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REVIEW OF EOR PROJECT TRENDS AND THERMAL EOR TECHNOLOGY -- TOPICAL REPORT

By
James F. Pautz
Partha Sarathi
Rex Thomas

March 1990

Performed Under Cooperative Agreement No. FC22-83FE60149

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By James F. Pautz, Partha S. Sarathi, and Rex D. Thomas

ABSTRACT

Information on United States (U.S.) enhanced oil recovery (EOR) projects is analyzed to discern trends in applications of EOR technologies. This work is based on an evaluation of current literature and analysis of the Department of Energy (DOE) EOR project data base which contains information on over 1,300 projects. Three-quarters of current U.S. oil production attributed to EOR is derived from thermal EOR processes (TEOR). Changes in the technology of TEOR since the 1984 "Enhanced Oil Recovery" study by the National Petroleum Council[1] (NPC) are reviewed in terms of the current applied technology and reported research.

The steady decline in the number of EOR project starts each year since 1981 was strongly influenced by declining oil prices during that period. Only two new project starts for 1988 were found in the literature. Continuing increases in oil production attributable to EOR indicate that the application of new EOR technology is generally confined to expansion of existing projects rather than starting new projects. Another project trend is toward low risk projects for which reservoir characteristics are the same as those of earlier successful projects. Although details on many successful projects are provided in the technical literature along with those of unsuccessful projects, reporting on smaller projects, such as single horizontally drilled wells or profile modifications, is frequently not done. Many of the better reported projects were part of the DOE's cost-shared and incentive programs. Despite the general lack of enthusiasm for EOR, several innovative techniques such as mining, horizontal drilling, and microbial flooding have been tried in the past few years. Despite the economic setbacks caused by lower oil prices, EOR technology does continue to advance and is an important component for adding new oil reserves.

A review of technology advances in TEOR indicated that most of the developments are progressing as envisioned by the NPC in 1984. Current (1988) production is within 8% of the peak production projected by the NPC study for its Implemented Technology Case at $20/bbl oil. Pilot tests using steam-foam additives for improved reservoir conformance have been technically successful, but the economics of the process have been mixed and not well published. A good understanding of the theoretical mechanisms involved in the foam process

is lacking, so general field application is not expected soon. Improvements in steam-delivery systems have occurred with the wide use of insulated tubulars and cogeneration. Improved production practices have enhanced the economics of steamflooding EOR. The emerging horizontal drilling technology may present additional reservoir targets for TEOR processes that were not envisioned by the NPC. Thermoelectric processes are also emerging to broaden the applicability of TEOR. The lack of progress toward dealing with environmental issues envisioned to start in 1995 by the NPC's Advanced Technology Case makes the 1.2 billion barrels of the estimated targeted ultimate recovery doubtful. The other incremental 2.2 billion barrels over the NPC's Implemented Technology Case may still be feasible, but timing is likely to be different due to environmental limitations as well as lower pricing.

SUMMARY

The nation has increased its dependency on foreign sources of crude oil to roughly 50%. One method of minimizing this dependency is through the development and domestic implementation of enhanced oil recovery (EOR) technologies. The landmark EOR study by the NPC[1] (National Petroleum Council) has influenced the strategies of many companies and the government toward petroleum production and EOR research.

Oil prices since 1985 have been lower than the worst case scenario in the 1984 study. One question is what effect has this had on the development of the technologies envisioned by the NPC?

Oil production from EOR projects has increased since 1984 from 480,000 to 710,000 barrels per day (up 46%) in 1988. Steam EOR projects represent roughly three-quarters of this production during both 1984 and 1988. EOR project starts have dropped from 100 in 1984 to just 2 reported in 1988. This trend could indicate that technology improvements have been successful in keeping established projects expanding but generally have not extended EOR activity to new reservoir conditions. A competing factor is the high costs of the infrastructure for a new project site, it is less expensive to expand an existing project than start a new one. An analysis of the reservoir characteristics of new projects during the past 4 years indicate reservoir targets with characteristics similar to those of earlier successful projects.

A review of technical papers presented through the Society of Petroleum Engineers indicated that technical interest in EOR has remained high during the 1984 to 1988 period, with a 5% increase in the number of EOR related papers.

There has been a slight shift from chemical process oriented papers to gas displacement oriented papers with thermal oriented papers remaining at about the same level. This would indicate that industry and government are continuing to fund EOR research. This research would appear to be in areas of the most economic promise at today's oil prices and not towards the long term potential of the chemical processes envisioned by the NPC study.

A detailed review of the technologies in the thermal EOR processes compared to the the technology advances envisioned by the NPC study generally indicates that technology has advanced as expected, with a few, but important, exceptions. The survival and expansion of steamflooding processes indicate that cost-saving advances, such as cogeneration and other operational efficiencies, have dominated the thermal EOR industry. The NPC had envisioned an advanced technology to scavenge heat from steam projects when they became marginal. Recent periods of low prices have caused operators to advance this technology by curtailing steam injection or reduce the quality of steam. Results have been mixed and generally show that technically justified reduction of heat input to the reservoir can prolong the economic life of a project.

The NPC's Advanced Technology Case estimated 0.6 billion barrels more oil recovered from technical advances in existing projects and 1.2 billion barrels by improved dealing with environmental issues over the Implemented Technology Case at $30/barrel oil. Expansions of existing projects have probably been slower than that projected by the NPC scenarios, but the 0.6 billion barrel target still appears feasible. The 1.2 billion barrel target that requires technical resolution of environmental issues is no closer than at the time of the NPC study.

Pilot tests of foams to improve reservoir conformance in steamflooding projects by reducing the effects of gravity override have been trending toward improving economics after a series of technical successes. The semi-continuous application of surfactant and inert gas with steam is not an implemented technology but has the potential to meet the 1995 timetable envisioned by the NPC's Advanced Technology Case for extending projects economic lives. The rapid development of horizontal drilling and completion technology has the potential to improve oil production of existing projects as well as to expand the target for steamflooding projects. Innovative schemes for placement of heat in reservoirs relative to producing wells are being studied in pilot projects. A better understanding of reservoirs and fluid flows has made in-fill drilling technology a potential alternative to horizontal drilling. The effect of these two emerging technologies might be reviewed for inclusion in future advanced technology scenarios.

The wet, in situ oxygen combustion process has made some progress since the NPC study with one successful pilot, but generally in situ combustion projects have been attempted infrequently since the NPC study.

Thermal processes that use electricity or electromagnetic energy to stimulate production have been proposed. Although a few have been successfully field tested from a technical perspective, considerable innovation is needed before the processes can be commercially viable.

INTRODUCTION

The objective of this study was to identify and analyze trends in EOR technology. Three inter-related approaches were made to accomplish this objective: (1) analyze data on EOR projects and project starts, (2) identify frequency and subject of recent literature about EOR, and (3) analyze recent TEOR technology developments. This is one of a series of annual reports evaluating trends in EOR technology.[2-4]

The National Institute for Petroleum and Energy Research (NIPER), under a cooperative agreement with the Department of Energy (DOE), is collecting data on new and recently reported EOR (enhanced oil recovery) projects for inclusion in DOE's EOR Project Database.[5] As part of this task, NIPER analyzes the technology trends in EOR in support of the Tertiary Oil Recovery Information System (TORIS). In addition to the analysis of the data in the project data bases, a search of the literature about EOR was categorized to give an indication of the direction of future advances in EOR. An in-depth review of technology trends in TEOR processes relative to the NPC study was made to determine if basic technological assumptions have been impacted. TEOR was chosen for detailed review because of its relative importance to current EOR production.

The single biggest impact on fulfilling the technology assumptions and the estimated oil production in the NPC study has been the price of oil. After peaking in 1981, oil prices gradually declined until 1986 when the average oil price dropped below the 1979 level to $12.51/barrel annual average domestic wellhead price. Interest in initiating EOR projects paralleled oil price with a brief period of increasing EOR project frequency in 1980 and 1981 followed by a gradual decline through 1985. Figure 1 shows these changes in project starts and price. Table 1 shows oil price changes for average wellhead prices and refiner's cost for oil since 1979.[6-7] The rapid drop in the price of oil early in 1986 drastically changed the outlook for EOR. Oil production from EOR projects increased only about 5 % from 1986 to 1988.[8-9] However the number of active projects decreased, and the number of new project starts was down. The Energy Information Administration (EIA) report "Annual Outlook for Oil and Gas 1989" predicts EOR production will remain steady through the turn of the century. The July 1989 estimate for wellhead price is $16.26/bbl (refiner's cost $18.31/bbl).[7]

Late in 1985, the press was still reporting on the importance of EOR projects and how they were adding to U.S reserves. Oil production from EOR projects was increasing,[8-9] and the future for EOR looked bright. Some states passed, and other states consideried, tax incentives for EOR projects, and by 1987 most producing states had done something to help the oil industry. The assistance was limited since most of these states also were facing tough economic times.[10-13] As reported in the latest (March through July, 1989) issues of the American Oil and Gas Reporter, many tax incentives have been proposed but few have been passed. As long as the price of oil remains low, tax incentives and technology advances are the best ways to increase EOR production.[14] In the same reference the authors concluded that tax incentives could have the equivalent effect of raising the price of oil $4 a barrel (in the $20/bbl range), and technology advances could have an similar effect. Research continues to lower EOR costs.[15] So as long as the price of oil remains steady or is rising new projects will be started. During the past year, some of the laws passed have had an unintended adverse effect on EOR. A good example of this is in Alaska where Arco has had to delay development of the West Sak field project due to changes in the tax law.[16]

ANALYSIS OF TRENDS IN THE DOE PROJECT DATABASE

Location of EOR Projects

EOR projects are located in the states that produce the most oil. California has the most at 456 reported project starts. Texas is a distant second at 288 project starts. Wyoming (122 project starts), Oklahoma (113 project starts), Louisiana (99 project starts), Illinois (44 project starts), and Kansas (31 project starts) are the other states that have more than 25 EOR projects in the database. Eighteen other oil-producing states have had EOR projects started within their boundaries. Table 2 and figure 2 contain statistics on project starts by state.

Frequency of EOR Processes

The database classifies 1,304 EOR projects into 14 different EOR processes. For this report these processes are summarized into the following four major categories:

1. Thermal - in situ combustion, conventional steam, cyclical steam, and unconventional steam.
2. Chemical - alkaline flood, microemulsion flood, and polymer.
3. Gas displacement - immiscible carbon dioxide (CO_2), miscible CO_2, nitrogen gas, and hydrocarbon gas.
4. Other - heavy oil recovery, microbial, and others.

The thermal category represents 40% of the projects in the database and is closely followed by the chemical category representing 37% of the projects. A major portion of the chemical category is accounted for by polymer processes which represent 27% of the database. Gas displacement projects represent 22% of the database while the other category has only 1% of the projects. Figure 3 and table 3 present the statistics for each specific process.

The frequency of projects is not directly related to oil production. In 1988 thermal projects produced about 76 % of the oil, as shown in figure 4, followed by gas injection projects. On the more specific process level, polymer flooding, the most frequent at 27% of project starts, came in sixth in terms of production accounting for only 3 % of 1988 EOR production.[8,17] Oil production from thermal projects seems to have leveled off after years of increase, so increases in EOR oil production can be attributed to gas displacement projects.

Thermal Projects

More oil is produced by thermal technology than all other EOR techniques combined. Most thermally produced oil is heavy oil, and most comes from California. The most important factors in thermal oil recovery are permeability and permeability variations of oil reservoirs, viscosities of oils and how they vary with temperature. Gravity segregation is also important and tied to both of these factors. Predictions of future thermal EOR are strongly dependent on advances made in the technology. A recent publication[14] estimates that advances in technology are equivalent to an increase in oil price from $20 to $24/bbl.

The advances in TEOR and possible future advances are discussed in detail in a later section of this report. This section is devoted to a review of background information and data in the DOE database.

Thermal EOR processes are the most important of all EOR processes in terms of oil production, as shown in figure 3, contributing about three-fourths of the total U.S. EOR production. The Oil & Gas Journal[8-9] (O&GJ) reported 480,000 BOPD (barrels of oil per day) for 201 active EOR projects in 1986 and estimated 465,000 BOPD for 152 active thermal projects in 1988. According to an Interstates Oil Compact Commission (IOCC) report, steamdrive production in California was 530,000 BOPD, indicating a TEOR production of 540,000 BOPD in the U.S. during 1988.[17] Total EOR production was 605,000 BOPD in 1986 and 710,000 BOPD in 1988 (O&GJ estimated adjusted upward for the actual California TEOR production). DOE's EOR project database contains information on 522 thermal EOR projects that had been started by January 1, 1989. More than 95 % of the thermal oil production comes from steam projects, and more than 90 % of the projects and production is in California. The influence of oil price on the number of thermal projects started is similar to the influence on all EOR projects, as shown in figure 1. According to the Division of Oil and Gas, State of California, oil production from thermal EOR projects declined about 5 % following the drop in oil price early in 1986. However, by the end of 1986 thermal recovery had recovered to 172.7 million barrels, compared to 170.9 million barrels in 1985. Most of this increase was the result of innovations and refinements in steam production technology. Some operators converted their steamfloods to hot water floods which accounted for about 40 million barrels of 1986 thermal production. In 1987, California's steam recovery was down to 171 million barrels of oil.

Conventional Steam

Steam drive is the most important of the thermal processes, contributing over two-thirds of the oil produced by thermal projects. A very good review (51 references) of conventional steamflood field projects by Cheih Chu was published in 1985.[18] This article detailed 28 selected steamflood projects and developed a screening guide for new projects based on the results. All technical aspects of steamflood field projects are discussed including project design, performance prediction, well completions, surface facilities, and operational problems and their remedies. A more recent review was presented at the IOCC winter meeting in 1989.[17]

A summary of the information available in DOE's database on steam drive projects started in 1980 through 1988 is given in table 4. All of these projects are in sandstone formations, and well over 90 % of them are in California. The number of steam drive projects increased through 1981 when oil prices peaked. Another small increase in project starts was seen in 1984 when the price of oil seemed to be stable. Only six new steam projects have been reported for 1987 and none for 1988 which clearly shows the number of project starts has bottomed. How long project starts remain low depends mainly on oil price and its stability.

The average areas given in table 4 are reported to provide some concept of size. Reported sizes range from 1 acre to 5,070 acres. One problem with this type of summary is the way a project's size is perceived by the operating company. One operator might report a 5-acre project knowing it may be expanded later to 1,000 acres, whereas another company might consider that project as a 1,000-acre project with only 5 acres currently active. Over the period 1980 through 1982, the depth and range of API gravity of these projects increased as operators tried light oil steamflooding and more risky projects when the oil price was up.

A comprehensive state-of the-art review of light oil steamflooding was recently published by NIPER.[19] The report details 37 field projects (27 in U.S.) of which 20 were considered technically successful and 9 unsuccessful. Besides the field studies, this report includes a comprehensive review of laboratory and simulation studies.

Cyclic Steam

No new cyclic steam (huff 'n' puff) projects were reported as started in 1987 and only one in 1986. Many of the steam drive projects used the cyclic steam process to get started but are not counted as projects under this process. Comprehensive reviews that included good discussions of cyclic steam field projects were given by Farouq Ali[20] and Farouq Ali and Meldau.[21] Information is available on only seven project starts in the 80's. This is not enough information to establish separate statistical trends for this process, so they are included with conventional steam projects. No significant changes in project trends were detected following this addition.

In Situ Combustion

In situ combustion, sometimes called fireflooding, has been around since the mid 1930s and is an effective technique for recovering oil, especially heavy oil. The latest comprehensive review is by Chieh Chu[22] in 1982 and contains 76 references. That paper detailed 25 (17 in U.S.) selected successful field projects and 9 (all in U.S.) that were aborted.

No new in situ combustion projects are recorded as having started in 1987, only one started in 1986, and only two in 1985. One of the projects started in 1985 was shut down and later restarted in 1987. As can be seen in table 5, there are not enough projects to show trends. Although it is not obvious from the table, 1980 was the peak year for this process which currently seems to be out of favor in this country. The NPC estimated that 1.3 billion barrels would be produced by new projects in its Implemented Technology Case. The current trend indicates that the NPC was too optimistic for this thermal process.

Unconventional Steam And Heavy Oil

Unconventional steam was originally defined as steam at depths greater than 2,500 feet or API gravities lower than 10. This definition is used when the operator does classify the project as conventional. The only valid trend shown in table 6 is in the correlation of the number of project starts with oil price. As with other thermal projects, all starts were in sandstone reservoirs. There are not enough projects in this category to calculate any other trends. No new project starts were reported for 1986 or 1987.

During this time period, only three EOR projects have been classified as heavy oil, a poorly defined term. Since all of these projects use heat from sources other than steam or combustion, they have been placed in a separate category called Other Thermal Projects.

A detailed discussion of TEOR technology advances since the NPC study is presented later in the report. The above discussion is based on observable trends seen in the EOR project database.

Chemical Projects

Chemical processes include surfactant, alkaline, and polymer projects with all their many variants and combinations. These processes work by controlling the oil's mobility and/or lowering the interfacial tension (IFT) which results in lowering the residual oil saturation in the reservoir. The wide variety of chemicals is shown in a recent article[23] which lists 91 chemicals (available from 20 suppliers) and how they are applied in EOR.

Over the past few years, polymer projects have been the most frequent (in terms of new projects started) of all EOR processes, whereas surfactant and alkaline projects are still out of favor.[24] Low oil prices resulted in no new starts of surfactant and alkaline projects for 1987. Two polymer projects did include a small amount of alkaline and/or surfactant; however, the amounts were so small that they require the label polymer with chemical additive. The effect of price on the total number of chemical project starts follows the trend seen for all EOR projects (figure 1) with a peak in activity in 1980 and 1983.

Estimated oil production[8-9] was 16,900 BOPD for 206 chemical EOR projects in 1986 and 22,500 BOPD for 124 projects in 1988. While these numbers show a large increase on a percentage basis, the total oil production and production per project is small compared to that of thermal projects.

Surfactant Flooding

The surfactant (microemulsion, micellar-polymer, etc.) EOR process is complicated and expensive which is why the number of new projects started has declined so much since 1980. The number of projects (table 7) is too small to establish trends other than the decline of project starts with oil price. The peak year for surfactant EOR projects was 1980. During 1980 and 1981, more risky projects, (carbonates and deeper projects) were tried, which probably was the result of government incentives and rising oil prices. The few projects started in 1983, 1984, and 1985 were all in sandstone at moderate depths, in other words low risk projects. No new project starts were reported for 1986, 1987 or 1988.

Polymer

The latest review of polymer flooding[25] is the one published by researchers at Phillips Petroleum Co. in December 1987. It details 27 projects and lists 16 references. This paper builds on a previous review[26] which had 131 references.

Polymer flooding is the least expensive of the chemical group and by far the most popular with 7 new projects started in 1987 and 2 (the only new EOR projects) in 1988. Most of the project starts are in the mid-continent area.

Polymer projects by independent oil producers and major integrated companies have followed slightly different development trends. The number of projects started by independent oil producers (table 8) peaked in 1981 at 16 projects when oil prices were high and then fell to around 10 per year until 1985 when it increased dramatically to 19. The cause of the second rise is not fully known but probably is due to good economic results and a better understanding from earlier projects. The peak for starts by major oil companies was delayed 2 years to 1983 and 1984 when the number of projects reached the 40's and then declined to the 20's for the next 2 years.

Although recovery for each polymer project is low, they are very popular because the cost per barrel of oil recovered is also low. The reason for this pattern of development is not known; however, the windfall profit tax may have been involved.

Project areas are given only as a rough guide for the reader; however, the overall increase in size with time is probably real. There appears to be a slight trend toward deeper projects; however, the deepest projects were started in 1982 and 1983. Many of the projects in table 8 may not have been started. Of the planned 38 polymer projects listed in the O&GJ in 1986[9] only 1 was started, and 6 were postponed. Few of these were included in DOE's EOR database.

Most projects continue to be in sandstone because of the degrading effect of calcium and other multivalent ions on popular polyacrylamide polymers. No trends were observed for average API gravity or porosity. Average API gravity is about 34°, but covers a broad range as shown in table 8. Porosity also covers a broad range. Other reservoir characteristics important in polymer flooding are type of polymer used, brine salinity, multivalent ion concentration, and reservoir temperatures. Type of polymer was reported only 25 times from 1980 through 1987. As expected, polyacrylamides were the most frequently used with 88 % of the projects, 8 % were biopolymer, and 4 % were cellulose based.

Only 20 values of salinity were found, all in 1980 and 1981. Projects were started in waters ranging from fresh (238 ppm) to strong brine (195,000 ppm). Average salinity was 50,000 ppm. No values for calcium, magnesium, or any combination of multivalent ions were reported for this time period. The data in table 9 indicates reservoir temperature of polymer flood projects rose from 1983 to 1985. This is in agreement with depth trends in table 8. This trend is due to the development and application of more thermally stable polymers. Temperature was not reported for the projects started in 1987 and 1988 but depth indicates 3 were low-temperature, low-risk and 4 were moderate-temperature with moderate-risk.

Alkaline Flooding

The alkaline (caustic) process is complicated, moderately expensive, and applicable only to some acidic crudes which explains the small number of projects in table 10. Both of the new projects started in 1986 involve the use of another agent. One includes polymer and the other a small amount of co-surfactant. A small amount of alkaline additive was used in two polymer projects in 1987. The only real trend for this process is the decline in the number of project starts. The large number of projects started in 1980 was caused by the DOE Tertiary Oil Incentive program and rising oil prices. Although no new project starts were reported for 1982, 1984, 1985, 1987, or 1988, there are prospects for an increase in a mixed surfactant/alkaline/polymer process projects in the future.

Gas Displacement Projects

The total number of active gas projects[8] in 1988 had decreased 13.5 %, from 104 in 1986 to 90 in 1988. Oil production rates from these projects increased from 108,000 BOPD in 1986 to 150,000 BOPD early in 1988. DOE's EOR project database (table 3) contains information on 283 gas projects reported as started by the end of 1988. Most (198) of these are miscible gas projects. The increase in project starts in 1980 and 1981 and the decrease in 1982 correspond with oil price. The reason for the small peak in the number of project starts 1983 is not known. The increase in 1985 and 1986 indicates that oil companies thought that oil price had leveled off. NIPER has modified the DOE EOR project database so these projects are identified by gas type in addition to miscible or immiscible. Carbon dioxide miscible projects and hydrocarbon gas projects are discussed under the miscible heading followed by immiscible carbon dioxide and nitrogen projects under the immiscible heading. No flue gas projects have been reported as started since 1977 and therefore are not included in this report.

Carbon dioxide injection (miscible and immiscible) projects are the second most frequent process, following polymer, in terms of project starts since the price of oil peaked in 1981. An excellent summary of results from 30 field tests was presented at the Society of Petroleum Engineers Rocky Mountain Regional meeting in 1989.[27] The paper details 21 miscible, 4 immiscible, and 5 cyclic projects. The authors had intended to discuss both successful and unsuccessful projects; however, no information on unsuccessful projects was found. Major oil companies have committed large sums of money to developing carbon dioxide sources and are thereby committed to using this gas.

Miscible

The miscible recovery process involves the injection of a fluid (usually a gas at surface conditions) which at reservoir conditions forms a fluid that dissolves in the reservoir oil. Gases used include hydrocarbons, carbon dioxide, flue gas, and nitrogen. Most recent starts use carbon dioxide. Most nitrogen projects are considered to be immiscible or only partially miscible and are therefore discussed with the immiscible projects. No new flue gas project starts have been reported since 1977 and are therefore not included in this study.

Carbon Dioxide Miscible Projects

The main trends seen in table 11 for carbon dioxide miscible projects are the decrease in project starts since 1980-81 and the increase in major oil company participation since 1982. Most of these projects are in the Permian Basin of West Texas and New Mexico which is now the world leader in CO_2 EOR.[8] Project areas range from 25 to 16,000 acres, and average sizes are shown to provide an estimate of project size. Project depth appeared to be getting shallower, until 1986. Several new deep projects in Louisiana and Mississippi were cancelled. The O&GJ[8] reports that only 9 of the 43 projects listed as planned in 1986 survived (5 were started and 4 postponed). Oil production from miscible CO_2 projects increased from 28,440 BOPD in 1986 to 64,190 in 1988. No new projects were reported as having started in 1987. Although 5 were reported as planned for 1988,[8] none were reported as having started.

Hydrocarbon Miscible Projects

Hydrocarbon injection project starts (table 12) peaked in 1981 when the price of oil peaked at 6 new projects as would be expected and peaked again at 8 new projects in 1983. The reason for this peak is not known; it seems the new projects dropped before the price of natural gas peaked in 1984 (average wellhead price). Oil production from this process decreased from 33,770 BOPD in 1986 to an estimated 25,940 BOPD in 1988. Production should have increased as the projects started in 1983 began to contribute. Arco's Pruhdoe Bay Alaska project started in December 1982 is expected to be a major contributor for this process. No trends were seen in reservoir characteristics (table 12). No new projects were reported for 1988. A review of the gas injection projects in California[28] was presented at the SPE California Regional Meeting in 1989. Details of 12 projects started between 1940 and 1960 are discussed.

Immiscible

Although some immiscible projects use nitrogen or flue gas, most use carbon dioxide at pressures below minimum miscibility. These projects include cyclic (huff 'n' puff), gas drive, and gas cap injection in dipping reservoirs. Field experience in 28 Texas CO_2 huff 'n' puff projects was discussed in a recent paper.[29] The authors concluded that the method should be more widely applied and presented a new method for predicting recovery. Total immiscible production was estimated to be 8,000 BOPD in 1984 and 20,000 BOPD in 1986 and 1988.

Carbon Dioxide Immiscible Projects

Carbon dioxide immiscible projects are summarized in table 13. As with polymer projects, a peak in starts occurred in 1983, 2 years after oil prices peaked. These projects require more planning and longer lead times, which may have caused some of this lag. Another peak in project starts occurred in 1986, most of these are Texaco projects in Louisiana. Most of these were later cancelled. Data in the table show a definite increase in both average depth and API gravity, which increase the chances of success.

Most of these projects were major oil company starts, and most were in sandstone. Reported project areas vary widely and are based on too few data, as well as being influenced by operator perception. Leaving out three large projects (one each in 1981, 1982, and 1985) would leave data indicating that project size is becoming smaller. This is probably a real trend caused by many new Louisiana offshore projects which usually have an area of less than 100 acres. Most immiscible projects are in Louisiana and Texas.

Nitrogen Projects

Information on nitrogen injection projects is summarized in table 14. The number of project starts peaked in 1981 when the price of oil peaked. Almost all of these projects were started by major oil companies. All of the projects started since 1981 have been very light (API gravity greater than 46°), which lowers the risk for this process.

Other Process Technologies

Other process category is a combination of the emerging technologies, such as microbial and the radically different processes. Representing roughly 1% of the EOR projects in the database, this category is significant only for future potential of its processes.

Microbial

Microbial enhanced oil recovery (MEOR) was added to the DOE EOR project database last year. NIPER has collected information on over 40 projects worldwide. Ten of these are in the United States but only 4 of these had enough information on them to be included in DOE's database. Major oil companies were associated with only 2 of the 10 projects. The high current interest is shown by the start dates for these projects, 2 in the fifties, 2 in the seventies, 3 in 1986, and 3 in 1987. No new projects were reported for 1988. This process is still in the research stage with only two of the projects large enough to be commercial. Two of the projects are aerobic, 7 anaerobic, and one unknown.

Reservoir characteristics for these projects are all very similar. Most are sandstones, only one is limestone, average depth is 1,800 feet (deepest 2,600), and API oil gravity is between 34° and 40°.

Other Novel Processes

This category includes such processes as electro-osmosis and oilfield mining. These are very high-risk processes, and few will be started in this period of low oil prices. Data on one new mining project were found cited in 1985. Interest also seems to be increasing in horizontal drilling,[30] but information was too vague to be included in DOE's database.

TECHNOLOGY TRENDS IN EOR LITERATURE

A limited search of EOR literature from 1980 through 1988 was conducted and the results were studied. To avoid duplication and the large number of articles on taxes, oil supply, oil demand, and general articles on the importance of EOR; the literature search was limited to Society of Petroleum Engineers (SPE) publications. The literature was classified by the three major categories of processes (thermal, chemical and gas displacement) and by whether it was reporting field-oriented research or laboratory-oriented research. Results are summarized in table 15.

An obvious trend in the EOR literature is that 3 to 4 times as many papers are published in even-numbered years as in odd-numbered years. This is caused by the biennial DOE/SPE symposium on EOR during even-numbered years. To eliminate the bias of this anomaly, the data were grouped in year-pairs; 1988 and 1987 as the latest year-pair to 1981 and 1982 as the earliest year-pair. The total number of publications dropped 15% from 132 during the 1981-1982 period to 110 during the 1983-1984 period and has since remained about constant at 114 during the latest year-pair. The most significant trend has been a 35% increase of publications on gas displacement technology (laboratory and Field) from 40 in the earliest period, 1981-1982, to 54 in the latest period.

SPE publications on EOR field projects dropped by 30% from 61 during the 1981-1982 period to 42 during the next year-pair, 1983-1984. After remaining at the same level (43 EOR field-oriented publications) for 1985-1986, the number of field oriented reports recovered half way to the 1981-1982 level at 50 publications in the 1987-1988 year-pair. The trend in field-oriented publications for thermal technologies has been a steady decline from 14 in the 1981-1982 period to 7 in the 1985-1986 period followed by a complete recovery to 13 publications in the latest period, 1987-1988. Field reports on chemical EOR has steadily dropped from 23 publications in 1981-1982 to 10 in the latest period. Reports on gas displacement projects dropped 40% from 23 in the 1981-1982 year-pair to 14 in the following period, 1983-1984, and recovered to 22 publications in 1985-1986. Gas displacement is the only technology that had more field reports at 27 in the latest period, 1987-1988, than in the earliest period.

SPE publications oriented toward laboratory research have been nearly constant, around the 64 publication average for the 4 year-pairs. The mix between the process technology area has changed. Thermal has dropped from 28% of the laboratory-oriented publications in 1981-1982 to 17% in the 1987-1988 year-pair. Chemical technology laboratory work dropped from the dominant process at 47% of SPE EOR laboratory publications in the earliest period to 33% in the latest period. Gas displacement increased from 25% of laboratory oriented SPE publications to 43% during the period reviewed.

TRENDS IN TEOR TECHNOLOGY

An in depth review of the technology trends in TEOR processes relative to the NPC study was made to determine if the basic technological assumptions in the NPC report have been impacted. TEOR was chosen for detailed review because of its relative importance to current EOR production.

The single biggest impact on fulfilling the technology assumptions and the estimated oil production in the NPC study has been the price of oil. After peaking in 1981, oil price gradually declined until 1986 when average oil price dropped below the 1979 level to $12.51/barrel annual average domestic wellhead price. The lowest price scenario used in the NPC study for its Advanced Technology Case was $30/barrel, so production forecasts and the implementation of advanced technologies are expected to be more optimistic than what has been experienced. In spite of low prices, TEOR has been maintained and expanded. The following is a review of the technology improvements that have allowed that trend.

Thermal Processes in the NPC Study

A 30-year production horizon used by the NPC estimated ultimate oil production of 10.5 billion barrels by thermal EOR processes for an Advanced Technology Case. This production represents 38% of the production estimated for all EOR processes in this landmark EOR study. The Implemented Technology Case estimated 6.5 billion barrels (5.1 billion from existing projects). These estimates used $30 per barrel oil. At $20 per barrel oil, the estimated recovery for the Implemented Technology dropped to 4 billion barrels and a peak production rate of 610,000 barrels of oil per day (BOPD) about 1990. This compares to an actual estimated production rate of 540,000 BOPD for thermal projects in 1988, or an 8% shortfall of the projection. Current estimates are that California TEOR production has peaked and will continue to decline.[17]

The difference in screening criteria for Advanced and Implemented Technology cases for two thermal processes -- steam and in situ combustion -- and the difference in estimated ultimate oil recovery are shown in table 16. Less stringent criteria in the Advanced Technology Case reflected expected advances in technology to allow the use of steam processes in deeper, thinner, and tighter reservoirs. The Implemented Technology Case represented the technology proven by field tests and in place as of 1984. The Advanced

Technology Case represented improved heat delivery and improved reservoir conformance for reservoirs that are steam drive targets and improved environmental controls for thermal processes. The conformance improvement was estimated to attain an additional 10% of OOIP recovery and contributed 0.6 billion barrels of ultimate recovery. Roughly 1.2 billion barrel potential recovery was added from Santa Barbara and Los Angeles counties by projecting technology to offset current environmental limitations.

Thermal Recovery Technology in 1984 (NPC)

All technologies in use today were either in use or envisioned at the time of the NPC study. The following are technology areas that were partially proven and expected to impact the future.

- Improved reservoir conformance. Surfactant foams and foaming agents had been applied to gravity override problems in numerous field test with mixed technical results and marginal economic success.
- Waterflooding after steam drive. One test had been successful at scavenging heat to produce additional oil.
- Downhole steam generation. Proven technically feasible in field demonstrations but needed modifications and improvements for prolonged use to an economic alternative.
- Injection of noncondensible gases with steam. This was mainly envisioned as an extension of the downhole steam generator with the exhaust gases injected into the reservoir. CO_2 injection with steam was also considered a possibility. Neither had any field demonstrations.
- Hydraulically fracturing the reservoir during or before steam injection. A field demonstration had shown technical feasibility of increasing production by fracturing but the economics were questionable.
- Light-oil steam drive. Field tests were in progress at the time of the study but results were unavailable.
- Insulated tubulars. These had demonstrated operation below 3,000 feet but showed a need for better thermal packers. Packers with hi-temp elastomeric seals and metal-to-metal seals were in development in 1984.
- Cogeneration. Several units in operation and projected for widespread use in the later 1980's to improve the economics.
- Use of oxygen-enriched air for in situ combustion. Field demonstration had shown this process evolution to be feasible but benefits were not demonstrated in improved recovery or reduced costs.

Technology Changes in Thermal EOR

Screening Criteria

Screening criteria have been presented by many authors[1,31] and institutions, as an attempt to document reservoir and fluid properties needed for successful implementations of thermal recovery processes. These criteria assigned values for various parameters such as depth, pressure, pay thickness, permeability and transmissibility, porosity, initial oil saturation, oil viscosity and density, which are recommended maxima or minima for a particular process.

Although several authors have indicated the use of engineering judgment in the application of these criteria to target reservoirs, part of the industry tend to regard them as sacred, that is, all criteria must be met before a process can be considered for a particular reservoir. Since many of the criteria used for thermal processes--steam injection and in situ combustion -- are being violated by commercial operations, each criterion must be examined on an individual basis. Dugdale and Belgrave[32] discussed in detail the different screening criteria in light of recent technological developments and concluded that screening criteria should not be used to eliminate reservoirs from consideration for thermal recovery. They suggested that each reservoir should be examined on an individual basis as though no guideline exists. According to Dugdale and Belgrave, there can only be two important criteria which a thermal process must meet:

(1) Can the process heat the reservoir efficiently and economically?

(2) Can the process produce oil economically?

They question whether the assignment of values to a set of reservoir parameters can answer these two guidelines, without first conducting a detailed analysis of the reservoir, the process variables, their possible modifications, and operating costs.

Improved Reservoir Conformance

This section reviews the steam-foam process with major emphasis on steam-foam field projects that were evaluated or conducted after the NPC study. An understanding of the mechanisms of foam-flow in porous media is still in its infancy; however, progress is being made.

Gravity override and channeling of steam through high-permeability streaks are known to have adverse effects on the efficiency of steam injection. The injection of foaming agents in combination with steam has been proposed for reducing the mobility in these channels, for diverting the injected steam into alternate flow paths and for increasing oil production.[33-35] Another mechanism appears to be the reduction of interfacial tension (IFT) between oil and water by surface active agents. This reduction in IFT, called the "detergent effect," causes oil to be mobilized and thus increase recovery. The late seventies and the eighties have seen many steam-foam pilots being implemented. A summary of some of the more important steam-foam pilot results reported in the literature is presented in table 17. These field projects are briefly summarized in the next few paragraphs. This summary does not include the steam soak applications reported in the literature since this technology was widely known before the NPC study. For a complete review of field projects, the reader is directed to other references.[36]

Surfactants are generally injected as periodic slugs, continuously, or semi-continuously. All three modes of application are practiced in the field with the trend toward more economical semi-continuous applications.

Slug Applications of Surfactant

In a typical slug application method, about 300 to 800 pounds of active surfactants is injected into the steam at the wellhead, yielding a wellhead surfactant concentration of 3 to 15%. In almost all reported cases, no inert gas was injected with steam, and the vapor phase of steam provide the gas required for formation of the foam structure.

The slug application is specifically designed to provide resistance to flow near the wellbore vicinity; hence, this mode of application is practiced in cases where all of the steam is entering a single thief zone or in wells completed in a single, high-permeable sand within a multiple layer reservoir.

The first application of the slug method of steam foam in a steam drive was initiated in 1978 in Kern River (CA) field.[37] In this pilot, each injector received a 55-gallon slug of surfactant once every 10 days for 11 months. An incremental 109,000 barrels of oil production was attributed to the 67,000 active pounds of surfactant injected, which equates to 0.6 pounds of surfactant per incremental barrel of oil produced. The steam quality was 0.6. Test results indicated that the slug treatments were successful at improving injection profiles, but that improvement diminished during the interim between slugs.

In 1979, the DOE funded two separate steam-foam field demonstrations. The first was a six-well steam-foam pilot conducted in Kern Front field. The material selected for this test was intentionally not thermally stable so as to minimize emulsion problems at the production facilities.[38] It reported an injection of 196,200 active pounds of surfactant over a duration of 141 weeks (one treatment per week) that resulted in 96,160 barrels of incremental oil production. This translates to 2.0 pounds of surfactant per incremental barrel of oil. In evaluating the performance of this demonstration project, DOE[39] came to the following conclusions: (1) as the project unfolded, no useful data were obtained; (2) the selected patterns were a poor choice for the test site; (3) steam channels were not identified, and the oil production was insensitive to steam injection rate: (4) there was no evidence to indicate that the injected surfactants diverted steam from "steam channels" to unswept intervals in the pay sand or contributed to increased oil recovery; (5) evidence exists that incremental oil production was mostly due to the overwhelming water "influx" into the project test area; (6) post project evaluation of wells was incomplete and the lack of success lay in part with poor operational planning and implementation.

The second demonstration project involved three, separate, short-term pilots conducted at Cat Canyon (CA), San Ardo (CA), and Midway-Sunset (CA) fields from mid-1981 to early 1982. The Cat Canyon reservoir is 3,160 feet deep with relatively tight thief zones that demand high injection rates which translates to a steam temperature of 550° F. Since the surfactant utilized had very little stability at this temperature, the foam was ineffective.[40] The next pilot conducted at San Ardo (TX) field indicated that the foam was successful in altering the steam profile, but due to the short duration of the test, the results were questionable.[41] The third pilot conducted at Midway-Sunset field showed a significant improvement in performance during the test. Oil production in the pilot area increased from 18 bbl/day prior to the test to 72 bbl/day during the test period. The oil-steam ratio increased from a base of 0.04 to 0.13 by the end of the test.[41]

In another cost-shared project, a pilot was conducted in 1981 at Kern River field to verify Stanford University Petroleum Research Institute's (SUPRI) laboratory results. In this pilot, surfactant slugs with a total of 88,462 active pounds of surfactants and 5% mole fraction of gaseous nitrogen were injected in the liquid phase of steam.[42-43] The total incremental oil produced was approximately 27,000 barrels, which translates to 3.3 pounds of surfactant per incremental barrel of oil produced.

Continuous Application of Surfactant

In this process, a low concentration of surfactant (0.5 wt %) and a non-condensable gas usually nitrogen (0.1 to 0.6 mol %) are injected continuously into the steam in an effort to built a large propagating bank of foam in the reservoir.

Several field pilots utilizing this method have been conducted by major oil companies. In 1981, the first continuous foam injection pilot was initiated in Kern River (CA) field on the Mecca lease.[44] In this four injector pilot, 0.5 wt % of three alpha olefin sulfonate surfactants and 0.06% mol % nitrogen were injected continuously with steam. This pilot test was terminated in 1985. The same operator initiated another continuous foam project in Kern River, approximately 2 miles from the first pilot, on the Bishop lease.[44] Extensive monitoring of subsurface data indicated that foam increased the apparent viscosity of steam by a factor of 20 to 60 near the injector and allowed steam to contact oil in the lower part of the reservoir. This resulted in an incremental oil recovery of 196,000 barrels from the Mecca lease and 82,000 barrels from the Bishop lease. This amounts to 7.1 pounds of surfactant per incremental barrel of oil for the Mecca lease and 15.1 pounds of surfactant per incremental barrel of oil for the Bishop lease. The pilot results indicated: (1) the steam-foam injection process was technically successful; (2) there was a 2-year lag between the start of foam injection and major production response; the delay being attributed to surfactant retention in the rock; (3) surfactant utilization was poor and finally (4) the residual oil saturation to steam foam was the same as that to steam (no detergent action).

In another pilot test, initiated in November 1984 at Guadalupe field near Santa Maria, California, the operator tested side by side an alpha olefin sulfonate, an alkyl aryl sulfonate and alkyl toluene sulfonate by injecting foam into different adjacent wells at 0.75% (wt) along with 25 scf (standard cubic feet) nitrogen per barrel of steam for 6 days.[45] Injectivity tests showed that alkyl toluene sulfonate (ATS) performed the best under the test condition and was selected for use in the pilot. For 10 months, surfactant was injected continuously along with nitrogen. The operator reported an incremental oil production of 29,400 barrels which translates to a surfactant consumption of 8.7 pounds per incremental barrel of oil produced.

A continuous application steam-foam pilot was also conducted at the Midway Sunset (CA) field on the Dome Tumbador lease from January 1985 to

January 1988[46]. An alpha olefin sulfonate at 0.5 wt % and nitrogen at 18 scf/bbl of steam were injected continuously for 3 years. However, the published production only covers the first 2 years of the project. An estimated 207,000 barrels of incremental oil from corresponding 4,016,583 pounds surfactant, 8,776,085 pounds salt, and 28,487,616 scf nitrogen was produced. This translates to 5.8 pounds of surfactant per incremental barrel of oil.

Semi-Continuous Applications of Surfactant

The intent of semi-continuous foam application is to optimize the economics of the steam-foam process by minimizing the surfactant consumption per incremental barrel of oil produced. This injection scheme is similar to continuous injection in all respects, except that in semi-continuous applications, the surfactant and inert gas are added to steam only periodically. In a typical semi-continuous application, surfactant and inert gases are added to steam for 48 hours followed by 48 hours of non-treatment.

The first semi-continuous foam pilot was initiated in May 1983 in Section 15A of Midway Sunset (CA) field.[47] During the 15 weeks of treatment 13,600 active pounds of surfactant and 441,000 scf (standard cubic feet) of nitrogen were injected. The project was terminated in May 1984, during which time the pilot produced 53,000 barrels incremental oil. This amounts to 0.26 pounds of surfactant per incremental barrel of oil produced.

Another 20-week semi-continuous steam-foam pilot in Section 26C of Midway Sunset field produced 15,000 barrels of incremental oil and consumed 15,000 active pounds of surfactant and 831,000 scf nitrogen.

Outside of California, two steam-foam pilots were initiated in 1983 at Winkleman Dome Nugget field in Fremont County, Wyoming.[48] The pilots were initiated in two patterns of a mature steamflood suffering steam breakthrough. In pilot 1, 15% by weight of ATS surfactant was injected, while in pilot 2, 35% by weight of same surfactant was injected. In both pilots surfactant was injected as a slug. In both pilots, steam breakthrough was controlled, and steam injection rates were restored to previous levels. By June 1984, pilot 1 had produced 15,000 barrels of incremental oil, while no incremental oil was produced in pilot 2. On a simple cashflow basis, pilot 1 was economic, while pilot 2 showed a loss.

Current Developments

Eson et al.[49] reported the start-up of nine separate steam-foam pilots, in 1988 in California. These projects were in various fields including Cymric, Kern River, McKittrick, Midway Sunset and South Beldridge but the results from these operations have not been reported.

Review of the Performance of Steam-Foam Projects

The published literature indicated that the use of surfactant with steam has improved the sweep efficiency and recovered additional oil in majority of the cases. However, the economics are variable due to generally high surfactant consumption per barrel of incremental oil produced. Field tests suggest that semi-continuous application of surfactant could be economical at current oil prices when the technology is understood better. However, for a project to be economically successful, the amount and frequency of surfactant injection must be optimized.

Research Potential for Conformance Improvement

While steam-foam processes have been demonstrated to be successful, they are not consistently economic at current prices. The understanding of mechanisms is not advanced. Hirasaki[50] suggested that the greatest improvement needed in steam-foam formulations is a system that (1) will more rapidly propagate low mobility foam in the divalent ion environments resulting from ion exchange and in the presence of residual oil and (2) will reduce residual oil saturation.

Another method for improving conformance is the development of emulsion blocking.[51-52] The advantage would be more complete blocking and at lower cost. Emulsion formation maybe part of the mechanism in "foam" projects that don't have inert gas injected with the steam. A planned field demonstration was cancelled because of the decline in oil prices in 1986.

Waterflooding After Steam Drive

The NPC study had seen this as an advanced technology to scavenge heat to produce additional oil. The current revision of this concept is a post-steam hot water/low quality steamflood consisting of either hot water or low quality

(10%) steam injection into mature steamfloods. The change to hot water/low quality steam injection represents a fine tuning of the heating process and project economics. By injecting hot water, operators can keep the reservoir temperature at acceptable level, while bypassing steam generators. The hot water is reclaimed from the water produced with oil. By keeping the water in a closed system, the operators were able to maintain water temperature at about 250°F for reinjection into the producing zone. This concept was widely tested during the 1986 drop in oil prices with mixed results. One major operator (Chervon) "has decided it won't cut so much on steam quality this time because it considers steam a long term resource,"[53] while another operator (Texaco) has used TEOR tailout as a successful tactic.[54]

The switch from steam to hot water continues to accelerate.[55] According to California Division of Oil and Gas, the number of hot water injectors grew from 124 in 1986 to 374 in 1987 in California's Kern River field, where operators increasingly are switching from steam to hot water. Most of the wells switched to hot water are on the Canfield, Section 33, Central Point, Clampit, Apollo, Revenue, Red Bank, Reed, Alma, Kern A, Knob Hill, Gold Standard, Aztec, Kern River, Mutal and Wilson leases.[55] When wells are switched for cost cutting reasons alone, oil recovery usually decreases, but if the switch to hot water is for technical reasons, oil recovery often increases.

American Naphtha and Monte Cristo II steam drive projects located within Kern River field were converted from high quality steam (greater than 40%) to low-quality steam (10% quality at the wellhead) injection in September 1981 and February 1982 by the operator.[56] Monte Cristo II project consists of nine 2.5-acre 5-spot inverted patterns and has been under steam injection since May 1975. The steam injection rate in Monte Cristo II ranged from 1,100 to 1,660 CWE (cold water equivalent) b/d during the period May 1975 to February 1982. During this period, oil production peaked at 300 BOPD in 1978 then decreased to 240 BOPD at the beginning of 1979 and declined further to 110 BOPD by the end of 1981. To conserve fuel and to improve project economy, the operator lowered the steam quality from 70% to 10%. The conversion improved project performance, and the oil production increased from a low of 40 BOPD at the start of low-quality steam injection to 204 BOPD by the end of 1984.

The American Naphtha Project consisted of sixteen 2.5-acre, 5-spot patterns and was under high-quality steam injection from May 1974 to April 1978. In April 1978, steam injection was discontinued, and a cold waterflood was initiated. Injection of cold water did not arrest the production decline. Cold water injection was discontinued after 6 months, and the high-quality steam injection was restarted. Restart of steam injection resulted in production increase, and production peaked at 420 BOPD in July 1981. To conserve generator fuel, the operator lowered the steam quality to 10% in September 1981. At the time of conversion, the project area had produced 33 % of the oil in place at the start of the continuous steam injection. After 5 months of low-quality steam injection, the operator saw the production increase from a low of 167 BOPD to 273 BOPD over a period of 6 months. The operator attributed the increased production to improved sweep efficiency.

Economic necessity has forced operators to test this advanced technology. Results generally have been favorable when the process is closely monitored and implemented in a planned manner. Specific data may not be published as many of the tests were cost-cutting measures and minimizing cost continues to be a priority.

Downhole Steam Generation

Since the NPC study, this technology has generally advanced as expected. The service life of the downhole steam generator is relatively short due to thermal stress corrosion. While some progress in new corrosion resistance materials and combustion design is reasonable, a major breakthrough would be needed for this technology to replace surface steam generation technology. Advances in surface steam generation (including cogeneration) technology that allows the use of produced water with high total dissolved solids and improved insulation of delivery systems make it the technology of economic choice for the foreseeable future.[57]

Injection Of Non-Condensible Gases With Steam

Gas injection with steam may improve oil recovery and production performance. Interest in using non-condensible gas with steam has increased in recent years with the development of steam-foam process and light oil steamflooding.

Three pilots involving steam and inert gas were under implementation in Canada in 1989.[58] None have been reported in the U.S. In the first pilot, superheated steam and carbon dioxide are being injected in the Cold Lake tar sand in Alberta. Steam slug, carbon dioxide, and Naphta are being injected in another pilot near Fort McMurray. The third pilot involves the injection of steam and natural gas at Kearl Lake field in Alberta.

Several laboratory studies involving steam, CO_2, nitrogen, and/or flue gas have been reported since the 1984 NPC study. These studies included linear corefloods and scaled and unscaled 2-D physical models. These studies indicate a modest improvement in total oil recovery from the steam/gas floods compared to steam only injection. The steam/CO_2 process yielded the highest recovery. The steam non-condensible process is not effective in improving oil recovery when applied to a live oil situation.

Hydraulically Fracturing The Reservoir And Steam Injection

At the time of the NPC study, this technology was unproven. The literature shows limited progress in the past 5 years and still is seen as unproven.

One recently reported test in Canada shows continued interest as well as potential for fracture technology improving thermal processes. The Ipiatik pilot in Canada used a chemical additive in conjunction with propped fracturing with the cyclic steam process.[59] The pilot target was 11° API oil in the Wabiskaw reservoir. Seven wells were drilled in 1984 and were stimulated by three steam cycles. By the third cycle, production had dropped to 50% of the first cycle. Wells drilled in 1987 and 1988 were fractured and propped before steam stimulation. First cycle oil production was 33 to 100% higher than from the unfractured well. The third cycle production was 50 to 140% higher than the third cycle production from the unfractured well.

Light-Oil Steamflooding

At least two reasons account for increasing interest in light oil steamflooding (1) an increasing number of light crude oil fields now being waterflooded are approaching their economic limit, and (2) steamflooding is one of the most successful EOR methods. Recently Strycker and Sarathi[19] reviewed the state-of-the-art of light oil steamflooding.

A light oil steamflooding project[60] was initiated in April 1985 at Buena Vista Mills field in Kern County, California in a 65-acre area. The reservoir is 2,500 feet deep with a gross thickness of 108 feet holding 27° API crude oil. Prior to initiating the project, the operator successfully conducted a 6-month steam injection test in 1981.[61] The test showed that steam can be injected into the reservoir at rates and qualities necessary for efficient recovery of the oil. It also showed that unlike a heavy oil reservoir, the light oil reservoir responded almost immediately to steam injection. Computer simulation studies showed that approximately 50% of oil initially in place can be recovered economically, and steam will propagate in a piston like manner in the reservoir. The steamflood increased production from a pre-steam level of about 20 bbl/day to a peak of 300 bbl/day. Low oil prices and steam breakthrough in a high-permeability zone contributed to the decision to shut the project down after 22 months and recovery of 0.2 million barrels of oil.[62]

Several laboratory studies, including linear and two-dimensional sandpack steamfloods and steam distillation yields of light oil, indicated that the recovery efficiency of a light oil steamflood is strongly influenced by the chemical nature of the crude oil, and gravity override of steam remains a potential problem in light oil steamflooding.[63]

DOE has initiated two light oil steamfloods in the naval reserves, Elk Hills (CA) and Teapot Dome (WY). The flood in Teaapot Dome was started in 1986 and plans are to expand the project. The flood in Elk Hills was initiate late in 1987. The results of these two projects should allow better analysis of the potential for this relatively untried process.

Numerical simulations of light oil steamflooding indicated that up to 60% of OIP (oil-in-place) at the start of a steamflood can be recovered economically.[60,64] The simulations indicate rock-fluid properties have a greater influence on steamflood performance than design and operating variables. This advanced technology has made little progress towards implementation since the NPC study but continues to hold promise.

Insulated Tubulars

Insulated tubulars were an area in which the NPC saw rapid development, and generally insulated tubulars have reduced heat losses and minimized casing problems due to excessive heat stresses in the past 5 years. Field tests have indicated that economic benefits can be improved by minimizing wellbore reflux and employing good operating practices when running the tubing.

Wellbore reflux drastically lowers the advantages of insulated tubing over bare tubes. Wilhite[65] has studied the refluxing problem in steam injection wells. These phenomena occur in wells in which insulated tubing is set on a packer without removing the water from the casing annulus before the injection of steam and when the packer leaks. Refluxing can be prevented by removing water from the annulus by evacuation and maintaining a gas blanket such as nitrogen in casing annulus.

Advances in the insulating material development reduced the effective thermal conductivity of the insulating system from 0.03 BTU-ft/(hr-ft^2-F°) to 0.01 BTU-ft/(hr-ft^2-F°) resulting in improved performance. Other advances in materials have prolonged the tubing life especially in H_2S environments. A specific example of advances in insulated tubulars is the injection of steam into a 9,000 ft. deep reservoir in Boscan field (Venezuela).[66] The reservoir pressure is 1,490 psi and is probably the deepest steam injection test ever atempted.

The technological advances in insulated tubulars have likely met or exceeded the expectations of the NPC study.

Cogeneration

The late eighties has been the time of cogeneration projects. The following are a sample of projects either completed or nearing completion: 49.5-megawatt coal fired cogeneration plant in Mount Poso field, 36-megawatt coal fired cogeneration plant in Jasmin field, 37-megawatt coal fired cogeneration plant in Poso Creek field, 225-megawatt cogeneration plant on the Anderson lease of Midway-Sunset field, 42-megawatt cogeneration plant in Coalinga field, 300-megawatt Omar Hill cogeneration plant in the Kern River field, and 300-megawatt Sycamore cogeneration plant in Kern River field.[54,65] Although additional projects are being planned, negotiating the sale of electricity to utilities is becoming more difficult due to a current excess in electrical capacity.[67] As long as the operator can use most of the electrity generated, cogeneration should be economical as well as an improvement for environmental offset.

Oxygen Enriched In Situ Combustion

Innovations in combustion technology have continued in spite of the general lack of interest in the technology. A wet, in situ, oxygen-combustion process was field tested in Espersion Dome field in southeastern Texas to gain experience in safe handling and downhole injection of high purity oxygen in an oilfield environment.[68]

In 1984, the injection well was ignited using a synthetic mixture of 20% oxygen and 80% nitrogen. The synthetic air mixture was continued 1 month to allow the combustion front to move away from the injection wellbore. Over the next 3 months, oxygen concentration was gradually increased to 95%. The project was terminated at the end of 1987. A total of 200 MMscf (million cubic feet at standard conditions) of oxygen and 55 MMscf of nitrogen had been injected during the 3-year period. The operator found only 6.6 MMscf of unreacted oxygen produced back, indicating a 97% efficiency burn. A total of 90,000 barrels of oil was recovered. The natural water drive dominated the combustion process and assisted in displacing the oil. The reservoir is 45 feet thick and 2,700 feet deep. The crude oil is 21° API. The porosity and permeability are 31% and 1 darcy, respectively.

Even though the operator encountered several operational problems, the project was considered a success and plans on conducting additional tests.

Advances In Steamflooding Beyond The NPC's Expectation

Infill Drilling

This has become an implemented technology with 574 infill wells drilled between 1982 and 1986 contributing an incremental 10,000 BOPD.[69] The practice is to convert a five-spot well configuration to a nine-spot by drilling producer wells at the mid-points of the pattern boundaries. Although the intent is to produce by-passed oil, in homogeneous reservoirs it is believed mainly to accelerate production rather than to increase incremental recovery.[17]

Horizontal Wells

Horizontal drilling technology has and continues to improve at a rapid rate since the brief mention in the NPC study. As such, horizontal wells are being adapted to improve recovery efficiencies in new or modified thermal recovery processes. Horizontal wells as compared to vertical wells increase the direct contact between wellbores and pay zones. The perforated interval per vertical well is limited to the pay zone thickness while the perforated interval for a horizontal well could be 1,000 feet, and improvements in technologies are increasing this distance. Although the technology is promising, just increasing the exposure of the reservoir may not proportionately increase drainage area and production.[70]

Steamflooding of thin pay zones may be economic with horizontal drilling where vertical drilling would be uneconomical due to insufficient wellbore openings for production and associated heat losses. The relative cost per foot of horizontal wells is trending toward the cost of deviated wells as the technology is more widely used.[71] In addition, the technology offers a way to improve flood sweep efficiency and hence recovery efficiency through improved distribution of drive fluids.

Horizontal wells in conjunction with steam drive were pilot tested in Kern River (CA) field in 1983.[72] This field test consisted of eight horizontal wells drilled from a 500-foot vertical shaft into the base of a heavy oil column. The targeted pay zone consisted of an unconsolidated sand, Q1, 77 feet thick (net) with horizontal and vertical permeabilities of 300 and 60 millidarcies. The total oil in place in the 25-acre pilot area was about 3 million stock tank barrels (STB). The Q1 sand was selected as the target for the steam pilot because it contained two-thirds of the oil. Steam was injected into the pilot at the rate of about 2,900 barrels per day of cold water equivalent for 14 months. The pilot recovered approximately 47,000 STB of oil in response to the injection of 788,000 barrels of cold water equivalent steam. This equates to a cumulative oil-steam ratio of 0.06 bbl/bbl. The pilot was terminated due to unfavorable economics although the oil recovery rate and process efficiency were improving at the time of pilot abandonment. Post pilot analysis attributed the disappointing performance to low vertical permeability and low oil saturation in the pilot site. It was concluded that horizontal well steamdrive is technically promising because of the absence of steam override, but a poor site selection led to project failure.

Field tests in the Athabasca McMurray formation in Alberta, Canada[73] were conducted to investigate the feasibility of horizontal well steamdrive in the Athabasca tar sands. Three horizontal wells were drilled and completed in the oil sands. During production, two modes of steam operation were tested: hot finger stimulation and steamdrive. After about a month of operation in the hot finger mode, interwell communication was achieved between wells spaced 25 feet apart when the operating model was changed to steam drive. The pilot was discontinued after $1\frac{1}{2}$ years of operation. It was concluded the pilot was a success and that the two horizontal well steamdrive process is a technically feasible concept. The results of the pilot were not published.

Limited laboratory studies conducted on a physical model recovered more oil than indicated for a vertical well with the same amount of steam injection.[74-75] Numerical simulation of the horizontal well steamdrive process indicates that horizontal wells are effective in recovering oil in blind spot areas in a mature steamflood project. These studies also indicate that incorporating horizontal wells at the start of a steamflood project can alleviate the steam override problem and improve sweep and recovery efficiency. Horizontal wells can recover more oil sooner and thus shorten project lives.

This technology was briefly mentioned in the NPC study as an advanced technology with promise. Limited field testing has resulted in mixed results and economic application of the technology has yet to be demonstrated. The improving costs for horizontal drilling and completion may make this technology an important contributor in the 1990s. Advances in the horizontal length of wells may have advantages in sensitive areas such as Santa Barbara and Los Angeles counties where development is held back for environmental concerns.

In addition to the horizontal drilling technology, two innovative methods of heat placement in reservoirs have evolved. Steam assisted gravity drainage (SAGD) and heated annulus steam (HAS) drive are currently being tested by Alberta Oil Sands Technology and Research Authority in Canada (AOSTRA).

Steam Assisted Gravity Drainage Process (SAGD Process)

SAGD is a production method which exploits the tendency of oil heated by steam to flow from the top to the bottom of the reservoir. In practice a well pair is located near the bottom of an oil column with an horizontal producer completed about 6 feet above the base of the pay zone and an injector above the producer. The wells are located as close as possible to one another with no pressure drop, other than gravity head between them. When steam is injected, a steam chamber is created in the reservoir. Steam flows to the boundary of the chamber, condenses, and gives up its heat to the surrounding oil sand. The condensate and heated oil flow by gravity to the horizontal production well at the bottom of the chamber. As the oil is removed, the steam chamber becomes longer by growing upwards and sideways. The pressure within the steam chamber remains essentially constant.

The advantages of the SAGD process[75] are (1) the sweep and displacement efficiencies are high; (2) in contrast to conventional steamdrive, the hot oil is produced as soon as it is displaced from the formation; and (3) oil, condensed water and steam flow through independent flow channels, and this results in favorable relative permeability effects for oil flow.

The disadvantages of the process are (1) a relatively thick (50 feet or better) oil column is needed and (2) several oil zones separated by thick continuous shale barriers may require drilling of horizontal holes in each layer.

Extensive laboratory and numerical simulation investigations of the concept demonstrated that SAGD is a thermally efficient oil production mechanism. Simulation studies indicated that for the same amount of total fluid production a scheme with a pair of horizontal wells, one injector and one producer, gives higher oil recovery than the other production schemes tested. Experimental results also indicate that vertical fracture improves the efficiency of the SAGD process.

The SAGD concept was field tested at the Lemming Pilot in the Cold Lake Tar Sand, Alberta.[76] Results obtained confirmed the technical feasibility of the process. SAGD process is currently being field tested by AOSTRA at the underground test facility (UTF), near Fort McMurray, Alberta. The SAGD pilot consists of three pairs of horizontal wells, each pair has a producer completed 6 to 10 feet above the base of the payzone and an injector 18 feet above the producer. The well pairs are separated by 80 feet. AOSTRA started injecting steam in the first well pair in December 1987.[77] Heating of the first well pair lasted 3 months, which the project authorities considered sufficient to ensure mobilization of flow paths through any shale barriers that may lie between injector and producer. After the heating phase, the wells were allowed to produced. The wells are 1,200 feet long. Authorities estimate that it will take about a year of operation to measure the drainage rate properly in the reservoir.[77] AOSTRA plans to drill additional wells (1,700 to 3,200 feet long) to continue the experimentation of SAGD process.

Heated Annulus Steam Drive (HAS Drive)

HAS Drive is an in situ thermal process for recovering heavy oil or bitumen from tar sands. The process, patented by Chevron, involves a cased unperforated horizontal well called the HAS well, running between a vertical steam injection well and a vertical production well. The horizontal well intersects, but is not in communication with the vertical wells. High-pressure, high temperature steam is circulated in a closed loop through the HAS well. Steam is injected through the tubing and returns through the casing. The circulated steam heats the surrounding oil by conduction, and creates a low viscosity flow path in the formation around the HAS well. Steam is then injected via the vertical well into the reservoir at one end of the flow path to move the oil along the path towards the producer. Steam circulation in the HAS well is maintained at a sufficient rate to keep the communication path between production and injection wells open throughout the life of the project. Redford[78] discussed in detail the advantages and disadvantages of this process. The process is currently being field tested by AOSTRA at its underground test facility. The well setup for HAS Drive is a vertical steam injector close to a horizontal HAS well, and the producer is a short horizontal well, lying to the side of the HAS well. Steaming of the HAS well began in October 1987. Production rates were described as "satisfactory."

Electrothermal Processes

Electrothermal Processes utilize electricity or electromagnetic energy to thermally stimulate heavy oil reservoirs. Over the past decade several processes have been proposed but few of them have been field tested successfully. While the results indicate that this new technology is technically feasible, considerable innovation is needed in the area of electrode design and in the optimization of electrode siting before the process can become commercially viable.

Some of the proposed electrothermal processes include: (1) electric preheat steamdrive (EPSD) process, (2) electrothermic process, (3) radio frequency (RF) stimulation, (4) electromagnetic flooding, (5) eddy current heating, (6) the electrocarbonization process and (7) microwave retorting. Of these, only the EPSD electrothermic and RF stimulation processes have been field tested. Chute and Vermeylen[79] have presented an overview of the existing state of this new technology. A brief summary of selected processes is presented in the following paragraphs.

EPSD Process

This process developed at the University of Alberta, Canada involves the preheating of the formation by electromagnetic energy to a temperature sufficient to lower the viscosity of oil to the point, where it can be displaced by steam. During the preheating phase, the current flows between adjacent wells which serves as electrodes. The rate of power dissipation is controlled so that the connate water is not vaporized, and a conductive path through the formation is maintained. Field testing of this concept began in April 1981 on a 150 acre site near Stoney Mountain, south of Fort McMurray, Alberta Canada. The pilot consisted of four electrode/producer wells on approximately 30 meter spacing. In addition, eight observation wells were used to monitor temperature and electrical potential profiles. The electrodes consisted of sections of slotted liner about 15 meter in length surrounded by an under reamed gravel packed region, saturated with brine to maintain electrical contact with the formation. The current was delivered to the electrodes via the insulated well bore casing.

The power source consisted of a 2,500 KVA (kilo-Volt-Ampere) three-phase transformer, and the maximum current level was 1,000A (Amperes). Electrodes 1 and 4 were excited from the same phase while wells 2 and 3 were excited from the remaining two phases. After 5 months of preheating, the formation temperature rose to 78° C from an initial temperature of 10° C. Preheating was then discontinued and the recovery of this preheated bitumen was attempted by steam injection. The results[80] indicated that while the formation was successfully heated, subsequent bitumen recovery was poor due to geological factors.

Electrothermic Process

In this process, an alternating current was applied directly to the reservoir to stimulate the formation. The production tubing is used as a conductor and a concentric string of fiberglass pipe is used to electrically insulate the produciton tubing. The producing tubing is connected to an electrode placed at the reservoir level. The electrode was formed by packing steel shot into a specially under-reamed section at the bottom of the well.

Because of the electrolytes in the formation water, the electrical conductivity of the formation is generally sufficient for the current to flow while ensuring the dispersion of heat within the layer. The current returns by means of a surface electrode placed at a certain distance from the stimulated well.[81]

Several well completion methods have been developed for formations of various depths, thickness and oil viscosities. The electrical efficiency of the process depends primarily on the depth of the well and the resistivity of the formation into which the electrode is placed. The "electrothermic process" has been used to enhance production from heavy oil deposits since 1970, with some success. Table 18 adopted from reference[82] shows some typical field results.

Single Well Radio Frequency Stimulation Process

Another approach to thermal stimulation in heavy oil reservoirs consists of radio frequency heating at frequencies ranging from a few hundred kilohertz to microwave frequencies. The concept first patented in the mid 50s has further been refined and developed by the IIT Research Institute of Chicago, IL. The process consists of completing monopole or dipole antenna structures down hole and applying radio frequency energy to them. The electromagnetic energy is allowed to radiate away from the excitor into the pay zone. The depth to which those waves can penetrate into the formation is limited, and the heating is generally confined to the near wellbore region. However, unlike the electrothermic process, heating can be continued even after the formation water near the wellbore has flashed to steam. In this way, the heated zone is gradually advanced radially outward into the formation.

Single well stimulation tests based on RF heating have been successfully completed in Ardmore and Tulsa, OK.[83-84] The Ardmore, OK test[83] was conducted in a 50-foot thick unconsolidated sand. The reservoir is 300 feet deep. A single well was drilled and cased to the top of the pay zone. A specially designed cylindrical copper clad steel antenna excitor was installed downhole. The bottom portion of this excitor served as the producer and consisted of a stainless steel screen in direct contact with a gravel pack. The antenna was powered from a 6.78 MHz (mega-Hertz), 40 kw transmitter. The reservoir contain 6° API oil at 100 psi reservoir pressure. The heating began in mid-December 1984. After several months of heating the near wellbore temperature was raised from 18° to 100° C. At 4.5 feet from the wellbore antenna, the temperature was 65° C and 15 feet away it was 33° C. The production increased from zero to 2 barrels per day.

Tri-Plate Radio Frequency Heating of Oil Sand[85]

This process targeted toward tar sands, utilizes an array of three parallel rows of electrodes to guide electromagnetic energy into the tar sand deposit. In this process, the electrodes of the inner row are excited with respect to the outer rows. This allows the heating effect to be confined within the rows of electrodes. The electrode patterns, the operating frequency, well spacings, and electrode lengths are selected so that the formation enclosed by the three rows of electrodes is heated as uniformly as possible.

The process developed by the IIT Research Institute was pilot tested in the asphalt ridge deposit near Vernal, UT. Three rows of electrode wells were vertically drilled into a surface outcrop to a depth of 6 meters, 38 electrodes, 10 in the middle row and 14 in each outer row was used. The heated volume was about 25 m^3.

The tar produced by vaporization of the formation water and by gravity drainage was collected in a 12x12x8 foot collection room mined under the electrode array. During the test, the operating frequency was maintained at 2.2875 MHz until all the connate water was vaporized. The frequency was then raised to 13.5 MHz to maintain a high heating rate. The temperature of the volume under investigation reached 200° C after 20 days of heating and an appreciable amount of oil was produced. This recovery represented 35% of the total bitumen content held within the test volume.

Novel Recovery Methods

Novel recovery concepts are ideas which have been proposed but not field tested. These ideas are mostly applicable to low gravity, heavy oils.

In Situ Hydrogenation[86]

This process involves heating a wellbore with superheated steam and then plugging it. Hydrogen is then injected into the wellbore where the developers[86] claim it dissolves in the hydrocarbon and reduces its viscosity by hydrocracking. The oil is removed by depressurizing the wellbore. Downhole oxygen and hydrogen combustors are needed to produce the injectants. According to the process developers, about 40 to 60% of the oil-in-place can be recovered by this approach.

Stapp[87] recently assessed the potential for in situ hydrogenation using laboratory studies on 4 different heavy oils. The experiments were carried out in simulated reservoir conditions and with either hydrogen or nitrogen to isolate the effects of hyrogenation. The results did not indicate that significant hydrogenation occurred and that any improved oil production is from thermal alterations. The addition of catalysts had a slight effect and led Stapp to conclude that in situ hydrogenation has very limited potential.

Ablation Process[78]

It has been suggested that when part of the bitumen (heavy oil) is reinjected with steam, the pressure drop between injector and producer will increase due to the injected bitumen acting as a partial blocking agent for steam. This increase in pressure drop will then force the steam and hence the heat front to rise. This upward expansion of steam zone will cause the bitumen surrounding the hot zone to ablate away, thus exposing the cold oil zone to steam. When most of the reservoir has been heated in this manner, the remaining oil can be recovered by conventional steamdrive.

Physical and numerical simulation studies of the process predicted high oil recovery at an acceptable steam-oil ratio.

Environmental

Environmental issues for TEOR are both technical and political. The progress in the technical area relate to the new methods for generating steam. Increased use of cogeneration and gas boilers have reduced air pollution and will continue to reduce pollution. Areas with targeted resources by the NPC Advanced Technology Case for TEOR are in nonattainment areas with high population. As long as these areas remain nonattainment areas and the petroleum industry has a reputation for pollution, expansion may be limited.

DISCUSSION

The business environment for the U.S. petroleum industry, and EOR in particular, has been volatile in recent years. Average oil prices have dropped below $13 per barrel in both 1986 and 1988. This low oil price has caused a drop in domestic oil production and cancellation of numerous EOR projects. Domestic oil production has dropped to half this Nation's consumption rate of crude oil with little expectation for improvement. EOR project starts have dropped from around 100 per year in 1983 to 1986 to a small fraction in 1987 and 1988. (See table 19.)

The 1984 NPC EOR study[1] had a major influence on the development of EOR during the eighties. The majors (integrated oil companies) included EOR as major strategic elements in their plans for maintaining oil reserves from 1983 to 1986. Significant portions of their research budgets were directed toward the opportunities outlined in the NPC study. Until 1986, oil prices were expected to be relatively constant at the worst through the early 1990's and at rates where good EOR projects would be profitable. A critical price for EOR was thought to be in the lower to middle $20's/bbl. The plausibility of EOR came into question in 1986 when oil prices dropped to half the levels considered necessary for new EOR projects. The low price caused reviews of strategies, restructuring and major reduction in research staffs. The momentum of planning, procurement, and organizational commitment may explain why project starts in 1986 remained high at 91 starts. By 1987, the recorded EOR starts had dropped to 16.

Frequency of project starts and trends in their reservoir data are an important indication of EOR technology application. The count and data for EOR projects in the DOE database reflect the EOR projects that have been reported in the literature. Although periodic surveys of the industry would assure a better count and more complete data, federal regulations make govenment-funded surveys difficult to be approved. The O&GJ does conduct a biennial survey in even-numbered years that provides a major input of missed projects. Since the last review was in early 1988, project starts in the database for 1987 should not increase much while the number for 1988 could increase significantly.

Oil prices recovered in 1987 enough to keep some projects from being canceled. Momentum and expectations of higher prices are thought to have been important factors in the actual start of these projects. Plans in early 1988[8] indicated that project starts for 1988 would be higher than starts in 1987, but again oil prices fell far enough below the economic breakeven for most EOR projects that plans were changed. Only 2 new EOR projects have been confirmed for 1988 in the literature reviewed by NIPER.

Previous analyses[2-4] have relied heavily on the trends of data in the DOE EOR project database for changes in applications of EOR technology. With few additions to the database this year, the observed trends in technology continue to be the same. The confirming observation is the oil price of the last three years is not sufficient to justify new EOR projects.

A review of the frequency of projects by process by year in table 19 does give some insight as to the processes likely to be used in the future when oil prices recover. Polymer, conventional steam, and immiscible carbon dioxide projects had significant starts in 1986 which indicates adequate confidence in those technologies. Advances into deeper and hotter reservoirs indicated improving polymers. The project frequency data plus the EOR production trends (figure 4) imply additional gas and thermal project starts when new EOR projects are economic. Surfactant projects are not likely to resume soon except as a refinement to another technology.

Because of the lack of new project data, other indications of changes in EOR technology were considered in this study. The literature generated by SPE was analyzed for the period 1980 to 1988 (table 15). The trends generally confirm those seen in the DOE database. The trend towards gas displacement and away from chemical processes is more noticeable. This could also reflect a prediction of the future. Technology interest in gas displacement moved to near 50% of publications in the latest 2-year period.

The one surprise was the decrease in SPE's technical interest in TEOR as evidenced by the 21% of EOR publications on TEOR. All of the decreases were in laboratory-oriented publications, which might indicate a maturing of the TEOR technology. A competing factor is publication opportunities in Canadian Petroleum Technology conferences, UNITAR, and World Petroleum Congress. The EOR reports in these conferences and publications are dominated by TEOR. In addition, Canadian federal and regional governments have supported extensive heavy oil research. The Canadian research is presented in their publications. SPE has a policy of minimizing duplication of reporting the same research. Therefore the decrease in SPE TEOR publications may not mean as drastic a decrease in technical interest in TEOR as the statistics imply. With TEOR accounting for over three-quarters of EOR production, it is difficult to believe that technical interest is only 20 % of EOR interest.

The total volume of SPE literature on EOR and EOR technology has remained relatively stable during the period studied when year-pairs are compared. One conclusion might be that technical interest in EOR continues at the same high level of the early eighties in spite of the lack of project starts. This high interest conclusion could be refuted by the practice of SPE symposia to cover a balanced range of subjects and a single biennial symposium devoted to EOR. Since SPE has not cut back on EOR publications, it does show a continued technical interest and technical commitment to EOR. Cuts in petroleum industry research staffs and recent strategy shifts to international opportunies by the majors make it difficult to beleive that interest in EOR has not dropped.

The increasing oil production from TEOR projects is not reflected in the statistics on new project starts. This increasing production trend and the major position of TEOR in the U.S. encouraged the in depth review of TEOR technology advances presented in the earlier section. The advances of the technology were measured against the technology base established by the 1984 NPC EOR study. The technology advances that target 10.5 billion barrels of oil in the TEOR Advanced Technology Case were reviewed for progress as well as a review of the emerging technologies.

TEOR is a bright spot for the NPC study. The production estimates in the study compare well with recent history. Steam drive technology advances projected for implementation in 1995 in the Advanced Technology Case appear realistic and possibly conservative. New combinations of technology may open possibilities for TEOR that were nothing more than ideas 5 years ago. Economic and technological advances in horizontal drilling that may make thermal treatment of shallow, thin reservoirs economic is a potential that few foresaw.

CONCLUSIONS

Data trends confirm the dominant effect of oil price on EOR. New EOR project starts have all but disappeared as oil prices in 1986, 1987, and 1988 were below the hurdle rate needed for profitable new projects. Reservoir characteristics of new projects have not changed in recent years from those sucessful in the past.

Trends in the SPE literature indicate increasing interest in gas displacement technology to nearly 50% of all EOR-related SPE publications. A stable number of EOR-related SPE publications indicate continuing technical interest in EOR.

Technology trends in TEOR have been toward improving recovery efficiencies, cost factors, and air pollution. These technology improvements are in line with those envisioned by the 1984 NPC study. In addition, the production from TEOR is in the range of that estimated by the study in spite of the recent price history being below the $20/bbl worst case scenario. There are some emerging technologies, such as horizontal drilling and electrothermal, that could expect to expand the resource targets for TEOR beyond those in the NPC study. Unfortunately technical progress towards recovering resources in environmentally sensitive areas, Los Angeles and Santa Barbara counties, targeted in the Advanced Technology Case does not appear likely in the near term.

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TABLES

TABLE 1. - Average U.S. crude oil prices

	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	7/89
Wellhead price, $/bbl	12.64	21.59	31.77	28.52	26.19	25.88	24.09	12.51	15.40	12.57	16.26
Refiners' cost, $/bbl	14.27	24.23	34.33	31.22	28.87	28.53	26.66	14.82	17.76	14.76	18.31

TABLE 2. - Distribution of EOR projects in DOE's database by state

State	Projects	State	Projects	State	Projects	State	Projects
AK	5	IN	3	MS	16	PA	6
AL	7	KS	31	MT	19	SD	1
AR	11	KY	10	ND	8	TX	288
CA	456	LA	99	NE	6	UT	10
CO	8	MI	1	NM	22	WV	8
FL	2	MO	6	OK	113	WY	122
IL	44						

TABLE 3. - Frequency of EOR processes in the DOE Database (1-1-89)

Process	Number of projects
In situ combustion	88
Conventional steam drive	247
Cyclic steam injection	123
Unconventional steam drive	59
Alkaline flooding	55
Microemulsion flooding	84
Polymer flooding	347
Immiscible gas displacement	85
Miscible fluid displacement	198
Heavy oil recovery	5
Microbial	7
Other	5
Total	1,303

TABLE 4. - Steam project starts

Year started	(1) Majors #/Total	(2) Area, acres	(3) Avg depth	(4) Range depth	(5) Avg API°	(6) Range API°	(7) Avg porosity	(8) Range porosity
1980	14/19	292	1140	120-2700	13.9	8-24	30.6	20-42
1981	32/40	107	1436	350-4500	14.3	2-30	29.6	18-37
1982	20/24	54	1704	500-3500	13.8	8-30	30.3	7.5-37
1983	13/18	121	1164	300-2550	12.5	11-16	32.5	31-38
1984	15/21	104	1303	350-1900	13.6	11-18	33.1	29-37
1985	15/21	39	1490	200-4400	13.3	8-22	31.7	16-40
1986	18/22	207	1486	400-3300	14.3	10-21	33.0	28-35
1987	5/6	168	1210	500-3000	14.1	11-21	35.0	34-36

(1) Number of projects started by major oil companies/total EOR projects started.
(2) Average reported area in acres.
(3) Average depth to top of producing formation in feet.
(4) Shallowest project - deepest project.
(5) Average API gravity.
(6) Range of API gravities.
(7) Average reported porosity in %.
(8) Range of porosities in %.

TABLE 5. - In situ combustion project starts.

Year started	(1) Majors #/Total	(2) Area, acres	(3) Avg depth	(4) Range depth	(5) Avg API°	(6) Range API°	(7) #SS/ Proj	(8) Avg poro.	(9) Range porosity
1980	6/10	134	877	150-2350	23.3	14.7-32	10/0	23.2	18-36.9
1981	3/4	43	1283	950-1500	19.9	15-29	3/0	28.4	19.7-33.1
1982	1/2	112	1100	1100	21	21	-----	38	38
1983	-----	-----	-----	-----	-----	-----	-----	-----	-----
1984	1/1	-----	800	-----	17	-----	1/0	32	-----
1985	1/2	17	2650	500-4800	19.5	8-21	-----	33	28-38
1986	0/1	600	1250	1250	11.5	11.5	1/0	-----	-----

(1) Number of projects started by major oil companies/total EOR projects started.
(2) Average reported area in acres.
(3) Average depth to top of producing formation in feet.
(4) Shallowest project - deepest project.
(5) Average API gravity.
(6) Range of API gravities.
(7) Number of projects reported in sandstone/number in limestone.
(8) Average reported porosity in %.
(9) Range of porosities in %.

TABLE 6. - Unconventional steam project starts

Year started	(1) Majors #/Total	(2) Area, acres	(3) Avg depth	(4) Range depth	(5) Avg API°	(6) Range API°	(7) #SS/ Proj	(8) Avg poro.	(9) Range porosity
1980	2/5	112	2773	2100-3200	8.6	2-14	5/0	29.6	29-30.1
1981	6/8	87	3175	2701-4500	21.6	10-47	7/0	30.2	18-35
1982	3/3	101	2675	2575-2850	14.7	13-17	3/0	28.5	27-30
1983	1/1	80	3400	3400	11	11	1/0	30	30
1984	1/1	----	3800	3800	22	22	----	31	31
1985	1/1	2240	7500	7500	28.5	28.5	0/1	4.5	4.5

(1) Number of projects started by major oil companies/total EOR projects started.
(2) Average reported area in acres.
(3) Average depth to top of producing formation in feet.
(4) Shallowest project - deepest project.
(5) Average API gravity.
(6) Range of API gravities.
(7) Number of projects reported in sandstone/number in limestone.
(8) Average reported porosity in %.
(9) Range of porosities in %.

TABLE 7. - Surfactant project starts

Year started	(1) Majors #/Total	(2) Area, acres	(3) Avg depth	(4) Range depth	(5) Avg API°	(6) Range API°	(7) #SS/ Proj	(8) Avg poro.	(9) Range porosity
1980	9/20	74	3677	510-7983	32.2	21-43	17/1	21.8	14.7-31.8
1981	3/3	38	3187	1600-5060	37	32-40	2/1	18.3	11-24
1982	2/3	—	1400	950-1800	37.7	29-45	—	20.7	20-21
1983	1/1	200	2317	-----	37	—	1/0	19.0	----
1984	1/1	45	3950	-----	27	—	1/0	28.8	----
1985	2/3	3	3133	900-4600	29.3	20-39	2/0	16.2	14-20.6

(1) Number of projects started by major oil companies/total EOR projects started.
(2) Average reported area in acres.
(3) Average depth to top of producing formation in feet.
(4) Shallowest project - deepest project.
(5) Average API gravity.
(6) Range of API gravities.
(7) Number of projects reported in sandstone/number in limestone.
(8) Average reported porosity in %.
(9) Range of porosities in %.

TABLE 8. - Polymer project starts

Year started	(1) Majors #/Total	(2) Area, acres	(3) Avg depth	(4) Range depth	(5) Avg API°	(6) Range API°	(7) #SS/ Proj	(8) Avg poro.	(9) Range porosity
1980	6/19	869	4046	1500-7301	32.8	16-43	13/3	16.0	6.0-31.3
1981	18/34	1344	3293	480-8300	33.6	12-49	10/2	18.0	7.1-41.9
1982	25/34	1274	4159	550-12000	34.1	20-47	12/2	17.8	4.1-35
1983	42/53	1310	4571	999-11400	34.4	22-48	14/8	16.6	7.7-30
1984	45/54	1181	4587	775-8700	32.2	17-42	29/13	17.4	7.7-42.3
1985	20/39	2242	4904	630-9400	33.5	20-47	25/5	17.5	9.6-28
1986	25/36	2444	4514	700-13000	32.5	16-46	5/1	17.0	8.5-30.1
1987	0/5	123	5129	800-9515	27.0	20-32	5/0	18.6	14.9-23

(1) Number of projects started by major oil companies/total EOR projects started.
(2) Average reported area in acres.
(3) Average depth to top of producing formation in feet.
(4) Shallowest project - deepest project.
(5) Average API gravity.
(6) Range of API gravities.
(7) Number of projects reported in sandstone/number in limestone.
(8) Average reported porosity in %.
(9) Range of porosities in %.

TABLE 9. -Data on temperature and salinity of polymer project starts

Temperature Data

Year started	No. of Projects	No. Reporting	Avg. Temp °F	High, Temp °F	Low Temp °F
1980	19	18	141	217	93
1981	34	27	98	175	70
1982	32	18	114	90	65
1983	52	38	112	190	80
1984	49	45	122	200	78
1984	37	21	134	240	83
1986	26	8	123	165	95

Salinity Data

Year started	No. of Projects	No. Reporting	Ave Salinity, ppm[1]	High Salinity, ppm[1]	Low Salinity ppm[1]
1980	9	12	31,400	195,000	238
1981	34	8	57,600	123,000	50

[1] Salinity in parts per million (total dissolved solids).

TABLE 10. - Alkaline project starts

Year started	(1) Majors #/Total	(2) Area, acres	(3) Avg depth	(4) Range depth	(5) Avg API°	(6) Range API°	(7) #SS/ Proj	(8) Avg poro.	(9) Range porosity
1980	3/13	1364	3400	405-10130	32.3	16-43	9/4	18.8	13.4-31
1981	3/9	213	5373	740-10250	29.8	18-42	7/1	24.6	13-32.1
1983	0/1	1100	4200	4200	39.0	----	----	17.0	17.0
1986	2/2	3	5675	5650-5700	28.5	25-32	----	31.0	31.0

(1) Number of projects started by major oil companies/total EOR projects started.
(2) Average reported area in acres.
(3) Average depth to top of producing formation in feet.
(4) Shallowest project - deepest project.
(5) Average API gravity.
(6) Range of API gravities.
(7) Number of projects reported in sandstone/number in limestone.
(8) Average reported porosity in %.
(9) Range of porosities in %.

TABLE 11. -Carbon dioxide miscible project starts

Year started	(1) Majors #/Total	(2) Area, acres	(3) Avg depth	(4) Range depth	(5) Avg API°	(6) Range API°	(7) #SS/ Proj	(8) Avg poro.	(9) Range porosity
1980	14/26	1581	5679	1000-10400	35.7	14-45	11/9	17.0	9-37
1981	15/28	2430	6030	1300-11530	36.4	14-44	13/11	16.9	6-37
1982	4/10	991	7220	2300-13000	34.2	14-49	5/1	17.1	8.5-27
1983	4/6	6169	6724	4900-8500	38.8	33-43	1/3	14.0	8-30
1984	7/8	3936	6515	5050-13275	33.9	28-45	1/6	13.8	6.4-30
1985	8/11	5094	5981	1270-10750	36.8	20-41	4/5	16.5	7.7-29
1986	6/8	3410	6438	800-12000	35.5	28-46	1/2	13.0	10-15

(1) Number of projects started by major oil companies/total EOR projects started.
(2) Average reported area in acres.
(3) Average depth to top of producing formation in feet.
(4) Shallowest project - deepest project.
(5) Average API gravity.
(6) Range of API gravities.
(7) Number of projects reported in sandstone/number in limestone.
(8) Average reported porosity in %.
(9) Range of porosities in %.

TABLE 12. -Hydrocarbon project starts

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year started	Majors #/Total	Area, acres	Avg depth	Range depth	Avg API°	Range API°	#SS/ Proj	Avg poro.	Range porosity
1980	0/2	388	1750	500-3000	29.5	18-41	2/0	25.0	---
1981	5/6	974	10739	1200-16150	38.8	35-48	5/1	25.6	16-31
1982	0/2	640	8900	8800-9000	32.6	25-40	0/1	16.2	10-22
1983	8/8	6.5	6553	4300-11270	32.6	19-43	3/0	26.9	9-33
1984	2/2	53	8250	8000-8500	34.5	33-36	2/0	29.5	29-30
1985	3/3	849	5050	4500-5750	31.3	29-33	1/2	17.0	9-30
1986	1/1	15360	6000	----	24.0	----	1/0	22.0	----
1987	1/1	13500	8800	----	27.0	----	1/0	22.0	----

(1) Number of projects started by major oil companies/total EOR projects started.
(2) Average reported area in acres.
(3) Average depth to top of producing formation in feet.
(4) Shallowest project - deepest project.
(5) Average API gravity.
(6) Range of API gravities.
(7) Number of projects reported in sandstone/number in limestone.
(8) Average reported porosity in %.
(9) Range of porosities in %.

TABLE 13. - Immiscible carbon dioxide project starts

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year started	Majors #/Total	Area, acres	Avg depth	Range depth	Avg API°	Range API°	#SS/ Proj	Avg poro.	Range porosity
1980	----	----	----	----	----	----	----	----	----
1981	1/1	----	12000	----	47.0	----	----	5.0	----
1982	4/4	766	5184	3785-9000	23.7	23-25	1/0	27.0	25-30
1983	15/16	540	4948	2600-10000	25.6	14-39	2/0	25.8	13-31
1984	10/11	231	6745	1300-10200	32.9	14-47	5/0	21.1	8-31
1985	11/11	2106	8350	1400-13125	33.7	26-42	6/1	22.4	4.5-32
1986	20/21	264	9728	5200-14000	37.0	31-45	20/0	22.0	----

(1) Number of projects started by major oil companies/total EOR projects started.
(2) Average reported area in acres.
(3) Average depth to top of producing formation in feet.
(4) Shallowest project - deepest project.
(5) Average API gravity.
(6) Range of API gravities.
(7) Number of projects reported in sandstone/number in limestone.
(8) Average reported porosity in %.
(9) Range of porosities in %.

TABLE 14. -Nitrogen project starts

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year Started	Majors #/Total	Area, acres	Avg depth	Range depth	Avg API°	Range API°	#SS/ Proj	Avg poro.	Range porosity
1980	2/3	893	6900	5800-11000	37.7	21-46	1/1	16.8	12-27
1981	5/5	5449	9828	7350-15552	43.8	38-51	1/2	9.2	4-14
1982	1/1	5120	9000	----	60.0	----	0/1	5.5	----
1983	1/1	1500	12000	----	46.0	----	1/0	11.0	----
1984	1/1	23279	18500	----	60.0	----	0/1	14.2	----
1985	1/1	600	15565	----	48.0	----	0/1	12.0	----

(1) Number of projects started by major oil companies/total EOR projects started.
(2) Average reported area in acres.
(3) Average depth to top of producing formation in feet.
(4) Shallowest project - deepest project.
(5) Average API gravity.
(6) Range of API gravities.
(7) Number of projects reported in sandstone/number in limestone.
(8) Average reported porosity in %.
(9) Range of porosities in %.

Table 15.- Annual distribution of SPE technical EOR publications

Year	Total	Field	Lab	Thermal		Chemical		Gas		Other
				Field	Lab	Field	Lab	Field	Lab	
1988	91	37	54	8	10	10	17	19	23	4
1987	23	13	9	5	1	0	4	8	4	1
1986	74	26	46	3	7	7	22	16	17	2
1985	32	17	14	4	8	7	2	6	4	1
1984	87	34	52	5	11	17	23	12	18	1
1983	23	8	14	5	7	1	5	2	2	1
1982	84	37	45	9	16	13	22	14	7	2
1981	48	24	23	5	3	10	10	9	10	1
1980	38	11	24	5	7	3	11	3	6	3
Year-Pairs										
87-88	114	50	63	13	11	10	21	27	27	5
85-86	106	43	60	7	15	14	24	22	21	3
83-84	110	42	66	10	18	18	28	14	20	2
81-82	132	61	68	14	19	23	32	23	17	3

Table 16. Thermal recovery screening criteria and resulting production estimates[1]

	Steam Injection		In Situ Combustion	
	Implemented Technology	Advanced Technology	Implemented Technology	Advanced Technology
Depth, ft	≤3,000	≤5,000	≤11,500	-
Net Pay, ft	≥20	≥15	≥20	≥10
Porosity,[2]%	≥0.20	≥0.15	≥0.20	≥0.15
Oil saturation X porosity	≥0.10	≥0.08	≥0.08	≥0.08
Permeability, md	≥250	≥10	≥35	≥10
Oil gravity, °API	10 to 34	-	10 to 34	
Oil viscosity, cP	≤15,000	-	≤5,000	≤5,000
Transmissibitlity, md-ft/cP	≥5	-	≥	-
Current reservoir pressure, psia	≤1,5000	≤2,000	≤2,000	≤4,000
Ultimate production from on going projects, billion barrels	4.4	5.1	-	-
Ulitmate production from new projects, billion barrels	0.8	3.3	1.3	2.1

1 Adapted from the NPC report.[1]

2 Ignored if oil satuartion X porosity criteria are satisfied.

TABLE 17. - Review of the performance of steam-foam pilot projects

Field/ State	Project/ Operator	Surfactant (1)	Injection Mode (2)	Incremental Recovery, % of OIP (3)	Surfactant Consumption, lb/bbl oil (4)	Surfactant Cost, $/bbl (5)
Kern River, CA	Mecca Shell	ABS, AOS	Cont.	14	7.1	5.44
Kern River, CA	Bishop Shell	AOS	Cont.	8.5	9.8	11.58
Midway-Sunset, CA	Dome Tumbador Unocal	AOS	Cont.	5.4	5.8	4.5
Midway-Sunset, CA	15A Chevron	Chaser SD-1000	Semi-Cont.	5.8	1.0	1.35
Midway-Sunset, CA	26C. Chevron	Chaser SD-1000	Semi-Cont.	2.7	3.3	4.42
Guadalupe, CA	Santa Maria Unocal	ATS (Suntech-IV)	Cont.	6.8	8.7	11.75
Cat-Canyon, CA	- Conoco	Thermophoam-BWD	Slug	-	Surfactant ineffective	-
San Ardo, CA	Texaco	Thermophoam-BWD	Slug	-	Too small a slug and too short a pilot period	
Kern River, CA	McManus PLC-Stanford	ATS (Suntech-IV)	Slug	5.1	3.3	4.42
North Kernfield CA	B2-3 PLC-Corco	ATS (Suntech-IV)	Slug	3.6	2.0	1.8
Winkleman, WY	Pilot-1 Amoco	ATS (Suntech-IV)	Slug	5.2	2.04	4.8
Midway Sunset, CA	590-21N Santa Fe	Thermophoam-BWD	Slug	10*	0.7	0.57

(1) ABS - Alkyl Benzene Sulfonate; AOS - Alpha Olefin Sulfonate, C16-C18; SD-1000 - Chevron trade name; ATS - Alkyl Toluene Sulfonate, C15-18; Suntech-IV™ - Trade name of Sun Chemical Co. which is principally an ATS; Termophoam-BWD™ - Tradename of Far Best Product.

(2) Cont- Continuous injection of surfactant; Semi-Cont - Semi-continuous injection; Slug - Injected as slug.

(3) % of oil in place due to foam injection.

(4) Pounds of surfactant per barrel of recovered incremental oil.

(5) $ per barrel of incremental oil recovered.

TABLE 18. - Summary of electrothermic process field results

Field Location	Depth, feet	Oil Gravity, °API	(1) Pwr. Consump., kW	(2) Before Pdtn. Rate, BOPD	(3) After Pdtn. Rate, BOPD
Southwest Texas	3,300	11	150	0	76
Eastern Utah	2,970	22	60	4	50
South Central OK	7,920	11	56-100	0	80

(1) Electrical power consumption.
(2) Production prior to electrical heating.
(3) Production after electrical heating.

TABLE 19. - Summary of EOR project starts each year by process

	1980	1981	1982	1983	1984	1985	1986	1987	1988
Conventional steam	19	40	24	18	21	21	22	6	0
In Situ combustion	10	4	2	0	1	2	1	0	0
Unconventional steam	5	8	3	1	1	1	0	1	0
Surfactant (micellar -polymer)	20	3	3	1	1	3	0	0	0
Polymer	19	34	34	53	54	40	36	7	2
Alkaline	13	9	0	1	0	0	2	0	0
Carbon dioxide miscible	26	28	10	6	8	11	7	0	0
Hydrocarbon gas	2	6	2	8	2	3	1	1	0
Carbon dioxide immiscible	0	1	4	16	11	11	21	0	0
Nitrogen gas	3	5	1	1	1	1	0	0	0
Microbial	___	___	___	___	___	___	3	1	0
Total	117	138	81	104	100	91	93	16	2

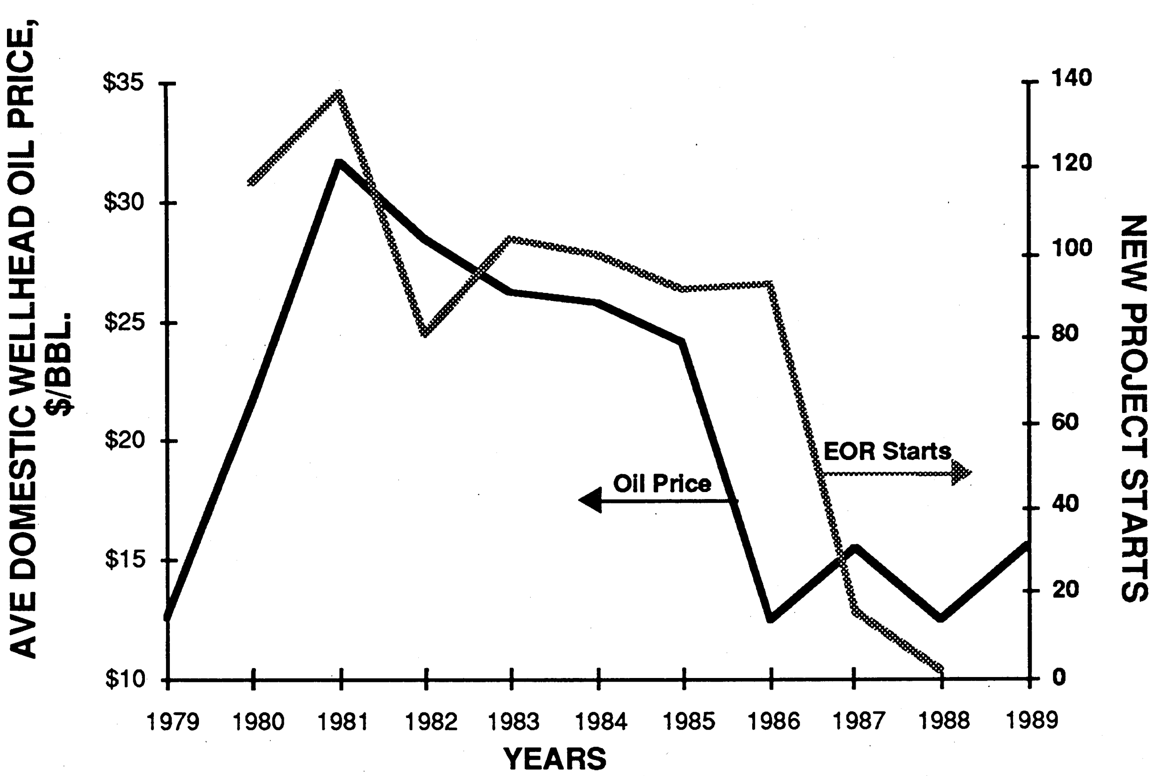

FIGURE 1. - Oil prices compared to EOR project starts.

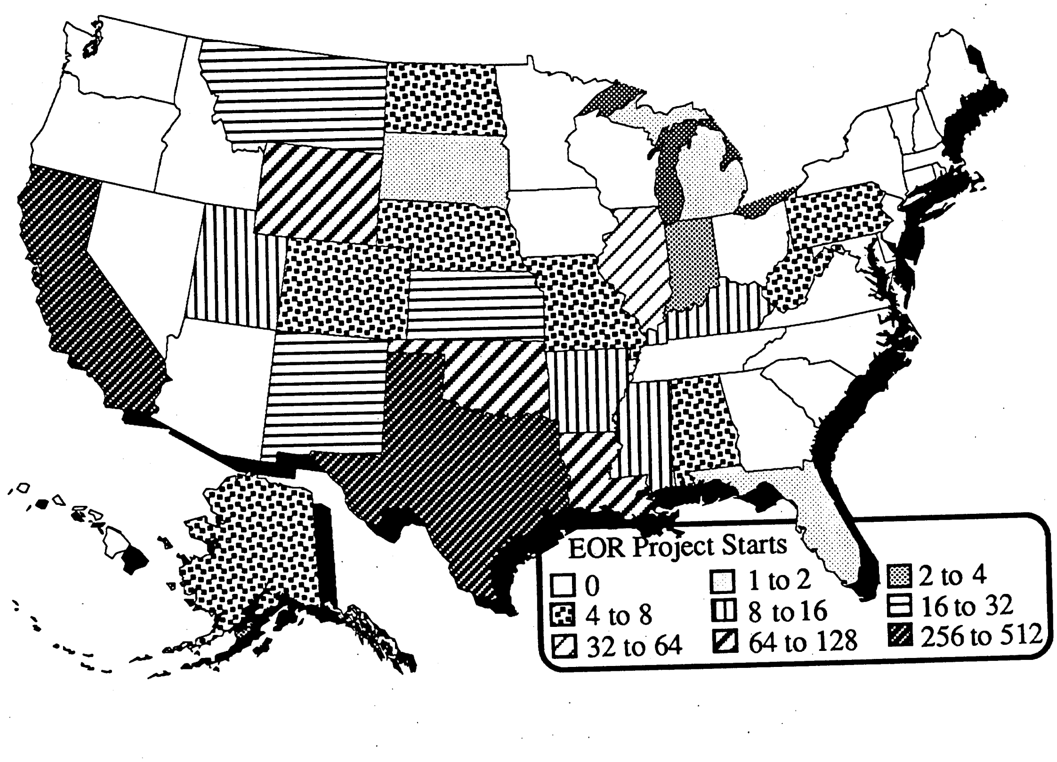

FIGURE 2. - Map showing the distribution of EOR projects by state.

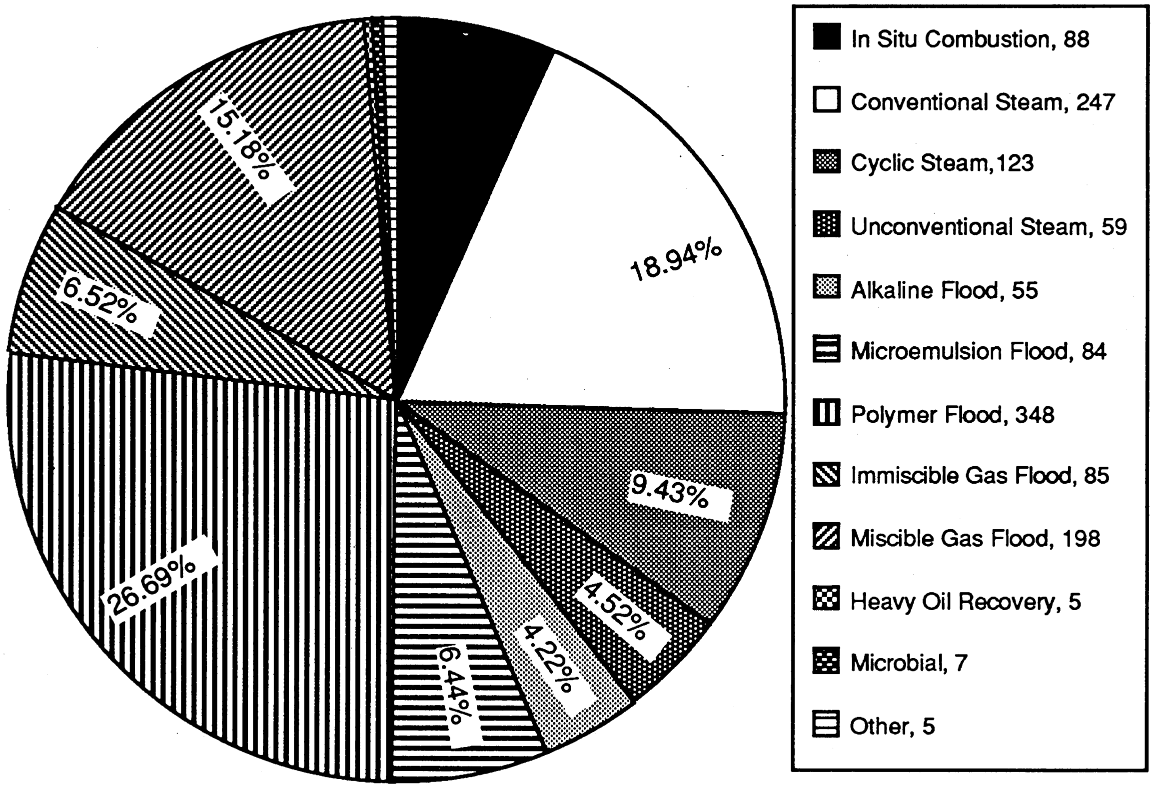

FIGURE 3. - Distribution of EOR projects in the DOE database by process.

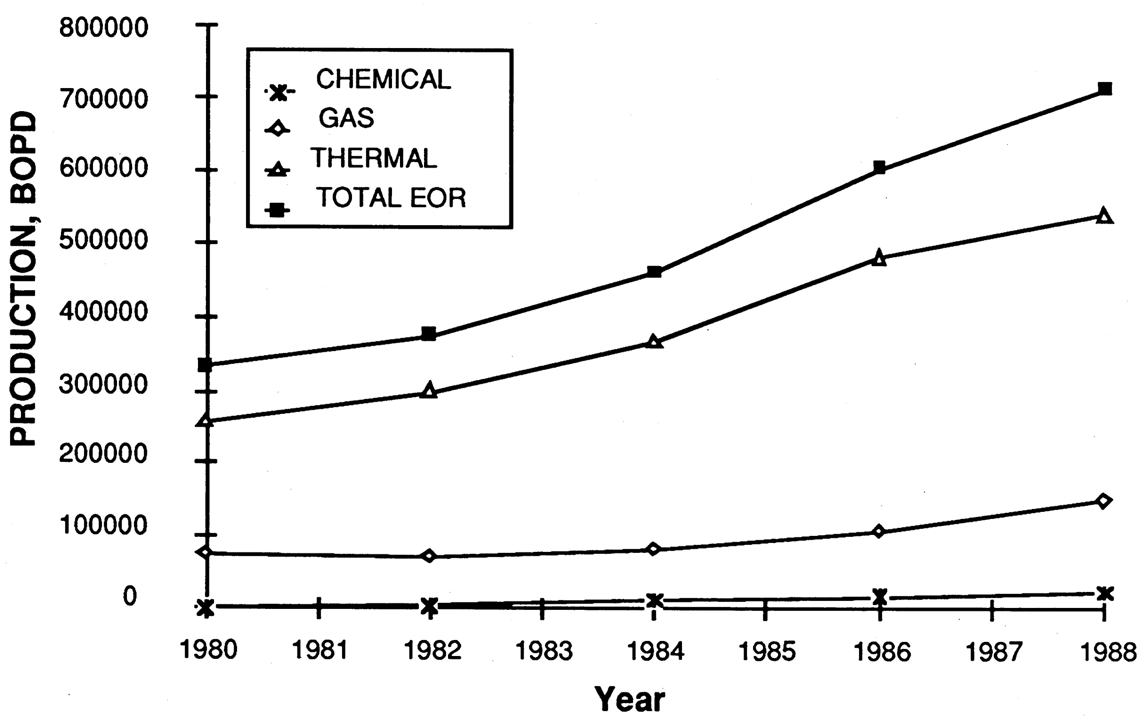

FIGURE 4. - Daily EOR oil production rate by category for the U.S.

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