals
- o air separation products

Ethylene and co-products are the petrochemicals of primary importance. Ethylene is made by the steam pyrolysis of petroleum fractions or natural gas liquids. Major co-products include propylene, butadiene, butylenes, and "pyrolysis gasoline." Pyrolysis gasoline is a mixture of liquid aromatic and unsaturated compounds. The proportion of ethylene and the various co-products made depend upon the feedstock and the pyrolysis conditions.. Ethylene and propylene, the basic olefins, are the major products and the starting materials for whole lines of derivative chemicals and polymers. Pyrolysis feedstock and fuel costs are crucially important in determining production costs.

A wide array of organic derivative chemicals are made from ethylene, propylene, and other chemical starting materials. Little generalization can be made concerning these many chemicals. The production cost and price of these chemicals tend to increase as the yield from primary chemicals decreases and the number of required reaction steps increases. There are usually a large number of alternative chemical products for a particular application. Therefore, the sales volume is usually low for expensive derivative chemicals requiring several steps of synthesis.

Syngas chemicals made from carbon monoxide-hydrogen mixtures currently include only a small number of simple compounds containing one carbon atom or no carbon at all. Some of these syngas chemicals are also the basis of various chemical derivatives.

Polymer products are a special kind of chemical derivative in that they are valuable for their structural or mechanical properties. Various polymers are used for structural parts, films, fibers, coatings, and adhesives. Most polymers are made from simple chemical derivatives, principally ethylene, propylene, benzene, and p-xylene.

Fertilizers are inorganic chemicals, many of which are nitrogenous compounds derived from ammonia, a syngas product. Other inorganic compounds include a wide variety of products derived from minerals such as sulfur, limestone, potash, and phosphorous. Of particular interest, because of high electricity usage, are the chloralkali products. Air separation products including nitrogen, oxygen, and rare gases are included as chemicals only because of the extraordinary technique of cryogenic separation required.

35x

Coal Applications and Technology

Coal is used within the chemical process industry primarily to supply process heat and power. Only rarely is coal now used as a chemical feedstock. Little new coal technology developed or substantially improved in the past 20 years is used, although there are several promising applications. A recent development, not caused by new technology, is increased use of cogeneration with the sale of electric power. Originally projected to be largely based on coal, the majority of actual cogeneration projects are based on natural gas.

Figure 6-1 is an example flow sheet of ethylene production via ethane cracking showing various fuel use applications. Direct fuel firing is required in the cracking furnace. Steam is needed as a diluent in the ethane feed. Shaft or electric power is needed for the compressors and for the coldbox refrigeration system.

The chemicals with high energy requirements are the best candidates for increased coal use. For example, Dow Chemical, a leader in cogeneration, is also a leading producer of energy intensive electrochemicals. In fact, the lack of availability of cheap nuclear power at Dow's Midland, Michigan plant led to the displacement of many units to the Gulf Coast. The generation of electricity from coal economically and in an environmentally acceptable manner would clearly be advantageous to electrochemicals production. Such a method could be coal gasification/combined cycle or fluidized bed combustion. However, in either case, the economic advantage over conventional coal based power generation is likely to be modest.

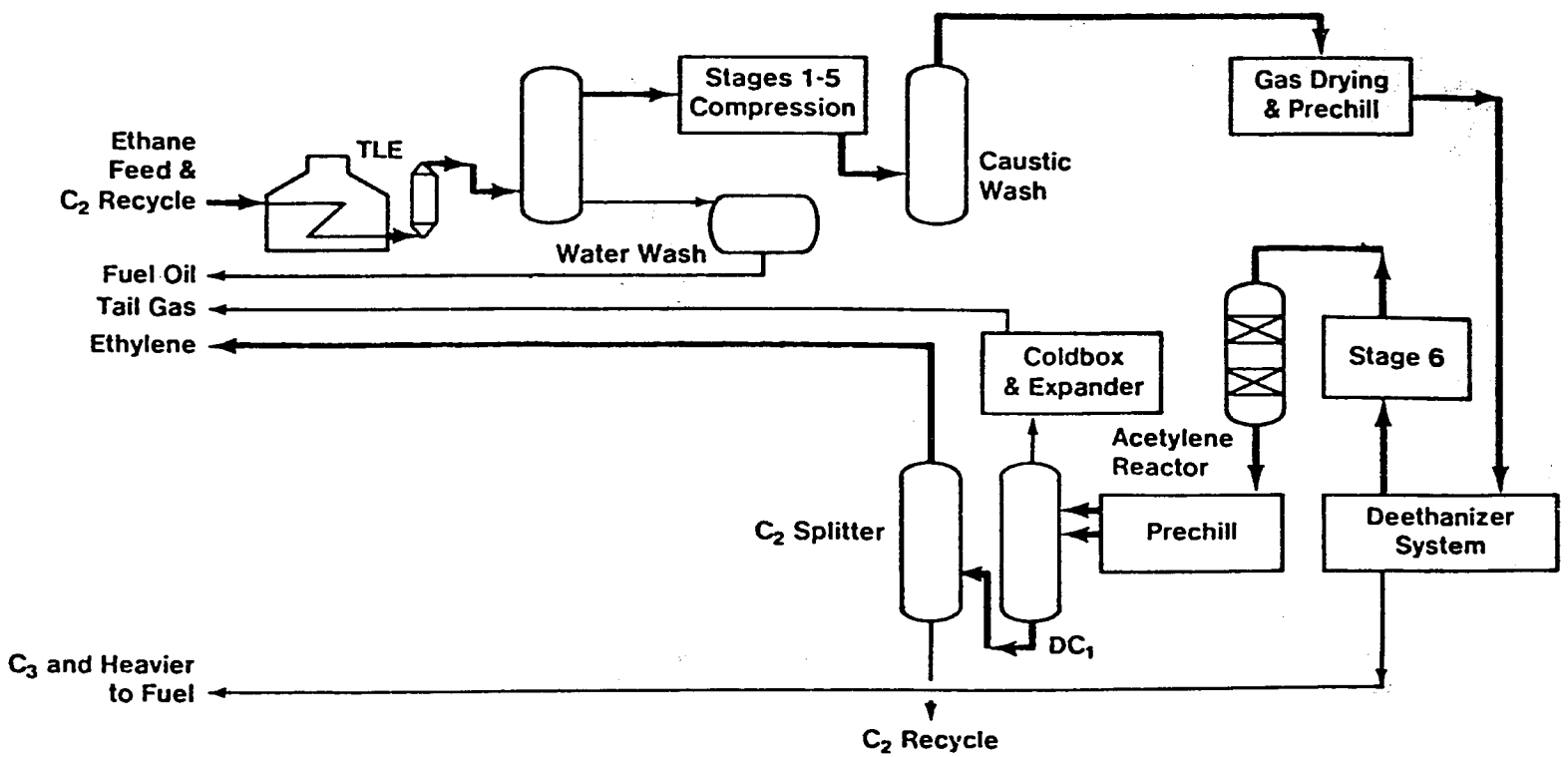
High level process heat via coal firing could be attractive if the technology is available and the differential between gas and coal prices is large enough. Furnaces for heat for pyrolysis for ethylene production (for example, Figure 6-1) and for catalytic steam reforming are large fuel users. Many other endothermic processes also have direct heat requirements that are currently met by firing natural gas.

Probably the most important long-term development for the U.S. chemical industry would be the expanded use of coal as a feedstock. Depending upon the chemical produced, economical coal gasification or liquefaction processes along with necessary auxiliary processes would be needed to use coal as a practical chemical feedstock. Coal is already being gasified in one plant in Tennessee to produce syngas and subsequently methanol and acetic anhydride. The development of a large scale coal-based syngas chemicals industry will depend on a large price differential between natural gas and coal. Additional technology development would be helpful to allow the economical gasification of low-rank coals to syngas. Also, development work is needed on syngas chemistry and catalysis if syngas-based products are to compete with ethylene-based products.

The full commercialization of fluidized bed combustion with sulfur capture would allow the economical use of coal in small and intermediate-size single boilers with emissions control. Industry representatives were unanimous in their opinions that fluidized bed combustion with sulfur capture is not yet fully commercial in spite of the operation of pioneer units. Their concern was with reliability of units in meeting sulfur emissions requirements. It will probably require one or even two commercial FBC units operating successfully in chemical plants to relieve this concern.

Figure 6-1

ETHANE CRACKING



Source: Hydrocarbon Processing, p. 84, March 1984

37x

Candidate Chemicals for Coal Use

There is no simple rule as to which types of chemical plants coal use is the most applicable. In general, high purchased fuels requirements indicate the potential need for increased coal usage. The use of purchased fuels and electricity (counted as 10,000 Btu/kWh) in the chemical industry decreased from 3,514 trillion Btu in 1980 to 2,814 trillion Btu in 1983 [1]. In the same time period the use of coal increased from 302 trillion Btu to 318 trillion Btu. Therefore, coal as a percentage of total purchased fuels and electricity increased from 8.6% to 11.3% in that three year period. It is noted that coal firing also generated much of the purchased electricity. A total of 53% of utility-generated electricity in the United States in 1983 was generated by coal firing.

At the time of this analysis the fuel use by segment of the chemical industry was available only through 1981 [3]. Even those data are incomplete to avoid revealing proprietary information about a single company. The incomplete data are listed in Table 6-3. The coal usage appears to be 9.3% of total fuels and electricity (10,000 Btu/kWh) purchased by the chemical industry.

The industry segments where coal appears to be underused are industrial inorganic chemicals, agricultural chemicals (primarily fertilizers), and perhaps industrial organic chemicals. In the absence of more precise data, the best assumption is that coal was especially underused in Gulf Coast plants at that time. It is believed that more coal could be used especially at ethylene plants and ammonia plants. Chemical complexes with a variety of petrochemicals produced are also good candidates for increased coal use. The use that should be easiest to justify economically is the cogeneration of steam and PURPA power. The use of coal to produce high level direct heat will require the development of new technology.

The widespread use of coal as a feedstock will require drastic increases in gas prices as well as new technology. The most likely new chemicals to be made from coal-derived syngas will be these with growing demand and with high yields from syngas. Chemicals made from syngas with a low hydrogen/carbon monoxide ratio will be favored, as is the case with acetic anhydride produced by Tennessee Eastman.

Interaction with the Oil Refining Industry

Many petrochemical plants are interdependent with oil refineries. Frequently, the petrochemical plant processes refinery gases or liquids to recover chemical products. In some cases a petrochemical plant and a refinery owned by the same company are integrated in a large complex. Those refinery/chemical complexes are obviously prime candidates for innovative fuel uses. SFA Pacific believes that those complexes will ultimately use coal for a substantial portion of their fuel needs. A case in point is the Exxon refinery/petrochemical plant as Baton Rouge, Louisiana. A major coal/cogeneration project at that complex is now deferred due to economics, but may be reactivated when oil and gas prices rise again.

The large scale penetration of methanol into the gasoline market would represent a major new opportunity for integration of petrochemical and refinery operations. However there appears to be little likelihood of such a development for at least 15 years because of poor economics at current oil prices. In the meantime, the accelerated push to remove lead from gasoline improves the prospects for chemical octane improvers.

Table 6-3

PURCHASED FUELS AND ELECTRICITY
IN THE CHEMICAL INDUSTRY, 1981

SIC Code	Product Group	Total Purchased Fuels & Electricity Trillions of Btu's	Coal and Coke Used, Trillions of Btu's
281	Industrial Inorganic Chemicals	958	65
282	Plastic Materials and Synthetics	558	114
283	Drugs	108	8
284	Soaps, Cleaners, and Toilet Goods	71	1[a]
2851	Paints and Allied Products	22	0
286	Industrial Organic Chemicals	1,241	111
287	Agricultural Chemicals	432	8[a]
289	Miscellaneous Chemicals	112	17
28	Total Chemical Industry	3,502	324

a) SFA Pacific estimate

Source: Reference [3], Purchased electricity calculated at 20,000 Btu/kWh

39x

The chemical and refining industries have many similarities in terms of types of processes and equipment employed. However, there are also many differences in terms of numbers of products, quantities of products, and plant design philosophy. Chemical companies also put more effort into product marketing than do oil refiners.

Issues Affecting Overall Growth and Fuel Use

The two major factors affecting the type and quantity of fuels used are growth of production and fuel conservation. Other important factors include environmental constraints, fuel and electricity prices, and changing competition in the industry.

The combination of slower industry growth and energy conservation has resulted in a sharp decline in overall fuel needs in the chemical industry. Consequently, a project to convert to coal is a retrofit which must be justified by cost savings. At current fuel prices that justification is difficult.

A major cause of the slow growth of the U.S. chemical industry is the loss of export markets to chemicals made from cheap foreign feedstocks. Imports of basic chemicals have likewise made significant inroads into the U.S. markets. Essentially no new capacity is being built at this time in the United States for basic chemicals such as ethylene, methanol, and ammonia. It is possible that a few new production units for these chemicals will be built in a few years as domestic demand increases and old plants are decommissioned. U.S.-made derivative chemicals can compete better than basic chemicals because of lesser energy content and superior American expertise in the production and marketing of these chemicals. Consequently, many companies have emphasized expansion in the "specialty chemical" production.

An additional cause of slower chemical growth is the slow growth or decline of U.S. "smokestack" industries, many of which are customers for chemical products. In addition, the great increase in value of the U.S. dollar vis-a-vis other currencies hurts the competitiveness of U.S. chemicals at home and abroad.

The Expanded Use of Coal in the Chemical Industry

Coal has made steady progress over the past few years in terms of fraction of total fuel used in the chemical industry. However, the actual increase in volume of sales to this industry has been small because of reduced overall fuel use. The retrofit investment required must be justified by cost savings achieved by using coal rather than the current fuel, oil or gas. This type of investment has been more difficult to justify since the OPEC oil price drop in 1983, along with the changed perception of future prices. It is likely, however, that coal-capable equipment will increasingly be specified in the future when new facilities are constructed.

Favorable Conditions for Coal Use

Favorable conditions for coal use include coal being much cheaper than gas and oil with the gap widening, only a moderate investment required, a high fuel requirement, and a growing demand for the chemical which is being made. These conditions are not all likely to apply at once.

The gap between coal and other fuel prices is as great or greater than it was a few years ago. However, at that time the gap was widening. Now the gap seems to be steady.

The investment in coal handling, storage, and combustion facilities can be considerable even if little special emissions control is required. In general, however, control of particulates and perhaps sulfur dioxide is needed. Ash disposal is a problem at some locations. Finally, a major investment is required if the boiler is not coal capable or is undersized when fired with coal.

A high fuel requirement in terms of product value is essential to justify the expense of conversion by fuel cost savings. A high avoided cost for electricity and a significant steam requirement may make the generation of PURPA electricity profitable. Finally, the importance of a growing market for the product is important in that it provides assurance that the investment will be profitable and it may mean no special retrofit investment.

The location of the proposed facility is also important. Proximity to a coal mine or to navigable water facility reduces the transportation cost for coal. A roomy location provides space for coal storage and ash disposal.

Uncertainties and Obstacles

The greatest uncertainty for coal use in the chemical industry is the relative price of oil and gas versus coal. Actually, it will always be the outlook for future relative prices that determines industry attitude toward coal. The outlook at any particular time is largely determined by existing trends in relative prices. In other words, nothing stampedes industry more toward coal than repeated price increases of oil and gas.

Coal has a special obstacle in the environmental concerns pertaining to its use. These concerns derive from emissions of the sulfur and ash contained in coal and the difficulty of controlling nitrogen oxides formed during coal combustion.

Government actions frequently cause uncertainty even when designed to encourage coal use. Stability of rules and regulations gives industry confidence that a good decision will not be upset by abrupt changes in policy. Clear and stable environmental regulations are particularly important. For example, the promulgation of New Source Performance Standards (NSPS) for industrial boilers was delayed for years. Only recently the EPA released the NSPS values for particulates and nitrogen oxides. The NSPS for sulfur dioxide is still pending.

Coal price appears to be of least concern at present. Coal supplies at reasonable cost are vast in the United States. No aspect of coal mining is currently a prospective cause of cost driven price increases as safety and reclamation were a decade ago. However, coal transportation costs continue to rise. Coal slurry pipeline enabling legislation would be helpful in increasing competition in coal transportation.

Industry Attitude

SFA Pacific personnel discussed prospects for coal usage in chemical plants with representatives of several companies. The views of these representatives, although diverging somewhat on degree and timing, nevertheless agreed that the economics of coal use today are considerably less favorable than only a few years ago. The key factors were seen to be the improved outlook for gas prices over the next decade and the requirement for higher investment for coal use than originally planned. The differential of gas prices over coal prices needed to justify coal projects was estimated by some of the industry representatives to be in the range of $3 to $6 million Btu. The current differential is typically only about $1 per million Btu.

4/x

Industry representatives in general did not believe that technology availability was the factor limiting coal use. All indicated that poor current economics was the limiting factor. SFA believes that renewed increases in oil and gas prices would result in the projection of larger coal/gas price differentials in the future and would again justify many projects.

Significant variation in views existed among the various personnel contacted. Some concentrated on the high capital costs needed for coal use, and others worried more about lower projections of gas prices. It was clear that some cost projections for coal use resulted in part from the company's conservative design philosophy. Also, it appeared that those contacted put considerable and perhaps excessive weight on the existing situation even when projecting economic factors ten or more years in the future.

The attitude of chemical industry personnel toward coal use is straightforward. They are for it if it is economical; they are opposed if it is uneconomical. Chemical industry personnel state that plant management is very receptive to coal use with no special "it can't be done" concerns. Industry personnel do express concern over changing economic conditions over the life of an investment. It also appeared that occasionally conservative design philosophy can make coal conversion unduly expensive. Naturally, the correct design philosophy is debatable with one engineer's prudent design being another engineer's "gold plated" design. Design philosophy is especially crucial with respect to environmental control design, already subject to considerable variation.

Industry personnel tend toward cautious projections of the future with great emphasis on currently existing conditions. This is understandable since their own jobs and frequently their own investments are on the line. Nevertheless, their current views tend toward flat oil prices for a long time. They all seem to remember the 1970s well, though, and are keeping their powder dry for renewed "oil shocks." Fortunately, many decisions on coal usage can be implemented in a year or two and are not subject to long lead times. This is particularly true for adding coal handling facilities to coal-capable boilers. Even new boilers can be installed in this time frame if there are no special environmental problems.

Utilization Time Frames

The most reliable method of forecasting increased coal usage is by tying it to oil/gas prices. Some increase will continue even at today's prices as coal capable boilers are increasingly fired with coal. Today, the average difference between delivered gas and coal prices is barely $1 per million Btu. Some industry personnel expressed the opinion that at least $3 per million Btu difference was necessary to justify a new coal project. Others believed that at least double that difference was necessary. Perhaps these views mean that if the gas price is $5 and increasing with coal at $2, then additional increases are likely that will result in a profitable project. At worst if the $3 difference persists the return on the project investment will be modest but not disastrous.

The 1983 DOE "low" projection of natural gas price for industrial use had it exceeding $4/million Btu in 1983. Clearly, it did not and now stands at about $3/million Btu. The industrial gas price was also projected to exceed $5 in 1990 (1983 dollars). In fact, it now appears likely to take 10 years or more for the current natural gas surplus to be worked off and gas prices to reach $5/million Btu (1983 dollars). The 1995 time frame appears reasonable for renewed industrial emphasis on coal. This projection is highly speculative and could change considerably in either direction. Still a ten-year time frame for such a change to occur is comfortably long for gas surplus reduction.

At the same time that coal use is increasing one must expect energy conservation to continue until economic equilibrium is reached at the current price. It is seen that energy conservation is driven mostly by the high oil and gas prices that drive increased coal usage.

By 1990 coal usage is likely to continue to increase at today's prices to about 16% of total purchased energy (primary energy equivalent) with total annual usage dropping to about 2,400 trillion Btu. Therefore, total coal use would be about 380 trillion Btu/year. After the gas price reaches $5, coal use would be expected to rise to 500 trillion Btu/year with total chemical industry energy usage remaining at about 2,400 trillion Btu/year.

Most Attractive R&D Candidates for the Chemical Industry

Chemical industry representatives expressed little enthusiasm for coal usage R&D except for long-range research (coal structure, revolutionary coal conversion techniques). It does appear that a few areas of R&D could be promising for the medium term (about 15 years). Specifically, fluidized bed combustion with sulfur capture could provide a flexible and economic method of burning coal with environmental acceptability to provide high level process heat. Also promising would be the perfection of techniques for firing micronized coal or coal slurry for high level process heat. A wide range of emission control techniques also need to be made available to satisfy various requirements for control of sulfur dioxides, nitrogen oxides, and particulates emitted in the burning of coal.

Also useful would be the development of coal gasification-to-syngas techniques for low rank coal, complementary to the Texaco process for high-rank coal. A long range goal remains the development of coal liquefaction as a substitute source of liquid hydrocarbons.

The development and commercialization of syngas chemistry and catalysis analogous to that which has been developed based on ethylene could result in long-term fundamental changes in the industry. Syngas-based routes to chemical products would allow coal (or methane in natural gas) to be used widely as a feedstock. The economics are not favorable today for most such products, but if petroleum and natural gas liquids rise greatly in price, syngas-based chemicals could become competitive. A wide variety of syngas chemicals and routes have already been researched [4]. Ultimate possibilities seem to be limited only by numerous alternatives offered by organic chemistry. Other promising R&D work on syngas would be the development of economical methods of carbon monoxide/hydrogen separation, acid gas removal, and sulfur recovery.

References

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3. Department of Commerce, MC82-S-4 (Part 1), "Fuels and Electric Energy Consumed, Part 1, Industry Groups and Industries," issued June 1983.

4. A. Aquilo, J. S. Alder, D. N. Freeman, and R. J. H. Voorhoeve, "Focus on C_1 Chemistry," Hydrocarbon Processing, p. 57, March 1983.

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SECTION 7

OIL REFINING INDUSTRY ASSESSMENT

Conclusions

The refining industry is a mature industry. In contrast to the integrated steel industry, it is highly modern and efficient by world standards. Growth will be moderate and gradual due to price induced conservation both by the refiner and by the consumer of the end-products. Modifications to refinery structure will be dictated principally by changes in product market requirements (increased lighter products and unleaded gasoline, together with decreased heavy fuel oil), heavier and dirtier crude oil feeds, and local environmental requirements. Coal use in refineries will be slow to develop.

A variety of conclusions and observations come from this work -- some fairly obvious and some not so obvious. The most pertinent are presented as follows:

- o In the range of 7 to 11 percent of the barrel of oil processed in a refinery is consumed to meet the energy needs of the refinery. The initial markets for coal in refining will be in helping to meet this 7-11 percent loss rather than in the direct replacement of liquids.

- o Petroleum coke will lead the way for the eventual use of coal in refineries. Substantial quantities of fuel-grade coke (high sulfur) are now available at prices below coal prices and the amount will increase as heavier crude oils are used and coking capacity is increased.

- o Near-term (to 1995) utilization of coal will be in conventional fired boilers (primarily pulverized fuel suspension fired systems) for steam and power. However, coming into use during the period will be atmospheric fluidized bed combustion for steam production.

- o Longer-term (beyond 1995) utilization technologies will most likely include first:
  - coal gasification for production of fuel gas and power

  and later:
  - coal gasification for production of synthesis gas with subsequent production of liquid products
  - production of BTX by hydropyrolysis
  - co-refining of coal with petroleum residues may eventually be used if a reasonable level of synergism can be developed

- o Major uncertainties regarding the future use of coal in refining are:
  - world oil prices
  - natural gas prices
  - changes in refinery energy requirements
  - changes in refined products markets
  - environmental requirements
  - taxation

o Major obstacles to the future use of coal in refining are:

- depressed industry growth
- lack of experience using solid fuels
- lagging development of new coal utilization technologies
- low industry profitability

o Major favorable conditions for using coal will be:

- experience with producing and using coke
- attractive cogeneration options
- proximity to both rail and barge transportation

o Best areas for research and development appear to be:

- technology for direct firing of coal for radiant heat
- fluidized bed combustion for process heat
- direct conversion of synthesis gas to gasoline and middle distillates
- high yield production of higher alcohols directly from synthesis gas
- hydropyrolysis for production of BTX
- co-processing of petroleum residues

o The petroleum industry will likely maintain a robust research and development capability

o Coal will almost certainly work its way into oil refining. The main uncertainty is when.

Industry Definition

The oil refining industry is defined as that part of the petroleum industry involved only in refining raw crude oil into refined marketable products. The range of products includes finished transportation fuels, finished fuels for stationary systems, petrochemical feedstocks, and a volumetrically small but important variety of specialty products and by-products such as lube oils, waxes, asphalt, organic acids, and elemental sulfur. In terms of energy content as a fraction of the crude oil barrel fed to the refinery the most important products are:

o Gasoline (all types)
o Jet fuel
o Diesel
o Kerosene and furnace oils
o Residual fuel oil
o Olefins (ethylene, propylene, butenes)
o Aromatics (benzene, toluene, xylenes)
o Liquefied petroleum gas (LPG - mainly propane and butane)
o Coke (all types)

45K

Technically, for purposes of this analysis, the refining industry is generally defined by the Bureau of the Census SIC 2911. However, care must be exercised in using the Bureau of Census energy data since some internally generated sources of fuel and energy are not included in the data published in the Annual Survey of Manufacturers (e.g., coke consumed in catalytic cracking).

Specifically not included in the analysis of this report is energy consumed in producing crude oil or transporting it to the refinery gate.

Characteristics of the U.S. Refining Industry

The U.S. oil refining industry is extremely mature. Basically, the industry experienced its infancy during the last four decades of the nineteenth century. This was followed by the period of relentless growth between 1900 and the early 1970s. This growth in oil refining was made possible on the one hand by the finding of large reserves of cheap-to-produce domestic oil, and on the other hand by the development and widespread use of the automobile and other modes of transportation, together with vigorous widespread industrial expansion facilitated by cheap energy.

The dramatic oil price increases imposed by OPEC in concert with the Arab embargo period of 1973-74 and the Iranian disruptions of the late 1970s caused drastic changes in the use of refined products in the U.S. The net result was a peaking in crude oil throughput to refineries in the late 1970s as illustrated in Table 7-1.

Table 7-1

U.S. REFINERY CAPACITY AND THROUGHPUT
(operable refineries)

Year	Crude Oil Feed million b/d	Total Throughput (2) million b/d	Refining Capacity (1) million b/d	Utilization %
1950	5.7	6.0	6.2	97
1960	8.1	8.6	9.8	87
1970	10.9	11.8	12.0	98
1973	12.4	13.4	13.7	98
1978	14.7	15.5	17.0	91
1980	13.5	14.0	18.0	78
1983	11.7	12.6	16.9	75
1984	Ca.11.0	Ca.12.5	Ca.16.5	Ca.75

Source: References 1, 2
Values for 1984 are SFA estimates

1) Crude distillation capacity
2) Crude oil plus natural gas plant liquids and some unfinished fuels

U.S. refinery throughput declined between 1978 and 1983 and is now generally forecasted to grow modestly over the next 25 years. The latest published DOE EIA mid-price world oil forecast [3] projects an increase in total U.S. petroleum end-use consumption to increase to 17.4 million b/d by 1995 from 15.2 million b/d in 1983 (see Appendix B for DOE EIA low, mid, and high world oil price projections together with the resultant Petroleum Supply and Disposition projections).

A related obvious result of the decline in refinery throughput in the 1970s together with a long-term continued conservation effort was first the abandonment of planned new refinery construction, second, the lack of plans for any new refinery construction, and finally the shutting down of marginal refineries. An example of the first was the cancellation in the early 1970s of Shell Oil's long-planned mid-Atlantic coast refinery. The second point is illustrated by the fact that the last new grass roots U.S. refinery came on stream in the mid-1970s. The final point is illustrated in Table 7-2, which shows the number of operating refineries in the U.S. by year.

The number of refineries reached 324 in 1981 and has steeply declined due principally to the closure of many smaller and less flexible refineries. The 247 refineries operable in January 1984 was the lowest number recorded since the Bureau of Mines began data collection in 1918. The highest number was 632 in 1936. The decline between 1936 and the late 1940s was due principally to the shutdown of small uneconomic refineries. The decline since 1981 in the number of refineries has been due to a complex variety of factors: reduced throughput induced by consumer related energy conservation, elimination of crude oil price controls, the lead phase-out, effects of a prolonged recession, and increasing importation of refined products. The U.S. refinery industry is now consolidating rather than expanding. Continued consolidation of the industry through mergers will also likely result in additional refinery shutdowns, although the shakeout of less-efficient refineries will likely slow down.

Table 7-2

U.S. REFINERIES

Year	Number
1936	632
1950	320
1960	290
1970	262
1975	262
1980(1)	319
1981(1)	324
1982(1)	301
1983(1)	258
1984(1)	247

Source: References 1, 2

1) January 1

The character of the refining industry is undergoing a slow and long-term change caused by factors other than conservation, reduced throughput and reduced product demand. The required product mix, the declining quality of available crudes, and the phaseout of lead are changing refinery requirements and are resulting in modifications to existing refineries even though no new refineries are being built. Refinery capacity, as measured by crude distillation capacity, has declined in recent years; however, in a variety of refineries downstream capacity has been modified to permit use of heavier and dirtier crude oils. Thus, overall refinery flexibility has been improved, and this trend will continue to some degree although the trend had slowed considerably by early 1985 due to the resultant narrowing in the quality-related price differential between crude oils. A narrowing in the price differential between light (higher quality) crudes and heavy (lower quality) crudes reduces the profitability of investments in bottom-of-the-barrel upgrading facilities.

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In contrast to the steel industry, which is undergoing a rather rapid major transition, and the chemical industry, which is broadly diverse and dynamic in nature, the refining industry is gradually changing in terms of mix of technology to meet the gradual changes in feedstock characteristics and end market requirements. The gradually decreasing quality of available crude oils on the one hand and the phasing out of lead octane enhancers in gasoline on the other are examples of these changes. Moreover, the overall refinery yield structure will change as well if gasoline production continues to decline as projected [3] (see mid-price projection in Appendix B). U.S. gasoline production reached a peak in 1978 at 7.4 million b/d and then dropped to 6.6 million b/d by 1983. Gasoline production is forecast to decline further to about 6 million b/d by 1995 (mid-price projection) [3].

Another problem that may further disrupt refinery balance is the prospect of increased imports of refined products. Countries with low-cost oil production and control of refining capacity are in a good position to move low-priced refined products into world markets. Such products could easily be priced to undercut the cost of products from domestic refining operations in the more industrialized countries.

Traditionally, the oil industry has done most of its own research and development in the evolution of new technology. This situation will continue in the foreseeable future. The bulk of refining research and development is conducted by the integrated oil companies. It is anticipated that the oil industry will continue to be high cash flow operation, in large part due to oil and gas production revenues, and will continue to be able to fund its own refining-related research and development. A bad financial year in an integrated U.S. oil company is a relative thing compared to the pervasive financial problems of the U.S. steel industry.

U.S. refinery feedstock requirements are forecast [3] to be increasingly supplied by imports. This situation will likely be a driving force for considering alternatives for refinery fuel and power requirements where such alternatives would free up "hydrogen rich" streams for production of liquid products.

The refining industry in 1983 used 2.53 quads of fuel and electric power in the course of refining 11.7 million b/d (24.8 quads) of crude oil. This fuel and power requirement is exceeded only by the chemical industry.

Oil Refinery Structure and Technology

The discussion of oil refining technology presented here will be necessarily brief; detailed information and background is available in a variety of reference books on the subject. However, sufficient discussion is included as pertinent in order to begin an analysis of where coal might logically be used in refining.

Figure 7-1 is a simplified flow diagram of a somewhat "typical" U.S. refinery. Simply stated, the refinery separates and/or converts components in the crude oil, producing a variety of end product fuels and other products. The most important in terms of volume and revenue are gasoline, middle distillates (including kerosene, jet fuel, diesel, distillate fuel oil), and residual fuel oil. Other marketable products include asphalt, lube oils, waxes, petroleum coke, and liquefied petroleum gases (LPG). Another important refinery product is fuel gas but this is used almost entirely internally for refinery fuel.

These factors are all discussed in varying degrees in other parts of the report but are addressed together in this section of the report to provide perspective.

World Oil Prices (Price Induced Conservation)

As mentioned earlier, the most pronounced effect on petroleum consumption and refinery fuel use patterns will be made by the price level of world oil. This was the unanimous opinion of the refining industry personnel SFA Pacific discussed this project with. Existing excess capacity together with the prospect of oil prices stabilizing throughout the 1980s at or near those of early 1985 will effectively stifle most refinery investment other than that needed to meet mandated environmental regulations and fuel specifications.

The higher oil and natural gas prices and higher refinery throughput forecasted for the 1990s and later will slowly bring on new investment for expanded capacity and flexibility for crude choice and refinery fuel use.

Oil prices at current and higher levels will ensure that refinery conservation efforts continue. Refiners indicate that the roughly 25 percent reduction in energy use per barrel between 1972 and 1983 may be increased to the range of 40 percent sometime in the 1990s. There continues to be a strong industry commitment to conservation in spite of the recent lower oil prices.

Higher oil and natural gas prices will likely lead to natural gas consumption at about current levels [7] or lower to the year 2000. At the same time consumption of coke should increase significantly. Petroleum coke production (marketable) was 17.9 million tons in 1983 [2] and SFA Pacific projects that this will increase to the range of 20-22 million by the mid-to-late 1990s. In 1983 about 38% of coke production contained less than 2% sulfur, 14% was in the range of 2-3% sulfur and 48% was greater than 3%. Most of the petroleum coke entering fuel markets is above three percent sulfur. Future additional supplies of coke will be principally greater than 3% and will be used mainly for fuel. Table 7-6 shows end markets for U.S. green coke.

Table 7-6

MARKETS FOR U.S. GREEN PETROLEUM COKE - 1983

Market	Percent of Production
Steel	32
Calcined Coke	28
Cement	25
Electric Utilities	8
Other	7
	100

Source: Reference 8

About 32% of the green coke produced in 1983 was used domestically. About 20% of total production was exported to Japan, 42% to Europe, and the remainder to a variety of countries. About 12 million tons of petroleum coke was exported in 1983. Very little coke is currently used in the U.S. as refinery fuel. However, the situation is beginning to change as refiners build coke firing capabilities.

Changing Feedstock Quality

The gradually declining quality of crude oil will lead both to increased hydrogen requirements and increased coke production. Furthermore, both factors will work gradually in the direction of changing refinery fuel consumption patterns. Hydrogen manufacture is highly energy intensive. Coking operations are also, but to a lesser degree. Both will impose an additional energy load on the refinery. Coke produced will be available for refinery fuel.

Changes in Refined Products Markets

The principal characteristics of refined product markets projected over the next 15 to 20 years appear to be a flat or slightly reduced demand for gasoline and residual fuel oil, somewhat increasing demand for middle distillates, and the phasing out of leaded gasoline (and thus increasing refinery operating severity). Some additional hydrogen will be available from new catalytic reforming capacity. However, the net effect will be increased hydrogen requirements (in addition to those necessitated by lower crude quality) and increased refinery energy requirements that will likely offset much of the anticipated energy savings due to continued conservation efforts.

Environmental Requirements

Environmental concern has mandated the reduction and eventual elimination of lead in gasoline. As discussed earlier, this results in high refinery operation severity to meet octane requirements in the absence of lead octane enhancers. This in turn leads to increased refinery energy requirements.

Since there will be little or no new refinery construction in the U.S. in the foreseeable future, emission of sulfur and nitrogen oxides will relate principally to new units built in existing refineries and the potential for more stringent regulations for existing units. So called "acid rain" legislation would likely have the largest effect on existing refineries. Tighter emissions regulations for sulfur and nitrogen oxides would likely lead to reduced energy efficiency as well as additional capital requirements for new burners in retrofits.

Environmental regulations will encourage the continued use of clean fuels, such as refinery fuel gas and natural gas. However, options such as fluidized bed combustion and coke or coal gasification will be increasingly considered according to SFA's observation of industry opinion. The increased use of lower quality crude oils will also lead to increased sulfur recovery requirements.

Taxation

Some tax considerations will continue to affect refinery investment, fuel use, and refined products mix.

Investment tax credits (if continued) will encourage all types of investment and will probably be one of the most important incentives for investments related to energy conservation.

The single largest process energy load for the Alliance refinery is catalytic cracking; however, as mentioned earlier this unit meets much of its own energy requirements by burning residual coke deposited on the catalyst. Next are crude distillation operations and catalytic reforming which require high level radiant heat. Other than the utility plant, the other major refinery unit energy consumers either use mainly process steam or electric power, at least for the refinery case example discussed here. The use of a hydrocracker would usually necessitate an additional source of hydrogen that, depending on duty, could be a large high-level consumer of fuel.

Thus far, the discussion has addressed potential refinery applications of coal as a fuel supplement or replacement. This includes direct firing for power generation and for production of process steam, direct firing for high-level process heat, and gasification for fuel gas production. The other major potential or candidate use for coal is as a refinery feedstock. The two principal routes to coal-based liquids are indirect production through coal gasification for producing synthesis gas or hydrogen, or direct production via hydroliquefaction or some type of pyrolysis.

Indirect production or supplementation of refinery feedstocks based on synthesis gas will likely include the following:

- methanol
- methyl tertiary butyl ether (MTBE)
- gasoline or mid-distillates
- higher alcohols (C_2 - C_4 range)
- hydrogen

Methanol can be used in motor vehicles either blended with gasoline or as a straight (or nearly pure) fuel. Methanol is routinely produced world-wide by well-developed commercial technology. Furthermore, methanol in the presence of butanols is currently being blended into unleaded gasoline in the U.S. in limited circumstances. Methanol is also being tested as a straight fuel on a large scale in California with funding by the state. While its use is quite limited at this time, large quantities of methanol could potentially be used either by blending into gasoline or as a gasoline replacement fuel.

MTBE is an octane enhancer currently being used in the U.S. and elsewhere as a gasoline blending component (5 to 10 percent normally) in much the same way that toluene is used, and, in fact, MTBE competes directly with toluene on an economic octane barrel basis. MTBE is produced from methanol (produced from synthesis gas) and isobutylene (available from ethylene crackers and catalytic cracking). SFA Pacific estimates U.S. production of MTBE in 1984 at approximately 750,000 tons (14,000 b/d).

A great deal of research and development work has been done over the past few years in producing gasoline or middle distillates from synthesis gas either directly or via methanol. The production of gasoline via methanol (Mobil's MTG process) is by far the most advanced. A 13,000 b/d commercial plant is under construction and due to start-up in mid-1985 in New Zealand based on synthesis gas produced from natural gas using Mobil's fixed-bed MTG technology. In addition, a 100 b/d pilot plant has been operated for the past two years in West Germany using a fluid-bed version of Mobil's MTG process. Other widespread research work aimed at producing middle distillates from synthesis gas or methanol is not as far advanced.

Production of higher alcohols is also useful for co-solvent use with methanol. Several companies have announced they have processes approaching commercial application, e.g., Snamprogetti, IFP, Lurgi, and Dow Chemical. All of these processes are based on synthesis gas, which could be produced from coal.

Hydrogen requirements in refining are substantial; SFA Pacific estimates that there is installed hydrogen reforming plant capacity in the U.S. of about 2,000 MMscf/d. In addition, about twice that amount of hydrogen is available from catalytic reforming (gasoline production). This hydrogen is consumed in a variety of hydroprocesses as shown in Table 7-5 together with estimated consumption per barrel for each type:

Table 7-5

TYPICAL REFINERY UNIT HYDROGEN CONSUMPTION

Process	scf/bbl
Naphtha HDS	10-20
Distillate Hydrotreating	50-250
Heavy Oil Hydrotreating	300-750
Residuum Hydrotreating	650-1600
Gas Oil/Resid. Hydrocracking	1500-3000

Source: SFA Pacific, Inc.

Refinery hydrogen consumption will increase as more heavy and dirty crudes are processed in the U.S. Hydrogen production via coal gasification for use in hydroprocessing refinery streams is one variation of synthesis gas-based indirect liquefaction that potentially improves refinery liquid yield.

Development of processes for the production of liquids from coal has proceeded for several years up to the level of large pilot plants. The EDS, H-Coal and SRC processes are three prominent examples based on hydroprocessing. Co-processing of coal and petroleum residues by hydroprocessing is a variation of such technology specifically aimed at a refinery setting. Several pyrolysis processes have also been under development but at smaller scale than the hydroprocessing systems mentioned.

Section 5 of this report discusses coal liquefaction and gasification technology in more detail.

Issues Affecting Overall Growth and Fuel Use

As indicated in the Department of Energy forecast (mid-price forecast of Reference 1) as shown in Table B-1, U.S. refinery throughput is projected to remain fairly flat through the 1980s and then to increase in the range of 5 percent per year in the 1990s.

Overall growth and fuel use in the U.S. refining industry will be influenced by a variety of factors. Five major factors are:

- world oil prices (price induced conservation)
- changes in feedstock quality
- changes in refined products markets
- environmental requirements
- taxation

- o Direct firing for process heat

- o Gasification for production of fuel gas

Feedstock Source

- o Gasification for synthesis gas (followed by production of liquid fuels) and hydrogen

- o Direct liquefaction for supplemental liquids production

Coal will likely be used first in central power and steam generation within refineries. The latter four applications mentioned will likely come later and not necessarily in the order listed. Therefore, the most important early use of coal will be in supplementing refinery fuel and power uses.

In 1983 domestic U.S. refineries processed 11.7 million barrels/day of crude oil (24.8 quads). At the same time refinery fuel and power consumption was 2.53 quads. Table 7-3 illustrates U.S. refinery energy consumption in 1983 by type. Therefore, refinery consumption of energy is approximately 600,000 Btu/barrel of crude oil. throughput, and for the most part ranges from 7 to 11 percent of throughput depending on refinery complexity and crude type. Price induced conservation efforts brought on by the oil price increases of the 1970s reduced average per barrel energy consumption 25.6 percent [5] by 1983 from the reference year of 1972. This figure is adjusted for the higher severity operations and requirements for 1983 versus 1972. If no adjustments are made then the reduction is 9.6 percent.

From Table 7-3 it is seen that approximately two thirds of U.S. refinery energy is derived from refinery fuel gas and natural gas. It will be in this area of consumption that coal will likely have the earliest potential. Natural gas of course could be replaced first since it is a "fuel of choice." Refinery gas is produced in the refinery as a consequence of refinery operations and currently has little use other than for fuel. Coal could likely first replace both natural gas and refinery gas where they are used for generating power and raising steam. The refinery gas displaced would then be available for production of hydrogen or synthesis gas which could be used in turn for production of liquid fuels. However, the traditional lynch-pin of the refinery fuel system is fuel gas and modification of its use will not come about quickly or simply. Another fairly large source of refinery energy is what is termed catalyst coke (16.5 percent). This is coke that is burned off of the catalyst during regeneration in catalytic cracking. The combustion energy generated provides the necessary heat for the endothermic cracking reactions together with providing surplus energy for generation of steam and power.

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Table 7-3

U.S. REFINERY ENERGY CONSUMPTION - 1983

	Consumption	
	10^{12} Btu	%
Refinery Gas	1,086.9	42.9
Natural Gas	565.1	22.4
Catalyst Coke	419.3	16.5
Residual Fuel Oil	134.2	5.3
LPG & Propane	31.2	1.2
Marketable Coke	13.7	0.5
Distillate Fuel Oil	4.5	0.2
Other Liquids	6.2	0.2
Coal	6.5	0.3
Purchased Electric Power	244.2	9.6
Purchased Steam	22.8	0.9
	2,534.6	100.0

Source: Developed from References 2 and 5

The example energy use profile for a modern U.S. refinery is shown in Table 7-4. This is presented for the Gulf Oil refinery* located in Alliance, Louisiana. While no specific refinery is "typical" this energy profile illustrates roughly where energy is used in a modern U.S. refinery. There are several differences between the Alliance refinery and the typical U.S. refinery illustrated in Figure 7-1. Probably the most energy intensive difference is that the Alliance refinery has no hydrocracker.

Table 7-4

GULF ALLIANCE REFINERY ENERGY PROFILE
ENERGY DISTRIBUTION BY UNITS

(Thousand Btu/bbl of oil charged to refinery)

	Energy Input to Units	
Catalytic Cracking	133	(24%)
Atm. and Vac. Dist.	90	(16%)
Catalytic Reforming	60	(11%)
Alkylation	52	(9%)
CO Boiler & Utilities	52	(9%)
Offsites	43	(8%)
Aromatics Extraction	31	(6%)
Gas Oil HDS	19	(3%)
Naphtha HDS	16	(3%)
Delayed Coking	16	(3%)
Saturate Gas Plant	13	(2%)
Hydro-dealkylation	11	(2%)
Jet Fuel HDS	11	(2%)
Sulfur Plant	7	(1%)
Miscellaneous	7	(1%)
	560	100%

Source: Adapted from Reference 6
Base operating period 9/26/77 - 10/6/77 at 214,600 b/d feed (crude, isobutane and toluene)

* Purchased in 1984 by Standard Oil of Ohio following Chevron's purchase of Gulf Oil Company.

- The outlook is good for application of both fluid bed combustion and slagging combustion.

- Oil shale looks like a cheaper source of refinery liquids than coal.

- Gasoline from coal-based methanol does not appear practical earlier than the year 2000.

- An excellent area of research is the production of transportation fuel range liquids directly from synthesis gas.

- "Coal does not flow through pipes very well" and therefore gasification for fuel gas looks good long-term (at least 10 years away)

Utilization Time Frames

Projecting time frames for utilization of conventional and advanced technology is always a difficult thing. This is especially so for coal since there is almost no coal used in the refining industry -- even in conventional combustion equipment. As pointed out earlier, the two factors of (1) little or no refinery growth and (2) stable oil and natural gas prices will stifle the use of coal over the near-term (1985-1995). If as projected, oil prices began to increase in real terms again in the early 1990s, and there is sustained growth in refinery throughput, then use of coal will be viewed more seriously by the oil refining industry.

The following coal based technologies are considered in this projection for refinery use:

- conventional combustion
- advanced combustion
- gasification
- coal-based synthesis gas products
- direct liquefaction

Conventional combustion. Coal fired conventional combustion is now apparently used nationally to the extent of only about 300,000 tons/yr, all in PADD 1. To SFA's knowledge no additional conventional coal fired facilities are planned in the near future for refinery sites. However, as discussed earlier, some retrofitting and new construction is underway for coke-fired steam production. SFA Pacific sees little coal being used as long as fuel-grade coke is available nearby. It is unlikely there will be more than limited new coal firing (of any kind) in conventional refineries before 1990 -- and probably not before 1995. By then it is likely that fluidized bed combustion will be chosen over conventional pulverized or stoker systems, because of better fuel flexibility.

Advanced combustion. For this discussion we include fluidized bed combustion and two-stage slagging combustion. The outlook is good for commercial application of both technologies, especially atmospheric fluidized bed combustion.

Atmospheric fluidized bed combustion is now being commercialized in large scale commercial applications. With this technology it is now more a matter of accumulating commercial experience in order to be accepted by the refining industry as technically and commercially proven. In October 1984 Sohio started up

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a small demonstration fluidized bed unit at its Lima, Ohio refinery. The system is a Keeler/Dorr-Oliver bubbling bed unit of 70,000 lb/hr steam capacity. The system is designed to operate on coal or coke and was starting up on coal. Quaker State Oil Refining Corp. is replacing three existing gas/oil fired boilers at its refinery in Newell, West Virginia with two of the same type of systems. Each system is rated at 120,000 lb/hr steam. The Quaker State units will be operated on coal with start-up planned for mid-1985. Flexibility for use of both coke and coal or other heavy fuels will be a positive factor in commercial applications of fluidized bed combustion. The projected time frame for utilization in refineries is the same as for conventional combustion.

Two-stage slagging combustion is still a developmental technology which must be commercially demonstrated before refiners will consider using it. It is unlikely to be used before the 1995-2000 period.

Gasification. The most likely first use in a refinery would be supplemental production of fuel gas using coke initially and then coal. High temperature slagging systems will likely be favored for solids with low reactivity such as petroleum coke. SFA Pacific projects that coal gasification will not begin to appear until the time frame 1995-2000. Natural gas and fuel gas prices must be significantly higher than current levels in order to justify coal gasification for a refinery setting, although there will be specific cogeneration opportunities.

A forerunner of coal gasification in refineries is the Flexicoking process of Exxon Research and Engineering Co. Flexicoking is basically fluidized bed coking with fluidized bed coke gasification in a separate vessel integrated into the overall design. The first U.S. application of this technology is a 22,000 b/d unit in Shell Oil's Martinez, California refinery that started up in 1983. A second unit has since been announced for construction at Exxon USA's Baytown, Texas refinery.

Coal-based synthesis gas products. Synthesis gas products considered here for a refinery setting are light transportation fuels and octane enhancers, e.g., methanol, gasoline, diesel/mid-distillates, and higher alcohols.

Methanol production from synthesis gas is already widely commercialized. In addition, there are several processes for producing methanol together with high concentrations of C_2 to C_4 alcohols. Furthermore, low-priced methanol based on cheap natural gas is now being used in limited quantities in low-level gasoline blends. Some of Tennessee Eastman's coal-based methanol has also been used in this way. The production of gasoline from methanol will become a commercial reality this year when the New Zealand MTG plant comes on stream. Research and development work continues for the production of diesel and mid-distillates both from methanol and directly from synthesis gas.

The outlook for all of these synthesis gas-based fuels (whether from natural gas or coal) is muddled even more than other coal-based fuels. On the one hand the price of natural gas must increase significantly in the future for coal to compete. On the other hand it is difficult to foresee what choice will be made between methanol and gasoline-from-methanol when supplemental supplies of automobile fuel are again needed. In view of the current perceptions it is hard to see any of these light fuels produced from coal based synthesis gas before the year 2000.

Direct liquefaction. Several hydroliquefaction processes have advanced to a significant stage of development. Additional large scale pilot development is likely necessary before a commercial venture will come about. SFA Pacific does not see commercial application of direct coal liquefaction earlier than the

the use of coal relative to "easy-to-handle" gases and liquids. The handling of a solid fuel for refinery use is not something that many refiners are familiar with. The attitude probably reflects itself quantitatively in the differential cost estimated when comparisons are made between using coal versus gas and liquid fuels. Refinery use of petroleum coke will be a first step toward getting refinery personnel used to using a solid fuel and also will lead to refined estimates of differential costs for using competitive fuels.

Commercial coal utilization technology currently applicable and available to the refining industry is basically restricted to conventional combustion systems. For large industrial boiler use this is mainly pulverized fuel boilers. High pressure coal gasification technology is now commercially demonstrated (Texaco); however, it is unlikely that any coal will be gasified in refining as long as there is fuel-grade coke available nearby.

The development of new technologies opens up new areas of application and is an important factor in bringing coal into refineries. Prominent examples are fluidized-bed combustion for highly flexible solid-fuel (including coke) combustion operation, and slagging combustion for radiant heat duty directly from coal.

Fluidized-bed combustion may be an economical way to replace radiant heat sources in heating refinery oil streams. The process fluid could be heated in the tubes of the coal-fired FBC rather than in radiant furnaces fired by gas or oil. Heat transfer in the fluidized bed system is quite good. However, the principal problem is that a new FBC heater installation will be required to replace the existing radiant heater. The use of a staged slagging combustion offers the potential of retrofitting existing refinery heaters. This will be an important factor in an industry facing little growth over the next 15 to 20 years. However, sulfur oxide and NOx emissions will still be an issue with staged slagging combustion.

The prospects for use of CWM in process heaters will depend on development of an economical procedure for reducing ash to low levels, certainly less than 0.5 wt.%. Deashing will not largely effect sulfur oxides or NOx emissions, and their control must be handled separately by some mixture of low-sulfur coal, combustion modifications and FGD.

Low oil industry profitability will tend to discourage investments in either new coal utilization or retrofit applications, i.e., use of liquid and gaseous fuels will tend to continue. In periods of poor profitability, new investment, if any, tends to be in new areas that will generate revenue. Investment in cost saving projects, such as fuel switching, certainly will be done if the economics meet individual company "hurdle" requirements; however, when cost differences alone are not large, then new business revenue generation activities will generally win out.

Industry Attitude

In the course of this work it was critical to meet with representatives of the refining industry both to hear their perceptions on how coal might enter the refinery and also for the SFA Pacific staff personnel to use them as a sounding board for perceived ideas. Functional areas of responsibility primarily included planning, forecasting, engineering, research and development.

Other portions of this overall section, "Oil Refining Industry Assessment" are the SFA Pacific analysis, perceptions and conclusions for specific subjects with occasional comment by industrial personnel included. This subsection, "Industry Attitude," presents in distilled form observations of the discussions

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with refining industry personnel. The following comments are presented with an appropriate degree of SFA Pacific editorial license regarding the primary question, "What is the outlook for the use of coal in the U.S. refining industry?"

- o Any significant use of coal in refineries is a "long way away" (at least 15 years).

- o The general perception exists that the "real cost" of using coal is too high to justify switching from gas or liquids for fuel.

- o Cogeneration is a good idea that will stand on its own economically in specific cases. It may be that the only significant coal use in refineries for many years will be cogeneration. However, PURPA is a "house of cards" that can collapse quickly by a change of the law.

- o Refineries are producers of fuel in the course of their operation, and the amount of fuel produced will increase as crude oil feedstocks get heavier. Therefore, they are not much worried about using coal to improve fuel flexibility.

- o Coal will compete in the refinery almost entirely in what growth markets there are, rather than as a fuel replacement in an existing operation.

- o The following general ranking of priorities for coal use in refineries emerged:

  1. boiler use for steam and power
  2. gasification for fuel gas
  3. direct firing in crude heaters

- o Quite a few boilers will be shut down over the next few years as steam requirements decrease due to continued conservation efforts and increased use of electric power.

- o There appear to be only a few coal capable boilers in the refining industry.

- o The main three drawbacks to the use of coal are:

  1. lack of economic incentive
     - need a wider spread between the costs of using coal and oil/gas in order for coal to displace oil or gas (basis prospects in early 1985)
  2. environmental considerations
  3. lack of availability of cost effective coal utilization technology
     - a mixed perception exists as to whether fluid bed combustion with minimum 90% sulfur capture is as yet commercially proven

- o The best area for federal R&D assistance may be in new routes to chemicals.

having petroleum coke available for use at the refinery, another extremely important factor is the actual use of coke as a refining fuel. Coke is being used in a few refinery site situations. The largest application of coke firing in the world is Suncor's tar sands operation near Fort McMurray, Alberta. The primary upgrading technology there is delayed coking of recovered bitumen. Approximately 2,200 tons/day of delayed coke is burned in three pulverized fuel boilers, each rated at 750,000 lbs/hr of steam. The steam is used for power generation and process steam (principally for the hot water extraction process).

In the U.S., Champlin Oil Co. installed boilers in the early 1980s for firing with coke at its Corpus Christi refinery. For several years the Getty refinery in Delaware City has supplied coke across the fence to Delmarva Power and Light's power station there. Shell Oil Company is just completing modification to three boilers (a total of 2 million lb/hr) to permit buring of coke at their refinery near New Orleans. In Shell's system the boilers which were installed in 1978 have fired only fuel oil, pitch, and gas; however, the fireboxes were designed to handle the longer residence time and greater flue gas volume of coke or coal. Modifications include the addition of pulverizers and bag houses. These three boilers are scheduled to start-up on delayed coke in the first quarter of 1985.

Approximately 600,000 tons of petroleum coke was marketed to four electic utilities in 1983 (Delmarva Power and Light Co., Northern States Power Co., Pennsylvania Power and Light Co., and Wisconsin Power and Light Co.).

ARCO in cooperation with Applied Energy Systems (AES) is constructing a petroleum coke fired steam/electric cogeneration plant in Pasadena, Texas. ARCO will supply the coke (about 1,400 tons/day) to AES who will sell about 150 MW of power to Houston Lighting and Power. ARCO will also take some process steam and power for its refinery which is adjacent to the new plant. Conventional pulverized coal boilers are being used.

As of January 1, 1984, U.S. coking capacity was about 22 million tons/yr in 54 refineries [10]. As mentioned earlier, 1983 coke production was 17.9 million tons. It is unlikely that coal will be used in a specific refinery as long as fuel-grade coke is available at or near the refinery.

As discussed earlier in the report, transportation will be a major component of the refinery site cost of coal. The use of coal will be enhanced the closer the refinery is located to reasonably priced coal supply and if both the options of rail and barge transport are available to ensure competitive pricing of transport.

Cogeneration will provide additional favorable potential for coal where large steam requirements are present and where the power can be sold profitably to local electric utilities. The cheapest fuel for such operation will be first petroleum coke and ultimately coal. Exxon in the early 1980s shelved plans to construct a coal-fired cogeneration system for the Baton Rouge refinery to replace a natural gas fired system.

Locations where both a refinery (or refineries) and a large chemical complex are located on the same or adjacent sites should provide a favorable condition for coal use. In such cases the opportunity for joint cogeneration should be attractive. In the longer term such proximity may well encourage joint synthesis gas based production of chemicals and higher value fuels, with the synthesis gas being produced by coke, coal, residue, or refinery fuel gas. A timely example of such coordinated operation is the Shell Oil Co. coke boiler modification project at the Shell Norco refinery mentioned earlier. The new coke-fired operation continues to provide large amounts of steam for process use and compressor drives to the onsite olefin plant.

Uncertainties and Obstacles

A variety of important uncertainties and obstacles will affect the when-and-if of coal entry into the U.S. refining industry. By their nature, a certain amount of overlap exists between uncertainties and obstacles. For example, the projected price level of world crude oil in 1995 would be an uncertainty in the use of coal in refining; however, low oil prices in 1995 would be an obstacle to the use of coal. Likewise, cheap and abundant natural gas is an obstacle to coal use, but the projected price level is an uncertainty.

The uncertainties regarding the future use of coal in refining are basically the same as the issues discussed previously in the section "Issues Affecting Overall Growth and Fuel Use" but with an added uncertainty, natural gas. Therefore, based on this work the uncertainties SFA Pacific sees are:

- o world oil prices
- o changes in feedstock quality and energy requirements
- o changes in refined products markets
- o environmental requirements
- o taxation
- o natural gas prices

For the most part these uncertainties were discussed in the previous section and will not be repeated here. However, a few comments and additions are in order.

Environmental considerations were discussed earlier with respect to overall refinery growth and fuel use. The use of coal, primarily for combustion, will present difficult emissions problems in some areas of the country. For example, the stringent emissions regulations in effect in the largest metropolitan areas of California may effectively block the use of any type of coal combustion technology available now or in the next 20 years. Coal gasification may be the only coal-based technology capable of meeting emissions regulations in those locations. This environmental issue is thus an uncertainty and an obstacle and is highly regional in importance.

Natural gas price was not considered to be an issue in the overall growth of the refining industry because it is basically interchangeable with refinery fuel gas and liquids for fuel applications and is interchangeable with fuel gas for hydrogen production. Therefore its price and availability will have little influence on refining industry growth. However, the price and availability of natural gas can have an important impact on refinery use of coal since the two will compete directly on price for fuel use, and natural gas is therefore considered here as an uncertainty for growth of coal use.

Several obstacles to the use of coal appear evident:

- o industry mind set against the use of coal
- o lagging development of new coal utilization technologies
- o low industry profitability

Unlike the steel industry, which has traditionally used and depended upon coal, the U.S. refining industry as currently constituted uses virtually no coal in its operations. Furthermore, most of the refinery people who were involved in coal use when the industry did use some coal are now retired. It is a perception of SFA Pacific that there is a definite mind set in some parts of the refining industry against

The use of ethanol as a gasoline blending component will continue and likely expand as long as substantial tax subsidies exist to support its use. Without such subsidies, ethanol cannot compete economically with other conventional high-octane blending components. If equivalent subsidies were accorded liquid fuels based on domestic coal or natural gas, the use of such fuels would be substantial and would likely be limited by the amount of tax revenue loss the state and federal governments would be willing to sustain.

A comment on PURPA regulations is included in this section although it is not strictly a tax-related consideration. PURPA regulations can make it attractive for refineries to increase on-site generation of power and steam with sales of power to electric utilities. In general, SFA's observation is that the refining industry does not view the regulation as much of a potential economic benefit since the benefits can easily be eliminated by changes in the law. However, a potential driving force for PURPA supported cogeneration would be a lack of necessary capacity expansion by the electric utility industry. In general, however, the electric utility industry has considerable excess capacity.

Interaction with the Chemical Industry

The interaction between the oil refining industry and segments of the chemical industry has been significant and is discussed here from the standpoint of the refinery (see the related discussion in the section on Chemical Industry Assessments -- Interaction with the Oil Refining Industry).

Most of the petrochemical industry grew up on or adjacent to existing refinery sites or was planned and built as part of new refineries. The most important interactions are in the two product lines of olefins (principally ethylene) and aromatics (principally benzene/toluene/xylenes-BTX). A large fraction of the nation's ethylene and BTX is produced in joint refining/chemical complexes, many of which were originally refinery sites alone.

Ethylene production based on cracking of gas oils, naphthas, and some lighter liquids (oil refinery products) is normally located at a refinery site. In addition to the feedstock supply situation, gas oil and naphtha crackers, in particular, return significant amounts of products to the refinery, including crude gasoline, propylene and butylenes for alkylation or production of MTBE, and some cracked gas-oils for eventual blending into fuel oils. The interaction is further tightened by integration of utilities (electric power and steam) between the refinery and chemical plant.

Much of the BTX consumed by the chemical industry is produced from refinery operation, principally catalytic reforming and extraction operations. Some benzene is produced specifically for chemical use by hydro-dealkylation of toluene. Although not tightly integrated with chemical operations, the aromatics balance is an important economic consideration in the operation of many refineries.

Sites which have both refineries and chemical plants located together will generally be good opportunities for cogeneration (with or without PURPA). In many cases utility integration has existed for years. Such joint arrangements will provide logical opportunities for use of both coke and coal.

The Expanded Use of Coal in the Refining Industry

As emphasized earlier, very little coal is currently consumed in the U.S. refining industry, only about 300,000 tons in 1983. This represents only a quarter of one-percent of all energy consumed in refineries that year. Since virtually no coal is used in refining, this discussion of the "expanded use" of coal in

the refining industry is therefore more one of "introduction" (or perhaps re-introduction) of coal into the industry.

Favorable Conditions for Coal Use

Conditions favorable for the use of coal will generally be of two types:

- o Broad in scope, industry-wide or worldwide
- o Refinery specific

Conditions in the category of broad-in-scope are such things as world crude oil prices, natural gas prices, security of supply for feedstocks and fuels, projected demand for refined products, and the development and commercialization of new coal utilization technologies.

Coal use in refining will be favored by oil and natural gas prices that are increasing or projected to increase. Since the U.S. refining industry is not expanding and unlikely to do so for the next ten to fifteen years, the use of coal will come about as the result of fuel switching and retrofitting. Retrofitting existing oil and gas fired systems for coal is more costly than designing for coal firing in new construction. Stable prices for competitive fuels and lack of new construction opportunities will therefore lead to higher-cost coal-based options than would be available in a period of refinery expansion. In like manner, a secure or perceived secure supply of crude oil and natural gas will not provide a motivation for fuel switching in a non-growth refining environment. On the other hand, fuel supply uncertainty will encourage fuel flexibility, which will in turn favor designing facilities with coal capability.

As mentioned above, stagnant growth in the refining industry will severely restrict new construction. Concurrently, stagnant project demand for refined products and depressed product prices will also stifle even retrofit applications because of refinery-side depressed earnings.

The development and commercialization of new coal utilization technology will help to expand the potential application of coal in refining. Prominent examples of such emerging technologies are: fluid bed combustion, CWM or pulverized coal slagging combustion, coal gasification, and technology for direct conversion of coal or coal-based synthesis gas to light liquids or finished products.

Favorable conditions for coal use associated with refinery specific considerations include such things as:

- o existing refinery production of petroleum coke
- o existing refinery use of coke
- o proximity to both rail and barge links for coal transport options
- o favorable cogeneration options
- o joint or adjacent location with a large chemical complex

An important factor in introducing coal into use in a specific refinery will be the presence of coke production technology [9]. Coke "on the ground" at a specific refinery site will be the cheapest source of solid carbonaceous fuel available to that refinery. Except for low sulfur or specialty cokes which have high value markets in anode or electrode applications, coke will be cheaper than coal because it has no transportation cost. Transportation is a major cost factor for refinery-delivered coal. In addition to

2000-2010 period due to costs compared to conventional oil, the questionable value of coal liquids in a refinery, and lack of commercial experience. A further drawback is that shale oil is generally perceived to be a cheaper and higher quality petroleum substitute. However, co-processing of coal (in small amounts) with petroleum residues may develop sooner if significant synergism can be shown to exist by processing the two feeds together.

Hydropyrolysis for production of high-value aromatics (BTX) has the potential of producing "maximum value" products directly from coal. However, much development work remains to be done and ultimate costs are likely to be high. Any such process will produce large amounts of by-product char. A key consideration will be economic utilization of the char, which will likely be fairly high in sulfur and ash. Refinery use of fluidized bed combustion appears to be an attractive option for using this char. If hydropyrolysis technology can be developed at a reasonable pace and projected costs are competitive with alternatives this technology might be commercialized in the 2000-2010 time frame.

The foregoing projections are based on SFA's perceptions and interpretations of industry views -- projections being what they are, "let the buyer beware."

Most Attractive R&D Candidates for the Oil Refining Industry

As discussed earlier in this section of the report, there are several areas where R&D efforts would assist in using coal in the refining industry. The most attractive candidate areas for R&D appear to be:

- o Technology for direct firing of coal to provide radiant heat
- o Fluidized bed combustion for process heat
- o Technology for the direct conversion of synthesis gas to gasoline or middle distillate at high yield
- o High-yield production of higher alcohols directly from synthesis gas
- o Hydropyrolysis technology for high yields of BTX
- o Co-processing of petroleum residues and coal

The development of technology for the direct firing of coal to provide radiant heat would permit coal to compete directly with refinery gas and natural gas, or fuel oil for the highest value thermal uses in a refinery, e.g., fired heaters. The extension of fluidized bed combustion to process heaters would accomplish the same thing, but not for retrofits.

The development of a process to directly convert synthesis gas to liquid transportation range fuels would be significantly less costly than going through the methanol step, assuming high yields are achieved.

Production of higher alcohols (C_2 - C_4) for blending with methanol into gasoline would be desirable if methanol blends are used to any substantial degree.

If successfully developed, hydropyrolysis technology for BTX production would provide a way to directly convert coal to high value fuel and petrochemical components. Economic use of by-product char will be a key issue.

Co-processing of coal and petroleum residues may prove to be the most economic form of direct coal hydroliquefaction. A key factor will be the degree of synergism.

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SECTION 8

STEEL INDUSTRY ASSESSMENT

Conclusions

The U.S. Steel Industry has traditionally been the dominant force in coal utilization by the industrial sector. That dominance has recently diminished with the steep decline of U.S. steel production. However, there must be expanded use of coal in the U.S. steel industry for the integrated steel maker to remain competitive and for the mini mills to expand significantly. Moreover, this expanded coal use will not be the traditional metallurgical coal used in coke ovens, but in the advanced technologies for continuous iron/steel making processes based on lower cost steam coal.

The U.S. steel industry is currently undergoing the most radical changes in its entire history. These changes are primarily due to the following:

- o weak markets for steel
- o smaller market share due to increased imports
- o over capacity
- o poor profitability

There are two fundamentally different steel producers in the U.S.: the large integrated steel mill and the small mini mills. Most of the recent decline in the U.S. steel industry has been at the expense of the integrated steel mills which suffer from high operating costs. A coke crisis will develop before 1990 as integrated steel producers are only reinvesting in steel finishing (continuous casting) while aging iron making facilities continue to deteriorate. At the same time the mini mills have continued to be very profitable and have expanded to over 20% of the U.S. finished steel production.

The following conclusions and observations can be made regarding coal use by the U.S. Steel industry:

- o The long-term survival of the U.S. integrated steel industry will require the development of continuous iron/steel making technology which is based on low-cost and abundant steam coal. This is due to the high capital and operating cost associated with conventional batch operation coke ovens, blast furnaces and basic oxygen furnaces.

- o Several continuous iron making technologies are currently being tested at pilot plant scale. The KR process appears to be the leader.

- o The continued long-term growth and profitability of mini mills could be restricted by the price and availability of high quality scrap. The best alternative appears to be coal gasification integrated with the conventional Midrex direct reduced iron (DRI) process. The leading coal gasification process for this application appears to be the Sumitomo/KHD process because the hot raw gas is sulfur free and is about 95% reducing gas (H_2 + CO). Therefore, the hot raw gas can be fed directly to the DRI reactor.

67X

o Major uncertainties regarding the future use of coal in the steel industry are:

- fluctuation in total U.S. steel industry demand
- amount of imported steel (finished or semi-finished
- increased mini mill steel production that is currently not coal based
- long-term high-quality scrap supply/price
- long-term coke supply/price

o Major obstacles to future use of coal in the steel industry are:

- low profitability of integrated mills
- slow acceptance of technology change by integrated steel mills
- resistance of technology change by the steel workers union as most new technologies require less labor

o Major favorable conditions for increased use of coal by the steel industry are:

- increased U.S. steel production (larger demand/less imports)
- increased steel production by integrated steel mills
- expansion of mini mills into coal-based direct iron ore reduction

o Best areas of research and development appear to be:

- continuous steam-coal-based iron-making processes as an alternative to conventional coke ovens and blast furnaces.
- coal gasification integrated with direct iron ore reduction processes as an alternative to high quality scrap.
- Continuous basic oxygen furnace (BOF) for better utilization of BOF gas
- Separation of CO from N_2 for better utilization of blast furnace gas
- removal of sulfur from hot coal-derived gas without cooling the gas (hot gas clean-up)

Industry Definition

The definition of the United States steel industry for this study is based on the U.S. Department of Commerce's Standard Industrial Classification (SIC) code 331, entitled "Blast Furnace Steel Works, and Rolling and Finishing Mills" [1]. This major three digit SIC classification includes integrated steelmakers, non-integrated mini mills, and independent producers of finished steel which purchase and process semifinished steel. This definition does not include iron ore preparation, foundries, or nonferrous metals.

SIC code 331 is normally the largest energy consumer in the annual Census of Manufacturers report of fuels and electric energy consumed by industry groups. Furthermore, the actual energy consumed by the steel industry is much larger than the SIC code 331 as this industrial energy census does not include metallurgical (coking) coal. The most useful reference on the energy use of the U.S. steel industry is the Annual Statistical Report [2] produced by the American Iron and Steel Institute (AISI).

The total energy requirement to produce a ton of molten pig iron is about 12 million Btu or about 0.55 tons of coke. The amount of coke can be reduced to about 0.45 tons by injecting oil, tar, natural gas or steam coal into the blast furnace with the hot air. However, the total energy requirement stays at about 12 million Btu consumed in the blast furnace per ton of hot melt produced. It is more useful to consider the metallurgical coal energy requirements per ton of hot melt which is about 20 million Btu. Table 8-1 shows the energy inputs and outputs for both the coke oven and blast furnace based on the feed metallurgical coal. It should be noted that only 40% of the coal energy goes directly to iron making whereas 45% of the coal energy is converted to fuel gas.

Direct Reduction

An alternative iron making process is direct reduction. This process currently accounts for only 1% of the world iron production; however, it is becoming increasingly important as high-quality scrap supplies become tenuous. Most direct reduction processes involve the conversion of iron ore pellets to reduced (oxygen removed) iron pellets by reaction with synthesis gas (H_2 and CO) in moving or fluidized bed reactors. Essentially all of these processes utilize steam/methane reforming of natural gas to generate the required hot synthesis gas. Because of the high natural gas demand, about 12-15 million Btu per ton reduced solid iron, most of these plants are built in areas of the world where natural gas prices are very low.

Steel Making

Iron along with recycled scrap is refined into raw steel by any of the three following steelmaking processes:

- open hearth furnace
- basic oxygen furnaces (BOF)
- electric arc furnaces (EAF)

The open hearth furnace is an antiquated process which has been replaced by the basic oxygen furnace. However, almost 10% of the U.S. raw steel production is still produced by open hearth furnaces, whereas the last open hearth furnace in Japan was shut down over 5 years ago. Essentially all the molten iron produced in blast furnaces is processed into raw steel in BOF. As the name implies, oxygen is blown into the molten iron, which contains over 4% carbon. The oxygen reacts with the carbon to produce mostly CO. This reaction also removes a number of trace impurities from the iron. Important drawbacks are that the BOF is not continuous and it can only process a small amount of scrap. The batch operation greatly limits effective uses of the large amount of relatively good heating value (220 Btu/scf) fuel gas produced in the BOF furnaces.

Electric arc furnaces are used to melt and refine scrap as well as solid direct-reduced iron. A large amount of high-quality scrap is produced within the steel mill, amounting to over 20% of the raw steel converted in finishing. Furthermore, scrap can also be purchased at very reasonable prices relative to iron-making process costs. The use of purchased scrap and EAF-based steelmaking has grown rapidly over the last 10 years as this process is the heart of the mini mill. EAF steelmaking now accounts for over 30% of U.S. raw steel production and is expected to continue to grow until availability of high quality scrap limits EAF at about 40-50% of raw steel production. As the name implies, electric arc furnaces use a direct electric arc as the heat source. Carbon electrodes are used which also supply carbon for refining the steel. Similar to BOF, the EAF has the disadvantage of being a batch process.

Table 8-1

PIG IRON ENERGY REQUIREMENTS

1 ton molten pig iron from iron ore requires
0.55 ton coke = 0.75 ton metallurgical coal = 20 million Btu

COKE OVEN

IN	Percent
Metallurgical Coal	100
Fuel Gas	10
Total	110%

OUT	Percent
Blast Furnace Coke	60
Coke Oven Gas	20
Heat Loss	15
Coke Breeze	10
Tars/Oils	5
Total	110%

BLAST FURNACE

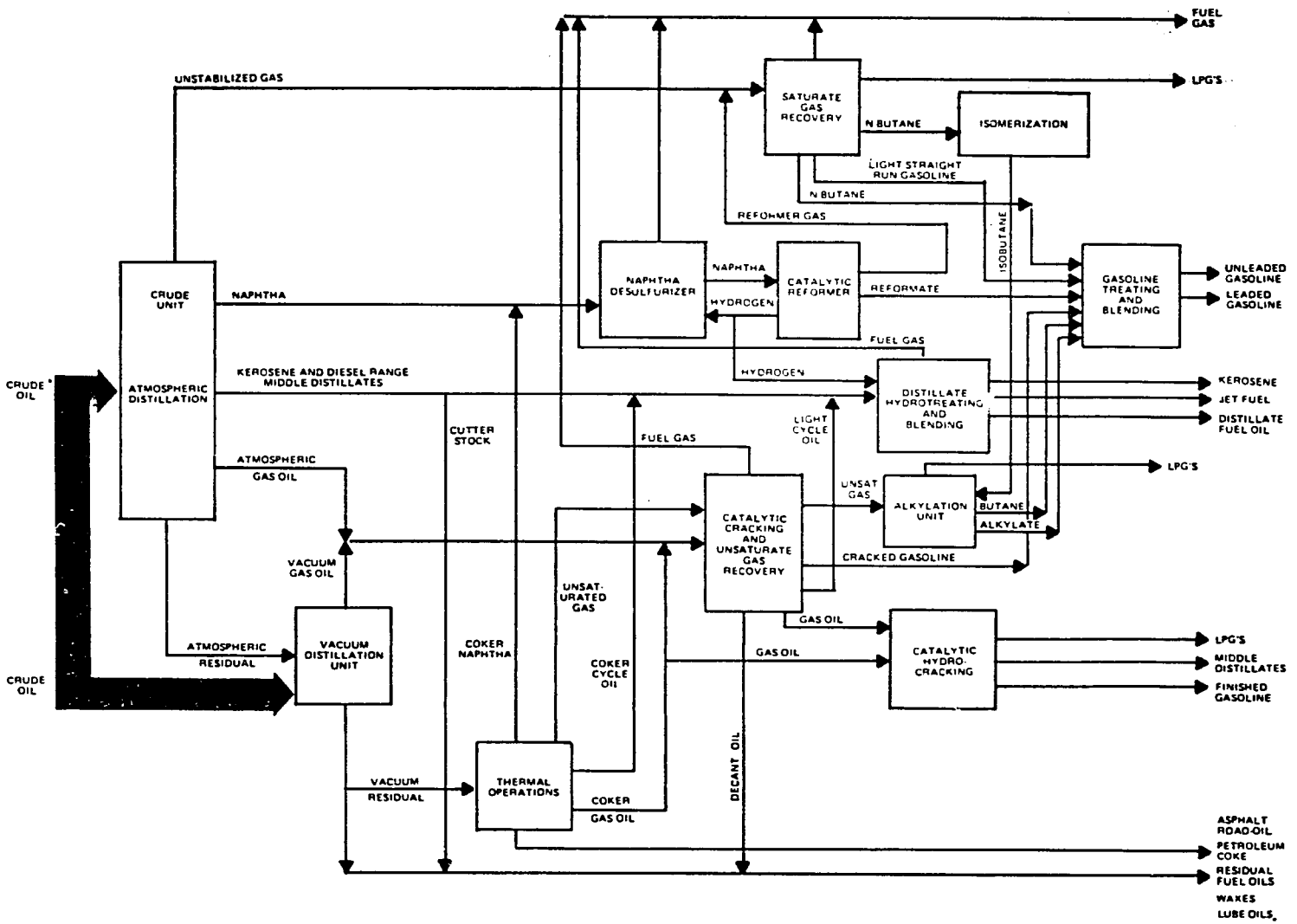
IN	Percent
Coke	60
Fuel to Heat Air	10
	70%

OUT	Percent
Reduced Hot Melt	40
Blast Furnace Gas	25
Heat Loss	5
	70%

Source: SFA Pacific, Inc.

Figure 7-1

SIMPLIFIED FLOW DIAGRAM OF A TYPICAL U.S. REFINERY



Source: Reference 2

The three main categories of refining units are:

- o crude fractionation
- o thermal and catalytic conversion
- o gasoline tailoring

Crude fractionation includes both atmospheric fractionation and vacuum flashing to separate the crude oil into cuts (by boiling range) suitable for downstream processing.

The primary function of the thermal and catalytic conversion system is to break down large molecular weight materials into smaller gasoline and distillate fuel-range components. Thermal conversion systems include such processes as delayed coking, fluid coking, Flexicoking, and visbreaking. Catalytic conversion systems include such processes as catalytic cracking and catalytic hydrocracking. Catalytic cracking and catalytic hydrocracking have traditionally operated with relatively "clean" distillate feeds; however, recent commercial development is extending their application to the upgrading of residual fuel oils, e.g., the Heavy Oil Cracking process (for catalytic cracking) and the LC Fining and H-Oil processes (for catalytic hydrocracking).

Gasoline tailoring, for the discussion here, is comprised of processes which specifically produce entirely gasoline blending feedstocks which can be blended directly into a finished gasoline. Included in this category are catalytic reforming, alkylation, dimerization, and C_5/C_6 isomerization. The fractionation and conversion processes also produce gasoline-range cuts but only a little of these materials are blended directly into gasoline without further downstream processing.

In addition to the three major types of systems discussed above are other important peripheral process units including desulfurization units, blending operations, lube and wax production, gas recovery and purification operations, a utilities systems for steam and power, sulfur recovery, and a hydrogen production system. The refinery depicted in Figure 7-1 does not show a hydrogen plant. Refineries with hydrocrackers will normally have a hydrogen plant, particularly those with residue hydrocrackers which require large quantities of hydrogen per barrel of feed treated. Catalytic reforming is a net producer of hydrogen which can satisfy more modest requirements of other refineries.

Candidate Uses for Coal in the U.S. Refining Industry

Before the advent of abundant supplies of cheap natural gas in the 1950s, limited amounts of coal had been used in the refining industry for many years. The principal use of that coal was firing boilers for refinery power requirements and steam for process uses and direct drives. However, some coal was even used for direct process heat in "pot stills" for crude oil flashing. In contrast, today, almost no coal is used in oil refining. In 1983 approximately 300,000 tons of coal was consumed in the U.S., approximating only 0.25 percent [2,5] of energy consumed for refinery operation. This coal was used for firing boilers principally in refineries in the Appalachian Region of the country.

Potentially coal will find application in oil refining in the following five basic ways:

Fuel Supplement or Replacement

- o Direct firing for power generation and production of process steam

Steel Manufacturing Technology [3, 4]

The manufacture of steel is capital, energy and labor intensive. The oil and chemical industries are also capital and energy intensive; however, the steel industry has the important difference of being labor intensive. The high labor cost associated with steel making is due to the large number of process steps. Furthermore, several of these processes are not continuous which greatly increases both operating and maintenance labor costs.

Figure 8-1 is a simplified block flow diagram showing the various steps and process alternatives for each step in steel making. The overall process involves converting iron ore to finished steel products. This requires removing oxygen and other impurities from the iron ore, adding carbon and trace metals, melting, and finally producing the finished steel in marketable shapes.

Agglomeration

The beginning feedstock is iron ore, which is usually processed at the mine into large-size agglomerates which are required for the iron making processes. Iron ore pellets are generally considered a world market commodity. An increasing percent of the iron ore pellets consumed in the U.S. steel mills is imported. This is because of price/quality advantages for imported pellets caused by the following:

- o favorable exchange rates (strong U.S. dollar)
- o higher grade ores
- o large new ore processing and mining facilities
- o lower labor costs

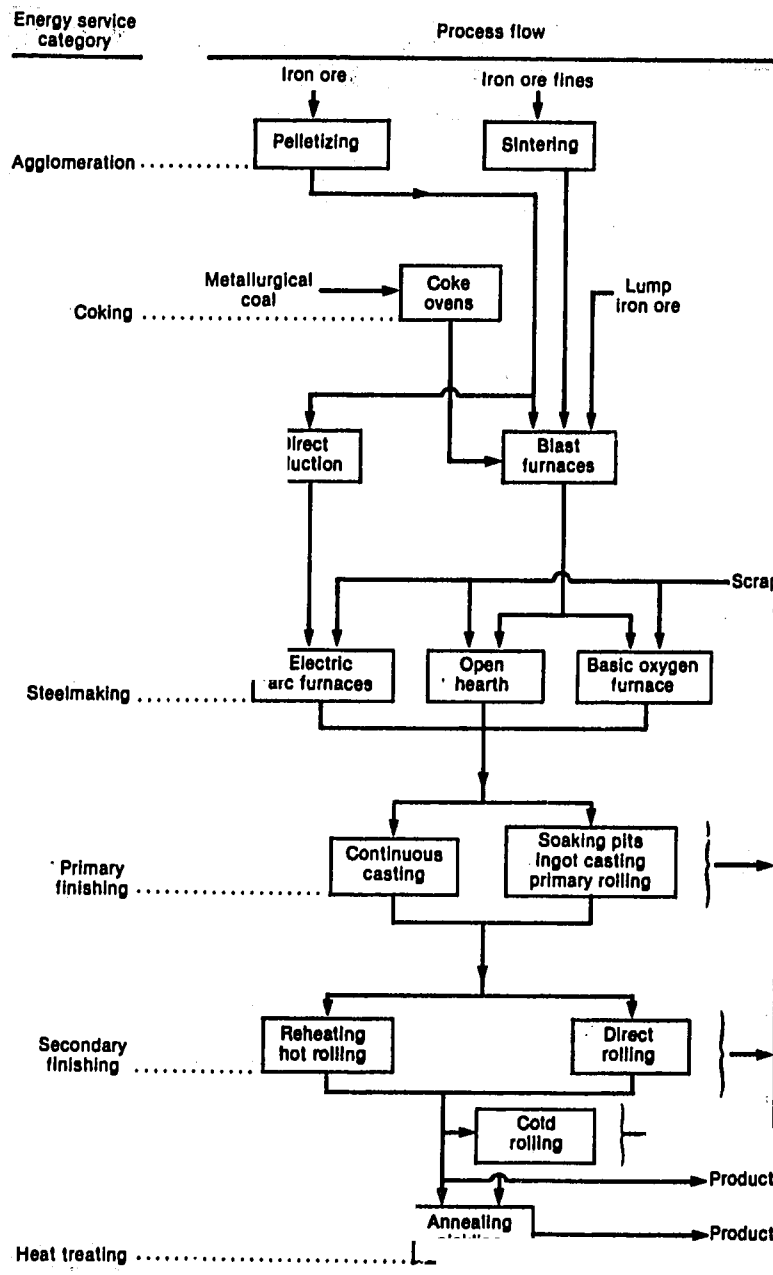
Iron Making

The heart of steel making is the iron making process, which includes the coke ovens and the blast furnaces which convert iron ore to molten iron, commonly called pig iron. Much of the energy consumed in steel making is in this step. In the blast furnace air preheated to about 2000°F is injected into a moving bed of iron ore, limestone and coke. Limestone is used as a fluxing agent to lower the melting temperature of slag. It also helps remove impurities from the iron and coke such as sulfur and slag. The function of the coke is unique as is supplies the energy and strength to support the heavy moving bed plus the carbon to remove the oxygen from the iron ore. The blast furnace produces a large amount of low-Btu fuel gas. Blast furnace gas is used to preheat the blast furnace air; however, the low heating value (90 Btu/scf) limits it uses for premium fuel applications. The blast furnace is a continuous process although the solids are added and the molten iron is removed in intermittent batches.

Coke is produced in coke ovens which indirectly heat and devolatize coal in the absence of oxygen. The most important properties of coke as required by the blast furnace are large size and strength. Therefore, only certain caking (agglomerating) coals can be used in coke ovens. These coals are called metallurgical coals. The coking process produces a large amount of medium Btu fuel gas plus some tars and oils. The relatively high heating value (500 Btu/scf) coke oven gas can easily be used in place of premium fuels such as natural gas or fuel oil. Coke ovens are operated batchwise at atmospheric pressure. Coal is charged into the hot oven and then after about 18 hours the red hot coke is pushed out of the oven and direct quenched with water. This batch operation creates severe environmental problems as well as worker exposure to the fumes of coal tar products.

Figure 8-1

PROCESS FLOWS IN THE IRON AND STEEL INDUSTRY



Source: Energy Productivity Center, Mellon Institute, Final Report on Industrial Energy Productivity Project, Vol. 4, The Iron and Steel Industry, September 1982

Steel Finishing

Finishing of steel generally involves first solidifying the molten steel into a primary shape followed by rolling or stamping into a finished product. The antiquated way to do this involves ingot casting followed by primary and then secondary rolling or stamping. This method requires a large amount of heating with premium fuel in soaking pits, involves several batch operating steps, and produces about 30% scrap. The improved process alternative is continuous casting where molten steel is continuously poured into molds that solidify the steel into primary shapes which can then be fed directly to secondary rolling. Continuous casting requires only a small amount of premium energy and very little labor, and it produces substantially less scrap than ingot processing. Continuous casting currently accounts for about 33% of U.S. finished steel production but is projected to grow to over 75% by 1990. It should be noted, however, that over 75% of the Japanese steel production is already by continuous casting.

Characteristics of the U.S. Steel Industry

The U.S. steel industry is currently undergoing the most radical change of its entire history. These changes are primarily due to the following:

- o weak markets for steel
- o smaller share of the markets due to larger imports
- o overcapacity
- o poor profitability

Furthermore, there are two fundamentally different kinds of steel producers in the United States: the large integrated steel mills and the small mini mills. These two steel producers have very different characteristics.

Integrated Steel Producer

Integrated steel producers are the very large corporations that own and operate almost every aspect of steel production from the iron ore and coal reserves to the finished steel fabrication and sales. These companies such as U.S. Steel and Bethlehem Steel were the historic giants which led the U.S. steel industry. However, these integrated steel producers are now suffering the most during the current recession in the steel industry. Large U.S. integrated steel mills are suffering large operating losses, and overcapacity which is causing plant shutdowns and layoffs.

The current decline of the U.S. integrated steel mills in part began with poor decisions in the 1960s and events of the 1970s. The 1960s and early 1970s were strong growth and profitable times for the steel industry. During that time the integrated steel producers were slow to accept two important technology changes in steelmaking: basic oxygen furnaces and continuous casting. SFA speculates that the slow acceptance may have been due to the fact that both technologies were invented and developed by others. The large U.S. steel companies have difficulty accepting technology not invented here (NIH). During that same time, the U.S. integrated steel companies gave the United Steelworkers of America union essentially anything they demanded to avoid strikes. Steel management was more concerned with short term profits/production than with controlling costs. This led to an enormous labor inefficiency due to union work rules and union labor/benefits costs which were substantially higher than those of any other union worker in the United States. Furthermore, union contracts included cost of living adjustments which were heavily inflationary.

By the early 1970s the U.S. integrated steel mills had an enormous capacity of antiquated technology which was energy inefficient and required a large amount of labor which was also inefficiently utilized and overpaid.

The energy-related events of the 1970s devastated the integrated steel producers because this industry is capital, energy and labor intensive. The oil price increases forced increases in their energy costs and at the same time reduced demand for steel due to the recession, down sizing of cars, and general substitution of other materials. The high inflation rates increased the cost of capital through high interest rates. Steel production costs were further increased due to the built in labor cost escalation. The Environmental Protection Agency (EPA) and Occupational Safety and Health Administration (OSHA) issued regulations requiring large investments during a time of limited capital and low demand for new facilities. This required mostly retrofit investment which usually reduced capacity and at the same time increased operating costs. Furthermore, the EPA and OSHA regulations need not be met by the integrated steel mills' foreign competitors.

The current situation for the integrated steel producers is one of survival. This involves consolidation, plant shutdowns, and massive layoffs. Most integrated steel producers are currently in a "hand to mouth" financial existence. They are not profitable enough to generate the capital required to make the investments needed to be more competitive and profitable. Therefore, it appears that integrated steel producers will invest their limited capital in steel finishing (i.e., continuous casting) and marketing. The investments are small (relative to iron or steel making) and the return on investments are best as continuous casting greatly reduces energy and labor cost compared to ingot production. However, neglect of reinvestment in iron making will eventually lead to a crisis situation in the availability of coke.

The integrated steel producers are now looking toward the U.S. Government for help. The U.S. steel industry would like import restrictions similar to those in the auto industry to increase profitability and sales volume. During the last five years of voluntary auto import restrictions the U.S. auto industry grew strong and very profitable while making large investments in the world's most modern auto manufacturing technology. It appears the U.S. government will be able to negotiate a voluntary import restriction on steel. However, it is doubtful that the U.S. integrated steel producers can grow strong and profitable during these import restriction periods unless they invest in advanced continuous technologies. Batch operation technology is too expensive because of much higher fuel and labor requirements. It appears the major steel companies may also realize this as the steel industry is attempting to develop several large joint government/steel company funded programs in research and development of advanced continuous iron and steel making technologies.

Mini Mills

Mini mills are an American success story. Few people realize that some of the most profitable and lowest cost steel producers in the world are mini mills in the United States. These companies are usually aggressive, small, non-union steel companies which produce steel from purchased scrap via electric arc furnaces and continuous casting. They are commonly called mini mills due to the small plant sizes and simple manufacturing technology. Traditionally, the integrated steel mills did not consider mini mills a serious competitor because mini mills began by making only unsophisticated steels such as reinforcing bar. This application can use low quality steel (from low quality scrap) and simple finishing. However, mini mills have now expanded into relatively sophisticated shapes and higher quality steel. Since the early 1970s mini mills have grown from only 2% of U.S. finished steel production to over 20% in 1983. Furthermore, it is quite possible that mini mills could account for as much as 40% U.S. finished steel production by 1995.

Mini mills differ from integrated steel producers in almost every aspect of the business. Mini mills have little control over their feedstock and energy supply/price as they purchase most scrap, electricity and natural gas. Mini mills are small companies that maintain low overhead cost, move quickly and take risks. Mini mills aggressively accept and improve innovative technologies invented by others. The non-union employees of mini mills generally make as much as members of the Steelworkers Union; however, a large portion of their pay is usually in production incentives or profit sharing. The labor productivity of mini mills is usually over 800 tons per employee per year which is three to four times greater than in integrated mills. Mini mills have expanded their markets by simply being the lowest cost supplier while maintaining sufficient steel quality for the specific product or application.

The mini mills are currently faced with important long-term problems. Continued market growth will require mini mills to expand into sheet steel products. Conventional continuous casting for sheet steel production involves large capacity six inch thick slabs. Mini mills are currently working with several technology developers of an innovative thin strip (1 to 1½ inch) casting machine. SFA Pacific observes that most integrated steel producers do not believe mini mills can produce strip steel because of the large capacity required and the technical limitation of the thin strip continuous casting. However, the integrated steel producer has consistently underestimated the mini mills. The long-term supply and price of high quality scrap may well be a more important problem which could restrict the growth of mini mills. Quality of scrap generally refers to the content of tramp elements (residual metals such as copper, tin, nickel, chromium and molybdenum). The lower the percent of tramp elements the higher the quality of the scrap. Expanded markets for mini mills require higher quality steel products. The availability of high-quality scrap in the U.S. will decline with the continued decline of the domestic integrated steel mill foundries and machine shops. Scrap from imported products (mainly Japanese cars) as well as U.S.-produced steel products is increasingly higher in copper. SFA Pacific believes this could lead to increased prices for high quality scrap which will reduce the economic competitiveness of mini mills. This will lead to world commodity sales of imported direct reduced iron (DRI) from merchant plants in countries with low cost iron ore and/or natural gas. Long term, however, the mini mills must consider utilizing innovative iron making technology based on low cost domestic steam coals to control feedstock costs.

Statistics [2]

Table 8-2 highlights several important statistics for the steel industry which illustrate that the world steel industry is in the midst of a recession while the U.S. steel industry is in the midst of a severe depression. Table 8-2 shows the wild fluctuation in the U.S. steel production over the last 10 years and the current low capacity factor. Because of this the following tables in this section will contain statistics for 1983 as well as 1979, the last year of reasonable U.S. production and capacity factor.

Table 8-3 contains overview data on the U.S. steel industry. Steel employment has dropped significantly in the last few years, however, it is still high relative to sales per employee compared to the oil and chemicals industries. Steel company assets and capital expenditures show the industry is liquidating steel investments while greatly expanding non-steel investments. It is generally believed that the U.S. steel industry would require about $6 billion per year capital expenditure to modernize the industry.

Tables 8-4 and 8-5 show the U.S. steel production statistics. It must be noted that mini mills produced about 22% of the total domestic shipped steel in 1983, whereas mini mill production was only about 12% in 1979. This large percentage increase in mini mill production can make the 1983 statistics somewhat misleading in terms of the following:

75x

Table 8-2

STATISTICAL HIGHLIGHTS OF THE U.S. STEEL INDUSTRY

Year	Raw Steel				U.S. Finished Steel			
	World Production 10^3 st	U.S. Production			U.S. Production 10^3 st	Less Exports 10^3 st	Plus Imports 10^3 st	Apparent Supply 10^3 st
		10^3 st	% of World Production	% of U.S. Capacity				
1983	731,646	84,615	11.6	56.2	67,584	1,199	17,070	83,455
1982	710,738	74,577	10.5	48.4	61,567	1,842	16,663	76,388
1981	779,399	120,828	15.5	78.3	88,450	2,904	19,898	105,444
1980	790,419	111,835	14.2	72.8	83,853	4,101	15,495	95,247
1979	824,486	136,341	16.5	87.8	100,262	2,818	17,518	114,962
1978	790,607	137,031	17.3	86.8	97,935	2,422	21,135	116,648
1977	741,828	125,333	16.9	78.4	91,147	2,003	19,307	108,451
1976	745,592	128,000	17.2	80.9	89,447	2,654	14,285	101,078
1975	712,033	116,642	16.4	76.2	79,957	2,953	12,012	89,016
1974	782,798	145,720	18.6	N/A	109,472	5,833	15,970	119,609

Source: derived by SFA Pacific Inc. from Reference [2]

Table 8-3

U.S. STEEL INDUSTRY OVERVIEW

	1983	1979
% Capacity Utilization	56.2	87.8
Direct Steel Employees	243,000	453,000
Steel Company Assets		
Steel $ billions	25.6	27.2
Non-Steel $ billions	19.6	10.4
Steel Sales as % of GNP	1.1	2.4
Steel Sales as % of Steel Company Revenues	56.0	78.0
Net Income $ Billions	-3.6	+1.2
Steel Company Capital Expenditures		
Steel $ billions	1.9	2.4
Non-Steel $ billions	1.3	0.9
Total Energy quads	1.8	3.4
Total Energy as % of Total U.S.	2.3	4.1

Source: derived by SFA Pacific, Inc. from Reference [2]

Table 8-4

U.S. STEEL INDUSTRY STATISTICS

	1983	1979
Finished Steel, millions of tons	67.6	100.3
Imports , millions of tons	17.1	17.5
Raw Steel, millions of tons	84.6	136.3
% of Capacity	56.2	87.8
Raw Steel % by Type Furnace		
Open Hearth	7.0	14.0
BOF	61.5	61.1
Electric	31.5	24.9
% Yield Raw Steel to Finished Steel	80.0	73.6
% Yield by Continuous Casting	32.1	16.9

Source: derived by SFA Pacific, Inc. from Reference [2]

Table 8-5

U.S. FINISHED STEEL PRODUCTION

	1983	1979
Finished Steel, millions of tons	67.6	100.3
Unit Production	Tons/Ton Finished Steel	
Raw Steel	1.25	1.3
Scrap	0.71	0.77
Pig Iron	0.72	0.87
Oxygen	0.10	0.17
Iron Ore	1.08	1.26
Coke	0.40	0.56
Met Coal	0.54	0.76
Energy: quads	1.76	3.42
million Btu/Ton Shipped	26.00	34.10

Source: derived by SFA Pacific, Inc. from Reference [2]

- o percent electric steel making
- o percent continuous casting
- o tons of iron ore and coke/metallurgical coal per ton finished steel
- o energy consumption per ton finished steel

Final 1984 figures are expected to show that U.S. steel industry production increased in 1984 from the dismal 1983 records. This increase is less impressive after considering that most of the increased production is from restarted antiquated integrated steel mills which soon must be shut down permanently. Table 8-5 also shows that scrap accounted for 50% of finished steel in 1983 which is considered about the maximum use of scrap as a percent of total steel to maintain scrap supplies.

Table 8-6 summarizes the energy consumed in the U.S. steel industry. Coal is the dominant energy source in the steel industry, used mostly as metallurgical coal. Furthermore, U.S. steel industry use of coal is the dominant market for total industrial coal consumption. Natural gas is also a major fuel used by the steel industry. However, the use of this premium fuel can be substantially reduced as natural gas prices increase and if the integrated steel mills modernize to become more efficient.

The steel industry produces a large amount of by-product fuel gas from the metallurgical coal. Table 8-7 lists the analysis, production and use of these fuel gases. Coke oven gas is the most important as it is easily substituted for premium natural gas and oil applications. Blast furnace gas is the largest source of fuel gas, but its low energy value limits its uses. Basic oxygen furnace (BOF) gas is under-utilized because it is produced in cyclic batch operation. Direct combustion of blast furnace and BOF gas to generate steam should be considered poor utilization as low cost steam coal could be a long-term lower-cost fuel to generate steam. Better utilization would be in fuel gas applications where these gases replace premium fuels such as oil or natural gas.

Coal Applications

There are a number of applications for the use of coal in the steel industry. In fact, the steel industy is already predominantly coal based. However, there are also additional applications for coal in the steel industry which could develop in the future.

Coke Ovens

Metallurgical coal use in coke ovens is the overwhelming coal application in traditional steel making. However, the growth in purchased scrap-based steel making (mini mills) has reduced the overall metallurgical coal consumption per ton of shipped steel as illustrated in Table 8-5. Blast furnace operation also affects metallurgical coal. About 0.55 ton of coke or 0.75 ton of coal is consumed per ton of hot iron melt for an average blast furnace operated on 100% coke. SFA Pacific believes a coke shortage will develop within the next few years. Therefore most blast furnaces in the U.S. will be operated at minimum coke requirement which is about 0.45 ton coke per ton hot iron melt. This coke requirement is equivalent to 0.61 ton of metallurgical coal per ton of hot iron melt. This low coke rate will be maintained by natural gas injection in blast furnace tuyeres for the short term and then conversion to steam coal injection for the long term.

Table 8-6

U.S. STEEL INDUSTRY ENERGY CONSUMPTION

		1983 Quads	1983 Energy %
Met Coal	30.5 million tons	0.79	55
Coke Stock/Imports	4.2 million tons	0.11	
Steam Coal	2.3 million tons	0.06	
Natural Gas	1,040 million scf/d	0.38	25
Oil and LPG	28,200 b/d	0.06*	
Purchased Electricity	4,160 MW	0.36*	20
		1.76	100

		1979 Quads	1979 Energy %
Met Coal	69.4 million tons	1.80	60
Coke Stock/Imports	8.0 million tons	0.21	
Steam Coal	2.0 million tons	0.05	
Natural Gas	1,760 million scf/d	0.64	25
Oil and LPG	93,800 b/d	0.21*	
Purchased Electricity	5,790 MW	0.51*	15
		3.42	100

* 10,000 Btu/kWh

Source: derived by SFA Pacific, Inc. from Reference [2]

Table 8-7

STEEL MILL PRODUCED FUEL GAS

Volume %	Coke Oven	Blast Furnace	BOF
H_2	50	1	1
CH_4	30	-	-
CO	6	28	70
CO_2	2	11	15
N_2	5	60	14
Others	7	-	-
	100	100	100
Btu/scf	500	90	220
U.S. Production - Quads			
1983	0.17	0.21	0.07
1979	0.38	0.41	0.12
Uses	- Coke oven heating - General replacement for natural gas or oil	- Blast furnace heating - Coke oven heating - Direct combustion generate steam/power	- Direct combustion to generate steam/power

Source: derived by SFA Pacific, Inc. from References [2] and [4]

Conventional by-product type coke oven technology has changed very little in over 50 years. The only changes have been increased size and the addition of pollution control equipment. The Jewells Coal and Coke Company has developed a modified coke oven design which is operating at its mine in Vansant, Virginia. The process, called the Thompson non-recovery type coke oven, differs from the conventional by-product coke oven as all of the coke oven gas is combusted for direct heating of the coke oven. Conventional coke ovens collect and separate the coke oven gas and tars/oils of which only a portion (about 40% of the by-product energy) is used to indirectly heat the coke oven. The Thompson process has the advantage of much lower capital cost and operating cost than a conventional coke oven. Furthermore, non-recovery coke ovens could be built at the coal mines. However, the Thompson process has the major disadvantage of converting all the excess energy of coking into hot flue gas. We believe the net economics of the conventional by-product coke oven are better due to the value of the excess coke oven gas as a replacement for natural gas. Based on our discussions with the industry, SFA Pacific believes the integrated steel producers may not want to invest in new conventional coke ovens due to severe shortage of capital and concerns over EPA and OSHA regulations regarding new coke ovens. Therefore, a market could develop for steel mill purchase of coke. This would begin as imported coke. However, once world steel demand recovers, the availability of imported coke will become limited while the price would escalate. Thompson non-recovery coke ovens could then be quickly built at mine locations owned and operated by coal companies.

An other potential alternative to conventional coke ovens are form coke, or briquette, processes. There are a number of these processes, the most notable of which is the FMC process, which was developed in a large pilot plant (250 tons/day) in Kemmerer, Wyoming. However, based on our discussions with the industry, SFA Pacific believes there is currently little interest in these types of processes. This is likely due to potentially high costs as these technologies are extremely complex, requiring six or more interdependent processing steps. Furthermore, these processes usually require binders and produce coke oven type by-products, and the coke does not perform as well in a blast furnace as conventional coke does.

Coal Injection into Blast Furnaces

Based on our discussions with the industry, SFA Pacific believes a coke shortage will develop in the U.S. which will lead to a large use of steam coal injection in the tuyeres of blast furnaces. The maximum coal injection is about 0.10 ton of steam coal per ton of hot iron melt.

Dry pulverized coal injection into the tuyeres of blast furnaces is a technology developed in the U.S. by Armco Steel and Babcock and Wilcox almost 20 years ago. The technology has not been greatly used in the U.S. due to the more favorable economics of injecting low cost regulated natural gas into the tuyeres. However, coal injection is being utilized in Japan, and several U.S. steel mills are now considering this technology because of the upcoming shortage of coke and the rising price of natural gas.

Coal-Based Utilities

The electricity consumption in steel making is significant and will continue to rise with the increase of electric arc furnace based scrap steel making. The majority of the U.S. steel producers are located in areas of the nation where electricity is primarily generated from coal. Furthermore, many of the integrated steel mills produce a portion of their electricity requirements. Most of these in-plant utility facilities are steam-coal-based or utilize coal derived fuel gases such as blast furnace or coke oven gas.

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Integrated steel producers have some steam requirements. Thereby they could possibly expand coal use by generating excess electricity for sales to utilities under the PURPA law. However, SFA Pacific does not believe this will happen based on our discussions with the industry. Most integrated steel mills are located in areas where the PURPA electricity rates are not high. Furthermore, most integrated steel producers are short of capital and cannot afford the investments in expanded coal-based utilities. A potential exception could be the expanded use of combustion turbines which have been specially developed for use with blast furnace gas. Combustion turbines are relatively low cost and they increase the efficiency of this low-Btu fuel gas utilization.

Coal Gasification

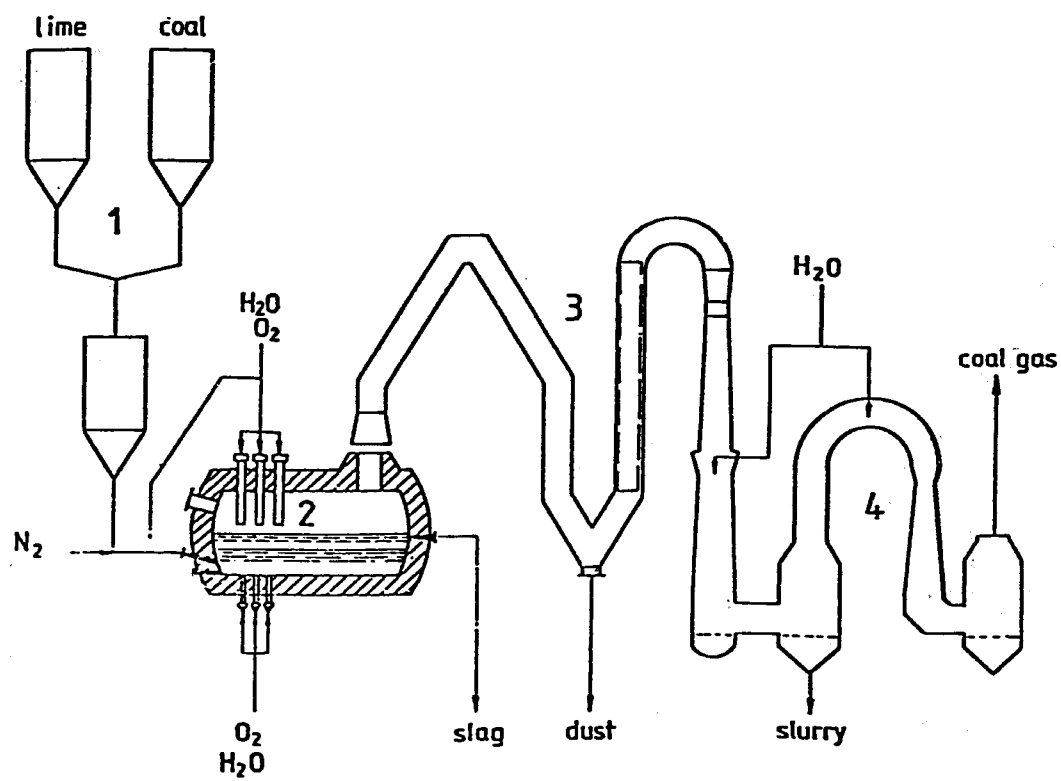
As illustrated in Table 8-6, the U.S. steel industry consumes a large amount of natural gas. Therefore, coal gasification could be considered an alternative for purchased natural gas if coal-derived fuel gas could be produced at a competitive price. Furthermore, the integrated steel mills have existing coal handling facilities, low and medium Btu gas distribution systems and under-utilized oxygen plant capacity. However, SFA believes there are some major limitations that could significantly limit the utilization of coal gasification in the U.S. steel industry. The foremost problem is the short-term supply and price of natural gas which detracts from the consideration of alternative fuels. Another problem is that integrated steel producers do not have the capital required for investments in coal gasification. Finally and most importantly, if integrated steel mills are modernized and made more efficient, the plants can meet essentially all the plant fuel gas requirements with coke oven, blast furnace and BOF gas. In fact, several modern and efficient integrated steel mills in Japan require essentially no premium fuels and even produce some excess fuel gas. Currently, the integrated steel producers are not making the capital investments required for an integrated steel mill to be self sufficient in fuel gas. Therefore, a market for coal-derived fuel gas could develop because of the long term price and availability of natural gas. However, this market would probably require the coal gasification plant to be owned by perhaps a oil or chemical company with over the fence "take or pay" contracts similar to oxygen purchases by steel companies.

A better potential for coal gasification in the steel industry is use of this technology in conjunction with direct reduction of iron ore. The supply and price of high quality scrap could ultimately limit the growth of mini mills and the expanded use of electric arc furnaces by integrated steel mills. This could lead to increased markets for direct reduced iron (DRI). The initial growth in DRI will be imports from areas of the world where low-cost natural gas is available as the energy source for the iron reduction. However, long term, the economics and security of supply will favor coal gasification-based direct reduction or direct coal-based iron ore reduction in the U.S.

Coal gasification has a number of advantages for use with commercial direct iron ore reduction processes. Specifically, direct reduction processes can directly utilize the high carbon monoxide (CO) content and sensible heat in raw gas leaving the gasifier. The best coal gasification technology for the application appears to be the Sumitomo/KHD molten iron bath process because this system removes essentially all the sulfur without cooling the raw gas and the raw gas is about 95% CO and H_2. The presence of CO_2, H_2O, CH_4 and sulfur (H_2S) in the raw gas or cooling of the raw gas for removal of these compounds reduces the potential economics of coal gasification-based iron ore reduction. A 60 ton/day (dry coal basis) Sumitomo/ KHD pilot plant has been successfully operated in Japan and a 250 ton/day demonstration plant will begin operation in Sweden in 1986 [5]. Figure 8-2 shows a flow sheet of the demonstration plant. Another attractive coal gasification technology for this application could be the Shell process as the raw gas from this process is also about 95% CO and H_2. However, the Shell process would add sulfur to the iron or

Figure 8-2

KHD/SUMITOMO DEMONSTRATION PLANT



1. coal-lime-injection system
2. gasifier
3. waste heat system
4. scrubber

Source: KHD Humboldt Wedag

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require use of developmental hot sulfur removal processes for direct hot gas use for iron ore reduction. Shell has successfully operated a 150 ton/day pilot plant in Germany and is now considering building a demonstration plant in Deer Park, Texas.

It has recently been announced that the Chinese government will build a KRW (Westinghouse) coal gasifier for iron ore reduction at the Fularji Heavy Machinery steel plant. The KRW coal gasification process is a fluidized bed which has been operated only at a small pilot scale. This process produces a raw gas high in H_2O, CO_2, CH_4 and H_2S which detracts from direct use of the hot raw gas for direct iron ore reduction.

Direct iron ore reduction processes have the disadvantage of converting only a portion of the H_2 and CO feed to H_2O and CO_2 per pass. However, the raw gas leaving the iron ore reduction furnace can be purified and recycled or used only "once through" and utilized to supply an inplant-produced fuel gas. The "once through" design could have an advantage if the steel mill is purchasing significant amounts of high cost oil, natural gas or electricity.

Direct Coal-Based Iron Ore Reduction

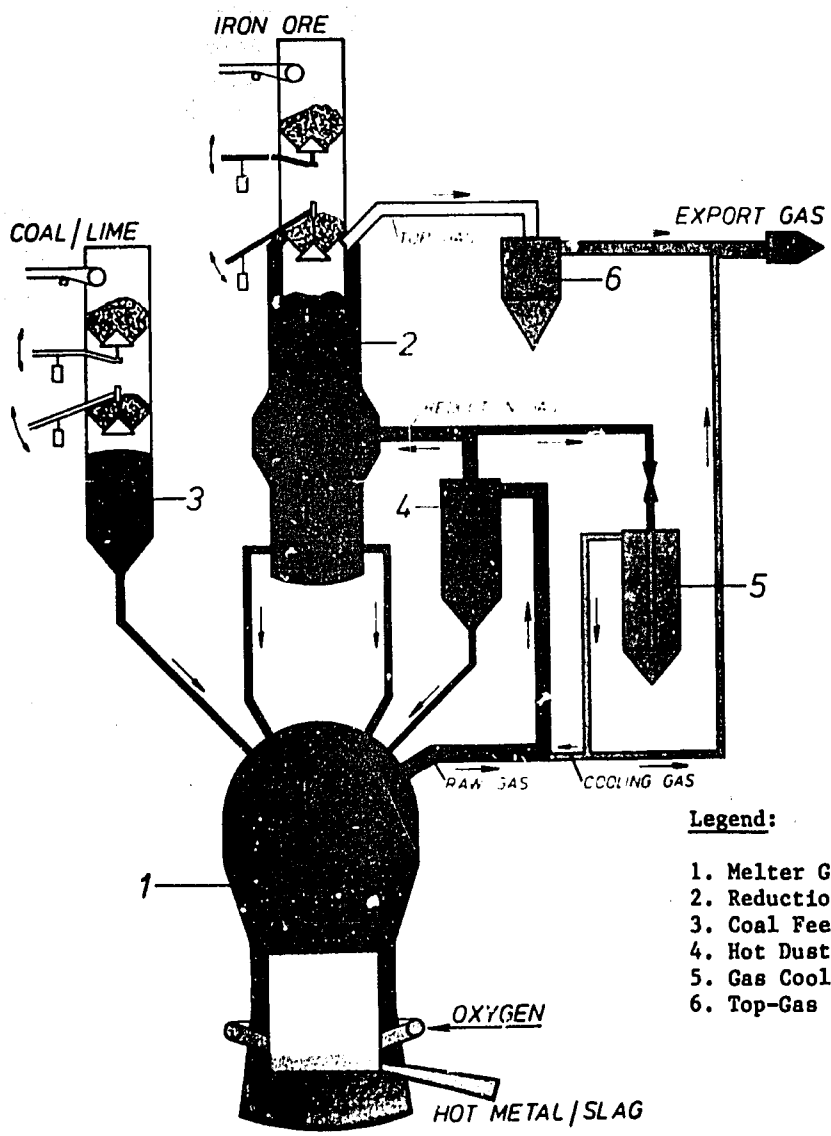
The high capital and operating cost of coke ovens and blast furnaces create a large potential for an alternative coal based iron making process. The ideal process should be continuous, and based on low-cost steam coal. Relative to the batch operation of coke ovens and blast furnaces, any reasonable continuous process would avoid high operating/maintenance cost and environment/worker health problems, and could be more efficient. The original work on continuous coal-based iron ore reduction in the 1960s concentrated on the use of rotary kiln technology. Although several kiln type processes are now utilized, they appear to have very limited potential. Coal-based rotary kiln iron ore technologies suffer from limited capacity, poor carbon conversion and high operating/maintenance costs. Furthermore, the kilns cannot be pressurized and sealed to avoid pollution problems and for effective recovery of by-product fuel gas.

The most interesting current development in direct continuous coal-based iron making involves the KR process [6]. This process, developed by Korf and Voest Alpine, involves the direct integration of a fluidized bed coal gasifier with an iron ore reduction shaft furnace and a modified basic oxygen furnace. Figure 8-3 shows a basic flow sheet for the KR process. Coal is gasified in an oxygen-blown fluidized bed gasifier. The hot raw gas leaving the gasifier is fed directly to a Midrex shaft type iron reduction furnace. The gas leaving the top of the shaft furnace can be used as fuel gas or purified and recycled. Hot reduced iron pellets are transferred directly from the bottom of the shaft furnace into the top of the fluidized bed gasifier. The iron pellets pass down through the fluidized bed and are melted directly under the fluidized bed gasifier in the same vessel. The iron melter appears to be a modified bottom blown basic oxygen furnace. A 200 ton/day (coal basis) pilot plant has been operating at Kehl, West Germany since 1981. In November, 1984, 2,800 tons of U.S. bituminous coal and 3,500 tons of U.S. iron ore pellets were successfully processed in this pilot plant. This test was sponsored by a consortium of U.S. organizations, including the DOE, the State of Minnesota, Inland Steel, U.S. Steel and the American Iron and Steel Institute. There is considerable interest in building a demonstration plant of this process in the United States.

The KR process has a number of potential advantages over conventional coke oven and blast furnace iron making. The continuous operation assures low cost and efficient operation even at relatively small scale, plus few environmental/worker health problems. However, the process has some coal choice limitations, and

Figure 8-3

KR - PLANT BASIC FLOW SHEET



Legend:

1. Melter Gasifier
2. Reduction Shaft Furnace
3. Coal Feed Bin
4. Hot Dust Cyclone
5. Gas Cooler
6. Top-Gas Cooler

Source: Korf Engineering GmbH

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all the coal ash and sulfur directly contact the iron. Also, the heart of the process is a fluidized bed coal gasifier which is utilized in a very complex integration with two more conventional iron making processes. Traditionally, there have been major problems with operation scale-up and carbon conversions of conventional fluidized bed coal gasifiers.

There are several other direct coal-based iron making processes under development. Sumitomo Metals is developing a system similar to the KR process except with an entrained flow gasifier and the addition of a small amount of coke. It should be noted that the Sumitomo iron making process is a completely separate development not to be confused with the Sumitomo/KHD coal gasification process. The Swedish government has been developing a process called INRED which integrates the coal-based reduction with electric arc melting. A consortium which includes Westinghouse, Minnesota Power, the State of Minnesota and Picklands Mather are developing a process called Mesabi Metal which integrates the coal based reduction with electric plasma melting. It should be noted that the INRED and Mesabi processes consume large amounts of electricity. Over the last few years, U.S. steam coal prices have remained constant while U.S. electricity prices have greatly risen due to the high cost of nuclear plants, environmental controls on coal plants, and continued use of premium fuels in electricity generation. If this trend continues the total coal-based iron-making processes (like KR) will have a large operating cost advantage over those iron making processes which require coal and electricity (like the Mesabi process).

Another competitor to the KR process is the Sumitomo/KHD gasification process followed by the Midrex process and then electric furnace melting of reduced iron pellets. This type of system has less potential coal gasification problems, less complex integration, utilizes any low cost steam coal and avoids contacting coal ash and sulfur with the iron.

Miscellaneous

There are other miscellaneous coal applications which could have potential for the steel industry. An interesting application of fluidized bed combustion (FBC) of coal is currently being demonstrated in Germany. The FBC is utilized to indirectly heat compressed air to about 1500°F which is then expanded to generate power. This technology could be modified to replace blast furnace gas with steam coal in preheating the blast furnace air. After compressing the blast air, FBC technology could be used to preheat the compressed air to 1,500°F. Additional heat could be added by inline combustion of blast furnace or basic oxygen furnace gas to achieve the normal air preheat temperature of 2,000°F. Combustion of these CO rich gases avoids adding H_2O combustion products to the hot blast air, which is undesirable. Alternatively, fuel could be combusted for indirect final heating of the air if new developing ceramic heat exchangers are utilized. This would avoid the cyclic operation of checker brick heating and would save over 75% of the blast furnace gas normally utilized to preheat the blast air. However, this would only be economical if a higher value use is found for the replaced blast furnace gas than preheating blast air. A promising high value application would be electric power generation with combustion turbines or use of blast furnace gas to replace oil or natural gas.

Several technologies could lead to better utilization of blast furnace and basic oxygen furnaces gases which are indirectly coal-derived. The commercially proven COSORB process can be used to recover high purity CO from these gases for chemical uses. In fact, a COSORB system is currently being installed for this application in a steel mill in Japan. The developmental BEACON technology could be used to convert these gases into a mixture of CH_4 and H_2. The BEACON process under very preliminary bench scale development by TRW and SOHIO reacts CO to a highly reactive carbon via catalytic deposition. Steam can then react with

the carbon to form CH_4 and H_2. Therefore the low-Btu blast furnace gas can be converted into medium-Btu gas which would greatly improve its usefulness. Basic oxygen furnace (BOF) gas can also be used more effectively. The Republic (now LTV) steel mill in Cleveland uses the "suppressed combustion system" on a BOF to recover the 220 Btu/scf gas from the cyclic furnace [7]. Either the development of a continuous BOF or use of a high pressure gas holder could convert this cyclic BOF produced fuel gas into a continuous fuel gas supply. This would greatly improve the utility of BOF gas.

Coke oven gas has some potential high-value applications which could develop in the future, assuming integrated steel mills modernize and become more efficient and fuel gases from blast furnaces and basic oxygen furnaces are more effectively utilized. Specifically, coke oven gas could be easily converted into substitute natural gas, pure hydrogen or synthesis gas (H_2 and CO) for catalytic reaction into high-value chemicals.

Issues Affecting Overall Growth and Fuel Use

The fuel use in the U.S. steel industry has sharply declined from 3.42 quads in 1979 to 1.76 quads in 1983. This decline is mostly due to the severe drop in U.S. steel production. Furthermore, the total energy consumption per ton of finished steel has also sharply dropped from 1979 to 1983. Most of the drop is not due to improved integrated mill efficiency but due to a large increase of percent of steel produced by scrap-based mini mills. This illustrates why the U.S. steel industry is not currently increasing coal use. Nevertheless, there are a number of important issues which will effect long term growth and fuel use.

Total U.S. Steel Demand

Steel remains the most important engineering material in the world. Steel is the dominant material in major appliances and automobiles. The per capita consumption of steel is an order or magnitude greater than for aluminum or plastics. Furthermore, there are no cost-competitive performance substitutes for steel in applications where strength is important, such as equipment bodies and frames, machinery, piping, bridges and buildings.

Over the last 10 years the apparent annual steel consumption in the U.S. has wildly fluctuated between a high of about 120 million tons in 1974 and a low of about 75 million tons in 1982. The 1984 steel consumption was about 100 million tons. Steel demand is quite sensitive to economic activity. Steel demand projections by essentially all the econometric modellers have recently demonstrated their inability to project future U.S. steel demand within ±25%.

U.S. Steel Production Versus Imports

In 1984 imported steel reached an all time high of 26% of U.S. steel consumption (about 26 million tons). The major integrated U.S. steel companies have been trying to persuade the Administration that their survival depends on firm import restrictions. It appears that the Administration has been able to negotiate a series of voluntary limits with most of the major steel exporting countries which should restrict U.S. imports to 21% of U.S. steel consumption. These voluntary import restrictions include semi-finished slabs; however, several of the major integrated steel mills consider imported semi-finished slabs an attractive alternative to reinvestment in their aging domestic iron making facilities.

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Integrated Versus Mini Mill Steel Production

Most of the recent decline in U.S. steel production has been at the expense of the integrated steel mills while mini mills have continued to expand. Mini mill steel production is now over 15 million tons of finished steel per year while U.S. integrated mill production was only about 60 million tons finished steel in 1984.

Integrated steel production requires about 25-35 million Btu of total energy per ton of finished steel. The majority of this energy, usually 65-70%, is supplied by metallurgical coal. Steam coal is usually about 5% while natural gas and some oil supply 20-25% and purchased electricity supplies another 5% of this total energy. Mini mills only require about 5 million Btu of total energy per ton finished steel. About half this energy is natural gas and half is electricity (based on 3413 Btu/kWh). It should be noted that a large portion of the electricity purchased by mini mills is generated from coal. The mini mill electricity consumption of about 750 kWh per ton translates to steam coal energy of 7 million Btu per ton of steel.

Continued growth in mini mill-based steel production will require expansion into sheet steel which makes the development of thin continuous casting critical. Furthermore, the continued growth of mini mills could be limited by the price/supply of high quality scrap. However, the limitation can be resolved by the increased use of direct reduced iron (DRI) technology. This technology would be natural gas based with imported DRI or coal gasification based with U.S. produced DRI.

Reinvestment and Modernization of Integrated Steel Mills

The large variation in the energy required by integrated steel production (25-35 million Btu per ton of finished steel) reflects the large amount of antiquated steel making capacity which exists in the U.S. The highest energy requirements are for integrated steel mills which utilize small blast furnaces, open hearth furnaces, and ingot based steel finishing. The lowest energy requirements for integrated steel utilize modern blast furnaces, basic oxygen furnaces and continuous casting. Most of the new efficient Japanese integrated steel mills are as high as 85-90% coal based with the remaining energy being mostly electricity and a very small amount of oil [8]. Increased coal use (as a percentage of total energy) even in the most modern and efficient integrated steel mills will slightly increase total energy requirements. Increased coal use can actually lead to a slight excess in coal derived fuel gases which can be sold or utilized to generate electricity.

It appears that most of U.S. integrated steel producers may not be profitable enough to make all the reinvestment required to become "world class" efficient integrated steel makers. As discussed earlier, we speculate that limited capital will be invested in replacing ingot based steel finishing with continuous casting while the iron making facilities continue to decay. This will lead to reduced natural gas requirements until a coke crisis develops.

Will There Ever be Another New Coke Oven Built in The U.S.?

The current weak steel markets are helping integrated steel producers avoid a long term problem regarding coke ovens. If U.S. integrated steel production ever returns to more than about 75 million tons/year of finished steel, a critical coke shortage will develop. It is questionable if a new coke oven will ever be built again in the U.S. due to the high capital and operating costs of the basic design, plus the large added cost and uncertainty associated with proposed EPA and OSHA laws. Current activity in coke

ovens centers on repairs and rebuilds of existing facilities which avoid most EPA and OSHA problems. However, ultimately this coke oven dilemma must be addressed.

Coke ovens directly or indirectly supply over 60% of the total energy requirement in inefficient integrated U.S. steel making and as high as 90% of the total energy in modern efficient Japanese integrated steel making. Coal based iron making technology is essential to the long term economic viability of the U.S. steel industry. The abundance and low cost of high quality steam coals is one of the few advantages the U.S. steel industry has over its competition. The issue is if U.S. steel production in the future will be based on higher-cost metallurgical coals and batch-operation coke ovens or lower cost steam coals based on advanced continuous iron-making technologies.

SFA Pacific believes a severe coke shortage will develop in the U.S. by 1990. Alternatives as a coke crisis developes include the following:

- o injection of natural gas or steam coal in the tuyeres of blast furnaces to reduce coke demand by about 20%
- o imported coke
- o imported semi-finished steel
- o development of continuous steam coal based iron making processes such as the KR process

The last alternative is the best long-term choice. Assuming U.S. integrated steel producers begin to replace aging coke oven and blast furnaces with advanced steam coal-based iron making technology, excess metallurgical coal mining capacity would develop in the U.S. However, this change from metallurgical to steam coal-based iron making would be very slow due to a number of uncertainties and obstacles. SFA Pacific believes the U.S. integrated steel mills would sell unnecessary metallurgical coal mines and reserves which would probably be purchased by foreign integrated steel producers who have new coke ovens and blast furnaces.

The Expanded Use of Coal in the Steel Industry

The steel industry is the traditional dominant force in coal utilization by the industrial sector. That dominance has recently diminished with the demise of U.S. steel production. However, there must be expanded use of coal in the U.S. steel industry for the integrated steel maker to survive and for the mini mills to expand.

Favorable Conditions for Coal Use

The key issue to increased coal use by the steel industry is increase in total U.S. steel production from the current depressed levels. This is controlled by the general health of the economy and the amount of steel imports.

A secondary issue is increased integrated steel mill production versus increased mini mill production. The direct coal consumption by integrated steel mills is 0.8 to 0.9 tons of coal per ton of finished steel of which about 90% is metallurgical coal and 10% is steam coal. Purchased electricity by integrated mills (about 500 kWh per ton finished steel) is equivalent to an additional indirect coal use of 0.2 tons steam coal per ton finished steel. The mini mills have no direct coal use. However, the purchased electricity (about 750 kWh per ton finished steel) is equivalent to 0.3 tons steam coal per ton finished steel.

The indirect coal consumption of mini mills could increase in the future. Any substantial growth in mini mill steel making will require direct reduced iron (DRI) to supplement the supplies of high quality scrap. This will begin as imported natural gas based DRI but will ultimately be domestic coal-based DRI.

Uncertainties and Obstacles

The expanded use of coal in the U.S. steel industry faces uncertainties and obstacles in every regard The key uncertainties include:

- o total U.S. steel demand
- o imports
- o integrated versus mini mill steel production
- o long-term high-quality scrap supply/price
- o long-term coke supply/price

All of these uncertainties have been discussed in the previous section entitled "Issues Affecting Overall Growth and Fuel Use."

The key obstacles to expanded use of coal in the U.S. steel industry are the low profitability and slow acceptance of technology change by the integrated steel mill. The U.S. steel companies require extensive modernization and union work rules changes to make U.S. integrated steel mills cost competitive. This will require investment in new technology that can produce more high quality steel with less premium energy (oil and gas) and less labor. Low profitability limits the available capital for investment in new technology which involves higher risk and development cost. The low profitability also relates to more employee lay-offs which are of course resisted by unions. This is especially true when new technology directly replaces an antiquated technology which required substantially more labor. The incredible low acceptance of basic oxygen furnaces and continuous casting during previous years of high profitability demonstrated a serious problem in big steel decision making. However, these obstacles could diminish due to the increasing ownership of U.S. steel companies by Japanese steel companies. Japanese steel companies could supply needed capital and a fresh approach. Furthermore, Japanese management should improve union relations, will look at long term return on investment, and will quickly accept and improve upon technology invented by others.

Industry Attitude

Steel industry attitudes do not hinder expanded coal use. The integrated steel making industry is not afraid of coal since the industry is already predominantly coal based. Furthermore, coke ovens are a technology which is an integrated part of the industry, not merely a small operating cost such as utilities in a chemical or oil industry. However, steel industry attitudes toward technology change, as discussed in the previous sections entitled "Characteristics of the U.S. Steel Industry" and "Uncertainties and Obstacles," could slow the industry's acceptance of new coal based technologies. The most important new coal coal based technology could be continuous steam coal based iron making processes as an alternative to batch operation coke oven and blast furnaces. Slow acceptance of this technology could assure continued poor profitability and the continued long term demise of the integrated steel producers.

The mini mill industry is not afraid of coal or technology change. In fact, many mini mills were originally steel fabricators that expanded into steel making due to the high price they were charged for steel by integrated steel mills. However, mini mills do not have the requirements for coal technology short

term due to available scrap supplies and to the existing steel uses supplied by mini mills. Long term the supply/price of high quality scrap could require coal-based direct reduced iron ore (DRI). However, mini mills would prefer to purchase DRI like they currently purchase scrap. Therefore, DRI could begin as imported natural gas based DRI before domestic coal-based DRI could be considered by mini mills.

Utilization Time Frames

Coal will continue to be the dominant energy consumed in the U.S. steel industry. However, the total steel market, imports, and ratio between integrated and mini mill steel could make the coal usage fluctuate widely with time. The direct coal consumption by integrated steel mills will remain relatively constant at 0.8 to 0.9 ton coal per ton finished steel. Plant modernization and improved efficiency will mostly reduce premium (oil and gas) fuel requirements, not coal requirements. Investments in new continuous iron making technologies and steam coal injection into blast furnaces could change the coal mix from mostly metallurgical coal to lower cost steam coal. However, this shift from metallurgical coal to steam coal could only develop after a coke crisis has occurred. SFA Pacific speculates that a coke crisis will develop before 1990.

The mini mills directly consume essentially no coal at the present time. However, if mini mills can expand their markets into sheet steel, the long term supply and price of scrap could create a market for direct reduced iron (DRI). This market would begin based on imported natural gas based DRI and then develop into domestic steam coal based DRI. Assuming use of the Sumitomo/KHD coal gasifier and the Midrex shaft reduction furnace, the steam coal requirement for coal based DRI would be about 0.7 to 0.8 tons coal per ton finished steel. The time frame for coal based DRI plants in the United States could begin in the mid to late 1990s. However, this can only develop after a high quality scrap crisis has occurred. SFA Pacific speculates that a scrap crisis could develop about 1990.

Most Attractive R&D Candidates for the Steel Industry

Integrated Steel Making

The fundamental problem with conventional integrated steel making technology is that it is labor, energy and capital intensive. Most integrated steel mills in the U.S. are relatively old and are significantly less energy and labor efficient than new mills. Because of this, most if not all integrated steel mills in the U.S. are not competitive with a modern integrated steel mill in Japan, South Korea, and Brazil. Furthermore, even a "grass roots" modern U.S. integrated steel mill based on the latest conventional technology would probably not be cost competitive with recently completed mills in South Korea or Brazil. This is because these countries have an order of magnitude lower steel worker wage rate than the U.S. and do not meet standards similar to those set by EPA or OSHA for U.S. steel mills. Even Japan cannot compete with South Korea because of the lower labor rates and the lack of environmental/worker health regulations in South Korea. Therefore the U.S. integrated steel producers must consider radical technology changes that can significantly reduce labor requirement, use mostly low cost steam coals and avoid environmental/worker health problems.

The future of the U.S. integrated steel industry will rely on the development of continuous steam coal based iron making technology to replace coke ovens. The U.S. integrated steel companies are finally recognizing the advantages of continuous casting over ingot based steel finishing. Specifically, continuous casting requires significantly less labor and less premium energy. Any continuous system has these inherent

advantages over a batch operation. Once integrated steel makers have converted most of the steel finishing to continuous casting, the problems of aging iron and steel making facilities must be resolved. A continuous steam coal based iron making process would have the same type of advantage as continuous casting and would resolve major EPA/OSHA problems associated with batch operation coke ovens.

As discussed in the Coal Application section, there are several steam coal based continuous iron making processes under development. The KR process appears to be the leader due to its more advanced state of development. However, all these processes rely on a coal gasification/oxidation stage as a integral part of the process. The gasification step is generally integrated between the iron melt and the iron ore reduction sections. This means that the coal ash and sulfur are in direct contact with the iron. Furthermore, the key technical uncertainty is the gasifier and its integration with the more technically proven iron ore reduction and hot melt sections. The successful scale-up of separate coal gasification processes by experienced coal gasification experts has traditionally been difficult. The direct integration of coal gasification with the iron reduction and melting sections plus coal ash and sulfur removal from the iron will be even more difficult.

An alternative process to the KR process is a separately developed coal gasification process with a commercial iron ore reduction process followed by a commercial electric furnace. It is important on economic grounds to use a coal gasification process that produces raw gas which is rich in H_2 and CO and low in CO_2 and H_2O. The hot raw gas can thereby be efficiently used directly in the iron ore reduction furnace. The best coal gasification process appears to be the the Sumitomo/KHD process since this gasifier is unique in that the hot raw gas is sulfur free. A secondary technical issue that would improve other coal gasification processes (such as the Shell gasifier) in this application is hot gas clean up to remove coal-derived H_2S from the hot raw coal gas. DOE, Westinghouse and Midrex are doing interesting research in this area. However, coal gasification/iron ore reduction systems will still work without hot sulfur removal. Sulfur can be removed from the hot iron melt as required with the KR process.

An additional area of R&D for the integrated steel maker is more efficient use of coal derived fuel gas. Specifically, basic oxygen furnace (BOF) and blast furnace gas is under-utilized. Better use of these fuel gases would directly replace natural gas. Development of a continuous BOF process would greatly improve the potential for more effective utilization of BOF gas. Development of a process to separate CO from N_2 would greatly improve the potential for more effective utilization of blast furnace gas.

Mini Mills

Most mini mill operators are probably not aware that steam coal based technology could greatly affect the long-term growth and economics of mini mill steel making. Mini mills are now expanding into markets for higher quality steel. Specifically, the current development of thin strip continuous casting could double mini mill production over the next ten years. However, the availability and price of high quality scrap could limit mini mill growth.

Mini mills may soon face a crisis in scrap quality. They will begin to supplement scrap with some imported direct reduced iron (DRI) based on low cost natural gas. The scrap quality could continue to deteriorate and imported DRI requirements could continue to increase. These changes would cause the prices of high quality scrap and DRI to be high thereby reducing the economic attractiveness of mini mills. This may ultimately force mini mills to consider steam coal based iron making technology.

Much of the mini mill success has been based on readily accepting and improving new technology invented by others. Once integrated steel makers or technology developers have demonstrated continuous steam coal based iron making technologies, the mini mills could move quickly into this area of steel making.

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SECTION 9

COMMON UNCERTAINTIES TO EXPANDED USE OF COAL IN THE CHEMICAL, OIL REFINING AND STEEL INDUSTRIES

Table 9-1 shows delivered prices paid by the U.S. industrial sector for fuels and electricity in 1971 and 1981. It is interesting to note that all fuels have increased in price over that time frame at a higher rate than steam coal. Furthermore, the current delivered price of steam coal is significantly less than any other fuel. Nevertheless, industry has not converted to or expanded coal use at near the rate projected by most energy/economic modellers. The lower than expected expansion in use of coal by industry is due in part to the following uncertainties:

- o environmental
- o competing energy prices
- o financing
- o industrial growth
- o attitudes

Environmental

Coal has inherent environmental problems relative to its competition: natural gas and oil. Coal contains ash, sulfur and nitrogen which convert to particulates, sulfur dioxide and nitrogen oxides when the coal is utilized. However, there are technologies available to reduce these emissions to acceptable levels.

The key uncertainty associated with environmental limitation on expanded use of coal is not emissions control per se, but delays and confusion caused in defining what levels of emissions are acceptable to which agencies under what laws. Depending on the size and location of a proposed coal utilization unit the following agencies could be involved in permitting:

- o Environmental Protection Agency (EPA)
- o Bureau of Land Management (BLM)
- o National Institute of Occupational Safety and Health (NIOSH)
- o Occupational Safety and Health Administration (OSHA)
- o State Environmental and Occupational Safety and Health Agencies
- o Regional Air Quality Agency
- o County Air Quality Agency
- o City Air Quality Agency

The following regulations, laws, classifications, conditions, and terms represent some of the major issues with which a user of coal must contend.

- o Federal New Source Performance Standards (NSPS)
- o Clean Air Act (CAA)
- o Prevention of Significant Deterioration (PSD) of ambient air quality
- o Best Available Control Technology (BACT)
- o Class I, II or III air quality areas

Table 9-1

ENERGY PRICES PAID BY INDUSTRIAL SECTOR

	1971		1981		1981/1971
	$/million Btu	Ratio to Steam Coal Price	$/million Btu	Ratio to Steam Coal Price	~~10 %~~ % Price Increase
Steam Coal	0.41	1.00	1.51	1.00	36%
Metallurgical Coal	0.54	1.32	2.42	1.60	44%
Natural Gas	0.37	0.90	2.92	1.93	78%
Residual Fuel Oil	0.61	1.49	4.84	3.21	79 3
Distillate Fuel Oil	0.75	1.83	7.39	4.89	98 5
Electricity	3.21	7.83	12.57	8.32	39 2

Source: derived from Table 19, Annual Energy Review 1983, DOE/EIA-0384 (83) Washington, D.C., April 1984

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- o Wilderness Provision of the Federal Land Policy and Management Act of 1976
- o State Implementation Plan (SIP)
- o Proposed acid rain laws which affect existing units
- o Non-Attainment Area (NAA)
- o Trace elements
- o Occupational exposure standards
- o Visibility
- o Hazardous wastes
- o Environmental Impact Statement (EIS)

In themselves these issues are not insurmountable obstacles for a potential user of coal. However, they do add a significant layer of uncertainty to the use of coal, rather than oil or gas. This is particularly so when standards are changed, thus presenting potential coal users with a moving target.

Industry would use more coal if it were confident of the economic advantages of coal over other fuels and of the time required to bring coal technology into service. However, at the current time, industry cannot quickly or easily define what environmental limits are required to utilize coal for a specific site and application, which must be done before the economics can be objectively analyzed. Sadly, the environmental uncertainties tend to promote "status quo." In many cases, continuing to burn high sulfur residual oil with no emission controls avoids the additional costs and disruption required to replace the residual oil with coal. This occurs even though the coal unit is probably more economical including emission controls required for the new system.

Competing Energy Prices

The key competition affecting expanded use of coal in industry is natural gas. However, there are major uncertainties which make projecting the price and availability of natural gas difficult, if not impossible. Industry hopes that price controls will be removed from natural gas which would let the price go to its true market value, thereby assuring long term availability. If prices are regulated at artificially low levels, consumption will rise while no economic incentives exist to explore and develop additional supplies. This situation would lead to natural gas supply shortages identical to the winter of 1975/1976 and thereby to restriction on natural gas use by industry.

The general concensus among energy price forecasts is that deregulated natural gas will eventually go to price parity with low sulfur residual fuel oil. The critical issue is what the oil price will be. Over the last 12 years energy forecasters have demonstrated a gross inability to predict oil prices.

A useful way to analyze the economics of coal use relative to fuel oil or natural gas is the ratio of delivered energy cost. At a fuel oil/steam coal cost ratio of about 2.5 to 3.0 the economics of coal use become very attractive. This high fuel cost difference is a reflection of the higher capital cost of using coal.

It must be recognized that coal prices are quite independent of oil/natural gas prices. For example, between 1979 and 1982 coal prices changed very little while oil prices tripled. The great reserves, competition and large number of suppliers assure coal price will remain relatively constant in the future and more related to production cost. However, oil and in turn natural gas prices could change significantly in the future due to cartel control, politics, and a quickly declining ratio of U.S. reserves to total U.S. consumption.

Financing

The capital cost of equipment and facilities required to utilize coal are significantly higher than those required to utilize fuel oil or natural gas for the same application. However, the higher capital cost required to utilize coal must be compared to the operating cost savings associated with the much lower energy price of coal relative to fuel oil or natural gas. Unfortunately, financial uncertainties work against coal due to the high capital costs.

Specifically, many "heavy" industries in the U.S., such as the major U.S. steel companies, are currently suffering from low profitability. Therefore capital for investment is limited and coal related investments are delayed due to the high capital cost even if the return on investment appears attractive.

High interest rates work against coal investments due to its additional cost on borrowed capital. High interest rates also require higher return of equity investment which again work against higher capital cost projects such as coal.

There is a significant time delay between the time the large investment in coal-based facilities is made and the time of operation, when the fuel savings will be realized. This delay can detract from coal related investments even when the long term return on investment is attractive. Sadly, many executives must be most concerned about very short term profitability of their companies due to the fact that many investors are short term oriented. Low quarterly profits can cause sell-off of a company's stock by investors, thereby jeopardizing the executive's job.

Industrial Growth

There is currently a lack of growth in the oil and steel industries as well as certain areas of the chemical industry. Because of this, many companies in these industries are diversifying and investing in other industries. Most of these investments have been in industries that are not energy intensive, such as retailing, service industries, office equipment and specialty chemicals. Investments in these areas have little prospects for use of coal.

The lack of growth also detracts from use of coal in existing facilities. The economics of coal use in a green field expansion are generally much better than when considering retrofitting of existing oil or gas fired facilities with amortized equipment plus limitations such as space, emissions or infrastructure.

Attitudes

Idaho Supreme Potatoes Inc., is a very small company in Firth, Idaho, which grows and processes raw potatoes into instant potato products. The plant used natural gas fired boilers to generate the 55,000-75,000 lbs/hr of steam required to dry the potatoes and heat the facilities. During the winter of 1981/1982 operating costs reached what was considered an excessive level due to the cost of natural gas which had risen to $4.00 per million Btu, creating monthly fuel bills of $250,000. In less than one year, engineering, construction, and start-up were successfully completed at the existing plant of new facilities to generate 70,000 lbs/hr of steam by pulverized coal combustion. Field-erected stoker and fluidized bed coal fired boilers were considered but were rejected because of high cost. A 125,000 lbs/hr used residual oil fired A-type packaged boiler was purchased. This boiler was re-tubed and modified to burn pulverized coal at a de-rated capacity of 70,000 lbs/hr steam. The design included fabric filter particulate control and

burns low sulfur coal without flue gas desulfurization. The entire project cost was only about $1.5 million and produced a very high return on investment as the payback (investment divided by operating cost savings) was only one year [1].

The important question must be asked, how five Idaho potato farmers can get a high return on investment for converting from natural gas to coal at the same time that most large oil, chemical and steel companies conclude that conversion from natural gas to coal is not economical? There are some fundamental attitude differences between large and small companies which make coal conversion more difficult for large companies.

Conversion from natural gas or fuel oil to coal will obviously make the jobs of the plant operations personnel more difficult. However, conversion to coal will produce large fuel cost savings. Generally, the larger the company, the more difficult it is to effect such a change. Therefore, it may be more difficult to convince operations personnel at a large company that converting to coal, which makes their jobs more difficult, is justified.

Conversion from natural gas or fuel oil to coal requires significant investment. Large companies generally design for excess capacity and spare equipment to assure high reliability. Large companies also utilize high cost "top of the line" equipment. This type of extra cost over design is devastating to coal equipment due to inherently high capital cost even without the over design. Most large companies would not consider modifying a used boiler (with no excess capacity) to save money, as was done by the Idaho potato farmers.

Conversion from natural gas or fuel oil to coal requires a "hero" to convince management of the savings, convince operational personnel that the more difficult use of coal is justified, tightly manage the project to control capital cost and put up with the harassment required to figure out and obtain all the required regulatory approvals. It is uncommon to find this type of hero in a large company because there are usually no incentives to justify the risk. However, small companies can more easily generate this type of "hero". The management, operation and engineers could all be the same person or even the "hero" at a small company. Furthermore, the cost savings of coal conversion could generate direct economic rewards to the hero at a small company.

Reference

1. "Conversion of Packaged Boiler to Micronized Coal Cuts Operating Cost," Power, May 1984.

APPENDIX A

GLOSSARY AND ABBREVIATIONS

AFBC	atmospheric fluidized bed combustion
ARCO	Atlantic Richfield Company
bbl	U.S. barrel = 42 U.S. gallons
BGC	British Gas Corporation
Btu	British thermal unit (1 Btu = 0.252 kilocalories)
BTX	benzene, toluene, xylenes
b/d	U.S. barrel per day
°C	temperature, degrees centigrade (Celsius)
Ca/S	Calcium-to-sulfur ratio
CGCC	coal gasification/combined cycle
CWM	coal water mixtures
d	day
DRI	direct reduced iron
DOE	U.S. Department of Energy
EAF	electric arc furnace
EDS	Exxon Donor Solvent
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
FBC	fluidized bed combustion
°F	temperature, degrees Fahrenheit (°F=1.8°C+32)
FGD	flue gas desulfurization
FMC	FMC Corporation
gal	U.S. gallon (1 gal = 3.785 liters)
GKT	Koppers-Totzek coal gasification process
gpm	U.S. gallon per minute (1 gpm = 0.227 cubic meters per hour)
HDS	hydrodesulfurization
hr	hour
HTW	High Temperature Winkler
IFP	Institut Francais du Petrole
INRED	Swedish coal reduction process
KHD	Kloeckner-Humbolt-Deutz, AG
KR	iron making process incorporating coal gasification, developed by Korf and Voest Alpine companies
K-T	Koppers-Totzek
KW	kilowatt (1,000 watts), based on electrical output unless otherwise stated
kWh	kilowatt-hour
lb	pound (1 lb = 0.4536 kilograms)
LPG	liquified petroleum gases
metallurgical coke	special high-carbon material for steel making
MHD	magnetohydrodynamics
MM	million
MTBI	methyl tertiary butyl ether
MTG	methanol-to-gasoline
MW	megawatt
MWH	megawatt-hour
N/A	not available
NOx	nitrogen oxides

OPEC	Organization of Petroleum Exporting Countries
OSHA	Occupational Heath and Safety Administration
Oxinol	methanol-tertiary butyl alcohol blend used as an octane enhancer
PADD	Petroleum Administration for Defense Districts
petroleum coke	carbonaceous solid remaining after coking (destructive distillation) of residual oil
PFBC	pressurized fluidized bed combustion
ppm	parts per million
psig	pounds per square inch guage (14.7 pounds per square inch = 1 atmosphere = 1.033 kilograms/square centimeters
PURPA	Public Utilities Regulatory Policv Act
quad	one quadrillion (10^{15}) Btu
R&D	research and development
scf	standard cubic feet, 1 atmosphere, 60°F (1 scf = 0.02679 normal cubic meter)
SIC	standard industrial classification (code numbers given to industry groups by the U.S. Bureau of Bureau of Census)
S.I.	spark ignition
st	short ton (1 st = 2,000 pounds = 907 kilograms)
synthesis gas (or syngas)	gas consisting principally of CO and H_2
ton	short ton if not otherwise identified
vol%	volume percent
wt%	weight percent

APPENDIX B

WORLD OIL PRICE PROJECTIONS TO 1995

World oil price projections are reproduced here from the Annual Energy Outlook 1983 developed by the Department of Energy, Energy Information Administration and published in May 1984 [Reference 1]. Low, middle and high scenarios for world oil prices are reproduced in Table B-1. The basis for the projections is explained in detail in Reference 1.

Projections for United States coal prices are reproduced from Reference 1 in Table B-2. Estimates are presented both for average mine mouth price and for average price delivered to industrial users.

Projections for United States natural gas prices are reproduced from Reference 1 in Table B-3. Estimates are presented both for average well head price and for average price delivered to industrial consumers.

1. Annual Energy Outlook 1983, Energy Information Administration, U.S. Department of Energy, May 1984.

Table B-1

WORLD OIL PRICE PROJECTIONS[1], 1983 - 1995
(1983 dollars/barrel)

	LOW	MIDDLE	HIGH
1983 (actual)	29.35	29.35	29.35
1984	24.16	27.79	29.91
1985	22.44	26.52	30.53
1986	22.28	25.56	31.14
1987	22.32	26.98	34.12
1988	23.97	30.62	38.18
1989	26.69	33.75	41.78
1990	29.16	36.65	45.64
1991	31.98	39.38	50.66
1992	33.74	42.45	53.81
1993	34.95	45.00	56.88
1994	35.90	47.61	60.54
1995	36.54	50.49	65.89

1. The average cost of imported crude oil to U.S. refiners

Source: Reference 1

Table B-2

U.S. COAL PRICE PROJECTIONS, 1983 - 1995
(1983 dollars/short ton)

	Estimated Average Mine Mouth Price[1]		
	LOW	MIDDLE	HIGH
1983 (actual)	28.14	28.14	28.14
1984	29.32	29.30	29.31
1985	29.43	29.51	29.42
1986	29.54	29.56	29.52
1987	29.78	29.78	29.75
1988	29.94	29.92	29.90
1989	30.13	30.13	30.09
1990	30.37	30.36	30.30
1995	31.71	31.67	31.60

	Average Price to Industrial Users[1]		
	LOW	MIDDLE	HIGH
1983 (actual)	42.54	42.54	42.54
1984	48.84	48.83	48.82
1985	48.60	48.59	48.56
1986	49.70	49.65	49.61
1987	50.69	50.60	50.52
1988	51.72	51.60	51.48
1989	52.87	52.71	52.54
1990	53.92	53.72	53.50
1995	63.52	62.92	62.30

1. Based on low, middle and high world oil price scenarios (Table B-1).

Source: Reference 1

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Table B-3

U.S. NATURAL GAS PRICE PROJECTIONS, 1983 - 1995

(1983 dollars/1000 cubic feet)

	Average Wellhead Price[1]		
	LOW	MIDDLE	HIGH
1983 (actual)	2.60	2.60	2.60
1984	2.60	2.60	2.60
1985	2.63	2.68	2.71
1986	2.65	2.70	2.79
1987	2.73	2.86	2.93
1988	2.87	3.06	3.14
1989	3.08	3.34	3.45
1990	3.42	3.62	3.83
1995	5.68	6.33	6.70

	Average Price[1] to Industrial Consumers		
	LOW	MIDDLE	HIGH
1983 (actual)	4.29	4.29	4.29
1984	4.27	4.29	4.31
1985	4.36	4.45	4.51
1986	4.46	4.53	4.67
1987	4.57	4.74	4.85
1988	4.75	5.00	5.13
1989	5.02	5.33	5.49
1990	5.41	5.70	5.93
1995	8.05	8.86	9.40

1. Based on low, middle and high world oil price scenarios (Table B-1).

Source: Reference 1

APPENDIX C

INDUSTRIAL COMPANIES CONTACTED

During the course of the analysis, it was desirable to contact companies in the chemical, oil refining, and steel industries to discuss pertinent portions of the work and to get feedback on preliminary perceptions and conclusions. The following is a tabulation of industrial organizations contacted.

American Iron and Steel Institute
American Petroleum Institute
ARCO
Ashland Oil, Inc.
Association of Iron and Steel Engineers
Bethlehem Steel Corporation
British Petroleum Company
Chevron Research Company
Dow Chemical U.S.A.
DuPont
Exxon Company, U.S.A.
Exxon Chemical Americas
Gulf Research and Development Company
Idemitsu Kosan
Inland Steel Company
Keeler/Dorr-Oliver
Midrex Corporation
Nippon Kokan
Nucor Corporation
Petroleos Mexicanos
Quaker State Oil Refining Corporation
Shell Chemical Company
Shell Oil Company
Standard Oil Company (Ohio)
Sun Company
Texaco U.S.A.
Union Carbide Corporation
United States Steel Corporation

SFA Pacific appreciates the interest these organizations expressed in this project and the time their personnel spent with the SFA Pacific staff on behalf of the project.

*U.S. GOVERNMENT PRINTING OFFICE: 1985-461-209:30004

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DYNATECH R/D COMPANY

DIRECT LIQUEFACTION OF PEAT AND LIGNITE TO BTX-TYPE LIQUID FUEL

Final Technical Report for Period:
June 1, 1981 - August 31, 1984

DOE Contract No. DE-AC01-81ER10914-2
Dynatech Project No. DOE-6
Dynatech Report No. 2314

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October 26, 1984

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DIRECT LIQUEFACTION OF PEAT AND LIGNITE TO BTX-TYPE LIQUID FUEL

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SUMMARY

This report relates the work on the experimental research and development program for the direct liquefaction of peat and lignite to a BTX-type liquid fuel. This work was carried out in the final year of a three-year Department of Energy (Advanced Energy Projects Division) sponsored program. The liquefaction study built on the experimental work done in the first two years of the program which was directed towards the development of a biochemical process for production of alcohol fuel from peat.

Both the BTX-type and alcohol fuel processes have as their major feature an alkaline hydrolysis pretreatment of the peat and lignite. The goal of this pretreatment is the breakdown of the complex macromolecular peat and lignite structures to simple aliphatic and aromatic compounds. Owing to the geological history of the peat and lignite, these organic compounds are highly oxygenated and, under alkaline conditions, water-soluble to a large extent. It was proposed to investigate the susceptibility of these organics to further chemical treatment and biological treatment for production of BTX-type and alcohol fuels, respectively.

The work directed toward the production of BTX-type fuel was done this past year and is detailed in this report. The experimental program involved laboratory scale work in two process steps:

(1) alkaline hydrolysis for pretreatment; and

(2) catalytic decarboxylation for conversion of pretreatment products to BTX-type fuel.

Both of these areas were approached independently to establish the technical feasibility of the operation and to determine process operating conditions and yields.

The pretreatment experiments called for reaction of lignite, water, and sodium carbonate under batch conditions. The optimal conditions

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for breakdown of the lignite were found to be 250°C (ϕ hours, 8% volatile solids loading, and 20% sodium carbonate (weight by weight volatile solids)). Under these conditions, 63% of the input lignite volatile solids were solubilized. Longer reaction times and/or higher temperatures resulted in repolymerization, i.e., further coalification, of the hydrolysis products. A decrease in alkali or an increase in solids loading resulted in lower yields. This work is presented in Section 3.

Decarboxylation experiments were carried out using benzoic acid and pretreated lignite. Two procedures for chemical decarboxylation were investigated:

(1) the copper/quinoline method; and

(2) the persulfate/silver ion method.

The former method showed some conversion of benzoic acid to benzene, but quantitation was difficult with the complexity of the product mixture. The latter method showed an identifiable 41% yield of benzene. Because the persulfate/silver ion decarboxylation is carried out in an aqueous medium, it was the preferred method for lignite decarboxylations. Under conditions analogous to the model studies using persulfate/silver, lignite hydrolysate was subjected to decarboxylation. The product mixture showed 6% conversion of the hydrolysate to volatile organic liquid, i.e., 4% overall conversion of the input lignite volatile solids. The decarboxylation work is detailed in Section 4.

The preliminary engineering designs for pilot and full-scale facilities are presented in Sections 5 and 6, respectively. The pilot-scale facility is actually an expanded scale laboratory facility which accommodates both CSTR and plug flow reactors. The facility is designed for the extraction of the necessary engineering data, specifically detailed time/temperature profiles. The lack of this capability was found to be a limiting factor in the batch reactor work using lignite.

The capital and operating costs for a full-scale facility are also detailed within. This analysis utilized the Aspen Plus® computer model in the calculation of all material flows, process energy requirements, equipment sizing, and equipment characterizations. The costing was for the "base case" process where 63% of the input lignite volatile solids are solubilized and 50% of the solubilized material is decarboxylated. For a 20,000 TPD plant producing an 18,000 BTU/lb liquid fuel, the fuel cost is $1.16 per gallon. This price is most sensitive to solids loadings in the pretreatment reactor. The complete design, costing, and sensitivity analysis is detailed in Section 6.

Section 1

INTRODUCTION

1.1 The Focus on Peat and Lignite

The diminishing world-wide petroleum reserves and rising crude oil prices have created the need to find other raw materials for the production of fuels and feedstock chemicals. Private industry and the state and federal governments are undertaking a substantial research and development program to utilize other readily available resources to bridge the gap between supply and demand. The sizeable deposits of peat and lignite in the United States may provide raw materials for the production of significant quantities of liquid fuels and organic chemicals as well as fuel gas.

With the exception of this DoE-AEPD sponsored project, the DOE focus on peat utilization has been largely directed to producing pipeline quality methane from peat. In a similar manner, lignite utilization has been directed largely to producing substitute natural gas — an example being the Great Plains Gasification Plant in Beulah, North Dakota. The great potential for both peat and lignite is to be realized only if a full range of fuels, not just substitute gas, is produced from peat and lignite.

The energy resources associated with peat and lignite are as follows:

PEAT: Recent estimates indicate that peat covers approximately 152 x 10^6 hectares (375 million acres) of the earth's surface. Sufficient quantities of peat reserves exist in the United States to make this a potentially valuable natural resource. A comparison with other energy reserves shows that peat reserves (1,443 quads) are greater than the energy from uranium (1,156

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quads), shale oil reserves (1,160 quads), and the combined reserves of petroleum and natural gas (1,408 quads) (Rader 1977). Only coal reserves (5,000-10,000 quads) represent a greater energy reserve in the U.S. The quantity of peat makes it a vast and largely untapped potential energy source, an alternative to imported petroleum.

LIGNITE: In addition to peat, the use of selected lower rank coals, especially lignite, should be considered for processing. In this regard, it is of interest to consider the amount and location of lignite in the United States. A breakdown of all the estimated coal reserves in the United States for the four major ranks of coals is given as follows (Aueritt 1967):

Coal Rank	Remaining Recoverable Reserves (billion tons)	Percent of Total
Bituminous	671	43.0
Sub-bituminous	428	27.4
Lignite	447	28.7
Anthracite	13	0.9
	1,559	100.0

If only sub-bituminous coal and lignite are considered as especially suitable to the proposed process, then it is seen that this amounts to 56.1% of remaining recoverable coal reserves.

The location of peat and lignite reserves in the United States is of interest. It is seen that lignite is located largely in Montana, Wyoming and North Dakota. Peat is located largely in Minnesota, Michigan, and North Carolina. It is interesting to consider the regional impact of the processes utilizing peat and lignite with respect to current coal production. The present leading coal producing states are, in decreasing order of production, West Virginia, Kentucky, Pennsylvania, Illinois, Ohio,

and Virginia (1968 production figures [National Coal Association 1974]). These states are those with substantial reserves of bituminous coal. Thus, the development of a process for conversion of peat and lignite would have a substantial national impact, because such conversion will take place in areas where coal is not presently mined. Thus, the use of an environmentally acceptable technique would be acceptable.

1.2 Peat and Lignite Utilization

The combustion of either dry peat or lignite will release the greatest amount of energy (approximately 10,000 BTU/lb). However, because peat is harvested from bogs, its moisture content is high, and combustion requires pre-drying, a costly and energy-intensive process. In a similar manner, lignite has both a high moisture content and a high ash content. Conventional combustion for electrical power — when applied to either peat or lignite — has been found economically unattractive.

The problems associated with combustion of low-rank coals can be avoided by taking advantage of alternative utilization methods. The peat and lignite can be used as fuels in several forms. Solid fuel utilization methods traditionally rely on methods for carbonizing, briquetting, or drying. Additional methods for solids beneficiation, such as desulfurization, require some physical or chemical pretreatment. Gasification of low-rank coals is another utilization method, but one which will require some eventual process adaptation for special applications to high moisture, high ash coals. Liquefaction is also a probable technology for utilization of low-rank coals. Here, also, the technology of the major bituminous coal liquefaction processes must be adapted and improved if the methods are to meet with reasonable success using peat and lignite.

As an alternative, it was proposed to wet process peat and lignite and convert these materials to liquid and gaseous fuels. Specifically, the objective of this work has been recovery of the energy from peat and lignite in the form of both liquid and gaseous fuels. For

each case, the conversion process is carried out in two stages. In the first stage, the coalified material, i.e., the peat or lignite, undergoes hydrolysis to reduce the complex aromatic molecular structure to simple aromatics. In the second stage of the process, the simple aromatics are either anaerobically fermented to fuel gas or otherwise converted to liquid fuel, such as pentanol or benzene. Thus, the conversion process applied to the coalified materials is a combination of an initial hydrolytic treatment ("pretreatment") and a chemical or biological treatment. Biological treatment of peat hydrolysates for production of chemicals was investigated in the first two years of this program (Dynatech Report No. 2260, Levy et al., 1983). Chemical treatment of lignite hydrolysates was the focus of the third year of this program and will be detailed here.

Section 2

PROGRAM PLAN

2.1 Overview of the Program Plan

The entire program was carried out over a three-year period. The first two years of the program focused on the process for the conversion of peat to an alcohol fuel. The laboratory plan for this work was divided into three stages: (1) alkaline oxidation of peat, (2) microbial conversion of solubilized peat to organic acids, and (3) electrolytic oxidation of the organic acids to alcohol fuels. The laboratory work identified optimal loading rates, temperatures, residence times, etc., for each stage of the process. These experimental results provided the bases for the engineering design and economic analyses for a full-scale facility, and preliminary design of a pilot-scale facility for the conversion of peat to an alcohol fuel. The full account of this work was presented in a previous report (Dynatech Report No. 2260, Levy et al., 1983).

Having identified an appropriate experimental method for the hydrolytic breakdown of the peat, work was directed toward applying similar reaction chemistry to lignite. The emphasis was on coordinating alkaline hydrolysis and chemical decarboxylation with the goal of producing a BTX-type liquid fuel from lignite. The intention of this program was to examine the operating parameters of the proposed stages: (1) alkaline hydrolysis of lignite, (2) oxidation of hydrolysis products, and (3) decarboxylation of the final hydrolysate to BTX-type liquid fuel. Those results led to preliminary engineering designs for full and pilot-scale facilities.

2.2 The Program Outline

The lignite liquefaction program to produce a BTX-type liquid fuel included work on pretreatment of lignite, recovery of pretreated lignite material, and subsequent conversion of the lignite products to

BTX-type liquid fuel. Included in this program was a preliminary engineering economic analysis for full and pilot-scale facilities to project process costs. The work described herein was to conduct the experimental process development work for the proposed lignite liquefaction process. A complete description of the program tasks specific to this last year follows.

Task 1: Pretreatment of Lignite to Form Water-Soluble Aromatics

Alkaline pretreatment of peat under oxidative conditions (up to 200°C) promotes degradation of the peat and lignite to low molecular weight, water-soluble aromatics suitable for anaerobic fermentation. Somewhat more severe pretreatment conditions of lignite (up to 300°C) were employed to attain optimum solubilization and conversion to simple aromatics suitable for a liquid fuel. Parameters investigated included pH, temperature, solids loading, oxygen concentration, and time. This liquefaction study was built on the peat work which was oriented toward the goal of pretreatment with fermentation to chemicals. The principal objective of this task was to maximize conditions for yield of soluble material from lignite.

Task 2: Decarboxylation of Water Soluble Aromatics

The alkaline hydrolysis of lignite was to yield water soluble aromatics for recovery as a liquid fuel. This concept was built on the results of the earlier work where this treatment technique was used to break the complex lignin-like, aromatic structure of peat for fermentation. An example of the type of product which was anticipated is benzoic acid. This single-ring aromatic is a benzene ring with one carboxylic acid group capable of salt formation and, thus, water-soluble functionality. Upon further treatment at slightly higher temperatures, the benzoic acid will undergo decarboxylation to yield benzene, a possible liquid fuel. In a similar manner, other single ring carboxylic acids would, upon decarboxylation, yield BTX-type liquid fuels. This was the basis of the liquid fuel recovery technique investigated as part of this program task. The objective of this task was to establish the conditions for the conversion of the water soluble lignite aromatics to BTX-type liquid fuel.

Task 3: Chemical Analysis for Documentation and Verification of Results

Integral to the overall program was the chemical analysis. Methods used in the evaluation of lignite included gel permeation chromatography (GPC), high pressure liquid chromatography (HPLC), gas chromatography (GC) and standard wet chemistry and gravimetric extraction procedures. In addition, viscosities were run using model BTX-type liquid fuels to verify suitability as a liquid fuel and to establish a basis for comparing this material to petroleum-based liquid fuels.

Task 4: Evaluation of Product Recovery Systems

A system was designed for removal and recovery of the BTX-type fuel.

Task 5: Preliminary Process Economics for a Pilot and Full-Scale Facility

This task provides estimates of the capital and operating costs for a pilot and a full-sized facility based on data obtained from the experimental program. Additional research requirements were also delineated. A computer-aided optimization and sensitivity analysis was also performed to determine desired plant operating conditions. Preliminary conceptual designs for adaption of this process to an integrated energy recovery system were prepared and cost estimates made for the BTX-type fuel facility.

Task 6: Industrial/University Review Committee and Workshop

An Industrial/University Review Committee was instated to facilitate the transfer of DoE-sponsored technology to industry and to provide for practical direction to meet industry needs. To this end, the review committee included industrial participation from those firms: a) controlling peat and lignite natural resources; b) involved in converting fossil fuels to marketable motor fuel products; c) conducting engine testing; d) carrying out environmental assessment of alternative fuels; and

e) employing process development engineers. Providing further balance to the industrial participants were several participants from universities. Regular meetings of the Review Committee were held (see Appendix C.)

2.3 Program Outline: Objectives and Accomplishments

Task 1: Pretreatment of Lignite to Form Water-soluble Aromatics

OBJECTIVE: Determine conditions of maximum solubilization

ACCOMPLISHMENTS:

- Established conditions for maximum solubilization of lignite.
- Investigated effect of percent solids loading on solubilization.
- Determined effect of oxygen flow rate on solubilization.

Task 2: Decarboxylation of Water-soluble Aromatics

OBJECTIVE: Establish conditions for conversion of water-soluble aromatics to BTX-type liquids.

ACCOMPLISHMENTS:

- Achieved decarboxylation of model compounds, to yield BTX-type liquids.
- Investigated decarboxylation of treated lignite.

Task 3: Chemical Analysis for Documentation and Verification of Results

OBJECTIVE: Establish appropriate analytical scheme.

ACCOMPLISHMENTS:

- Employed standard wet chemical and gravimetric techniques as well as colorimetry and viscometry to characterize starting material and products.

- Utilized gel permeation chromatography, thin layer chromatography, high pressure liquid chromatography and gas chromatography to analyze products.

Task 4: Evaluation of Product Recovery Systems

OBJECTIVE: Design system for removal and recovery of BTX.

ACCOMPLISHMENTS:

- Investigated product recovery systems.

Task 5: Preliminary Process Design for a Pilot and Full-scale Facility

OBJECTIVES: - Establish preliminary conceptual designs.
- Estimate capital and operating costs.
- Delineate additional research requirements.

ACCOMPLISHMENTS:

- Established preliminary design.

- Determined major equipment costs for pilot facility.

- Determined capital and operating costs for full-scale facility.

- Defined additional research requirements.

Task 6: Industrial/University Review Committee Meetings and Review

OBJECTIVE: Provide practical direction via review and comment.

ACCOMPLISHMENTS:

- Held periodic committee meetings
- Conducted a workshop to review project results.

Task 7: Technical Reporting

OBJECTIVE: Prepare comprehensive technical reports.

ACCOMPLISHMENTS:

- Provided interim progress reports.
- Prepared comprehensive technical report at conclusion of project.

Section 3

ALKALINE SOLUBILIZATION AND OXIDATION OF LIGNITE

3.1 Background

3.1.1 The Origins of Lignite

A combination of chemical, biological and physical processes contributes to the natural decomposition of plant material. The various plant constituents decompose at different rates in accordance with their respective susceptibilities to these natural mechanisms of attack. Thus, over time, the deposition of plant materials represents an accumulation of differentiated responses to different geological phenomena.

The plant constituents are accumulated as peat, a material which is composed primarily of macerals, less so of minerals, with water and gases in pore-like interstices. The macerals represent the organic constituents of the plant material, e.g., cellulose and lignin. As all of these materials are variably subjected to decay, they are incorporated into sedimentary strata, and altered by natural physical and chemical processes. As the material is acted upon, it undergoes a molecular metamorphosis manifested in the generation of "new" materials which are physically distinct and unique in their fundamental properties. This process is known as "coalification."

3.1.2 The Structure of Lignite

As peat is subjected to geological alteration, its organic constituents become chemically more complex. The severity of the conditions affects the physical properties of the resultant material. This coalified material is then classified according to rank with the lignites at the low-rank, followed by sub-bituminous, bituminous, and anthracitic coals.

Because lignite is in the early stages of coalification, it retains some of the characteristics of wood. Pieces of plant debris and remains of cellular structure are visible in electron micrographs. The

molecular structure then represents the earliest stages of geological metamorphism of plant material.

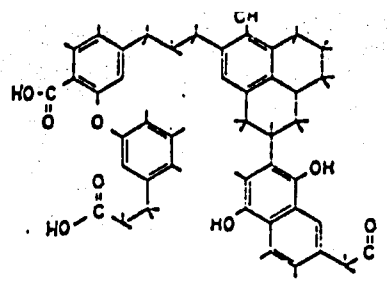
The major structural constituents of lignite are derived from three sources: a) cellulose; b) lignin; and c) other plant components, e.g., protein, dispersed in the plant tissues. The coalification process is a deoxygenation/dehydration process. In the early stages, coalification does not create a large number of tertiary bonds. Because these are the bonds which contribute to a strong three-dimensional structure, lignites have loose structures.

The molecular structure of the organic portion of lignite can be represented as shown in Figure 3.1. The major features are summarized as follows. First, in comparison to higher rank coals, lignites have low aromaticity. Lignite is approximately 60% aromatic, peat 50%, and bituminous greater than 70%. Second, aromatic clusters are primarily one and two rings, i.e., aromatics have not yet fused into complex multi-ring forms. In contrast, bituminous coals are comprised of fused ring systems of 3 or more aromatics. Finally, oxygen-containing functional groups are prevalent. These groups are represented by carboxylate, phenolic and ethereal components, groups which chemically account for the complex fused-ring structure of higher rank coals.

The remaining lignite components are moisture and ash. Again, the relative proportions of these are indicative of the rank of lignite. Lignite typically has a high moisture content when compared to other (higher rank) coals. Water is incorporated into the lignite matrix in an intermolecular hydrogen bonding between the water and the oxygen functional groups in the lignite. The ash-containing portion of lignite can be further divided into the inorganics and the minerals. The inorganics, e.g., calcium and sodium, are to some extent relatively mobile ions, presumably associated with the carboxylic acid functional groups; thus, some lignites can have levels of these inorganics. The mineral matter is primarily represented by clays, pyrite, and quartz. Frequently, the mineral particles are quite small and often appear finely dispersed throughout the carbonaceous material.

Figure 3.1

Structural Features of Lignite



Adapted with modification from Sondreal et al., 1982.

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3.1.3 The Reactivity of Lignite

Examination of the organic portion of the lignite matrix as represented in Figure 3.1 reveals several important clues to its potential reactivity. A large portion of the aromatic material exists as single rings. These aromatics are joined in a network of carbon-carbon and carbon-oxygen linkages. Aliphatic units are incorporated as aromatic side-chains, alone or in conjunction with other aromatic groups.

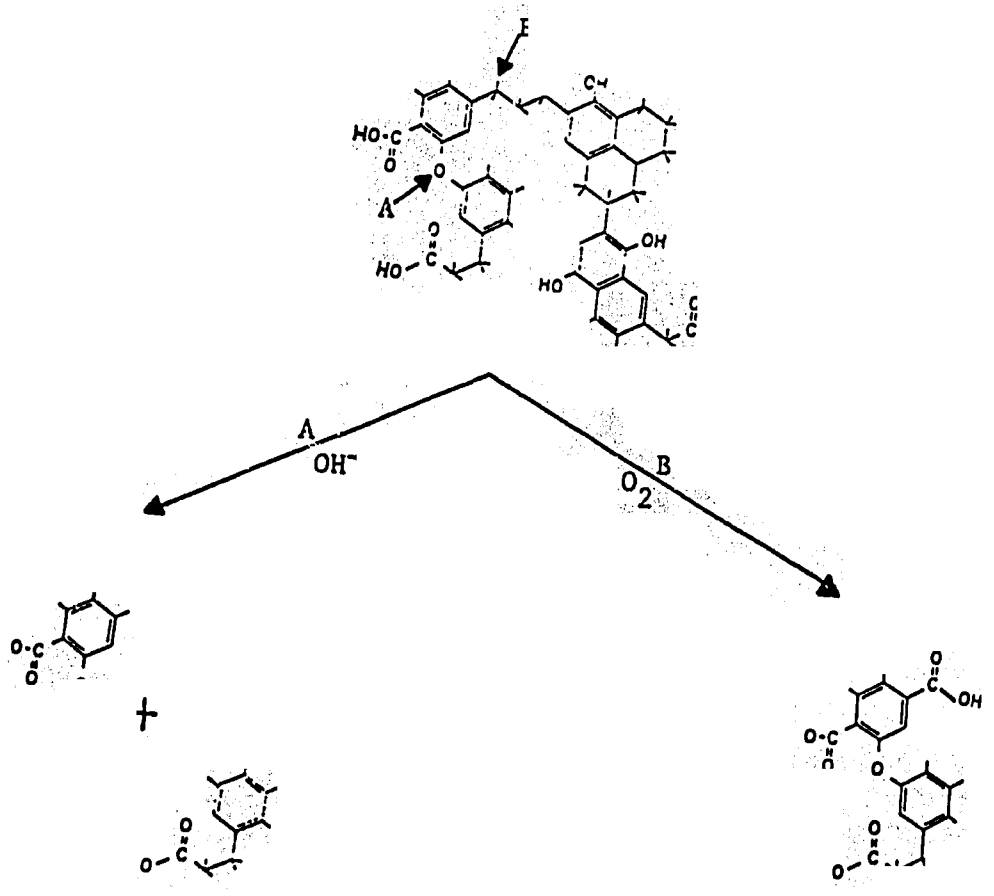
This matrix structure is representative of a particular stage of the coalification process, a continuous process of deoxygenation which has resulted in the structural elimination of water. It is this process which contributes to the increasing molecular complexity up through the coal ranks. Thus, it might be expected that reversal of the coalification by hydrolytic reaction could result in considerable degradation of the coal structure into simpler units. This is true especially in the lower ranks of coals, e.g., peat and lignite.

Alkaline hydrolysis can be exploited in conjunction with oxidative processes to break certain well-defined bonds in the lignite. The carbon-oxygen linkages are particularly susceptible to the alkaline hydrolysis. Likening the lignite structure to a polyester/polyether-type material, phenols and carboxylic acids will be the probable products of a base hydrolysis (Figure 3.2a). The carbon-carbon linkages, as found, for example, in the alkylbenzene portions of the lignite matrix, can be effectively cleaved upon oxidation. Generally, the products of an oxidation will be carboxylic acids (Figure 3.2b). Thus, a careful "aqueous alkali oxidation" can effect a reversal of the coalification process particularly in low rank coals.

The effectiveness of an aqueous alkali oxidation will be primarily dependent upon the structural "maturity" of the organic matrix and not upon the ash or moisture characteristics of a ranked coal. A treatment process which incorporates the elements of an alkaline hydrolysis will obviously require water and alkali. Lignites obtained from different

Figure 3.2

Aqueous Alkali Oxidation of Lignite



A Alkaline hydrolysis
B Oxidation

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sources vary primarily in ash and moisture content; the organic matrices are similar. Thus, the degree of lignite reactivity, as judged by breakdown potential, can theoretically be regulated by adjustment of added water and alkali in consideration of inherent moisture and ash for a particular sample.

3.2 Program Plan for Alkaline Solubilization and Oxidation of Lignite

The objective of the solubilization and oxidation of lignite is the production of single-ring aromatic compounds which can be treated to yield BTX-type liquids. Solubilization of lignite has been accomplished under alkaline conditions. Based on Dynatech's previous work with peat, it was suggested that oxidation would increase the yield of low-molecular weight products.

With these objectives in mind, the following program plan was proposed:

- Characterization of raw lignite;
- Investigation of varying solubilization conditions (e.g., solids loading, temperature, concentration of alkali, type of alkali);
- Investigation of varying oxidation conditions (e.g., flow rate of input circulation);
- Characterization of products using standard wet chemical techniques and analytical instrumentation (e.g., extraction, gravimetric analysis, HPLC, GC, GPC, IR, spectroscopy, petrography);
- Evaluations and optimization of experimental procedures;
- Isolation of BTX-type products; and
- Preparation of an appropriate process design.

3.3 Alkaline Solubilization and Oxidation of Lignite — Experimental Procedures

3.3.1 Determination of Lignite Characteristics

Before investigating solubilization and oxidation procedures it was necessary to determine various characteristics of the lignite. Two samples of lignite were received from Meridian Land and Mineral Company (Billings, Montana). These samples were labelled "Buelah" and "Gascoyne," indicating the origin of the lignite. The Buelah lignite was used for this study.

First, the Buelah lignite was sent to Resource Engineering Incorporated (REI) of Waltham, Massachusetts, to be crushed. After being crushed to ¼-inch, a sample of the material was retained by REI for ultimate and proximate analysis (report in Appendix A). The remainder of the crushed lignite was wet-packed and returned to Dynatech.

The final type of analysis performed on the untreated lignite was the solids analysis done on the stock lignite slurry and the pre-treatment slurries. The stock lignite slurry was prepared by wet ball milling the ¼-inch wet-packed crushed lignite (as received from REI) and sieving to -100 mesh. Pre-treatment slurry was prepared by diluting the stock slurry to the required percent volatile solids, then adding the appropriate amount of alkali.

Two types of solids analysis were performed: (1) total solids, and (2) ash content. Total solids were determined by the following method. Samples were measured into dry round-bottom flasks and the volume reduced *in vacuo* using a Buchi Rotavapor-R rotary evaporator. The flasks were then placed in a desiccator over anhydrous $CaSO_4$ and dried *in vacuo* to constant weight.

After drying, the ash content was determined. Samples were measured into dry evaporating dishes and placed in a 100°C Blue M Stabil-Therm

Gravity Oven for six hours. The samples were then cooled and weighed. The dried samples were heated at 600°C in a Lindberg M51442 muffle furnace for six hours. After cooling in a desiccator, the residual material was weighed to determine ash content. Volatile solids were determined from the difference between the total solids and the ash.

3.3.2 Preparation of the Lignite Slurry

A stock lignite slurry was prepared by wet ball milling the 1/4-inch wet-packed crushed lignite sample (as received from REI) and sifting to -100 mesh. Pre-treatment slurry was prepared by diluting the stock slurry to the required percent volatile solids, then adding the appropriate amount of alkali on the basis of grams carbonate per gram of lignite volatile solids.

3.3.3 Solubilization Experiments

Solubilization parameters were extensively investigated to determine optional reaction conditions. The factors investigated were:

- Temperature
- Time
- Amount of alkali
- Type of alkali
- Loading of volatile solids.

A. Time/Temperature

A series of treatments was conducted at different temperatures. The charge to the reactor was kept constant at 7.5% volatile solids and 0.2 gram Na_2CO_3/gram volatile solids for this study. The three temperatures studied were 200°C, 250°C and 300°C. Samples were taken at designated intervals during the treatment.

B. Amount/Type of Alkali

The second series of experiments was designed to investigate the effects of different types of alkali and of different amounts of alkali.

Two compounds were chosen as alkali: NaOH and Na_2CO_3. A single treatment using NaOH was done at 300°C. The NaOH used was equal in sodium-equivalents to the Na_2CO_3 used in the time/temperature series described previously (i.e., 3.8 sodium meq/gram volatile solids). In addition, the effect of varying the amount of Na_2CO_3 was also investigated. The amount of Na_2CO_3 added was varied from 0.05g Na_2CO_3 to 0.3g Na_2CO_3 per gram volatile solids. Finally, a control treatment, with no additive, was also performed.

C. Solids Loading

The final solubilization factor investigated was the amount of volatile solids used for the treatment. This amount varied from 4.0% to 11.9% volatile solids (w/v) in the slurry charged to the reactor.

3.3.4 Oxidation Experiments

After evaluating factors which directly affect solubilization, the process of oxidation and its effects on the overall solubilization were investigated. A series of experiments was designed to examine the effect of different air flow rates on solubilization of volatile solids. In addition, a set of experiments was conducted to investigate the oxidation of solubilized hydrolysis products compared to non-solubilized hydrolysis products.

The first series of oxidations investigated the effect of the input air flow rate. Three flow rates were chosen; temperature, concentration of Na_2CO_3, and lignite loading were held constant for the three oxidations. The flow rates chosen were 400 mL/min, 740 mL/min and 1000 mL/min. The oxidations were done at 200°C, with 0.5g Na_2CO_3 per gram volatile solids and a 4% VS loading. In all three oxidations, samples were taken at designated intervals for solids analysis.

The second series of oxidations investigated the effects of oxidation on solubilized vs. non-solubilized hydrolysis products. An initial hydrolysis was conducted to provide solubilized and non-solubilized product. This treatment was done at 250°, with 0.25g Na_2CO_3/g VS and an 8% VS

loading. The mixture was brought up to 250°C and then cooled. Solubilized material was separated from non-solubilized material by centrifugation at 8800 x g for 15 minutes. The entire batch of treated material was centrifuged. The supernatant material was designated the "solubilized" and the pellet material was designated the "non-solubilized."

The next step in this set of experiments was oxidation of these two materials. Both oxidations were conducted under the same conditions at 200° C, with 0.5g Na_2Co_3/g VS and a 4% VS loading.

3.3.5 Analytical Methods

Treatment samples were characterized via solids analysis, percent extractables, and petrography. Solubilized material was analyzed via high performance liquid chromatography (HPLC) and gas chromatography (GC), and extracted samples were analyzed for molecular weight distribution via gel permeation chromatography (GPC).

A. Solids Analysis

Reaction samples are measured into dry round bottom flasks. The samples are initially reduced *in vacuo* using a Buchi Rotavapor-R rotary evaporator. The flasks are subsequently placed in a desiccator over anhydrous $CaSO_4$ and dried *in vacuo* to constant weight for determination of total solids.

Another aliquot of the reaction mixture (pellets, supernatants, or slurries) is measured into a dry evaporating dish. For the determination of oven-dried material, the dish is placed in a 100°C Blue M Stabil-Therm Gravity Oven for 6 hours, cooled, and weighed for oven-dried total solids. Subsequently, the dried material is heated at 600°C in a Lindberg M51442 muffle furnace for an additional 6 hours. After cooling, the residual material is weighed for the determination of ash content.

B. Percent Extractables

A pellet, isolated from an acidified portion of reaction slurry, is placed in a beaker and dried to constant weight *in vacuo*. It is stirred with 20 mℓ tetrahydrofuran for one hour, then stirred with warming for five minutes. The mixture is vacuum filtered into a tared beaker and the filtrate is allowed to dry to constant weight to determine percent extractable solids.

C. Petrography

Petrographic analyses were performed by Resource Engineering Incorporated, Waltham, MA (report in Appendix A). Pre- and post-treatment samples were submitted. The pre-treatment sample was obtained from a portion of the lignite as provided. The post-treatment sample was obtained after washing and drying the pellet isolated by centrifugation. (The reaction slurry was first acidified to pH 2 with concentrated HCl.)

D. High Performance Liquid Chromatography

The liquid chromatograph used is a Waters system equipped with a M-45 solvent delivery system, a U6K injector, a free standing model 440 absorbance detector set at 254 nm, and a 10-mv strip chart recorder. The column used was a Regis Octadecyl Workhorse (30 cm x 4.6 mm).

A monocratic eluent system was chosen on the basis of its ability to separate four characteristic products (benzoic acid, syringic acid, syringaldehyde, and vanillin). This system was 45% MeOH/1% H_3PO_4. Spectro-grade glass-distilled methanol is obtained from Burdick and Jackson Laboratories, Inc. Phosphoric acid is Mallinckrodt reagent grade. Distilled water is filtered, deionized, and passed through a carbon bed in a system from Sybron/Barnstead. After the solvent system is prepared, it is filtered through a Millipore type HA 0.45-μm filter and degassed with a Branson sonicator before use.

Solutions of 5-10 μg/mℓ of the standards (benzoic acid, syringic acid, syringaldehyde, and vanillin) are prepared in 45% MeOH. The retention volumes of these standards are determined by injecting 100 μℓ of the solutions into the aforementioned chromatographic system. Filtered reaction solutions are diluted with MeOH and characterized with respect to this standardization.

E. Gas Chromatography

The volatile organic liquid determinations in this phase of the study are made using a Perkin-Elmer gas chromatograph equipped with a Gow-Mac Series 750 flame ionization detector and a Houston Instrument OmniScribe recorder. The separation is carried out on a Chromasorb 101 column (1/4 in. x 5 ft) under conditions of linear programming over the temperature range 100-200°C (15°C/min) with nitrogen as the carrier gas. The chromatograph is calibrated for analysis of methanol, acetone, acetic acid, propionic acid, butyric acid, and valeric acid. Reaction samples are filtered using a Millipore HA filter before injection.

F. Gel Permeation Chromatography

The extracts obtained from the extraction are analyzed by gel permeation chromatography in order to determine the size of the molecules which are extractable. Tetrahydrofuran is used as the carrier solvent. The column is restyragel packed, 30 cm long. A Waters Associates chromatography pump Model 6000A, and Waters Differential Refractometer R401 detector is used.

3.4 Results and Discussion of Solubilization and Oxidation Experiments

The extensive investigation of solubilization parameters and the effects of oxidation reveal several interesting conclusions. These conclusions are discussed in the following sections.

3.4.1 Temperature/Time Studies

Following the experimental protocol established in the first quarter of work, a testing regime was set up in which lignite was heated with aqueous alkali at various temperatures. The goal was to determine the influence of temperature and time on the degree of lignite breakdown under conditions of alkaline hydrolysis. This phase of the experimental program can be summarized as a series of three basic temperature/time experiments: (1) 200°C/4 hrs, (2) 250°C/4 hrs, and (3) 300°C/5.75 hrs. In each experiment, a lignite slurry was treated at the specified temperature with samples being withdrawn when the reactor reached temperature, and 0.5 hour, 1.0 hour, 20 hours, and 4.0 hours (or 5.75 hours) thereafter. Each of these "hot-drawn" samples was characterized with respect to the percent of the input volatile solids solubilized and the percent isolable, THF-extractable material. In the first quarter of work, this analytical format was established as the one which would best accommodate the needs of the program by providing an informative scientific and engineering data base. In addition, the samples were qualitatively evaluated with respect to physical appearance.

3.4.2 Physical Characterization

A. Appearance

The final product slurries of alkaline solubilizations at 200°, 250°, and 300°C compare as follows. The 200°C product is gelatinous (mud-like) and does not settle over time. It is medium brown in color, and does not disperse at all, or generate any surface film when dropped into clean water. By contrast, the 250°C product is a mobile, yellowish brown liquid of high opacity; when dropped into water is rapidly generates a small, stable surface film. The 300°C product is an oily slightly brownish grey/black mobile liquid of somewhat stronger odor than the others, when dropped into water is generates a very rapidly spreading surface film, which subsequently contracts and wrinkles. Both the 250°C and the 300°C products

throw dense layers of solid upon standing; however, in all cases the particulate nature of the products, though not directly visible, is demonstrated by a slow diffusion speed in water.

B. Scanning Electron Microscopy

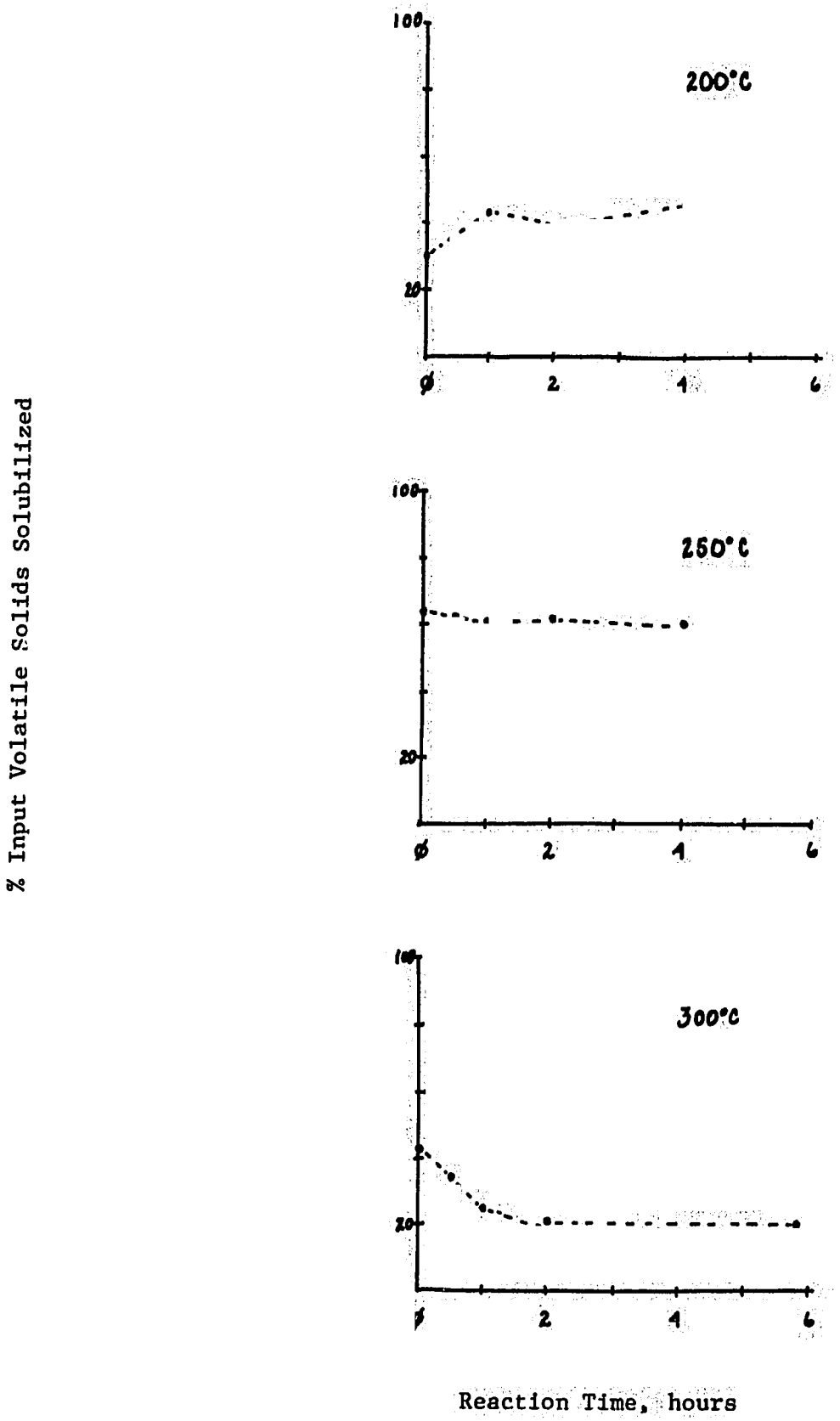
A suspended particle size analysis was performed to determine the physical effects of Na_2CO_3, temperature, and pressure on the lignite. This was accomplished by analyzing pretreatment samples using scanning electron microscopy (SEM). The specifications of the analysis are as follows: treatment 020031, 8% volatile solids loading, and 0.2 gms Na_2CO_2/gm VS. Samples were taken before carbonate addition after carbonate addition, and at T = 150°C, 200°C and 250°C. A variety of magnifications ranging from x11 to x3200 were used on each sample. First, general particle size distribution was investigated. Then, the analysis concentrated on specific particles to determine the change in physical shape as the treatment progressed. In general, it was shown that although particle size distribution remained constant, particle texture and shape was affected by the treatment. Before the treatment, particles were smoother and more geometric in shape whereas samples at 200°C and 255°C were chipped, rough, crusty, and much less geometric. An Elemental Distribution Analysis by X-ray (EDAX) was performed on the samples. It is interesting to note that over time there is a decrease of sodium on the particles (corresponding to the "crust") which may have indicate a leaching of entrapped ions. Elements found in later stages of treatment include silicon, phosphorus, sulfur, calcium, and small amounts of sodium. The collection of micrographs is included in Appendix B.

3.4.3 Solubilization

For each of the experiments, the interim samples were analyzed to determine the percent solubilization of input volatile solids which was effected by the treatment. The percent solubilization was calculated on the basis of the change in volatile solids distribution after centrifugation of a pre-treatment slurry (i.e., lignite, alkali, and water) and a post-treatment sample. The results are represented graphically in Figure 3.3 and summarized in the following.

Figure 3.3

Lignite Solubilization With Sodium Carbonate



Comparison of the solubilization behavior within each temperature experiment yields dissimilar trends at the three different temperatures. In the 200°C experiment, successive time samples show an increase in the volatile solids solubilized from 30% at temperature to a maximum of 53% after 4.0 hours. The percent volatile solids solubilized in the 250°C experiment remained relatively constant throughout the course of the experiment having reached a 63% maximum at temperature. Finally, in the 300°C experiment, the observed solubilization decreased over time with a high of 43% volatile solids solubilized at temperature falling to a low of 17% after 5.75 hours. On the basis of these solubilization figures, the ideal temperature for hydrolytic breakdown under the conditions as specified is 250°C, with extended treatment times having an insignificant influence.

A possible explanation for the observed behavior can be realized upon examining the competing chemistries involved. It has been established (see Dynatech Report No. 2244, Wise et al., 1983) that two processes are evident here: (1) alkaline hydrolysis of the ethereal lignite matrix to yield low molecular weight aromatic material, and (2) repolymerization of free radical reaction intermediates to yield high molecular weight coalified solids. In light of the experimental results it would appear that temperature and time can both affect the degree to which either of the competing reactions occurs. During a 200°C treatment, hydrolysis seems to predominate, while during a 300°C treatment repolymerization predominates. In the 250°C experiment, the explanation is less obvious. At extended reaction times, an increase in hydrolysis does not seem evident and repolymerization appears controlled.

3.4.4 Acid Precipitation

The product slurries from each of the temperature/time experiments were initially separated into the base-soluble and base-insoluble fractions. This allowed for the determination of the percent of input volatile solids solubilized as detailed in the preceding section. The procedure can effectively identify the amount of water-soluble species of low molecular weight material which was produced via the hydrolysis.

The solubilized material - particularly the volatile solids - can be further characterized on the basis of its behavior in acidic media. Because of the structural characteristics of the input lignite and the hydrolytic nature of the reaction process, the solubilized material is expected to be high in polar functional groups, such as aromatic hydroxy and carboxylic acid groups. While this material would remain in solution in a product slurry of pH 10, acidification should precipitate some of the solids to allow for further characterization and identification.

The alkaline solution containing dissolved products was separated from any solids that were suspended in the reaction slurry. This solution was subsequently acidified to pH 2.0 with concentrated hydrochloric acid. An experimental maneuver such as this is intended for laboratory identifications only; by no means is it intended for eventual process work. Acidification is an effective method of isolation for low molecular weight breakdown material of characteristic oxygen functionality. The procedure provides sufficient solid for subsequent analytical work.

The data corresponding to the acidifications are presented in Table 3.1. The four columns in the table identify the following: (1) the sample; (2) the percent of input volatile solids solubilized (shown graphically in Figure 3.3); (3) the percent of the solubilized volatile solids which can be precipitated by acid; and (4) the percent which the latter, i.e., (3), is of the input volatile material. The results indicate that in the majority of the samples virtually all of the solubilized material can be precipitated by acid. This is particularly true for the 200°C and 250°C treatments in which greater than 96% of the solubilized volatile solids were precipitated. With the samples from the 300°C treatment a substantial percentage (>82%) of the solubilized solid was isolable after acidification; the cases where the yield was low correspond to samples in which solubilization was also low. It appears, then, that acidification is an effective experimental procedure if isolation of breakdown material is desired. This method was exploited for the large-scale collection of treatment products.

Table 3.1

ACID PRECIPITATION

SAMPLE		INPUT VOLATILE SOLIDS SOLUBILIZED (%)	ACID-PRECIPIABLE SOLUBILIZED VOLATILE SOLIDS (%)	ACID-PRECIPITABLE INPUT VOLATILE SOLIDS (%)
Temp	Time			
200°C	0 h	30	99	30
	1	45	99	45
	2	42	97	41
	4	53	99	52
250°C	0 h	63	96	60
	1/2	63	97	61
	1	61	97	59
	2	64	97	62
	4	63	96	60
300°C	0 h	43	93	40
	1/2	34	93	40
	1	25	91	23
	2	22	82	18
	5 3/4	17	86	15

3.4.5 Extraction

The low molecular weight material which is produced in the lignite hydrolysis can be further characterized in terms of its solubility in organic solvents, i.e., its "extractability." Generally, tetrahydrofuran (THF) is used as the organic solvent because its reasonably low polarity allows the separation of low molecular weight, non-polar material from a complex product slurry. The product mixture will contain many compounds of dramatically different polarities. Extraction with THF can be used to differentiate products on the basis of polarity.

In this work, product solids were subjected to two different extractions for comparison as shown in Figure 3.4. For the first case, a pellet (1) was isolated from a centrifuged slurry sample which had been acidified (pH 2.0) in toto. For the second, the pellet (2) was obtained from an acidified supernatant only. Pellet (1) is representative of all possible product solids because the isolation protocol includes insoluble product residues. Alternatively, pellet (2) contains only that material solubilized in the hydrolysis. It would seem likely that most of the more non-polar, THF-extractable material would be available in pellet (1). Pellet (2) is primarily aromatic material of characteristic oxygen functionality which tends to be slightly more polar. It is important to note that the material of pellet (2) would be entirely contained within pellet (1).

The results of the extractions are presented graphically in Figure 3.5. The percent extractables relative to pellet total solids are shown for both pellet (1) and pellet (2). The trends in the extraction behaviors can be interpreted in terms of the competing reaction chemistries, in much the same way as those on the solubilizations were. In those cases where a greater percentage of extracted material is in pellet (2) - rather than pellet (1) - it would appear that more of the extractable products are solubilized, low molecular weight compounds of reasonably low polarity with

Figure 3.4

Flow Chart for THF Extractions

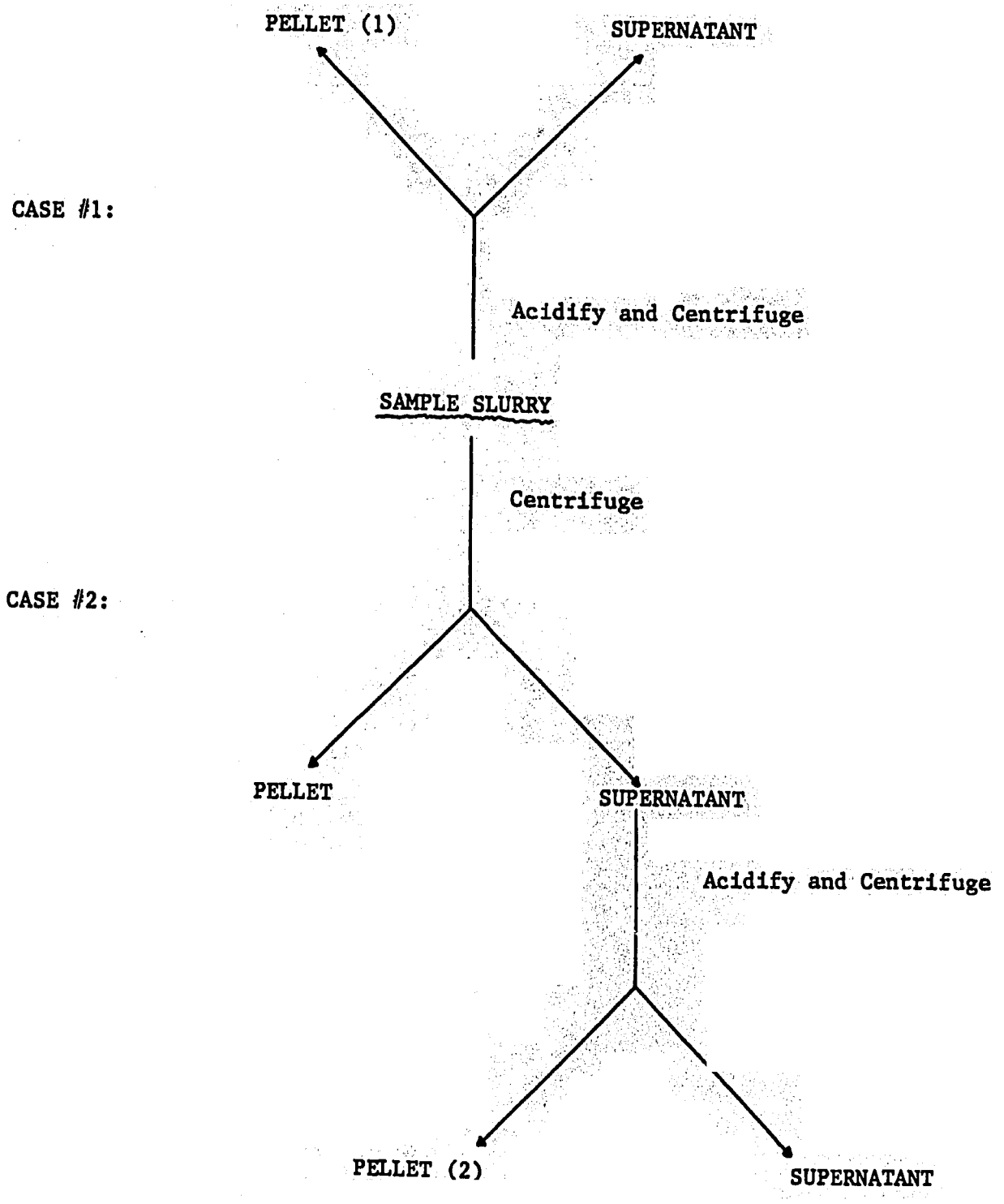


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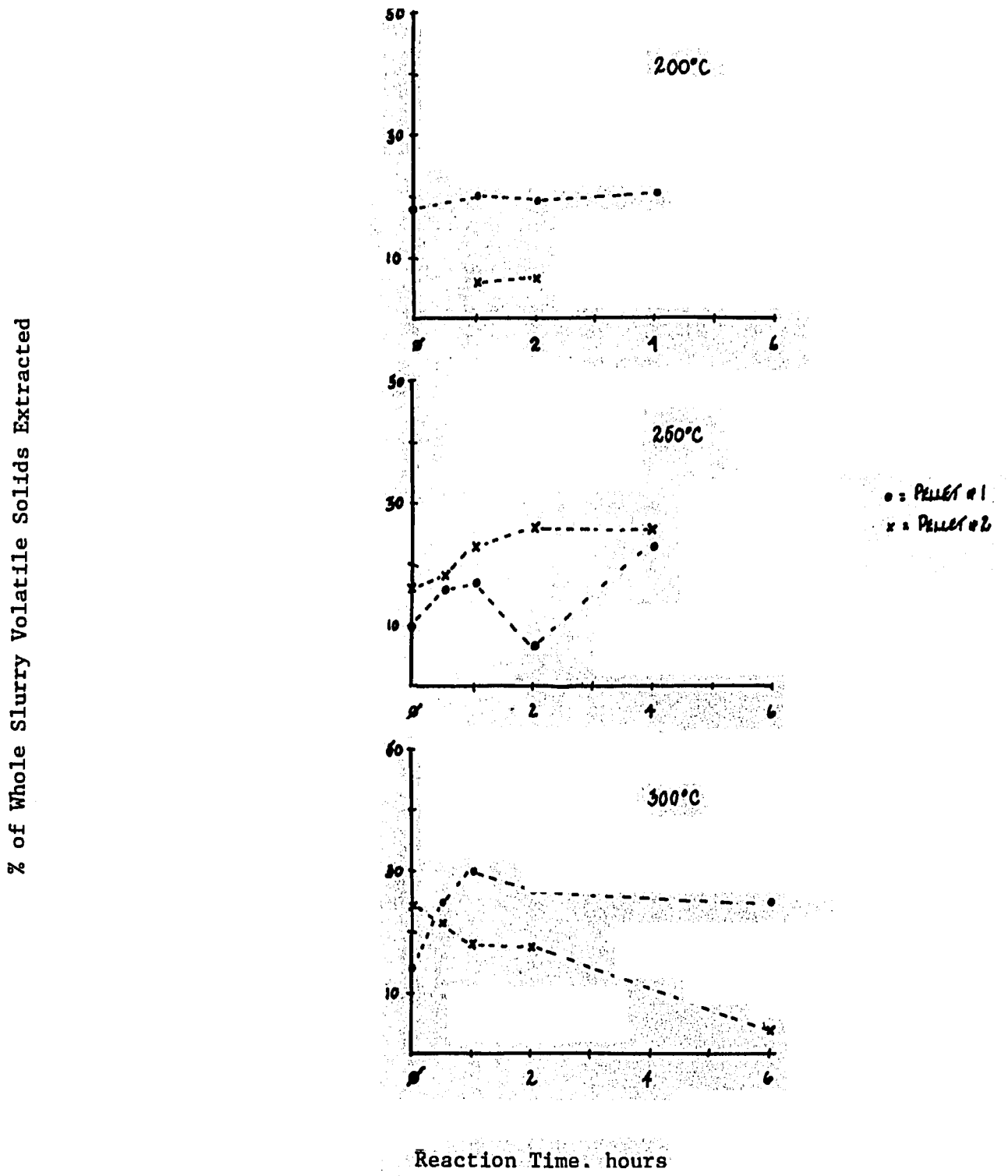
Figure 3.5

THF-Extractable Pellet Solids



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repolymerized macromolecules comprising a major portion of the original reaction residue. Alternatively, when the greater percentage of extracted material is in pellet (1), it would appear that much of the breakdown material is water-insoluble, low molecular weight product which is sufficiently non-polar to allow for extraction by THF. The relative distributions of the various product types are a direct result of the hydrolysis and the repolymerization.

With the 200°C treatment it would appear that most of the extractable material produced initially is the water-insoluble solid which is of reasonably low molecular weight (molecular weight data follows); the solubilized material is not amenable to extraction. The extractables from the 250°C treatment, on the other hand, can be found primarily in the solubilized product fraction which arises from the hydrolysis; the reaction residue contributes very little to the extractables. This phenomenon was time-dependent with percent extractables increasing over time. Extraction of the products from the 300°C treatment was greatest with the reaction residues rather than the solubilized material. This behavior also showed some time-dependence. Extraction of the residue increased over time while that of the solubilized material decreased.

In comparing these results with those on the solubilization, it seems that there may be some compatible trends in the reaction chemistry which can inferred from the data. The results suggest that in those cases where hydrolysis is the predominant chemistry the percent solubilization is highest and the greater percentage of extractable product is in that solubilized material (e.g., the 250°C treatment). Alternatively, when repolymerization successfully competes with hydrolysis, the percent solubilization is lower and the majority of the extractable product is in the reaction residue.

The extracted materials were characterized with respect to the molecular weight distribution. This provides some verification of predicted product characteristics. Gel permeation chromatography (GPC) was used to

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The extracted materials were characterized with respect to the molecular weight distribution. This provides some verification of predicted product characteristics. Gel permeation chromatography (GPC) was used to

obtain molecular weight profiles for each of the extracts. Generally, the extraction was effective in separating products of molecular weight less than 1000 with the 50-500 molecular weight range being the predominant one. The GPC profiles that are presented in Figure 3.6 are illustrative of the tracings obtained with each of the extracts. The GPC data shown is for a series of extracts of pellet (1)'s from a 200°C treatment.

3.4.6 Additive Studies

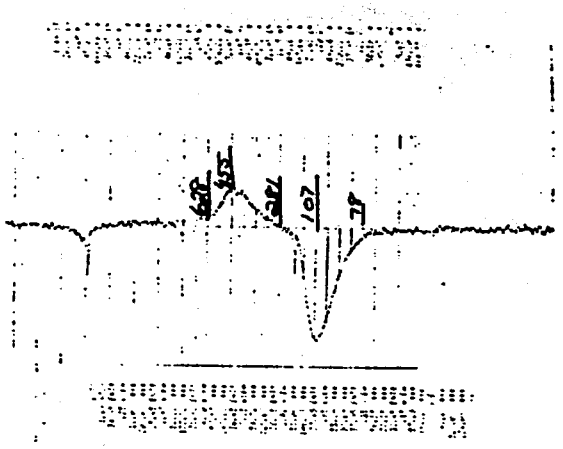
A series of experiments was conducted to investigate the role of the sodium carbonate in the alkaline hydrolysis. Previous work by Dynatech scientists investigating the role of the carbonate in the solubilization of peat had established some of the importance of the sodium cation in successful hydrolyses. In addition, modern knowledge in liquefaction science supports the idea that the size of a sodium cation makes possible diffusion into lignite pores; thus, the cation acts in both the physical and chemical breakdown of lignite. The strong implication that sodium has a major role in the alkaline hydrolysis influenced the direction of this phase of the experimental program.

Three experiments were conducted at 300°C. Using the standard format for reactor loadings, a slurry was prepared which contained lignite, water, and either nothing or one of the following: (1) sodium carbonate or (2) sodium hydroxide. The obvious difference in each of these input slurries is the pre-treatment pH. An initial assumption might then have been that the sodium hydroxide (at an initial pH of 12.0) would be the most effective in promoting the hydrolysis. The pH of the starting and the interim samples is shown in Table 3.2.

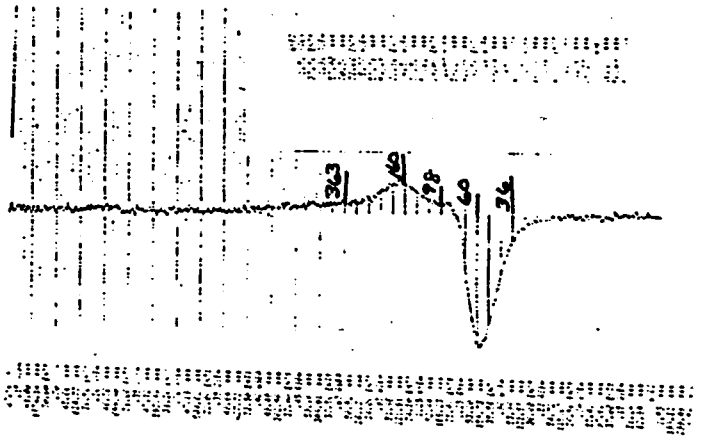
The results of each of the different additive treatments were interpreted in terms of the percent solubilization of input volatile solids, as well as in terms of physical appearance. As far as physical appearance, the final product slurries of 300°C solubilizations with Na_2CO_3, NaOH, and no added base, compare as follows.

Figure 3.6

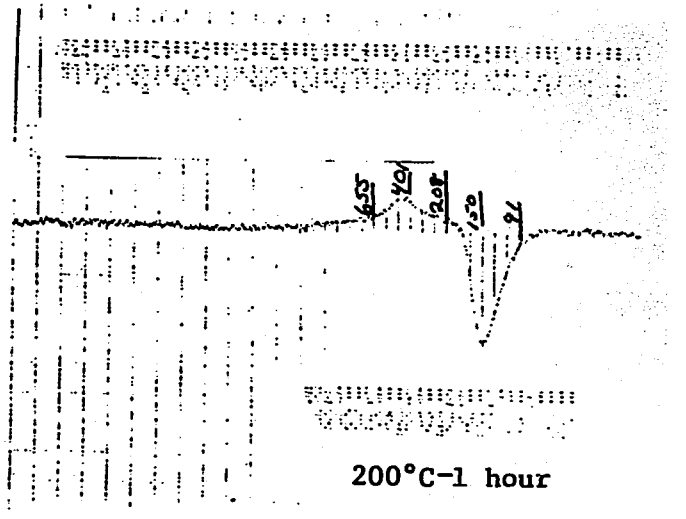
GPC Tracings of Pellet Extracts



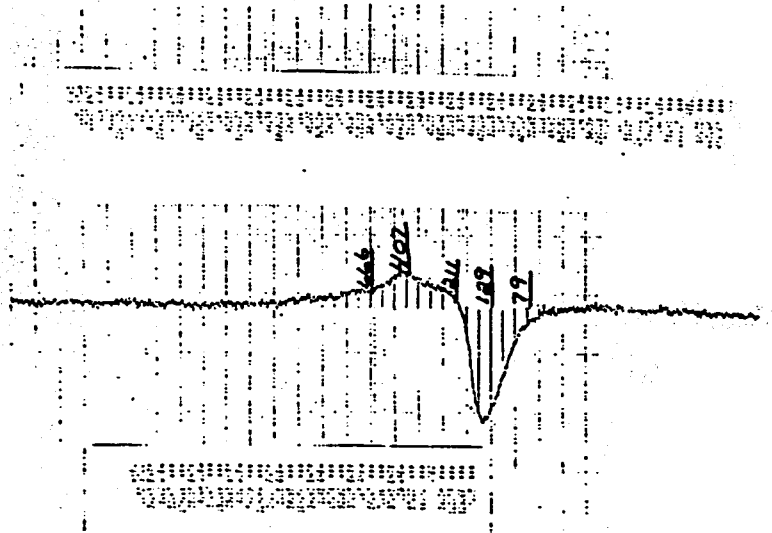
200°C–at temperature



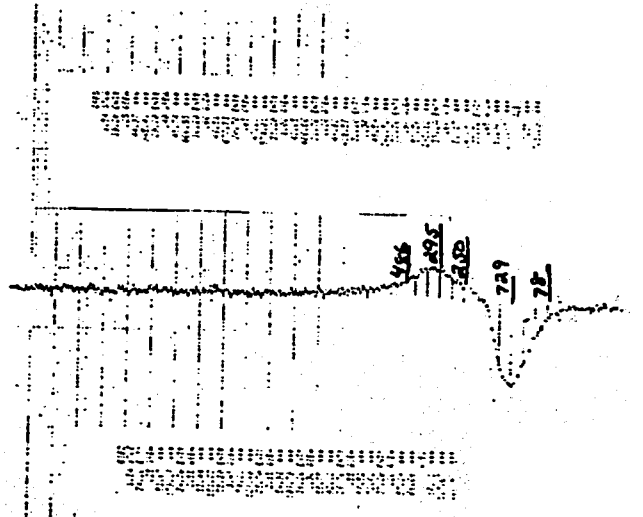
200°C–1/2 hour



200°C–1 hour



200°C–2 hours



200°C–4 hours

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Table 3.2

ADDITIVES AND pH

ADDITIVE	TIME, hr	pH
Sodium Carbonate	input	10.10
	0	10.07
	0.5	9.87
	1.0	9.73
	2.0	9.59
	5.75	9.23
Sodium Hydroxide	input	12.02
	0	10.25
	2.0	10.59
	4.0	10.12
None	input	7.85
	0	7.80
	1.0	7.50
	3.0	7.60

The product from 300°C solubilization in the presence of Na_2CO_3 is a slightly brownish grey/black mobile liquid which throws a solids layer on standing. The product from NaOH-assisted treatment differs essentially only by being much browner. Both these products are sub-visibly particulate. By contrast, the product from a no-base-present treatment is a pure grey/black, with no trace of brown tint. No solids layer is observed to form on standing, yet, the slurry consists of macroscopic, easily visible particles. All three products generate rapidly spreading surface films when dropped into water, including throwing the film upwards from a submerged drop (indicative of hydrophobic constituents). This film expands rapidly to stable final size in the case of the NaOH and no-base products, but shrinks after initial spread with the Na_2CO_3 product, as if an initially hydrophobic layer dispersed into the water over time. The Na_2CO_3-and NaOH-generated products had similar odors, but the no-base product slurry was considerably blander, though not odorless.

The solubilization data are presented graphically in Figure 3.7. In terms of percent solubilization, there are obvious differences in the effectiveness of the treatments. Without any additive, there was no evidence of matrix breakdown. The same was true in the case where sodium hydroxide was added. The most efficient treatment, then, was in the sodium carbonate case. The interpretation of the data is not obvious on the basis of solubilization only. These would appear to be no reason a priori as to why sodium hydroxide was ineffective in promoting hydrolysis.

In addition to the above analyses, the sodium hydroxide and sodium carbonate treatments were evaluated in terms of product extractability. The results are presented in Figure 3.8. The data show trends similar to those of the initial time/temperature work. That is, as solubilization decreases, the percent extractables in pellet (1) increases while that in pellet (2) decreases. It is important to note, however, that in terms of extractability it appears that the sodium hydroxide was effective in generating low molecular weight, water-insoluble product.

Figure 3.7

Lignite Solubilization With Various Additives

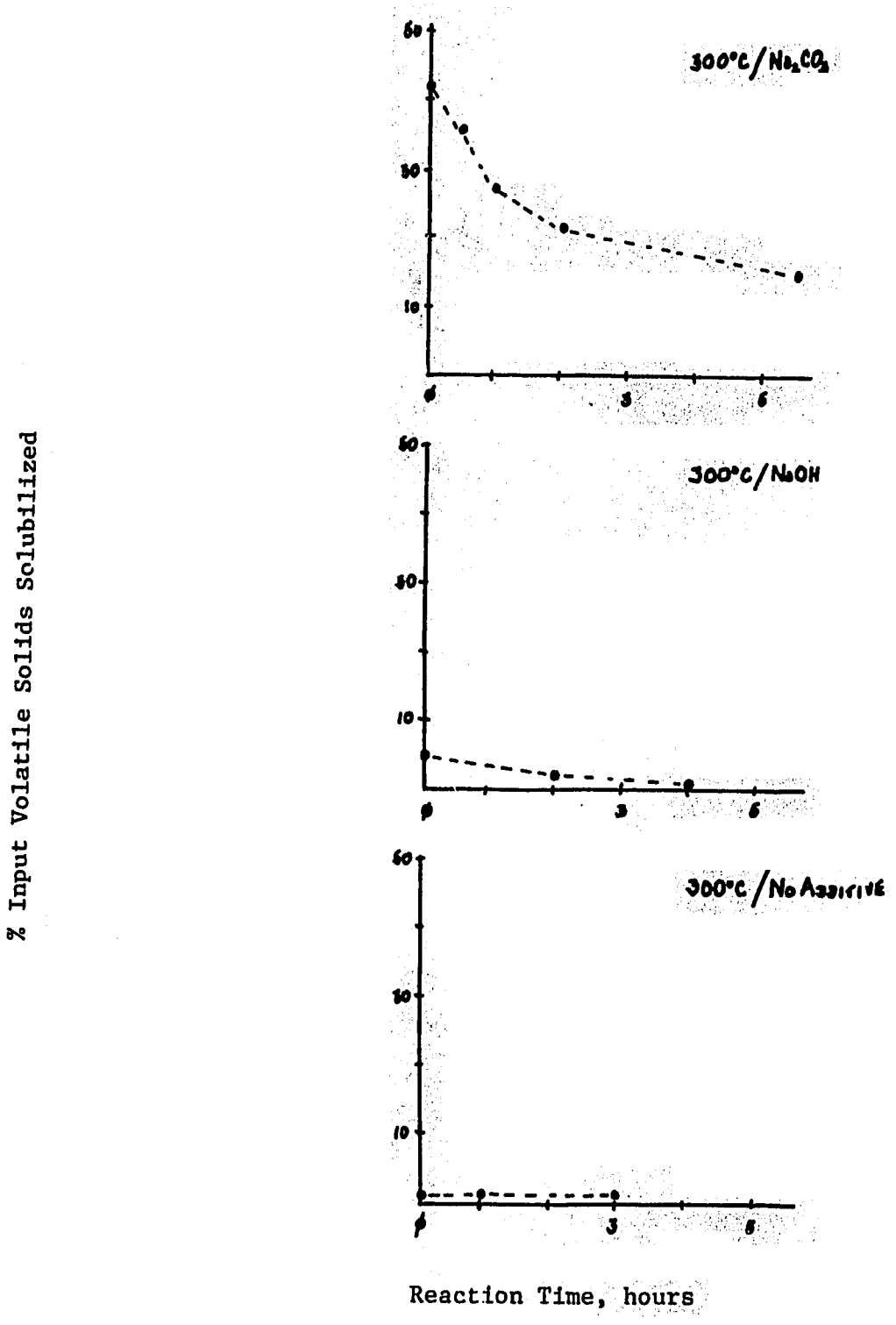

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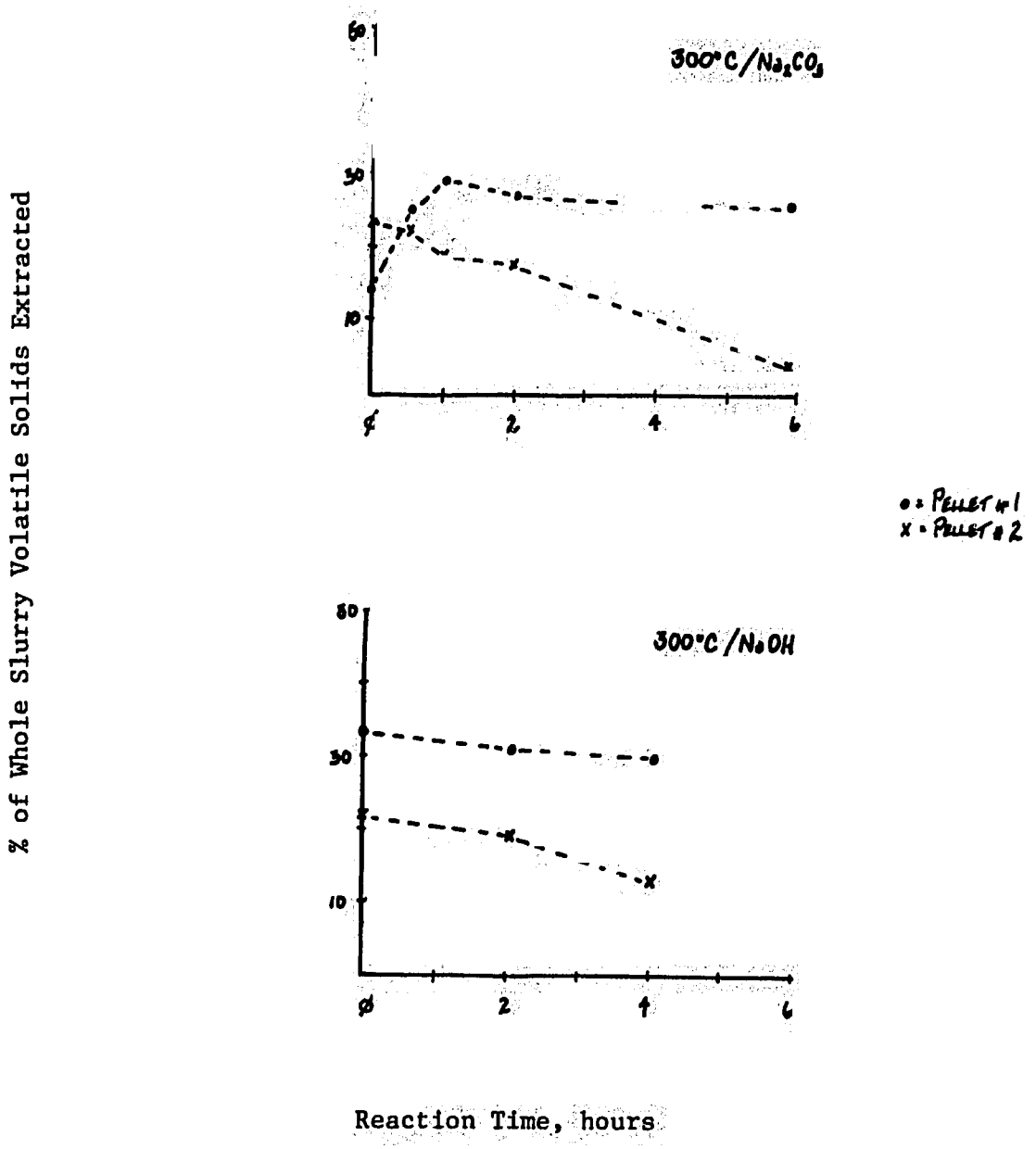
Figure 3.8

THF-Extractable Pellet Solids: Additive Variations



3.4.7 Oxidation Experiments

Table 3.3 shows the conditions for the oxidations in this series of experiments and the %VS solubilized as a result of oxidation. The %VS in the first supernatant decreases significantly in all cases as the oxidation proceeds. However, the %TS remains the same. Apparently, the oxidation is causing precipitation of the volatile solids solubilized. Table 3.4 shows the %VS in the whole slurry and in the first supernatant. Although both categories show some decreases, the %VS in the whole slurry decreases only very gradually. On the other hand, the %VS solubilized shows a large and sharp decrease as soon as the first sample in drawn. This implies that the solubilized volatile solids are susceptible to oxidation in a way other than combustion. The second set of oxidation experiments was designed to test this theory.

Table 3.5 compares the volatile solids data from the separate oxidations of solubilized materials and of non-solubilized materials. Again, the %VS solubilized decreases during oxidation of each type of slurry, while the %TS remains virtually constant. In addition, the %VS solubilized decreases sharply once oxidation of the solubilized material begins, as observed in the previous series of experiments.

The %VS solubilized does not decrease as drastically in the oxidation of non-solubilized material as with the solubilized material. This confirms the theory that solubilized materials are more susceptible to oxidation phenomena than non-solubilized material. In addition, oxidation does not increase solubilization of non-solubilized material. This implies that a two-stage pretreatment process, consisting of solubilization followed by oxidation, would not significantly increase solubilization above the level obtained by the solubilization alone.

Oxidation within the prescribed pretreatment regime effects the solubilized hydrolysis products rather than the non-solubilized hydrolysis products. Oxidation should promote degradation of the non-solubilized material. Oxidation, however, does not do this, but rather promotes the

Table 3.3

OXIDATION CONDITIONS* AND %VS SOLUBILIZED

CONDITIONS	SAMPLE	%VS SOLUBILIZED
400 mL/min	input (at 200°C)	2.3
	3/4 hr oxidation	0.5
	2 hrs oxidation	0.5
740 mL/min	input (at 200°C)	3.0
	1/2 hr oxidation	0.6
	1 hr oxidation	0.4
	2 hrs oxidation	0.5
	3 hrs oxidation	0.8
1000 mL/min	input (at 200°C)	2.7
	1/2 hr oxidation	0.5
	1 hr oxidation	0.5
	3 hr oxidation	0.7

* Note: All of these oxidations were done at 200°C.

Table 3.4

TOTAL VOLATILE SOLIDS COMPARED TO % VS SOLUBILIZED

SAMPLE	% TOTAL VS	% VS SOLUBILIZED
400 mL/min		
input (at 200°C)	4.5%	2.3%
3/4 hr oxidation	4.0	0.5
2 hrs oxidation	2.8	0.5
740 mL/min		
input (at 200°C)	5.1	3.0
1/2 hr oxidation	5.0	0.6
1 hr oxidation	4.6	0.4
2 hrs oxidation	4.9	0.5
3 hrs oxidation	4.7	0.8
1000 mL/min		
input (at 200°C)	5.2	2.7
1/2 hr oxidation	5.0	0.5
1 hr oxidation	4.7	0.5
3 hrs oxidation	4.6	0.7

Table 3.5

VOLATILE SOLIDS DATA FROM OXIDATIONS OF SOLUBILIZED AND NON-SOLUBILIZED MATERIAL

SOLUBILIZED MATERIAL	% TOTAL VS	% VS SOLUBILIZED	%VS sol/ % Tot VS
Input	4.1%	3.1%	0.76
at 200°C	5.6	2.9	0.52
1/2 hr oxidation	3.8	0.1	0.03
1 hr oxidation	3.6	0.1	0.03
2 hrs oxidation	3.3	0.2	0.06

NON-SOLUBILIZED MATERIAL	% TOTAL VS	% VS SOLUBILIZED	%VS sol/ % Tot VS
Input	6.1%	1.2%	0.20
at 200°C	6.0	1.6	0.27
1/2 hr oxidation	5.6	0.8	0.14
81 min oxidation	5.5	0.8	0.15
155 min oxidation	5.2	1.1	0.21

prescription of solubilized hydrolyses product. There are two possible explanation for this: (1) oxidation encourages repolymerization via free radical reaction, or (2) oxidation encourges precipitation via surface charring and agglomeration. In addition, oxidative degradation of non-solubilized material is most likely ineffectual on the "coalified" hydrolysis product (see Table 3.5). Further investigation may be interesting, particularly within the format of the proposed pilot facility which is capable of "fast reaction kinetics" (see Section 5).

Section 4

DECARBOXYLATION OF AROMATIC CARBOXYLIC ACIDS

4.1 Background

The initial products of alkaline oxidation are aromatic aldehydes, alcohols, and carboxylic acids with methoxy side-chains. Low molecular weight alkyl carboxylic acids are also formed. These products are depicted in Figure 4.1. Further oxidation leads to degradation of the aromatic nuclei. The methoxy content of the product also decreases with time, ostensibly due to the elimination of side-chains from the aromatic nuclei.

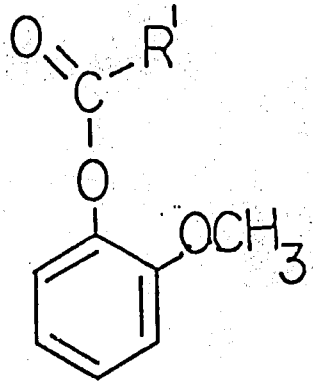
4.1.1 Recovery of Aromatics

Systems for the recovery of the aromatic products are of many different types. Solvent extraction of organic chemicals such as aromatic organic acids from aqueous solution is a technique which has been under consideration for some years. Ethyl acetate, along with diethyl ether, has been suggested as an efficient extraction medium at low acid concentrations. Recently, novel solvent extraction media were developed. This new technology is based on the use of trioctylphosphine oxide in combination with other solvents (Helsel and Dence, 1975). Higher molecular weight acids (butyric or larger) can be efficiently extracted into a liquid hydrocarbon solvent such as kerosene. It would be anticipated that aromatic organic acids could be similarly extractable.

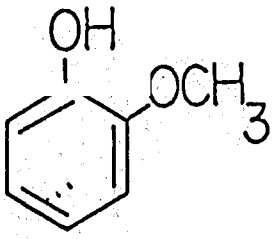
An alternate approach to conventional solvent extraction followed by distillation is solvent extraction followed by re-extraction into an aqueous base. This technique had been successfully employed at Dynatech in work concerned with liquid fuels production from biomass. Organic acids butyric and higher are selectively extracted and concentrated in aqueous base. Concentrations of acid salts obtained in the aqueous base have exceeded 1.0 N. Other approaches to recovery of the aromatic organic

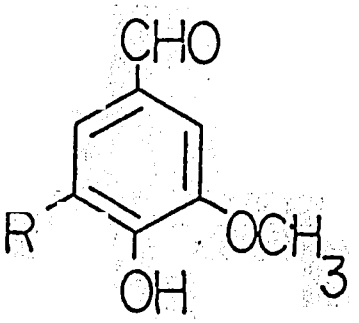
Figure 4.1

MODEL COMPOUNDS
(ALKALINE OXIDATION PRODUCTS)



RCOOH





WHERE

$R' = H$ OR CH_2OH

$R. = H$ OR $[CH_3]_3C$ OR OCH_3

acids include the addition of an inorganic acid, such as HCl, resulting in the direct precipitation of the aromatic.

4.1.2 Decarboxylation of Aromatic Carboxylic Acids

It has been known for a long time that organic carboxylic acids, particularly aromatic carboxylic acids can be decarboxylated by heating their salts with excess alkali to produce the parent hydrocarbon. The over-all reaction is presumed to be:

$$RCOO^- M^+ + M^+OH^- \xrightarrow{\Delta} R\text{-}H + M_2CO_3$$

Kerkovines and Dimrath (1913) found that aromatic carboxylic acids obtained from oxidation of charcoal could be decarboxylated efficiently by heating their barium salts. Shortly thereafter, Fisher (1919, 1921a, 1921b) found that the sodium salts of aromatic carboxylic acids made from coal oxidation could be decarboxylated by heating them with water to approximately 450°C under pressure. Juettner and others (1935) found that Fisher's method could be used to obtain up to a 94 percent yield from a pure sample of aromatic carboxylic acids. Entel (1955) found that the decarboxylation of aromatic acids produced by alkaline oxidation of coal could be carried out at 250°C if the copper salts were used. It is interesting to note that he was able to effect 96-99 percent decarboxylation by this method. Subsequently, workers at Dow Chemical Company (Montgomery and Holly, 1956, 1958) decarboxylated the copper salts of these acids at 265°C using quinoline as a catalyst and claimed improved results. The results of the product analysis resulting from the copper-quinoline decarboxylation of aromatic acids obtained from the alkaline oxidation of Pocahontas No. 3 bituminous coal are presented in Table 4.1. This has related interest to both peat and lignite.

The results of other workers indicate that nearly quantitative decarboxylation is possible by a variety of techniques. A choice betwen these techniques can be made on economic considerations. It is quite possible that decarboxylation of water soluble aromatic acids will be

Table 4.1

PRODUCT ANALYSIS OF DECARBOXYLATED AROMATIC ACIDS*

COMPOUND	YIELD† g/kg	PORTION OF TOTAL NUCLEI†† %	COMPOUND	YIELD† g/kg	PORTION OF TOTAL NUCLEI†† %
Mass 280	*	-	Benzophenone	7.6	1.7
Mass 268	*	-	Phenanthrene	15	3.3
Mass 260	*	-	Mass 178 (not phenanthrene)	*	-
Mass 258	*	-	Mass 176 (C_7-benzene)	0.7	0.2
Mass 254	*	-	Methylbiphenyl	2.8	0.6
Mass 244	0.007	0.002	Mass 166	0.3	0.07
Mass 234	*	-	Mass 160	0.5	0.1
Mass 232	*	-	Mass 158	*	-
Terphenyl (m- and p-)	5.6	1.2	Biphenyl	41	9.0
Mass 228	0.06	0.02	C_5-benzene	8.1	1.8
Mass 226 ($C_{14}H_{16}O_3$)	0.02	0.009	Methylnaphthalene (α and β)	172	38
Mass 220	*	-	Butylbenzene	1.8	0.4
Mass 218	*	-	Naphthalene	15	3.3
Mass 204 (Phenylnaphthalene)	5.4	1.2	Mass 122	0.1	0.02
Mass 202 (Not fused aromatic ring system)	2.1	0.5	C_2-benzene	0.2	0.04
Mass 196	0.9	0.2	Toluene	3.4	0.75
Mass 184 ($C_{14}H_{16}$)	0.7	0.2	Benzene	91.4	20.0

* Present † Total yield 378 g/kg †† Total of all portions 83 per cent.

*from Montgomery and Holly, 1958.

feasible with peat and lignite hydrolysis products; thus, yielding a BTX-type liquid fuel. Alternative methods to recover the aromatics, as described above, should also be practical.

4.2 Program Plan for Decarboxylation of Pretreated Lignite

A carefully planned alkaline hydrolysis can effect a reversal of the coalification process, particularly in the low rank coals. It was expected that this reversal of the coalification would result in considerable degradation of the coal structure into much simpler chemical units. A chemical functionality common to the breakdown products is the carboxylic acid group. It was a goal of this program to remove the carboxylic acid group (via "decarboxylation") from lignite hydrolysis products to yield water-insoluble organics suitable for use as fuel.

One of chemical methods for decarboxylation of aromatic carboxylic acids is the copper-quinoline method. In fact, this technique was demonstrated using coal acids (Montgomery and Holly, 1956). The mechanism by which the acids are decarboxylated is a combination of thermal and chemical actions. The copper salts of the carboxylic acids are combined with quinoline (a high-238°C-boiling solvent) and heated to reflux. The quinoline facilitates solvolysis, as well as temperature control. The method is closely allied to pure thermal methods in which salts of the acids are heated to 250°C. The copper-quinoline technique was thus chosen for investigation on the basis of its proven success.

Based upon overall applicability to the proposed process, as well as technical and economic considerations, the persulfate/silver ion method of decarboxylation (Fristad et al., 1983) was also chosen for investigation. This method uses sodium persulfate in conjuction with a transition metal catalyst to facilitate carboxylic acid decarboxylation. The sodium persulfate is a powerful oxidant which is relatively inexpensive and easily handled. Its high activation barrier makes the use of persulfate

alone unreasonable at low temperatures. However, when combined with a transition metal catalyst (e.g., a silver ion) the activation barrier of the persulfate ion is reduced and lower reaction temperatures are feasible. In addition, the persulfate serves as an effective electron shuttle to produce active metal species which can participate in the chemical reactions themselves. The mechanism for decarboxylation by the reagent pair is schematicized in Figure 4.2.

Operating on the premise that the major products of the alkaline hydrolysis would be benzoic acid-like, the program plan was to investigate the conditions for decarboxylation of benzoic acid using the persulfate/silver ion method. Maximum operating conditions were to be identified with respect to solvent composition, reagent concentrations, and reaction temperatures. In the final stage of the decarboxylation work, the hydrolysis products of the lignite pretreatment were to be subjected to the "best case" decarboxylation for determination of the percent conversion to water-insoluble organics. The products of the reactions were analyzed by GC, in all cases, and HPLC, in those cases where applicable.

4.3 Decarboxylation of Aromatic Carboxylic Acids - Experimental Procedures

4.3.1 Decarboxylation: The Copper/Quinoline Method

A. Decarboxylation of Benzoic Acid

The procedure used to decarboxylate benzoic acid is a modification of that reported by Buckles and Wheeler (1963) in the synthesis of cis-stilbene from α-phenylcinnamic acid. A 1000-mℓ, three-necked flask is equipped with reflux condenser, magnetic stirrer and thermometer. Benzoic acid (0.205 mol, 25.00 g) and anhydrous cupric sulfate catalyst (.024 mol, 4 g) are added. To this is added freshly-distilled quinoline (2.38 mol, 281

Figure 4.2

Mechanism for Decarboxylation of Organic Acids

$$Ag(I) + S_2O_8^{2-} \rightarrow Ag(II) + SO_4^{-}\cdot + SO_4^{2-} \quad (1)$$

$$Ag(I) + SO_4^{-}\cdot \rightarrow Ag(II) + SO_4^{2-} \quad (2)$$

$$Ag(II) + RCO_2H \rightarrow Ag(I) + RCO_2\cdot + H^+ \quad (3)$$

$$RCO_2\cdot \rightarrow R\cdot + CO_2 \quad (4)$$

$$R\cdot + H\text{-solv} \rightarrow RH + \cdot\text{solv} \quad (5)$$

* From W.E. Fristad et al., 1983.

mℓ) and the system is heated to 210°C using a heating mantle. The temperature of the system is maintained between 210°-225°C for 1.25h after which the flask is cooled and the reaction mixture is gravity-filtered into a 500 mℓ sound-bottomed flask. At this point the reaction mixture smells strongly of benzene. The flask containing the reaction mixture is fitted with a Vigereaux column and the contents are fractionally distilled.

B. Decarboxylation of Benzoic Acid-Time Study

The procedure described in (A) is repeated with the exception that the amount of each reagent is reduced by 50 percent. Samples of the reaction mixture are taken before heating, at 100°C, 200°C, and 0.5h, 1.0h, and 1.25h after the temperature reaches 210°C.

4.3.2 Decarboxylation: The Silver/Persulfate Method

A. Decarboxylation of Benzoic Acid

A 250-mℓ three-necked flask is fitted with reflux condenser, addition funnel, thermometer and magnetic stirrer. Benzoic acid (0.14 mol, 15.88g) and silver nitrate (2.6 mmol, 0.4g) are dissolved in a mixture of 100 mℓ acetonitrile and 33 mℓ water. This solution is added to the flask and heated to reflux (78°C). Sodium persulfate (260 mmol, 61.91g) is added to 67 mℓ water and heated to dissolution. The sodium persulfate is added to the reaction flask over a period of 15 minutes. When addition is complete, the flask is allowed to reflux an additional 5 minutes. After cooling, the reaction mixture is a yellow 2-phase liquid. The layers are separated; the upper layer is washed with saturated sodium bicarbonate solution and the bottom later is washed with ether. The reaction mixture is extracted with ether and saturated sodium bicarbonate as described above.

B. Decarboxylation of Lignite Hydrolysis Products

A concentrate of lignite hydrolysis products is obtained as follows. The "best case" slurry (250°C/ϕ time) is separated by centrifugation.

The solubilized organics are precipitated by acidification (conc HCl, pH 2.0) of the supernatant. The organics are isolated by centrifugation and then dried. This material is considered the essence of the lignite hydrolysate and in this best case amounts to about 63% of the input volatile solids.

The decarboxylation procedure described in (A) is followed with the concentrated lignite hydrolysate replacing the benzoic acid. The reactant amounts are as follows: lignite concentrate (5.0 g), sodium persulfate (84 mmol, 20.0 g), silver nitrate (.98 mmol, .15 g).

4.3.3 Chromatographic Methods of Analysis

The volatile organic liquid determinations of decarboxylation products are made via gas chromatography (GC). Other organic determinations are made via high performance liquid chromatography (HPLC).

A. Gas Chromatography

The volatile organic liquid samples in this phase of the program are analyzed using a Varian 3700 gas chromatograph equipped with a Varian Model 2010 flame ionization detector and a Spectra-Physics 4270 printer, plotter, integrator. The separation is carried out on an Alltech stainless steel AT-1000 on Graphpac column (1/4 in x 6 ft; 80/100 mesh). Samples are run under conditions of linear programming over the temperature range 150°- 210°C (10°C/min) with nitrogen as the carrier gas (30 mℓ/min). The injector temperature is set at 220°C, detector temperature at 230°C. Solutions of standards are prepared in ethanol.

B. High Performance Liquid Chromatography

The organic products are analyzed using a Waters (Milford, MA) HPLC system equipped with a M45 solvent delivery system, a U6K injector, a Model R401 differential refractometer, and a Fisher Recordall Series 5000

recorder. Separation is carried out on a Regis Octadecyl Workhorse column (30 cm x 4.6 mm) using CH_3OH/1% CH_3COOH (1:1) as the eluent. Solutions of standards are prepared in eluent.

4.4 Results and Discussion of Decarboxylation Studies

The strategy for using the model compounds in the decarboxylation studies was three-fold. First, it was desirable to reproduce the literature work to serve as a verification of results and as grounds for development of pertinent analytical protocols. Second, it was of interest to determine the sensitivities in various parameters of the decarboxylation operation. Third, it was necessary to generate data for a best case analysis in the preliminary process designs. This approach was justified in view of the complexity of the lignite solubilization material. Once the experimental plan was defined with the model compounds, lignite hydrolysate was subjected to decarboxylation.

4.4.1 Decarboxylation of Benzoic Acid

One of the procedures used to decarboxylate benzoic acid was the copper sulfate/quinoline method. Benzoic acid was heated to reflux in quinoline with copper sulfate added as catyalyst. At the end of the reaction time, the mixture smelled very strongly of benzene. Distillation of this reaction mixture yielded three fractions: (1) 51°-56°C (1.95 g); (2) 56°- 80°C (3.73 g); (3) 80°-200°C (150g).

Gas chromatographic analyses showed the major benzene yield in fractions (1) and (2). Quinoline peaks appeared prominently in all three fractions even though the high boiling point of quinoline would seem to preclude it from distilling at the lower temperature ranges. An attempt was made to remove quinoline from the reaction mixture by dissolving it in 10% HCl before the distillation. This resulted in precipitation of a large amount of black, granular solid (possibly decomposed benzoic acid) in a dark orange solution. After filtration and distillation, GC analyses still showed a predominance of quinoline in the samples. This over-shadowed the benzene analyses making benzene quantitation impossible.

The second procedure which was used in the decarboxylation of benzoic acid was the persulfate/silver ion method. A mixture of benzoic acid and sodium persulfate was heated to reflux in a solution of 50% acetonitrile/water. At the end of the reaction time, the mixture was a two-phase liquid. However, encouraging this two-phase liquid was, a control experiment sine benzoic acid also produced a two-phase liquid. This suggest that the strong oxidizing nature of the reactants may act to promote polymerization and, hence, the H_2O-insolubility of the acetonitrile.

The persulfate/silver on method was investigated with respect to the effects of reactant concentrations and time on yield of benzene. Both phases of the reaction mixtures were analyzed via GC for the presence of benzene. As would be expected, the majority of the benzene which was generated reported to the upper (i.e., the non-aqueous) layer.

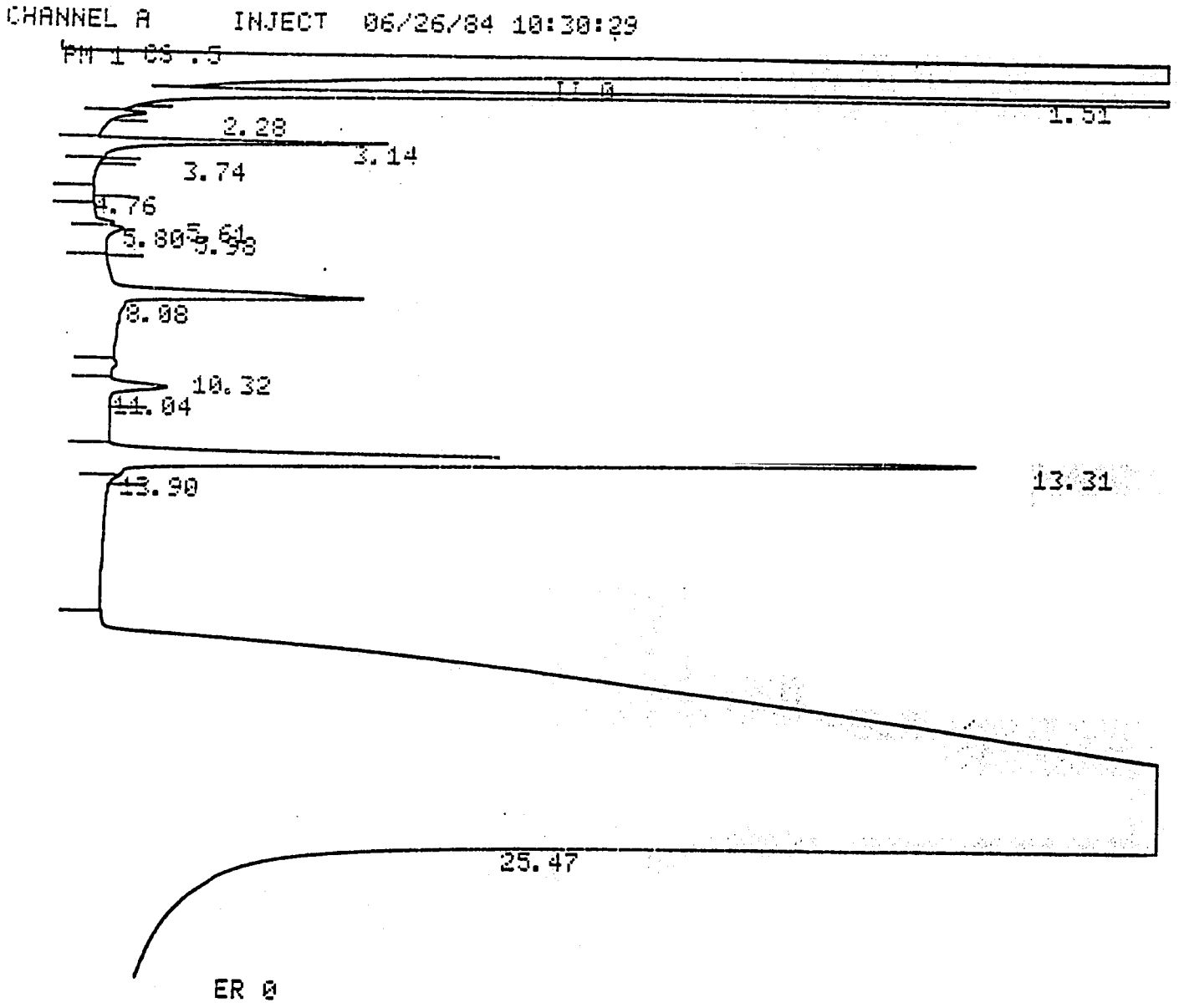
The GC analysis of the "base case" decarboxylation (50% acetonitrile/H_2O; 20 minutes) is shown in Figure 4.3. The yield of benzene from this reaction was 38%. A time study of this decarboxylation showed varying yields with time, a maximum benzene yield of 41% achieved at one hour reaction time (Figure 4.4). The decreased yield of benzene at the longer reaction time (i.e., two hours) indicates increasing complexity of reaction under the strong oxidizing conditions.

The persulfate/silver ion method of decarboxylation effectively eliminates the use of quinoline, a solvent which is not exceedingly desirable from a process standpoint. The method is simple, fast, and energy conservative. It does, however, call for the use of acetonitrile in the reaction process, another solvent which is not so desirable in a process. The acetonitrile serves as the proton donor (see decarboxylation scheme, Figure 4.2) and this plays an important role in the reaction. Because this work addresses an eventual commercial process it was important to determine how much acetonitrile is necessary for the decarboxylation.

Benzoic acid was subjected to persulfate/silver on decarboxylation in 50:50 acetonitrile/water, 25:75 acetonitrile/water, and 100%

Figure 4.3

GC Analysis: Base Case Decarboxylation



INPUT OVERRANGE AT RT= 0.68

DOE-6-3 06/26/84 10:30:29 CH= "A" PS= 1.

FILE 4. METHOD 5. RUN 20 INDEX 1

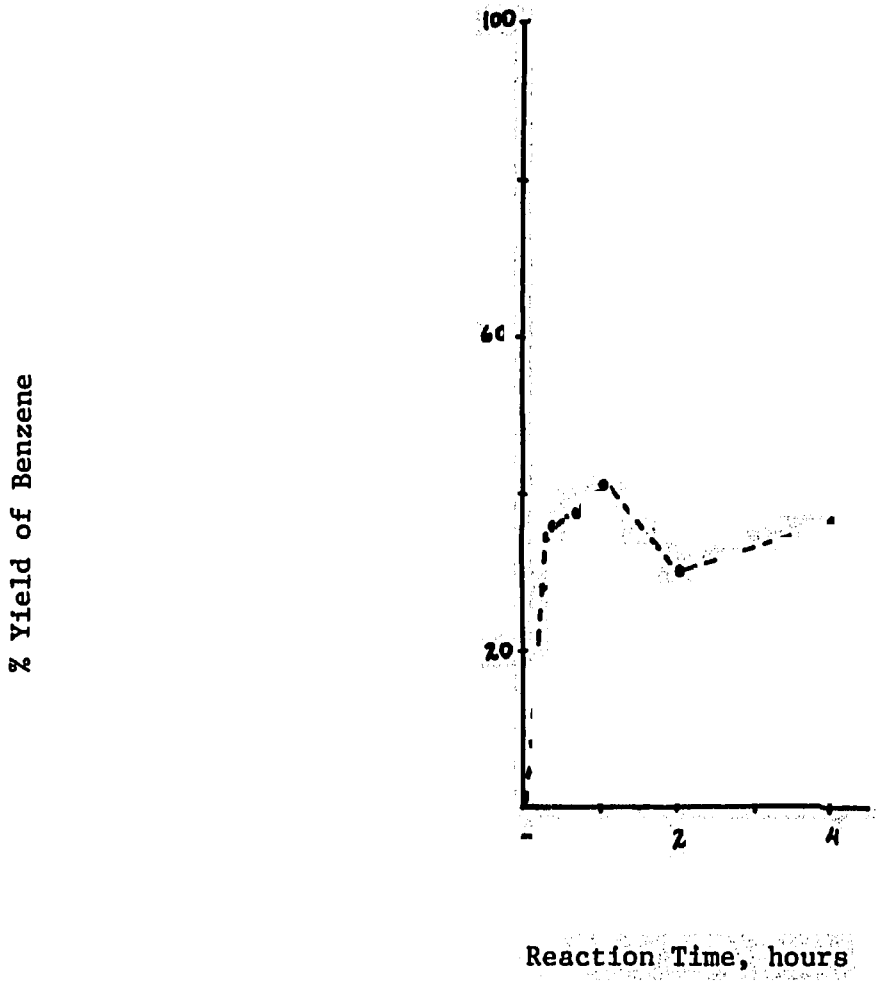
ANALYST: DMH

SAMPLE 1 020407-D

NAME	MMOL/L	RT	AREA	BC	RF	RRT
BENZENE	140.543	1.51	2707306	01	19263.25	1.
TOTALS	140.543		8404518			

Figure 4.4

Time Course for Decarboxylation of Benzoic Acid: Base Case



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water. Relative reactant concentrations are shown in Figure 4.5. A reduction in the amount of acetonitrile had a profound effect on the efficiency of reaction. Whereas in the 50:50 case there was a 36% yield of benzene, in the 25:75 case the yield dropped to 6%. There was negligible decarboxylation under totally aqueous conditions. These results illustrate the need for a donor solvent if reaction is to be effective. However, in the decarboxylation of lignite hydrolysate it may not be necessary to add 50% acetonitrile to the process stream. Some of the products of the alkaline hydrolysis may be effective proton donors themselves (e.g., the phenolic compounds).

4.4.2 Decarboxylation of Lignite Hydrolysate

Lignite hydrolysate was subjected to decarboxylation using the persulfate/silver ion method. Rather than using the entire hydrolysis slurry for the experimental work, only the solubilized organics were used. The hydrolysis slurry was centrifuged, and the resulting supernatant was decanted and acidified. The organic material which was precipitated was isolated upon centrifugation. This material was used because it was assumed to be richest in the carboxylic acid-like product most susceptible to decarboxylation.

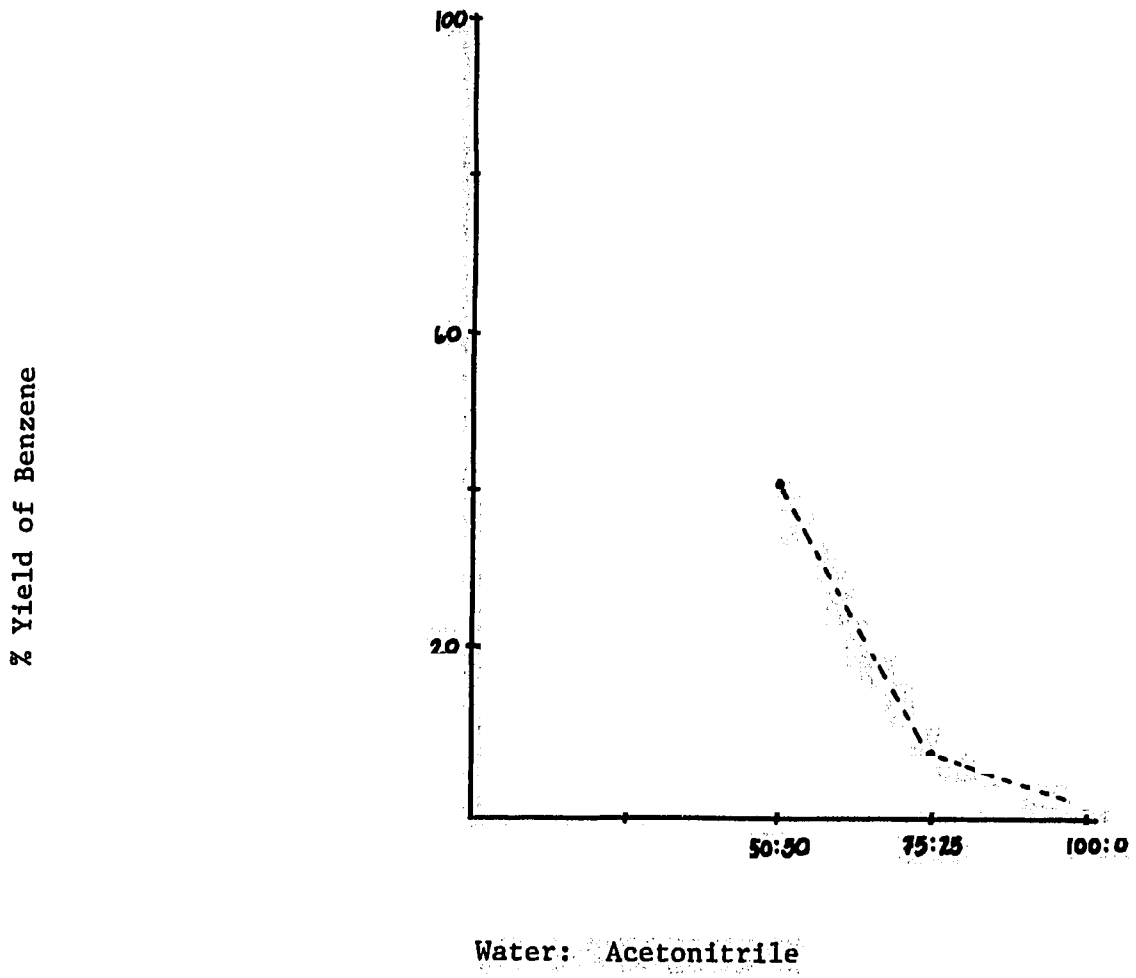
The organic hydrolysate was combined with sodium persulfate and silver nitrate in 50% acetonitrile. The reaction mixture was heated to 100°C in a Parr bomb and cooled. The product was analyzed via GC.

The 6% yield of water-insoluble organic material represents 4% overall conversion of the input lignite volatile solids. This, unto itself, is certainly not so overwhelmingly encouraging for start-up of a full-scale process. It does indicate, though, that there may be some promise for the production of BTX-type liquid fuels from lignite.

The work shown here represents a limited and isolated effort in decarboxylation of a lignite hydrolysate. The products of the hydrolysis

Figure 4.5

Decarboxylation of Benzoic Acid: Acetonitrile/Water Variations



are exceedingly complex. Future work should be directed towards two research areas. One is the extensive identification of the major components of the products of lignite breakdown. If these materials are subject to rigorous characterization and identification, they can be fit more adequately into the decarboxylation scheme. The mechanistic details for decarboxylation of the lignite hydrolysate will be better understood in light of the product identifications. The second area for future research concerns the investigation of the role of the catalyst in the decarboxylation. From a process viewpoint, is is important to identify the form the catalyst must take (e.g., fixed-bed), the lifetime of the catalyst (for purposes of regeneration), and any improvements in catalyst performance. This is a cumbersome task, but one which must be accomplished if the direct liquefaction of lignite is to be considered a viable means of liquid fuels production.

Section 5

THE PILOT - SCALE FACILITY FOR DIRECT LIQUEFACTION OF LIGNITE

The laboratory phase of the liquefaction program illustrated that lignite could be solubilized under conditions of alkaline hydrolysis. The hydrolysate contained aromatic organic acids which are capable of decarboxylation to water-insoluble organics. The experimental program was used to identify some of the necessary processing conditions, such as temperature and alkali concentration, and to characterize the nature of the reacted material. Under batch conditions, maximum lignite solubilization was observed at 250°C, 8% volatile solids loading, and 20% sodium carbonate (weight per weight of lignite volatile solids). The results demonstrated the feasibility of an aqueous treatment of lignite and provided insight into the preliminary design of a pilot-scale facility.

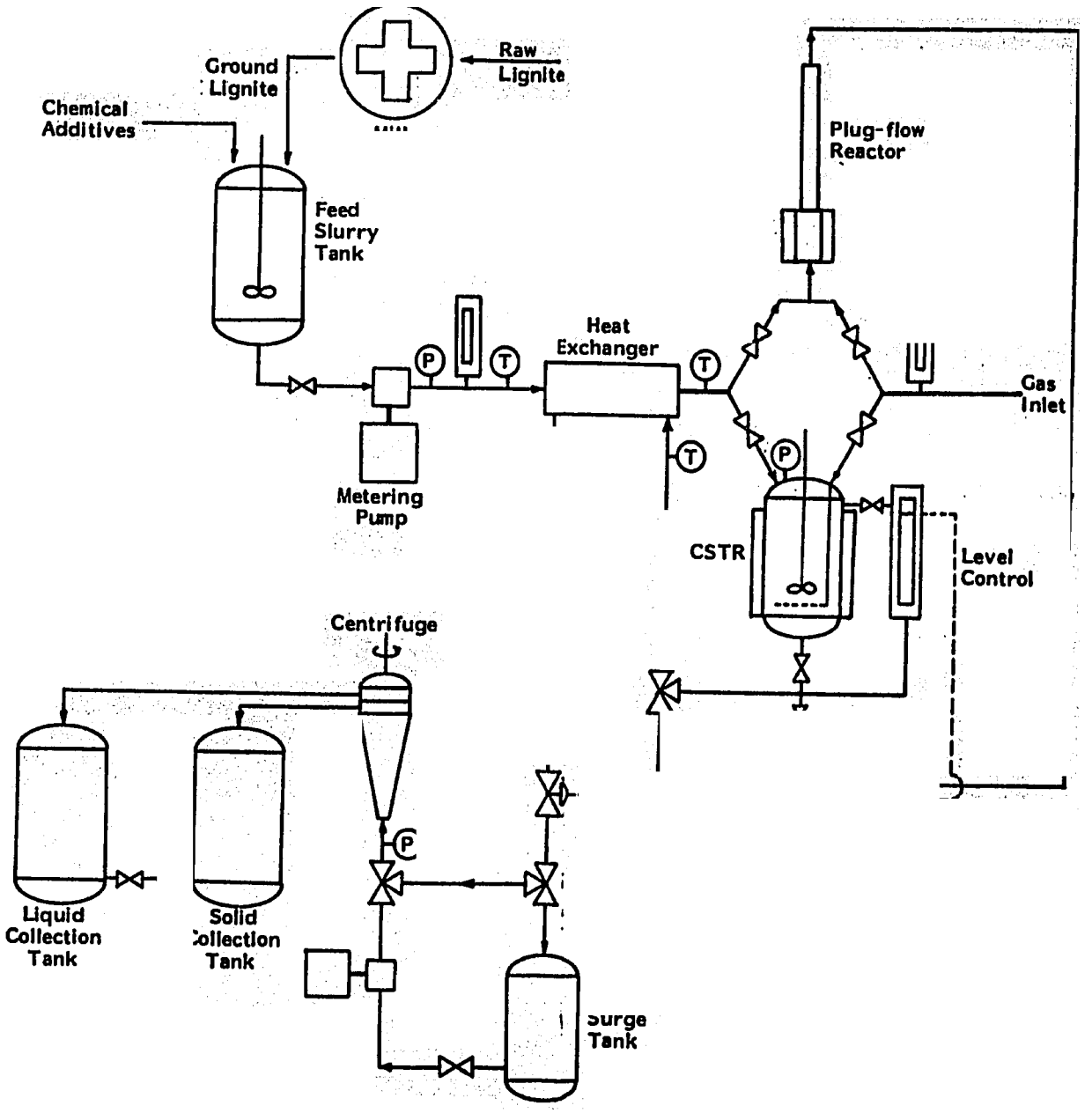
Here, "pilot-scale" is taken to mean an expanded scale laboratory facility. In this light, the pilot phase of the research would concentrate on the more detailed analysis of the alkaline hydrolysis of the lignite in an effort to "optimize" the process. The work would focus on the development of a kinetic model which identifies the reaction time-temperature profiles, as well as the reactant concentrations corresponding to maximum solubilization of the lignite under the "pilot conditions."

5.1 The Reactor System for Lignite Pretreatment

The pretreatment apparatus which was utilized in the laboratory program at Dynatech is a batch reactor system. It is neither sufficiently large for the production of enough extracted material for use in subsequent processing steps, nor is it sufficiently versatile for achieving the short retention times necessary for a detailed kinetic study. Therefore, it is proposed to build a continuous apparatus for the pilot-scale work. This satisfies the scaled-up throughout requirements for investigation of subsequent processing steps, and yields meaningful results for the development of a predictive kinetic model. The apparatus is schematicized in Figure 5.1

Figure 5.1

Preliminary Design for Laboratory Hydrolysis Unit



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Because limited information is currently available which would suggest an appropriate retention time for a continuous system, some preliminary experiments are necessary. For short retention times, on the order of seconds, a plug flow reaction system would seem to be appropriate. For longer reaction times, on the order of minutes, a CSTR would probably be appropriate. The batch system currently in use has a retention time on the order of hours and experiments have indicated that shorter retention times are necessary. Maximum solubilization under batch conditions was achieved when the reaction just reached 250°C - longer reaction times resulted in rapid repolymerization of the reaction intermediates (see Section 3).

The equipment differences between a plug flow reactor and a CSTR are small, except for the reaction chamber itself. The feed tanks, pumps, valving, reactant stream quench and instrumentation are the same for both systems. The plug flow reaction chamber is a jacketed tube which rapidly heats the reaction mixture, and maintains the elevated temperature for a specified time. The CSTR chamber is a jacketed vessel in which the entering stream is heated by mixing with the reacting mixture. In both systems the residence time is adjusted by varying the flow rate of the reactants.

The parameters which would be investigated in this pilot-scale program are temperature, mean residence time, coal concentration and particle size, and chemical additive concentrations. These parameters would be varied, with the objective of developing a predictive model to describe the dynamics of the process, to be used to approximate the optimal design conditions. To cover the broad range of residence times, both the plug flow (1-30 sec residence times) and CSTR (2-60 min residence times) systems could be used.

The kinetic model which would result from the pilot program would indicate the optimal time-temperature profile. This would give some indication as to whether a staged reactor configuration would be appropriate for the overall process design. Staging would be an attractive addition to

the pilot-scale facility since it would offer an advantage in materials handling and potentially add to the yield of desirable product.

5.2 Capital Costs for the Pilot-Scale Pretreatment System.

The pilot-scale pretreatment system schematicized in Figure 5.1 has been designed for a laboratory scale program. The costs for the continuous reaction equipment would be $33,210; for the pertinent glassware the costs would be $3000. The costs are itemized in Table 5.1.

Table 5.1

THE PILOT-SCALE PRETREATMENT SYSTEM

A. CONTINUOUS REACTION EQUIPMENT

	$ AMOUNT
Reactor 26, 1000 psi 600°F (Temp Control)	4,200
Sight	450
Level Control	250
Control Value	300
Centrifuge	12,000
Mill	3,200
Pumps: Feed 200 ml/min 1500 psi	750
Centrifuge 2 l/min	400
Storage Tanks: 10L	70
(3) 20L	330
1L (surge, 1000 psi)	170
Tank Agitator	300
Heat Exchanger (High pressure)	250
Values: (2) 3-Way Ball	210
(1) Metering	50
(8) Ball	600
Gauges: (3) Pressure	50
(8) Temperature	250
(2) Electronic Flow	4,000
(1) Rotameter (Gas)	200
Tubing	300
Assorted Fittings	750
Recording Equipment	1,500
Steam Assembly	2,000
Explosion-proof	630
	$33,210

Table 5.1 (Continued)

B. LABORATORY GLASSWARE

	$ AMOUNT
Evaporator	480
Distilling Apparatus	1,010
Heating Mantle	450
Variac	200
Extraction Apparatus	310
Heating Mantle	200
Variac	100
Clamps, Supports, Tubing	250
	$ 3,000

Section 6

THE FULL-SCALE FACILITY FOR DIRECT LIQUEFACTION OF LIGNITE

The results of the laboratory program were used to design a full-scale facility for the direct liquefaction of lignite to BTX-type fuel. The preliminary process design was evaluated by Dr. Ernest E. Kern of Houston Lighting and Power Company, a member of the Industrial/University Review Committee, with the assistance of the engineering staff at Dynatech. The Aspen Plus® (Aspen Technology, Inc., Cambridge, MA) process simulator and economic evaluation system was used to develop a computer model from the preliminary process design. The use of the Aspen Plus® computer program allowed for the calculation of all heat and material balances for the liquefaction process, of all equipment sizing, and of all capital and operating costs.

6.1 Full-Scale Process Design

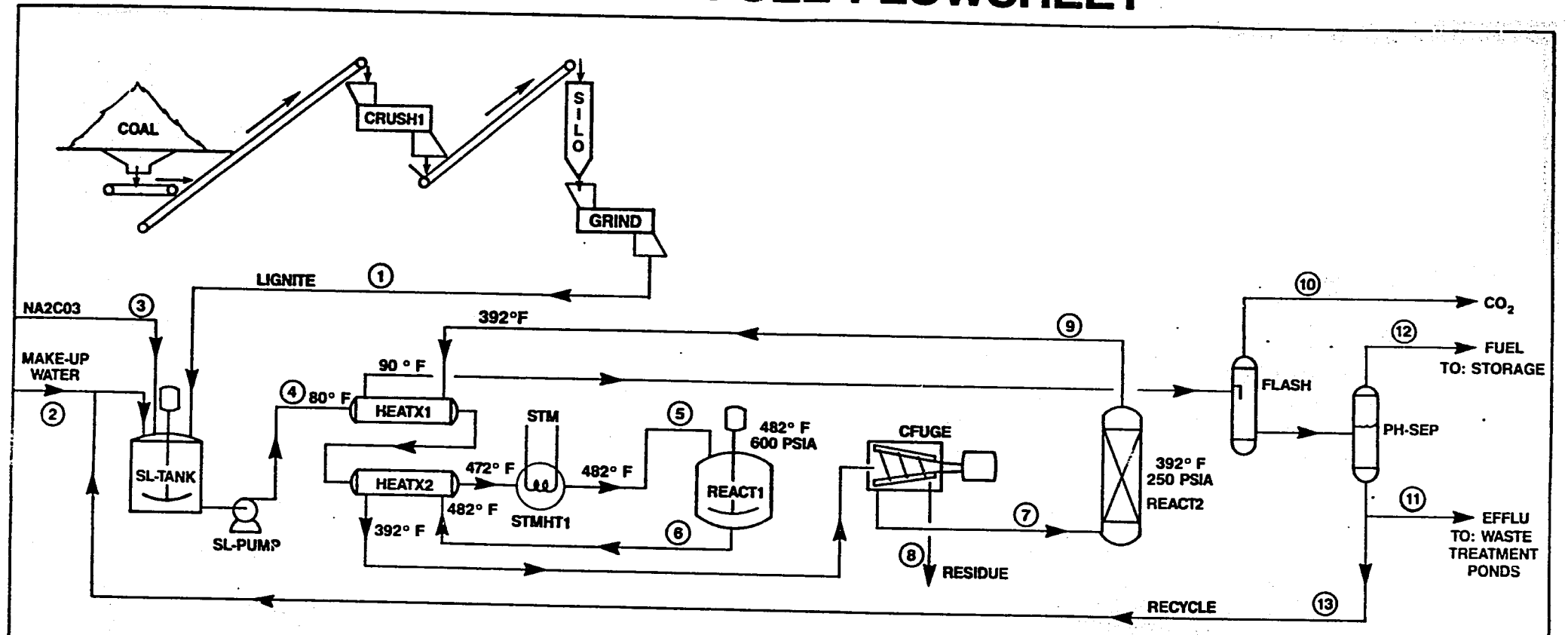
The flowsheet diagram for the liquefaction of lignite to BTX-type fuel is shown in Figure 6.1. The process is depicted as a two-stage chemical treatment. The first step is the alkaline hydrolysis where the complex macromolecular structure of lignite is broken down to water-soluble salts of aromatic acids. The second step is the catalytic decarboxylation where the aromatic acids are converted to water-insoluble organic liquids. Model compounds were used to characterize the product streams. Benzoic acid was chosen to model the products of the first reaction, toluene the products of the second reaction.

The process depicted in Figure 6.1 consists of the following unit operations:

1. Coal Handling (Conveying and Storage);
2. Crusting and Grinding;
3. Slurry Preparation and Handling;
4. Heat Exchange;
5. Alkaline Hydrolysis - Reactor No. 1;
6. Solids Separation (Centrifuge);
7. Decarboxylation - Reactor No. 2;
8. Separations (Gas-Liquid and Liquid-Liquid); and
9. Waste Treatment.

Figure 6.1

BTX—TYPE FUEL FLOWSHEET



BASE CASE 50% RECYCLE — THOUSAND LBS / HR

STRM ID / COMPONENT	1 LIGNITE	2 WATER	3 NA2C03	4 SLURRY	5 REA1-FD	6 REA1-OUT	7 OVFLW1	8 RESID1	9 REA2-OUT	10 CO2	11 EFFLU	12 BTX-PROD	13 RECYCLE
H20	0	2335	0	4583	4583	5000	4500	500	4500	0	2250	0	2250
CO2	0	0	0	0	0	33	30	3	140	140	0	0	0
ACIDS	0	0	0	152	152	677	610	68	305	0	152	0	152
BTX-FUEL	0	0	0	0	0	0	0	0	230	0	0	230	0
NA2C03	0	0	167	167	167	167	0	167	0	0	0	0	0
COAL	1667	0	0	1667	1667	158	0	158	0	0	0	0	0
ASH	0	0	0	0	0	417	0	417	0	0	0	0	0
RESID	0	0	0	0	0	117	0	117	0	0	0	0	0
TOTAL,000#/HR	1667	2335	167	6568	6568	6569	5140	1429	5175	140	2402	230	2402
TONS/DAY	20000	28020	2000	78821	78821	78829	61676	17146	62098	1679	28826	2760	28825
TEMP. F		72		80	482	482	392		392	90	90	90	90
PRESS. PSI		45		630	600	585	250		235	65	65	65	65

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This process design was detailed in an earlier report (Dynatech Report No. 2282). The conditions for reaction are detailed in Sections 3 and 4. The base case conditions for production of BTX-type fuel can be summarized as in Table 6.1.

The base case heat and material balances are for a 20,000 TPD plant producing 15,000 barrels per day of fuel. The base case costs are shown in Table 6.2. The total capital investment required is estimated to be $644 million at 50% debt. In order to achieve a 17% interest rate of return on equity, it is required that the initial selling price be $8.95 per million BTU's ($1.16 per gallon).

Obviously, the price of $1.16 per gallon is not very competitive in today's marketplace. Prices for No. 2 heating oil and unleaded gasoline are currently around $0.75 per gallon. However, the price of $1.16 per gallon is attractive when compared to alternative coal liquefaction and gasification prices.

6.2 Sensitivity Analysis

The Aspen Plus® program was utilized to get a sensitivity analysis of the initial selling price ($8.95 per million BTU's). The parameters investigated included: slurry solids concentration, lignite price, debt ratios, and heat transfer coefficients. The results are summarized in Table 6.4.

The most profound effect was with the slurry solids concentration. There are higher capital costs for equipment which must handle large volumes of water. A change in the slurry concentration from 27% solids to 8% solids triples the volume of slurry and doubles the equipment cost. This results in an increase of 50% in the selling price of the product.

Increasing the cost of the lignite from $12/ton to $18/ton causes a 12% increase in the product price from $8.95/MKB to $10.06/MKB.

Table 6.1

DIRECT LIQUEFACTION OF LIGNITE TO BTX-TYPE FUEL:
BASE CASE PARAMETERS

Lignite Feed Rate	20,000 TPD
Lignite Heating Value	6,000 BTU/LB
Lignite Price	$12/Ton
Recycle Process Water	50% of Effluent Stream
Reactor-1 Conversion	63% of Volatile Solids
Reactor-2 Conversion	50% of Acids
BTX-Type Fuel Heating Value	18,000 BTU/LB
Interest Rate of Return on Equity	15%
Inflation	7%/Year
Project Start	March 1985
Commercial Production	October 1988
Percent Debt	50%

Table 6.2

BASE CASE RESULTS

INVESTMENT	$ MILLION
Physical Plant	$ 389
Interest During Construction (10%)	37
Start-up	63
Tax Credit	-51
Working Capital	89
Contingency	117
TOTAL	$ 644

SCHEDULE	
Project Start	March 1985
Commercial Production	October 1988

REVENUE	
Capacity Production Rate (Tons/Day)	2760
Normal Production Rate (Tons/Day)	2346
Initial Selling Price ($/Ton 1988)	437
Initial Selling Price ($MKB 1988)	12.14
Initial Selling Price ($MKB 1984)	8.95
Initial Selling Price ($/Gal 1984)	1.16
Return on Investment	17.4%
Payout Time (Years)	5.8

CAPITAL INVESTMENT	$ MILLION
Total Equipment Cost*	123
Total Field Construction Cost	310
Total Depreciable Cost	506
Total Capital	668

ANNUAL OPERATING COST 1988	
Total Raw Materials	148
Total Utilities	25
Waste Treatment	2.9
Catalyst	2.9
Labor	32
Supplies	12
General Works	28
Depreciation	34
Gross Operating Cost	$285

* (See Table 6.3).

Table 6.3

EQUIPMENT COSTS: BASE CASE

ITEM	NO. OF UNITS	DESIGN P, T OR MOTOR SIZE	SIZE EACH	$ x 1000 UNIT PRICE	$ x 1000 TOTAL	$ x 1000 INSTALLED
Coal Hdl Equipment	1	-	20,000 TPD	-	4,669	24,746
Coal Silos	8	-	800 TON	77	612	3,266
Crushers	2	750HP MOTOR	1,500 TPH	147	294	878
Grinders	8	750HP MOTOR	100 TPH	184	1,470	4,390
Slurry Tanks	16	W/75HP AGIT'RS	20,000 GAL	51	821	3,045
Slurry Pumps	16	300HP MOTOR	575 GPM	31	499	1,408
Heat Exchangers	32	650PSI, 500°F	73 MBH	499	15,981	41,441
Steam Heat Exchangers	16	800PSI, 550°F	4.8 MBH	16	257	667
Reactors No. 1	16	650PSI, 500°F	46,000 GAL	495	7,925	26,987
Centrifuges	4	750HP MOTOR	100 TPH	662	2,646	6,648
Reactors No. 2	8	275PSI, 450°F	34,000 GAL	382	3,058	8,477
Flash Tanks	8	75PSI, 150°F	30,000 GAL	81	651	2,361
Phase Separators	8	75PSI, 150°F	30,000 GAL	81	651	2,36L
Storage Tanks	6	75PSI, 150°F	400,000 GAL	99	592	3,159
Waste Water Treatment	1	ATM	-	-	-	9,027
TOTAL					40,126	138,861

Table 6.4

SENSITIVITY ANALYSIS

CASE	LIGNITE PRICE $/TON	PERCENT DEBT %	SLURRY SOLIDS %	EQUIPMENT COST	INVESTMENT PHYSICAL COST	$M TOTAL COST	INITIAL SELLING PRICE		PRESENT VALUE $/MKB	COMMERCIAL PRODUCTION DATE
							$/TON	$/MKB		
A (base case)	12	50	27	123	389	644	437	12.14	8.95	Oct 1988
B	12	0	27	123	389	607	462	12.83	9.46	Oct 1988
C	12	80	27	123	389	666	422	11.72	8.65	Oct 1988
D	18	50	27	123	389	664	491	13.64	10.06	Oct 1988
E	12	50	13	157	512	823	498	13.83	10.03	Dec 1988
F	12	50	8	235	813	1273	681	18.92	13.49	Apr 1989
G (U=150)*	12	50	27	167	543	873	526	14.61	10.60	Jan 1989

Table IV: Results of the case study on the direct liquefaction of lignite using the Aspen Plus® costing model. The effect of lignite price, slurry solids concentration, percent debt and heat transfer coefficient on the initial selling price of the product was determined assuming a 15% interest rate of return on equity.

* Heat Transfer Coefficient U=350 Btu/hr·Ft^2·°F in all other cases.

The financing of the plant using different debt ratios also has a profound effect on the selling price of the product. For percent debts of 0, 50, and 80 percent, the risks of the project are shared in construction years, but so are profits in subsequent years. Selling prices are $8.95/MKB for 50%, $9.46/MKB for 0%, and $8.65/MKB for 80% debt ratio at $12/ton lignite and 27% solids.

The heat transfer coefficient was used to size the heat exchangers. The heat exchangers are the single most expensive item on the equipment list (see Table 6.3). Lowering the heat transfer coefficient from 350 to 150 BTU/hr•sqft•°F increases the number of heat exchangers from 48 to 128. The total equipment cost increases from $123 million to $ 167 million. This increases the fuel cost 18%.

Section 7

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Appendix A

COAL ANALYSIS REPORTS

As Submitted By:

Resource Engineering Incorporated
Waltham, MA 02154

The following reports detail the ultimate, proximate and petrographic analyses of the original lignite samples and the pretreated lignite samples from this experimental program. The original lignite samples were obtained from the Buelah mine and are identified as R455 (9/13/82), A790 (6/7/83), and A942, (11/28/83). The pretreated lignite samples were residues from a 300°C/0.5 hour and a 100°C/21 day hydrolysis. These are identified as A817 and R486 (both 300°C treatments) and A895 (a 100°C treatment). The analyses are presented chronologically as reported, along with pertinent correspondence from the REI technical staff.

Resource Engineering Incorporated

80 Bacon Street, Waltham, Massachusetts 02154 (617) 894-6720

Sept. 13, 1982

Dr. Donald L. Wise
Vice President
Dynatech R/D Company
99 Erie Street
Cambridge, MA 02139

Dear Don,

It was quite interesting to meet with David S. Gleason. He seemed to have a positive view of what has been done, as far as I could determine.

Attached is the report of the petrographic data we discussed during Mr. Gleason's visit of the residue from one of Dynatech's leach experiments on Meridian lignite. In addition to the petrographic analysis, we performed an ash determination to help establish the dissolution level of the ash, as well as the organic coal components. The ash level in the residue was not substantially different from the average value of the original lignite. This suggests that the ash is not being substantially concentrated in the residue.

This report completes the work that REI agreed to do on this phase of the study. If Dynatech is commissioned by Meridian to perform some of the additional work that Mr. Gleason mentioned while he was here, I am sure that we can assist you again in characterization of feeds and residues and in the interpretation of results.

Please call and let me know how the visit went from your end. If other questions should arise, if you wish to have us pursue additional work, or if we can help with a proposal effort to continue the work, we will be happy to cooperate.

Very truly yours,

William J. Mallio

Dr. William J. Mallio
Vice President

WJM/rmm

Attachments (3)

Sept. 13, 1982

PETROGRAPHIC COMPARISON OF LIGNITE AND LEACHED RESIDUE

The following descriptions refer to photomicrographs presented in Figure 1.

R455

R455 is the original lignite sample from which the solid residues were leached. This coal consists of several components or macerals which have been measured quantitatively (by volume %) and are presented in the enclosed petrographic analysis (Table I). It should be noted that this sample has a total vitrinite content of 63.21% and an average vitrinite reflectance in oil of 0.32. The ash was found to be 12.96 (weight%) on a dry basis. This sample exhibits a noticeable banding in its microstructure.

R486 is the solid residue taken from Dynatech's experiment; a high temperature basic leach of the original lignite sample. Remnants of identifiable coal macerals are still present in the residue, however, in much reduced amounts. Total vitrinite is only 6.24% as compared to 63.21% in the original lignite (See Table I). Exinite and semi-fusinite totals also dropped significantly in the residue. These data are based on a quantitative petrographic analysis of the residue. A "residual matrix" was found to be present in the residue which accounted for 64.38% of the total sample (by volume). The matrix is organic and is somewhat similar to coal in its general appearance. However, it is lighter in color than the vitrinite in the original lignite and its reflectance is considerably higher (0.45). The reflectance of the remnant vitrinite particles in the residue was found to be the same as that of the vitrinite in the original lignite. There is a little difference in ash between the two samples. The residue has an ash of 16.36% (dry basis) compared to 12.96% for the lignite. Banding, which was present in the original sample, is noticeably absent in the residue.

R455- Original Lignite Sample

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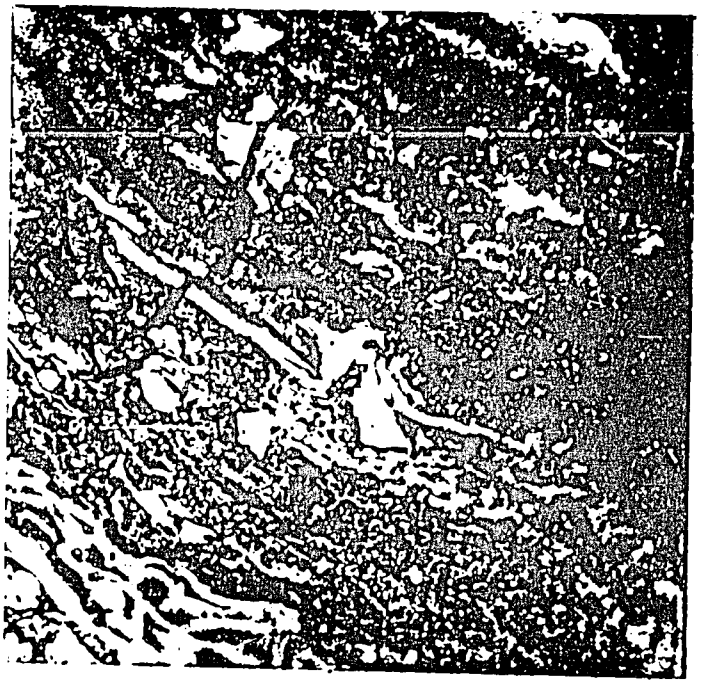
0 40μ



R455- Original Lignite Sample

|----------|
0 40μ

R486- Residual Lignite Sample

|----------|
0 40μ

Figure 1

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TABLE I

Sample	V_2	V_3	V	Matrix	VT*	E	R	SF	Total	SF	M	F	MM	Total	Avg Ro
R455 Lignite	15.97	39.11	--		8.13	7.77	0.74	2.40	74.12	4.80	8.50	5.00	7.58	25.88	.32
R486 Residue	--	--	6.24**	64.38		1.62	--	2.17***	--	--	11.65	4.24	9.70	--	.45

Abbreviations for entities:

V_2 = vitrinoid type 2 (average reflectance in oil 0.20 to 0.29, etc.)
E = exinoids
R = resinoids
SF = semi-fusinoids
M = micrinoids
F = fusinoids
MM = mineral matter calculated from following formula:

$$MM = \frac{\dfrac{1.08\ \text{Ash, \%} + 0.55\ \text{Sulfur, \%}}{2.8\ (\text{avg. sp. gr. of mineral matter})}}{\dfrac{100 - (1.08\ \text{Ash, \%} + 0.55\ \text{Sulfur, \%})}{1.35\ (\text{avg. sp. gr. of coal entities})} + \dfrac{1.08\ \text{Ash, \%} + 0.55\ \text{Sulfur, \%}}{2.8}} \times 100$$

*VT = telinite or cellular vitrinite
**Includes all vitrinoid types
***Includes all semi-fusinoid types

Resource Engineering Incorporated

80 Bacon Street, Waltham, Massachusetts 02154 (617) 894-6720

DATE September 9, 1983

ULTIMATE AND PROXIMATE ANALYSIS

YOUR PURCHASE ORDER # 29674 ANALYSIS REPORT: A 895

SAMPLE RECEIVED: 8/18/83 SAMPLE: Lignite Residue

RECEIVED FROM: Dynatech R/D Co.
99 Erie Street
Cambridge, MA 02139

Attn: Dr. Debra Trantolo

	AS RECEIVED	DRY BASIS
% MOISTURE	6.54	---
% ASH	20.30	21.72
% VOLATILE MATTER	36.30	38.84
% FIXED CARBON	36.86	39.44
% SULFUR	0.27	0.29
% CHLORINE	0.02	0.02
% CARBON	51.43	55.03
% HYDROGEN	3.11	3.33
% NITROGEN	.58	.62
% OXYGEN (By Difference)	17.75	18.99
BTU/LB.	8518	9115
MAF - BTU/LB.	---	11643

RESPECTFULLY SUBMITTED BY Thomas E. Schuler

Thomas Schuler
Laboratory Manager

Resource Engineering Incorporated

80 Bacon Street, Waltham, Massachusetts 02154 (617) 894-6720

TO: Dr. Debra Trantolo
Dynatech R/D Co.
99 Erie Street
Cambridge, MA 02139

FROM: John R. Pilling
Resource Engineering Inc.

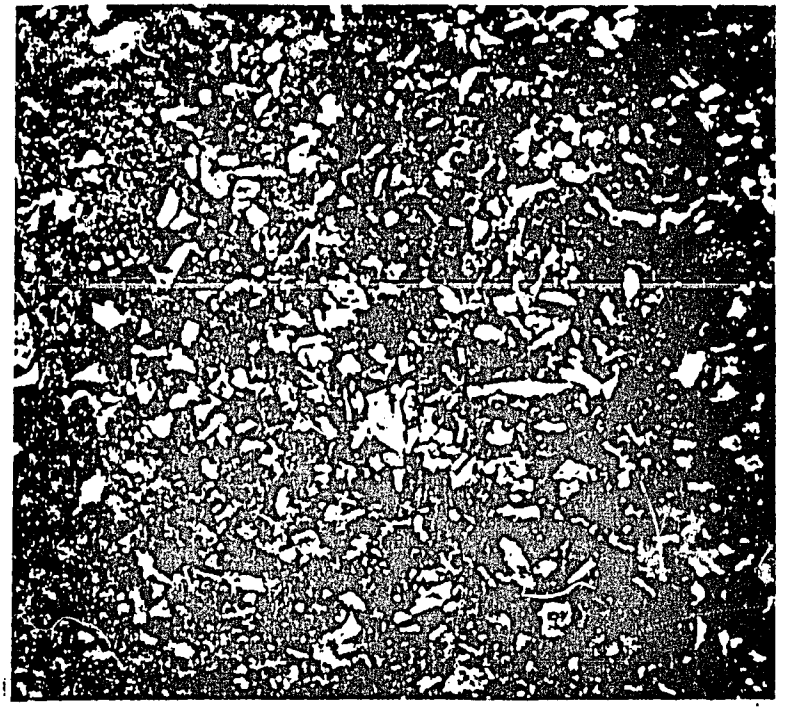
DATE: September 9, 1983

SUBJECT: Petrographic Analysis of Leached Residue

The following description refers to photomicrographs presented in Figure 1.

A 895 A895 is the solid residue taken from Dynatech's experiment; a high temperature basic leach of the original lignite sample. Remnants of identifiable coal macerals are still present in the residue; however, in much reduced amounts. Total vitrinite is only 12.1% as compared to 64.8% in the lignite received 4/27/83 (See Table 1). Exinite, semi-fusinite and fusinite totals also dropped significantly in the residue. These data are based on a quantitative petrographic analysis of the residue. A "residual matrix" was found to be present which accounted for 62.8% of the total residue sample (by volume). The matrix is organic and is somewhat similar to coal in its general appearance. However, it is lighter in color than the vitrinite in the original lignite and its reflectance is considerably higher (0.63) as compared to the lignite (0.31). The reflectance of the remnant vitrinite particles in the residue (0.30) was found to be the same as that of the vitrinite in the original lignite (0.31). There is considerable difference in ash between the two samples. The residue has an ash of 21.72% (dry basis) compared to 7.73% for the lignite. Banding, which was present in the original lignite, is noticeably absent in the residue. The ultimate analyses of the two materials show some differences in the carbon, hydrogen and nitrogen values on a dry basis (See Table 2). The residue has a carbon of 55.03% as compared to 68.60% in the original lignite. Hydrogen for the residue is 3.33% as compared to 4.07% for the lignite, and nitrogen is 0.62% for the residue as compared to 0.84% for the lignite.

John R. Pilling, Geologist



A 895 Residue from leaching lignite sample showing remnants of original lignite particles embedded in "residual matrix".

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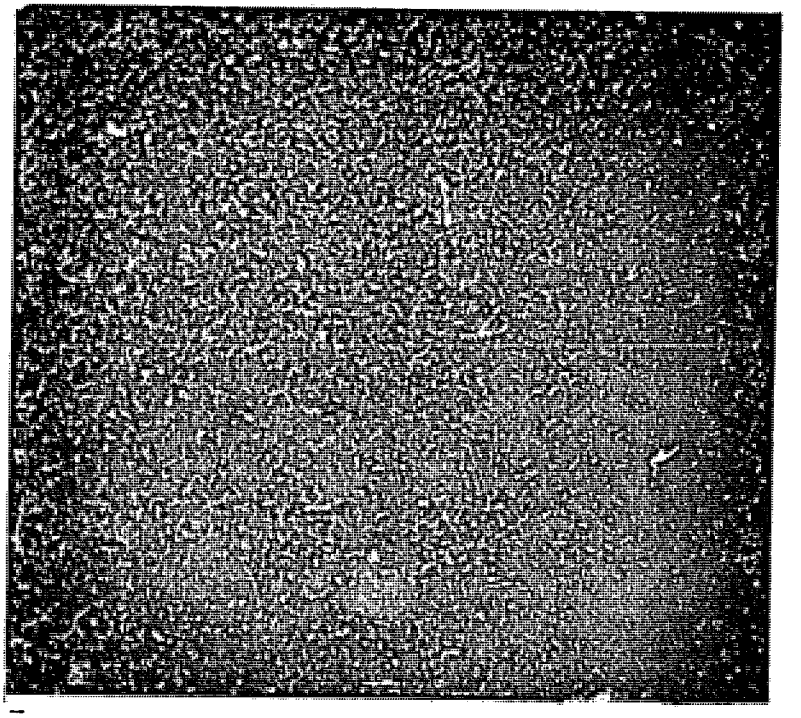
0 40μ



A 895 Common texture of "residual matrix" in residue. The residual matrix accounts for more than 60% of the volume of the residue.

|----------|
0 40μ

Figure 1

Resource Engineering Incorporated

80 Bacon Street, Waltham, Massachusetts 02154 (617) 894-6720

July 5, 1983

Dr. Debra Trantolo
Dynatech R/D Co.
99 Erie Street
Cambridge, MA 02139

Dear Debra,

Attached is our report on the original coal (Buelah lignite) and the residue after leaching. The data suggests that the vitrinite component has been affected and the volume replaced by the "residual matrix". Note that the microstructure and reflectance of the "matrix" is very different from that of vitrinite. The overall chemical composition must not be substantially different, however, as indicated by the comparison of the ultimate analysis of the residue as compared to that of the starting material.

This suggests two possibilities: (1) the residual matrix may be a precipitate upon removal from the system; and (2) the residual matrix may be a reaction intermediate. That is, the "matrix" may be in an altered state, where the lignite structure has been partly broken down, changing it's physical appearance.

I suggested, when we met last week, that an infrared scan be made of the starting material and the residue. This might give some hint, in a broad way, of changes in bonding.

Please let me know if anything else is needed.

Very truly yours,

Bill Mallio

Dr. W. J. Mallio
Vice President

WJM/vs
Enc.

Resource Engineering Incorporated

80 Bacon Street, Waltham, Massachusetts 02154 (617) 894-6720

DATE June 7, 1983

COAL ANALYSIS REPORT

ULTIMATE AND PROXIMATE ANALYSIS

YOUR PURCHASE ORDER # 29166 ANALYSIS REPORT: A 790

SAMPLE RECEIVED: 4/27/83 SAMPLE: Lignite Buelah Zap

RECEIVED FROM: Dr. Debra Trantola

Dynatech R/D Company
99 Erie Street
Cambridge, MA 02139

	AS RECEIVED	DRY BASIS
% MOISTURE	38.25	
% ASH	4.77	7.73
% VOLATILE MATTER	26.24	42.49
% FIXED CARBON	30.74	49.78
% SULFUR	0.34	0.55
% CHLORINE	0.03	0.05
% CARBON	42.36	68.60
% HYDROGEN *	2.51	4.07
% NITROGEN	0.52	0.84
% OXYGEN * (By Difference)	11.21	18.16
BTU/Lb	6986	11313
MAF - BTU/Lb.	-	12260

* Excluding moisture

cc: Dr. Donald L. Wise

RESPECTFULLY SUBMITTED BY Thomas Schuler
Thomas Schuler
Laboratory Manager

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Resource Engineering Incorporated

80 Bacon Street, Waltham, Massachusetts 02154 (617) 894-6720

DATE June 7, 1983

COAL ANALYSIS REPORT

YOUR PURCHASE ORDER # 29166

ANALYSIS REPORT: A 790

SAMPLE RECEIVED: 4/27/83

SAMPLE: Lignite Buelah Zap

RECEIVED FROM:

Dr. Debra Trantola

Dynatech R/D Company
99 Erie Street
Cambridge, MA 02139

ASH ANALYSIS

% SiO_2	20.5
% Al_2O_3	11.3
% Fe_2O_3	3.22
% CaO	28.0
% MgO	8.55
% Na_2O	3.05
% K_2O	0.53
% TiO_2	0.63
% MnO	0.16
% P_2O_5	1.08
% SO_3	20.2

RESPECTFULLY SUBMITTED BY

Thomas Schuler
Laboratory Manager

cc: Dr. Donald L. Wise

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Resource Engineering Incorporated

80 Bacon Street, Waltham, Massachusetts 02154 (617) 894-6720

TABLE II

DATE June 22, 1983

COAL ANALYSIS REPORT

ULTIMATE AND PROXIMATE ANALYSIS

YOUR PURCHASE ORDER # 29166

ANALYSIS REPORT: A 817

SAMPLE RECEIVED: 6/7/83

SAMPLE: Residual lignite Solids
Post Cook B 017470-1

RECEIVED FROM:

Dr. Debra Trantola
Dynatech R/D Co.
99 Erie Street
Cambridge, MA 02139

	AS RECEIVED	DRY BASIS
% MOISTURE	3.64	
% ASH	13.11	13.61
% VOLATILE MATTER	-	-
% FIXED CARBON	-	-
% SULFUR	0.16	0.16
% CHLORINE	0.03	0.03
% CARBON	63.94	66.36
% HYDROGEN*	3.59	3.73
% NITROGEN	0.88	0.91
% OXYGEN (By Difference)*	14.65	15.20
BTU/Lb.	-	-
MAF - BTU/Lb.	-	-

* Excluding moisture

RESPECTFULLY SUBMITTED BY Thomas Schuler
Thomas Schuler
Laboratory Manager

cc: Dr. Donald L. Wise ✓

Resource Engineering Incorporated

80 Bacon Street, Waltham, Massachusetts 02154 (617) 894-6720

TO: Dr. Debra Trantolo
Dynatech R/D Co.
99 Erie Street
Cambridge, MA 02139

FROM: John R. Pilling
Resource Engineering, Inc.
80 Bacon Street
Waltham, MA 02154

DATE: July 5, 1983

SUBJECT: Petrographic Comparison of Lignite and Leached Residue

The following descriptions refer to photomicrographs presented in Figure 1.

A790

A790 is the original lignite sample from which the solid components or macerals which have been measured quantitatively (by volume %) and are presented in the enclosed petrographic analysis (Table 1). It should be noted that this sample has a total vitrinite content of 64.8% and an average vitrinite reflectance in oil of 0.31. The ash was found to be 7.73 (weight %) on a dry basis. This sample exhibits a noticeable banding in its microstructure.

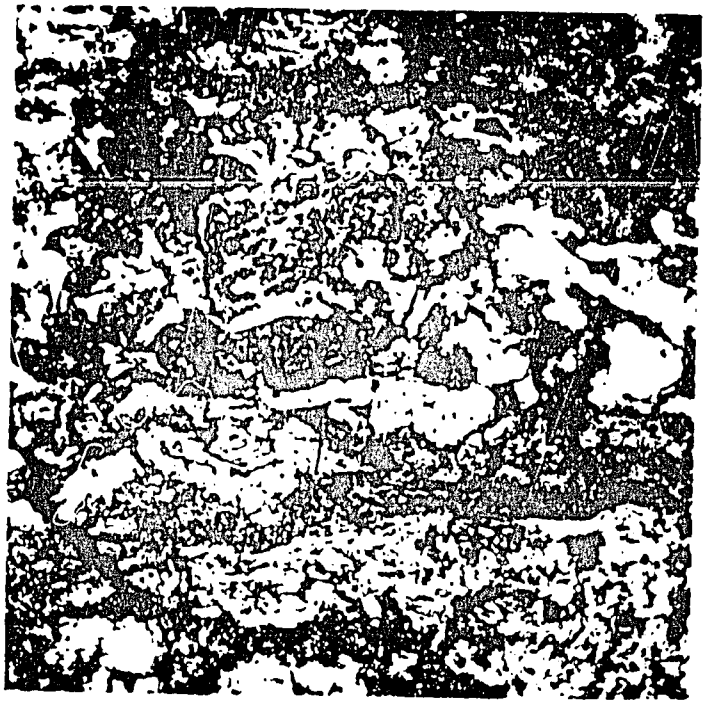
A817

A817 is the solid residue taken from Dynatech's experiment; a high temperature basic leach of the original lignite sample. Remnants of ider coal macerals are still present in the residue; however, in much reduced a Total vitrinite is only 16.2% as compared to 64.8% in the original lignite (S 1). Exinite, semi-fusinite and fusinite totals also dropped significantly esidue. These data are based on a quantitative petrographic analysis of the . A "residual matrix" was found to be present in the residue which accounted for 64.3% of the total sample (by volume). The matrix is organic and is somewhat similar to coal

in its general appearance. However, it is lighter in color than the vitrinite in the original lignite and its reflectance is considerably higher (0.71). The reflectance of the remnant vitrinite particles in the residue was found to be the same as that of the vitrinite in the original lignite. There is some difference in ash between the two samples. The residue has an ash of 13.61% (dry basis) compared to 7.73% for the lignite. Banding, which was present in the original sample, is noticeably absent in the residue. The ultimate analyses of the two materials show some noticeable similarities in the carbon, hydrogen and nitrogen values on a dry basis (See Table 2). The residue has a carbon of 66.36% as compared to 68.60% in the original lignite. Hydrogen for the residue is 3.73% as compared to 4.07% for the lignite, and nitrogen is 0.91% for the residue as compared to 0.84% for the lignite.

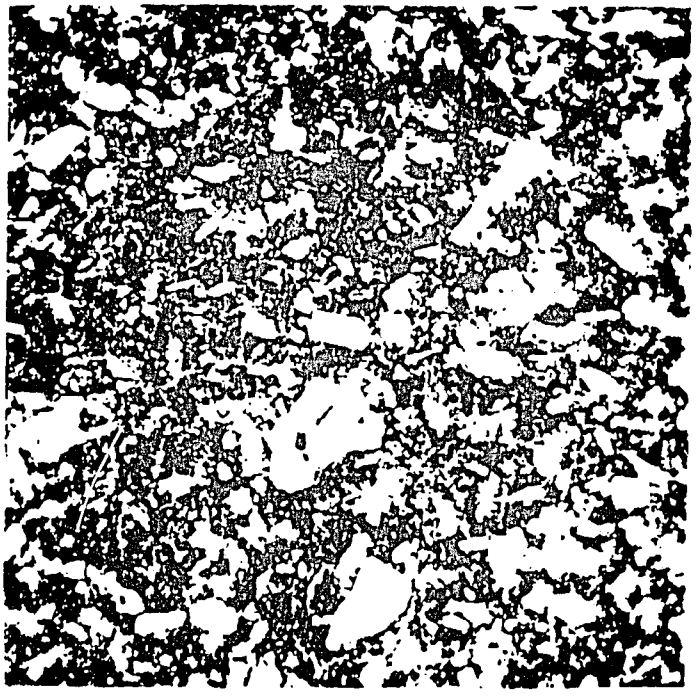
John R. Pilling
Geologist

JRP/vs



A790 Original Lignite Sample
|----------|
0 40μ

A790 Original Lignite Sample
|----------|
0 40μ



A817 Residual Lignite Sample
|----------|
0 40μ

Figure 1

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TABLE I

Sample	V_2	V_3	V_4	V	V	Matrix	VT*	E	R	SF	Total SF		M	F	MM	Total	Avg. Ro
A 790 Lignite	27.50	25.30	2.19				9.85	6.98	1.92	1.02	74.76	2.04	8.22	10.61	4.37	25.24	0.31
A 817 Residue	--	--	--	16.15**		64.32		0.65	--	1.01***	--	--	9.41	0.74	7.72	--	0.71

Abbreviations for entities:

V_3 = vitrinoid type 3 (average reflectance in oil 0.30 to 0.39, etc.)

E = exinoids

R = resinoids

SF = semi-fusinoids

M = micrinoids

F = fusinoids

*VT = telinite or cellular vitrinite

MM = mineral matter calculated from following formula:

$$MM = \frac{100 - \left(\frac{1.08\ \text{Ash, \%} + 0.55\ \text{Sulfur, \%}}{2.8\ \text{(avg sp gr of mineral matter)}}\right)}{1.35\ \text{(avg sp gr of coal entities)}} + \frac{1.08\ \text{Ash, \%} + 0.55\ \text{Sulfur, \%}}{2.8} \times 100$$

** Includes all vitrinoid types

*** Includes all semi-fusinoid types

Resource Engineering Incorporated

80 Bacon Street, Waltham, Massachusetts 02154 (617) 894-6720

DATE Nov. 28, 1983

ANALYSIS REPORT

ULTIMATE AND PROXIMATE ANALYSIS

YOUR PURCHASE ORDER # 29942 ANALYSIS REPORT: A 942

SAMPLE RECEIVED: 10/27/83 SAMPLE: Lignite: Beulah Zap

RECEIVED FROM: Dynatech R/D Company
99 Erie Street
Cambridge, MA 02139

Attn: Dr. Debra Trantola

	AS RECEIVED	DRY BASIS
% MOISTURE	34.69	--
% ASH	6.83	10.46
% VOLATILE MATTER	30.13	46.13
% FIXED CARBON	28.35	43.41
% SULFUR	0.74	1.14
% CHLORINE	0.02	0.03
% CARBON	43.05	65.91
% HYDROGEN *	2.70	4.13
% NITROGEN	.55	0.84
% OXYGEN * (By Difference)	11.42	17.49
BTU/Lb.	7059	10808
MAF BTU/Lb.		12070

RESPECTFULLY SUBMITTED BY Thomas L. Schuler
Thomas Schuler
Laboratory Manager

* Excluding Moisture

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SAMPLE	V_2	V_3	V	V	V	V	V	V.	V	V	VT*	E	R	SF	TOTAL	SF	M	F	MM	TOTAL	AV. RO
A 942 Lignite	28.45	24.23									10.13	7.22	1.41	4.22	75.66	-	8.23	9.84	6.27	24.34	0.28

Abbreviations for entities:

V_3 = vitrinoids
E = exinoids
R = resinoids
SF = semi-fusinoids
M = micrinoids
F = fusinoids
*VT = telinite or cellular vitrinite
MM = mineral matter calculated from following formula:

$$\frac{1.08\ \text{Ash, \%} + 0.55\ \text{Sulfur, \%}}{2.8\ \text{(avg sp gr of mineral matter)}}$$

$$MM \quad \frac{100 - (1.08\ \text{Ash, \%} + 0.55\ \text{Sulfur, \%})}{1.35\ \text{(avg sp gr of coal entities)}} + \frac{1.08\ \text{Ash, \%} + 0.55\ \text{Sulfur, \%}}{2.8} \times 10$$

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Appendix B

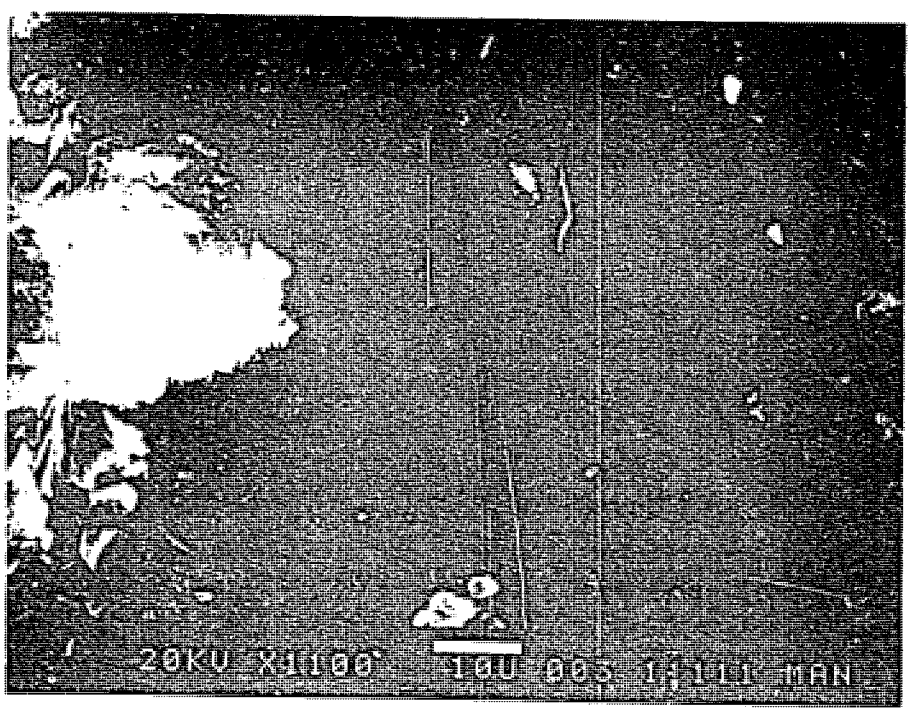
SCANNING ELECTRON MICROGRAPHS

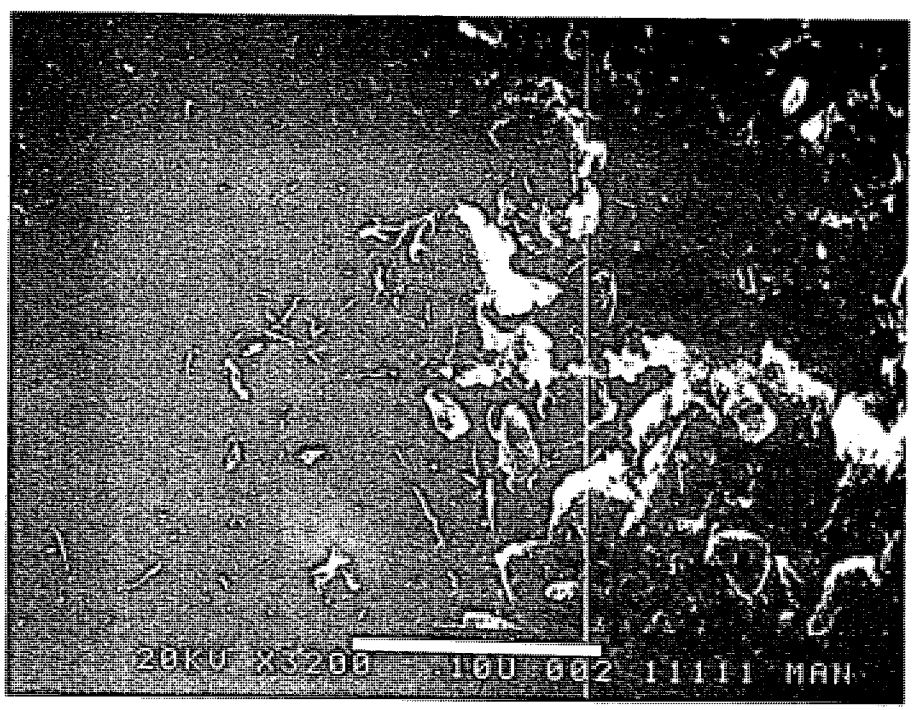
As Submitted By:

Manlabs, Inc.
Cambridge, MA 02139

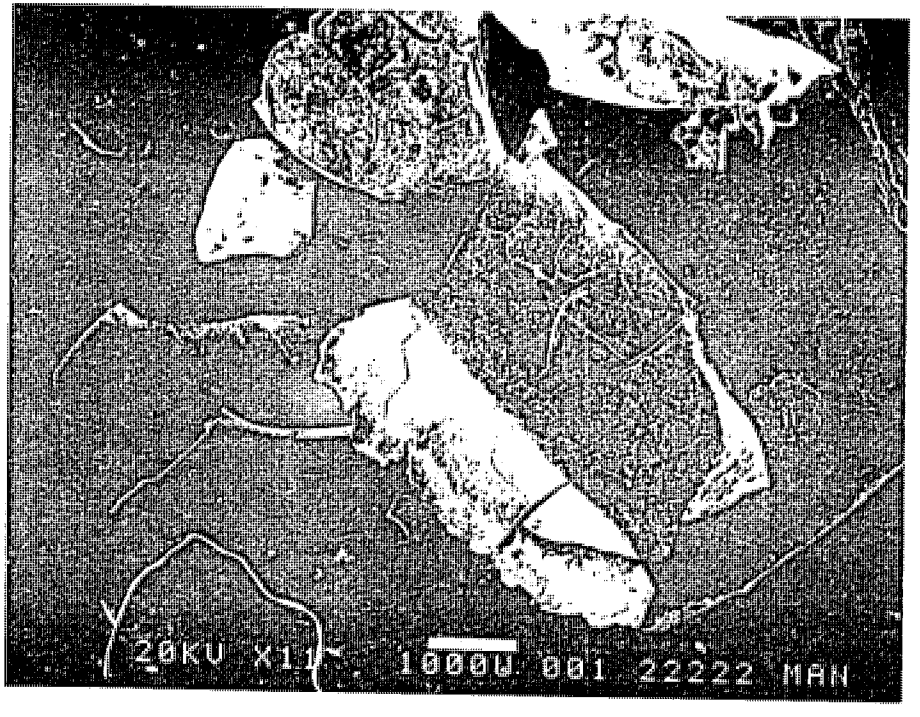
These micrographs were done on residues from the "base case" pretreatment of Buelah lignite (8% volatile solids, 20% sodium carbonate). A sample of the original slurry was retained for analysis. Subsequent samples were taken at 150°C, 200°C, and 250°C. Micrographs were recorded at various magnifications and sample surfaces characterized via EDAX (Energy Distribution Analysis via X-ray). EDAX results are detailed in the text.

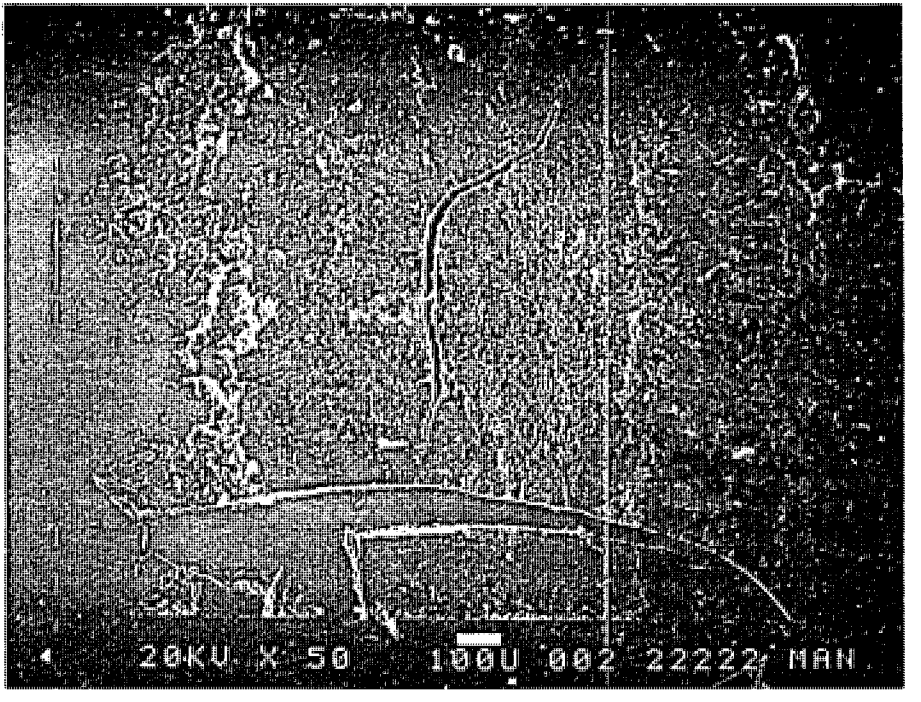
SAMPLE A: ORIGINAL LIGNITE





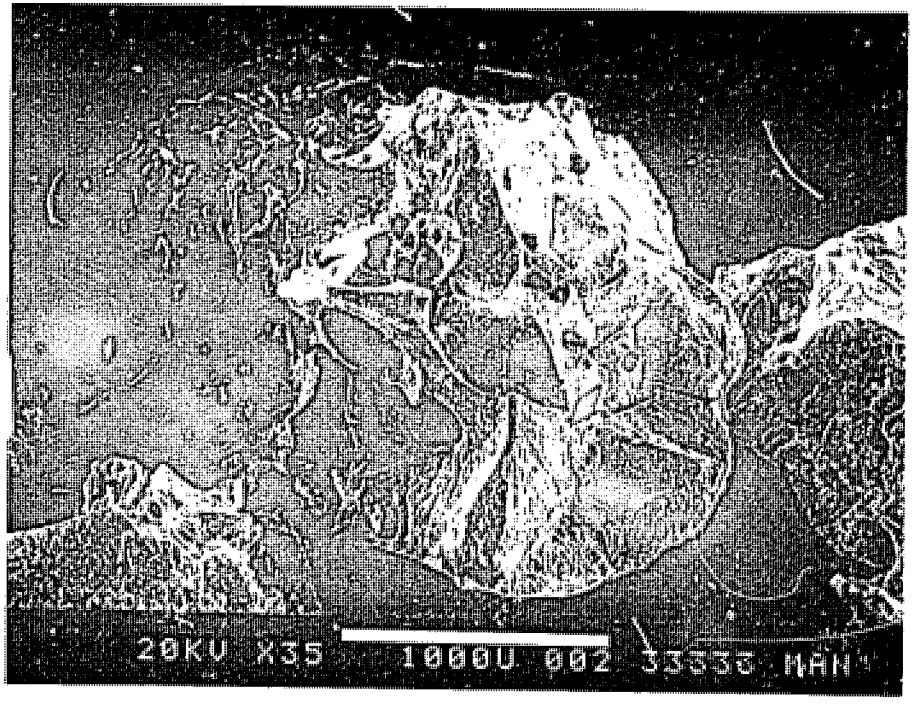
SAMPLE B: 150°C

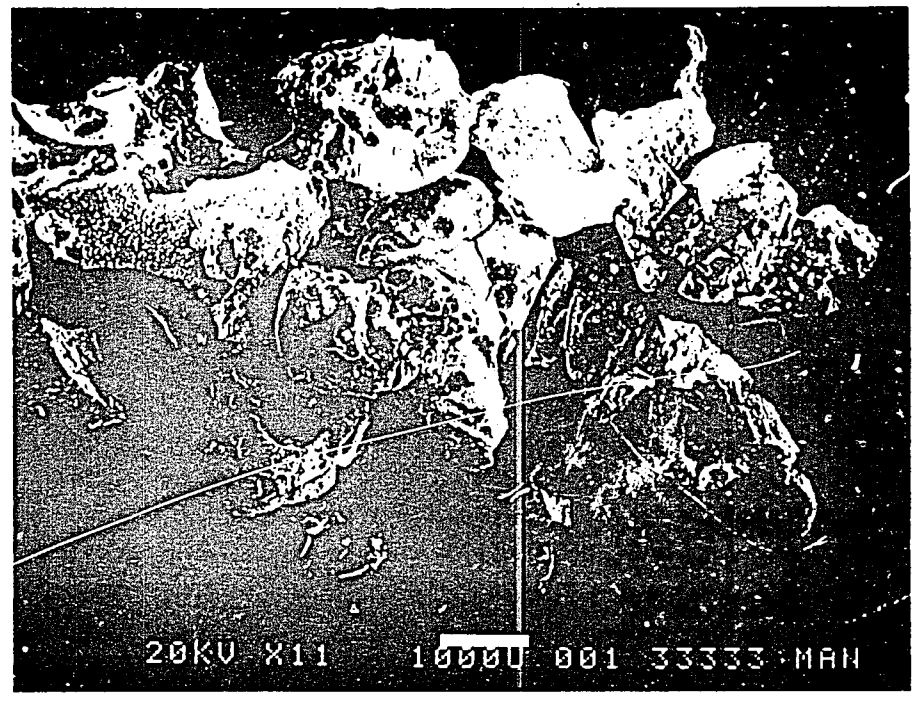




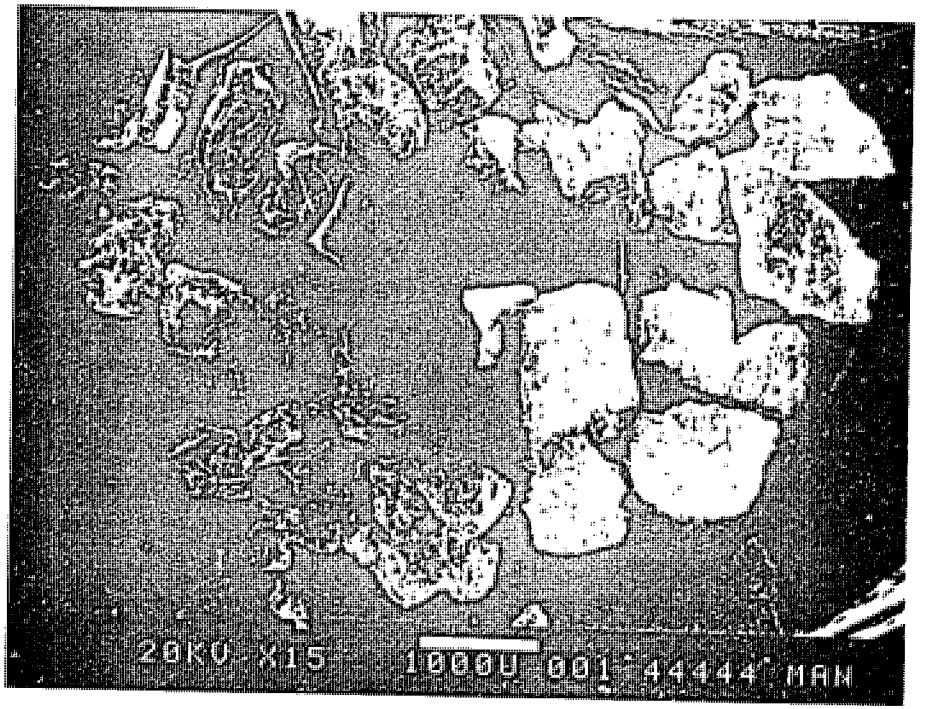
2/2

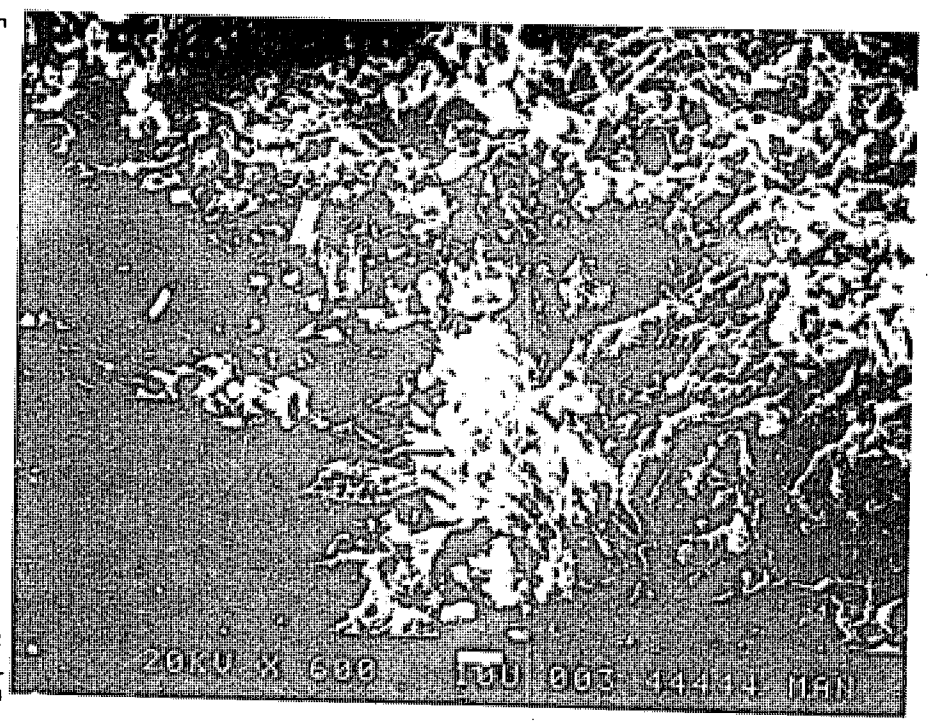
SAMPLE C: 200°C

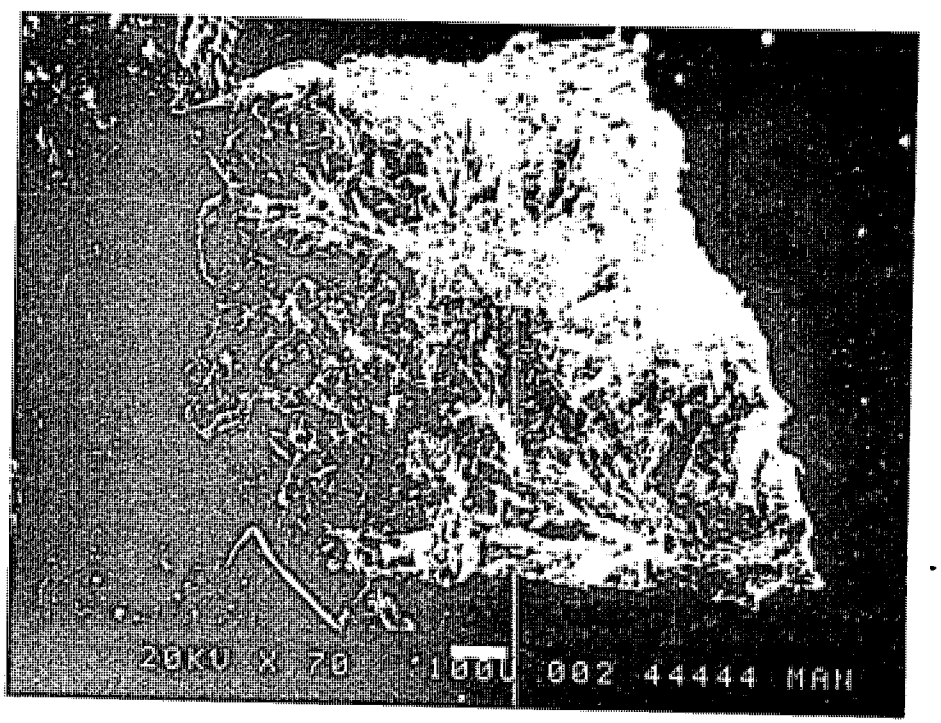




SAMPLE D: 250°C







Appendix C

THE INDUSTRIAL/UNIVERSITY REVIEW COMMITTEE

An Industrial/University Review Committee was organized to review the technical accomplishments of this liquefaction program. The regular review by members of the committee provided continued guidance for project direction. This monitoring by IURC members was intended to insure that technologies that result from this program will be transferred from DoE sponsorship to industrial sponsorship.

Two formal meetings were held with the IURC, one at the program inception and one at its completion. The agendas for these two meetings are enclosed, as well as a complete listing of IURC members. Informal review meetings with IURC members were also included during the course of this program.

INDUSTRIAL/UNIVERSITY REVIEW COMMITTEE

"Direct Liquefaction of Peat and Lignite to BTX-Type Liquid Fuel"

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AGENDA -

INDUSTRIAL/UNIVERSITY REVIEW COMMITTEE MEETING

September 28, 1983

"Direct Liquefaction of Peat and Lignite to BTX-Type Liquid Fuel"

9:00 am	Introduction Debra J. Trantolo, Program Manager
9:15 am	The Project and the Department of Energy Donald L. Wise
9:30 am	The Project and Meridian Land and Minerals David S. Gleason, Committee Chairperson
9:45 am	Coffee and Doughnut Break
10:00 am	The Chemistry D.J. Trantolo
10:15 am	The Process Peter F. Levy
10:30 am	Results to Date D.J. Trantolo
10:45 am	Present Work and Plans D.J. Trantolo
11:00 am	Discussion: Specific Comments and Recommendations D.S. Gleason, Moderator
12:00 noon	Luncheon The Engineer's Club, Prudential Building, Boston
	Closing Remarks D.J. Trantolo D.S. Gleason

GENERAL NOTES FROM IURC MEETING OF SEPTEMBER 28, 1983

- A crucial questions is whether continued work should be at higher temperatures and shorter reaction times. Some experiments should be done to determine if higher yields are obtained from high temperatures and shorter times, or lower temperatures and longer times.

- Should keep in mind that this is an applied research program. The work should be directed at those things that are most important, those with the greatest economic impact. Where do we get the best yield at the economic optimum? What we need first is a model of reasonable options. We need a model to hypothesize a reasonable result -- need to define the program using a process model.

- An initial step might be to form a process design model rather than continued gathering of data.

- Agree with the concern about process concept rather than technical data. Has there been any attempt to look at ways to improve economics in a big hurry? Reviewer believes some confusion on the question of volatile vs. nonvolatile solids; we need a project nomenclature. Reviewer believes this is an ambitious project -- believes we shouldn't overextend what we are trying to do.

- Inserts a note supporting the idea that we have to have some fundamental data (in response to discussion on modeling).

- Stresses again the idea that a conceptual model is important.

- We could spend all the money on the project on modeling -- what is needed is to have lab people who are willing to make optimistic projections.

- There is a possibility that the findings might be better in a nonfuel than in a fuel application.

- Maybe there is more financial reward to be gained by conversion to alternating non-fuel, i.e., chemical lignite products. Expresses concern about what happens to the sodium during the running of the experiment. (Discussion concerning what happens to the sodium during the reaction.)

- Thinks we should look at the commercial angle. Discusses projects in Yugoslavia to derive other kinds of products from lignite.

- Believes it is important to recognize the extended peat work done at Dynatech in both modeling and process development work -- stresses that there has been little work done with lignite in process development aspects -- there may be opportunities to develop processing steps for the future.

- Stresses problems connected with where and when we should develop a model -- problems of time and financing.

- Stresses the importance of the limited time available. Believes we should determine which products have been produced to date. Says we should conduct an analysis of product formed.

- Recommendation to monitor viscosity of solution at various points in the process and to determine what products have been produced.

- What are the solids residue? What is the difference between residues from peat and lignite? (Discussion: fact that peat is easily solubilized with very little residue.)

- In any commercial application must know characteristics of the residues, this must not be ignored. Is this a good fuel or what? Must know if you are going to have a lot of toxic residues to get rid of. Stresses that different source of lignite will give different results.

- Discussed fact that the residue is not that much different from the original lignite. This residue might have potential as a fuel in and of itself. Must keep in mind that the ash levels have been increased.

- Prof. McGinnis discussed a Canadian process for cooking of plant materials. The process involved adding a small amount of active aromatics which appears to stop the polymerization reaction and keep the lignin solubilized. He believes there should be studies done at lower temperatures. Also, need some way to decide quickly during the course of the experiment whether it is a good product or not.

- A viscosity probe might be used. Could be loaded on the stirrer on the reactor.

- Knowing the final composition is crucial. Ultimate composition is important.

Project Review

Direct Liquefaction of Peat and Lignite to BTX-Type Fuel

Thursday, August 9, 1984
Museum of Science, Boston, MA

TIME	PRESENTATION	SPEAKER
08:45 - 09:00	INTRODUCTION	Debra J. Trantolo, Ph.D. Dynatech R/D Company
09:00 - 09:15	OVERVIEW	Donald L. Wise, Ph.D. Dynatech R/D Company
09:15 - 09:45	ACID HYDROLYSIS OF LIGNOCELLULOSIC MATERIALS	Hans Grethlein, Ph.D. Prof. of Chemical Engineering Dartmouth College
09:45 - 10:15	ALKALINE HYDROLYSIS OF LIGNOCELLULOSIC MATERIALS	Gary McGinnis, Ph.D. Forest Products Utilization Laboratory Mississippi State University
10:15 - 10:30	COFFEE BREAK	
10:30 - 11:00	LIQUEFACTION OF LIGNITE TO BTX-TYPE FUEL	Debra J. Trantolo
11:00 - 11:30	PROCESS OVERVIEW-ENGINEERING ASPECTS	Stephen G. Haralampu, Sc.D. Dynatech R/D Company
11:30 - 12:00	A LIGNITE CONVERSION SYSTEM	Ernest E. Kern, Ph.D. Consulting Engineering Houston Lighting and Power Company
12:00 - 01:30	LUNCH (SONESTA HOTEL)	
01:30 - 02:00	USE OF LIGNIN WASTES IN COAL LIQUEFACTION	Robert Coughlin, Ph.D. Prof. of Chemical Engineering University of Connecticut
02:00 - 02:15	CATALYSIS OF LOW GRADE COAL CONVERSION	Kenneth Nicholas, Ph.D. Prof. of Chemistry University of Oklahoma (Summary Presentation by DJT)
02:15 - 02:30	COMMERCIALIZATION OF PEAT DE-CARBOXYLATION	John Rohrer Vice President - Engineering Signal Cleanfuels Inc.
02:30 - 03:00	COMMERCIALIZATION OF THE NOVEL COAL INDUSTRIES	Burl Davis Project Manager Gulf R/D Company
03:00 - 04:00	DISCUSSION AND RECOMMENDATIONS	

FOSSIL ENERGY

DOE/PC/30259-1
Vol. 1 of 2

AN EVALUATION OF HEAVY OIL MINING

Final Report

Volume I

Work Performed for the Department of Energy
Under Contract No. DE-AC03-80PC30259

Date Published—March 1983

Energy Development Consultants/
Stone & Webster Engineering Corporation
Golden, Colorado

U. S. DEPARTMENT OF ENERGY

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Printed in the United States of America. Available from:
National Technical Information Service
U.S. Department of Commerce
5285 Port Royal Road
Springfield, VA 22161

NTIS price codes
Paper copy: $21.00
Microfiche copy: $4.00

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DOE/PC/30259-1
Vol. 1 of 2
Distribution Category UC-92a

AN EVALUATION OF HEAVY OIL MINING

Final Report

Volume I

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UNITED STATES DEPARTMENT OF ENERGY

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GENERAL OUTLINE

AN EVALUATION OF HEAVY OIL MINING

VOLUME I

I EXECUTIVE SUMMARY

II INTRODUCTION

1. TASK I - SELECTION OF HEAVY OIL RESERVOIRS AMENABLE TO MINING TECHNOLOGY

VOLUME II

2. TASK II - EVALUATION OF MINING TECHNOLOGIES

3. TASK III - DEVELOPMENT OF PRELIMINARY MINING SYSTEMS CONCEPTS

APPENDIX A - GEOTECHNICAL REPORT OF THE KERN RIVER FIELD, KERN COUNTY, CALIFORNIA

APPENDIX B - GEOTECHNICAL REPORT ON THE NORTHEAST AREA OF THE MCKITTRICK FIELD, KERN COUNTY, CALIFORNIA

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ACKNOWLEDGMENTS

This report was prepared by Energy Development Consultants, Inc. (EDC) under the U.S. Department of Energy Contract No. DE-AC03-80PC30259. The contract was initiated under the Enhanced Oil Recovery Technology Program.

The investigative team expresses its gratitude to the staffs of the Carbondale Mining Technology Center and the San Francisco Operations Office for support throughout the study. Special thanks to the technical and secretarial staff of Stone & Webster Engineering Corporation for their assistance in the preparation of this report.

I. EXECUTIVE SUMMARY

To date, oil production in the United States has been confined primarily to light oil (20° gravity and higher). However, for a combination of reasons, in recent years there has been increasing interest in developing heavy oil reserves in the United States and abroad. This interest is due in part to concerns about world energy supplies. In addition, studies have indicated that there are vast heavy oil deposits in the U.S. This in combination with the decline in lighter oil reserves has brought about more attention to developing advanced technologies that can increase the recovery of these reserves.

One of the technologies being advanced on an experimental basis for recovering heavy oil reserves is oil mining. So far, little has been done in this field, particularly in the United States. Because of this situation the U.S. Department of Energy (DOE) commissioned this and other studies to determine the technical and economic feasibility of recovering heavy oil by mining or mining-assisted methods. The project proceeded under three tasks, as follows:

Task I: Evaluate the heavy oil resource amenable to mine production
Task II: Evaluate mine technology
Task III: Develop preliminary mining concepts for heavy oil resources

This report was prepared for the U.S. Department of Energy by Energy Development Consultants, Inc. In addition, a number of firms were engaged to assist in technology evaluation and specific analysis of oil reservoirs amenable to mining and to serve as consultants relative to certain technical and economic aspects of the work. The following firms were contributors to the work:

Stone & Webster Engineering Corporation
Stone & Webster Management Consultants, Inc.

R. Trent & Associates
Lewin & Associates
Foster Miller & Associates

TASK I

Based on evaluation of the heavy oil resource amenable to mine production, the Kern River Field (Kern County, California) has the best potential reservoir for surface mining. The northeast area of the McKittrick Field has the best potential for underground mining. These findings are based on evaluation of these fields in terms of the heavy oil resource, the existing technology for recovering it, the economics of development, and the constraints on development. This approach addresses the geologic, engineering and economic realities of each resource or deposit, and by assuming various levels of technology and their rate of deployment, this approach provides a solid foundation for the evaluation of the U.S. heavy oil resource and potential reserves.

The reservoir and production data for the 652 heavy oil reservoirs in the U.S. could be consolidated and form the core of a central repository for data on heavy oil reservoirs as a national data base of mineable heavy oil reservoirs. The information and data currently available for a reservoir identifies the resource but does not provide sufficient information required to make a commitment to a mining project. For example, there is a lack of descriptive data relating to the structure of the strata below the reservoir. Different criteria from that specified in this study would enable other sites to be considered in different areas of the United States.

TASK II

Two types of mining are considered in this report: (1) surface extractive, and (2) mining for access. Extractive mining was eliminated from consideration in this study due to uncertainties and potential difficulties in several safety, environmental and technical aspects of this technology.

Surface mining is the cheapest method of extracting near-surface ore. Surface mining basically involves: (1) stripping the overburden, (2)

removing the ore, (3) processing the ore, (4) disposal of solid wastes, and (5) reclaiming the mine area. In order for a surface mine to be considered, the reservoir must be fairly close to the surface and contain high quality ore. A discussion of the technological problems associated with surface mining techniques is included in Section 3.5 of this report. A surface extractive mining project is currently under development by Getty Oil in the McKittrick Field, San Joaquin Valley, California.

Underground mining for access represents a unique blend of mining and petroleum engineering. Development of a reservoir using this method would consist of two or more vertical shafts sunk to a depth below the target reservoir, a network of horizontal drifts driven below the target reservoir within the project area, and a system of wells drilled from the access drifts into the reservoir above. Enhanced Oil Recovery techniques may also be required. The major constraints will be the temperature of the mine workings and the available resource. A practical depth limit of 5000 feet or less is generally desirable, although some regions of the country have a more favorable geothermal gradient which would allow consideration of deeper targets. A discussion of the technological problems associated with the underground mining for access techniques is included in Section 3.6 of this report. A small demonstration project using this technique is currently being developed by Barber Oil Co. in the Kern River Field, San Joaquin Valley, California.

Except for the oily surface of the exposed ore in a surface mine, which makes traction more difficult and deteriorates rubber products, i.e., tires, hoses and electrical cable coverings, the surface extractive mining system appeared feasible from technical, environmental and economical considerations. Underground extractive mining systems have potential technical, environmental and economic limitations that preclude their application for removing the oil bearing ore to the surface. The mining for access method, particularly with thermal assistance, appears feasible from all technical, environmental and economic considerations.

TASK III

Based on a production of 38,150 barrels of heavy crude oil per day a Kern River Field specific site was evaluated for surface extraction. The total capital investment is approximately $310 million, or an investment of $8,122 per daily barrel. The labor cost per ton of ore mined is $1.17 and is the second largest operating cost center. The largest operating cost center is equipment, totaling $2.02 per ton of ore. The total annual operating cost is estimated to be $4.35 per ton of ore produced. Assuming a cost of $11.22 per barrel of oil, surface processing facilities that were not within the scope of this study, a total cost per barrel of heavy oil for the surface mining system is $27.26.

The McKittrick Field specific site was evaluated for a mining for access method both with and without thermal assistance. The maximum total capital investment for the 200-foot well spacing mining for access case is approximately $185 million dollars for a total field production of 2 million barrels of heavy crude. For a 20-year project life and a maximum total revenue of $150 million dollars based on this production, only 81 percent of the invested capital would be recovered, making the project unattractive.

For the ease of enhancement through thermal assistance to a mining for access method, the total capital investment is approximately $184 million dollars to recover 50 percent of the residual oil, and the required selling price of the crude oil must be $43.25 per barrel to provide a 20 percent return on investment. The use of steam injection in a reservoir changes the basis for comparing economics not only because each reservoir reacts differently but because the reservoir would be developed on an incremental basis of 3-4 year projects rather than a 20 year project. The production for a 18.6-acre pattern would be approximately 1,230,000 barrels for a 4-year project.

From this study, the following is evident:

- Heavy oil reservoirs and projects should be examined on an individual basis.

- The available data on heavy oil reservoirs are not sufficient to determine accurate estimates of reserves and rock characteristics of the reservoir and lower strata.

- The projection of reservoir recovery is difficult for underground mining methods whether extractive or mining for access because of insufficient experience in the use of these methods and the difference in reservoir characteristics.

- Research and development is required in opening a pilot site-specific mine to identify the problems and resolve them in parallel projects.

The surface extractive system appears to be the most attractive, and the potential for recovering oil by mining is very good.

II INTRODUCTION

Until recently, little attention has been given to known heavy oil reservoirs in the United States, which have produced only about one-third of their total estimated volume. Production has consisted mainly of light oil (20° API gravity and higher). It is known that after conventional production, a field consists primarily of 20° API gravity oil and lower. In fact, over 100 billion barrels of heavy oil remain in known reservoirs after completion of primary, secondary, and tertiary recovery techniques. The United States has used a total of 120 billion barrels of oil since the 1890's. Therefore, if even a third of this resource could be obtained by mining, it would add significantly to our reserves. With the concern about the world energy supply, more attention is being given to advanced technologies that can increase the recovery of these reserves.

One such technology being applied on an experimental basis is oil mining. So far, little has been done in this field. In the past, after exploration has taken place, little data has been collected for the strata surrounding the oil reservoir, especially below the reservoir. Therefore, information such as rock strength, rock characteristics, aquifer characteristics, etc., are not always available, and without this type of information, it is difficult to carry out a detailed mining program with any degree of accuracy or reliability.

It has been shown that an average of 33 to 38 percent of an oil resource can be recovered using primary, secondary, and tertiary methods. Primary recovery involves drilling wells into oil bearing zones, which may contain oil, gas, and water. Well production is implemented by withdrawing oil

from the reservoir by gravity drainage to the well or from an active reservoir drive which forces reservoir fluids to the well, and in many cases, up the well bore to the ground surface. If the reservoir drive energy is insufficient, a pump is required to bring the oil to the surface. Examples of reservoir drive mechanisms include free gas at the top of a reservoir forming a gas cap, dissolved gas within the oil itself, and water bearing zones below the reservoir. These mechanisms are called gas drive, dissolved gas, and water drive, respectively.

As recovery continues from a reservoir, fluid pressures decline reducing the forces that drive these fluids to the well bore and simultaneously forming a discrete gas phase that impedes fluid flow. At this point, secondary or tertiary recovery methods may be applied. These methods are grouped under the term of enhanced oil recovery (EOR). Secondary recovery includes immiscible gas injection and water flooding, while tertiary methods include injection of steam (cyclic or direct drive), chemical flooding, and in situ combustion. In general, enhanced oil recovery techniques add about $2 to $10 to the cost of each barrel of oil produced. Consequently, there is an economic limit to EOR techniques depending on the current market price of oil.

The target for heavy oil mining is the approximately 65 percent of oil remaining in depleted reservoirs after application of primary and EOR techniques. Some studies indicate that up to 80 percent of the oil remaining after primary and EOR techniques may be recovered using mining methods. Furthermore, the 100 billion barrels of heavy oil available in known reservoirs could be surpassed by large numbers of undiscovered deposits and quantities of heavy oil within known fields that have been bypassed in favor of lighter oil. In addition, there may be a high number of abandoned fields with heavy oil; however, little information is available on these. This suggests that there is an enormous resource available for extraction by mining.

The primary objectives of this study, as set forth by the Department of Energy, were as follows:

- Review and identify heavy oil reservoirs within the continental United States that are amenable to mining

- Evaluate existing mining technologies applicable to oil mining

- Apply the most promising technologies to specific sites

SCOPE

Volume I of this report details the results of a study to select the best target reservoirs in the United States amenable to heavy oil mining, in accordance with the U.S. Department of Energy Contract No. DE-AC03-80PC30259. The study was limited to conventional reservoirs containing oil with API gravity of 10° to 20° sufficiently mobile to be characterized as a heavy oil rather than as tar sand. A series of screening processes was used to rank the areas of study, develop a comprehensive listing of heavy oil reservoirs, and determine the most appropriate targets for surface and underground mining technologies.

Volume II is an evaluation of preliminary mining concepts. Existing mining methods were reviewed for their application to heavy oil and for their environmental compatibility and economic viability. Initially, three mining concepts were selected for review: surface mining, extractive mining, and mining for access.

- Surface Mining

  Surface mining involves the actual removal of the host rock and processing it to produce oil. The disposing of the large amount of waste material produced by this method is an environmental problem. This method utilizes two possible mining systems: strip mining and open pit mining (terrace mining).

  As shown in Task 1, within DOE-specified parameters, only six sites (all in California) were available for consideration. These sites were found to be suitable for open pit (terrace) mining only, and therefore, strip mining was eliminated as an alternative.

- Extractive Mining

Extractive mining consists of developing an access system from the ground surface into the host rock itself. As the method implies, the rock is extracted by mining from the ore zone. The ore, once mined, is transported to the surface for processing. It is possible to return the waste material underground for disposal and thus, to contribute to roof control for reduction of ground subsidence.

Two types of mining methods were applied here: (1) methods applicable to thin seams (7-20 feet) and (2) methods applicable to thick seams (20-50 feet).

Thin seam application considered mining techniques such as room and pillar (without benching) and longwall.

Thick seam application considered mining techniques such as room and piller (with benching); chamber and pillar; longwall; sub-level stoping; and hydraulic mining.

During the review of extractive mining methods, it became apparent that from information gathered-- i.e., host rock characteristics, environmental and safety aspects, and preliminary economics--extractive mining methods were not conducive to heavy oil mining. The recommendation that extractive mining be removed from further study was accepted by DOE.

- Mining for Access

The access method of mining provides physical entry to an area in close proximity beneath an oil-bearing zone. This mining system consists of shafts and a tunnel network below the ore zone in a more stable strata. Access to the oil-bearing formation is via drilling at selected intervals throughout the tunnel networks.

The safety factor is of utmost importance in this type of mining operation. Once drilling has been completed, oil production is controlled via stand pipes and valves. Oil flows with the assistance of gravity into the tunnel network to the shaft bottom for pumping to the surface, where normal oil processing takes place.

Areas of study under this method included technical feasibility; resource requirements; equipment requirements, reliability and availability; safety; environmental impacts; and economics.

The information obtained from Tasks I and II was then used in Task III to develop preliminary mining concepts for the two specific sites in California. Each method has been evaluated for resource requirements, technological and safety constraints, production capabilities, and reclamation procedures.

A detailed technical and economic analysis of two site-specific mining operations was developed. In addition, a cost/production comparison was developed on mining for access operations involving gravity drainage and on gravity drainage plus thermal assistance.

STUDY APPROACH AND METHODOLOGY

The approach to the evaluation of heavy oil mining is set forth in the Work Plan proposed by Energy Development Consultants, Inc. (carried through by Stone & Webster Engineering Corporation) and approved, with modifications, by the Department of Energy. The Work Plan divides the work into three tasks as follows:

Task I - Heavy Oil Resource Amenable to Mine Production - To evaluate the heavy oil resource amenable to mining by gathering and developing sufficient information on the heavy oil resource to provide a basis for subsequent recovery analysis by mining.

Task II - Mining Technology - To generate a data base of current and projected heavy oil mining methods and equipment, and evaluate existing and planned heavy oil mining projects.

Task III - Preliminary Mining System Concepts - Mining system concepts having the greatest potential for the development of the U.S. heavy oil resource was determined. From those concepts selected, a detailed technical and economic analysis was performed on two site-specific heavy oil mining developments.

PREVIOUS STUDIES

Two studies have been undertaken in recent years on the feasibility of heavy oil mining. "Oil Mining - A Technical and Economic Feasibility Study of Oil Production by Mining Methods" by Golder Associates characterizes oil fields amenable to mining techniques; inventories known U.S. oil fields offering such potential; divides fields into surface and underground mining system types; and selects candidates for conceptual mining systems, cost analysis and environmental evaluation.

"Mining for Petroleum: Feasibility Study" by Energy Development Consultants, Inc. evaluates two potential modified in situ methods for recovering heavy residual oil remaining in reservoirs after normal pumping methods have ceased. Mining engineering, production rates, and candidate reserve areas in the U.S. are discussed.

STUDY PARTICIPANTS

In order to accomplish the complex requirements of the study in the most efficient manner, Energy Development Consultants, Inc. engaged the services of a number of firms to assist in technology evaluation and specific analysis of oil reservoirs amenable to mining and to serve as consultants relative to certain technical

and economic aspects of the work. The following firms were contributors to the work:

Stone & Webster Engineering Corporation

Stone & Webster Management Consultants, Inc.

R. Trent & Associates

Lewin & Associates

Foster Miller & Associates

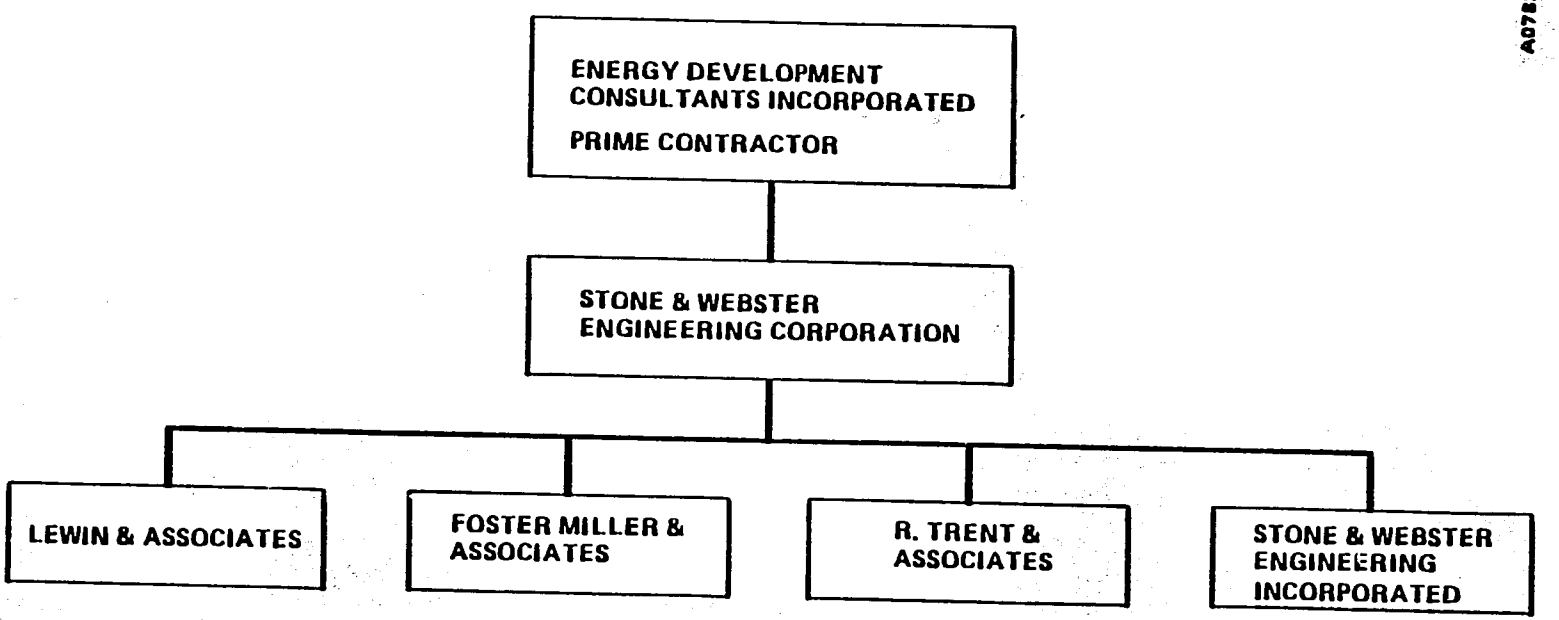
REPORT ORGANIZATION

The first section of the report (Section I, Executive Summary) summarizes the work of Tasks I, II, and III and presents conclusions. Task I, which represents the bulk of Volume I, describes the selection process for determining the heavy oil reservoirs amenable to mining technology. Various screening processes are described along with target reservoirs.

Volume II contains Task II, Evaluation of Mining Technologies, and Task III, Development of Preliminary Mining Systems Concepts. Task II presents a historical review of heavy oil projects through current and planned projects. It also details various mining methods applicable to heavy oil mining. Task III describes the development of two site-specific heavy oil mining operations.

Existing data on the mining of heavy oil was used as much as possible. Principal data sources are referenced in the report, while additional data, drawings, and calculations, which are too voluminous to include in the report, are on file in SWEC's offices in Denver.

ORGANIZATIONAL AND REPORTING STRUCTURE



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1.0 SELECTION OF HEAVY OIL RESERVOIRS AMENABLE TO MINING TECHNOLOGY

1.1 GENERAL CONSIDERATIONS

The purpose of Task I under U.S. Department of Energy Contract No. DE-AC22-80PC30259 was to conduct a survey of heavy oil reservoirs in the United States amenable to mining and recommend the five best targets for demonstrating "mining for oil" technology. The study was limited to conventional reservoirs containing heavy oil between 10 and 20 degrees API gravity and mobile enough to be distinguished from a tar sand.

To accomplish this task, available literature on heavy oil reservoirs was reviewed, and a series of four screens was applied to each reservoir to select those with the most favorable characteristics for mining. Finally, ranking equations were developed to select the best targets.

Figure 1-1, the flow chart depicting the selection process, shows how the study proceeded from general to specific. Starting with the heavy oil resource base, a series of screens was applied to select the reservoirs with the most desirable parameters for mining. Finally, a ranking equation was applied to choose the best target reservoirs for detailed study.

A total of 652 reservoirs passed Screen 1 and Screen 2 and are less than 5000 feet deep with greater than 10 ft net pay. The parameters of each reservoir are shown in Table 1-1. (Table 1-1 is located at the back of this report and is divided into separate geographic areas by index tabs.) The estimated total resource for these 652 reservoirs is 38 billion barrels. From this initial list, only 81 reservoirs passed Screen 3 and Screen 4, and thus, are amenable to mining. Over 67% of the initial resource, or 26 billion barrels, is estimated to be in these 81 reservoirs.

It should be emphasized here that the "best" targets chosen within the limitations of this study may not represent the most favored reservoirs for demonstrating mining for oil technology. More desirable targets may exist which contain light oil that is closer to the surface, do not require

enhanced oil recovery techniques, have underlying rocks of greater competency, and have no problems associated with seismicity or groundwater. However, this study has defined the best targets for heavy oil mining.

1.1.1 Definitions

After an initial review, it was readily apparent that there is some confusion over the terms "heavy oil," "reservoir," "resource," and "reserve." These are defined here as they are used in this report.

1.1.1.1 Heavy Oil

The First International Conference on the Future of Heavy Crude and Tar Sands (Unitar, 1979) was unable to resolve the question of how best to define heavy crude oil. As a result of their efforts, however, some common characteristics have been described.

Heavy crude oil is generally thought of as having an API gravity between 10 and 20 degrees, poor mobility, high viscosity, dark color, high metals content (up to 500 parts per million (ppm)), sulphur content of three percent by weight or more, and the presence of asphaltenes up to 50 percent by weight (Meyer, 1979). The upper limit of 20 degrees API gravity was chosen because it roughly corresponds to the lower limit of primary and secondary recovery possibilities. Oil with an API gravity less than 10 degrees is called ultraheavy, and is excluded from this study per DOE guidelines for this study.

Mobility is the criterion used to distinguish heavy oils from tar sands, and is defined as the permeability divided by the viscosity. In general, reservoirs with any historical production are considered to have some mobility, and therefore, are included in this study. It is interesting to note that the viscosity is dependent on the temperature and the amount of dissolved gas. Therefore, a tar sand deposit could have initially been a conventional pressurized reservoir containing light oil with gas in

solution, but due to natural tectonic forces or overpressuring, the reservoir cap may have been broken allowing the gas to escape, thus increasing the viscosity of the reservoir. Another mechanism which allows lighter oil fractions to escape is erosion, resulting in the reservoir being closer to the surface with a lower temperature.

1.1.1.2 Reservoir

There is no established definition of a reservoir. This is primarily due to the varying complex geologic conditions in which reservoirs exist. In general, however, differentiation should be made between a reservoir and a field. A field is a group of reservoirs related to single geologic feature. In contrast, a reservoir is a unique entity composed of four essential elements: (1) the reservoir rock, (2) pore space, (3) fluid content, and (4) reservoir trap. Reservoir rocks are described in Section 2.5 of this report. The pore space, or voids, is expressed as a percentage of the total volume of the rock and is normally referred to as porosity. The rate at which fluids may move through interconnected pores of the rock is called its permeability. The fluids that occupy the pore space may consist of oil, water, and gas. The reservoir trap is the element that prevents the fluids from escaping and may be structural, stratigraphic, or a combination of both. In most cases, a reservoir corresponds to an oil bearing section of one geologic formation, but in some cases a reservoir may include several geologic formations that are hydraulically connected. Reservoirs may also contain a number of pay zones which yield oil separately in permeable sections of the reservoir. The gross pay thickness is the total thickness of the reservoir itself, whereas the net pay thickness is the cumulative thickness of the individual pay zones.

1.1.1.3 Resource Versus Reserve

A resource is defined as the remaining oil in place in conventional reservoirs or near-surface deposits. A reserve is that portion of the remaining oil in place that is recoverable both economically and technologically. A recoverable resource is that portion of the remaining

oil in place that is believed to be producible under favorable economics and development of new technology. The recoverable resource relates best to mining, and for this study, is assumed to be approximately 50 percent of the remaining oil in place for each reservoir considered.

1.1.2 Geologic Considerations

Geologic considerations applied to all heavy oil reservoirs screened for each mining technique included the lithology of the reservoir rocks, geologic structure, and hydrogeology of the reservoir area, and the tectonic history and seismicity of the reservoir area.

Heavy oil reservoir rocks are generally found in several lithologies. These include sandstones, fractured limestones, dolomites or other carbonates, fractured shales, and diatomite. Of these lithologies, sandstones are generally considered the most desirable reservoirs from which to recover heavy oil, because they usually possess high porosity and permeability. Unconsolidated sands have considerably higher porosity (25 to 40 percent) than do consolidated sands (less than 29 percent). Carbonate reservoirs are generally highly variable and can only be evaluated on an individual basis. These rocks are harder to drill and tend to inhibit enhanced oil recovery techniques because injected fluids such as steam, water or caustic chemicals tend to carry carbonaceous material in solution and deposit the same material elsewhere in the reservoir, reducing permeability. Dolomite generally provides the best carbonate reservoir due to higher porosity and higher elastic modulus which results in more fracturing in these strata. Fractured shale reservoirs possess only secondary porosity created by fractures and joints in the rock mass. Secondary porosity is generally much lower than the corresponding primary porosity found in sandstones. In addition, the secondary permeability associated with the same fractures is high compared to primary permeability in sandstones. Therefore, oil contained in fractured shale reservoirs tends to have high mobility and is either produced very quickly or is moved by geologic processes. For these reasons, fractured shale reservoirs are not considered good potential targets for heavy oil mining.

Geologic structure of heavy oil reservoirs is perhaps the most important characteristic in determining the suitability of a reservoir to oil recovery by any mining technique. The intensity and style of folding and faulting varies tremendously between the heavy oil reservoirs considered in this study. Anticlines, homoclines, and monoclines are common folding styles in the reservoirs considered in this study. The dip of these folds varies from a few degrees to tens of degrees. Thrust, normal, reverse, and strike-slip faults were common in the heavy oil reservoirs studied, and the throw across these faults varied from a few feet to greater than one mile.

Generally, the heavy oil reservoirs with the simplest geologic structure will result in the fewest problems to successful mine development. Steeply dipping beds and faults complicate the mine planning and ultimately increase the costs of any mining venture.

Hydrogeology of the reservoir area will determine, in many cases, the feasibility of developing a mine. The location of the water table, pore water pressures, permeability of the rock, groundwater flows, and water quality are all important considerations. High groundwater inflow into either an open pit or underground openings may cause serious construction problems, schedule delays, and increased costs for dewatering systems. Furthermore, each drainage well drilled in a mining for access scheme is likely to produce a certain percentage of water for each barrel of oil produced. This water may be of low quality requiring disposal in an approved area.

The tectonic history of a heavy oil reservoir area influences the seismic risk associated with that area and often determines the in situ stresses within the ground. In-situ stresses can either benefit or hinder the successful development of underground openings depending on their orientation and magnitude, and the orientation and size of the underground openings.

The seismicity of an area will generally influence the feasibility of developing a mine. The risk of constructing underground tunnels is

significantly increased in areas of active faulting. Furthermore, design of surface facilities must include resistance to ground motion in areas of large magnitude earthquakes.

1.1.3 U.S. Heavy Oil Mining Policy and Outlook

There is much confusion as to exactly how heavy oil mining will be regulated and taxed. The government appears to be favorable to the development of this technology at this time, and is encouraging industry to move forward with demonstration projects. Therefore, it appears that heavy oil mining will be exempt from the windfall profits tax, and incentive programs with tax credits may be created to encourage development of this technology. At this time, however, there appears to be some confusion whether to regulate this technology under mining or petroleum. Resolution of this question depends on the definition of heavy oil, which falls between the definition of conventional oil and tar sands. Tar sands are treated as an ore because recovery of this resource is only possible using extractive mining technology. Heavy oil, on the other hand, can be recovered by either method.

It is not entirely clear how a heavy oil mining project would be leased or how potential conflicts with surface activity would be resolved. Mining claims and petroleum prospects may be leased separately, and conflicts may result by tapping a reservoir from below using a mining for access scheme in a reservoir that is also tapped from above using surface wells. Surface mining, on the other hand, would eliminate surface wells altogether. These conflicts could lead to costly lawsuits, which would be a detriment to both parties involved. On the other hand, through a cooperative effort, both parties could benefit. For instance, in underground mining for access technology, the surface wells could be used to inject water to force the oil downward into the mine's production wells.

FLOW CHART OF SELECTION PROCESS

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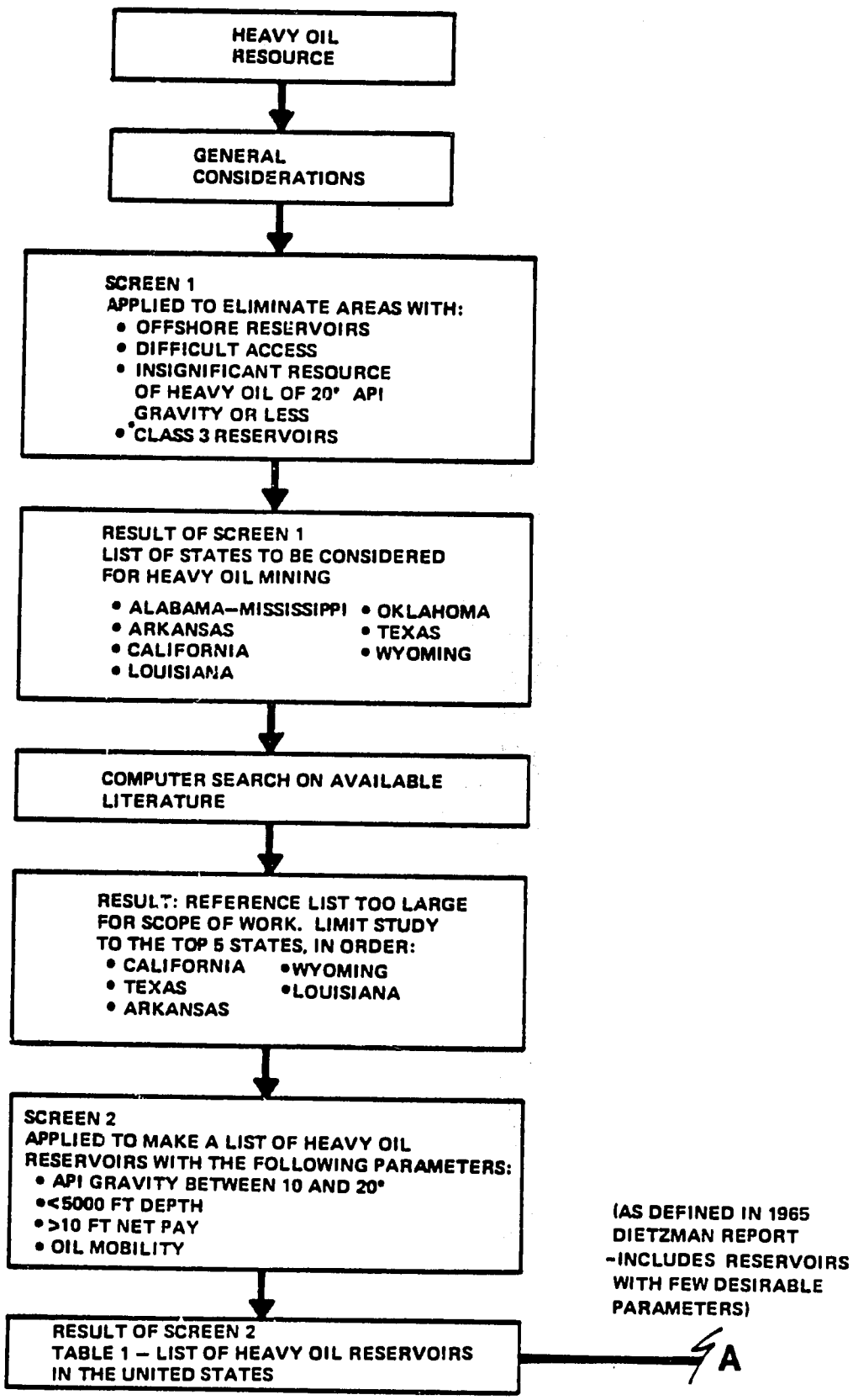

FIGURE 1-

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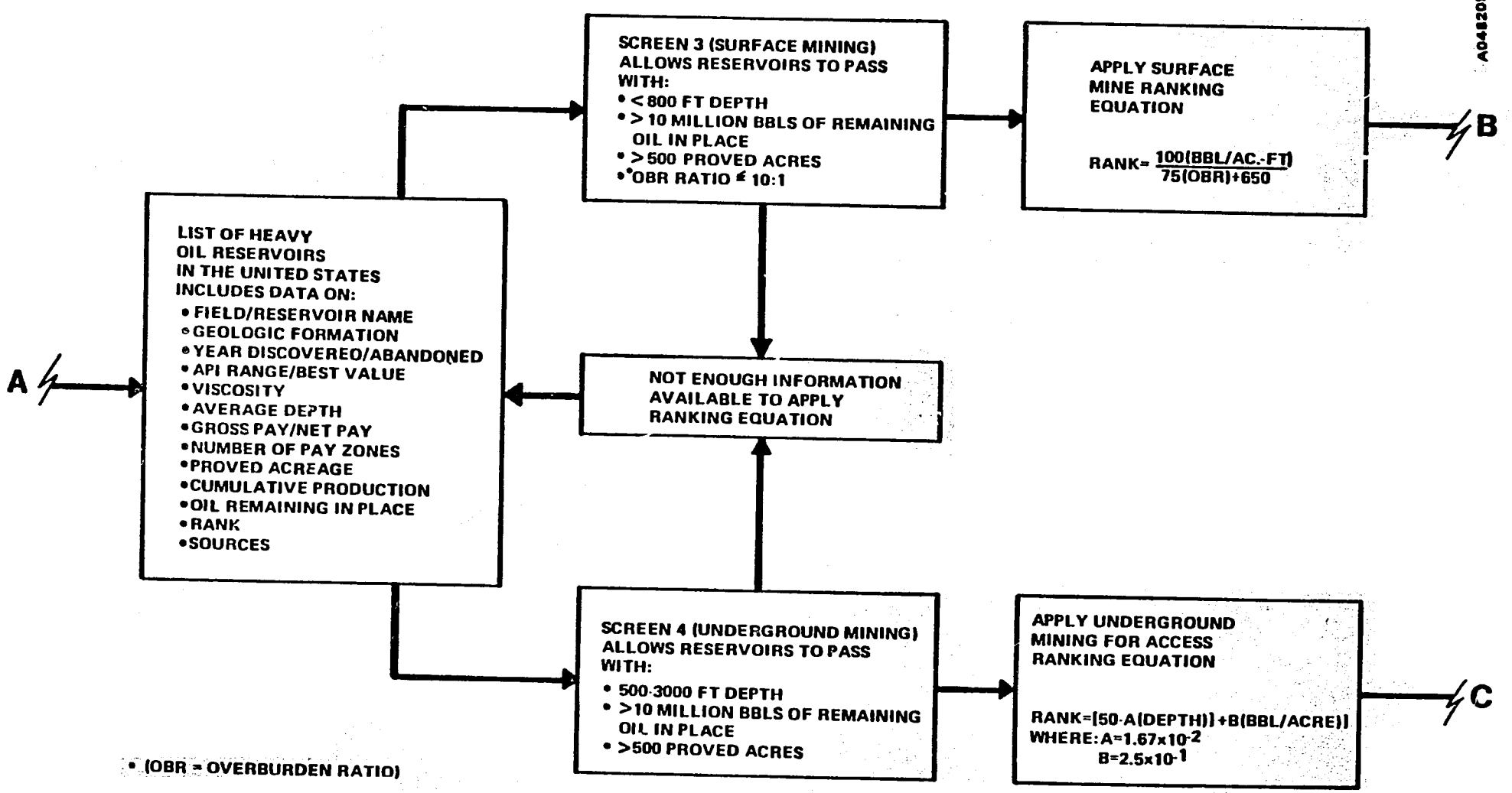

FIGURE 1-1 (CONT.)

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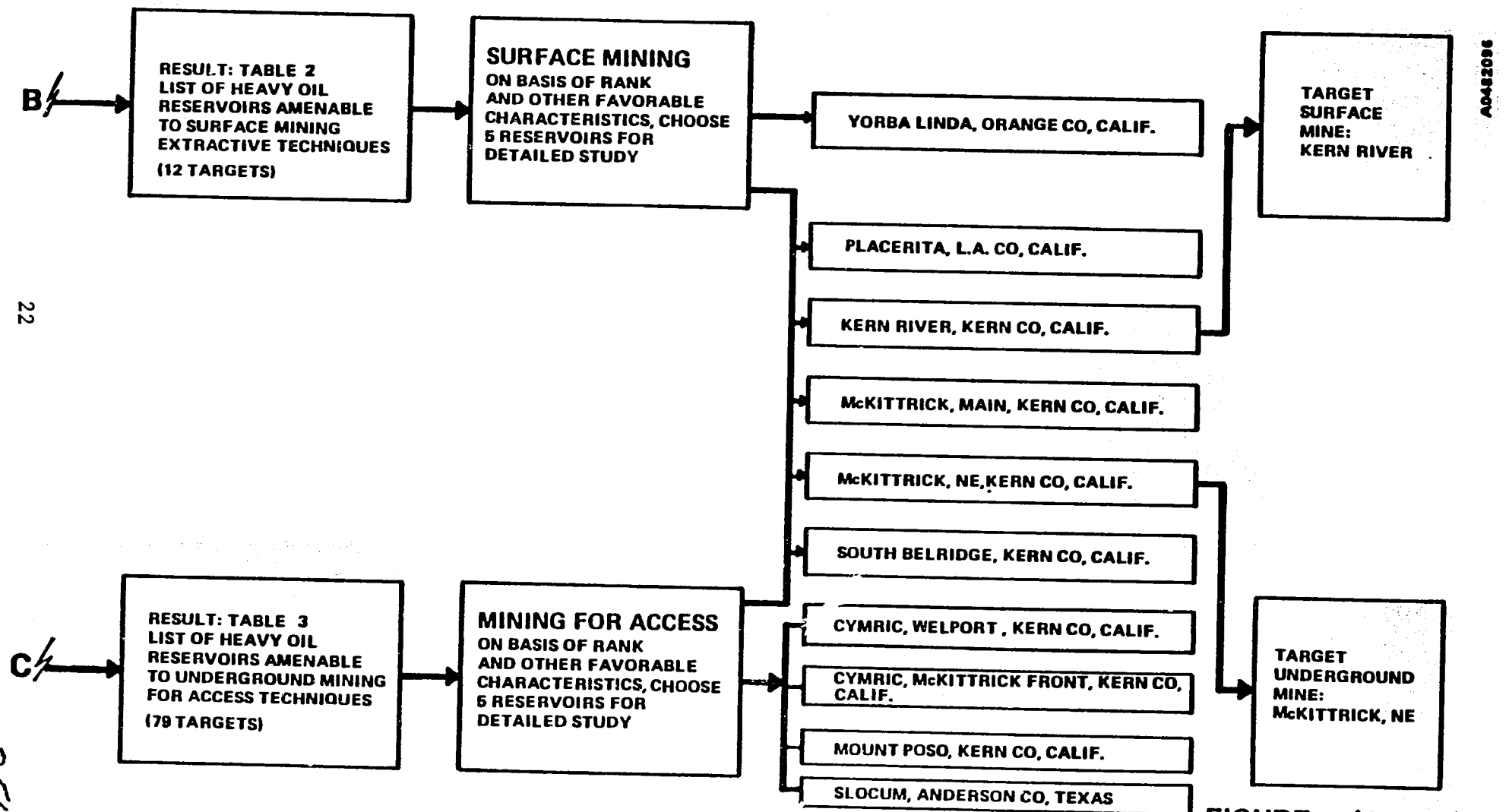

FIGURE 1-1 (CONT.)

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1.2 SCREENING CRITERIA

This study's objective was to identify the five best reservoirs as candidates for detailed study into the feasibility and economics of the two mining techniques being considered for heavy oil recovery (i.e., surface mining and mining for access). The purpose of Task I was to select one reservoir for each mining technique. To accomplish this goal a sequence of screens was applied to each reservoir:

1.2.1 Screen 1 - Fatal Flaw Screen

Screen 1 was a fatal flaw screen where four parameters were applied to each region of the United States containing heavy oil reservoirs. These parameters are outlined on the following page:

1. No consideration given to reservoirs located offshore.

2. No consideration given to heavy oil reservoirs located in remote areas with severe climatic extremes and transportation and/or delivery problems.

3. Elimination of states which contain an insignificant resource of heavy oil of 20 degrees API gravity or less.

4. Elimination of states with only Class 3 reservoirs, as defined in the 1965 Dietzman report. Class 3 reservoirs have few desirable parameters.

By applying this screen, a listing of states containing a significant heavy oil resource with API gravity less than 20 degrees was made. A description was made of the general characteristics of the heavy oil reservoirs in each state that passed Screen 1.

An initial survey of heavy oil deposit locations was made using the publications listed below:

1. Dietzman, W. D., et al., 1965, Heavy Crude Oil Reservoirs in the United States - A survey: U.S. Bureau of Mines IC#8263, 53 p.

2. U.S. Bureau of Mines, 1967, Heavy Crude Oil: U.S. Bureau of Mines IC#8352, 76 p.

3. Meyer, R. F., and W. D. Dietzman, 1979, World Geography of Heavy Oils: in the First International Conference on the Future of Heavy Crude & Tar Sands, UNITAR, pp. 16-27.

4. Whiting, R. L., 1979, Heavy Crude Oil & Tar Sands Resources in the United States: Emphasis on the State of Texas: in the First International Conference on the Future of Heavy Crude & Tar Sands, UNITAR, pp. 90-96

Figure 1-2, reproduced from the 1967 U.S. Bureau of Mines report, shows the location of heavy oil deposits. By applying the first two parameters of Screen 1, the state of Alaska and offshore areas of California, Louisiana, and Texas were eliminated from this study.

The 1965 Dietzman report contains a comprehensive listing of all the conventional reservoirs within the United States with an API gravity of less than 25 degrees. Using this information, and estimates of the heavy oil resource, the U.S. Bureau of Mines published Circular #8352, which discussed the heavy oil resource by PAD District (Petroleum Administration Defense District), and divided the reservoirs into three classes:

Class 1 -Includes reservoirs with all the desirable parameters, such as sandstone reservoirs less than 3000

feet deep, oil saturation greater than 750 bbl/acre-ft., net pay thickness of greater than 10 feet, and mobility of oil.

Class 2 -Includes reservoirs with some of the desirable parameters.

Class 3 -Includes reservoirs with few of the desirable parameters.

Only those states which contained a significant resource in Class 1 and 2 reservoirs were included in this study. A discussion of the resource by PAD District follows:

PAD District #1 includes all the Atlantic Coastal States. No states passed Screen 1. Florida was eliminated because all the heavy oil was between 20 and 25 degrees API gravity.

PAD District #2 includes all the Midwestern States. Oklahoma was the only state to pass Screen 1. Missouri, Kentucky, Nebraska, and North Dakota were eliminated because all the heavy oil was between 20 and 25 degrees API gravity. Kansas, Indiana, Illinois, and Michigan were eliminated because they contained only Class 3 reservoirs. Deposits of heavy oil/tar sands occur on the border between Kansas and Missouri, but since they do not occur in conventional reservoirs, they were not considered in this study.

PAD District #3 includes all the Gulf Coastal States. Alabama, Mississippi, Arkansas, Louisiana, and Texas all passed Screen 1. New Mexico was eliminated because it contained only Class 3 reservoirs.

PAD District #4 includes all the Central Western States. Utah and Wyoming passed Screen 1. Colorado was eliminated because it contained only Class 3 reservoirs. Montana was eliminated because it contained an insignificant resource of heavy oil of less than 20 degrees API gravity. Because of the confusion over whether the 616 million barrels of oil of less than 20 degrees API gravity in Utah is heavy oil or tar sands, Utah was eliminated from this study.

PAD District #5 includes all the Pacific Coastal States. California was the only state to pass Screen 1.

The result of Screen 1 is a listing of states with known heavy oil reservoirs containing oil less than 20 degrees API gravity, and is presented below:

- Alabama - Mississippi
- Arkansas
- California
- Louisiana
- Oklahoma
- Texas
- Wyoming

California has the largest Class 1 heavy oil resource, followed by Arkansas, Texas, Wyoming, and Louisiana.

- Alabama - Mississippi

Although there is a large resource of heavy oil with API gravity between 10 and 20 degrees in Alabama and Mississippi, none occurs within Class 1 reservoirs. Over 1400 million barrels are available from Class 2 reservoirs, with most of the resource in carbonate rocks greater than 3000 feet deep.

Publications on known oil and gas fields by the Shreveport and Mississippi geological societies were reviewed, and it was determined that a small number of heavy oil reservoirs with some favorable parameters exist in Alabama and Mississippi. Locations of these oil and gas fields are shown in Figure 1-3 and Figure 1-5.

All of these reservoirs occur within the Mississippi Salt Basin, which extends from southeastern Arkansas, into west central Mississippi, and slightly into southwestern Alabama (see Figure 1-4 and Figure 1-6). This tectonic feature includes over 50 known salt domes, the well known igneous

Jackson Dome, and extensive zones of normal faults, including the Pickons-Gilbertown-Pollard fault zones. Salt lies at depths ranging from 200 feet to more than 20,000 feet. Oil traps may be due to normal faults or doming or a combination of both. The Eutaw Formation and Selma Group, both Pennsylvanian in age, contain the largest amount of heavy oil, with the Lower Eocene Wilcox Formation contributing a minor amount. The Eutaw and Selma rocks are composed primarily of chalks and marls, sometimes grading laterally into sandstones. The Wilcox Formation is predominantly a sandstone.

According to Monograph 12 of the U.S. Bureau of Mines, entitled "Surface and Shallow Oil-Impregnated Rocks and Shallow Oil Fields", there is a northwest to southeast trending belt of asphalt extending for almost 70 miles across Alabama and partially into northeastern Mississippi. Whether or not this deposit could be classified as a heavy oil or tar sand as it increases in depth is unknown at this time.

o <u>Arkansas</u>

Arkansas has a large resource of heavy oil of less than 20 degrees API gravity, up to 4500 million barrels, of which 86 percent occurs in Class 1 reservoirs, and the remaining 14 percent in Class 2 reservoirs.

An initial review of many publications of the Arkansas Division of Oil and Gas revealed that a large number of heavy oil reservoirs exist in Arkansas with the desirable parameters. Most are moderately deep (1000-3000 ft.) with thin net pay thickness (10-30 ft.).

All of the heavy oil deposits occur within the southern part of Arkansas, on the Gulf Coastal Plain which also extends into Louisiana and Texas (See Figure 1-7 for location of the oil and gas fields, and Figure 1-8 for major tectonic features in this area). The area contains prolific Mesozoic reservoirs. Figure 1-21 shows a generalized stratigraphic column. Jurassic rocks with heavy oil include those of the Cotton Valley Group. The Hosston Formation and Trinity Group of Lower Cretaceous, and the Taylor

Group, Austin Group, and Tuscaloosa all contain substantial amounts of heavy oil. The rocks are a series of clays, shales, chalks, limestones, and sands, most of which are loosely to semi-consolidated. Trapping mechanisms are predominantly anticlinal folds, although some accumulation is due to normal faulting or a combination of both.

Arkansas has some shallow petroleum impregnated rocks of Carboniferous age in both its northwestern part and southwestern part. Since this study deals primarily with known reservoirs, these deposits were not investigated further.

o <u>California</u>

California is a leading producer of heavy oil, with current production of over 400,000 barrels of oil per day with less than 16 degrees API gravity. This represents well over 70 percent of current U.S. heavy oil production. Estimates of the remaining oil resource in place are as high as 40,000 million barrels, with over 80 percent within Class 1 reservoirs. At least half of this resource comes from the giant fields at the southern end of the San Joaquin Valley in Kern County, such as Midway-Sunset, McKittrick, Kern River, and South Belridge. The remaining resource occurs within the Los Angeles and Ventura Basins of Southern California.

An enormous amount of data is compiled on heavy oil reservoirs by the California Division of Oil and Gas. Publications on oil and gas fields were reviewed and it was determined that there are a large number of conventional oil reservoirs containing heavy oil with desirable parameters. They are found at depths ranging from shallow to deep and have rather thick net pays up to 1000 ft. See Figure 1-9 to Figure 1-17 for location of these heavy oil fields.

A description of the regional geology of the San Joaquin Valley, Los Angeles Basin, and Ventura Basin follows.

The San Joaquin Valley makes up the southern three-fifths of the Great Valley, a large elongate northwest-trending asymmetric structural trough that has been filled with a very thick sequence of sediments ranging in age from Jurassic to recent (Hackel, 1966). The Great Valley is approximately 450 miles long and averages about 50 miles in width. The valley surface is characterized by a nearly flat alluvial plain bordered by the Tehachapi Mountains to the south, the Klamath Mountains to the north, the Sierra Nevada Range to the east and the Coast Ranges to the west. The entire valley has a pronounced southward regional tilt and is cut by two major cross-valley faults; the Stockton Fault located east of San Francisco and the White Wolf Fault located along the southern margin of the valley.

The San Joaquin Valley is separated from the Sacramento Valley to the north by the Stockton Fault and associated Stockton Arch. The sedimentary sequence within the San Joaquin Valley consists of Cretaceous to Tertiary marine sandstones and finer clastics with an increasing percentage of continental deposits in younger sediments. The maximum thickness of this sedimentary sequence approaches six miles in some parts of the San Joaquin Valley. Stratigraphic columns are presented on Figure 1-18.

Structural mobility along the western margin of the San Joaquin Valley has resulted in large flexural folding and associated faults. Large anticlines along the western edge of the valley are responsible for the large oil accumulations which have resulted in the majority of California's historical oil production. Many folds extend eastward beyond the valley axis. This structural mobility has resulted from compressional tectonics and lateral strike-slip movement related to the San Andreas fault system located only several miles west of the valley at its southern margin. Several large thrust faults are associated with the major folds and many large normal faults are found throughout the valley.

Many types of oil traps are responsible for the oil accumulations in the San Joaquin Valley. These traps include: anticlines, faulted monoclines, sealing by overlap across truncated reservoirs in a structural nose, lenticular sands, impoundment below a tar seal, and down dip below an

outcrop in reservoirs with low fluid levels. Of these trap types, anticlines are by far the most significant and have resulted in the huge oil fields located along the southwestern part of the valley. Faulting, lensing and changes in permeability often act in association with the anticlinal folding to produce oil traps in these large reservoirs.

In contrast, the Los Angeles Basin topographically is a plains area that contains various hills and knolls that reflect underlying anticlinal structures. The basin covers a land area of about 1450 square miles, extending along the coast for about 70 miles and inland for 40 miles. The maximum depth of sediments has been estimated to be 31,000 feet. The stratigraphic sections for the basin are given in Figure 1-19. The sediments are predominantly unconsolidated Tertiary clastic sediments, composed primarily of shales, silts, sands, and conglomerates. Major faults and prominent fold axes trend northwesterly across the basin. The trapping mechanism is predominantly anticlinal with some faulting.

The Ventura Basin, north of the Los Angeles Basin, lies between the Transverse Ranges in Central Coastal California. The topography reflects the underlying structure, with valleys representing synclines and mountains representing anticlines. The maximum thickness of sediments in the basin has been estimated to be over 58,000 feet. A stratigraphic section is shown on Figure 1-19. All in all, the rocks in the Ventura Basin are similar to those in the Los Angeles Basin, starting with marine at the western end and grading into continental deposits eastward. Trapping is mostly due to faulting and faulted anticlines.

In addition to heavy oil in conventional reservoirs, California has a large resource of oil bearing diatomaceous earth. Diatomite is an accumulation of diatoms, or siliceous phytoplankton that live near the surface of cold waters, and is commonly unconsolidated, has high porosity, and very low permeability. Although these deposits do not yield oil readily to wells, many of them lie close to the surface and could be particularly amenable to surface mining. In fact, Getty Oil is currently developing a demonstration project for such a deposit near the McKittrick Field in Kern County. However, a survey of these deposits is beyond the scope of work of this study.

o Louisiana

Over 388 million barrels of oil with less than 20 degrees API gravity occur within Class 1 reservoirs in the state of Louisiana.

A review of publications of the Shreveport and Lafayette geological societies showed that there is a small number of heavy oil reservoirs in Louisiana, most of them shallow with thin net pays (less than 30 feet). The majority of these reservoirs occur in northwestern Louisiana, with some on the southwestern Louisiana Gulf Coast. See Figure 1-20 for the location of the oil and gas fields and major structural trends.

The state of Louisiana occurs within the Gulf Coast Geosyncline which extends into the adjoining states of Texas and Mississippi. This geosyncline has many distinctive features, such as a younging of outcrops in bands towards the coast and a major zone of growth faulting along the coast. Much of the heavy oil in southwestern Louisiana occurs within the Anahuac trend, in reservoirs ranging from Pliocene to Eocene in age. Rocks are primarily alternating beds of sandstone and shale, and traps include saltdomes, anticlines, faults, nose closures, and sand pinchouts. In northern Louisiana, the regional geology is very similar to that of southern Arkansas. Tertiary reservoirs have produced the most oil, and trapping is due to anticlines, faults and truncation with overlap. See Figure 1-21 for a stratigraphic column of North Louisiana.

o Oklahoma

According to USBM Circular #8352, 472 million barrels of heavy oil resources are available in Oklahoma with 20 degrees API gravity or less. Eight percent of this resource is available in Class 1 reservoirs, seven percent in Class 2 reservoirs, and 85 percent in Class 3 reservoirs.

Publications from the Oklahoma Geologic Survey were reviewed, including a symposium on oil and gas fields. They show many heavy oil reservoirs, with varying depths and net pays up to 82 feet in thickness. However, the

resource is spread thin throughout many fields so that few reservoirs appear amenable to mining. Most of the reservoirs occur in south-central Oklahoma, as shown in Figure 1-22.

Oklahoma is a unique state in that it contains all types of tectonic features, such as major uplifts, basins of depositions, mountain belts developed from geosynclines, major unconformities, and convergence. Figure 1-23 clearly shows these tectonic features. The heavy oil deposits are concentrated around the junction of Paul's Valley Uplift, the Arbuckle Mountains, and the Ardmore Basin. A few conventional reservoirs with heavy oil less than 5000 feet deep were found in the deep Anardanko Basin and the central Oklahoma platform.

Heavy oil is produced throughout the Ordovician, Pennsylvanian, and Permian stratigraphic section as shown on Figure 1-24. Production occurs from the Simpson Group, Deese Group, Hoxber Group, and Pontatoc Group. The Pennsylvanian section in south Oklahoma is generally a sandstone-shale sequence, whereas trending north it becomes shale and limestone. Generally, many reservoirs are found within a single field.

Studies performed by the DOE indicate that there may be a large resource of heavy oil in south-central Oklahoma, as yet unexploited by conventional means, and occurs predominantly in the Ordovician Simpson Sandstones which appear to be continuous and have net pays greater than 100 feet thick.

o <u>Texas</u>

Texas is the leading oil producing state in the United States, and it contains a significant resource of heavy oil in conventional reservoirs. There are over 10,000 million barrels of heavy oil of less than 20 degrees API gravity, with 6 percent of the resource in Class 1 reservoirs, 26 percent in Class 2 reservoirs, and 67 percent in Class 3 reservoirs. Although a number of reservoirs were eliminated by Screen 1, 600 million barrels are in Class 1 reservoirs, and 2600 million barrels in Class 2 reservoirs, a considerable resource. The largest accumulation occurs

within the Gulf Coast Onshore Province which includes south Texas and east Texas. Smaller accumulations occur in west Texas and north Texas. The areas have been divided into Railroad Commission Districts for convenience and are shown in Figure 1-25.

A review of the many available publications in Texas (see bibliography) revealed a large number of heavy oil reservoirs for consideration. The depth of these reservoirs varies, but many of them occur at relatively shallow depths. The reservoirs are rather thin, with net pay thickness varying from 10 to 40 feet.

Figure 1-26 is a tectonic map of Texas showing some striking structural features. The Gulf Coastal Plain is a depression in the earth's crust caused by an accumulation of Cretaceous and Tertiary sediments up to 75,000 feet thick. Inland are two major uplifts, the Marathon and the Llano, the East Texas Embayment containing the Tyler Basin, and numerous other basins, such as the Midland Basin and the Palo Duro Basin, as shown on the map.

Texas is divided into six major oil provinces, each with its own stratigraphic and structural features. A discussion of each would be beyond the scope of this work. In general, Texas can be divided into Cenozoic, Mesozoic, and Paleozoic producing sections, with most of the heavy oil occuring in Cenozoic reservoir rocks. In the Gulf Coast province, the rocks strike parallel to the coast, with bands of rocks becoming progressively younger towards the south. Growth faulting is a major structural feature. Texas is an area with extensive underlying salt from Jurassic deposits. This salt forms many salt domes throughout the coast and the interior. In general, the rock features are similar to those of other Gulf Coast states, with sand-shale sections predominant to the south and carbonates to the north.

o <u>Wyoming</u>

Wyoming contains large heavy oil deposits, with over one billion barrels of heavy oil of less than 20 degrees API gravity. Over 70 percent occurs in Class 1 reservoirs, and 26 percent in Class 2 reservoirs and 4 percent in

Class 3 reservoirs. The resource occurs primarily within the Big Horn Basin, Wind River Basin, and the Casper Arch area. See Figure 1-27 for location of oil and gas fields.

Publications of geological societies in Wyoming were reviewed and they revealed that a large number of heavy oil reservoirs are available for consideration, many of them deep (3000 ft), with net pays ranging from 10 to 180 ft thick.

Heavy oil occurs within both Paleozoic and Mesozoic Formations. The Pennsylvanian Tensleep is the leading producer followed by the Permian Phosphoria (Embar), Triassic Dinwoody, Mississippian Madison, and Upper Triassic Nugget Sands. The Madison and Tensleep are the major reservoirs. A stratigraphic section is presented in Figure 1-28.

Production of heavy oil mainly occurs around the peripheries of the Big Horn and Wind River basins at shallow to moderate depths in high structural positions, which indicate a release of solution gas and associated increased viscosity. Reservoirs on the west side of the Big Horn Basin have weak water drives, and enhanced oil recovery techniques have greatly improved recovery.

1.2.2 Screen 2 - Listing of Heavy Oil Reservoirs

Screen 2 consists of several parameters considered to be the limit of technical or economic feasibility for mining in general. At the end of Screen 1, a computer search was made to identify available literature on heavy oil reservoirs in the eight top states. An enormous amount of information was available, much of it conflicting, which would require an extensive review that would have exceeded the scope of this study. Therefore, Screen 2 was applied to the top five states: California, Arkansas, Texas, Wyoming, and Louisiana. Screen 2 was used to compile a list of heavy oil reservoirs with the following parameters:

1. API gravity between 10 and 20 degrees.

2. Oil mobility - Defined as the permeability divided by the viscosity. In absence of viscosity data, reservoirs with any historical production.

3. Less than 5000 ft deep.

4. Greater than 10 ft net pay.

The first and second parameters in Screen 2 were specifically designed to select only those reservoirs containing heavy oil. Differentiation of heavy oil from tar sands and light oils was accomplished by these two parameters, which reflect the current industry definition of heavy oil.

A depth of 5000 ft was considered the maximum practical depth where existing underground mining techniques could be utilized profitably in a mining for access development scheme. The net pay and amount of recoverable heavy oil would obviously have to increase with depth for a mining for access development to be profitable.

A net pay of 10 ft was selected as the minimum reservoir thickness that could be profitably developed using mining techniques. The actual minimum

net pay thickness that would be economical for a given heavy oil reservoir depends on the porosity, permeability, oil saturation, gas-oil ratio, depth to the producing zone, and the API gravity and viscosity of the oil.

In other words, the amount of recoverable oil per unit area of a given oil reservoir rather than the net pay of that reservoir will ultimately determine whether or not a mining scheme will be profitable. Given typical values for heavy oil reservoir rocks and heavy oils, a net pay zone 10 ft thick is considered to be the minimum thickness that could result in a profitable oil recovery system using mining techniques.

Using Screen 2, a review of available literature was made within the top 5 states. A list of the summary publications used is given below:

1. Dietzman, W.D., et al., 1965, Heavy Crude Oil Reservoirs in the United States-a survey: U.S. Bureau of Mines IC #8263, 53p.

2. U.S. Bureau of Mines, 1964, Surface and Shallow Oil-Impregnated Rocks and Shallow Oil Fields in the United States: U.S. Bureau of Mines, Monograph 12, 375p.

3. International Oil Scouts Association, 1977, International Oil and Gas Development-Yearbook 1976 (Review of 1975)-Part II.-Production: V.46, 335p.

4. Kujawa, Patrick, 1981, Heavy Oil Reservoirs Recoverable by Thermal Technology, Volume I, II, & III: U.S. Department of Energy Publication DOE/ET/12380-1, Contract No. AC03-78ET12380.

5. Various other summary publications by state, such as symposiums on oil and gas fields, division of oil and gas publications, geological societies publications, and reports on enhanced oil recovery operations (see bibliographics for each state).

These publications were used to make a comprehensive listing of the reservoirs within the top 5 states that passed Screen 2. The results are tabulated in Table 1-1, List of Heavy Oil Reservoirs in the United States, which is located at the end this report.

One thing that became readily apparent from the literature review and detailed study of the 10 best targets is that many conflicting reports exist for each reservoir. This results from several operators in the same field, each using their own proprietary data and testing program. In order to minimize potential contradictions or uncertainties, all the available literature on each field would have to be reviewed, including publications from the divisions of oil & gas, geological societies, geological surveys, associations of petroleum geologists, AIME-petroleum section, state universities and schools, and reports on enhanced oil recovery. In addition, each operator and all organizations would have to be contacted, and finally, a visit to the site to contact the landowners might be required. This level of effort was beyond the scope of this project; therefore, each parameter in Table 1-1 is somewhat uncertain. However, the best were reported, and where considerable uncertainty or discrepancy existed, a range was given. The Kujawa (1981) report was relied upon heavily to determine the best values, but as became apparent from the detailed study even these values are uncertain.

The result of Screen 2 is Table 1-1, List of Heavy Oil Reservoirs in the United States, compiled for the states of California, Arkansas, Texas, Wyoming, and Louisiana. Figure 1-29 shows an example of the table, and the complete tables are given at the end of this report. A description of how each value was compiled is given here. The field name and county is given in Column 1. The reservoir name, given in Column 2, varies and may include an area name, a formation name, or a specific name related to some geologic or localized feature. The geologic formation, Column 3, is the name assigned to a rock strata with distinctive lithologic features.

The year discovered and year abandoned are given, respectively, in Column 4 and 5. The year of discovery does not necessarily correspond to the first well drilled in the area with minor oil showings, but rather to the year in which the first well was drilled with significant initial production. The year abandoned corresponds to the time at which primary, secondary, and possibly tertiary production was completed.

The API gravity range and best value of API gravity is shown in Columns 6 and 7. In most cases, there was great variation of API gravity values from different sources. Therefore a range was reported and if part of it fell within 10 to 20 degrees API gravity, the reservoir was included in Table 1-1. Best values of API gravity are based on the Kujawa (1981) report, or total agreement of all sources. Only those reservoirs with API values between 10 and 20 degrees were included in Table 1-1.

Viscosity of the oil at borehole temperature, in centipoise, was included in Column 8. Viscosity data are seldom reported and all the values listed in the table are from the Kujawa (1981) report.

The average depth of the reservoir, in Column 9, was reported as an average best value or a range in average values.

Gross pay, average net pay, and the number of pay zones are reported in Columns 10, 11, and 12, respectively. Gross pay is reported only when a reliable value was reported, and although it is entirely possible that some average net pay values may actually be gross pay, if uncertain they were reported as net pay. The cumulative thickness of the individual pay zones equals net pay.

The reservoir area, in acres, is the limit of proven production in a field for that particular reservoir only, and is reported in Column 13.

Columns 14, 15 and 16 cover cumulative production of the reservoir if available, and if not, the reported cumulative production for the field. The field name is shown under the production value if the reservoir

production is uncertain and only the production figures for the field are available. The cumulative production for oil in 1000 bbls and gas in 1000 mcf is reported for the most recent year obtainable.

Estimated remaining oil in place is based on calculations of the original oil in place, production curves, and cumulative production. A large number of estimates were taken from the Kujawa (1981) report. Due to the lack of data on a large number of reservoirs, a very rough estimate of remaining oil was made using the following equation developed by Stone & Webster in discussion with Mr. Dan Bass:

$$ROIP = Pc\ (100/Y - 1)$$

where ROIP = Estimated Remaining Oil in Place
Pc = Cumulative production
Y = Cumulative production year minus year of discovery, not greater than 30.

Comparison of these estimates with reliable reported values showed that if the oil had moderate to high mobility, the estimate was good, but if the oil had low mobility, the estimate could be multiplied by a factor from 1 to 10 to obtain a true value. Calculated estimates of cumulative production are a minimum value based on an average of 30% recovery after 30 years, and will serve to identify those reservoirs with resources over 10 million bbls cumulative production. Values are reported in Column 17, with an (e) if estimated using this equation.

Column 18 provided an opportunity to indicate a serious flaw in a given field or reservoir to development by surface extractive or underground mining for access techniques. This column was rarely used.

Descriptions of Screens 3 and 4 explain how the rank numbers were developed for Column 19. This approach provided an effective way to illustrate which reservoirs had the most favorable combination of parameters for mining technology. An S or an M appears before the number and corresponds to

surface mining or mining for access, respectively. Numbers over 100 were deemed most favorable. A number in parenthesis shows the number of uncertain parameters in the ranking equation. An "X" in the rank column indicates that not enough information was available to make an evaluation.

Finally, Column 20 corresponds to the references used to obtain this information by listing the reference number. See the Bibliography, Section V, for a complete list.

1.2.3 Screen 3 - Surface Mining

The objective of this phase was to select five of the "best" candidate reservoirs (using surface mining oil recovery techniques) from the extensive list of potential heavy oil reservoirs developed using Screens 1 and 2. This selection was accomplished by first applying a third screen, Screen 3, to each of the reservoirs contained in Table 1-2 and then ranking the reservoirs which passed Screen 3 using a ranking equation described later in this section. The top reservoirs were selected for more detailed characterization after which one was recommended as the best candidate for detailed evaluation of the technical and economic feasibility using surface mining techniques.

Surface mining to recover heavy oil is similar in many ways to surface mining for coal or oil shale. The reservoir rocks, or ore, are generally buried within a sequence of unconsolidated to moderately consolidated sedimentary rocks including sandstone, shale, limestone, dolomite siltstone, claystone, etc. Recent alluvial deposits of varying thickness generally overlie this sedimentary sequence. A basic description of the surface mining techniques needed to recover heavy oil includes: (1) stripping the overburden down to the top of the ore zone, (2) removing the ore from the open pit, (3) processing the ore to remove the oil, (4) disposing of the spent ore and overburden, and (5) reclaiming the mine and disposal area after the operation has been completed.

TABLE 1-2

LIST OF RESERVOIRS AMENABLE TO SURFACE MINING TECHNOLOGY

CALIFORNIA-CENTRAL COASTAL

FIELD NAME	COUNTY	RESERVOIR NAME	RANK
Casmalia	Santa Barbara	Monterey	S-4-(2)

CALIFORNIA-SAN JOAQUIN VALLEY

FIELD NAME	COUNTY	RESERVOIR NAME	RANK
Kern River	Kern	Kern River	S-128
McKittrick	Kern	Main Area, Upper	S-123-(2)
Belridge	Kern	South Area, Tulare	S-113-(2)
Lost Hills	Kern	Main Area	S-50
McKittrick	Kern	N.E. Area	S-31-(1)
Coalinga	Kern	West Area, Temblor	S-23
Belridge	Kern	North Area, Shallow	S-5-(1)

CALIFORNIA-SOUTHERN

FIELD NAME	COUNTY	RESERVOIR NAME	RANK
Yorba Linda	Orange	Shallow	S-169-(2)
Placerita	Los Angeles	Shepard & Kraft	S-120
Los Angeles City	Los Angeles	Miocene	S-62-(2)

LOUISIANA

FIELD NAME	COUNTY	RESERVOIR NAME	RANK
Bellevue	Bossier	Nacatoch	S-40-(1)

The selection process consisted of applying Screen 3 to the comprehensive list of potential heavy oil reservoirs amenable to mining. Screen 3 consisted of the following parameters:

1. Reservoir depth of less than 800 ft

2. Greater than 10,000,000 barrels of oil remaining in place

3. Greater than 500 acres proven resources

4. Overburden (and interburden) ratio of less than or equal to 10 to 1

The reservoirs which passed this screen were then ranked to establish a relative order among them. Ranking was accomplished by applying the following equation:

$$\text{Rank} = 100\ (\text{BBL/ACRE-FT})/(75)(\text{OBR})+650)$$

where: Rank = a number greater than zero
OBR = overburden (and interburden) ratio for the reservoir
BBL/ACRE-FT = calculated value of barrels per acre-foot for the reservoir based on oil remaining in place, reservoir area and net pay thickness in ft.

A detailed description of the derivation of this equation is included later in this section. The rank obtained for each reservoir provided an opportunity to group these reservoirs in relative order of suitability from best to worst. It is stressed here that ranking resulted in only a relative ordering of these candidate reservoirs. Because of uncertainties in the ranking variables an uncertainty of 10 to 15 points was assumed in the value of a given rank.

Five reservoirs with highest rank and favorable reservoir characteristics were selected for more detailed analysis and description. Additional literature searches produced detailed papers with descriptions of the geology, structure, stratigraphy and development history. A summary of this information is included in the descriptions of these five reservoirs and is presented in Section 1.3 of this report.

The final outcome of this effort was to recommend one of the five best reservoirs for more detailed characterization as the best candidate for heavy oil recovery using surface mining techniques. This recommendation was based on the structure, lithology, groundwater, reservoir characteristics, and land use of the five candidate reservoirs.

1.2.3.1 Basic Assumptions for Screen 3 Parameters

Most of the assumptions made for this analysis have a direct impact on the economics of the entire mining scheme. The type of mining equipment used for stripping overburden and ore significantly impacts the cost of mining. The type of stripping equipment depends in turn on the lithology and competency of the overburden and ore material. Stripping costs increase as the equipment used goes from draglines or bucketwheel excavators to truck and shovel operations to blasting with truck and shovel or loader combinations. Draglines or bucket wheel excavators were assumed feasible in all analyses of surface mining in this study. This type of equipment generally performs well and at low cost per yard of material handled in unconsolidated or weakly consolidated rocks as are commonly associated with the heavy oil reservoirs under consideration in this study.

Processing the reservoir zone rock or ore was assumed to be similar to the processing associated with oil production from oil shale. Bulk handling systems and crushers in combination with a retorting or stripping process would probably be required for sucessful extraction of the heavy oil from the mined reservoir rocks. It was assumed that processing costs would be somewhat less that those anticipated for oil shale because of the higher porosity and permeability and because of lower competency of most heavy oil reservoir rocks as compared to oil shale.

Processed ore and overburden require disposal in a controlled waste disposal area. Disposal of these materials would probably be subject to the same controls, permits and regulations as are similar mine spoils in other mining industries. Reclamation of both the disposal area and mine area would be required at the completion of a heavy oil surface mining project.

Government regulatory bodies responsible for permitting, regulating and monitoring existing surface mines in the coal, oil shale, and metals industries would have responsibility for a heavy oil mine. Regulations and permits required by the Office of Surface Mining, Bureau of Mined Land Reclamation, Environmental Protection Agency and others would have to be followed in the development of a heavy oil surface mine.

The technical problems associated with development of a surface mine to recover heavy oil would be approximately the same as those encountered in surface mining for other ores. Groundwater control, pit slope stability, land disturbance, waste disposal and reclamation, control of natural gas, and development of adequate and economic processing technologies are a few examples of the technical problems associated with development of a heavy oil surface mine. In addition to the control of natural gas, emissions of hydrocarbon gases may need to be considered.

The basic economic assumptions made for this analysis were required to establish approximate limits for use in Screen 3. The maximum overburden ratio, maximum depth to the top of a reservoir, minimum acreage, and minimum amount of oil remaining in place were all based on the economic assumptions outlined below.

The approximate value of a barrel of heavy crude oil was assumed to be 30 dollars. Mining costs for overburden removal and ore recovery were based on dragline operation and estimated to be approximately 35 cents per yard. These assumptions resulted in estimated mining costs of four to five dollars per barrel for "average" reservoirs less than 800 ft deep. Processing costs were estimated between 10 and 25 dollars per barrel, and

taxes, overhead, profit and intangibles were estimated between 5 and 10 dollars per barrel. These estimates indicate that a heavy oil reservoir would be marginally profitable if it was 800 ft deep with an overburden ratio of 10 to 1. These limits were therefore selected for use in Screen 3. No groundwater control or other major mining costs due to difficult subsurface mining conditions were included in these estimates. Reservoir depth and or overburden ratio would have to be reduced to maintain marginal profitability if significant groundwater inflows or other problems were expected at a given location. A 20-to-30 year operating life was assumed for all mine plans considered in this study.

1.2.3.2 Parameters in Screen 3

The purpose of this section is to describe the assumptions and the logic used to obtain each of the parameters used in Screen 3.

A maximum reservoir depth of 800 ft was estimated to be the limit for economical development of a surface mine for heavy oil recovery. This depth was selected rather arbitrarily because of the many variables involved. These variables include the overburden ratio, net pay of the target reservoir, estimated resources in the reservoir, lithology and competency of the reservoir rocks and overburden, potential for groundwater inflow, and price of oil.

The reservoir depth from which surface mining can produce heavy oil economically can be evaluated with confidence only on a site-specific basis. This was not possible for all potential reservoirs within the time constraints of this study. In addition to the considerations outlined above, 800 ft was selected as a depth at which underground mining techniques compete favorably with surface mining techniques in terms of cost. Increasing rock consolidation and competency below 800 ft make excavation with draglines and/or bucketwheel excavators less efficient or impossible, and provide better rocks for development of unsupported underground openings.

A requirement of at least 10 million barrels of oil remaining in place was considered to be an estimate of the potential resource required to cover the capital costs associated with developing a surface mine and processing plant. Recovery of less than 50 percent of the estimated oil remaining in place was assumed in determining the minimum estimated resource required for consideration in Screen 3.

A proven surface area of at least 500 acres was included to eliminate smaller fields from consideration. Only reservoirs suitable for a major mine development capable of producing several thousand barrels of oil per day over a 20- to 40-year period were considered for this study. A proven surface area of at least 500 acres was considered necessary to:

1. Provide enough room to develop a surface mine. Note here that area for disposal of overburden, interburden and waste "ore" is not considered in this 500 acre area. An offsite permitted disposal area would be required in the vicinity of the surface mine.

2. Provide adequate resources to allow an operation period of at least 20 years for an "average" reservoir.

Clearly, smaller or larger proven acreage could result in economic mine development depending on the depth, thickness, resources and lithologies of individual heavy oil reservoirs.

An overburden ratio of 10 to 1 was estimated to be the upper limit for in economical development of a heavy oil reservoir by surface mining techniques. This conclusion is based on the economic assumptions discussed in the preceding section of this report.

1.2.3.3 Ranking Equation

A method of ranking the 12 reservoirs remaining after Screen 3 was necessary to order them in terms of potential profitable mine development.

Two parameters were selected to order these reservoirs -- the overburden (including interburden) ratio and the number of barrels per acre-foot calculated for each reservoir.

Each parameter was given approximately equal weight in the ranking equation. Constants were included in the equation such that a marginally profitable reservoir would have a rank of 100. The constants were derived from an empirical relationship relating the number of barrels per acre-foot required at various overburden ratios. This empirical relationship was as follows:

$$B/A\text{-}F = 650 + 0.75\ (OBR)$$

where: B/A-F = required bbls/acre-ft for marginal profitability
OBR = overburden ratio

This linear relationship is based on the assumption that 650 barrels per acre-ft are required for marginal profitability if the ore is exposed at the ground surface and 1400 barrels per acre-ft are required for marginal profitability when the overburden ratio is 10 to 1.

The ranking equation that resulted from this analysis is as follows:

$$Rank = 100\ (BBL/ACRE\text{-}FT)/(75)(OBR)+650)$$

where: OBR = overburden ratio (including interburden)
BBL/ACRE-FT = calculated value of barrels per acre-foot based on estimated oil remaining in-place, proven reservoir area and net pay thickness in ft.

1.2.3.4 Selection of the Best Targets For Surface Mining

Table 1-2 is a listing of the 12 surface mining targets to which the ranking equation was applied. Only five reservoirs had a rank of over 100, with three in the San Joaquin Valley, and the other two in Los Angeles County. No surface mining targets were available in Arkansas, Texas, or Wyoming. The five best targets are described in Section 1.4 of this report and are summarized briefly below.

The five reservoirs with highest rank are the Kern River (128), South Belridge (113), Main Area McKittrick (113), Yorba Linda (169) and Placerita (120). Considering uncertainties, all five reservoirs except the Yorba Linda have about the same rank. Evaluation of these five reservoirs based on the detailed descriptions given in Section 1.4 of this report was required to determine which reservoir should be selected as the best candidate for detailed feasibility and economic analysis.

The Kern River Field appears to represent the best potential target for surface mining to recover heavy oil. It has a vast resource remaining in place, covers in excess of 9000 proven acres, a gross pay of about 800 ft, a net pay of 220 ft, and about 1400 barrels/acre-ft of recoverable oil. In addition, the producing zones outcrop at the eastern edge of the field; therefore, surface mining could begin with an overburden ratio of 0 to 1 and progress down dip to an economic mining limit. Potential problems to sucessful surface mining at the Kern River Field include high potential groundwater inflows, interference with current surface activity and seismicity of the area.

The South Belridge Field is an attractive potential surface mining target, placing second to the Kern River Field. The South Belridge Field has a vast resource remaining in place, covers in excess of 8000 proven acres, a gross pay of about 450 ft, a net pay of about 100 ft, and an estimated 1700 barrels per acre-ft of recoverable oil. The depth to the reservoir varies from 400 to 850 ft. Potential problems to successful surface mining at the South Belridge field include high groundwater inflows, interference with surface activity and seismicity of the area.

The main area of the McKittrick Field has similar potential problems to successful surface mining as do Kern River and South Belridge. The depth to the reservoir at the main area of the McKittrick Field varies from 200 to 600 ft and was the primary reason that Kern River was selected over this field.

The Yorba Linda Field was eliminated from consideration after the detailed description was completed. The detailed research into this field indicated that the surface area and estimated reserves within the only reservoir that could be considered for surface mining were too small. Only 180 acres of proven area and approximately 50 million barrels of resources exist in this upper reservoir in the Yorba Linda Field. In addition, current land use in the vicinity of the Yorba Linda Field consists of residential housing developments. This land use is inherently incompatible with surface mining activities.

The Placerita Field was eliminated from consideration because detailed study indicated that only 350 acres of proven area are available for surface mining. The field is located in close proximity to the San Gabriel Fault zone, an active fault that has experienced large movements during historic time. Finally, the Placerita Field is in the greater Los Angeles area and current or near-future land use may be incompatible with surface mining activities.

1.2.3.5 Result of Detailed Study

The Kern River Field, Kern County, California is recommended for the detailed site-specific study into the technical and economic feasibility of heavy oil production using surface mining techniques. This field represents the best available target based on the screening and selection process described in this section.

1.2.4 Screen 4 - Underground Mining for Access

The objective of this phase of the study was to select from the list of potential heavy oil reservoirs developed using Screens 1 and 2, the five "best" candidate reservoirs for underground mining for access. This selection was accomplished by first applying Screen 4 to each of the reservoirs in Table 1-3 and then ranking those reservoirs which passed Screen 4 using a ranking equation described later in this section. The top five reservoirs were selected for more detailed characterization after which one was recommended as the best candidate for detailed evaluation of technical and economic feasibility.

Mining for access techniques for heavy oil recovery represent a unique blending of two existing and advanced technologies, underground mining and petroleum engineering. A project utilizing the concept of mining for access would consist of two or more vertical access shafts from the ground surface to a point below a target reservoir, a system of horizontal drifts to the limits of the reservoir or lease area, and a system of wells drilled from the access drifts into the reservoir above. The well system would be drilled in a fan-like pattern from individual access drifts to penetrate the reservoir in the entire production area with recovery wells. Steam, air or chemical injection or other forms of enhanced oil recovery could be used in conjunction with production wells from the access drifts. Recovered oil from individual wells would be carried to a central collection point in a closed system and ultimately pumped to the ground surface for transportation to markets. This brief description of the mining for access technology for heavy oil recovery illustrates the unique blend of mining engineering and petroleum engineering required for successful implementation of this technology.

The selection process for mining for access consisted of applying Screen 4 to the comprehensive list of potential heavy oil reservoirs amenable to mining that was obtained by using Screens 1 and 2 as described in Section 1.2.1 and 1.2.2 of this report. Screen 4 consisted of the following parameters:

1. Reservoir depths less than 3000 ft

2. Greater than 10,000,000 barrels of oil remaining in place

3. Greater than 500 acres of proven resources

The reservoirs that passed this screen were ranked to establish a relative order with regard to the suitability for heavy oil recovery using underground mining for access techniques. Ranking was accomplished by applying the following equation:

Rank = 50-(A*(DEPTH)) + (B*(BBL/ACRE))

where: A = a constant with a value of 1.67×10^{-2}

B = a constant with a value of 2.5×10^{-4}

DEPTH = Estimated average depth to top of reservoir

BBL/ACRE = Calculated barrels per acre based on estimated remaining oil in place and proven reservoir area.

A detailed description of the derivation of this equation is included later in this section. The rank obtained for each reservoir provided an opportunity to group these reservoirs in order of relative suitability from best to worst. It is stressed here that ranking resulted in only a relative ordering of these candidate reservoirs. Because of uncertainties in the ranking variables an uncertainty of 10 to 15 points was assumed in the value of a given rank.

Five reservoirs with highest rank and favorable reservoir characteristics were selected for more detailed analysis and description. Additional literature searches produced detailed papers with descriptions of the geology, structure, stratigraphy and development history. A summary of this information is included in the descriptions of the five reservoirs and is presented in Section 1.3 of this report.

The final result of this effort was the recommendation of one reservoir as the best candidate for development of underground mining for access technology for heavy oil production. This recommendation was based on the characteristics of the structure, lithology, groundwater, reservoir characteristics, and present land use of the five candidate reservoirs.

1.2.4.1 Basic Assumptions

Many of the assumptions made for this analysis have a direct impact on the economics of the mining system. A discussion of the major assumptions and considerations regarding the conceptual mining for access plan is given below. Many generalizations were required that may prove unacceptable for specific sites after a detailed understanding of the subsurface conditions and rock mechanics parameters are obtained.

Several methods of underground mining may be used to develop the underground openings required for the mining for access scene. Most of the heavy oil reservoirs under consideration lie within a thick sequence of sedimentary rocks, including sandstones, shales, carbonates, and in combinations of these basic rocks, including silty-claystones, sandy-siltstones and others. Many of these reservoirs consist of lithologies that are unconsolidated to loosely consolidated. Many reservoirs, such as those in the San Joaquin Valley, California, are overlain by thick deposits of unconsolidated recent alluvial deposits. Because of the low competency of many of the lithologies commonly associated with heavy oil reservoirs, continuous mining machines, tunnel boring machines and large-diameter shaft drilling machines are all considered to be technically feasible for use in developing underground openings for the mining for access technology.

Conventional drill-blast-muck techniques for shaft sinking or tunnelling are considered feasible but generally are more costly compared to shaft drilling and tunneling machines. This is particularly true in softer rocks where a significant quantity of underground space is required.

It was assumed that thermal assistance would be required to produce oil in the mining access scene. The minimum overburden required to sucessfully employ this enhanced oil recovery technique was assumed to be 500 ft. Therefore, no reservoirs with overburden of less than 500 ft were considered for this technology.

Government regulations that may impact the mining for access technology is difficult to assess because the technology requires a unique blend of two existing technologies, mining and petroleum. Each of these existing technologies currently is regulated by different groups of governmental agencies. Until specific jurisdiction is established among these governmental agencies, the exact regulations, taxes and pricing structure that will govern mining for access projects is uncertain. State divisions of oil and gas, the Department of Energy, Environmental Protection Agency, Bureau of Mined Land Reclamation, Department of Health, Office of Safety and Health Administration, Mining, Safety and Health Administration and the Bureau of Mines are examples of the existing governmental regulatory agencies which may have jurisdicion over some aspects of a mining for access project.

The mine environment within the underground space required for a mining for access project is assumed to be a gassy environment similar to very gassy coal or oil shale mines, requiring permissible equipment. Hydrocarbon gases associated with most heavy oil reservoirs are under pressure, often dissolved in the oil, and represent a complex set of gases, including methane, ethane, propane, and hexane. Although the horizontal drifts would be driven a significant depth below the reservoir horizon, gas pockets in these underlying rocks and potential gas seepage or blowouts from wells drilled into the reservoir make the environment within these openings hazardous.

Technical problems associated with sucessful implementation of a mining for access project to produce heavy oil include the same problems associated with developing an underground coal mine. Some of these problems are as follows: control of groundwater inflow, ventilation for a gassy mine environment, stability of all underground openings over the operational

life of the project, durability of the same openings to traffic, blowout prevention from wells drilled from the access openings, design of an oil gathering system, enhanced oil recovery techniques, potential for significant ground surface subsidence from large fluid withdrawals, disposal of waste rock produced during development of the underground space, and disposal or use of potential large quantities of groundwater co-produced with the heavy oil.

The economic assumptions for the mining for access technology were necessarily very general due to the lack of specific information regarding the subsurface conditions at each of the reservoirs under consideration. Basically, it was assumed that the depths to which underground mining for coal is sucessfully accomplished today represents the technical and economic limit for successful recovery of heavy oil using mining for access techniques. In addition, a 20- to 30-year project life was assumed in establishing limits of depth, resources, and surface area in Screen 4.

1.2.4.2 Parameters in Screen 4

A depth of 3000 ft was selected as a reasonable lower limit for both technical and economic feasibility. This approaches the depth of successful existing underground mines for recovery of coal and potash. These mine types are considered to have similar technical problems and economic restraints to potential mining for access technology for heavy oil.

Greater than 500 acres of proven resources remaining in place was included to ensure that sufficient reserves were available to sustain a significant level of heavy oil production over a 20- to 30-year project life. This time period is needed to allow sufficient capitalization of initial development costs to make a project profitable. Items responsible for high development costs for a mining for access project include shafts and drifts, production well drilling, oil gathering system and enhanced oil recovery systems.

1.2.4.3 Ranking Equation

A method of ranking the 78 reservoirs remaining after Screen 4 was necessary to order them from best to worst in terms of potential profitable mine development. Two parameters were selected to order these reservoirs, the depth to the top of each reservoir and the number of barrels per acre calculated for each reservoir.

Each of these parameters was given approximately equal weight in the ranking equation. This was done by introducing constants into the equation such that it would assign a rank between 80 and 100 to an "average" reservoir in the group under consideration. The distribution of depth and barrels per acre was determined for all of the reservoirs that passed Screen 4. These distributions are shown in Figure 1-30 and 1-31.

The constants in the ranking equation were based on the distribution of the depths and resources of the reservoirs that passed Screen 4. Constant "A" was selected such that 100 percent of the distribution of the depth to the top of the reservoirs was less than the selected value. The constant "A" is based on a depth of 3000 ft. The constant "B" was selected such that 75 percent of the resources, expressed as barrels per acre, of the reservoirs that passed Screen 4 were less than the selected value. The constant "B" is based on resources of 200,000 barrels per acre. Because of the constants, the ranking equation produces a rank of 100 for a reservoir with a depth of one foot and resources of 200,000 barrels per acre.

The ranking equation that resulted from this analysis is as follows:

$$\text{Rank} = 50-(A*(\text{DEPTH})) + (B*(\text{BBL/ACRE}))$$

where: $A = 50/3000 = 1.67 \times 10^{-2}$

$B = 50/200{,}000 = 2.5 \times 10^{-4}$

DEPTH = Estimated average depth to top of reservoir

BBL/ACRE = Calculated barrels per acre based on estimated remaining oil in place and proven reservoir area.

Four of the reservoirs with highest rank from the equation described above were also among the five best candidates for surface mining. Therefore, an additional four reservoirs with high rank for underground mining were included for detailed description. A total of nine reservoirs were described in detail and evaluated to select the best candidate for development by mining for access technology. This best candidate was recommended for subsequent detailed analysis of the technical and economic feasibility of heavy oil production using mining for access technology.

1.2.4.4 Selection of the Best Targets for Underground Mining for Access

After applying the ranking equation of the 79 reservoirs which passed Screen 4, it became apparent that there are a large number of reservoirs available for consideration and that each one would have to be studied separately. Over half of these reservoirs were listed in California, as shown in Table 1-3. The remaining portion was distributed equally among Arkansas, Louisiana, Texas, and Wyoming. Out of an initial list of 66 reservoirs in Arkansas, only 6 reservoirs passed Screen 4 and were given a rank. Rank numbers were quite low, from 11 to 36, this being primarily due to thin net pays.

Only 12 reservoirs in Louisiana passed Screen 2, and after applying Screen 4, only 5 were left and given a rank. The rank numbers vary from 29 to 40, due to thin net pays but fairly shallow depths.

A total of 47 reservoirs in California passed Screen 4. The rank numbers in the San Joaquin Valley and Southern California were the highest, up to 161, being primarily due to thick net pays and a high quality resource.

A total of 15 reservoirs in Texas passed Screen 4, with rank numbers varying from 11 to 60. This is almost entirely due to the fact that most of the reservoir rocks were discontinuous with many lateral changes leading to small productive acres and thin pays.

TABLE 1-3

LIST OF RESERVOIRS AMENABLE TO UNDERGROUND MINING FOR ACCESS TECHNOLOGY

CALIFORNIA - CENTAL COASTAL

FIELD NAME	COUNTY	RESERVOIR NAME	RANK
San Ardo	Monterey	Main Area, Lombardi	M-55
San Ardo	Monterey	Main Area, Aurignac	M-28
Cat Canyon	Santa Barbara	Gato Ridge Area, Sisquoc	M-46-(1)
Casmalia	Santa Barbara	Monterey	M-45-(2)
Guadalupe	Santa Barbara		M-32
Cat Canyon	Santa Barbara	New Area West, Pliocene	M-18
Santa Maria Valley	Santa Barbara	Main Area, Monterey	M-17-(3)
Lompoc	Santa Barbara	Monterey	M-15-(1)
Cat Canyon	Santa Barbara	Central Area, Sisquoc	M-14-(1)

CALIFORNIA - SAN JOAQUIN VALLEY

FIELD NAME	COUNTY	RESERVOIR NAME	RANK
McKittrick	Kern	Main Area, Upper	M-132-(2)
Kern River	Kern/Fresno	Kern River	M-110
McKittrick	Kern	NE Area, Upper	M-88-(2)
Cymric	Kern	McKittrick Front Area Tulare	M-84
Cymric	Kern	Welport Area	M-84
Belridge	Kern	South Area, Tulare	M-81-(1)
Midway-Sunset	Kern	Others	M-65
Mount Poso	Kern	Mount Poso Area, Vedder	M-63
Kern Bluff	Kern	Transition-Santa Margarita	M-58-(1)
Poso Creek	Kern	Premier Area, Etchegoin-Chanac	M-58-(2)
Edison	Kern	Main Area, Upper	M-54-(1)
McDonald Anticline	Kern		M-47-(3)
Lost Hills	Kern	Main Area	M-44
Belridge	Kern	North Area, Shallow	M-42-(2)
Kern Front	Kern	Main Area	M-41
Round Mountain	Kern	Main Area, Vedder	M-39
Mount Poso	Kern	Dominion Area	M-34
Dominion	Kern	Vedder	M-30-(1)
Coalinga	Kern	West Area, Temblor	M-29
Edison	Kern	Wicker, Freeman-Jewett, Walker	M-29-(3)
Edison	Kern	Race Hill Track Area	M-21-(3)
Tejon-Grapevine	Kern	Western Area, Transition-Santa Margarita	M-19
Fruitvale	Kern	Main Area, Chanac & Kernco	M-8-(2)

TABLE 1-3 (cont'd)

LIST OF RESERVOIRS AMENABLE TO UNDERGROUND MINING FOR ACCESS TECHNOLOGY

CALIFORNIA - SAN JOAQUIN VALLEY

FIELD NAME	COUNTY	RESERVOIR NAME	RANK
Inglewood	Los Angeles	Vickers	M-161
Placerita	Los Angeles	Shepard & Kraft	M-126-(1)
Wilmington	Los Angeles	East Area, F.B.- VI Ranger	M-117
Wilmington	Los Angeles	East Area, F.B.- 90-S Ranger	M-115
Wilmington	Los Angeles	Harbor Area, F.B. IV Tar	M-68-(1)

CALIFORNIA - SOUTHERN

FIELD NAME	COUNTY	RESERVOIR NAME	RANK
Los Angeles City	Los Angeles	Miocene	M-64-(2)
Wilmington	Los Angeles	Harbor Area, F.B. V-Tar	M-63
Huntington Beach	Orange	North Area, Bolsa	M-61-(1)
Wilmington	Los Angeles	Harbor Area, F.B. IV Ranger	M-55-(1)
Wilmington	Los Angeles	Harbor Area, F.B. V Ranger	M-54
Wilmington	Los Angeles	Terminal Area, F.B. III Ranger	M-51-(1)
Wilmington	Los Angeles	East Area, F.B. VII Ranger	M-42
Whittier	Los Angeles	Central Area, 1st, 2nd, 3rd and 4th	M-42-(1)
Salt Lake	Los Angeles	Main Area, A thru F Zones	M-39-(2)
Wilmington	Los Angeles	Harbor Area, F.B. VI Ranger	M-36-(1)
Wilmington	Los Angeles	East Area, F.B. VI Upper Term	M-23

ARKANSAS

FIELD NAME	COUNTY	RESERVOIR NAME	RANK
Irma	Nevada	Old Nacatoch	M-36
Troy	Nevada	Old Nacatoch	M-28-(1)
El Dorado	Union	East Area, Nacatoch	M-18-(2)
Smackover	Union	Old Area, Tokio	M-15-(1)
Lick Creek	Bradley/Union	Meakin	M-11
Champognolle	Union	Graves	M-11-(3)

TABLE 1-3 (cont'd)

LIST OF RESERVOIRS AMENABLE TO UNDERGROUND MINING FOR ACCESS TECHNOLOGY

TEXAS

FIELD NAME	COUNTY	RESERVOIR NAME	RANK
Sour Lake	Hardin-RRCD#3	Oligocene	M-60-(2)
Slocum	Anderson-RRCD#6	Currizo	M-52
Toborg	Pecos/Crockett RRCD#8	Toborg Sand	M-50-(1)
West Columbia	Brazoria-RRCD#3	Oligocene	M-50-(2)
Little Tom	Zavala-RRCD#1	San Miguel	M-41-(1)
Taylor-Ina	RRCD#1	Navarro	M-41-(1)
Moores Orchard	Fort Bend RRCD#3	Miocene	M-40-(3)
Escabas	Zapata-RRCD#4	Jackson	M-37-(1)
Casa Blanca	Duval-RRCD#4	Cole Sand	M-36-(1)
Cedro Hill	Duval-RRCD#4	Cole Sand	M-32
Eagle Hill	Duval-RRCD#4	Cole Sand	M-31-(2)
Lundell	Duval-RRCD#4	Jackson	M-28
Las Animas-Lefeure	Jim Hogg-RRCD#4	Jackson	M-25
Olson	Crockett-RRCD#4	Crayburg-San Andres	M-18-(2)
Baston	Hardin-RRCD#3	Old, Oligocene	M-11-(2)

WYOMING

FIELD NAME	COUNTY	RESERVOIR NAME	RANK
LaBarge	Lincoln/Sublette	Almy	M-49-(1)
Frannie	Park	Madison	M-42-(1)
Dallas Dome	Fremont.	Tensleep	M-39-(2)
Hamilton Dome	Hot Springs	Tensleep	M-31
Tisdale	Johnson	East Area, Tensleep	M-19-(1)

LOUISIANA

FIELD NAME	COUNTY	RESERVOIR NAME	RANK
Starks	Cakasieu	Pliocene-Upper Miocene	M-40-(1)
Caddo-Pine Island	Caddo	Nacatoch	M-39-(1)
Welsh	Jefferson Davis	Pliocene	M-34-(1)
Nebo-Hemphill	LaSalle	Cockfield	M-30-(1)
Lake Pelto	Terebonne	Miocene	M-29-(1)

From an initial list of 70 reservoirs in Wyoming, only 5 passed Screen 4 because the reservoirs were deep (3000 ft), and had less than 500 proven acres. Rank numbers vary from 19 to 49.

Out of the 79 reservoirs listed in Table 1-3, nine were chosen for detailed study on the basis of rank and other favorable factors. The nine reservoirs under consideration are in the Northeast Area of the McKittrick Field (M-88), Main Area of the McKittrick Field (M-126), Kern River Field (M-110), South Belridge Field (M-81), Welport Area of the Cymric Field

(M-84), McKittrick Front Area of the Cymric Field (M-84), Mount Poso Field (M-63), Slocum Field (M-52), and the Placerita Field (M-119). Some reservoirs were eliminated from detailed study because of unfavorable factors, such as high seismicity, subsidence, or land use. For example, although the Wilmington Field in Los Angeles County has a large resource, it is in a zone of high magnitude earthquakes, has experienced subsidence up to 30 feet due to withdrawal of oil, and is overlain by expensive housing developments. The Inglewood Field in Los Angeles County was eliminated for the same reasons.

Each of these reservoirs was evaluated based on the detailed descriptions given in Section 1.4 to determine which reservoir appeared to have the most favorable characteristics for development. One reservoir was recommended for detailed analysis of the technical and economic feasibility of mining for access techniques. This reservoir is in the northeast area of the McKittrick Field.

The northeast area of the McKittrick Field is recommended as the best area for detailed study because of favorable characteristics in the reservoir, structure, and rocks below the reservoir zone. The northeast area of the McKittrick Field has an estimated 280 million barrels of oil remaining in place, covers an average area of 1450 acres, has an average depth to the producing zones of 650 ft, and has approximately 119,300 barrels per acre of oil resources. Relatively competent, hard Reef Ridge shale underlies the reservoir. The depth to this shale below the Amnicola zone is at least

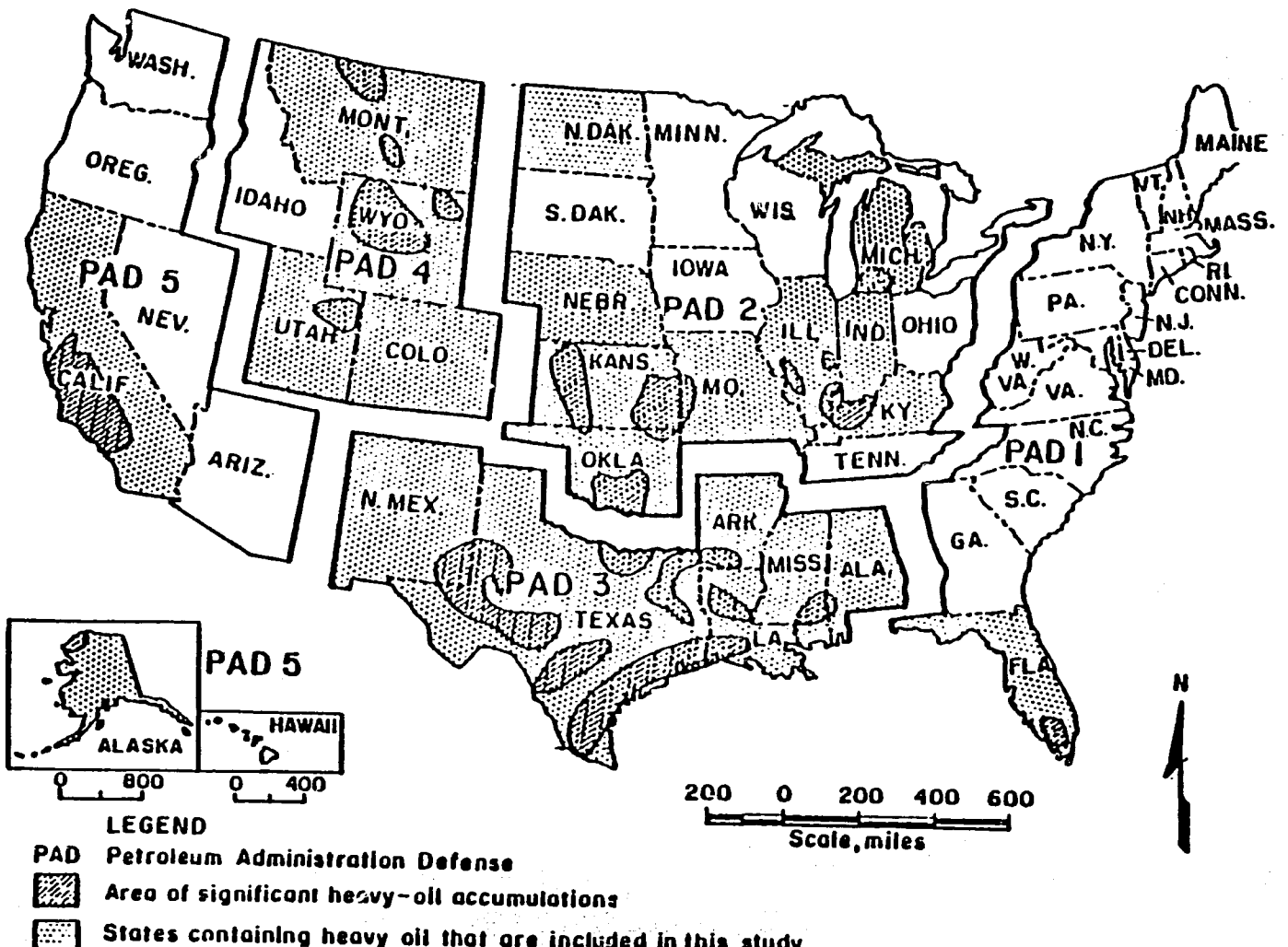
1000 ft. This shale is approximately 350 ft thick. No active faulting is reported within the northeast area of the McKittrick Field. Problems include potentially large groundwater inflows in the unconsolidated sediments above the reservoir, competition for surface area with existing petroleum production, and high seismic risk of the area.

The Slocum Field has rather large resources at shallow depth but was not selected for further detailed study because the reservoir is underlain by semi-consolidated sands and sandy-clays of the Wilcox Formation. Further research is required to determine the engineering properties of these rocks so that an estimate can be made of the support required to maintain stable underground openings in these strata. The Slocum Field has estimated remaining resources of 106 million barrels, covers a proven area of 2500 acres, averages 530 ft deep and has a net pay thickness of 25 ft. Potential problems to the successful development in the reservoir include competition for surface area with existing petroleum recovery activities and soft ground.

The Placerita Field has large resources at moderate depths but has weak, unconsolidated pebble conglomerate and coarse sandstone of the lower Pico Formation underlying the reservoir. Slightly greater depth and soft ground below the reservoir are the reasons that the Placerita field was not recommended for further detailed study. The Placerita field has estimated proven resources of 265 million barrels, covers a proven area of 700 acreas, averages 1530 ft deep, and has a net pay thickness of 300 to 450 ft. Potential problems to successful development in this reservoir include high seismic risk of the area, active faulting which has displaced recent terrace gravels in the field area, close proximity to the San Gabriel Fault Zone, potential conflicts with future residential land use, and unconsolidated soft ground.

1.2.4.5. Result of Detailed Study

The Northeast Area of the McKittrick Field is recommended as the best candidate for mining for access technology for heavy oil recovery. Further detailed analysis is recommended to determine the economic and technical feasibility for the reservoir within the Tulare Formation in the northeast area of the McKittrick field as a specific case example.



- States Containing Heavy Crude Oil Included in This Study.

Figure 1-2
(Source: 33)

A0882074

294

OIL AND GAS FIELDS IN ALABAMA

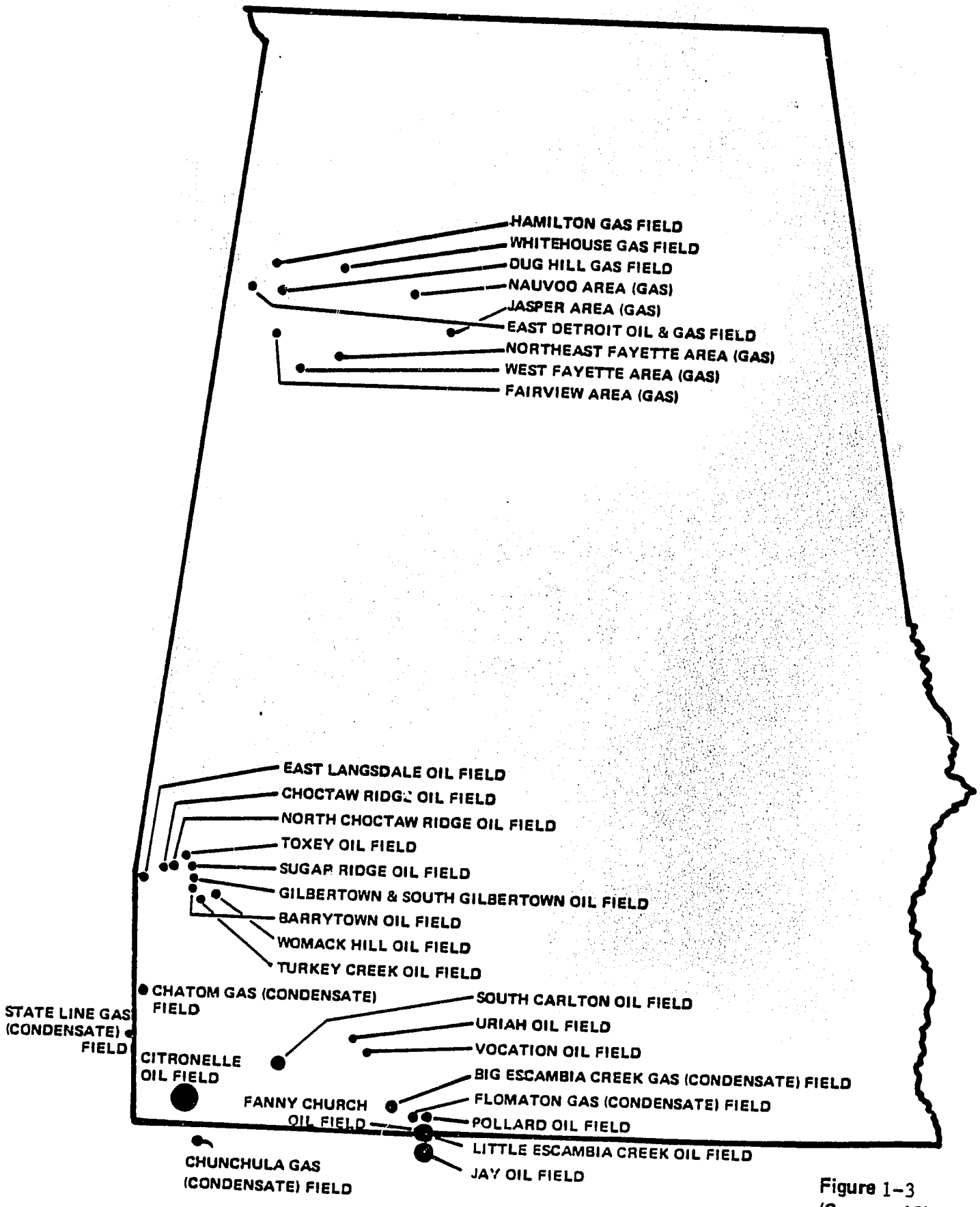
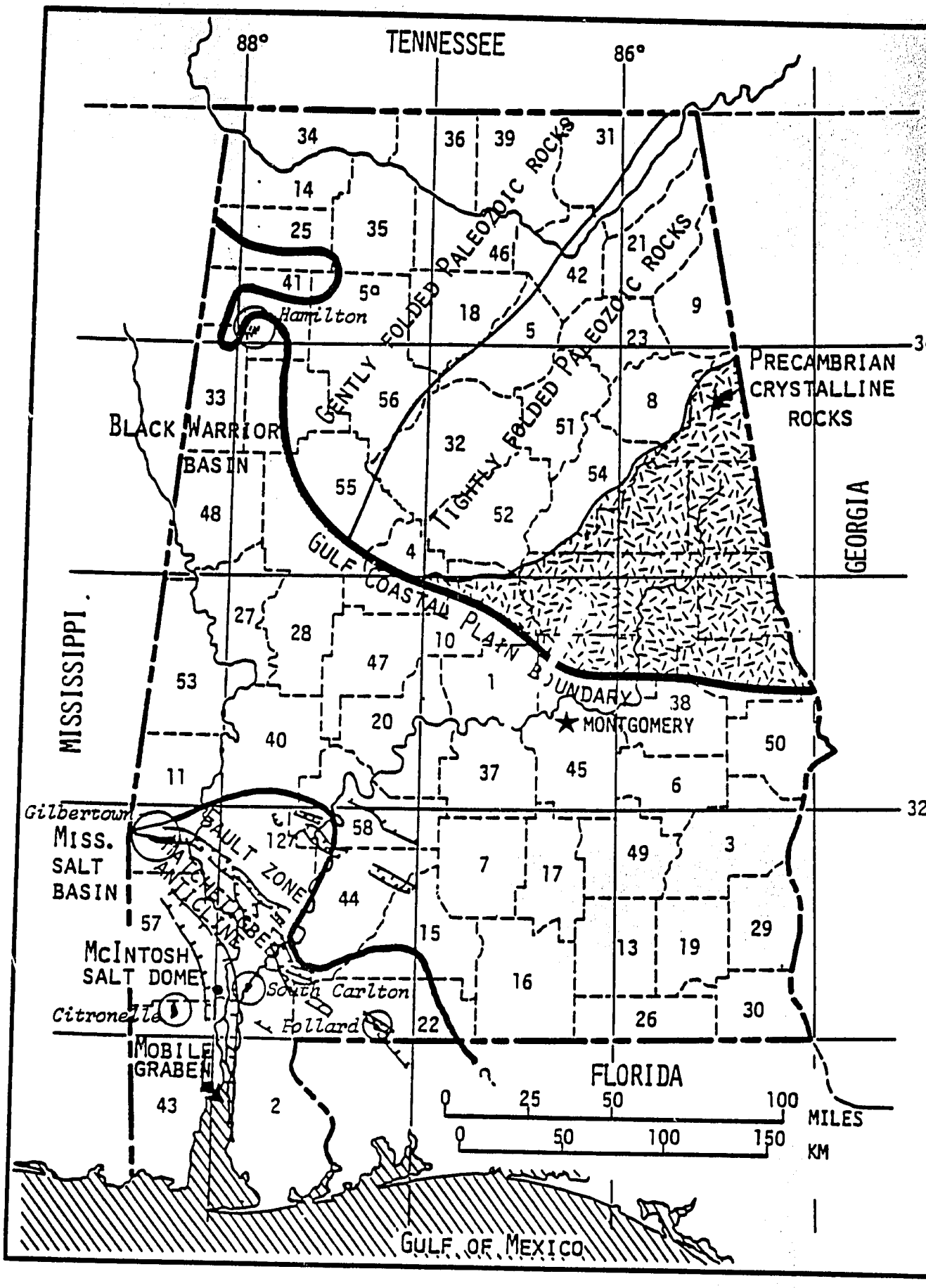


Figure 1-3
(Source: 18)

295.

1 Autauga
2 Baldwin
3 Barbour
4 Bibb
5 Blount
6 Bullock
7 Butler
8 Calhoun
9 Cherokee
10 Chilton
11 Choctaw
12 Clarke
13 Coffee
14 Colbert
15 Conecuh
16 Covington
17 Crenshaw
18 Cullman
19 Dale
20 Dallas
21 DeKalb
22 Escambia
23 Etowah
24 Fayette
25 Franklin
26 Geneva
27 Greene
28 Hale
29 Henry
30 Houston
31 Jackson
32 Jefferson
33 Lamar
34 Lauderdale
35 Lawrence
36 Limestone
37 Lowndes
38 Macon
39 Madison
40 Marengo
41 Marion
42 Marshall
43 Mobile
44 Monroe
45 Montgomery
46 Morgan
47 Perry
48 Pickens
49 Pike
50 Russell
51 St. Clair
52 Shelby
53 Sumter
54 Talladega
55 Tuscaloosa
56 Walker
57 Washington
58 Wilcox
59 Winston



Alabama. Index, tectonic, and oil and gas field map. County Key on left.

Figure 1-4
(Source: 21)

296

Adams	65	Smith
Alcorn	66	Stone
Amite	67	Sunflower
Attala	68	Tallahatchie
Benton	69	Tate
Bolivar	70	Tippah
Calhoun	71	Tishomingo
Carroll	72	Tunica
Chicasaw	73	Union
Choctaw	74	Walthall
Claiborne	75	Warren
Clarke	76	Washington
Clay	77	Wayne
Coahoma	78	Webster
Copiah	79	Wilkinson
Covington	80	Winston
DeSoto	81	Yalobusha
Forrest	82	Yazoo
Franklin		
George		
Greene		
Grenada		
Hancock		
Harrison		
Hinds		
Holmes		
Humphreys		
Issaquena		
Itawamba		
Jackson		
Jasper		
Jefferson		
Jefferson Davis		
Jones		
Kemper		
Lafayette		
Lamar		
Lauderdale		
Lawrence		
Leake		
Lee		
Leflore		
Lincoln		
Lowndes		
Madison		
Marion		
Marshall		
Monroe		
Montgomery		
Neshoba		
Newton		
Noxubee		
Oktibbeha		
Panola		
Pearl River		
Perry		
Pike		
Pontotoc		
Prentiss		
Quitman		
Rankin		
Scott		
Sharkey		
Simpson		

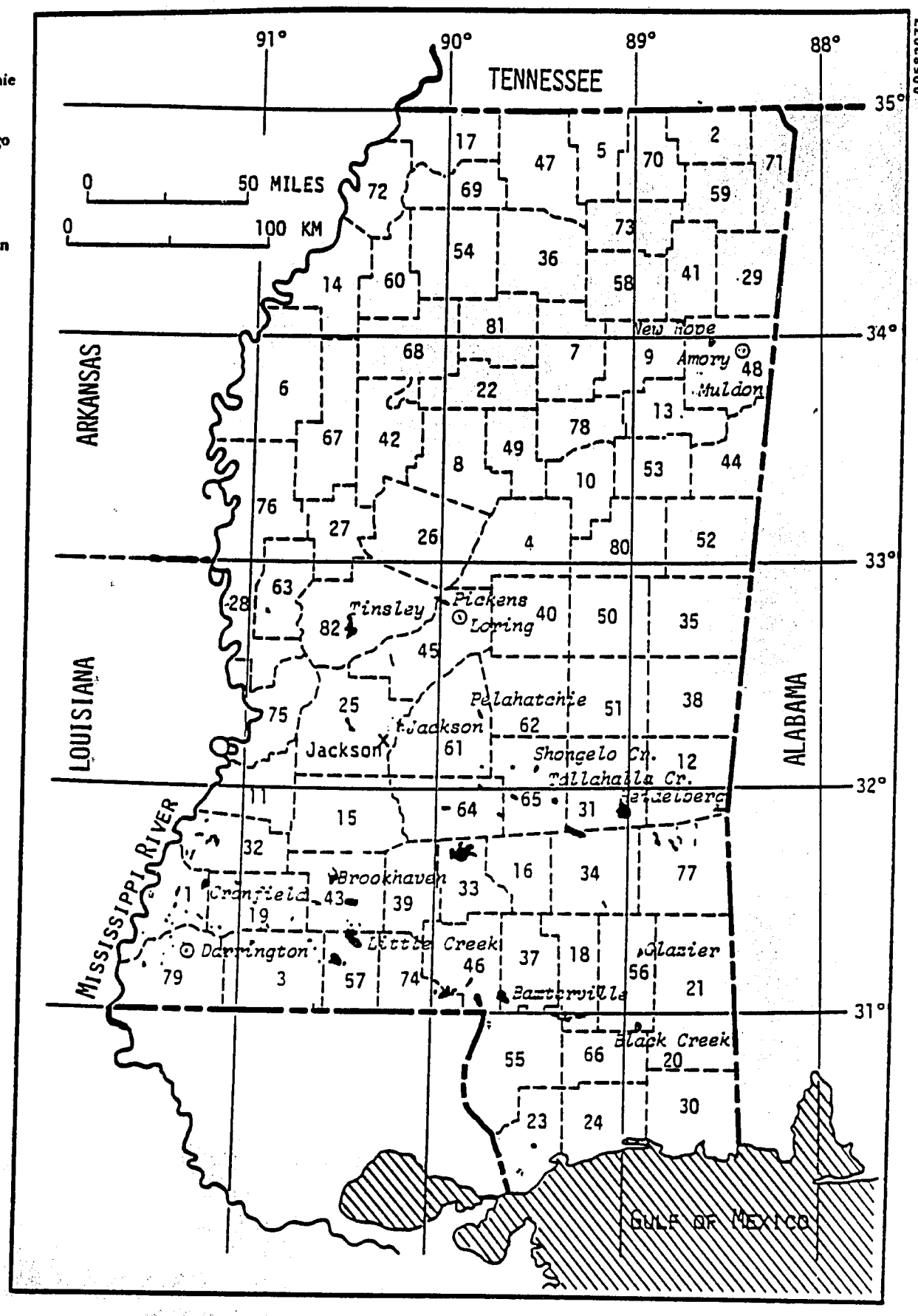
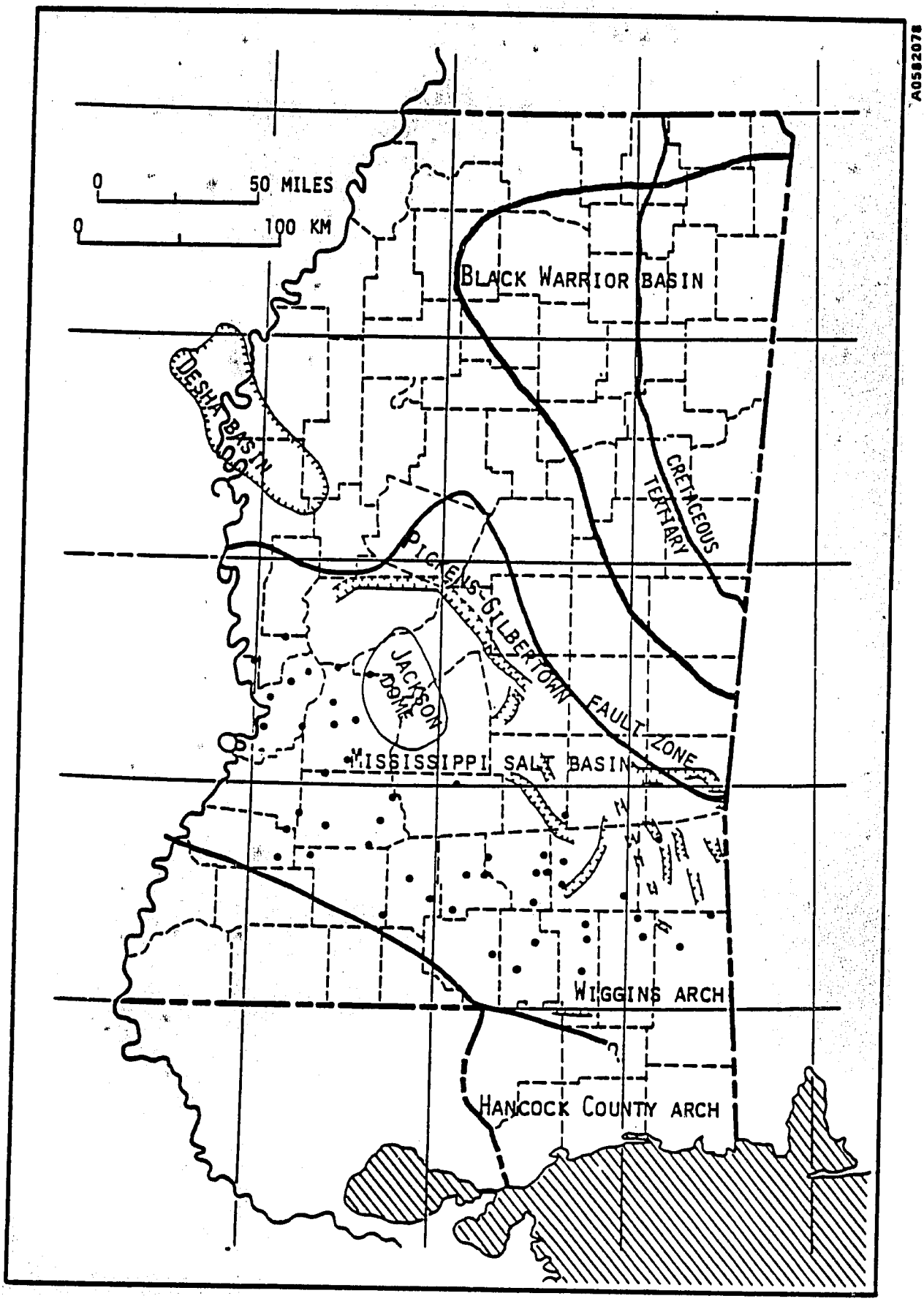


FIGURE 22.1 Mississippi. Index map with oil and gas fields. County Key on left.

Figure 1-5
(Source: 21)

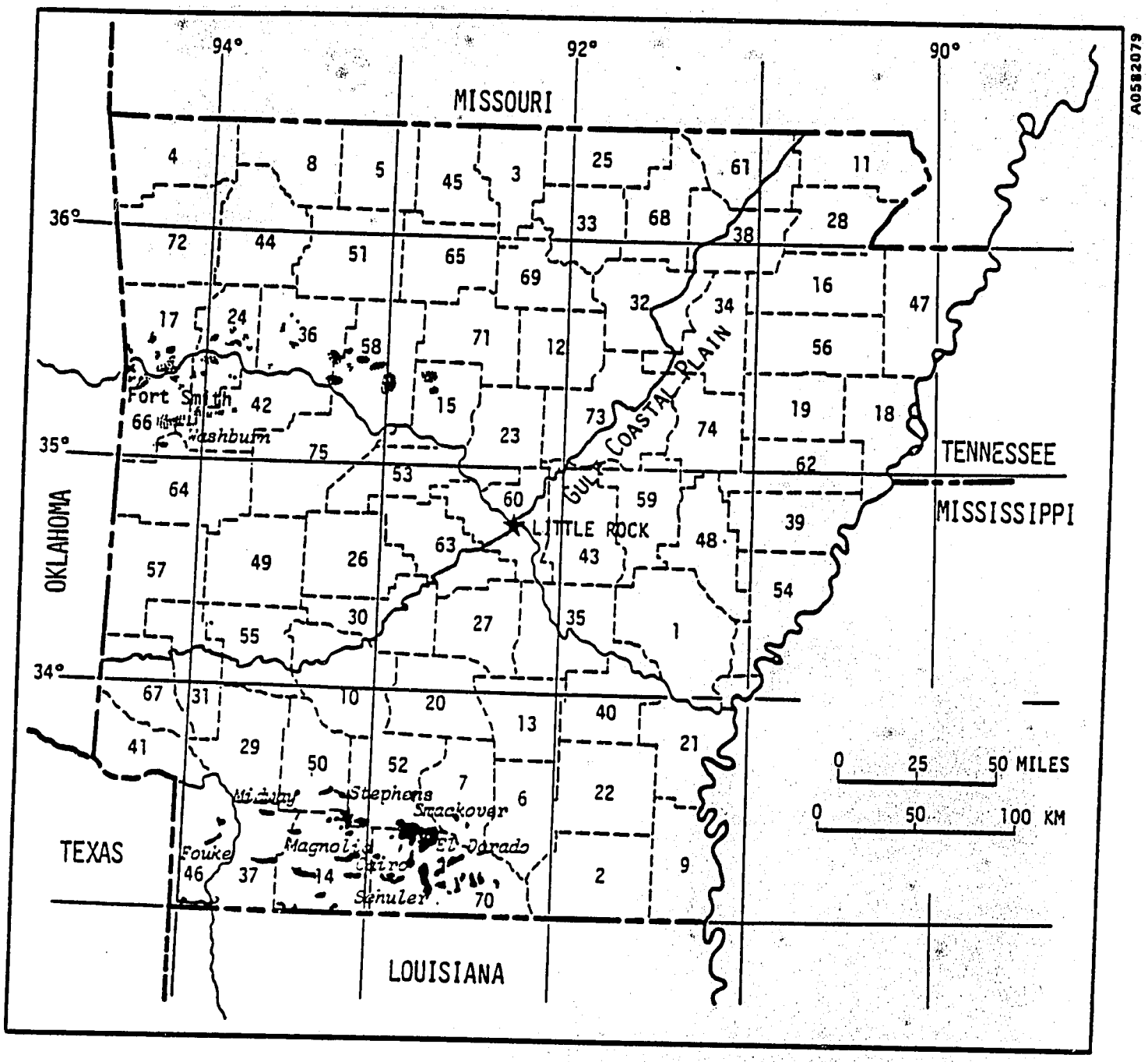
297



Mississippi. Tectonic map. Solid circles are known piercement salt domes.

Figure 1-6
(Source: 21)

298

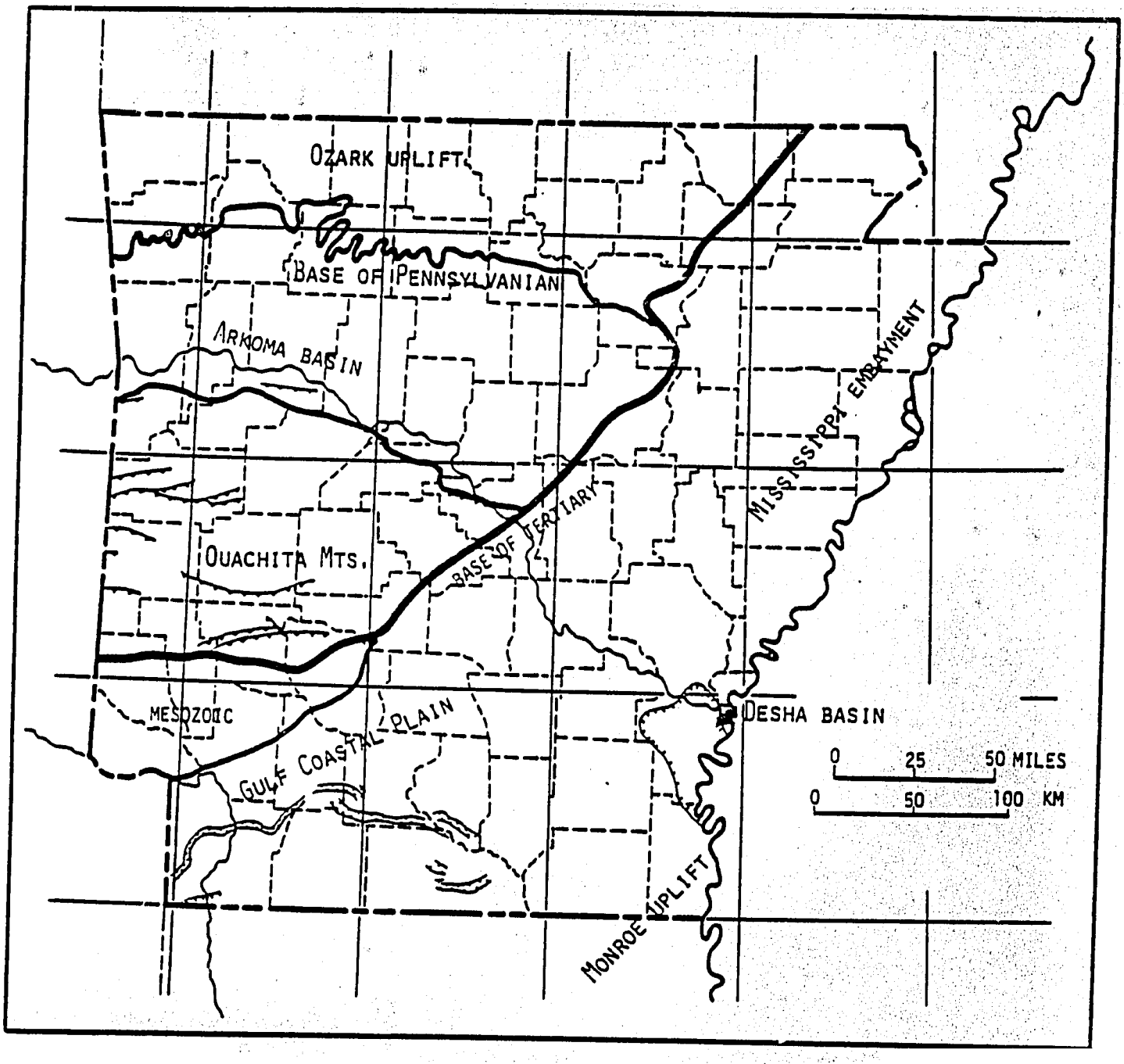


Arkansas. Index map, with oil and gas fields. County Key:

1	Arkansas	12	Cleburne	23	Faulkner	34	Jackson	45	Marion	56	Poinsett	66	Sebastian
2	Ashley	13	Cleveland	24	Franklin	35	Jefferson	46	Miller	57	Polk	67	Sevier
3	Baxter	14	Columbia	25	Fulton	36	Johnson	47	Mississippi	58	Pope	68	Sharp
4	Benton	15	Conway	26	Garland	37	Lafayette	48	Monroe	59	Prairie	69	Stone
5	Boone	16	Craighead	27	Grant	38	Lawrence	49	Montgomery	60	Pulaski	70	Union
6	Bradley	17	Crawford	28	Greene	39	Lee	50	Nevada	61	Randolph	71	Van Buren
7	Calhoun	18	Crittenden	29	Hempstead	40	Lincoln	51	Newton	62	St. Francis	72	Washington
8	Carroll	19	Cross	30	Hot Spring	41	Little River	52	Ouachita	63	Saline	73	White
9	Chicot	20	Dallas	31	Howard	42	Logan	53	Perry	64	Scott	74	Woodruff
10	Clark	21	Desha	32	Independence	43	Lonoke	54	Phillips	65	Searcy	75	Yell
11	Clay	22	Drew	33	Izard	44	Madison	55	Pike				

Figure 1-7
(Source: 21)

299



Arkansas. Major tectonic features. Shows principal fault zones only.

Figure 1–8
(Source 21)

300

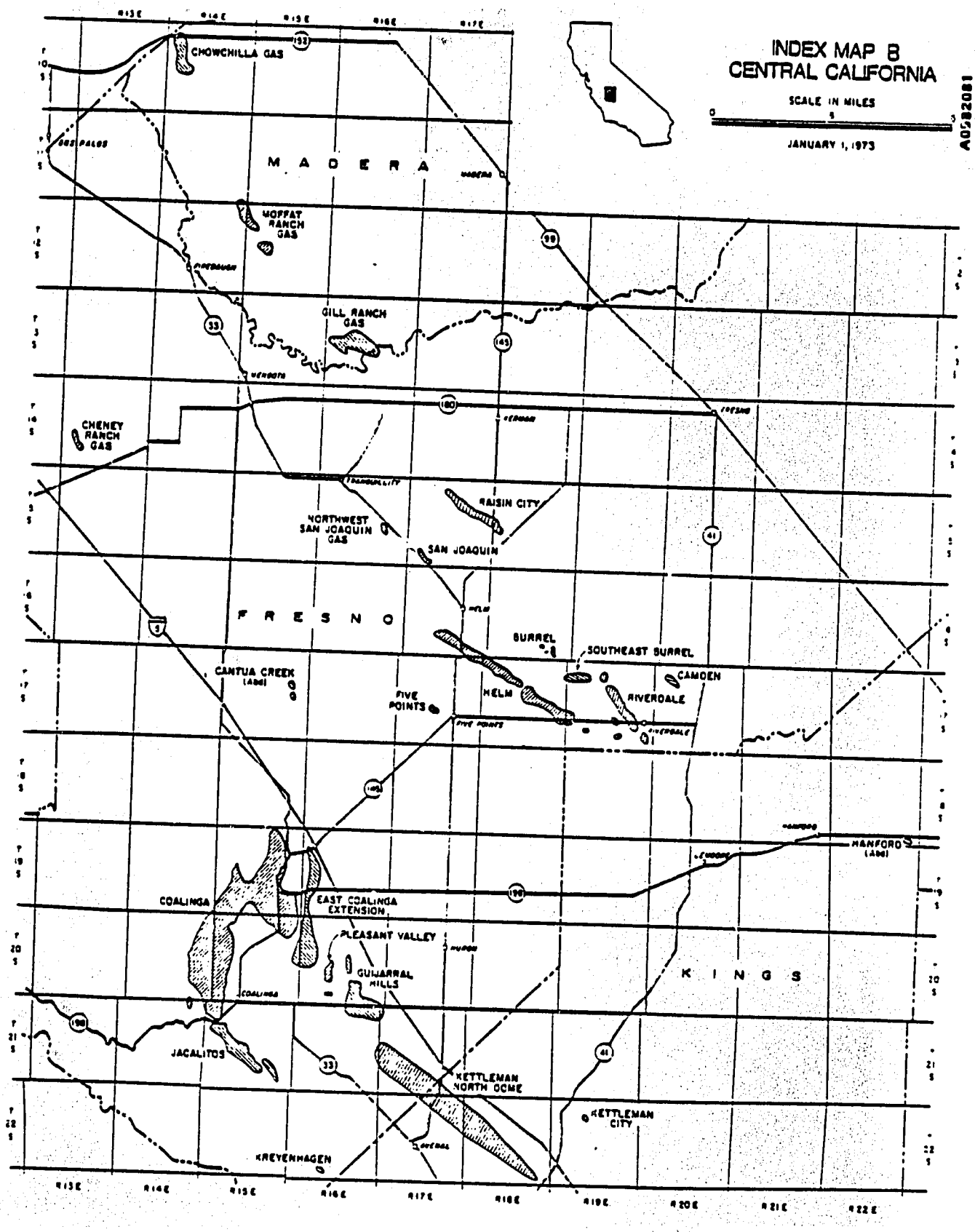


Figure 1-9
(Source: 62)

301

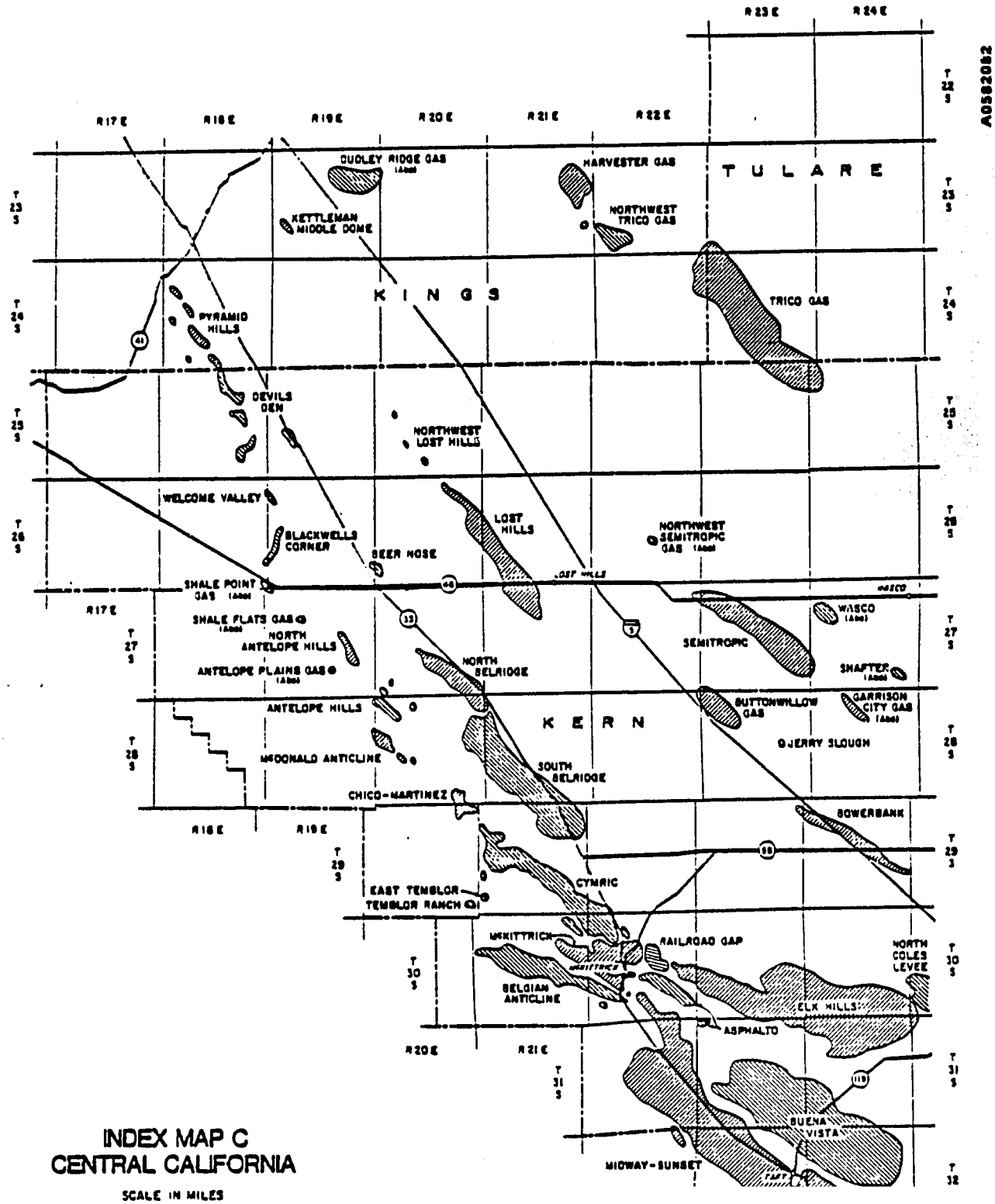


Figure 1-10
(Source: 62)

302

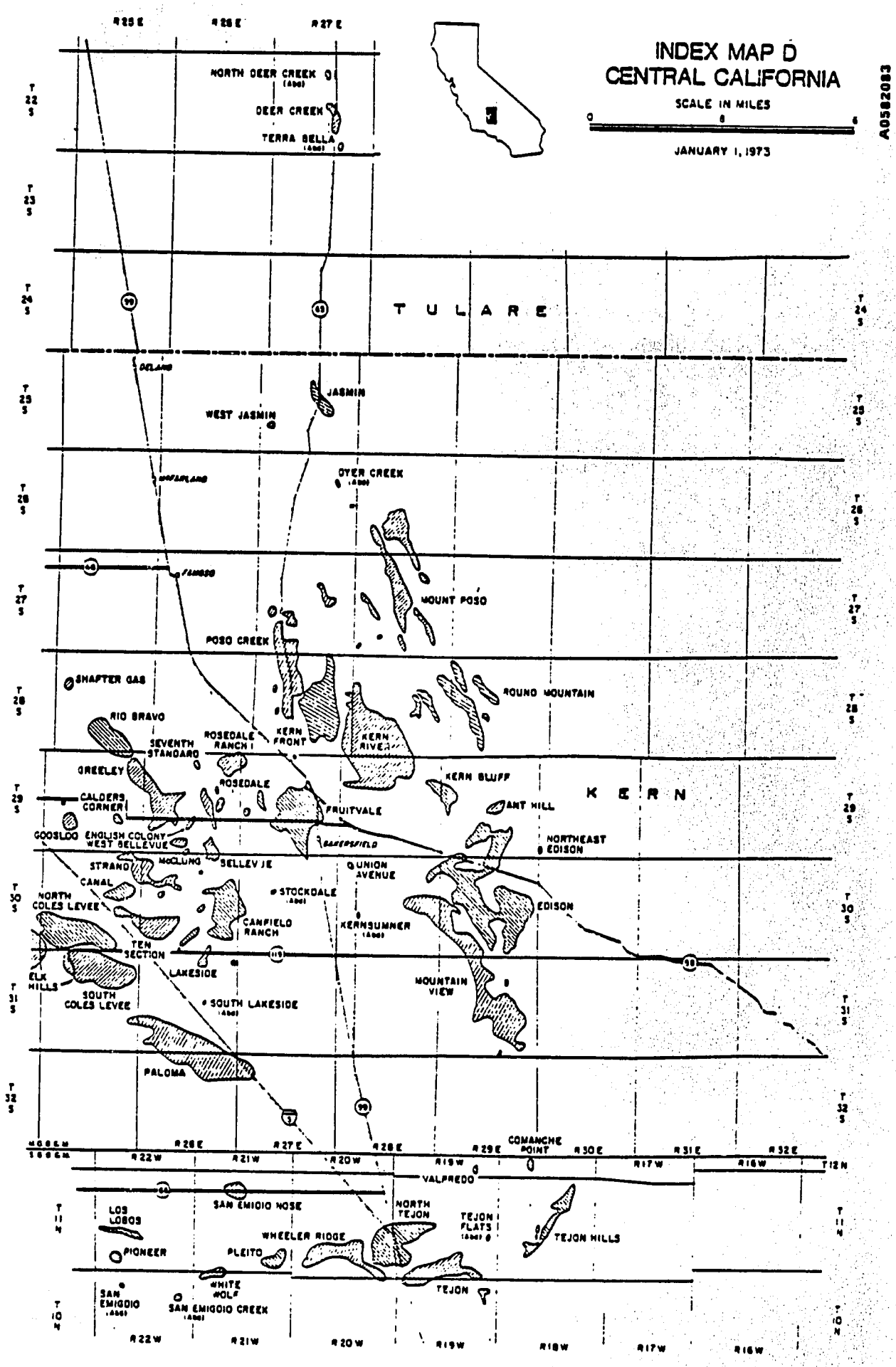
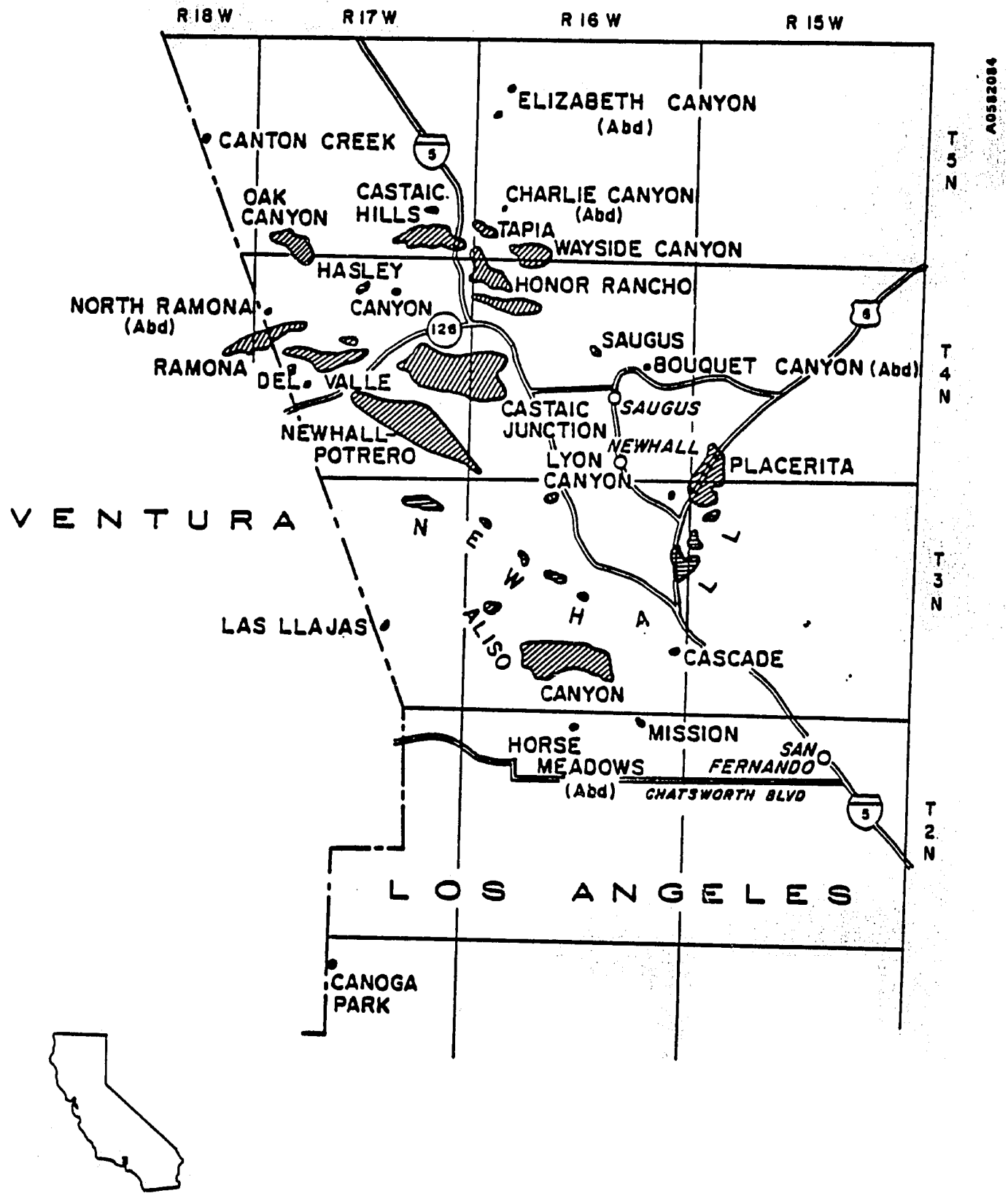


Figure 1-11
(Source: 62)

303



MAP A
SOUTH CALIFORNIA
SCALE IN MILES
0 4 8 12
JANUARY 1, 1974

Figure 1-12
(Source: 63)

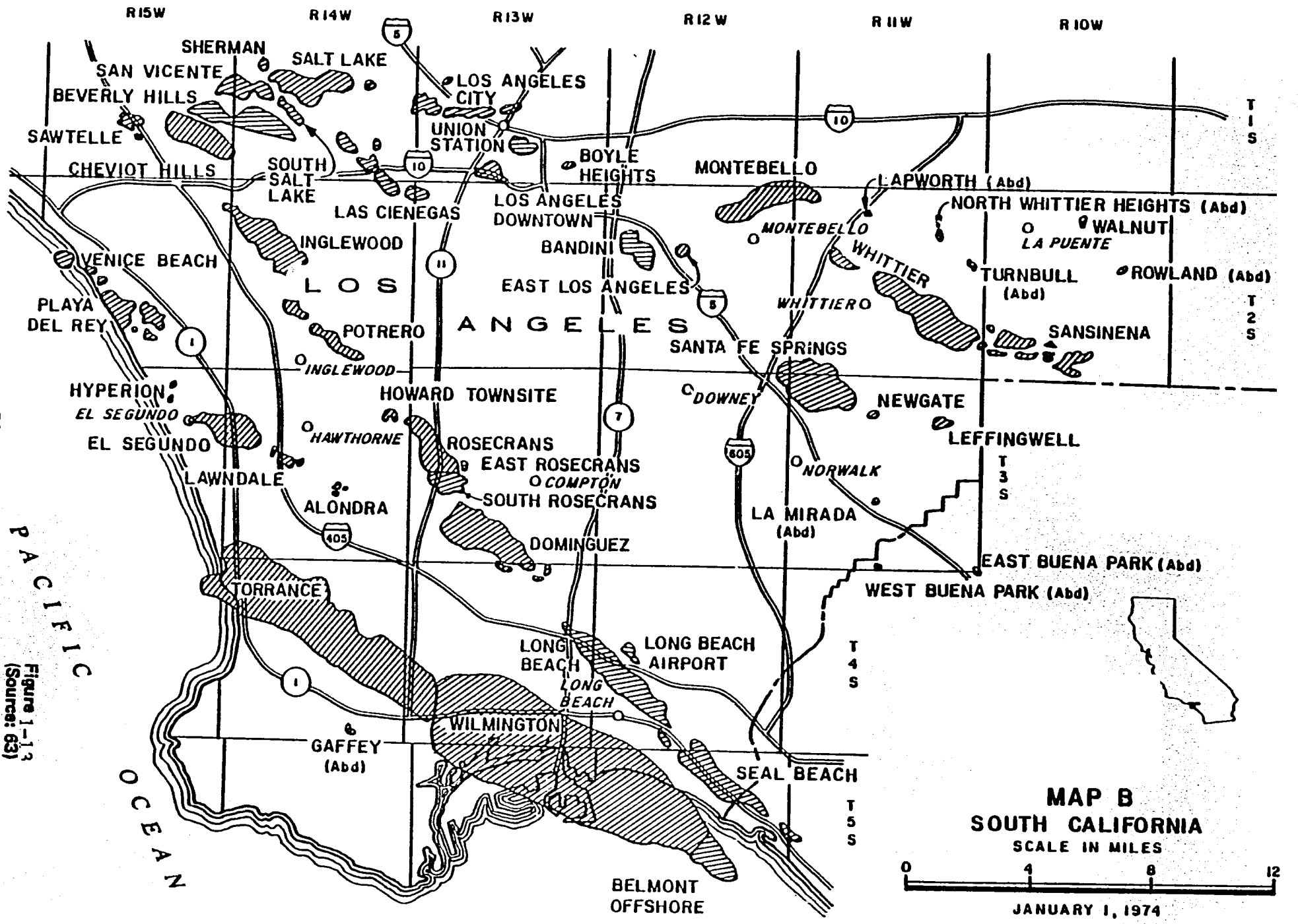


Figure 1-13
(Source: 63)

305

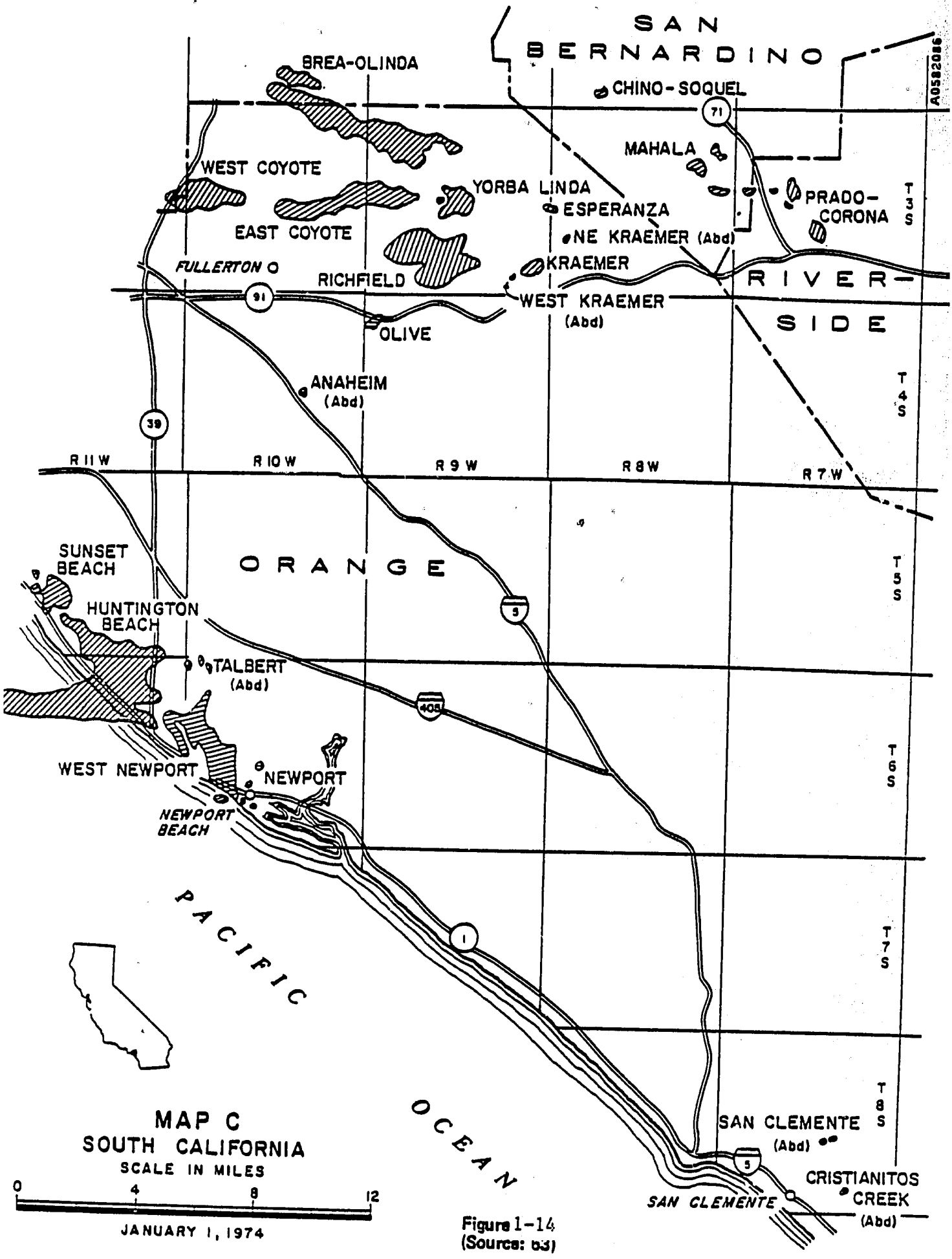


Figure 1-14
(Source: 63)

306

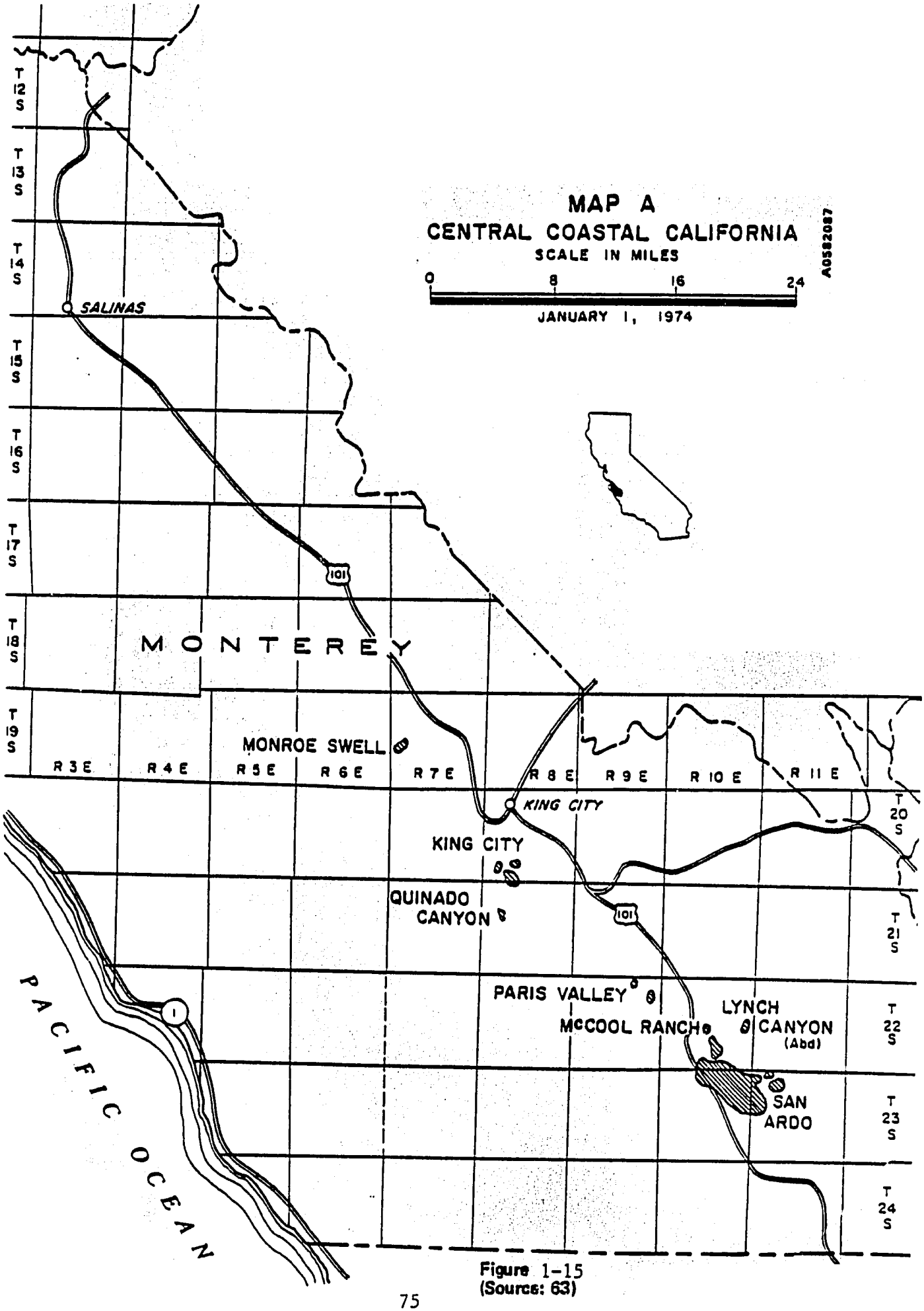


Figure 1-15
(Source: 63)

307

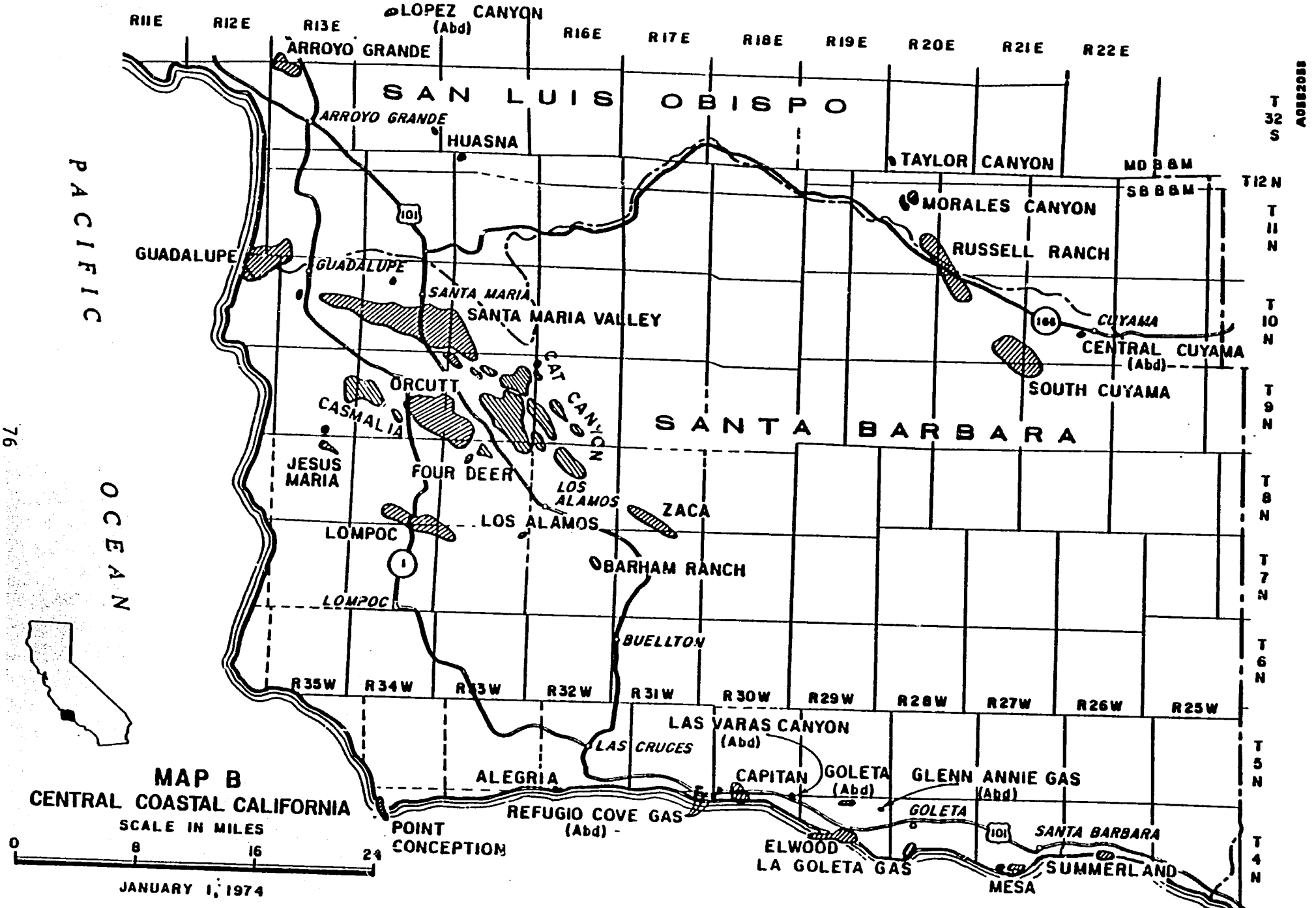
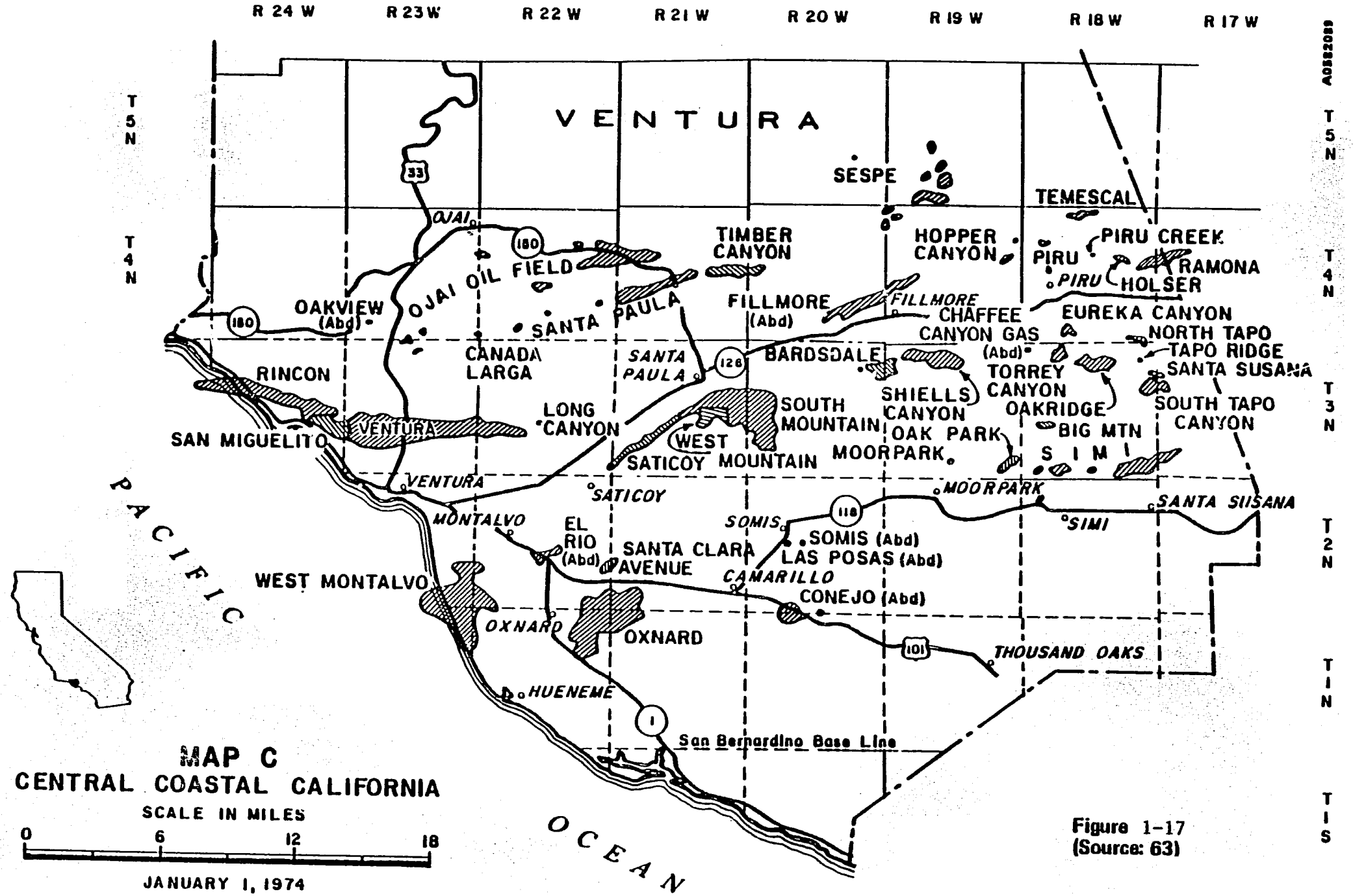


Figure1-16
(Source: 63)

308



MAP C
CENTRAL COASTAL CALIFORNIA

Figure 1-17
(Source: 63)

309

EPOCH	SACRAMENTO VALLEY		SAN JOAQUIN VALLEY			
			WEST SIDE-CENTRAL		EAST SIDE	
Pleistocene	Red Bluff		Tulare	■	Kern River	■
Upper Pliocene	Tehama	■	San Joaquin	■	Kern River	■
Lower Pliocene	Tehama-Mehrten	■	Etchegoin	■	Etchegoin	■
Mio-Pliocene	Not recognized		Reef Ridge	■	Chanac	■
Upper Miocene	Mehrten		Antelope-McLure Stevens McDonald	■	Santa Margarita Fruitvale	■
Middle Miocene	Valley Springs		McDonald Devilwater Gould Button Beds	■	Round Mountain Olcese	■
Lower Miocene			Media Carneros Santos-Vaqueros Phacoides Salt Creek	■	Olcese Freeman-Jewitt Pyramid Hill Vedder Walker	■
Oligocene	Absent		Tumey-Wagonwheel Oceanic	■	Tumey Walker	■
Eocene	Markley Nortonville Domengine Ione Capay Meganos	■	Kreyenhagen Point of Rocks Canoas Domengine-Avenal	■	Walker-Famoso	■
Paleocene	Meganos-Martinez	■	Martinez	■	Absent	
Upper Cretaceous	Chico (Starkey-Winters- (Sacramento-Forbes (Guinda-Funks- (Sites-Yolo-Venado (Antelope-Salt Cr.	■	Moreno Panoche	■ ■	Absent	
Lower Cretaceous	Horsetown Paskenta		Part of Panoche and other units		Absent	
Jurassic and older	Knoxville (west side)		Basement complex (Franciscan)		Schist Granite	■

■ Denotes oil production ■ Denotes dry gas production

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Stratigraphic columns, Great Valley of California, including both San Joaquin and Sacramento basins. *Courtesy California Division of Oil and Gas (1960, p. 8).*

Figure 1-18
(Source: 21)

310

EPOCH	WESTERN LOS ANGELES BASIN Southwest of Newport-Inglewood Fault Zone		EASTERN LOS ANGELES BASIN Northeast of Newport-Inglewood Fault Zone	
UPPER PLEISTOCENE	Terrace deposits Palos Verdes		Terrace deposits Palos Verdes	
LOWER PLEISTOCENE	San Pedro-Timms Point-Lomita		La Habra	■
UPPER PLIOCENE	Pico	■	La Habra Pico	■
LOWER PLIOCENE	Repetto	■	Repetto	■
UPPER MIOCENE	Puente or Monterey	■	Puente or Monterey	■
MIDDLE MIOCENE	Monterey		Monterey Topanga	■
LOWER MIOCENE	Absent		Vaqueros	
OLIGOCENE	Absent		Sespe	
EOCENE	Absent		Santiago	
PALEOCENE	Absent		"Martinez"-Silverado	
UPPER CRETACEOUS	Absent		"Chico" (Williams-Ladd-Trabuco)	
JURASSIC (?) and older	Catalina schist (Franciscan ?)	■	Santa Monica Slate Plutonics	

■ Denotes Oil Production ▨ Denotes Dry Gas Production

A0582091

Los Angeles basin; reservoir rocks. *California Division of Oil and Gas (1961, Part 2, p. 501).*

EPOCH	CENTRAL VENTURA BASIN		EASTERN VENTURA BASIN Including Soledad and San Fernando Basins	
Upper Pleistocene	Terrace deposits and older alluvium		Terrace deposits	
Lower Pleistocene	Saugus San Pedro-Las Posas Santa Barbara	■	Saugus	
Upper Pliocene	Pico	■	Sunshine Ranch Pico	■
Lower Pliocene	Repetto	■	Repetto Towsley	■
Upper Miocene	Santa Margarita Monterey-Modelo	■	Modelo-Monterey Castaic-Mint Canyon	■
Middle Miocene	Monterey-Modelo Conejo-Topanga	■	Modelo-Mint Canyon Topanga-Tick Canyon	
Lower Miocene	Rincon Vaqueros	■	Topanga Vaqueros-Tick Canyon	
Oligocene	Sespe	■	Vasquez-Sespe	
Eocene	Sespe-Coldwater-Cozy Dell-Matilija-Llajas-Juncal-Santa Susana	■	Vasquez Llajas Santa Susana	■
Paleocene	"Martinez"	■	"Martinez"	
Upper Cretaceous	"Chico"	■	"Chico"	■
Jurassic (?) and older	Basement complex		Placerita series Granite	

■ Denotes Oil Production ▨ Denotes Dry Gas Production

California. Reservoir rocks, Ventura basin. *Courtesy California Division of Oil and Gas (1961, Part 2, p. 501).*

Figure 1-10
(Source: 21)

311x

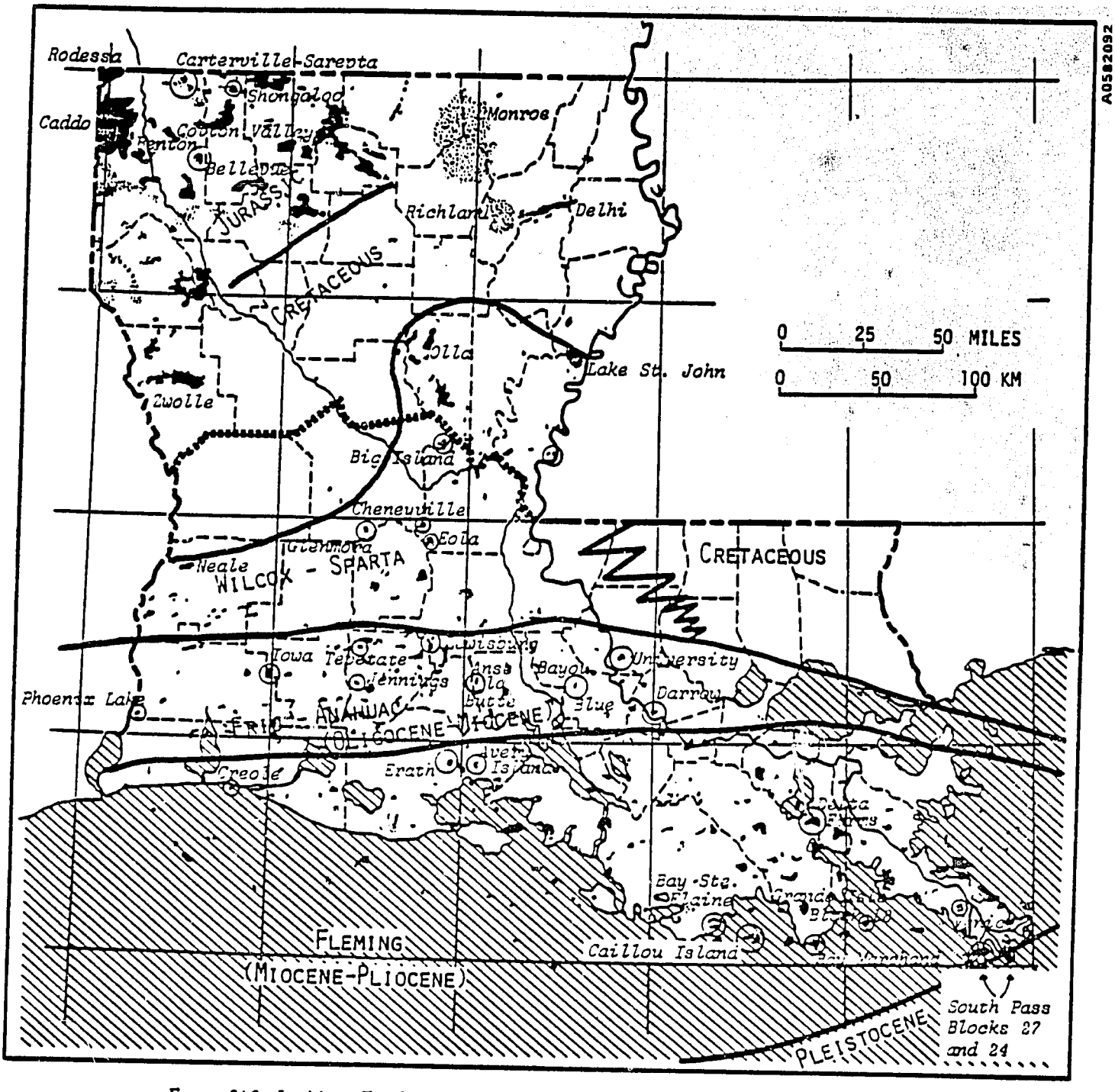
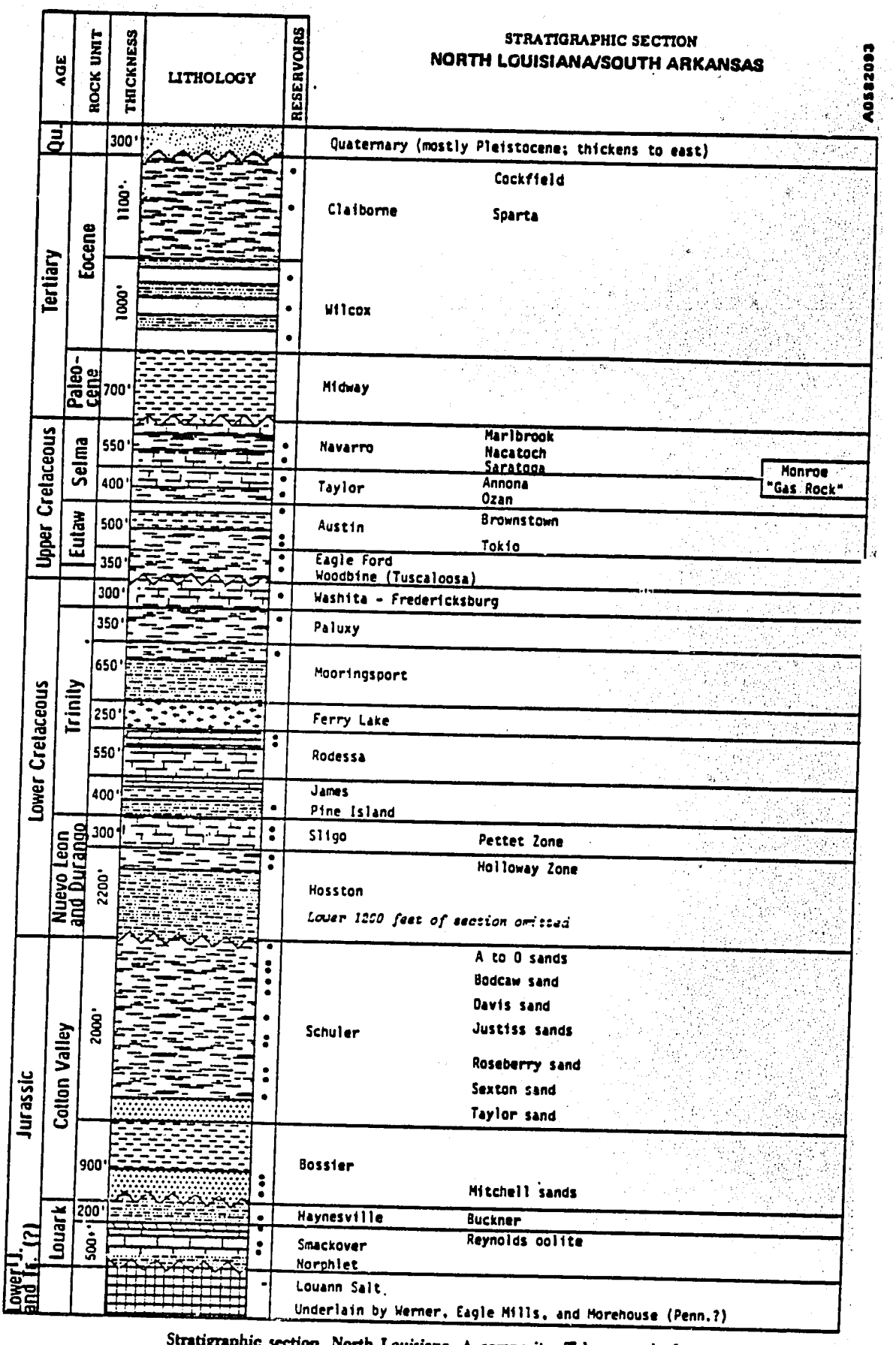


FIGURE 24.2 Louisiana. Trends and oil and gas fields. The heavy dashed line crossing the mid-section is the arbitrary division between North and South Louisiana (or Louisiana Gulf Coast). *Trend lines and names courtesy of James P. Spillers (letter dated 21 October, 1968).*

Figure 1-20 (Source: 21)

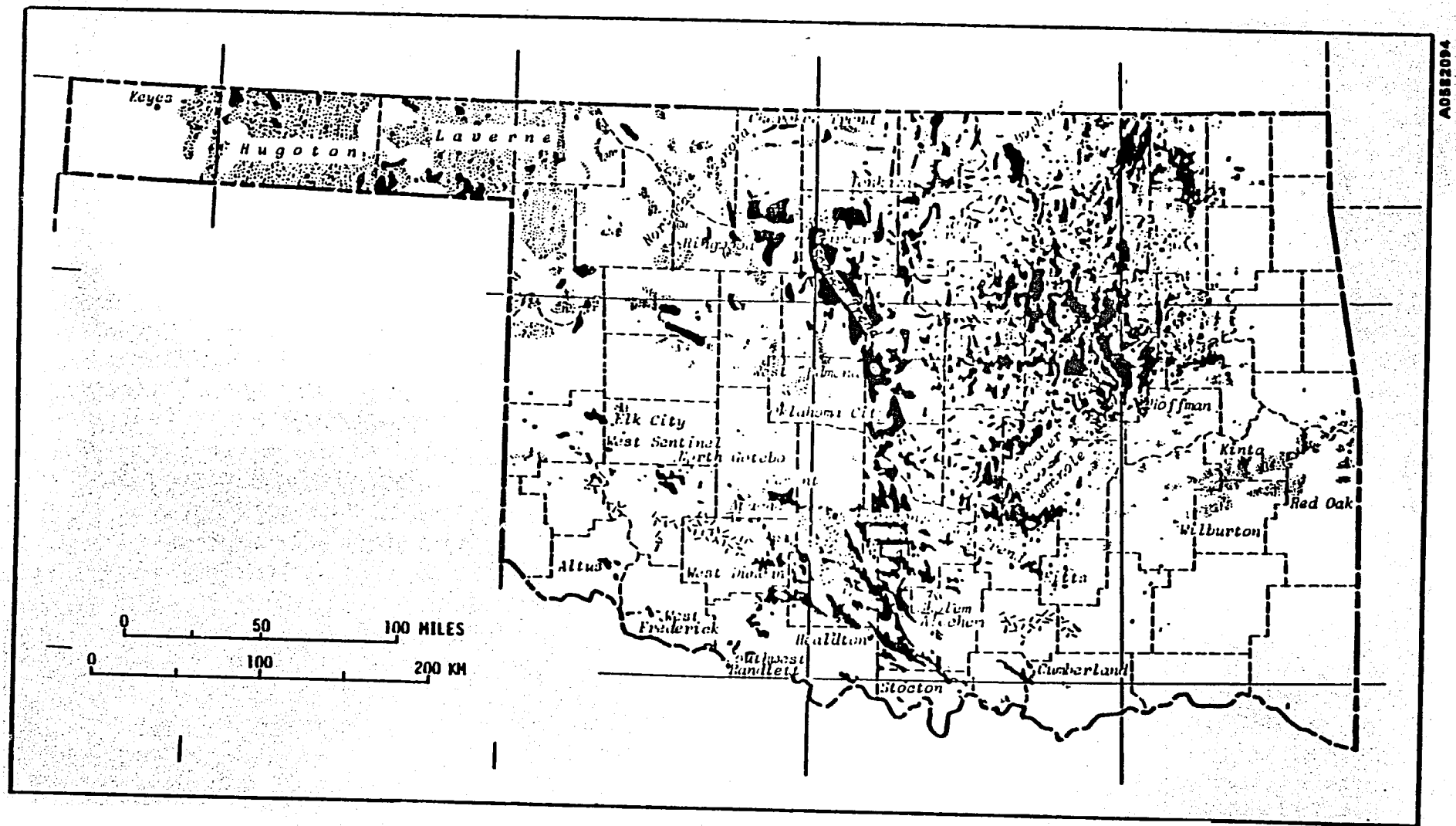
3/2



Stratigraphic section, North Louisiana. A composite. Taken mostly from *James L. Martin et al. (1954, Plates 3 and 13)*, and partly from *Lafayette and New Orleans Geological Societies (1968, Figure 2, p. 380)*.

Figure 1-21 (Source: 21)

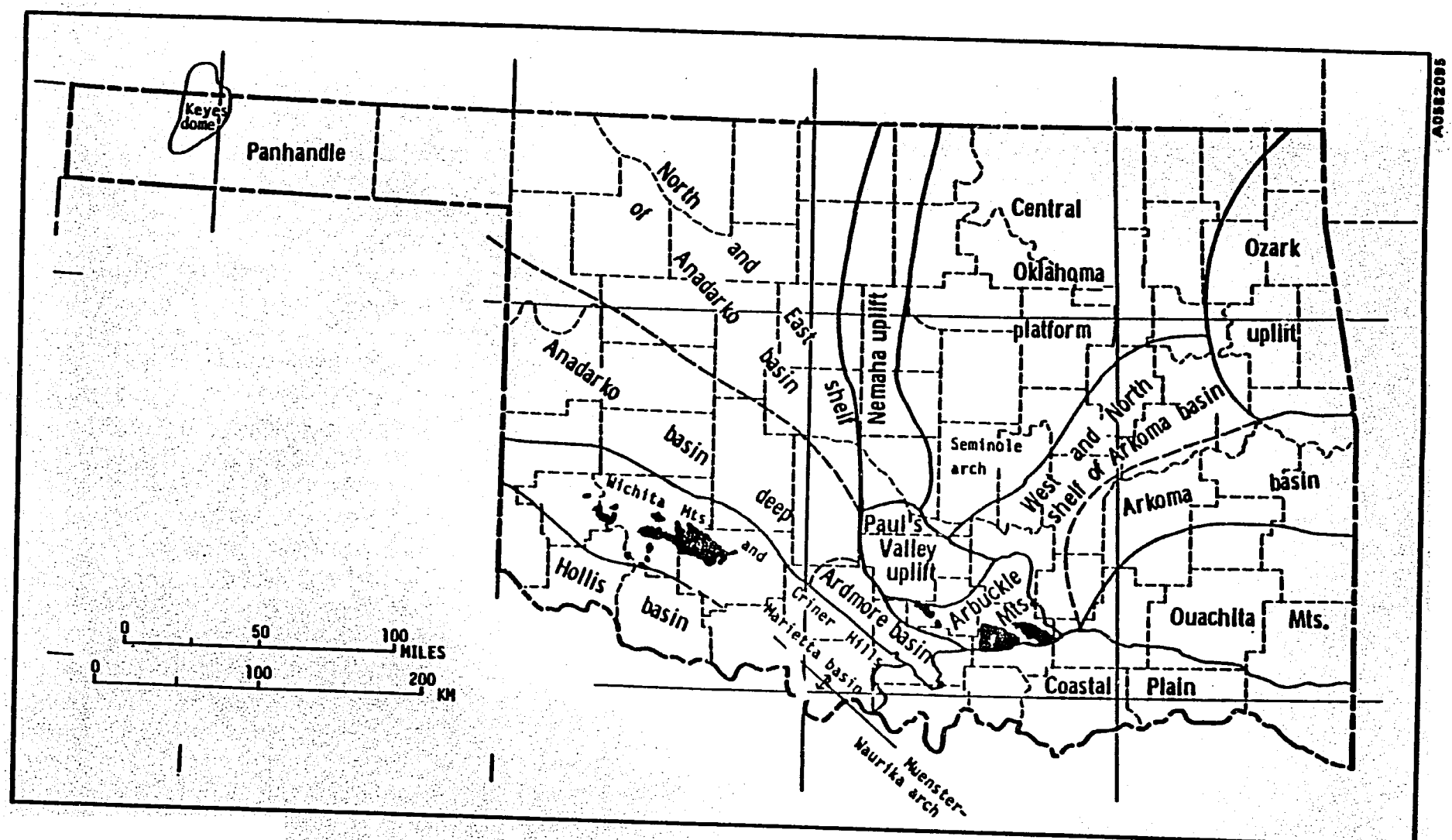
313



Oklahoma. Oil and gas fields, also showing larger basement rock outcrops. Names of fields discussed in text that are in congested areas not shown. For these fields see location within county in text, and position of county in Figure 18.1.

Figure 1-22
(Source: 21)

314



Oklahoma. Tectonic map. The larger basement rock areas are shown in solid black.
After F. L. Mackey and Jack P. F. Bowles, Jr. (1963) and George V. Cohee et al. (1962).

Figure 1-23 (Source: 21)

3/5.

Generalized Stratigraphic Section

SYSTEM	SERIES*	GROUP	FORMATION OR RESERVOIR ROCK NAME (Asterisk designates rock unit producing oil or gas)
T.			Ogallala, Late Tertiary continental deposits in western Oklahoma
CRET.	Gulfian	Colorado	Occurs both in Cimarron Co. in panhandle and in southeast Oklahoma.
	Comanchean		Dakota Sandstone in Cimarron Co., Paluxy Sandstone in southeast; Bilbo sand*
J.			Cimarron Co.
TR.		Dockum	Panhandle only
PERMIAN	Ochoan		Outcropping red beds in western Oklahoma
	Guadalupean	Whitehorse El Reno	
	Leonardian		Local sands* in lower part produce in southeast Anadarko basin
	Wolfcampian	Chase	Gas reservoirs* in Hugoton field
		Council Grove	
		Admire	
PENNSYLVANIAN	Virgilian	Wabaunsee to Douglas	"Granite wash"* Hoover sand* Endicott sand* Tonkawa (Slaughter) sand*
	Missourian	Lansing	Perry sand*
		Kansas City	Cottage Grove sand Hogshooter limestone* Layton sand* County Line lime*
		Pleasanton	Checkerboard lime* Cleveland sand*
	Desmoinesian	Marmaton	Wayside sand* Peru sand* Oswego Limestone*
		"Cherokee"	Prue sand*; Squirrel sand* Skinner sand* Red Fork sand*; Burbank sand*; Earlsboro sand*; Dora sand* Bartlesville sand*; Glenn sand* Booch sand* Burgess sand*
	Atokan	L. Dornick Hills	Dutcher Sand*; Gilcrease Sand*
	Morrowan	L. Dornick Hills	Wapanucka Limestone Union Valley Formation; Cromwell sand*; Primrose sand*
	Springeran		Springer sand*
SIL.-DEV.-MISS.	Chesterian Maramecian		Goddard Shale Caney Shale; "Chester Lime"*; Manning Limestone Sycamore Limestone
	Osagean Kinderhookian		Boone Chert; "Mississippi chat"*; "Mississippi lime"*; Arkansas Novaculite Woodford Shale; Misener sand*
	Oriskanian to Albion	Hunton*	Bois d' Arc Limestone*
ORDOVICIAN	Cincinnatian Trentonian		Sylvan Shale Viola Limestone
	Black Riverian Chazyian	Simpson*	Bromide sand*; "Wilcox sand"* McLish sand* Oil Creek sand*
	Canadian	Arbuckle*	"Siliceous lime"*; Turkey Mt. sand*
CAMBRIAN	Croixian		
		Timbered Hills	Reagan sand*
Precambrian crystallines			Granites, porphyries, basic igneous rocks, metasediments

Hoxbar*

Desse*

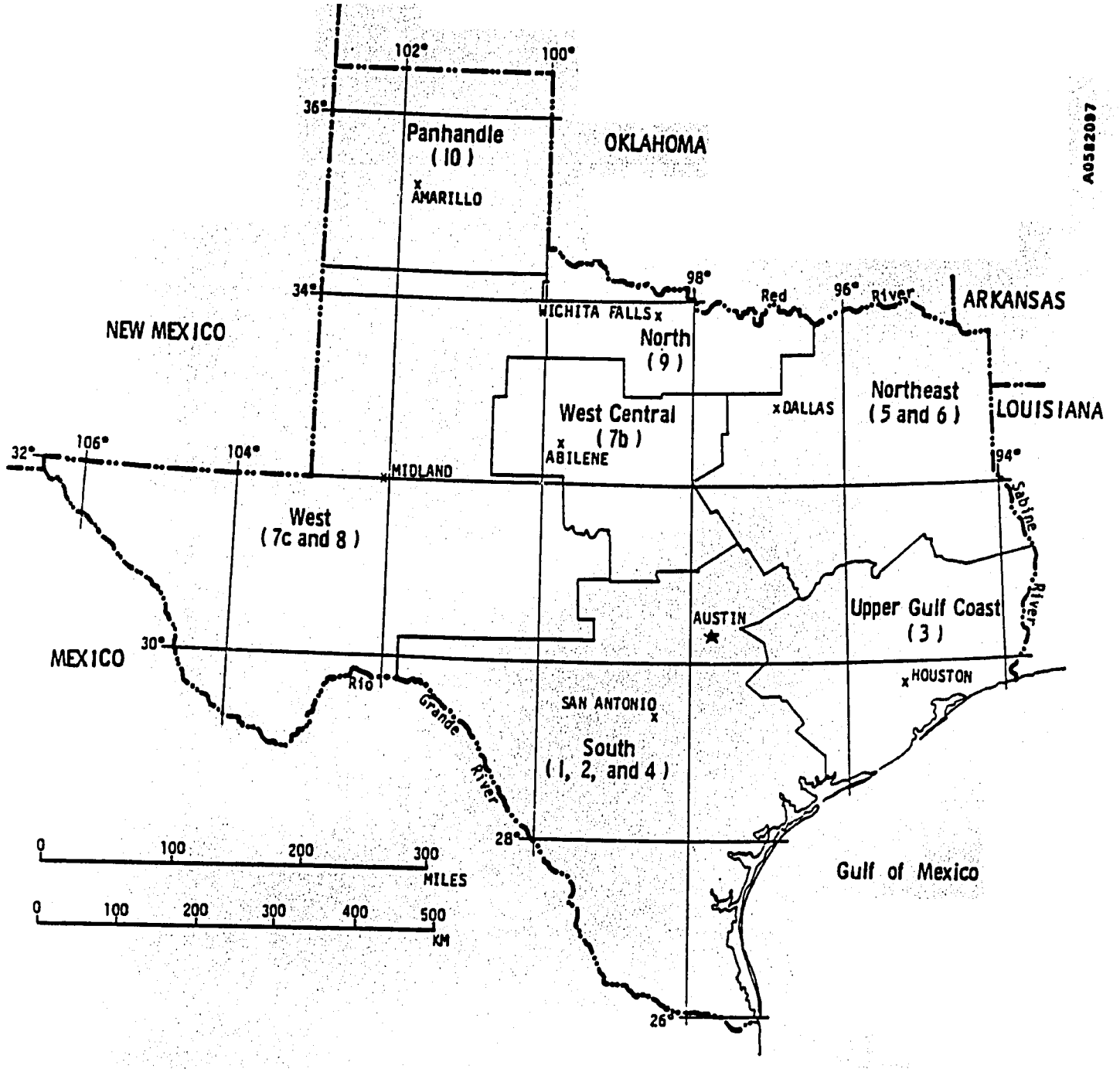
Pontotoc*

Lone Grove sands*

Stratigraphic section, Oklahoma. *Data derived from various sources, including especially Carl C. Branson (1958) and Louise Jordan (1957).*

Figure 1-24 (Source: 21)

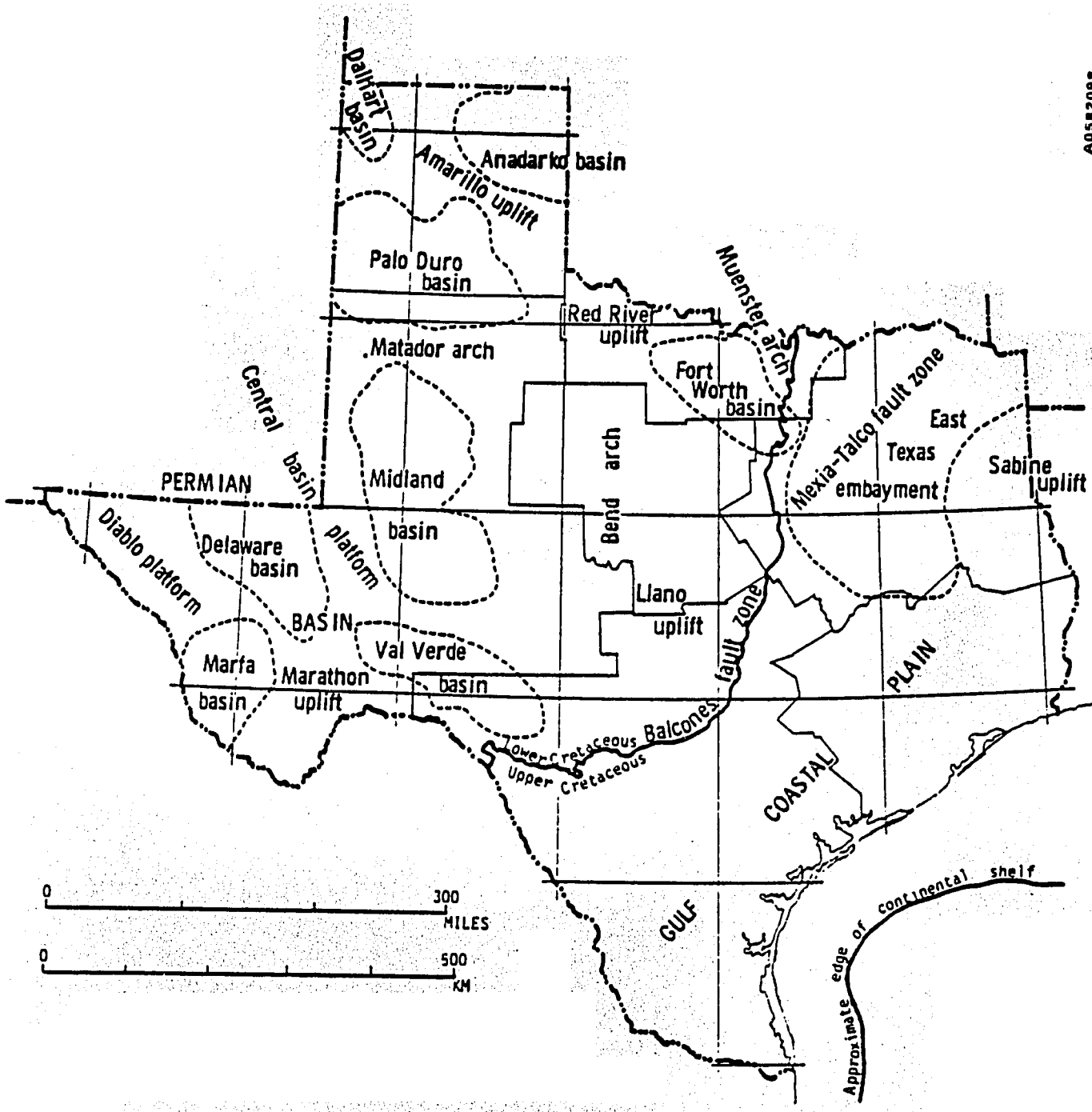
316



Texas (Division IV). Index map, showing areas discussed separately in following chapters. Numbers in parentheses are Texas Railroad Commission district numbers.

Figure 1-25
(Source: 21)

317



Texas. Major tectonic features. Heavy black line crossing state from south to north is contact between Lower and Upper Cretaceous; also the inner edge of Gulf Coastal Plain.

Figure 1-26
(Source: 21)

318

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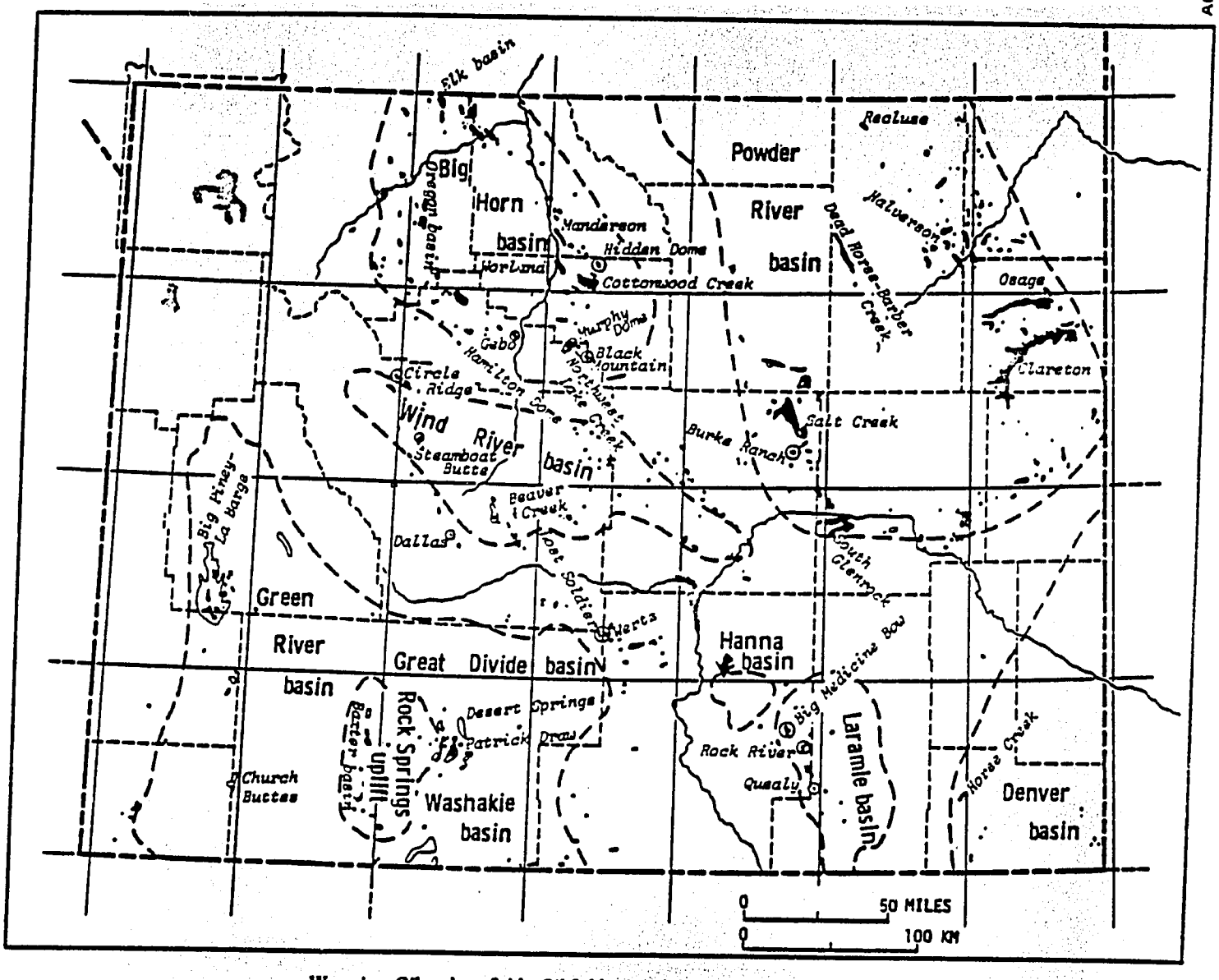


Wyoming. Oil and gas fields. Oil fields are solid black. Index map for fields mentioned in text.

Figure 1-27
(Source: 21)

319

ERA	PERIOD	GROUP OR FORMATION	RESERVOIRS
Cenozoic	Pliocene Miocene	North Park and/or Brown's Park	
	Oligocene	White River	
	Eocene	Bridger Green River Wind River	"Wasatch" sands
	Paleocene	Fort Union	Fort Union sands
Mesozoic	Cretaceous	Lance	
		Pierre: Lewis, Mesaverde	Various sands, including Almond at top
		Pierre: Steele	Sussex Shannon Cody Shale, with reservoir sandstone near base
		Niobrara	
		Frontier	Frontier and Wall Creek sands
		Mowry	
		Muddy	Muddy sands; Newcastle Sand; Dynneson Sand
		Thermopolis	
		Inyan Kara	Fall River and "Dakota" sands Lakota sands
	Jurassic	Morrison	
		Sundance	Sundance sands
	Triassic	Nugget	Nugget sand
		Red Peak or Chugwater	Crow Mountain sand; Curtis sand
		Dinwoody	
Paleozoic	Permian	Phosphoria or Goose Egg	Phosphoria (Embar) Limestone
	Pennsylvanian	Wells or Tensleep or Casper	Tensleep sand; Minnelusa Formation
		Amsden	Darwin sand
	Mississippian	Brazer Madison	Madison Limestone
	Devonian	Darby	
	Ordovician	Big Horn	Big Horn Dolomite
	Cambrian	Gallatin	Deadwood sand
		Gros Ventre	
		Flathead	Flatsand sand

A0582100

FIGURE 34.4 Wyoming. Composite stratigraphic table, emphasizing the oil and gas reservoirs. Not to scale. *Compiled from stratigraphic nomenclature charts published in various Guidebooks of the Wyoming Geological Association.*

Figure 1-28
(Source: 21)

320

TABLE 1

LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: _____

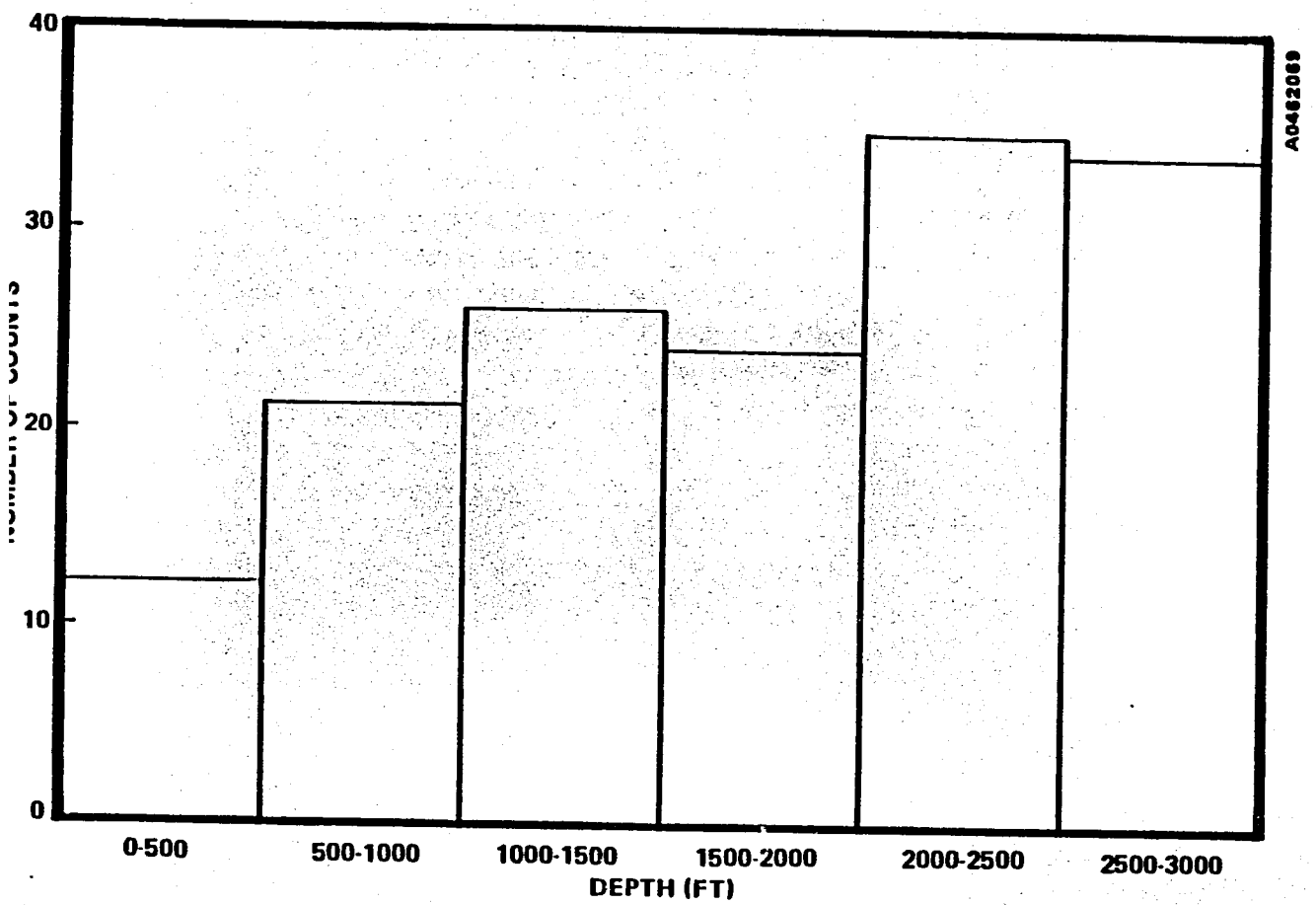
PAGE ___ OF ___

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC.	YEAR ABD	API RANGE (°)	BEST API VALUE (°)	VISC-OSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO OF PAY ZONES	RES AREA (ACRES)	CUMULATIVE PRODUCTION			OIL REMAINING IN PLACE (1,000 bbl)	RANK	RANK	REF
													DATE	OIL (1,000 bbl)	GAS (1,000 mcf)				
1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20

A0582101

Figure 1-29

321

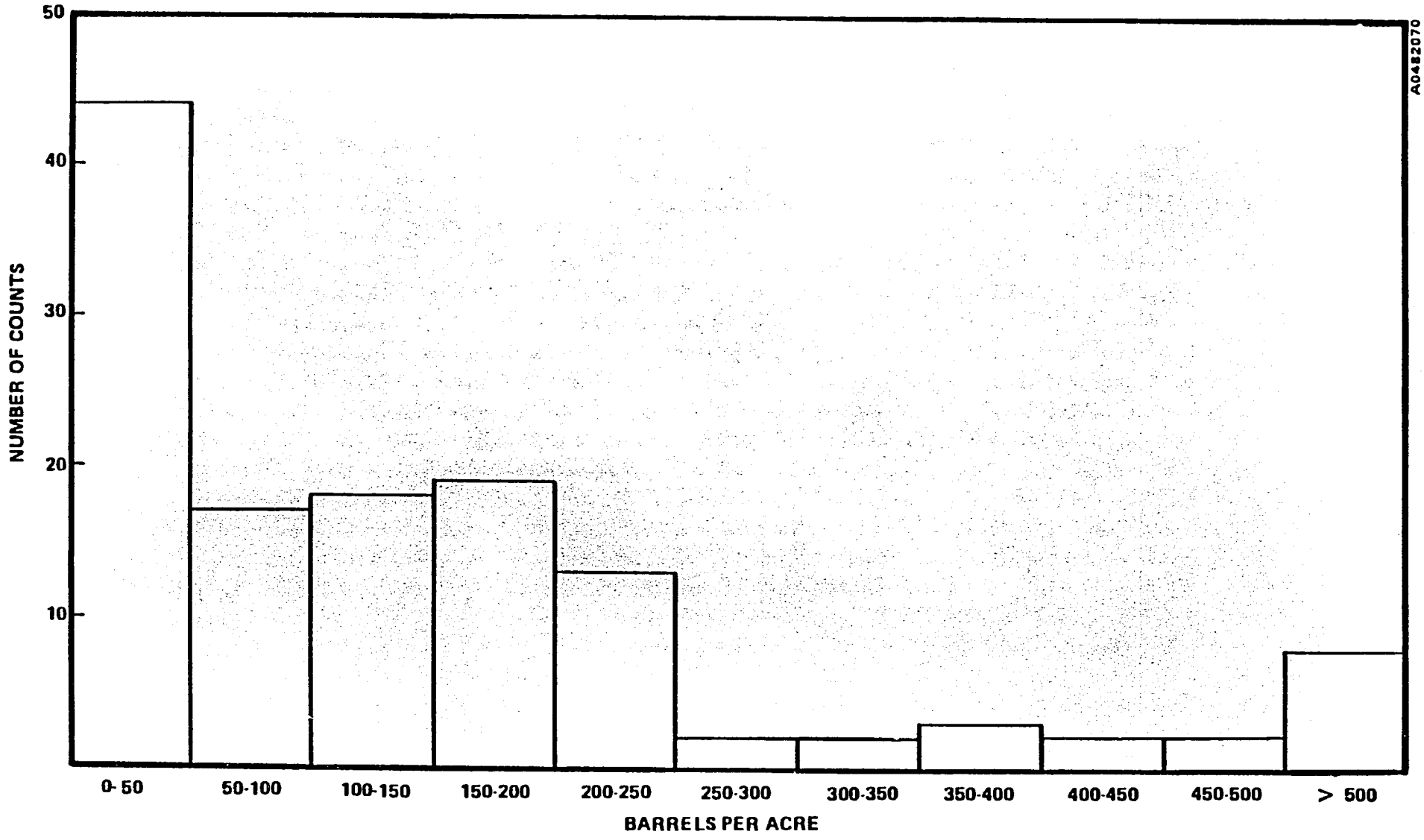


DISTRIBUTION OF DEPTH TO TOP OF RESERVOIR – ALL AREAS

DISTRIBUTION OF DEPTH TO TOP OF RESERVOIRS THAT PASSED SCREEN 4

Figure 1–30

322



DISTRIBUTION OF RESOURCES (BBL/ACRE) OF RESERVOIRS PASSING SCREEN 4

Figure 1-31

323.

1.3 DETAILED DESCRIPTION OF TARGET RESERVOIRS

The following is a detailed description of the ten target reservoirs. Each section discusses historical production, geology, reservoir characteristics, groundwater, and rock mechanics considerations.

1.3.1 Cymric Field - Kern County, California (McKittrick Front Area, Tulare-Reef Ridge Reservoir)

The McKittrick Front Area of the Cymric Field was chosen for detailed study based on a ranking of M-84. This rank reflects the large surface area, relatively shallow depth for underground mining for access, and rather large estimated remaining oil in place. Table 1-4 summarizes of all the reservoir parameters which influenced the ranking.

The McKittrick Front Area comprises approximately the southeastern third of the Cymric Field and extends from just north of the town of McKittrick, Kern County, California, northwesterly to the foothills of the Temblor Range. This area of the field covers approximately 1,380 acres located on gently sloping alluvial fans and low, rounded hills dissected by gullies. Ground surface elevations range from 600 to 1,000 ft above sea level and is covered with sparse native grasses and shrubs due to very low annual precipitation and the absence of fresh groundwater.

1.3.1.1 Historical Production

The McKittrick Front Area of the Cymric Field was first discovered in 1909 when the Nacirema Oil Company completed a shallow well in the Tulare sands. The first significant extension of production was in 1916 when oil was discovered again in the Tulare Sand but about three miles northwest of the discovery well. Deeper producing zones were discovered about one year later when Standard Oil Company of California completed a successful well 2,553 ft deep in the Olig Sand. By 1945 over one hundred wells were completed in the field, predominantly in the Tulare zone. At that time, significant discoveries were made in several deeper zones. Production from

these reservoirs has been increasing to the present time. Cyclic steam injection to enhance oil recovery techniques have been used successfully to increase production of heavy oil from the field since 1963.

The producing formations in the McKittrick Front Area of the Cymric Field include the Tulare, Reef Ridge, Carneros, Phacoides, and Oceanic zones. Only the two uppermost zones are discussed here, since all the producing zones are too deep to mine economically.

1.3.1.2 Geology

For a description of the regional geology of the McKittrick Front Area of the Cymric Field, please refer to the description of the regional geology of the main area of the McKittrick Field.

1.3.1.3 Reservoir/Field Geology

The stratigraphy of the McKittrick Front Area of the Cymric Field is characterized by unconsolidated to weakly consolidated sediments ranging from Upper Eocene to Recent in age. A brief description of the stratigraphic units from the ground surface down to the Reef Ridge Shale is given here. All stratigraphic units below the Reef Ridge Shale are considered too deep to recover economically by mining compared to the units nearer the ground surface. A description of these units follows:

- <u>Alluvium</u> - Recent deposits of sand and gravel, zero to 100 ft thick.

- <u>Tulare Formation</u> - Pleistocene buff colored fine to coarse grained unconsolidated sandstones that are poorly sorted, friable and locally conglomeratic. Some interbeds of buff silts and blue-green clays. Includes Amnicola zone of well-rounded highly pervious sand. Approximate total thickness 100 to 2,000 ft.

- San Joaquin Formation - Pliocene to Pleistocene blue and green claystone that is locally silty with fine-grained, thinly bedded sand. Approximate thickness 0 to 400 ft.

- Etchegoin Formation - Pliocene gray to blue-gray siltstone, compact and interbedded with fine silty sands.

- Reef Ridge Formation - Upper Miocene

  - Olig Sand Member - conglomeratic gray sands, friable with interbedded sands and siltstone. Approximate thickness 0 to 100 ft.

  - Second McKittrick Sand Member - gray, fine to coarse-grained sands, poorly sorted with abundant pebbles and cobbles and interbedded with gray-brown siltstone. Approximate thickness 0 to 300 ft.

  - Reef Ridge Shale Member - gray-brown siltstone, firm, clayey and diatomaceous. Approximate thickness 0 to 100 ft.

The geologic structure of the McKittrick Front Area of the Cymric Field represents the southern part of a large, doubly plunging, northwest trending anticline which characterizes the entire area of the Cymric Field. This large ancliclinal fold is displaced by several northeast trending normal faults which progressively down-drop the northeastern fold limb. Both the folding and faulting are pre-Pliocene in age, and Pliocene and younger formations rest inconformably on an eroded surface of Miocene sediments. The younger sediments have a predominantly Monoclinal structure with a very gentle dip to the northeast.

The structure of the McKittrick Front Area of the Cymric Field is essentially monoclinal down to the upper Miocene erosional surface, with local undulations and cut by at least five normal faults which trend northwest and are down-dropped to the northeast up to 200 ft. The Bacon

Hills Fault passes approximately one mile to the west of the McKittrick Front Area separating it from the 1-Y area farther to the west. The Bacon Hills Fault is a major strike-slip fault with an estimated right lateral movement of 1.5 miles.

The dip of the beds down to the base of the Pliocene sediments is very shallow, about 5 to 10 degrees to the northeast. The dip of the northeast limb of the anticline in Miocene and older sediments is between 12 and 18 degrees to the northeast.

The McKittrick Front Area of the Cymric Field lies within a zone of high seismic risk, a zone where Modified Mercalli Intensities of VIII or greater have been experienced during historic time. Algermissen (1976) suggests that a horizontal acceleration of about 50 percent of gravity in bedrock has a 10 percent chance of being exceeded in 50 years. The high seismic risk in this area is related to tectonic activity along the San Andreas Fault and other active faults located near the field. No active faults are reported in the literature immediately within the McKittrick Front area of the Cymric Field but the type of movement along the Bacon Hills Fault suggests that it may be related to the San Andreas Fault zone. Therefore, renewed movement along this and other normal faults in the area is quite probable.

Trap mechanisms for reservoirs in the McKittrick Front Area of the Cymric Field vary with depth. Shallow reservoirs in the Tulare Formation are controlled by stratigraphic changes in permeability, minor flexures, and faulting. Deeper reservoirs in Miocene and older rocks are structurally controlled by faulting and along the axis of the anticlinal fold in the area.

1.3.1.4 Reservoir Characteristics

Only the shallow producing zones of the McKittrick Front Area of the Cymric Field are considered. These zones are contained within the Tulare Formation. The deepest zone considered is the Amnicola Sand at the base of the Tulare Formation.

Deeper zones in the Cymric Field produce lighter oils with API gravity ranging from 30 to more than 50 degrees. The depth to the base of the Tulare Formation producing zones within the Tulare Formation consist of a number of sand zones of variable thickness which occur near the base of the formation. The deepest and most significant producer of these sand zones is the Anmicola Sand, which is about 85 ft thick. The depth of the reservoir in the Tulare Formation varies from about 650 ft to 1,400 ft and averages about 1,000 ft. The Anmicola sand ranges in depth from about 800 to 1,400 ft, average 1,200 ft. Net pay thickness of the Tulare Formation is approximately 275 ft, and the average net pay thickness of the Amnicola zone is 125 ft. The producing zones in the Tulare Formation are unconsolidated sands and silty sands which have an average porosity of 37 percent and average permeability of 200 millidarcies. A complete listing of these parameters is given in Table 1-4.

Reported reservoir conditions for producing zones in the Tulare Formation include borehole temperatures of 100 degrees initial oil saturations of 66 percent and current (1980) oil saturations of 57 percent. The reservoir drive mechanism is solution gas. These parameters are summarized in Table 1-4.

Reported values for the fluids within the producing zones of the Tulare Formation include average API gravity of 12.5 degrees ranging from 11.0 to 15.0 degrees, average oil viscosity of 3,000 centipoise at borehole temperature, sulfur content of 1.16 percent and carbon residue of 6.8 percent. Many wells produced sand during early development. These same wells often produced up to 1,000,000 cubic feet of gas per day for a short time after they were completed. Several early wells had gas blowouts. Salty water is produced with the oil from the Tulare Formation, and dissolved solid concentrations are about 1,700 parts per million. Table 1-4. has a complete listing of data for reservoir fluids in the Tulare Formation.

1.3.1.5 Groundwater

Groundwater levels within the Tulare Formation are essentially flat. Faulting appears to disrupt the groundwater regime in some parts of the McKittrick Front Area of the Cymric Field. Water saturation within the producing zones in the Tulare Formation are reported to be 43 percent, and consequently large quantities of water are produced with the oil from these zones. Cumulative production data indicate that approximately seven barrels of water per barrel of oil have been produced from the pay zones in the Tulare Formation.

1.3.1.6 Rock Mechanics

Very little information is available regarding the engineering characteristics of the rocks in the McKittrick Front Area of the Cymric Field, particularly information that would allow quantitative estimates of the behavior of these rocks in large cut slopes of a system of underground openings. A qualitative assessment of this behavior is given here based on the lithology, degree of fracturing and general rock descriptions reported in the literature.

All of the rocks under consideration in the McKittrick Front area of the Cymric Field are unconsolidated. The rocks overlying the reservoir rocks in the Tulare Formation consist of alluvial gravels and silts and clays. The fine grained sediments are described as friable, probably due to their unconsolidated condition. These strata are expected to have low unconfined compressive strength, low hardness, and low elastic modulus. They would probably require continuous support in underground openings. Shrinkage, swelling and slaking would be expected in the silt and clay zones. Gravel and other alluvial deposits at the surface may contain significant groundwater. High permeability of these sediments could result in very high groundwater inflows to shafts or other underground openings made in these materials.

The reservoir rocks consist of unconsolidated sands and silty sands. These rocks are expected to have low unconfined compressive strength, low hardness, and high porosity and permeability. Continuous support would probably be required for these strata in underground openings, and running sand from shaft walls or floor should be expected in all zones containing water with the heavy oil.

Rocks below the reservoir are described as claystone. They are weakly consolidated and probably have low unconfined compressive strength, low hardness, low elastic modulus and low permeability. Swelling, shrinkage and slaking could be expected with changes in moisture content of these materials. Nearly continuous support and low durability of both roofs and floors of underground openings would be expected for these rocks.

1.3.1.7 Conclusions

The McKittrick Front Area of the Cymric Field is a potential target for heavy oil recovery using mining for access techniques. Several factors make this area a favorable target including the large resource remaining in the field even after the extensive production from the field since 1909, the large surface area of the field, and the relatively shallow depth to the producing zones.

Several factors which represent potential problems to heavy oil mining recovery using mining for access techniques in the McKittrick Front Area include gas associated with the oil in the producing zones, potential large groundwater inflows, soft ground conditions, competition for surface area and reservoir management from existing surface wells, and high seismic risk. Weak claystones below the reservoir may result in poor floor conditions in drifts requiring continuous maintenance or lining to provide stable access for underground equipment. In addition, large quantities of water would probably be produced with the oil. Some of this water could be utilized for steam injection in conjunction with the mining for access system. Large quantities of low quality water would require disposal as with existing surface recovery methods in the Welport Area.

TABLE 1-4

CYMRIC OIL FIELD, KERN COUNTY, CALIFORNIA

GENERAL INFORMATION

Reservoir Name:	McKittrick Front Area		
Discovery Year:	1909	No of Wells:	240
		Area, Acres:	1380
Formation:	Tulare	Land Use:	Petroleum Recovery
Geologic Age:	Pleistocene		

RESERVOIR INFORMATION

General		Structure	
Avg. Depth, Ft:	1000	Faulting:	Minor
Net Pay, ft:	275	Folding:	Minor
Lithology:	Sand	Dip, ^{o} :	5-10
Consolidation:	Unconsolidated	**Conditions**	
Porosity, %:	37	BHT, ^{o}F:	100
Permeability, md:	200	Current BHP, psi:	Unknown
Trap Type:	Anticline	Initial Oil Sat.%:	66
Reservoir Drive:	Solution gas	Current Oil Sat.%:	57
		Current GOR, scf/bbl:	5

ROCK MECHANICS PARAMETERS

Unconfined Compressive Strength, psi:	Low
Elastic Modulus:	Low
Hardness:	Low

TABLE 1-4 (cont'd)

FLUID CHARACTERISTICS

Oil Gravity, API:	12.5 (Range: 11-15)
Sulfur Content, %:	1.16
Carbon Residue, %:	6.8
Water Salinity, ppm:	1700

CHARACTERISTICS OF OVERLYING ROCK

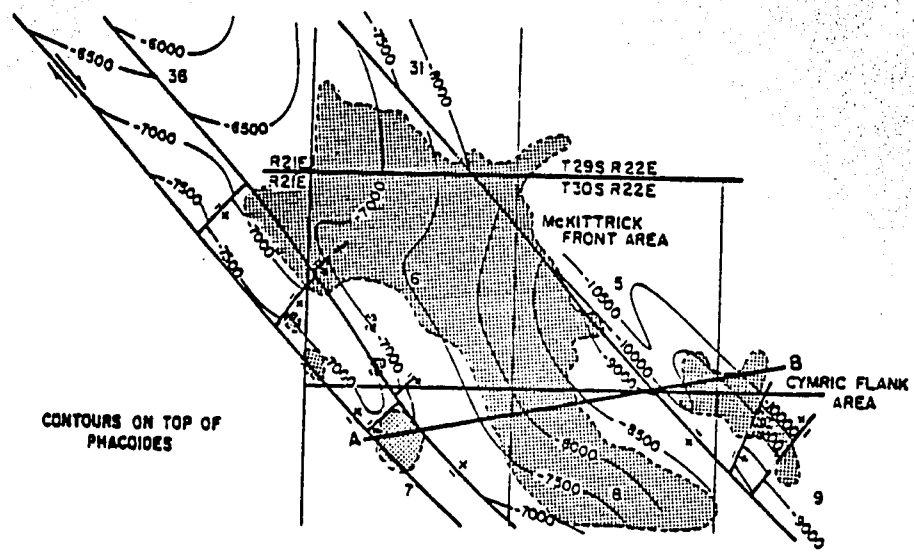
Geologic Formation(s):	Tulare Formation, Recent Alluvi
Geologic Age:	Pleistocene, Recent
Lithology:	Silt, Clay, Sand
Thickness, ft:	650-800 avg.
Consolidation:	Unconsolidated
Structure:	Faulted Monocline
Unconfined Compressive Strength, psi:	Low
Elastic Modulii:	Low
Hardness:	Low
Geologic Formation(s)	San Joaquin
Geologic Age:	Pliocene-Pleistocene
Lithology:	Claystone
Thickness, ft:	0-400 ft.
Consolidation:	Loosely Consolidated
Structure:	Faulted Monocline
Strength, psi:	Low
Modulii:	Low
Hardness:	Low

TABLE 1-4 (cont'd)

PRODUCTION DATA
(probably figures for all reservoirs within the field)

Original Oil in Place, STB:		311,000,000
Cumulative Prod. (1977):	Oil, BBL:	28,967,720
	Gas, MCF:	2,342,000
	Water, BBL:	201,806,000
Oil Remaining in Place, STB:		282,000,000
BBL/Acre:		409,000
BBL/Acre-Ft:		1636
Enhanced Oil Recovery:	1967 water flood 1961-present cyclic steam 1975-present steam drive	

CYMRIC OIL FIELD
Cymric Flank Area and McKittrick Flank Area



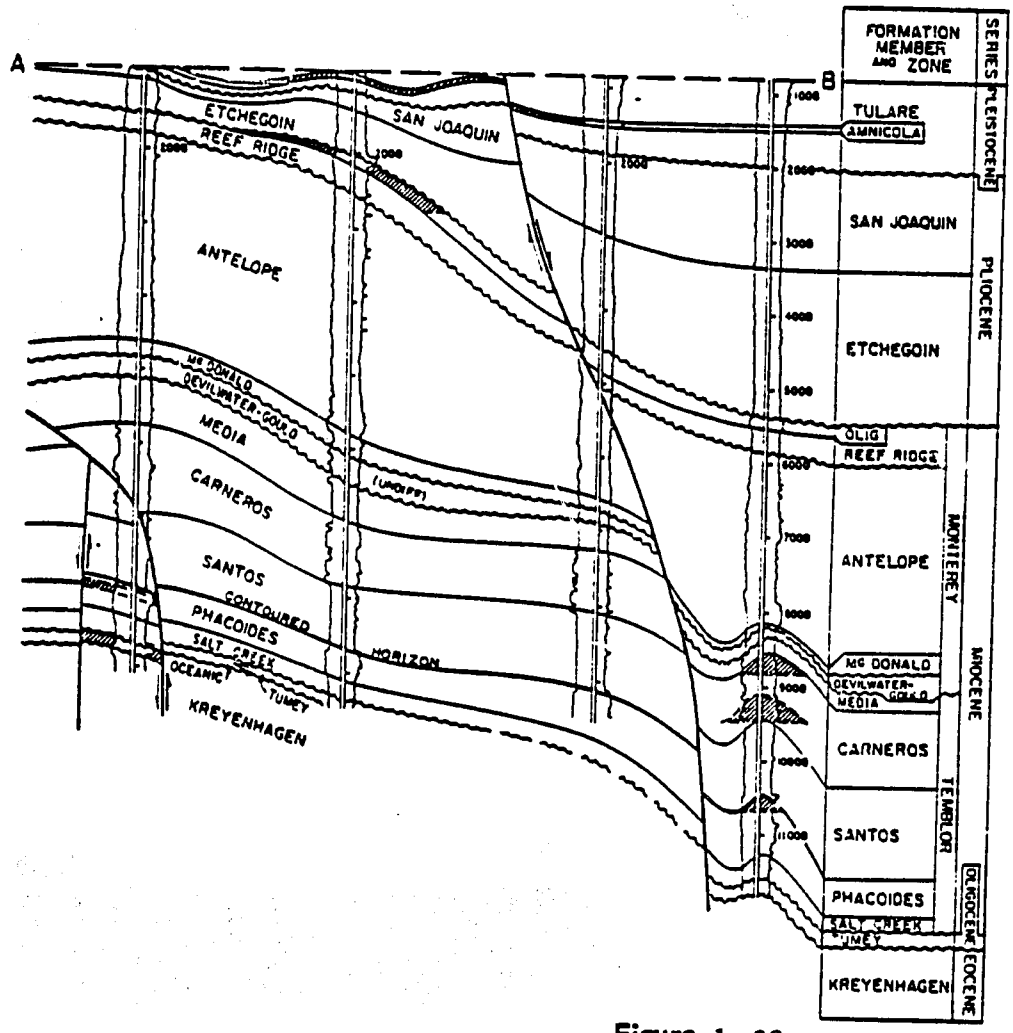


Figure 1-32
(Source: 62)

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1.3.2 Cymric Field, Kern County, California (Welport Area, Tulare Reservoir)

The Welport Area of the Cymric Field was chosen for detailed study based on a ranking of M-84. This rank reflects the large surface area, relatively shallow depth considered for mining for access techniques, and large estimated resources. Table 1-5 contains a summary of the reservoir parameters which influenced the ranking.

The Welport Area comprises approximately the northern two-thirds of the Cymric Field, which extends from just north of the town of McKittrick, Kern County, California, northwesterly to the foothills of the Temblor Range. The Cymric Field covers an area about six miles long and one mile wide from the Elk Hills to the Temblor Range. The uppermost reservoir in the Welport Area is the only reservoir considered here because all deeper reservoirs contain lighter oils with API gravity greater than 30 degrees. The proven area of this reservoir is 1,670 acres. The ground surface is a gently sloping alluvial plain, and is sparsely covered with native desert grasses and shrubs. Surface elevations average 700 feet above sea level. Present land use in the field area is petroleum development and some rangeland. The area is very dry, with annual precipitation of less than 14 inches.

1.3.2.1 Historical Production

The Welport Area of the Cymric Field was first discovered in 1916 with a successful well completed in a producing sand in the Tulare Formation. At that time the entire Cymric Field was considered part of the McKittrick and Temblor fields. This continued until January 1, 1947, when the approximate present area of the Cymric Field was renamed as a distinct field. During the development of the Welport Area, deeper producing zones were discovered and production slowly increased. In the early 1960's enhanced oil recovery techniques were introduced which increased production of the heavy oils in the upper reservoir.

1.3.2.2 Geology

For a description of the regional geology of the Welport Area of the Cymric Field, please refer to the description of the regional geology of the San Joaquin Valley in Section 3.3.3. See Figure 1-33 for a geologic section and structure contour map of the reservoir.

The stratigraphy of the Welport Area of the Cymric Field is characterized by unconsolidated to weakly consolidated sediments ranging in age from upper Eocene to present. Only the uppermost of these sediments are considered here, as follows:

- Alluvium - Recent sand and gravel, unconsolidated. Approximate thickness 0 to 100 feet.

- Tulare Formation - Pleistocene buff colored fine to coarse grained unconsolidated sandstones that are poorly sorted, friable and locally conglomeratic. Some interbeds of buff silts and blue-green clays. Includes Amnicola Zone of well-rounded, highly pervious sand. Approximate total thickness 100 to 2,000 feet.

The geologic structure of the Welport Area of the Cymric Field characterized by part of a large, doubly-plunging, northwest trending anticline which characterizes the entire area of the Cymric Field at depth. The sediments of the Tulare Formation unconformably overly this anticline. Structure in the Tulare Formation consists of a gentle monocline dipping approximately 5 to 10 degrees northeast. Several normal faults cut this monocline, and the faults trend northwest and are down-dropped between 100 and 200 feet to the northeast. Some localized gentle undulations exist within the sediments of the Tulare Formation.

The Welport Area of the Cymric Field lies within a zone of high seismic risk, where Modified Mercalli Intensities of VIII or greater have been

experienced during historic time. Algermissen (1976) suggests that a horizontal acceleration of about 50 percent of gravity in bedrock has a 10 percent chance of being exceeded in 50 years. The high seismic risk in this area of California is related to tectonic activity along the San Andreas Fault and other active faults located near the field. No active faults are reported in the literature immediately within the Welport Area of the Cymric Field. However, the type of movement along the Bacon Hills Fault, right lateral strike slip of 1.5 miles, suggests that this fault is related to the San Andreas Fault Zone. The Bacon Hills Fault passes along the western boundary of the Welport Area and renewed movement possible probably due to its structural similarity with the active San Andreas Fault System.

Trap mechanisms for producing zones within the Tulare Formation are primarily lateral changes in permeability, minor flexures and faulting.

1.3.2.3 Reservoir Characteristics

The producing zones in the Tulare Formation consist of a series of sands, the most significant of which is the Amnicola Zone. The average depth of the Amnicola Zone is 1000 feet in the Welport Area and its thickness ranges from 50 to 450 feet. The average net pay of the Tulare Formation in the Welport Area is 125 feet, therefore the significance of the Amnicola Zone is apparent. The depth to the base of the Tulare Formation reaches 3000 feet in some parts of the Welport Area.

Reported reservoir conditions for producing zones in the Tulare Formation include borehole temperatures of 100 degrees Fahrenheit, initial oil saturation of 66 percent, current (1981) oil saturation of 60 percent, current gas oil ratio of 10 SCF/BBL. The drive mechanism within the reservoir is solution gas. These parameters are summarized in Table 1-5.

1.3.2.4 Groundwater

Groundwater levels within the Tulare Formation are essentially level. Faulting disrupts the groundwater regime in some parts of the Welport Area

of the Cymric Field. Water saturation within the producing zones in the Tulare Formation are reported to be 40 percent, and consequently large quantities of water are produced with the oil from these zones. Cumulative production data indicate that approximately 8.5 barrels of water per barrel of oil have been produced from the pay zones in the Tulare Formation.

1.3.2.5 Rock Mechanics

Very little information is available regarding the engineering characteristics of the rocks in the Welport Area of the Cymric Field, particularly information that would allow quantitative estimates of the behavior of these rocks in large cut slopes or a system of underground openings. A qualitative assessment of this behavior is given here based on lithology, degree of fracturing, and general rock descriptions reported in the literature.

All of the rocks under consideration in the Welport Area of the Cymric Field are unconsolidated. Two formations are under consideration, recent alluvial deposits and Pleistocene sands, silts and clays of the Tulare Formation.

Strata overlying the reservoir rocks in the Welport Area of the Cymric Field probably have low unconfined compressive strength, low hardness and a low elastic modulus. The sand and gravel zones probably have high permeability and may produce large groundwater inflows to underground openings. All strata are described as friable, probably due to their unconsolidated condition. Fine grained strata may undergo swelling, shrinkage and slaking in response to changes in moisture content. All these materials will probably require soft ground tunnelling techniques including continous ground support, dewatering and provisions to prevent running ground in zones of high groundwater inflow.

Reservoir rocks consist of unconsolidated sands and silty sands. These strata are expected to have low unconfined compressive strength, low hardness and high porosity and permeability. Soft ground tunnelling

techniques would probably be required for underground openings in these materials including continuous ground support, dewatering and provisions to prevent running ground.

The rocks below the reservoir are in the Tulare Formation in the Welport Area of the Cymric Field. They are the same as those described for above the reservoir in the preceding paragraphs. Horizontal mine opening floors are expected to have low durability in these materials. Continuous lining may be required to maintain openings in suitable condition for vehicular traffic.

1.3.2.6 Conclusions

The Welport Area of the Cymric Field is a potential target for heavy oil recovery using mining for access techniques. Several factors make this area a favorable target including the large resource remaining in the field even after extensive production from the field, which began in 1916; the large surface area of the field; and the relatively shallow depth to the producing zones.

Several factors which represent potential problems to heavy oil recovery using mining for access techniques in the Welport Area include gas associated with the oil in the producing zones, potential large groundwater inflow, soft ground conditions, competition for surface area and reservoir management from existing surface wells, and high seismic risk. In addition, large quantities of water would probably be produced with the oil. Some of this water could be utilized for steam injection in conjunction with the mining for access system. Large quantities of low quality water would require disposal as with existing surface recovery methods.

TABLE 1-5

CYMRIC FIELD, KERN COUNTY, CALIFORNIA

GENERAL INFORMATION

Reservoir Name:	Welport Area, Tulare		
Discovery Year:	1916	No. of Wells:	305
Formation:	Tulare (Amnicola)	Area, Acres:	1670
Geologic Age:	Pleistocene	Land Use:	Range, petroleum recovery

RESERVOIR INFORMATION

General		Structure	
Ave. Depth, ft:	1000	Faulting:	Minor
Gross Pay, ft:	350	Folding:	Minor flexure
Net Pay, ft:	125	Dip°:	5-10
Lithology:	Sand	**Conditions**	
Consolidation:	Unconsolidated	BHT, °F:	100
Porosity, %:	37	Initial Oil Sat, %:	66
Permeability, md:	200	Current Oil Sat, %:	60
Trap Type:	Faults, changes in lithology	Current GOR, scf/bbl:	10
Reservoir Drive:	Solution gas		

ROCK MECHANICS PARAMETERS

Unconfined Compressive Strength, psi:	Low
Elastic Modulii:	Low
Hardness:	Low

TABLE 1-5 (cont'd)

FLUID CHARACTERISTICS

Oil Gravity, ^{o} API:	12.5 (Range: 10-21)
Viscosity @ BHT, cp:	3000
Sulfur Content, %:	1.16
Carbon Residue, %:	6.8
Water Salinity, ppm:	6000

CHARACTERISTICS OF OVERLYING ROCK

Geologic Formation(s):	Alluvium, Tulare
Geologic Age:	Recent, Pleistocene
Lithology:	Gravel, Sand, Silt, Clay
Thickness, ft:	0-100, 100-2000
Consolidation:	Unconsolidated
Structure:	Faulted Monocline
Unconfined Compressive Strength, psi:	Low
Elastic Modulii:	Low
Hardness:	Low
Fractures:	Low

CHARACTERISTICS OF UNDERLYING ROCK

Geologic Formation(s):	Tulare
Geologic Age:	Pleistocene
Lithology:	Silt, Clay
Thickness, ft:	100-2000
Consolidation:	Unconsolidated
Structure:	Faulted Monocline

TABLE 1-5_(cont'd

Unconfined Compressive Strength, psi:	Low
Elastic Modulii:	Low
Hardness:	Low
Fractures:	Low

PRODUCTION DATA

Original Oil in Place, stb:		376,600,000
Cum Prod (12/31/77):	Oil, bbl:	34,886,165
	Gas, mcf:	1,458,000
	Water,bbl:	296,279,000
Oil Remaining in Place, stb:		341,800,000
Bbl/acre - ft:		1637
Enhanced Oil Recovery (Year, Type):		1964 - present Cyclic steam

CYMRIC OIL FIELD
Weiport Area

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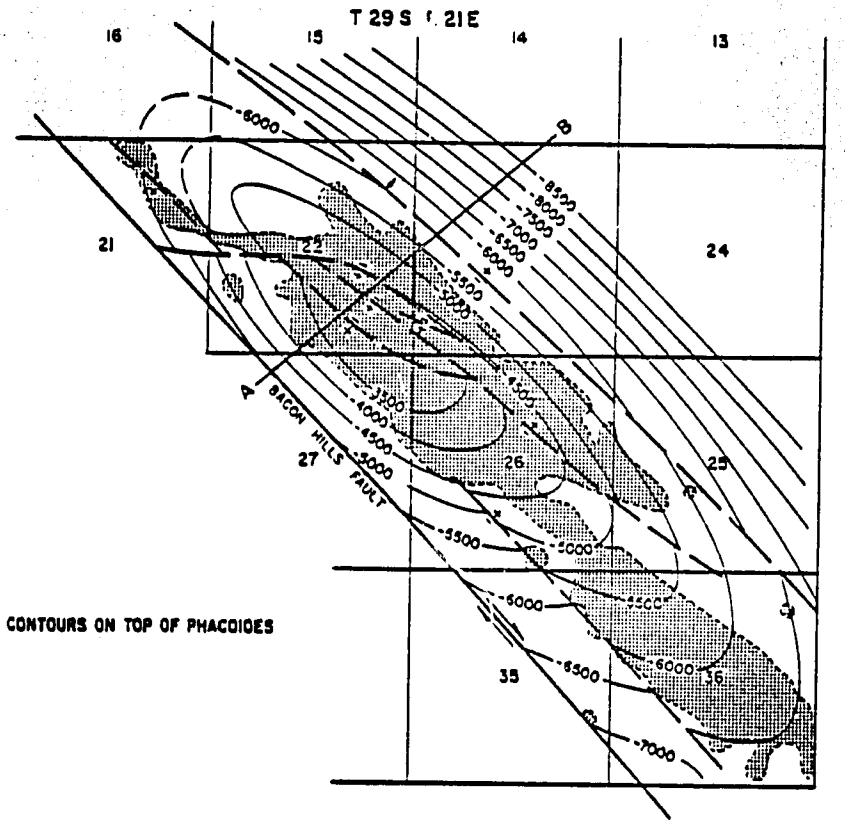

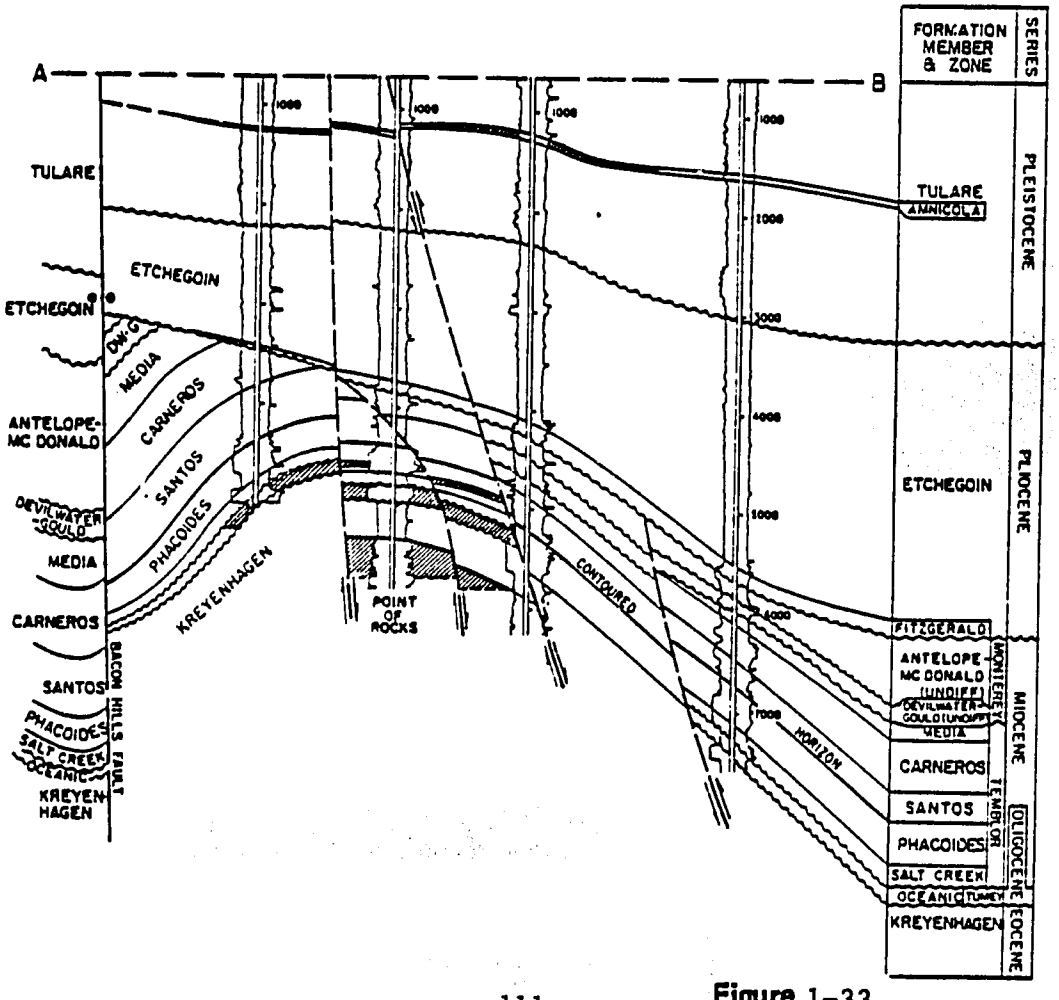

Figure 1-33
(Source: 62)

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1.3.3 Kern River Field, Kern County, California (Kern River Reservoir)

Kern River was chosen for detailed study on the basis of a ranking of S-110-(1) and M-110. This is primarily due to its shallow depth (0 to 1500 ft), a high saturation of 1400 bbl/acre feet, and an OBR ratio which varies from 0:1 at the east end of the field to 10:1 at a maximum. Table 1-6 summarizes all the reservoir parameters.

The Kern River Oil Field is located on the east side of the San Joaquin Valley, approximately 5 miles northeast of Bakersfield, California in an area of low rolling hills that are generally barren of vegetation. The field consists of 9,435 proved acres within T.28S., R.27E., T.28.S, R.28.E; and T.29S., R.28E.

1.3.3.1 Historical Background

The field was first discovered in 1899 when several wells were drilled by hand to recover lubricating oil. The first successful well, completed using a hand auger, supplied lubricating oil to Bakersfield. By 1904 the field was producing 17,000,000 barrels of oil per year. Production tapered off after that year and the field produced at a lower rate until 1943. Because of the World War II, production increased dramatically from 1943 to 1948 when more than 600 new wells were drilled; production rose during the early 50's due to demand from the Korean War. Production was increased again after the introduction of steam displacement technologies in the mid-1950's. The Kern River Field was rated California's fourth largest oil field in 1978 in terms of daily production.

Today there are 5144 producing wells in the Kern River Field, and secondary and tertiary recovery techniques are being successfully implemented. More than 10 steam drive projects are currently active in the Kern River Field (Kujawa, 1981).

1.3.3.2 Geology

The Kern River Field lies at the eastern side of the San Joaquin Basin in its southern-most end. It is one of a number of fields along the Bakersfield Arch, a sub-surface high which divides the basin.

Below is a brief outline of the stratigraphy. Please refer to Figure 1-34 for a cross section through the field.

Age	Formation	Description
Recent	Alluvium	Sands and gravels deposited by the Kern River.
Pleistocene -Pliocene	Kern River	Gray to brown unconsolidated sands interbedded with blue-gray mudstones. Becomes finer towards bottom. (Approximately 500 feet thick)
Lower Pliocene -Upper Miocene	Chanac	Land laid beds very similar to the Kern River. (Approximately 500 feet thick)
Upper Miocene	Santa Margarita	Fine to coarsed grained marine sands, streaks, of carbonaceous silt, gray to blue. (Approximately 300 feet thick)
Middle Miocene	Fruitvale Shale	Coarse carbonaceous shale. (Approximately 200 feet thick)
Middle Miocene	Round Mountain Silt	Marine siltstone and mudstone, shaly, gray to brown. (Approximately 600-700 feet thick)
Middle -Lower Miocene	Oicese Sand	Medium to coarse grained sand, occasional stringers of silt, blue -gray.(Approximately 700 feet thick)
Lower Miocene	Freeman -Jewett	Marine silt and ash. (Approximately 1000 feet thick)
Lower Miocene	Vedder	Marine, grades upward from siltstone to coarse sandstone. (Approximately 900 feet thick)

345.

Eocene		Alternating layers of green gritty sand, claystone, and ash (Approximately 200 feet thick)
Pre-Tertiary	Basement	Granite

The lithologies within the Kern River Field are relatively underformed but are in one homoclinal structure. The general dip of the formation is 4 to 6 degrees to the southwest. See Figure 1-34.

Three faults are known to exist in the Kern River Formation within the limits of the Kern River Field. The Kern Front Fault is in the northwestern portion of the field and strikes approximately N10°E. This fault is an active normal fault (Nicholson). The China Grade Fault and Gun Club Fault are in the southwestern part of the field and strike approximately N88°W. Both are normal faults which are downthrown to the south.

Two minor normal faults have been mapped near the center of the Kern River Field. These faults have very small offsets evidenced by small displacements in the oil water contact in that part of the field. These faults are named the Sterany Fault and Omar Fault (Nicholson).

The area is very prone to ground shaking, and earthquakes over magnitude 8 on the Richter Scale have occurred frequently in the past. However, the area is many miles from any major fault zone and is therefore thought to pose less risk than fields in the San Joaquin Valley. Any surface facilities would have to be designed for possible attenuated ground movement.

1.3.3.3 Reservoir Characteristics

The producing horizons of the Kern River Oil Field occur entirely within the Kern River Formation, which is composed of up to nine thick, productive sand bodies varying from 30 feet to 100 feet thick, separated by mudstones averaging 20 feet in thickness. The sand bodies occur in a vertically repeated sequence, starting with a basal conglomerate with pebbles from 1/4

inch to 12 inches in diameter, overlain by cross stratified, coarse, poorly sorted sandstone, grading finer upwards into a mudstone composed of fine sandy silt with a minor amount of clay. The Sierra Nevada batholith was the primary source of these sediments, which were deposited almost entirely by the Kern River in a braided alluvial system. The top of the reservoir varies from the surface at the east end of the field to as much as 1500 feet at its southern-most end. The trapping mechanism for the heavy oil is predominantly stratigraphic with an updip tar seal and stratigraphic pinchouts.

The reservoir has an average porosity of 35 percent, permeability of 4,000 millidarcies, borehole temperature of 90 degrees Fahrenheit, current borehole pressure of 50 psi, and a current oil saturation of 52 percent. Solution gas and gravity serves as a driving mechanism.

The oil has an API gravity of 14 degrees, viscosity of 4,000 centipoises which decreases to 15 cp at 250 degrees Fahrenheit, a sulfur content of 1.19 percent, and carbon residue of 6.8 percent.

1.3.3.4 Groundwater

The Kern River groundwater storage unit occupies nearly 700 square miles with an estimated groundwater storage capacity of 10,790,000 acre-feet. Specific yield varies from 11 to 16 percent (Davis, 1959).

Oil wells in the Kern River Field produce large quantities of water, which is unavoidable due to the segregation of oil and water sands caused by interfingering. The waters are very fresh with only 90 ppm of dissolved salts (Kujawa, 1981).

Top water is a problem at the west end of the field and edge water encroaches from the south and west. Much of the water is probably in confined aquifers.

Groundwater would be a major potential problem in developing a mine at the Kern River Field.

1.3.3.5 Rock Mechanics Considerations

The deposits overlying the Kern River Formation are very similar to the formation itself and have a maximum thickness of 600 feet. They are highly unconsolidated and are composed of loose gravel, sand, and silt. Excavation is expected to proceed at a high rate in these deposits.

The Kern River Formation is unconsolidated, of low to moderate strength, and soft to moderately hard.

The Chanac Formation underlies the Kern River Formation and is so similar it is hard to distinguish between the two.

1.3.3.6 Conclusions

The Kern River Field is (and will remain so for many years to come) an excellent target to demonstrate the effectiveness of mining heavy oil.

The field would probably first be developed as a surface mine, and then, upon extraction of all the ore possible by surface techniques, be converted into a mining for access project. Low cost surface mining equipment such as bucketwheel excavators could be used to remove the overburden and ore. The southern end of the San Joaquin Valley is ideal for such an operation. Potential problems include groundwater, seismicity, and current drilling activities on the surface.

TABLE 1-6

KERN RIVER OIL FIELD, KERN COUNTY, CALIFORNIA

GENERAL INFORMATION

Reservoir Name: Pliocene-Kern River

Discovery Year: 1899

Formation: Kern River

Geologic Age: Pliocene

No. of Wells: 5144

Area, Acres: 9435

Land Use: Grazing

RESERVOIR INFORMATION

General

Ave. Depth, ft: 1000

Gross Pay, ft: 800

Net Pay, ft: 220

No. of Pay Zones: 3

Lithology: Sand separated by mudstones

Consolidation: Unconsolidated

Heterogeneity: low

Clay Content, %: 3-8

Porosity, %: 35

Permeability, md: 4000

Trap type: Stratigraphic

Barrier to Flow: Yes

Reservoir Drive: Solution Gas/Gravity Drive

Structure

Faulting: minor

Folding: Homocline

Dip, °: 4.0

Conditions

BHT, °F: 90

Intial BHP, psi: 225

Current BHP, psi: 50

Initial Oil Sat, %: 66

Current Oil Sat,%: 52(e)

FLUID CHARACTERISTICS

Oil Gravity, API: 14° Range: 11° to 16°

Viscosity @ BHT, cp: 4000

Sulfur Content, %: 1.19

FLUID CHARACTERISTICS (cont'd)

Carbon Residue, %: 6.8

Water Salinity, ppm: 90

CHARACTERISTICS OF OVERYLING ROCK

Geologic Formation(s): Alluvium

Geologic Age: Recent

Lithology: Sands & Gravels

Thickness: varies

Consolidation: unconsolidated

Strength, psi: Low to moderate

Hardness: Soft to moderately hard

CHARACTERISTICS OF UNDERLYING ROCK

Geologic Formation(s): Chanac

Geologic Age: Lower Pliocene/Upper Miocene

Lithology: Sand separated by mudstones

Thickness: 500 ft.

Consolidation: Unconsolidated

Heterogeneity: Low

PRODUCTION DATA

Original Oil in Place, STB: 3,629,100,000

Cam Prod (12/31/77): Oil, BBL: 726,207,040

Gas, MCF: 2,605,000

Oil Remaining in Place, STB: 2,902,900,000

BBL/Acre: 307,674

PRODUCTION DATA (cont'd)

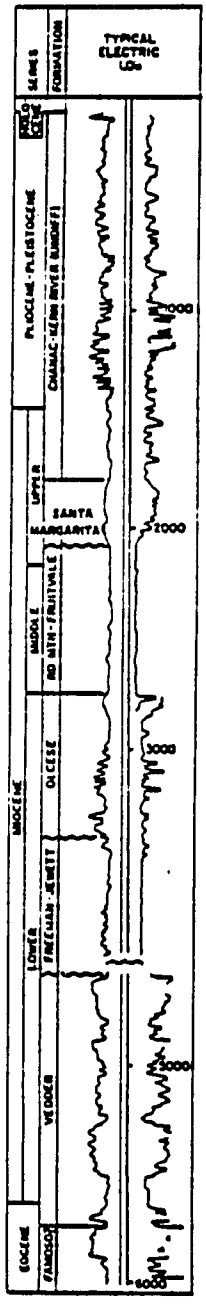
BBL/Acre - ft: 1399

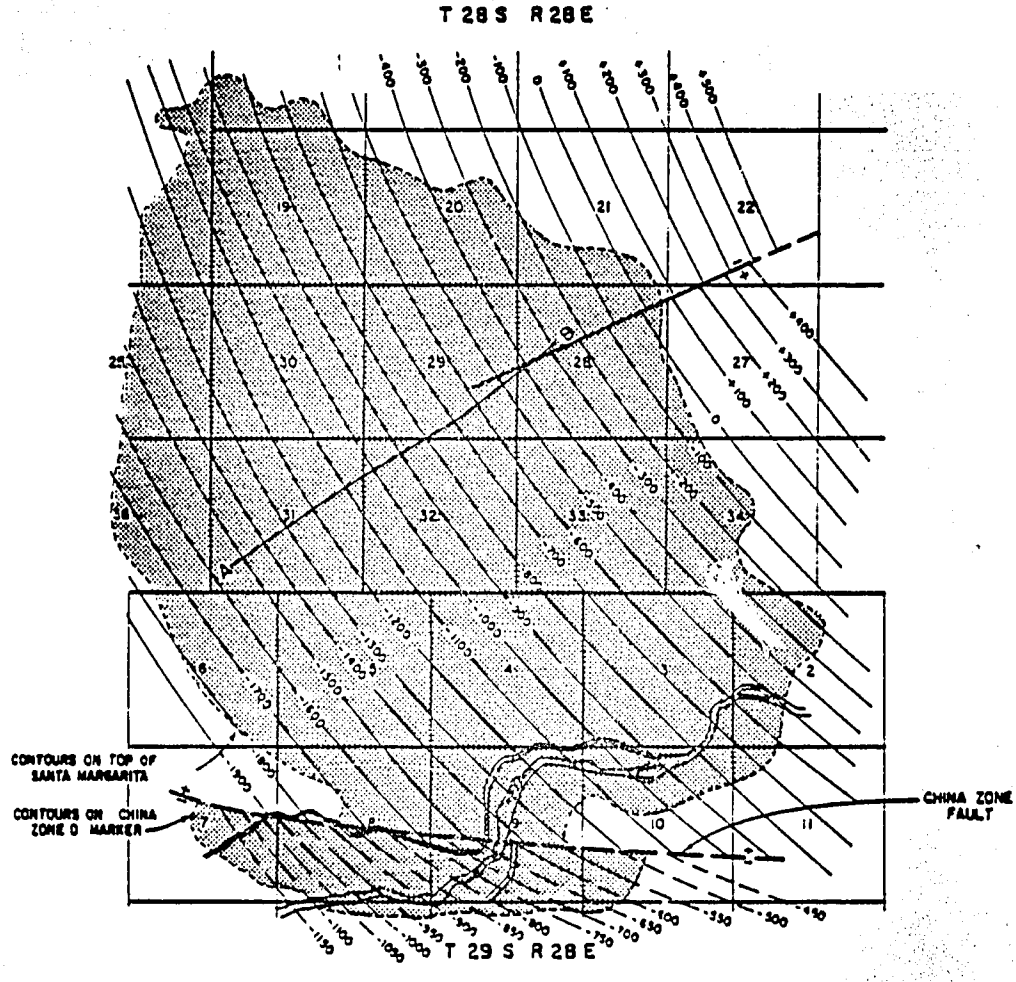
Secondary Production (Year, Type): 1961, Cyclic Steam

Tertiary Production (Year, Type): 1962, Steam Drive

KERN RIVER OIL FIELD

A0582104





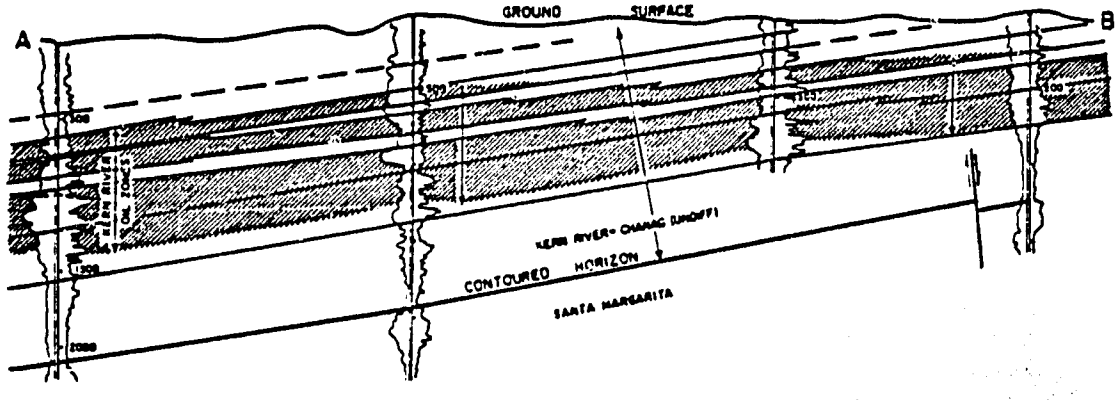


Figure 1-34
(Source: 62)

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1.3.4 McKittrick Field, Kern County, California
(Main Area, Tulare-Olig Reservoir)

The main area of the McKittrick Field was chosen for detailed study on the basis of a ranking of S-123-(2) and M-126. These ranking reflect the relatively shallow depths to the uppermost producing zones, large proven resources and surface area, and thick net pay of the target reservoir. Table 1-7 is a summary of the reservoir characteristics.

The McKittrick Field is located on the west side of the San Joaquin Valley, in Kern County, near the town of McKittrick, California. The field consists of 1430 acres (Kujawa, 1981) located in parts of Section 11, 12, 13, and 14, T. 30.S, R.21E. and Sec. 18, 19, 20, and 29, T.30S., R22E.

The topography at the main area of the McKittrick Field is one of low-lying hills dissected by many gullies, the drainage pattern generally extending in a northeasterly direction. The area of the field is separated from the Temblor Range to the west by the Little Santa Maria Valley. Ground elevations vary from El. 1,150 to El. 1,500 ft above sea level and the ground surface is covered with scattered patches of chaparral.

Present land use in the area of the McKittrick field consists of open range, densely spaced oil wells and some minor oil processessing facilities. The small town of McKittrick is located at the eastern margin of the field.

1.3.4.1 Historical Production

The field was discovered by early prospectors who mined brea deposits and oil and tar seeps. No exact date is known for the first discovery of the field but early prospecting was done prior to 1861. During the 1860's some exploitation of the field was begun primarily utilizing shallow pits to mine the brea deposits which were used to produce kerosene and lubricating oil. The first wells were drilled during the 1880's to withdraw crude oil from deeper deposits in the McKittrick Field. These early wells were

drilled approximately 400 to 500 ft deep and produced a "liquid asphalt" or heavy oil. Several wells had difficulty with this heavy oil, resulting in low production rates and stuck drilling tools. In 1898 the McKittrick Field began serious production which peaked at 5,807,360 barrels of oil in 1909. This declined to a lower steady rate of production which continued at 937,716 barrels of oil during 1955. In 1977 production from the McKittrick Field had increased to 2,871,362 barrels of oil and 66,000 million cubic feet (MCF) of gas. Cyclic steam recovery techniques have been used to enhance development from the field since 1962.

1.3.4.2 Geology

The McKittrick Field is one of several large oil fields located along the western margin of the San Joaquin Valley. Please refer to Section 1.3.3.3 for a description of the regional geology. Figure 1-35 shows a structure contour map and geologic cross section of the field.

The stratigraphy of the main area of the McKittrick Field is characterized by weakly consolidated to unconsolidated sediments ranging from upper Miocene to Recent in age. A brief description of each formation in the McKittrick Field from youngest to oldest follows:

- Alluvium - recent deposits of predominantly earthy gypsum that is white, soft and powdery and approximately 0 to 200 ft thick.

- Tulare Formation - Pleistocene deposits of brea or viscous asphalt formed by the evaporation of volatile components from oil in seepages. Approximate thickness 0 to 50 ft.

- Miocene Shale - displaced Miocene diatomaceous shale, light buff tan, fractured to crumbly with irregular and lightly distorted bedding. Laminae of tan hard shale and occasional lenses of sand and conglomerate. Occasional heavy oil showing. Approximate thickness is 700 ft.

- Tulare Formation - Pleistocene gray sand, ill-sorted with abundant chert and shale pebbles, interfingered with blue-green claystone and brown shale. Approximate thickness 300 ft.

- San Joaquin Clay Formation - Pliocene gray-green claystone and sandy clay with alternating fresh water and marine fossils at the base. Average thickness 0-450 ft.

- Etchegoin Formation - Pliocene gray-green sandy claystone with streaks of fine-grained gray sandstone and siltstone.

- Reef Ridge Formation - Upper Miocene age.

  Olig Member - conglomerate and coarse sand, granitic and metamorphic clasts, friable, high permeability and porosity. Interbedded with blue-gray siltstone. Approximate thickness 100 to 1000 ft.

  Shale Member - light blue-gray and light brown diatomaceous shale and siltstone. Approximate thickness 600 ft.

  Marvic Member - blue-gray sandstone, medium to coarse grained, firm, friable, good permeability and porosity. Interbedded with granitic conglomerates having a silty matrix. Approximate thickness 0 to 400 ft.

- Antelope Formation - Upper Miocene brown to dark brown shale, hard, interbedded with thin stringers of brown chert, gray sandstone and bentonitic siltstone. Occasional tar shows. Approximate thickness 0 to 3,000 ft.

- McDonald Formation - Upper Miocene dark brown shale, very hard, silicious, cherty with some thin laminae of brown silty, limey shale. Approximate thickness 0 - unknown ft.

The geologic structure of the main area of the McKittrick Field is characterized by a northeast dipping monocline truncated by a northwest trending, southwest dipping thrust fault. The structure is complicated by a series of normal faults trending predominantly northeast.

The maximum northeasterly dip of the oil bearing beds within the monocline is 25 degrees except for a zone immediately northeast of the thrust fault where these beds were dragged upward by the fault movement and dip nearly vertically. The main area of the McKittrick Field has been subjected to repeated crustal movements, tilting, and faulting. The latest of these crustal movements are related to the uplift of the Temblor Range, located immediately west of the field, which occurred along enechelon thrust faults dipping to the southwest. It is one of these thrust faults that has intersected the oil bearing rocks of the McKittrick Field, tilting the beds on either side of the fault.

The northeast trending normal faults exhibit displacements of 200 to 500 ft at the top of the Olig Sand, the major oil producing zone of the McKittrick Field. These faults are more numerous in the northwestern portion of the field and remain active today, evidenced by offset of wells that have crossed these faults.

A major unconformity exists between the mass of displaced, severely broken and fractured Maricopa shale which overlies the Tulare Formation throughout most of the field. Interpretations of the method of emplacement of this thick shale mass include a major thrust fault from the southwest, rapid denudation of nearby shale areas or massive landslides down the northeast flank of the Temblor Range.

The main area of the McKittrick Field lies within a zone of high seismic risk, where Modified Mercalli Intensities of VIII or greater have been experienced during historic time. Other work (Algermissen, 1976) suggests that a horizontal acceleration of about 50 percent of gravity in bedrock has a 10 percent chance of being exceeded only in 50 years. The high

seismic risk at the main area of the McKittrick Field is associated with tectonic activity along the San Andreas and other active faults located near the field.

The trap type in the main area of the McKittrick Field is a faulted monocline. Oil bearing sandstones of the Olig Member and Tulare Formation are brought into direct contact with older Reef Ridge Shales by the fault. The shale provides the trap, and therefore the faulted contact between the Olig and Tulare with the shales defines the western boundary of the main area of the McKittrick Field.

1.3.4.3 Reservoir Characteristics

The major producing zones in the main area of the McKittrick Field are the Tulare Formation and Olig Member. The Tulare Formation contains oil bearing sands which are interfingered with sandy clay zones. Depth to the top of the Tulare varies from 200 to 600 ft throughout the field, and the total thickness of the formation varies from 300 to 500 ft. The Tulare is discontinuous over the field area and is generally not found in the northwestern half of the field. The Olig Member is continuous throughout the entire area of the McKittrick Field and represents the major producing zone. It is a soft and extremely permeable sand varying from 100 to 1000 ft thick. Depth to the top of the Olig Member varies from about 700 to 1,300 ft averaging about 900 ft throughout a large percentage of the field area. The sand has a high porosity, (36 percent) and high permeability reported as high as 40 darcies but generally 1,000 millidarcies.

Reported reservoir conditions include bore hole temperatures of 99 degrees fahrenheit, initial oil saturation of 70 percent, current (1981) oil saturation of 52 percent, and reservoir drive mechanism of gravity drainage and solution gas drive.

Characteristics of the oil within the reservoirs in the McKittrick Field include an average of 15 degrees API gravity oil, ranging from 11 to 17 degrees API gravity, oil viscosity at borehole temperature of 800 centipoise, average sulfur content of 0.96 percent, average carbon residue of 2.0 percent, water salinity of 6,000 parts per million.

1.3.4.4 Groundwater

There was some shallow groundwater in the McKittrick Field early in its development. The source of this water was the Santa Maria Valley at the foot of the Temblor Range which overflowed into the surface beds of the McKittrick Field. Drilling of water wells in the valley lowered the water table and terminated the overflow into the McKittrick Field.

Occasional zones of sulphurous water occur in thin, isolated sand lenses above the Olig member. These are found at depths between 100 and 500 ft. No artesian flow has been observed in these groundwater bearing zones.

The major source of groundwater in the McKittrick Field is the Olig sand. It has occasionally produced artesian flow. During production from the field edge, water from the Olig Member encrouched upon producing oil wells. Massive water withdrawals depleted the source of this edge water, which is now controlled with standard production wells. Permeability in the Olig Member has been estimated at 40 darcies.

1.3.4.5 Rock Mechanics Considerations

Very little information is available regarding the engineering characteristics of the reservoir rocks or the rocks overlying or underlying the reservoir rocks, information that would allow quantitative estimates of the behavior of these rocks in large cut slopes or in a system of underground openings such as shafts, drifts and other underground working chambers. A qualitative assessment of these parameters is presented here based on the lithology, degree of fracturing, and general descriptions of these rocks in the literature and on well logs from several representative wells in the main area of the McKittrick Field.

Most of the lithologies within the main area of the McKittrick Field are either unconsolidated or weakly consolidated shales, sandstones, shaly sandstones and sandy shales all deposited in Tertiary time. Some portions of the deepest rocks under consideration at the McKittrick Field, notably the Reef Ridge Formation, are loosely consolidated and represent the greatest degree of consolidation of any of the lithologies in the field.

Rocks overlying the reservoir rocks in the main area of the McKittrick Field include diatomite, gyprock and a thick section of displaced Miocene shale. Generally, diatomite and gyprock are soft, friable rocks with very low strength. If these rocks are unconsolidated to loosely consolidated they probably have very low strength, would be easy to excavate, and would require continuous ground support in underground openings. The displaced Miocene Shales are described in the literature as highly fractured, broken and pulverized. Shales generally exhibit low strength, low hardness, moderate to high compressibility, and often slake, shrink or swell when subjected to changes in moisture content. Shales have high porosity on a microscopic scale, but because they are composed of very fine particles, they generally have very low permeability. Because the Miocene shales are highly fractured and broken they probably have very low strength and higher permeability due to secondary permeability along the fractures.

The reservoir rocks include sands and sands interfingered with sandy clays in the upper portions of the reservoir section. The entire sequence is described as unconsolidated to loosely consolidated with high porosity and permeability in the sand zones. These rocks probably possess low strength and would require continuous ground support in underground openings. Core logs indicate that the Olig Member sands are very coarse to pebbly in some zones.

The rocks below the reservoir are semi-consolidated to consolidated shales of the Reef Ridge Formation. Occasional sand zones exist within this formation but they occur deeper than the zone of interest for mine development at the McKittrick Field. These shales probably possess low strength, low hardness, and exhibit varying amounts of swelling, shrinkage and slaking in response to changes in moisture content.

1.3.4.6 Conclusions

The main area of the McKittrick Field is an attractive potential target for both surface and underground mining for access techniques for recovery of heavy oil. The surface area is sufficient, the reserves are adequate, and

the depth to the active producing zones and corresponding overburden ratio make it an attractive potential target for oil recovery using both surface and mining for access techniques. The unconsolidated to semi-consolidated the rocks both above and within the producing zones would allow surface mining using large, efficient earthmoving tools such as draglines or bucketwheel excavators. The semi-consolidated to consolidated shales below the producing formations are probably adequate for developing drifts for drilling access below the reservoir for mining for access.

Potential problems to exploitation of the main area of the McKittrick Field include the high seismic risk, active faults and present oil recovery activities throughout the field. The potential for high ground accelerations from seismic events would have to be considered in the design of all surface facilities and large cut slopes. Active faulting has displaced wells in the field, and intersecting active faults with underground openings could lead to failure of those openings. The location of active faults would have to be identified prior to developing underground openings for a mining for access oil recovery system. The current high density of active oil wells throughout the McKittrick Field would interfere with any attempts at recovery of additional oil using mining techniques. Mining techniques are probably not feasible in the McKittrick Field until much of the present surface activity has ceased to be profitable.

Another potential target for oil recovery by surface mining techniques is the diatomite that extends from the ground surface down to approximately 150 ft over much of the field. Because of the low permeability of this material it has not produced oil during the past development of the McKittrick Field. Surface mining of this diatomite and subsequent retorting could prove to be an attractive method of recovering heavy oil from the McKittrick Field.

TABLE 1-7

MCKITTRICK FIELD, KERN COUNTY, CALIFORNIA

GENERAL INFORMATION

Reservoir Name:	Main Area-Upper	No. of Wells:	575
Discovery Year:	1896	Area, Acres:	1430
Formation:	Tulare, Olig Member of Reef Ridge Formation	Hand Use:	Oil production
Geologic Age:	Pliocene		

RESERVOIR INFORMATION

General		Structure	
Ave. Depth, ft:	400-1200	Faulting:	Minor
Gross Pay, ft:	1000	Folding:	Regional dip
Net Pay, ft:	265	Dip, °:	27
		Conditions	
Lithology:	Sand	BHT, °F:	110
Consolidation:	Unconsolidated-loosely consolidated	Initial BHP, psi:	450
		Current BHP, psi:	100
Porosity, %:	36	Initial Oil Sat.%:	60
Permeability, md:	1,000 (average)	Current Oil Sat.%:	42(e)
Trap Type:	Faulted monocline	Initial Wtr. Sat.%:	40
Barrier to Flow:	Yes, shale	Current Wtr. Sat.%:	58
Reservoir Drive:	Gas, gravity		

ROCK MECHANICS PARAMETERS

Strengh, psi	Low
Elastic Modulii:	Low
Hardness:	Low?

TABLE 1-7 (cont'd)

FLUID CHARACTERISTICS

Oil Gravity, API	15 (Range: 11-17)
Viscosity @ BHT, cp:	800
Sulfur Content, %:	.96
Carbon Residue, %:	2.0
Water Salinity, ppm:	6000

CHARACTERISTICS OF OVERLYING ROCK

Geologic Formation(s)	Miocene Shale, Pleistocene Diatomite
Geologic Age:	Miocene, Pleistocene, Recent
Lithology:	Shale, diatomite
Consolidation:	Unconsolidated - loosely consolidated
Structure:	Shale broken, pulverized, fractured
Strength, psi:	Low
Hardness:	Low
Fractures:	Highly Fractured Shale
Geologic Formation(s)	Reef Ridge
Geologic Age:	Upper Miocene
Lithology:	Shale
Thickness:	Greater than 500 ft.
Consolidation:	Loosely consolidated
Strength, psi:	Low ?
Hardness:	Low ?
Fractures:	Relatively unfractured
PRODUCTION DATA:	Field, includes several deeper reservoirs
Original Oil in Place, stb:	705,600,000 (field)

Table 1-7 (cont'd)

Cumulative Prod. (12/31/77):	
Oil, BBL:	159,343,068
Gas, MCF:	8,768,000
Oil Remaining in Place, stb:	546,200,000
bbl/Acre:	381,958
bbl/Acre-Ft:	1440

Enhanced Oil Recovery (Year, Type): 1962-present, cyclic steam

MC KITTRICK OIL FIELD

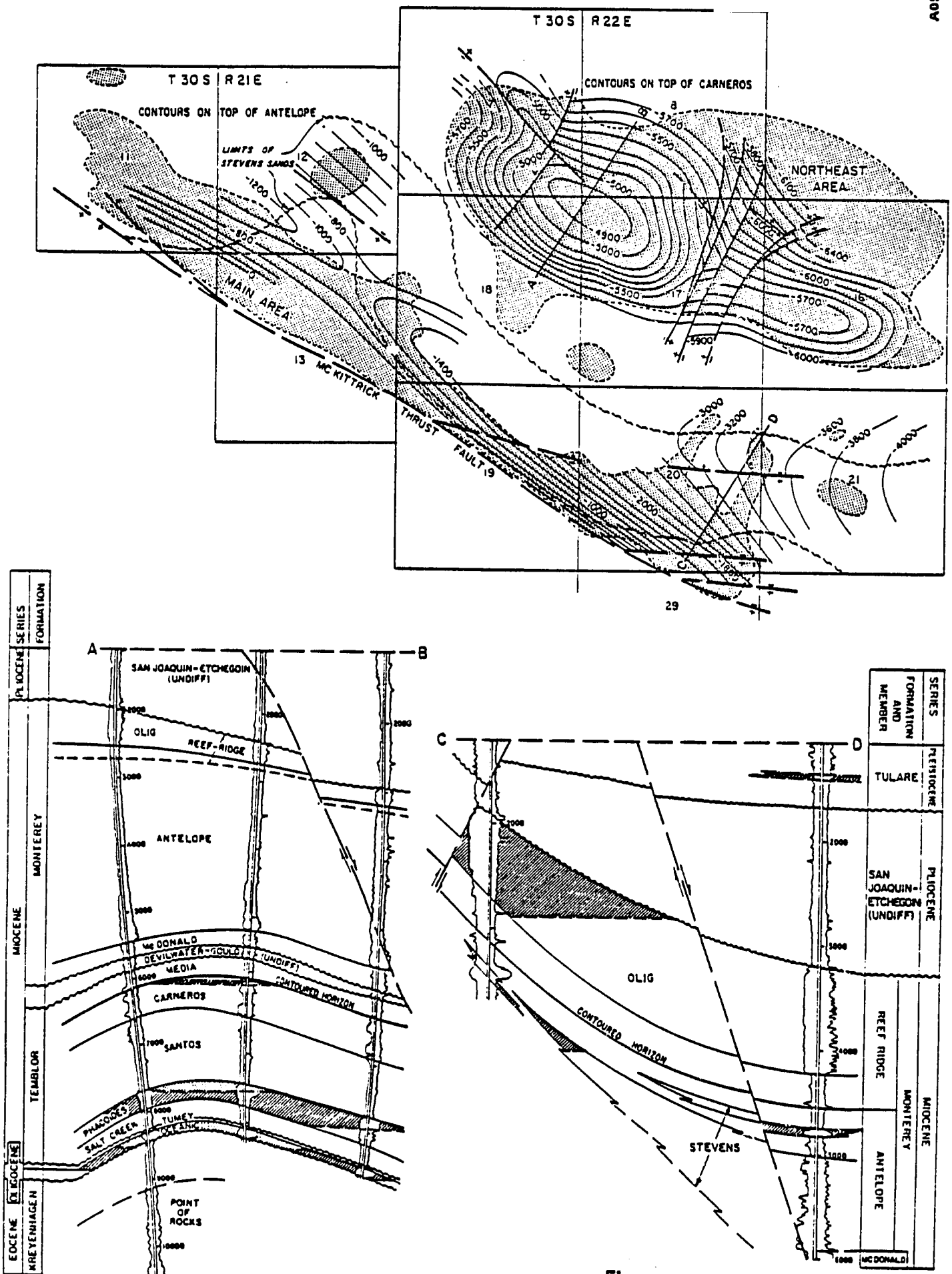

Figure 1-35
(Source: 62)

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1.3.5 McKittrick Oil Field - Northeast Area
(Northeast Area, Tulare-Olig Reservoir)

The Northeast Area of the McKittrick Oil Field was chosen for detailed study on the basis of a ranking of S-31 and M-88-(2). These rankings reflect the relatively shallow depths to the uppermost producting zones in the field, and thick gross pay of these and deeper producing zones. See Table 1-8 for a summary of all reservoir parameters.

The Northeast Area of the McKittrick Oil Field is located 14 miles northwest of Taft, Kern County, California. The field covers 1,450 proven acres in portions of Sec. 7, 8, 9, 16, 17, and 18, T.30S., R.22E. Eight operators controlled the acreage in 1965.

The topography at the Northeast Area of the McKittrick Field consists of the dissected foothills of the Temblor Range. Drainage is generally to the northeast. Ground elevations range from 850 ft to 1,125 ft above sea level and the ground surface is covered with scattered patches of chaparral.

1.3.5.1 Historical Production

The field was first discovered in 1906 when the Fearless Oil Company drilled the first well to a depth of 2,500 ft. Several other wells were drilled between 1908 and 1944 with little success. In 1944 Standard Oil Company of California completed a successful well which produced 28 barrels of oil per day from a depth of 1,944 to 2,030 ft. Many other wells produced oil from this zone, and gas was discovered over some portions of the field. Several deeper reservoirs were discovered during 1962 to 1965 ranging in depth from 3,000 ft to 10,200 ft. Very large oil and gas recoveries were successfully implemented in these zones. The largest of these was completed in 1965 by the Standard Oil Company of California and resulted in 9,000 barrels of oil and 800 mcf of gas per day.

Fire flood, cyclic steam injection, steam flood and water flood enhanced oil recovery techniques have been successfully used in the field since 1964

to produce heavy oil from these reservoirs. The producing formations at the northeast area of the McKittrick Field include the Tulare, Olig, Antelope, Carneros, Phacoides, Oceanic, and Point of Rocks zones which range in age from late Eocene to Pleistocene. Only the two uppermost producing zones were considered here, since the remainder of the producing zones are considered too deep to recover oil economically by mining.

1.3.5.2 Geology

For a description of the regional geology of the Northeast Area of the McKittrick Field, please refer to the description of the regional geology in Section 1.3.3.3 of this report. Figure 1-35 shows a geologic section and structure map of the reservoir.

The stratigraphy of the Northeast Area of the McKittrick Field is characterized by unconsolidated to weakly consolidated sediments ranging from late Eocene to Pleistocene in age. A brief description of the stratigraphic units from the ground surface down to the Reef Ridge Shale of the Reef Ridge Formation is given here. All stratigraphic units below the Reef Ridge Shale are considered beyond the economic limit for this study. A description of these units follows:

- <u>Tulare Formation</u> - Pleistocene deposits with an upper portion of pebbly conglomerate and sandstone that are friable, lenticular, poorly sorted and cross bedded. Minor thin beds of olive-green and blue-green mudstone. Approximate thickness 800-1000 ft. Below these beds is a 25- to 80- ft. thick zone of gray to brown sandstone that is poorly sorted, fiable and very micaceous. The basal portion consists of at least 400 ft of mudstone and siltstone that is poorly sorted, friable with indistinct bedding.
- <u>San Joaquin Formation</u> - Pliocene blue-green to gray-green mudstones and persistent minor siltstone and sandstone. Approximate thickness 800 to 1200 ft.

- Etchegoin Formation - Pliocene gray to gray-green and blue to blue-green sandy claystone, siltstone and fine grained sandstone. Poorly sorted with indistinct bedding throughout.

- Reef Ridge Formation - Upper Miocene.

  - Olig Sand - Up to 550 ft of gray pebbly conglomerate and sandstone that is fiable, poorly sorted and micaceous with angular to subangular grains. . 'gh porosity and permeability.

  - Reef Ridge Shale - Hard brown shale and silty shale that is highly siliceous, laminated and exhibits splintery fracture. Approximate thickness 60-350 ft.

The geologic structure of the Northeast Area of the McKittrick Field consists of three small, nearly symmetrical, gentle anticlines. The fold axes trend northwest and each limb dips gently, reaching a maximum dip of 20 degrees. The folds are well defined at the surface but become less apparent at depth. Several minor normal faults are defined within the field. The majority of these faults parallel the axes of the anticlines, trending northwest.

The Northeast Area of the McKittrick Field lies within a zone of high seismic risk, where Modified Mercalli Intensities of VIII or greater have been experience during historic time. Other work (Algermissen, 1976) suggests that a horizontal acceleration of 50 percent of gravity in bedrock has a 10 percent chance of being exceeded in 50 years. The high seismic risk at the Northeast Area of the McKittrick Field is related to tectonic activity along the San Andreas Fault and other active faults located near the field. No active faults are reported in the literature immediately within the Northeast Area of the McKittrick Field

The trapping mechanism in the Northeast Area of the McKittrick Field is a series of anticlines. Faulting plays a minor role in concentrating local oil and gas accumulations within the field, and changes in permeability in the producing sands within the field are thought to play an important role in local hydrocarbon concentrations within each reservoir.

1.3.5.3 Reservoir Characteristics

The producing zones under consideration in the Northeast Area of the McKittrick Field are the Tulare Formation and the Olig Member of the Reef Ridge Formation.

The producing zones in the Tulare Formation have an average depth of 650 ft throughout the field and an average net thickness of 400 ft. The Amnicola zone within the Tulare Formation is a continuous sand which has produced major amounts of gas since 1959. This zone is located approximately 800 to 900 ft below the ground surface throughout most of the field area and ranges from 25 to 80 ft thick. Production from the Tulare Formation ranks fourth among all the reservoirs in the Northeast Area of the McKittrick Field. Permeability within the producing zone is about 3,000 millidarcies and the porosity is about 35 percent. The Amnicola zone has significantly higher porosity (40 percent) and permeability (6,000 millidarcies), because the sand grains are better sorted and more rounded than in the other producing zones. The rocks of the Tulare Formation are unconsolidated.

Production from the Olig Member of the Reef Ridge Formation ranks lowest of all producing formations within the Northeast Area of the McKittrick Field. The producing zone from the Olig Member is 86 to 240 ft thick and had been developed over only 15 acres in 1965. Porosity and permeability average approximately 35 percent and 3,000 millidarcies, respectively. The rocks of the Olig Formation are unconsolidated.

Reported reservoir conditions for producing zones in the Tulare Formation and Olig Member include borehole temperatures of 89 degrees Fahrenheit, current oil saturation of 63 percent, and water drive mechanism in each

producing zone. Gas produced from the Amnicola zone flowed to the ground surface under reservoir pressure. These characteristics are sumarized in Table 1-8.

Characteristics of the oil within these two zones include average API gravity of 14.3 degrees ranging from 12 to 17 degrees, average sulfur content of 0.88 percent, and average water salinity of 4,200 ppm.

1.3.5.4 Groundwater

Abundant groundwater has been produced along with the oil and gas in the Northeast Area of the McKittrick Field. Cumulative production data indicates that three barrels of water have been produced for each barrel of oil on the average. This water containes a high percentage of dissolved solids and is commonly sulphurous. It is disposed of in unlined evaporation ponds.

1.3.5.5 Rock Mechanics

Very little information is available regarding the engineering characteristics of the rocks in the Northeast Area of the McKittrick Field, particularly information that would allow quantitative estimates of the behavior of these rocks in large cut slopes or a system of underground openings. A qualitative assessment of this behavior is given here based on the lithology, degree of fracturing and general rock descriptions in the literature.

All of the rocks under consideration in the Northeast Area of the McKittrick Field are unconsolidated except the shales of the Reef Ridge Formation. Drilling rates in the unconsolidated rocks are reported very high, 2000 ft. in two days or less.

The rocks overlying the reservoir rocks in the Northeast Area of the McKittrick Field include sandstones, pebbly conglomerates, shales and mudstones. These are all described as friable, probably due to their

unconsolidated condition. These rocks are expected to have low unconfined compressive strength, low hardness, rather low elastic modulii and are expected to require considerable support in underground openings. The mudstones and shales would probably exhibit swelling, slaking and shrinkage with changes in moisture content.

The reservoir rocks consist of sandstones and pebbly conglomerates. These rocks are described as friable and generally poorly sorted. Because the reservoir rocks are unconsolidated, they would probably have low unconfined compressive strength, low hardness and high porosity and permeability. Continuous support would probably be required for underground openings in these rocks. Drilling and excavation would be expected to proceed at high rates in these rocks.

Rocks below the reservoir (Olig Member) are described as hard shale and silty shale. They are probably consolidated, have low to moderate compressive strength and low hardness. They would probably have swelling, shrinkage and slaking in response to changes in moisture content.

1.3.5.6 Conclusions

The Northeast Area of the McKittrick Field is a potential target for both surface mining and underground mining for access techniques of heavy oil recovery. The surface area of the field is sufficient, proven acreage is about 1450 acres and the upper two producing zones are approximately 650 ft below the ground surface and have a combined gross thickness of 900 ft.

All rocks to the base of the lower producing zone are unconsolidated, making excavation for surface mining feasible using large, efficient earth moving equipment such as draglines or bucketwheel excavators.

The consolidated shales below the reservoir rocks are probably adequate for developing access drifts and other openings. They would appear to have low permeability to protect unlined openings from oil or gas seepage from adjacent reservoirs.

Potential problems to exploitation of the Northeast Area of the McKittrick Field include the high seismic risk of the area, potential high inflows of groundwater, potential for active faults, and interference with present oil recovery operations in the field. Potential high ground accelerations would have to be considered in the design of all surface facilities and large cut slopes. Active faulting is not reported in the field, but some faults exist in the field which displace the Pliocene and Pleistocene rocks in the upper producing zones. The location of potentially active faults would have to be identified prior to mine development to minimize adverse impacts to either surface pit slopes or underground openings. Large groundwater inflows would be expected into either an open pit or underground openings which intersected either the reservoir rocks or the rocks above the reservoir. Interference with existing active oil wells in the field must be considered: surface mining techniques may be impractical to implement until much of the present surface activity has ended.

TABLE 1-8

MCKITTRICK FIELD, KERN COUNTY, CALIFORNIA

GENERAL INFORMATION

Reservoir Name:	Northeast Area, Tulare-Olig		
Discovery Year:	1944	No. of Wells:	242
Formation:	Tulare, Olig Member of the Reef Ridge Formation	Area, Acres:	1450
Geologic Age:	Pliocene -Pleistocene	Land Use:	Range/oil Recovery

RESERVOIR INFORMATION

General		Structure	
Ave. Depth, ft:	650	Faulting	Minor
Gross Pay, ft:	900	Folding:	3 gentle anticlines
Net Pay, ft:	186-740	Dip, °:	20 maximum
Lithology:	Sandstone and conglomerate	**Conditions**	
Consolidation:	Unconsolidated	BHT, °F:	89
Porosity, %:	35	Initial BHP, psi:	Artesian flow
Permeability, md:	3000	Current BHP, psi:	Unknown
Trap Type:	Anticline	Initial Oil Sat.%:	66
Barrier to Flow:	Changes in permeability	Current Oil Sat.%:	63
Reservoir Drive:	Water drive	Current GOR, scf/bbl:	1088

ROCK MECHANICS PARAMETERS

Unconfined Compressive Strength, psi:	Low
Hardness:	Low

TABLE 1-8 (cont'd)

FLUID CHARACTERISTICS

Oil Gravity, ^{o} API: 14.3 (Range: 12 to 17)	
Sulfur Content,%:	0.88
Water Salinity, ppm:	4200

CHARACTERISTICS OF OVERLYING ROCK

Geologic Formation(s):	Tulare
Geologic Age:	Pleistocene
Lithology:	Conglomerate, Sandstone, Shale
Consolidation:	Unconsolidated
Structure:	Gentle anticlines
Unconfined Compressive Strength, psi:	Low
Hardness:	Low

CHARACTERISTICS OF UNDERLYING ROCK

Geologic Formation(s):	Reef Ridge Shale
Geologic Age:	Upper Miocene
Lithology:	Shale and Silty Shale
Thickness, ft.:	350 maximum
Consolidation:	Consolidated
Structure:	Very gentle fold
Unconfined Compressive Strength, psi:	Low - moderate
Hardness:	Low - moderate
Fractures:	Unknown

TABLE 1-8 (cont'd)

PRODUCTION DATA
(probably figures for all reservoirs within the field)

Original Oil in Place, stb:		300,000,000
Cum Prod (Dec., 1977):	Oil, bbl:	11,043,738
	Gas, mcf:	2,451,000
	Water, bbl:	33,337,000
Oil Remaining in Place, stb:		289,000,000
Bbl/acre:		199,300
Bbl/acre - ft:		1,644
Enhanced Oil Recovery (Year, Type):		1964-present; cyclic steam, steam flood, water flood, fire flood

1.3.6 Mount Poso Oil Field, Kern County, California (Main Area Vedder Reservoir)

The Main Area of the Mount Poso Oil Field has a ranking of M-63 due to its resource of over 170,000 bbl/acre within 2220 proved acres and its relatively shallow depth of 1800 ft. See Table 1-9 for a summary of reservoir characteristics.

Located approximately 12 miles northeast of the city of Bakersfield in the southeastern part of the San Joaquin Valley, the Mount Poso Field covers over 50 square miles and is second only to the nearby Kern River Field in cumulative production. It is in an area of low foothills of the Sierra Nevada Mountains.

Although six separate areas have been identified with the Mount Poso Field, this report is concerned only with the main area, which is the largest.

1.3.6.1 Historical Production

Mount Poso Oil Field was discovered in 1926 by Shell Oil Company when they drilled Vedder #1 well, which produced 300 barrels of oil per day of 16° API oil from the Pyramid Hill and Upper Vedder sands.

In 1963, Shell Oil tested sands below the Upper Vedder and found a new oil zone which was named the Lower Vedder. Since that time, two more underlying oil zones were discovered and named, respectively, the Third and Fourth Vedder Sands.

In 1952 secondary oil production was initiated by many operators using waterflooding techniques. Up to 370,000 barrels of water was injected. In 1963, a cyclic steam program was initiated by Shell, and in 1972 Shell disposed of 29,926,000 barrels of water within the reservoir by injection.

Due to an active water drive and other favorable conditions, over 160 million barrels of oil, or about 30 percent of the original oil in place, have been recovered.

1.3.6.2 Geology

The Mount Poso Oil Field is situated on the southeastern flank of the San Joaquin Basin, north of the Kern River Arch, an east-west structural feature. Please refer to Section 1.3.3.3 of this report for a description of the regional geology, Figure 1-37 for a structure contour map, and Figure 1-38 for a geologic section of the reservoir.

The stratigraphy of the area is outlined in an excellent stratigraphic section prepared by the California Division of Oil and Gas which is reproduced in this report as Figure 1-36 (Albright, 1957).

The structure of the area is a southwest dipping homocline cut by a system of normal faults which generally parallel the strike of the beds. The dip of the beds range from 4 to 7 degrees and apparently have not been folded except for tilting.

The main area of the field is cut by the Mount Poso Fault, a wide fracture zone over 300 feet wide made up of a series of step faults which, in general, parallel the strike of the beds and dips 60 to 70 degrees to the east. The eastern block has been downthrown as much as 500 feet. This fault, being the trapping mechanism, provides lateral closure to the reservoir where it cuts across the strike of the beds.

The area is sufficiently far enough from the San Andreas Fault System so that strike-slip movement is not experienced locally. However, as in the case of the Kern River Oil Field, the area is very prone to ground shaking from earthquakes up to magnitude 8 of the Richter Scale, and surface facilities will have to be designed to resist attenuated ground movement.

1.3.6.3 Reservoir Characteristics

The Pyramid Hill Zone, which overlies the Vedder, is a very fine-grained, tight oil sand up to 160 feet thick and is a minor contributor to oil production in the main area. As the base of the Pyramid Hills is a "grit"

zone, a distinctive bed of poorly sorted fine to coarse sand with black chert granules and quartz pebbles in a clayey silt matrix up to 10 feet thick, which marks the top of the underlying Vedder Formation.

The Upper Vedder pay zone consists of fine to medium, silty, loose sand with basal thin, hard calcareous streaks of sandstone. It is 40 to 50 feet thick and underlain by 20 to 35 feet of fine tight sands. A 10-foot impermeable grit zone lies between the Upper and Lower Vedder.

Underlying pay zones include the Lower Vedder, Third Vedder, and Fourth Vedder sands. The lower Vedder is about 80 feet thick and is second in importance in cumulative production. The Third Vedder Zone varies from 100 to 170 feet thick and is separated from the Lower Vedder by a 10 foot silt bed. The Fourth Vedder was discovered in 1957 and is productive up to the Mount Poso Fault.

The top of the Vedder Zone varies from 1,500 to 2,500 feet deep. All of the Vedder Zones combined have an average gross pay of 350 feet, net pay of 292 feet, porosity of 33 percent and permeability of 10,000 centipoises. Although the borehole pressure has declined from 450 to 100 psi, an active water drive still exists in the reservoir. Oil saturation has declined from 60 percent to 42 percent, whereas water saturation has increased from 40 percent to 52 percent.

The oil itself is heavy with an average API gravity of 16 degrees, a viscosity of 280 centipoises at a borehole temperature of 110 degrees Fahrenheit, and a sulfur content of .68 percent.

1.3.6.4 Groundwater

The Mount Poso area is within the Kern River hyrdologic unit which covers nearly 700 square miles, has an estimated groundwater storage capacity of 10,790,000 acre-feet and a specific yield of 11 percent (Davis, 1959). The water quality is not as good as it is at Kern River due to a higher percentage of dissolved salts, up to 1,400 ppm. It can be assumed the area has a large amount of recharge due to the active water drive.

1.3.6.5 Rock Mechanics Considerations

The overlying rock consists of six separate formations, each with its own characteristics and parameters. In general, the rock consists of unconsolidated sediments of gravel, sand, silt, and clay which will require extensive support. Samples of each layer would have to be taken and tested to determine the support requirements for underground openings.

The underlying non-marine Walker Formation is composed of sands, gravels and green clay interbeds. There is not enough information to determine if this could function as a level for tunnel openings.

1.3.6.6 Conclusions

The Mount Poso Oil Field remains a potential target for demonstrating for access technology. However, due to its greater depth as compared to other targets, it should be put on the back burner for a while until shallow targets have proved the effectiveness of this technology. Potential problems include defining the overlying deposits, groundwater, and conflicts with current land use.

TABLE 1-9

MOUNT POSO OIL FIELD, KERN COUNTY, CALIFORNIA

GENERAL INFORMATION

Reservoir Name:	Main Area, Vedder		
Discovery Year:	1926	No. of Wells:	338
Formation:	Vedder	Area, Acres:	2220
Geologic Age:	Miocene	Land Use:	Unknown

RESERVOIR INFORMATION

General		Structure	
Avg. Depth, ft:	1806	Faulting:	Minor
Gross Pay, ft:	350	Folding:	Regional dip
Net Pay, ft:	292	Dip, degrees:	27
No of Pay Zones:	3	Conditions	
Lithology:	Sand	BHT, °F:	110
Consolidation:	Semi-Consolidated	Initial BHP, psi:	450
Heterogeneity:	Unknown	Current BHP, psi:	100
Porosity, %:	33	Initial Oil Sat, %:	60
Permeability, md:	10,000	Current Oil Sat, %:	42(e)
Trap Type:	Faulted Homocline	Initial Wtr. Sat, %:	40
Barrier to Flow:	Yes	Current Wtr. Sat., %:	58
Reservoir Drive:	Water drive		

ROCK MECHANICS PARAMETERS

Unconfined Compressive Strength, psi:	Low
Elastic Modulii:	Low
Hardness:	Low to Moderate

TABLE 1-9 (cont'd)

FLUID CHARACTERISTICS

Oil Gravity, °API	16 (Range: 12 to 17)
Viscosity @ BHT, cp:	280
Sulfur Content, %	.68
Water Salinity, ppm:	1400

CHARACTERISTICS OF OVERLYING ROCK

Geologic Formation(s):	Includes many (See Stratigraphic Column, Figure 36)
Geologic Age:	Miocene to Recent
Lithology:	Sands, Silts, Claystones
Thickness, ft:	1800
Consolidation:	Mostly unconsolidated
Heterogeneity:	Varies
Unconfined Compressive Strength, psi:	Low
Elastic Modulii:	Low
Hardness:	Low

CHARACTERISTICS OF OVERLYING ROCK

Geologic Formation(s):	Walker
Geologic Age:	Eocene
Lithology:	Coarse sands and gravel with green clay interbeds
Thickness, ft:	250-850
Consolidation:	Unconsolidated to Semi-Consolidated
Unconfined Compressive Strength, psi:	Low
Elastic Modulii:	Low
Hardness:	Low to Moderate

TABLE 1-9 (cont'd)

PRODUCTION DATA

Original Oil in Place, stb:	547,000,000
Cum. Prod. (12/31/77): Oil, bbl:	161,460,360
Oil Remaining in Place, stb:	386,000,000
Bbl/acre:	173,874
Bbl/acre-ft:	1074
Secondary Production (Year, Type):	1952-1960, water flood 1972, water disposal
Tertiary Production (Year, Type):	1963, cyclic steam steam drive

TABLE I
GENERALIZED STRATIGRAPHIC SECTION
MOUNT POSO OIL FIELD

Epoch		Formation or Equivalent	Thickness (feet)	Lithology
Recent		Alluvium	very thin	Unconsolidated recent stream deposits of gravel, sand, silt and clay
Pleistocene & Pliocene		Kern River Series	0-850′ ±	Non-Marine Poorly-sorted, tan, green, bluish pebbles, boulders, sandy clay, and silt (Etchegoin marine finger possibly present near base in most westerly portion of the field)
Miocene	Upper	Santa Margarita Sand	0-150′ ±	Medium grained light gray sand
	Middle	Round Mountain Silt	0-200′ ±	Firm, fine grained, brown siltstone
		Olcese Sand	400-750′ ±	Unconsolidated, medium to coarse gray sand with occasional pebble and siltstone beds—grading to fine grained sand with clay and silt in lower portion
	Lower	Freeman—Jewett Silt	200-800 ±	Fine, brownish-gray, sandy siltstone and claystone beds, ashy in upper portion
		Pyramid Hill Sand (Jewett Sand)	50-240 ±	Silty, light gray to brown fine sand, almost siltstone (oil shows over most of field) grit zone at base
		Vedder Sand — Upper, Lower, Third, Fourth	50-850 ±	Blue-gray, medium grained, well sorted clean sand, interbedded with brown organic siltstone members. Basal members transgress upward on E. side of field into non-marine Walker formation
Eocene		Walker	250-850 ±	Non-Marine Coarse sands and gravels, green clay interbeds. (Thin Famoso marine finger may possibly be present in SW. corner of field)
Jurassic		Basement Complex		(Schist—Dominion area only) Granitic—all other areas

Figure 1-36
(Source: 45)

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MOUNT POSO OIL FIELD

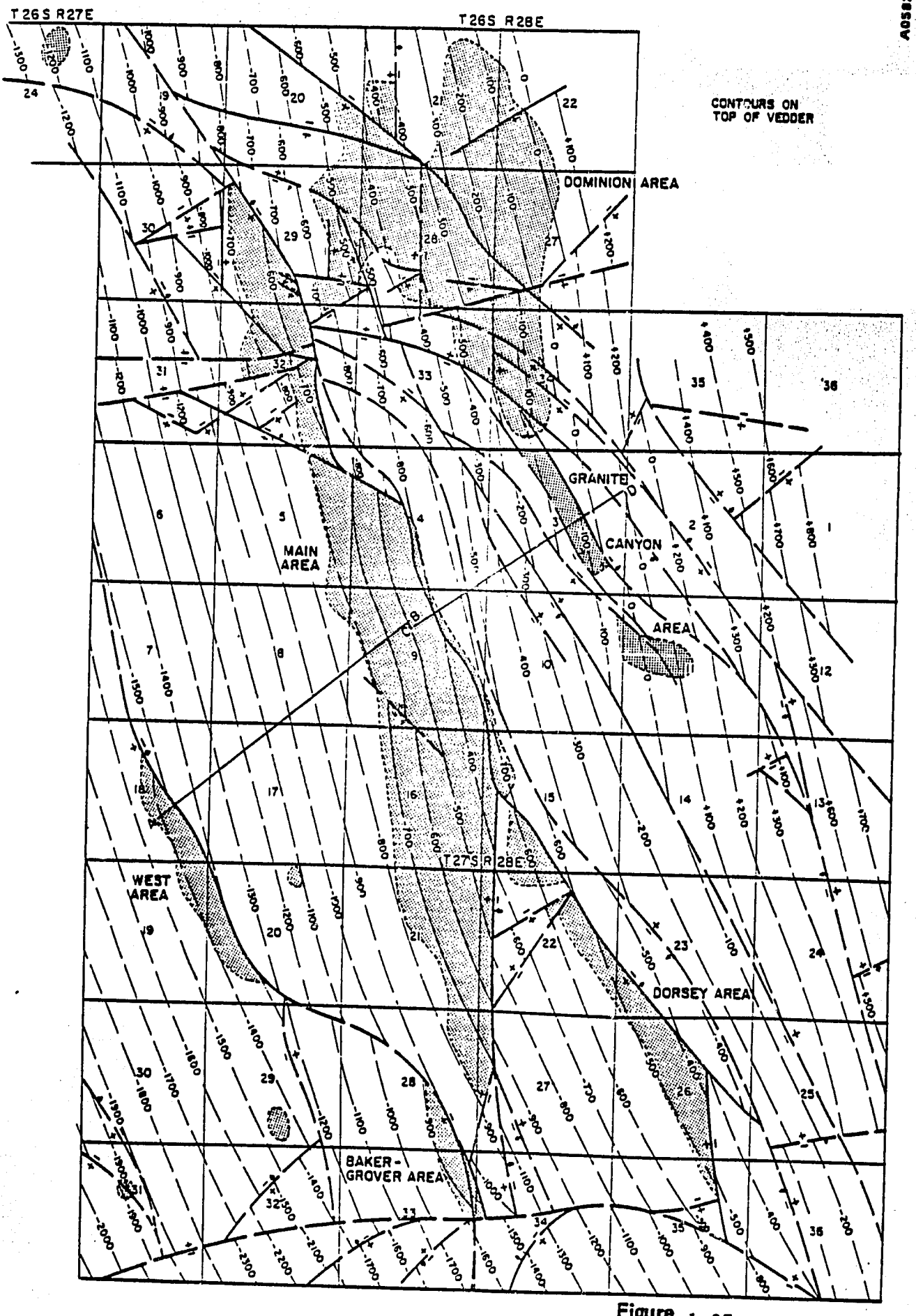

Figure 1-37
(Source:62)

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MOUNT POSO OIL FIELD

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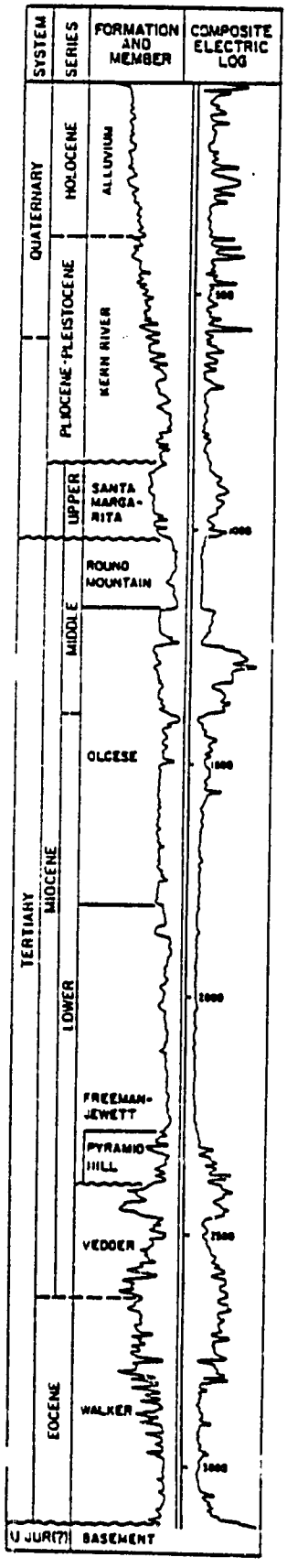

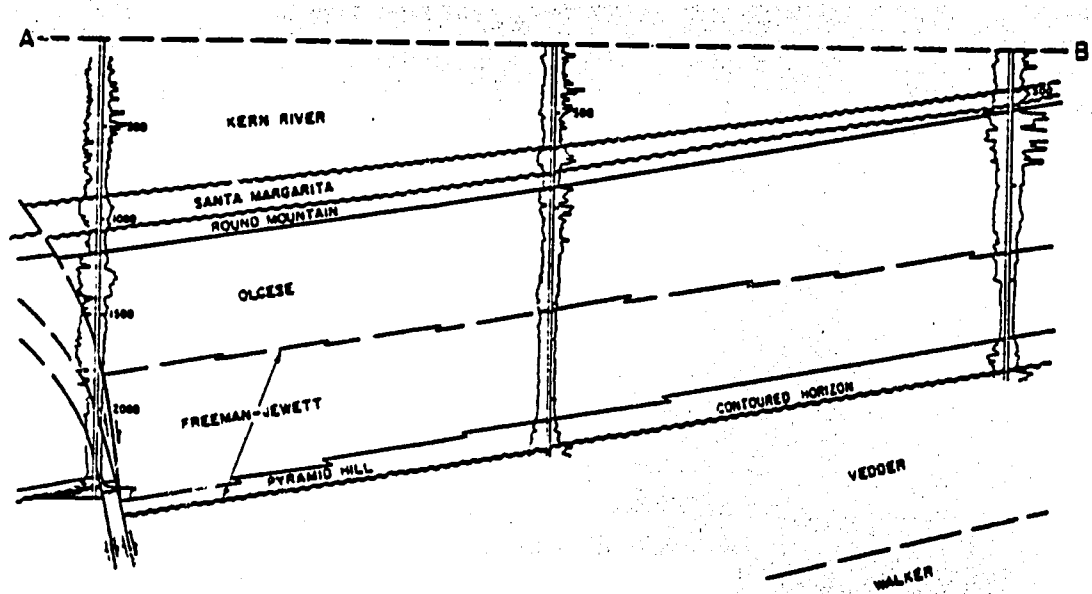

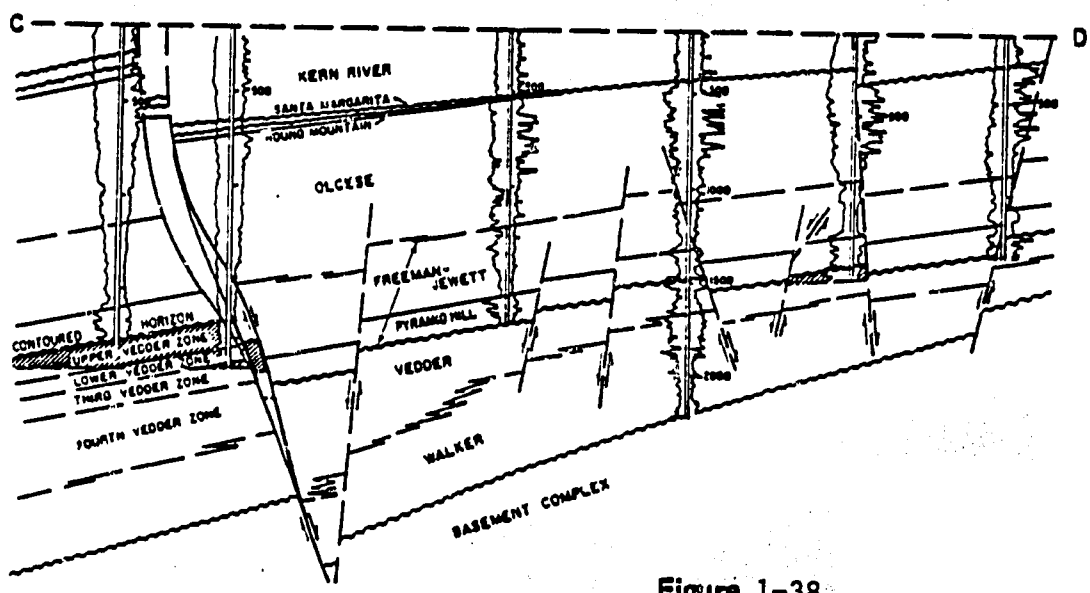

Figure 1-38
(Source: 62)

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1.3.7 Placerita Field, Los Angeles County, California (Upper and Lower Kraft Reservoir)

The Placerita Field was chosen for detailed study on the basis of a ranking of S-120 and M-126. This is due to the shallow depth of the producing formations (600-1,700 ft), an overburden/interburden ratio ranging from 3:1 to 6:1, and a high oil saturation of 1263 bbl/ac-ft. In addition, it covers 700 acres and has 378,857 bbl/acre. This field would be best developed by a combination of surface mining and mining for access technology. See Table 1-10 for a summary of reservoir characteristics.

The Placerita Field is about two miles west of the town of Newhall in the new part of Los Angeles County. It is situated along Placerita Canyon and is easily accessible by the Sierra Highway, which crosses the field. The field is within the Angeles National Forest in an area of rolling hills rising 500 ft above the valley floor. The land is used predominantly for grazing.

1.3.7.1 Historical Production

Four wells were drilled in the area between 1920 and 1938 which yielded a maximum of 10 barrels of oil per day of heavy black crude. The field itself was not discovered until 1948, when Nelson-Phillips completed Kraft No. 1, which yielded 100 barrels of oil per day of 16 degrees API oil. The area was named the Kraft-York Area, and in 1949, completion of Juanita #1 well, which yielded 340 barrels of oil per day of 22 degrees API oil, opened up another area, the Juanita Area. Primary production was completed by 1954 and secondary production was initiated with a water flooding program by Crown Central Petroleum Corp. Tertiary production was begun in 1964 by experimenting with cyclic steam and in situ combustion. Cyclic steam proved to the most successful and was carried out until 1971. The field currently has over 200 producing wells and 700 productive acres. It is believed only 14 percent of the original oil in place has been recovered, leaving up to 265 million barrels of oil remaining in place.

1.3.7.2 Geology

Three important geologic provinces adjoin in the Placerita Canyon area, which complicates the geology of the area. The field itself lies at the eastern end of the Ventura Basin but is also adjacent to the western edge of the San Gabriel Mountains and the northwest portion of the Los Angeles Basin.

Please refer to Section 1.3.3.3 of this report for a description of the regional geology, Figure 1-39 for a structure contour map, and Figure 1-40 for a geologic section of the field.

The stratigraphy of the area consists of Tertiary and Quaternary sediments which are semi-consolidated to unconsolidated sandstones, conglomerates, siltstones, and shales. The detailed stratigraphy is outlined below:

STRATIGRAPHY

AGE	FORMATION	DESCRIPTION
Recent	Alluvium	These stream deposits of the Santa Clara River consist mostly of sands and gravels up to 100 ft thick.
Upper Pleistocene	Terrace Deposits	These deposits overlie much of the Placerita Field and consist of coarse, poorly sorted conglomerate, gravel and sand with an approximate thickness of 675 ft.
Lower Pleistocene	Saugus	The Saugus overlies the producing zones and consists mostly of light colored

conglomerates and coarse sandstone, much of which is cross-bedded and unconsoli- dated. The approximate thick- ness is 2,000 ft.

Upper Pliocene	Sunshine Ranch Member	The Sunshine Ranch consists of continental and blackish water conglomerates, green sandstone and mudstone, thin freshwater limestone, and red beds which reach a maximum thickness of 1,300 ft.
Upper Pliocene	Upper Pico Member	The Upper Pico consists of well-stratified light-colored coarse sandstone, conglomerate, and interbedded fossiliferous siltstone up to 1,000 ft thick.
Middle Pliocene	Lower Pico	The Lower Pico includes white pebble conglomerate, coarse sandstone with fine sandstone lenses, thin, brown siltstone beds, much of which is cross bedded. It reaches 700 ft thick.
Lower Pliocene	Repetto	The Repetto is divided into an upper siltstone member and the lower member which consists of marine sandstone and conglomerate with a maximum thickness of 400 ft.

387x

Upper Miocene	Mint Canyon	This formation consisting of continental deposits appears only north of the San Gabriel fault and is up to 2,400 ft thick.
Eocene	Domengine Martinez	The oldest sedimentary deposits in the area consist of well indurated shale, sandstone, and conglomerate.

Structural deformation of the sedimentary deposits began in Middle Miocene time with uplift of the San Gabriel Mountains causing tilting of the beds 18 degrees to the northwest. Two major fault zones border the field: the San Gabriel and the Whitney. The San Gabriel Fault Zone is the limit of production to the north and has a general strike of N65W. It is parallel to the San Andreas Fault System and is closely related with 700 feet of throw and at least 2 1/2 miles of horizontal displacement. The San Fernando earthquake occurred along the San Gabriel Fault Zone in 1971 and caused great structural damage. The Whitney Fault strikes north-south and represents the limit of production to the east. The west block was upthrown relative to the east side in Upper Pliocene time. Minor faults such as the Orwig have no bearing on the trapping mechanism but separate pools of differing gravity. The terrace deposits overlying the field are highly faulted.

1.3.7.3 Reservoir Characteristics

The producing zones have been named the Upper and Lower Kraft and appear to lie in the basal Sunshine Ranch and Upper Pico. The Upper Kraft Zone is overlain by a well-defined shale 70-100 ft thick which has been named the Upper Kraft Shale. The Upper Kraft Zone itself varies from 170 to 250 ft thick. In between the Upper and Lower Kraft zones is a fairly uniform shale 20-50 ft thick which has been named the Lower Kraft Shale. The Lower Kraft Zone varies from 300 to 450 ft thick. The Upper and Lower Kraft

zones are highly lenticular and consist of cross-bedded sandstone, siltstone, sandy mudstone, and conglomerate. The Upper and Lower Kraft shales are highly variable with varying amounts of shale. Underlying the productive zones are shales, sandstones, and conglomerates of Pico age.

The reservoir itself has an average porosity of 33 percent, permeability of 2,500 millidarcies, and average borehole temperature of 99 degrees. The initial oil saturation was 60 percent and is currently 50 percent with a gas-oil ratio of 16 percent. There are no active drives in the reservoir and most production was due to gravity drainage.

The oil has an API gravity of 16 degrees, viscosity of 320 centipoise at borehole temperature, sulfur content of 0.3 percent and a carbon residue of 0.3 percent. The water contains 2,600 ppm of total dissolved solids.

1.3.7.4 Groundwater

Data was not available for groundwater in the Placerita Field.

1.3.7.5 Rock Mechanics

Little can be inferred about rock mechanics from the information available; however, from the description of the rock, it appears most of the material is unconsolidated and highly variable. The rock varies from siltstone to sandstone, to poorly sorted conglomerate. The overlying terrace deposits and Saugus Formation could be easily excavated using low cost surface mining equipment such as draglines and bucketwheel excavators. As much as half of the field could be developed as a surface mine and then the rest could be developed using mining for access technology. A review of existing well data would be required to determine the best place to drill the shaft and tunnels in underlying formations due to the highly variable nature of the formations. The Lower and Upper Kraft shales and the underlying Pico formations are all possibilities. All the mine workings would require considerable support due to the unconsolidated nature of the rock.

1.3.7.6 Conclusions

The Placerita Field is a target for mining of heavy oil. The major obstacle is that the field lies just south of a major active fault system and could experience severe ground shaking during the active project life. All the mine workings would require a considerable safety factor against the earthquake hazard. In addition, it is uncertain if there is a conflict of land use at this time. The Sierra Highway crossing the field would have to be rerouted.

TABLE 1-10

PLACERITA OIL FIELD, LOS ANGELES COUNTY, CALIFORNIA

GENERAL INFORMATION

Reservoir Name:	Upper & Lower Kraft		
Discovery Year:	1948	No of Wells:	205
Formation:	Saugus-Pico	Area, Acres:	700
Geologic Age:	Pliocene	Land Use:	Grazing

RESERVOIR INFORMATION

General		Structure	
Avg. Depth, ft:	1527	Faulting:	Two major faults, several minor
Gross Pay, ft:	450 to 900	Folding:	Regional Dip
Net Pay, ft:	300 to 450	Dip, °:	18
No of Pay Zones:	3	**Conditions**	
Lithology:	Sand/Conglomerates	BHT, °F:	99
Consolidation:	Unconsolidated	Initial Oil Sat.%:	60
Heterogeneity:	High	Current Oil Sat.%:	50
Porosity, %:	33	Current Wtr. Sat.%:	16
Permeability, md:	2,500		
Trap Type:	Structural-faulted homocline		

TABLE 1-10 (cont'd)

ROCK MECHANICS PARAMETERS

Unconfined Compressive Strength, psi:	Low
Elastic Modulii:	Low
Hardness:	Low

FLUID CHARACTERISTICS

Oil Gravity, °API:	16 (Range: 9 to 23)
Viscosity @ BHT, cp:	320
Sulfur Content, %:	.3
Carbon Residue, %:	.3
Water Salinity, ppm:	2600

CHARACTERISTICS OF OVERLYING ROCK

Geologic Formation(s):	Terrace Deposits, Sagus
Geologic Age:	Pleistocene
Lithology:	San & Gravel, Conglomerates and Sandstone
Thickness, ft:	Terrace Deposits (up to 675) Sagus (up to 2000)
Consolidation:	Unconsolidated
Heterogeneity:	High
Structure:	Highly Faulted
Unconfined Compressive Strength, psi:	Low
Elastic Modulii:	Low
Hardness:	Low

TABLE 1-10 (cont'd)

CHARACTERISTICS OF UNDERLYING ROCK

Geologic Formation(s):	Lower Pico
Geologic Age:	Middle Pliocene
Lithology:	Pebble Conglomerate and Coarse Sandstone
Thickness, ft:	700
Consolidation:	Unconsolidated
Heterogeneity:	High
Unconfined Compressive Strength, psi:	Low
Elastic Modulii:	Low
Hardness:	Low to moderate

PRODUCTION DATA

Original Oil in Place, stb:		307,200,000
Cum. Prod. (12/31/77):	Oil, bbl:	42,016,974
	Gas, mcf:	6,795,000
Oil Remaining in Place, stb:		265,200,000
Bbl/acre:		1263
Secondary Production (Year, Type):		1954, waterflood
Tertiary Production (Year, Type):		1964, cyclic steam

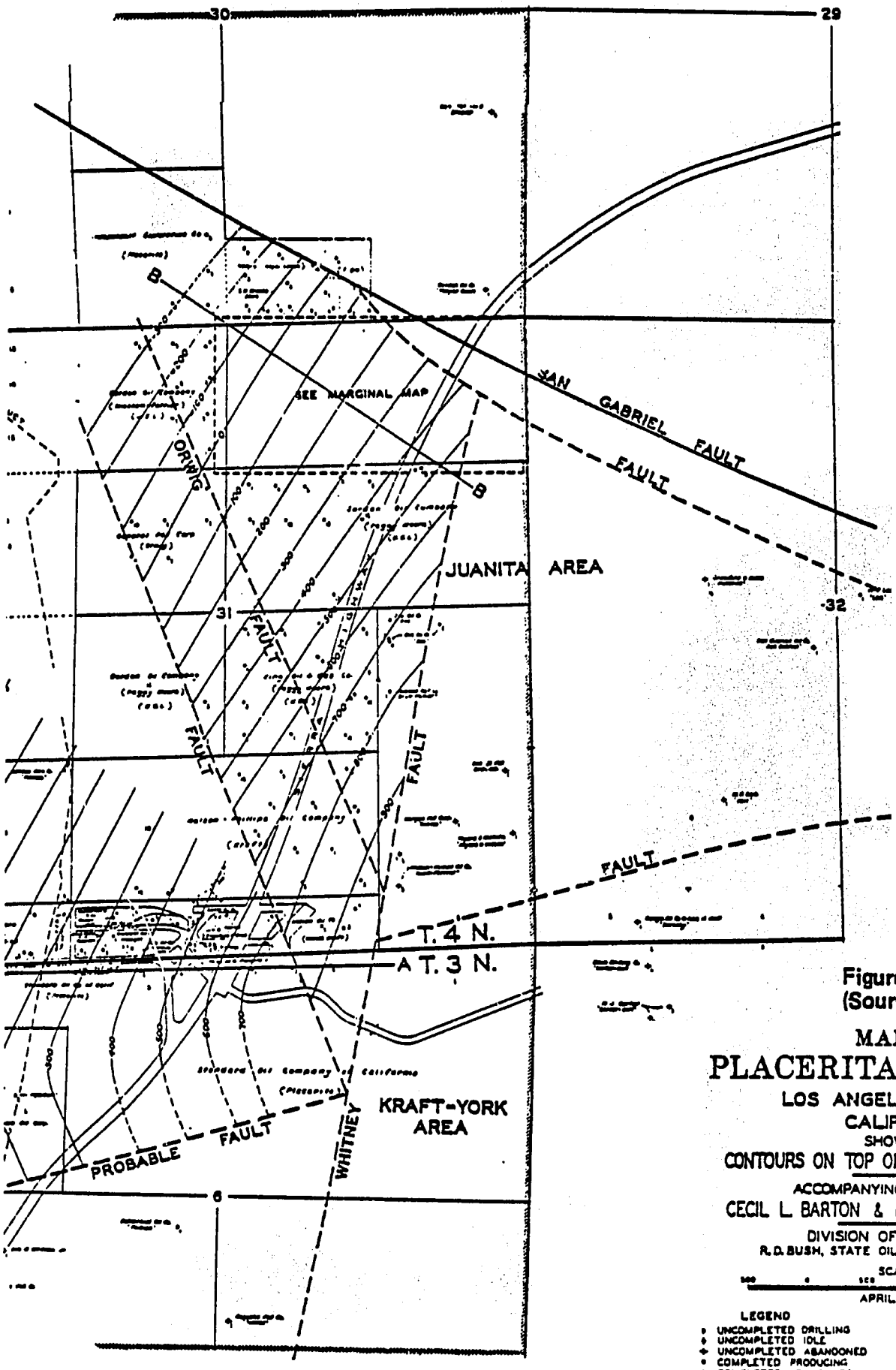

Figure 1-39
(Source: 53)

MAP OF
PLACERITA OIL FIELD
LOS ANGELES COUNTY
CALIFORNIA
SHOWING
CONTOURS ON TOP OF LOWER KRAFT ZONE
ACCOMPANYING REPORT BY
CECIL L. BARTON & NORMAN N. SAMPSON
DIVISION OF OIL & GAS
R.D. BUSH, STATE OIL & GAS SUPERVISOR
SCALE
APRIL 1950

LEGEND
- UNCOMPLETED DRILLING
- UNCOMPLETED IDLE
- UNCOMPLETED ABANDONED
- COMPLETED PRODUCING
- COMPLETED ABANDONED

DATUM - SEA LEVEL
CONTOUR INTERVAL 100 FT.

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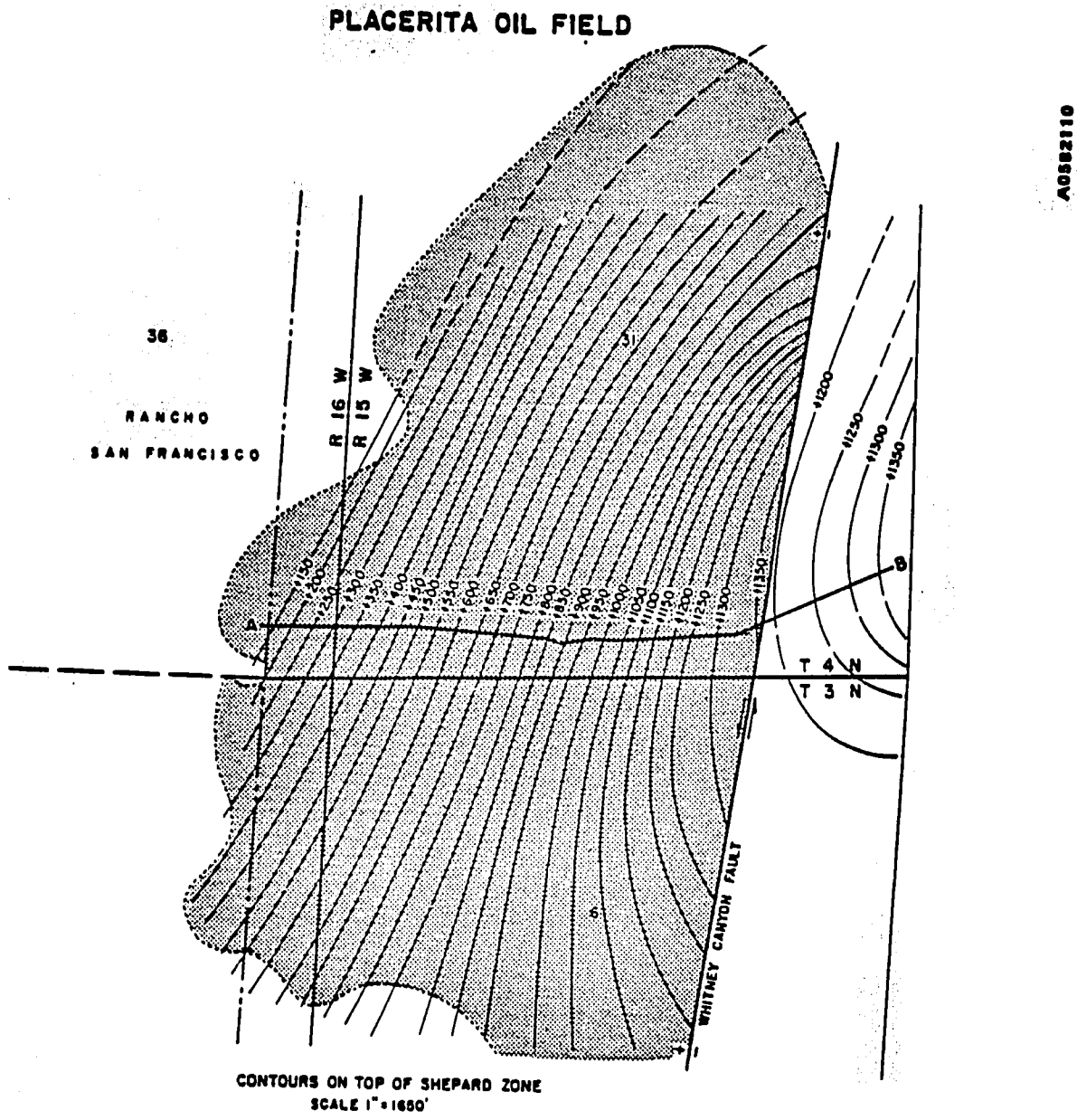

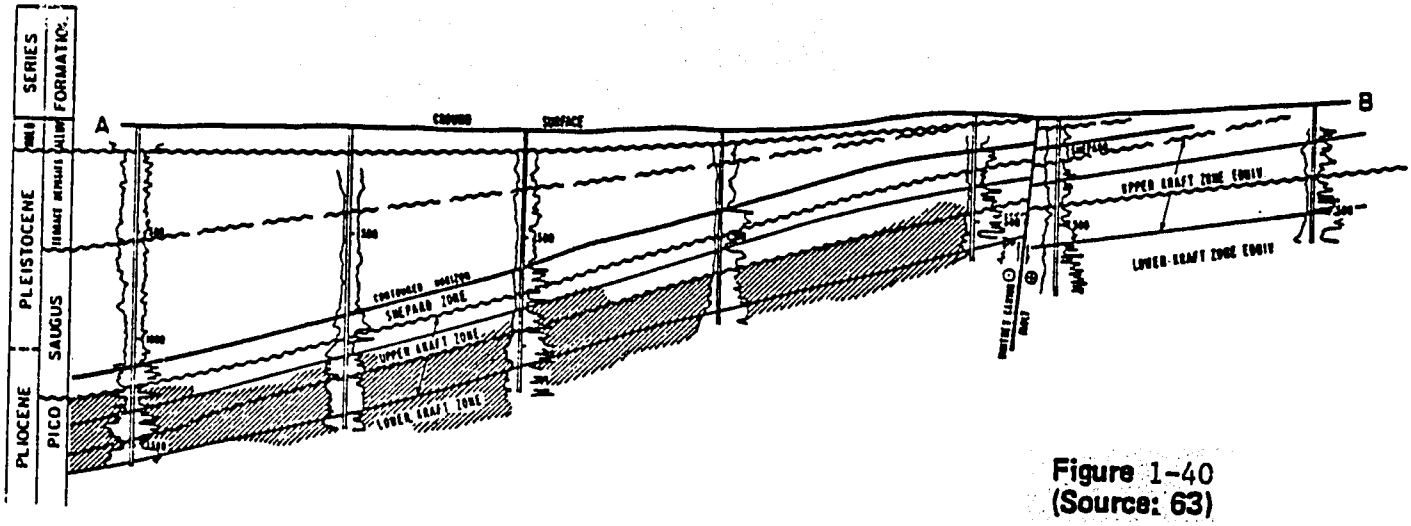

Figure 1-40
(Source: 63)

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1.3.8 Slocum Field, Anderson County, Texas
(Carrizo Sand Reservoir)

The Slocum Oil Field was the only field chosen for detailed study outside of California. It has a ranking of M-52, primarily due to its shallow depth and a resource of 42,000 bbl/acre. See Table 1-11 for a summary of reservoir characteristics.

The field is located within Railroad Commission District No.6 in the northeastern portion of Texas, approximately 9 miles southeast of the town of Palestine, and 40 miles southwest of the giant East Texas Field. It is located on a part of the Gulf Coastal Plain which is characterized by uplands of low relief and broad river valleys. Figure 1-41 shows the location of the field, a viscosity-temperature curve, and a type log.

1.3.8.1 Historical Production

The Slocum Field was first discovered in 1935 by Gulf Oil Company with oil production from the Woodbine and Sub-Clarksville sands. Due to marginal recovery, the field was abandoned until 1956, when discovery of its new reservoir on the southeast flank of Slocum Dome was made. Much of the production came from the deep Woodbine Formation. The Carrizo itself did not become an important reservoir until 1964, when a steam drive program was initiated.

Typical primary production wells produced only 1-2 barrels of oil per day, which led to recovery of about 390,000 barrels of heavy oil from the Carrizo Sand, or about 1 percent of the original oil in place. This is primarily due to the high viscosity of the oil at borehole temperature. By injecting steam in a water sand which underlies the oil zone, production was increased tremendously so that up to 40 percent of the original oil in place can be recovered. Tenneco abandoned its tertiary project in 1978. Shell is expected to continue with its steam/water injection program until 1984. Estimates of the remaining oil in place are as high as 106 million barrels of heavy oil. No significant gas production has come from the Carrizo Sand.

1.3.8.2 Geology

The Slocum Dome lies in northeast Texas within the Tyler Basin, a major depression in the East Texas embayment. The basin is bounded by the Sabine uplift to the east, the Ouachita Mountains of southeastern Oklahoma to the north, and the Bend Arch to the west. In its deepest portion the basin is filled with 15,000 feet of Jurassic, Cretaceous, and Tertiary sediments. The Mexia-Talco Fault Zone cuts through the north and west flanks of the Tyler Basin and has an average width of five miles. At least 17 piercement salt domes have been found in the area (Landes, 1970). Please refer to Section 1.3.3.6 for a description of the regional geology.

The Slocum Dome is a deep-seated salt dome characterized by an elliptical outline in map view and a central graben located perpendicular to its elongate axis(Read, 1959). It is one of the largest salt domes in northeast Texas, being 8 miles long and 6 miles wide. Faulting was active during Upper Cretaceous time but current seismic activity is very low.

A detailed description of the rocks cannot be given here, but in general, the section is characterized by an abundance of limestone, alternating with sandstones, siltstones, and mudstone in semi-consolidated to consolidated deposits.

1.3.8.3 Reservoir Characteristics

In the Slocum Dome area heavy oil is produced from the Carrizo Formation, the lowest member of the Clairborne Group, and is composed of laminated or thinly stratified white to red sands and sandy clays up to 200 feet in thickness. The Carrizo is further divided into a lower and upper member divided by a shale up to 10 feet in thickness. The Upper Carrizo Sand is characterized by a 48-foot thick oil zone overlying on 2-foot-thick water zone. The pay zone is shallow (500-600 ft depth) and averages 25 feet of net pay. The trapping mechanism is predominantly anticlinal, bounded on the north by a fault and elsewhere by the oil-water contact.

The Carrizo Sand is generally very clean, has an average porosity of 37 percent, permeability which varies from 2,600 to 3,500 millidarcies, a current borehole pressure of 120 psi, and an estimated oil saturation of 61 percent. Gravity drainage is the predominant reservoir drive.

The heavy crude has an API gravity of 19 degrees, viscosity which varies from 1000 to 3000 centipoises at a borehole temperature of 75 degrees Farenheit, and a borehole pressure of 110 pounds per square inch.

1.3.8.4 Groundwater

During the steam drive project an abundant supply of groundwater was discovered in the 1,500-foot-deep Wilcox Sand. Three gravel-packed wells supplied 26,000 barrels of high quality water per day with only 10 ppm of total dissolved solids. The water contains both sulfate-reducing and sulfite-oxidizing bacteria.

1.3.8.5 Rock Mechanics

No information was readily available on the overlying formations.

The Carrizo Formation is composed of laminated sands and sandy clays, and is probably semi-consolidated, of low to moderate strength, and soft to moderately hard.

The Wilcox underlies the Carrizo and is up to 1,400 ft thick. The Wilcox is so similar to the Carrizo that it is hard to define its contact. The rocks would probably require less support in underground openings than would the San Joaquin Valley reservoir studied for this report.

1.3.8.6 Conclusions

If estimates of remaining oil in place are reliable, then Slocum Field in Texas is probably a good candidate to demonstrate mining for access technology. More work is needed to determine the characteristics of the overlying rock, groundwater conditions, and rock mechanics parameters. Possible problems include groundwater, land use conflicts, and unconsolidated overlying deposits which will require extensive bracing and support.

TABLE 1-11

SLOCUM FIELD, ANDERSON COUNTY, TEXAS

RAILROAD DISTRICT NO. 6

GENERAL INFORMATION

Reservoir Name:	Carrizo Sand	No. of Wells:	227
Discovery Name:	1955	Area, Acres:	2500
Formation:	Carrizo	Land Use:	Unknown
Geologic Age:	Eocene		

RESERVOIR INFORMATION

General		Structure	
Avg. Depth, ft:	530	Faulting:	Yes
Gross Pay, ft:	48	Folding:	Anticlinal
Net Pay, ft:	25	Dip, °:	Uknown
Lithology:	Sand	Conditions	
Consolidation:	Semi-consolidated	BHT, °F:	75
	Consolidated	Initial BHP, psi:	120
Porosity, %:	37	Current BHP, psi:	120
Permeability, md:	2655	Initial Oil Sat.%:	66
Trap Type:	Structural-faulted domal anticline	Current Oil Sat.%:	61(e)
Reservoir Drive:	Gravity drainage		

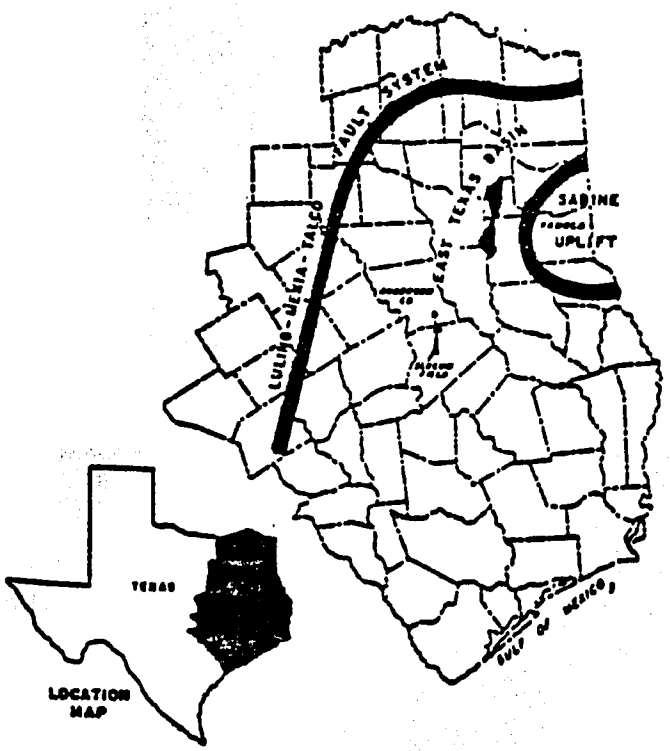
ROCK MECHANICS PARAMETERS

Unconfined Compressive Strength, psi:	Low to Moderate
Elastic Modulii:	Low
Hardness:	Low to Moderate

TABLE 1-11 (cont'd)

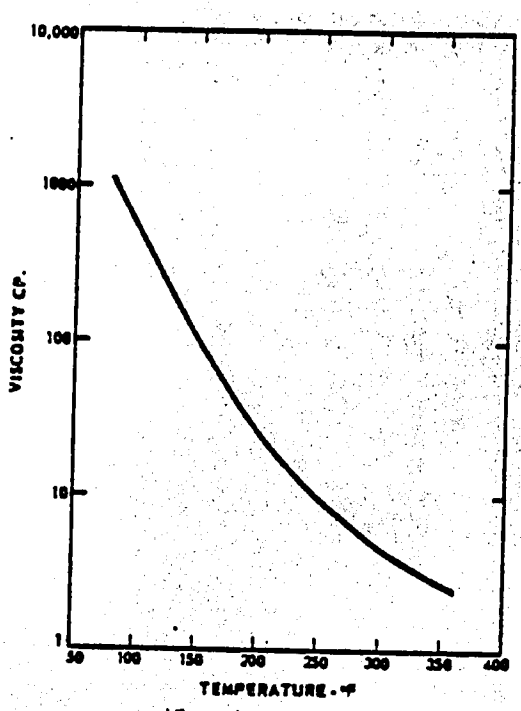
FLUID CHARACTERISTICS	
Oil Gravity, °API	19
Viscosity @ BHT, cp:	1000
CHARACTERISTICS OF UNDERLYING ROCK	
Geologic Formation(s):	Wilcox
Geologic Age:	Eocene
Lithology:	Sands & Sandy Clays
Thickness:	140 ft.
Consolidation:	Semi-consolidated
Unconfined Compressive Strength, psi:	Low to Moderate
Elastic Modulii:	Low
Hardness:	Low to Moderate
PRODUCTION DATA	
Original Oil in Place, stb:	114,100,000
Cum. Prod. (12/31/77) Oil, bbl:	8,029,865
Oil Remaining in Place, stb:	106,100,000
Bbl/acre:	42,400
Bbl/acre-ft:	1698
Secondary Production (Year, Type):	1967-1984, steam drive
Tertiary Production (Year, Type):	1969-1978, steam drive

400

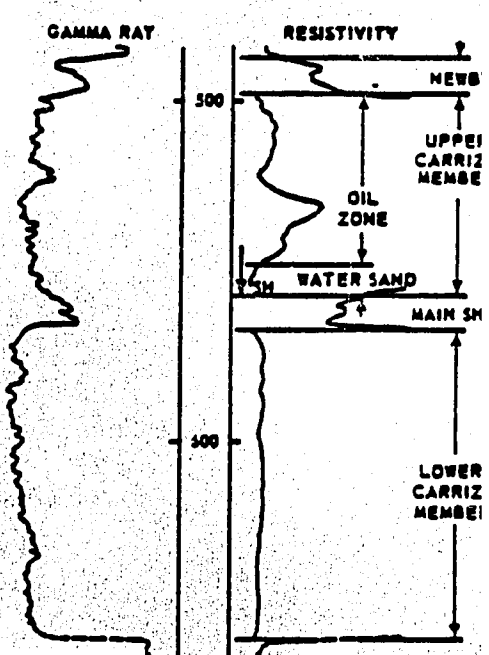


Slocum field.

APRIL, 1973



Viscosity-temperature curve.



Type log.

Figure 1-41
(Source: 62)

401

1.3.9 South Belridge Field, Kern County, California (Tulare-Etchegoin Reservoir)

The South Belridge Field was chosen for detailed study based on a ranking of S-113-(2) and M-81-(1). This rank reflects the large surface area, shallow depth to producing formations and large estimated resources remaining in the field today. Table 1-12 contains a summary of the reservoir parameters which influenced the ranking.

The South Belridge Field is located approximately 40 miles west of Bakersfield and 10 miles north of McKittrick, Kern County, California. The proven area of the field is approximately 8610 acres. The ground surface is a flat to very gently sloping alluvial plain east of the Temblor Range. The ground surface elevation averages 600 ft above sea level over the field area and is covered with sparse desert vegetation. The average annual rainfall in the area is less than 14 inches. Present land use in the field area is almost exclusively surface oil recovery. Surface wells are closely spaced making other land use within the South Belridge field impossible.

Only the producing zones within the Tulare and Etchegoin formations are considered in the following discussion. Deeper producing zones contain lighter oils with API gravity greater than 20 degrees.

1.3.9.1 Historical Production

The South Belridge Field was discovered in 1911 when a sucessful well was completed in the Tulare Formation. Development in the field was slow after an initial flurry of drilling immediately after discovery of the field until increased demand for heavy oil in 1942 resulted in a dramatic increase in the development of the field. Enhanced oil recovery techniques, including fire flooding, cyclic steam injection and steam flooding, have resulted in increased production of heavy oil from the South Belridge Field since 1963.

1.3.9.2 Geology

The South Belridge Field is located within the Southern-most portion of the San Joaquin Basin. Please refer to Section 1.3.3.3 for a description of the regional geology. Figure 1-42 is a structure contour map and geologic cross section of the field.

The stratigraphy of the South Belridge field is characterized by unconsolidated to weakly consolidated sediments ranging from Upper Miocene to Recent in age. A description of the sediments down to the deepest producing zone under consideration is given below:

- Alluvium - Recent deposits of alluvial gravel, sand and silt. Approximate thickness 300 ft.

- Tulare Formation - Pleistocene blue-gray clays, sands and silts and black oil sands. Some areas of green, gray, brown, tan, and buff clays. Approximate thickness 400 to 1100 ft.

- San Joaquin Clay - Pliocene green and green-gray clays, sands and silts. Approximate thickness 0 to 200 ft.

- Etchegoin Formation - Pliocene highly variable clays, silts and sands. Approximate thickness 0 to 500 ft.

The geologic structure of the South Belridge Field consists of a sharp anticline trending northwest involving Miocene and older strata, less steeply folded Pliocene strata and very gently folded Pleistocene strata. Several major unconformities exist within the field, the most significant of which is between the Pleistocene deposits of the Tulare Formation and on Pliocene deposits, including the Belridge diatomite, Etchegoin Formation, and San Joaquin Clay. Approximate dip of the sediments in the Tulare Formation ranges from 3 to 15 degrees. Several normal faults are defined within the upper sediments in the South Belridge Field. Most of these faults trend approximately east-west and are down-dropped to the north. Displacement across these faults is generally 50 ft or less.

The South Belridge Field lies within a zone of high seismic risk, a zone where Modified Mercalli Intensities of VIII or greater have been experienced during historic time. Algermissen (1976) suggests that a horizontal acceleration of about 50 percent of gravity in bedrock has a 10 percent chance of being exceeded in 50 years. The high seismic risk in this area of California is related to tectonic activity along the San Andreas Fault and other active faults located near the field. No active faults are reported in the literature immediately within the South Belridge Field.

Trap mechanisms for producing zones within the Tulare and Etchegoin formations are permeability variations on a homocline and an anticline with minor faulting, respectively.

1.3.9.3 Reservoir Characteristics

The producing zones in the Tulare Formation comprise the majority of potential resources in the South Belridge Field. The Tulare Formation is divided into three zones: the Upper Tulare, the Upper Tulare Oil Zone, and the Lower Tulare Oil Zone. Both oil zones are produced together in the field and consist of unconsolidated, poorly sorted sands. The Upper Tulare Oil Zone is between 400 and 850 ft deep and ranges from 200 to 300 ft thick. The upper zone is not continuous over the entire field but is confined to the southern two-thirds of the field area. The Lower Tulare Oil Zone is between 650 and 1100 ft deep and ranges from 50 to 300 ft thick. Rich oil sands comprise about 50 percent of the total thickness of the lower zone. The lower zone is continuous throughout the entire field. The highest portions of this lower zone are the least productive because they are thinner and siltier in these areas.

The producing zones in the Etchegoin Formation are of minor importance as compared to production from the Tulare Formation. Productive areas are associated with sandy-silt and silt stringers within the top 50 to 200 ft of the Belridge Diatomite. These productive areas are laterally discontinuous due to unconformities and faulting at this horizon.

Approximate depth to these producing zones is between 800 and 1,500 ft. Reported reservoir conditions include borehole temperatures of 95 degrees Fahrenheit, initial oil saturation of 76 percent, current oil saturation of 66 percent, and gas-oil ratio of 15 SCF/BBL. The drive mechanisms within the reservoir include solution gas, water drive and gas drive. These parameters are summarized in Table 1-12.

Reported values for fluids within the producing zones under consideration in the South Belridge Field include average API gravity of 17.8, average oil viscosity of 1600 centipoise at borehole temperature, sulfur content of 0.23 percent, carbon residue of 5.9 percent and water salinity of 12,000 ppm. Table 1-12 has a complete listing of data for reservoir fluids in the producing zones under consideration in the South Belridge Field.

1.3.9.4 Groundwater

Water saturation in the producing zones in the South Belridge Field is reported to be approximately 34 percent. Large quantities of low quality water are produced with the oil: approximately eight barrels of water are produced with each barrel of oil in the zones under consideration in the South Belridge Field. Disposal of this water has been in unlined evaporation ponds and by reinjection into disposal wells.

1.3.9.5 Rock Mechanics

There is very little informaton regarding the engineering characteristics of the rocks in the South Belridge Field, particularly information that would allow quantitative estimates of the behavior of these rocks in large cut slopes or a system of underground openings. A qualitative assessment of this behavior is given here based on lithology, degree of fracturing, and general rock descriptions reported in the literature.

All of the rocks under consideration in the South Belridge Field are unconsolidated. A total of four formations are under consideration: recent alluvial deposits, and Pleistocene sands, silts and clays of the San Joaquin and Etchegoin Formations.

The alluvial gravels and strata of the Upper Tulare Formation which overlie the reservoir rocks have low strength, low elastic modulus and probably low hardness. The gravels and sand zones have high permeability and could produce large groundwater inflows into either an open pit or underground mine opening. Fine grained sediments, silts and clays may be expected to exhibit swelling, shrinkage or flaking in response to changes in moisture content. Soft ground tunneling techniques including continuous ground support, dewatering, and provisions to prevent running ground would probably be required for underground openings in most of these materials. Cut slopes through the finer grained sediments would require low angles to be stable over a long period of time.

Reservoir rocks consist of unconsolidated sands and silty sands. These are expected to have low unconfined compressive strength, low hardness, and high porosity and permeability. The reported value for the porosity of these materials is 37 percent and the permeability is 3000 millidarcies. High groundwater inflows would be expected into either an open pit or underground opening that intersected these reservoir rocks.

Strata underlying the reservoir rocks are very similar to overlying rocks in most of the field. In addition, diatomite underlies the reservoir rocks in many areas of the field. These strata would probably require soft ground tunnelling techniques. Continuous floor lining would probably be required to provide durable floors for vehicular traffic in horizontal underground openings in these materials.

1.3.9.6 Conclusions

The South Belridge Field is a potential target for heavy oil recovery using either surface mining or mining for access techniques. Several factors make this area a favorable target, including the large resource remaining in the field even after the extensive production which began in 1911, the large surface area of the field, and the shallow depth to the producing zones.

Several factors which represent potential problems to heavy oil recovery using surface mining or mining for access techniques in the South Belridge Field include the potential for large groundwater inflows, soft ground conditions, low strength materials, competition for surface area and reservoir management from existing surface wells, and high seismic risk. In addition, large quantities of water will be produced with the oil if mining for access techniques are used. Some of this water could be used for steam injection, but large quantities of low quality water would require disposal as with existing surface recovery methods.

TABLE 1-12

SOUTH BELRIDGE FIELD, KERN COUNTY, CALIFORNIA

GENERAL INFORMAT

Reservoir Name:	Tulare, Etchegoin		
Discovery Year:	1911	No. of Wells:	3283
Formation:	Tulare, San Joaquin, Etchegoin	Area, Acres:	8610
Geologic Age:	Pliocene to Recent	Land Use:	Range, petroleum recovery

RESERVOIR INFORMAT

General

Ave. Depth, ft:	700
Gross Pay, ft	450
Net Pay, ft:	100
Lithology:	Sand, silty-sand
Consolidation:	Unconsolidated
Porosity, %:	35; 34-37
Permeability, md:	3,000; 1800-13,000
Trap type:	Anticline with minor faulting, Monocline with permeability variations.
Reservoir Drive:	Solution gas, water drive and gas drive.

Structure

Faulting:	Minor
Folding:	Gentle
Dip, degrees:	3-15

Conditions

BHT, °F:	95
Current BHP, psi:	450
Initial Oil Sat.%:	76
Current Oil Sat.%:	66
Current GOR, scf/bbl:	15

TABLE 1-12 (cont'd)

ROCK MECHANICS PARAMETERS

Unconfined Compressive Strength, psi:	Low
Elastic Modulii:	Low
Hardness:	Low

FLUID CHARACTERISTICS

Oil Gravity, °API:	17
Viscosity @ BHT, cp:	1600
Sulfur Content, %:	0.23
Carbon Residue, %:	5.9
Water Salinity, ppm:	12,000

CHARACTERISTICS OF OVERLYING ROCK

Geologic Formation(s):	Alluvium, Upper Tulare
Geologic Age:	Recent, Pleistocene
Lithology:	Gravel, Sand, Silt, Clay
Thickness, ft:	450-750 ft.
Consolidation:	Unconsolidated
Structure:	Homocline
Unconfined Compressive Strength, psi:	Low
Elastic Modulii:	Low
Hardness:	Low

TABLE 1-12 (cont'd)

CHARACTERISTICS OF UNDERLYING ROCK

Geologic Formation(s):	Belridge Diatomite
Geologic Age:	Pliocene
Lithology:	Shale, Diatomite
Thickness, ft:	Greater than 1000
Consolidation:	Unconsolidated to loosely consolidated
Structure:	Anticline with minor faulting
Unconfined Compressive Strength, psi:	Low
Elastic Modulii:	Low
Hardness:	Low
Fractures:	Moderate

PRODUCTION DATA

Original Oil in Place, stb:		1,700,000,000
Cam Prod (12/31/77):	Oil, bbl:	228,012,550
	Gas, mcf:	20,429,000
Oil Remaining in Place, stb:		1,472,000,000
Bbl/acre:		170,963
Bbl/acre - ft:		1,710
Enhanced Oil Recovery (Year, Type):		1965 - present air injection for fire flood 1964 - present cyclic steam 1963 - present steam flood

410

SOUTH BELRIDGE OIL FIELD

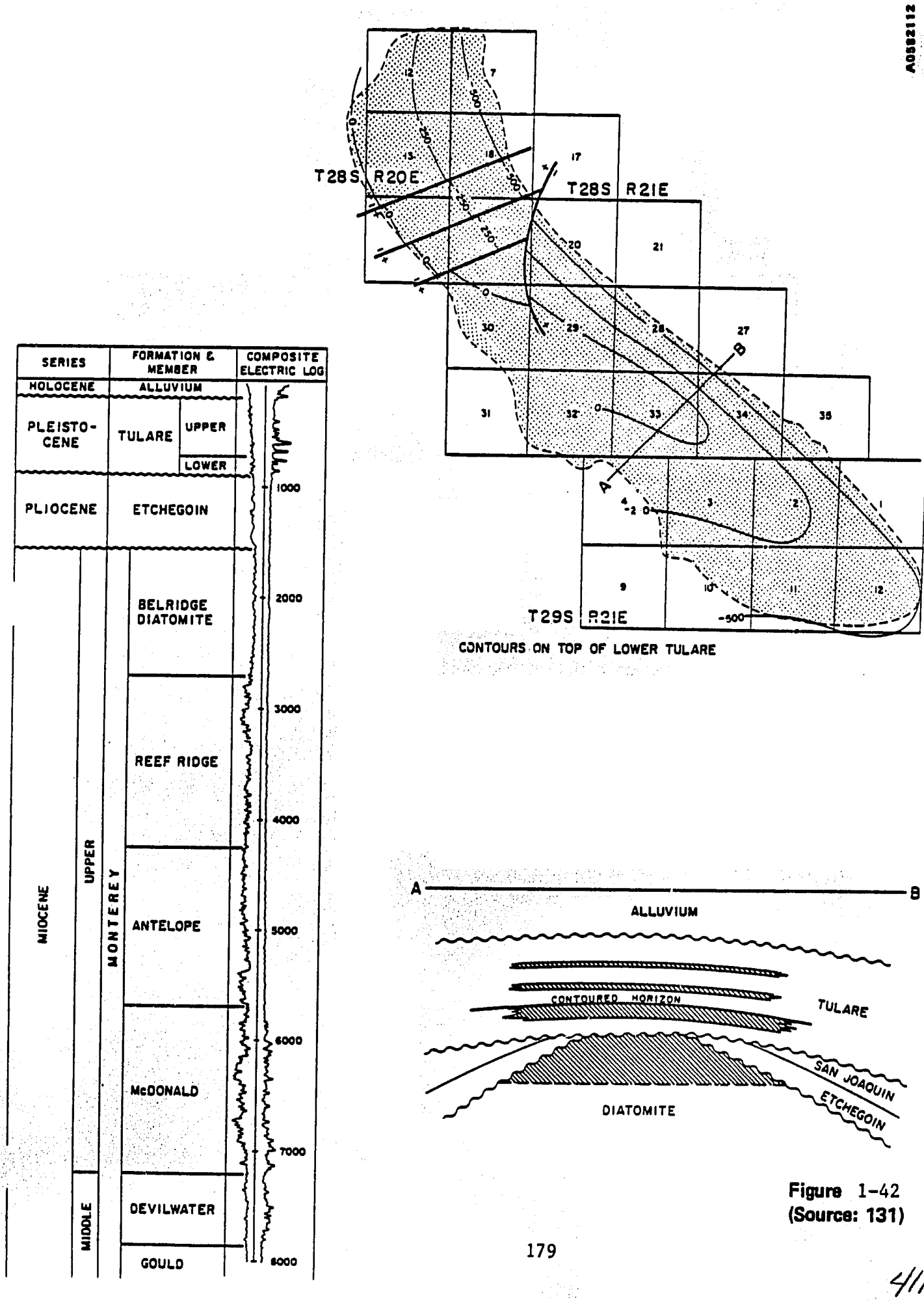


Figure 1-42
(Source: 131)

411

1.3.10 Yorba Linda Field, Orange County, California (La Habra Reservoir)

The shallow reservoir of the Yorba Linda Field was chosen for detailed study on the basis of a ranking of S-169-(1). This high ranking was due to a low overburden/interburden ratio of 1.25:1, a high saturation of 1,254 bbl/acre-ft., and an area of 620 acres. See Table 1-13 for a summary of all the reservoir parameters.

The Yorba Linda Field lies on the eastern periphery of the Los Angeles Basin at the base of the Chino Hills in an area of rolling to hilly terrain. The field is northwest of the town of Yorba Linda in an area of citrus and avocado orchards which are gradually being replaced by expensive housing developments.

1.3.10.1 Historical Production

The field was discovered in 1938 with production from the Repetto "E" sand. The shallow zone was not discovered until 1954, when Gulf Oil Co. drilled well YLUA #1-A which produced 6 barrels of oil per day barrels of oil per day from the La Habra Zone. By adding down-the-hole heaters in subsequent wells the daily production of the shallow zone was increased to 350 barrels of oil per day (BOPD). Primary development was completed in 1959 when Shell Oil Co. began experimenting with steam injection. Continuous steam injection proved to be unsatisfactory because it failed to build an oil bank. By using the "huff and puff" method of steam soak, however, primary production was increased five times until the shallow zone was producing up to 7,000 BOPD. A direct steam drive program was undertaken again in 1971 and this time, production was increased to 9,000 BOPD. Shell again switched over to Steam Soak in 1974 when production began to decline. Estimates of recovery show primary production recovered only 5 to 8 percent of the original oil in place, whereas the ultimate thermal recovery will be as high as 55 percent. Estimates of the remaining oil in place vary from 50 million bbls to 300 million bbls.

1.3.10.2 Geology

The Yorba Linda Field lies on the east boundary of the Los Angeles Basin along the Whittier Fault Zone. Figure 1-43 is a map outline of the field, and Figure 1-44 shows an east-west cross section through the field.

The stratigraphy of the area is fairly straight forward. Recent alluvial deposits overlie the shallow zone and are composed of unconsolidated clays and gravel. The La Habra Formation consists of massive conglomerates, shales, poorly sorted sands, and siltstones deposited in a submarine fan channel system. Shallow zone production comes from two conglomerate zones within the La Habra. The Repetto Formation underlying the La Habra is composed of very lenticular sands which are poorly sorted, conglomeritic, and interbedded with shale.

The structure of the field is a faulted homocline which dips about 15 degrees SW. Two major faults border the field: one trending NW-SE and dipping SW located north of the field, and the other to the south and trending NE-SW. These faults are very likely to be active, since the San Andreas Fault System lies only a few miles to the east.

1.3.10.3 Reservoir Characteristics

The producing horizons of the shallow zone are divided into upper and lower conglomerate zones. These zones consist of unconsolidated, poorly sorted sands and subrounded clasts up to six inches in diameter which have a porosity of 30 percent and permeability of 600 millidarcies. The upper zone is shallow (650 ft deep), averages 375 ft of oil pay, has a productive area of 180 acres, and is overlain by massive siltstone which acts a barrier to vertical flow. The lower zone is subdivided into several separate pools because of interbedded impermeable silt lenses which are lenticular and discontinuous. This zone averages 1,000 ft depth, 175 ft of net pay, and covers 105 acres.

The oil itself has an API gravity of 13 degrees and a viscosity of 6,400 cp at a borehole temperature of 85 degrees Fahrenheit. The trapping mechanism is uncertain but may be a combination of faulting and permeability discontinuities.

1.3.10.4 Groundwater

Little can be inferred about the hydrogeology of the site based on the information readily available. It is known, however, that the climate can be classified as Mediterranean due to mild winters of limited precipitation and warm, dry summers. In addition, the area has an average rainfall of 15 inches/year, average surface runoff of 5 inches/year, and average annual infiltration of 5 inches/year.

1.3.10.5 Rock Mechanics

Very little information is available on the engineering characteristics of the rocks in the Yorba Linda Field that would allow an evaluation of the behavior of these rocks in large cut slopes.

The alluvium overlying the shallow zone consists of unconsolidated clays and gravels which have low strength, low elastic modulus, and low hardness. Depending on percentage and distribution of clay, and the hydrogeology, this zone could produce high groundwater inflows into the open pit area. The low competency of this rock would allow extensive use of low cost surface mining equipment such as draglines and bucketwheel excavators. Cut slopes would require low angles to be stable over a period of time.

Little information is available on the massive siltstones overlying the La Habra except that they were deposited as a final stage of channel abandonment up to 100 ft thick, are laterally discontinuous, and act as a barrier to flow. They are likely to have higher competency than the overlying alluvium, but still could be easily excavated using the same equipment outlined above.

The upper conglomerate zone of the La Habra consists of poorly sorted sands and sub-rounded clasts up to 6 inches in diameter. Because of the high porosity and permeability of this unconsolidated material, high groundwater inflows are expected. Excavation could proceed as outlined above.

1.3.10.6 Conclusions

From the initial screening, it appeared that the Yorba Linda Field would be a prime target for surface mining technology. However, detailed study indicated that there are three major obstacles to developing this field:

1. Land use - Major housing developments overlie the field.

2. Reported acreage - It was reported that the shallow zone covered 620 acres. However, this is inaccurate, and in actuality the zone only covers 320 acres. In addition, the upper zone covering only 180 acres, is the only zone amenable to surface mining.

3. The reported remaining oil in place is very likely too high and in all probability closer to 50 million bbls in the upper zone.

4. Seismicity - The field lies several miles west of the San Andreas Fault System and has felt the full intensity of a magnitude 8 earthquake. Therefore, the additional cost of designing surface facilities to withstand the impacts would be prohibitive.

These factors reduce the feasibility of developing the Yorba Linda Field using surface mining technology.

TABLE 1-13

YORBA LINDA OIL FIELD, ORANGE COUNTY, CALIFORNIA

GENERAL INFORMATION

Reservoir Name:	La Habra	No. of Wells:	397
Discovery Year:	1954	Area, Acres:	620
Formation:	La Habra	Land Use:	Housing Development/ Orange and Avocado Groves
Geologic Age:	Pleistocene		

RESERVOIR INFORMATION

General		Structure	
Ave. Depth, ft:	650	Faulting:	Minor
Gross Pay, ft:	1100	Dip, degrees:	10
Net Pay, ft:	400		
No of Pay Zones:	2		
Lithology:	Conglomerate	**Conditions**	
Consolidation:	Unconsolidated		
Heterogeneity:	High	BHT, °F:	85
Porosity, %:	30	Initial Oil Sat:	65%
Permeability, md:	600	Current Oil Sat:	54% (e)
Trap type:	Structure - Sand Lenses on Homocline		
Reservoir Drive:	Drainage		
Unconfined Compressive Strength, psi:		Low	
Elastic Modulii:		Low	

TABLE 1-13 (cont'd)

ROCK MECHANICS PARAMETERS

Hardness:	Low to Moderately Hard

FLUID CHARACTERISTICS

Oil Gravity, °API:		13
Range:	12 - 14	
Viscosity @ BHT, cp:		6400
Sulfur Content, %:		1.86
Carbon Residue, %:		6.4

CHARACTERISTICS OF OVERLYING ROCK

Geologic Formation(s):	Alluvium/Siltstone
Geologic Age:	Recent
Lithology:	Clay & Gravel/Silt
Thickness, ft:	200 - 700/100
Consolidation:	Unconsolidated
Heterogeneity:	High
Unconfined Compressive Strength, psi:	Low
Elastic Modulii:	Low
Hardness:	Low
Geologic Formation(s):	Repetto
Geologic Age:	Pliocene
Lithology:	Sand, Conglomerate, Shale, and Siltstone
Thickness:	1050 or greater
Consolidation:	Unconsolidated
Heterogeneity:	High (lenticular, discontinuous)
Structure:	Highly Faulted

PRODUCTION DATA

Original Oil in place, stb:		100-360 million
Cum Prod (1/1/78):	Oil, bbl:	46,380,125
	Gas, mcf:	172,000
	Water, bbl:	173,927,000
Oil Remaining in Place, stb:		50-300 million
Tertiary Production (Year, Type):		1960, cyclic steam 1971, steam drive

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YORBA LINDA OIL FIELD

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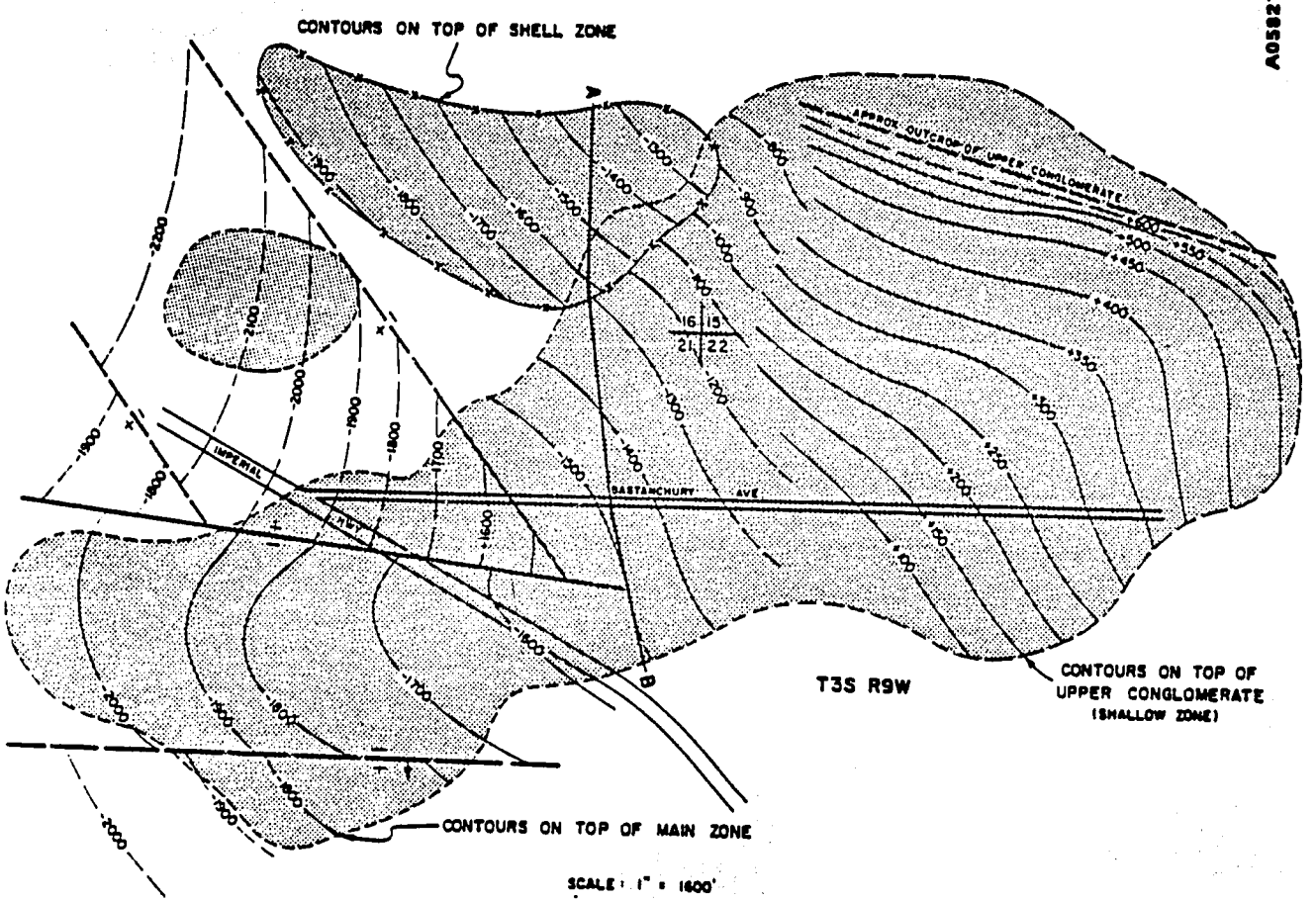

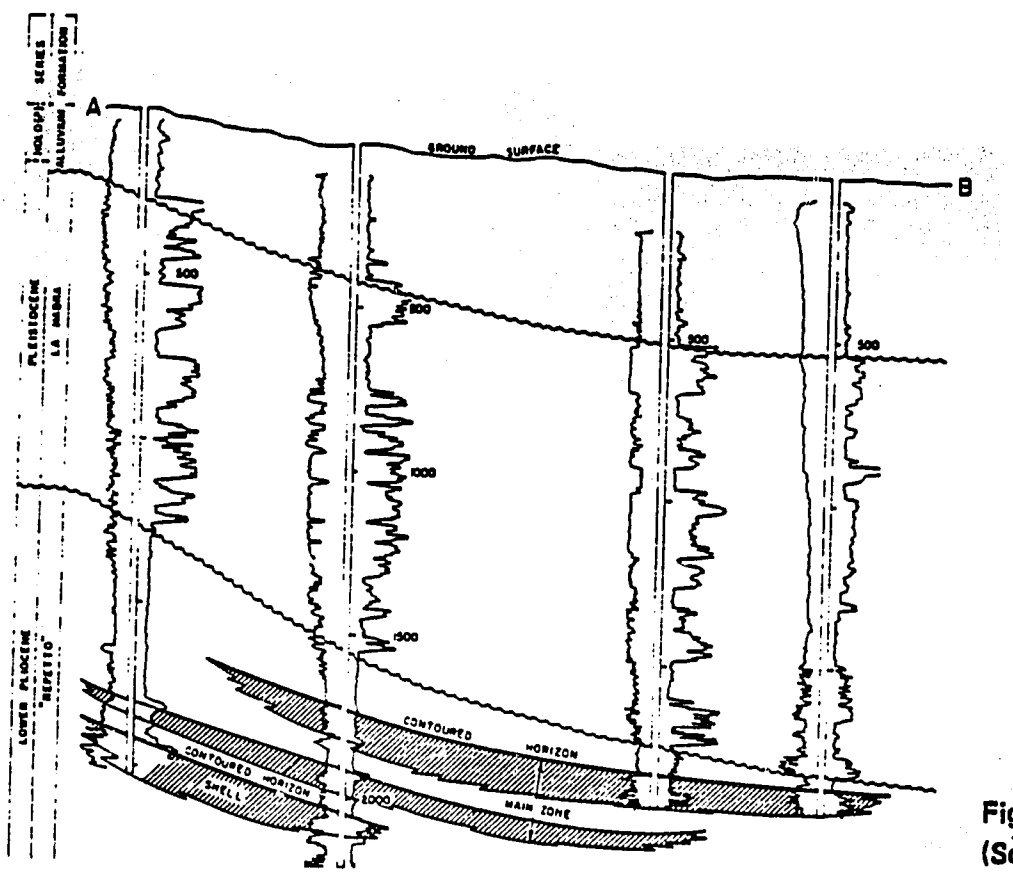

Figure 1-43
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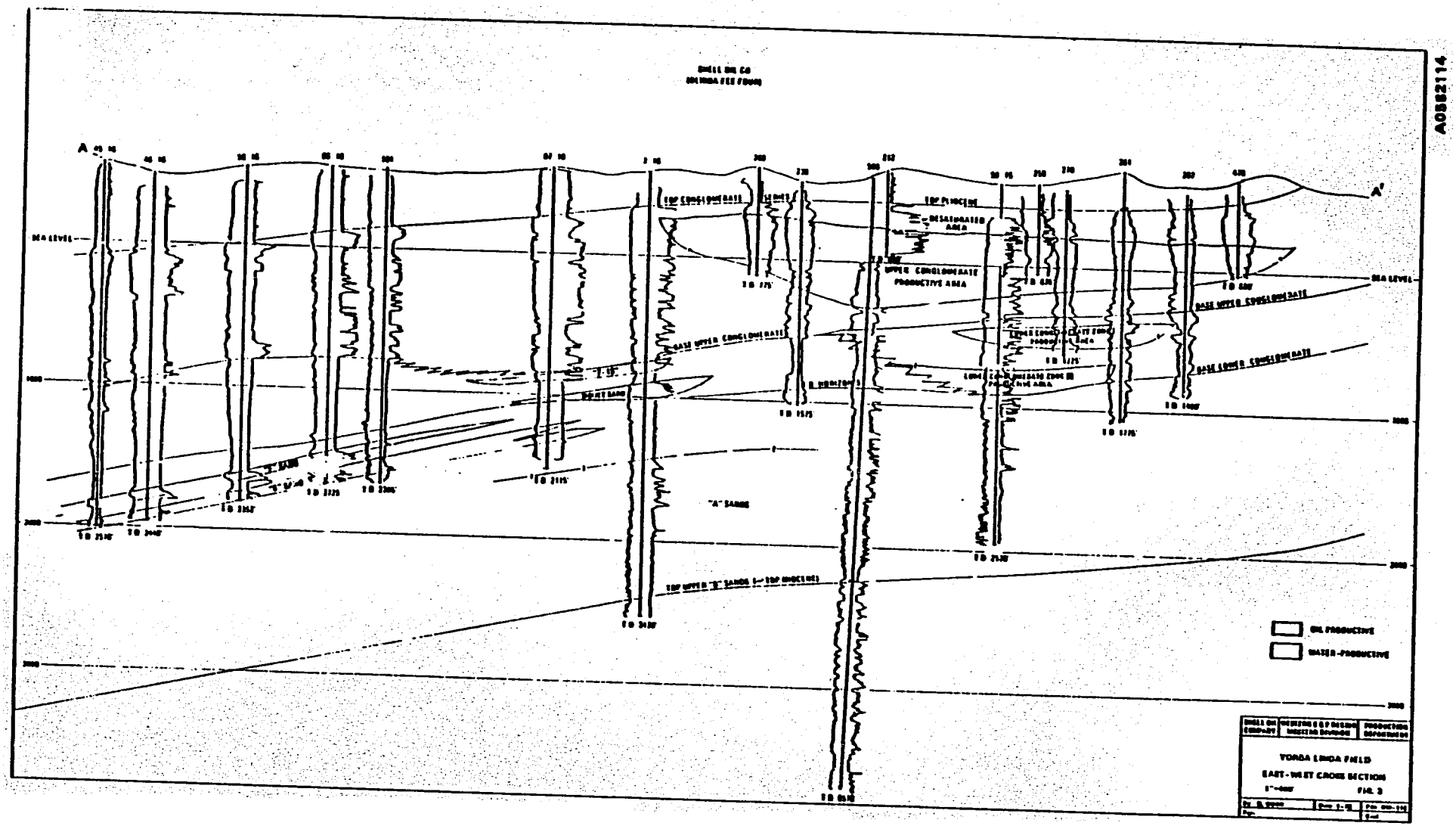

Figure 1-44
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1.4 PRELIMINARY STRUCTURE FOR A NATIONAL DATA BASE OF MINEABLE HEAVY OIL RESERVOIRS

The reservoir and production data for the 652 heavy oil reservoirs could fo the core of a central repository for data on heavy oil reservoirs.

Most of the petroleum producing states gather production data, and many of them require a filing when secondary or tertiary operations are initiated. In addition, federal, state, and local geological surveys have gathered data that may be pertinent to assessing the feasibility of, and planning of, a mine. Thus, while a large amount of data is available in the public domain, it is scattered between many locations, it has not been consolidated and assessed, and the data available differs among states.

The national data base on mineable heavy oil deposits should consist of the following elements:

1. A consistent data collection form and procedures.

2. Detailed topographic maps, isopach maps, and sectional maps on high potential deposits.

3. An up-to-date status report of activities underway in the high potential targets.

4. Routine working relations with the various local, state, and federal bodies that compile the basic data.

5. A central repository with decentralized access.

6. A core and log library to provide the potential for independent appraisals to be made of selected deposits.

By assisting in the identification of potential heavy oil areas or fields, and by providing current detailed information on them, this data base could spur the development of heavy oil mining.

TABLE 1

LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: ARKANSAS

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC.	YEAR ABD.	API RANGE (°)	BEST API VALUE (°)	VISCOSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO. OF PAY ZONES	REL. AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1,000 bbl)	CUMULATIVE PRODUCTION GAS (1,000 mcf)	OIL REMAINING IN PLACE (1,000 bbl)	FLAW	RANK	REF
ARTESIAN (Calhoun)	Meakin	Meakin	1951			14		2560 to 2651		11		320 to 430	1980	587		3,649			11 42
BODCAW (Nevada)	Nacatoch	Nacatoch	1959			14		930											11 18
BRAGG CAMDEN (Ouachita)	Nacatoch	Nacatoch	1934			16		1356		13		20	1980	40		235			11 18 42
BUENA VISTA (Ouachita)	Nacatoch	Nacatoch	1956		14 to 15			1270		9 to 10		75	1976	155		593			11 18 42
CALION (Union)	Nacatoch	Nacatoch	1953			15		2090					1964	.7		2(e)			11
CHAMPAGNOLIE (Union)	Meakin	Meakin	1927			20		2450		10		4475 Field	1964	22,137 Field		51,653(e)		M-11-(3)	11
	Graves	Graves	1929			20		2580		10									11 42
CHARIVARI CREEK (Bradley)	Nacatoch	Nacatoch	1963			19		2397		6 to 23		20 to 60	1980	108		1,686			11 18 42
CYPRESS CREEK (Union)	Graves	Graves	1960			16		2755		6 to 10		10 to 20	1980	59		4			11 18 42
EL. DORADO (Union)	Nacatoch East Area	Nacatoch	1921			20	66	2149		7 to 51		1826 Field	1980	11,831 Field		27,606(e)		M-18-(2)	11 42 41
FALCON (Nevada)	Nacatoch	Nacatoch	1938			17		1650		12		380	1964	783		2,290(e)			11 18
	Nacatoch	Nacatoch	1938			14		1180		12			1976	997		2,326(e)			
	Hill	Hill	1966			15		2384		11		40	1976	10		397			18 42
	Blossom	Blossom	1954		16 to 26			2360		13		90	1964	167		1,303			11 42
FOUKE (Miller)	Tuscaloosa North Area	Tuscaloosa	1958		20 to 30			3334		10		800	1976	2,819		7,013			11 18 42

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TABLE 1

LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: ARKANSAS

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC	YEAR ABD.	API RANGE (-)	BEST API VALUE (-)	VISC-OSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO OF PAY ZONES	RES. AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1 000 bbl)	CUMULATIVE PRODUCTION GAS (1 000 mcf)	OIL REMAINING IN PLACE (1 000 bbl)	PLAN	RANK	REF
GARLAND CITY, NEW	Tuscaloosa	Tuscaloosa	1960			19		2580		21 to 7		20	1976	11		505			11 18 42
	Paluxy	Paluxy	1951			13		3311		10 to 3		150	1980	200		1,670			11 18 42
GUM CREEK (Ouachita)	Nacatoch	Nacatoch	1941		17 to 21			1590		15		280 Yield	1980	1946		4,541(e)			11 18 41
	Blossom	Blossom	1945		20 to 24		47	2325		17 to 12									11 18 41
	Tokio	Tokio	1945		17 to 21		117	2470		14 to 15									11 18 41
HAMPTON (Calhoun)	Nacatoch	Nacatoch	1954			16		2286		18		10		.2		1,650			1,18 2,41
	Meakin	Meakin	1943			14		2514		24		160	1980	767		3,430			1,18 2,41
HERVEY (Miller)	Rodessa-Hill	Rodessa-Hill	1955		18 to 21			3621		11 to 5		40	1980	10		535			1,18 42
IRMA (Nevada)	Old	Nacatoch	1921			14		1150		13		2300	1978	10,647		51,500		M-36	20,11 18,42
LAKE JUNE (Lafayette)	Tokio	Tokio	1966			20		2552		7.5 to .12		40	1980	107		213			18 42
LEWISVILLE (Lafayette)	Tokio	Tokio	1939			19		2300		11 to 9		120	1980	489		1,579			1,18 42
	Tokio West Area	Tokio	1946		19 to 20			2450		7 to 12		267	1980	1900		2,835			1,18 42
	Tuscaloosa West Area	Tuscaloosa	1954			19		2850		12 to 14		20	1980	24		230			1,18 42

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TABLE 1

LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: ARKANSAS

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC.	YEAR ABD.	API RANGE (-)	BEST API VALUE (-)	VISC-OSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO. OF PAY ZONES	RES. AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1,000 bbl)	CUMULATIVE PRODUCTION GAS (1,000 mcf)	OIL REMAINING IN PLACE (1,000 bbl)	FLAW	RANK	REF
LICK CREEK (Bradley/ Union)	Meakin	Meakin	1957			18	188	2548		12		1,120	1980	4,625		14,300		M-11	20, 1[illegible] 18, 4[illegible]
	Nacatoch	Nacatoch	1960			17		2270		20		20	1980	156		197			11, 1[illegible] 42
	Travis Peak	Travis Peak	1966			16		2928		15		20	1980	48					11 18
LOCUST BAYOU (Calhoun)	Meakin	Meakin	1947			15		1990		10 to 15		100	1980	291		784			11, 1[illegible] 42
MAYTON	Paluxy-Williams	Paluxy	1967			18		3620		16			1980	197		1,300(e)			18
	Paluxy Lowe	Paluxy	1968			18		3546		15(e)									18
MCKINNEY BAYOU (Miller)	Paluxy	Paluxy	1955			20		3060		10 to 12		40	1980	1585		4,800(e)			18
MIDWAY (Lafay-ette)	Tuscaloosa	Tuscaloosa	1973			12		2390		14			1980	2		30(e)			
MORO BAY (Calhoun)	Cotton Valley	Cotton Valley	1952			13		3458		6 to 10		20	1976	20		60(e)			11 18
PIGEON HILL (Union)	Cotton Valley	Cotton Valley	1953			15		4290 to 4387		13 to 11		120	1980	171		1,453(e)			11 18 42
RAMSEY CREEK (Union)	Hosston	Hosston	1950			18		2900		14		40	1967	6		566			42
RIVER BEND (Union)	Meakin	Meakin	1959			17		2560		10		10	1980	1		4(e)			11 18
SANDY BEND (Union)	Nacatoch	Nacatoch	1947			19		2260		20 to		5330	1980	10,686		153,851		M-19	11 18
SEMINARY CHURCH (Ouachita)	Tokio	Tokio	1971			18		2540		12		120	1980	53		540(e)			18

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TABLE 1

LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: ARKANSAS

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC.	YEAR ABD.	API RANGE (°)	BEST API VALUE (°)	VISCOSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY* (FT)	AVERAGE NET PAY THICKNESS (FT)	NO. OF PAY ZONES	RES. AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1,000 bbl)	CUMULATIVE PRODUCTION GAS (1,000 mcf)	OIL REMAINING IN PLACE (1,000 bbl)	FLAW	RANK	REF
SHILOH (Lafayette)	Tokio	Tokio	1964		14 to 18			2698		4 to 12		10 to 90	1980	368		401			11 18 42
SMACKOVER OLD (Union)	Nacatoch	Nacatoch	1922		18 to 23.	18		2000		50	3	43970 Field	1978	513,494 (field)		1,626,000 (e) (Field)		X	20 11 18
	Meakin	Meakin	1923			19		2230		16			1967					X	42
	Tokio	Tokio	1954			19		2640		19			1978					M-15-(1)	20 11 18
SPIRIT LAKE (Lafayette/ Miller)	Buckrange	Buckrange	1948			19		2650		11 to 49		10 to 110	1976	3.7		122			11 18 42
STAMPS (Lafayette)	Tokio	Tokio	1955			16		2350		12		760 (field	1980	1,826		8,415			11 18 42
	Tuscaloosa	Tuscaloosa	1955		20 to 21			2599		7 to 10		240	1980	234		1,338			11 18 42
	Tokio, East Area	Tokio	1954			19		2490		3 to 15		110	1976	200		266			11 18 42
	Tokio, West Area	Tokio	1956			18		2568		14		10 to 40	1964	21		802			11 18 42
	Paluxy West Area	Paluxy	1956			17		3308		11 to 14		20 to 40	1980	18		213			11 18 42
STEPHENS (Columbia & Ouachita	Nacatoch	Nacatoch	1921			13	424 @100 F	1510		10		10	1964	36,586 (field)		85,367 (e)			11 18 41
	Tokio	Tokio				17		2350		7 to 15		20	1980	106		250(e			41

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TABLE 1

LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: ARKANSAS

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC.	YEAR ABD.	API RANGE (°)	BEST API VALUE (°)	VISC-OSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO. OF PAY ZONES	RES. AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1 000 bbl)	CUMULATIVE PRODUCTION GAS (1 000 mcf)	OIL REMAINING IN PLACE (1 000 bbl)	FLAW	RANK	REF
STEPHENS (Ouach./ Col.)	Tokio, Curry Area	Tokio	1941		14 to 17			2260		14 to 15		20	1980	44		323			11 18 42
TROY (Nevada)	Old Nacatoch	Nacatoch	1921 to 1936		14 to 22	14		1220		18		997	1980	8715 (field)		25,185		M-28-(1)	20 41,11 18,42
	Old Tokio	Tokio	1921 to 1936		18 to 22	20		2150		15		540						x	11,18 41,42
	Nacatoch, East Area	Nacatoch	1956			15		1309		10		20	1967	72		161			42
WESSON (Ouachita)	Tokio	Tokio	1946			19		2340		11		90	1980	330		1,031			11 18 42
WILLIS-VILLE (Nevada)	Nacatoch	Nacatoch	1951			14		1211		6 to 30		80	1980	200		3,725			11 18 42
	Nacatoch, SW Area	Nacatoch	1956			14		1140		11 to 13		460	1980	2889		7,853			11 18 42
	Nacatoch, West Area	Nacatoch	1957			15		1200 to 1205		22 to 25		80	1980	768		1,432			11 18 42
	Tokio West Area	Tokio	1955			19		2138		10 to 24		50	1980	232		1,088			11 18,42
Willmington (Union)	Graves	Graves	1943			17		2768		16		60	1980	203		931			11,18 42,41
WIN-CHESTER (Union)	Meakin	Meakin	1956			20		2638		10 to 12		360	1980	947		2,995			11 18 42
WOODLEY (Union)	Nacatoch	Nacatoch	1922			20		2200		8 to 12		744	1980	339		6,809			11,18 42,41

TABLE 1

LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: CALIFORNIA - CENTRAL COASTAL

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC.	YEAR ABD.	API RANGE (°)	BEST API VALUE (°)	VISCOSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO. OF PAY ZONES	RES. AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1,000 bbl)	CUMULATIVE PRODUCTION GAS (1,000 mcf)	OIL REMAINING IN PLACE (1,000 bbl)	FLAM	BANK	REF
ARROYO GRANDE (San Luis Obispo Co.)	Martin, Oak Park Area	Pismo	1929			15		2890		50	2	90 (Pool	1976	498 (Pool)	4	1162(e)			11 18 63
	Elberta, Oak Park Area		1930			14		3100		50									
ARROYO GRANDE (San Luis Obispo Co.)	Tiber Area, Dollie	Pismo	1906			15		750		300	3	320 (Pool	1980	3,700 (Pool)		8633(e)			11 18 63
	Martin		1908			13		2000		100									
	Eberta		1908			13		2500		100									
BARHAM RANCH (Santa Barbara Co.)	Basal Sisquoc	Sisquoc	1945			14		1400		500		60	1980	180 (Field)					11 18 63
	Arenaceous & Chenty	Monterey	1943		13 to 15			2800 to 4381											
CASMALIA (Santa Barbara Co.- Santa Maria District	Monterey	Monterey	1905		8 to 23			700		1275		2090	1980	34,300		80,000(e)		S-4-(2)	11 18 63
	Point Sal	Point Sal	1916			10		2750		500									18 63
CAT CANYON (Santa Barbara Co. & District Santa Maria District	East, Old Area, East	Monterey	1908		6 to 17	11		3001		400		1680	1978	18,021	1,214	42,049(e)			11,18 20,63
	Sisquoc Area, Others	Lower Pliocene	1958		9 to 15	13	350	3200		126		1120	1978	32,398	4,523	217,800			20 11 18,63
	Sisquoc Area, Thomas	Pliocene	1954			18				500			1976	1,403	189	5,000(e)			11 18 63
	West, Pliocene, Old Areas	Sisquoc	1908		14 to 20	15		3043		54		2930	1978	44,354	19,994	201,100			20 11 18,63
	New Area, West	Pliocene	1956		8 to 14	12		2749		45		590	1978	7,523	1,624	33,700		M-18	20,11 18,63

TABLE 1

LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: CALIFORNIA - CENTRAL COASTAL

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC	YEAR ABD.	API RANGE (°)	BEST API VALUE (°)	VISCOSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO. OF PAY ZONES	RES. AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1,000 bbl)	CUMULATIVE PRODUCTION GAS (1,000 mcf)	OIL REMAINING IN PLACE (1,000 bbl)	FLAW	RANK	REF
CAT CANYON (Santa Barbara Co.)	Cherty-Bentonitic Brown, Olivera Canyon	Monterey	1944			10		3000		1200		210	1973	4,578		10,700(e)			
	Buff and Brown, Olivera Canyon Area	Monterey	1944			10		4000		300									
CAT CANYON (Santa Barbara Co. - Santa Maria Dist.)	Sisquoc, Central Area	Sisquoc	1956			13		2800		45		590	1980	8,009		25,400(e)		M-14-(1)	63
CAT CANYON (Santa Barbara Co.)	Sisquoc, Gato Ridge Area	Sisquoc	1937			14		2210		200		690	1980	38,400		89,600(e)		M-46-1	
	Buff and Brown Gato Ridge Area	Monterey	1915			13		3800		300		690							
CONEJO (Ventura Co.)	Unnamed	Alluium	1892			18		150		90			1973	110	12	257(e)			
ELSMERE (Los Angeles)	Pico	Pico Pliocene	1889			18		2069		100									
GUADALUPE (Santa Barbara & San Luis Obispo Co.) Santa Maria District	Sisquoc -Monterey	Sisquoc -Monterey	1948		8 to 14	11		2832		90(e)		1990	1980	28,000	16,822	232,700		M-32	11 63

TABLE 1

LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: CALIFORNIA CENTRAL COASTAL

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC.	YEAR ABD.	API RANGE (°)	BEST API VALUE (°)	VISC-OSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO. OF PAY ZONES	REE. AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1,000 bbl)	CUMULATIVE PRODUCTION GAS (1,000 mcf)	OIL REMAINING IN PLACE (1,000 bbl)	FLAW	RANK	REF
HOLLISTER (San Benito Co)	Lamerias Area	Bisquoc	1950			20		2083				20	1964	7		45(e)			11 18
HOLSER (Ventura Co.)	Modelo U	Modelo U	1954			17		1000		450		110	1980	800		2300 (e)			11 18
HOOPER CANYON (Ventura Co.)	Modelo, North Area	Modelo	1890			14		660					1980	100		233(e)			11 63
	Modelo Main Area	Modelo	1884		18			1000		1500		80	1980	2,600		1880(e)			11 63
HUASNA (St. Luis Obispo Co.)	Fractured Shale, Tar Springs Area	Monterey	1928		18			2085 to 3015		110			1980	30		70(e)			18 63
JESUS MARIA (Santa Barbara Co.)	Buff, Brown and Dark Brown	Monterey	1948 to 1952		8 to 12			2600 to 2900		290 to 500	2	60	1973	148	5	600(e)			11 18 63
KING CITY (Monterey Co.)	Miocene, Doud Area	Monterey	1959		16 to 17	16		2115		100		110	1980	1,800	39	17,000			11 20 63
	Thorup, Doud 3-1-62 Area	Monterey	1963			13		1860		30		20	1973	.6		3(e)			63
	Thorup, Kent - Basham Area	Monterey	1961			17		2450		65		40	1973	106		780(e)			63

TABLE 1

LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: CALIFORNIA - CENTRAL COASTAL

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC	YEAR ABD	API RANGE (°)	BEST API VALUE (°)	VISCOSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO OF PAY ZONES	RES AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1 000 bbl)	CUMULATIVE PRODUCTION GAS (1 000 mcf)	OIL REMAINING IN PLACE (1 000 bbl)	FLAW	RANK	REF
LA HONDA (San Mateo)	South Area	Miocene	1959			16		1567					1964	262		5000(e)			11
LAS POSAS (Ventura) Santa Clara Valley District	Sespe-Eocene	Sespe-Llajas	1957		14 to 21			4600		2000		20	1980	13		45(e)			18 63
LOPEZ CANYON (St. Luiz Obespo)	Point Sal	Monterey	1963			15		2500 to 2930		37		10	1976	2		15(e)			10 63
LOMPOC (Santa Barbara) (Santa Maria District)	Monterey	Monterey	1903		15 to 26	20		2799		500		2110	1980	42,000	43,000	98,000(e)		M-15-(1)	20
LYNCH CANYON (Monterey)	Lanigan	Monterey	1962		10 to 12			1800		55		140	1973	124		1,000(e)			11 63
MCCOOL RANCH (Monterey)	Lombardi	Monterey	1964			12		2150		30		80	1973	109		1,100(e)			63
MESA (Santa Barbara)	Vasqueros, Main Area	Vasqueros	1929			18		2200		50		200	1980	3,700		8,600(e)			63
	Vasqueros, Palisades Area	Vasqueros	1929			20		2150		60		10	1973	21		50(e)			63

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TABLE 1

LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: CALIFORNIA - CENTRAL COASTAL

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC	YEAR ABD	API RANGE (°)	BEST API VALUE (°)	VISCOSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO OF PAY ZONES	RES AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1,000 bbl)	CUMULATIVE PRODUCTION GAS (1,000 mcf)	OIL REMAINING IN PLACE (1,000 bbl)	PLAN	RANK	REF
MONROE SWELL (Monterey)	44	Monterey	1960			19		2000		200		50	1980	300		1200(e)			11
	Doud	Monterey	1959			19		2900		200									63
	Beedy	Monterey	1949			17		3200		150									11,63
OAKRIDGE (Santa Clara Dist.)	Miocene	Monterey	1952		20 to 21	20		2450		90		425	1978	12,315	8,065	33,200			11,63 20 11 18 63
OJAI	Unnamed Sisar Creek Area	Saugus-Monterey	1900		11 to 30	17		750		40		190	1978	2,110	350	12,800			20 18 63
	Unnamed Sulphur Mountain Area	Monterey	1927			16		1450		450		80	1980	300	700(e)				18 63 11
OXNARD (Ventura Co.)	Miocene Tar	Monterey	1937			13		2800	400	80(e)		1860 to 1330	1980	11,500		26,800(e)			18 63
PARIS VALLEY (Monterey Co.)	Basal Ansberry, Biaggi Area	Monterey	1948			13		1090		70		10	1973	.3		1(e)			63
	Basal Ansberry, Main Area	Monterey	1958			12		710		80		30	1980	13		50(e)			11 18 63
PIRU	Modelo, Warring Canyon Area	Modelo	1921			20		500		200		20	1973	10		25(e)			11 18 63

TABLE 1

LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: CALIFORNIA -CENTRAL COASTAL

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC	YEAR ABD	API RANGE (°)	BEST API VALUE (°)	VISC-OSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO OF PAY ZONES	RES AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1 000 bbl)	CUMULATIVE PRODUCTION GAS (1 000 mcf)	OIL REMAINING IN PLACE (1 000 bbl)	FLAW	RANK	REF
PIRU (Ventura Co.)	Unnamed, Creek Area	Modelo	1956			15		2000		100		10	1973	4		20(e)			11 18 63
PETALUMA (Sonoma)			1948			20		985					1964	1		5(e)			11
QUINADA CANYON (Monterey Co.)	Gamboa -Kelly	Monterey	1963		19 to 20			2035 to 2179		60		10	1980	8		40(e)			11 18 63
RAMONA (Los Angeles & Ventura Co.)	Kern	Modelo	1945		15 to 31			3500		350		590 (Field)	1978	19,346 (Field)	37,031 (Field)	45,140(e			11 18 63
SAN ARDO (Monterey Co.) Salinas Valley District	Lombardi, North Area	Monterey	1947			10		2100		40		120	1980	306	0	710(e)			11 18 63
	Lombardi, Main Area	Monterey	1948		10 to 13	11	3000	2122		115		4200	1978	200,483		685,300		M-55	20 11 18 63
	Aurignac, Main Area	Monterey	1948		11 to 14	12	300	2350		100		3500	1978	113,796		528,000		M-48	20 11 18 63
SANTA BARBARA (Santa Barbara)	Vasqueros, Mesa Area	Vasqueros	1929			17		1913		50		240	1964	4		9(e)			11

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LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: CALIFORNIA -CENTRAL COASTAL

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC	YEAR ABD	API RANGE (-)	BEST API VALUE (-)	VISCOSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO OF PAY ZONES	RES AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1 000 bbl)	CUMULATIVE PRODUCTION GAS (1 000 mcf)	OIL REMAINING IN PLACE (1 000 bbl)	FLAW	RANK	REF
SANTA MARIA (Santa Barbara) (Santa Maria District)	Foxen -Sisquoc Main Area	Foxen -Sisquoc	1934			17		2000		200		4020 Field	1978	150,000 (Field)	216,445 (Field)	350,000 (e)		x	18 63
	Main Area, 1 Santa Margarita 2 Arenaceous 3 Cherty 4 Bentonitic 5 Buff & Brown 6 Dark Brown	Monterey	1934		6 to 20	15	85	3330 to 4711		1035	6							x	20 11 18 63
	Main Area, 1 Oil Sand 2 Siltstone & Shell	Point Sal	1936		15 to 16			4330 to 4520		2030	2							x	18 63
	Foxen, North Area	Foxen	1965			13		2250	340	20(e)		10	1980	.9		5(e)			18 63
	Foxen, West Area	Foxen	1953		12 to 14			3490		160		120	1980	543					18 63
	Sisquoc, West	Sisquoc	1953			19		3610		280			1974 (pool)		195	1500(e)			18 63
	Monterey, West	Monterey	1953			14		4410		200									1863
	Knoxville West Area	Knoxville	1953			14		4660		10 to 300									18 63
SARGENT (Santa Clara Co.)	Pliocene	Sisquoc	1886			17		915					1976	788		1840(e)			18
SESPE (Ventura Co.)	Middle Sespe, Foot of the Hill	Sespe	1891			20		600		45		70	1976	20,168 (Field)	18,281 (Field)	47,100 (e) (Field)			
	Basal Sespe Foot of the Hill Area	Sespe	1935		20 to 22			1200 to 1883		70 to 395									

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FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC	YEAR ABD	API RANGE (°)	BEST API VALUE (°)	VISCOSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO OF PAY ZONES	RES AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1 000 bbl)	CUMULATIVE PRODUCTION GAS (1 000 mcf)	OIL REMAINING IN PLACE (1 000 bbl)	FLAW	RANK	REF
SESPE (Ventura Co.)	Coldwater, Section 23 & 26 Area	Coldwater	1901			12		825		220		50	1976	20,168 (Field)	18,281 (Field)	47,100(e) (Field)			
SIMI. (Ventura Co.)	1st Sespe, Alamos Area	Sespe	1971			19		1450		550		30	1974	37	17	1200(e)			18 63
SIMI,	1st (Upper) Canada La Brea	Sespe	1910			15		650		220		130	1974	876	312	2100(e)			
	Canada La Brea 1st (Lower)	Sespe	1910			17		975		300									18 63
	Canada La Brea 2nd,	Sespe	1910			19		1600		325									
	Canada La Brea 3rd,	Sespe	1910			20		2235		200									
SISAR-SILVER-THREAD (Ventura Co.)			1885			17		1063		350		270	1964	3714		8700(e)			11
SOMIS (Ventura Co.)	B-1	Sespe	1955			16		3950		500		10	1980	2		6(e)			11 18 63
SUMMER-LAND, (Santa Barbara Co.)	Vasqueros, Onshore Area	Vasqueros	1929			16		1400		300		110	1980	3210	0	7500(e)			11 18 63
TAPO, (Ventura Co.)	Modelo, North Area	Modelo	1882			18		1500		35 to 190		90 to 135	1974	1002 (Field	159 (Field)	2340(e) (Field)			

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LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: CALIFORNIA - CENTRAL COASTAL

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC	YEAR ABD	API RANGE (°)	BEST API VALUE (°)	VISCOSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO OF PAY ZONES	RES AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1,000 mbl)	CUMULATIVE PRODUCTION GAS (1,000 mcf)	OIL REMAINING IN PLACE (1,000 bbl)	FLAW	RANK	REF
TAPO CANYON (Ventura Co.)	2nd Sespe South	Sespe	1954			18		1800		8 to 20		240							11 18 63
	3rd Sespe South	Sespe	1954			18		1880		220									
	4th Sespe South Area	Sespe	1954		17 to 21	19		2200 to 2376		180		70(e)	1980	487	203	10,000			20 11 18 63
TAPO RIDGE (Ventura Co.)	1325 Sand	Modelo	1954			17		1750		160		10	1974	.05		.1(e)			18 63
TOWNSITE (Los Angeles)			1948			20		1957					1964	57		760(e			11
TUNNEL (Los Angeles)			1900			18		1486		200									11
WEST MTN. (Ventura Co.)	Sespe	Sespe	1946			20		4500	1500	50(e)		240 to 340	1980	3536	2500	8300(e)			11 18
WHITNEY CANYON (Los Angeles)			1883			14		1226		150									11
WILEY CANYON (Los Angeles)			1883			12		3920		200									11

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LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: CALIFORNIA . SAN JOAQUIN VALLEY

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC	YEAR ABD	API RANGE (-)	BEST API VALUE (-)	VISC-OSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO OF PAY ZONES	RES AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1 000 bbl)	CUMULATIVE PRODUCTION GAS (1 000 mcf)	OIL REMAINING IN PLACE (1 000 bbl)	FLAW	RANK	REF
ALFERITZ MAIN AREA (Kern)			1931			18		1693		275		430	1976	1263		3000(e)			11 18
AIMA (Kern)	Vedder	Vedder	1947			13		2769		15		70	1964	536		2700(e)			11
ANT HILL	Olcese Sand	Olcese	1944		12 to 14	14		2286		100		285	1980	6063	233	42,100			20,11 18,62
ANTELOPE HILLS, HOPKINS AREA (Kern)	Point of Rocks, Hopkins Area	Kroyen-hagen	1944			17		2244		30 to 100		70	1976	397		930(e)			11 18 62
	Williams Area, Upper	Tulare	1971			12		845 to 1400		10 to 80		410	1980	34		350(e)			18 62
	Williams Area, East Block Agua	Temblor	1943		17 to 24	19		2300		120		145	1978	4146		23,900			20 11 18 62
	Williams Area, East Block Button Bed	Temblor	1942		18 to 21	20		2335		85			1978	2317		5400(e)			20 11 18 62
	Williams Area, W.B. Button Bed-Agua	Temblor	1942		15 to 18	17		2298		150		265	1978	7147		56,800(e)			20 11 18 62
	Button Bed, IIA & Agua, North Area	Temblor	1950		15 to 16	16		1311 to 2340		75 to 120	3	280	1978	3325	718	30,500			20 11 18 62
ASPHALTO (Kern)	Etchegoin	Etchegoin	1923		15 to 19			3050		15		820	1980	107		250 (e			11 18 6.
BAKER (Kern)	Vedder	Vedder	1935			16		1758		25		80	1964	3422		8,000 (e			11

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LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: CALIFORNIA – SAN JOAQUIN VALLEY

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC	YEAR ABD	API RANGE (°)	BEST API VALUE (°)	VISCOSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO OF PAY ZONES	RES AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1 000 bbl)	CUMULATIVE PRODUCTION GAS (1 000 mcf)	OIL REMAINING IN PLACE (1 000 bbl)	FLAW	NAME	REF
BELGIAN ANTICLINE (Kern)	Phacoides, New Area	Phacoides	1954		10 to 22			1400		55		850						X	
BELRIDGE, (Kern)	Shallow, North Area	Tulare-Etchegoin	1917		12 to 24	12		600		60	2	2080	1978	7761	11,287	18,100 (e)		M-42-(2) S-5-(1)	20 11 18 62
	North Area, Fractured Shale	Monterey	1912		10 to 32			3500		400		2070							
	Tulare, South	Tulare	1911			14	1600	700	450	100		3610	1980	261,470	20,430	1,472,000		M-81-(1)	20 11 18 62
	Etchegoin, South	Etchegoin	1943			13	1600	700	450	100								S-113-(2)	20 62
	Diatomite, South	Diatomite	1911			25	1600	700	450	100									20 62
BLACKWELLS CORNER (Kern)	Devilwater	Temblor	1944			13		700		25		50	1980	893					11 18 62 20
	Agua	Temblor	1943			14		1300		85		190	1978		91	18,500			11 18 62 20
CHICO-MARTINEZ (Kern)	Etchegoin	Etchegoin	1927			12		900		35		290	1980	340					11 18 62
COALINGA (Kern)	West Side Area Temblor	Temblor	1900		12 to 22	15		1852		50		6400	1980	253,400	144,880	252,600		M-29 S-23	20 11 18 62
COFFEE CANYON (Kern)	Vedder	Vedder	1927			17		1616		180		405	1964	197,984		465,000 (e)			11
COMANCHE POINT (Kern)	Santa Margarita	Santa Margarita	1947			14		650		100		55	1980	204		500(e)			11 18 62

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FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC	YEAR ABD	API RANGE (-)	BEST API VALUE (-)	VISC-OSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO OF PAY ZONES	RES AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1 000 bbl)	CUMULATIVE PRODUCTION GAS (1 000 mcf)	OIL REMAINING IN PLACE (1 000 bbl)	FLAW	RANK	REF
CYMRIC (Kern)	McKittrick Front Area, Reef Ridge	Monterey	1917		16 to 20	18		2300		160		125	1978	6919	2349	23,800			20 11 18 62
	McKittrick Front Area, Tulare	Tulare	1909		11 to 15	13		1000		275		1380	1980 1978	30,640	2342	282,000		M-84	20 11 18 62
	Salt Creek Main Area Corneros Unit	Temblor	1946		17 to 24	20		2400		150		310	1980 1978	24,403	542	43,800			20 11 18 62
	Sheep Springs Area 54-21	Etchegoin	1929		14 to 18	17		2450		75		170(e	1980 1978	3568	1728	18,400			20 11 18 62
	Weport Area	Tulare	1916		10 to 21	13		1000		125		1670	1980 1978	38,567	1458	341,800		M-84	20 11 18 62
	1-Y Area 1st & 2nd McKittrick	Monterey	1939 & 1953			14		1150		310	2	110	1980	342		900(e)			11 18 62
	Salt Creek, Main Area	Etchegoin	1946			13		650		60		455	1980	88		205(e)			11 18 62
DEER CREEK (Tulare)	Santa Margarita	Santa Margarita	1953			16		715		20		145	1980	1321		3600(e)			11 18 62
	Main Sand, North Area	Santa Margarita	1961			12		790		25		5 to 15	1980	5		20(e)			18 62
DEVIL'S DEN (Kern)	Esudo Alferitz Area	Monterey	1952			15		1100		100		480 (Field)	1976	489		1150(e)			
	Corneros -Auge, Alferitz	Temblor	1938			15		1350		150									11 6 18
	Tumey, Alferitz Area	Tumey	1931		18 to 32			2000		500									

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LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: CALIFORNIA SAN JOAQUIN VALLEY

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC.	YEAR ABD.	API RANGE (-)	BEST API VALUE (-)	VISCOSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO. OF PAY ZONES	RES. AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1,000 bbl)	CUMULATIVE PRODUCTION GAS (1,000 mcf)	OIL REMAINING IN PLACE (1,000 bbl)	FLAW	RANK	REF
DEVILS DEN (Kern)	Old Area, Santos & Salt Creek	Temblor	1901		14 to 19			200		310	2	340	1980	200	.1	500(e)			62
	Tumey Old Area	Tumey	1901			16		300		300									62
	Point of Rocks Old Area	Kreyenhagen	1901			18		200		200									62
DOMINION (Kern)	Vedder	Vedder	1931			15		1520		47		505	1964	4425		10,350 (e)		M-30-(1)	11
DORSEY (Kern)	Vedder	Vedder	1928			16		1499		25		400	1964	3537		8300(e			11
DYER CREEK (Kern)	Vedder	Vedder	1941	1952		15		2340	75			20	1980	38	0	90(e			11 62 10
EDISON MAIN AREA (Kern)	Main Area, Upper	Kern River Chanac	1931		14 to 28	19	310	1100	450	80	2	1500 (e)	1978	23,733	3343	136,700		M-54-(1)	11 18 62
	Wicker, Main Area	Wicker	1945			16		1500 to 2500		20 to 105		2525 (Pool)	1978	66,117 (Pool)	12,377 (Pool)	155,000 (Pool)		M-29-(3)	11 18 62
	Main Area, Freemon-Jewett	Freeman-Jewett	1934		16 to 29			3100		65									
	Main Area, Walker	Walker	1934			20		2900		120									
	Groves Area, Chanac	Chanac	1953			16		1130		30 to 65		260	1980	1,665		4100(e)			11 18 62
	Groves, Area Olcese	Olcese	1950			13		3450	100			80	1980	1,278		3000(e)			11 18 62
	Jeppi Area, Santa Margarita	Santa Margarita	1948			20		3500		30		685 (Pool)	1974	5,511 (Pool)	11,454 (Pool)	13,000(e (Pool)			18 62
	Wicker -Hozu Portals Fairfax Area	Fruitvale -Round Mountain	1934 & 1928			19 15		4402		110	3	490	1978	3,757	164	9000(e)			

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EDISON (Kern)	Race Track Hill Area, Chanac	Chanac	1954			15		1070		150		1565 (Pool)	1974	15,794 (Pool)	36,309 (Pool)	63,200(e) (Pool)		M-21-(3)	10 62
	Race Track Hill Santa Margarita	Santa Margarita	1954			13		1830		40									
	Race Track Hill Area, Wicker	Fruitvale	1952			14		3200		130									
	Race Track Hill Area, Nozu	Mound Mountain	1947			16		3260		200									
	West Area, Chanac-Santa Margarita	Chanac-Santa Margarita	1935		19 to 23	20		3846		100		1125	1978	23,032	3,608	134,100			10 62
	West Area, Nozu	Mound Mountain	1935			20		4500		75									62
	West Area, Porter	Olcese	1951			20		4400		100									
	Northeast Area Chanac	Chanac	1935			12		350	120			40	1974	17,128	0	40,000 (e)			62
[illegible] (Kern)	Greenacres Area Lerdo	Etchegoin	1953	1970		20		4300		60		20	1976	41	0	140(e)			11 18 62
	Greenacres Area Chanac	Chanac	1954	1957		19		4400		30			1976	1	0	4(e)			11 18 62
	Main Area, Chanac -Kernco	Etchegoin -Chanac -Santa Margarita	1928		15 to 23			3000 to 4500		89 to 1225		2680 to 3370	1978	103,110	36,093	245,800		M-8-(2)	20 11 18 62
GONYER ANTICLINE (Kern)	Gonyer	Temblor	1956			12		1700		450		10	1980	3	4	10(e)			11 18 62
GRANITE CANYON (Kern)	Vedder	Vedder	1936			15		1415		30		115	1964	721		1700(e)			11 18

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JASMIN (Kern)	Pyramid Hill	Jewett	1964	1966	12 to 16	13		1705		130		310 to 455	1980	2300	0	12,100 (e)			11 18 62
	Cantleberry Sands	Vedder	1946		12 to 16	13		2750		30 to 80									
	Ramona, West Area	Eocene	1959			19		4261		25			1976	62		300(e)			10
KERN BLUFF (Kern)	Transition -Santa Margarita	Tran-sition Santa Margarita	1944		14 to 16	15		1082		85		610 to 690	1978	10,400		67,700		M-58-(1)	20 11 18 62
KERN FRONT (Kern)	Main	Etchegoin -Chanac	1914			14	400	2265		84		5540	1980 1978	152,000 16,564		648,500		M-41	20 11 1862
KERN RIVER (Kern & Fresno)	Pliocene -Kern River	Kern River	1899		11 to 16	14	4000	1008	800	220		9435	1980 1976	795,200	2,605	2,902,900		M-110 S-128	20 11 18 62
KETTLE-MAN MID DOME (Kings)	Etchegoin -Jacalitos	Etchegoin Jacalitos	1926			11		2700		30		250 (Field)	1976	534		1300(e)			11 18 62
KREYEN-HAGEN (Kern)	Temblor	Temblor	1949			16		450		130		70	1980	17		40(e)			11 18 62
LOST HILLS (Kern)	Main	Tulare Etchegoin Monterey Temblor	1910		12 to 38	38	60	1928	300	63	5	4000	1978	113,722	25,540	420,000		M-44 S-50	11 18 62

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MCDONALD ANTICLINE (Kern)	Fractured Shale	Monterey	1953			13		500		1000		620	1976	15,170 (Field)	12,437 (Field)	50,800(e)		M-4[illegible]-(1)	11 18 62
	D-1	Monterey	1951			19		1200		60									
	Layman 101	Monterey	1951			19		1400		100									
	Tolco 7th Devilwater	Monterey	1951			20		2600		80									
	Phacoides	Temblor	1945			20		1300		50									
	Bacon Hills Area	Oceanic	1947			20		1550					1976	168	885	400(e)			18
MCKITTRICK (Kern)	Northeast Area, Upper	Tulare -Monterey	1944		12 to 17	14		650 to 800	900			1440 (Field)	1978	11,044 (Tulare Mont. Only)	2,451	289,000		M-88-(2) S-31-(1)	20 18 62
	Main Area Upper	Tulare -Monterey	1887		11 to 17	15	800	500 to 1191	1000	265		1430	1978	159,343 (Field)	8,768 (Field)	546,200 (Field)		M-132-(8) S-123-(2)	20 11 18 62
	Basal Reef Ridge, Main Area	Monterey	1944		14 to 21			1500		400								x	62 18
	Main Area, Stevens	Monterey	1964		18 to 32			2000 to 4750		175			1976	10,096	13,598	74,100 (e)		x	62 18
MIDWAY -SUNSET (Kern)	Tulare	Tulare	1894			13		200 to 1400		50 to 200								x	
	Oligocene	Etchegoin	1950		14 to 16	15		1950	300	113		320	1978	5,191	4,860	61,800			20 11 18 62
	Others (includes many)	Pliocene	1901		11 to 29	16	400	1687	350	125		24,370	1978	1,161,954 (87% of field)		4,200,000		M-65	20 11 18 62

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TABLE 1

LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: CALIFORNIA - SAN JOAQUIN VALLEY

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC	YEAR ABD	API RANGE (-)	BEST API VALUE (-)	VISC-OSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO OF PAY ZONES	RES AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1 000 bbl)	CUMULATIVE PRODUCTION GAS (1 000 mcf)	OIL REMAINING IN PLACE (1 000 bbl)	FLAW	RANK	REF
MIDWAY -SUNSET (Kern)	Spellacy 200 Sand	Monterey	1974			11	6500	550	200	150		250	1978	96		50,000			20
	Republic	Miocene	1928		15 to 23	19		2667	340	150			1978	23,211	11,149	26,000(e)		X	20 18
	Ethel D	Mclure	1950			18		3108					1976	5,630	6,699	16,000(e)			18
	Quality	Mclure	1936			15		2065					1976	16,776		40,000(e)		X	18
	Metson	Miocene	1953			11		1203		400			1976	6,562	1,063	16,100(e)		X	18
	Leutholtz -Antelope	Monterey	1945			18		3265		350			1976	17,347	9,475	40,500(e)			18
	Spellacy 1-6 Sand	Monterey	1974			15												X	18
	Spellacy 75 Sand	Monterey	1974			11												X	18
	Note: It is unclear how many reservoirs are included in Others Many more reservoirs listed individually in Vol. I - "Calif. Oil & Gas Fields"																		
MOUNT POSO (Kern)	Baker-Grover Area	Upper Vedder	1935			15		1750		25		90	1980	3700	0	8,640(e)			62
	Dominion Area	Vedder	1926		13 to 16	15		1584		40		655	1980 1978	6380		27,600		M-34	62 20
	Dorsey Area	Vedder	1928		15 to 16	16		1542		30		375	1978	4819		14,400			20 62
	Granite Canyon Area	Vedder	1936			15		1390		30		130	1980	880	0	2,050(e)			62
	Mount Poso Area Pyramid Hill	Pyramid Hill	1926			17		1600		160								X	62
	Mount Poso Area, Vedder	Vedder	1926		12 to 17	16		1806		292	3	2220	1980	174,773		386,000		M-63	20 62
	West Area Section 18	Vedder	1943			16		2575		15 to 50		220	1980	3,043		7,100 (e)			62

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LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: CALIFORNIA -- SAN JOAQUIN VALLEY

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC.	YEAR ABD	API RANGE (°)	BEST API VALUE (°)	VISCOSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO OF PAY ZONES	RES AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1 000 bbl)	CUMULATIVE PRODUCTION GAS (1 000 mcf)	OIL REMAINING IN PLACE (1 000 bbl)	RLAW	RANK	REF
MOUNT POSO (Kern)	Mount Poso Area, Gill (Vedder)	Vedder	1954			14		2162		50			1976	4		15(e)			18
	West Area	Vedder	1956			17		2616		10			1976	2		8(e)			18
PLEITO (Kern)	Creek Area, Santa Margarita	Santa Margarita	1951		13 to 20	18		4300	200	150			1980 1978	1,548	1,139	31,100			62 20
POSO CREEK, (Kern)	McVan Area, Basal Etchegoin	Etchegoin	1932			13		1150		40		280	1980 1978	3,600	15,800				11
	McVan Area, Vedder	Vedder	1949			17		3160		30									62
	Etchegoin	Basal Etchegoin	1938			12		1800		90		190							62
	Enas Area, Chanac	Chanac	1929		12 to 13	12		2115	300	150		165(e)	1978		3	37,400			20 62
	Premier Area, Main-	Etchegoin			11 to 14	14		2400	390	240		3285	1980 1978	60,246	5,344	637,000		M-58-(2)	20
	Premier Area, Main-	Chanac	1919		11 to 14	14			390	240								x	18 62
	Premier Area, Main, Kelly 2	Santa Margarita	1946			15		3100		40									62
PYRAMID HILLS (Kings)	Dagony Area, -Kr zone	Kreyenhagen	1954			16		650		125		120	1980 1976	1,160 (includes Eocene)	23	3300(e)			11 18 6
	Morris Area, -Miocene	Temblor	1951		12 to 16			850		40		185 (Pool)	1974	1,755 (includes Eocene)	5,524	5900(e)			11 10 6
	Morris Area, -Kr zone Point of rocks	Kreyenhagen	1955		12 to 19			800		70								x	

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TABLE 1

LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: CALIFORNIA - SAN JOAQUIN VALLEY

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC	YEAR ABD	API RANGE (-)	BEST API VALUE (-)	VISCOSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO OF PAY ZONES	RES AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1 000 bbl)	CUMULATIVE PRODUCTION GAS (1 000 mcf)	OIL REMAINING IN PLACE (1 000 bbl)	FLAW	NAME	REF
PYRAMID HILLS (Kern)	West Slope Area -Kr zone	Kreyenhagen	1940			17		800		120		260	1980 1976	2,210	823	5200(e)			18 62
RAILROAD GAP (Kern)	Annicola	Tulare	1965			14		1100		60		470	1980	1,080		6200(e)			18 62
RAISIN CITY (Fresno)	Miocene Tar	Zilch	1946		16 to 21	17		4680		20		1670 (field)	1980	10,860		25,400(e)			11 18 62
ROSEDALE RANCH (Kern)	Etchegoin Sand	Etchegoin	1965			15		3500		100		630	1980	670	180	3800(e)			18 62
	Lerdo	Etchegoin	1945		15 to 21	18		4311	200	70		600	1980 1978	6,760	5,247	44,500			11 18 62
	KCL 31-38	Chanac	1953			20		4675		80			1976	5,807	3490	17,800(e)			18 62
ROUND MOUNTAIN (Kern)	Alma Area	Vedder	1947			13		2600		15		80	1980	670	0	1600(e)			18 62
	Coffee Canyon Area	Jewett & Vedder	1928		15 to 19	17		1500 to 1650	205	180	2	435	1980	19,460		33,900			11 18 62,20
	Main Area Pyramid Hill	Jewett	1927			18		1900		130									11 18 62
	Main Area Vedder	Vedder	1927		13 to 25	16		1946	160	80		990	1978	51,784		85,400		M-39	11 18 62 20
	Sharktooth Area	Vedder	1943			13		2400		25		270	1980	5,030	56	12,000(e)			11 18,62
	Pyramid Area, Pyramid Hill	Jewett	1944			18		1250		130		300 (Pool)	1980	6,070	7	15,000(e)			11 18 62
	Pyramid Area Vedder	Vedder	1937			16		1390		40									11 18 62
	Pyramid Area, Walker	Walker	1943			20		1535		50									11 18 62

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TABLE 1

LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: CALIFORNIA SAN JOAQUIN VALLEY

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC	YEAR ABD	API RANGE (-)	BEST API VALUE (-)	VISC-OSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO OF PAY ZONES	RES AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1 000 bbl)	CUMULATIVE PRODUCTION GAS (1 000 mcf)	OIL REMAINING IN PLACE (1 000 bbl)	FLAW	RANK	REF
RUSSELL RANCH (Santa Barbara)	Main Area 138-5		1955	1971		13		14 to 24		68		10	1964	1,644		16,700(e)			11 18
TEJON -GRAPEVINE (Kern)	Centra Area Transition	Transition	1944			17		2725		85		485	1980 1976	510	150	2000(e)			11 18 62
	Central Area Santa Margarita	Santa	1950			18		~~2900~~		100			1976	2,388	3,116	6800(e)			11 18 62
	Eastern Area	Transition & Santa Margarita	1943			18		2000		150		210	1980 1976	1,590	309	4000(e)			18 62
	Southeast Area 2-1 Sand	Fruitvale	1951			16		2670		20		155 (Pool)	1980 1976	1,720 (Includes reserve)	238 lower	4100(e)			18 62
	Southeast Area Upper Reserve	Fruitvale	1951			17		1810		20 to 190									
	Western Area Transition & Santa Margarita	Transition & Santa Margarita	1945		14 to 18	16		2649		55		540	1980 1978	10,920	258	28,000		M-19	20 18 62
	Western Area, Pulv	Fruitvale	1949			20		4600		125			1980	120	2,337	300(e)			18 62
TEMBLOR, (Kern).	East Area, Phacoides	Temblor	1953			20		2060		25		40	1974	15	0	60(e)			18
TEMBLOR RANCH (Kern)	Ranch Area, Phacoides	Temblor	1900			16		400		60		90	1980	1,130	0				11 62 18
TERRA BELLA (Kern)	Santa Margarita	Santa Margarita	1930			16		860		100		15	1974	18	0				62 18
UNION AVENUE (Kern)	Chanac	Chanac	1941			15		4100		200		50	1980 1974	1,340 (Includes Santa Margarita)	829	2,600(e)			62 18

TABLE 1

LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: CALIFORNIA - SAN JOAQUIN VALLEY

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC	YEAR ABD	API RANGE (-)	BEST API VALUE (-)	VISCOSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO OF PAY ZONES	RES AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1 000 bbl)	CUMULATIVE PRODUCTION GAS (1 000 mcf)	OIL REMAINING IN PLACE (1 000 bbl)	FLAW	RANK	REF
VALLECITOS (San Benito)	Ashurst Area	Domengine -Yokut	1958	1963		20		1058		60		40	1974	13	0	70(e)			62
	Cedar Flat Area, San Carlos	Martinez	1948			15		1000		70		20	1974	8	0	25(e)			62
WELCOME VALLEY (Kern)	Tumey	Tumey	1952			12		100		100		110	1980	40		100(e)			62 18
WHEELER RIDGE (Kern)	Northeast Area, PA-2	Fruitvale	1955			18		2900		240		80 to 160	1980 1976	1,230 (Includes Fruitvale & Vedder)	328	3,700(e)			62 11
WHITE WOLF	700 Sand	Etchegoin	1964			16		815		350		90	1978	888	0	5500(e)			11 62 20
	Reef Ridge	Monterey	1959			14		2800		200									
	Antelope	Monterey	1964			14		1770		740									

TABLE 1

LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: CALIFORNIA SOUTHERN

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC	YEAR ABD	API RANGE (°)	BEST API VALUE (°)	VISC-OSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO OF PAY ZONES	RES AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1,000 bbl)	CUMULATIVE PRODUCTION GAS (1,000 mcf)	OIL REMAINING IN PLACE (1,000 bbl)	FLAW	RANK	REF
ALISO CANYON (San Fernando Dist.-Los Ang. Co.)	Main Area Aliso	Pico	1950		12 to 17	17		4379		100		200(e)	1978	5,324	2,658	19,400			20 13 18 63
ANAHEIM (Orange Co.)	Oil Sand	Pico	1951	1952		11		4350		130		10	1980	4		10 (u)			62 18
BEVERLY HILLS (L.A. Co)	West Area Wolfskill	Repetto	1900		15 to 25			2500		150(e)		120	1976	4,793	2,366	30,600			11 18 63 20
BREA-OLINDA (L.A. & Orange Co.)	Olinda Area	Repetto-Puente	1897		14 to 26	18	40	3235	1100	400	3	705(e)	1976	160,000 (e)	240,000	317,300			11 20 63 18
	E-F Zone	Puente-Topanga	1880		18 to 28			1200		300								x	63 10
CHARLIE CANYON (L.A. Co.)	Unnamed	Sagus	1958	1963		14		600		20		10	1980	.2		1(e)			63
COYOTE (Orange Co.)	Hualde, East Area	Repetto	1909		17 to 20			2500		50								x	63 18
	Top Zone, West Area	Repetto	1918			19		2900	125			750(e)	1980	1,716		4,004(u)			11 18 63
GAFFEY (L.A. Co.)	Pliocene	Repetto	1955	1967		10		1500		100		20	1974	10		45(e)			63 11 18
HASLEY CANYON (L.A. Co.)	Val Verde	Modelo	1944		13 to 18			4800		200		30	1974	32		75(u)			63 10

TABLE 1

LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: CALIFORNIA SOUTHERN

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC.	YEAR ABD.	API RANGE (°)	BEST API VALUE (°)	VISCOSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO OF PAY ZONES	RES. AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1 000 bbl)	CUMULATIVE PRODUCTION GAS (1 000 mcf)	OIL REMAINING IN PLACE (1 000 bbl)	FLAW	RANK	REF
WILMINGTON (L.A. Co.)	Terminal Area Fault Block II-B Rang	Repetto -Puente	1937		18 to 23	20	50	2500	500	150	5	80	1978	9,759	7,004	10,600			20 18
	Terminal Area Fault Block III Ranger	Repetto -Puente	1937		14 to 23	18	50	2500	500	138	5	500	1978	51,648	32,714	84,500		H-51-(1)	20 11 18
	Town Lot Area F.B.I. Tar-Ranger-Term	Repetto	1934		12 to 20	15	84	3100	1050	250		2095 (e)	1978	121,354		726,200			20 11 18
	Town Lot Area Fault Block II-A Ranger	Repetto -Puente	1937		12 to 27	14	50	2500	500	150	5	235(e	1978	10,781		56,800			20 11 18
	Town Lot Area Fault Block II-A Upper	Puente	1937		12 to 15	13	450	3575	570	300	3	104	1978	1,956		53,400			20 11 18
	Town Lot Area Fault Block III Ranger	Repetto -Puente	1937		12 to 22	18	50	2500	500	150	5	200	1978	10,886		46,700			20 11 18
YORBA LINDA (Orange Co.)	Main (Smith)	Repetto	1930		13 to 17	16	1500	1800 to 2132	85	70		200(e	1978	8,074	786	14,300			20 11 62 18
	Shallow	La Habra	1954		12 to 14	13	6400	350 to 650		400	2	620(e	1978	46,360	172	311,000		N-167-(2) S-169-(2)	20 11 62 18
	Shell	Repetto	1930		13 to 20	17		1733		125		90(e)	1978	4,640	883	19,100			20 11 62,18
	Miocene Contact	Puente	1961			15		2900		70			1976	248	83				11 18

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TABLE 1

LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: LOUISIANA

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC.	YEAR ABD.	API RANGE (°)	BEST API VALUE (°)	VISC-OSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO OF PAY ZONES	REL AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1 000 bbl)	CUMULATIVE PRODUCTION GAS (1 000 mcf)	OIL REMAINING IN PLACE (1 000 bbl)	FLAW	RANK	REF
ASHLAND (Tuscaloosa)	Tuscaloosa	Lower Tuscaloosa	1946			20		3288		20		320							116
BELLEVUE (Bossier)	Nacatoch	Nacatoch	1921		18 to 19	19	580	300		27 to 60	1	3080	1978	7,170		92,700		S-40-(1)	11 20
CADDO-PINE ISLAND (Caddo)	Nacatoch	Nacatoch	1906			20	280	767		14 to 40	1	85000 to 00480	1978	319,600		745,800 (e)		S-0 M-39-(1)	11 20
CAMERON MEADOWS (Cameron)	Pleist-Plio	Pleist-Plio	1931			20		1338		10 to 220		1200	1976	15,781	142,516	6,000			18 11 115
CHARENTON (St. Mary			1936			20		1000										X	11
LAKE PELTO (Terebonne)		Peisto-cene to Upper Miocene Miocene	1929			17		1320 to 16065				4860	1964	54,994		50,000		M-29-(1)	11 112
MANIFEST (Catahoula)	Sparta	Sparta	1942			20		1810		10		280	1964	146		340 (e)			11 116
NEBO-HEMPHILL (LaSalle)	Cockfield	Cockfield	1942			19		1420		9 to 15		8120	1978	68,620 (Field)		160,200 (e) (Field)		M-31-(1)	11
STARKS, (Calcasieu	Plio - U Mio	Plio - U Mio	1927			20		742 to 3690		447	5	2210 (Field	1976	8,597 (Field)	6,133 (Field)	20,100 (e)		M 40-(1)	18 11
WELSH (Jefferson Davis)	Pliocene	Pliocene	1903			21		1148		206		3420	1976	19,823	80,024	46,300 (e)		M-34-(1)	18
WHITE CASTLE (Iverville)	WC RD U SU V SU RD	Miocene	1974			16	300	1200		175		57	1977	740	273	12,600			20
WHITE SULPHUR SPRINGS (La Salle)		Cockfield	1927			20		794		9		400	1964	5		12 (e)			11

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TABLE 1

LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: TEXAS SW - SAN ANTONIO - RR CD#1

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC.	YEAR ABD.	API RANGE (°)	BEST API VALUE (°)	VISC-OSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO OF PAY ZONES	RES AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1 000 bbl)	CUMULATIVE PRODUCTION GAS (1 000 mcf)	OIL REMAINING IN PLACE (1 000 bbl)	FLAW	RANK	REF
BILLY HOLLAND (Edwards)	Billy Holland	Fredericksburg or Glen Rose	1948		17 to 18			532 to 552		11								X	11
CALLIHAM (McMullen)	Mirando	Mirando	1902 to 1910			20		500 to 1050		10 to 15		90							11 18
CAMPANA CHERNOSKY (McMullen)	Chernosky, South Area	Chernosky	1958			20		2225		20		520	1970	1,247		5,000 (e)			11 18
CHAS H. JONES (Guadalupe)	Austin Chalk	Austin Chalk	1969			14		2402 to 2430		28			1980	4		30 (e)			18 29
CHITTIM (Maverick)	San Miguel	San Miguel	1962			12		48		35 to 51		160	1980	1		5 (e)			11
	Eagle Ford	Eagle Ford	1964			19		1986 to 2018		32			1980	10		50 (e)			10
COFFEY (Bexar)	Anacacho	Anacacho	1934			13		1017 to 1034					1967	13		30 (e)			11
CROWN (Atascosa)	Navarro South Area & Northeast Area	Navarro	1954			19		492 to 4631		13		54	1980	33		94 (e)			11 18
CROWTHER (McMullen)	Jackson-Yegua	Jackson-Yegua	1915			18 to 20		500		20		1	1980	26		60 (e)			11 18
DEL MONTE (Zavala)	San Miguel D	San Miguel D	1961			20		3409		34		40	1980	30		130 (e)			11 18
DILWORTH RANCH (McMullen)	Pettus	Pettus	1950			20		500 to 1000					1964	38		230 (e)			11 18
DINSMOOR (Atascosa)	Carrizo	Carrizo	1952			19		2060 to 2075		12		90	1980	790		2040 (e)			11 18
DUNLAY (Medina)	Serpentine	Serpentine	1938			18		542 to 550				10	1976	2		5 (e)			11 18

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TABLE 1

LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: TEXAS SW - SAN ANTONIO - RR COM1

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC.	YEAR ABD.	API RANGE (-)	BEST API VALUE (-)	VISC-OSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO OF PAY ZONES	RES. AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1 000 bbl)	CUMULATIVE PRODUCTION GAS (1 000 mcf)	OIL REMAINING IN PLACE (1 000 bbl)	PLAN	RANK	REF
FLORES-VILLE (Wilson)	Reklaw	Reklaw	1941			18		635 to 640										X	11
FOSS (McMullen)	Mirando Sand	Mirando Sand	1959			20		490				60	1980	41		160 (e)			11 18
HARPOLE (Uvalde)	San Miguel	San Miguel	1974			10		428 to 448		20			1980	1		20 (e)			18
HELEN (Zavala)	Anacacho	Anacacho	1978			18		1906		12(e)		3	1980	20		1,000 (e)			
HOLMAN RANCH (Edwards)	Ellenburger	Ellen-burger	1947			14 to 20		550		10 to 32		50 to 640	1980	148		350 (e)			11 10
INA-ADAMS (Medina)	Escondido or Navarro - Taylor	Escondido or Navarro - Taylor	1923			20		840 to 925		12			1976			310 (e)			11 10
JACOB (McMullen Live Oak)	Pettus - Yegua	Pettus - Yegua	1932			20 to 21		1000 to 1050		10		182 (Field)	1980	5,436 (Field)		12,700 (e)			11 10
JEANNIE (Zavala)	Serpentine	Serpentine	1976			12		3500		600 (e)		45	1980	55		1,400 (e)			
JERRY HOUSE (Zavala)	Escondido	Escondido	1978			13		1142				5	1980	1		50 (e)			
LA VERNIA (Guada-lupe)	190 Sand	Carrizo - Wilcox	1960			17 to 19		189		10		20	1980	12		50 (e)			11 18 29
LITTLE ALAMO (McMullen)	Queen City	Queen City	1947			18 to 23		2258		10		320 (Field)	1980	119		300 (e)			11 18
LITTLE TOM (Zavala)	San Miguel A, A-1, C, & D Sands	San Miguel	1950			14	90	2750	35	14		5500	1978	53		76,100		M-4-(1)	20
LOSOYA (Bexor)	Austin Chalk	Austin Chalk	1957			17		1855		20		30	1980	33		110 (e)			11 18

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TABLE 1

LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: TEXAS SW SAN ANTONIO - RR CDN1

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC.	YEAR ABD.	API RANGE (°)	BEST API VALUE (°)	VISC-OSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO OF PAY ZONES	REE AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1 000 bbl)	CUMULATIVE PRODUCTION GAS (1 000 mcf)	OIL REMAINING IN PLACE (1 000 bbl)	FLAW	RANK	REF
LYTLE (Bexar)	Lower Anacacho	Anacacho	1954			20		1200		10		10	1980	3		10 (e)			11 18
MASSIE	Paluxy West Area	Paluxy	1959		17 to 18			360		14		40	1980	94		360 (e)			11 18
NEW BERLIN (Guada-lupe)	Austin Chalk	Austin Chalk	1938			20		1650		30			1934			3 (e)			11
NETA (Zavala	Bracero	Bracero	1952			19		3273					1980	1		3 (e)			
PLEASA-TON (Atascosa)	Carrizo Sand, South Area	Carrizo Sand	1952			18		1887		26		320	1980	43		120 (e)			11 10
PRYOR RANCH (Zavala)	Elaine, West Area	Elaine	1977			15		2506		26(±)			1980	14		460 (e)			
RINEHART (Bexar)	Austin Chalk	Austin Chalk	1956			20		1163		40 to 90		360 to 1400	1980	640		2,100 (e)			11
SAN JOSE (McMullen)	Cole	Cole	1947			18 to 21		1179		12		60	1980	24		60 (e)			11 18
SAYERS-VILLE (Bastrop)	Buda - Georgetown	Buda - George-town	1952			17 to 18		2875 to 3056		12		40	1980	4		10 (e)			11 18
SEQUIN (Guada-lupe)	Buda Limestone	Buda Limestone	1948			12		1000 to 1192		50		40	1980	1		2 (e)			11 18
TAYLOR - INA	Navarro	Navarro	1936			16	390	900		20		4700	1980	3,097		120,600		M-41-1	20 11 18
TILDEN (McMullen)	S. Yegua South Area	Yegua	1974			17		620		22			1980	1		20 (e)			11 18
TURNEY (Edwards)	Glen Rose	Glen Rose	1939			20		425 to 600		10		80	1980	12		30 (e)			11 18
WALT (Edwards)	Paluxy	Paluxy	1961			17		284		12 to 37		80	1980	30		130 (e)			11 18

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TABLE 1

LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: TEXAS SH SAN ANTONIO RR CD#1

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC.	YEAR ABD.	API RANGE (°)	BEST API VALUE (°)	VISC-OSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO. OF PAY ZONES	RES. AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1,000 bbl)	CUMULATIVE PRODUCTION GAS (1,000 mcf)	OIL REMAINING IN PLACE (1,000 bbl)	FLAW	RANK	REF
WARDLAW (Edwards)	Glen Rose	Glen Rose	1947			18		235 to 300		18		135	1980	37		90 (e)			11 18
WHERRY & GREEN (Atascosa)	Carrizo	Carrizo - Wilcox	1952			19		1690		27		80	1980	226		600 (e)			11 18
YANCY (Medina)	Navarro	Navarro	1938			18		818		15			1980	1		2 (e)			11 18

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TABLE 1

LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: TEXAS SW CORPUS CHRISTI-RRCD#2

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC.	YEAR ABD	API RANGE (-)	BEST API VALUE (-)	VISC-OSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO OF PAY ZONES	RES. AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1 000 bbl)	CUMULATIVE PRODUCTION GAS (1 000 mcf)	OIL REMAINING IN PLACE (1 000 bbl)	FLAW	RANK	REF
ALBRETCH (Goliad)	Yegua	Yegua	1952			17		4642		20		400	1980	212		550 (e)			11 18
HUFF (Refugio)	2950 Sand	Miocene	1951			20		2942		51			1980	23		60 (e)			11 18
KITTIE (Live Oak)	Jackson	Jackson	1943			20		1432		10		30	1980	53		130 (e)			11 18
MT. LUCAS (Live Oak)	Frio	Catahoula	1956			20		2849		12		40	1980	13		40 (e)			11 18
OAKVILLE (Bee) or (Live Oak)	Oakville 2000	Jackson - Yegua	1936			20		1830		30		600	1980	1842		4,300 (e)	G		11 18
VICTORIA (Victoria)	Met	Met	1940			19		3017		20		120	1980	1449		3,400 (e)			11 18

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TABLE 1

LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: TEXAS GULF COAST – RR CD#3

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC	YEAR ABD.	API RANGE (-)	BEST API VALUE (-)	VISC-OSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO OF PAY ZONES	RES. AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1,000 bbl)	CUMULATIVE PRODUCTION GAS (1,000 mcf)	OIL REMAINING IN PLACE (1,000 bbl)	FLAW	RANK	REF
ARNIM (Fayette)	Wilcox, East Area	Wilcox	1950		20 to 21			2151		17		240	1900	39		100 (e)			11, 18
BASTON OLD (Hardin)	Miocene	Miocene	1903		15 to 24			189 to 679				2730 Field							11 18
	Oligocene	Oligocene	1903		19 to 22			2879 to 3083					1976	43,620		101,000 (e		M-11-(?)	11 18
BIG CREEK (Fort Bend)	Miocene	Miocene	1922		18 to 25			800		15		130 Field	1976	22,097		51,600 (e			11 18
BIG HILL (Jefferson)	Miocene	Miocene	1942			20		1770			[illegible]	40	1948	1					136
BLUE RIDGE (Fort Bend)	Miocene	Miocene	1919		18 to 25			1650 to 2540					1964	19,354		45,200 (e		X	11
BOLING (Whaton)	Caprock	Caprock	1925			18		230 to 570		20		10	1976	22,498		52,500 (e			11 10 136
	Iago	Iago	1964			20		4800					1980	263		1,400 (e			11,10 136
CISTERN (Fayette)		Recklaw	1943			18		1160 to 2870		10 to 45		200	1976	212 (Field)		500 (e) (Field)			11 18 136
		Wilcox	1952			17		1130		35		20							11,10 136
	Wilcox J.	Wilcox	1966			16		2243 to 2258		15									11 18 136
	Wilcox L.	Wilcox	1979			20		2871											136
	Wilcox, North Area	Wilcox	1952			18		1130				20	1980	21		55 (e)			18 136
DAMON MOUND (Brazoria)	Frio, SE Fault Block	Frio	1955			15		3725					1980	1		2 (e)			11 18
ELM GROVE (Fayette)	Upper Wilcox	Wilcox	1953			20		1886		10		160	1980	83		230 (e)			11 18

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TABLE 1

LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: TEXAS GULF COAST - RR CD#3

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC.	YEAR ABD.	API RANGE (°)	BEST API VALUE (°)	VISC-OSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO OF PAY ZONES	REC. AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1,000 bbl)	CUMULATIVE PRODUCTION GAS (1,000 mcf)	OIL REMAINING IN PLACE (1,000 bbl)	FLAW	RANK	REF
HANKAMER (Liberty)	Miocene	Miocene	1951			15		2650					1976	97		300 (e			11 18
	Frio	Frio	1951			15		4207					1980	1,300		3,200 (e			11 18
HIGH ISLAND (Fort Bend)	Porous Caprock		1904			19		150 to 200		50 to 200		2500 Field)	1948	23,343 (Field)		54,467 (e (Field)		X	136
HULL (Liberty Co.)	Caprock		1908			15 to 20		500			2	16000 Field)	1976	173,575 (Field)		405,100 (e (Field)		X	11 18 136
HUMBLE (Harris Co.)	Super Caprock	Lissie Reynosa	1904			16 to 20		580 to 1200				4000 Field)	1976	144,665 (Field)		337,600 (e (Field)		X	11 18 136
		Miocene	1904			19		1590 to 1610											11 18 136
		Miocene	1904			20		4678											11,18 136
		Jackson	1904			19		4750 to 4770											11 18 136
	Light Riverside	Frio - Yegua	1948			18		2900 to 4800					1976	1,986		5,200 (e)			11 18 136
LOST LAKE (Chambers)	Lost Lake 2300 W	Marginulina - Frio	1929			20		2382		10 to 30		430	1980	1,263		3,000 (e)			11 18 136
MCDADE (Lee)	Wilcox 2875 Sand	Wilcox	1953			18		2875				10	1964	.3		2 (e)			11 18
MOORES ORCHARD (Fort Bend)	Miocene	Miocene	1926			20		900 to 950				1590 Field)	1964	12,718 (Field)		29,700 (e)		M-40-(3)	11 136
MULDOON (Fayette)	Drenner Southwest Area	Wilcox	1962			20		2302					1976	213		1,400 (e)			11 18
NASH (Fort Bend)	Miocene	Miocene	1945			18		3700 to 4250				1500 Field)	1976	4,657 (Field)		10,900 (e)			11 18 136

TABLE 1

LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: TEXAS GULF COAST - RR CD#3

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC.	YEAR ABD.	API RANGE (°)	BEST API VALUE (°)	VISC-OSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO OF PAY ZONES	RES AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1 000 bbl)	CUMULATIVE PRODUCTION GAS (1 000 mcf)	OIL REMAINING IN PLACE (1 000 bbl)	FLAW	RANK	REF
NASH (Fort Bend)	Oligocene	Oligocene	1945			19		3978 to 4800				1500 (Field)	1976	4,657 (Field)		10,900 (e)			11 18 136
RACOON BEND (Austin)	Miocene Y	Miocene	1958 to 1967			19		1952	600			1800 (e) (Field)	1980	602		4,100 (e)			18
	Miocene Z	Miocene	1956 to 1967			19		2194					1980	671		4,500 (e)			18
	Oakville 970	Oakville	1956 to 1971			15		984					1980	21		220 (e)			18 136
	Paine	Paine	1952 to 1967			19		2734					1980	220		1,500 (e)			18
SARATOGA (Hardin)	Miocene	Miocene	1901		15 to 25			500 to 2300		10	5		1976	46,059 (Field)		107,500 (e) (Field)		X	11 18 136
SOUR LAKE (Hardin)	Pliocene - Miocene	Pliocene - Miocene	1902		16 to 24			230 to 2000				4900 (Field)	1976	118,309 (Field)		276,100 (e) (Field		M-60-(2)	11 18
	Oligocene	Oligocene			16 to 24			2000 to 3702											11 18
WEST COLUMBIA (Brazaria)	Caprock	Miocene	1915		18 to 20			600 to 3708		70		6310 (Field)	1976	110,788 (Field)		258,600 (e) (Field)		M-50-(2)	11 18

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TABLE 1

LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: TEXAS SW CORPUS C.RISTI-RR CD#4

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC.	YEAR ABD.	API RANGE (-)	BEST API VALUE (-)	VISC-OSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO OF PAY ZONES	RES. AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1,000 bbl)	CUMULATIVE PRODUCTION GAS (1,000 mcf)	OIL REMAINING IN PLACE (1,000 bbl)	FLAW	RANK	REF
ALBRECHT (Star)	85 Sand	Frio	1960			17		84		11		1000	1964	7		170 (e)			11 18
ALTA VERDE (Brooks)	900 Sand	Oakville	1952			20		900 to 904		27		40	1980	3		8 (e)			11 18
BRUJA VIEJA (Jim Hogg)	Cole Sand	Jackson Group	1950			18		1755				40	1980	1		2 (e)			11 18
BRUNI (Webb)	Jackson South Area	Jackson	1944			18		1781 to 1804		10		40 (Field)	1980	1		2 (e)			11 18
CASA BLANCA (Duval)	Cole Sand	Jackson Group	1938 to 1939		20 to 21			1005 to 1225		50 to 75		820 to 1000	1980	4,447		10,400 (e)		M-36-(1)	11 18
CEDRO HILL (Duval)	Cole Sand	Jackson Group	1938		19 to 20	19		1336 to 1500		12		1800	1980	6,427		31,600		M-32	20 11 18
CHARAMOUSCA (Duval)	Jackson or Mirando	Jackson or Mirando	1935 to 1937			20		1065 to 1540		10		720 (Field)	1980	1,505		3,600 (e)			11 18
CHARMOUSCA (Duval)	Cole Sand South Area	Jackson	1940			19		1525		10		400 (Field)	1980	2,240 (Field)		5,300 (e) (Field)			11 18
	Jackson South Area	Jackson	1948			20		1583 to 1618		14									11 18
CHARCO DE DONDO (Zapata)	Jackson	Jackson	1913			18		147 to 459		15 to 33		1000 (Field)	1980	622 (Field)		1,500 (e)			11 18
COLE (Duval)	Cole East Area	Cole	1941		20 to 22			1720 to 1762		25			1980	14		40 (e)			11 18
COLHERA (Duval)	Jackson	Jackson	1936			19		1425 to 1500		10 to 90		1000 to 1800	1980	3,535		8,300 (e)			11 18
DCR-79 (Duval)	Cole "B" Sand	Jackson	1948			20		1454		24		500 to 600 (Field)	1980	1,439		3,400 (e)			11 18

TABLE 1

LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: TEXAS SW - CORPUS CHRISTI-RR CDN

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC.	YEAR ABD.	API RANGE (-)	BEST API VALUE (-)	VISC-OSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO. OF PAY ZONES	RES. AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1 000 bbl)	CUMULATIVE PRODUCTION GAS (1 000 mcf)	OIL REMAINING IN PLACE (1 000 bbl)	FLAW	RANK	REF
DINN (Duva)	Jackson	Jackson	1949		19 to 49			1777 to 1805		6 to 43		300 (Field)	1980	275		650 (e)			11 18
EAGLE HILL (Duval)	Cole Sand	Jackson	1933		19 to 22			1405 to 2650		10 to 126		700 (Field)	1980	5,438		12,700 (e)		M-31-(2)	11 18
ESCOBAS (Zapata)	Jackson	Jackson	1933		20 to 21			1000 to 1600		19		2240	1980	12,810 (Field)		29,900 (e)		M-37-(1)	11 18
GOVERNMENT WELLS (Duval)	900 Sand North Area	Catahoula	1948			20		918				30	1980	289		600 (e)			11 18
	1000 Sand North Area	Catahoula	1950			19		1062					1976	50		150 (e)			11 18
GOVERNMENT WELLS (Duval)	1900 Hockley South Area	Hockley	1965			19		1904		10		360	1980	30		170 (e)			18
HOFFMAN (Duval)	Cole Sand East Area	Jackson	1950		20 to 23			1984 to 2038		15 to 116		350	1980	1,318		3,100 (e)			11 18
JOE MOSS (Zapata)	Jackson	Jackson	1947			20		715		62			1976	42		100 (e)			18
KINGSVILLE (Kleberg)	2500 Sand	Miocene	1963			19		2533		20			1980	64		300 (e)			11 18
KOHLER DEEP (Duval)	1910 Sand	Cole	1967			20		1813		17			1976	.1		1 (e)			18
LAS ANIMAS (Jim Hogg)	Jackson	Jackson	1937			19		1778 to 1823		11		160	1976	306		720 (e)			11 18
LAS ANIMAS -LEFEVRE (Jim Hogg)	Jackson Cole	Jackson	1937			19	41	1800	125	15		1200	1980	3,246		23,100		M-25	20 11 18
LEASE HOLDERS (Webb)	Hockley	Hockley	1922			18		1000 to 1015					1964	25		60 (e)			11

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TABLE 1

LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: TEXAS SW - CORPUS CHRISTI-RR CD#4

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC.	YEAR ABD.	API RANGE (-)	BEST API VALUE (-)	VISCOSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO OF PAY ZONES	RES. AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1 000 bbl)	CUMULATIVE PRODUCTION GAS (1 000 mcf)	OIL REMAINING IN PLACE (1 000 bbl)	FLAW	RANK	REF
LOPEZ (Duval)	Lopez Sand North Area	Jackson	1951			20		2048 to 2064		10 to 65		400	1980	2,045		5,000 (e)			11 18
LOS OLMOS (Starr)	Frio	Frio	1925		19 to 20			371		10 to 17		770							18
LUNDELL (Duval)	Jackson Cole	Jackson	1937		19 to 20	20	23	1550		12		5000	1980	9,719		75,600		M-20	20 11 18
MESQUITE BONITA (Duval)	Sibley Sand	Frio	1957			20		3042 to 3049		12		10	1976	46		200 (e)			11 18
MIRANDO VALLEY (Zapata)	Jackson	Jackson	1921		20 to 21			1425		115		530 (Field)	1976	1,739 (Field)		4,100 (e)			11 18
	Cook Mtn.	Cook Mtn.	1959			20		4041		12									11 18
NEELY (Duval)	1150 Sand West Area	Jackson	1962			20		1132		20			1980	95		440 (e)			11 18
ORLEE (Duval)	Jackson	Jackson	1950			20		1686 to 1746		16		80	1980	203		480 (e)			11 18
PALANGANA DOME	Catahoula	Catahoula	1928			16		442 to 540		9 to 10		100 (Field)	1976	23		60 (e)			11 10
PETERS (Duval)	1st Cole Sand North Area	Jackson Cole	1959		19 to 20			1746					1980	42		160 (e)			11 18
PETROX	Chemosky Sand	Jackson	1955			20		2024 to 2136		11 to 15			1980	1,856		5,600 (e)			11 18
PIEDRAS PINTAS (Duval)	Oakville	Oakville	1898		16 to 18			160 to 230		30 to 121			1976	3		7 (e)			11 18
	Catahoula	Catahoula	1935			12		460 to 480											11
PRESA DE ORO (Webb)	Yegua C	Yegua	1962			20		1112					1980	134		610 (e			11 10

TABLE 1

LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: TEXAS SH CORPUS CHRISTI RR CD#4

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC.	YEAR ABD.	API RANGE (°)	BEST API VALUE (°)	VISC-OSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO. OF PAY ZONES	RES. AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1,000 bbl)	CUMULATIVE PRODUCTION GAS (1,000 mcf)	OIL REMAINING IN PLACE (1,000 bbl)	PLAN	RANK	REF
RANCHO SOLO (Duval)	Jackson	Jackson	1937			19		1849		20		500	1980	464		1,100 (e)			11 18
REISER (Webb)	Jackson	Jackson	1909			16		650 to 920		15 to 20									11 18
REYNOLDS (Jim Wells)			1939			20		3145 to 5100											11
RICHARDSON (Duval)	Jackson	Jackson	1944			18		1765 to 1784		31		260	1980	138		330 (e)			11 18
SAXET (Nueces)	Oakville & Hetrogteging	Oakville & Anahuac	1930			20	80	3380		18		9900	1976	62,246		121,500			20 11 16
SEJITA (Duval)	Zone 10 A East Area	Miocene	1955			18		1256		12		20	1980	21		64 (e)			11 18
	1170 Sand	Miocene	1967			18		1218		30			1980	3		20 (e)			18
SEVENTY SIX (Duval)	Jackson	Jackson	1947			19		1322		12		40	1980	14		35 (e)			11 18
	800 Sand South Area	Frio	1950			17		870		16 to 25			1980	47		110 (e)			11 18
SINTON SHALLOW (San Patricio)	Catahoula West Area	Catahoula	1944			19		3368				770	1964	4,022		16,100 (e)			11

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TABLE 1

LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: TEXAS EAST - HR CD#5

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC.	YEAR ABD.	API RANGE (°)	BEST API VALUE (°)	VISC-OSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO. OF PAY ZONES	RES. AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1,000 bbl)	CUMULATIVE PRODUCTION GAS (1,000 mcf)	OIL REMAINING IN PLACE (1,000 bbl)	FLAW	RANK	REF
COHO (Hopkins - Wood)	Sub-Clarksville	Sub-Clarks-ville	1954			18		4028				180	1980	936		2,700 (e)			11 18
MITCHELL CREEK (Hopkins)	Paluxy	Paluxy	1948		14 to 18			4505 to 4575		29		220	1980	1,187		2,800 (e)			11 18
WITHER-SPOON - HCKEE (Navarro	Nacatoch	Nacatoch	1924			19		825		19		400	1980	1		2 (e)			11 18

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TABLE 1

LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: TEXAS EAST - RR CD#6

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC	YEAR ABD	API RANGE (-)	BEST API VALUE (-)	VISC-OSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO OF PAY ZONES	RES AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1,000 bbl)	CUMULATIVE PRODUCTION GAS (1,000 mcf)	OIL REMAINING IN PLACE (1,000 bbl)	FLAW	RANK	REF
ALBA (Wood)	Sub-Clarksville	Sub-Clarks-Ville	1948		15 to 16			4050 to 4074		10		1360	1980	6,184		14,500 (e			11 18
CAMP HILL (Anderson)	Carrizo - Wilcox	Carrizo - Wilcox	1955			19	600	420		25		650	1980	1,900		30,600			20 11 18
COATS (Wood)	Sub-Clarksville	Sub-Clarks-ville	1949			14		4508		12		80	1980	12		30 (e			11 18
CONCORD (Anderson)	Woodbine	Woodbine	1942 to 1960			12		3848 to 4484		20		20	1980	17		70 (e			11 18
CONCORD DOME (Anderson)	Woodbine	Woodbine	1960			12		4404 to 4409		14		600	1980	1,477		6,000 (e			11 18
DALBY SPRINGS (Bowie)	Paluxy	Paluxy	1952			18		4363 to 4367		12		40	1980	39		100 (e			11 18
FOREST HILL (Wood)	Eagle Ford	Eagle Ford	1950			16		4443 to 4452		20		40 to 1200	1980	3,998		9,400 (e			11 18
	Harris Sd.	Harris Sd.	1954			15		4680		16			1976	747		2,650 (e			18
	Harris Sd. (B to F Segments)	Harris Sd. (B to F Segments)	1954			10	9526	4800		13 (each Sd.)	5	2856	1978	1,057		52,200			20 18
	1st Sub - Clarksville	Harris	1965			20		4632		10			1976	100		810 (e			18
HAWKINS (Wood)	Woodbine	Woodbine	1940		19 to 25			4531 to 4800		75 to 100		9500 to 13980	1980	699,179		1,631,500 (e			11 18
	Sub-Clarksville	Sub-Clarks-ville	1940			19		4100		6			1976	576,820		1,346,000 (e			18
JANNA-PAT (Wood)	Sub-Clarksville	Sub-Clarks-ville	1979			18		4608		15 (e			1980	2		200 (e			
MANZIEL (Wood)	FB-A Sub-a Clarksville	Sub-Clarks-ville	1970			18		4156 to 4169		13			1980	133		1,200 (e			18

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TABLE 1

LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: TEXAS LAST : RR CD#6

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC.	YEAR ABD.	API RANGE (°)	BEST API VALUE (°)	VISC-OSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO. OF PAY ZONES	RES AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1,000 bbl)	CUMULATIVE PRODUCTION GAS (1,000 mcf)	OIL REMAINING IN PLACE (1,000 bbl)	FLAW	RANK	REF
HANZIEL (Wood)	Sub-Clarksville Southeast Area	Sub-Clarks-ville	1967			18		4144 to 4166		22			1980	282		1,900 (d			18
HCCRARY (Wood)	Sub-Clarksville	Sub-Clarks-ville	1952			20		4364		10		140	1980	1,079		2,800 (e			11 18
HIDWAY LAKE (Wood)	Eagle Ford	Eagle Ford	1950			18		4530		17		1230	1980	5,470		12,800 (e			18
HINEOLA (Wood)	Sub-Clarksville	Sub-Clarks-ville	1949			18		4608 to 4612		40		40	1980	3		(e			11 18
NEWSOME (Camp)	Sub-Clarksville	Sub-Clarks-ville	1953			18		3854 to 3857		10		620	1980	1,652		4,500 (e			11 18
NOLAN EDWARD (Wood)	Sub-Clarksville	Sub-Clarks-ville	1949			20		4709 to 4762		13 to 26		120 to 620	1980	2,300		5,400 (e			11 18
NOLLINGTON (Titus)	Sub-Clarksville	Sub-Clarks-ville	1964			20		2652 to 2694		15			1980	6		35 (e			11 18
NOVA (Wood)	Sub-Clarksville	Sub-Clarks-ville	1971			20		4800		15 (e)			1980	85		860 (e			11 18
PEWITT RANCH (Titus)	Paluxy	Paluxy	1949			19	32	4507		29		1180	1980	20,012		35,500			20 11 18
PURT (Anderson	Woodbine	Woodbine	1963		6 to 19			3088		22		160	1980	132		650 (e			11 18
QUITMAN (Wood)	Sub-Clarksville	Sub-Clarks-ville	1947		14 to 16			3736 to 3930		10 to 14		360	1980	6,065		14,200 (e			11 18
SLOCUM (Anderson	Caprizo Sand	Carrizo	1955		19 to 20	19	1000	530		25		2500	1980	8,344		106,100		M-52	20 11 18
SUGAR HILL (Titus)	Paluxy	Paluxy	1952		10			4391 to 4836		11		120	1980	208		5:0 (e			11 18

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TABLE 1

LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: TEXAS (AST - RR CD#6)

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC.	YEAR ABD.	API RANGE (°)	BEST API VALUE (°)	VISC-OSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO. OF PAY ZONES	RES. AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1,000 bbl)	CUMULATIVE PRODUCTION GAS (1,000 mcf)	OIL REMAINING IN PLACE (1,000 bbl)	FLAW	RANK	REF
TALCO (Franklin	Paluxy West Area	Paluxy	1978			17		4296		20 (e)			1980	80		4,000 (e)			
TAMI (Wood)	Sub-Clarksville	Sub-Clarksville	1978			13				15 (e)			1980	16		800 (e)			
TULLY (Franklin	Paluxy	Paluxy	1979			19		4456		20 (e)			1980	1		100 (e)			
WOODLAND (Red River)	1770 Sand	Paluxy	1956			14		1773		13		20	1980	2		6 (e)			11 10

TABLE 1

LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: TEXAS WEST CENTRAL - RR CONTD

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC.	YEAR ABD.	API RANGE (-)	BEST API VALUE (-)	VISC-OSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO OF PAY ZONES	RES. AREA (ACRES)	CUMULATIVE PRODUCTION			OIL REMAINING IN PLACE (1,000 MM)	FLAW	RANK	REF
													DATE	OIL (1,000 MM)	GAS (1,000 MM)				
JOSIE (Callahan)	Cisco	Cisco	1948			20		1554		12		40	1980	1		2(e)			11

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TABLE 1

LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: TEXAS WEST - RR CD#7C

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC.	YEAR ABD.	API RANGE (°)	BEST API VALUE (°)	VISCOSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO. OF PAY ZONES	RES AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1 000 bbl)	CUMULATIVE PRODUCTION GAS (1 000 mcf)	OIL REMAINING IN PLACE (1,000 bbl)	FLAW	RANK	REF
BRATTON (McCulloch)	Strawn	Strawn	1979			18		726					1980	1		100 (e)			
DOREEN SHALLOW (Kimble)	Buck Sand	Buck Sand	1954			20		1072 to 1075				120	1980	1		3 (e)			11 18
OLSON (Crockett)	Grayburg - San Andres	Grayburg - San Andres	1940		18 to 26			2063		20 to 40		2600 to 5300	1980	12,130		28,400 (e)		M-10-(2)	11 18
SCHUYLER (Terrell)	Leonard South Area	Leonard	1966			17		4312		12			1980	2		15 (e)			18
WILSON RANCH (Sutton)	Wolfcamp	Wolfcamp	1975			20		3842 to 3873		37			1976	.2		20 (e)			18

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TABLE 1

LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: TEXAS WEST - RR CDWB

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC.	YEAR ABD.	API RANGE (°)	BEST API VALUE (°)	VISC-OSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO OF PAY ZONES	RES AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1,000 bbl)	CUMULATIVE PRODUCTION GAS (1,000 mcf)	OIL REMAINING IN PLACE (1,000 bbl)	FLAW	RANK	REF
CORONET (Howard)	2900	Glorieta	1952		19 to 22			2740 to 2893		15		620	1980	532		1,400 (e			11 18
HASSEY (Pecos)	1000		1978		20			1004		10 (e)			1980	8		400 (e			
DATES (Pecos)	Rustler	Rustler	1947		18			790		10 to 55		320 to 360	1980	951		2,300 (e			11 18
PYOTE (Ward)	Yates - Seven Rivers	Yates - Seven Rivers	1942		19 to 21			2820 to 2827		20		80	1976	338		789 (e			11 18
SAND HILLS (Crane)	Holt Oil South Area	Holt	1966		20			3717		10			1976	77		700 (e			18
SCHULER (Pecos)	Leonard	Leonard	1964		19 to 20			4600 to 4619		19			1980	5		39 (e			18
TOBORG (Pecos-Crockett)	Toborg Sand	Trinity Group	1929		19 to 21		371	500		27		5000	1980	38,900		166,000		M-50-(1)	20 11 18
WEHTZ (Pecos)	Grayburg West Area	Grayburg	1965		16			1690 to 1710		20			1980	2		15 (e			18

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TABLE 1

LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: TEXAS NORTH RR CD#9

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC.	YEAR ABD.	API RANGE (°)	BEST API VALUE (°)	VISC-OSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO OF PAY ZONES	RES AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1,000 bbl)	CUMULATIVE PRODUCTION GAS (1,000 mcf)	OIL REMAINING IN PLACE (1,000 bbl)	FLAW	RANK	REF
DARBOUR (Grayson)	Strawn Sand	Strawn	1954			20		4655		23		20	1976	12		45 (e)			11 18
BOLTON (Young)	Strawn	Strawn	1956			20		3418 to 3424		10		40	1980	31		100 (e)			11 18
DANGLE (Cooke)	1600 Strawn	Strawn	1954			16		1614		31		80	1980	208		600 (e)			11 18
DOVE (Cooke)	Strawn	Strawn	1950			18		2992 to 3253		30		260	1980	1,775		4,200 (e)			11 18
HESTER (Grayson)	4800 Sand	Strawn	1954			18		4870 to 5657		18		20	1980	32		100 (e)			11 18
LAKE LENAPAH (Archer)	Caddo Limestone	Caddo Limestone	1956			15		3596 to 5346		10		80	1976	3		15 (e)			11 18
MACOY (Grayson)	Strawn 4200 East Area	Strawn	1956			16		4184		19		40	1980	33		110 (e)			11 18
PILOT POINT (Denton)	Strawn	Strawn	1951			20		1550		15		60	1980	19		50 (e)			11 18
SOUTHMAYD (Grayson)	Barnes	Barnes	1975			14		4838		17			1980	30		600 (e)			18
	Strawn	Pennsylvania Strawn	1965			20		4712 to 4760		48			1980	39		230 (e)			11 18

TABLE I

LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: WYOMING

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC.	YEAR ABD.	API RANGE (-)	BEST API VALUE (-)	VISC-OSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO OF PAY ZONES	RES AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1,000 bbl)	CUMULATIVE PRODUCTION GAS (1,000 mcf)	OIL REMAINING IN PLACE (1,000 bbl)	FLAW	RANK	REF
BIG HOLLOW (Albany)	Muddy Sand	Muddy	1938		18 to 22			800 to 925		10 to 20		120	1976	35		85 (e)			11 18 152
BISON BASON (Fremont)	4th Frontier Sand	Frontier	1923 to 1929		16 to 18			977 to 1100		12 to 14		180 to 220	1976	1,762	554	1,300 (e)			11,18 152 41
BRENNING BASIN (Converse)	White River	White River	1896		15 to 36			350					1976	7		16 (e)			5 18
CASPER CREEK (Natrona)	Tensleep, South Area	Tensleep	1919		13 to 15	15		2400		150		240	1978	8,567		36,400			5011 18 152
CLARK RANCH (Natrona)	Tensleep	Tensleep	1955			15		4678 to 4695		17		320	1979	1,326	148	4,200 (e)			11 18 152
CRYSTAL CREEK (Big Horn)	Tensleep	Tensleep	1919 to 1940		19 to 24			960 to 997		7 to 20		80 to 160	1976	35		90 (e)			11 18 152
DALLAS DOME (Fremont)	Tensleep Sand	Tensleep	1927			19		1110 to 1137		26 to 40		660	1976	9,001		21,000 (e)		M-39-(2	
DUBOIS (Fremont)	Phosphoria	Phosphor-ia	1946		20 to 21			2060 to 2300		50 to 100		80 to 240	1980	166		400 (e)			11 18
DUTTON BASIN (Fremont)	Phosphoria	Phosphor-ia	1967			20		760		50 to 60		40	1976		.9				18
EMERALD (Nation)	Tensleep	Tensleep	1975		20 to 22			4000 to 4020		12		80	1980	12 to 227		4,400 (e			18
FERRIS (Carbon)	Chugwater	Chugwater	1928			18		2500											152
FOURBEAR (Park)	Phosphoria Limestone	Phosphor-ia	1962			14		3464		25		2960 (Field)	1976	31,492 (Field)	6	40 (e (Field)			18
	Darwin Sand	Amsden	1928			14		3180 to 3470											11 18
	Madison Limestone	Madison	1948			14		3470 to 3702		15 to 50									11 18

TABLE 1

LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: WYOMING

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC.	YEAR ABD.	API RANGE (°)	BEST API VALUE (°)	VISC-OSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO OF PAY ZONES	REC. AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1,000 bbl)	CUMULATIVE PRODUCTION GAS (1,000 mcf)	OIL REMAINING IN PLACE (1,000 bbl)	FLAW	FRANK	REF
FOURBEAR (Park)	Tensleep Sand	Tensleep	1928			14		2875 to 2890		60								X	11 18
	Dinwoody	Dinwoody	1973			14		3268		28		2960							18
FRANNIE (Park)	Madison Limestone	Madison	1929		18 to 27			2925 to 3013		60 to 70		1180	1976	83,345 (Field)	192	194,500 (e)		M-42-(1)	18 152 11
GARLAND (Big Horn)	Madison Limestone	Madison	1930		19 to 23			3090 to 4000		50 to 900		1110 to 8240	1976	122,565 (Field)		286,000 (e) (Field)			11 18 145
GARLOCK DOME (Big Horn)	Madison Limestone	Madison				19		4424											11
HALFMOON (Park)	Ember - Tensleep	Phosphor-ia and Tensleep	1944		14 to 18	18		3365		40		640	1978	3,908		20,600			20 11 18 152
HAMILTON DOME (Hot Springs)	Tensleep	Tensleep	1947			20		4550		54		450	1978	4,600	22,288	18,700			20 11 18
	Curtis Sand	Chugwater	1918		19 to 20			2000 to 2162		10 to 15		2400						X	11 18
	Tensleep	Tensleep	1929		15 to 25	20	42	2750		175		2175	1978	143,500	107	231,800		M-31	20,11 18 152
	Madison Limestone	Madison	1948			15		3048 to 3300		120 to 160		400							11 18 152
	Big Horn Dolomite	Big Horn	1953			16		3475 to 3500		40									1110 41 152
HERRICK DOME (Albany)	Tensleep Sand	Tensleep	1947		20 to 22			3675		17 to 82		120 to 130	1980	913	104	2,200 (e)			11 18 152
HIDDEN DOME (Washakie)	Tensleep	Tensleep	1947		19 to 20	20		4550		54		450	1978	4,600		18,700			20 11 18
HUNT (Park)	Tensleep	Tensleep	1966			15		4210 to 4225		28		160	1976	222 (Field)		2,000 (e)			18 41

TABLE 1

LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: WYOMING

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC.	YEAR ABD.	API RANGE (°)	BEST API VALUE (°)	VISC-OSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO. OF PAY ZONES	RES. AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1,000 bbl)	CUMULATIVE PRODUCTION GAS (1,000 mcf)	OIL REMAINING IN PLACE (1,000 bbl)	FLAW	RANK	REF
KIRBY CREEK (Hot Springs)	Phosphoria	Phosphor-ia	1918		20 to 23			3492 to 3580		60		240	1976	770	13,484	1,800 (e)			147 11 18
KING DOME (Hot Springs)	Phosphoria	Phosphor-ia	1964			18		2850				80	1980	77		410 (e)			18
LA BARGE (Lincoln & Sublette)	Almy	Wasatch	1924		17 to 24			650 to 1100		Variable 25'	4	1160	1976	20,576	36,054	48,100 (e)		M-49-(1)	11 18 152 41
LAMB & LAMB ANTICLINE (Big Horn)	Madison Limestone	Madison	1951		18 to 25			3812		14		800							11 10 152
LITTLE BUFFALO BASIN (Park)	Ember	Phosphor-ia	1943 to 1944		20 to 21			4264 to 4488		30									11 18 152
LITTLE LARAMIE (Albany)	Tensleep	Tensleep	1948		19 to 20			3741		60		240	1980	927	88	2,200 (e)			11 18 152
LOVELL DRAW (Big Horn)	Phosphoria	Phosphor-ia	1976			17		2004		31									
MURPHY DOME (Hot Springs)	Curtis Sand	Chugwater	1961			19		3176		12		1520	1976	34,207 (Field)		80,000 (e) (Field)			11 18
NEWCASTLE (Weston)	Newcastle S.S.	Newcastle	1941		20 to 22			500 to 1200		38		40	1976	6		15 (e)			152 11 18
OIL MOUNTAIN (Hattona)	Tensleep	Tensleep	1945			13		2655		30		40 to 80	1980	76	5	180 (e)			11 18 152
OREGON BASIN (Park)	Madison Limestone, North Area	Madison	1943 to 1944		19 to 20			3900 to 4500		60 to 200		3454							11 18
	Madison Limestone, South Area	Madison	1942			19		4136											11 10

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TABLE 1

LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: WYOMING

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC.	YEAR ABD.	API RANGE (°)	BEST API VALUE (°)	VISC-OSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO. OF PAY ZONES	RES. AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1,000 bbl)	CUMULATIVE PRODUCTION GAS (1,000 mcf)	OIL REMAINING IN PLACE (1,000 bbl)	F. AM	RANK	REF
OREGON BASIN (Park)	Phosphoria West Area	Phosphor-ia	1955		16 to 18			4311 to 4348		37		120	1980	639	1	2,000 (e)			11 18
PINE MOUNTAIN (Natrona)	Phosphoria	Phosphor-ia	1914			19		1535		15±								X	152
PITCHFORK (Park)	Embar	Phosphor-ia	1930		18 to 19			3400		25		1640 (Field)	1976	16,664 (Field)		39,900 (e)			11 18 152
	Tensleep	Tensleep	1930		18 to 19			3711		127									11 18 152
	Madison	Madison	1948			15		4219		35									11,18 152
POISON SPIDER (Natrona)	Sundance Sand	Sundance	1917		18 to 21			1290 to 1450		35 to 91		460 to 1840	1976	1,189	2,730	6,400 (e)			11 18
RED SPRINGS (Hot Springs)	Madison Limestone	Madison	1919			11		900 to 1882		30 to 60		320	1976	253	241	570 (e)			11 18 152
ROCKY FORD (Campbell)	Minnelusa	Minnelusa	1909	1909	15 to 16			176		120 to 210			--		820				11 18 152
SAGE CREEK (Big Horn - Park)	Madison	Madison	1947 to 1948	1963	18 to 20			3135 to 3356				40 to 200	1976	22	--	60 (e)			11 18 152
SAGE CREEK ANTICLINE (Fremont)	Phosphoria	Phosphor-ia	1947 to 1959		20			1130 to 2150		20		180 (Field)	1964	4		80 (e)			11 18 152
SHEEP - POINT (Park)	Phosphoria	Phosphor-ia	1957			17		3264		20		200	1976	295	29	1,300 (e)			152 18
SHOSHONE (Park)	Embar - Tensleep	Phosphor-ia - Tensleep	1915 to 1929		20 to 21			4565		60		180 to 320	1976	1,850		4,400 (e)			11 10 152

TABLE 1

LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: WYOMING

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC.	YEAR ABD.	API RANGE (°)	BEST API VALUE (°)	VISC-OSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO. OF PAY ZONES	RES. AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1,000 bbl)	CUMULATIVE PRODUCTION GAS (1,000 mcf)	OIL REMAINING IN PLACE (1,000 bbl)	FLAM	BANK	REF
SHOSHONE (Park)	Embar Limestone, South Area	Phosphor-ia	1947	1949	18 to 28			3705 to 3760		30		40	1964	3		15 (e)			11 18 152
SPENCE DOME (Bighorn)	Madison - L.S. Darwin - S.S.	Madison Amsden	1944			19		500		15 to 30		100 to 880	1976	221	.2	520 (e)			11 18 152
SPINDLE-TOP (Natrona)	Tensleep, North Area	Tensleep	1959			19		2300		37			1961	78		4,000 (e)			152
	Sundance Sand	Sundance	1922			19		1100		40		120 to 320	1976	221					11 18 152
SPRING CREEK (Park)	Embar South Area	Phosphor-ia	1929			15		4139		30		1160 (Field)	1976	10,325 (Field)	95	230 (e) (Field)			11 18 152
	Tensleep South Area	Tensleep	1929			15 to 17		3908		50 to 184									11 18 152
	Amsden South Area	Amsden	1947			14 to 17		4502		37 to 50									11 18 152
	Madison South Area	Madison	1947			11 to 14		4579		187									11 18 152
SUNSHINE (Park)	Phosphoria, North Area	Phosphor-ia	1955			16 to 18		3562		22		360 (Field)	1976	584		2,600 (e)			11 18 152
	Tensleep North Area	Tensleep	1928			14		3825		100									11,18 152
	Embar South Area	Phosphor-ia	1926			19		2480 to 2700		30 to 44		80	1976	286		670 (e)			11 18 152
T. E. RANCH (Park)	Phosphoria	Phosphor-ia	1959			14 to 16		3908		11 to 26		160	1964 to 1976	15 to 24		80 (e)			11 10
TISDALE (Johnson)	Tensleep East Area	Tensleep	1959			20 to 21	20	2244		30		500	1978	2,411	50	12,800		M-19-(1)	20 18

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TABLE 1

LIST OF HEAVY OIL RESERVOIRS IN THE UNITED STATES

STATE: WYOMING

FIELD NAME (COUNTY)	RESERVOIR NAME	GEOLOGIC FORMATION	YEAR DISC.	YEAR ABD.	API RANGE (°)	BEST API VALUE (°)	VISC-OSITY (CP)	AVERAGE DEPTH (FT)	GROSS PAY (FT)	AVERAGE NET PAY THICKNESS (FT)	NO OF PAY ZONES	RES. AREA (ACRES)	CUMULATIVE PRODUCTION DATE	CUMULATIVE PRODUCTION OIL (1,000 bbl)	CUMULATIVE PRODUCTION GAS (1,000 mcf)	OIL REMAINING IN PLACE (1,000 bbl)	FLAW	RANK	REF
TORCH-LIGHT (Big Horn)	Madison	Madison	1948		20 to 23			3450 to 3550		20		790							152 18 11
WARM SPRINGS (Hot Springs)	Embar	Phosphor-ia	1917		18 to 22			900 to 1000		40		120 to 390	1976	975		2,300 (e)			11 18 152
WILDHORSE BUTTE (Hot Springs)	Phorphoria	Phosphor-ia	1917 to 1919		12 to 14			1120 to 1202		30 to 60		100	1976	6		15 (e)			11 18 152
WILLOW DRAW (Park)	Tensleep	Tensleep	1972			15		4549		18		760	1976	1,052 (Field)		25,300 (e)			10
WINKLEMAN DOME (Fremont)	Nugget	Nugget	1944			14		1286		57		207	1978	2,653		10,307			

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☆U.S. GOVERNMENT PRINTING OFFICE: 1983- 669-030/3

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FOSSIL ENERGY

DOE/PC/30259-1
Vol. 2 of 2

AN EVALUATION OF HEAVY OIL MINING
Final Report

Volume II

Work Performed for the Department of Energy
Under Contract No. DE-AC03-80PC30259

Date Published—March 1983

Energy Development Consultants/
Stone & Webster Engineering Corporation
Golden, Colorado

U. S. DEPARTMENT OF ENERGY

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Printed in the United States of America. Available from:
National Technical Information Service
U.S. Department of Commerce
5285 Port Royal Road
Springfield, VA 22161

NTIS price codes
Paper copy: $24.00
Microfiche copy: $4.00

490

DOE/PC/30259-1
Vol. 2 of 2
Distribution Category UC-92a

AN EVALUATION OF HEAVY OIL MINING
Final Report
Volume II

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Work Performed for the Department of Energy
Under Contract No. DE-AC03-80PC30259

Date Published—March 1983

UNITED STATES DEPARTMENT OF ENERGY

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AN EVALUATION OF HEAVY OIL MINING

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ACKNOWLEDGMENTS

This report was prepared by Energy Development Consultants, Inc. (EDC) under the U.S. Department of Energy Contract No. DE-AC03-80PC30259. The contract was initiated under the Enhanced Oil Recovery Technology Program.

The investigative team expresses its gratitude to the staffs of the Carbondale Mining Technology Center and the San Francisco Operations Office for support throughout the study. Special thanks to the technical and secretarial staff of Stone & Webster Engineering Corporation for their assistance in the preparation of this report.

2.0 EVALUATION OF HEAVY OIL MINING TECHNOLOGIES

2.1 HISTORICAL REVIEW OF HEAVY OIL MINING PROJECTS

The mining of rock outcrops for their oil content dates back to antiquity, and in fact, it was a feature of many local economies prior to the industrial revolution. The mining of oil, petroleum, asphalt, and other bitumens was practiced in the Sinai Peninsula and the Euphrates River Valley prior to 5000 B.C. Mining was generally accomplished by shafts or wells sunk on the oil seep, followed by bailing with buckets or other containers. Later, as the technology progressed, shafts were sunk deeper and drifts were driven into oil sands to establish better drainage. These methods were practiced in Rumania, France, Germany, and other countries.

Rock asphalt, tar sands, and asphalt lakes in the New World were occasionally mined by surface techniques. Both Christopher Columbus and Sir Walter Raleigh reportedly used tar from a deposit on the island of Trinidad to caulk their ships during their sea voyages. Later, during the nineteenth century, many east coast cities of the United States used this same material to make asphalt street paving.

While foreign countries have had varying degrees of success in recovering oil by underground methods, there has been relatively little research into oil mining in the United States. In 1932 a U.S. Bureau of Mines bulletin concluded that under certain conditions oil mining might be preferred over conventional recovery methods. This conclusion was based upon studies of oil mining methods used in Europe at oil sand mines in the Pechelbronn Field, Alsace, France; and the Wietze Field, Hannover, Germany.

The remainder of this section describes some of the more significant heavy oil mining projects in the United States and other countries.

2.1.1 United States

Historically, prices for petroleum and petroleum products have been so low that petroleum mining ventures generally have not been economically

feasible. While there have been a number of attempts at petroleum mining over the years, the abundant supply of petroleum from wells made most of these ventures unprofitable.

Shortly after the discovery that oil could be produced from underground strata by drilling a well from the surface, the first oil shaft in the United States was sunk in Tarentum, Pennsylvania, in 1859. Because little or no oil was recovered from this shaft another was sunk nearby, and mined oil sand was brought to the surface. This operation was discontinued after a miner was killed by an explosion from methane gas build-up.

The first successful shaft or pit sunk for oil in the United States was completed in 1865 in Macksburg, Ohio. However, mining at this site produced no more oil than the traditional well method.

In 1866 a series of 31 oil-drainage tunnels was reportedly driven into the oil sands of Sulphur Mountain in Ventura County, California, by the Union Oil Company of California. Approximately 12,000 barrels of oil per month were produced until 1895. One of the tunnels reached a length of 1,900 feet.

A hot-water washing process was operated in Carpenteria, California, from 1891 to 1899 to separate oil from mined sandstone. A peak of 100 tons of mined rock per day was reached before the operation was shut down due to competition from low-priced asphalt manufactured from domestic and Mexican crude petroleum.

In 1893 a plant was built to recover bitumen from the bituminous limestone mined near Uvalde, Texas. The bitumen, which was about 12 to 15 percent by weight of the limestone, was extracted by treating the rock with hot water and naphtha in a series of steam-jacketed extractors.

At the turn of the century, a drift was driven into a shallow syncline to drain light oil near Fruita, Colorado. In 1922 it was reported to have produced about 50 barrels per day. However, when production dropped to 1

1/2 barrels per day in 1927, the operation was discontinued. It was reopened in 1947 and produced an additional 1,000 gallons of oil, which was used primarily for medicinal purposes.

Another mine, in the same area, near Urado, Utah, produced high quality lubricating oils. Capable of producing between 5 and 10 barrels per day, the mine consisted of a well sunk in the sand beds below the oil shales of the Green River Formation. A 375-foot tunnel was driven into the upper sand layer.

Hard bituminous sandstone containing about 10 to 12 percent bitumen was mined at Woodford, Oklahoma, from 1911 to 1913. The rock was treated in hot water tanks to recover the bitumen. Maximum throughput was approximately 40 tons of rock per 10-hour period.

Prior to 1920, numerous other attempts were made in the United States to mine bituminous rock for oil recovery. However, all of the plants were eventually forced to shut down after relatively short operating lives. High operating costs and competition from oil producing wells were the main reasons for discontinuing operation.

Attempts have been made to mine oil-saturated diatomaceous shales in Santa Barbara County, California, and to recover oil by distillation. Because these shales differ both physically and chemically from oil shales in other parts of the United States and other countries, the oil can be extracted by solvents, such as benzol, chloroform and pyridline, rather than by destructive distillation.

In 1922 Mr. Leo Ramney undertook a mining venture in the Jacksboro Oil Field northwest of Fort Worth, Texas. Located in a small structural dome, the pay zone, which is a sand lens below a limestone cap, was previously drilled with about 100 wells. The mining venture consisted of a main tunnel running along the top of the limestone cap with vertical holes driven through the cap into the oil sand. While the mine was not a commercial success because of the relatively small amount of hydrocarbons

present, the venture did enable Ramney to develop a patent specification for a system of underground mining for oil.

In the early 1920's a 40-tpd plant was constructed at the largest of the known diatomaceous deposits near Casmalia, California. The combustion process employed by this facility recovered approximately 95 percent of the in-place oil, with between 30 and 35 gallons of 14 degree API oil per ton of rock. Operations were discontinued because of competition from cheaper well oil, but not before it had demonstrated that the recovery of oil from shale was technically feasible.

In 1939 the Ohio Level Well Company experimented with horizontal holes drilled radially from a shaft into the oil-producing sands of First Cow Run in Morgan County, Ohio. After three holes were drilled which produced a few barrels of oil per day, the company was dissolved because of financial difficulties.

In the early 1940's a horizontal drilling method was used by the Venango Development Corporation in a hydrocarbon formation in the Franklin Oil Field in Venango County, Pennsylvania. This method, developed in part on two previous projects in Ohio, consisted of sinking a vertical shaft to the bottom of an oil sand and drilling holes in a horizontal plane radiating outward from the chamber. The shaft was 10 feet in diameter and 370 feet deep, with at least two holes drilled outward to a length of over 200 feet. No production records are available to indicate the degree of success of this project.

The first petroleum mining project in Kansas was developed in 1943 on abandoned oil leases in Miami County. While accurate production records are not available, the average production was reported to be approximately 500 barrels per acre. The mining methods were similar to those used in Ohio and Pennsylvania. The crude oil was reportedly 29 to 31 API, and initial mining efforts produced 25 to 50 barrels per day.

In 1945 a second attempt was made to drill horizontal wells from the bottom of a shaft in Morgan County, Ohio. The Blakson Oil Company of Charleston, West Virginia, sank a shaft 113 feet into the oil sands of First Cow Run. The original plan was to drill 24 horizontal wells; however, the first two holes, while successfully drilled and yielding 12 to 14 barrels per day, were so expensive to operate that the project was abandoned. The wells were subsequently operated by some local men for a few years but were eventually shut down.

During the late 1940's a plant near Vernal, Utah, was recovering oil from outcropping sandstones by a hot-water washing process. Resins, which were used for making specialty products, were obtained from the recovered bitumen.

2.1.2 France

Oil has been obtained from the Pechelbronn region in the Rhine Valley north of Strasbourg, Alsace, France, since the Middle Ages. The first official concession for mining was granted by the French king in the middle 18th century after galleries were driven into the outcrop of the bituminous sands. Mining operations ceased in the late nineteenth century in favor of wells drilled from the surface; however, mining was resumed during World War I when additional oil was needed for the war effort.

The three mines in the Pechelbronn Field consisted of a system of drainage levels and inclined crosscuts. Because the rock zone underneath the oil-bearing zone was fractured, the primary mining method at Pechelbronn involved driving galleries into the overlying marlstone and sinking pits into the oil zone. The two methods employed for obtaining oil were natural drainage and drainage forced by compressed air. The mines were operated by Germany from 1870 through 1919, and again during World War II. During the 1930's oil production from mining techniques reached a maximum. After World War II, when France again regained possession, oil mining resumed on a scale comparable to pre-war operations. However, deeper mining operations became increasingly difficult due to the presence of a high

geothermal gradient, and operations eventually ceased.

2.1.3 Germany

Mining for petroleum in Germany dates back to 1919 to the Wietze Field, near Hannover. It should be noted that this field had been producing oil since 1880 by conventional pumping methods. The mining methods used at Wietze were started by the same German company which had exploited the Pechelbronn mines during World War I. The Wietze mine is located on the flanks of salt domes which thrust up through sedimentary layers of rock. The oil-bearing strata are located in four horizons composed of beds of sand, sandstone or clay-sand separated by clay beds. They total about 200 feet in thickness and lie at fairly steep angles.

The mining techniques employed were highly labor intensive and consisted of both direct and indirect methods. One of the sand strata contained oil and sand so tightly packed that fluid would not drain. A longwall face was excavated, and the oil sand was mined directly and brought to the surface for washing and separation. Most of the strata in the Wietze mine, however, was drained using the "Pechelbronn" (indirect) method. As of 1953, the indirect method has accounted for 72 percent of the oil recovered; the direct method, 26 percent; and horizontal wells, 2 percent. Historically, this has been the only known operation where significant oil production has been sustained from underground direct mining.

Direct mining methods were generally developed after the oil content had been reduced by other extraction methods and also in viscous oil from lower grade sands. Indirect methods involved driving drifts along the strike and connecting them at intervals with crosscuts, and drilling drainage holes into the reservoir rock. The cost of producing oil by the indirect method was reported to be one-half the cost of recovering the oil by steaming and washing the mined sand. The average cost of the mined oil was only about one-third more than the cost of producing oil by pumping from wells in the Wietze field.

2.1.4 Japan

In 1940 Japan began mining for petroleum by underground methods in the Katsurazawa district of the Higashiyama Oil Field to recover additional oil from the sands not recoverable by wells drilled from the surface. The mine was a wartime operation which, at peak production, comprised about 2.5 percent of the total oil production of Japan.

The mining scheme, using drainage galleries, was basically the same as at Pechelbronn; however, the development work was actually done in the oil sands. The operation consisted essentially of sinking a shaft into the oil sand, driving a network of tunnels into and below the sands, then draining the residual oil not recoverable by wells from the surface through pits and drill holes.

Oil gravity was approximately 26° API, and although the oil content in the field was extremely variable due to depletion by wells, estimates of the oil sands were approximately 1,100 barrels per acre-foot, or about 0.4 barrels per ton. Mine production increased steadily from 1940 to 1946, with a peak production of 37,354 barrels in 1945. Although the mine operation was a failure as a financial enterprise because it lost money in five of seven years it was in operation, it did prove that it was technically feasible to drain oil through underground galleries.

2.1.5 Canada

The Athabaska area of Alberta, Canada, has probably the world's largest deposit of outcropping bituminous sandstones. Yields are estimated at about one barrel of oil per ton of sandstone, with upwards of 500 million barrels recoverable in areas of little or no overburden.

During the late 1940's two semi-commercial operations were underway: Abasand Oil, Ltd., in northern Alberta, and Oil Sands, Ltd., near Lake Athabaska. Both were surface mining operations. After mining, the sandstone was transported to a separating plant where it was mixed with hot water; light oil was added in a flotation process to separate the oil.

Shell Canada, Ltd. tested an emulsion process in field trials between 1957 and 1962 which yielded a bitumen-in-water emulsion of low viscosity. Shell also successfully experimented with the formation of horizontal fractures to establish flow between injection and production wells.

Great Canadian Oil Sands, Ltd. began surface mining or tar sands in the Athabaska region in 1967. Design-level output was reached in 1970, and by 1972 average production was more than 50,000 barrels per day. The overall mining operation included muskeg removal (up to 20 feet thick), overburden removal (80 percent of which was used to construct earthen dikes to contain future mill tailings), oil mining and transportation (processing 140,000 tons per day of oil sand), and construction of earthwork dikes. Because of the large pieces of equipment involved, the mining system was very capital intensive but not labor intensive.

2.1.6 Malagasy Republic

The Malagasy Republic has heavy oil and tar sand deposits in the west-central and southwest parts of the island. Although there are approximately 780 million tons of mineable deposits reportedly containing about 3 billion barrels of heavy oil and tar, very little of this has been recovered at the Bemolanga field, the largest deposit on the island.

In 1962 two quarries and a pilot plant were opened at Bemolanga to find a hot water recovery process that could be applied to an industrial plant. In 1965 an in situ combustion process instituted by a French society proved unsuccessful. Between 1972 and 1974, two thermal studies were conducted by the University of Tananarive and TOSCO. These studies were directed at problems relating to insitu combustion techniques. No further heavy oil recovery processes have been studied or attempted.

2.1.7 Rumania

The southern and eastern portions of Rumania contain the known deposits of heavy oil in that country. Historically, Rumania has been self-sufficient

with regard to oil production, partially due to efforts to improve the recovery of heavy oil. Such efforts have included conventional water flooding, in situ combustion, steam injection, polymer flooding, micellar solution flooding, CO_2 injection, bacterial activity, and mining.

In 1925 the Sarata-Monteoru deposit was developed using gravity drainage into mine galleries. Later, horizontally descending wells were drilled from these galleries, enhancing the recovery of oil to 55 to 60 percent.

2.1.8 U.S.S.R.

The U.S.S.R. contains several areas of heavy oil deposits along with a large number of reservoirs with higher gravity, viscous crude oils. As a result, the Soviets have for years conducted research and field tests on a wide variety of methods for recovery of viscous crude oils. The petroleum deposits are generally divided into five separate provinces. Only two, the Volga-Urals and the Caspian Sea/North Caucasus area, have been exploited using heavy oil recovery processes.

As far back as the late 1800's studies by D.J. Mendeleev cited an increase of heavy oil recovery by the introduction of steam into oil-bearing rocks. Tests were performed from 1947 to 1950 in the Shodnitsa field in the Ukraine mixing flue gas and steam to enhance oil recovery. In 1965-66 thermal stimulation was initiated on a practical basis when cyclic steam treatment was applied in the Krasnodar and Sakhalin area.

2.1.9 Venezuela

Heavy oil production began in Venezuela in 1914 with the discovery and subsequent development of the Mene Grande field; however, it was not until 1957 that a field test was made to investigate the effects of applying steam to heat the reservoir. In 1961 a steam displacement test was performed in the northern part of the Tia Juana field. Even though six years of operational data proved that the method is less favorable than the steam-soak process used at Mene Grande, plans for a large scale steam

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displacement project were drawn up in 1972. In 1978, 19 injector wells and 132 producing wells began operation in the Tia Juana field.

In 1959 in situ combustion testing was initiated at the Tia Juana field. Other tests, including alternate air and water injection schemes, were made in the Tia Juana field during the 1960's, but these encountered many problems and the results were inconclusive.

Other in situ combustion tests, which were carried out during the same period in eastern Venezuela, showed more promise. One of these, in the Miga field, involving a dry forward combustion process, is still operating today after its initiation in 1964.

2.2 EXISTING AND PLANNED HEAVY OIL PROJECTS

2.2.1 United States

o Surface Mining

The Getty Oil Company is now operating in the McKittrick Field near Bakersfield, California, on two state-of-the-art processes to extract heavy oil from a large deposit of diatomaceous earth. The McKittrick Field has been producing oil by conventional means since 1896 peaking at 15,900 barrels per day. A program has been launched to test a solvent extraction process, developed by Dravo Corporation, and the Lurgi-Rhurgas retorting process, developed by Lurgi Mineroltechnik. These pilot facilities will run side-by-side to extract virtually 100 percent of the heavy oil contained in the mined material.

The mining operation is a conventional open-pit mine, which is projected to produce about 34,000 tons of oil-yielding diatomaceous earth. Approximately 45 percent of the in-place oil is expected to be recovered, eventually yielding 380 million barrels of oil. Operation of the pilot plants will assist Getty Oil in determining which extraction method is best suited for commercial-scale development.

The Dravo plant produced 160 barrels per day of 14 to 15 API gravity crude oil from 250 tons per day of diatomite ore. The Lurgi plant, which started operation around January 1, 1982, is currently yielding 150 barrels per day of 15 to 17 API gravity oil and naphtha from about 250 tons per day of ore. Commercial-scale plants are projected to produce 20,000 barrels per day of oil from 32,000 tons per day of ore from the Lurgi process, and 24,500 barrels per day from 32,000 tons per day of ore from the Dravo process.

The Shell Oil Company plans to use mining operations to recover heavy oil from the Belridge South Field, Kern County, California. This prospective open-pit operation would be located approximately 12 miles northwest of

McKittrick. The shallowest producing zones are the Tulare Sands, which are about 400 feet thick.

Shell is also analyzing the San Miguel sands of southwestern Texas for primary heavy oil production. With the prospect being relatively shallow (2000 feet), two areas are being evaluated for surface mining and another for thermal recovery by Shell Mining Ventures. Analysis of the oil indicated that the oil gravity is less than 8 API and possibly as low as 0 to 3 API.

American Mining and Exploration Company is planning an oil mining project near Santa Rosa, New Mexico, in 11,000 acres of sands. The company estimates that 250 million barrels of oil will be mined and processed with solvents, with a recovery factor of 95 percent.

o Underground Mining

One of the most recent oil mining ventures is by Continental Oil Company (CONOCO) in the Lakota Sand of the North Tisdale Oil Field, Powder River Basin, Wyoming. Characteristics of the production zone are reservoir rock and fluid properties amenable to gravity drainage development. The project basically consists of a decline tunnel conventionally mined into a hillside. This approach provides access to the oil sand from which an array of horizontal drainholes are drilled to varying lengths.

The Lakota Sands have afforded only marginal success from conventional oil wells since development began in 1953. While production from mining methods dropped to about 30 barrels per day in late 1981, from an initial 100 barrels per day, the yield is expected to be long-lived. Experimentation with various stimulations such as chemical wash treatments, a carbon dioxide flush, and possible experimentation with steam injection is also being considered for the horizontal drainholes. Future plans also include reservoir repressuring with air injection in an effort to maximize recovery. In addition to the decline tunnel, CONOCO has completed a vertical shaft in the same formation, near the original site. At the

bottom of the shaft a chamber has been mined, and several radial holes are currently being drilled.

A study was begun early this year to determine the feasibility of producing light crude oil from a mine by gravity drainage in the Caddo-Pine Island Field, Louisiana. Here, the Upper Cretaceous Annona chalk contains approximately 100,000 barrels per acre of 41-43 API gravity oil in place. A shale layer below the Annona chalk appears strong enough to serve as roof rock. Therefore, it would be possible to sink a vertical shaft just below the shale layer and drill horizontal tunnels in hub and spoke fashion away from the vertical shaft. Wells would then be drilled upward into the oil-bearing formation, draining it by gravity. Petrol Industries, Inc., of Shreveport, Louisiana, has retained Keplinger & Associates, Inc., of Houston, Texas, to perform a feasibility study for this project.

Cornell Heavy Oil Process, Inc. (HOPCO) has nearly completed the construction of a heavy oil recovery demonstration project at the Kern River field in Kern County, California. The company expects to be producing oil by mid-1982 using steam injection and gravity drainage. The HOPCO process involves excavating and creating a cavern constructed of reinforced concrete, which would serve as a working chamber for drilling horizontal steam injection wells beneath the oil-bearing sands. A computer simulation model for this facility has defined a multiple cycle sequence of steam injection, steam soak, and heavy oil production. A five-cycle sequence for this site will require about 5 years of operational time to recover approximately 65 percent of the oil in place. Steam injection would average about three barrels of water equivalent for each barrel of crude oil produced.

Arco Oil & Gas Company of Plano, Texas, has been experimenting with an oil drilling rig which can drill holes around right-angle bends. Field testing began earlier this year in an Oklahoma well for tapping oil deposits adjacent to a drill hole. Arco plans to use this new device to drill wheel-spoke patterns from an original hole for draining an area more completely of its oil.

In another venture, Eagle Exploration Company plans to start drilling in the Black Hills uplift next year to lay the foundation (cores and geological data) for a steam project for heavy oil recovery in northeastern Wyoming.

2.2.2 France

The French are conducting some research in improved oil recovery processes. Pilot operations using both microemulsion and polymer flooding have shown satisfactory yields in the Chateaurenard Field in the Paris basin. A steam-flood process is also underway in the Laoq Field in fractured limestone. Results here have been favorable.

2.2.3 Japan

The Japan National Oil Company has conducted some research in improved oil recovery processes. Most of the major activity in heavy oil recovery is being conducted with a group of companies in the oil sands of Alberta, Canada, applying steam with electrical preheating.

2.2.4 Canada

The production of oil from the tar sand deposits in Canada has become increasingly more economical in the last several years. Many private companies are spending large sums of money to develop systems to recover the vast oil reserves locked up in these deposits. To date, all the mining operations have used surface mining methods. The largest and most significant surface mining operations currently producing oil are located in the Athabaska tar sands of northeastern Alberta, with the McMurray Formation containing about 90 percent of the heavy oil deposits in that region. An estimated 74 billion barrels of in-place heavy oil is covered with less than 150 feet of overburden. The total of known reserves in Alberta is estimated to be about 895 billion barrels, beneath 2,300 feet of overburden.

Great Canadian Oil Sands, Ltd. has been in operation since 1967 producing oil by muskeg and overburden stripping and oil sand mining. As oil sands are removed from underlying limestone, tailings from the processing plant are brought into the worked-out area and the land is reclaimed. With plant input of 140,000 tpd of oil sand and an overburden removal of 70,000 tpd, plant output is about 55,000 barrels of oil per day with 90 percent recovery.

In 1978 Syncrude Canada, Ltd. was projecting its operation to be 125,000 barrels of oil per day. Utilizing a system of large draglines, Syncrude will have to move approximately 92 million tons of oil sand and 45 million tons of overburden to reach their design production.

Shell Canada, Ltd. and Shell Explorer, Ltd. will utilize a scheme similar to the one used by Syncrude. Their design capacity is 100,000 barrels per day of product, which will require 225,000 tons of ore and the removal of 85,000 tons of overburden per day.

With 92 percent of the in-place heavy oil in Alberta lying at depths of between 150 and 2,500 feet, surface mining techniques would be prohibitively expensive; therefore, in situ techniques are being researched in order to eliminate bulk materials handling and reduce many of the environmental problems associated with surface disturbance. One in situ process undertaken by Amoco Canada utilizes a combination fire flood/water flood process. Shell Canada, Ltd. has successfully experimented with the formation of horizontal fractures to establish subsurface flow of oil between injection and production wells. Steam injection has been used by Imperial Oil, Ltd., Shell Canada, Ltd., and Gulf Oil Canada to recover heavy oil from bituminous deposits.

In 1978 Petro-Canada began work on a horizontal drilling project at an outcrop site. Drilling was begun in the spring of 1979 and steam injection started in August of 1979.

2.2.5 Rumania

Rumania is currently using a wide variety of methods to increase recovery of both heavy and light (less viscous) oils. There are over 100 oil fields under active artificial water drive. Four full-scale in situ combustion projects are currently in progress. Steam injection is now being used in the Morene field yielding a recovery rate of 25 percent as opposed to a primary recovery rate of only 5 percent. Several projects, active and under design, are utilizing CO_2 injection.

2.2.6 U.S.S.R

Since 1968 the Soviet Union has been using a specific underground mining technique to recover heavy viscous oil at the Yarega Field near Ukhta, northeast of Moscow. Originally developed in 1932 by surface wells, the oil field yielded only about 2 percent of the proven reserves. The deposit was mined by drilling wells into the reservoir from underground chambers. While production increased, recovery was still only about 6 percent. Therefore, in 1968, a new method was developed which combined drilling of closely-spaced wells from underground chambers and steam injection. With this new method, recovery improved to approximately 40 percent, mine production increased, and the cost of production per barrel of crude dropped by half.

The Yarega method of mining heavy oil is essentially an in situ process, with only a small amount of development rock to be handled. It is capable of recovering high viscosity oil not recoverable by conventional oil well pumping. Viscosity of the heavy oil is lowered dramatically by the application of high-intensity, low-pressure steam. Both steam and production wells are drilled primarily in the pay zone, allowing for higher thermal efficiency, rather than in barren formations between the surface and the pay zone.

Because of the encouraging results at Yarega, the Soviet Union began preliminary work in 1976 on a new commercial-size underground heavy oil

mine to test the economic feasibility of modified Yarega methods for the recovery of heavy oil from the old Balakhany fields near Baku in Azerbaijan. The Balakhany oil mine is designed to recover heavy oil from an area of about 500 acres. Two vertical shafts will be sunk below the pay zone with large horizontal tunnels similar to drifts in coal mines connecting the shafts. Small-diameter holes will be drilled upward at varying angles from these tunnels into the pay zone, allowing viscous crude oil to flow downward, by gravity, into storage tanks. While the opening of the first underground mine in the Baku area was originally scheduled for 1978, delays in design, equipment, electric power lines and government funding have pushed the start-up date back to late 1982 or 1983.

The Soviet Union is also planning to recover heavy viscous oil from offshore fields in Azerbaijan by undersea mines. Two methods of reaching the deposits are feasible, depending on the distance of the oil field from shore and the water depth. When the prospective oil field lies near the shore or on an island where the water is more than 330-500 feet deep, a vertical shaft will be drilled on-shore to a level 200-260 feet below the sea bottom. Horizontal drifts will then be bored at that level, running from the vertical shaft for the full length of the underlying oil field. For oil fields lying far from shore in depths of less than 330-500 feet, a vertical shaft (caisson) will be located off shore and set in place on the bottom of the sea over the center of the oil field. Once the caisson is in place, a vertical shaft will be drilled to a depth of 200-260 feet below the sea bottom, with horizontal drifts radiating outward from the vertical shaft the extent of the underlying oil field.

Undersea mines for the recovery of heavy oil will employ one of the Yarega methods (Ukhta, slanting wells, or gravity), or an adaptation of one of the methods being developed for the Balakhany underground heavy oil mine under construction in Azerbaijan. Experience at Yarega has shown that the spacing of production and steam injection wells is the most important single factor in the coefficient of recovery. Closer spacing results in lower steam losses, faster heating, and greater and quicker extraction of heavy oil from a mining section.

Since 1973 the Soviets have been testing a new variant of the fire-flooding technique at two old Azerbaijan oil fields north of Baku. With a 25-kw electric heating unit installed in the wells at the pay zone level, compressed air is injected into the reservoir through specially drilled ignition wells and heated as it is forced into the reservoir. Recovery from this technique has been reported to be as high as 54 percent of heavy in-place oil.

The Soviets estimate that there are at least 25 heavy oil fields in the Baku area at a depth of 1600 feet or less where various mining methods can be applied successfully. The first commercially-operated heavy oil field, by the in situ combustion process, was in the Khorosany area of Azerbijan. Started in 1973, it was converted to a "wet" combustion project in 1974. By 1977 it was producing 3 1/2 times the rate in 1972 by conventional water flooding.

In addition to steam and combustion processes, the Soviets are also working on two other methods of in situ heat generation: electrical downhole heating and thermochemical heating (hydrochloric acid and magnesium treatment). Polymer flooding has been successfully field tested in the Kuyibyushev region, Bashkiria, and the heavy oil deposits of the Tartar region. While extensive research on chemical flooding is being conducted by the All-Union Research Institute in Moscow, no field testing is being conducted.

2.2.7 Venezuela

There are currently 40 projects involving secondary heavy oil recovery in Venezuela today. Of these, 34 are steam-soak, most of which are in the Tia Juana Field. There is intense interest in recovery in the vast Orinoco Heavy Oil Belt utilizing primarily caustic flooding, emulsion, and CO_2 injection procedures. However, the steam-soak process is expected to continue as the prime method for improved heavy oil recovery in all regions of Venezuela because of proven success over the last 20 years.

2.2.8 Brazil

Few known deposits of heavy oil have been found in Brazil; however, in 1962 studies were performed in the northeastern area in Sergipe-Alagoas on oil of 14° - 28° API gravity. While those early projects had only limited success, the Brazilian national oil company, Petrobras, was working with American consultants on techniques such as polymer flooding and micellar slugs. More recently, a heavy oil reservoir was discovered offshore near Rio de Janiero.

2.2.9 Indonesia

The largest known heavy oil field in Indonesia is in central Sumatra, with about 3 billion barrels on in-place viscous oil. Other known heavy oil fields are in southern and offshore Sumatra and in Borneo. The only known heavy oil recovery process currently in operation is a steam-soak project operated by Calter Pacific, of Indonesia, in central Sumatra. Despite major problems, the effort has shown promising results with ultimate recovery expected to significantly surpass the less than 10 percent primary recovery.

2.2.10 Peru

Heavy oil deposits in Peru occur primarily in the northeastern portion of the country, which is estimated to have approximately 1.5 billion barrels of in-place oil. Occidental Petroleum Corporation has initiated pilot projects for development of reservoirs which normally produce oil by a natural water-drive method.

2.2.11 Trinidad

Estimates of heavy oil deposits in Trinidad are as high as 40 billion barrels. Currently, Texaco and Tesoro-Trinidad are pursuing heavy oil recovery by a steam displacement process.

2.2.12 Turkey

All known heavy oil deposits in Turkey lie in the eastern part of the country; however, recovery has been attempted in only one field, Bati Raman, discovered in 1961. By 1967 primary recovery had yielded only 1.5 percent of in-place oil. Since then, water flooding, continuous and cyclic steam injection, and air injection have been attempted on pilot projects. Engineering studies are currently underway to evaluate alternative recovery methods.

The major documented producers of heavy oil are shown in Figure 2-1.

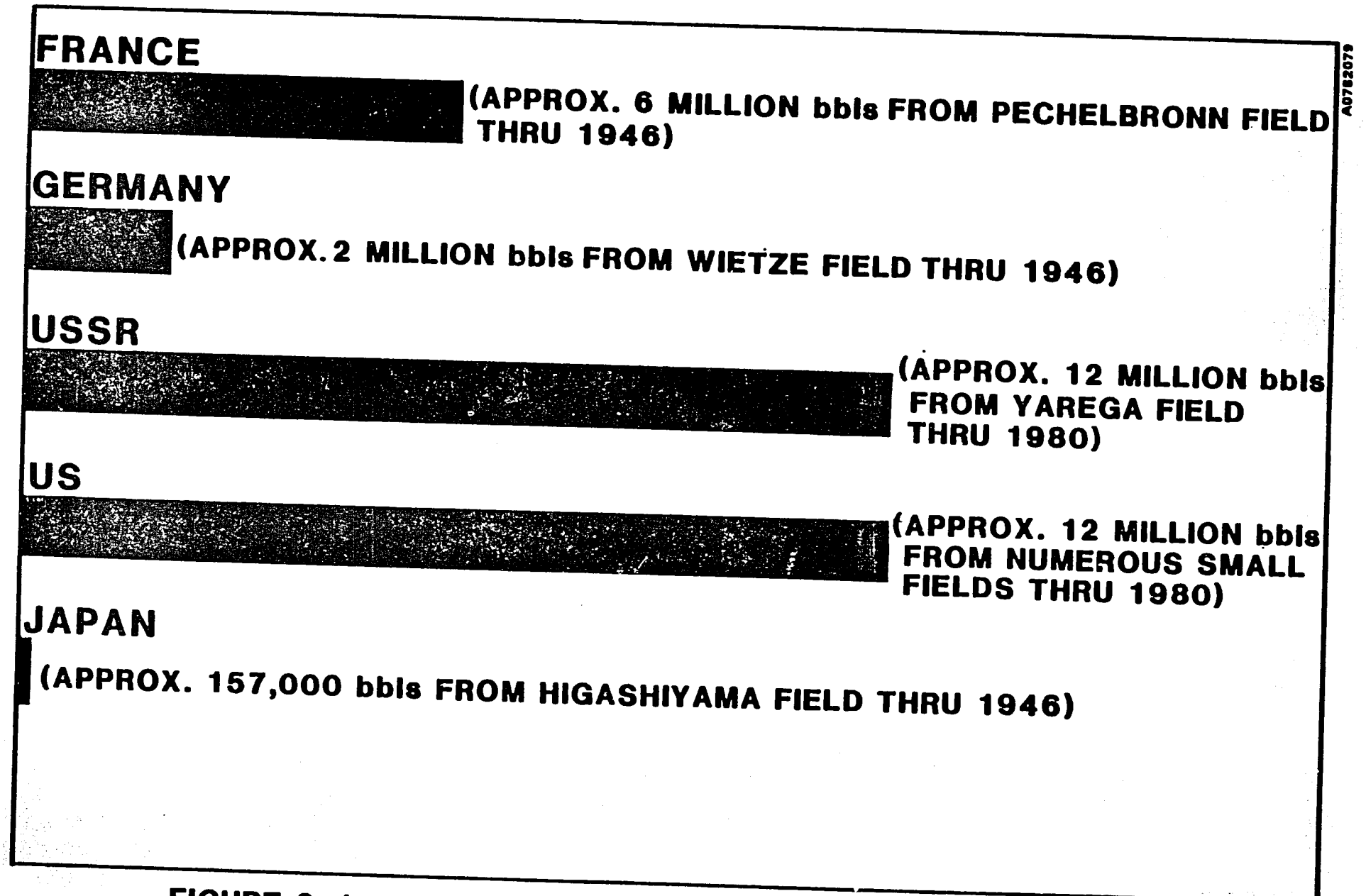

FIGURE 2-1 MAJOR DOCUMENTED PRODUCERS OF HEAVY OIL

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2.3 POTENTIAL MINING METHODS

Previous sections of this report have described mining methods currently being used throughout the world as well as those being planned or under initial development. These mining techniques can be categorized as follows:

1. Surface Mining
2. Underground Mining
3. In Situ Mining (Mining for Access)

Each of these mining techniques will be described in detail in light of the following:

- Technical Considerations
- Equipment and Systems
- Safety Considerations
- Econimic Considerations
- Environmental Considerations

2.3.1 Surface Extractive Mining

Surface mining methods can be classified in two categories:

1. Strip Mining
2. Open Pit (includes terrace mining)

- Strip Mining

Strip mining is a method in which the ore body is mined horizontally. It is a strip mine in which the waste material and overburden are replaced into the excavation pit as the mining progresses. Depending upon the specific requirements of the Office of Surface Mining (OSM) it may be necessary to replace the overburden material as well as the reservoir rock in the same sequence, as it was removed originally. If this type of

requirement is imposed, it would greatly add to the cost of surface mining for oil. OSM may also require the operation to compact each of the layers of overburden to approximately their original compressive strength. This too would significantly impact the cost of the operation.

Typical strip mining operations involve the removal of the overburden by either trucks, shovels, front end loaders or bucketwheel excavators. As the material is removed it is transported by truck or belt conveyor to another portion of the pit that has been mined out, and at that point it is replaced. The depth of overburden to be removed will depend on the quantity and quality of the oil reservoir below the overburden. It should be noted that the removal of overburden for the first portion of the pit must be stockpiled and the top soil separated from the remainder of the overburden. The process is necessary so that when the mining operation is complete, the topsoil can be placed on top of the overburden for complete reclamation.

The initial pit cost can vary greatly if the depth is more than 20 to 50 feet. If the overburden is not too deep, it may be efficient to use large draglines for overburden removal so that they can cast the material from one side of the strip pit to the other side without having any secondary transportation for overburden removal.

o <u>Open Pit Mining</u>

Open pit mining is a method in which mining progresses vertically downwards following the ore body. In the case of an open pit, the overburden and ore are removed, usually with trucks and shovels or conveyors or trains. The overburden material and clean reservoir material is placed at an alternate location rather than in the pit from which it was removed. Open pit methods are generally used for deposits that have a large amount of overburden with a sand thickness of 500 to 1,000 feet. In some cases an open pit can never be reclaimed.

2.3.1.1 Technical Considerations

Some of the more significant reservoir characteristics that will affect surface extractive mining as well as underground extractive and mining for access operations are identified in Table 2-1. A summary identification of risk analysis associated with surface mining operations is shown in Table 2-2.

Summarized below are additional technical considerations associated with surface extractive mining operations.

o <u>Geology</u>

Geology of deposits for heavy oil mining have traditionally been evaluated for their petroleum characteristics. For example, very few of the reservoirs reviewed in Task I had any information concerning the characteristics of the rocks above or below the reservoir. This will require additional drilling if mining techniques are used to determine what affect they will have on the mining method.

Geological settings can affect production of surface mines by having areas of heavy faulting, severe dips, heavy jointing, groundwater, and slope stability problems. Prior to any mining it is necessary to know major and minor access of fractures and joints so that the mine design configuration can be adapted to take advantage of these characteristics. In the case of high influxes of groundwater, it may be necessary to dewater the entire area by the use of drainage wells. It may be also necessary to review the feasibility of dredge type mining of these reservoirs.

o <u>Rock Characteristics</u>

Where petroleum engineers and geologists are concerned mainly with rock porosity, permeability, oil content and water content, the mining engineer is concerned with compressive strengths and shear strengths as well as porosity and permeability. Stability problems could make a very good heavy oil deposit unmineable.

TABLE 2-1

RESERVOIR CHARACTERISTICS

Characteristics	Parameters
1) Porosity	15 to 30%
2) Compressive strength	
a. Overburden	2,800-24,000 psi (sandstone) 4,300-36,000 psi (limestone)
b. Reservoir	
3) Permeability	.005-several darcies
4) Oil saturation	50-70 percent of pore space
5) Overburden consolidation	Consolidated to unconsolidated
6) Deposit consolidation	Consolidated to unconsolidated
7) Amount of methane	0-50 s.c.f./reservoir barrel
8) Strength and competency of sealer (shale)	70-2,530 psi
9) Fracturing/joints in reservoir	Dependent upon production history of reservoir
10) Gravity	10° to 20° API
11) Thickness of formation	Dependent upon economic consideration (barrels per acre), few ft to hundreds of ft
12) Viscosity	Less than 100 centipoises
13) Reservoir pressure	Dependent on depth
14) Reservoir temperature at depth	Increase of 2°C F/1,000 ft
15) Pressurized gas concentrations	Approximate top 1/3 of reservoir
16) Groundwater inflow, if any	Generally in bottom 1/3 of reservoir
17) Amount of water in oil zone	10-30%
18) Faulting	Depending on geographic area in United States and reservoir

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TABLE 2-1 (cont'd)

RESERVOIR CHARACTERISTICS

Characteristic	Parameters
19) Overburden pressure	Approximately 1 psi/ft of depth
20) Existence of trace gases (other than methane)	H_2S, CO , HC gases

TABLE 2-2

SURFACE RISK ANALYSIS ASSOCIATED WITH SURFACE EXTRACTIVE MINING

Mining Function	Specific Hazard	Probability Location & Safety Hazard	Risk Severity Rating 1-Low Risk 10-High Risk
A. Overburden			
Mining	Soft bottom (porosity)	Near pit bottom (sinking equipment)	2
Mining	Gas	Near pit bottom Near faults/joints (fire, explosion, asphyxiation)	3
Mining	Water/oil Near faults/ joints (maintenance, fire)	Near pit bottom	4

TABLE 2-2 (cont'd)

SURFACE RISK ANALYSIS ASSOCIATED WITH SURFACE EXTRACTIVE MINING

Mining Function	Specific Hazard	Probability Location & Safety Hazard	Risk Severity Rating 1-Low Risk 10-High Risk
B. Orebody			
Drilling	Soft bottom (porosity) Sinking equipment	On benches (highwall stability)	5
	Gas (fire, explosion, asphyxiation)	Hole blow out	1
	Water	In hole (high pressure)	7
Oil		In hole (high pressure, fire)	10
Blasting	Fire	On face In muck pile	7
Gas		Liberated from muck pile	7
Ripping	Soft bottom	On bench (sinking of machine)	5
	Gas	Liberated while ripping	3
	Oil	On surface	6

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o Topography

The topography of an oil deposit may affect which mining method or modification of a mining method is used because of disposal problems associated with reservoir rock and the rock removed from above or below the reservoir. Some of these problems have been encountered in the oil shale projects of western Colorado.

o Climate

Climate is an important consideration in surface mining operations. During hot summer periods oil will flow more freely from the rock than during the winter. Areas with heavy rainfall will cause problems with equipment and mine access roads. Climate will also affect the emission of gases from underground and surface operations. For example, during periods of low pressure there is more likelihood of greater gas emission from exposed rock than during periods of high pressure.

2.3.1.2 Equipment and Systems

The equipment used for surface extractive mining of heavy oil sands is divided into two categories; equipment used for overburden and waste removal and equipment used for ore removal. Equipment used for overburden removal will, in most cases, consist of dozers and scrapers for the removal and storage of topsoil, and drills, trucks, and shovels/front end loaders for the removal of waste rock and overburden. In cases where unconsolidated material is encountered the use of bucketwheel excavators might be considered. Ancillary equipment includes blasting trucks, maintenance vehicles such as lube trucks, mechanic trucks, portable water pumps, and lighting plants for nighttime operation.

The use of 5 to 6-cubic-yard equipment required for waste rock and overburden removal is dependent upon the overall mine size. Equipment can range in size from small 5 to 6-cubic-yard front end loaders with 25-ton trucks up to and including 12 to 16-cubic-yard front end loaders/electric

shovels and 200-ton trucks. If blast hole drilling equipment is required, rotary drills or rotary down-the-hole hammer drills that can produce holes up to 12 inches in diameter should be considered.

Blasting in most situations can be accomplished with an ammonium nitrate/fuel oil (ANFO) mixture. However, if the overburden is extremely wet, a form of water gel or slurry type explosive is used. Sumps and ditches must be developed to handle the water. Table 2-3 identifies equipment and systems that can be used for surface extractive mining operations.

o Excavation

Excavation of the ore itself is most likely accomplished by one of three methods, two of which do not require blasting. For the first method it is assumed that the reservoir has a high porosity, which makes it possible to use large crawler type equipment similar to the AC-41 or the Caterpillar D-10. If this is the case, single or dual parallelogram rippers may be sufficient to rip the reservoir rock.

Once the rock has been ripped from place it can be loaded with scrapers or front end loaders/trucks. One of the many advantages of this type of mining is that crawler type equipment has fewer rubber components than drill/blast/truck/shovel operations and thus fewer maintenance/repair problems.

The second method of mining is conventional drilling and blasting techniques. In this case some research and development would be required to determine what type of explosive is best suited for the operation in terms of fire potential and post explosions. Once the rock is broken it can be loaded using shovels or front end loaders. Shovels are preferable, again because of the lack of rubber components. Ore is hauled to the processing plant with large trucks in the 25 to 200-ton range.

TABLE 2-3

EQUIPMENT AND SYSTEMS
SURFACE EXTRACTIVE MINING

Mining Function	Conventional Mining Practice & Criteria	Heavy Oil/Tar Sand Criteria & Constraints
Overburden removal	Overburden removed by conventional drilling, blasting, shovels/loaders and trucks; bucketwheel excavators; draglines and scrapers	Remove overburden with same equipment only made permissible
	Non-gassy environment	Install gas detection devices on all equipment
	Non-slick environment	Use chains on rubber-tired equipment
	Non-oily environment	Look into using an alternate material for tires, hoses and other rubber accessories
	Benches constructed according to current MSHA regs	Lower benches if in tar sands or unconsolidated material i.e., MSHA may need to change regs for oil mining
	Drilling holes with rotary drill rigs or down-the-hole hammers	Make current rotary drill rigs permissible
	Blasting	With various explosives ANFO water gel or slurry
	Conveyors used for haulage in conjunction with in-pit portable crushers	Use oil resistant cover and components on belt conveyor
	Standard portable crushing facilities	Develop portable crushers and other equipment with larger base surface areas to reduce ground pressure
Ore Removal	Use of bucketwheel excavator in unconsolidated material	Use bucketwheel excavator with modifications to mine wet, slick and gummy material
	Use of conventional drilling, blasting, shovels/loaders and trucks	Cutter immersed in water seal for spark suppression

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TABLE 2-3 (cont'd)

EQUIPMENT AND SYSTEMS
SURFACE EXTRACTIVE MINING

Mining Function	Conventional Mining Practice & Criteria	Heavy Oil/Tar Sand Criteria & Constraints
	Use of portable crushers and belt conveyors to replace trucks	Install fans at the face to disperse heavy gas as pockets are encountered
	Bench height meets minimum requirements of MSHA	Modify continuous excavator teeth to dig hard, frozen rock (wintertime use); geographical location.
	Bench configuration to fit ore body	Additional wear on rubber tires due to frozen, slick haulage surface. Need better tires or use crawler-mounted equipment
	Blast size regulated by environmental conditions	In conventional mining (drill blast, muck) use of permissible explosives with stemming will be required.
	Road Maintenance	Additional preventive maintenance required due to abnormal wear on equipment
		Additional road maintenance required
		Modification of all rubber accessories, i.e., tires, hydraulic hoses on belt conveyors and in-pit equipment
	Large dewatering system required to keep pit dry	Large dewatering system required to keep pit dry

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The third method is large bucketwheel excavators. This is possible only in highly unconsolidated material. As the material is removed from the face by the bucketwheel it is moved by belt conveyor to a possible secondary crusher station where it is reduced in size then placed on a belt conveyor system for removal to the processing plant. It should be noted that this type of operation is very inflexible, particularly in situations where the material changes characteristics. A significant amount of down time could be incurred while modifying the operation to one of the other two mining methods described above.

Depending on mine configuration it may be desirable to use a series of crawler type crushers and belt conveyors similar to those recommended for bucketwheel excavators for the movement of ore from the face area to the processing plant for the first two methods. The advantage to this type of material handling is that fewer rubber components are required and that fewer personnel are required.

For surface extractive mining of heavy oil sand deposits, the excavation equipment required for soil and overburden removal can consist of draglines, bucketwheel excavators and truck-shovels or scrapers. With draglines the deposit must be such that one or more draglines can cast the overburden a sufficient distance to leave a bench of ore exposed for further mining. The overburden will usually be removed with scrapers that operate in tandem with push dozers.

The overburden must be stockpiled or placed on the reclaim spoil area. If the overburden consists of consolidated sandstones and shales it will be necessary to blast; blasted ore must be removed with front end loaders, trucks or shovels to a portable crusher belt system. Once access to the ore has been gained, the technique for removing the ore will be the same as that just discussed.

o <u>Production Capability</u>

Open pit mines have higher production capabilities than any of the other mining methods to be discussed with the possible exception of strip mining.

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o <u>Production Capability</u>

Open pit mines have higher production capabilities than any of the other mining methods to be discussed with the possible exception of strip mining.

Current production of an open pit mine in the United States can be as much as 500,000 tpd of ore and waste rock. Production capabilities are restricted only by pit configuration.

o Reliability

Open pit mines are very reliable with the exception of those located in geographic areas where severe winter weather or heavy rains can shut down mining operations for extended periods. In general, if a pit is designed correctly and equipment selected carefully, the operating efficiency of such a pit should be in excess of 90%.

2.3.1.3 Safety Considerations

The major safety factors that can be expected in surface extractive oil mining are highwall and rock strength for bench stability; effects of oil on the haul roads, especially during rainy periods; the possibility of heavy gases, such as hydrogen sulfide, that can accumulate in low lying areas; and control of water inflow. In addition to these general safety factors, it is necessary to identify specific physical variables and conditions of heavy oil deposits that represent potential safety risks and technological constraints to heavy oil mining. A detailed assessment of the physical variables potentially encountered in surface extractive mining is developed and ranked in Tables 2-4 and 2-5.

2.3.1.4 Economic Considerations

A hypothetical surface mine was developed here to determine what would be the approximate costs in 1982 dollars of operating such a mine for heavy oil extraction.

The Task 1 screening process concluded that no sites were suitable for strip mining; therefore, open pit (terrace) mining was the only option considered here for surface extraction of ore. Both fixed capital and operating costs were compared only for those areas that would be affected by the particular mining method. For example, mineral rights acquisition was not considered because the costs would be constant for either method.

TABLE 2-4

SUMMARY IDENTIFICATION OF RISK ANALYSIS-SURFACE STRIP MINING

Mining Function	Specific Hazard	Probability Location & Safety Hazard	Risk Severity Rating 1-Low Risk 10-High Risk
A. Overburden			
Mining	Soft bottom (porosity)	Near pit bottom (sinking equipment)	2
Mining	Gas	Near pit bottom Near faults/joints (fire, explosion, asphyxiation)	3
Mining	Water/oil	Near pit bottom Near faults/joints (maintenance, fire)	4
B. Orebody			
Drilling	Soft bottom (porosity)	On benches (highwall stability) Sinking equipment	5
	Gas	Hole blow out (fire, explosion, asphyxiation)	1
	Water	In hole (high pressure)	7
	Oil	In hole (high pressure, fire)	10
Blasting	Fire	On face In muck pile	7
	Gas	Liberated from muck pile	7
Ripping	Soft Bottom	On bench (sinking of machine)	5
	Gas	Liberated while ripping	3
	Oil	On surface	6

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TABLE 2-4 (cont'd)

SUMMARY IDENTIFICATION OF RISK ANALYSIS-SURFACE STRIP MINING

Mining Function	Specific Hazard	Probability Location & Safety Hazard	Risk Severity Rating 1-Low Risk 10-High Risk
Mucking (FEL)	Soft bottom	On bench (caving-sinking)	5
	Oil	Tire deterioration (driving and maintenance)	10
	Porosity	On bench (highwall caving)	
Mucking (shovel)	Soft bottom (porosity)	On bench (sinking tramming)	5
		(highwall caving)	4
Haulage Trucks	Soft bottom	Same as above	
	Oil	rubber parts	10
Conveyors	Oil	rubber parts	10

TABLE 2-5

SUMMARY IDENTIFICATION OF RISK ANALYSIS - SURFACE OPEN PIT MINING

Mining Function	Specific Hazard	Probability Location & Safety Hazard	Risk Severity Rating 1-Low Risk 10-High Risk
A. Overburden			
Mining	Soft bottom (porosity)	Near pit bottom (sinking equipment)	2
Mining	Gas	Near pit bottom Near faults/joints (fire, explosion, asphyxiation)	3
Mining	Water/Oil	Near pit bottom Near faults/joints (maintenance, fire)	4

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TABLE 2-5 (cont'd)

SUMMARY IDENTIFICATION OF RISK ANALYSIS - SURFACE OPEN PIT MINING

Mining Function	Specific Hazard	Probability Location & Safety Hazard	Risk Severity Rating 1-Low Risk 10-High Risk
B. Orebody			
Drilling	Soft bottom (porosity)	On benches (highwall stability) Sinking equipment	5
	Gas	Hole blow out (fire, explosion, asphyxiation)	1
	Water	In hole (high pressure)	7
	Oil	In hole (high pressure, fire)	10
Blasting	Fire	On face In muck pile	7
	Gas	Liberated from muck pile	7
Ripping	Soft bottom	On bench (sinking of machine)	5
	Gas	Liberated while ripping	3
	Oil	On surface	6
Mucking (FEL)	Soft bottom	On bench (caving-sinking)	5
	Oil	Tire deterioration (driving and maintenance)	10
	Porosity	On bench (highwall caving)	
Mucking (shovel)	Soft bottom (porosity)	On bench (sinking tramming) (highwall caving)	5 4
Haulage Trucks	Soft bottom Oil	Same as above rubber parts	10
Conveyors	Oil	rubber parts	10

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In general it was concluded that, on a hypothetical basis, there is little, if any, difference in the cost of mining between surface open pit and surface strip mining.

For a surface extractive mine (open pit), the estimated cost per ton of ore mine is $6.42 (1982 dollars). Considering the value of a ton of ore at 0.35 barrels of oil, this calculates to $18.35 per barrel of oil.

In the case of strip mining, if a site were suitable it would be necessary to incur additional costs for the continual building of haul roads to replace the overburden and waste material in the workout pit. However, this would be about equal to the costs for the additional haul distance required for the disposal waste and overburden material from an open pit. The figures used for cost estimation were derived from the U.S. Bureau of Mines, Straam engineering handbook, and from standard mining engineering formulas.

On a first approximation of open pit mining costs, the following basis was used:

- Total tons required for removal: 13,210,863,000
- Total tons of ore required for removal: 3,136,320,000
- Days per year: 363
- Days per week: 7
- Hours per shift: 8
- Ore production tons: 70,000 tpd
- Waste tons: 294,700 tpd
- Weight of ore and waste: 130 lbs per cubic ft, 3,510 lbs per cubic yard
- Shift per day: 3

This resulted in a waste to ore ratio of 4:21:1. The mine was designed to produce 70,000 tons of ore per day for a proposed oil production rate of 25,000 barrels per day. To accomplish this it would be necessary to remove 294,700 tpd of waste material.

During startup it was assumed that adequate equipment would be purchased for removal of overburden at a rate of 200,000 tpd to gain access to the ore deposit. At this rate it would be necessary to remove 59,375,250 tons of waste prior to production. At a removal rate of 200,000 tpd, it would take 297 days of pre-stripping to reach the ore body.

At a mining rate of 70,000 tons of ore per day, the life of the ore body would be 44,805 days, or on a basis of 363 operating days per year, total production would total 123 years. The following costs were initially developed with the aid of the Straam mining cost estimating handbook.

1. Cost for clearing brush and timber equals $424 per day.

2. Drilling and blasting during the production phase equals $37,392 per day

3. Excavation, load and haul equals $205,576 per day.

4. General items (communication, sanitation, housekeeping, fire protection, and electrical) equal $10,232 per day.

5. Water supply systems equal $1,368 per day.

6. Drainage and disposal systems equal $924 per day.

7. General expense (administrative salaries and wages, administrative purchases, administrative equipment operation) equals $31,432 per day.

Summary

Total operating costs on a daily basis are: clearing $424; drill and blast $37,392; excavation, load and haul $205,576; general $10,232; water supply system $1,368; drainage and disposal systems $924; and general expense $31,432. Total daily operating cost equals $287,348. This cost represents $0.79 per ton for the total tons mined or $4.10 per ton for each ton of ore mined. Capital costs related to the Straam estimate are as follows:

ITEM	COST
Clearing	$18,997,000
Water System	337,820
Drainage System	358,700
Communication System	258,100
Fueling System	1,030,950
Electrical System	3,115,000
Repair Shops and Warehouse	7,607,500
Offices and Laboratories	805,500
Surface Buildings	501,200
Mining Equipment	148,200,000
TOTAL	$181,211,770

As can be noted, capital costs will be considerable for a surface mining operation. No effort was made at this time to determine the cost per ton based on depreciation rates of the equipment. Table 2-6 lists suggested economic parameters for surface extractive mining basically considering

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TABLE 2-6

SUGGESTED ECONOMIC PARAMETERS
FOR
SURFACE EXTRACTIVE MINING

Fixed Capital

1) Mineral Rights Acquisition: Constant

2) Environmental Impact Statement and Legal Fees: Constant

3) Further Exploration and Development Drilling: Constant

4) Removal of Overburden and Waste: Slightly higher for open pit

5) Construction of Shafts or Drifts, Opening Up of Haulage Ways, and Working Faces: Not applicable

6) Further Process Development (Laboratory and Pilot Plant Experiments): Not applicable

7) Plant and Equipment:

- o Land - Open pit higher due to dispersal of waste and process rock
- o Water Supply - Not available
- o Power Plant - Not applicable
- o Railroad Spur and Access Roads - Open pit less because strip roads move as mine moves
- o Waste Disposal - Open pit haulage higher
- o Mine Plant - Not applicable
- o Benefication Facilities - Not applicable
- o Service Buildings - Not applicable
- o Storage - Not applicable
- o Transportation Facilities - Not applicable
- o Material Handling Facilities - Not applicable

8) Working Capital:

- o Cash On Hand - Constant
- o Accounts Receivable - Constant
- o Inventories (Parts and Supplies) - Slightly higher for open pit

9) Start Up Costs: Not applicable

10) Contingency Allowance and Cost Escalation: Constant

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TABLE 2-6 (cont'd)

SUGGESTED ECONOMIC PARAMETERS
FOR
SURFACE EXTRACTIVE MINING

Operating Costs

1) Labor: Constant

- o Wages, Including Overtime
- o Salaries for Administrative and Clerical Staff
- o Vacation and Hospitalization Payment
- o Fringe Benefits - Social Security, Unemployment
- o Insurance, Workmen's Compensation, Other Insurance

2) Energy:

- o Power and Fuel Used - Open pit slightly higher due to longer haul

3) Supplies:

- o Explosives - Constant
- o Timber - Not applicable
- o Lubricants - Slightly higher for open pit
- o Chemicals - Constant

4) Parts:

- o Spare Parts for Machinery and Equipment - Open pit slightly higher due to haul

5) Maintenance and Services:

- o Repairs, Hauling, Professional Costs, Telephone
- o Travel - Same as 4

6) Royalty Payments - Constant

7) Interest Payments - Constant

8) Depreciation, Depletion Allowance, etc. - Constant

9) Taxes - Constant

A more detailed estimate of open pit mining costs is summarized in Table 2-7. The cost per ton of ore totals $6.42 compared with the $4.10 in the previous approximation estimate.

TABLE 2-7

ESTIMATED COST OF OPEN PIT SURFACE MINE

Summary (#/ton of ore per day)

Item	Capital $/1000	OP $/1000	$/ton
Shovel:	39,600	11,640	0.458
Trucks:	212,800	131,577	5.178
Drilling:	1,995	4,215	0.166
Powder:			
Caps		580	0.023
Powder		15,033	0.592
	254,395	163,055	6.417

OPEN PIT SURFACE MINE ESTIMATE

Basis:

Blast large as possible to avoid small pieces of ore (dust size).

Days per year	= 363
Days per week	= 7
Hours per shift	= 8
Ore Production tons	= 70,000 tons/day
Oil Production	= 25,000 bbl/day
Waste Tons	= 294,000 tons/day
Strip Ratio	= 4.2:1
Ore and Waste	= 130 lb/ft^3, 3510 lb/yd^3
Shifts per day	= 3
Swell Factor	= 3
Bucket Fillability	= 0.80
Mechanical Availability	= Shovel = 0.95 Trucks = 0.80
Shift Efficiency	= 0.80
Utilization of Available Units	= 0.98
Angle of Swing	= 90°

TABLE 2-7 (cont'd)

ESTIMATED COST OF OPEN PIT SURFACE MINE

Shovel Cycle Time = 40 sec.

Dipper Capacity: $BC = \frac{Q}{(C)\ (\frac{1}{S})\ (A)\ (U)\ (Bf)\ (P)}$

Where:

Bc = dipper capacity
Q = production required (Bank cubic yds per hour)
C = cycles per hour for a 90° swing (minutes) 60/(tc)/(dc)
tc = shovel cycle time for a 90° swing (minutes)
dc = digging depth factor
A = mechanical U = utilization of available units
BF = dipper factor (fillability/swell factor)
S = swing factor (a function of swing)
P = propel time factor - time required to propel the shovel during maneuvering

$$C = \frac{60}{(66.66)\ (1.02)} = 88$$

S = 1.0 for 90° swing

$$Bf = \frac{0.8}{1.6} = 0.50$$

Shovel Selection:

Cubic Yards Required Per Hour:

$$Yd^3/hr = \frac{364{,}000 \text{ tons/day}}{(24 \text{ hr/day})\ (0.80 \text{ shift eff.})} \times \frac{2000 \text{ lbs/ton}}{3510 \text{ lb yd}^3}$$

Yd^3/hr = 10,802 Bank yd^3/hr

Hourly Capacity for One 17 yd^3 Shovel and No. Required:

$$Q = (Bc)\ (C)\ (\tfrac{1}{S})\ (A)\ (U)\ (Bf)\ (P)$$

$$Q = (17)\ (88)\ (\tfrac{1}{1})\ (0.95)\ (0.98)\ (0.50)\ (0.80) = 557 \text{ yd}^3/\text{hour}$$

$$\frac{10{,}802 \text{ bank yd}^3/\text{hr required}}{557 \text{ bank yd}^3/\text{hr for 17 yd}^3 \text{ shovel}} = 19.39 \text{ shovels required}$$

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TABLE 2-7 (cont'd)

ESTIMATED COST OF OPEN PIT SURFACE MINE

Hourly Capacity for One 24 yd^3 Shovel and No. Required:

$$Q = (24) \cdot (88) \left(\frac{1}{1}\right) (0.95) (0.98) (0.50) (0.80) = 787 \ yd^3/hour$$

$$\frac{10,802}{787} = 13.73 \text{ shovels required}$$

Hourly Capacity for One 32 yd^3 Shovel and No. Required:

$$Q = (32) (88) \left(\frac{1}{1}\right) (0.95) (0.98) (0.50) (0.80) = 1049 \ yd^3/hour$$

$$\frac{10.802}{1,049} = 10.20 \text{ shovels required}$$

Annual Operating Hours per Unit per Year:

(24 hrs/day) (0.80 eff) (363 days/yr) = 6970 hrs/yr

Number of Shovels Required

Shovel Size yd^3	Units Required	Units Purchased
17	20	22
24	14	16
32	11	13

Capital and Operating Costs

Shovel Size	# of Units	Capital Cost ($000)	Total Cap. Cost ($000)	Annual Operating Cost/Unit ($000)	Total Annual Op. Cost ($000)
17	20(22)	$1,800	$39,600	(83.44)(6970)= 582	$11,640
24	14(16)	2,600	41,600	(100.00)(6970)= 697	9,758
32	11(13)	3,500	45,500	(125.17)(6970)= 872	9,592

Capital and operating costs are from Marion Dresser, Marion. Power Shovel Division, Dresser Industries, Inc., (1981 Dollars).

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TABLE 2-7 (cont'd)

ESTIMATED COST OF OPEN PIT SURFACE MINE

Worst Case 17 yd^3 Shovel

Operating cost per ton of ore and waste

$$\frac{\$11,640,000}{(364,000 \text{ tons/day})\ (363 \text{ days/yr})} = \$0.0881/\text{ton}$$

Operating cost per ton of ore

$$\frac{\$11,640,000}{(70,000 \text{ tons/day})\ (363 \text{ days/yr})} = \$0.458/\text{ton}$$

Truck Selection:

Truck performance, capital and operating costs from WABCO, July, 1981.

Haulage trucks considered:

120 ton end dump
240 ton end dump

Truck Cycle Time (See Table 2-7A)

TABLE 2-7 (cont'd)

ESTIMATED COST OF OPEN PIT SURFACE MINE

Truck	Loaded (Min)	Empty (Min)	Total Travel Time (Min)
120 ton	13.74	16.35	30.09
250 ton	16.85	14.67	31.52

Truck Specifications

Model	BHP	Max. Cap. Tons	Truck Cap. Cu. Yd.	Head Cap. Cu. Yd.	Empty Wt. lbs.
120	1200	120	54	83	184,260
250	2475	250	100	163	365,000

Load Time $\frac{(\text{Truck box yd}^3)}{(\text{Shovel yd}^3)\ (\text{Shovel Swingtime})}$

Shovel	Truck 120 Ton	250 Ton
17	4.76	8.82
24	3.38	6.25
32	2.53	4.69

NUMBER OF PASSES

Shovel Capacity: (17 yd³) (0.5 Bf) = 8.5 yd³
(24 yd³) (0.5 Bf) = 12 yd³
(32 yd³) (0.5 Bf) = 16 yd³

Shovel	Truck 120 tons 54 yd³	250 tons 100 yd³
17	6.35	11.76
24	4.50	8.33
32	3.38	6.25

TABLE 2-7 (cont'd)

ESTIMATED COST OF OPEN PIT SURFACE MINE

SPOT AND DUMP TIME = 1.5 Min.

Total Cycle Time

= haul time + return time + load time + spot and dump time

Shovel	Truck 120 ton	Truck 250 ton
17	30.09 + 4.76 + 1.5 = 36.35	31.52 + 8.82 + 1.5 = 41.84
24	30.09 + 3.38 + 1.5 = 34.97	31.52 + 6.25 + 1.5 = 39.27
32	30.09 + 2.53 + 1.5 = 34.12	31.52 + 4.69 + 1.5 = 37.71

Number of Trucks Required

TIME TO SPOT = 0.75 Min.

Shovel	Truck 120 Ton	Truck 250 Ton
17	4.76 + 0.75 = 5.51	8.82 + 0.75 = 9.57
24	3.38 + 0.75 = 4.13	6.25 + 0.75 = 7.00
32	2.53 + 0.75 + 3.28	4.60 + 0.75 = 5.44

TRUCKS PER HOUR REQUIRED TO KEEP SHOVEL BUSY

Shovel	Truck 120 Ton	Truck 250 Ton
17	$\frac{60}{5.51}$ = 10.89	$\frac{60}{9.57}$ = 6.27
24	$\frac{60}{4.13}$ = 14.53	$\frac{60}{7.00}$ = 8.57
32	$\frac{60}{3.28}$ = 18.29	$\frac{60}{5.44}$ = 11.03

TABLE 2-7 (cont'd)

ESTIMATED COST OF OPEN PIT SURFACE MINE

TRUCKS REQUIRED AT 80% EFFICIENCY

Shovel	Truck 120 Ton	Truck 250 Ton
17	$\frac{10.89}{0.8 \text{ eff}} = 13.61$	$\frac{6.27}{0.8 \text{ eff}} = 7.84$
24	$\frac{14.53}{0.8 \text{ eff}} = 18.16$	$\frac{8.57}{0.8 \text{ eff}} = 10.71$
32	$\frac{18.29}{0.8 \text{ eff}} = 22.86$	$\frac{11.03}{0.8 \text{ eff}} = 13.79$

TRUCKS REQUIRED PER SHOVEL

Shovel	Truck 120 Ton	Truck 250 Ton
17	14	8
24	19	11
32	23	14

TOTAL TRUCKS REQUIRED

Shovel	Truck 120 Ton	Truck 250 Ton
17	280	160
24	266	154
32	253	154

CAPITAL AND OPERATING COSTS

WABCO Trucks
DDAD Engines - July, 1981

Model	List Price	Hourly Op. Cost Per Truck
120 ton	$ 760,000	$ 67.42
250 ton	1,720,000	108.48

550.

TABLE 2-7 (cont'd)

ESTIMATED COST OF OPEN PIT SURFACE MINE

List price includes tires:

120 ton = $ 42,620 (set of six)

250 ton = 103,830 (set of six)

Hourly cost includes 30% fringe benefits

Fuel, diesel @ 1.15/gal.
Maintenance and Lube
Tires
Operator Wage @ $11/hr

CAPITAL COSTS

Shovel	Trucks 120 ton ($000)	Trucks 250 ton ($000)
17	(280 trucks) (760) = $212,800	(160 trucks) (1,720) = $275,200
24	(266 trucks) (760) = $202,160	(154 trucks) (1,720) = $264,880
32	(253 trucks) (760) = $192,280	(154 trucks) (1,720) = $264,880

ANNUAL OPERATING COSTS

6870 hrs/yr.

Shovel	Truck 120 ton ($000)	Truck 250 ton ($000)
17	(280) (6970) (67.42) = 131,577	(160) (6970) (108.48) = 120,977
24	(266) (6970) (67.42) = 124,998	(154) (6970) (108.48) = 116,440
32	(253) (6970) (67.42) = 118,889	(154) (6970) (108.48) = 116,440

WORST CASE 17 yd^3 shovel and 120 ton trucks

Operating cost per ton of ore and waste

$$\frac{131,577,000}{(364,000 \text{ tons/day})\ (363 \text{ days/yr})} = \$0.966/\text{ton}$$

Operating cost per ton of ore

$$\frac{131,577,000}{(70,000 \text{ tons/day})\ (363 \text{ days/yr})} = \$5.178/\text{ton}$$

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TABLE 2-7 (cont'd)

ESTIMATED COST OF OPEN PIT SURFACE MINE

DRILLING AND BLASTING:

Bench Height: 40 ft.

Sub Drill: 4 ft. ($\frac{1}{3}$ x stemming)

Powder Factor: 0.25 lb/ton

Hole size: 6 inch

Stemming: $\frac{(24)\ (0.5')}{12} = 12$ ft.

Powder Column: 40' + 4' -12' = 32 ft.

Explosives per foot - 15.93 lb/ft.

Total explosive load per hole = 510 lb.

Hole pattern - 23' x 15' (DuPont method)
24' x 15' (Ash method)

Tons per hole: 23' x 15' pattern

$$(23')\ (15')\ (40')\ \frac{(130\ lb/ft^3)}{2000\ lb/ton} = 897\ tons/hole$$

Hole per day required:

$$\frac{364{,}000\ tpd}{897\ tons/hole} = 407\ holes\ per\ day$$

Holes per shift and per drill:

$$\frac{406\ holes/day}{3\ shifts/day} = 136\ holes/shift$$

(136 holes/shift) (44 ft/hole) = 5984 ft.
(190 ft/hr/drill) (6.5 hr/sh) = 1235 ft/shift/drill

$$\frac{5984\ ft}{1235\ ft/sh/drill} = 4.85\ drill$$

Use 5 drills. Purchase 7 drills.

TABLE 2-7 (cont'd)

ESTIMATED COST OF OPEN PIT SURFACE MINE

CAPITAL COST

(7 drills) ($285,000/drill) = $1,995,000.00

OPERATING COST

Based on the following, the cost per ft. is $0.65.

Labor:	
Driller	$12.00 hr.
Helper	$10.00 hr.
Fuel	9.5 gal/hr
Fuel Cost	$1.02/gal
Maintenance	$16.50/hr
Lube	$1.00/hr
Bit Life	6500 ft.
Bit Cost	$245.00
Pipe Cost	$0.03/ft
Sub Cost	$0.02/ft
Rig Life	5 years @ 1600 hr/yr.

Daily Cost:

(406 holes/day) (44 ft/hole) = 17,864 ft/day

(17,864 ft/day) ($0.65/ft) = $11,612/day

Annual Operating Cost:

(11,612/day) (363 day/yr) = $4,215,156

Operation Cost per ton of ore plus waste:

$$\frac{\$4,215,156}{(364,000 \text{ tons/day})\ (363 \text{ days/yr})} = 0.0319 \text{ per ton}$$

Operating Cost per ton of ore:

$$\frac{\$4,215,156}{(70,000 \text{ tons/day})\ (363 \text{ days/yr})} = 0.166/\text{ton}$$

TABLE 2-7 (cont'd)

ESTIMATED COST OF OPEN PIT SURFACE MINE

Powder:

CAP COST:

2 caps per hole @ $2.00 = $4.00/hole

Annual Operating Cost:

(406 holes/day) (363 day/yr) ($4/hole) - $589,512 = 0.0232/ton ore

POWDER COST:

ANFO (510 lb/hole) (406 holes) (363 day/yr) ($0.20/lb) = $15,032,556

Operating cost per ton of ore plus waste:

$$\frac{\$15,032,556}{(364,000 \text{ tons/day})\ (363 \text{ days/yr})} = 0.114/\text{ton}$$

Operation Cost per ton ore for ANFO:

$$\frac{\$15,032,556}{(70,000 \text{ tons/day})\ (363 \text{ days/yr})} = \$0.592 \text{ ton}$$

REFERENCE MATERIAL

1.) Terex (GM)

2) WABCO Handbook

3) Marion Ohio

4) DuPont Handbook

5) Open Pit Mine Planning & Design

6) Caterpillar Handbook

7) Surface Mine Handbook

Table 2-7A

Truck Cycle Time

	Haul Segment	Distance ft.	% Grade	% Roll. Resist.	% Total Resist.	Speed Limit mph.	Entrance Speed, mph.	Max Speed mph.	Exit Speed mph.	Speed Factor*	Average Speed, mph	Travel Time mins.	
A) 120C	1	500	0	4	4	30	0	18	18	0.51	9.18	0.62	
	2	5500	10	4	14	30	18	5	5	1.0	5.0	12.50	
	3	500	0	4	4	30	5	18	0	0.51	9.18	0.62	
												13.74	Total Haul
	Return												
	3	500	0	4	4	30	0	29.5	29.5	0.535	15.78	0.36	
	2	5500	-10	4	-6	30	29.5	4.0	4.0	1.0	4.0	15.63	
	1	500	0	4	4	30	4.0	29.5	0	0.535	15.78	0.36	
												16.35	Total Return
B) 3200B	1	500	0	4	4	30	0	21.5	21.5	0.435	9.35	0.61	
	2	5500	10	4	14	30	21.5	4.0	4.0	1.0	4.0	15.63	
	3	500	0	4	4	30	4.0	21.5	0	0.435	9.35	0.61	
												16.85	Total Haul
	Return												
	3	500	0	4	4	30	0	27.5	27.5	0.535	14.72	0.39	
	2	5500	-10	4	-6	30	27.5	4.5	4.5	1.0	4.5	13.89	
	1	500	0	4	4	30	4.5	27.5	0	0.535	14.72	0.39	
												14.67	Total Return

Ramp is based on: a) 550 ft lift at 10% b) Trucks dump the ore or waste on conveyor feeder outside the pit

*Speed factor is used to convert the maximum speed to average speed. It is a function of the haul road length, truck wt and Hp.

(Ref: Production and Cost Estimating of Material Movement with Earthmoving Equipment, TEREX)

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strip mining and open pit mining (terrace mining) as the only two alternatives.

2.3.1.5 Environmental Considerations

The major impacts associated with surface extractive mining for heavy oil are related to the disposal of solid wastes and to the disturbance of large surface areas.

Surface mining creates large volumes of solid waste in the form of topsoil, overburden and spent oil-bearing rock. In most cases, the overburden will be used to fill the mine when operations are terminated or as it continues, as in a strip mining operation, with the topsoil to be used to revegetate the area. Ideally, the spent oil-bearing rock is returned to the mine and used as the fill material. In the case of an open pit if this is not possible, either due to the chemical composition of the material (whether spent or raw) or to specific regulations, the rock would have to be disposed of at an appropriate disposal site.

Surface mining requires the disruption of large tracts of land, both for the actual construction of the mine and also for possible on-site storage of topsoil and overburden. This large-scale disturbance makes the impact of surface mining on the terrestrial ecology a major area of concern. In order to assess the impact of this mining method on the terrestrial ecology, a detailed survey must be undertaken. The survey must identify any rare and endangered species in the area and provide baseline data for assessing the potential impacts of mining. The extent of the survey will depend, in large measure, on the amount and quality of existing site-specific data. However, enough data must be collected to support licensing activities and for quantitative assessment of potential impacts.

Surface mining methods may greatly affect both the surface and groundwater hydrology near the site area. Local streams and watersheds are affected both by the development of the mine and the storage of topsoil and overburden. The predominant effects of surface water hydrology are changes in the local soil erosion, runoff, and sediment transport rates. These

changes affect the quality and quantity of flow in streams and rivers near a site and may also have an adverse impact on the indigenous aquatic population. Impacts on surface water quality can normally be avoided by careful planning in conjunction with sound engineering practices. A chemical analysis of the topsoil and overburden will indicate which constituents will be present in the runoff flow, and this information can be used in the design of treatment facilities capable of meeting federal, state, and local discharge criteria. Erosion and sediment transport can be minimized by using acceptable erosion control practices and with sedimentation ponds, if necessary, to meet discharge requirements.

The impact of surface mining on groundwater sources depends on the type of aquifer present and its location with respect to the mine. To assess potential impacts, the characteristics of the aquifer must be determined from a field monitoring program or from existing data. Groundwater which accumulates in the mine must be removed and, depending on the local surface water quality and specific regulations, either discharged to a surface water source or reinjected into the aquifer.

Noise and fugitive dust are the other major areas of environmental concern related to surface mining. The impacts associated with noise and dust are dependent on the types of equipment used, the location of the mine, and the number of access roads with respect to populated areas. Noise is controlled, to some extent, by the use of adequate mufflers on all trucks and construction equipment. Fugitive dust from access roads is minimized through periodic application of water or other wetting agents to the road surface.

The surface extractive mining method with the most severe environmental impact is an open pit mine. Environmental problems associated with an open pit mine include those areas that will be covered with the overburden and clean oil sand after processing. The ultimate use of such a site, once mined out, will be very critical regarding the feasibility of this type of operation. Many open pits, such as quarries, can be used as lakes once mining is complete. In the case of a heavy oil reservoir it is very likely that some oil residue will remain after mining has ceased, and therefore it

is unlikely that such a site could be used as a recreational lake.

The environmental impact of a strip mine may be the least of all the surface mining methods to be reviewed if properly designed, maintained, and reclaimed. Once the area has been reclaimed it can be restored to near original contours and natural vegetation.

2.3.2 Underground Mining

There are currently no large underground extractive mines in the United States. The largest capacity underground mine in the United States is a copper mine in Arizona with a hoisting capacity of slightly more than 100,000 tpd.

Because of the many unknowns associated with underground extractive mining of heavy oil (i.e., mine gases, both light and heavy, compressive strength of oil reservoir sands, explosibility and flammability of waste rock, and equipment maintenance related problems), this type of mining for this application would require a considerable amount of research and development. At this time, it is assumed that the most feasible method of underground extractive mining for heavy oil would involve some type of continuous mining equipment such as drum miners, roadheaders, and longwalls. However, for reservoir thickness that would make an underground mine economically attractive, the feasibility of this equipment is diminished because of its economic limitations. Because of this economic consideration, a review of a number of mining methods is provided below.

- Room and Pillar

Room and pillar mining is well suited for level or slightly dipping ore bodies. In order to use this method, the ore must have competent roof and floor characteristics. The dimensions of the rooms and pillars are determined by the load the pillars can take and the competence of the ore to support large roof spans. The actual oil content and porosity of the rock also determine the mine entry dimensions. This method of mining produces a checker board pattern. The principle of this system is that the

pillars left in place support the roof while the rooms are excavated. (See Figures 2-2 and 2-3.)

After mining has reached its boundary, three alternatives are possible.

1. Leave the area as is and avoid subsidence
2. Remove the pillars in sequence and have controlled subsidence
3. Use spent ore as a backfill to reduce subsidence when removing pillars

By removing the pillars, the overall recovery rate is 80% compared to much less with the pillars left in situ.

Geological conditions permitting, ore bodies over 100 feet thick may be bench mined. (See Figure 2-4.) The initial development is on one level, followed by the removal of a second lower level, increasing the roadway height two fold and doubling production, while exposure remains the same. In seams where thickness is in the hundreds of feet, multi-level mining with this system is possible. To date room and pillar is used in the production of salt, coal, oil, shale, potash, etc.

o <u>Longwall Mining</u>

Longwall mining (See Figures 2-5 and 2-6) has been in use in Europe and the U.S. for many years. Faceline lengths ranged from 300 to 500 feet in length. The coal was won by handstripping. This involved allocating a length of faceline to a miner which he had to strip using a pick and shovel, hence the term "stripper." The sequence of mining consisted of the night shift undercutting the coal, the dayshift drilling, blasting and loading out the coal, and the afternoon shift advancing the conveyor to complete the cycle. All roof supports were timber, and each stripper was responsible for roof supports in his area. A complete cycle took 24 hours.

Today, with high powered shearers and hydraulic self-advancing roof supports coupled to armored face conveyors, it is possible to carry out several mining cycles during one shift, with reduced manpower and more

safety. Facelines today average 600 feet long with the length controlled by local geological conditions. Longwalls can now operate on inclines of 45° by using additional equipment.

Seams being mined by this method vary in height from approximately 3 to 10 feet. Experiments are planned to carry out double lift techniques, which in principle are similar to bench mining. The first lift is taken, closely followed by a second.

In the case of longwall mining for oil, several factors must be considered:

1. The compressive strength of coal varies from 700 to 3,500 psi, whereas the strata to be mined during oil mining operations may be in the 12,000 to 15,000 psi range. It is doubtful if shearers could penetrate this type of strata.

2. The oily conditions would not be conducive to longwall operation or safety.

3. The ore abrasiveness would result in a very short lifetime of equipment such as conveyors, shearer drums, bits and bedframes.

The advantages and disadvantages of this mining technique are as follows:

Advantages	Disadvantages
1. Highly mechanized	1. High spark risk while mining
2. 75% recovery of reserve	2. High maintenance costs
3. More efficient ventilation	3. Slippery working conditions
4. Controlled subsidence	

o <u>Chamber and Pillar</u>

This is an extension of room and pillar mining. In this system (See Figure 2-7) by mining alternate chambers (which are larger than rooms) and then

back-filling spent ore, it is possible to reduce the size of pillars left in place and subsequently increasing the overall recovery rate. However, when extracting such large amounts of ore the most efficient method is conventional mining. Backfilling may be done by conveyor and/or pneumatics and it may also be possible to drill small diameter shafts (5-8 ft. diameter) in order to return the spent ore underground without interfering with the normal production system. This system may be used in multi-level mining operations.

The advantages and disadvantages of chamber and pillar mining operations are provided below:

Advantages	Disadvantages
1. Backfilling can commence at an early stage of production	1. Ventilation control
2. 60% recovery (increased if backfilling in operation)	2. Vehicle movement under slippery conditions
3. High production/low cost	3. Water control problems
4. Less movement of vehicles when compared to room & pillar	

o <u>Sub-Level Stoping</u>

This method is suitable for mining thick seams because of its high production/low cost ratio. It involves mining several horizons at one time. A typical layout would involve developing three horizons at predetermined levels (see Figure 2-8). From these horizons, access tunnels would be driven into a chamber area where long, small diameter holes would be ring-drilled to the boundary of the chambers to be blasted. The chamber is then blasted and loaded out in sequence. For example, the area between

levels 1 & 2 would be blasted and mined out first, followed by blasting and loading out between levels 2 & 3.

By having additional roadways between the chambers, ventilation is maintained and backfilling can be done if required to reduce subsidence. Should the compressive strength of the rock allow, mining of tunnels may be done by mechanical means rather than drill and blast, thereby increasing the safety margin, reducing the amount of explosives required and improving working conditions.

The advantages and disadvantages of this mining technique are:

Advantages	Disadvantages
1. High production/low cost	1. Ventilation control
2. Recovery 60%	2. Water control
3. Can be used in very steep seams	3. Emission of oil through drawchutes and drawpoints
4. The main level for mining can be developed in the strata below the oil reservoir, helping to reduce in-reservoir problems, for example gas, oily conditions, etc.	4. Porosity of ore

o <u>Block Caving</u>

This is not considered a practical method for use in oil mining due to lack of control of large areas when caving occurs. Also, water in the work area could be difficult if not impossible to control. Release of large volumes of gas is also possible. Subsidence on a large scale would also create surface problems and perhaps upset aquifers between the mine level and the surface.

In light of the constraints described above extractive mining will be limited to the following types of deposits:

Case 1. - Those with a minimum thickness of 7 ft and a maximum thickness of 20 ft

Case 2. - Those with a minimum thickness of 20 ft and a maximum thickness of 50 ft

Case 3. - Those thicker than 50 ft

o Case 1

For those deposits less than 20 ft thick, mining methods such as room and pillar, longwall, and shortwall are considered to be the primary mining options. In the case of room and pillar mining, the amount of extraction is determined by the size of the pillar(s) that must be left for overburden support. If it is determined that surface subsidence is acceptable, the pillars can be removed to some extent during retreat. However, if the surface must be protected, a pillar of adequate size to assure surface support must be left intact. A few of the major unknowns about pillar mining of an oil reservoir are the following:

1. The effect of porosity on the compressive strength of the pillars. With a good reservoir, the porosity can be in the range of 20 to 30 percent, which would indicate poor rock strength in compression.

2. The effect of oil seeping from the pillars, which may increase the potential for combustion. In the case of coal mines, limestone dust is used on all exposed surfaces. In oil mining, this type of dusting would not be effective, since the dust would become covered with the oil and would be ineffective in a very short time.

3. Because room and pillar mining operations generally utilize equipment and belt conveyors which have rubber components, it would be necessary to develop a synthetic material to replace these types of components. This is necessary since oil degrades rubber products quickly. In room and pillar mining the reservoir would probably be removed using continuous mining methods. Continuous mining methods include the use of continuous miners such as the Jeffrey 120 HR, roadheaders similar to the VOEST-ALPINE or the Dosco roadheader. In all likelihood, drill and blast techniques would not be used in underground extractive mining. If blasting is used it will be necessary to use permissible explosives and electric millisecond delays.

The second method of underground extractive mining (for ore bodies of 7 ft-20 ft thick) that should be considered is longwall mining. Longwall mining is currently used in coal mines, trona mines, salt mines, and iron ore mines at thicknesses up to 16 ft.

In the case of oil mining, longwall may be the only feasible method for this height of ore body, since it would give a higher recovery rate, allow for control of subsidence if backfilling is not used, reduce worker exposure to roof falls, and facilitate an overall effective ventilation. To utilize longwall oil mining techniques, it will be necessary to do some research and development on the types of cutters and face conveyor materials that will withstand the high abrasiveness of most oil sands. The experiences of the South African coal miners in longwall mining of deep gold deposits should be studied for applicability of face conveyors in oil mining.

Shortwall mining is a modified longwall/continuous mining method where the ore is removed from the face with a continuous miner while the roof is supported by hydraulic supports similar to those used on longwall faces. One of the more important problems encountered in shortwall mining of coal is that the material transported by shuttle cars from the continuous miner to the nearest material handling facility is very inefficient. There has

been some effort in the last few years to develop a continuous material handling system from the discharge of the continuous miner to the first material transport station. Trials are still in progress.

Another mining method that may have adaptability to oil mining is hydraulics. There has been very little hydraulic underground mining done in the United States. Coal has been mined hydraulically in Canada, and the U.S. Bureau of Mines has studied the feasibility of mining coal hydraulically in the United States. The only extensive hydraulic mining in the United States is at the gilsonite mines south of Vernal, Utah.

Hydraulic mining of an oil reservoir may have several advantages. Specifically:

1. It would not be necessary to have electrical or diesel equipment underground.

2. There would be no steel bits in use which can cause sparking and ignition.

3. The hydraulic mining process may be used for partial separation of the oil from the sand during the mining phase.

Some disadvantages of hydraulic mining of heavy oil reservoirs include:

1. The necessity to have a high pressure, high volume hydraulic system.

2. The potential lack of control of pillar size and configuration as compared with conventional methods.

3. The necessity to construct ditches or piping systems for removal of the oil/ore to the surface.

4. The oil sands, when in slurry, can be highly abrasive to pipes and pumps. This method is best in seams that have a sufficient pitch or dip that allows the material to flow to a central collecting point.

In the case of extractive mining, all methods, including those just discussed, would require an additional effort in anticipating problems resulting from safety in the form of mine gases, roof falls, pillar collapse, adequate ventilation, and associated hazards such as slipping and falling on oil impregnated floors, oil film residue on equipment, etc.

Equipment maintenance problems should also be anticipated with regard to rubber deterioration and in the necessity for developing an engine that will prevent ignition of gases that are far more volatile than methane. While current engine exhaust systems are designed with a heat factor that will not ignite methane, gases which may be encountered in oil mining operations may have a much lower flash point than methane. In fact, it may not be possible to use diesel powered equipment in underground heavy oil mining. All equipment may be restricted to electric equipment or pneumatic equipment. In the case of electrical equipment, all trailing cable covers, electric supply cable covers, and rubber grommets must be made from some synthetic material other than rubber. Other maintenance related to equipment will be the oil-laden residue dust that will be on the equipment.

Further information on safety as well as systems and equipment is included in Sections 2.3.2.2 and 2.3.2.3, respectively.

o <u>Case 2</u>

If room and pillar mining is used it is necessary to use bench operations. Specifically, there is an advance heading where the face is drilled and blasted with the use of horizontal holes followed by a bench of approximately the same height for vertical drilled holes similar to open pit mines.

If longwall mining is used, it is necessary to use a multiple slice method where, for example, five slices each 10 feet thick will be required for a 50-ft-thick reservoir. However, if the sand is very friable, it may be necessary to use the French longwall caving method (see Figure 2-9) where the ore above the initial pass is caved to a rear armored conveyor for removal.

o Case 3

Shortwall mining is unlikely to be feasible for ore bodies more than 20 ft thick because of the short face length and the necessity for multiple pillars to comply with current U.S. mining laws. Hydraulic mining of ore bodies 20 to 50 ft thick will probably be more attractive than for ore bodies less than 20 ft thick. All of the same advantages and disadvantages of hydraulic mining of thinner ore bodies apply to the thicker ones. Overall, when mining ore bodies of 20 to 50 ft thick, all of the problems that were previously discussed with thin extractive oil mining will apply to thick extractive oil mining.

With the thicker ore body, more problems can be expected in the ventilation system, pillar stability and material handling. In ore bodies more than 50 ft thick, special techniques must be developed to overcome the additional problems of pillar stability and ventilation. Room and pillar mining would not be as successful in these thicker ore bodies, mainly due to pillar stability. Longwall mining may still be possible using multiple slice methods: for example, ten slices for a 100-ft-thick ore body, or the French Soutrag caving method. The U.S. Bureau of Mines has developed studies of thick seam mining of coal that may have adaptability to thick seam mining of heavy oil reservoirs. Shortwall mining of thick reservoirs is not considered applicable.

Hydraulic mining may be very attractive if a method of benching can be established. In steeply pitching heavy oil reservoirs this method is also very attractive by leaving random pillars.

In addition to the methods just described for thicker seams, other feasible methods are the sublevel caving mining method with or without backfill, shrinkage stope methods with or without backfill, and cut and fill stoping methods. For these methods to be successful, it is necessary to backfill the processed reservoir sand to prevent major surface subsidence problems An advantage to each of these methods is that costs can be reduced by producing more tons per man shift.

2.3.2.1 Technical Considerations

The major constraints to the technical feasibility of underground extractive mining would be the amount of overburden, the degree of consolidation of the ore bearing reservoir, and the amount of water and gas present. Underground mining in the oil-bearing zone has some additional problems compared to surface mining because of the confined conditions (see Table 2-1). A summary identification of risk analysis associated with underground extractive mining operations is shown on Table 2-8.

Additional technical considerations are discussed as they apply to underground extractive mining.

o Geology

The geology of deposits for heavy oil mining have traditionally been evaluated for the petroleum characteristics. For example, very few of the reservoirs reviewed in Task I had any information concerning the characteristics of the rocks above the reservoir. Additional drilling will be required if mining techniques are used to determine what affect they will have on the mining method.

o Rock Characteristics

While petroleum engineers and geologists are concerned mainly with rock porosity, permeability, oil content and water content, mining engineers are concerned with compressive strengths and shear strengths as well as

TABLE 2-8

SUMMARY IDENTIFICATION OF RISK ANALYSIS
UNDERGROUND EXTRACTIVE MINING

Mining Function	Specific Hazard	Probability Location & Safety Hazard	Risk Severity Rating 1-Low Risk 10-High Risk
U.G. Facilities Warehouse Shops	Oil, gas	Entire area (fire, explosion asphyxiation)	5
Ore loading	Porosity	Stability (caving)	5
Mining Continuous Miner	Porosity	Stability (caving, heaving, spalling)	5
		Soft bottom (sinking)	4
	Oil and gas	As above plus rubber parts	5
Haulage Shuttle car	Oil and gas	As above	5
	Porosity	As above	10
Belts	Porosity	As above plus keeping aligned	10
	Oil and gas	As above plus rubber parts	10
Mining in general	Gas	High pressure blowouts	10

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porosity and permeability. These additional parameters must be considered, because stability problems can make a good heavy oil deposit unmineable.

o Topography

The topography of an oil deposit must be considered in deciding what mining method or modification of a mining method should be used, because of disposal problems associated with reservoir rock and the rock removed from the reservoir. Some of these problems are similar to disposal problems expected for the oil shale projects in western Colorado.

o Climate

Climate is not considered to be a significant factor in underground extractive mining operations. However, climate will affect the emission of gases from underground operations. For example, during periods of low pressure, gas emission from exposed rock is more likely than during periods of high pressure.

o Mining Environment

In any type of underground mining, the amount of gas emitted requires more ventilation than that required for miner comfort and particulate removal. Mining of an oil bearing rock will require much more ventilation because of the gas and oil fumes.

o Summary

A complete evaluation of any deposit is required to determine what modification to existing techniques are needed because of the geology, rock characteristics, topography and climate. Site-specific conditions such as faults, dips, anticlines, synclines, unconsolidated rock, topography, and climate are critical in their effect on a proposed method.

2.3.2.2 Equipment and Systems

Underground extractive mining of a heavy oil reservoir requires the same type of equipment as that used for underground mining of coal, uranium, limestone, oil shale, potash, and corresponding minerals. The major considerations in equipment use are the environment and/or atmosphere in a wet (water and/or oil) mine plus a greater chance of gaseous intrusion requiring extra ventilation. Table 2-9 identifies the equipment and systems used in underground extractive mining.

The major constraints to the technical feasibility of underground extractive mining is the amount of overburden, the quality of the oil reservoir below the overburden, the degree of consolidation of the oil bearing rocks, and the amounts of gas and water present. Access to an underground heavy oil reservoir can be by means of vertical shafts, slopes or drifts. Any unusual problems in the development and opening of a mine are unlikely; however, once entry is made into the oil reservoir, there are many hazards to be considered from an equipment standpoint.

As noted in Table 2-9, the major obstacles to adapting conventional mining practices to heavy oil are those associated with the presence of oil, oil residue, oil dust, and various light and heavy gases. The presence of oil will be a serious maintenance factor on all rubber accessories and products used on the mining equipment.

In addition, the presence of many gases will constitute a safety hazard. For example, heavy gases such as hydrogen sulfide are likely to be released from any groundwater or reservoir water encountered. The only known mining technique to overcome this problem is to contain all mine water in conduits. When water is encountered along the floor, all ditches can contain conduits to keep the hydrogen sulfide from being liberated as the water flows. In the case of water running from drill holes, cracks, or fissures in the roof or ribs, it will be necessary to install pipes and connect these to conduits along the floor. Gas detectors will have to be modified or developed for equipment and personnel to deal with lighter gases. If the gases encountered have a lower flash point than methane, the

TABLE 2-9

EQUIPMENT AND SYSTEMS
UNDERGROUND EXTRACTIVE MINING

Mining Function	Conventional Mining Practice & Criteria	Heavy Oil/Tar Sand Criteria & Constraints
Shaft Sinking	Collar shaft with a concrete section going down to competent bedrock	If unconsolidated surface material - tar sands - excavate a larger collar section and install liner plate or sheet piling which will serve as back-forming for collar section
	Sink using drill, blast muck method	Can use drill, blast, muck until come in contact with the reservoir i.e. must use a shaft sinker
	Shafts larger than 18' Eimco-630 mucker is best or Cactus grab	Shaft sinker cutter immersed in water seal for spark suppression in gassy environment
	Shafts can be rectangular, circular, elliptical, or square	Allow only permissible equipment underground and look at existing permissible equipment to determine how to adapt it to oil mining
	Most common practice is to sink circular shafts with concrete lining in hard rock situations and to sink conventionally or drill shafts in sedimentary deposits	Use circular shaft due to ground control problems
	If a considerable amount of water is encountered, it is necessary to use chemical and cement grout or freeze the ground	If a considerable amount of water is encountered, it is necessary to use chemical and cement grout or freeze the ground
		Additional ventilation required when in gassy environment
Ore Mining	Non-permissible equipment used in hardrock applications.	Only permissible equipment can be used in gassy mine

TABLE 2-9 (cont'd)

EQUIPMENT AND SYSTEMS
UNDERGROUND EXTRACTIVE MINING

Mining Function	Conventional Mining Practice & Criteria	Heavy Oil/Tar Sand Criteria & Constraints
	Square, elliptical, rectangular and round tunnels are driven	Drive circular tunnels due to ground control problems. Additional support may be required due to poor ground conditions
Ore Mining	Corrosion negligible due to H_2S	In high H_2S levels all water must be in pipes. Corrosion could be high due to wet mine with H_2S and HC gases
	Non-slick and non-oily environment. Material transport is usually accomplished by trucks, shuttle cars and belt conveyors. In gassy conditions, primary haulage with shuttlecars; secondary haulage with rail and belt conveyors	Because it is slick and oily must use high extractive rubber-tired type equipment or rail haulage: if using rubber tired equipment must replace tires often. Additional preventative maintenance required
	Conventional mining done by drilling and blasting. Blasting is done with ANFO, water gel, slurry or dynamite if non-gassy; if gassy, permissible explosives. Reciprocal and radial cutter heads used on borers. Alternate is continuous mining road-headers, longwall, or shortwall	Requires careful drilling and blasting. Only radial cutter heads can be used due to the soft rock. Modify longwalls for oil mining. Standard continuous miner with cutter head modified for oil mining
	Rock dusting to control dust problem	Careful use of rock dust in oil mining
	Dust control is usually with water or steam	Dust control more difficult because of possible oil mist atmosphere
	Current firefighting agents - water, chemicals, foam-generating machines and rock dust are to be in working section	Increase firefighting equipment in each working section excluding water

TABLE 2-9 (cont'd)

EQUIPMENT AND SYSTEMS
UNDERGROUND EXTRACTIVE MINING

Mining Function	Conventional Mining Practice & Criteria	Heavy Oil/Tar Sand Criteria & Constraints
	AC and DC used underground	AC or battery powered equipment to suppress sparking and arcing during operations

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exhaust systems of all diesel equipment will have to be cooled to prevent flash back from intake systems, etc. With electrical equipment, MSHA regulations may have to be reviewed in order to determine if spark gaps for electrical equipment will be sufficient to prevent ignition of lighter fraction gases.

It will also be necessary to have the actual mining equipment specially designed for the environment encountered. For example, the type of face equipment to be used would be a continuous type miner or longwall system. Drifts and rooms would be developed with continuous mining type equipment. Explosives probably would not be used for mining heavy oil reservoirs. If continuous miners were used, typical haulage systems would be similar to that used in coal operations i.e., shuttle cars; however, the oil content of the ore would cause serious maintenance problems with all rubber components, including hydraulic hoses and trailing cables. To overcome this problem, a feasible solution may be the use of bridge conveyors behind the continuous miners. Bridge conveyors can operate on tracks similar to continuous miners. Synthetic materials can be used for hydraulic hoses, electrical grommets, electrical wiring, etc., to satisfy permissibility requirements. Belt conveyors can also be made of a synthetic material that is not affected by the oil.

Another type of underground haulage that may have applicability is rail haulage. In very thick heavy oil sands, a rail haulage system can be designed to handle up to several thousand tons per hour.

o <u>Production Capabilities</u>

In almost all cases, the production capabilities of the equipment to be modified for heavy oil mining should be approximately the same as when the equipment is used in a conventional mining mode. The one area that may affect production capability is increased time required for routine maintenance on a permissible piece of equipment. In most cases it would be necessary to have specialized equipment for adverse conditions to maintain

production. This type of equipment is not available at this time, and in most cases it would probably have to be developed for site-specific conditions.

The production capability of room and pillar mining is best in deposits of 7 to 20 ft in thickness. When the deposit is thicker than 20 ft, it will be necessary to use a modified bench-type mining similar to that proposed for the oil shale mines in western Colorado. The productivity of these bench type mines will be restricted due to equipment size limitation. Maximum size of permissible equipment is the major constraint to productivity.

Longwall operations have produced in excess of 10,000 tons of coal per shift in the United States. With proper design, longwall operations can be and should be highly productive in the mining of heavy oil sands.

High production is possible with sublevel caving at minimal cost. However, to obtain maximum production, a great deal of pre-mine planning and pre-development will be required.

Production costs for a heavy oil mining project underground will be higher than for conventional mining of coal and associated minerals, mainly because of the lack of experience in equipment selection. Costs will be higher also because of the permissibility requirements.

Production costs are increased also with less efficient equipment, because more equipment is required to produce the same amount of tonnage. Concurrently, more manpower will be required to operate more but less efficient equipment.

o <u>Reliability</u>

Equipment used for heavy oil mining will be less reliable than in a conventional mining operation. Reliability will be affected by more sophisticated monitoring devices required to maintain the permissible

rating. With most pieces of equipment as it becomes more sophisticated, the reliability, or sometimes referred to as the availability, of the equipment is lessened.

The room and pillar method is very reliable. It offers the flexibility of being able to move from one location in a mine to another. Also, the equipment used in thinner seams has been proven in coal, potash, trona, etc., and has an excellent record.

One of the disadvantages of a longwall system is that if any one component shuts down the entire longwall section may have to shut down. Therefore it is advisable to have a minimum of one spare longwall production section on standby at all times to maintain a constant flow of production.

A sublevel operation reliability of production is quite high. Overall efficiency of a sublevel operation should provide production rates in excess of 90% when operated 365 days per year.

Considerations of equipment and systems specific to heavy oil underground extractive mining technology are addressed below. These considerations also apply to mining for access.

o <u>Shafts</u>

With extractive mining, larger shaft diameters are more important than when mining for access because all ore is removed to the surface. In mining for access, only the ore mined during the development stage is brought to the surface. In either case, the shaft diameter should still be able to accommodate air volume requirements; therefore, it should be possible to blind drill shafts 10-12 ft in diameter, penetrate the oil reservoir, and control any high pressure gas or water which may be encountered.

It should be noted that shaft development engineers can sink a shaft by first drilling test holes to check in advance for any unforeseen problems. The use of full face vertical boring rigs may be used in problem areas when water and gas are expected only if the strata is pregrouted or frozen.

At present V-mole shaft borers can be used only in situations where pilot holes are already in operation, and access is available to the pilot hole base for muck removal purposes. With current technology, it is possible to drill shafts in excess of 20 feet in diameter. For example, a 24-foot diameter shaft was sunk in Alabama for a coal mine 1,132 feet deep using a Wirth V-mole borer which is capable of giving a 25-foot length of bored and lined shaft per day. This machine has a total of 72 disc cutters varying from 8 inch to 13 inch diameter. All equipment is permissible, and total horsepower is 980.

Ventilation is of major concern in this type of operation. There are two options available for ventilation--forced air or exhaust. In most instances the exhaust system is preferred because of better dust control. In this case, air is drawn down the shaft, between the machine and the shaft walls down to the cutting face, drawn up the middle of the machine, and by means of vent tubes is returned to the surface. Any gas and dust is therefore removed as soon as it is produced. The exhaust ventilation system of can be complimented by a forced air fan operated from the surface, if necessary.

Machine operation is controlled manually via hydraulics. Alignment is accomplished by two laser beams set up on the surface and pinpointed on exact targets on the machine proper. These targets are photo diode amp arrays and on-board calculations maintain the machine on line. Machine deviation has been kept to within 0.25 inches. The machine cycle is as follows: 20 feet is developed in advance (which is the maximum stroke achieved) at which time all service lines are extended. All pipes are 20-foot lengths, and flexiduct is used to keep the ventilation system intact. The shaft lining, consisting of concrete, is placed in two 10-foot operations. All muck is removed via a small diameter pilot hole which connects to a previously developed mine drift.

Companies involved in the manufacture of this type of equipment are designing full face borers to work in blind holes, getting rid of the ore by slurry systems to the surface.

Since 1971, about 3.800 KM of open or blind shafts have been sunk in Europe using the open or blind shaft systems. A further 2.5 KM of shaft development ranging in diameter from 7M to 8.5M is under construction. At present a blind borer is being tested using a hydraulic mucking system. Since most shafts operate under wet conditions, this would appear to be a logical mucking arrangement. The volumetric water to solid ratio is 7:1. In the initial tasks carried out from January to July 1978, 56.66M of shaft was bored in 70 boring days with hydraulic mucking. The maximum daily boring rate was 3M and the highest monthly advance was 20.85M of completed and lined shaft. As a rule, boring was done on two shifts, the third being reserved for maintenance and repair work. The boring rates remained behind expected levels. It should be noted, however, that this was a totally new experiment in mucking and this was only a trial.

o Skip Winding

The advantages of skip winding over cage winding for equal outputs are as follows:

1. Initial costs are lower because of small cross-section and less extensive and elaborate shaft head facilities. There is also a slight advantage since the gross load is less for a given useful load and requires a lighter headgear, pulleys and rope. A smaller and cheaper winding engine is required for the same useful load.

2. The mine cars only circulate underground, so about 30 percent fewer cars are needed, and large cars can be used without expensive and extensive alterations to surface and winding equipment.

3. The skip winding plant is essentially automatic in operation, reducing the manpower required in onsetting and banking. The manpower required is about a quarter of that necessary for long gantries with gravity running and half that required with modern short circuits employing traversers, shunt backs, etc.

4. Power consumption is lower per ton raised.

5. Decking time is reduced, leading to increased output or reduced acceleration with lower peak loads.

6. The possibility is increased for concentrated winding at one of a number of shafts or delivering coal or oil ore by conveyors right from the face to the skip bunker in the pit bottom.

7. There are no accidents from displaced cars. It should be noted that it is more economical to use a skip having the weight of only 60 to 100 percent of the useful loads than cages and cars which may amount together to nearly twice the useful load and cannot easily be reduced even by the use of light alloys for the cage. This consideration becomes more important as the winding depth increases, and skips of light alloy have in some cases been used to reduce the size of rope required to give a reasonable factor of safety with the largest possible useful loads. Skips have the further advantage that they can be discharged automatically in less time than is required to change cars on cages, thus making possible more winds per hour and increasing the capacity of the shaft.

The disadvantages of skip winding are as follows:

1. There is increased breaking of ore, particularly if the ore is friable. The breakage of ore, and the economics of skip winding, depends on the friability of the ore and the manner of loading and unloading the skip, the requirements of the market for different sizes of ore, and the relative prices of these sizes. At Mansfield Colliery, England, skip winding of the fairly friable High Hazels seam resulted in a decrease of 3 percent in the over 8-inch size and of 4 1/2 percent in the 8-4 inch size, with a corresponding increase in the less-than-1-inch sizes.

2. More ore dust is produced, requiring the use of the upcast shaft for skip winding or the installation of a dust extraction plant plus the high capital cost of re-equipping the existing cage winding equipment. In the case of a new colliery, this is not a disadvantage.

3. Special arrangements must be made for personnel riding. This generally means the provision of one or more man-riding decks, which increases the weight of the skip. It is preferable to raise and lower the men at another shaft equipped with cages and to have loose temporary decks to fit the skip for winding men in an emergency to comply with the legal requirement of two means of degress from the mine.

4. There is a difficulty in winding out or importing dirt for pneumatic stowing. Again, this could best be dealt with by winding a separate shaft.

5. With a mixing of seams and the difficulty of keeping them separate unless large storage space is provided, cars are required in the pit bottom, which means extra vehicles are needed. The conveyor on the surface may then be marked with chalk where one quality ends and the next begins and may be diverted to the requisite picking belt or cleaning plant.

o <u>Tunneling</u>

In mining today, more use is being made of mechanical methods of tunneling as opposed to conventional drilling and blasting. Two methods are:

1. <u>Conventional</u> - drilling and blasting
2. <u>Mechanization</u> - full face borers and roadheaders

- Conventional

Drilling and blasting consists of several steps rather than one continuous mining method:

1. drill and blast
2. muck out
3. secure roof

Drill and blasting equipment is very flexible and can be maneuvered around tight corners or make 90 turns in tunnels without any great difficulty. This equipment can be used on inclines up to 1-4 by using track mounted equipment.

While drilling and blasting has been in use for years, it does have disadvantages. In certain conditions, it is difficult to control the overbreak when blasting. The use of explosives at any time creates an additional safety hazard. Pneumatic drills are usually noisy, and lubricant fumes fill the air. Also, water is usually a problem with drilling.

- Mechanization

Roadheaders:

This type of machine came into use in British coal mines in the early 1960's, mainly as a development machine for entries to longwall face lines. It was a single boom machine electro/hydraulically operated. The machine weighed 17 tons, and had a track floor pressure of only 17 psi, which was very helpful when operating in soft floor conditions.

This machine can cut any profile whether it is square, rectangular, semi-circular, or circular. It operates on a continuous cycle, cutting and loading out at the same time. The system requires a crew of three: an operator, assistant, and loader/operator. This type of machine lends itself well to belt conveying, which eliminates any kind of exhaust gases

or fumes from diesel equipment if used. The noise level is relatively low, and the overall horsepower of the machine is also low. This machine will operate up to a maximum grade of 1 in 4. On steep inclines it can be fitted with side stells or mounted on a special skid arrangement to operate on grades up to 1 in 1 (45).

Roadheaders usually become uneconomical at rock strengths of 16,000 psi and over. In certain instances, harder rock has been mined, but only when laminations occur in the strata making it easier to remove the rock rather than to actually cut it out. Another feature is that it can give a smooth profile, control of overbreak is better, and in bad ground, roof control is better. Since the 1960's, larger, heavier and more productive machines have been developed along with great improvement in the design and quality of cutting bits used on the machines. Greater attention has been given to cutting heads, and in certain cases, head designs have been drawn up to suit individual installations.

Ventilation for a roadheader is normally of the exhaust type. The flexible vent tube is hung from the roof and the leading tube entry is retained as near the working face as is practically possible. By doing this, less dust is allowed to circulate back into the operator's area and helps avoid gas accumulation. This system allows fresh air to enter the tunnel or heading behind the operator and confines the dust to the immediate face area. Depending upon the air quality in the mine in general, the operator should always be working in "fresh air." The dust laden return can be ventilated to atmosphere in an unused return roadway. When the air has to pass along another section where men are working, dust trays may be used in conjunction with the ventilation fan.

The machines weigh 80 tons or more and are equipped with two cutting heads and heavy loading systems. Production rates of 1,000 to 2,000 tpd have been achieved in a coal mine in South Africa. Obviously, output will depend on several factors such as rock compressive strength, roadway size, load out arrangements, general conditions, etc. Another feature of this type of machine is that it can be easily dismantled into small sub-assemblies for lowering underground where entries limit the unit size.

Full-Face Borers:

This type of mining machine has limited use. While it can cut rock or much higher compressive strength and advance much faster than a road header, it must have uniform and continuous seam characteristics. For example, if the machine should encounter soft ground, it will tend to sink and will be harder to control or steer, etc. Therefore, this type of machine is suitable for long, straight drives.. It is virtually impossible to maneuver it around turns as would be required in oil mines. It has greater horsepower than the roadheader. A machine of this size requires a larger area underground in order to assemble the machine, i.e., larger than normal drift size. Assembly time is greater than that of roadheaders or drilling equipment. Another disadvantage is that the machine must be completely dismantled before being moved to another site.

Over the past ten years over 40 km of underground tunnels have been bored by tunnelling machines in the German coal industry, and a further 140 km is projected by 1990.

Table 2-10 shows a comparison of three methods of excavating tunnels.

2.3.2.3 Safety Considerations

Underground extractive mining, whether in the mining of a heavy oil deposit or in extraction of minerals and coal, introduces more hazards, and therefore safety considerations, than does a surface mine. The safety requirements for mining of heavy oil deposits will require a safety program and associated codes and regulations that are more stringent than the mining industry is accustomed to.

The following are the various areas of concern with respect to heavy oil mining by underground extractive methods, such as room and pillar, longwall, etc.

Of the mining methods discussed, it is apparent that from a safety standpoint, underground extractive mining is the least attractive method

COMPARISON OF THREE METHODS OF EXCAVATION FOR 3-4 M. DIAMETER TUNNELS

Item		Drill & Blast	Roadheader	Full Face Machine
Costs 1978 Great Britain	Initial Cost	Low	Low	High
	Running Cost	High	Low	Medium
Typical Progress m/100 Working Hr. Wk. (Great Britain)	Favourable Ground	50	70	130
	Badly Faulted Ground	30	35	Highly Variable 0 – 35 ( )
Installation	Equipment Delivery Time	1 month	2 month	12 months
	Installation Time	2 weeks	2 weeks	6 weeks
	Space Required	No Restrictions	Most can be installed within tunnel diameter	Requires erection chamber 1.5 – 3 times greater than tunnel diameter
	Operating Radius	No Restrictions	90°	About 10 – 20°
	Gradient	Any	14°	Generally 10°
	Tunnel Shape	Any	Most	Circular
Application		Most Rock Types	Dependent upon rock hardness and abrasivity	Most Rock Types
Mining Application		Normal Method of Excavation	Selectively can excavate mineral bands. Adequately flexible for complex mining roadways	Limited to driving long access roadways
Ground Disturbance		High	Low	Low
Overbreak		High	Low	Low
General Access for tunnelling operations and maintenance		Good	Good	Fair to Very Poor
Support	Quantity	Can be High	Minimum	Minimum
	Position Installed	Face	Face	3 – 12 metres behind face
	Type	Any	Any	Most machines restrict use of shotcrete, some prevent installation of arches
Faulted Ground		No Major Restrictions	No Major Restrictions	Some machines have severe restrictions to mucking and support
Ground Treatment and Advance Probing		No Major Restrictions	No Major Restrictions	Severe Restrictions
Geometry		Generally Unlimited	Continually Variable within Limits	Circular profile unchangeable once fixed

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TABLE 2-10

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for heavy oil. Mining takes place within the ore body and creates many problems (confined conditions, for instance). Ore in the 20-30% porosity range contains a lot of oil, which will make the floor slippery and reduce traction for mine transportation, mining equipment, and the miners. The oil can also create a difficult working environment from the release of potentially toxic vapors. The porosity of the rock will also contribute to insecure roof support from less compressive strength of the rock under load. Underground fires are also more of a hazard because of oil and gases in the mining areas.

Water and gas would be removed during normal oil production, but it is still quite possible that localized pockets of high pressure water and gas may be encountered. This ever present possibility must be considered at all times during extractive mining operations. Ventilation, of utmost importance in any underground operation, must be very well monitored at all times.

Fire fighting protection is also important. Under normal conditions it is possible to have a piped water system throughout a mine for handling any fire problem; however, oil fires cannot be fought with water, and therefore a system incorporating chemical agents must be used. This in itself is a problem in that the chemical agent will be handled when in closed conditions.

All electrical systems must be inspected before use in a mine due to the effects of oil on the protective rubber coating. Many heat sources will have to be adequately protected, ventilated and/or cooled to prevent gas or oil ignitions. Something as simple as an overheating brake drum on a vehicle could turn into a disasterous mine fire and/or explosion. As noted earlier, if mechanical mining machines are used, attention will be given to such details as the quality and grade of steel used in the cutting tools in order to reduce the risk of spark or generation of ignition temperature.

Table 2-8 is a summary identification of risk analysis for underground extractive mining and also refers to specific hazards. The following paragraphs highlight the specific hazards.

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o Mine Gases

This section reviews the fire/explosion and toxicity hazards associated with methane and other (heavier) hydrocarbon gases encountered in heavy oil mining. Bacterial decomposition of organic matter is the source of methane in coal mines, but in mining of heavy oils, methane and other volatile hydrocarbon gases are released to the air directly due to the gas vapor pressure in the heavy oil deposit.

The vapor pressure of the hydrogen gases is related to volatility, which decreases as the molecular weight of the gas increases. The molecular weight of hydrocarbon gases are generally related to the number of carbon atoms linked together. Figure 2-10 indicates the relationship between the number of carbon atoms in each molecule of gas and the gas characteristics, such as volatility, odor, and state. Hydrocarbons with C1 through C4 are gases at standard temperature and pressure conditions, while C5 through C8 are liquids and C18 and above are solids; volatility decreases as the chain length increases. All hydrocarbon gases with the exception of methane (CH_4), which is odorless, have characteristic odors; however it is difficult to distinguish one from another.

o Threshold Odor Value (TOV)

The threshold odor value (TOV) is the minimum concentration at which a substance can be detected with the sense of smell. The TOV values are shown in Figure 2-11.

Each hydrocarbon has a TOV generally expressed in parts per million (ppm). For example, the TOV of ethane and propane are 20,000 ppm and 10,000 ppm, respectively. Heavier hydrocarbons tend to have lower TOVs.

o Threshold Limit Values (TLV)

The threshold limit value (TLV) is a concentration selected by industrial and health agencies as a permissible level for prolonged exposure, as seen

in Figure 2-11. Comparison of the TOV and TLV indicates that except for methane, which is odorless, the TLVs are lower than the TOVs.

The light hydrocarbons (methane, ethane, propane, and butane) are asphyxiants, and the heavy hydrocarbons are toxic and can cause headaches and nausea, and prolonged exposure will cause narcosis, convulsions and death. Figure 2-11 also shows adverse physiological reactions at various concentrations and exposure times. MSHA regulations require removal of men from work areas when the concentration of methane reaches 1%.

For safety, the detection of these gases with gas meters is imperative. Methane is lighter than air and tends to collect near the roof of the mine roadway, and all other hydrocarbons are heavier than air and tend to collect near the floor of the roadway. Therefore, these areas are the most important for proper detection of dangerous levels of gas. H_2S is also heavier than air and will accumulate near the floor levels.

o Upper and Lower Explosion Limits

A given hydrocarbon or mixture of hydrocarbons will produce an explosion only if the fuel (hydrocarbon gases) to air ratio is within certain limits. If the amount of fuel present is above or below these limits, an explosion will not take place, but the gases may still burn. Figure 2-12 shows the upper and lower explosion limits for hydrocarbon gases from C1 through C10. As an example, if methane is present in concentrations between 5% to 15%, it will explode if brought in contact with a heat source such as a spark, arc, or flame.

o Ventilation

In order to reduce the possibility of gas collecting in the mine and causing fires and explosions, the mine must be well ventilated. There are two methods of ventilation, forced and extractive. Forced air ventilation is far more effective in moving air than is the extractive system; however, it tends to create more dust, which can in itself be potentially hazardous.

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According to CFR-30, Section 56.21-1, a mine is deemed gassy, and therefore operated as gassy, if:

a.) The state in which the mine is located classifies the mine as gassy, or

b.) Flammable gases emanating from the ore body or the strata surrounding has been ignited in the mine; or

c.) A concentration of 0.25% or more by analyses, of flammable gas emanating only from the ore body or the strata surrounding 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 an existing gassy mine.

These regulations refer to gassy underground metal and non-metal mines. Metal and non-metal mines that have operated or that are currently operating under this classification include potash mines in southeast Utah, trona mines in Wyoming, salt mines in Louisiana, and limestone mines in Missouri. The major operating differences between non-gassy and gassy underground mines is in the ventilation, equipment and explosive used. There are certain potash mines in the Carlsbad area of New Mexico that are now obtaining a special gassy classification.

The importance of methane and other gases in heavy oil mines is significant from the standpoint that it is not possible at this time to purchase permissible diesel engines of sufficient size to provide optimum equipment sizing in those deposits more than 20 ft thick. For an engine to be certified for operation in a gassy atmosphere, it must pass several tests performed by the Technical Support Group of MSHA at its testing facilities located near Tridelphia, Pennsylvania. This facility is now capable of testing engines up to 400 H.P. During recent discussions at Tridelphia, MSHA indicated that they plan to modify the facility for testing engines up to 600 H.P. However, proposed modifications will not take place for another 4 to 5 years. From this standpoint, safety in underground oil

mining will likely be restricted to the use of electrical equipment. In addition to the dangers with methane and hydrogen sulfide, it will be necessary to conduct some research to determine what other types of gases can occur in an oil reservoir that will require additional ventilation or safety equipment to provide a safe working environment for the employees.

The following are concerns specific to mining methods for underground extractive mining:

For room and pillar and chamber and pillar, ventilation is critical and must be addressed carefully by use of curtains and lattice to avoid cross circuits between rooms and chambers. The porosity of the rocks are of concern for the pillars to withstand the pressures of the overburden, and in multi-land mining, the upper levels. Cores do not always identify faults and vertical fissures that may exist, and these create a safety hazard in pillar support along with the oil porosity of the ore. Safety factors related to sublevel caving would be the emission of oil through drawchutes and drawpoints, the presence of gases as in all underground mining, and the danger of in-ore body development due to low rock strength.

Longwall mining offers the greatest margin of safety of any underground mining method. It requires a minimum of development time exposure for employees and provides a maximum amount of exposure time while under the protection of steel longwall supports. In longwall mining, gases can be handled much more efficiently than in any other underground mining operation methods. If multi-level longwall is used, although one of the safest mining methods, the armored conveyor at the rear of the supports adds a hazard not found in conventional longwall mining. The caving aspect of this typical mining creates hangups that may cause large surges of ore and a potential danger to personnel and equipment.

A method of alleviating potential safety problems is to use a mine monitoring and control system (MC). MC systems have been in use in Europe for over 10 years. These systems help increase productivity and safety, and they lower costs. The initial monitoring was done on methane, carbone

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monoxide, and general air conditions (velocity, pressure, humidity, dust, etc.). Today the system has been developed to cover a much wider field. MC systems can monitor such things as conveyors, pumps, fans, compressors, winding gear, etc. Electricity can be used more efficiently. For example: One mine had peak loading rates applied for electricity charges and had the main turbine pumps starting simultaneously, thus increasing the peak load. By adjusting the startup times, the peak load was drastically reduced as were their electricity bills. This point was brought to light via an MC system. The build-up can be detected at an early stage and remedial action taken, thereby creating a safer mine environment.

A mine-wide MC system using a control center equipped with control console and screen can call up any area of the mine for an instant check. A printed daily report on conditions, activities and production can be made for each section of the mine.

A typical MC layout would be one main unit in the mine office plus several out-stations located underground in the vicinity of the working areas. This system would operate on low voltage (8V D.C.). All units are intrinsically safe. Each station unit is equipped with a visible display panel with a manual control backup for the remote control center.

Each out-station would be capable of handling 29 digital and analog inputs. Analog inputs would continuously measure a variable quantity, such as methane, water level, or conveyor flow. Digital monitors cover switches or contacts. Each out-station is linked to the main control unit via cable. The range of the MC system may be 10 miles.

The use of computers with an MC system adds more benefit to the system and will continuously record, provide reports at regular intervals, and store information on magnetic tapes. As the amount of monitoring work required for underground operations steadily increases, so does the use of process computers. Computer-backed operations management is always that much easier to apply where MS systems have been previously used. This has been demonstrated in the successful application of process computers to ventilation, haulages, conveyors, winding equipment, and supply systems.

Cost benefits are significant when discussed in terms of safety, whereas in relation to production and downtime, estimates can be made. For example, should a main conveyor stop for some reason, lost time in contacting a mechanic or an electrician and time spent fault finding can be greatly reduced by an MC system. Such things as voltage, motor/gearbox temperature, belt overload, belt misalignment, etc., can be monitored. This information can be passed on to the breakdown crew for use in determining the fault. Manpower can also be reduced by using such a system. MC can also warn of an impending breakdown, so that remedial action can be taken to avoid major breakdowns, costly repairs and lost production.

Such a system is made by Transmittion of England for use by the National Coal Board. U.S. approvals are pending. Most U.S. mine out-station sites would be located in intake or fresh airways where MSHA permits are not required. A typical MC system in the U.S. would cost perhaps $20,000 to $30,000 per section. Depending on the required degree of sophistication, 30% more can be added to the cost. One point of interest is: should MSHA allow elimination of an air entry for longwall development due to increased monitoring for fire hazard using CO sensors in belt entries, the estimated saving could be in the area of $700,000 per section.

The system could monitor the following:

Monitoring and Control Motors General
- Digging and drilling equipment - output
- Pumps - delivery rate for power input
- Temperatures - bearings and windings

Fans - Ventilation
- Differential pressure
- HP input
- Vibration
- Bearing

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barometric pressure at key mine points
air flow direction
air temperature
air flow
humidity
mine gas content
ventilation door positions

Sumps and pump systems - water
pump levels
start pumps
stop pumps
monitor motor and bearing temps
control water valves
control start stop sequence for different pump

Monitor and control sub-surface equipment.

Monitor hoists

Automatically controlled hoists and haulage equipment.

Automatic or remote control of sealed areas of mine; allow gas levels to go above explosive levels and operate without manual intervention or ventilation.

In the event of high gas concentration and full remote, gas could be pumped out at usable pressure for commercial sale.

System must operate when all other systems and power are off.

Provide operator facilities to amend, adjust or override program when circumstances dictate.

Provide operator facilities to reprogram PLC's in mine from the surface.

Multiplex system must have speed to give adequate response even under emergency conditions of a maximum number of stations reporting and still have the capacity to control signals to start

Production

- Collect data
- Store data
- Display or print data

Automatic mine monitoring of key safety and mine factors such as mine environment, machine performance, crew performance, and ore source and movement results in a fully integrated, highly productive, safe mining system.

For flexibility, this system displays all data through intelligent CRT's in the mine control room. The rest of the system comprises multiplex cables connecting each of the system's remote interfaces. Each remote or intelligent remote is able to control and monitor its own area under program control with minimum communication with the main control panel. As a result, the operator is able to concentrate on the "exceptions" without having to sort them from the general data.

If the control room processor is out of service, the remote processor can store/record events of interest together with the time of occurrence. The stored information is automatically sent to the control room processor when it is again placed in service.

The monitoring system can monitor its own peripheral equipment, thus improving safety and reliability. This is required for failure analysis from the control room processor.

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Complete mine monitoring will result in increased productivity and safety. Monitoring and control of the following are possible using current technology:

Fans and Air Damper Controls

Motor temperature and current
Motor trip
Motor running
Alarms (rough bearing, vibration, bearing over temperature)
Start or stop fans from air flow
Damper control for air flow diversion where needed

* Belt air can be used at working face with proper monitoring on a five entry system, if air velocity is 50 ft. per minute or greater. This deviation would have to be approved by MSHA. This system is now in use in two mines in the U.S.A.

Conveyors

In conjunction with scales, tonnage output by each shift and/or long haul operation can be monitored.

Drive problem isolation.

Remote start and stop from control room.
Alarm for plugged chutes, belt misalignment, belt slip, motor trip, conveyor tension, etc.

Conveyors can be adjusted in terms of torque/time match and power/time to ensure smooth and positive start-up and conveyor take-up and tensioning.

Longwall Operation

Monitor drive motors

Percentage coal extraction

Machine problem isolation.

Face misalignment can be measured and corrected without local manual intervention.

Tramming time versus mining time can be correlated with coal delivery.

Bits can be changed after recorded mining time.

Data such as volts, amps, power, oil pressure, oil temperature, chock location, and longwall straightness can be monitored from the control room.

Pinning time can be measured for each area and where it is done.

Maintenance

Maintenance can be scheduled on the basis of actual machine operating time.

Time to failure and repair time can be recorded for different types of equipment and different manufacturers.

Methane monitors can be automatically calibrated.

Pumps can be changed before flooding occurs due to pump wear and loss of output.

Optimization and Coordination of All Subsurface Activity

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Displays can be designed in minutes by control room personnel to match the mine configuration and display maximum data.

Conveyors and ore handling subsurface equipment may be signaled for start, or started or stopped as required, to optimize usage of men, conveyors, miners, and other equipment.

Power consumption: Equipment not in use can be shut down. Conveyors, lights, and substations in non-work areas can be shut down, reducing the mine electrical load.

General Monitoring

Since air velocities and entry sizes determine location and quality of CO monitors for fire detection, the system can ensure air velocities are adequate to meet reduced sensor requirements.

Methane (CH_4) monitoring can be automatically accomplished with local and control room annunciation.

Mine CO and CH_4 can be continuously monitored while the mine is unoccupied on days off. Gas problems can be anticipated and remedied before the miners report for work by the next working day.

High water in sumps can be detected before damage is done. Auxiliary pumps can be started before there is a problem.

High substation currents or temperatures can be detected before damage occurs. Ground fault trips can be annunciated. Feeder breakers can be opened or closed from the main control room.

Locating fires in unoccupied areas of the mine can be accomplished much more effectively with CO monitors than with the conventional point temperature sensors. Men can be directed to the area of the mine in which the CO has moved beyond the alarm point and indicates a

smoldering fire in the air stream. The number of CO monitors are determined by the air velocity and mine configuration as well as the type of equipment located in the area. In beltways it is often acceptable to place CO sensors 300 + ft. apart depending on air velocity.

Voice Communication and Video Monitors

Voice communications can be handled on the monitoring and control cabling. As a result, the paging system or communication system can be extended to any monitored area of the mine with minimal wiring.

Video monitors are now available which can provide continuous scanning of an operation also using the monitoring and control cable system for video data transmission. In particularly dangerous areas it may be advantageous to use this option.

2.3.2.4 Economic Considerations

This section is an economic analysis of underground extractive mining systems to recover the oil-bearing rock and transport it to the surface for processing. The scope of work includes the rock being brought to the top of the shaft or surface only, and not to the oil recovery processing facilities on the surface.

The capital and operating costs for room and pillar and longwall mining systems were developed in 1982 dollars, and the analysis showed these methods to be economically infeasible. Based on the high capital and operating costs for these methods, the block caving and sublevel caving systems were not further considered, because these two methods are always more expensive due to their inherent subsidence problems.

The economic model format used was the same as for the surface extractive systems (Table 2-6). Table 2-11 illustrates economic parameters for each system examined; these parameters are constant except for the capital and operating costs.

TABLE 2-11

SUGGESTED ECONOMIC PARAMETERS FOR
UNDERGROUND EXTRACTIVE MINING

Fixed Capital

1) Mineral Rights Acquisition: Constant

2) Environmental Impact Statement and Legal Fees: Constant

3) Further Exploration and Development Drilling: Constant

4) Removal of Overburden and Waste: Not applicable

5) Construction of Shafts or Drifts, Opening Up of Haulage Ways, and Working Faces: Will depend upon each system

6) Further Process Development (Laboratory and Pilot Plant Experiments): Not applicable

7) Plant and Equipment:

- o Land - Constant
- o Water Supply - Constant
- o Power Plant - Constant
- o Railroad Spur and Access Roads - Constant
- o Waste Disposal - Constant
- o Mine Plant - Constant
- o Benefication Facilities - Constant
- o Service Buildings - Constant
- o Storage - Constant
- o Transportation Facilities - Constant
- o Material Handling Facilities - Constant

8) Working Capital:

- o Cash on Hand - Constant
- o Accounts Receivable - Constant
- o Inventories (Parts and Supplies) - Depends on system

9) Start Up Costs: Depends on system

10) Contingency Allowance and Cost Escalation: Constant

Start Up Costs

1) Labor:

- o Wages, Including Overtime - Constant
- o Salaries for Administrative and Clerical Staff - Constant
- o Vacation and Hospitalization Payment - Constant
- o Fringe Benefits - Social Security, Unemployment - Constant
- o Insurance, Workmen's Compensation, Other Insurance - Constant

TABLE 2-11 (cont'd)

SUGGESTED ECONOMIC PARAMETERS FOR
UNDERGROUND EXTRACTIVE MINING

2) Energy:

- o Power and Fuel Used - Constant

3) Supplies: Depends on system

- o Explosives - Depends on system
- o Timber - Depends on system
- o Lubricants - Depends on system
- o Chemicals - Constant

4) Parts:

- o Spare Parts for Machinery and Equipment - Depends on system

5) Maintenance and Services:

Repairs, Hauling, Professional Costs, Telephone, Travel - Constant

6) Royalty Payments - Constant

7) Interest Payments - Constant

8) Depreciation, Depletion Allowance, etc. - Constant

9) Taxes - Constant

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Table 2-12 presents the capital and operating costs for room and pillar and longwall mining systems.

The purpose of this economic analysis was to evaluate the underground extractive mining system based on cost in addition to environmental and technical considerations. From this analysis, a method was selected to be used for a site specific design.

The operating costs of both the room and pillar and longwall mining systems exceed the maximum expected revenue, i.e., the value of the oil bearing ore at 0.35 barrels per ton is $10.50 per ton at 100% oil recovery. Based on an assumed market price of $30 per barrel, the operating costs of $20 per ton for room and pillar and $27 per ton for longwall mining exceed the ore value, thereby making the systems uneconomical.

The data used in the calculations and estimating procedures was obtained from equipment manuals, capital and operating estimating handbooks, publications and mining research groups, as follows:

o Equipment Manufacturers

1) Atlas Copco, Denver, Colorado
   Jumbos, steel, bits

2) Card Corp., Denver, Colorado
   Hoists, skips, cages

3) Wagner, Denver, Colorado
   LHD's

4) Jelen & Sons, Golden, Colorado
   Roof bolts

TABLE 2-12

UNDERGROUND EXTRACTIVE MINING

ESTIMATE SUMMARY

Method	Capital Cost $\$x10^6$	Operating Cost $\$x10^6$	$/ton
Room and Pillar	82.0	508.2	20.00
Longwall	186.9	381.2	15.00

- Equipment Manuals

  1) Cost Reference Guide for Construction Equipment Equipment Guide Book Co., Dal.

  2) Atlas Copco Manual, 3rd Edition

  3) Wagner Mining Equipment Co., Cat. 150A

  4) New Compressed Air and Gas Data, Ingersoll Rand

- Estimating Handbooks

  1) Estimating System Handbook, Straam Engineers, Inc. Non-fossil fuel (mining for access below reservoir)

  2) Estimating Direct Costs of Developing in a Block Caving Mine, IC 8673

- Handbook and Research Groups

  1) SME Handbook

  2) U.S. Bureau of Mines

  3) Colorado School of Mines, Earth Mechanics Institute (EMI)

- <u>Longwall Extractive Mining System</u>

A hypothetical field was developed as a design area for longwall mining of a heavy oil deposit. The design is based on the same parameters as the room and pillar mining method, i.e., the mine is developed with shafts at the perimeter. From the shafts, a 7-entry system is driven lengthwise along the property along the centerline. To each side of this main entry system are the longwall panels. Each longwall panel has a 2-entry system

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of which the first entry on each side of the longwall panel are lost during the retreat mining cycle. Bleeder entries would be placed along the parameter on both sides of the property to comply with MSHA regulations. The longwall unit designed for this property has a maximum cutting height of 10 feet.

The total capital cost for this project is approximately $18 million, and total resource recovery can be approximately 78%. The cost of mining is approximately $15/ton for the production mining phase and approximately $12/ton for backfilling. It should be noted that the cost of $12/ton should be compared with the surface disposal cost of this type of material, i.e., surface disposal costs may be equal to or even greater than the cost of underground disposal because of residual oil that cannot be removed from the sand grains. Therefore, adequate protection must be provided for surface disposal that will not allow contamination of subsurface groundwater and surface runoff.

As seen in the calculations in this section, 19 longwall units each producing 3,000 tons per day in addition to 6 continuous mining units are required for development. Total daily production is 70,000 tons to produce 25,000 barrels of oil. To properly develop this type of mine it is assumed that the 19 longwall units and the 6 continuous mining units should be distributed over a minimum of three mining levels. This will allow time for the reconsolidation of the mine fill system where one or more passes is required, and also reduce the haulage problems associated with 100% of the production from one level. All the mining costs are based on the three-level concept.

Some of the major advantages of this type of mining for a heavy oil deposit is that longwall mining provides excellent recovery. Also, it can be operated as a gassy mine more safely than any other method.

A disadvantage of this method is that research would be required to develop longwall shearers and continuous miners that will cut this type of material in a safe manner because of the potential for explosive gases. Also, with

a porosity of 30%, there may be problems with support of the overall overburden and problems with the longwall supports gouging into a soft reservoir floor. As noted in earlier reports, the problems of bleeding oil causing deterioration of belts, etc., will also be encountered. It is reasonable to assume that additional ventilation will be required on the longwall face because of vapors that can bleed from the face during the mining phase. The problems with backstowing are still an unknown, but it would be assumed that a compaction factor of at least 85% will be required to prevent subsidence of upper levels during the mining phase and also to reduce the overall surface subsidence to a reasonable amount. Several methods of placing backfill are available, including pneumatic and hydraulic. Further study would be required to determine which method would work best with the clean sand grains that could be used for backfilling, as well as the type of binder, if any, needed to attain the necessary strengths.

Longwall Extractive Mining

Cost Summary

Capital Costs

Item	$ x 10^6
Equipment including shafts and hoisting	$184.4
Support Facilities	2.5
Total	$186.9

Operating Costs $15/ton

Design Summary and Longwall Development

A 10-foot seam is assumed with 7 main entries with dimensions of each entry of 16 feet wide, a barrier pillar of 203 feet and a pillar of 100 square.

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There are 2 submain entries either side of the longwall each having a width of 16 feet and a pillar of 100 feet square. Refer to Figure 2-6 for the longwall mine plan.

Results of calculations of footage developments for the property to be mined is as follows:

Mains	= 190,580 feet
Submains	= 455,056 feet
Bleeders	= 89,560 feet

Therefore tonnage to be mined as follows:

Development

$$735{,}196 \text{ ft} \times 160 \text{ sq. ft.} \times \frac{150\#/CF}{2000\#/\text{tons}} = 8.82 \times 10^6 \text{ tons}$$

Panels

$$837 \text{ ft.} \times 4489 \text{ ft.} \times 10 \text{ ft.} \times \frac{150\#/CF}{2000\#/\text{ton}} \times 32 \text{ panels} = 90.2 \times 10^6 \text{ tons}$$

Recovery is 79% based on a theoretical maximum tonnage of a 2 x 3-mile mine of 125.5×10^6 tons and 99.0×10^6 tons removed by the longwall extractive system.

Cost Calculations

Basis

Daily Tonnage = 70,000
Assume 20% daily production from development and 80% from panels

Mining Units

Continuous miner produces 2,500 tons per day per unit (2 shifts)
Longwall miners produce 3,000 tons per day per unit (2 shifts)

Therefore:

Continuous Miner Units

Longwall Miner Units

$$\frac{56{,}000 \text{ tons/day}}{3{,}000 \text{ tons/day/unit}} = 19 \text{ units}$$

Belt Conveyors

Face Conveyors (30") = 837.25 ft. per longwall unit
Submain conveyors (30") = 4692 ft. per panel
Main conveyors (54") = 16,440 ft.

Shafts

4 shafts of 20 ft. diameter each, concrete lined, 1220 feet deep.

Main Equipment

Item	$(million) Unit Cost	Units Required	Total Cost ($ x 106)
	5.73	19	108.870
Continuous Miner	0.43	6	2.580
Bolter	0.217	6	1.300

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30" face conveyor (837.25')	$6.00/in/ft.	19	2.863
30" panel conv. (4692')	"	19	16.046
54" main conv. (16,440')	"	3	15.980
Shafts including hoisting (20' x 1200')	9.20	4	36.800
			$184.439 x 10^6

Support Facilities

Ventilation System - 1.2×10^6
Water System - 0.3×10^6
Dewatering System - 0.1×10^6
Repair Shop - 0.9 x 106 (Surface and Underground)
2.5×10^6

Estimated Operating Cost per ton including depreciation
$15 per ton (Ref. D'Appolonia thick seam coal mining study)

With Backfilling, Cost per ton
$12 per ton (Estimated)

Total Operating Cost per ton = $27

EQUIPMENT MANUALS

1) Cost Reference Guide for Construction Equipment, Equipment Guide Book Co., Cal.

2) Atlas Copco Manual, 3rd Edition

3) Wagner Mining Equipment Co., Cat. 150A

4) New Compressed Air and Gas Data, Ingersoll Rand

ESTIMATING HANDBOOKS

1) Estimating System Handbook, Straam Engineers, Inc. Non-fossil fuel (mining for access below reservoir)

2) Estimating Direct Cost of Developing in a Block Caving Mine, IC 8673

HANDBOOK AND RESEARCH GROUPS

1) SME Handbook

2) U.S. Bureau of Mines

3) Colorado School of Mines (EMI)

o <u>Room and Pillar Extractive Mining System</u>

An economic analysis of a hypothetical property containing a heavy oil deposit was developed using a room and pillar mining system similar to that used in oil shale in order to estimate the capital and operating costs in 1982 dollars. The property consists of a 2 x 3-mile area with an overburden thickness of 500 feet, a gross oil zone of 600 feet, and a net pay of 250 feet. A similar analysis for the same property was developed previously using the longwall method. The major difference between that and the room and pillar method is that continuous miners would be used to avoid a drill and blasting sequence which is more hazardous in the oil deposit environment.

For this analysis, the mine is developed in accordance with Figures 2-2, 2-3 and 2-4, with the shafts at the perimeter of the mine. From the

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shafts, a 7-entry system is driven lengthwise along the center line to each side of the main entry system. The entire formation is mined leaving pillars 100 feet square and mining a 40-foot seam in 12-foot slices.

Total capital costs for this system are approximately $82 x 10^6, and total resource recovery is approximately 29%. The operating cost of mining is approximately $20 per ton.

An advantage of this system may be that continuous miners can be made relatively safe to use in an environment of oil and explosive gases, whereas drill and blasting techniques may not be.

The major disadvantages of this method are that there could be problems with support of the overall burden by the pillars, and recovery of the resource would decrease with a multi-level mine that requires larger pillars as the mine descends to full depth of the formation.

Room and Pillar Extractive Mining

Cost Summary

Capital Costs

Item	$ x 10^6
Equipment including shafts and hoisting	75.3
Support Facilities	6.7
	$ 82.0

Operating Costs $ 20/ton

o Design Summary and Room and Pillar Development

A 40-foot seam is mined with 7 main entries with rooms of 22 feet wide by 100 feet long by 40 feet high. Pillars on the main level are 100 feet square by 40 feet high.

The results of calculations of footage developments for the property to be mined are as follows:

Mains = 188,880 feet (Development)
Panels = 2,024,928 feet (Production)
2,213,808 feet

Therefore tonnage to be mined is as follows:

Development

$$188{,}880 \text{ ft.} \times 22 \text{ ft.} \times 40 \text{ ft.} \times \frac{150\#/CF}{2000\#/ton} = 125 \times 10^6 \text{ tons}$$

$$\text{Panels} = 2{,}024{,}928 \text{ ft.} \times 22 \text{ ft.} \times 40 \text{ ft.} \times \frac{150\#/CF}{2000\#/ton} = 133.6 \times 10^6 \text{ tons}$$

Recovery (per 40-foot level) is 29% based on a theoretical maximum tonnage of a 2 x 3-mile mine of 502×10^6 and $1.46.1 \times 10^6$ tons removed by the room-and pillar extractive system.

Cost Calculations

Basis

Daily Tonnage = 20,000

Mining Units

80 ft. advance per shift (8 hrs.)
792 tons/shift/miner

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At 2/3 availability = 528 tons/shift/miner
For 3 shifts per day = 23,333 tons per shift
Number of continuous miners is 44 per shift

Belt Conveyors

Panel conveyors (30") = 44,000 feet
Submain conveyors (48") = 10,154 feet
Main conveyors (66") = 16,440 feet

Shafts

4 shafts of 20 feet diameter each, concrete lined, 1220 feet deep

Main Equipment

Item	Unit Cost $\$ \times 10^6$	Units Required	Total Cost ($\$ \times 10^6$)
Drum Miners	0.43	44	18.92
Bolters	0.22	10	2.20
30" Panel Conveyors	6/in/ft	44	7.92
48" Submain Conveyors	"	2	2.90
66" Main Conveyors	"	1	6.55
Shafts including hoisting (20' x 1220')	9.20	4	36.80
			$\$75.29 \times 10^6$

Support Facilities

Ventilation System - 4.0×10^6
Water System - 0.5×10^6
Dewatering System - 0.3×10^6
Repair Shop - 1.9×10^6 (Surface and Underground)
$\$6.7 \times 10^6$

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Estimated Operating Cost per ton including depreciation
$20/ton (Straam and D'Appolonia)

2.3.2.5 Environmental Considerations

The environmental concerns associated with extractive mining are similar to those with the mining for access method described in Section 2.3.3.5. Based on the assumption that the oil-bearing rock will be processed at an off-site facility, then the terrestrial ecology, on-site waste storage, and surface hydrology impacts would be comparable to those of the access method. Waste materials generated by the processing of mined rock would be a major environmental concern, but would be directly related to the actual mine development unless the waste is to be used to backfill the mine as it was being developed or decommissioned.

Underground extractive mining can cause major disruption in groundwater near the mine site. With large volumes of rock being removed from the mine the potential for intercepting sizable quantities of groundwater is great. A monitoring program is required to determine the impact of the mining operation on both groundwater flow rates and water quality.

In order to determine if groundwater sources are being affected by mining activities, a groundwater monitoring program must be instituted. Pre-operational and operational water quality samples will have to be taken from existing and/or test wells on a regular basis. The samples are then analyzed and compared to determine if the mining operation is contributing to the deterioration of groundwater quality. If significant deterioration is detected, mitigating measures may have to be undertaken to correct the situation. The type of mitigating measures required will depend to a large extent on the existing uses of groundwater in the area and if the impacts are expected to be temporary or permanent.

Groundwater collected in the mine must be removed to the surface to allow for a continuous mining operation. The effluent must be analyzed to

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determine the degree of treatment required to allow it to be released either to surface water bodies or reinjected into the ground.

Air quality concerns arising from underground extractive mining focus primarily on the release of toxic or explosive gases. A dispersion study is generally required to determine the impact of releasing these gases to the atmosphere. Noise and fugitive dust are minor environmental issues, in that their impacts are expected to be minimal in an underground operation.

Underground extractive mining, however, may impose another environmental concern. For instance, land subsidence occurring from extractive mining could adversely impact surface and groundwater hydrology, terrestrial ecology and land use patterns of the area above the underground mine. At sites where the geologic conditions are favorable for subsidence to occur, additional analyses will be required to assess these and other potential impacts.

Socioeconomic issues arise mainly from the impact of construction and operation work forces. The development of a mine not only creates new jobs and increases the local tax base, but may also impact the local housing market, the availability and level of community services, and the economy of the area. These impacts must be assessed and factored into the economic evaluation of any project.

Existing land use patterns in the area surrounding a potential mine site need to be identified and the impacts associated with altering these patterns assessed. Changes in land use patterns can have far reaching economic and social impacts for surrounding communities and must be included in any siting evaluation.

The aesthetic impact associated with the mining operation may be a major concern in certain scenic or visually sensitive areas, especially near population centers and recreational areas. Visual impacts can be one of the most emotionally sensitive issues addressed during siting studies, and, as such, public participation in the early planning stages is encouraged in order to minimize future problems.

Room and pillar mining would have the least environmental impact of the underground extractive mining methods mentioned, if pillars of sufficient size remain to insure that no surface subsidence will take place. In the case where pillars must be removed to enhance resource recovery, it will be necessary to backfill the mine openings to prevent surface subsidence and the disturbance of any aquifers above the zone being mined.

In longwall mining it is possible to have a minimal environmental impact if each slice is backfilled with clean processed ore as the raw ore is removed. However, if subsidence is allowed, it can be controlled through proper mine design. By controlling subsidence there should be little surface disturbance and no disruption of underground aquifers above the ore body.

Sublevel caving and/or block caving methods would not be environmentally acceptable. With this type of mining the ground surface and aquifers are severely altered in the mine zone.

2.3.3 Mining for Access

Mining for access is a mining technology in which a heavy oil deposit is mined by shafts, drifts and/or tunnels. Once the network of entries is developed, there are several in situ petroleum technology methods that may be used to recover the oil from the deposit. For this study, the only method considered was a gravity drainage system (as specified by the DOE). This system consists of drilling into the deposit in a pattern of a multiple array of drains to allow the oil to flow to central collection points and subsequently to be pumped to a surface plant for storage or processing. The flow characteristics of the heavy oil can be enhanced by injecting steam into the drill holes of the deposit to lower the viscosity, increase the drill holes of the deposit to lower the viscosity, increase the drive potential and flow rates, and improve the overall recovery of oil from the deposit.

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Except for the actual extraction of oil bearing ore by underground mining systems such as room and pillar and longwall, mining for access requires shafts and a network of drifts. Therefore, most of the technical considerations, safety and equipment used for underground extractive mining development work is also used in this system. The same potential problems and concerns will need to be addressed with the acknowledgement that depending on the strata below the deposit, the hazards are less for mining for access than extractive mining in the actual heavy oil deposit.

Table 2-1 lists reservoir characteristics that will affect mining for access. Table 2-8, a risk analysis for underground extractive mining, also applies to mining for access.

2.3.3.1 Technical Considerations

The mining for access method of oil mining uses various drip drainage techniques. In the process of a gravity drainage system, many closely spaced holes are drilled into the reservoir from lined or unlined tunnels depending upon the strata. Once access has been gained to the strata below the reservoir, tunnels are driven and, either from the tunnel or incorporated in drill rooms, holes are drilled through the material between the tunnel level and the base of the reservoir and up to the top of the reservoir. This method is accomplished by first drilling an oversized hole 10 to 20 feet long into the shale or sandstone and casing the hole. Once the casing is cemented into place a blow-out preventor is attached to the casing. The production well is then drilled through the casing and into the reservoir. If the reservoir sand is competent enough to resist collapse, the hole is completed without casing. If the production sand is unconsolidated, a casing will be placed in the hole and perforated for its entire length or at predetermined production zones.

Hole spacing for gravity mining or thermal assisted mining depends on the reservoir characteristics, oil characteristics, and economic feasibility. This style of mining will be safer than extractive mining because the access tunnels, drifts, and rooms will be outside the oil reservoir. The

access shafts can be drilled and lined from the surface through the production ore zones and tunnels driven in strata that can be tested prior to mining for the presence of gases and/or water.

Having mine openings below a reservoir so that access holes can be drilled into the reservoir for gravity drainage or thermally assisted methods is an attractive feature of this method. Because the location of the reservoir is not critical, it is possible to pick the most competent zone for mine openings.

This mining method is not as dependent on reservoir characteristics as extractive mining because reservoir characteristics are important only from the standpoint of production of the ore after penetration of the drain holes into the deposit of heavy oil.

The reliability of an oil producing mine using the mining for access method is good except for consideration of different geologic areas where there is a potential for faults, joints and fissures that will impact this method. However, this method is still attractive because the access network can be planned to suit the conditions and bypass the problem areas.

The production of heavy oil from a deposit, depending upon the reservoir characteristics, can be improved by thermal assistance either from the surface or from the network of openings below the reservoir. Figure 2-13 shows a suggested method of enhancing production utilizing existing wells in an oil reservoir. The duct holes from below the reservoir through sequenced cycles can also be used for thermal imput to the heavy oil formation.

2.3.3.2 Equipment and Systems

The equipment and systems for the mining for access method involves shaft sinking and production of the oil through a network of tunnels, drifts and rooms similar to the underground extractive methods covered in Sections 2.3.2 to 2.3.2.5. There is some extraction of materials from the mining

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operations created in the development of the underground network, but no oil-bearing ore is produced. Table 2-13 covers shaft sinking and production for the mining for access method under Criteria and Constraints.

Figures 2-14, 2-15, and 2-16 illustrate the mining for access method of development necessary for production of oil from the deposit.

The equipment that can be used for this method are standard, off-the-shelf permissible mining equipment such as continuous miners, roadheaders, jumbo drills, front end loaders/gathering arm loaders, belt conveyors, shuttle cars, etc.

The mining for access method of developing a mine network below the reservoir offers as high a production capability as any of the previously discussed methods. Several development headings can be driven at one time and drill hole equipment can be mechanized. Production of the oil commences with the initial drifts and rooms completed, creating a cash flow at an early stage. Once the entire network of tunnels, drifts and rooms are complete and daily production is obtained, operating costs are significantly reduced. Also, at minimal capital costs, additional production may be achieved using existing equipment and increasing the number of openings, rooms, and drill holes into the heavy oil deposit.

For thermal assistance in the form of steam, surface boilers and a network of piping to distribute the steam to the drill holes are needed. Also, the steam from the boilers can be piped to the existing wells at the surface, or downhole steam generators can be used. The equipment needs modifications for this method but its use is conditional upon the costs and economics. Steam efficiency may be increased by the use of polymers or chemical additives introduced to the oil deposit.

2.3.3.3 Safety Considerations

Safety consideratons associated with mining for access equipment are not as critical as when mining within the ore body. However, because of the possibility of encountering gases that may escape from the reservoir to the

TABLE 2-13

EQUIPMENT AND SYSTEMS

Mining Function	Conventional Mining Practice & Criteria	Heavy Oil/Tar Sand Criteria & Constraints
Shaft sinking	Conventional shaft sinking and tunneling development	Same as conventional
Production	Tunnels lined in special circumstances for stability and ground control	Tunnels may have to be lined because water and unconsolidated strata when developing below the reservoir
	Groundwater control by a system dewatering system	Same as conventional
	Air conditioning required in very deep mines	Air conditioning may be required due to high temperatures because of proximity to reservoirs
		The headers for draining the oil must have blowout mechanisms on them for gas drainage
	Monitoring for methane	Monitor methane and other gases
		Lack of knowledge below reservoir
		Need permissible pumping system for oil
		Access holes must be cased similar to petroleum surface well
	Forward probing for gas and groundwater	Same as conventional

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mine openings below the reservoir, it is necessary to use permissible equipment. It is also necessary to monitor for other gases that could ignite from mining equipment. Other than this special feature, it is anticipated that standard off the shelf permissible mining equipment such as continuous miners, road headers, jumbo drills, front end loaders/gathering armloaders, belt conveyors, shuttle cars, etc., can be used in this type of mining.

Refer to Section 2.3.2.3, Safety Considerations, for the underground extractive mining methods, which discusses the hazards and risks of working within an actual heavy oil deposit. Except for shafts and the development of the underground network to access the reservoir, safety limitations are not critical for this method. The most important aspects will be using permissible equipment and monitoring for both gases and water.

Table 2-14 refers to the specific hazards associated with this method. For risks involving shafts, refer to Table 2-8, Section 2.3.2.3.

2.3.3.4 Economic Considerations

This section is based on a hypothetical site from which heavy oil is recovered using the mining for access method. The economic model used for both surface and underground extractive mining methods was not considered in developing the costs for the mining for access system. The only method of gravity drainage to be considered was that specified by the Department of Energy technical staff. This method involves mining a network of drifts and rooms below the reservoir to drill production holes up into the heavy oil deposit and draining the deposit by gravity. Also to be considered was enhancement of the heavy oil recovery by steam injection.

TABLE 2-14

SUMMARY IDENTIFICATION OF RISK ANALYSIS
MINING FOR ACCESS

Mining Function	Specific Hazard	Probability Location & Safety Hazard	Risk Severity Rating 1-Low Risk 10-High Risk
Mining	Bad ground below reservoir	Area between reservoir and mining level (caving, entrance of oil, gas)	2
Drilling	Blowouts Containment of oil, water, steam	Should not be a problem if holes are cased properly	1

Capital and operating costs were developed on a preliminary basis to provide cost information to be confirmed by a min design on a specific site (See Table 2-15). The data used in the calculations was obtained from equipment manufacturers, equipment manuals, capital and operating estimating handbooks, publications, and mining research groups, as follows:

o Equipment Manufacturers

1) Atlas Copco, Denver, Colorado
   Jumbos, steel, bits

2) Card Corp., Denver, Colorado
   Hoists, skips, cages

3) Wagner, Denver, Colorado
   LHD's

4) Jelen & Sons, Golden, Colorado
   Roof bolts

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- Equipment Manuals

  1) Cost Reference Guide for Construction Equipment
     Equipment Guide Book Co., Dal.

  2) Atlas Copco Manual, 3rd Edition

  3) Wagner Mining Equipment Co., Cat. 150A

  4) New Compressed Air and Gas Data, Ingersoll Rand

- Estimating Handbooks

  1) Estimating System Handbook, Straam Engineers, Inc.
     Non-fossil fuel (mining for access below reservoir)

TABLE 2-15

MINING FOR ACCESS

COST SUMMARY

Item	$x10^6$
Rooms, Mains, Crosscuts and Drifts	75.04
Shafts	5.76
Fan Holes	1030.00
Support Facilities	11.19
Total	$1121.99

Note:

Depending on the recovery of the oil from the deposit, the maximum cost per barrel ranges from $1.02 per barrel for 100% recovery to $4.08 per barrel for 25% recovery. Operating costs during production are estimated to range from $0.50 to $0.75 per barrel. Thermal assistance through steam injection is estimated to be $8 to $10 per barrel.

2) Estimating Direct Costs of Developing in a Block Caving Mine, IC 8673

o Handbook and Research Groups

1) SME Handbook

2) U.S. Bureau of Mines

3) Colorado School of Mines (EMI)

o Mining for Access Method

SUMMARY:

Field =	2 x 3 miles
Overburden	500 feet
Reservoir	
Thickness	600 feet
Net Pay	250 feet
Main level	100 ft below reservoir

The proposed method will include:

a) Sinking two 12-ft-diameter shafts in the middle of the field to the 1,200-ft level plus a 20-ft sump (total 1220 ft).

b) Developing five main entries along the 3 mile reservoir length of which two are fresh air, two return air, and one neutral for the main belt conveyor. This configuration conforms with the federal gassy mine classification CFR 30, Section 57.21.

c) Drill station drifts with crosscuts along the two mile length each side of the mains.

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d) Production holes at 100-ft centers along the drill station drifts.

e) See Figures 2-14, 2-15 and 2-16 for mine plan system.

Full scale development that will allow full production ratyes will take approximately 2 1/2 to 3 years. The equipment to be used includes: hydraulic jumbos, permissible diesel LHD's, belt conveyors and roof bolters. Permissible explosives will be used. Ventilation requirements will be based on gassy mine requirements. Minimum water drainage is assumed. The following section contains detailed calcualtions on mine development and capital costs. In all cost calculations, extreme case situations have been assumed. More information regarding the physical characteristics of the ore body will be required for the site-specific design in Task III.

o Design Summary and Development Rate

	Tons
Mains	1,060,000
Crosscuts (Mains)	290,000
Drifts	2,670,000
Crosscuts (Drifts)	240,000
Rooms	800,000
Total Tonnage	5,060,000

Number of Mains - (15 ft wide x 12 ft high)

Number of Crosscuts - 145 at 100 ft spacing (12 ft wide x 11 ft high)

Number of Drill Station Drifts - 26 (12 ft wide x 11 ft wide)

Number of Crosscuts - 1326 (12 ft wide x 11 ft high)

Number of Drill Rooms - 1326 (20 ft wide x 20 ft high x 20 ft long)

Fan Holes: Spacing at 100 ft at top of producing formation:

Number of Mains - 6	# of holes/fan	= 5
	# of main fans	= 612 (6 x 102)
	Total footage/fan	= 21,720 ft
	Total footage	= 13,290,000 ft

Number of Submains - 7 (5 middle + 2 end)

Middle:	#	= 5
	# of holes/fan	= 19
	# of submain fans	= 510 (102 x 5)
	Total footage/fan	= 12,200 ft
	Total footage	= 6,220,000 ft
End submains - 2	# of holes/fan	= 10
	# of submain fans	= 204 (201 x 2)
	Total footage/fan	= 5,320
	Total footage	= 1,080,000
	Total footage fan holes	= 20,590,000 ft

Support Facilities

Hoisting facilities	- $	8.63×10^6
Water System	-	0.22×10^6
Drainage System	-	0.08×10^6
Fueling System	-	0.04×10^6
Electrical System	-	1.12×10^6

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Repair Shop	-	0.65×10^6
Ventilation System	-	0.45×10^6
Total		\$ 11.19×10^6

2.3.3.5 Environmental Considerations

The environmental concerns associated with the mining for access method of heavy oil extraction appear to be relatively minor when compared to underground extractive mining. While site-specific conditions may dictate the need for a rigorous impact assessment, the potential impacts attributed to this mining method can be minimized or eliminated through the use of responsible engineering design and available technology.

Surface disturbance associated with a mining for access project is usually minimal. The area normally subject to disturbance is the surface facilities supporting the underground mining effort, the stockpile area where material removed from the access shafts and tunnels is stored, and access roads to the mine site. A terrestrial field survey is required to collect baseline data to support licensing activities and to define potential impact. However, the study area is expected to be considerably smaller than that required for the surface mining method.

Waste material removed during the development of access shafts and tunnels is normally stored on-site. A chemical analyses of the material is necessary to determine how it can be disposed. Once this is determined, then the material will be disposed at an approved site, in accordance with applicable regulations.

The mining for access method would probably have little impact on surface water hydrology. However, runoff from the waste material stockpile may have to be collected and treated before being discharged to any surface water bodies. A chemical analyses of the waste material can determine if, and to what extent, treatment of the runoff will be required. Groundwater is normally encountered when sinking the access shafts. This water can be

treated to be in compliance with existing regulations for water quality, then discharged to a surface water body or reinjected into the ground.

When steam is used to enhance the production rate or recovery efficiency of the access mining method, air quality concerns take on greater importance. Dispersion analyses must be performed to determine if atmospheric releases from the generating plant/boiler meet state and federal regulations. Meteorological data representative of the mining area is required for the performance of such an analysis. If representative data are not available an on-site monitoring program must be instituted to collect the necessary information.

Another air quality concern encountered with this mining method is the release of toxic or explosive gases to the atmosphere. A dispersion analyses may have to be performed in order to estimate the impact of these releases.

Noise and fugitive dust are other areas of concern. However, these are considered to be minor and can easily be controlled with available technology and appropriate suppression techniques to conform to applicable regulations.

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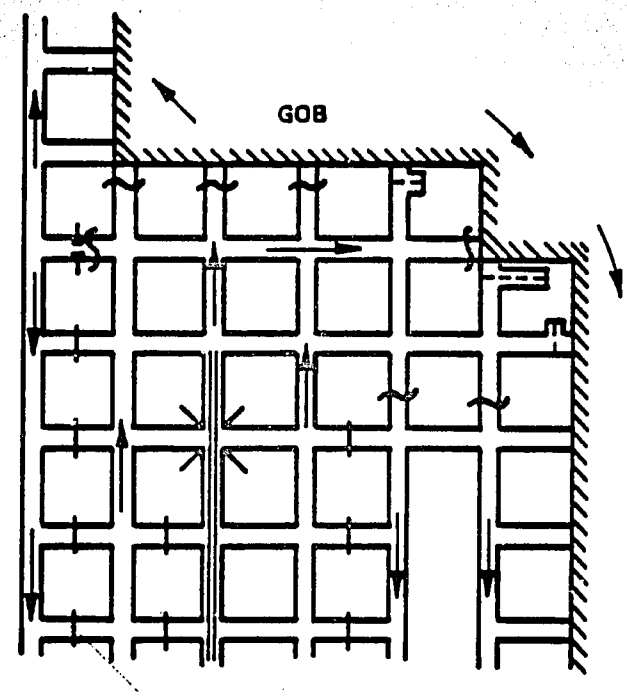
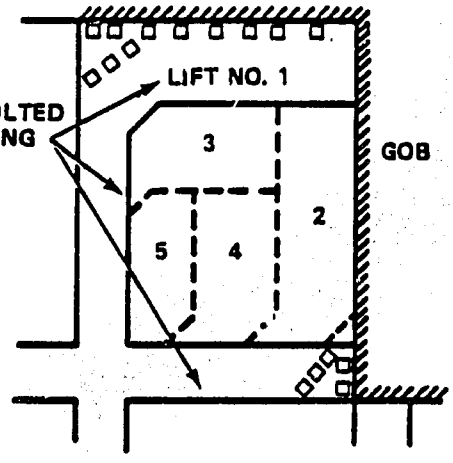


LEGEND

- MASONRY STOPPING
- CANBAS STOPPING
- STOPPING PARTIALLY OUT
- LINE BRATTICE
- TRACK OR BELT
- DIRECTION OF AIR FLOW
- LOADING STATION

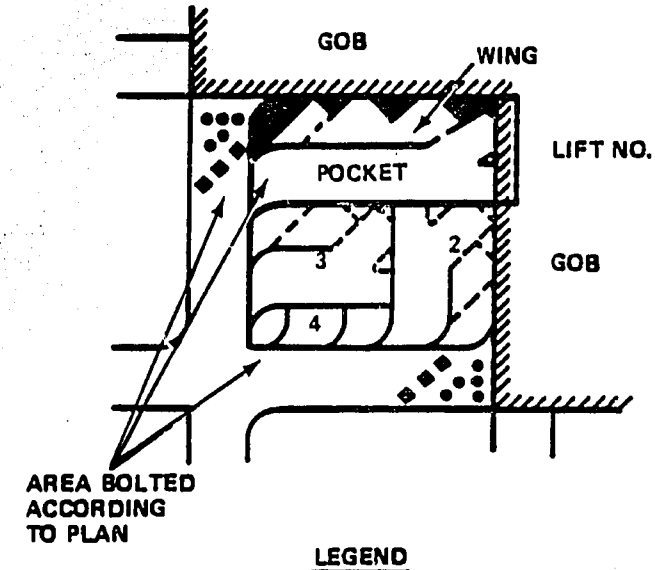
Pillar extraction on a flat rib line.



LEGEND

- CRIBS

Detail sequence of mining a pillar by the open-end system. Instead of cribs, many mines employ clusters of posts or multiple rows of posts.



LEGEND

- POSTS
- YIELDING JACKS

Detail sequence of extraction of a block of by the pocket-and-wing system.

FIGURE 2-2 ROOM AND PILLAR MINING

637

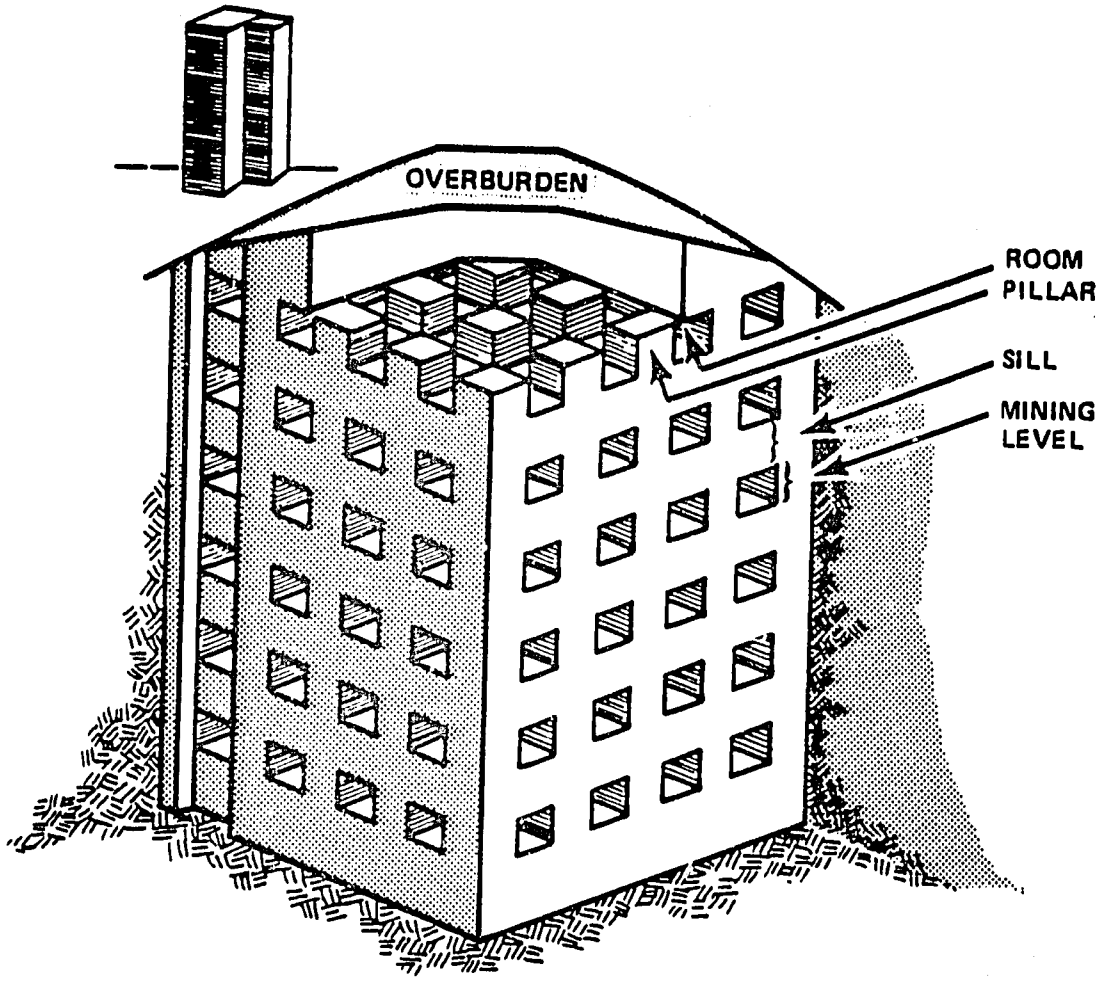


FIGURE 2-3 ROOM AND PILLAR MULTI-LEVEL MINING

638x

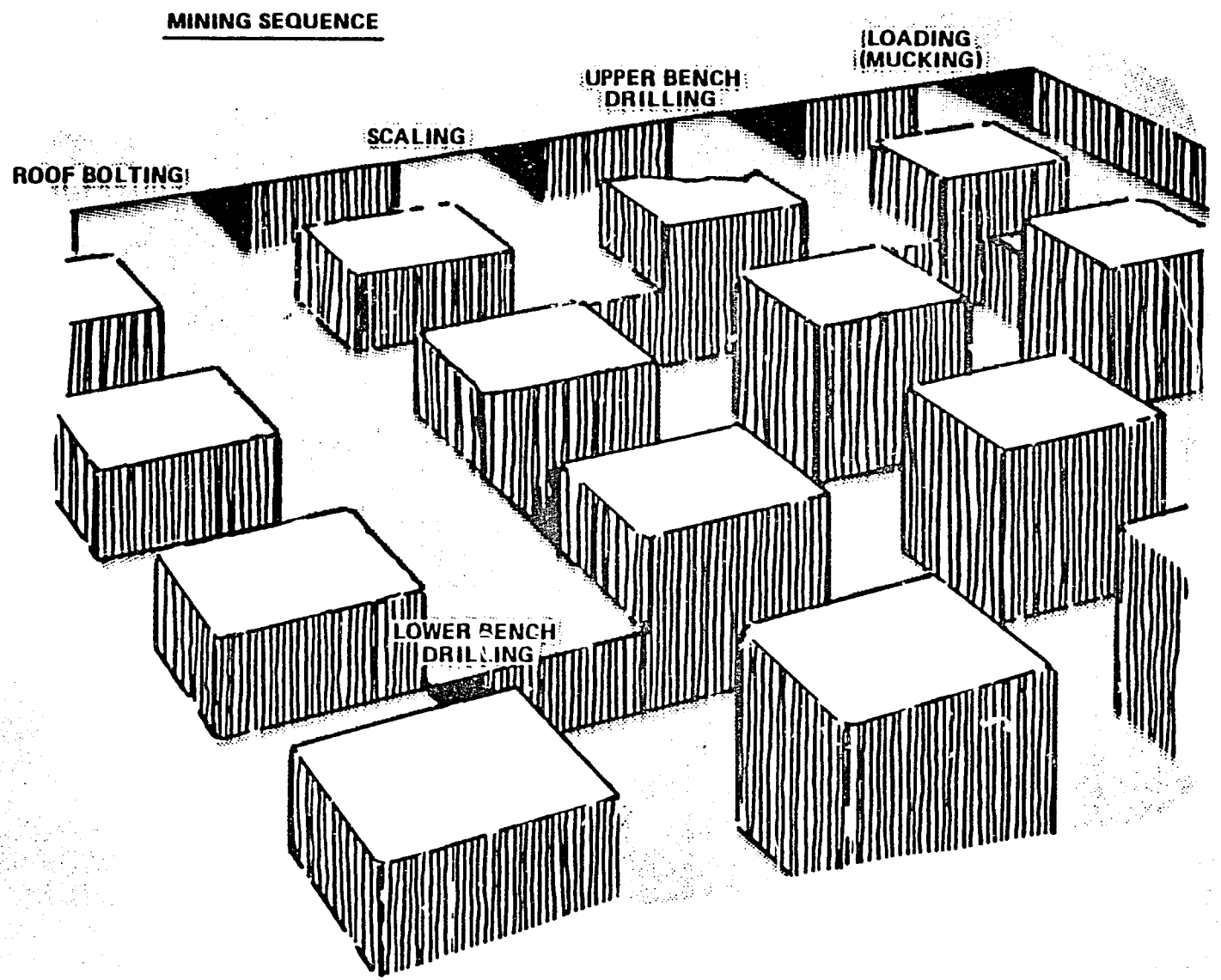


FIGURE 2-4 ROOM AND PILLAR METHOD USING BENCHING SYSTEM

A0881007

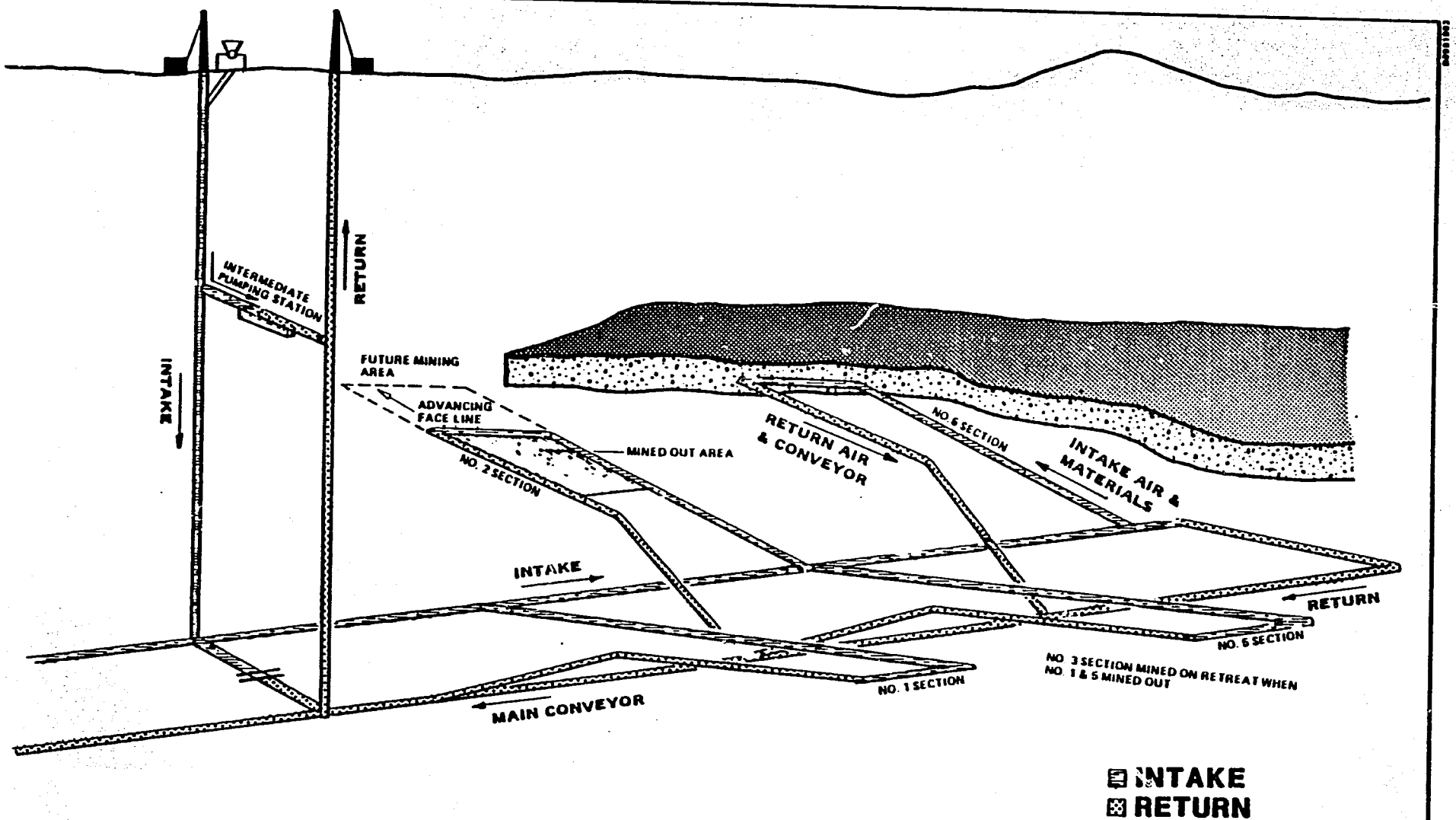


FIGURE 2-5 EUROPEAN LONGWALL MINING

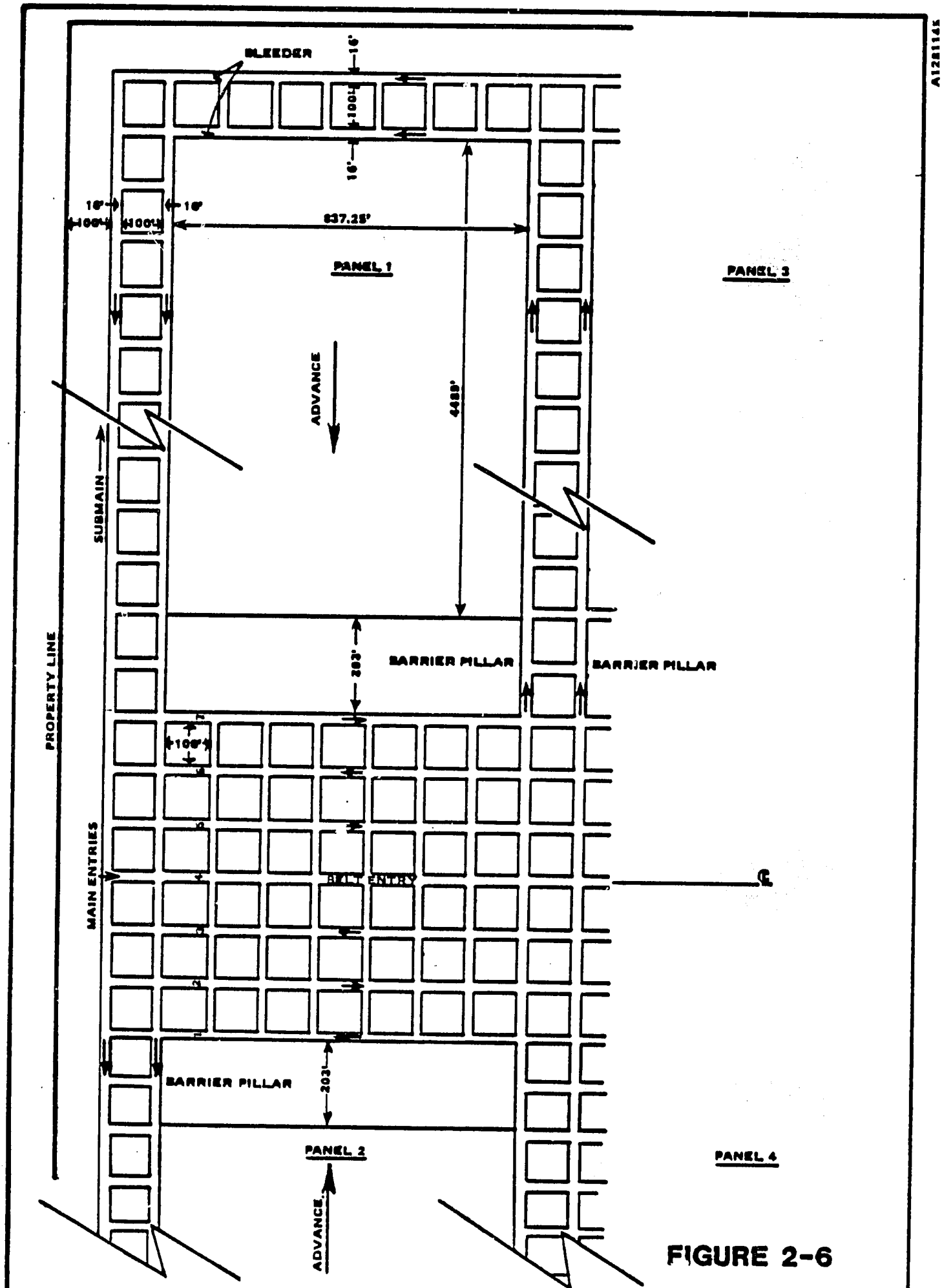


FIGURE 2-6

LONGWALL MINE PLAN GENERAL ARRANGEMENT - U.S.

631

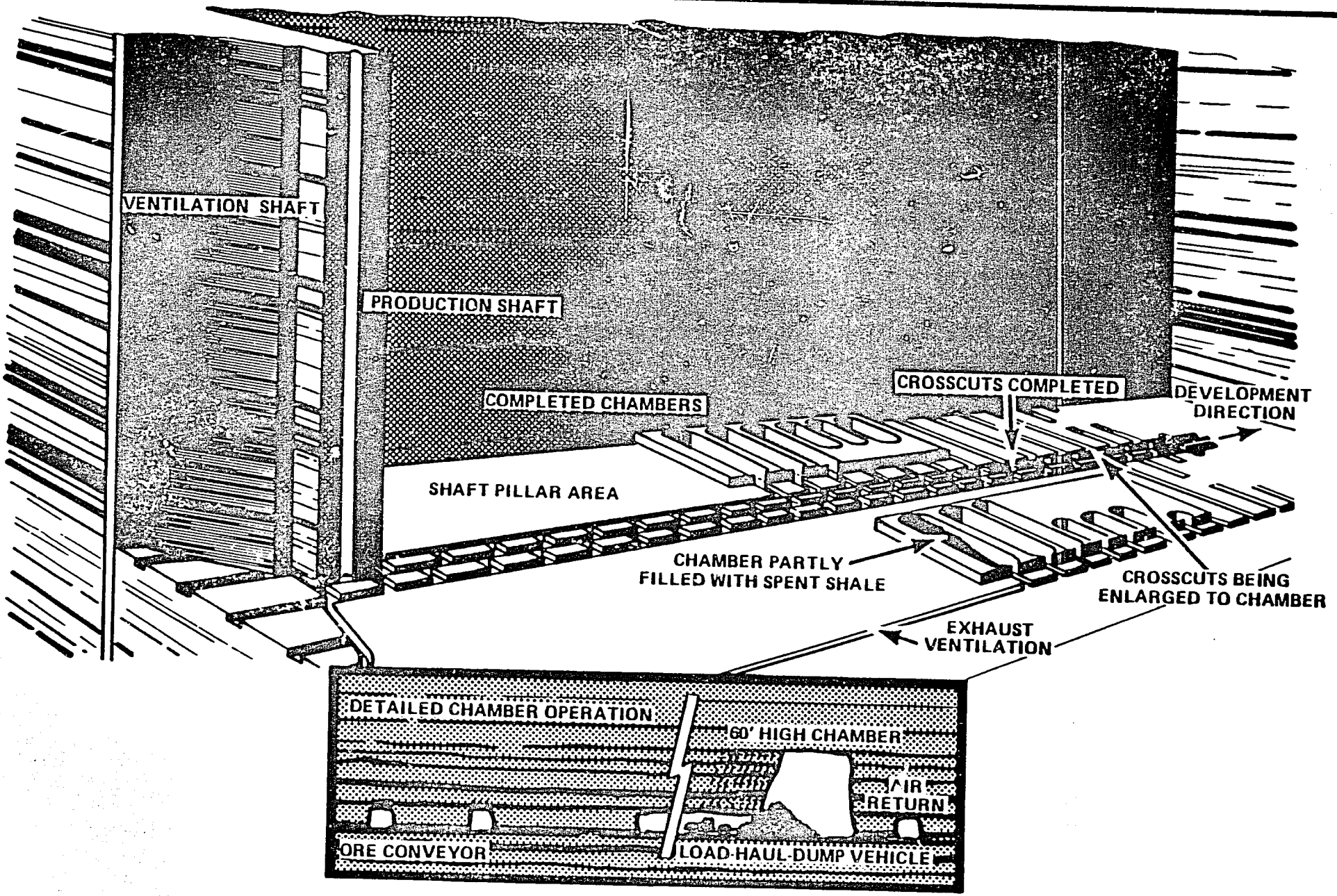


FIGURE 2-7 CHAMBER AND PILLAR MINING WITH BACKFILLING

632

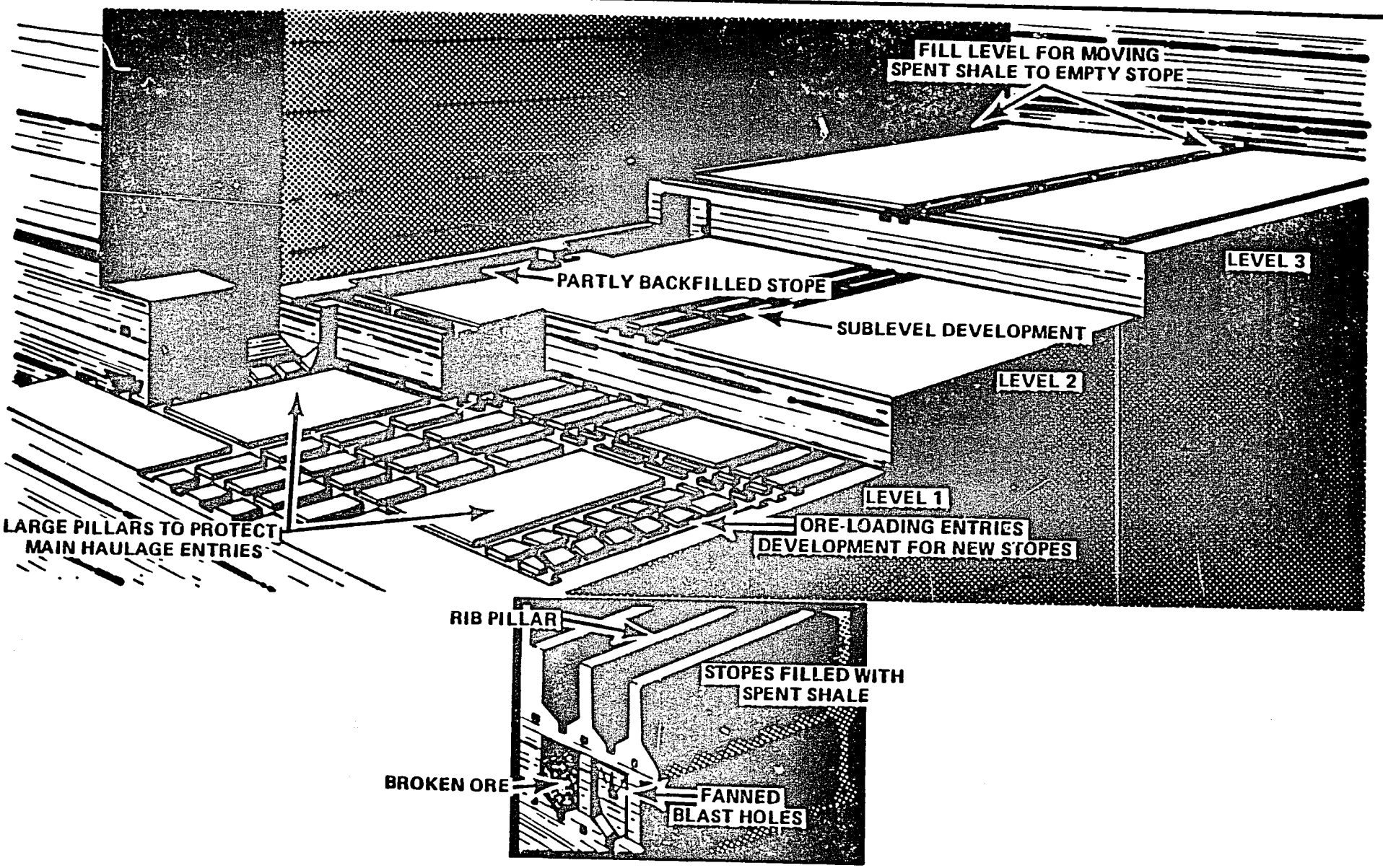


FIGURE 2-8 SUBLEVEL STOPING SYSTEM (WITH BACKFILLING)

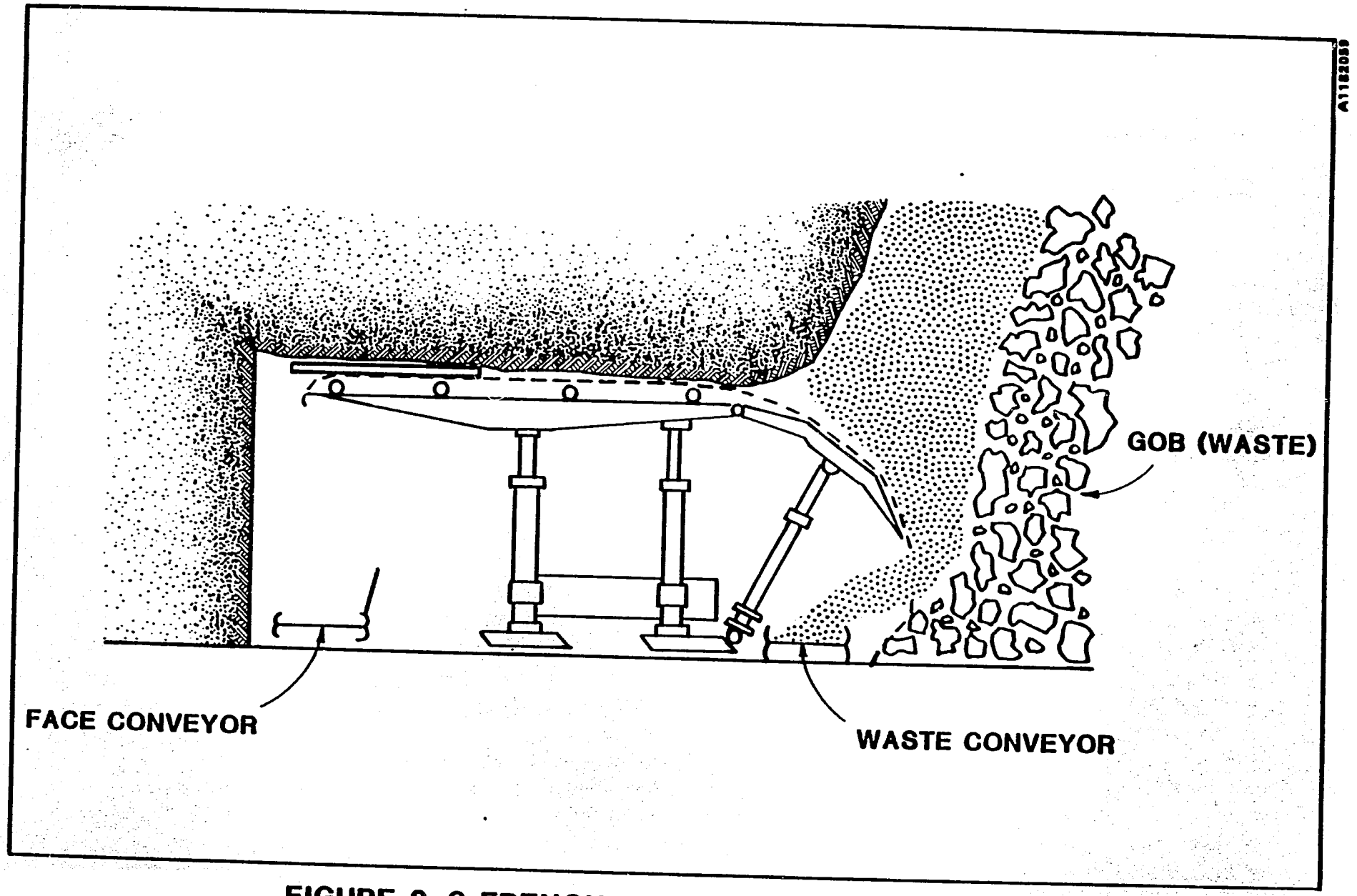


FIGURE 2-9 FRENCH LONGWALL CAVING METHOD

634

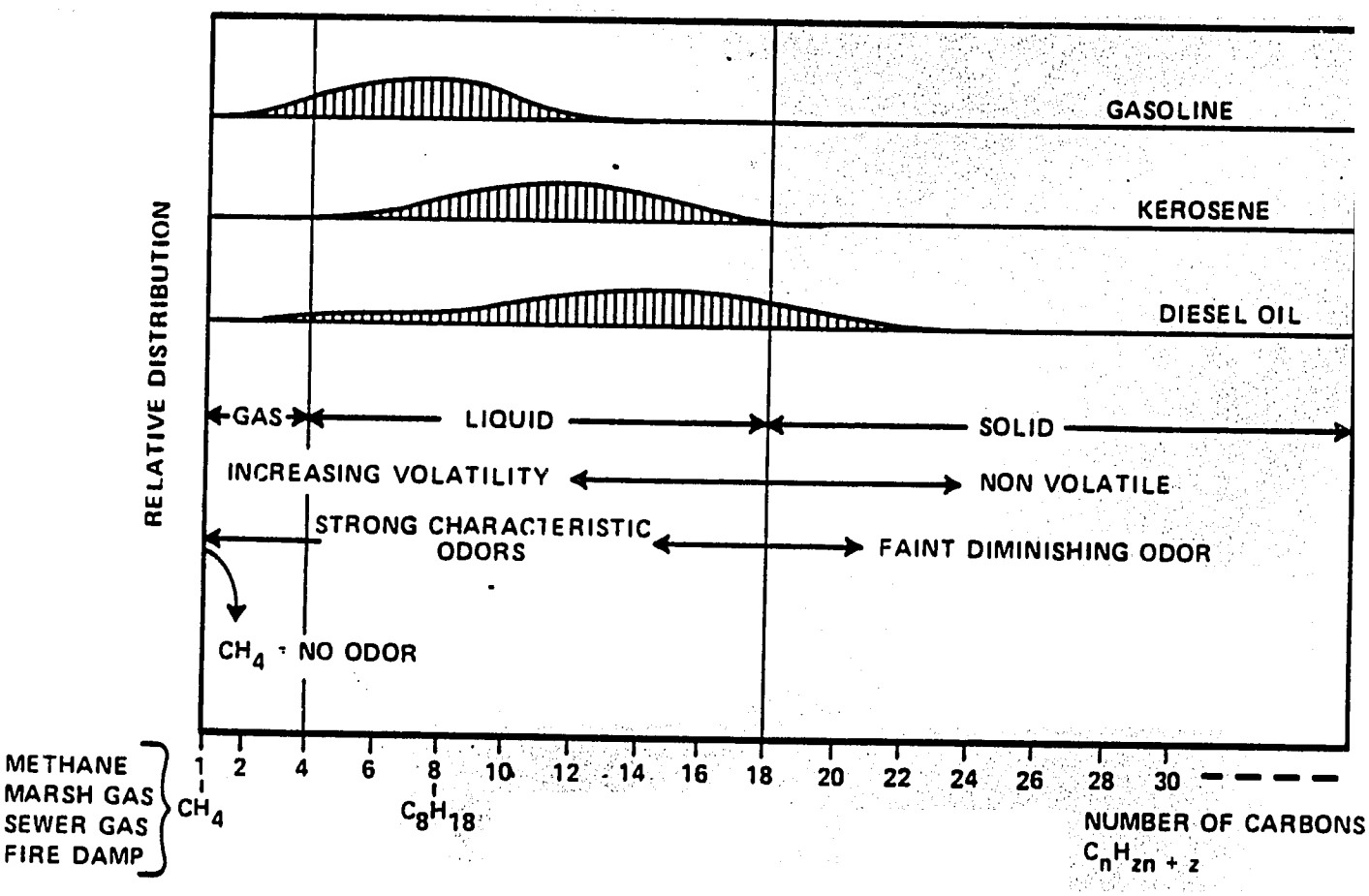
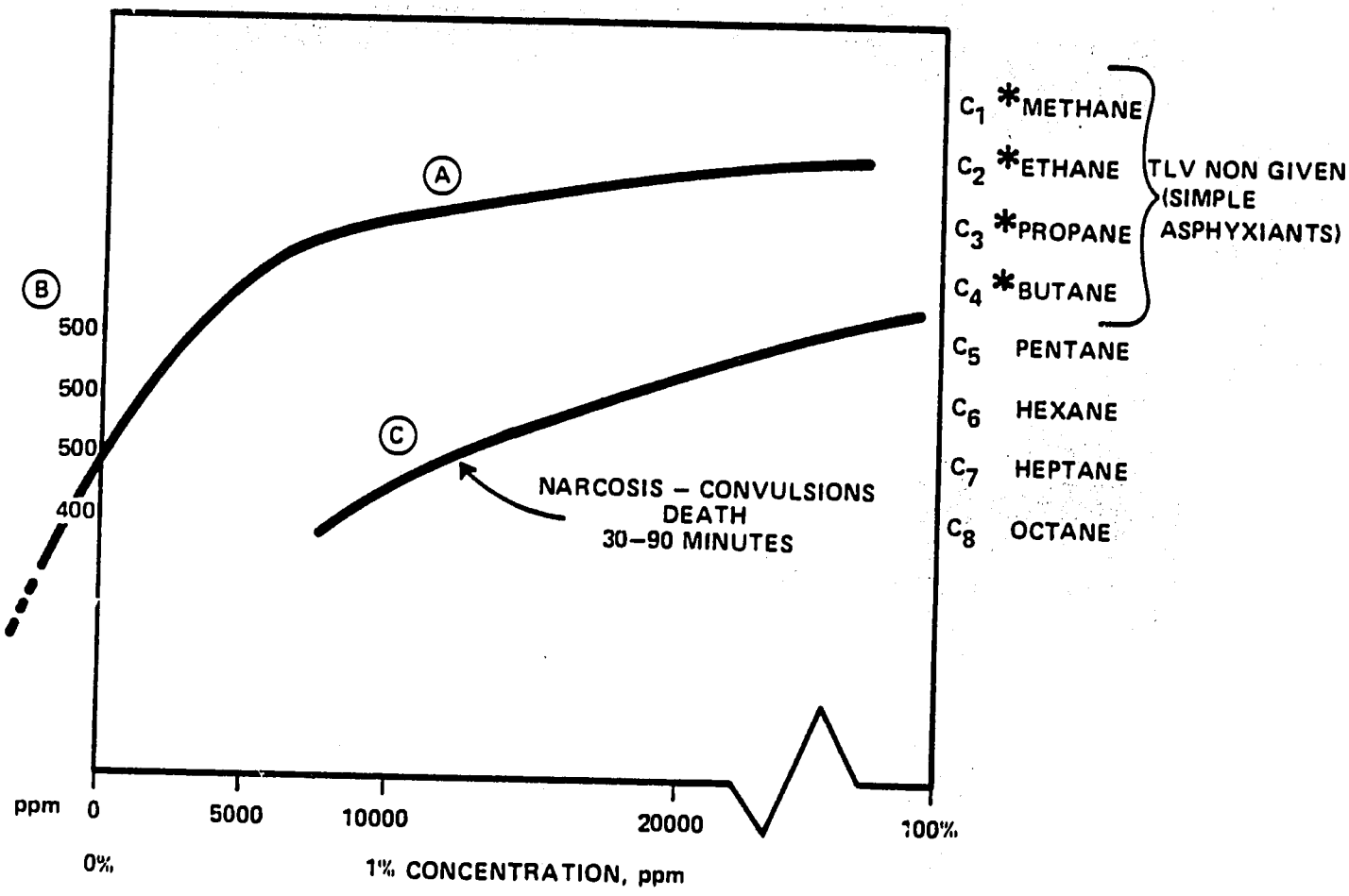


FIGURE 2-10
HYPOTHETICAL COMPOSITION OF SEVERAL WELL-KNOWN PETROLEUM PRODUCTS
(Complex Solutions of Solids, Liquids, and Gases)

635

A0981012



GASOLINE $C_1 - C_{10}$			
	TOV	5000 ppm	
	TLV	500 ppm	PROLONGED EXPOSURE ALLOWABLE
		1000 ppm	SEVERAL HOURS ALLOWABLE
		4000 ppm	TOLERABLE 1 HOUR
		10,000	DANGEROUS SHORT EXPOSURE
		20,000	FATAL SHORT EXPOSURE

LEGEND

(A) THRESHOLD ODOR VALUES (TOV)
(B) THRESHOLD LIMIT VALUES (TLV)
(C) ADVERSE PHYSIOLOGICAL RESPONSE

FIGURE 2-11

THRESHOLD VALUES OF HYDROCARBONS

636

A0981011

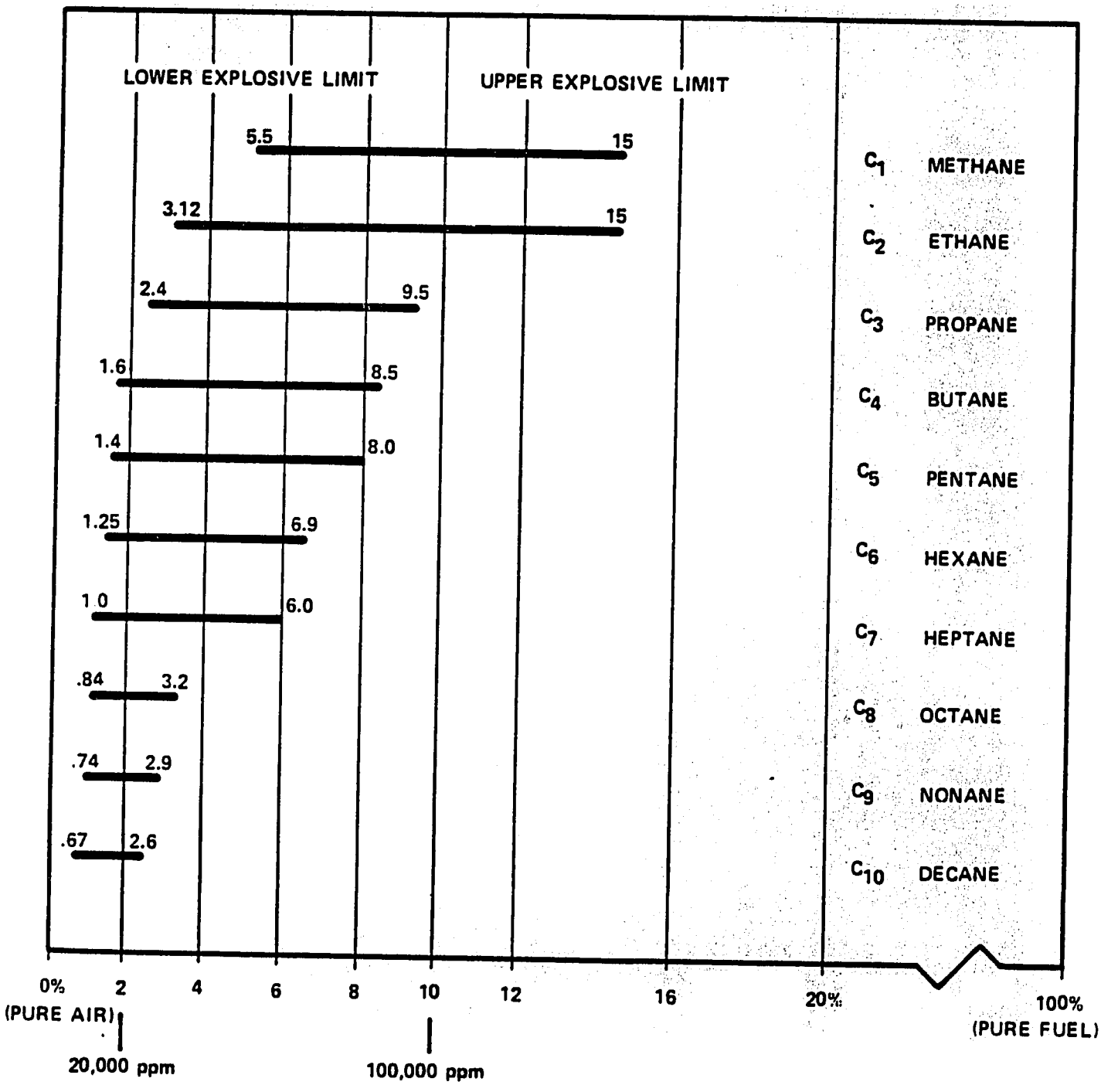


FIGURE 2-12

EXPLOSIVE LIMITS OF READILY VOLATILE HYDROCARBONS CONCENTRATION (% By Volume Fuel in Air)

637

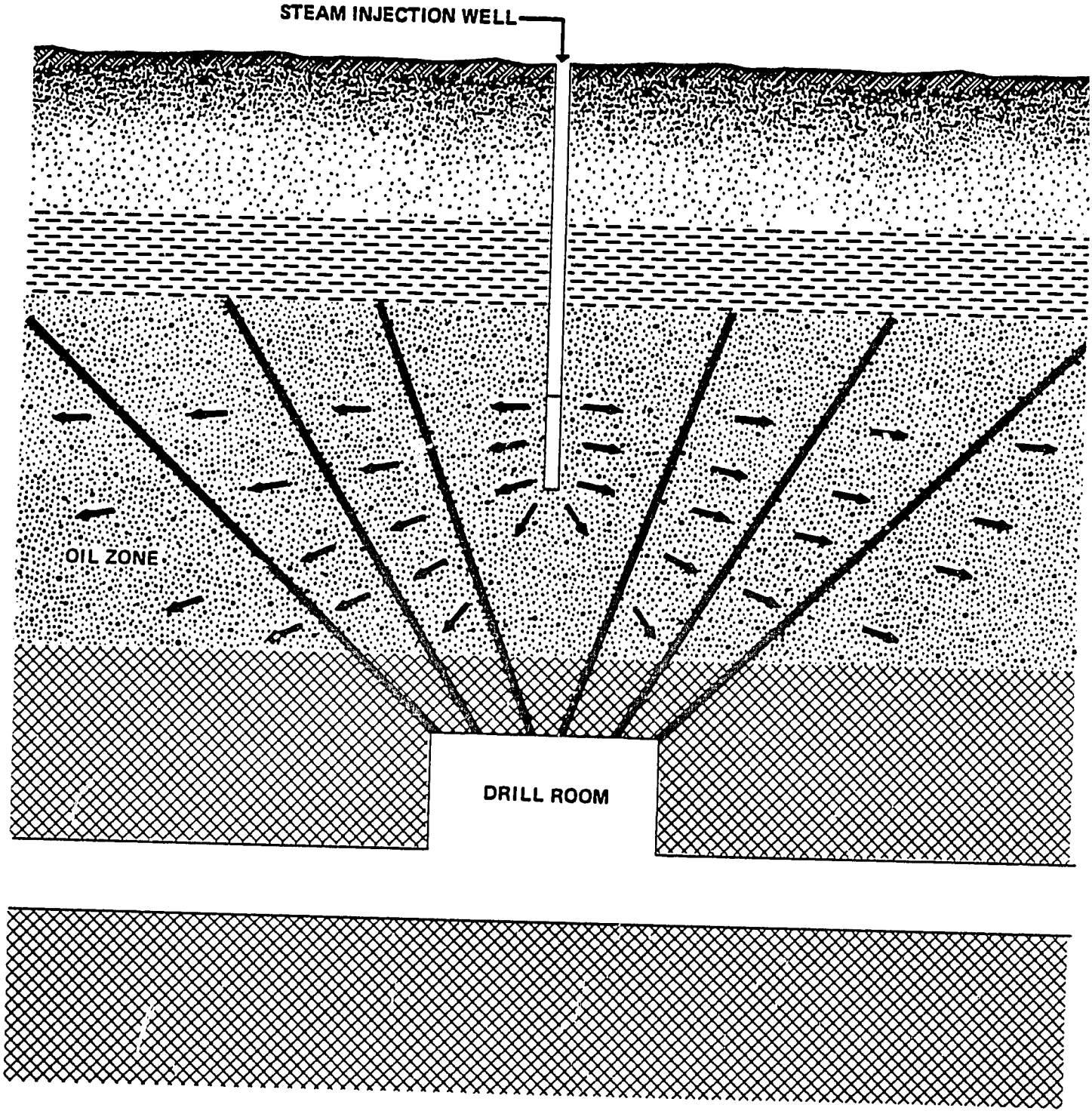


FIGURE 2-13 SURFACE THERMAL ASSISTANCE

638r

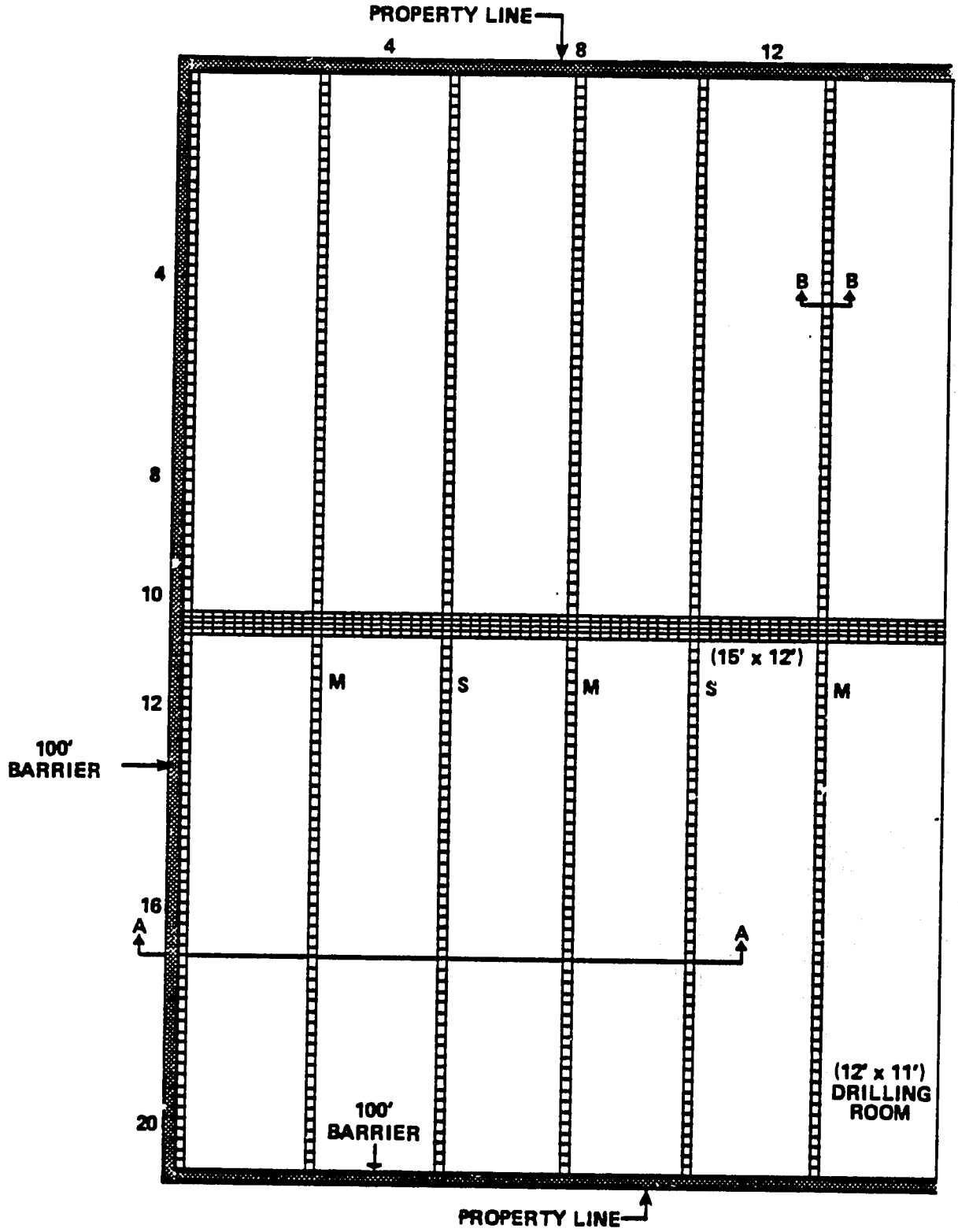


FIGURE 2-14 MINE PLAN GENERAL ARRANGEMENT

639

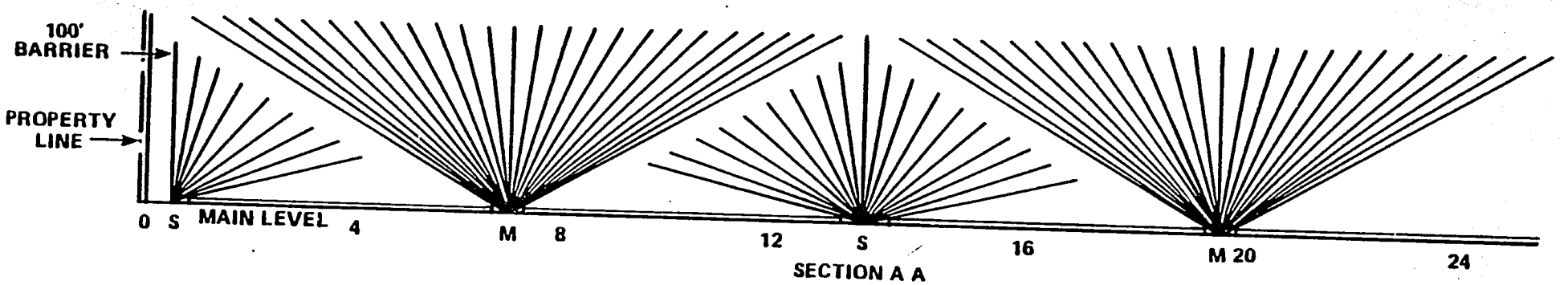


FIGURE 2-15 CROSS SECTION OF MINE PLAN GENERAL ARRANGEMENT

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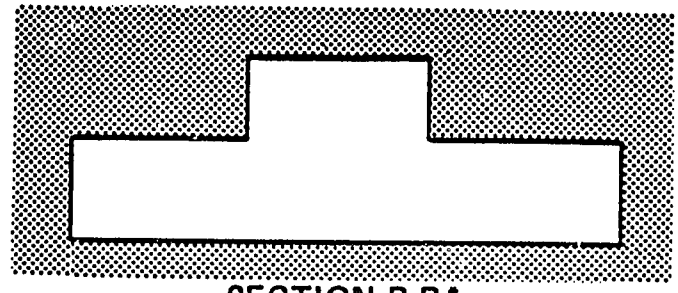
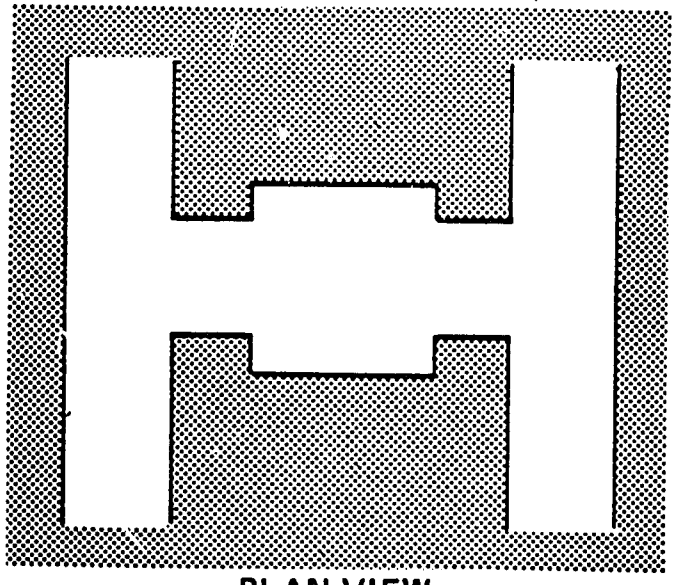


SECTION B-B*



PLAN VIEW

*SEE FIGURE 2–14

FIGURE 2-16
PRODUCTION HOLES
DRILLING ROOM

641

2.4 RESEARCH AND DEVELOPMENT

Available data indicates that mining of heavy oil is feasible from a technical, production, reliability, and safety aspect.

The three methods investigated --surface extractive, underground extractive and mining for access --all have limitations (excluding economics), as follows:

Mining Method	Item	Limitations
Surface Extractive	Overburden	Depth
	Resource	Thickness
	Equipment	None
	Manpower	None
Underground Extractive	Shafts	None
	Resource	Strengths and Thickness
Mining for Access	Equipment	Permissibility
	Manpower	None
	Shafts	None
	Resource	None
	Equipment	None
	Manpower	None

The only limitations to surface extractive mining are those associated with the stripping ratio (overburden to resource), and therefore there are economic limitations regardless of the material or mineral to be mined. The pit or mine face will naturally be oil laden and present some traction problems, but no research and development would be necessary to resolve this problem.

The limitations of underground extractive mining are in two categories. If the heavy oil host rock has strength and is competent, then the oil content may be low; conversely, if the oil content is high, the rock may not have the strength to withstand mining operations. The thickness of a reservoir is also a limitation, which is reflected in the economics.

The limitations with equipment needed for underground extractive mining are in the area of permissibility. The equipment which operates in coal and other mineral mines is rated permissible only for methane gas, for which monitoring systems have been developed. In an oil reservoir, the gases and combination of gases are different, and the explosivity limits have not been identified, nor has a monitoring system been designed to determine when the atmosphere is hazardous for a particular piece of equipment. Research and development is needed in this area not only to increase the inventory of permissible equipment, but also to improve the operating capabilities in cutting, boring, etc., to where ignition temperatures are lowered and sparking is eliminated or reduced. With oil surfaces, rubber products on tires, hoses, etc., may deteriorate, but engineering applications could solve this problem.

There do not appear to be any severe limitations in the mining for access methods other than the necessity to monitor gases that could be encountered in development of the network of production wells.

In summary, the most important and necessary research and development for heavy oil mining is to open a pilot site-specific mine, identify the problems, and resolve them for both surface extractive and mining for access projects. An underground extractive mine should not be considered at this time for economic reasons. Once the operational problems of other methods have been resolved, further efforts can be extended to a underground extractive mining project.

Figure 2-17 illustrates the process of developing an experimental oil mine in phases. This allows identification of flaws which research and development work can resolve, or the project will be discontinued due to insurmountable problems.

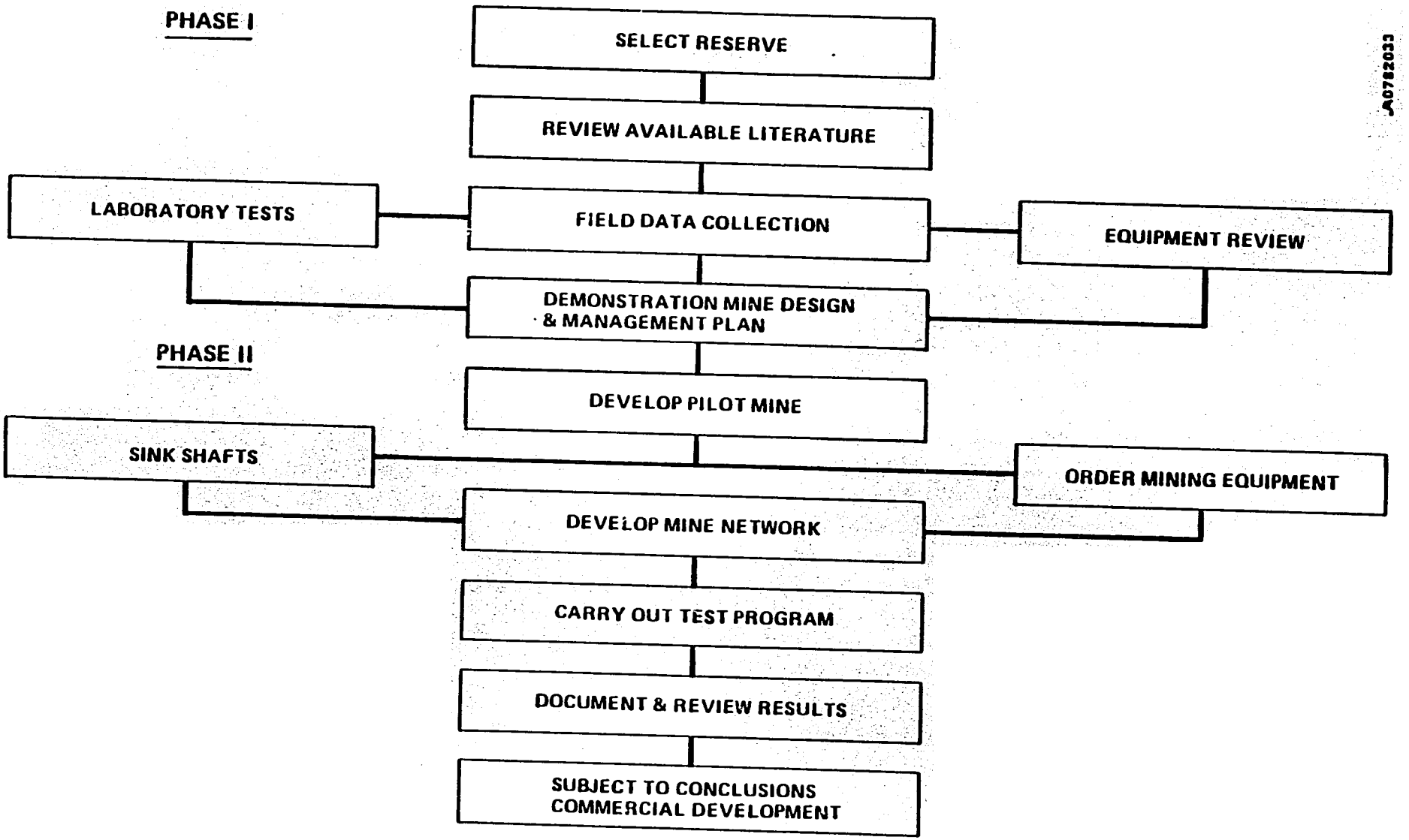


FIGURE 2-17 DEMONSTRATION PILOT OIL MINE FLOW CHART

6441x

3.0 DEVELOPMENT OF PRELIMINARY MINING SYSTEM CONCEPTS

3.1 THE KERN RIVER FIELD

3.1.1 Surface Extractive Mining of the Kern River Field

The purpose of this analysis is to determine the technical and economic feasibility of a surface extractive petroleum mining project for the Kern River Field located in Kern County, California. Using a set of reservoir screening criteria derived by the U.S. Department of Energy, and developed for the Task I section, the Kern River Field was selected for the site-specific design of a surface extractive mine.

In this analysis, oil-saturated ore is extracted from the reservoir in a modified open pit terrace pit mining operation. Waste ore and overburden is backfilled in the mine and oil-saturated sands are transported to processing facilities located outside the mine. Approximately 78,000 tons/day of ore is processed to yield 38,150 barrels/day of heavy crude oil.

The basic design criteria for the proposed Kern River Field surface mining project are summarized as follows:

- The ore body outcrops at the surface and has a homoclinal structure with a moderate dip angle of 4 degrees;

- The Kern River Field is particularly suited to terrace-type mining with level hauls for the backfilled waste material. The only vertical haulage required is for the oil saturated sands as they are transported to the processing facilities;

- A drill, blast, and shovel-loading mining cycle is utilized in the mine as opposed to continuous mining machinery because of a high degree of uncertainty regarding the overburden character; and

- The oil content of the reservoir averages 1,400 barrels per acre-foot in the net pay interval, and sufficient ore is mined to support the production of 38,150 barrels/day of oil from the processing plant.

3.1.1.1 Scope of the Site-Specific Mining Analysis

In the analysis, a site-specific mining design using modified open pit technology and incorporating initial, production and mature phases of pit geometry is developed. The objective of the analysis is to determine the economic viability of extractively mining the Kern River Field by surface mining techniques. A 20-year mine production schedule is shown in Table 3-1.

The analysis develops the time-dependent design of the open pit, specifying the equipment inventory required to meet the production level of 38,150 barrels/day. It also required developing budget-level cost engineering to determine the capital cost of the mine equipment, mine support facilities, and operating costs in 1982 dollars.

Using the cost engineering data, the analysis concludes with a series of cash flows demonstrating the economic viability of a surface extractive mine on the Kern River Field under a "base case" set of assumptions. Further, the sensitivity of project return-on-investment (ROI) is quantified as a function of the selling price of the heavy crude oil. This "generalizes" the results of the site-specific study and lends further insight to the feasibility of extractively mining the heavy oil fields of California.

3.1.1.2 Methodology

The methodology of this site-specific analysis consists of the following five steps:

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TABLE 3-1

SURFACE MINE PRODUCTION SCHEDULE
KERN RIVER FIELD
20-YEAR MINING SCHEDULE

	Tons/Yr. ($x\ 10^6$)	Tons/D ($x\ 10^3$)	Stripping Ratio	BPD[1]	20-Year Cumulative (10^6 Tons)
Pre-Stripping[2]	--	--	--	--	36.0
Ore	28.65	78.5	--	38,150	573.0
Waste[3]	75.65	207.3	2.64	--	1,513.0
	104.30	285.80	2.64	38,150	2,122.0

1) A plant recovery efficiency factor of 90 percent is assumed.

2) Pre-stripping operations are completed within one year. Cost for pre-stripping are capitalized.

3) "Waste" includes sub-ore and overburden material.

1) A stratigraphic analysis of the Kern River Field was performed in order to determine the critical site-specific conditions for the mine design;

2) A site-specific design was formulated using these data and the key parameters for equipment specification were determined, such as bench width and height, haulage distances, and overburden/interburden ratios;

3) Heavy mining equipment was specified and an inventory of purchase requirements was determined for the project as well as a personnel and equipment manning chart;

4) A cost engineering effort followed the specification of equipment type and mine infrastructure, and the capital and operating costs for the mining venture were determined; and

5) Using these cost engineering data, an economic analysis incorporating discounted cash flow results and sensitivity analyses were performed.

In addition to the above steps, a previous surface extractive mining design for the Kern River Field was reviewed and compared with present analysis. The earlier design, prepared by Golder Associates (Golder, 1978) presents an alternative equipment inventory that employs continuous-type mining machinery. The results of this analysis indicate that if continuous mining machinery is applicable to the Kern River Field, substantial investment returns can be realized.

3.1.1.3 Description of the Kern River Field

The key mine design data for an open pit mining system are highly site-specific. Therefore, in order to specify the detailed design criteria for the site-specific open pit mine on the Kern River Field, an exhaustive literature search was conducted indicating the values of critical geotechnical parameters.

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The Kern River Field was chosen for the detailed study of open pit mining technology on the basis of the comprehensive reservoir ranking system presented in Volume I of this report. This ranking system characterizes the overall U.S. heavy oil reservoir data base by identifying the categories of candidate mine systems and ranking the potential economic feasibility of these technologies on the basis of the salient features of the reservoir. The favorable ranking received by the Kern River Field for surface mining is primarily due to its shallow depth, high oil saturation, and low overburden ratio near the reservoir outcrop.

The Kern River Field is located on the east side of the San Joaquin Valley, approximately five miles northeast of Bakersfield, California, in an area of low rolling hills with sparse vegetation. The field consists of 9,435 proven acres which has been produced from surface wells.

o Geotechnical Information

A detailed geotechnical report on the Kern River Field is presented in Appendix A.

o Ore Grade and Total Oil In Place

The areal extent of the proposed surface mine at the Kern River Field is approximately three miles by one mile, covering approximately 2,600 acres of the 9,435 proven acres in the field.

Using the well log data in Appendix A, the oil content of the producing intervals is estimated to be 0.54 barrels per ton, based on an estimated current oil saturation of 52 percent and a porosity of 35 percent.

The producing horizons of the Kern River Field occur entirely within the Kern River Formation, which is composed of up to 9 feet thick, productive sand bodies varying from 30 feet to 100 feet thick, separated by mudstones averaging 20 feet thick. The sand bodies occur in a vertically repeated

sequence, starting with a basal conglomerate with pebbles from 1/4 inch to 12 inches in diameter, overlain by cross stratified, coarse, poorly sorted sandstone, grading finer upwards into a mudstone composed of fine sandy silt with a minor amount of clay. The Sierra Nevada Batholith is located near the Kern River in a braided alluvial system. The top of the reservoir varies from the surface at the east end of the field to as much as 1,500 feet at its southernmost end. The trapping mechanism for the heavy oil is predominantly stratigraphic with an updip tar seal and stratigraphic pinchouts.

The oil saturation of the Kern River Field is estimated to be 307,674 barrels per acre with a net pay interval of 220 feet yielding 1,399 barrels per acre-foot in the pay zone. The total oil in place over the 2,600-acre mining target is approximately 800 million barrels. With a required production of 38,150 barrels per day, the life of the 2,600-acre surface mine is estimated to be 60 years.

The oil produced from the Kern River Field has a gravity of 14 degrees API and a viscosity of 4,000 centipoise which decreases sharply with temperature. For example, at 250 degrees Fahrenheit the viscosity of the crude is only 15 centipoise, which explains in part the tremendous success of steam-thermal operations in the Kern River area. The sulfur content of the oil produced is 1.19 percent with a carbon residue of 6.8 percent.

o <u>Historical Production</u>

The Kern River Field was first discovered in 1889 when several wells were drilled by hand to recover lubricating oil. The first successful well, completed using a hand auger, supplied lubricating oil to the Bakersfield, California, area. By 1904 the field was producing 17,000,000 barrels of oil per year. Production declined from this level, and the field produced at a lower rate until 1943. As a result of World War II, production increased dramatically, and from 1943 to 1948 more than 600 new wells were drilled. This trend continued in the early fifties due to the petroleum demand during the Korean War. Production again increased after the

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introduction of steam displacement, and other enhanced oil recovery technologies were introduced in the mid-1950's. The importance of the field is demonstrated by the fact that in 1978 the Kern River Field was rated California's fourth largest oil reservoir in terms of daily production.

3.1.2 Open Pit Mining of the Kern River Field

In this section a design for a hypothetical surface extractive heavy oil mine was developed for the Kern River Field in California. The design selected has been adapted from a combination of open pit and terrace mining technologies and incorporates the site-specific geotechnical criteria presented in Volume 1.

Critical design criteria, engineering data, production scheduling, and equipment and manpower requirements are presented in this section in order to estimate the capital and operating costs for a surface extractive mining operation using a combination modified open pit and terrace mining technology.

3.1.2.1 Modified Open Pit Mine Design

The surface mine considered is best described as a modified open pit mining system utilizing a combination of a terrace pit level-haul system and an open pit system in which ore is hauled up ramps out of the pit by trucks. The Kern River Field is particularly well suited to a terrace mining type of system with level-hauls for the transportation of overburden and interburden waste material for backfilling into previously mined areas of the pit.

The Kern River Field outcrops and the ore body has a dip angle of approximately four degrees over the 9,400-acre reservoir extent. Figure 3-1 displays this geometry and presents a cross-sectional view of a mine using the modified open pit technology selected. Interburden and overburden waste material is transported on level terraces around the pit

(denoted as levels T1, T2, and T3 in Figure 3-1) to the dump areas on the eastern end of the Kern River Field. This allows for all stratigraphic oil-bearing zones to be recovered whil eliminating the need for the vertical transport of all but the oil-bearing sands. As seen in Figure 3-1, waste from bench "A" goes to "A'" in the backfill area, "B" goes to "B'", etc. The ore removed from the bottom of the terrace pit is transported to the surface processing facilities by 120-ton trucks travelling along the terraces and gaining height by semi-permanent ramps established at the extreme ends of the pit.

The initial waste-to-ore ratio for the outcropping ore body is 2.64:1 which is the lowest and most economically favorable ratio throughout the entire life of the Kern River surface mine. Therefore, in order to optimize the initial-phase economics of the project, the pit will be initially developed with a long, narrow-pit geometry taking advantage of the low waste-to-ore ratio in the outcrop zone. As the pit expands, thereby widening the long initial cut, the amount of overburden material to be removed increases steadily and the waste-to-ore ratio increases to a 4.0:1 ratio by the termination of the 20-year mine production operations.

In order to initiate the mining operations, approximately 36,000,000 tons of overburden must be removed in a strip approximately 6,000 feet long in a cross section of roughly 100,000 square feet. By backfilling the mined-out area using the level-haul methodology, preproduction stripping is kept to an absolute minimum and only the stripped material will have to be dumped outside of the pit limits. Further, the ore body is rapidly intersected by this approach and all of the oil-saturated sand intervals encountered are of positive economic value. The initial cut lengthens to a three-mile long strip while the mine is advancing outward and downward along the dip angle into the ore body. This long "strip" is sectionalized so that at three separate intervals semi-permanent haul ramps can be established between terraces in order for the ore to be removed from the bottom of the mine while the interburden and overburden waste is hauled on the level terraces around the pit to backfill the previously mined areas.

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Mine production is scheduled to provide enough ore to the processing facilities to generate 38,150 barrels per day of heavy crude oil. This requires mining 78,500 tons per day of ore material at a calculated "grade" of 0.54 barrels per ton as based on historical oil production and core data. A processing efficiency factor of 90 percent is assumed for "stripping" the oil from the saturated sands. The product output from the ore processing facilities is quite sensitive to the oil content of the feed processed by the separation units. Thus, it is necessary to define a cut-off grade for the ore in order to evaluate the mine economics. Ore with an organic content less than a defined cut-off grade is considered to be waste as defined by the term "sub-ore" and is not processed. The cut-off grade for the mining plan considered on the Kern River Field has been carefully calculated by estimates of the oil in-place and time-averaged stripping ratio and is defined to be 0.24 barrels per ton (10 gallons per ton). Definitions for overburden, sub-ore, and ore are presented as follows:

- Overburden - All material between the ground surface and the top of the highest ore zone with no organic content.

- Sub-ore - Low-grade oil-saturated material with less than 10 gallons per ton oil content.

- Ore - Oil-saturated sands with a grade greater than 0.24 barrels per ton and averaging 0.54 barrels per ton in the Kern River Field.

These definitions are useful in the calculation of the required production schedule for the mine. Clearly, as the mine evolves and expands outward from the initial pre-stripping cut, the amount of overburden increases as does the waste-to-ore ratio. By calculating the average grade of the ore and its "dilution" by sub-ore and overburden waste material, the required ore production, in order to maintain a 38,150 barrel per day output from the processing facilities, is estimated. For the 20-year plant average, 78,500 tons per day of ore are mined with 207,300 tons per day of waste material (overburden and sub-ore) backfilled into the mine.

After the ore has been processed, the tailings are placed on top of the upper bench of the backfilled mine area and a reclaimed ground surface is established, as shown in Figure 3-1.

The removal and conveyance of sub-ore and overburden waste material is considered within the scope of the total open pit mining operation. The replacement of the processed ore tailings, however, is considered part of the processing costs for recovery of the oil. Therefore, the defined scope of the modified open pit mining operation incorporates the following unit steps:

- Mining of overburden, sub-ore, and ore;
- Transport of the overburden and sub-ore materials to the backfill site and backfilling; and
- Conveyance of the ore out of the open pit to the surface processing facilities.

3.1.2.2 Mine Design Criteria

The modified open pit mine evolves in three distinct phases: the initial phase pit, the production phase pit, and the ultimate operation phase. Each of these three phases of operation represents separable trends in the development of pit geometry and the inventories of mining equipment. The equipment mix selected remains constant throughout the production phase for the mining technology considered.

The objective of the initial phase of operation is to remove a sufficient quantity of overburden so that full-scale ore production can proceed. In the Kern River Field, the initial phase pit consists of a 6,000-foot strip approximately 700 feet wide where the initial terraces and ore haulage ramps are established. Approximately 36,000,000 tons of ore are removed during this phase and the initial phase of operations continues with the lengthening of the 6,000-foot pre-strip pit to approximately 16,800 feet (3 miles) in length.

654x

The production phase commences after sufficient overburden is removed and the full ore zone is intersected. During this phase, operations are discontinued for lengthening the northwest by southeast extension and efforts are concentrated on mining the ore by following the down-dip ore body on the 4° incline. Semi-permanent haul ramps are established in order to transport ore from the bottom of the pit out of the mine to the processing facilities, and terraces following a level-haul geometry are established around the perimeter of the sectionalized pit areas. During this phase the pit slope is kept to a 29° angle owing to the unconsolidated nature of the material and the presence of groundwater. The production phase operations continue for approximately 20 years. At this point the mine is approximately 8,000 feet wide and 600 feet deep at the deepest point along the footwall of the lowest bench, and is approximately three miles long. The mine is divided into three sectionalized areas. At the termination of the production phase pit the stripping ratio is approximately 3.64:1 with over 277,000,000 barrels of oil produced over the project life.

The ultimate phase of operations involves expanding the surface mine across the entire 9,400 proven acres of the Kern River Field. At this point significant waste-to-ore ratios are encountered, and the economic viability of the mining operation depends heavily on the percentage of the capital return premium that can be re-directed from the processing facilities to the mining operation in order to correct for the excessive cost of waste transport and disposal.

The site-specific mining design considered in this chapter for the Kern River Field does not detail the design or economics for the ultimate phase pit. A 20-year economic project is considered reasonable for a heavy oil mining operation in view of the investment opportunities elsewhere in the synthetic fuels production technology array. Investments requiring an investment period of longer than 20 years are currently viewed as unattractive by most participants in the synthetic fuels industry.

- Pre-Production Operations

Production from the mine is initiated by removing sufficient overburden in order to initiate the full-scale production of ore from the mine. As previously discussed, a 6,000-foot cut, approximately 700 feet wide, is established at the toe of the ore zone outcrop on the northeast side of the Kern River Field. The overburden is removed and conveyed out of the pit to an off-site overburden storage area. Simultaneously with this pre-stripping operation, the processing facilities for removing the oil from the saturated sands are constructed and the water and electrical infrastructure facilities are installed. The pre-stripping operations at the toe of the ore body outcrop are conducted so that sub-ore and overburden waste material can be backfilled without vertical haulage throughout the production phase of mine operations. A road of 8 percent grade is established from the ore body level as a series of ramps between the terrace haulageways which are level. These ramps are maintained as the pit expands by forming a terrace-to-terrace access ramp as the working cut has advanced along each bench. The haul roads established are a minimum width of 75 feet and are constructed with safety berms along the edge.

At the end of the pre-production operations phase, the ore body is exposed, and sufficient room has been established for waste backfilling in the mine. Also, an ore haulageway has been established to bring ore from the bottom of the pit (ore zone) by truck to the processing facilities located approximately 1.5 miles from the mine.

- Production Operations

The Kern River Field is mined by a standard drill-blast-muck (DBM) method using shovel loading and truck haulage. This mine method is employed in all phases of the mine. The modified open pit approach maximizes the use of level hauls to the backfill areas and only the oil-bearing material will be transported vertically out of the pit. This modified terrace pit method has several advantages for the equipment array selected:

- Operating costs for the mine are reduced owing to the level hauls for the bulk (over two-thirds) of the material mined;

- The use of the large electric shovels is easier than in a normal open pit because of the larger working areas on the benches in the terrace pit approach; and

- Large capacity diesel-electric drive haulage trucks can be used to lower the unit costs of mining and improve the costs as compared to a pure open pit mining system.

The mine is designed with 50-foot-high benches and a minimum of 150-foot-wide terraces in the ore zone. The primary loading unit for all three pit phases are 24-cubic-yard electric power shovels. The shovels load the blasted rock into a fleet of 120 ton rear-end dump trucks on a continuous basis. An optimum 8:1 truck-to-shovel ratio is used in order to keep the mine cycle continuous throughout the three shifts per day operation.

Haulage roads for the sub-ore and overburden are routed through the inactive terraces of the mine and are maintained on a level-haul to the backfill area. The ore is transported to the pit ramp through the inclined terrace access ramps where it is discharged into a stockpile reclaim area prior to crushing in large gyratory crushers. From the reclaim area the ore is transported to the processing facilities with the waste sand tailings spread on the top of the uppermost backfill bench thereby creating a reclaimed ground surface.

The ore stockpile and reclaiming facilities are located approximately 1.5 miles from the eastern most pit rim extremity as established in the initial phase of mine operations. During the production phase of operations, the pit slope is kept to a maximum angle of 29 degrees because of the unconsolidated nature of the sands and the potential for water encroachment into the mine. This phase lasts approximately twenty years under the defined production schedule of 38,150 barrels of oil per day as discussed in the next section.

- Production Schedule and Ore Recovery

The production schedule for the 20-year mine life is shown in Table 3-1. The annual production levels of ore, sub-ore, and overburden are estimated on the basis of a three shifts per day, 364 operating days per year mining schedule. The amount of ore required as a feed to the processing facilities is estimated by calculating the average ore grade over the twenty-year mine life. Each day (three shifts) 78,500 tons of ore will be mined along with 207,300 tons of waste for a total mine production of 285,800 tons per day. The waste produced is backfilled in the mine, and the only vertical haulage is for the ore to the processing facilities outside of the pit limits. The total oil production from the processing plant, including a 90 percent efficiency factor for oil extraction, is 38,150 barrels per day.

- Overburden, Sub-ore, and Process Ore Disposal

The disposal of overburden and sub-ore is considered a component of the total modified open pit/terrace pit mining operation. Disposal operations proceed on a haul-dump-spread cycle. Waste is discharged from the 120-ton dump trucks and distributed over the working sections of the disposal area on the selected terrace by rubber-tired dozers. The material is further spread with bulldozing equipment and is subsequently compacted naturally. In the backfilling area on the eastern edge of the pit, the terraces are a minimum of 150 feet wide. The material is spread as well as "cast" over the edge of the terrace to the next level, thereby creating a highwall, with the geometry incorporating a natural angle of repose for the cast material. The material on the working terrace is naturally compacted and the backfilling operations continue in a cyclical manner.

Although not within the scope of the mining operations, the tailings from the ore processing facility are spread on top of the uppermost backfilled terrace bench and compacted in a manner similar to the waste backfill. Topsoil will be placed above this revised ground surface and vegetated.

3.1.2.3 Mine Equipment Selection

In this section the equipment inventory required for the mining and backfilling operations is defined, as well as the personnel requirements and support and ancillary facilities needed to sustain mine production.

An alternative equipment mix using bucketwheel excavators is considered. The use of bucketwheel-type excavating equipment is discussed and compared to the equipment inventory defined for DBM technology.

o <u>Required Equipment: Mining and Backfilling</u>

Equipment schedules are calculated on the basis of three seven-hour shifts per day, 365 operating days per year. The number of drilling, blasting and loading units in operation is determined by the required annual production rates of ore, sub-ore and overburden. In estimating the number of operating units, contingencies for the efficiency, functional availability and maintenance of the equipment are accounted. Tables 3-2, 3-3 and 3-4 list the total equipment inventory for mining and backfilling in the Kern River Field. Excavating, hauling and maintenance equipment are specified and the purchase requirements are indicated.

The following is a brief description of each equipment category: For drilling the benches, large rotary electric blast hole drills are used in all phases of the mine development. A bore size of 6 inches is used to drill the rounds vertically into the terrace benches. The total drill hole length is 43 feet, 40 feet of bench plus a 3-foot extension.

A powder factor of 0.25 pounds of ANFO per ton is used and high density water gels are used to "booster" the ANFO charge. Given this required blasting factor, a drill pattern of 20 feet by 20 feet is utilized. By estimating the total number of feet drilled per bench round, four operating rigs are required.

TABLE 3-2

EQUIPMENT SELECTION: PRODUCTION PHASE MINING OPERATIONS[1]
KERN RIVER FIELD
MODIFIED OPEN PIT

Equipment Item	Purchase Requirement
Shovels (24 yd^3 Electric Power Units)	9
Trucks (120 Ton Diesel with Electric Drive)	64
Blast Hole Drills	5
ANFO Trucks	5

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TABLE 3-3

EQUIPMENT SELECTION: MINING SUPPORT AND ANCILLARY EQUIPMENT

Equipment Item	Purchase Requirement
FEL: 16 yd^3	5
Bulldozer (410 Hp Cat D9H or equivalent)	9
Grader (250 Hp Cat 16G or equivalent)	5
Fuel Trucks	2
Lube Trucks	4
Tire Trucks	4
Electrical Truck	4
Maintenance Trucks	4
Water Trucks	5
Personnel Carriers	8
Misc. Vehicles (Jeeps, Ambulances, and Pickups)	

[1] Total ton of ore, sub-ore and overburden mined equals 285,800 TPD.

TABLE 3-4

EQUIPMENT SELECTION: OVERBURDEN AND SUB-ORE BACKFILLING [1]
KERN RIVER FIELD
MODIFIED OPEN PIT

Equipment Item	Purchase Requirement
Bulldozer (Cat D9H or equivalent)	8
Water Truck (Cat 631B or equivalent plus 10,000 gallon trailer)	2
Support Equipment:	
Fuel Truck	2
Lube Truck	2
Tire Truck	2
Maintenance Truck	2
Support Vehicles	
Personnel Carriers (Bus)	5
Pickups/Jeeps	10

1 Total tons of overburden and sub-ore backfilled equals 207,300 TPD.

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The loading and hauling system selected for the Kern River mine consists of 24-cubic-yard electric power shovels and 120-ton off-highway trucks. Muck is loaded at the bench into the 120-ton trucks and "trammed" over prepared haul roads either on-level to the backfill area, or up a series of haulage ramps to the pit perimeter where an ore stockpile and reclaim area is located. The truck fleet contains 64 units which will be serviced by 9 electric power shovels. The eight-to-one ratio of trucks to shovels is considered optimal for the type of terrace mining operation planned.

Nine shovels are employed in the operation spread over a total of five benches with three shovels working in the ore zone and five shovels continuously active in the sub-ore (interburden) benches and overburden cuts. At any given time, one shovel is idled for preventative maintenance and repair.

The shovel loading and haulage system constitutes the single largest percentage of the equipment capital cost for the mine (over 66 percent). Thus, the efficiency of this system is critical to the economic success of the mine, and a sufficient number of units must be available so that preventative maintenance can be performed. By extending the equipment life substantially through maintenance, the required replacement capital penalty for the mine operation is reduced. A sufficient number of mechanical personnel and shop facilities have been estimated for the design to accommodate the maintenance requirements.

The overburden and backfilling operations require an equipment inventory of dozers to distribute and grade the sub-ore and overburden material over the backfill terrace benches as well as keeping the dump benches clean. Compaction is achieved naturally by the multitude of passes of the large equipment on the levels. A minimum density of 80 pounds per cubic foot is achieved.

o <u>Personnel Requirements</u>

The personnel requirements for the Kern River Field heavy oil surface mine are summarized in Tables 3-5 and 3-6. Two groups of personnel are defined for the mining operations and the waste backfilling operation. Each group

TABLE 3-5

PERSONNEL REQUIREMENTS: MINING OPERATIONS
KERN RIVER FIELD
MODIFIED OPEN PIT

Position/Operator	Total Personnel [1]
Equipment Operators	
Shovel Operators	32
Shovel Helpers	32
Truck Drivers	232
Drill Operators	15
Driller Helpers	15
Blasters	8
Blasting Helper	16
FEL Operators	9
Bulldozer Operators	16
Grader Operators	15
Equipment Maintenance Personnel	
Fuel Truck Crew	4
Lube Truck Crew	16
Tire Truck Crew	16
Maintenance Truck Crew	16
Mechanics (Roving)	16
Assistant Mechanics (Roving)	16
Electric Truck Crew	16
Water Truck Crew	16
Position/Operator	
Shop Mechanics	40
Assistant Shop Mechanics	40
Welders	20
Assistant Welders	20
Laborers	20
Small Tools Crew	20
Indirect Personnel	
Mine Superintendent	1
Shift Superintendents	4
Mechanic Superintendents	4
Chief Engineer	1
Planning Engineers	2
Safety Engineer	1
Environmental Engineer	1
Surveyors	2

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TABLE 3-5 (cont'd)

PERSONNEL REQUIREMENTS: MINING OPERATIONS
KERN RIVER FIELD
MODIFIED OPEN PIT

Position/Operator	Total Personnel [1]
Surveyor Assistants	4
Clerical Personnel	10
Warehouse Personnel	12
First Aid Personnel	4
Security Personnel	4
Drivers	8
TOTAL	724

TABLE 3-6

PERSONNEL REQUIREMENTS: OVERBURDEN AND SUB-ORE BACKFILLING
KERN RIVER FIELD
MODIFIED OPEN PIT

Position/Operator	Total Personnel[1]
Equipment Operators:	
Bulldozer Operators	32
Water Truck Drivers	8
Equipment Maintenance Personnel	
Fuel Truck Crew	8
Lube Truck Crew	8
Tire Truck Crew	8
Maintenance Truck Crew	8
Mechanics (Roving)	8
Assistant Mechanics (Roving)	8
Shop Mechanics[2]	-
Indirect Personnel[2]	-
TOTAL	88

[1] Based on a 3-shifts per day backfilling operation with 4 crews; (3 active and 1 relief crew). Each crew works 40 hours per week, 48 weeks per year (1920 hours per man).

[2] Included in Mining Personnel Schedule.

contains equipment maintenance personnel, and the indirect personnel requirements for supervision, engineering and surveying are burdened to the mining operation.

The number of personnel required for equipment operation is based on a three shifts per day mining operation and four crews; one relief crew for each of three active crews. Each equipment crew works 40 hours per week, 48 weeks per year. The size of each crew is based on the personnel requirements for each piece of equipment and the number of units in operation during each shift.

In support of the mining operations, 276 personnel serve as mechanics (both mobile and shop), welders, laborers and fuel/lube jobbers. Fifty-eight personnel--salaried professional and clerical--indirectly support the mining activity in supervisory and engineering capacities. Similarly, the backfilling operations employ 40 equipment operators and 48 roving mechanics and fuel jobbers. The indirect personnel discussed above serve both the mining and backfilling operations in a centralized administration building located on-site.

Thus, the total personnel required for the overall heavy oil mining operation to provide 78,500 tons per day of 0.54 barrels per ton ore to the processing plant is 812 semi-skilled, skilled, and professional people. The mining operation employs 724 workers, and the backfilling operation employs 88 equipment operators.

- Ancillary and Support Facilities

Facilities for supplying electricity to the mine, maintaining and repairing the equipment, and supplying food, water and sanitary facilities to the mine personnel are included in the surface mine design ancillary facilities.

Electricity is supplied by a 130 KV transmission line that originates from a substation estimated to be 13 miles away. At the mine site, a substation and load control center is supplied. Power is consumed in the mine by the electric shovels (4,000-4,500 KW), drills, mine lights (500-1000 KW), changehouse and shops.

The personnel changehouse is used by the workers between shifts and as an emergency triage clinic. Potable water is supplied to the changehouse by the water treatment plant constructed on-site. It is believed that the construction of self-contained facilities for the mine is a viable option and competitive with the cost of piping municipal water over a considerable distance. With the mine and plant in full operation approximately 800 workers will be employed in the mine, and a minimum of 500 workers will be employed in the processing plant. Thus, the establishment of a local potable water supply from treated raw water and the development of local sewage and domestic waste treatment capability is considered preferable.

In addition to the changehouse, other buildings constructed on-site include a warehouse for storing heavy equipment, pipe, steel and explosives, administrative offices and shop facilities. The shops are charged with maintaining the mine equipment, and two separate facilities are constructed: one for light equipment (drills, jeeps, ANFO trucks, fuel trucks, etc.), and one for heavy loading and hauling equipment.

o <u>Alternate Equipment Inventories and Mining Technologies</u>

Alternative mining systems have been proposed for surface terrace pit mining system in the Kern River Field. In Golder, 1978 a terrace mining system utilizing bucketwheel excavators was proposed that produced approximately 130,000 tons per day of ore. Three large bucketwheel units are employed in this design with each unit handling a 200 foot vertical cut on a 120 foot face. Ore and overburden handling is effected by feeding the material onto belt wagons which then transfer the rock and ore to main trunk conveyors located on each terrace edge. The overburden material would be transported around the pit to a stacker on each bench elevation and the material is dumped back into the worked out areas of the mining operation.

The technical feasibility of using bucketwheel excavators was not extensively addressed in the Golder report (op.cit.). Although this type of large-volume mining machinery has been used very successfully in Europe in coal mining operations, there have been no successful attempts to use

bucketwheel excavators in a reservoir mining situation. The feasibility of using this system largely hinges on the type of overburden conditions encountered in the Kern River Area. Large boulders or extremely hard sedimentary deposits could diminish the effectiveness and efficiency of this system dramatically.

However, if the system is technically feasible, substantial unit cost economies of scale could be witnessed. Golder (op.cit.) reports a unit cost of $0.95 per ton of ore which is less than 20 percent of the mining cost for ore using the modified open pit design with drilling, blasting, and mucking equipment.

Thus, if bucketwheel excavators can be used the cost of mining can be significantly lowered thereby effecting the economic feasibility of surface extractive mining of heavy oil deposits in the Kern River area.

3.1.2.4 Economics of Open Pit Mining in the Kern River Field

The results of the capital cost, operating cost and cash flow analyses for modified open pit mining in the Kern River Field are presented in this section. Capital expenditures for the mining and backfilling equipment, overburden pre-stripping, utilities, buildings and project engineering were estimated on the basis of the purchase requirements outlined in the previous section. Operating costs were evaluated on the basis of the required personnel for the mining and backfilling operations and the number of minimal net equipment operating hours required to meet the defined production schedule for ore and waste material backfill.

Data for the capital and operating cost estimates were procured from a variety of sources, including equipment vendors, literature on heavy oil mining, and cost estimating handbooks. Approximately 50 percent of the total capital cost for equipment and utilities was procured by vendor quotations for this study. All cost bases are estimated in fiscal year 1982 dollars for both capital and operating cost centers. Labor rates are projected from wage statistics provided by the U.S. Bureau of Labor Statistics. They reflect the judgment of the present authors in the assessment of labor demand and the hourly costs of personnel.

A "base case" cash flow analysis was defined using fixed assumptions for royalties, taxes, equipment depreciation, resource depletion and the FOB price of heavy crude oil. The analysis includes the results of the discounted cash flow base case and plot of mine return-on-investment (internal ROI) as a function of the required oil selling price.

o Capital Cost Analysis

The capital investment summary for the Kern River Field modified open pit mine is presented in Table 3-7. The gross investment is divided into the following five major categories:

- Mine Equipment
- Mine Pre-Development
- Support Facilities
- Working Capital
- Replacement Capital

The capital expenditure required for the production phase of mining and backfilling equipment is given in Table 3-8. Unit costs for the equipment items specified were procured from heavy equipment vendors. No allowances for volume discounts were credited to the purchase costs of the machinery.

The costs for mine development items are based on an estimate of 36 million tons of pre-stripping at a calculated cost of $1.30-$1.50 per ton. Previously published estimates of the pre-stripping requirements for the Kern River Field (Golder, 1978) indicate a similar cost of development and overburden removal of approximately $50 million. The pre-stripping overburden quantity is estimated from the production schedule for the initial phase mine. The mine utilities as itemized in Table 3-9 total $7.5 million. Also included in the development costs are exploration and engineering, which are estimated at 10 percent of the gross equipment budget costs for the project.

TABLE 3-7

CAPITAL INVESTMENT SUMMARY (BUDGET ESTIMATE)[1]
KERN RIVER FIELD
MODIFIED OPEN PIT

ITEM	TOTAL COST ($ FY 1982)	UNIT COST
MINE EQUIPMENT CAPITAL:		
Mining Equipment:	$95,990,000	
Backfilling Equipment	6,240,000	
Subtotal	$102,230,000	$2,680/BBL
DEVELOPMENT CAPITAL ITEMS:		
Mine Pre-Stripping:	$50,000,000	
Mine Utilities:	7,500,000	
Exploration & Engineering:	15,970,000	1926/BBL
Subtotal	$73,470,000	
SUPPORT FACILITIES:		
Mine Shop, Warehouse & Changehouse:	$3,750,000	98/BBL
WORKING CAPITAL:	20,481,700	537/BBL
REPLACEMENT CAPITAL:	69,500,000	1822/BBL
CONTINGENCY (15%):	40,414,800	1059/BBL
TOTAL CAPITAL INVESTMENT	$309,846,500	8,122/BBL

1 Based on a plant production of 38,150 barrels of heavy crude oil per day.

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TABLE 3-8

CAPITAL COSTS: MINING AND BACKFILLING EQUIPMENT
KERN RIVER FIELD
MODIFIED OPEN PIT

Item	Purchase Requirement	Cost/Unit [1]	Total Cost ($FY 1982)
Mining Equipment			
Shovels (24cy Electric)	9	$3,500,000	$31,500,000
Trucks (120 Ton)	64	790,000	50,560,000
Blast Hole Drills	5	285,000	1,425,000
ANFO Trucks	5	50,000	250,000
FEL: 16 yd^3	5	740,000	3,700,000
Bulldozer (410 Hp)	9	320,000	2,880,000
Grader (250 Hp)	5	275,000	1,375,000
Fuel Trucks	2	50,000	100,000
Lube Trucks	4	50,000	200,000
Tire Trucks	4	50,000	200,000
Electric Trucks	4	50,000	200,000
Maintenance Trucks	4	50,000	200,000
Water Trucks	5	440,000	2,200,000
Personnel Carriers	8	120,000	960,000
Misc Vehicles	20	12,000	240,000
SUBTOTAL		$6,782,000	$95,990,000
Backfilling Equipment			
Bulldozer (410 Hp)	8	$530,000	$4,240,000
Water Truck (10,000 gal)	2	440,000	880,000
Fuel Truck	2	50,000	100,000
Lube Truck	2	50,000	100,000
Tire Truck	2	50,000	100,000
Maintenance Truck	2	50,000	100,000
Personnel Carriers	5	120,000	600,000
Pickups/Jeeps	10	12,000	120,000
Subtotal		1,302,000	6,240,000
TOTAL		$8,084,000	$102,230,000

[1] New Equipment Cost; Vendor Quotations for 4th Quarter, FY 1982.

Table 3-9 details the budget estimates for the utilities (electricity, water and sewage) and support facilities. The cost of buildings and support facilities are based on completed (construction)costs per square foot. The unit costs of construction listed were taken from estimates by civil construction contractor.

The working capital amount shown in Table 3-7 is calculated as 60 days of operating equipment, labor and materials costs for the mine operation without revenue, depreciation or taxes accounted.

The replacement capital requirement is an indirect capital expense estimated from the initial cost of mining equipment and the accepted equipment lifetimes in the type of mining environment anticipated. The number of replacement cycles is based on a 20-year mine life. The shovel loading equipment is assumed to have an operating life of 20 years and is purchased only once at the start of the mining operations. Haulage trucks, however, are assigned a replacement life of 5 years maximum service with no salvage value assumed. Other types of mine equipment specified have usable lifetimes of three to seven years in length and their purchase is accounted in the replacement capital total. Replacement capital has been calculated based on a 6 percent per year escalation and a return on money of 20 percent per year.

A contingency of 15 percent is added to the subtotal capital expenditures to account for unlisted capital items and miscellaneous unlisted equipment not included in the budget-type estimate prepared for this analysis.

- Operating Cost Analysis

The estimated operating costs for the Kern River Field surface mine are summarized in Table 3-10. The total annual operating cost is divided into four principal operating cost centers:

- Labor Costs
- Supplies Costs

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TABLE 3-9

CAPITAL COSTS: UTILITIES AND SUPPORT FACILITIES
KERN RIVER FIELD
MODIFIED OPEN PIT

Item	Quantity	Unit Cost	Total Cost ($FY 1982)
Utilities			
(1) Electricity: 130 KV Transmission, Substation, Distribution and Control	13 mi	$250,000/mi	$3,250,000
(2) Mine Lighting	L.S.	(Vendor Estimate)	1,500,000
(3) Raw Water Utilities: Well, Solids Knockout, Turbidity Treatment and Distribution	L.S.	$500,000 per package	500,000
(4) Potable Water Utilities Treatment and Distribution	L.S.	$750,000 per package	750,000
(5) Domestic Waste Treatment	L.S.	(Package Vendor Estimate)	1,500,000
SUBTOTAL			$7,500,000
Buildings			
(6) Mine Changehouse	9000 SF	$50/ft^2 (inst.)	$ $450,000
(7) Warehouse	9000 SF	$40/ft^2 (inst.)	360,000
(8) Light Equipment Shop (Tool Equipped)	12,000 SF	$75/ft^2 (inst.)	900,000
(9) Heavy Equipment Shop (Tool Equipped)	17,000 SF	$95/ft^2 (inst.)	1,615,000
(10) Administrative Offices			425,000
SUBTOTAL			$3,750,000

TABLE 3-10

ESTIMATED ANNUAL OPERATION COSTS
KERN RIVER FIELD
MODIFIED OPEN PIT

ITEM	ANNUAL COST ($ FY1982)	COST/ORE-TON[1]
LABOR COSTS:		
Mature Phase Mining Operations:	$27,377,600	
Backfilling Operations:	3,592,900	
Indirect Labor:	2,654,800	
Subtotal	$33,625,300	$1.17
SUPPLIES COSTS:		
Drilling Supplies:	$2,873,300	
Blasting Supplies:	10,689,600	
Subtotal	$13,562,900	$0.47
EQUIPMENT OPERATING COSTS:		
Mature Phase Mining Operations:	$51,712,300	
Backfilling Operations:	6,082,200	
Subtotal	$57,794,500	$2.02
GENERAL AND ADMINISTRATIVE COSTS:		
Corporate Burden/Working Interest:	$3,362,500	$0.12
CONTINGENCY (15%):	16,251,800	$0.57
TOTAL ANNUAL OPERATING COST:	$124,597,000	$4.35

1 Cost per ton of ore mined. Production equals 78,500 TPD of ore and 207,300 TPD of waste rock.

- Equipment Operating Expenses (EOE)
- General and Administrative Costs

A contingency of 15 percent is added to the operating cost subtotal to account for unlisted operating cost centers in the budget type estimate prepared for this analysis.

In Section 3.1.2, the personnel requirements of the mining and backfilling operations are specified on the basis of the equipment inventory selected and the number of operating units per shift. A total of four equipment crews were defined with three crews active and one crew on rotating relief. Each man works a 40-hour week, 48 weeks per year. In Table 3-11, the total labor costs are presented for the mining and backfilling operations. The burdened unit costs are based on data from the U.S. Bureau of Labor Statistics and are adjusted to the wage scales expected for a large surface extractive mine in California. A burden of 45 percent is added to the direct cost of labor to cover vacation pay, holidays, workmen's compensation, insurance and other fringe benefits.

The total labor cost per ton of ore mined is $1.17, and constituting the second largest operating cost center.

Table 3-12 gives the estimate for the drilling and blasting supplies cost. The estimate is based on the number of rounds drilled per day to meet the mine production schedule and on the blasting factor specified.

Drilling and blasting supplies total approximately $.47 per ton of ore produced. Other supplies, such as fuel, lubricant and repair parts, are included in the equipment operating expense (EOE) unit costs.

The total annual cost of equipment operation and maintenance is shown in Table 3-13. The hourly EOE estimates were procured from a combination of equipment vendors and industry handbook estimates. The annual operating cost is based on 7,644 total machine operating hours per year. The downtime allowance for each equipment category is accounted in the purchase inventory with more units purchased than operate per shift. A statistical

TABLE 3-11

OPERATING COSTS: MINING AND BACKFILLING LABOR COSTS
KERN RIVER FIELD
MODIFIED OPEN PIT

Position/Labor Category	Burdened Unit Cost	Number Personnel	Crew Cost/Hr.	Total Annual Cost
Equipment Operators (Mine):				
Shovel Operators	21.27	32	680.64	$1,306,800
Shovel Helpers	21.27	32	680.64	1,306,800
Truck Drivers	21.27	232	4,934.64	9,474,500
Drill Operators	20.77	15	311.55	598,200
Driller Helpers	20.77	15	311.55	598,200
Blasters	20.77	8	166.16	319,000
Blasting Helper	20.77	1	332.32	638,100
FEL Operators	20.30	9	182.70	350,800
Bulldozer Operators	21.27	16	340.32	653,400
Grader Operators	20.30	15	304.50	584,600
SUBTOTAL				$15,830,400
Equipment Maintenance Personnel (Mine):				
Fuel Truck Crew	21.27	4	85.08	$163,400
Lube Truck Crew	21.27	16	340.32	653,400
Tire Truck Crew	21.27	16	340.32	653,400
Maintenance Truck Crew	21.27	16	340.32	653,400
Mechanic (Roving)	23.16	16	370.56	711,500
Asst Mechanic (Roving)	21.27	16	340.32	653,400
Electric Truck Crew	21.27	16	340.32	653,400
Water Truck Crew	21.27	16	340.32	653,400
Shop Mechanics	23.16	40	926.40	1,778,700
Asst Shop Mechanics	21.27	40	850.80	1,633,500
Welders	23.16	20	463.20	889,300
Asst Welders	21.27	20	425.40	816,800
Laborers	20.30	20	425.40	816,800
Small Tools Crew	21.27	20	425.40	816,800
SUBTOTAL				$11,547,200
Equipment Operators (Waste Backfill):				
Bulldozer Operators	20.78	32	665.10	1,277,000
Water Truck Drivers	21.27	8	170.16	326,700

TABLE 3-11 (cont'd)

Position/Labor Category	Burdened Unit Cost	Number Personnel	Crew Cost/Hr.	Total Annual Cost
Equipment Maintenance Personnel (Backfilling):				
Fuel Truck Crew	21.27	8	170.16	$326,700
Lube Truck Crew	21.27	8	170.16	326,700
Tire Truck Crew	21.27	8	170.16	326,700
Maintenance Truck Crew	21.27	8	170.16	326,700
Mechanics (Roving)	23.16	8	185.28	355,700
Asst. Mechanics (Roving)	21.27	8	170.16	326,700
SUBTOTAL				$3,592,900
Indirect Personnel (All Operations)				
Mine Superintendant	31.82	1	31.82	$66,200
Shift Superintendants	27.84	4	111.36	231,600
Mechanic Superintendants	27.84	4	111.36	231,600
Chief Engineer	27.84	1	27.84	57,900
Planning Engineers	23.86	2	47.72	99,300
Safety Engineer	23.86	1	23.86	49,600
Environmental Engineer	23.86	1	23.86	49,600
Surveyors	23.06	2	46.12	88,600
Surveyor Assts	21.27	4	85.08	177,000
Clerical Personnel	20.00	10	200.00	416,000
Warehouse Personnel	21.27	12	255.24	490,100
First Aid Personnel	21.27	4	85.08	177,000
Security Personnel	20.00	4	80.00	166,400
Drivers	21.27	8	170.16	353,900
SUBTOTAL				$2,654,800
TOTAL				$33,625,300

TABLE 3-12

OPERATING COSTS: DRILLING AND BLASTING SUPPLIES BREAKDOWN
KERN RIVER FIELD
MODIFIED OPEN PIT

ITEM		COST
1.	Drilling Supplies:	
	Holes drilled per day:	276
	Footage per hole:	44 ft.
	Cost per foot:	$.65/ft
	Cost per day:	$7,894/day
	Annual Cost:	$2,873,300/year
2.	Blasting Supplies:	
	Cost per hole (dry):	
	210 lbs bulk ANFO @ $.20/lb	$42.00
	50 lbs H_2O gel @ $.80/lb	$40.00
	2 primers @ $1.80 each	$ 3.60
	2 caps @ $2.00 each	$ 4.00
		$89.60
	Cost per hole (wet):	
	Substitute bagged ANFO	$131.60
	Total explosives cost per day:	
	60% of holes dry	
	40% of holes wet	
	Cost per day dry holes:	
	(276)(.60)(89.60) =	$14,838/day
	Cost per day wet holes:	
	(276)(.40)(131.60) =	14,529/day
	Total Cost per Day =	$29,367/day
	Annual Explosives Cost:	$10,689,600

1 Includes bit cost, pipe cost and small tools. Labor, maintenance and EOE accounted elsewhere.

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TABLE 3-13

OPERATING COSTS: EQUIPMENT OPERATING EXPENSES
KERN RIVER FIELD
MODIFIED OPEN PIT

Operating Unit	Operating Cost[1] Per Hour	Number Operating	Total Cost/Hr.	Total[2] Annual Cost
Mining Operations				
Shovels (24 yd^3)	117.18	8	937.44	$7,165,800
Trucks (120-ton)	68.92	58	3,997.36	30,555,800
Blast Hole Drills	27.33	4	109.32	835,600
ANFO Trucks	25.25	4	101.00	772,000
FEL: 16 yd^3	68.50	4	273.60	2,091,400
Bulldozer (410 Hp.)	51.55	8	412.40	3,152,400
Grader	43.25	4	173.00	1,322,400
Fuel Trucks	15.00	2	30.00	229,300
Lube Trucks	15.00	4	60.00	458,600
Tire Trucks	15.00	4	60.00	458,600
Electric Trucks	15.00	4	60.00	458,600
Maintenance Trucks	15.00	4	60.00	458,600
Water Trucks	35.25	4	141.00	1,077,800
Personnel Carriers	25.00	8	200.00	1,528,800
Misc. Vehicles	15.00	10	150.00	1,146,600
SUBTOTAL				$51,712,300

TABLE 3-13 (cont'd)

OPERATING COSTS: EQUIPMENT OPERATING EXPENSES
KERN RIVER FIELD
MODIFIED OPEN PIT

Operating Unit	Operating Cost[1] Per Hour	Number Operating	Total Cost/Hr.	Total[2] Annual Cost
Backfilling Operations				
Bulldozer (410 Hp)	60.02	8	480.19	$3,670,600
Water Truck	35.25	2	70.50	538,900
Fuel Truck	15.00	2	30.00	229,300
Lube Truck	15.00	2	30.00	229,300
Tire Truck	15.00	2	30.00	229,300
Maintenance Truck	15.00	2	30.00	229,300
Personnel Carrier	25.00	2	50.00	382,200
Misc. Vehicles	15.00	5	75.00	573,300
SUBTOTAL				$6,082,200
TOTAL				$57,794,500

1 Operating Cost per Hour is defined as Equipment Operating Expenses (EOE): Fuel, Power, Repair Parts, Tires/Trucks; O&M Labor not included (accounted in Personnel Requirements). Vendor Quotes.

2 Based on 7 hours of operation per shift, 3-shifts per day, 364 days per year (7,644 total machine operating hours per year). Downtime allowance accounted in equipment purchase inventory.

3 Less bits, steel and explosives costs.

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allowance factor for units taken out of service for routine maintenance and repair is used in calculating the total number of units required for purchase.

Equipment operating expenses --$2.02 per ton of ore-- are overwhelmingly the largest unit cost for the modified open pit mining operation design for the Kern River Field.

A general and administrative burden of 10 percent of the annual labor cost is added to the total mine operating cost to cover charges for the home office (corporate burden) and pay interest on the working capital needs for the project.

The summary direct unit cost for the Kern River Field heavy oil mine is estimated to be $4.35 per ton of ore produced. For each ton of ore, 2.64 tons of waste, sub-ore and overburden are produced. Thus the direct unit cost of mining using the shovel and truck mining method is $1.20 per gross ton of rock. The direct unit cost does not include a return-on-investment capital, taxes or royalty.

o <u>Summary of Economics and Cash Flow Results</u>

A capital investment of approximately $310 million is required for the mine operation to supply the ore processing plant which produces 38,150 barrels of oil per day. This equates to an investment of $8,122 barrel per day of plant capacity. The cost of the ore processing equipment can be as expensive as, and in some cases can exceed, the cost of the mine. Golder (1978) estimates the cost of processing equipment for the Kern River Field to be approximately $5,000 barrel per day which is considered "low," compared with many of the other process plants presented.

The calculated cost of $4.35 per ore-ton ($1.20 per gross-ton mined) is considerably higher than the mining costs usually calculated. Golder (1978) reports a cost of $.945 per ton of ore for the Kern River Field; however, the mining design used for the estimate incorporates large continuous excavating equipment with conveyor transport. The feasibility of using these high-volume, low-cost units is uncertain at present.

However, if these units are used, the cost of ore mining drops to nearly 20 percent of the mining cost using drill, blast, and loading techniques.

- Cash Flow Analysis

The approach used to analyze the economics of modified open pit surface mining was a discounted cash flow in which revenues were derived to meet expenses, recover capital costs, and provide a desired rate of return. Based on this required level of revenues and the estimated annual output price per ton of ore was derived.

The assumptions used in the cash flow analysis were:

Capital Requirements

- Indirect Field Cost (2%)
- Engineering Cost (3.5%)
- Overhead and Administrative (5%)

Operating Expenses

- Indirect Labor Costs (4.5%)
- Administrative and General Expenses (3.55%)
- Insurance Costs for 75 Percent of the Plant (0.5%)

Depreciation

- Based on ACRS Tax Guidelines

Depletion Allowance

- No Depletion Allowance Taken

Escalation

- For Both Replacement Equipment and Applicable Operating Expenses (6%)

Royalties and Taxes

- Royalty (12.5%)
- Effective Tax Rate (51.2%)
  State Taxes (9.6%)

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Federal Taxes (46.0%)

- Investment Tax Credit (10%)
- No Severance Tax or Energy Tax Credits
- No Property Tax Considered

o Economic Feasibility

The resulting implied selling price of $27.26 is considered marginally acceptable, based on the price of comparable heavy oil. An analysis of mining cost components reveals that the critical component of the cash flow analysis --operating expenses-- represents approximately $8.95 per barrel of the cost.

The large amounts of capital required are mainly due to direct cost and preproduction and contingency costs. Direct costs include the cost of equipment and facilities. The major component of preproduction or development costs is the cost of overburden removal. The critical factor affecting this cost is the ratio of overburden thickness to ore thickness. Variables such as the ore grade and specific overburden characteristics and the market value of oil affect this ratio and project economics. The large surface-accessible deposits in California offer economic benefits from the operation size.

The project's sensitivity to operating expenses remains the most important factor affecting the total cost as well as mining cost. Additional cost from further operations must be considered before the economic feasibility can be determined.

Once mined, the oil must still be extracted from the ore. Surface operations require handling the heavy oil in a solid form, which is more expensive than in either a liquid or gaseous state. The ore must be transported, then prepared for extraction by crushing or grinding. The high cost of ore transportation necessitates locating an extraction or processing plant a relatively short distance from the mine area, requiring

additional capital investments. Several oil recovery processes are possible to separate the substances, including thermal, chemical solvent or water extraction, and various combinations of each method. Upgrading may also be necessary at transportation and refining stages. As with tar sands, heavy oil extraction provides the opportunity of combining recovery with partial upgrading. The amount of processing required and its cost depend, in part, on the quality of oil and its potential uses.

The grade of heavy oil affects the price paid per barrel. Heavy oil quality varies greatly between conventional crude oil and tar sands. The nature of the oil, its viscosity, specific gravity, pour point, and impurities, affect the cost of processing and the sale price. Depending upon the heavy oil quality, prices have been ranging between $5 to $10 less than the going price of world oil. The current glut of oil on the world market forces down the price per barrel, causing expensive enchanced oil recovery methods to become uneconomical. The heavy oil quality and its possible uses become important at this point. The higher quality oil with fewer impurities requires less processing and provides greater potential uses, raising its sale price and lowering its costs. The economics depend on a number of factors, any number of which could significantly alter a development decision.

The final consideration affecting the project's economic feasibility is the desired return-on-investment (ROI). The difference between an ROI of 20 percent and one of 10 percent results in an increase of a little greater than $1.50 ton in the mining cost. These results can be attributed to the overwhelming effect of high operating costs on the project.

The economic feasibility of modified open pit mining is affected by the following internal economic factors:

- The high cost of operating expenses (this is the most critical component);

- The high initial capital cost of equipment;

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- The high expected capital cost of a processing plant;

- The initial high capital cost of overburden removal and development; and

- The relatively high required return on investment (due to external economic factors).

External economic considerations include:

- The price of oil

- The supply and demand for oil

- Federal policies

The recent closures of oil shale and tar sand operations demonstrate the vulnerability of high-risk energy projects. Continued trends of increasing oil usage, however, are still projected due to the lack of suitable alternatives. Enchanced oil recovery projects offer risks from a known product. Despite the current economic conditions, the heavy oil modifield open pit mining studied in this report appears to be a marginally economic alternative.

o <u>Project Sensitivity to Oil Selling Price</u>

In Figure 3-2, a curve showing the sensitivity of mine internal ROI to the selling price of heavy crude oil is presented. The minimum ROI believed necessary to attract risk venture capital to the project is 20 percent, implying a required oil selling price of $27.26 per barrel. The approximate breakdown of costs is given as follows for a uniform 20 percent project return:

DIRECT COST BREAKDOWN

	$/TON	$/BBL
Mining Cost	5.53	11.38
Mine Payback (@ 20% ROI)	1.72	3.54
Mining Subtotal	$7.25	$14.92
Processing Costs (See in Golder Pg.	1.95	4.01
Processing Plant 272,4,5 $1.33/ton)	2.00	4.12
Payback (@ 20% ROI)		
Tailings Disposal	1.50	3.09
Processing Subtotal	$5.45	$11.22
G&A/Admin. Burden (@ 10% Process Costs)	.54	1.12
GRAND TOTAL	$13.24	$27.26

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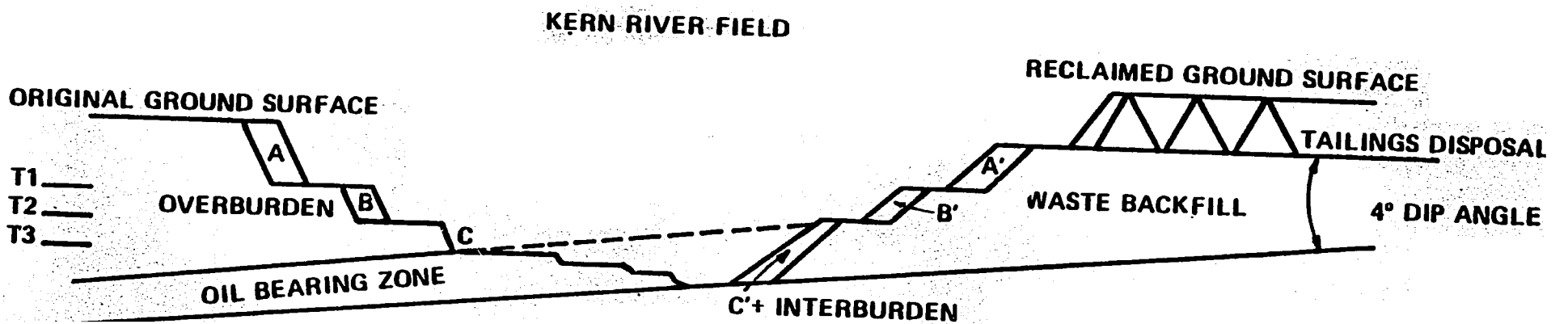

Source: Modified from Golder, 1978

FIGURE 3-1 MODIFIED OPEN PIT/TERRACE PIT MINING

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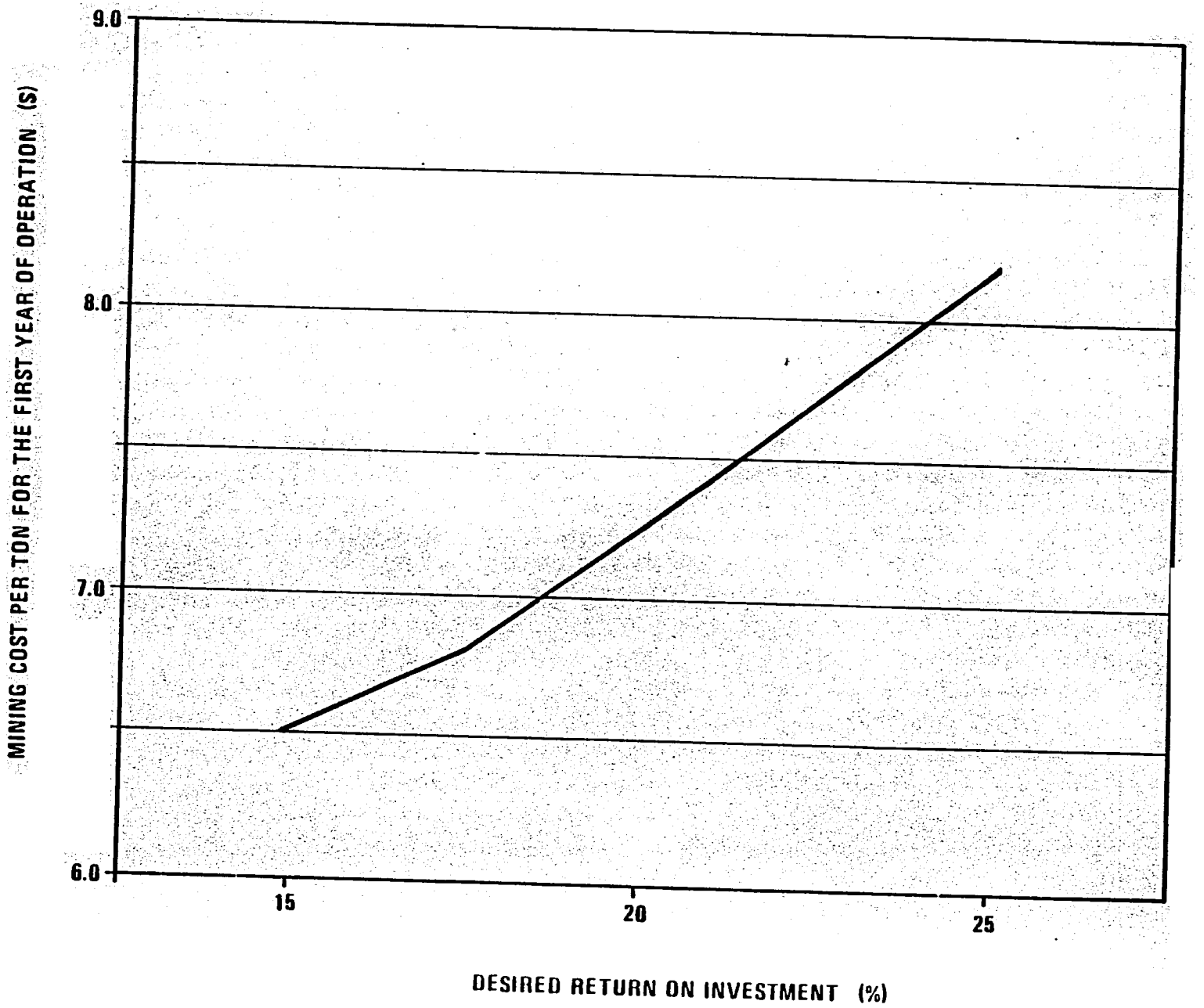
FIGURE 3-2

HEAVY OIL MODIFIED OPEN PIT MINING

RETURN ON INVESTMENT SENSITIVITY ANALYSIS



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3.2 THE MCKITTRICK FIELD

3.2.1 Gravity Drainage Without Thermal Assistance

The purpose of this section is to determine the capital and operating costs of an underground gravity drainage petroleum mining project operating without thermal assistance in a heavy oil reservoir in Kern County, California. Using a set of reservoir selection criteria developed by the U.S. Department of Energy for the Task I screening effort, the Northeast McKittrick Field was chosen for site-specific design.

The basic reservoir parameters for the portion of the McKittrick Field selected are summarized below:

- The field is very shallow, with the top of the 400-foot reservoir interval located approximately 650 feet below the ground surface.

- The oil is extremely viscous, ranging from 11° to 13° API, with a viscosity of over 8,500 centipoise at the average borehole temperature of 90°F.

- The permeability of the reservoir is quite high, with an absolute value of 3,000 millidarcies and a relative permeability of 1,500 millidarcies.

- The oil content of the reservoir averages 1,600 barrels per acre-ft. in the net pay interval.

In this section five separate gravity drainage producing patterns are identified for the McKittrick Field. A preliminary mine access design is developed for each of the five producing patterns and the capital costs and rates of gravity drainage are estimated.

The objective of this analysis is to determine which of the five producing patterns ranging in production well spacing from 100 feet to 500 feet,

yield the optimum economic return on investment (ROI). The results of the analysis indicate that none of the five well spacing patterns analyzed are economically attractive for the reservoir conditions assumed for the McKittrick Field. The viscosity of the crude oil is extremely high at natural reservoir temperatures implying that the oil production rates by gravity drainage without thermal viscosity modification are exceedingly low. In all cases analyzed, the total sum of revenue over the 20-year project life equals only a fraction of the initial capital investment. Case I, which has a 100-foot well bore spacing and the highest total capital cost, represents the only drainage design that approaches economic viability. In this case, approximately 81 percent of the initial capital outlay is realized in gross production over the 20-year project life. This is contrasted with an alternate case which is based on a 200-foot production well-spacing which earns a total of 31 percent of the initial capital investment.

From the analysis it is concluded that production by unassisted underground gravity drainage is an inappropriate technology for shallow heavy oil reservoirs. Gravity drainage technology is uneconomical in heavy oil fields without thermal assistance to modify the viscosity of the oil to improve its mobility and enhance active drainage mechanisms. For moderately viscous reservoirs (500 cp - 1,500 cp) the analysis further indicates that a dense production well spacing is required in order to achieve a sufficient flow of revenue during the early project life; however, this is weighed against the costs of establishing a high density of production wells with optimal well spacing. The analyses performed indicate that as the viscosity of the produced crude drops, the optimum well bore spacing increases. If the oil in-place in the McKittrick Field is reduced to a five centipoise viscosity by steam soak, the optimum production well density is between 200 and 300 feet (0.9 - 2.0 acres per production well).

3.2.1.1 Methodology

In this analysis the economics of five gravity drainage mine designs were evaluated for the site-specific conditions of the McKittrick Field in Kern

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County, California. Viscosity, permeability, and reservoir core data were utilized in the development of each of the five petroleum mine access designs.

The designs varied with the density of production wells and the number of tunnels required for sub-reservoir infill drilling. In the following section each of the production patterns is described with the well bore spacing, number of access tunnels employed, number of production holes drilled, total footage of production holes, and the number of access shafts indicated.

Preliminary designs for the five production patterns were developed and the capital costs for each of the gravity drainage access mines estimated. Oil production rates were calculated for each project year from reservoir equations describing radial drainage into a production well bore. A project time-to-payback ratio was used to determine that all five drainage cases were uneconomical. Since the Net Present Value (NPV) of the projects investigated was negative throughout the project lifetimes, a cash flow analysis demonstrates a negative ROI for all cases studied.

3.2.1.2 Definition of Production Patterns Analyzed

In this section, five cases of production spacings and patterns are defined using underground gravity drainage technology, and in Sections 3.2.1.3 and 3.2.1.4 the estimated costs of these patterns and their corresponding production rates are established. The analysis is initiated by defining a three- or four-tunnel production access network for the five drilling patterns considered.

The five cases are defined below:

NAME	WELL SPACING (FT)	NO. TUNNELS	NO. PROD. HOLES
Production Pattern I	100	4	3,115
Production Pattern II	200	4	810
Production Pattern III	300	4	360
Production Pattern IV	400	3	207
Production Pattern V	500	3	126

Figures 3-3 through 3-7 shows the geometry of the producing patterns shown in plan view on the 9,000-foot (E-W dimension) by 3,600-foot (N-S dimension) provided by Stone & Webster Engineering Corporation (SWEC) to initiate the analysis.

o Production Pattern I

Pattern I has a well spacing of 100 feet drilled from galleries constructed in four independent tunnels. Three basic production spots are utilized: 1) a pattern containing 54 production holes; 2) one containing 48 production holes; and 3) one containing 45 production holes. The pattern as defined is constructed from Pattern II by sub-reservoir infill drilling to close the spacing from 200 feet to 100 feet (with a 100 foot distance to the property line from the production holes bordering the boundary).

Calculation of Production Holes:

Pattern I is defined to have approximately four times the production well density as Pattern II. Detailed calculations of the number of production wells required yields:

Well count (E-W) Axis: 45 holes + (45-1) holes = 89 holes

Well count (N-S) Axis: 18 holes + (18-1) holes = 35 holes

Total number of production holes: (89 x 35) = 3,115

Average length of each production hole: 615.0 feet

TOTAL PATTERN PRODUCTION HOLE LENGTH: 1,918,436 feet

o Production Pattern II

The well spacing utilized in this pattern is 200 feet on a four-tunnel network as displayed in Figure 3-4. Drilling galleries are spaced 600 feet apart for all four tunnels and two basic spots are used: a 15-hole pattern and a 16-hole pattern.

Calculation of Production Holes:

Tunnel 1: 15 patterns @ 15 holes/pattern = 225
Tunnel 2: 15 patterns @ 12 holes/pattern = 180
Tunnel 3: 15 patterns @ 12 holes/pattern = 180
Tunnel 4: 15 patterns @ 15 holes/pattern = 225
810 holes

Average length of each production hole: 621.8 feet

TOTAL PATTERN PRODUCTION HOLE LENGTH: 503,658 feet

o Production Pattern III

Pattern III is based on a well spacing of 300 feet, with three tunnels on a spacing of 900 feet, and the north and south tunnels 450 feet from the property boundaries. Drilling galleries are 900 feet apart for the 9-spot pattern, and each east-west tunnel has 10 drilling galleries for a total of 40 galleries on the 743.8-acre property.

Calculation of Production Holes:

40 galleries @ 9 holes/gallery = 360 holes

Average length of hole: 606.2 feet

TOTAL PATTERN PRODUCTION HOLE LENGTH: 218,214 feet

o Production Pattern IV:

Pattern IV has a well spacing of 400 feet, with three tunnels on a spacing of 1200 feet. Drilling galleries are 1200 feet apart for the 9-spot pattern. On the east end of the field a partial pattern is used as shown in Figure 3-6.

Calculation of Production Holes:

21 full patterns @ 9 holes/pattern:	189
3 half-patterns @ 6 holes/half-pattern:	18 holes
	207 production holes

Average length of each production hole: 675.7 feet

TOTAL PATTERN PRODUCTION HOLE LENGTH: 139,867 feet

o Production Pattern V

This pattern has a well spacing of 500 feet, with three tunnels on a spacing of 1500 feet. The north and south tunnels run within 300 feet of the property borders. These upper and lower tunnel sets are half-patterns to achieve the 500-foot spacing desired in this production pattern.

Calculation of Production Holes:

12 half-patterns @ 6 holes/pattern:	72 holes
6 full patterns @ 9 holes/pattern:	54 holes
	126 holes

Average length of hole: 738.1 feet

TOTAL PATTERN PRODUCTION HOLE LENGTH: 92,996.0 feet

o Analysis of Production Well Lengths

In this section the total production drilling footage for the five production patterns is calculated in support of the capital cost analysis presented in Section 3.2.1.4. An average hole length is generated from the layouts shown in Figures 3-3 through 3-7. The geometry of each production pattern is accounted for in the calculation of average bore length and total production well footage.

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The inherent symmetry of the n-spot patterns utilized in the design establishes a table of distances and hole lengths on a weight-averaged basis. Assigning a numerical weight to each hole, calculating its length by the triangular rule (Pythagorean Theorem) and deriving a weighted sum, allows an average production hole length to be estimated.

From the total footage calculation for the pattern, a cost of drilling and completing the production system can be estimated. Unit costs for drilling, as well as shafting, tunneling, and excavating, are given in Section 3.2.1.4. This effort is in preparation for the economic payback analysis for the gravity drainage operation in the McKittrick Field.

The following table summarizes the results from Tables 3-14 through 3-18.

Production Pattern	Spacing	No. Holes	Avg. Hole Length (ft)	Total Pattern Footage (ft)
I	100	3,115	615.0	1,918,436
II	200	810	621.8	503,658
III	300	360	606.2	218,214
IV	400	207	675.7	139,867
V	500	126	738.1	92,996

These figures are based on the reservoir dimensions and conditions established by SWEC, as follows:

- Reservoir Area Dimensions:
  9,000 ft. (E-W) x 3,600 ft. (N-S) = 744 acres

- Overburden:
  (Non-Producing Sands, Tulare) = 650 ft.

- Producing Interval:
  400 ft./lenticular oil saturated sands (Tulare Sands)

- Vertical Distance from Tunnel Center to Top of Producing Zone: 500 ft.

TABLE 3-14

PRODUCTION PATTERN I ANALYSIS
PRODUCTION HOLE LENGTHS

Columnar Series (See Exhibit I)	E-W Distance (ft)	N-S Distance (ft)	Depth 500(ft)	Length (ft) $(D^2NS+D^2EW+(500)^2)^{1/2}$	Numerical Weight*	Sub-Total
Series A	300'	800	Constant	836.7	1	836.7
	"	500		768.1	1	768.1
	"	400	"	707.1	1	707.1
	"	300		655.7	1	655.7
	"	200	"	616.4	2	1232.8
	"	100		591.6	2	1183.2
	"	0		583.1	1	583.1
Series B	200'	600	"	806.23	2	1612.5
		500		734.8	2	1469.7
		400		670.82	2	1341.6
		300		616.4	2	1232.8
		200		574.5	4	2297.8
		100		547.7	4	2190.9
		0		538.52	2	1077.0
Series C	100'	600	"	787.4	2	1574.8
		500		714.1	2	1296.2
		400		648.1	2	1296.2
		300		591.6	2	1183.2
		200		547.7	4	2190.9
		100		519.6	4	2078.5
		0		509.9	2	1019.8
Series D	0'	600	"	781.0	1	781.0
		500		707.1	1	707.1
		400		640.3	1	640.3
		300		583.1	1	583.1
		200		538.5	2	1077.0
		100		509.9	2	1019.8
		0		500	1	500.0
Totals						33,257 ft.

Dividing 33,257 ft by 54 holes = 615 ft/hole

*Asymmetrical pattern, thus numerical weights are not normally distributed. Weight represents the number of holes with the listed distances and depth.

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TABLE 3-15

PRODUCTION PATTERN II ANALYSIS
PRODUCTION HOLE LENGTHS

Columnar Series (See Exhibit II)	E-W Distance (ft)	N-S Distance (ft)	Depth 500(ft)	Length (ft) $(D^2NS+D^2EW+(500)^2)^{1/2}$	Numerical Weight*	Sub-Total
Series A	200	600		806.2	2	1612.5
	"	400		670.8	2	1341.5
		200		574.5	4	2297.8
		100		538.5	2	1077.0
Series B	0	600	"	781.0	1	781.0
		400		640.3	1	840.3
		200		538.5	2	1077.0
		0		500.0	1	500.0
				15	9327.3	

Dividing 9327.3 ft.by 15 holes = 621.8 ft/hole

*Asymmetrical pattern, thus numerical weights are not normally distributed. Weight represents the number of holes with the listed distances and depth.

TABLE 3-16

PRODUCTION PATTERN III ANALYSIS
PRODUCTION HOLE LENGTHS

Columnar Series	E-W Distance (ft)	N-S Distance (ft)	Depth 500(ft)	Length (ft) $(D^2NS+D^2EW+(500)^2)^{1/2}$	Numerical Weight	Sub-Total
1	300	300	500	655.7	4	2,622.9
2	300	300	"	583.1	4	2,332.4
3	0	0	"	500.0	1	500.0
					9	5,455.4

Dividing 5,455.4 ft. by 9 holes = 606 ft/hole

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TABLE 3-17

PRODUCTION PATTERN IV ANALYSIS

Columnar Series	E-W Distance (ft)	N-S Distance (ft)	Depth 500(ft)	Length (ft) $(D^2NS+D^2EW+(500)^2)^{1/2}$	Numerical Weight	Sub-Total
1	400	400	500	754.9	4	3019.9
2	0	400	500	640.3	4	2561.3
5	0	0	500	500.0	1	500.0
					9	6081.2

Dividing 6,081.2 ft. by 9 holes = 675.7 ft/hole

TABLE 3-18

PRODUCTION PATTERN V ANALYSIS
PRODUCTION HOLE LENGTHS

Hole Number	E-W Distance (ft)	N-S Distance (ft)	Depth 500(ft)	Length (ft) $(D^2NS+D^2EW+(500)^2)1/2$	Numerical Weight	Sub-Total	No. Patterns	Total Footage
Half-Patterns								
1	500	0	500	707.1	3	2121.3		
4	500	500	500	866.0	2	1732.1		
2	0	0	500	500	$\frac{1}{6}$	500		
						4353.4'	12	52,240.8 ft.
Full-Patterns								
1	500	500	500	866.0	4	3464.1		
2	0	500	500	707.1	4	2828.4		
5	0	0	500	500	$\frac{1}{9}$	500		
						6792.5	6	40,755.2 ft.
								92,996.0 tot.ft

Dividing 92,996.0 ft. by 126 holes = 738 ft/hole

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3.2.1.3 Core Analysis and Production Rate Calculations

In this section, the analysis begins with a delineation of the oil producing zone by reviewing well log data provided by Chevron USA, and subsequently establishes key assumptions regarding the physical properties of the oil in the formation. Next, the rate of flow from each production hole is calculated using an analytical drainage equation from the literature under a fixed set of assumptions regarding the fluid and reservoir properties. The section is completed by a summary of production rates for the 300-foot production well spacing.

o <u>Delineation of the Oil Producing Zone</u>

Using the reservoir data and logs provided by the Task I research effort conducted by Stone & Webster, the oil producing intervals of the reservoir are defined together with the properties of the oil and reservoir rock material.

As a general starting point, the top of the producing sand intervals is defined to be 680 feet from the ground surface with 400 feet of producing sand (Tulare Formation) composed of lenticular oil saturated deposits. The absolute permeability for all the producing intervals in the formation is defined to be 3,000 millidarcies with a porosity of 35 percent. A borehole temperature of 89°F and a residual oil saturation of 63 percent are further assumed. The average gravity of the oil produced the McKittrick Field is 14.3 degrees API, with a range of 11 to 25 degrees. The gravity of the oil from the specific producing intervals ranges from 11 to 13 degrees API with a viscosity of 8,500 centipoise at reservoir temperature of 89°F.

o <u>Core Analysis</u>

Investigating the cores provided by Chevron USA on the subject field indicates that the Upper Tulare Formation has intermittent layers of oil saturated sand. A summary of the core analysis is contained in Table 3-19, and a summary of the producing intervals, depths, and thickness to be used in this analysis is given in Table 3-20.

TABLE 3-19

WELL-LOG ANALYSIS (PRELIMINARY)
UPPER TULARE FORMATION
N.E. MCKITTRICK FIELD

Depth, Top (ft.)	Thickness (ft.)	Cores/Comments Chevron 7-5	Speckles 8-2	Chevron 2-10W	Chevron 12-3
		(Corrected to + 250 ft)	(Corrected to + 50 ft)	(Corrected to -75 ft)	
680	20'	R, SP/log	30'R, SP/log	15'R	20'R, SP
700	5'	R, SP	15'R, SP/log	15'R	10'R, SP
725	5'	R, SP/strong	15'R, SP/log	10'R	N/A
750	15'-20'	R, SP/log	- *	5'R	-
790	17'	R, SP missing	-	(?)R, SP(?)	-
825 water		SP	-	525' H_2O CNP/BP/R,SP	-
870	10'	R, SP/log	-	10'R, SP	-
910	15'	R, SP/log	-	15-20'R, SP	-
960	8'	R, SP/log	-	-	-
975	8'	R, SP/log	-	10'R, SP @ (990')	-
1025	20'	R, SP/log	-	20'R, SP	-
1050	Shale				

* Not shown

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Table 3-20

mmary of Oil Producing Intervals
Upper Tulare Sands
N.E. McKittrick Field

Interval	Depth, Top (ft.)	Average Thickness (Ft.)	Estimated Oil Column Height (ft.) Average	Comments
1	680	25	19	SP,Lag (approx. 25% water, 75% oil)
2	700	15	10	"
3	725	15	10	"
4	750	5	4	"
5	870	10	8	"
6	910	15	10	"
7	975	80	8	"
8	1025	20	15	"
9	1050	Shale	--	--
TOTAL			84 (ft.)	

In many cases, the resistivity log indicates the presence of fluid, however, the "lagging" of the specific potential log is seen as a response delay in the core analysis. This probably indicates the presence of formation water at the bottom of the oil saturated intervals. Thus, the oil column heights are reduced by 75 percent for the intervals as indicated in Table 3-20. This assumption adjusts the oil column heights to a realistic figure and accounts for the presence of water and gas (low gas content).

o <u>Calculation of Total Oil In-Place</u>

Using the equation for calculating the amount of oil in-place:

$$S_p = \frac{7758\ Ah\ f\ (1-Sw)}{B_o}$$

where:

A = 743.8 acres - Area of the producing pattern.

$h = h_i$ = 84 ft (h_i from Table 3-2) - Defined to be the oil column height.

f = 35% - Porosity of the reservoir column.

(1 - Sw) = So = 63% - Saturated oil content of the reservoir.

B_o = 1.05 - Solution gas expansion ratio.

Thus, S_p = the reserves in place, is given as:

$$S_p = \frac{(7758)(743.8)(84)(.35)(.63)}{1.05}$$

$$= \underline{101,800,000\ \text{BIP}}$$

Therefore, for the entire portion of the McKittrick field under consideration the amount of oil in place is approximately 100 million barrels in the Upper Tulare Sands.

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o Summary of Oil Characteristics

Information was procured from a variety of sources regarding the characteristics of the oil and reservoir intervals in the Tulare Sands for the Northeast McKittrick Field. A great deal of confusion exists about the oil content and properties of oil in the upper Tulare Sands for this region, and these problems are further compounded by a general reluctance on the part of many operators in the area to reveal detailed information for active areas of the field. The information provided by Chevron is deeply appreciated as well as their support and cooperation in the data gathering task.

In order to accurately calculate the rate of oil production for gravity drainage and gravity drainage with steam drive, a detailed knowledge of the viscosity of the produced oil is required. Inquiries directed to the California Division of Oil and Gas and to Chevron USA which operates several steam drives in the area yielded a moderate amount of data regarding the Upper Tulare region of the McKittrick Field.

The basic information procured is detailed in Table 3-21. In summary, the range of oil gravity produced in the McKittrick area is from 11° API to 25° for production from the Upper Tulare Sands. No correlation exists (at present) between the depth of formation and the API gravity for the field. Further complicating this analysis are the different viscosity characteristics of the oil under alternate temperature regimes; the oil from individual oil-saturated intervals of the Upper Tulare exhibit radically different temperature-viscosity profiles. In order to proceed with this analysis, Chevron USA was contacted for information regarding the viscosity and gravity of oil produced from the Chevron 2-10W steam injection pattern.

In contrast to the confusion regarding the properties of oil in the McKittrick Field, there is a concensus regarding the oil content of the field. In several references the oil content of the field ranges from 180,000 BBL/acre to 199,300 BBL/acre, with an oil content of 1,600-1,644

TABLE 3-21

SUMMARY OF OIL CHARACTERISTICS

VISCOSITY

Sources: Chevron USA, Personal Communication
July 20, 1982
Well No. 2-10W
T30S, R22E
Section 9
California Division of Oil and Gas, Bakersfield Office

Reported Range of Viscosity (cp)	Average Viscosity (cp)	(Temperature °F)	Comments
10,000	--	90*	
8,000-9,000	8,500	90	BHT (89°F)
4,000-8,000	6,000	100	
85.7-114.6	100	250	
5.0- 15.7	10	300	

Gravity: Range: 11-25° API

*Temperature is greater than reported bottom-hole temperature (BHT) for the McKittrick Field.

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BBL/acre-foot. This implies a net oil-saturated interval of 110 to 120 feet for the Amnicola and Tulare Sands. Further, the Amnicola Sands have a published oil content of 1,600 BBL/acre-foot, with an interval thickness of 50 feet. In comparison with the core analysis presented earlier this indicates that the Upper Tulare Sands should have a producing net pay zone of 70-80 feet. This is in good agreement with the 84 feet calculated from the core analysis.

A general set of correlation curves is plotted in Figure 3-8 which shows the variation of viscosity with API gravity at various temperatures. This "family" of curves has been generated in part from data on the Kern River area and is generally applicable to the oil characterized in this analysis for the McKittrick Field, although actual sampling data must be procured for accurate viscosity measurements.

o <u>Calculation of Oil Production Rates</u>

The equation for the radial flow of oil into a borehole is given by the following equation (EDC, 1978):

$$Q = (7.1659 \times 10^{-4}) \frac{k}{mo} \frac{h^2 qo (y^2 - x^2)}{\ln (.472 r_e/r_w)}$$

where:

Q = The rate of oil flow from the slot in ft3 per hour.

K_o = The relative permeability of oil in the reservoir.

mo = The viscosity of the produced oil with V_p symbolizing the specific viscosity.

h = The height of the oil column from the drainage zone.

qo = The specific gravity of the oil.

y = The fractional height of the oil column at the maximum drainage radius.

x = The fractional oil column height of the borehole.

r_e = The well spacing radius of influence (generally taken to be one-half of the well spacing).

r_w = The radius of the well bore.

The following data have been provided in part by SWEC, Chevron USA, Inc. and the California Division of Oil and Gas:

k_o = (.5) (3,000 md) = 1.500 md
(Relative permeability approximated at .5 for water-wet intervals)

mo = qn_o = $.97n_o$ = 8,500 cp

(At bottom - hole temperatures, BHT =900F)

$$q = \frac{141.5}{131.5 = API^o}$$

API = 14.30, thus
q = .97

$$h2 = \underset{i=1}{S} (h_i 2) = 1030 \text{ ft.}^2$$

r_e = variable: Spacing 100', 200', 300', 400', 500',
r_e: 50', 100', 150', 200', 250'

$$r_w = 2.5'' = \frac{2.5}{12} = .21 \text{ ft.}$$

For example, substituting for the 100-foot well spacing core gives:

$$Q = (7.1659 \times 10\text{-}4) \frac{(1{,}500 \text{ md})(1030 \text{ ft2})\ (.97)\ (y2\text{-}x2)}{(8{,}500 \text{ cp}) \qquad \ln\left(.472\ \frac{50}{.21}\right)}$$

$$Q = .027\ (y2 - x2)$$

Let x = 0, and to convert from ft3/hr to BBL/day use a factor of 4.28 derived as:

$$1\ \frac{ft3}{hr} = 1\ \frac{ft3}{hr} \times 24\frac{hr}{day} \times 62.4\ \frac{lbs}{ft3} \times \frac{1 \text{ gal.}}{8.335 \text{ lbs}} \times \frac{BBL}{42 \text{ gal}}$$

$$= 4.28 \text{ BBL/day}$$

Thus, Q = .114 y2(BBL/day/hole)

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Deriving this for each of the five producing wells, assuming no interaction between wells and a linear superposition of production, according to the above equation gives:

Prod. Pattern	Rate ft3/hr	Rate BBL/Day/Hole	No. Holes	Prod. Rate Field (BPD)(y=1.0)	Spacing (ft)
I	.027	.114	3,115	356	100
II	.023	.100	810	81	200
III	.022	.093	360	33	300
IV	.021	.088	207	18	400
V	.020	.085	126	11	500

A calculation of the gravity drainage production rate under the 300-foot well spacing assumption is given in Table 3-22. Noting that the total production from the field over a 20-year investment life is 238,000 BBL indicates that the production of oil is extremely low due to the high oil viscosity. Even under the assumption of an escalating price track for the price of oil, the total economic return for the 300-foot production well spacing is approximately $20 million, or about 15 percent of the initial capital invested.

3.2.1.4 Economics of Gravity Drainage

In this section the economic results for gravity drainage (without thermal assistance) are given for the Northeast McKittrick Field. For the purposes of this study, a portion of the McKittrick Field was selected that has 400 feet of gross pay with the top of the oil producing interval 650 feet below the surface. Of the 400-foot interval of gross pay, 84 feet of the interval is oil-saturated sands. The deposit is extremely lenticular in formation and is separated by relatively impermeable shale layers. The largest continuous interval of oil-saturated sand is 25 feet with the average thickness 15 feet in extent. Saturation is approximately 1,600 barrels per acre-foot, as calculated from the core analysis, which is in good accord with published data for the area.

The cost of placing the underground gravity access mine was calculated based on a number of unit cost factors for development of the shafts,

TABLE 3-22

SUMMARY OF ECONOMIC RESULTS FOR GRAVITY DRAINAGE WITHOUT THERMAL ASSISTANCE

NORTHEAST MCKITTRICK FIELD, KERN COUNTY, CALIFORNIA

Case	Production Spacing (ft)	Capital Cost ($1,000)	Max. Total Recovery 20 years (BBL)	Max. Total Revenue 20 years[1] ($1,000)	Percent of Initial Capital Recovered
I	100	185,000	2,035,798	150,000	81%
II	200	139,300	591,300	43,568	31%
III	300	126,600	238,270	17,556	14%
IV	400	98,900	131,400	9,681	10%
V	500	96,200	80,300	5,916	6%

[1] Based on a 20-year average price of $73.68/BBL escalated at 8% P.A. from a 1982 base price of $32.50/BBl (3rd Quarter, 1982).

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tunnels, drifts, drilling galleries, and production holes. These values vary as a function of ground condition, and three basic cases were identified for the costing analysis: poor ground conditions; moderate ground conditions; and good ground conditions. A summary of the capital costs for the development of the underground access mine is given in Tables 3-23 through 3-27 under the assumption of moderate ground conditions. In these tables the cost of developing the underground mine, as well as the cost of production equipment, mine equipment, and lease-support facilities, are given.

The access mine cases are varied such that a production drainage hole is located on spacings that range from a minimum of 100 feet, to a maximum of 500 feet apart. The cost of developing the mine tunnels, as well as the production holes and the attending production equipment (heater treaters, product separators, and intermediate storage with pumping), is presented, and these costs range from a minimum of $96,000,000 to a maximum of $185,000,000 for the 100-foot well density case. The costs for the patterns with a high density of production holes increase significantly because of the cost of the drill holes and production equipment required to service the individual production patterns.

To further specify the economics for gravity drainage the following set of reservoir properties were provided by SWEC to conduct the analysis:

- the permeability of the reservoir rock is estimated to be 3,000 millidarcies with a relative permeability of 0.5;

- the viscosity of the oil at the bore hole temperature of 89°F is taken to be 8,500 centipoise; and

- the sum of oil column heights equal 84 feet over 9 major production intervals.

In regard to the oil column height analysis, the production from each individual lenticular oil-wet sand interval is based on an oil column height equal to 75 percent of the thickness of the lenticular deposit.

TABLE 3-23

WELL SPACING ECONOMIC ANALYSIS
PRODUCTION PATTERN: 100 FT WELL SPACING

BUDGET CAPITAL COSTS

Item/Descr.	No.	Total Footage	Unit Cost	Capital Cost
Capital Mining Equipment	Lot	N/A	---	$8,100,000
Shafts: 12'0	2	900 ft. ea	$3,000./ft.	5,400,000
6'0	8		$1,000./ft.	7,200,000
Production Tunnels:				
12' x 15'	4 @ 8,100	32,400 ft.	$2,500./ft.	81,000,000
12' x 15'	1 @ 2,700	2,700 ft.	$2,500./ft.	6,750,000
Drilling Galleries: 20' x 20'	60	N/A	$50,000./rm.	3,000,000
Production Holes: D & C1	3,115	1,918,436 ft.	$32.30/ft	61,965,000
Production Piping				
4" pipe (C.S.)		32,400 ft.	$14.00/ft.	454,000
8" pipe (C.S.)		2,700 ft.	$23.00/ft.	62,000
Gathering, Piping Pumping & Control o Pump(s) -- gpm spare w/controls and starter o Manifolds, and lines to surface included.	60 galleries	@	$81,700./10-spot	4,900,000
Surface Equipment & Water Re-injection System o Producing Sep. o Separator Free Water K.O. o Heater Treater o Surf. Treat and Water Re-injection System o Int. Storage o Accessory Equipment o Disposal & Treat o Re-injection Pumps o Electrical Dist.	60 galleries	@	$359,000./10-spot	4,188,000
Mine Development Facilities o Warehouse o Maintenance Shop				2,000,000
	TOTAL			$185,019,000

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TABLE 3-24

WELL SPACING ECONOMIC ANALYSIS
PRODUCTION PATTERN: 200 FT WELL SPACING

BUDGET CAPITAL COSTS

Item/Descr.	No.	Total Footage	Unit Cost	Capital Cost
Capital Mining Equipment	Lot	N/A	---	$8,100,000
Shafts: 12'0	2	900 ft. ea	$3,000./ft.	5,400,000
6'0	8		$1,000./ft.	7,200,000
Production Tunnels:				
12' x 15'	4	32,400 ft.	$2,500./ft.	81,000,000
12' x 15'	1	2,700 ft.	$2,500./ft.	6,750,000
Drilling Galleries: 20' x 20'	40	---	$50,000./rm.	3,000,000
Production Holes: D & C1	810	503,658 ft.	$32.30/ft	16,268,000
Production Piping				
4" pipe (C.S.)		32,400 ft.	$14.00/ft.	454,000
8" pipe (C.S.)		2,700 ft.	$23.00/ft.	62,000
Gathering, Piping Pumping & Control o Pump(s) -- gpm spare w/controls and starter o Manifolds, and lines to surface included.	60 galleries	@	$81,700./10-spot	4,900,000
Surface Equipment & Wat - Re-Injection System o Producing Sep. o Separator Free Water K.O. o Heater Treater o Surf. Treat and Water Re-Injection System o Int. Storage o Accessory Equipment o Disposal & Treat o Re-injection Pumps o Electrical Dist.	60 galleries	@	$359,000./10-spot	4,188,000
Mine Development Facilities o Warehouse o Maintenance Shop				2,000,000
TOTAL				$139,322,000

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TABLE 3-25
WELL SPACING ECONOMIC ANALYSIS
PRODUCTION PATTERN: 300 FT WELL SPACING

BUDGET CAPITAL COSTS

Item/Descr.	No.	Total Footage	Unit Cost	Capital Cost
Capital Mining Equipment	Lot	N/A	---	$8,100,000
Shafts: 12'0	2	900 ft. ea	$3,000./ft.	5,400,000
6'0	8		$1,000./ft.	7,200,000
Production Tunnels:				
12' x 15'	4	32,400 ft.	$2,500./ft.	81,000,000
12' x 15'	1	2,700 ft.	$2,500./ft.	6,750,000
Drilling Galleries: 20' x 20'	40	---	$50,000./rm.	2,000,000
Production Holes: D & C1	360	218,214 ft.	$32.30/ft	7,048,000
Production Piping				
4" pipe (C.S.)		32,400 ft.	$14.00/ft.	454,000
8" pipe (C.S.)		2,700 ft.	$23.00/ft.	62,000
Gathering, Piping Pumping & Control	40 galleries		3,268,000	
o Pump(s) -- gpm spare w/controls and starter				
o Manifolds, and lines to surface included.				
Surface Equipment & Water Re-injection System	40 galleries	@	$359,000./10-spot	3,283,000
o Producing Sep.				
o Separator Free Water K.O.				
o Heater Treater				
o Surf. Treat and Water Re-injection System				
o Int. Storage				
o Accessory Equipment				
o Disposal & Treat				
o Re-injection Pumps				
o Electrical Dist.				
Mine Development Facilities				
o Warehouse				2,000,000
o Maintenance Shop				
TOTAL			$126,565,000	

TABLE 3-26
WELL SPACING ECONOMIC ANALYSIS
PRODUCTION PATTERN: 400 FT WELL SPACING

BUDGET CAPITAL COSTS

Item/Descr.	No.	Total Footage	Unit Cost	Capital Cost
Capital Mining Equipment	Lot	N/A	---	$8,100,000
Shafts: 12'0	2	900 ft. ea	$3,000./ft.	5,400,000
6'0	6		$1,000./ft.	5,400,000
Production Tunnels:				
12' x 15'	3 @ 8,100	24,300 ft.	$2,500./ft.	60,750,000
12' x 15'	1 @ 2,700	2,700 ft.	$2,500./ft.	6,750,000
Drilling Galleries: 20' x 20'	24	N/A	$50,000./rm.	1,200,000
Production Holes: D & C1	207	139,867 ft.	$32.30/ft	4,518,000
Production Piping				
4" pipe (C.S.)	3 @ 9,000	27,000 ft.	$14.00/ft.	378,000
8" pipe (C.S.)	1 @ 2,700	2,700 ft.	$23.00/ft.	62,000
Gathering, Piping Pumping & Control o Pump(s) -- gpm spare w/controls and starter o Manifolds, and lines to surface included.	24 galleries	@	$81,700./10-spot	1,961,000
Surface Equipment & Water Re-injection System o Producing Sep. o Separator Free Water K.O. o Heater Treater o Surf. Treat and Water Re-injection System o Int. Storage o Accessory Equipment o Disposal & Treat o Re-injection Pumps o Electrical Dist.	24 galleries	@	$359,000./10-spot	2,417,000
Mine Development Facilities o Warehouse o Maintenance Shop				2,000,000
	TOTAL			$98,936,000

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TABLE 3-27

WELL SPACING ECONOMIC ANALYSIS
PRODUCTION PATTERN: 500 FT WELL SPACING

BUDGET CAPITAL COSTS

Item/Descr.	No.	Total Footage	Unit Cost	Capital Cost
Capital Mining Equipment	Lot	N/A	---	$8,100,000
Shafts: 12'0	2	900 ft. ea	$3,000./ft.	5,400,000
6'0	6		$1,000./ft.	5,400,000
Production Tunnels:				
12' x 15'	3 @ 8,100'	24,300 ft.	$2,500./ft.	60,750,000
12' x 15'	1 @ 2,700'	2,700 ft.	$2,500./ft.	6,750,000
Drilling Galleries: 20' x 20'	18	---	$50,000./rm.	900,000
Production Holes: D & C1				
Production Piping				
4" pipe (C.S.)				378,000
8" pipe (C.S.)				62,000
Gathering, Piping Pumping & Control	18 galleries	@	$81,700./10-spot	1,471,000
o Pump(s) -- gpm spare w/controls and starter				
o Manifolds, and lines to surface included.				
Surface Equipment & Water Re-Injection System	18 galleries	@	$359,000./10-spot	2,034,000
o Producing Sep.				
o Separator Free Water K.O.				
o Heater Treater				
o Surf. Treat and Water Re-Injection System				
o Int. Storage				
o Accessory Equipment				
o Disposal & Treat				
o Re-injection Pumps				
o Electrical Dist.				
Mine Development Facilities				
o Warehouse				2,000,000
o Maintenance Shop				
	TOTAL			$96,249,000

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This is assumed on the basis of two key factors: 1) The core analysis indicated "a lag" of the specific porosity log behind the indication of an oil-bearing zone on the resistivity log; thus, it appears as though the upper portion of the interval could be gas, while the lower portion of the oil column could be water; and 2) The McKittrick Field has been produced by water flood and is bounded by a peripheral hydrostatic head; therefore, the water content of the field is known to be significant.

The total column height used for the production calculations out of the entire reservoir is defined as the root mean square (RMS) of the individual column heights, and is not the sum of the individual interval depths. This gives the oil production rate calculation a realistic basis, while at the same time accounts for the impermeable shale layers between the lenticular oil deposits. Further, the overall reservoir has a maximum 20-degree angle downdip and the hydrostatic head from the 300-to 400-foot vertical rise is accounted for in the present calculation by assuming a linear superposition of rate functions for each of the individual production holes. Thus, it is assumed that, regardless of the production hole spacing utilized, the production from each hole does not impact or influence the production from adjacent wells in the field.

Clearly, this assumption remains unsupported and little or no data exists in the literature for testing its validity under general reservoir conditions. However, accounting for the hydrostatic head generated in this water drive reservoir by the formation incline, using a linear superposition of flow rates, an approximation to the flow rate from each producing bore is estimated.

Using the general flow equations for gravity drainage from a radial bore hole, the production performance is predicted for each of the five cases analyzed. In Section 3.2.1.3 the flow rate for Case III (300-foot well spacing) is calculated.

Based on the projected values of the oil recovered, the rate at which oil is produced from the reservoir, and the calculated mining costs, it is concluded that all five cases, as analyzed, are uneconomical because of:

1) the high viscosity of the oil in the Upper Tulare Sands; and 2) the low oil column heights interrupted by impermeable shale layers. As seen in Table 3-23, the five cases analyzed have a maximum total revenue earned that is a percentage of the initial capital investment for the gravity drainage project. Of the five cases, however, Case I, with the 100-foot spacing, appears to be the production pattern nearest to economic viability. Of course, in the percent of initial capital figure indicated in Table 3-22, no provisions for capital payback, operating cost, royalty, severances and taxes have been accounted and therefore the economics shown in Table 3-22 are optimistic and represent a "best case" evaluation of gravity drainage in heavy oil reservoirs.

The economics of gravity drainage for heavy oils can be significantly improved, however, by assisting the production of oil through viscosity modification with steam soak and steam drive. The following sections present an analysis regarding the enhanced production of oil from the gravity drainage mine through thermal assistance. For an incremental capital investment compared to the capital cost of the access mine tunnels, shafts, and production holes, a 10- to 100-fold increase in oil production can be realized. As indicated, earlier, the oil from these intervals is modified in viscosity significantly by the addition of heat and only slight increases in temperature cause major variations in the flow rate of oil from the production wells.

In conclusion, it is worthwhile to investigate the projected operating costs for gravity drainage without thermal assistance technology. This system when applied to a reservoir with a lighter crude oil (lower viscosity) and higher oil column height would be economical, and this analysis supports the conclusions developed in earlier public documents (EDC, 1978 and Golder, 1978) regarding the economic viability of gravity drainage technology in selected light oil reservoirs that have a substantial oil column height.

An analysis of operating costs for gravity drainage without thermal assistance is projected to be between $0.25 per barrel and $1.00 per barrel, varying as a function of the number of production wells required by

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the well spacing criterion and the pattern flow rate. Periodically the production holes must be worked over. This incurs a significant labor cost, particularly in reservoirs with highly paraffinic crude oils. Also contributing to the operating costs are general materials and supplies for maintaining mine access, the pumping system and heat treating facilities, and the costs of reinjecting formation water into the lower Olig Member. Approximately three barrels of water are produced for each barrel of oil from the McKittrick Field according to historical production data. Although this water is not treated, there is an associated electrical and maintenance cost with its reinjection into the deep water flood formation.

A final component to the operating cost is electrical power for the in-mine pumps that transport the oil and water from the collection sump, located in the mine, to the surface heater-treater and separation facilities. Although this pump would have a total brake horsepower (bhp) of less than 100 Hp, the maintenance cost for this unit will be high because of suspended particulates in the oil, thereby rapidly degrading seal tolerance. Labor and materials for pump maintenance have been accounted in the unit barrel operating costs estimated.

3.2.2 Gravity Drainage with Thermal Assistance

This section describes the design, methodology of operation, and economics of gravity drainage with thermal assistance. In the previous sections, five cases were developed with variable production well spacing for gravity drainage in the Northeast McKittrick Field, Kern County, California.

The cost of these preliminary gravity drainage mine designs were estimated together with calculated production curves for the assumed reservoir conditions and production well spacings. The results of this analysis show that the total recovery from gravity drainage without thermal assistance in this viscous crude oil reservoir is insufficient to generate a capital payback equal to the initial capital expenditure. Thus, it is concluded, specifically for the Northeast McKittrick Field and in general for the majority of shallow, heavy crude oil reservoirs, that the cash flow profile from gravity drainage without thermal assistance is too low in comparison

to the initial capital expenditures required for developing the access mine. However, it should not be taken from these conclusions that gravity drainage as a production technique is generally uneconomical. Contrary to the results obtained from the McKittrick Field, gravity drainage is, in general, an extremely successful technique for reservoirs that have lost solution drive or water flood energy. When applied to the proper reservoir, gravity drainage represents perhaps the most economical production technique available for recovering the residual oil saturation.

Thus, it is imperative that a correct set of selection criteria is developed in order to select those reservoirs most amenable to gravity drainage production. Current industry trends in reservoir selection for the gravity drainage technique often indicate that shallow, heavy crude oil reservoirs should be selected since these reservoirs exhibit little or no production under primary techniques, and are not generally responsive to secondary production methods. In reality, these concepts and the design criteria reflected by applying them could not be more incorrect. The proper set of selection criteria for reservoirs amenable to gravity drainage through underground access mines are deep reservoirs that contain light, low viscosity crude oil; and further, these reservoirs should have a high column of oil in a continuous, saturated interval.

Clearly, the type of reservoir outlined above is in sharp contrast to the heavy, shallow crude oil reservoirs of southern California where the oil columns can be quite small with the oil-saturated sands deposited in narrow, extremely lenticular deposits of fluvial sands.

It is interesting to note why industry has directed their focus toward the heavy, shallow crude oil reservoirs of California for the gravity drainage technique. The primary reasons for the selection criteria are believed to be:

1) Shallow fields are preferred because of perceived limited mining problems for shaft access and tunnel development; and

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2) These reservoirs do not responsed to the conventional array of primary and secondard recovery technologies; thus, gravity drainage is erroneously assumed to be a candidate technology for production from these fields.

In view of the above discussion, gravity drainage techniques, when applied to heavy, shallow crude oil reservoirs, must be assisted in some manner to improve production performance. This can be done in two distinct ways:

1) Improve the rate of oil flow by lowering the viscosity of the oil through thermally assisted production; and

2) The rate of oil production can be improved by increasing the effective oil column height by adding pressure to the oil- producing intervals that are separated by relatively impermeable cap rock.

A variation of steam drive technology can provide both of these production stimulation effects and the objective of this section is to present several alternative methods for thermally assisting the gravity drainage production mechanism for heavy crude oil reservoirs. In particular, the McKittrick Field will be further examined as a site-specific case for the thermal assistance of gravity drainage techniques.

The five cases for gravity drainage presented in the earlier sections will be modified to incorporate a specific thermal method in order to enhance the oil production rate. The McKittrick Field is a good candidate for steam flooding and steam drive, and several such steam injection projects are currently underway by Chevron USA in the Northeast McKittrick Field area. These current steam injection projects concern both the upper Tulare Sands as well as the Amnicola Zone, and data on the steam-drive techniques most effective for this field have been procured from the operators for use in this analysis.

3.2.2.1 Methodology

The site-specific analysis performed for thermal assistance of an underground gravity drainage project is divided into three basic parts:

1) A description of the selected thermal assistance method is presented together with a discussion of potential alternatives for thermal production;

2) A preliminary access mine design and an estimate of the capital costs for the thermal gravity drainge method is given for the Northeast McKittrick Field; and

3) A parametric economic analysis of the economics of gravity drainage with thermal assistance is presented under varying assumptions of total oil recovery.

Along with the three program steps outlined above, the study also incorporates review of current concepts for the thermal assistance of gravity drainage. Of all the methods available in the literature as well as those discussed in this study, three basic design categories describe the available technologies:

1) Steam drive techniques

2) Steam injection techniques

3) Cyclic steam injection and production

Various alternatives to each of these methods are presented, and a definitive methodology is selected on the design criteria of applying proven technologies to the McKittrick Field, thereby minimizing technical uncertainties, economic risks, and minimizing the associated uncertainties of regulatory restrictions on petroleum mine safety and operation.

The thermal method selected is a basic steam drive with steam injection into wells that are drilled from the surface. The injected steam is then driven into a multiple-spot peripheral pattern. The well spacing selected for analysis is 300 feet between each producing well on a nine-spot pattern and each injection well services a total area of approximately 8.5 acres.

The selected thermal assistance method is then costed on a preliminary basis using a combination of vendor quotations, scaling factors, handbook unit costs, and industry cost factors taken from the public literature. A summary of the equipment used in the steam production pattern is given together with the basic information for estimating the capital and operating costs.

Finally, the economics of the thermally assisted gravity drainage project are summarized on the basis of a variable rate of total recovery. A graph of the required oil selling price under a fixed ROI assumption is presented for various percentages of total oil recovery. This parametric analysis obviates the need for projecting the total amount of production from the field using computer analytical models, and yet provides enough information to warrant the economic attractiveness of the thermal assistance project under different assumptions of total oil recovery and world oil pricing policies.

The following sections present descriptions of the various thermal assistance techniques considered for adaptation to underground gravity drainage.

3.2.2.2 Steam Drive Techniques

The principal technology investigated in this analysis of thermally assisted gravity drainage is steam drive using surface injection wells. In this technique, injection wells are driven from the surface to the producing intervals with steam generating facilities located on skid-mounted steam generators on the surface. This technique is particularly suited to a shallow reservoir such as the McKittrick Field, and the costs of drilling the steam injection wells from the surface are

competitive with the costs of installing steam generation underground and injecting from boreholes drilled upward from the access tunnel.

The surface steam drive is applied in a manner similar to normal steam drive operations in the heavy oil fields of California with the injection well at the center of an nine-spot square peripheral pattern of producing wells. These producing wells are drilled, however, from the underground access galleries and differ somewhat from producing wells drilled from the surface in the total amount of lateral area exposed to each producing interval and the lack of required pumping equipment.

Under further consideration is underground steam-drive techniques, where steam is injected from the access tunnels through production holes that are converted to steam injection wells. The steam generator is located inside the mine tunnels and producing wells are converted to steam injection wells sequentially as the drive progresses outward through the pattern. More discussion on the techniques of applying a steam drive system to a gravity drainage project is covered in the following section.

In the underground steam generation case, serious consideration must be given to the practical and regulatory problems of locating a steam generator inside an oil petroleum mine. Hazards due to explosion, steam line rupture, and the injection of combustion air and handling of flue gases must be carefully considered. Several solutions to the permissibility of steam generators in an oil petroleum mine have been suggested, including enclosing the entire generator package in a sealed container that would not allow explosive volatiles to leak into the package and would further prevent radiant "hot spots" from forming, causing an external combustion hazard. Combustion air would be compressed at the surface and piped to the steam generator with the exhaust flue gases from the generator mixed with the steam as a miscible flooding agent. There have been reports of success using flue gas as a miscible flooding agent in several types of water flood and drive operations.

In a steam drive operation a large part of the steam injected is used to maintain a suitable pressure gradient for displacing heated oil to the

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producing wells from the injection well. Further, the heat content of the steam modifies the viscosity of the oil allowing the oil to flow more readily under both the pressure gradient and gravity drainage drive mechanisms. In heavy oil it is generally assumed that no solution gas exists and that reservoir energy from this driving mechanism is non-existent.

Steam drive operations can recover up to 50% of the residual oil saturation in a heavy oil reservoir (Lee, 1980) as contrasted with the steam-soak and cyclic steam processes which recover generally 5% to 15% of the residual oil in place. The steam drive process is energy intensive since it requires the use of a significant fraction (25% to 50%) of the energy in the produced petroleum for the generation of steam. In terms of barrels produced, approximately 200 to 300 barrels of oil per acre-foot of reservoir must be burned in order to generate the required steam to carry out the process and recover 40% to 50% of the oil in place. Thus, a key limitation to the applicability of a steam-drive is the amount of oil in the reservoir per acre-foot of gross pay.

For the site-specific case of the McKittrick Field, the oil content of the reservoir has been demonstrated by core analyses to contain approximately 1,100 to 1,600 barrels per acre-foot in the lenticular oil-saturated sand deposits in the Upper Tulare Formation. Further, these lens-shaped regions of saturated oil are bounded above and below by relatively impermeable cap rock which, although not contiguous, does not allow the passage of steam between producing zones and to "thief" zones over wide areas of the property. These regions are relatively impermeable to steam and generally do not act as "thief" zones in the steam drive operation; thus they are not included in the barrels per acre foot of gross pay calculation.

In summary, the primary factors that have a significant effect on the thermal efficiency of a steam drive and its economic viability are:

- oil saturation
- reservoir thickness
- steam injection rate

- steam pressure and quality
- oil viscosity

The overall efficiency of steam drive is usually rated by the ratio of oil produced to steam injected (in barrel units) over the life of the project. When calculated in this manner, the theoretical ratio of efficiency for a steam drive, where the energy consumed is equal to the energy produced, is approximately 14 barrels of steam per barrel of oil when a thermal efficiency of steam generation and distribution of 75% is accounted. For most California oil fields an economic limit of 8 barrels of steam per barrel of oil is generally considered. In the site-specific case of the McKittrick Field (northeast section), Chervon USA has witnessed a steam-to-oil ratio of approximately 5 barrels of steam per barrel of oil, as averaged over the life of the injection project. This same average injection is utilized in the calculation of the economics for the thermal assistance of gravity drainage in Section 3.2.5.5.

- Limitations of the Steam Drive Process

Several steam drive operations have reported a total recovery of 65% of the original oil in place, but recovery generally averages 40% to 50% of the residual oil saturation. The limitations on recovery efficiency are generally attributed to the following factors:

1) The loss of conformance of the steam to the reservoir oil saturated horizon;

2) A limited ability to vertically sweep the reservoir;

3) The presence of "thief" zones in the reservoirs that cause the steam-to-oil ratio to rise significantly; and

4) Significant heat losses from a water column or thermally conductive cap rock underneath the oil producing zone.

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Often in steam drive operations the lower 2/3 of the oil-producing interval is not swept by the steam because of the effect of "gravity override," where the steam overrides the oil-saturated zone(s). One primary means for increasing the overall recovery efficiency of a steam drive is to expand the steam sweep through the entire vertical oil producing zone(s). This can be accomplished in a number of ways, including the use of chemical additives and foam blocking agents, and mechanically directing the steam by the use of directional packers and steam injectors in the injection wells. Clearly, as the steam zones expand the pressure gradient for a given mass and flow rate decreases, and the productivity of the production well begins to decrease rapidly. With the rising steam-to-oil ratio, the steam-drive operation is usually abandoned as uneconomical. Breakthrough of the steam to the production wells, although considered benefical in some steam drives for the initial production of oil, represents the start of a generally irreversible decline in production operations. Significant breakthrough allows the steam-to-oil ratio to rise rapidly, and if not carefully controlled in terms of the injection rate and the injection pressure, the drive quickly becomes out of hand, and conformance control is lost, resulting in the abandonment of the drive.

o Methodology of Applying Steam Drive

In the McKittrick Field the steam drive technique is applied from surface injection wells that are completed through the oil-producing zones in the center of each nine-spot pattern. The steam injection well is cased with a high quality alloyed steel which is resistant to pressure damage and corrosion and is jet perforated in the individual production zones. As a further protection of the casing against thermal damage, the stringer joints are contoured to allow for thermal expansion and the entire well is completed using silicon-flour cement that is resistant to thermal degradation.

The production wells are drilled from the tunnels underneath the oil producing zones and eight such producing wells around the periphery of a 600-foot-square pattern are utilized as shown in Figure 3-5. In this configuration, the oil is either driven from the injecton well to the

producing well in a semi-vertical "bank" of heated oil, or else is "stripped" from the saturated sands by heating a thin layer of oil next to the steam zone through conductive heat transfer and mobilizing this fraction of the proximate oil. As in a conventional surface steam drive, breakthrough may occur, establishing gravity override of the steam between the injection and producing well. The steam sweep channel must then spread "vertically" through the reservoir in order to sweep the entire interval.

Ideally, a "buffer" additive such as a polymer could be added in order to improve the mobility ratio between the oil and steam drive, thus preventing early breakthrough and an excessive steam-to-oil ratio. Operational methodologies have been tried with both chemical mobility buffers and well as the injection of cold water and surfactant solutions but with limited reported success. Alternate operating methodologies call for enhancing an early breakthrough and then controlling the degree of vertical displacement of the steam-sweep channel through the use of additives, pressure adjustments, and steam injection rates in order to thoroughly sweep the entire producing interval. These two contrasting methodologies have yet to be firmly established in regard to their individual efficiencies and the mechanisms of oil displacement and oil mobilization; however the injection of steam with surfactant additives appears promising.

For the purposes of this analysis, a conventional steam drive was considered without the addition of chemical buffers or mobility ratio improving additives to the drive. Insufficient data exists for the upper Tulare zones of the McKittrick Field in order to specify a particular methodology and/or chemical formulation for optimizing the efficiency of a steam drive operation.

The drive will be operated until the steam-to-oil ratio rises above 8:1 or until 2.0 pore volumes of steam have been injected into the formation. The steam generated is initially at 80% quality, at maximum injection pressure of 600 psi. Steam is generated from purchased fuel oil or from lease crude oil at 75% total efficiency with a generator/boiler stream-factor of 0.95 on a calendar year average.

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The details of operating cost factors for calculating the economics for a steam drive project are given in the following section. The conditions and constraints indicated above outline the basic operating cost components for steam injection in the McKittrick Field, when used in conjunction with underground gravity drainage access.

o Discussion of Steam Drive Techniques

The application of steam drive technology to underground mine access for gravity drainage engenders a wide range of problems that are specific to the development of the McKittrick reservoir, as well as to the overall technology of steam drive production. For example, the Upper Tulare Sands of the Northeast McKittrick Field are extremely segregated and each production interval is separated by a relatively impermeable shale layer. This type of multiple zone structure can present an extreme problem in steam drive operations because of the differential rate at which individual zones produce and deplete, thereby selectively passing steam to the production borehole that is needed in the other producing intervals. The injection well can be blocked with a packer in the problem zone area, however, the zones below the packer are obviously removed from the drive operation.

Early breakthrough in almost any type of steam flooding operation where a pressure gradient drive mechanism is operating is considered detrimental to the economics of the steam drive operation. Under some operating methodologies, however, breakthrough is encouraged in order to initiate a vertical sweep through a thick oil-producing zone. Determining the methodologies applicable to a particular field requires a substantial knowledge of the reservoir and fluid properties of the very localized reservoir area around the steam drive.

Of further consideration in the McKittrick Field is the absolute pressure with which a steam drive can operate. On the average, the top of the producing formation considered in this analysis is 650 feet from the surface, and therefore a maximum drive pressure of approximately 600 psi is indicated. Steam pressures exceeding this level may potentially "lift" the

overburden above the reservoir and could cause subsequent ground swelling, heaving, and subsidence problems. Related to this effect is the impact of high pressure steam on the tunnel network below the oil-producing zone. Research is needed prior to using thermal assistance techniques with gravity drainage from underground access mines. Tunnel stress analyses to determine the maximum pressure attainable without a substantial risk of steam breakthrough to the tunnel workings or damage to the tunnels and/or production holes is required in such a research program.

In regard to steam drive using surface injection, there are several positive and negative tradeoffs that must be considered prior to the application of a thermal assistance technique. Using the surface injection of steam into the multiple-spot producing patterns is relatively inexpensive for the shallow McKittrick Field under consideration. Further, this technique is considered well within the array of conventional technology, and there are significantly fewer problems in the adaptation of steam drive methods to gravity drainage as compared with other potential thermal assistance techniques such as in situ combustion. Also, the capital and operating costs of surface steam drive are more predictable because it is a known technology, and thus the economic uncertainty of the project is substantially reduced.

The "downside" risks of applying surface steam drive to a gravity drainage system are summarized as follows:

- The potential for early breakthrough to the producing wells is high, particularly when narrow production well spacings are used.

- The application of steam drive in a reservoir where the dominating production mechanism is gravity drainage is somewhat in question in regard to the production rates anticipated. Further, the potential for creating extremely severe water/oil emulsions exists when the reservoir is producing in the gravity drainage mode with breakthrough steam passing into the production

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boreholes. The large expense for the equipment required of a high pressure steam drive may not be justified by the increased rate of oil production over low-pressure steam injection.

Thus, simple viscosity modification, assisting the predominant gravity drainage mechanism, may be a more efficient production system than steam drive in conjunction with gravity drainage. Further research into the flow of reservoir fluids under both mechanisms must be conducted and making realistic projections of the production rate under both modes would require a detailed computer simulation.

Despite these technical and economic uncertainties, surface steam drive is considered the "best" overall thermal technology because the problems are minimal compared with other thermal assist methods for use in conjunction with underground mine access production.

Further, the capital and operating costs for a steam drive system are easily quantified and the anticipated rates of production can at least be approximated on a worst-case basis by applying conventional steam drive models that are available in the literature.

3.2.2.3 Low-Pressure Steam Injection Technology

In the previous section the application of high-pressure drives to an underground gravity drainage project was considered. In this section, the application of low pressure steam to the producing formation is discussed.

The injection of low pressure steam to heavy oil reservoirs can be divided into four basic categories of techniques:

1) Low pressure steam can be injected into the producing formations from surface wells and executed in a steam-soak or cyclic "huff-and-puff" system;

2) The low pressure steam can be injected through the production boreholes drilled from the access tunnels underneath the reservoir;

3) Steam can be injected through long (4,500 feet) boreholes drilled from access drifts, with each of these horizontal steam injection bores located between parallel rows of production wells; and

4) Development can be conducted along the lines of the Yarega Field in the USSR whereby shafts sunk into the field (perhaps on regularly spaced intervals) are used as drilling galleries and radial holes for steam injection and production are drilled from the shaft with production holes inclined above the steam injection wells.

Regardless of the specific technique utilized for low pressure steam injection, the basic reservoir principles operating in the production of heavy oils under these technologies is similar. The viscosity of the oil is modified considerably, thus, enhancing the rate of drainage from the production slot. If low pressure steam is injected into the bottom of the producing formation it will migrate by gravity override to the top of the oil producing interval thereby providing pressure that can be related to an equivalent height of oil for inclusion in the gravity drainage rate equation. Noting that gravity drainage rates are proportional to the square, or "second power," of the oil column height, the addition of steam pressure to the producing formation as the steam migrates upward through the oil sands has a dramatic effect on the oil production rate, particularly when coupled with the modification of oil viscosity.

Low pressure steam injection procedures are extremely thermally efficient when compared to steam drive, using approximately 20 to 30 barrels per acre-foot for steam generation. As with steam drive technology, the primary factors having a significant effect on the thermal effciency of the process and its economical viability are the oil saturation, reservoir

thickness, steam injection rate, injection pressure and steam quality. High oil saturations are not as critical as with steam drive because of the lower energy usage in a low pressure steam injection operation. Also, the thickness of the production interval determines the degree of heat loss to base and cap rock formations which can be shown to be inversely proportional to the reservoir thickness.

In contrast to significantly smaller operating costs for lower pressure steam injection is the generally poor efficiency of oil recovery, which is usually 5 to 15 percent of the remaining oil in place. Thus, an economic analysis is generally used to determine the proper method for use in specific reservoir setting.

o Methodology of Low Pressure Steam Injection with Gravity Drainage

The most promising low pressure steam-thermal assist methods for use with gravity drainage are: 1) steam injection through the production boreholes in a modified "huff-and-puff"; and 2) a development method similar to the Yarega Field in the USSR.

In the first example, low pressure steam is injected through the production boreholes with steam generated underground in portable steam generator units. Alternating the wells between production and injection establishes a "huff-and-puff" system that is performed from the drilling gallery underneath the reservoir instead of from the surface through a single injection/production well. One concept in the application of this methodology is the "circle-soak" method which involves starting in the center of the well production pattern with low pressure steam injection and moving radially outward from the center of the pattern by sequentially converting the production wells into steam injection wells. After the soak has reached a certain radius of influence, all the wells are reconverted to the production mode. Any oil that is driven or displaced from the pattern during the "circle-soak" procedure is then produced at the peripheral wells when the adjacent patterns are steam soaked.

One of the most promising practical demonstrations of low pressure steam injection using mining techniques has been in the underground mine access project at Yarega Field. The results from this pilot operation have been extremely encouraging for low pressure injection techniques. This method could apply to the McKittrick Field, since the Yarega and McKittrick reservoirs and their oil properties are extremely similar. Both fields have a reported relative permeability to oil of 1,500 millidarcies (Golder, 1978) with a porosity of 35% and a mean oil gravity of about 14° degrees API. Also, the thickness of the main producing oil- zone is approximately 20 to 27 feet in the Yarega Field whereby the oil producing intervals in the McKittrick Field range from 5 to 20 feet in extent over a total of 8 oil-producing intervals. The oil saturation of both fields is approximately 1,600 bbls per acre-foot.

In the Yarega project, steam is produced at a central plant located on the surface or can be produced by portable steam generators that are located underground near the drilling gallery (proposed concept, Golder, 1978). The steam injection pressures utilized are on the order of 75 to 120 psi and the injection rates vary from several pounds to 4 or 5 tons per hour per well (Golder, 1978). The thermal efficiency of the process has been reported to be considerably higher for steam stimulation from underground steam generation rather than from surface generation due to lower friction and heat losses in long conduction pipes. As with the McKittrick Field, the viscosity of the oil in the Yarega Field is quite high and is reduced to an extreme degree with minor increases in temperature (to 30 centipoise at 200°F).

o <u>Discussion of the Low Pressure Steam Injection Techniques</u>

The advantages of low pressure steam injection technology when used in conjunction with gravity drainage in underground access mines are characterized as follows:

- A low steam-to-oil ratio;

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- Steam "fingering," or breakthrough, in conjunction with gravity override is not as critical to low pressure steam injection operations; and

- The low pressures utilized imply lower capital costs for steam production equipment for the steam drive. Similar reductions hold for casing and well completion costs in the low pressure operations.

In addition to these advantages the risk of steam interception in the tunnel workings is considerably reduced in low pressure steam injection operations when compared to the attendant risks in high pressure drive technology. In contrast the low pressure steam injection technology exhibits considerably reduced recovery percentages of the residual oil saturation, although no definitive studies have been done regarding the combined effects of low pressure steam injection and gravity drainage. It is possible that the combined effects of these two drainage mechanisms may approach the levels of recoveries commonly achieved in steam drive operations. Further research must be conducted in order to quantify joint production rates from these two drainage mechanisms.

A severe disadvantage to generating steam underground is a large array of permissibility, worker health and safety, and technical feasibility problems. Underground generation would further improve the net thermal efficiency of steam injection but the potential feasibility problems appear overwhelming at this time. However, it should be noted that the Soviets have proposed underground steam generation in the Yarega Field and are working on its application. In addition to the concept of portable underground steam generating plants, the Soviets have also proposed ideas pertaining to the injection of hot air into the reservoir to increase reservoir pressure and to provide a quasi-solution gas drive system. The methodology for heating the air would be recycle gas compression with a high degree of non-adiabatic heating. Actual trial results are pending for this novel approach to viscosity modification.

- Cyclic Injection Alternatives

In addition to the low pressure steam injection techniques discussed above, a modified "huff-and-puff" technique conducted by injecting steam into the individual production boreholes and subsequently producing after a two-to six-month soaking period is considered. The "huff-and-puff" method requires expensive casing that is corrosion resistance (alloy composition) and that provides for thermal expansion of the joints between stringers. These precautions are taken to prevent well damage during the steam injection phase of the cycle. Should damage occur, production is severely hampered. Completion of the well with silane cement further protects the cementation from thermal degradation.

Cyclic injection methodologies are worthy of further consideration in gravity drainage underground access petroleum mining. However, it appears at this preliminary stage of analysis that other steam injection methodologies are preferable.

3.2.2.4 Economics of Gravity Drainage With Thermal Assistance

In this section the results of an economic analysis for the application of thermal methods to an underground gravity drainage oil mine are presented. The economics are based on steam drive technology as applied to the Northeast McKittrick Field in Kern County, California. Surface steam-drive was selected for this economic analysis because of the low technical risks associated with its application, and because successful steam drives have been conducted in the McKittrick area. Since generating steam underground in a oil mining environment involves a lot of unknown risks, steam drive from surface injection wells are used for this analysis.

The analysis indicates that at the probable recovery level for this technology (50 percent of the residual oil saturation), the required selling price of crude oil must be $43.25 to provide a 20 percent ROI on the project, which is believed to be the minimum allowed ROI in order to attract risk capital to the venture.

The basic methodology utilized in estimating the economics of the thermally assisted gravity drainage mine was to divide the field into individual production patterns and to evaluate the rate-of-return on an individual producing pattern basis. The sum-of-return for all of the producing patterns that comprise the field determines the economics of applying the combination thermal and gravity drainage technology to the Northeast McKittrick Field. This approach was taken in order to accomplish two important goals of the economic analysis:

1) The capital costs of each pattern are more accurately estimated than if the field is taken as a single unit; and

2) In view of the large sum of capital required for the development of the entire field, it is likely that natural economic sub-divisions will occur dividing the overall investment among a number of different venture capital groups. The present approach focuses on the attractiveness of the project at a single investor level and extrapolates these results to the reservoir-level investment.

Thus, the capital and operating costs of a single pattern are estimated and the economics of developing the entire field are developed from the economics of the "unitized" area pattern.

Operating costs were estimated by projecting the costs of steam injection, well workover, pumping costs, and water re-injection. The costs of production, workover, and wastewater handling are available from a number of sources and account for a small percentage of the production costs from the pattern. The single largest operating cost is the cost of steam production and, in order to accurately quantify the amount of steam required, a simple analytical model was employed to calculate the required steam pressure, quality, and steam-oil ratio. Data was procured from a number of operating steam-drives on the Northeast McKittrick Field. The steam-oil ratio used over the life of these projects has been reported as

5:1, and this value was used in estimating the injectivity and amount of steam injected per day per pattern.

o Capital Costs

The capital cost analysis begins with a "unitization" of the McKittrick Field to the single-pattern level. A nine-spot pattern is defined with production from eight peripheral production wells drilled from sub-reservoir tunnels, and a steam-injection well located in the center of the spot drilled from the surface. Steam is generated on the surface in a 50 million Btu per hour rated generator that is capable of producing 3,288 barrels of steam per day of 80 percent quality at 1,000 psi, absolute. The required amount of steam for the 18.6-acre pattern is 3,123 barrels of 600 psia steam at a 70 percent quality at the injection points. There are 40 such patterns that comprise the total 743.8-acre McKittrick Field unit under consideration.

Table 3-28 shows the required equipment and capital costs for the steam generating and injection equipment for a single pattern. The costs shown have been procured from a variety of equipment vendors and industry handbook sources.

The basic components of the total capital costs for the steam equipment include:

- Steam injection well
- Wellhead and steam distribution
- Steam generator and flue gas scrubber

The injection well must be completed with special precautions taken such as: quality stringer jointing; high-alloy grade steel; and silane (silicone flour) cementation to avoid thermal shock and cracking. The degree of thermal service and corrosion in an injection well is severe, and precautions are taken to ensure its continued service over the defined eight-year pattern production period.

TABLE 3-28

GRAVITY DRAINAGE WITH THERMAL ASSISTANCE
McKITTRICK FIELD
BUDGET CAPITAL COSTS: SINGLE PATTERN (18.6 acres)

Item/Description	No.	Unit Cost	Data Source	Capital Cost
Site Preparation: (Survey, grading & cleaning, pit development, roads, power & water)	Activity	$15,000	Handbook Estimate, $1.50/ton for pit; $50/hr dozer; $1/ft power	$ 15,000
Steam Injection Well Drilling & Completion 4.5" Casing Outside 2-7/8" Dual Alloy Casing/Thermal Expanding Joints;Silane (silicone flour) Cement; Insulated; High Pressure-Non-corrosive; Cost Includes Packers	1@1,000 ft	$150/ft.	Chevron, Pers.Comm. 6.20.82 Costs for McKittrick	$ 150,000
Injector Wellhead;	1 wellhead	$70,000	Vendor	$ 70,000
Steam Distribution Lines, Valves Fittings, and Insulation (Installed Cost)	500 ft line with fittings	$100/ft.	Handbook	$ 50,000
Steam Generator: $50M^2$ BTU/hr Generator @1,000 psi	One per pattern	$357,000	Vendor	$ 357,000
Scrubber (NO_x & SO_x)	One per generator	$325,000	Vendor	$ 325,000
Generator & Scrubber: Shipping & Installation	Lot	$40,000	Vendcr	$ 40,000
Production Equipment, Gathering System & Pumping	--	--	--	Cost Incl. in Gravity Drainage Cost Estimate
			Subtotal	$1,007,000/ pattern

- $1,007,000 per production pattern
- $ 135,000 per 2.5 acre spot

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Table 3-29 integrates the costs of the gravity drainage access mine with the cost of steam production and injection for the 40-pattern field. From this table the capital cost of $4.59 million is shown to be the total cost of developing a single production pattern. The timing for construction of the pattern including the development of the steam generating facilities and drilling the injection wells is assumed to be one year. Naturally, several patterns would be completed simultaneously (approximately 15-20 at one time), thus, the total time for field development would be approximately 2.5 to 3.0 years.

A contingency of 10 percent has been added to the total capital cost figure to account for working capital, miscellaneous equipment, engineering and costing uncertainty.

o Operating Costs

Data from the active operators on the McKittrick Field indicate that the steam-oil ratio for steam drives is 5:1. This data was used to calculate the total steam production cost since it was the most reliable figure available for the analysis.

Table 3-30 presents the operating costs for a single 8-spot production pattern in the McKittrick Field. The majority (88 percent) of the annual operating cost of $2.54 million is attributable to the costs of purchasing fuel for steam production. This cost is based on the purchase of outside refined fuels (No. 2 fuel oil) for steam generation as opposed to using lease crude. For the "typical" operating scenario of 50 percent recovery using thermally assisted gravity drainage, the costs for steam generation are estimated to be $12.86/BBL, while the operating costs for gravity drainage alone are a fraction of this cost at $.45/BBL. Thus, the application of thermal assistance methods represents a substantial capital and operating cost commitment to a gravity drainage project.

The operating costs quoted above further illustrate the importance of defining proper selection criteria for gravity drainage technology. Light oil reservoirs (i.e., Appalachian, Ohio and West Virginia areas) provide a

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TABLE 3-29

GRAVITY DRAINAGE WITH THERMAL ASSISTANCE
McKITTRICK FIELD
CAPITAL COST SUMMARY
TOTAL FIELD DEVELOPMENT COSTS

Item/Description	No.	Unit Cost	Capital Cost
Gravity Drainage Underground Access Mine: Includes all Access, Production Wells, H_2O Treatment & Re-injection; Pumps, Piping & Oil Treatment		$126,565,000	$126,565,000
Steam Injection Facilities	40 Patterns (Table 5-1) (Exhibit III)	$1,007,000/pattern	$ 40,280,000
Subtotal			$166,845,000
Contingency, Working Capital & Engineering @ 10%			$ 16,684,500
TOTAL			$183,529,500

CONCLUSIONS

- The total capital cost for the development of the 744 acre Northeast McKittrick Field under gravity drainage with thermal assistance is $183,529,500 (FY 1982)
- There are 40 separate production patterns, thus the capital cost per pattern is $4,588,238 (FY 1982)

production well flowrate of a similar magnitude to the thermally modified heavy crude but have an associated operating cost of $0.45 - $1.00 per barrel instead of the $12.00 - $16.00 per barrel typical of many steam-drive operations.

Typical operating cost data for a steam-drive operation are presented as follows (Lewin, 1981):

Item	$/Produced Barrel (FY-1981)
Investment Costs	1-3
Operating Costs	4-6
Steam Costs (Purchased Fuel)	12-16
SUBTOTAL	17-25
Royalties & Severance	4
State and Federal Taxes	2
Windfall Profits Tax	3
SUBTOTAL	9
Capital Cost (ROI 15 percent)	1-2
TOTAL	27-36

The results of the present analysis fall within the ranges quoted for project recoveries in the 60 to 70 percent range. Because of the rising costs of fuel used in generating the steam ($.925/gal. or $38.55/BBL), the present selling cost per barrel of produced crude for a 15 percent return on equity is now nearly $40 per barrel (FY-1982).

o Production Revenues and Cash Flow Summary

A standard production profile has been assumed for the steam drive thermally assisted project analyzed in this section. This profile is derived from a number of steam drive projects in the McKittrick, Cymric and Kern River areas and represents the best available data on production timing.

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Recovery during the first and second years of the drive (injection operations) is assumed to be 50 percent and 70 percent, respectively, of the maximum production of the residual oil. Table 3-31 shows the percentage breakdown for an 8-year project schedule at varying degrees of ultimate residual oil recovery. The residual oil saturation in the Upper Tulare Sands of the Northeast McKittrick Field is quoted to be 63 percent with total reserves at 100 million barrels in place. After the production has peaked for a period of years, the production schedule will show a decline to 90 percent of the previous level constant rate during the next to the last year and 70 percent during the last year.

Project duration is based on the total amount of steam injected. Generally, it is assumed that a steam-oil ratio of greater than 8:1 is uneconomical, or if more than 2.0 pore volumes of steam have been injected, the drive is generally abandoned. The shutdown criterion of 8 years for this analysis was determined on the basis of the normalized steam-oil ratio reported by the field operators and by the 2.0 pore volumes of injected steam. This quantity of steam was used as the basis in calculating the operating costs shown in Table 3-30 and used in the cash flow analyses.

o <u>Cash Flow Analyses</u>

Based on the capital and operating costs estimated, an economic analysis was performed to determine the following information:

1) What is the current required selling price of the produced oil to achieve a conventional 10 percent return-on-investment (ROI)?

2) What is the required selling price of oil based on varying degrees of project success as measured by the percent of residual oil saturation recovered?

Tables 3-32 and 3-33 display the cash flow calculations. A selling price of $37.15/BBL is required to earn a modest 10 percent ROI, which is not believed to be substantial enough to attract venture capital to a project of the risk level anticipated.

TABLE 3-30
GRAVITY DRAINAGE WITH THERMAL ASSISTANCE
McKITTRICK FIELD

OPERATING COST ESTIMATE: SINGLE PATTERN

Cost Center	Unit Cost	Data Source	Annual Cost
Gravity Drainage Access Mine			
Normal Daily Expenses	$ 11,200/yr.	U.S.DOE(p.94)[1]	$ 11,200
Supervision & Overhead			
Labor (Pumper)	$ 19,200/yr.	"	19,200
Auto & Misc. Tools	$ 5,400/yr.	"	5,400
Power (15 HP pump Connected)	$ 6,570/yr.	Engr. Estimate	6,600
Repair Labor & Supplies	$ 18,200/yr.	U.S.DOE[1]	18,200
Well Workover & Casing Service	$ 24,900	"	24,900
Subtotal			$ 85,500
Steam Injection System			
Steam Generator O&M	$ 50,000/yr.	Lewin, 1981	50,000
Scrubber O&M	$100,000/yr.	"	100,000
Fuel Cost [2]	2.80/BBL steam ($.072 x Fuel Price) (Lewin, 1981)	"	2,224,700
Water Supply & Treatment	$.10/BBL steam	"	79,500
Subtotal			$2,454,200
TOTAL			$2,539,700

1 Costs and Indexes for Domestic Oil and Gas Field Equipment and Production Operations, 1981. U.S. Dept. of Energy, April 1982, DOE/EIA-0185(81).

2 No. 2 Fuel Oil; $.925/gal 3rd. Quarter 1982, Conversion Efficiency is 75% at 1:5 oil-steam injection ratio (2,179 BBL/day).

TABLE 3-31

GRAVITY DRAINAGE WITH THERMAL ASSISTANCE
PRODUCTION SCHEDULE (BBL)

Timing	% of Total Recovery Year	20% Total Recovery (BBL)	40% Total Recovery (BBL)	50% Total Recovery (BBL)	60% Total Recovery (BBL)	80% Total Recovery (BBL)
Construction	0					
Year 1	7	1,425,058	2,850,116	3,562,645	4,275,174	5,700,232
Year 2	11	2,239,377	4,478,754	5,598,442	6,718,131	8,957,508
Year 3	15	3,053,696	6,107,392	7,634,240	9,161,088	12,214,784
Year 4	15	3,053,696	6,107,392	7,634,240	9,161,088	12,214,784
Year 5	15	3,053,696	6,107,392	7,634,240	9,161,088	12,214,784
Year 6	13	2,646,536	5,293,073	6,616,341	7,939,609	10,586,146
Year 7	13	2,646,536	5,293,073	6,616,341	7,939,609	10,586,146
Year 8	11	2,239,377	4,478,754	5,598,442	6,718,131	8,957,508
TOTALS	100	20,357,972	40,715,946	50,894,931	61,073,918	81,431,892

TABLE 3-32

ECONOMIC ANALYSIS: SINGLE PRODUCTION PATTERN
GRAVITY DRAINAGE WITH THERMAL ASSISTANCE
MCKITTRICK FIELD
AFIT CASH FLOW CALCULATION ($ MILLIONS)

Assumptions:

- o 50% Oil Recovery
- o $37.15/BBL Oil Price
- o 1-Year Construction Phase
- o 5:1 Steam-Oil Ratio
- o Total Depreciable Amount = $1,378,275
- o No Depletion Allowance Assumed

Results:

- o ROI = 10% (NPV = .0003 @ 9.8%)
- o Payout approx. equal to 5.5 yrs

Year	7/8 Producing Income	Operating Costs	BFIT Income	Depreciation Costs	Taxable Income	51% Tax	WPT Tax	AFIT Income	Capital Outlay	Cash Flow
0-1	0	0	0	.196	CF	0	0	0	(4.59)	(4.59)
1-2	2.89	2.54	.35	.196	.154	.08	.26	.011	0	.01
2-3	4.55	2.54	2.01	.196	1.81	.93	.42	.665	0	.665
3-4	6.20	2.54	3.66	.196	3.46	1.77	.57	1.32	0	1.32
4-5	6.20	2.54	3.66	.196	3.46	1.77	.57	1.32	0	1.32
5-6	6.20	2.54	3.66	.196	3.46	1.77	.57	1.32	0	1.32
6-7	5.38	2.54	2.84	.196	2.64	1.35	.50	.992	0	.992
7-8	5.38	2.54	2.84	--	2.84	1.45	.50	.892	0	.892
8-9	4.55	2.54	2.01	--	2.01	1.03	.42	.565	0	.565
TOTALS	41.35	20.32	21.03	1.37	--	10.15	3.81	7.085	(4.59)	2.49

TABLE 3-33

CASH FLOW ANALYSES

Assumptions:

- o 50% Oil Recovery
- o Oil Selling Price $43.25/BBL
- o 1-Year Construction Phase
- o 5:1 Steam-Oil Ratio
- o Total Depreciable Amount = $1,378,275
- o No Depletion Allowance Assumed

Results:

- o ROI = 20% (NPV = .001 @ 20.0%)

Year	7/8 Producing Income	Operating Costs	BFIT Income	Depreciation Costs	Taxable Income	51% Tax	WPT Tax	AFIT Income	Capital Outlay	Cash Flow
0-1	0	0	0	.196	CF	0	0	0	(4.59)	(4.59)
1-2	3.37	2.54	.83	.196	.63	.32	.26	.25	0	.25
2-3	5.30	2.54	2.76	.196	2.56	1.31	.42	1.03	0	1.03
3-4	7.22	2.54	4.68	.196	4.48	2.29	.57	1.82	0	1.82
4-5	7.22	2.54	4.68	.196	4.48	2.29	.57	1.82	0	1.82
5-6	7.22	2.54	4.68	.196	4.48	2.29	.57	1.82	0	1.82
6-7	6.26	2.54	3.72	.196	3.52	1.80	.50	1.42	0	1.42
7-8	6.26	2.54	3.72	--	3.72	1.90	.50	1.32	0	1.32
8-9	5.30	2.54	2.76	--	2.76	1.41	.42	.93	0	.93
TOTALS	48.2	20.3	27.8	1.37	26.6	13.6	3.81	10.41	(4.59)	5.82

The assumptions used in the cash flow analyses are as follows:

1) Royalties and Taxes:

- Royalty: 1/8 (12.5 percent)
- State Taxes: 5 percent
- Federal Taxes: 46 percent
- No Investment or Energy Tax Credits
- Windfall Profits Tax: 30 percent Excise Tax on revenues above base (Tier 3) price. (Approx. $3/BBL).

2) Depreciation:

- Depreciation of mining and production equipment on 7-year straight-line basis.

3) Depletion Allowance:

- No Depletion Allowance taken.

4) Tax Credits:

- No ETC tax credits assumed.

5) Escalating Price Track:

- No escalation of oil prices assumed.

In Figure 3-9, the results of the economic analysis are summarized. The required selling price of the produced heavy crude as a function of the total recovery of the residual oil saturation (success of the steam-drive) is given for both purchased fuel and lease-crude steam generation cases. On the average burning leased crude allows a $7/BBL to $10/BBL reduction in cost because taxes are not paid on this portion of the production.

The final results of this analysis can be summarized as follows:

748x

In order for a thermally assisted gravity drainage project to be economically attractive (minimum of 20 percent ROI to attract risk capital) at today's oil prices, the project must recover over 60 percent of the residual oil saturation. This is believed to be a high expectation within the current technology array. Under the current oil pricing structure, gravity drainage techniques are most applicable to lighter oil fields with lower viscosities. As the world price of petroleum increases, the application of gravity drainage with thermal assistance to heavy oil fields becomes more attractive.

o <u>Steam Drive Model Calculations for the McKittrick Field</u>

Simple models for calculating the recovery of steam drives have been presented in several places in the literature (Jones, 1981; Myhill, et al., 1978; Lewin, 1981). These models attempt to quantify two of the greatest areas of uncertainty in achieving an economically attractive steam drive project:

- Estimating the incremental oil recovery and oil production rate; and

- Quantifying the relationship between the quantity of steam injected and the amount of oil recovered.

The recovery model developed by Lewin 1981 is used in this analysis to quantify the degree of total oil recovery. Empirical production data from a number of steam drives in the Kern River area are used to project the oil production rates. The correlation of the model to the actual historical levels of production in these drives has been very good (Jones, 1981).

The Lewin model has been adopted from the model by Myhill, et al., 1978, and internally accounts for the anticipated steam losses, heat losses to the base and cap rock formations, and calculates the average project steam-oil ratio on the basis of an internal energy balance for the reservoir.

In contrast, the rate of oil flow from the McKittrick Field under mine access gravity drainage is strongly dependent on the viscosity of the oil (inverse proportion) and thus, the latent heat obtained from steam condensation is critical to maintaining adequate gravity flow. Further, the total producing zone pressure generated from steam injection is equivalent to an increase in the effective oil column height which accelerates the rate of gravity flow on a quadratic scale (second power).

Thus, accounting for steam displacement and gravity drainage production is a complex task requiring extensive research and simulation modeling to achieve accurate productior estimates. In the production estimate presented here, a simple steam-drive model is adapted to the gravity drainage system. It is felt, however, that "worst case" production estimates are acquired by the application of this model and that the actual rate of oil flow and ultimate oil recovery will be significantly greater when the gravity drainage mechanism is properly accounted for in the calculations.

o <u>Calculation for Steam Drive</u>

Oil recovery is determined as a function of the steam injection rate, growth of the steam zone, the heat balance in the reservoir, and the dimensions of the producing intervals. The major factors determining the total oil recovery are related to the steam-oil ratio through the functions of dimensionless time, t_d, and the ratio of latent heat to sensible heat, h_d, defined as (Lewin, 1981):

$$t_d = \frac{4k_{h2} M_2 t}{Z_t^2 M_1^2}$$

and

$$h_d = \frac{f_{sd} L_v}{C_w WT}$$

750

where:

t	-	Time of steam injection (hours) = 32,615 hours
Z_t	-	Gross thickness of reservoir (feet) = 112 ft.
M_1	-	Average heat capacity of steam zone (BTU/ft^3-^{o}F) = 35 BTU/ft^3-^{o}F
M_2	-	Average heat capacity of cap and base rock (BTU/ft^3-^{o}F) = 35 BTU/ft^3-^{o}F
k_{h2}	-	Thermal conductivity of cap and base rock (BTU/ft-hr-^{o}F) = .975 BTU/ft-hr-^{o}F
L_v	-	Heat of vaporization of steam (BTU/lb) = 1167 BTU/lb (600 psia)
f_{sd}	-	Steam quality in reservoir (dimensionless) = .70
WT	-	Steam zone temperature minus original formation temperature (^{o}F) (400°F-89°F) = 311°F
C_w	-	Specific heat of water (BTU/lb/^{o}F) = 1.0 BTU/lb/^{o}F

The t_d and h_d functions are related through heat and mass transfer equations with parametric solutions as shown in Figure 3-10. After the normalized oil-steam ratio is found from Figure 3-10, the actual oil-steam ratio is calculated as:

$$F_{os} = N_{os} \cdot (\cdot \cdot S \cdot \frac{Z_n}{Z_t}) \cdot C$$

where:

F_{os}	- actual oil-steam ratio
N_{os}	- normalized oil-steam ratio (from Exhibit VII)
$\cdot$	- porosity = .35
S	- average initial saturation less average ending saturation = .31
Z_n	- net thickness of reservoir = 84 ft
Z_t	- gross thickness of reservoir = 112 ft
C	- empirical corrective factor of 0.75

Given a steam injection rate and the length of injection time, the cumulative oil production can be calculated from the oil-steam ratio, as follows:

$$\text{Cum. Rec. (bbl)} = F_{os} \cdot \text{(Steam Inj. Rate)} \cdot \text{(Time of Steam Inj.)}$$

Using the injection data provided by Chevron for the McKittrick Field an injection rate of 1.4 BBL of steam per acre-foot is used in the calculation of the cumulative oil recovery. The total time of steam injection is calculated from the criteria of 2.0 pore volumes of injected steam prior to operation shutdown.

Using the above equations and the data provided in Table 3-34, the calculated total barrels of steam injected are:

$$\begin{aligned}\text{Steam, BPD} &= (1.5\ \text{BBL/acre-ft.})(18.60\ \text{acre})(112\ \text{ft.}) \\ &= 3{,}123\ \text{BBL/day}\end{aligned}$$

Each 50 MMBTU per hour steam generator is capable of generating 3,288 barrels of steam at an 80 percent quality at 1000 psig each operating day with a 95 percent steam factor. Thus, one generator will suffice for each producing pattern in the McKittrick Field with multiple injection wells.

The total pore volume of the pattern is shown in Table 3-34 to be 4,244,000 barrels; thus, achieving 2.0 pore volumes of steam injection at a rate of 3,123 barrels per day will require 3.72 years (32,615 hours).

Using these figures in the expressions for t_d and h_d, we have:

$$t_d = \frac{4 \cdot (.975) \cdot (35) \cdot (32{,}615)}{(112)^2 \cdot (35)^2} = 29$$

$$h_d = \frac{(.7) \cdot (1167)}{(1.0) \cdot (311)} = 2.63$$

752 X

TABLE 3-34

RESERVOIR PARAMETERS FOR STEAM DRIVE CALCULATIONS

Northeast McKittrick Field

Item	Date
Reservoir Temperature, °F	89
Reservoir Thickness, ft	400
Gross Pay, ft.	112
Net Pay, ft.	84
Injection Interval, ft.[1]	84
Initial Oil Saturation (Post Primary)	.63
Oil Saturation (Post Steam Drive)[2]	.32
Oil Gravity °API	11-13°API, 12°API avg.[3]
Oil Viscosity, cp @ BHT (initial)	8,500
@ 300°F	5
Porosity	.35
Permeability (absolute), md.	3,000
(relative), md.	1,500
Pattern Spacing, acres/well	2.07
acres/producing well	2.32
Oil in Place/Multiple-Spot Pattern[3], MBBL	2,545
Pore Volume/Multiple-Spot Pattern[4], MBBL	4,244

---

[1] Multiple Zone Injection.

[2] 50 percent recovery initially projected for the steam drive operation; actual recovery is calculated.

[3] Upper Tulare Sands of Northeast McKittrick Field.

[4] Over 84-feet total of permeable saturated oil sands. Impermeable shale layers discounted in total pore volume calculations for injection period.

Using Figure 3-10 (Myhill, et al., 1978) it can be seen that the normalized oil-steam ratio is 4.75 and the actual oil-steam ratio is found by the formula:

$$F_{os} = \frac{(4.75) \cdot (.35) \cdot (.31) \cdot 84 \cdot (.75)}{112}$$

$$= .29 \text{ vol./vol.}$$

Since the amount of steam injected is 3,123 barrels per day for a period of 3.72 years, the total recovery from the 18.6 acre pattern (dense production well spacing) is approximately 1,229,000 barrels or approximately 48 percent of the residual oil saturation.

The steam injection model used in the analysis calculates the total recovery of oil by multiplying the oil-steam ratio by the total volume of injected steam. The rates of oil production for the model are assumed from empirical production data taken from several steam drive operations in the California heavy oil fields.

For a four-year project, the estimated production schedule would be:

Year	% of Incremental Recovery	BBL/Year
1	15	184,350
2	24	294,960
3	32	393,280
4	29	356,410
TOTAL	100	1,229,000

The Lewin model predicts that 48 percent of the residual oil in place is recovered with steam drive. This figure is reasonable in view of the uncertainty of the data employed in the calculations.

754x

As discused in the section on economic results, a selling price of $43.25 per barrel is required to attract venture capital to the project with a 20 percent ROI.

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6. Myhill, N. A., et al., "Steam Drive Correlation and Prediction." Society of Petroleum Engineers of ATME, February 1978.

7. Jones, J., "Steam Drive Model for Hand-Held Programmable Calculators." Society of Petroleum Engineers of AIME, September 1981.

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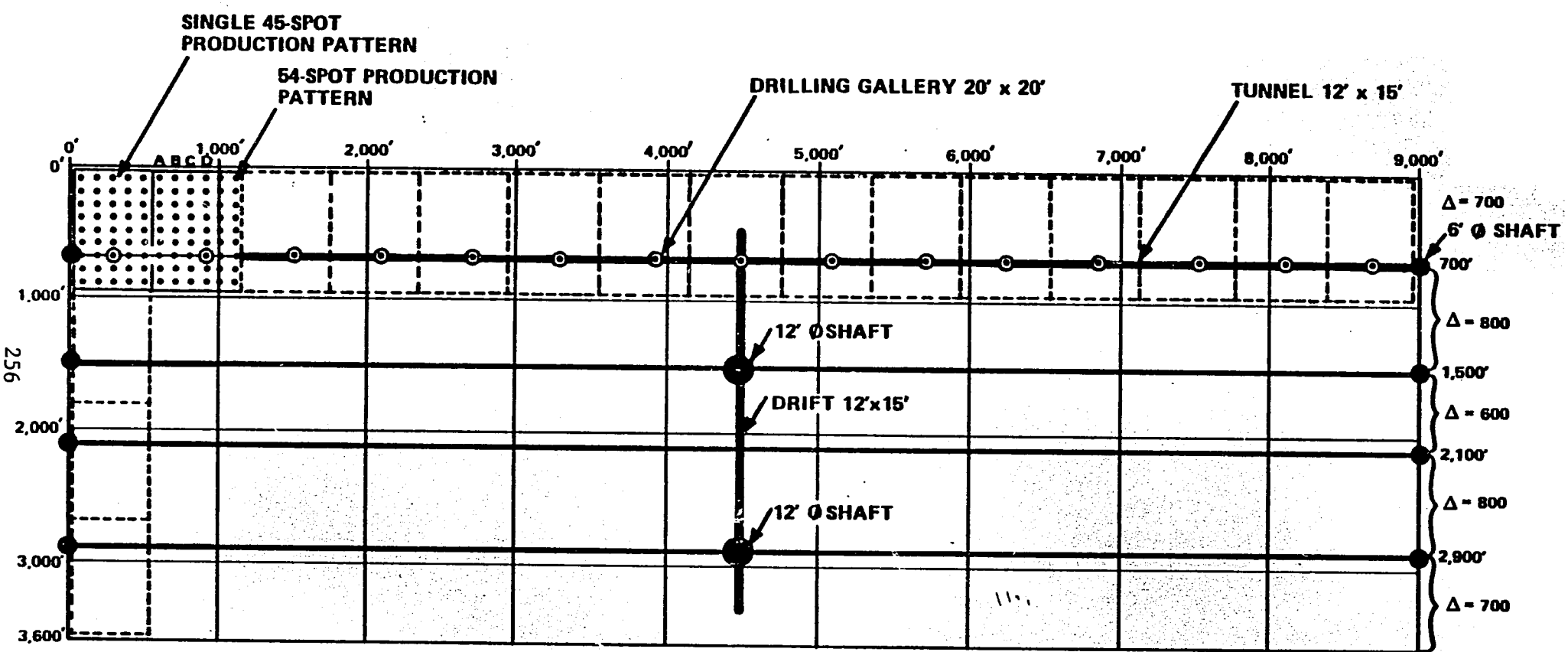
FIGURE 3-3
GRAVITY DRAINAGE MINE
100 ft. SPACING

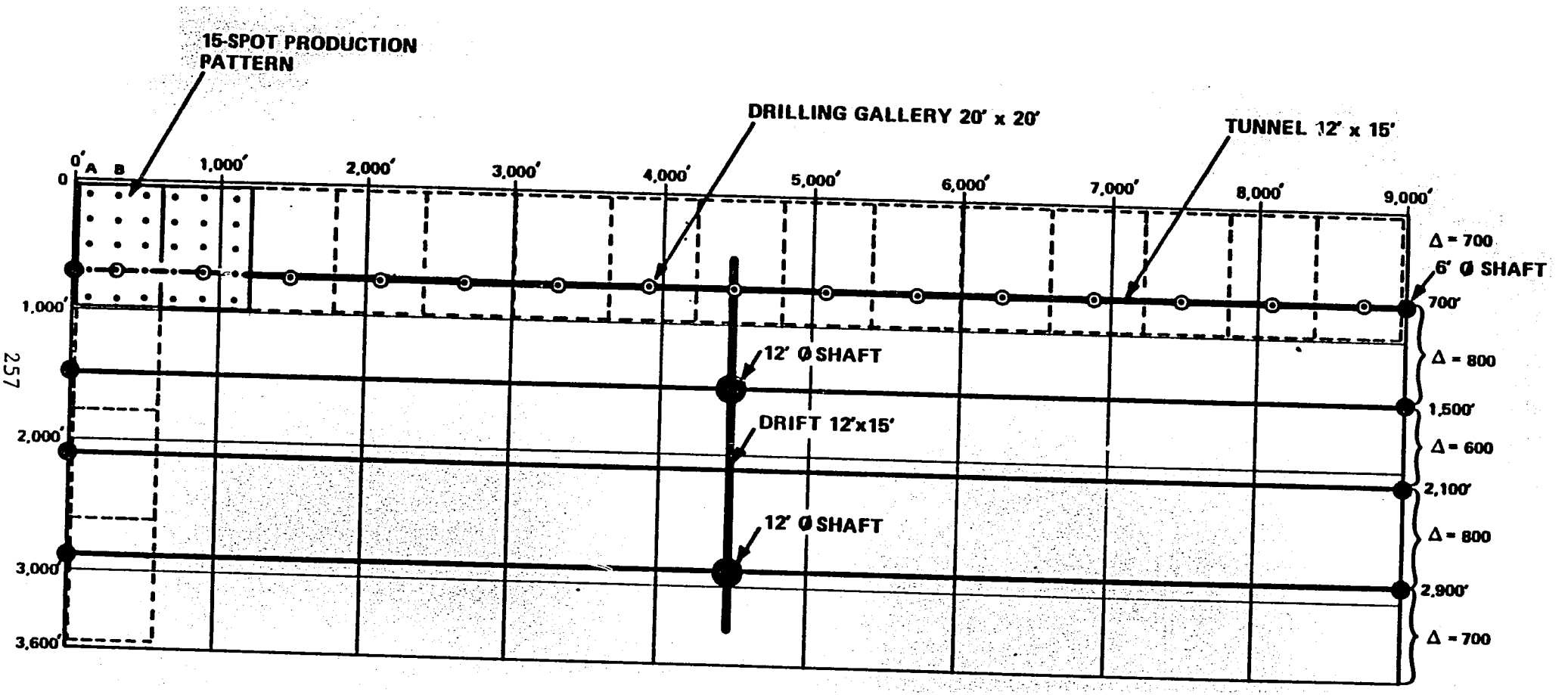


◉ 60 GALLERIES

• 3,115 PRODUCTION HOLES

A0782109

FIGURE 3-4
GRAVITY DRAINAGE MINE
200 ft. SPACING



◉ 60 GALLERIES

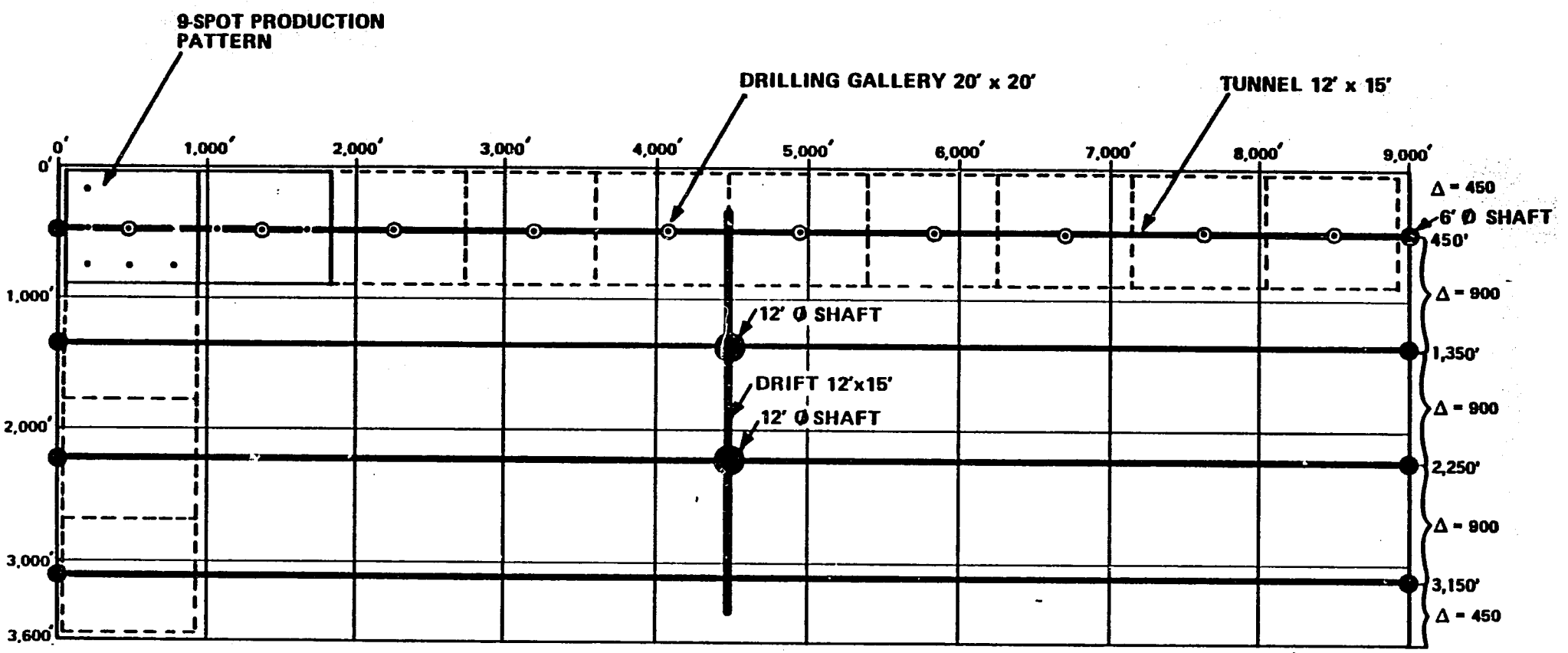
• 810 PRODUCTION HOLES

A0782110

257

758

FIGURE 3-5
GRAVITY DRAINAGE MINE
300 ft. SPACING



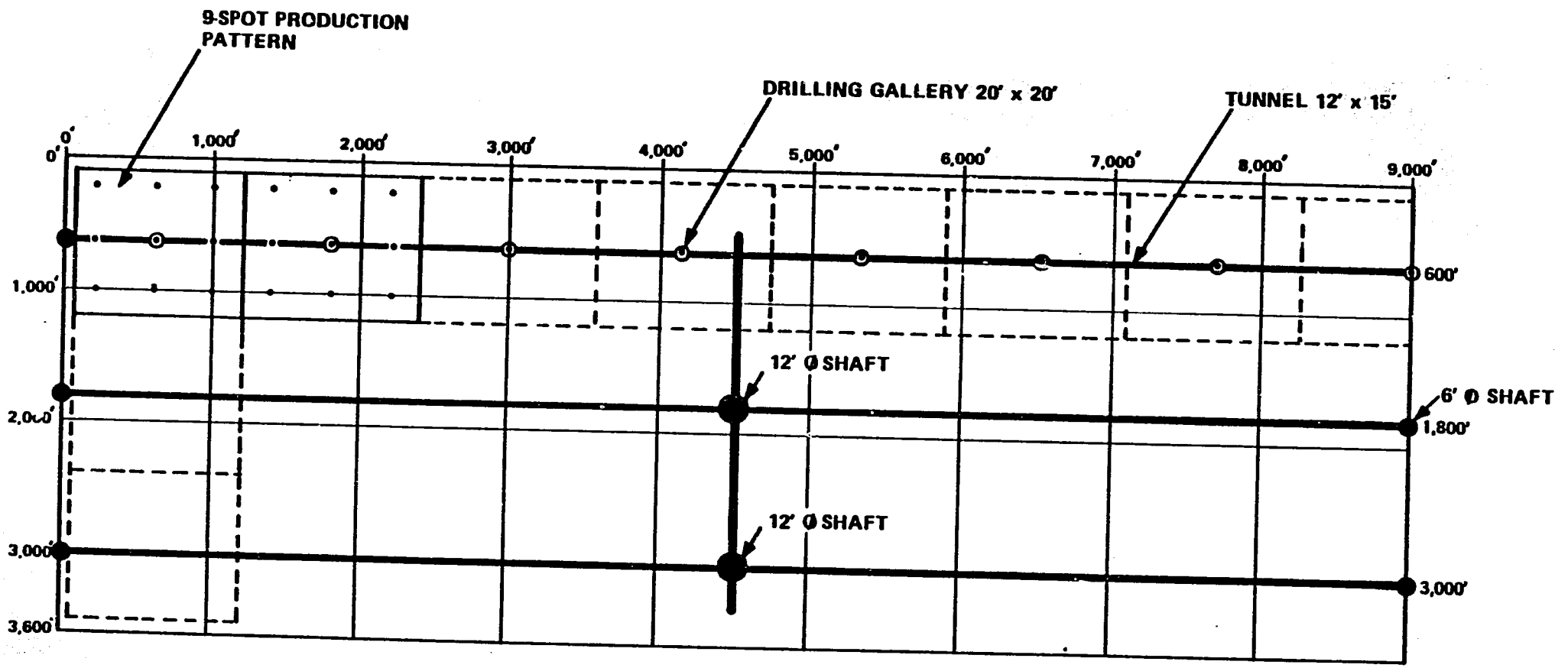
◉ 40 GALLERIES

• 360 PRODUCTION HOLES

A0782107

759

FIGURE 3-6
GRAVITY DRAINAGE MINE
400 ft. SPACING



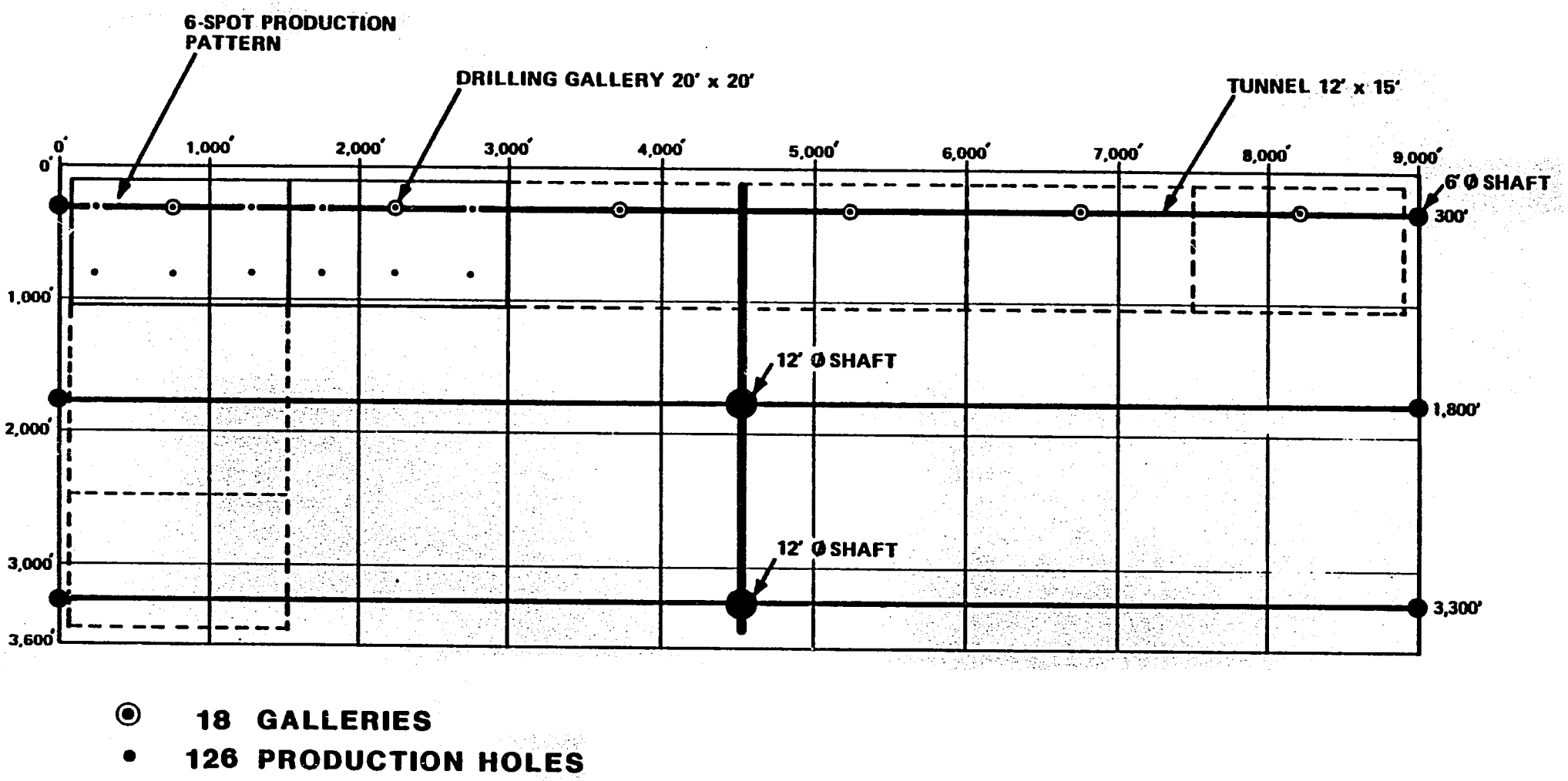
24 GALLERIES

207 PRODUCTION HOLES

760'

A0782111

FIGURE 3-7
GRAVITY DRAINAGE MINE
500 ft. SPACING



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A0882007

FIGURE 3-8
ABSOLUTE VISCOSITY AS A FUNCTION OF API GRAVITY FOR VARYING TEMPERATURES

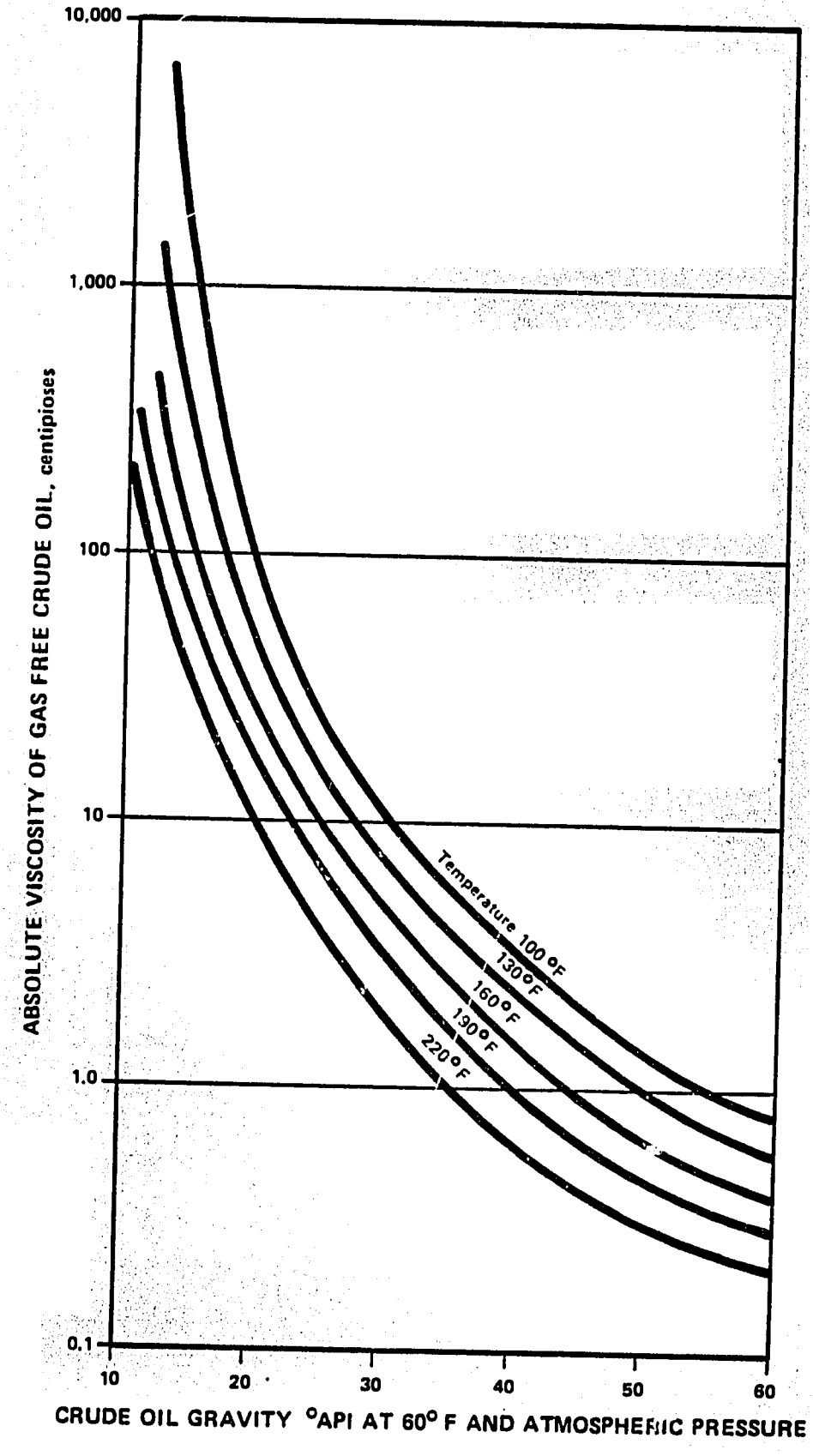

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FIGURE 3-9

REQUIRED OIL SELLING PRICE VS PERCENT OIL RECOVERY

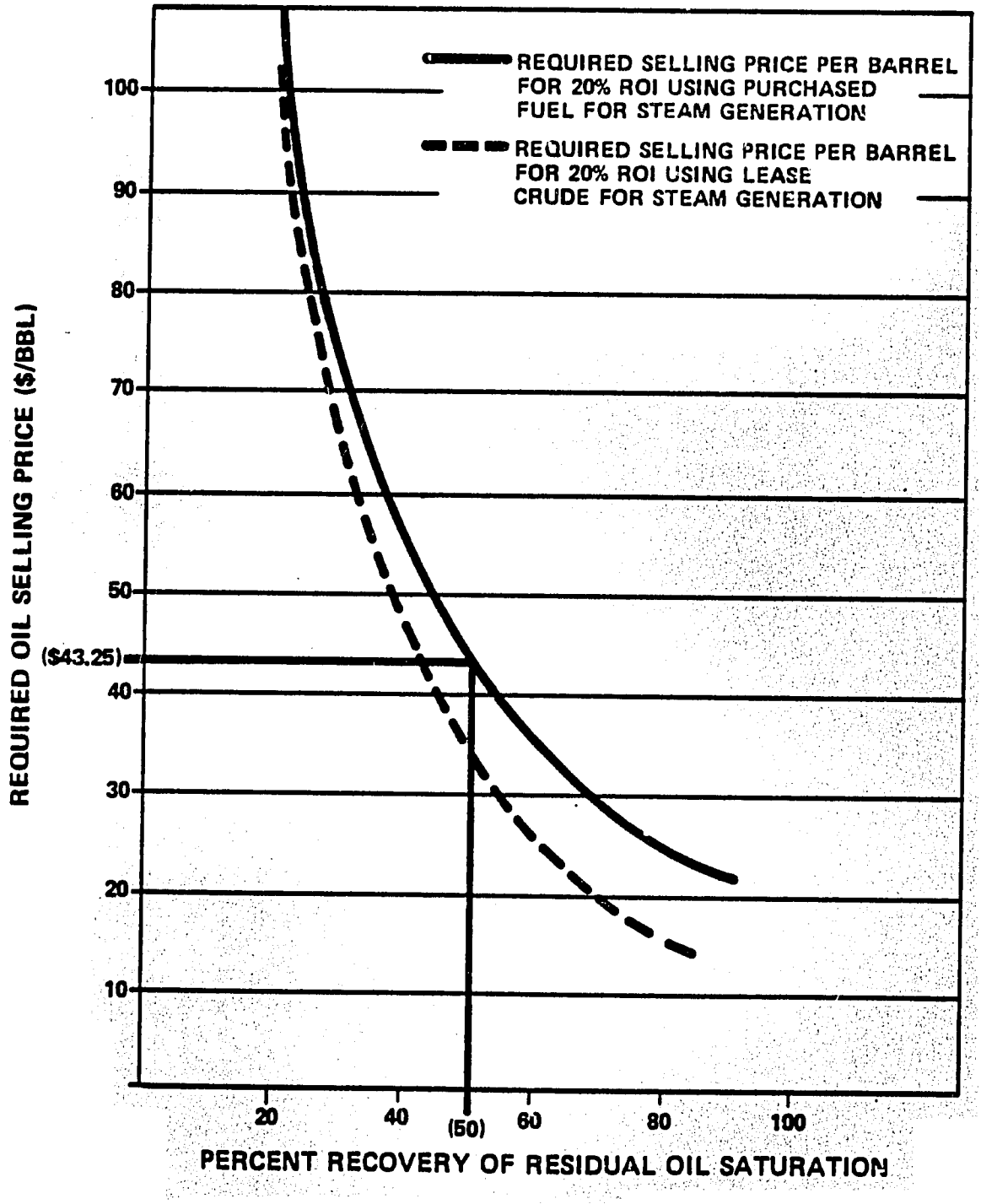

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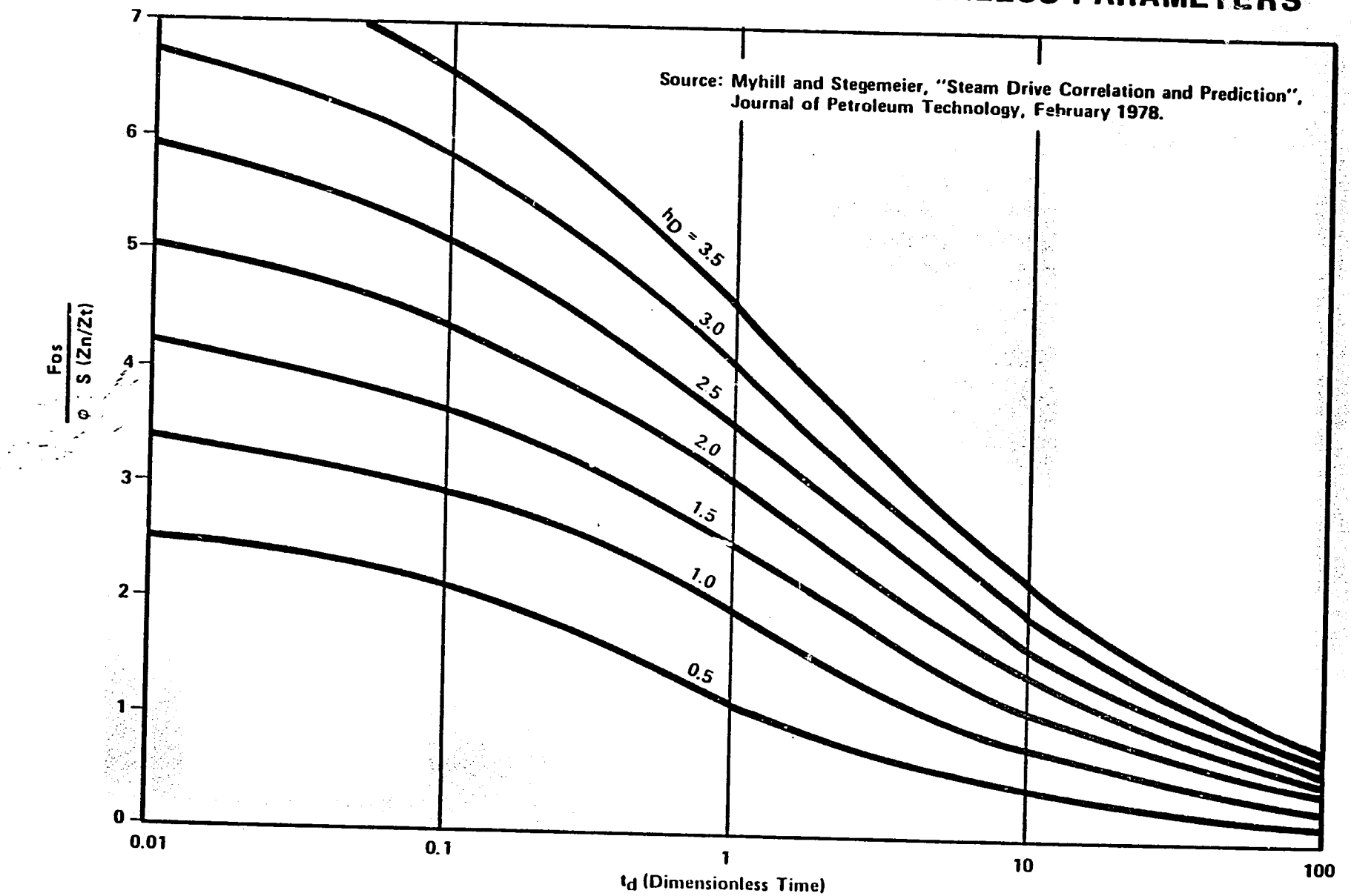
FIGURE 3-10

OIL/STEAM RATIO AS A FUNCTION OF DIMENSIONLESS PARAMETERS



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APPENDIX A

GEOTECHNICAL REPORT ON THE KERN RIVER FIELD, KERN COUNTY, CALIFORNIA

A Report by
Stone & Webster Engineering Corporation
P.O. Box 5406, Denver, Colorado 80217

Under Subcontract to
Energy Development Consultants
For
The U.S. Department of Energy
Under Contract: DE-AC03-80PC30259

December 1982

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INTRODUCTION

The purpose of this report is to provide geotechnical information on the Kern River Field in accordance with Task III of the U.S. Department of Energy contract No. DE-AC22-20P30259.

In this report, useful geotechnical parameters were extracted from existing well data, a structure contour/land ownership map was prepared, five representative wells were annotated to show relative stratigraphic correlations, tables were prepared to indicate the values of geotechnical parameters, and recommendations were made for a geotechnical investigation program.

SOURCES OF DATA

Almost all of the information on the field and drilled wells was obtained from the California Division of Oil and Gas, in Bakersfield, California. This included available literature, well histories, and geophysical well logs. An example of actual on-the-site conditions was provided by Barber Heavy Oil Process, Inc. (HOPCO) on the Kern River demonstration project.

DATA ANALYSIS

Analysis of the data took place in three stages:

1. preparation of a structure contour/land ownership map;
2. presentation of the well log information; and
3. extraction of geotechnical parameters.

The base map of the Kern River Field developed area (Figure 1) was prepared by utilizing a well location/land ownership map and a structure map showing contours on top of the Amnicola Sand published by the California Division of Oil and Gas. The limits of the development area are shown and consist of an approximate 1 mile by 5 mile area on the eastern end of the field.

Five representative wells were selected within this development area which are indicative of the geotechnical conditions. The locations of the wells are shown on Figure 1, along with additional information, such as, the year drilled, total depth, ground elevation, initial production, zone perforated, and available well logs. For easy readability, the important well log traces were combined on to a single sheet along with stratigraphic correlation of the major producing zones. (Figures 2, 3, 4, 5, & 6)

Finally, tables were prepared for two of the wells which presents the log interpretation data for all of the zones of interest. These tables include summaries of the shale index, bulk density, porosity, water saturation, compressional wave velocity, and calculated Young's modulus.

GEOTECHNICAL INFORMATION

Alluvium overlies the productive Kern River Formation which outcrops at the east end of the development area and dips to about 400 feet depth at the western end of the limits shown in Figure 1. The Kern River Formation is composed of up to nine thick productive sand bodies varying from 30 feet to 100 feet thick, separated by mudstones averaging 20 feet in thickness. It has a gross pay of approximately 800 feet, and a net pay of 220 feet. The five wells selected had alluvium overlying the top five producing horizons; the C, C1, G, K, and K1 zones.

The alluvium overlying the Kern River Formation was deposited by the Kern River and is very similar to underlying productive alluvium deposits. It is composed of unconsolidated sands and gravels with some clay layers. The well log data reveals it has a variable shale index, bulk density of 2.0 to 2.1 grams/cubic centimeter, variable porosity, water saturation of 50 to 100 percent and a variable sonic velocity.

The "C" zone, approximately 55 feet thick, has a variable shale index, bulk density of 2.1 to 2.2 grams/cubic centimeter, porosity of 17 to 40 percent,

768x

water saturation of 75 to 90 percent, compressional wave velocity of 6500 to 7100 feet per second, and an approximate Young's modulus of 100,000 to 120,000 pounds/square inch.

The "C1" zone, underlying the "C" zone, is approximately 92 feet thick and has a shale index which varies from 15 to 70 percent, bulk density of 2.1 to 2.2 grams/cubic centimeter, porosity of 20 to 30 percent, water saturation of 75 to 90 percent, compressional wave velocity of 7100 feet per second, and an approximate Young's modulus of 120,000 pounds/square inch.

The "G" zone, underlying the "C1" zone, is approximately 61 feet thick and has a shale index of 53 to 85 percent or more, bulk density of 2.1 to 2.2 grams/cubic centimeter, porosity of 10 to 15 percent, water saturation of 100 percent, compressional wave velocity of 5700 to 6700 feet/second, and an approximate Young's modulus of 80,000 to 110,000 pounds/square inch. This zone is non-productive at this location.

The "K" zone, underlying the "G" zone, is approximately 139 feet thick and has a shale index of 30 to 50 percent, bulk density of 2.1 to 2.2 grams/cubic centimeter, porosity of 10 to 30 percent, water saturation of 70 to 100 percent, compressional wave velocity of 6700 to 8300 feet/second and Young's modulus of 160,000 to 170,000 pounds/square inch.

The "K2" zone, underlying the "K" zone, has a variable shale index, bulk density of 2.1 to 2.2 grams/cubic centimeter, porosity of 20 to 30 percent, water saturation of 75 to 100 percent, compressional wave velocity of 2300 feet per second, and an approximate Young's modulus of 160,000 to 170,000 pounds/square inch.

Based on the rock properties summarized in the preceding paragraphs some general conclusions about rock mechanics parameters can be inferred. All the rocks under consideration are unconsolidated as indicated by the low average compressional wave velocities. Excavation of an open pit mine

could proceed, therefore, using low unit cost surface mining equipment, such as, draglines or bucket wheel excavators without drilling and blasting to loosen the overburden. Information obtained from Barber HOPCO indicates groundwater is absent from most of the field except for the west end at a depth of 1500 feet or more. Some connate water is expected in the productive oil zones.

RECOMMENDED GEOTECHNICAL INVESTIGATION PROGRAM

The purpose of the geotechnical investigations described in the following paragraphs is to provide adequate subsurface data to allow successful design and implementation of a large open pit mine at the Kern River Field. These investigations represent a large capital investment which are necessary and typical of the investigations required to develop a large, deep, open-pit mine as has been proposed for discussion at the Kern River Field.

The areal extent of the proposed surface mine at the Kern River field is approximately three miles long and one mile wide (Figure 1). The maximum total depth proposed for the open-pit is approximately 1000 feet.

The objectives of the geotechnical investigations for the proposed open pit mine at the Kern River Field are to determine the subsurface conditions including structural geology, hydrogeology, and the strength, deformability and other physical characteristics of the strata within the proposed mine area.

These objectives will be met through a multi-phase program of geotechncial investigations and pit-slope monitoring as described below.

The first phase of the geotechnical investigations would produce a final feasibility evaluation of developing a large open-pit mine in this part of the Kern River Field. The investigation would include an evaluation of all existing data in and near the vicinity of the proposed pit and a

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geotechnical assessment of existing subsurface borehole data. Acquisition of geotechnical subsurface borehole data would be doubled-up with resource characterization studies wherever possible. Several core borings would be drilled within the area of the proposed pit and the progress of each boring would be extensively logged for drilling rate, bit wear and drill fluid circulation loss. Continuous core from each boring would be logged in detail to record the engineering characteristics of rocks within the proposed pit area. The percent core recovered, rock quality designation (RQD), frequency and dip of joints, hardness and degree of weathering of both the rock and joints, and other characteristics of joints such as surface roughness and degree of irregularity would be noted on the boring logs.

Laboratory testing of these core samples would include a suite of tests to characterize the rocks with regard to their strength and deformability, hardness, abrasiveness, durability and mineralogical composition. Laboratory tests would include direct shear, triaxial compressive, slake durability on shaly strata, microscopic thin section analysis, and hardness and abrasion tests.

Other investigations during the preliminary phase of geotechnical investigations would include surficial geologic mapping, air photo interpretation and photogeologic mapping, and test pits and trenches where appropriate to assist in surface geologic mapping in areas of suspected faulting.

The results of these subsurface investigations and laboratory tests would be used to analyze the stability of proposed slopes within the limits of the pit. Areas of potential instability and/or groundwater inflow would be identified and additional investigations would follow in these areas as part of the second and final phase of the investigations.

The second phase of geotechnical investigations would consist of collection of additional subsurface data, primarily with additional core borings and

associated laboratory tests. The extent of this additional information would depend on the amount of uncertainty in the data obtained during the initial phase of the geotechnical investigation. Areas of potential faulting or other discontinuities within the weakly consolidated rock mass that were adversely oriented for pit slope stability would be further investigated to determine the orientation and shear strength of these features.

The geotechnical investigations outlined in the preceding paragraphs would provide adequate information for final mine layout and design. Periodic surveillance and detailed mapping of the pit slopes would continue through the development of the pit. If actual subsurface conditions differ significantly from those predicted by subsurface investigations or serious slope instability is indicated from surveillance measurements, the original slope stability analysis would be revised and the mine plan and slope configuration changed to accommodate the actual subsurface conditions.

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EXPLANATION OF TABLES AND FIGURES

FIGURES

Figure 1 is a base map of the field, showing the limits of the development area, land ownership, and the location of five wells within the field. Adjacent to each well is information on year completed, total depth, ground surface elevation, purpose of well, initial production, if any, zone perforated, and logs available. A legend is included on the base map itself.

Figures 2 through 6 are summary well log traces from each of the five representative wells selected within the field. If available, the following traces were shown using the indicated general abbreviations:

SP	Spontaneous Potential Log
GR	Gamma Ray Log
R	Resistivity Log
BD	Bulk Density Log
NP	Neutron Porosity Log
t	Interval Transit Time Log

More detailed well log abbreviations used on these summaries and elsewhere in this report are summarized below:

Electrical Logs

DI-SFL - Dual induction - spherically focused laterolog: includes deep inductive (ILd), medium induction (ILm), a spherically focused laterology (SFL), and spontaneous potential (SP).

DIL - Dual induction - laterolog: includes deep induction (ILd), medium induction, (ILm), and shallow investigation laterolog (LL8).

IES - Induction electrical survey: includes deep induction (GFF40), a sixteen inch normal log and spontaneous potential (SP).

Bulk Density Logs

FDC - Formation density - Borehole compensated gamma-gamma density log.

Porosity Log

SNP - Sidewall neutron porosity

CNL - Compensated neutron log: borehole compensated neutron porosity log.

Sonic Logs

BSL - Borehole compensated sonic log

Miscellaneous Logs

GR - Gamma ray: measures natural gamma ray count

ML - Micrologs

CBL - Cement bond log

C.P. - Computer Processed Logs

In addition, the zones of interest are shown by drawing the correlation lines across the well log traces.

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TABLES

Tables were prepared for the following wells:

Table 1 - Chevron #7-5
Table 2 - Chevron #2-10W

Parameters obtained for each zone of interest include depth to top of the producing zone, thickness, shale index, bulk density, porosity, water saturation, velocity, and Young's modulus. All parameters were obtained from the logs using weighted average values. Calculations required for shale index, velocity, and Young's modulus are given below.

SHALE INDEX

$$SI = \frac{GR - GR_{clean}}{GR_{clay} - GR_{clean}}$$

where: SI=Shale Index
GR=Gamma Ray Reading

Values for a clean sand and a clay are calculated by established a shale base line on the log, and then SI can be calculated using a weighted average gamma ray reading within the zone of interest.

COMPRESSIONAL WAVE VELOCITY

$$V_p = \frac{1x10^6}{\Delta t}$$

Where V_p = Compressional Wave Velocity (ft/sec)
Δt = Interval Transit Time (microseconds per foot)

The compressional wave velocity is the reciprocal of interval transit time. The value is multiplied by one million to obtain an answer in feet/second.

Young's Modulus

Young's Modulus values were calculated from the following relationship:

$$E = \frac{0.01348 \quad \rho(Vp)^2}{(Vp/Vs)^2} \qquad \frac{3\ (Vp/Vs)^2 - 4}{(Vp/Vs)^2 - 1}$$

where:

$$(Vp/Vs)^2 = \frac{2\ (1 - \nu)}{1 - 2\nu}$$

where: E - Young's modulus, psi

ρ - bulk density, gm/cc

V_p - compressional wave velocity, ft/sec

V_s - shear wave velocity, ft/sec

ν - Poisson's ratio

A value of 0.25 was assumed for Poisson's ratio which leads to the following:

$$(Vp/Vs)^2 = 3$$

and $$E = 0.01123\ \rho\ V_p^2$$

The shear velocity was calulated from the ratio $Vp/Vs = (3)^{1/2}$

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TABLE 1 - SUMMARY OF ROCK PROPERTIES FROM WELL REED #509

Field: Kern River
Well: Reed #509
Operator: Getty Oil Co. Date Completed: 5/26/76
Location: T28S R28E Surface Elevation 840 ft, Total Depth 810 ft.
Purpose: Steam Injection
Zone Completed: "K" 612-642
Lithology: Unconsolidated variable sands, alternating with mudstones and shales

Data Available: IES, FDC, BS6, SNP, GR

ZONE	TOP DEPTH ft	ZONE THICKNESS ft	SHALE (1) INDEX %	BULK (2) DENSITY gm/cc	POROSITY (3) %	WATER SATURATION %	V_p (4) 10^3 ft/sec	E (5) 10^6 psi
Alluvium	0	378	Variable	2.0-2.1	Variable		Variable	
C	378	62	34	2.10-2.15	17		6.5-7.1	1.0-1.2
C1	440	97	70	2.10-2.15	20-30		7.1	1.2
G	537	44	53	2.1-2.2	15		5.7-6.7	0.8-1.1
K	581	144	30-50	2.1-2.2	15-30		6.7-8.3	1.1-1.7
K2	725	--	30	2.1-2.2	20		8.3	1.6-1.7

(1) Shale index by gamma ray method

(2) Bulk density from gamma density log (FDC)

(3) Porosity from neutron porosity log (SNP) - sandstone matrix

(4) V_p (compressional wave velocity) from velocity log

(5) E (Young's Modulus) computed assuming Poisson's Ratio = 0.25

TABLE 2 - SUMMARY OF ROCK PROPERTIES FROM WELL NO. GETTY CORE HOLE #7

Field: Kern River
Well: Getty Core Hole #7
Operator: Getty Oil Co. Date Completed: 9/12/79
Location: S33, T28S, R28E Kern County, California
Purpose: Temperature Observation Surface Elevation 780 ft, Total Depth 780 ft.
Zone Completed:
Lithology: Unconsolidated variable sands, alternating with mudstones and shales

Data Available: D1-SFL, FDC-CNL-GR, ML-MLL, CYBERLOOK

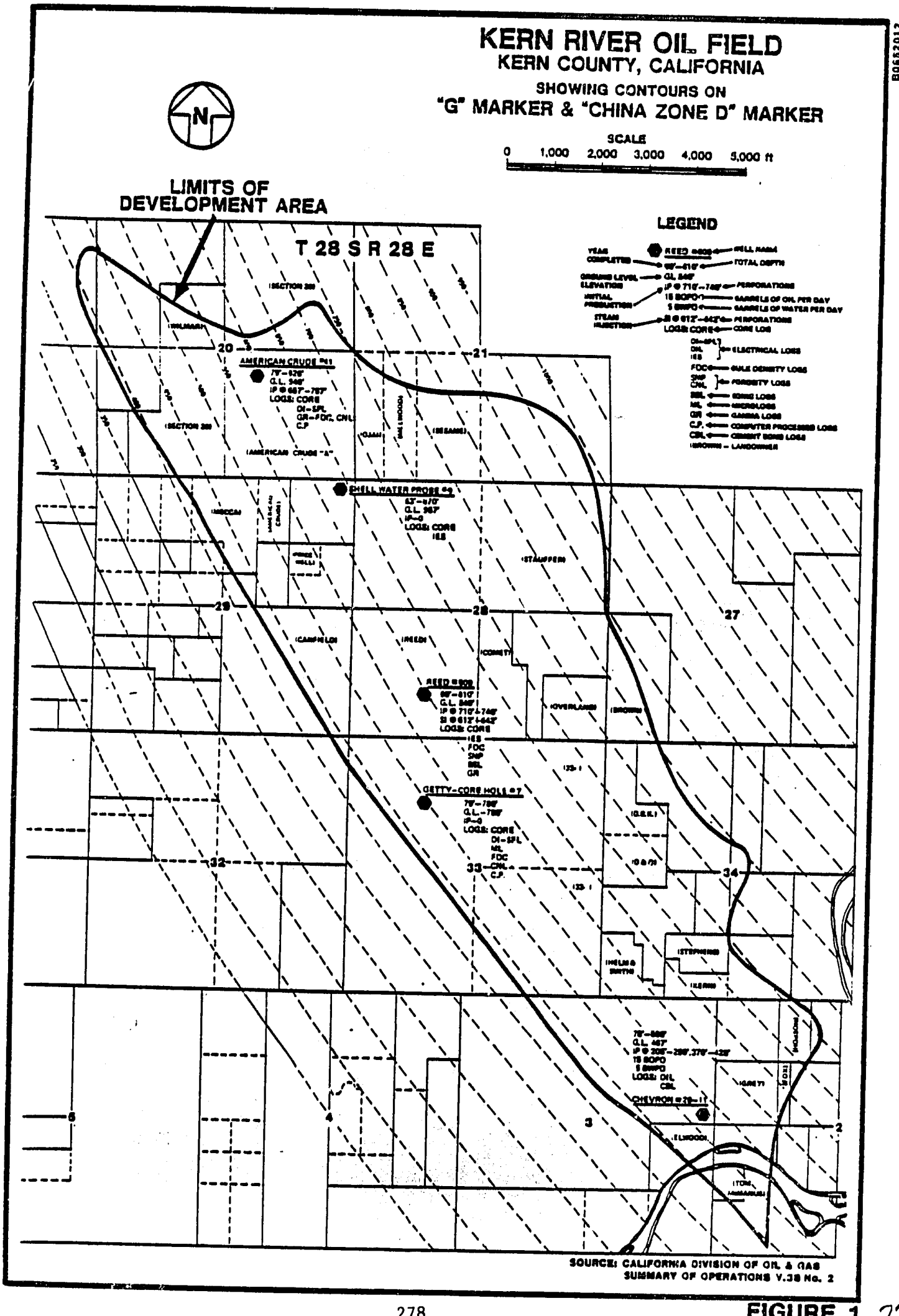
ZONE	TOP DEPTH ft	ZONE THICKNESS ft	SHALE (1) INDEX %	BULK (2) DENSITY gm/cc	POROSITY (3) %	WATER SATURATION %
Alluvium	0	318	Variable	2.05-21.0	Variable	80-100
C	318	52	Variable	2.1-2.2	25-40	75-90
C1	370	88	15-35	2.1-2.2	30	75-90
G	458	78	85+	2.1-2.2	10	100
K	536	134	Variable	2.1-2.2	10-30	70-100
K1	670		Variable	2.15	20-30	75-100

(1) Values from CYBERLOOK computer processed log.

(2) Bulk density from gamma density FDC log

(3) Porosity from neutron porosity log (SNP) - sandstone matrix

KERN RIVER OIL FIELD
KERN COUNTY, CALIFORNIA
SHOWING CONTOURS ON "G" MARKER & "CHINA ZONE D" MARKER



SOURCE: CALIFORNIA DIVISION OF OIL & GAS
SUMMARY OF OPERATIONS V.38 No. 2

FIGURE 1

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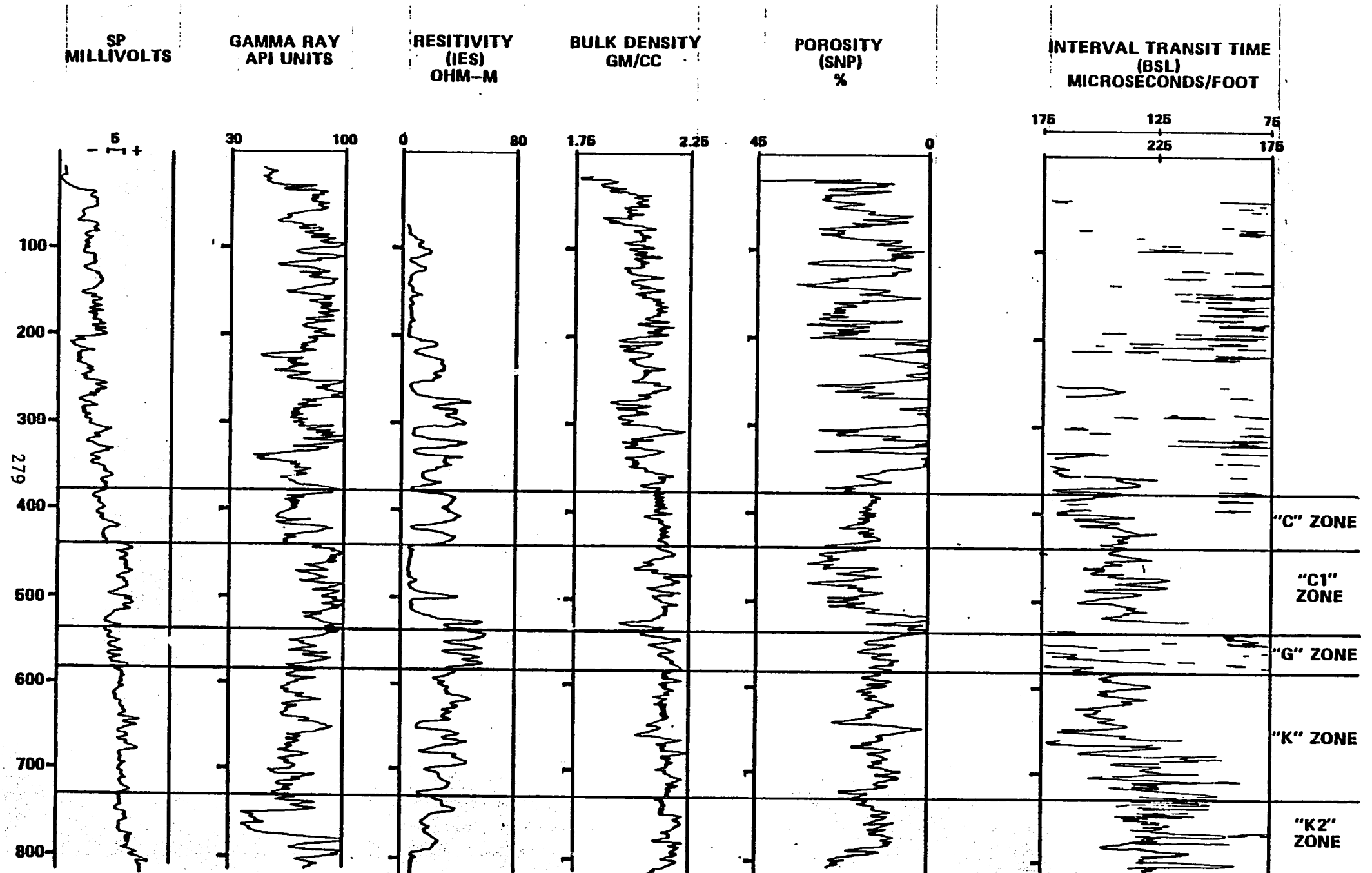


Figure 2
REED
#509

78a

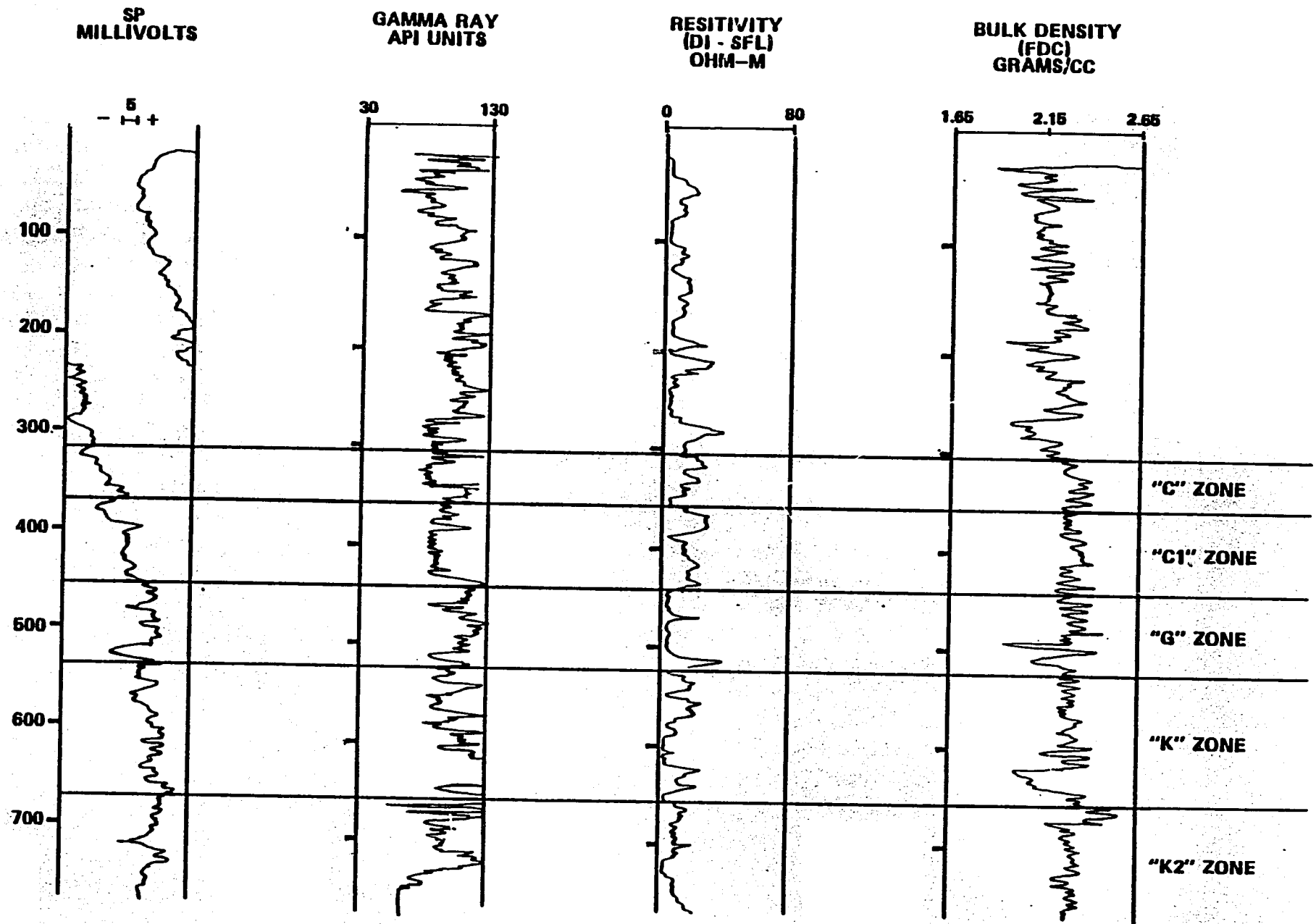


Figure 3
GETTY CORE HOLE
#7

781

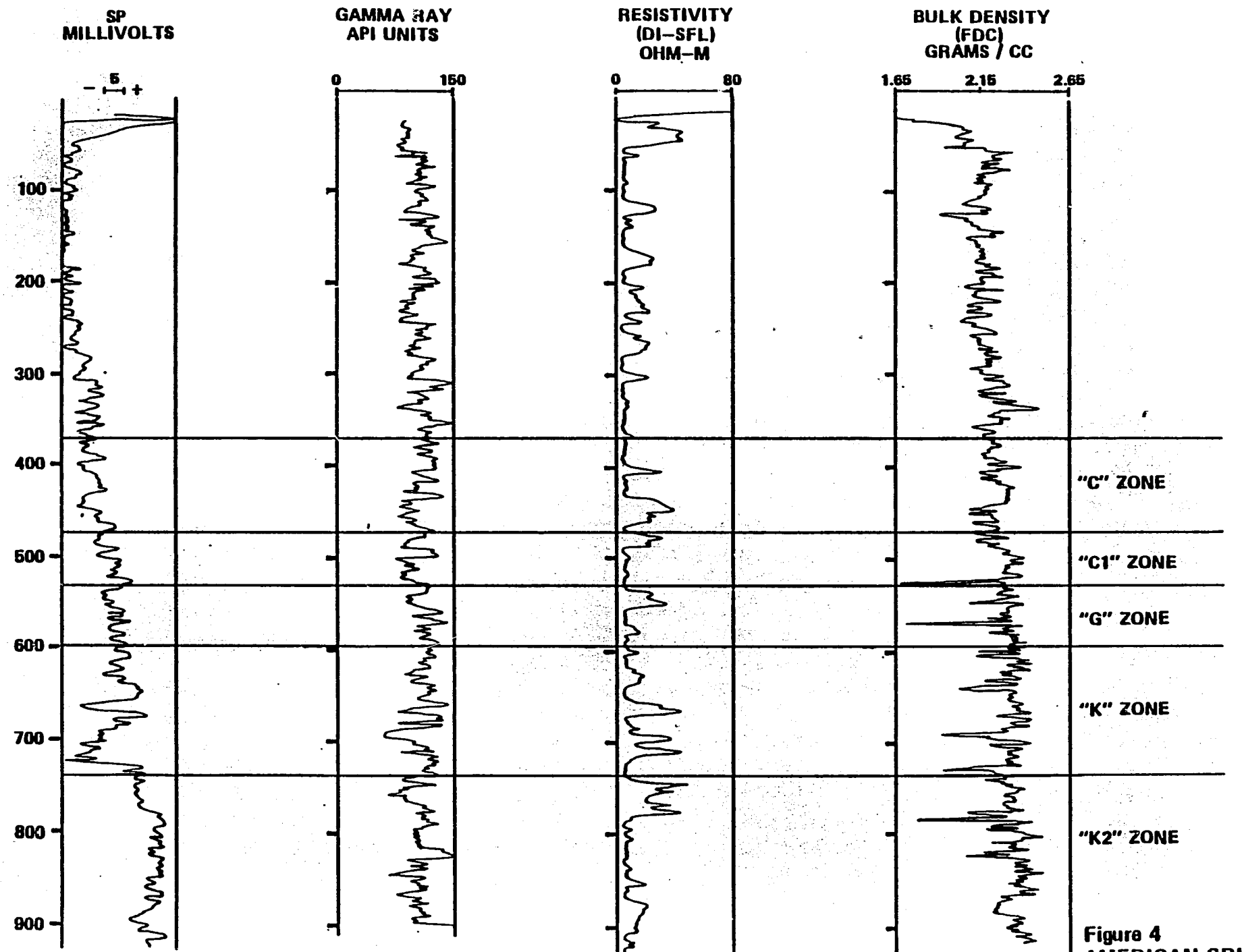


Figure 4
AMERICAN CRUDE
#41

782

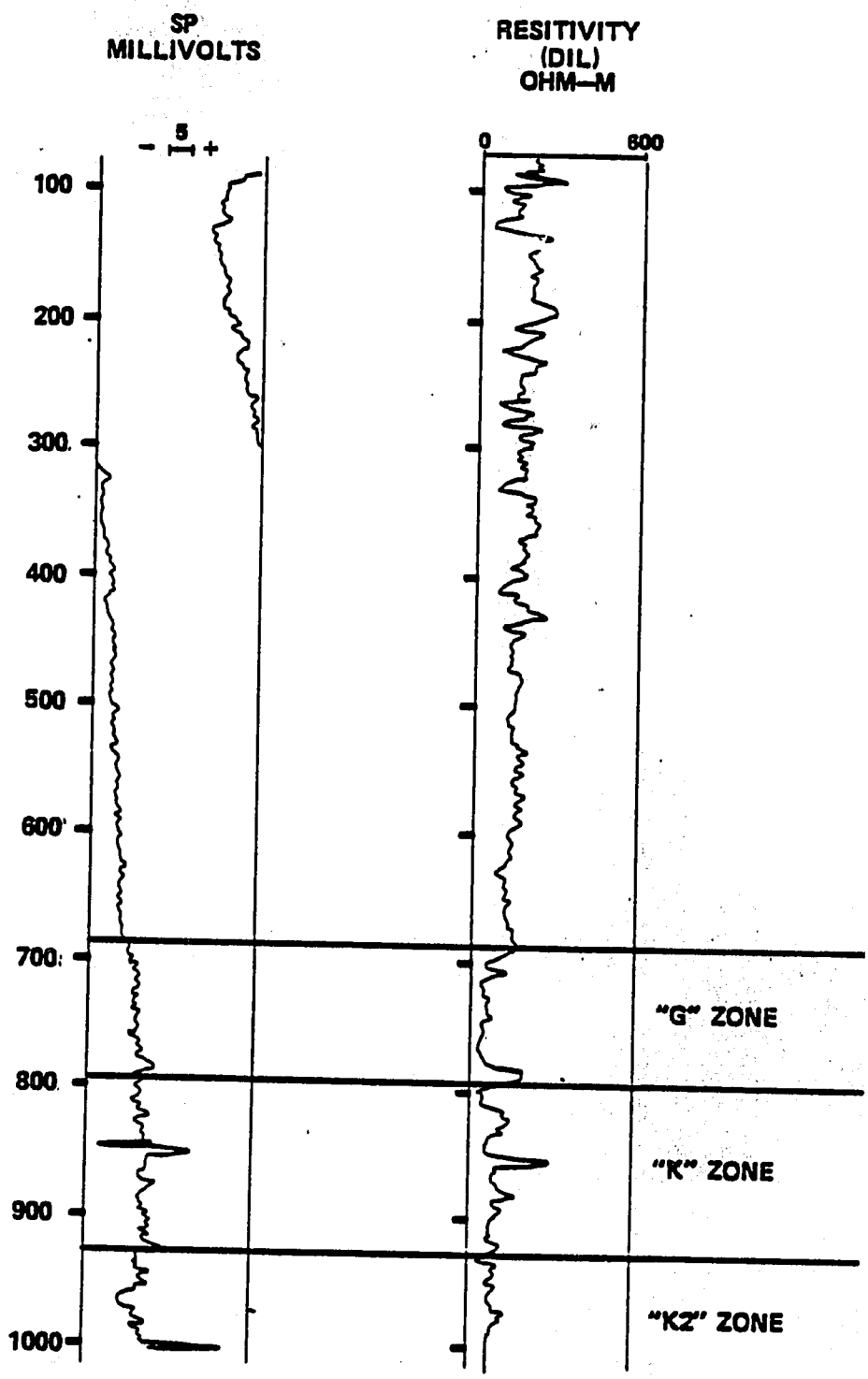
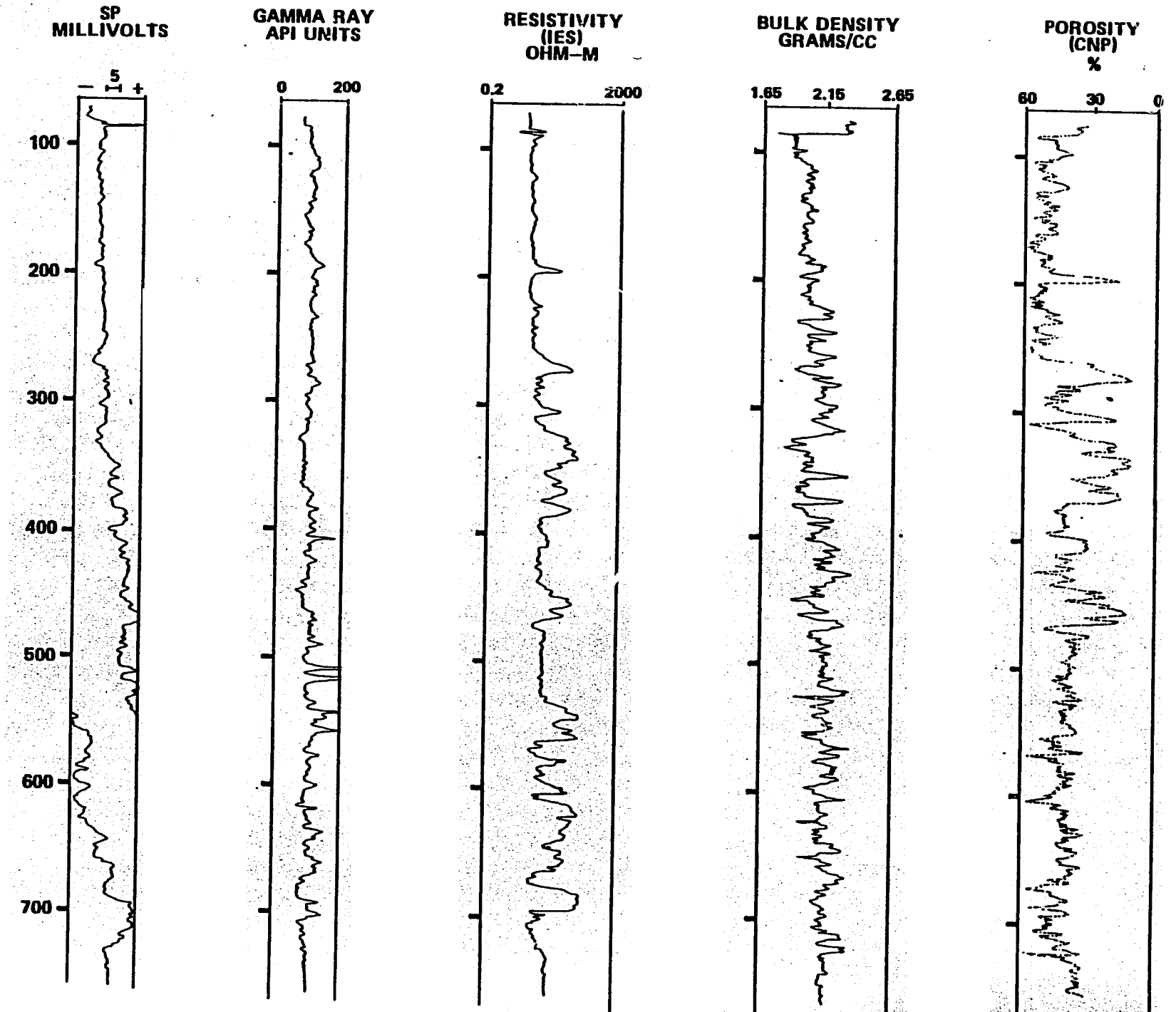


Figure 5
CHEVRON
#26—11

783



UPPER TULARE ONLY

Figure 6
CHEVRON
#12–3

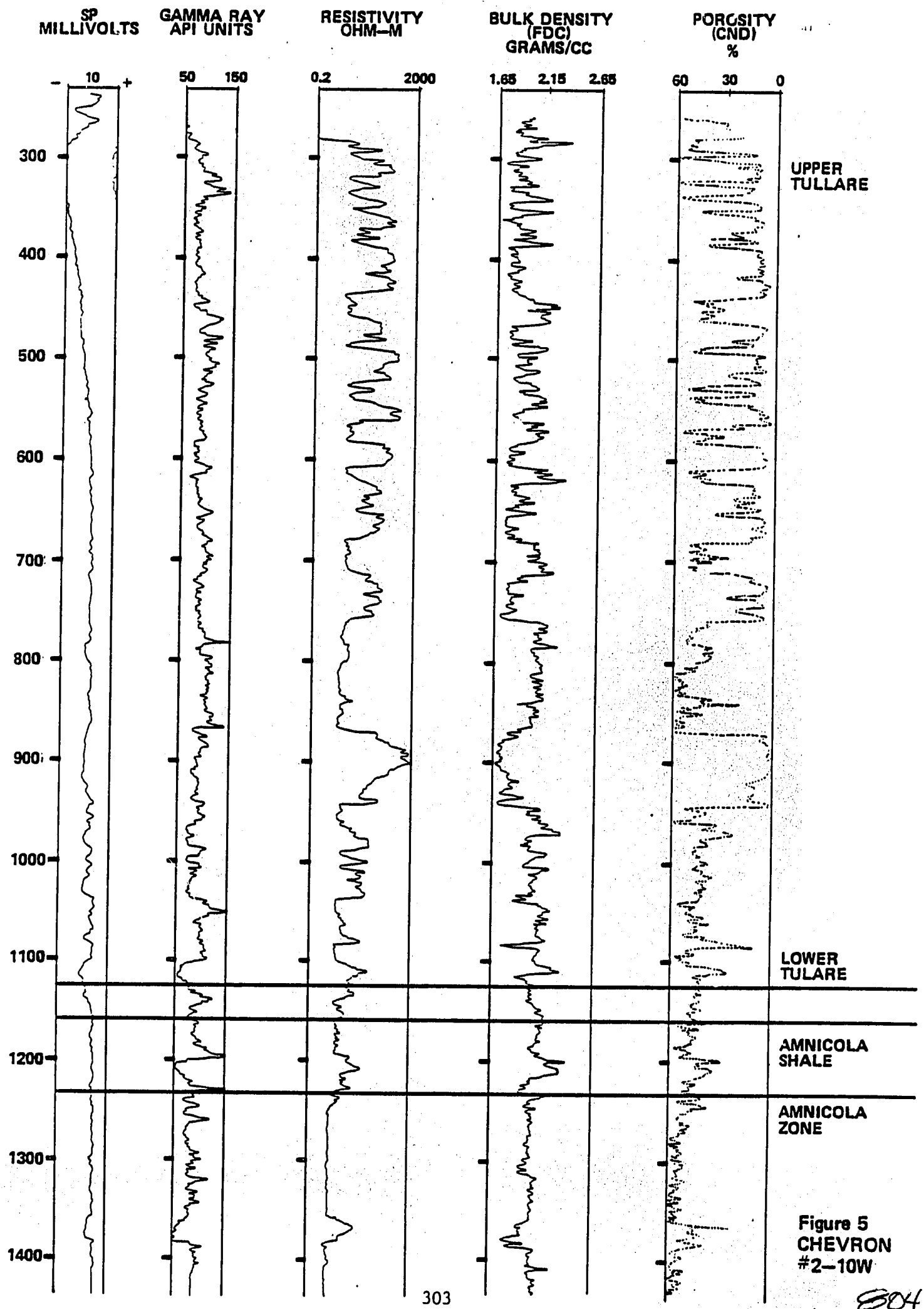


Figure 5
CHEVRON
#2–10W

804

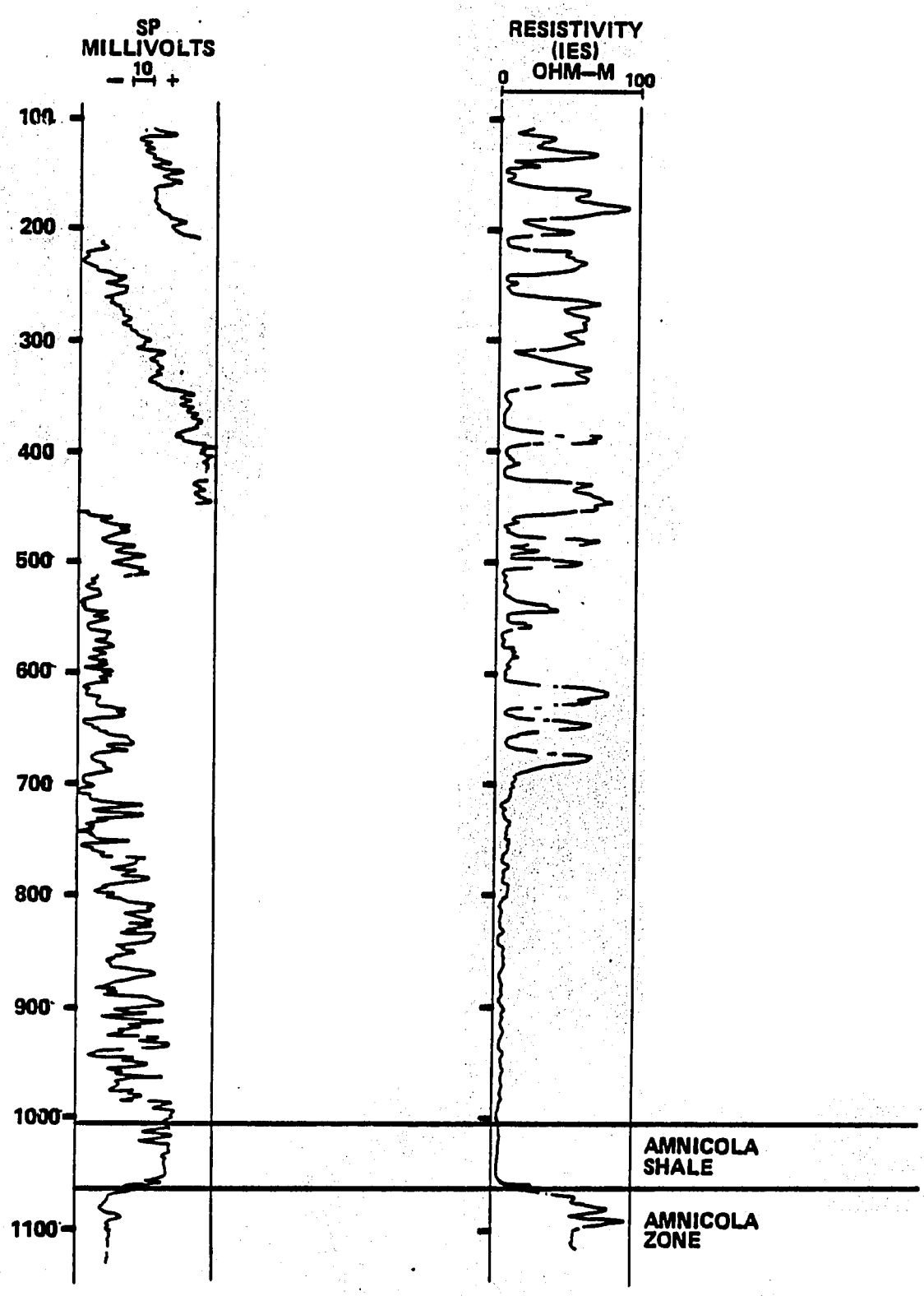


Figure 4
SPRECKLES
#8-2

803

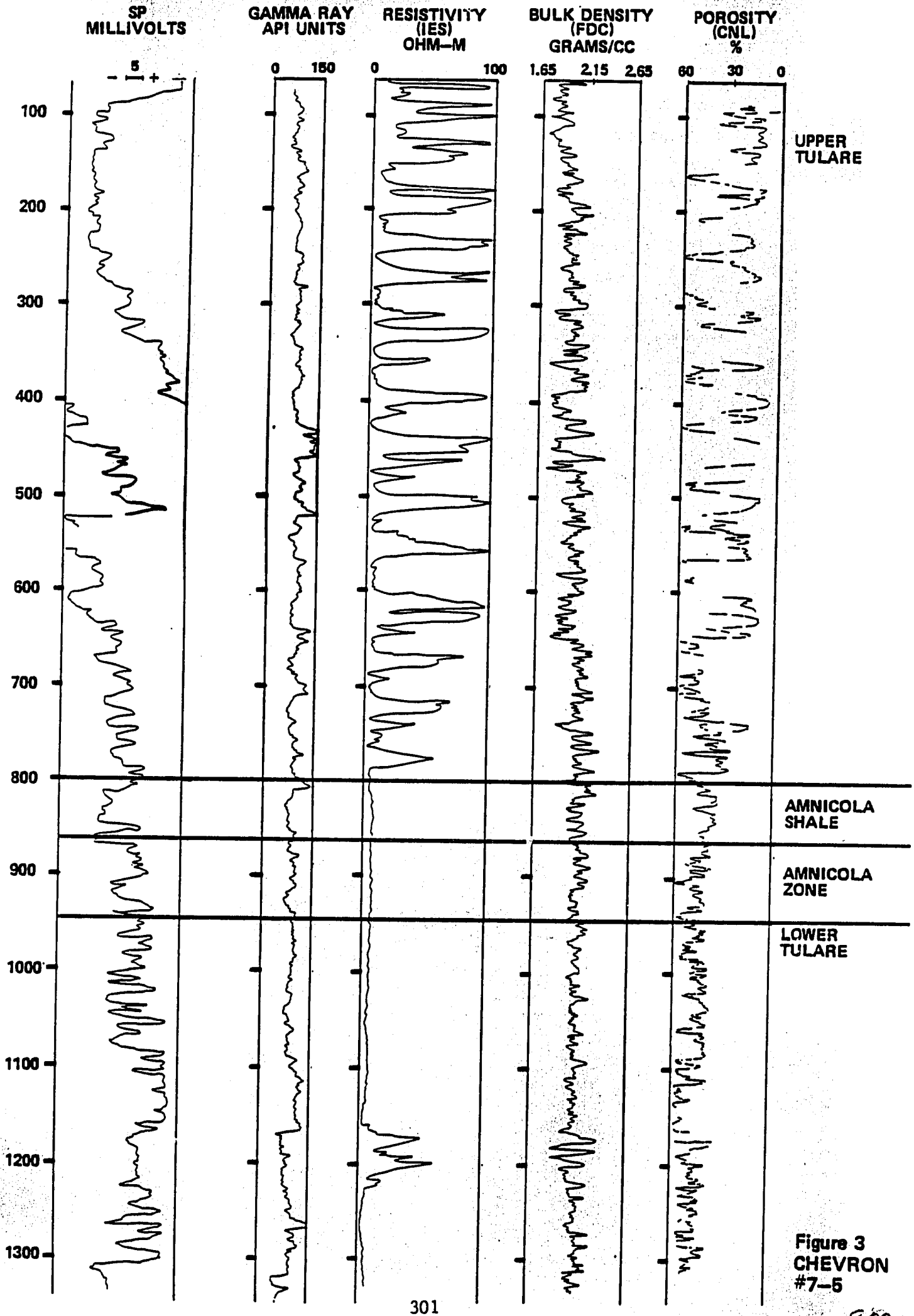


Figure 3
CHEVRON
#7–5

8.02

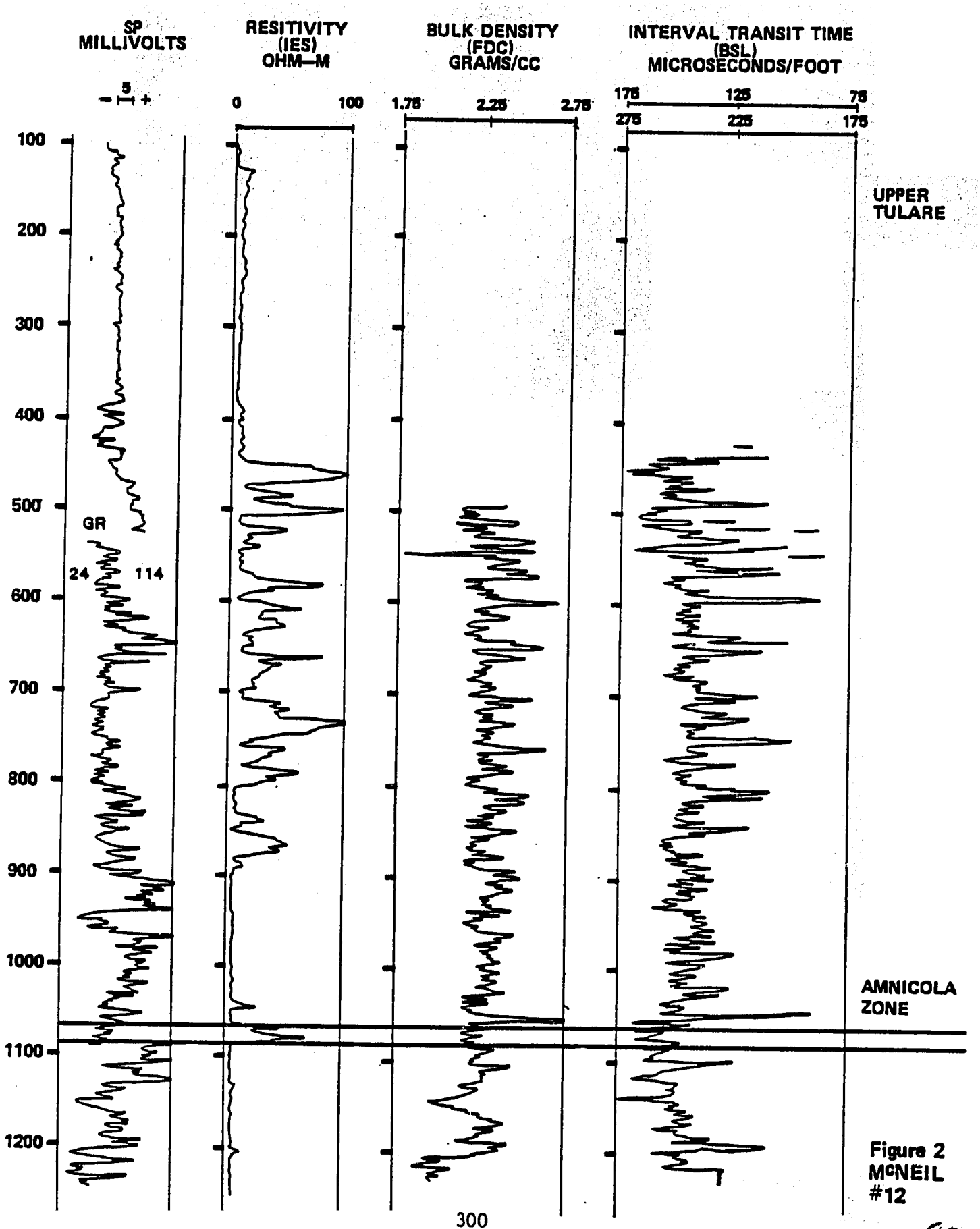
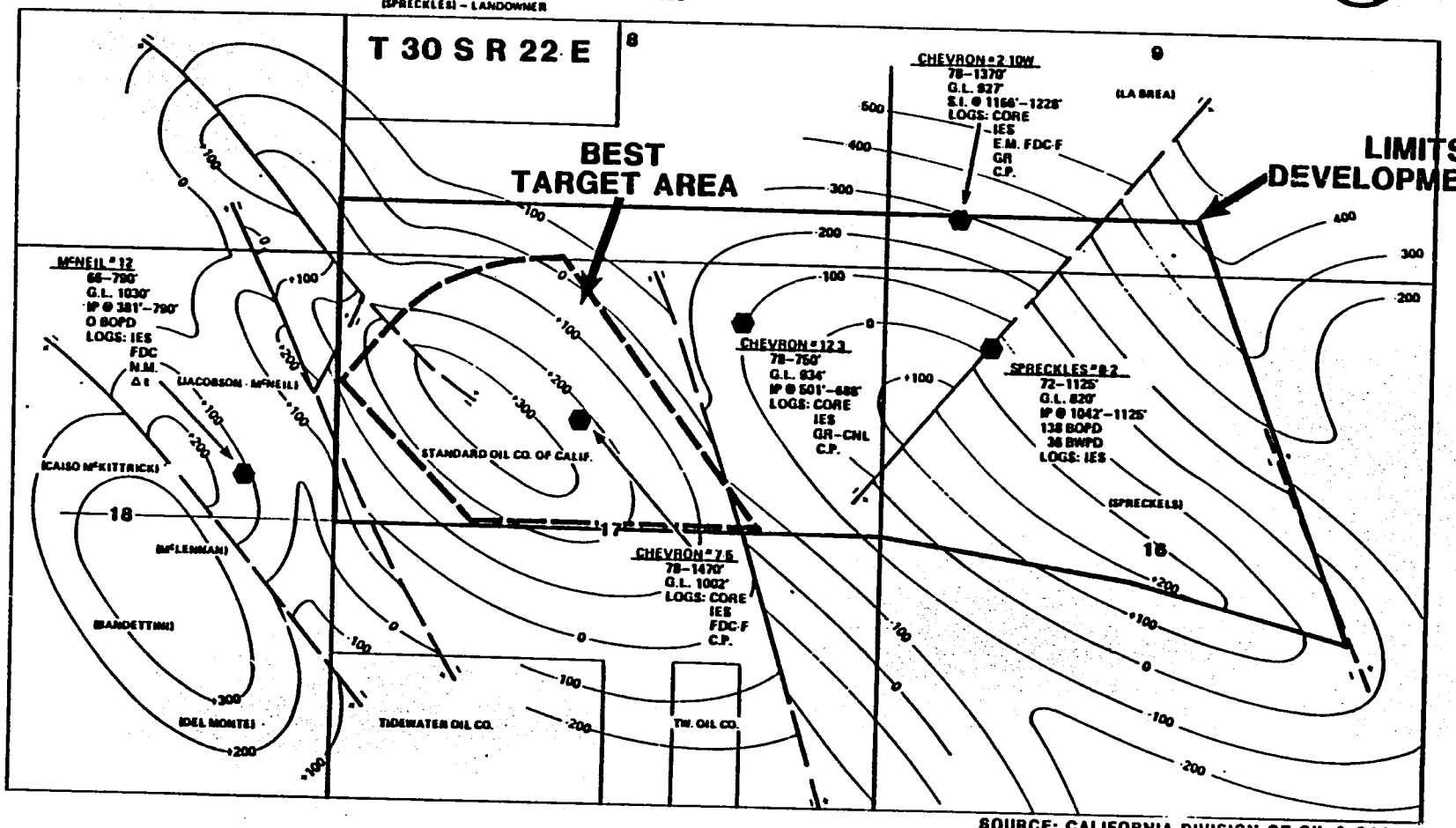


Figure 2
McNEIL
#12

801

NORTHEAST AREA OF THE MCKITTRICK OIL FIELD
KERN COUNTY, CALIFORNIA
SHOWING CONTOURS ON TOP OF AMNICOLA SAND



SOURCE: CALIFORNIA DIVISION OF OIL & GAS SUMMARY OF OPERATIONS V.48 No. 1

FIGURE

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TABLE 3 - SUMMARY OF ROCK PROPERTIES FROM WELL MCNEIL #12

Field: McKittrick NE
Well: McNeil #12
Operator: R.Jacobson Date Completed: 1/4/66
Location: S.9 T30S R22E Surface Elevation 1032.73 ft Total Depth 1250 ft
Zone Completed: 381-790 ft

Lithology: Unconsolidated - interbedded sands/silts/shales

Data Available: IES-FDC-NML-BSL

Zone	Top Depth (ft)	Thickness (ft)	Bulk (1) Density gm/cc	V_p (2) ft./sec.	E (3) $x10^6$ psi
Upper Tulare	--	65	2.16	7050	1.20
Amnicola Shale	65	97	2.14	7040	1.19
Amnicola Zone	1062	19	2.01	6135	0.85
Lower Tulare	1081	--	2.12	6140	0.90

(1) Bulk density from gamma-density log (FDC) - weighted average

(2) V_p computed from weighted average interval transit time

(3) E = Young's modulus computed from bulk density and V_p - assuming Poisson's Ratio = 0.25

TABLE 2 - SUMMARY OF ROCK PROPERTIES FROM WELL CHEVRON #2-10W

Field: McKittrick NE
Well: Chevron #2-10W
Operator: Chevron
Location: S.9 T30S R22E
Zone Completed: 1166-1228 ft

Date Completed: 3/16/82
Surface Elevation 921 ft Total Depth 1370 ft

Lithology: Unconsolidated - interbedded sands/silts/shales

Data Available: FDC-CNL-GR,DIL

Zone	Top Depth (ft)	Thickness (ft)	Shale (1) Index	Porosity 2 %	Bulk (3) Density gm/cc	Water Saturation (4) %
Upper Tulare	815	302	49	20	2.1	0.50%
Amnicola Sh.	1117	45	47	--	2.1	--
Anicola Zone	1162	69	29	48	2.0-2.1	0.17
Lower Tulare	1231	--	66	--	--	--

(1) Shale index by gamma ray method

(2) Porosity from nertron log (CNL)

(3) Bulk density from gamma density log (FDC)

(4) Water saturation calculated from electrical logs RW-0.275

TABLE 1 - SUMMARY OF ROCK PROPERTIES FROM WELL CHEVRON #7-5

Field: McKittrick NE
Well: Chevron #7-5
Operator: Chevron Date Completed: February 1979
Location: S.17, T20S, R22E, Kern County, California
Purpose: Oil Production Surface Elevation: 1008 ft. Total Depth 1421 ft.
Zone Completed: 940-1420 ft
Lithology: Unconsolidated - sands/silts/shales

Data Available: DI-SFL, FDC-CNL,-GR, CYBERLOOK, CORE DATA

Zone	Top Depth (ft)	Thickness (ft)	Shale (1) Index %	Bulk (2) Density gm/cc	Porosity (1) %	Water (1) Saturation %
Upper Tulare	300	502	Variable	1.7-2.2	20-40	Variable
Amnicola Shale	802	63	50	2.05	10-15	60-100%
Amnicola Zone	865	75	10-20	1.65-1.85	30-40	10-40
Lower	940	--	Variable	Variable	Variable	Variable

(1) Shale index, porosity, and water saturation from CYBERLOOK computer processed log

(2) Bulk density from gamma density (FDC) log

Young's Modulus

Young's Modulus values were calculated from the following relationship:

$$E = \frac{0.01348 \quad \rho(Vp)^2}{(Vp/Vs)^2} \qquad \frac{3\ (Vp/Vs)^2 - 4}{(Vp/Vs)^2 - 1}$$

where:

$$(Vp/Vs)^2 = \frac{2\ (1 - \nu)}{1 - 2\nu}$$

where: E = Young's modulus, psi

ρ = bulk density, gm/cc

V_p = compressional wave velocity, ft/sec

V_s = shear wave velocity, ft/sec

ν = Poisson's ratio

A value of 0.25 was assumed for Poisson's ratio which leads to the following:

$$(Vp/Vs)^2 = 3$$

and $$E = 0.01123\ \rho\ V_p^2$$

The shear velocity was calulated from the ratio $Vp/Vs = (3)^{1/2}$

TABLES

Tables were prepared for the following wells:

Table 1 - Chevron #7-5
Table 2 - Chevron #2-10W
Table 3 - McNeil #12

Parameters obtained for each zone of interest include depth to top of the producing zone, thickness, shale index, bulk density, porosity, water saturation, velocity, and Young's modulus. All parameters were obtained from the logs using weighted average values. Calculations required for shale index, velocity, and Young's modulus are given below.

SHALE INDEX

$$SI = \frac{GR - GR_{clean}}{GR_{clay} - GR_{clean}}$$

Where: SI=Shale Index
GR=Gamma Ray Reading

Values for a clean sand and a clay are calculated by established a shale base line on the log, and then SI can be calculated using a weighted average gamma ray reading within the zone of interest.

COMPRESSIONAL WAVE VELOCITY

$$V_p = \frac{1x10^6}{\Delta t}$$

Where V_p = Compressional Wave Velocity (ft/sec)
Δt = Interval Transit Time (microseconds per foot)

The compressional wave velocity is the reciprocal of interval transit time. The value is multiplied by one million to obtain an answer in feet/second.

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IES - Induction electrical survey: includes deep induction (GFF40), a sixteen-inch normal log and spontaneous potential (SP).

Bulk Density Logs

FDC - Formation density - Borehole compensated gamma-gamma density log.

Porosity Log

SNP - Sidewall neutron porosity

CNL - Compensated neutron log: borehole compensated neutron porosity log.

Sonic Logs

BSL - Borehole compensated sonic log

Miscellaneous Logs

GR - Gamma ray: measures natural gamma ray count

ML - Micrologs

CBL - Cement bond log

C.P. - Computer Processed Logs

In addition, the zones of interest are shown by drawing the correlation lines across the well log traces.

EXPLANATION OF TABLES AND FIGURES

FIGURES

Figure 1 is a base map of the field, showing the limits of the development area, land ownership, and the location of five wells within the field. Adjacent to each well is information on year completed, total depth, ground surface elevation, purpose of well, initial production, if any, zone perforated, and logs available. A legend is included on the base map itself.

Figures 2 through 6 are summary well log traces from each of the five representative wells selected within the field. If available, the following traces were shown using the indicated general abbreviations:

SP - Spontaneous Potential Log
GR - Gamma Ray Log
R - Resistivity Log
BD - Bulk Density Log
NP - Neutron Porosity Log
t - Interval Transit Time Log

More detailed well log abbreviations used on these summaries and elsewhere in this report are summarized below:

Electrical Logs

DI-SFL - Dual induction - spherically focused laterolog: includes deep inductive (ILd), medium induction (ILm), a spherically focused laterology (SFL), and spontaneous potential (SP).

DIL - Dual induction - laterolog: includes deep induction (ILd), medium induction, (ILm), and shallow investigation laterolog (LL8).

investigations. After the shaft and initial tunneling is completed, the final phase of geotechnical investigations would be performed.

The final phase of geotechnical investigations would be a continuation of the investigations undertaken for the shaft and initial tunneling phase of the work. The extent of these final investigations would depend on the success of the initial investigations in accurately predicting the subsurface conditions actually encountered in the shaft and initial tunnels. Additional borings along the axis of proposed tunnels would be drilled at approximately 1500-foot spacings and a similar suite of laboratory tests would be performed on core samples from these borings. The boring and sampling frequency for this phase of the investigation would depend on the variability of the ground and the problems encountered in completed tunnels at the site.

taking continuous core and the tunnel holes would be drilled taking intermittent core down to the tunnel zone where core would again be taken continuously. All core would be logged in detail with particular attention to engineering properties of the rocks including percent recovery, rock quality designtion (RQD), dip of joints, frequency or spacing of joints, roughness and/or irregularity of joint surfaces, joint filling, rock hardness, and degree of weathering.

Laboratory testing of core samples from these borings would include a suite of tests to characterize the hardness, abrasion, durability and strength of the rocks. Lab tests would include Moh's hardness, abrasion, slake-durability, x-ray diffraction and microscopic thin section analysis of representative core samples from each boring. Strength tests would include unconfined and triaxial compressive strength tests and determination of Young's Modulus.

In addition to the borings and associated laboratory testing outlined in the preceeding paragraphs, hydrogeologic testing would be performed in each boring after drilling was completed. At least one of these borings would be kept open as an observation well for hydrogeologic purposes. In addition to acquisition of subsurface data from the borings and laboratory tests described above, geologic mapping would be performed in the site area and vicinity. This mapping effort would begin with photogeologic interpretation of the site and surrounding area at least 5 miles from the site. Careful note would be taken for surface expression of any faulting, folding or other structure that would impact the development of the underground openings at the site. This photogeologic reconnaissance would be followed by field geologic mapping of questionable surface features indicated in the photographs.

When this phase of the geotechnical investigations was completed the shaft sinking and subsequent tunneling operations could begin. All underground openings would be mapped in detail, where possible, and the actual subsurface conditions compared to those predicted from the subsurface

RECOMMENDED GEOTECHNICAL INVESTIGATION PROGRAM

The purpose of the geotechnical investigations outlined below is to characterize the subsurface conditions and rock mass quality within the area proposed for development of underground openings so that appropriate tunneling techniques and adequate ground support can be designed and implemented at the site. The geotechnical investigations discussed below are for subsurface openings consisting of a central, large diameter shaft which extends to a depth below the heavy oil reservoir and a series of essentially horizontal interconnected tunnels which extend to the boundaries of the development area shown in Figure 1. The objective of these investigations is to minimize construction delay and/or technical difficulties due to unknown adverse ground conditions during the shaft sinking and tunnel driving phases of this project. This objective can be realized through the series of phased geotechnical investigations outlined in the following prargraphs.

The initial phase of the geotechnical investigations for a mining for access project at the McKittrick Northeast Field would consist of an extensive review of existing information. This would include published information on the geology, structure, geologic history, hydrogeology and stratigraphy of the McKittrick Northeast Field. Available subsurface data would be reviewed including all information, well histories, well logs and other available data from existing wells in the area.

The next phase of the investigation would consist of drilling three or four borings to obtain detailed subsurface information at the proposed location of the shaft and along the axis of one or more tunnels in the vicinity of the shaft. The shaft boring would be located at the centerline of the shaft and the remaining borings would be located approximately 1500 feet from the shaft along the proposed orientation of access tunnels. All borings would be closely monitored as drilling progressed with observations made of drilling rate, drill fluid loss, drill cuttings and other useful observations of the drilling opration. The shaft hole would be drilled

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thick. The Amnicola Shale, a potential tunneling zone, has a high shale index of 50 to 74 percent, a bulk density of 2.1 grams/cubic centimeter, a porosity of 10 to 15 percent, a water saturation of 60 to 100 percent, and a velocity of 6,600 ft/sec. The Amnicola Zone, on the other hand, is the most productive pay zone in the area with a shale index of 10 to 30 percent, a bulk density of 1.6 to 2.1 percent, porosity of 30 to 40 percent, permeability of 4,000 to 6,000 millidarcies, an oil saturation of 60 to 70 percent, and a zone velocity of 7,400 ft/sec. The Amnicola Sand Zone usually consists of gray to brown sandstone that is poorly sorted, friable, and very micaceous. Although the sand blankets the entire development area, it is oil saturated only on structural highs, barriers formed by faults and possibly tar seals. These conditions make it difficult to determine the productive limits. In addition, a minor amount of gas has been discovered in this zone.

The Lower Tulare consists of at least 400 feet of mudstones and siltstones that are poorly sorted, friable, and have indistinct bedding. All of the properties are highly variable.

Estimated rock mechanics parameters were obtained from the available geogphysical well logs. All the rocks under consideration are unconsolidated, friable, and poorly sorted. Recorded velocities are within the 6,000 to 7,000 ft/sec range indicating a soil-like condition. Consequently, these rocks are expected to have low elastic modulii, low unconfined compressive strength, and low hardness. Drilling and excavation of these rocks is expected to proceed at a high rate. A slurry drill using mud as a stabilizer would probably be the quickest, most effective, and cheapest way to drill a shaft in these rocks, which would later be sealed by installing a casing. The potential tunnel zone, the Amnicola Shale, is expected to have a stand-up time of less than a day with potential swelling, slaking, and shrinkage caused by changes in moisture content. Continuous support will be required for these openings, probably in the form of a liner. Since this is an active earthquake zone, extra care will have to be taken to delineate potential active fault zones to assure they do not cross an underground opening.

Based on this structure contour map and available information from wells throughout the field a development area of approximately one square mile was delineated. Five representative wells were selected from this development area. These wells are shown on the base map along with a legend which shows the available well logs. These logs are contained in the pocket at the back of this report. The important well log traces above and below the reservoir were combined on a single sheet for each well and are shown in Figure 2. These geophysical well logs provided information on porosity, water saturation, bulk density, velocity, and an approximate determination of elastic modulii. Table I summarizes these parameters. In addition, the various zones of interest were correlated and are shown on the well log traces.

GEOTECHNICAL INFORMATION

First, an attempt was made to determine the lithology of the zones of interest utilizing the available information. The Tulare Formation is the reservoir and has an approximate thickness of 800 to 1,000 feet. It consists of Pleistocene deposits of pebbly conglomerate, sandstone, siltstone, and mudstone, which are unconsolidated, poorly sorted, and lenticular.

For convenience, the Tulare has been divided into the Upper Tulare, the Amnicola Shale, the Amnicola Zone, and the Lower Tulare. The upper 300 feet of the Upper Tulare is almost never oil saturated and consists of variable deposits of pebbly conglomerate, sandstone, and minor thin beds of olive green mudstone. At a depth of approximately 300 to 500 feet, the Upper Tulare is variable and the interbedded sands may be oil saturated. The sands are usually poorly sorted, lenticular, friable, and cross-bedded. An analysis of well log information in the Upper Tulare shows a variable shale index, a bulk density of 1.7 to 2.2 grams/cubic centimeter, porosity of 20 to 40 percent, variable water saturation, and a velocity of 7,100 ft/sec.

Underlying the Upper Tulare is the Amnicola Shale, which varies from 40 to 60 feet thick, and the Amnicola Sand Zone, which varies from 25 to 80 feet

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INTRODUCTION

The purpose of this report is to provide geotechnical information on the Northeast Area of the McKittrick Field, which is the selected target reservoir for demonstrating underground mining for access technology, in accordance with Task III of the U.S. Department of Energy Contract No. DE-AC22-80P30259.

This report is intended to demonstrate how geotechnical information can be extracted from existing well data to provide information for mine layout and design. A structure contour map, five annotated well logs, and recommendations for a geotechnical investigation program are presented in this report in addition to brief descriptions of the geology, structure and engineering characteristics of the rocks in the Northest Area of the McKittrick Field.

SOURCES OF DATA

Available literature on the Northeast Area of the McKittrick Field was reviewed, along with well information, including geophysical well logs and well histories. All information was obtained from the California Division of Oil and Gas District No. 4 office in Bakersfield, California. In addition, a trip was made to Getty Oil's McKittrick Diatomite Project which provided a case history of actual conditions in the site area.

DATA ANALYSIS

As an initial step, a base map of the Northeast Area of the McKittrick Field was prepared by utilizing published maps from the California Division of Oil and Gas. A structure contour map and land ownership map was prepared and is attached to this report (Figure 1).

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APPENDIX B

GEOTECHNICAL REPORT ON THE NORTHEAST AREA OF THE MCKITTRICK FIELD, KERN COUNTY, CALIFORNIA

A Report by
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Under Subcontract to
Energy Development Consultants
For
The U.S. Department of Energy
Under Contract: DE-AC03-80PC30259

December 1982

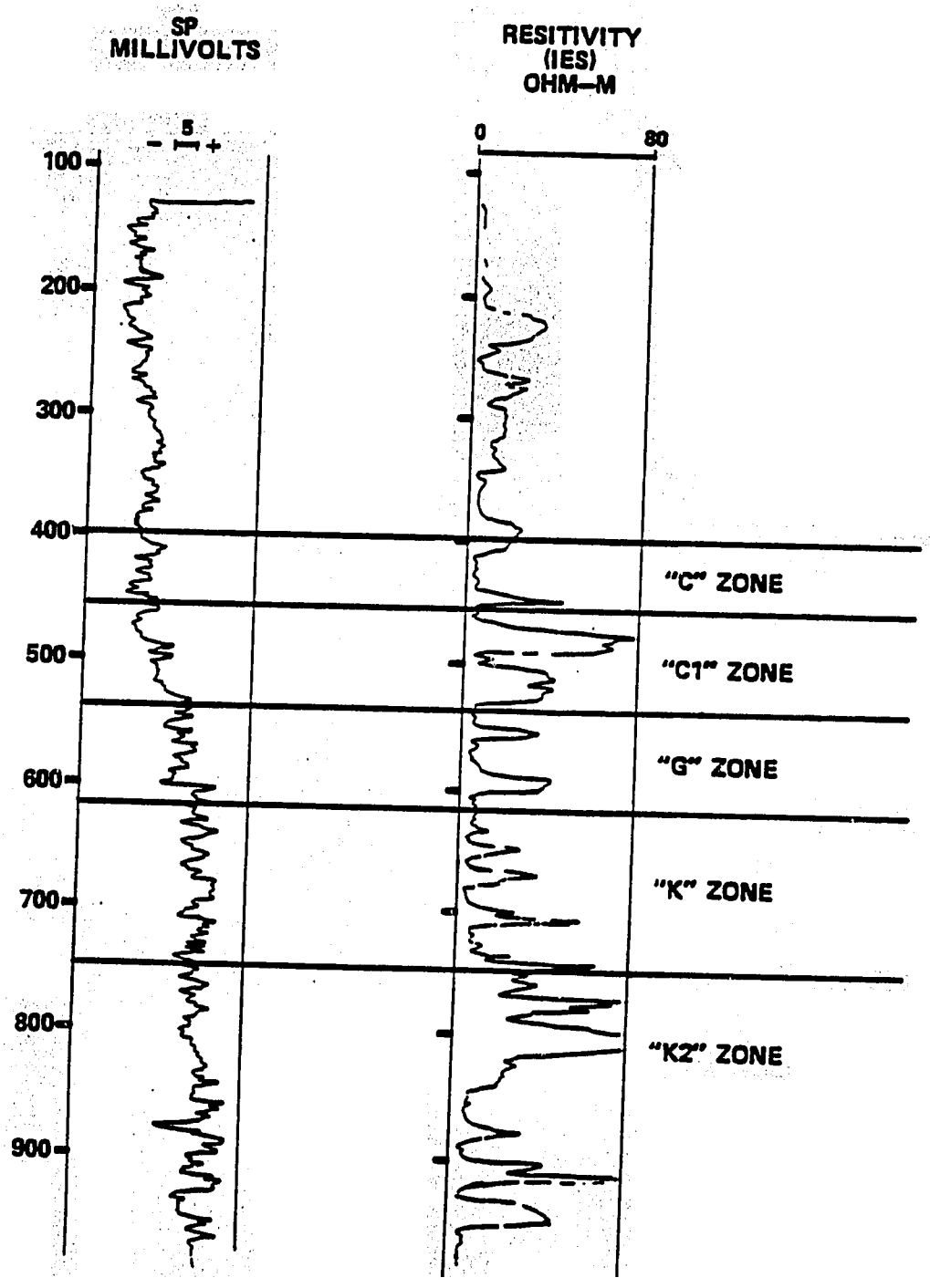

Figure 6
SHELL WATER PROBE
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