III. Oil Recovery Potential

III. Oil Recovery Potential

The Resource Base

Original Oil In Place

The American Petroleum Institute reports that as of December 31, 1975, about 442 billion barrels of oil had been discovered in the United States, including the North Slope of Alaska.[1] Of that amount, 109 billion barrels had been produced and an additional 37.7 billion barrels remained to be produced at current economic conditions and with existing technology. This figure includes 32.7 billion barrels of proved reserves and 5.0 billion barrels of indicated reserves. The total, 37.7 billion barrels, also includes 1.0 billion barrels of proved EOR reserves and 1.7 billion barrels of indicated EOR reserves.[2] The remaining 295 billion barrels represents the resource base for enhanced oil recovery (EOR). (The resource base includes 11 billion barrels in the North Slope of Alaska but does not include tar sands and oil shale. Technologies to obtain petroleum from these sources are sufficiently different from EOR processes to deserve separate study.)

Petroleum Reservoirs

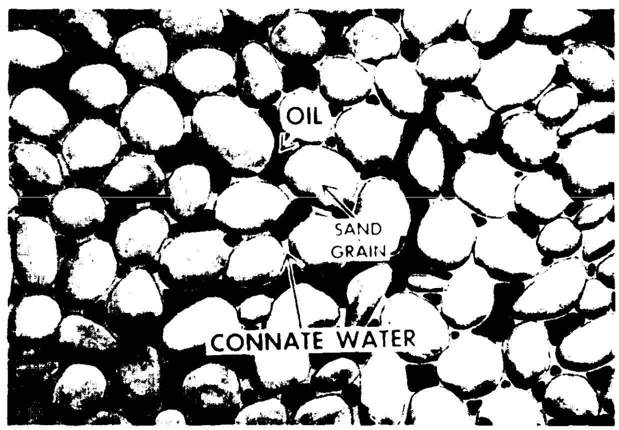
Oil is found in porous sedimentary rocks (sandstones and limestones) that were deposited under water and later overlain by formations that are impervious to these fluids. Localized accumulations of oil occur in traps (reservoirs) within these underground formations, or oil pools. An oil field is the surface region underlain by one or more of these separate oil reservoirs or pools.

Oil is found in such traps at depths of from less than 100 feet to more than 17,000 feet.[3] A reservoir may be small enough that a single well is sufficient to deplete it economically, or large enough to cover many square miles and require several thousand wells.

Oil is not found in underground lakes, but in open spaces between grains of rock; oil is held in these spaces much as water is held in a sponge, Almost invariably, water is mixed with oil in this open space between the grains; natural gas is found in the same kinds of formations. The distribution of fluids in one type of oil reservoir is displayed in figure 2.

Because oil is lighter than water, it tends to concentrate in the upper portions of a formation,

Figure 2. Close-up of Oil Between Grains of Rock



A thin film of water called connate water clings to the surface of the rock grains. This water occupies part of the space in the rock along with the oil.

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[1] *Reserves of Crude Oil, Natural Gas liquids, and Natural Gas in the United States and Canada as of December 31, 1975.* Joint publication by the American Gas Association, American Petroleum Institute, and Canadian Petroleum Association, Vol. 30, May 1976.

[2] *Enhanced Oil Recovery,* National Petroleum Council, December 1976

[3] "Production Depth Records Set in Three Areas, *World Oil,* p. 103, February 1975.

rising until it reaches an impervious barrier that forms a trap. Common traps include domes (figure 3), faults (figure 4), and salt domes (figure 5). An overlying cap rock can also seal off a formation in the manner shown in figure 6. Oil occasionally lies within sand bodies enclosed within a larger body of impervious shale (figure 7).

Regardless of rock type (sandstone, limestone) or trapping mechanism, there is little uniformity in the pattern in which different reservoirs contain and conduct fluids. This lack of uniformity influences both the amount of oil present in various regions of a reservoir and the degree to which injected fluids can sweep through a formation, collect oil, and force or carry it toward producing wells. It is this lack of a common pattern that introduces significant economic risk in every oil recovery project, including EOR.

Oil Recovery

Primary Recovery

The initial stage in producing oil from a reservoir is called primary production. During this stage oil is forced to the surface by such natural forces as: (a) expansion of oil, expansion of the contained gas, or both; (b) displacement by migration of naturally pressurized water from a communicating zone (i.e., a natural water drive); and (c) drainage downward from a high elevation in a reservoir to wells penetrating lower elevations.

The natural expulsive forces present in a given reservoir depend on rock and fluid properties, geologic structure and geometry of the reservoir, and to some degree on the rate of oil and gas production. Several of the forces may be present in a given reservoir. Recovery efficiencies in the primary stage vary from less than 10 percent to slightly more than 50 percent of the oil in place. Estimates of cumulative oil production, cumulative ultimate oil recovery, and cumulative original oil in place for 1959-75 are given in table 5.

Secondary Recovery

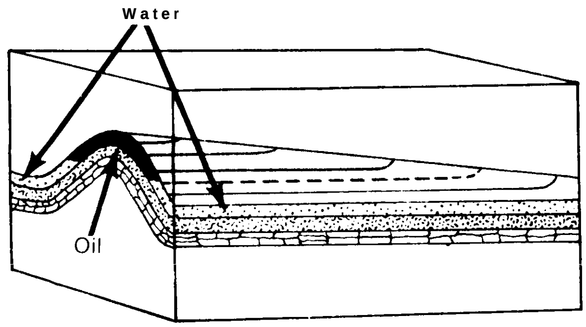
Most of a reservoir's oil remains in place after the natural energy pressurizing the reservoir has been dissipated. Several techniques for injecting fluids into an oil reservoir to augment the natural forces have been widely used for many years. Such fluid injection is generally known as secondary recovery. Fluids, most commonly natural gas and water, are injected through one series of wells to force oil toward another series of wells. The pattern of injection and production wells most appropriate to a reservoir are a matter of technical and economic judgment.

There is nothing inherent in fluid injection processes that requires their use only after the natural energy in a reservoir is exhausted. Indeed, it is frequently desirable to initiate such processes as soon as sufficient knowledge is available of the geology of the reservoir and the type of natural expulsive forces that are operative.

When water is the injection fluid, the process is commonly called waterflooding. If water is used to supplement a partially active natural water drive, the process is classified as a pressure maintenance project. When natural gas is injected, the operation is also called a pressure maintenance project. Injection of natural gas was widely used in the era of abundant low-cost gas, but the practice has decreased as the price of gas has increased.

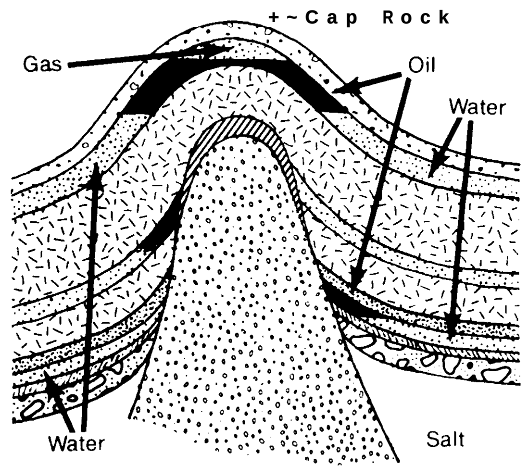
Types of Traps for Oil Accumulation*

Figure 3.



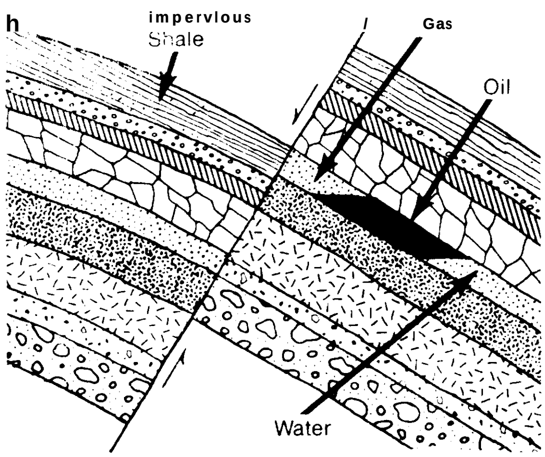
Oil accumulation in the top of a dome. Rock overlylng the dome is Impervious.

Figure 4.



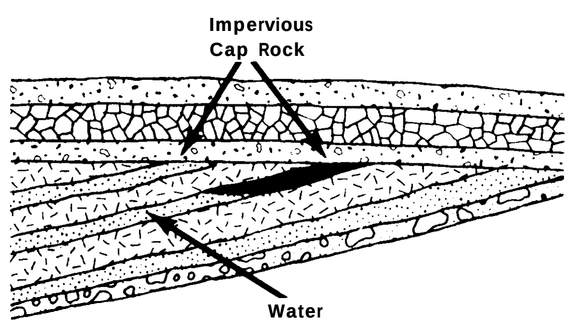
Oil accumulation in a dome at the top of a salt dome and also in a region on the side of the dome. Salt is Impervious to the oil.

Figure 5.



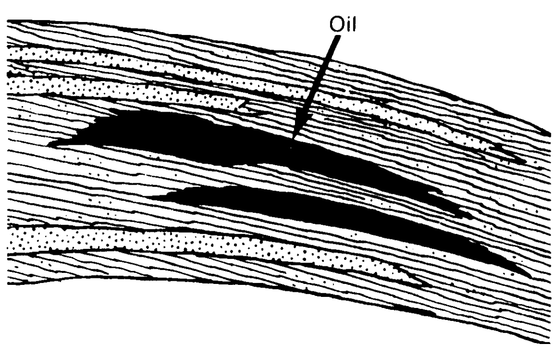
Oil accumulation caused by a fault. The block to the right has moved upward so the oil formation is opposite the impervious shale, forming a trap.

Figure 6.



Oil trapped by overlying impervious cap-rock that interrupts lower lying formation of sandstone or limestone.

Figure 7.



Oil trapped within larger body of impervious shale.

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Table 5
Historicai Record of Production, Proved Reserves, Uitimate Recovery, and Original Oil in Place, Cumulatively by Year, Total United States.
(Billions of Barrels of 42 U.S. Gallons)

Year	Cumulative production	1975 estimate of cumulative ultimate recovery**	1975 estimate of cumulative original oil in place**
1959	62.3	122.3	384.7
1960	64.7	123.3	387.8
1961	67.2	123.7	389.8
1962	69.8	124.7	392.5
1963	72.4	125.3	394.7
1964	75.1	126.2	397.8
1965	77.8	127,6	402.4
1966	80.6	128.0	404.4
1967	83.7	128.7	407.0
1968	86.8	139.2	432.5
1969 ...., ...	90.0	139.8	434.8
1970	93.3	140.4	437.1
1971	96.6	140.9	438.7
1972	99.9	141.1	439.6
1973	103.1	141.4	440.9
1974	106.1	141.6	441.4
1975	109.0	141.7	441.9

● "For all fields discovered prior to the indicated year in Column 1.
"*Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada as of December 31, 7975*, joint publication by the American Gas Association, American Petroleum Institute, and Canadian Petroleum Association, Vol. 30, May 1976

Secondary recovery is proven technology; indeed, a recent study indicates that 50 percent of all domestic crude oil comes from secondary recovery operations.[4]

Waterflooding is inherently more efficient than gas displacement in pressure-maintenance projects and is the preferred process where feasible. Cumulative recoveries by primary and secondary production, where the secondary production is waterflooding, average between 38 and 43 percent of the original oil in place.

Some reservoirs, principally those containing heavy oil that flows only with great difficulty, not only provide poor primary recovery but often are not susceptible to waterflooding. Enhanced oil recovery would be especially useful in some of these reservoirs.

Enhanced Recovery

Processes that inject fluids other than natural gas and water to augment a reservoir's ability to produce oil have been designated "improved," "tertiary," and "enhanced" oil recovery processes. The term used in this assessment is enhanced oil recovery (EOR).

According to American Petroleum Institute estimates of original oil in place and ultimate recovery, approximately two-thirds of the oil discovered will remain in an average reservoir after primary and secondary production. This inefficiency of oil recovery processes has long been known and the knowledge has stimulated laboratory and field testing of new processes for

[4]*Enhanced Oil Recovery,* National Petroleum Council, December 1976.

more than 50 years. Early experiments with unconventional fluids to improve oil recovery involved the use of steam (1920's)[5] and air for combustion to create heat (1935).[6]

Current EOR processes may be divided into four categories: (a) thermal, (b) miscible, *(c)* chemical, and (d) other. Most EOR processes represent essentially untried, high-risk technology. One thermal process has achieved moderately widespread commercialization. The mechanisms of miscible processes are reasonably well understood, but it is still difficult to predict whether they will work and be profitable in any given reservoir. The chemical processes are the most technically complex, but they also could produce the highest recovery efficiencies.

The potential applicability of all EOR processes is limited not only by technological constraints, but by economic, material, and institutional constraints as well.

Thermal Processes

Viscosity, a measure of a liquid's ability to flow, varies widely among crude oils. Some crudes flow like road tar, others as readily as water. High viscosity makes oil difficult to recover with primary or secondary production methods.

The viscosity of most oils dramatically decreases as temperature increases, and the purpose of all thermal oil-recovery processes is therefore to heat the oil to make it flow or make it easier to drive with injected fluids. An injected fluid may be steam or hot water (steam injection), or air (combustion processes).

Steam *Injection.* **—Steam injection is the most advanced and most widely used EOR process. it has been successfully** used in some reservoirs in California since the mid-1960's. There are two versions of the process: cyclic steam injection and steam drive. In the first, high-pressure steam or steam and hot water is injected into a well for a period of days or weeks. The injection is stopped and the reservoir is allowed to "soak." After a few days or weeks, the well is allowed to backflow to the surface. Pressure in the producing well is allowed to decrease and some of the water that condensed from steam during injection or that was injected as hot water then vaporizes and drives heated oil toward the producing well. When oil production has declined appreciably, the process is repeated. Because of its cyclic nature, this process is occasionally referred to as the "huff and puff" method.

The second method, steam drive or steam flooding, involves continuous injection of steam or steam and hot water in much the same way that water is injected in waterflooding. A reservoir or a portion thereof is developed with interlocking patterns of injection and production wells. During this process, a series of zones develop as the fluids move from injection well to producing well. Nearest the injection well is a steam zone, ahead of this is a zone of steam condensate (water), and in front of the condensed water is a band or region of oil being moved by the water. The steam and hot water zone together remove the oil and force it ahead of the water.

Cyclic steam injection is usually attempted in a reservoir before a full-scale steam drive is initiated, partially as a means of determining the technical feasibility of the process for a particular reservoir and partly to improve the efficiency of the subsequent steam drive. A steam drive, where applicable, will recover more oil than cyclic **steam injection and** is one of the five EOR methods used in this study of the national potential for EOR processes. Illustrations of the operation of cyclic steam injection and steam drive are given in figures 8 and 9, respectively.

Cornbustiorl Processes. -Combustion projects are technologically complex, and difficult to predict and control. Interest in the process has declined within the last 6 years relative to other EOR processes. Active field tests declined from 30 in 1970 to 21 in 1976. Eight of the projects

[5] *Secondary and Tertiary Oil* ***Recovery*** *Processes,* **Interstate Oil Compact Commission, Oklahoma City, Okla., p. 127, September 1974.**

[6] Ibid., **p. 94.**

Figure 8. Cyclic Steam Stimulation Process*

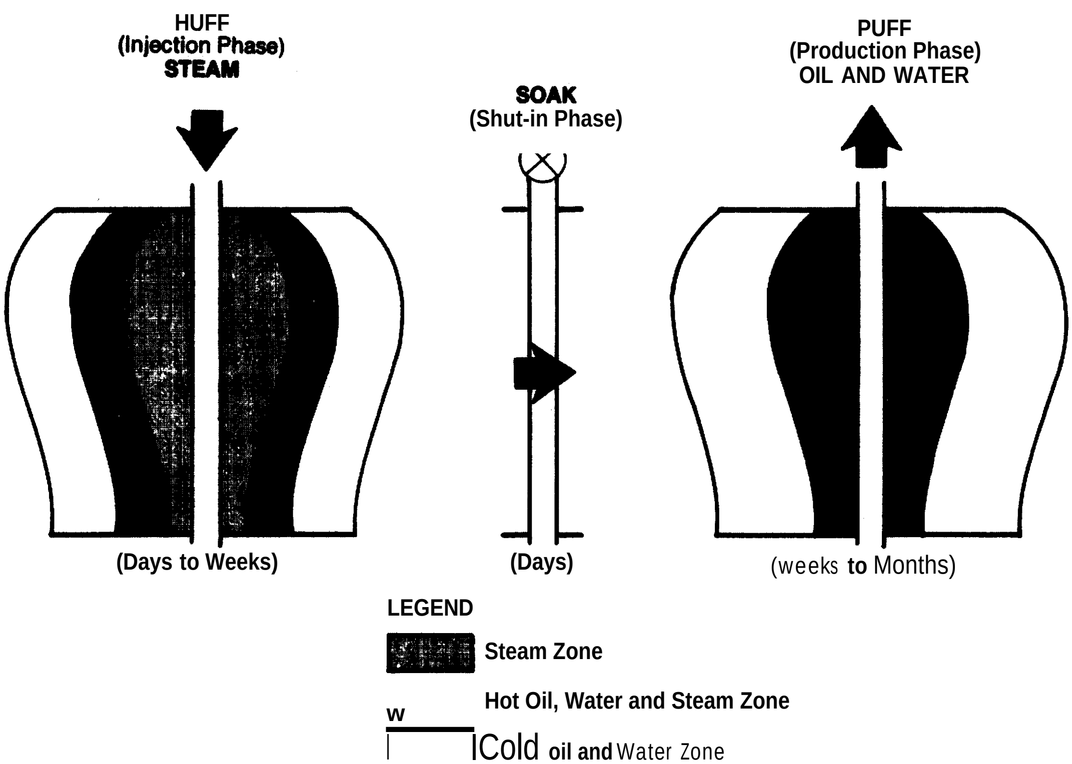
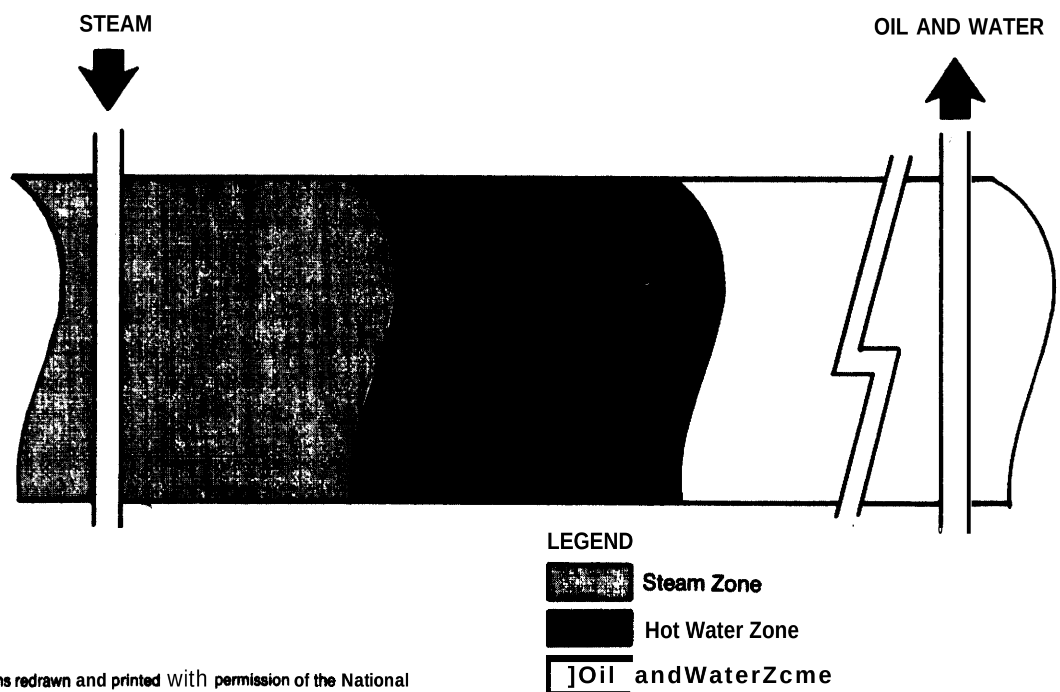


Figure 9. Steam Drive Process (Steam Flood)*



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have been termed successful, nine unsuccessful and four have not yet been evaluated.[7]

Injection of hot air will cause ignition of oil within a reservoir. Although some oil is lost by burning, the hot combustion product gases move ahead of the combustion zone to distill oil and push it toward producing wells. Air is injected through one pattern of wells and oil is produced from another interlocking pattern of wells in a manner similar to waterflooding. This process is referred to as fire flooding, in situ (in place) combustion, or forward combustion. Although originally conceived to apply to very viscous crude oils not susceptible to waterflooding, the method is theoretically applicable to a relatively wide range of crude oils.

An important modification of forward combustion is the wet combustion process. Much of the heat generated in forward combustion is left behind the burning front. This heat was used to raise the temperature of the rock to the temperature of the combustion. Some of this heat may be recovered by injection of alternate slugs of water and air. The water is vaporized when it touches the hot formation. The vapor moves through the combustion zone heating the oil ahead of it and assists the production of oil. With proper regulation of the proportion of water and air, the combustion can proceed at a higher thermal efficiency than under forward combustion without water injection.

Combustion processes compete, at least technologically, with steam and some other EOR processes, and the choice depends upon oil and reservoir characteristics. The wet combustion process is illustrated in figure 10. It is the combustion process selected for technical and economic modeling in this study.

Miscible Processes

Miscible processes are those in which an injected fluid dissolves in the oil it contacts, forming a single oil-like liquid that can flow through the reservoir more easily then the original crude. A variety of such processes have been developed using different fluids that can mix with oil, including alcohols, carbon dioxide, petroleum hydrocarbons such as propane or propane-butane mixtures, and petroleum gases rich in ethane, propane, butane, and pentane.

The fluid must be carefully selected for each reservoir and type of crude to ensure that the oil and injected fluid will mix. The cost of the injected fluid is quite high in all known processes, and therefore either the process must include a supplementary operation to recover expensive injected fluid, or the injected material must be used sparingly. In this process, a "slug," which varies from 5 to 50 percent of the reservoir volume, is pushed through the reservoir by gas, water (brine), or chemically treated brine to contact and displace the mixture of fluid and oil.

Miscible processes involve only moderately complex technology compared with other EOR processes. Although many miscible fluids have been field tested, much remains to be determined about the proper formulation of various chemical systems to effect complete volubility and to maintain this volubility in the reservoir as the solvent slug is pushed through it.

One large (50,000 acre) commercial project in Texas uses carbon dioxide ($C0_2$) as the miscible agent, Eight other $C0_2$ projects covering 9,400 acres are. in early stages of development.[8]

Because of the high value of hydrocarbons and chemicals derived from hydrocarbons, it is generally felt that such materials would not make desirable injection fluids under current or future economic conditions. For this reason, attention has turned to $C0_2$ as a solvent. Conditions for complete mixing of $C0_2$ with crude oil depend on reservoir temperature and pressure and on the chemical nature and density of the oil.

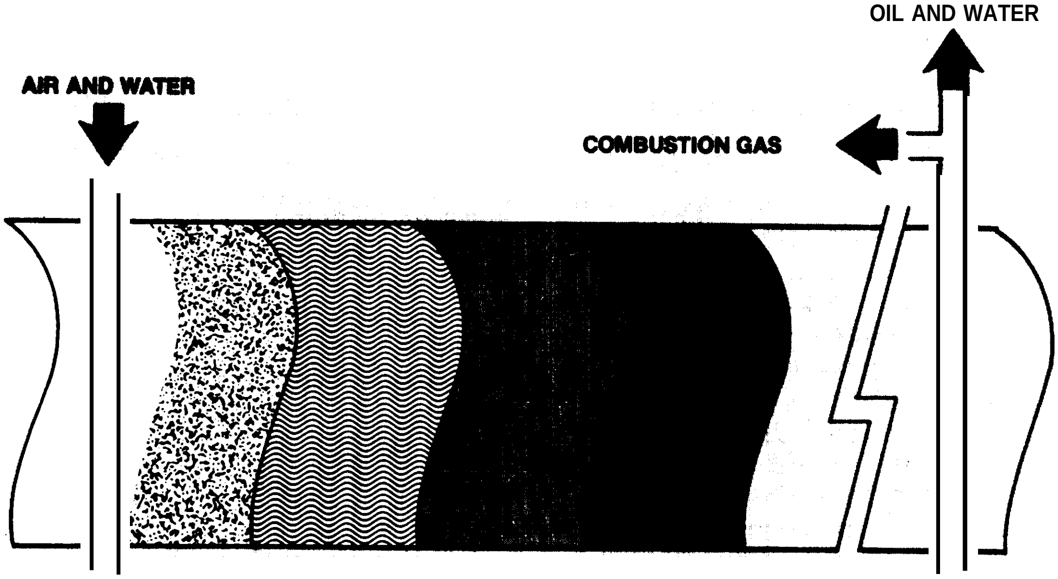
Although there are many possible CO_2 sources, the largest source should be naturally occurring deposits. Currently known sources of naturally occurring CO_2 are described in publications of the U.S. Bureau of Mines. A summary of CO_2 source locations is presented by the National petroleum Council,[9] although the actual

[7] *Management plan for Enhanced Oil Recovery,* ERDA 77-1 5/2, Vol. 2 (of 2), p. B-7, February 1977.

[8] *Management Plan for Enhanced Oil Recovery,* ERDA 77-1 5/2, Vol. 2 (of 2) p. B-4, February 1977.

[9] *Enhanced Oil Recovery,* National Petroleum Council, December 1976.

Figure 10. In-Situ Combustion Process-Wet Combustion*



LEGEND

- Injected Air and Water Zone
- Air and Vaporized Water Zone
- Combustion Zone
- Steam zone
- Hot Water Zone
- Oil and Water Zone

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amount of CO_2 at these locations is unknown. The potential demand for $C0_2$ is such that geological exploration is in progress.

A pictorial representation of a $C0_2$ miscible flood is shown in figure 11. In the past, CO_2 has sometimes, been injected into reservoirs in quantities and at pressures less than those necessary to achieve complete miscibility, resulting in less oil recovery than when complete mixing is achieved. In this assessment, quantities and pressures of CO_2 injected are designed to achieve complete miscibility.

Chemical Processes

Three EOR processes involve the use of chemicals—surfactant/polymer, polymer, and alkaline flooding.

Surfactant/Polyrner Flooding.—Surfactant/polymer flooding, also known as microemulsion flooding or micellar flooding, is the newest and most complex of the EOR processes, While it has a potential for superior oil recovery, few major field tests have been completed or evaluated. Several major tests are now under way to determine its technical and economic feasibility.

Surfactant/polymer flooding can be any one of several processes in which detergent-like materials are injected as a slug of fluid to modify the chemical interaction of oil with its surroundings. These processes emulsify or otherwise dissolve or partly dissolve the oil within the formation. Because of the cost of such agents, the volume of a slug can represent only a small percentage of the reservoir volume. To preserve the integrity of the slug as it moves through the reservoir, it is pushed by water to which a polymer has been added. The surfactant/polymer process is illustrated in figure 12.

The chemical composition of a slug and its size must be carefully selected for each reservoir/crude oil system. Not all parameters for this design process are well understood.

polymer Flooding. -Polymer flooding is a chemically augmented waterflood in which small concentrations of chemicals, such as polyacrylamides or polysaccharides, are added to injected water to increase the effectiveness of the water in displacing oil. The change in recov*ery* effectiveness is achieved by several different mechanisms, not all of which are completely understood. Improvement in the efficiency of waterflood recovery with the use of polymers is relatively modest, but it is large enough for the process to be in limited commercial use. If other EOR processes are technically possible they offer a possibility of both greater oil recovery and greater economic return than polymer flooding, although each reservoir must be evaluated individually to select the most effective process. As it is currently in use, polymer flooding is evaluated in this assessment.

Alkaline Flooding.—Water solutions of certain chemicals such as sodium hydroxide, sodium silicate, and sodium carbonate are strongly alkaline. These solutions will react with constituents present in some crude oils or present at the rock/crude oil interface to form detergent-like materials which reduce the ability of the formation to retain the oil. The few tests which have been reported are technically encouraging, but the technology is not nearly so well developed as those described previously. Alkaline flooding was not quantitatively evaluated in the present study, largely because there is too little information about key oil characteristics in the OTA reservoir data base which are crucial to a determination of the feasibility of alkaline flooding. Reservoirs not considered for alkaline flooding became candidates for other processes.

Other EOR Processes

Over the years, many processes for improving oil recovery have been developed, a large number of patents have been issued, and a significant number of processes have been field tested. In evaluating a conceptual process, it should be recognized that a single field test or patent represents but a small step toward commercial use on a scale large enough to influence the Nation's supply of crude oil. Some known processes have very limited application, For example, if thin coalbeds lay under an oil reservoir this coal could be ignited, the oil **above** it would be heated, its viscosity would be reduced, and it would be easier to recover. This relationship between oil and coal is rare, however, and the process is not important to total national energy production. Another example involves use of electrical

Figure 11. Carbon Dioxide Miscible Flooding Process*

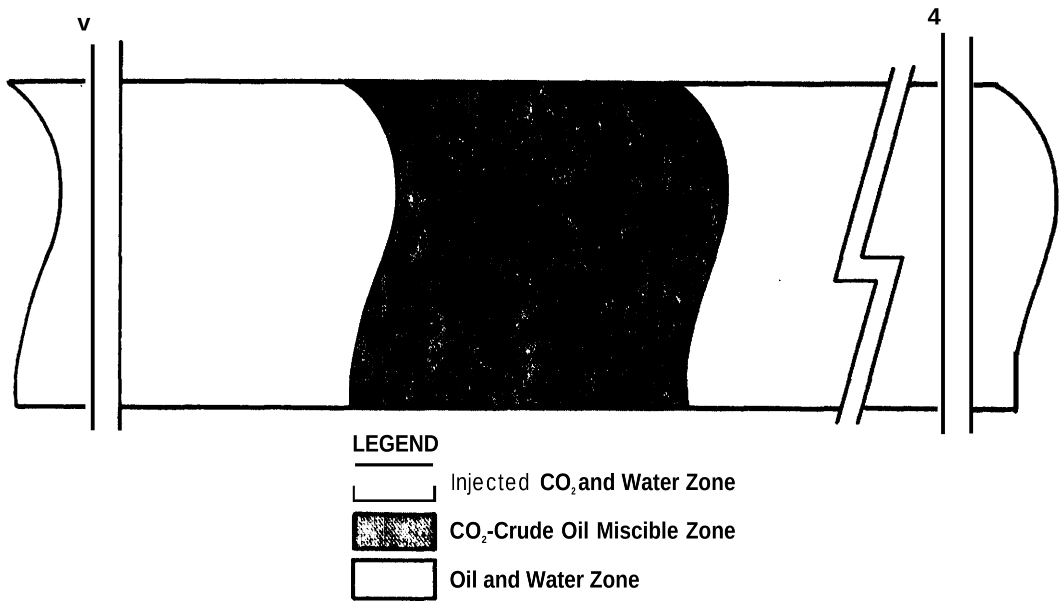
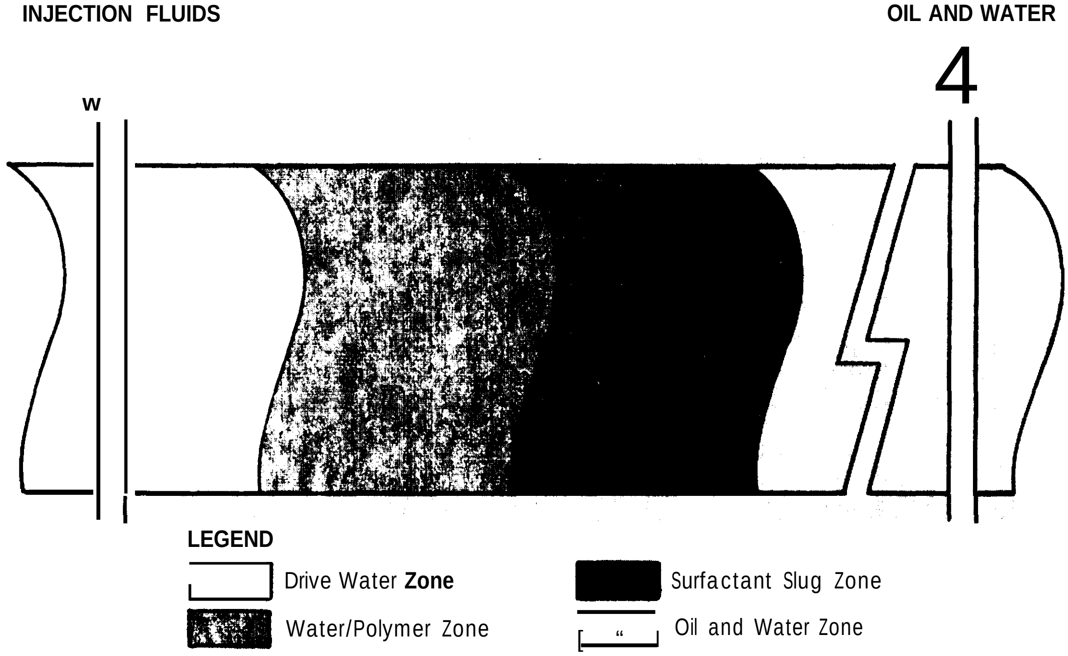


Figure 12. Surfactant Flooding Process



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energy to fracture an oil-bearing formation and form a carbon track or band between wells. This band would then be used as a high-resistance electrical pathway through which electric current would be applied, causing the "resistor" to heat the formation, reduce oil viscosity, and increase oil recovery. The process was conceived over 25 years ago and has been tested sporadically, but does not appear to have significant potential. A third process in this category is the use of bacteria for recovery of oil. Several variations have been conceived. These include use of bacteria within a reservoir to generate surface-active (detergent-like) materials that would perform much the same function as a surfactant/polymer flood. Although some bacteria are able to withstand temperatures and pressure found in oil reservoirs, none have been found that will both successfully generate useful modifying chemicals in sufficient amounts and also tolerate the chemical and thermal environments in most reservoirs. It is uncertain whether nutrients to keep them alive could be provided. Further, any strain of bacteria developed would need to be carefully screened for potential environmental impacts. Finally, even should the concept prove feasible, it is unlikely that the bacteria could be developed, tested, and used in commercial operation in time to influence oil recovery by the year 2000.

Oil Resource for Enhanced Oil Recovery Processes

Data Base

The analytic approach used in this assessment of EOR potential relies on reservoir-by-reservoir simulations. The accuracy of this approach depends on the extent, representativeness, and precision of the reservoir data file. Earlier reports[10 11] have been based on data from 245 large onshore reservoirs in California, Louisiana, and Texas. For this assessment, additional data were collected for onshore reservoirs in those States, for reservoirs in other producing areas of the United States, and for reservoirs in offshore areas (primarily the Gulf of Mexico). The expanded data base for this assessment was acquired from Federal, State, and private sources. After all available data were examined and cataloged, they were edited for volumetric consistency. These data were reviewed by OTA as other sources of information became available. Additional data led to reductions in estimates of remaining oil in place (ROIP) in California reservoirs which contained oil with gravities above 25° API.

The resulting data base for the assessment ineludes 385 fields from 19 States (table 6). These 385 fields (835 reservoirs) contain 52 percent of the known ROIP in the United States. The reservoir data in the OTA data base are representative of the known oil reservoirs in the United States.

Uncertainty in the Oil Resource

Two EOR processes, surfactant/polymer and CO_2 miscible, are generally applied after a reservoir has been waterflooded. A large portion of the resource for these processes will be located in the reservoir volume which was contacted by water. The oil remaining in this region is termed the residual oil saturation.

There is uncertainty in the estimates of residual oil saturation and hence in the oil which is potentially recoverable with surfactant/polymer and CO_2 miscible processes. A review of the technical literature and discussions with knowledgeable personnel in the oil industry led to the following observations:

a There are few reservoirs whose estimates of residual oil have been confirmed by independent measurement.

b The uncertainty in the aggregate estimate is due to a lack of confidence in measurement

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[10] *The Potential and Economics of Enhanced Oil Recovery*, Lewin and Associates, Inc., for the Federal Energy Administration, April 1976.

[11] *Enhanced Oil Recovery*, National Petroleum Council, December 1976.

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Table 6
Extent of the Reservoir Data Base Utilized in This Assessment of Enhanced Oil Recovery Potential

State	Remaining oil in place (MMB)	OTA database: Fields	Reservoirs	Remaining oil in place (MMB)	Percent of State
Alabama ... , ...	519	2	2	354	68
Alaska	14,827	6	9	14,601	98
Arkansas	2,768	3	3	1,328	48
California.	62,926	41	67	45,125	72
Colorado	3,002	21	21	1,490	50
Florida	556	3	3	465	84
Illinois	5,726	8	9	2,421	42
Kansas	10,403	28	28	3,345	32
Louisiana					
Onshore.	13,696	24	47	6,731	49
Offshore	7,349	24	372	2,983	41
Mississippi	2,988	11	12	1,187	40
Montana	3,796	15	15	1,443	38
New Mexico	11,241	15	18	4,960	44
North Dakota	1,849	6	7	548	30
Oklahoma	25,406	33	35	6,548	26
Pennsylvania.	5,344	5	6	1,077	20
Texas	100,591	111	146	54,221	54
Utah	2,725	6	6	1,734	64
West Virginia	2,064	2	2	194	9
Wyoming	10,628	21	27	4,543	43
Total States covered (MMB)	288,404	385	835	115,298	54

Total U.S. (MMB) 300,338a

OTA database is 52 percent of remaining oil in place in the United States.

“This value includes 3.3 billion barrels of oil which are included In API Indlcated reserves as recoverable by secondary methods. it does not include 1.0 billion barrels of enhanced 011 in the API proven reserves.

techniques compounded by a limited application of those methods.

c. The estimates of residual oil saturation may be off by as much as 15 to 25 percent (or more).

d. Estimates of the oil recoverable by surfactant/polymer and CO_2 miscible processes will have a large range of uncertainty because of the uncertainties in the estimates of residual oil saturation.

Methodology for Calculating Oil Recovery

Estimates of the amount of oil that can be recovered by the different EOR processes were based upon an individual analysis of each reservoir in the data file. Results from the individual reservoir calculations were then compiled and extrapolated to a national total. In outline form, the procedure consisted of the following steps.

Technical Screen

A technical screen was established for each process. Reservoir rock and crude oil properties were screened against standards which had to be met before an EOR process could be considered applicable to that reservoir. The technical screens for all processes are shown in table 7. These screening parameters were established after an assessment of current technology and incorporation of expected technological advances. Each reservoir was compared to the technical screen for every process and either accepted or rejected for each process. A reservoir could be a candidate for more than one EOR process.

Calculation of Reservoir Production and Economics

Reservoirs which passed the technical screen were then analyzed to determine probable production performance and economics. Those reservoirs eligible for more than one EOR process were analyzed for all processes for which they were technically acceptable. For each process, both an oil recovery model and an economic model were established, Oil recovery models, described in appendix B, were used to predict the amount of oil which would be recovered and the rate at which the oil would be produced. These recovery models all incorporate features which made the calculations dependent upon the particular characteristics of the reservoirs.

The economic model described in appendix B was used to compute, at a specified oil price, a rate of return on investment which would result from application of a selected EOR process to a particular reservoir. The economic model allowed for different operating and drilling costs in different geographic regions, different well spacings, variable EOR process costs, etc. The model also incorporated a field development scheme. This scheme allowed a specified number of years for pilot tests and economic and engineering evaluations. It also provided for development of a field on a set time schedule rather than for simultaneous implementation of an EOR process over the entire field.[12]

Final EOR Process Selection for Reservoirs Passing More Than One Technical Screen

For reservoirs passing more than one technical screen, production resulting from application of a recovery technique and economic models for each acceptable EOR process were compared. The process selected was the one which yielded the greatest ultimate oil recovery, as long as the process earned at least a 10-percent rate of return on investment at the world oil price of $13.7s per barrel. If no process earned 10 percent at the world oil price, then the alternate fuels price of $22 **per barrel was used, again selecting the process which yielded the greatest amount of oil. Reservoirs not yielding 10 percent** for any process at the alternate fuels price of $22 per barrel were placed in the process which appeared to have the best economic potential. Reservoirs were deleted from consideration if the computations at the alternate fuels price resulted in a negative return on investment.

Ultimate Recovery for the Nation

Ultimate recovery for the Nation was estimated by extrapolating the individual reservoir

[12] Our analysis assumed that enhanced recovery operations would be installed before producing wells are plugged and abandoned. If enhanced recovery operations are begun after producing wells are plugged and abandoned, oil recovery will be slightly more costly ($1 to $3 per barrel) and most likely delayed because of economics.

Table 7
Technical Screen
Enhanced Oil Recovery Processes

Property	Process: Carbon dioxide miscible	Steam drive	In situ combustion	Surfactant/polymer	Polymer
Oil gravity, °API	- - -	- - -	≤45	- - -	- - -
Oi viscosity, cp. .	≤12	- - -	- - -	1976: ≤10; 1980: ≤20; 1995: ≤30	≤ °°
Depth, ft.	<27°API, <7200; 27°–30°, ≥5500; >30°, ≥2500. Depth correlated to miscibility pressure (Temp. correction also applied - see appendix B)	> 5°° < 5°°°	> 500	- - -	- -
Temperature, °F	- - -	- - -	- - -	1976: ≤120; 1980: ≤170; 1985: ≤200; 1990: ≤225; 1995: ≤250	1976: ≤120; 1980: ≤170; 1985: ≤200; 1990: ≤225; 1995: ≤250
Permeability, mD	- - -	- - -	- - -	≥20	≥20
Transmissibility, mD-ft/cp .	- - -	≥100	≥20	- - -	- - -
Salinity of brine*	- - -	- - -	- - -	- - -	- - -
TDS, ppm.	- - -	- - -	- - -	<200,000	- - -
Rock type.	- - -	- - -	sandstone	sandstone	- - -

For all processes—Gas Cap Reservoir—Considered applicable for EOR processes if a waterflood had carried out or was in progress.
If an EOR test or process is in progress, then the reservoir is considered to qualify for that process.
*Insufficient information to screen on this variable.

performances. Because a significant amount of the oil in each oil-producing State was represented in the data base, extrapolations were made on a district or State basis. Total recovery for each State or district, for a selected oil price and rate of return, was calculated in the following manner: The oil recovered from reservoirs in the data base for that State or district was multiplied by the ratio of total oil remaining in the State or district to oil remaining in the State or district data-base reservoirs. (The one exception to this rule was for West Virginia, where the sample included only 9 percent of the total oil in the State. For West Virginia, only the oil in the data base was included in the composite results. Deletion of West Virginia from the extrapolation process has no significant effect on ultimate recovery estimates because oil remaining in those reservoirs constitutes less than 1 percent of the oil remaining in U.S. reservoirs.) "Oil remaining, " as used here, refers to oil remaining after ultimate primary and secondary recovery. State and district productions were summed to obtain national production.

Table 8
Schedule of Starting Dates
Based on Rate-of-Return Criterion

Date	Continuations of ongoing projects rate of return	New starts rate of return
1977	1 00/0	30 "/0
1978 ...., . . .	1 00/0	250/o
1979	10"/0	20 "/0
1980	"10"/0	19 "/0
1981	10%	18%
1982 , ...	10"/0	17'YO
1983	10%	160/0
1984	10%	15 "/0
1985	10%	14%
1986	10%	13"/0
1987 ...., . . .	1 0 %	12"/0
1988	10%	11 "/0
1989	10%	10"/0
1990-2000	10%	10"/0

Note: In the production models, after It has been decided to develop a reservoir, time is allowed to study the reservoir, conduct pilot tests and do engineering and economic analyses. These studies and evaluations are completed before initiating commercial production.

Rate of Production for the Nation

The starting date for the development of each reservoir was determined with the use of a rate-of-return criterion, Reservoirs earning the highest rates of return were assumed to be developed first. The schedule shown in table 8 was used to establish starting dates for reservoir evaluation, i.e., starting dates for pilot tests and economic and **engineering evaluations, which were then** followed by commercial development. Extrapolation of production rates from individual reservoirs to a State and then to the Nation was accomplished in the same manner as described for ultimate recovery.

This plan for reservoir development recognizes two factors which influence the application of improved oil recovery processes. First, it accounts in part for risk in that the highest rate-of-return projects will be initiated earliest when the technology is least certain. Lower rate-of-return projects would not be started until later dates, at which time the technological and economic risk should be reduced as a result of experience gained from field tests and commercial operations. Secondly, the timing plan in some measure simulates actual industry decisionmaking. As a general rule, the most promising projects are initiated first by industry.

While OTA believes the timing plan is reasonable, it still is only an approximation of what will actually occur. Other factors such as level of technological risk, alternative investment opportunities, availability of resources required for the processes, etc., will significantly influence the implementation rate of EOR.

Exclusion of Alaska

The EOR potential of Alaska was not examined, for several reasons. A large portion of that State's oil resource was included in the data base (table 6). However, OTA felt that the economic data base required for the EOR economic models was not sufficiently well established. Alaska is a relatively young producing area and most of its oil fields are in a hostile environment. Costs are known to be high and difficult to estimate for future EOR projects. Also, because Alaska is a young producing area and because costs are high, EOR projects probably will not be considered to any significant degree for several years.

Estimated Oil Recovery

Definition of Cases

It is not possible to predict with certainty how much oil can be recovered in the future with EOR processes. Therefore, two principal cases were established, covering a range in the technological performance of the different processes. The more optimistic of these was labeled the "advancing technology —high-process performance case. " The less optimistic was termed the "advancing technology —low-process performance case. " These cases were designed in an effort to calculate realistic estimates of future recovery and at the same time reflect the uncertainty which exists in OTA's projection.

In addition to these two principal cases, estimates were made of the effects of variations in key parameters, such as injected chemical (CO_2, surfactant) costs, minimum specified acceptable rate of return, and resource availability, on recovery. These estimates, in essence, involved extensions and modifications of the two principal cases.

A description of the principal cases follows.

Case I: Advancing Technology—High-Process Performance

It was assumed for this case that the EOR processes which are now in their developmental stage ($C0_2$ miscible, surfactant/polymer, polymer-augmented waterflooding, and in situ combustion) would work as now generally envisioned by the petroleum industry. The production models for these processes, which are described in appendix B, were based largely on reported laboratory results with limited data from field tests. The steam process is the only technique that can currently be classified as a commercial process and as a result its production model is based on more field experience than the others.

Because of the nature of surfactant/polymer and polymer-augmented waterflood processes and their early stage of development, OTA assumed that certain technological advances would occur between now and the year 2000.

In the case of surfactant/polymer flooding, it was assumed that research and field testing would lead to a reduction in the volume of oil used in the surfactant slug and the volume of polymer needed to displace the surfactant slug through the reservoir. Reductions by a factor of two were assumed for both oil and polymer volumes from values representative of current technology. Current surfactant formulations are tolerant of total dissolved salt content of about 20,000 parts per million (ppm). It was also assumed that developments in the formulation of surfactant and polymer systems would extend salinity tolerance to 200,000 ppm. Finally, it was assumed that technological advances would occur in surfactant/polymer and polymer-augmented waterflooding processes which would raise the temperature constraint to 250° F. The timing of the advances is shown in table 7.

A major technological assumption for the CO_2 miscible process was that between 4 and 6 thousand cubic feet (Mcf) of $C0_2$ would be injected per barrel of EOR oil recovered. Although current pilot tests with CO_2 indicate that this injection-volume ratio may be on the order of 10 Mcf per barrel of oil, it was assumed that a technological advance to the above-stated injection efficiency would be achieved.

The advancing technology-high-process performance case was considered to be unconstrained by chemical resource availability. This assumption is also of paramount importance. For example, the amount of CO_2 required at the world oil price recovery is 53 trillion cubic feet (Tcf) (not including recycled CO_2). This is a very large quantity of $C0_2$, which simply may not be available at CO_2 prices used in the calculation. Chemical availability was also assumed for surfactant/polymer and polymer-augmented waterflooding processes.

Technological advances were assumed in the field application of steam and in situ combustion processes. Well-completion technology, which permitted selective depletion of each major zone within a reservoir, was assumed. All major zones were developed sequentially. Methods for controlling volumetric sweep efficiency of both processes were assumed to develop so that the processes could be applied to 80 percent of the reservoir acreage.

It was assumed in this case that the EOR processes could be made to operate without damage to the environment and that this could be done at no additional cost. For the thermal processes, in particular, this is an important assumption. For example, air pollution limitations now existing in California would allow little or no new steam recovery in that State without technological advances to reduce pollutant levels from steam generation.

In California, a limited number of refineries capable of processing heavy oil, an entitlements program, and a prospect of competing crude supplies from Prudhoe Bay combine to reduce the State demand for heavy oil production. The OTA study assumes that a market exists for all heavy oil produced in California.

Enhanced oil recovery production was assumed to occur in any reservoir if the rate of return after taxes was greater than 10 percent. This further implies advances in technology to reduce risk of failure, because investments at interest rates of 10 percent will only be made for relatively low-risk projects. Risk has been taken into account, as explained in a previous section, in that the production timing plan was based on rate of return with the "best" projects being initiated first, However, in the calculations a large amount of oil is recovered at rate-of-return values just slightly above 10 percent,

The advancing technology-high-process performance case implies a significant commitment to a research and development program which would be carried out in concert with the commercial implementation. The technological advances will not be made, nor will risk be reduced to the level assumed, without such an effort.

Case II: Advancing Technology-Low-Process Performance

Case II is a conservative estimate of future recoveries which assumes that no EOR process will work as successfully as it does in the advancing technology-high-process performance case. Changes were made in the production models which led to reductions in recoveries averaging between 12 and 30 percent for the different EOR processes. The details of the low-process performance case for each process are given in appendix B.

Case II essentially assumed that less oil would be recovered by the EOR processes using as large a dollar investment as was assumed in the high-performance case. Resource constraints were not imposed, and the assumption was made that the processes would operate without environmental damage.

Calculation Results

Low- and High-Process Performance Cases

The results of the high-process performance and low-process performance cases are shown in tables 9 through 14, Table 15 presents ultimate recovery by State while table 16 shows extrapolation proportions for each process under high- and low-process performance assumptions. Table 9 gives the cumulative figures for all processes. Individual process recoveries are shown in the other tables. Results are shown for three oil prices: upper tier ($11.62 per barrel), world oil ($13.75 per barrel), and alternate fuels ($22.00 per barrel).

These two cases represent the range of recoveries considered feasible for EOR technology. For these cases, recoveries were not restricted by resource availability and technology to meet environmental protection standards. Markets were assumed for heavy oil in California. The difference between the cases thus results from differences in assumptions about the technological performance of the processes.

For the high-process performance case at the upper tier price, it is estimated that approximately 21.2 billion barrels of oil could be recovered. The recovery increases to about 29.4 billion barrels at the world oil price and 41.6 billion barrels at the selected alternate fuels price, Corresponding uitimate recoveries for the low-process performance case are 8.0 billion, 11.1 billion, and 25.3 billion barrels, respectively.

Table 9
Estimated Recoveries for
Advancing Technology-Low- and High-Process Performance Cases
Aii Processes

	Low-process performance case			High-process performance case		
	Upper tier price ($11.62/bbl)	World oil price ($13.75/bbl)	Alternate fuels price ($22.00/bbl)	Upper tier price ($11.62/bbl)	World oil price ($13.75/bbl)	Alternate fuels price ($22.00/bbl)
Ultimate recovery:						
(billion barrels)	8 0	11.1	2 5 3	21.2	29.4	41.6
Production rate in:						
(million barrels/day)						
1980. , ...	0.3	0.3	0.3	0.4	0.4	0.4
1985. ., ., ...	0.4	0.5	0.9	0.5	1.0	1.3
1990.	0.5	0.7	1.8	1.1	1.7	2.8
1995.	0,5	1.2	2.5	1.7	3.1	6.0
2000.	1,1	1.7	5.1	2.9	5.2	8.2
Cumulative production by:						
(million barrels)						
1980. ...., ...	400	400	400	500	500	500
1985.	1,200	1,300	1,700	1,700	2,000	2,400
1990, ., ...	2,000	2,300	4,200	3,300	4,700	6,200
1995.	2,800	3,800	7,500	5 , 6 0 0	8,700	12,800
2000. , ... , ...	4,200	6,900	‘1 6,000	10,400	17,300	29,200

Table 10
Estimated Recoveries for
Advancing Technology-Low- and High-Process Performance Cases
Steam Drive Process

	Low-process performance case			High-process performance case		
	Upper tier price $11.62/bbl)	World oil price [$13.75/bbl)	A1ternate fuels price ($22.00/bbl)	Upper tier price ($11.62/bbl)	World oil price ($13.75/bbl)	Alternate fuels price ($22.00/bbl)
Ultimate recovery:						
(billion barrels)	2.1	2.5	4.0	2.8	3..3	6.0
Production rate in:						
(million barrels/day)						
1980. . . . . ., ...	0.1	0 1	0.2	o.2	0.2	0.3
1985. ..., ...	0 2	0.2	0.3	0.2	0.2	0.4
1990, ..., . .	0,2	0.2	0.5	0.2	0.3	0.7
1995.	0.2	0.3	0.4	0.2	0.3	0.7
2000, , ..., ...	0.2	0.3	0.4	0,3	0.4	0.6
Cumulative production by:						
(million barrels)						
1980. . . . ., ...	200	200	200	300	300	400
1985. ., ..., ...,	500	500	700	800	800	1,100
1990. ...., ., ...	800	800	1,400	1,100	1,100	2,000
1995. , ...	1,200	1,300	2,300	1,400	1,700	3,300
2000. ..., ...	1,600	1,800	3,100	1,900	2,400	4,600

Table 11
Estimated Recoveries for
Advancing Technology-Low- and High-Process Performance Cases
In Situ Combustion

	Low-process performance case			High-process performance case		
	Upper tier price $11.62/bbl)	World oil price ($13.75/bbi)	Alternate fuels price ($22.00/bbl)	Upper tier price ($II.62/bbl)	world Oil price ($13,75/bbl)	Alternate fuels price ($22,00/bbll
Ultimate recovery: (billion barrels)	1.2	1.4	1.6	1.7	1.9	1.9
Production rate in: (million barrels/day)						
1980	0.1	0.1	0.1	0.1	0.1	0.1
1985	0.1	0.2	0.2	0.2	0.2	0.2
1990	0.2	0.3	0.3	0.3	0.3	0.4
1995 ..,	0.1	0.1	0,2	0.2	0.2	0.2
2000	0.1	0.1	0.1	0.1	0.1	0.1
Cumulative production by: (million barrels)						
1980	*	*	•	•	•	*
1985	300	300	300	300	400	400
1990	600	700	800	800	900	1,000
1995	900	1,100	1,200	1,200	1,400	1,500
2000	1,000	1,200	1,400	1,400	1,600	1,700

*Less than 005 million barrels of daily production, or less than 50 million barrels of cumulative production.

Table 12
Estimated Recoveries for
Advancing Technology-Low- and High-Process Performance Cases
Surfactant/Polymer

	Low-process performance case			High-process performance case		
	Upper tier price $11.62/bbl)	World oil price ($13.75/bbl)	A1ternate fuels price ($22.00/bbl)	Upper tier price $11.62/bbl)	World-oil price ($13.75‘bbl)	Alternate fuels price ($22.00/bbl)
Ultimate recovery: (billion barrels)	1 .0	2,3	7.1	7.2	10.0	12.2
Production rate in: (million barrels/day)						
1980	*	*	•	•	•	•
1985	*	*	0.1	•	0.2	0.2
1990	•	*	0.4	0.2	0.4	().7
1995,	*	0.1	0.2	0.2	0.8	1,3
2000	0.2	0.2	1.3	0.9	1.9	2.5
Cumulative production by: (million barrels)						
1980	*	*	*	•	•	*
1985	100	100	200	100	300	300
1990	100	100	600	400	900	1,000
1995	100	200	900	700	1,800	2,000
2000	300	500	2,700	1,800	4,400	6,200

● less than 0.05 million barrels of daily production, or less than 50 million b.irrc~ls of cumulative production

Table 13
Estimated Recoveries for Advancing Technology—Low- and High-Process Performance Cases
Carbon Dioxide Miscible

	Upper tier price ($11.62/bbl)	World oil price ($13.75/bbl)	Alternate fuels price ($22.00/bbl)	High-process performance case								
				Upper tier price ($11.62/bbl)			World oil price ($13.75/bbl)			Alternate fuels price ($22.00/bbl)		
				Onshore	Offshore	Tota	Onshore	Offshore	Tota	Onshore	Offshore	Total
Ultimate recovery (billion barrels) . . .	3.5	4.6	12.3	8.5	0.6	9.1	12.9	0.9	13.8	18.5	2.6	21.1
Production rate in: (million barrels/ day)**												
1980.	0.1	0.1	*	0.1	*	0.1	0.1	*	0.1	0.1	*	0.1
1985.	0.1	0.1	0.3	0.1	*	0.1	0.4	*	0.4	0.4	*	0.5
1990.	*	0.1	0.5	0.3	*	0.3	0.6	*	0.6	0.8	*	0.8
1995.	0.1	0.7	1.6	1.0	0.1	1.1	1.5	0.3	1.8	3.0	0.8	3.8
2000.	0.6	1.1	3.3	1.4	0.1	1.6	2.7	0.1	2.8	4.8	0.3	5.6
Cumulative production by: (million barrels)**												
1980.	100	100	100	100	*	100	100	*	[illegible]	100		
1985.	200	300	400	300	*	300	500	*	[illegible]	600		
1990.	300	500	1,200	700	100	800	1,400	200	1,[illegible]	1,700		1
1995.	400	1,000	2,800	1,700	300	1,900	3,000	500	3,[illegible]	4,400	1,	5
2000.	[illegible],100	3,100	8,500	4,400	500	4,900	7,600	900	8,[illegible]	13,700	2,	16

*Less than 0.05 million barrels of daily production, or less than 50 million barrels of cumulative production.

**Daily production figures rounded to 0.1 million barrels, cumulative production figures rounded to 100 million barrels; row totals may not add due to rounding.

Table 14
Estimated Recoveries for Advancing Technology-Low- and High-Process Performance Cases
Polymer-Augmented Waterflooding

	Low-process performance case			High-process performance case		
	Upper tier price ($11.62/bbl)	World oil price ($13.75/bbl)	Alternate fuels price ($22.00/bbl)	Upper tier price ($11.62/bbl)	World oil price ($13.75/bbl)	Alternate fuels price ($22.00/bbl)
Ultimate recovery: (billion barrels)	0.2	0.3	0.3	0.4	0.4	0,4
Production rate in: (million barrels/day)						
1980	*	•	•	*	*	•
1985	•	•	•	*	*	•
1990	0.1	0.1	0.1	0.1	0.1	0.1
1995	*	*	*	*	*	*
2000	•	*	•	*	•	•
Cumulative production by: (million barrels)						
1980		•	*	*	•	•
1985	100	100	100	100	100	100
1990	200	200	200	200	200	300
1995	200	300	300	300	400	400
2000	200	300	300	400	400	400

● Less than 0,05 million barrels of daily production, or less than SO million barrels of cumulative production.

Table 15
Ultimate Recovery by State
High-Process Performance

State	Ultimate recovery (billions of barrels)		
	Upper tier price ($11.62/bbl)	world oil price ($13.75/bbl)	Alternate fuels price ($2200/bbl)
California	6.8	7,8	11.4
Louisiana	1.1	1.2	2.0
Texas	4.7	7.9	11.6
New Mexico	1.2	1.7	1.7
Oklahoma	3.3	4.0	4.8
Kansas	1.6	2.3	2.7
Arkansas	0.3	0.4	0.4
Mississippi	0,2	0.3	0.4
Alabama	0,0	0.2	0.2
Florida	0.0	0.0	0.1
Colorado	0.0	0.4	0.4
Utah	0.0	0.0	0.2
Wyoming,	0.6	1.3	1.4
Montana	0.0	0.0	0.2
Illinois.	0.4	0.5	0.8
Pennsylvania	0.2	0,5	0.5
West Virginia	0.1	0.1	0.1
Offshore Gulf ot Mexico	0.6	0.9	2.6
Totals [a]	*21.2*	29.4	41.6

“Columns may not add due to roundlng

Table 16
Extrapolation of Ultimate Oil Recovery From Data Base Calculations to the Nation
World Oil Price ($13.75/bbl)

(Billions of Barrels)

Process	Low-process performance			High-process performance		
	Data base	Nation	Data base/ Nation percent	Data base	Nation	Data base/ Nation percent
Steam drive	1.40	2.5	56	1.83	3.3	55
In situ combustion	0.78	1.4	56	1.08	1.9	57
Carbon dioxide miscible	2.11	4.6	46	6.65	13.8	48
Surfactant/polymer	0.73	2.3	32	4.54	10.0	45
Polymer-augmented waterflood	0.15	0.3	50	0.19	0.4	48
Total	5.17	11.1	47	14.29	29.4	49

As indicated in table 9, all of this oil would not be recovered by the year 2000. For example, in the high-process performance case at the upper tier price, the production rate increases from slightly more than 0.5 MMBD in 1985 to nearly 3.0 MMBD in the year 2000. The daily production pattern shown results in a cumulative production by the year 2000 of 10.4 billion barrels, or sO percent of the projected ultimate recovery. At the other two oil prices, the production rate also increases through the year 2000. The cumulative productions by 2000 are 59 and 70 percent of ultimate recovery at the world oil and alternate fuels prices, respectively.

The five EOR processes examined yield markedly different amounts of oil as indicated in tables 10 through 14. This is illustrated by the high-process performance case. The CO_2 miscible process contributes about half of the ultimate recovery at the world oil and alternate fuels prices. The surfactant/polymer process is estimated to contribute about 30 percent of the total ultimate recovery and the thermal processes about 20 percent.

The only process found to be generally economical in the offshore reservoirs at the world oil price was CO_2 miscible. Other processes were found to be economical in only a very few reservoirs, Therefore, $C0_2$ miscible flooding was applied exclusively. The results are shown, along with the onshore recoveries, in table 13 for the high-process performance case. For low-process performance, offshore development was taken to be marginally economical and therefore unattractive.

Both the high- and low-process performance cases place great demands on resource requirements. For example, the amount of CO_2 that would be consumed in reaching the ultimate recovery at the world oil price is about 53 Tcf in the high-process performance case. This does not include about 18 Tcf of recycled $C0_2$. This is a very large amount of CO_2, and it is not known whether such a supply will be available at the costs assumed in the economic model.

Ultimate Oil Recovery by EOR Processes

Estimates of ultimate recovery were determined by extrapolating results from the 835 reservoirs in 19 States. Of the 835 reservoirs in the OTA data base, ***636*** were assigned to one of the five oil recovery processes. Nine reservoirs in Alaska were not evaluated for enhanced oil recovery processes due to insufficient cost data. Enhanced oil recovery processes were not technically feasible in the remaining ***190*** reservoirs.

The remaining oil in place (ROIP) in the 835 reservoirs is 155.3 billion barrels, which represents about 52 percent of the ROIP in the United States. About 14.6 billion barrels of this amount are in Alaskan reservoirs which were not considered for EOR processes. The ROIP in data base reservoirs which were evaluated for enhanced oil recovery processes was 140.7 billion barrels.

Net oil recovered from data base reservoirs by application of high-process performance models is 22.3 billion barrels at $30 per barrel. In estimating the net oil that can be recovered by enhanced oil processes, a reservoir was considered economic if it could be developed and yield a 10-percent rate of return at prices of $30 per barrel or less. This is about 95.5 percent of the oil considered technically recoverable using these models. Oil not recoverable under the high-process performance models is 133 billion barrels. Distribution of the potential recoverable and unrecoverable oil by process is shown in table 17.

Table 18 extends these results to the United States using the extrapolation procedure described in the section on *Ultimate Recovery for the Nation* on page 35.

The 49.2 billion barrels indicated as net oil recoverable by enhanced oil processes is an estimate of the upper limit of potential recovery at oil prices of $30 per barrel" or less. This is 95.6 percent of the oil considered to be recoverable. The estimate assumes successful application of EOR processes to all applicable reservoirs in the United States. If the EOR processes perform as assumed in the low-process performance case, the net potential EOR oil would be considerably less.

Unrecoverable oil in table 18 is estimated to be 248.8 billion barrels or 56.3 percent of the initial oil in place. About 76 billion barrels of oil will be left in reservoirs where no enhanced oil recovery process was considered applicable in the OTA study. Some portion of the 14.8 billion barrels which will remain in Alaskan reservoirs not evaluated in the OTA study may be recoverable at $30 per barrel. The approximately 170.4 billion barrels which remain in reservoirs after EOR processes are applied represent their inherent inefficiencies.

Table 17
Summary of Oil Recovery Evaluations
Data Base Resevoirs

Process	Reservoirs assigned[a] to process	Remaining oil in place (millions of barrels)	Net oil[b] recoverable (millions of barrels) at $30/barrel	Oil considered not recoverable (millions of barrels)
Steam drive	20	21,107	4,053	17,054
In situ combustion	20	7,585	1,126	6,459
CO_2 miscible				
Onshore	190	53,254	9,704	43,550
Offshore	294	2,695	1,298	1,397
Surfactant/Polymer	92	24,386	5,898	18,488
polymer augmented waterflood	20	3,949	189	3,760
No EOR	199	42,322	0	42,322
Total	835	155,298	22,268	133,030

[a]Process selected yielded maximum oil recovery at 10-percent rate of return or better at world oil price

[b]Oil used as fuel or injected as part of the displacement process was deducted from gross Production to find net production.

[c]Includes nine reservoirs in Alaska containing 14.6 billion barrels of remaining oil which were not evaluated due to insufficient cost data.

Discussion of Results

Table 18
Projected Distribution of Known Oil in the United States

	Billions of barrels	Percentage of original oil in place
Produced (December 31, 1975) . .	109.0	24.7
Proven reserve (including North Slope Alaska[a])	32.7	7.4
Indicated reserve[b]	5.0	1.1
Net oil recoverable by Enhanced oil processes in high-process performance case at $30/barrel. Not included in API proven or indicated reserves.	46.5	10.5
Unrecoverable oil		
Recoverable at price greater than $30/barrel	2.3	0.5
Oil left in reservoirs after enhanced oil recovery processes were applied and oil consumed as part of the recovery process	170.4	38.6
Oil in reservoirs where no enhanced oil recovery process was applicable at prices of $30/barrel[d]	76.1	17.2
	442.0	100.0

[a]API Proven Reserve (December 31, 1975) includes 1.0 billion barrels from enhanced oil recovery processes.
[b]API Indicated Reserve (December 31, 1975) includes 1.7 billion barrels from enhanced oil recovery processes.
[c]Net oil recoverable in the high-process performance case is 49.2 billion barrels. The 2.7 billion barrels included in API Proven and Indicated Reserves as of December 31, 1975 were deducted from computed net EOR oil.
[d]Reservoirs in Alaska which will contain 14.8 billion barrels of oil after deduction of Proven and Indicated Reserves were not evaluated in this study due to insufficient cost data.

Projections of this study are based on application of EOR processes to reservoirs in the lower 48 States.

Projected Results for the United States

Ultimate Recovery

Results of the advancing technology cases, summarized in table 19, are estimates of the lower and upper bounds of the volumes of oil which are potentially recoverable at upper tier, world oil and alternate fuels prices. These volumes, ranging from 8 billion to 42 billion barrels, are significant when compared to the American Petroleum Institute (API) proven oil reserves (December 31, 1975) of 32.7 billion barrels which remained to be produced from existing fields.[13]

Table 19
Uncertainty in Projections of Ultimate Recovery for Advancing Technology Cases

Oil price $/barrel	Ultimate recovery (billions of barrels) Low-process performance	High-process performance
Upper tier ($11.62/bbl)	8.0	21.2
World oil ($13.75/bbl)	11.1	29.4
Alternate fuels ($22.00/bbl) .	25.3	41.6

The wide range in estimates is caused primarily by uncertainties in projecting oil recovery from application of the surfactant/polymer and CO_2 miscible flooding processes. Both processes are in early stages of development.

Production Rate

Daily production rates for the advancing technology cases at world oil prices are superimposed on the projected U.S. decline curve in figure 13. peak production rates are projected to be the same order of magnitude as the projected production rate from API proven, indicated, and inferred reserves in existing fields. Production rates in the mid-1980's are projected to vary between 8 and 17 percent of the projected produc-

[13]An additional 5 billion barrels are recognized by the API as Indicated Additional Reserves. About 3.3 billion barrels are projected from secondary recovery. The remainder (1.7 billion barrels) are attributed to enhanced oil recovery processes. A total of 31.7 billion barrels of the proven oil reserve will be produced by primary and secondary methods. One billion barrels will be produced by EOR techniques at current economics.

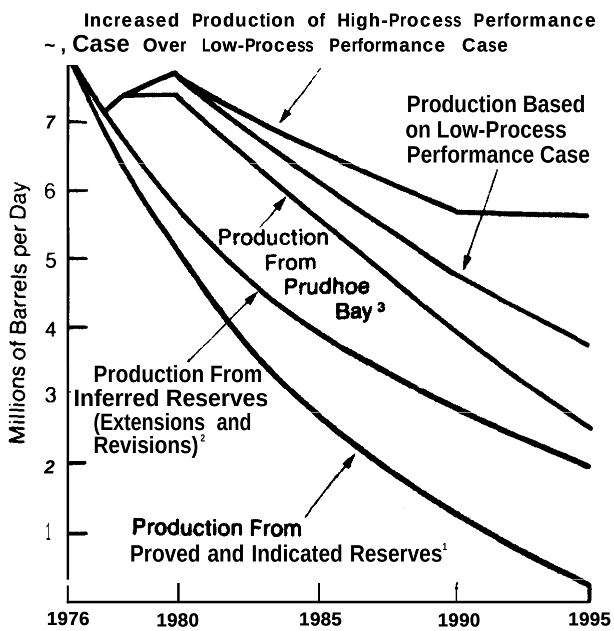
tion from existing fields by conventional methods.

Oil produced by improved oil recovery processes could become an important part of the Nation's oil supply for the period beginning in 1985 and extending beyond the year 2000. However, application of EOR technology would not offset the decline from existing fields until after 1990.

Uncertainties in Projections

The range of projections for ultimate recovery in table 19 and production rates in figure 13 represents OTA's judgment of the range of uncertainty which exists in the projections, Although uncertainties are present in projections of both ultimate recovery and production rate, the estimates of ultimate recovery are considered to be more certain than those for daily production rates.

Figure 13. Projected Production From Known U.S. Reservoirs, 1976-95, by Conventional Methods and by Enhanced Oil Recovery at World Oil Price



SOURCES [1]American Petroleum Institute, Reserves *of Crude Oil, Natural Gas Liquids, and Natural Gas in the U. S. and Canada as of December 30, 1975* Lewin & Associates, Inc for Federal Energy Administration, *Decline Curve Analysis, 1976*

[2] U S Geological Survey, *Circular 725,* 1975

[3] Federal Energy Administration, *National Energy Outlook,* 1976

Uncertainty in Ultimate Recovery

Projections of ultimate recovery at a specified oil price are uncertain because:

1) Estimates of ROIP volume and distribution within a reservoir may be as much as 25 percent (or more) in error. Further discussion of this problem is included in the section on the *Effect of Uncertainty in the Residual Oil Saturation and Volumetric Sweep on Projected Results* on page 50.

2) The ability to predict the oil recovery and the quantities of injected materials needed to obtain this recovery is different for each process and has wide ranges of uncertainty.

3) Materials used in the surfactant/polymer process are either derived from crude oil or compete with products derived from crude oil. Therefore, the costs of these components were increased for the purposes of this assessment as the price of crude oil increased. The cost of carbon dioxide was not varied with oil price. Because none of these materials is produced commercially in the volumes projected for this study, the cost estimates have some uncertainty. Sensitivity calculations described in appendix B show that both processes are extremely sensitive to costs of injected materials. A 50-percent increase in the estimated cost of chemicals would reduce the oil recovery from the surfactant/polymer process at $13.75 **per barrel** (high-process performance) from 10 billion barrels to 0.2 billion barrels. About 9 billion barrels of this oil would be recoverable at the alternate fuels price.

The demand for natural CO_2 may be high enough for owners of these deposits to negotiate prices considerably above the production costs assumed in this study. For example, a 50-percent increase in the price of CO_2 would reduce the potential production from the CO_2 process from 13.8

billion barrels at $13.75 per barrel (high-process performance) to 7.0 billion barrels.

4) It is not known whether large volumes of injection fluids, particularly CO_2, will be available.[14] A comprehensive report of CO_2 availability in the United States has not been published, although ERDA is currently conducting such a study.

5) The level of uncertainty is influenced by the stage of technological development of each process. Steam displacement technology has been proven in portions of several California reservoirs. In situ combustion and polymer flooding have been tested extensively with mixed results. Surfactant/polymer flooding and CO_2 miscible displacement are still being investigated in laboratory and field tests.

Projected ultimate recoveries for steam displacement and in situ combustion are based on selective development of each major zone in a reservoir and application of the processes to 80 percent of each reservoir area. Selective completion has been used successfully in portions of a few reservoirs in California. There is no reservoir in the OTA data base where steam displacement or in situ combustion has been applied to 80 percent of the total reservoir acreage.

The CO_2 miscible process model is based on laboratory data and a number of field tests. Recent indications from the field tests are that the ratio of CO_2 injected to oil recovered may range above 10 Mcf of CO_2 per barrel of oil.[15] The assumption used in the present study for the high-process performance case was that this ratio would generally be reduced to 4 to 6 Mcf of CO_2 per barrel of oil, with 25 percent of the injection material being recycled CO_2. The average value for the high-process performance case was 5. I Mcf. For the low-process performance case, the average ratio was 5.4 Mcf per barrel of oil.

The effect of using a lower CO_2 injection ratio is to reduce chemical costs and thereby improve the economics. As an example, if the cost of injected CO_2 were increased by **a factor of 1.5 for the high-process performance case, the ultimate recovery by CO_2 miscible at world oil prices would be reduced from 13.8 billion barrels to 7.0 billion barrels. Additional discussion is presented** in appendix B.

Significant technological advances were assumed in application of the surfactant/polymer process. Specific assumptions are compared in table 20. The effect of the assumed technological advances on ultimate recovery for the surfactant/polymer process (shown in table 21) results in an increase in ultimate recovery from 2.9 billion barrels under current technology to 10.0 billion barrels at high-process performance at world oil prices.

Table 20
Comparison of Technological Assumptions for the Surfactant/Polymer Process

	Current Technology	Advancing technology
Reservoir temperature	≤200°F	<250°F
Oil viscosity, cp.	≤20	<30
Salinity, ppm.	≤20,000"	≤200,000*
Oil content in surfactant slug, vol. percent. ... , ...	20	10
Size of surfactant slug, fraction of volume swept by preceding waterflood	10	10
Size of polymer bank, fraction of (region) volume swept by preceding waterflood. .	1.0	0.50

*Constraint which could not be applied due to absence of salinlty data,

Table 21
Comparison of Ultimate Recovery Under Two Technological Scenarios, Both Assuming High-Process Performance Surfactant/Polymer Process

Oil price $/barrel	Ultimate recovery (billions of barrels) Current technology	Advancing technology
Upper tier ($11.62/bbl)	0.2	7.2
World oil ($13.75/bbl)	2.9	10.0
Alternate fuels ($22.00/bbl) .	8.8	12.2

[14] EOR Workshop on Carbon Dioxide, Sponsored by ERDA Houston, Tex., April 1977.
[15] Ibid.

Uncertainty in Projected Production Rates

Production rate projections are influenced by the following factors:

1) A vigorous successful research and development and commercial exploitation program was assumed in the advancing technology cases. Time was allotted in the economic model for technical and economic pilot testing, which is necessary for fieldwide development. Each stage of testing was considered successful within a specified time frame. Development of the field was planned on a time schedule corresponding to normal oilfield development.

   partial success in initial field tests, low discovery rates for natural CO_2, and a slower rate of technological advance in the surfactant/polymer process are examples of factors which could delay or reduce the production rates projected in this study.

2) Production rates presented in tables 9 through 14 come from reservoirs which have a minimum discounted cash flow rate of return of 10 percent. Full-scale application of a process in a reservoir was done in a manner which approximates the pattern of industry investment decisions. In general, high-risk projects are undertaken early in a stage of technical development when the rate of return is high. Projects with 10-percent rate of return are undertaken when the risk of technical and economic failure is relatively low.

   The timing plan used to construct production rates for the Nation is dependent upon the projected rate of return for each reservoir. The economic model assumes that the reduction of technical and economic risk will occur at a rate (table 8) which initiates development of low rate-of-return (1 O percent) reservoirs in 1989. A result of this approximation is that a large volume of oil is produced after the year 2000 at the world oil price. Earlier or later reduction of risk could alter the annual production rates appreciably.

   The price of oil affects production rates in two ways. Higher oil prices encourage initiation of projects at earlier dates. Consequently, production from a reservoir which comes onstream in 1989 can be obtained at an earlier date and at a higher price if the technology is developed. A second effect of oil price is to add reservoirs at a higher price which cannot be developed economically at lower prices.

3) The rate-of-return criterion is a measure of risk in an advancing technology where the risks of technological and economic failures are high. In these instances, a high rate of return is required in order for the successful projects to carry those high-risk projects which fail.

Failures of a recovery process are not explicitly accounted for in this study. Thus, the projections of ultimate recovery and production rates assume a successful application of the process to every reservoir which meets the technical screen and the minimum after-tax rate of return. Thus, the projections have a built-in, but unknown, measure of optimism.

This optimism is offset to some extent by the fact that (1) the cost of failure in technical or economic pilot testing is comparatively small, and (2) no attempt was made to optimize process performance. Failure of a process in a reservoir at this stage would reduce the ultimate recovery and the predicted production rate. Overall economics for the process would not be significantly affected, provided other projects were economically successful.

If risk is reduced at a rate slower than that projected in table 8, only those projects and processes which have high rates of return will be pursued. For example, the majority of the surfactant/polymer flooding candidates have rates of return after taxes of between 10 and 15 **percent** at the world oil price for the high-process performance case, The technology is not proven and a 20-percent rate of return could be required by investors to offset the possibility of process failure in a given reservoir. If a 20-percent rate of return is required, few surfactant/polymer projects would be initiated.

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By contrast, steam displacement is a relatively proven process. Continued development and use of steam would be expected at rates of return of between 10 and 20 percent. The impact of high technical and economic risk on the ultimate recovery and production rates for all processes is illustrated by the comparison in table 22 for world oil prices. Reductions of 61 percent in ultimate production and 60 percent in average production rate for the time period from 1980 to 2000 are projected under high-risk conditions.

4) The production rate for the Nation is affected by environmental regulations and market conditions in California. Current environmental regulations limit the total emissions from steam generators and air compressors to pollution levels which existed in 1976. Under existing laws, the maximum incremental production rate from thermal methods in California will be 110,000 barrels per day. The impact of this constraint on the production rate is shown in table 23 for the advancing technology cases at world oil prices, Production rates for the Nation are reduced up to 29 percent for the period from 1980 to 1995 when constraints are applied. Ultimate recovery is not affected as the remaining oil will be produced after the year 2000.

A second factor limiting the development of thermal methods in California is the availability of refinery capacity to handle heavy oil. Heavy oil requires more processing to produce marketable products than do lighter oils such as Saudi Arabian light or Prudhoe Bay feedstocks. Ample supplies of these feedstocks on the west coast could suppress the development of heavy oil production even if environmental constraints were removed.

Effect of Uncertainty in Residual Oil Saturation and Volumetric Sweep on Projected Results

Residual Oil Saturation

The residual oil saturation in a reservoir following primary and secondary production sets an upper limit to the total amount of oil that could be produced using any EOR technique, no matter how good its performance may be. Thus, uncertainty about the residual oil saturation will lead to comparable uncertainty in the projected production from an EOR project, independent of uncertainty about process performance.

Table 22
High-Process Performance at World Oil Price ($13.75/bbl)

	Standard (1 O-percent rate of return)	High risk (20-percent rate of return)
Ultimate recovery (billion barrels)	29.4	9.5
Production rate in: (million barrels/day)		
1980	0.4	0.4
1985	1.0	0.5
1990	1.6	0.7
1995	3.1	1.0
2000	5.2	1.4
Cumulative production (million barrels)		
1980	500	500
1985	2,000	1,600
1990 ... ., ...	4,700	2,700
1995	8,700	4,100
2000, ...	17,300	6,800

Table 23
Impact of Technological Advances in Emission Control in California Thermal Recovery Projects on Projected Rates for the United States at World Oil Price ($13.75/bbl)

	Low-process per-		High-process per-	
	strained	strained	strained	strained
Ultimate recovery: (billion barrels)	11.1	11.1	29.4	29,4
Production rate: (million barrels/day)				
1980 ....., ...	0.3	0.3	0.4	0.3
1985, ...,	0.5	0.4	1.0	0.8
1990	0.7	0.5	1.7	1.4
1995	1.2	1.0	3.1	2.8
2000	1.7	1.5	5.2	4.9

The variations in parameters used to compare the high- and low-process performance cases for the surfactant/polymer and CO_2 miscible processes can also be used to simulate the effects of uncertainties in residual oil saturation. Specifically, the low-process performance case approximates a high-process performance case when the uncertainty in the residual oil saturation varies from 15 to 25 percent. As discussed in the section on *Uncertainty in the Oil Resource* on page 33, these figures represent the range of uncertainty which presently exists in the estimates of the process parameters.

Volumetric Sweep

The fraction of the reservoir which can be swept by the surfactant/polymer and CO_2 miscible processes was assumed to be the region which was previously contacted during waterflooding.[16] The volume of this region was assumed to be known with less certainty than residual oil saturation.

Two methods have been used to estimate the fraction of the volume of a reservoir that has been swept by earlier waterflooding. One method assigns values to reservoirs based on experience in the geographical region, The second method, used in the OTA study, is based on a material balance involving the oil initially present and the oil produced by primary and secondary methods.

The effect of these methods of determining sweep efficiencies was compared for the high-process performance case for a set of reservoirs consisting of 59 surfactant/polymer candidates and 211 onshore CO_2 miscible candidates. Use of estimated volumetric sweep efficiencies yielded 1.1 billion additional barrels of oil at the world oil price for the surfactant/polymer process. No significant difference was noted for onshore CO_2 results.

[16]Other possible interpretations are discussed in appendix B.

Maximum Oil Recovery by EOR Processes

Results of all cases show increased ultimate oil recovery with increased oil price. Further computations for the high-process performance case revealed that 95.6 percent of the oil considered technically recoverable would be produced at oil prices of $30 per barrel or less. Based on these estimates of technological advances, the volumes of oil which may be recoverable by enhanced oil process will not exceed 49.2 billion barrels for the United States (excluding Alaska). Thus, of the remaining 283 billion barrels of oil in the United States, excluding Alaska, 234 billion barrels are not recoverable under the technological advances assumed in the high-process performance case, Lower-process performance would reduce the ultimate recovery appreciably. Process improvements such as optimization of well spacing (i. e., infill drilling) and slug size were not considered in the OTA projections of ultimate recovery for the Nation, The effects of these improvements are expected to influence the projections less than the uncertainty in process performance. This assessment does not consider the potential of new processes or process modifications which might be developed at prices of $30 per barrel. These possibilities are not likely to have an impact on the Nation's crude oil supply during the period between 1976 and 2000.

Comparison With Other Studies

Estimates of the potential oil recovery and/or production rates resulting from the application of EOR processes have been published in seven documents.[17,18,19,20,21,22,23] Four of these[24,25,26,27] are based on surveys and other subjective methods and, as such, are considered preliminary estimates of the EOR potential for the Nation and not comparable to the OTA study in methodology, depth of investigation, or policy analysis.

Three of the studies[28,29,30] used a methodology similar to that used in the OTA study to estimate EOR potential. These studies are (1) the projections of enhanced oil recovery for California, Texas, and Louisiana, prepared by Lewin and Associates, Inc., for the Federal Energy Administration (FEA) (April 1976);[31] (2) the research and development program prepared by Lewin and Associates, Inc., for the Energy Research and Development Administration (ERDA) (November 1976);[32] and (3) an analysis of the potential for EOR from known fields in the United States prepared by the National Petroleum Council (NPC) for the Department of the Interior (December 1976).[33]

The methodologies of these studies are analogous in that the potential oil resource was determined using a reservoir-by-reservoir analysis. Each reservoir in the respective data base was considered for a possible EOR project. One or more EOR process was assigned to the reservoir. Oil recovery and economic simulations were made in a manner closely approximating commercial development in the oil industry. Ultimate production and production rates from economically acceptable reservoirs were used to extrapolate to the State and national totals.

Data bases varied somewhat between studies. The Lewin FEA and NPC studies used a common data base consisting of 245 reservoirs from California, Texas, and Louisiana. This data base was expanded to *352* reservoirs in 17 oil-producing States by Lewin and Associates, Inc., for their ERDA study. The OTA study incorporated, revised, and expanded the Lewin ERDA data base to 835 reservoirs containing 52 percent of the ROIP in the United States, as described in the section *Original Oil in* Place on page 23.

Cost data for development and operation of typical oilfields were obtained from the U.S.

[17] *The Estimated Recovery Potential of Conventional Source Domestic Crude Oil,* Mathematical, Inc., for the Environmental Protection Agency, May 1975.

[18] *Project Independence Report,* Federal Energy Administration, November 1974.

[19] *Planning Criteria Relative to a National RDT&D Program to the Enhanced Recovery of Crude Oil and Natural Gas,* Gulf Universities Research Consortium Report Number 130, November 1973.

[20] *Preliminary Field Test Recommendations and Prospective Crude Oil Fields or Reservoirs for High Priority Testing,* Gulf Universities Research Consortium Report Number 148, Feb. 28, 1976.

[21] *The Potential and Economics of Enhanced Oil Recovery,* Lewin and Associates, Inc., for the Federal Energy Administration, April 1976.

[22] *Research and Development in Enhanced Oil Recovery,* Lewin and Associates, Inc., Washington, D. C., November 1976.

[23] *Enhanced Oil Recovery,* National Petroleum Council, December 1976.

[24] *The Estimated Recovery Potential of Convention/ Source Domestic Crude Oil,* Mathematical, Inc., for the Environmental Protection Agency, May 1975.

[25] *Project, /dependence Report,* Federal Energy Administration, November 1974.

[26] *Planning Criteria Relative to a National RDT&D Program to the Enhanced Recovery of Crude Oil and Natural Gas,* Gulf Universities Research Consortium Report Number 130, November 1973.

[27] *Preliminary Field Test Recommendations and Prospective Crude Oil Fields or Reservoirs for High Priority Testing,* Gulf Universities Research Consortium Report Number 148, Feb. 28, 1976.

[28] *The Potential and Economics of Enhanced Oil Recovery,* Lewin and Associates, Inc., for the Federal Energy Administration, April 1976.

[29] *Research and Development in Enhanced Oil Recovery,* Lewin and Associates, Inc., Washington, D. C., November 1976.

[30] *Enhanced Oil Recovery,* National Petroleum Council, December 1976.

[31] *The Potential and Economics of Enhanced Oil Recovery,* Lewin and Associates, Inc., for the Federal Energy Administration, April 1976.

[32] *Research and Development in Enhanced Oil Recovery,* Lewin and Associates, Inc., Washington, D. C., November 1976.

[33] *Enhanced Oil Recovery,* National Petroleum Council, December 1976.

Bureau of Mines[34] for all studies. Adjustments were incorporated to account for price changes between the reference dates for each study.

Results of these studies are compared with OTA projected results in table 24 for 1976 upper tier and world oil prices. There is agreement In the order of magnitude of the ultimate recovery among all the studies. The NPC projections include a base case which represents best estimates of process performance and associated process costs, and a range of uncertainty in the base case estimates due to poorer or better than expected process performance. Estimates from the OTA low-process performance case are within the NPC range of uncertainty for all oil prices. The OTA high-process performance case estimates more oil recovery than the upper estimates of the NPC study. At the world oil price, the OTA estimate is about 24 percent higher. The Lewin ERDA cases for upper tier price and $13 per barrel are close to the range of OTA values. The OTA projections are lower than the Lewin FEA results for California, Texas, and Louisiana, even if oil

[34] *Research and Development in Enhanced Oil Recovery,* Lewin and Associates, Inc., Washington, D. C., November 1976.

Table 24
Projections of Ultimate Recovery and Production Rate From the Application of Enhanced Oil Recovery Processes

Study	Reference date	Minimum rate of return for projection	Oil price ($/bbl)	Potential ultimate recovery (billion barrels)	Potential production rate in 1985 (million barrels/day)
OTA					
Low-process performance.	1976	10 %	11.62	8.0	0.4
			13.75	11.1	0.5
High-process performance			11.62	21.2	0.5
			13.75	29.4	1.0
NPC'					
Poor performance	1976	10 %	10.00	3.1	
Expected performance (base case)				7.2	0.4
Better performance				13.4	
Poor performance			15,00	6.3	0.4
Expected performance (base case)				13.2	0.9
Better performance				26.9	1.6
ERDA[b]					
Industry base case**.	1976	00/0	11.63	11.9	0.6
			13.00	13.1	0.6
Industry base case w/ERDA R&D**			11.63	26.2	1.7
			13.00	30.1	2.1
FEA					
California, Texas, and Louisiana	1975				
Lower Bound, ...		20%	11.28	15.6***	1.0
Upper Bound.		80/0	11.28	30.5.	2.0

**Current tax case, 10-percent investment credit and expensing of injection materials and intangibles, with current environmental constraints.

"***Reserves added by the year 2000.

'*Enhanced Oil Recovery,* National Petroleum Council, Decemberl 976.

[b] *Research and Development in Enhanced Oil* **Recovery,** Lewin and Associates, **Inc.,** for the Energy Research and Development Ad"nist"tio"I November 1976.

' *The Potential and Economics of Enhanced Oil Recovery,* Lewinand Associates, Inc., for the Federal Energy Administration, April 1976.

price, rate of return, and costs were placed on the same basis.

Estimates of producing rates in 1985 vary widely between studies. In general, the OTA projections are within the range of the NPC base-case study results and the Lewin industry base-case simulation. The OTA results are lower than the Lewin ERDA research and development case and the Lewin FEA projection for California, Texas, and Louisiana. The apparent agreement in producing rates between the OTA high-performance case and the Lewin ERDA case does not constitute confirmation of projections from independent studies for reasons outlined in a later section.

OTA-NPC Results

The OTA study team was provided access to all reports, oil recovery models, cost data, and results from the NPC study. Comparisons of projected ultimate recovery and production rates were made on a reservoir-by-reservoir basis. The same reservoirs which were included in the NPC base case for $C0_2$, surfactant/polymer, steam, and in situ combustion processes were studied in detail using NPC models and OTA models. All differences between OTA and NPC results can be traced to differences in recovery models, supplies of injected materials, costs of injected materials, and, in some cases, the timing plan used in the simulation to initiate projects.

The NPC study included a geological screen in which individual reservoirs were judged as good, fair, poor, or no EOR, based on qualitative information on the geology of each reservoir gathered from industry sources. The OTA study assumed all reservoirs had the same quality since geological information was available on only a small portion of the reservoirs in the data base. No reservoir was rejected for geological reasons, with the exception of those with a large gas cap which might prevent waterflooding.

The distribution of oil in a reservoir was treated differently in the OTA models. The OTA models assume 95 percent of the remaining oil is located in 80 percent of the reservoir acreage. All oil produced by. EOR processes is developed from the reduced portion of the acreage. This assumption was implemented by increasing the net thickness in the region developed. The use of economic models to determine the EOR process when two or more processes were possible led to different assignments of many reservoirs in the OTA study.

Major differences between the NPC and OTA results are:

a. Recovery from application of $C0_2$ displacement in the OTA high-process performance case exceeds NPC estimates by a factor of about two at all oil prices for which calculations were made. Comparable recovery models were used and the agreement in ultimate recovery for reservoirs common to both studies is reasonably close, In Texas, the OTA recovery at world oil price by $C0_2$ flooding is about 5.6 billion barrels. The corresponding NPC recovery is a little over 4.0 billion barrels.

   The NPC geological screen eliminated certain reservoirs in Texas from their study which OTA's study calculated would produce about 0.5 billion barrels of oil with the $C0_2$ process. When extrapolation was made to the entire State, this amounted to about 0.9 billion barrels. Considering the Texas results, as well as the entire Nation, the NPC geological screen accounts for part of the difference but is not considered the major factor,

   Expansion of the data base to other oil-producing States and offshore Louisiana resulted in more reservoirs as potential candidates for $C0_2$. A result was that considerably more oil was produced from States other than Texas, California, and Louisiana in the OTA study than was projected in the NPC report. In addition, in the OTA study at the world oil price, an ultimate recovery of 0.9 billion barrels was projected to be produced from offshore reservoirs that were not in the NPC data base (table 13).

   Oil recovery for the NPC $C0_2$ models varied according to geologic classifications of good, fair, and poor. The OTA recovery models were designed to represent an "average" reservoir. The use of this "average" reservoir in the OTA study may account for a significant portion of the difference in results for the three States of California, Texas, and Louisiana.

Significantly different pricing plans for the CO_2 resource were used by OTA and NPC, Prices used were similar in geographical areas such as western Texas, which have a high probability of obtaining supplies of natural CO_2 by pipeline. However, for other areas such as Oklahoma and Kansas there is less certainty of carbon dioxide pipelines and the pricing plans were quite different. In general, the NPC study used a significantly higher cost for CO_2 in these areas. This is considered to be a major reason for the difference in results for the Nation. The OTA CO_2 pricing model is given in appendix B.

b. Oil recovery from OTA surfactant/polymer projections for the low-process performance case at $13.75 Per barrel (2.3 billion barrels) is bounded by the NPC base case (2.1 billion barrels) and the NPC 5-year project life case (5.6 billion barrels) at $15 per barrel. (The NPC base case used a 10-year life while OTA models assumed a 7-year life.) The OTA high-process performance case at world oil price (10.0 billion barrels) projects about 1.0 billion barrels less oil recovery than the NPC better-than-expected performance projections (1 1.2 billion barrels) at $15 per barrel.

Two factors are the primary contributors to the slight differences in results of the two studies. First, more than twice as many OTA reservoirs were assigned to the surfactant/polymer process as in the NPC study. Forty-five percent of these reservoirs were not in the Lewin FEA data base used by NPC.

A second difference in the results was due to NPC's assignment of higher chemical costs to reservoirs which were ranked poor in the geologic screen. The OTA study assumed all reservoirs were of the same quality. Comparable projections of ultimate recovery at a specified oil price were obtained on individual reservoirs which had the same geological ranking and swept volume in both studies. Sensitivity analyses show agreement of the low-process performance projections and projections made by increasing chemical costs so that all reservoirs were "poor."

Some differences were attributed to the approaches used to estimate the volume of each reservoir swept by the surfactant flood. A discussion of this is included in the section on *Volumetric Sweep* on page 51. No offshore reservoirs were found to be economically feasible for application of the surfactant/polymer process in the OTA study. The NPC results included an estimate of 261 million barrels from offshore Louisiana reservoirs at $15 per barrel,

c. The OTA estimates of oil recoverable by thermal methods are within the range of uncertainty projected in the NPC study. The OTA low-process performance estimates are within 0.4 billion barrels (12 percent) of NPC base-case projections at prices between $10 per barrel and $15 per barrel. Projections for the OTA high-process performance case at these prices are about 1.0 billion barrels less than performance from the NPC high-recovery estimates. Comparisons by process are included in appendix B.

Oil recovery models for thermal processes in the NPC study were developed for areas with uniform reservoir properties. Projected recoveries from reservoir-wide application of these models were adjusted to account for variation of reservoir properties and process performance. This was done by reducing the ultimate recovery for uniform reservoir and process performance by factors of 0.7, 0.6, and 0.5, corresponding to the NPC geological screen of good, fair, or poor. Large reservoirs were subdivided into two or three areas judged to have different quality. Multiple-zone reservoirs were developed simultaneously. Crude oil consumed as fuel was deducted from gross production prior to computation of royalty and severance taxes.

The OTA thermal recovery models were developed to represent the average reservoir performance. Reservoirs were not assigned geological rankings based on reservoir quality. Multiple-zone reservoirs were developed zone by zone. Royalty and severance taxes were paid on lease crude consumed as fuel. This is a significant cost, as about one-third of the production in steam displacement projects is consumed as fuel.

d. polymer flooding models in both studies produce comparable results when polymer injection is initiated at the beginning of a waterflood. Some differences exist for waterfloods which have been underway for some period of time. The NPC recovery model projects a decline in oil recovery with age of waterflood, while the OTA study does not. Polymer flooding does not contribute much oil in either study.

e. The NPC study projected recovery from alkaline flooding. The OTA study acknowledges the potential of alkaline flooding for selected reservoirs but did not include the process for detailed study. Reservoirs which were alkaline-flood candidates in the NPC study became candidates for other processes in the OTA study.

OTA-FEA, ERDA Results

The OTA study used the economic programs and timing plans for reservoir development which were used to produce the results for the Lewin and Associates, Inc., studies for FEA and ERDA. Oil prices and a minimum acceptable rate of return (1 O percent) were selected for the OTA study. Costs of injected materials were obtained from both Lewin and NPC studies. Oil recovery models for the OTA study were developed independently of previous Lewin studies. The FEA study reported projections for three States; California, Texas, and Louisiana. The ERDA results include data from 17 oil-producing States while the OTA results use data from 18 oil-producing States. Projections for the Nation in the OTA and ERDA studies were obtained by summing State totals.

The OTA advancing technology cases assume a vigorous research and development program, although the stimulus for the program was not identified. Lewin and Associates, Inc., ERDA program assumes all improvements in recovery over an industry base case comes from an extensive ERDA R&D program which removes environmental and market constraints for thermal operations in California, results in improved recovery efficiencies for processes, and extends the processes to reservoirs not considered candidates in the industry base case. Targeted R&D projects were identified for specific reservoirs.

The documentation of anticipated improvement in the various processes is described in the report.[35] Incremental process costs and process performance associated with proposed process improvements were not identified. Consequently, there is no basis for a direct comparison with the Lewin ERDA projections resulting from an extensive R&D program. The agreement between OTA projections and the Lewin ERDA projections should not be considered confirmation of either study by independent methodology.

Although the ultimate recoveries and rates from the Lewin studies are close to the OTA results, there are significant differences in the assumptions which were used to develop the results. Distributions of oil recovery by process are also different. Principal differences between the OTA and Lewin studies involve the projected recovery for each process.

The Oil recovery models used by Lewin and Associates, Inc., for the FEA and ERDA studies were reviewed on a reservoir-by-reservoir basis. Comparisons between OTA recovery models and Lewin models produced the following observations:

a. Recoveries from the CO_2 flooding process are comparable in specific reservoirs. The

[35] *Research and Development in Enhanced Oil Recovery*, Lewin and Associates, Inc., Washington, D. C., November 1976.

OTA high-process performance case, at the world oil price, projects about a 40 percent greater ultimate recovery from CO_2 than the total for the Lewin ERDA research and development case plus the industry base case. A primary reason is the presence of additional reservoirs in the extended data base of the OTA study. The OTA low-process performance result is about half the Lewin ERDA value at world oil price. Costs of manufactured CO_2 in some areas are higher than in the Lewin study and this contributes in a minor way to the differences.

b. There are large differences between projections of ultimate recovery from the steam displacement process. The ERDA industry base case estimates ultimate recovery to be 66 billion barrels at $13 per barrel. Incremental oil expected from proposed ERDA R&D programs 8.2 billion barrels at the same price. Thus, an ultimate recovery of 14.8 billion barrels is projected from steam displacement as a result of ongoing industry activity and proposed ERDA R&D programs.

The OTA study projects an ultimate recovery of 3.3 billion barrels from steam displacement processes at $13,7'5 per barrel. This projection is lower than the ERDA industry base case by a factor of 2, and is lower than the ERDA industry base case with ERDA R&D by a factor of 4.5. The OTA and ERDA projections of ultimate recovery from steam displacement vary over a large range because of differences in specific technological advances which were incorporated in the displacement models. Major differences are discussed in the following paragraphs.

About one-third of the oil produced in a steam displacement process is consumed to generate steam. The amount of steam produced by burning a barrel of lease crude is not known with certainty. The OTA computations assumed 12 barrels of steam were produced per barrel of oil consumed, while the ERDA models assume 16 barrels of steam per barrel of oil. Applying the ERDA factor to OTA computations would increase the ultimate recovery about 10 to 15 percent. Differences of this order of magnitude are not considered significant.

Replacement of crude oil by a cheaper source of energy such as coal is a proposed ERDA steam program. Incremental production of 1.0 billion barrels was expected from this program. A successful program could increase the net crude oil produced by a factor of one-third in fields where it could be implemented. However, widespread substitution of coal for lease crude would have to be done in a manner which would satisfy environmental constraints.[36] The OTA study does not evaluate this possibility.

One ERDA program for steam projects an ultimate recovery of 1.8 billion barrels from light-oil reservoirs (less than 25°API) in Texas, Louisiana, and the midcontinent by a steam distillation process. This process was not considered in the OTA study. implementation of steam distillation on an economic scale requires development of a fuel for steam generation which is less expensive than lease crude oil. These reservoirs were assigned to other processes in the OTA study.

The principal difference between ERDA and OTA projections is in the recovery models for the steam displacement process. The ERDA steam model was developed using data from current field operations which are generally conducted in the best zones of a reservoir. Every part of the reservoir is considered to perform like the regions now under development. Steam drive was limited to depths of 2,500 feet in the ERDA industry base case. Increase in the depth to 5,000 feet added 1.6 billion barrels in the ERDA R&D case. The ERDA R&D program includes anticipated improvements in recovery efficiency for reservoirs which are less than 2,500 feet deep. The eventual

[36] ERDA Workshops on Thermal Recovery of Crude Oil, University of Southern California, Mar. 29-30, 1977.
[37] Ibid.

R&D goal for these reservoirs was to improve the overall recovery efficiency of steam drive by 50 percent. Incremental ultimate recovery for this program was expected to be 2.3 billion barrels.

The OTA steam displacement models are based on development of the entire reservoir using average oil saturations and recovery efficiencies. All reservoirs 5,000 feet in depth or less were developed. The OTA models underestimate recoveries from the better sections of a reservoir and overstate recoveries from poorer zones. Overall recovery from the OTA models is believed to be representative of the average reservoir performance.

Closer agreement between the ERDA industry base case and the OTA projections at the world oil price can be obtained by reducing the ratio of injection wells to production wells, thereby reducing the capital investment. The ERDA industry base case assumes fieldwide development on the basis of 0.8 injection well per production well. The OTA advancing technology cases used 1.0 injection well per production well. Reduction of the number of injection wells to 0.3 per production **well in the** OTA computations makes steam displacement economic in several large California reservoirs at the world oil price. Ultimate recovery at this price increases from 3,3 billion barrels (one injection well/production well) to 5.3 billion barrels (0.3 injection well/production well). Producing rates increase correspondingly. This comparison indicates potential improvements could result from optimizing well spacing. Additional results are included in appendix B.

In summary, steam displacement projections in the ERDA industry base case and ERDA R&D case assume more technological advances than judged to be attainable in the OTA study.

c. OTA surfactant/polymer projections for both low- and high-process performance cases fall between the projections from Lewin's ERDA industry base case and Lewin's FEA results for California, Texas, and Louisiana, for different reasons. Projected surfactant recoveries in the Lewin FEA study ranged between 3.8 billion barrels and 8.8 billion barrels at $11 per barrel. These projections are larger than OTA projections under the same economic conditions because the recovery models are based on different representations of the displacement process.

The industry base case for ERDA limits application of the surfactant/polymer process to shallow homogeneous reservoirs in the midcontinent. Ultimate recovery was estimated to be 0.6 billion barrels at $13 per barrel. This corresponds to the OTA projected recovery of 2.3 billion barrels at the world oil price for the low-process performance case and 10 billion barrels for the high-process performance case. The ERDA R&D program for the surfactant/polymer process projects an ultimate recovery of 1.4 billion barrels at the world oil price.

California reservoirs, which are major surfactant/polymer contributors in the OTA study, were excluded from the ERDA industry base case by assuming that technology would not be developed in the absence of the ERDA R&D program. The OTA methodology resulted in assignment of more reservoirs to the surfactant/polymer process than in the ERDA cases. A major difference exists in volumes and costs of chemicals used in the ERDA calculations. These volumes approximate those which have been tested extensively **in shallow reservoirs** in Illinois. The OTA advancing technology cases project technological advances which would reduce the volumes of chemicals required. This has a profound effect on the development of the surfactant/polymer process, as the projected recovery for the high-process performance case at the world oil price is reduced from 10 billion barrels to 2.9 billion barrels when OTA current technology surfactant and polymer slugs are used in the economic model.

- d Ultimate recovery from polymer flooding varies from 0.2 billion to 0.4 billion barrels at the upper tier price in the OTA projections compared to 0.1 billion barrels in the ERDA industry base case. The OTA polymer model projects less recovery than the Lewin mod-cl 'for specific reservoirs. There were more reservoirs assigned to the polymer process in the OTA methodology.

Technological Constraints to EOR

Technological constraints are only one of several barriers to widespread commercialization of EOR[38] that include economic risks, capital availability, and institutional constraints. These constraints are coupled, and all must be removed or reduced to achieve major oil production from EOR processes.

The following section identifies and discusses the technological constraints that must be addressed in order to achieve the rate of progress that is postulated in the advancing technology case.

The technological constraints on EOR have been grouped in the following categories:

1. Resource availability.
2. Process performance,
3. Reservoir characteristics.
4. Materials availability.
5. Human resources.
6. Environmental impact.
7. Rate of technological evolution.

Resource Availability

The magnitude of the oil resource **for** EOR is not certain. The uncertainty is estimated to be 15 to 25 percent. Although this range may not seem large for the national resource, variation among reservoirs probably is larger. Furthermore, a small reduction in remaining oil in a reservoir may make it uneconomical to apply a high-cost EOR process at all, thereby leading to a disproportionate reduction in economically recoverable oil, The difference may be as high as the difference between the advancing technology-high- and low-process performance cases, which amounts to 18 billion barrels at the world oil price, equivalent to about half the current U.S. proved reserves.

Resource uncertainty represents a major technical and economic risk for any EOR project in any reservoir. Reduction of this risk would need high priority in any national program to stimulate EOR production.

Sampling a reservoir through core drilling, logging, and other well testing is an expensive, inexact, developing technology. The problem is that of finding methods which will probe outward a sufficient distance from a well bore to determine oil content in a large fraction of the region drained by the well. A further complication exists **in that oil saturation variations** occur both horizontally and vertically within a reservoir. Determinations at one well may not be applica**ble at other well sites.**

A program to stimulate EOR production should contain a major effort to promote measurement of residual oil saturations in key reservoirs until confidence is gained in methods to extrapolate **such data to other locations in the same** reservoir and other reservoirs. Equal emphasis should be placed on the gathering of such data and on the improvement of measurement methods.

Process Performance

Process Mechanisms

Enhanced oil recovery processes are in various stages of technological development. Even though steam drive is in limited commercial development, the outer limits of its applicability are not well understood. Steam drive can probably be extended to light **oil reservoirs but it has**

[38] *Management* **plan for *Enhanced* Oil *Recovery, ERDA,* Petroleum and Natural Gas Plan, ERDA 77-15/1, p. II-1, February 1977.**

not been tested extensively. Larger gaps in knowledge exist for other processes and process modifications which are in earlier stages of development. Field tests have consistently been undertaken with incomplete knowledge of the process mechanism. Most laboratory tests of processes are done on systems of simple geometry (generally linear or one-dimensional flow), leaving the problems that **occur because of the** more complex flow geometry to field testing.

As indicated in the section on *Process Field Tests* on page 61, extensive field testing of EOR processes will be required. As more field projects are undertaken, the tendency of industry is to shift research personnel from basic and theoretical studies to development activities. If this effort is widespread it may limit the ability of companies to undertake fundamental **EOR research. If this trend continues, additional public support for basic research applicable to EOR** may become advisable.

A major industry /Government coordinated effort is needed to thoroughly define the process mechanisms for each of the recognized basic EOR processes and process modifications, This effort would need to be initiated immediately and to proceed at a high level of activity for at least 5 years if the postulated rate of EOR applications is to be achieved.

Volumetric Sweep Efficiency

Recovery efficiency of all processes depends upon the fraction of the reservoir volume which can be swept by the process, i.e., sweep efficiency. Thus a strong economic incentive exists for improvement of volumetric sweep. Research in this area has **been carried** out for a number of years by many sectors of the oil production, oil service, and chemical industries. The importance to EOR success of improving sweep efficiency has been confirmed in a recent assessment of research needs.[40]

Despite the long-term effort on this problem, success has been limited. Solutions are not available for each process. Improvements are needed for each individual process and each process variation as well as for major classes of reservoirs. Progress will be difficult and will require major field testing supported by extensive prior laboratory work. This research effort, both basic and applied, must be significantly stimulated in the next 3 to 6 years in order to approach the estimated EOR production potential for the period between 1976 and the year 2000.

Brine-Compatible Injection Fluids

Enhanced oil recovery processes will **be used** largely in those parts of the country that face increasing shortages of fresh water. For surfactant/polymer and polymer flooding, relatively fresh water is still needed both for the polymer and surfactant solutions and for reservoir preflushing. Even where fresh water is available for preflushing, it is often not efficient in displacing brine. Consequently, injected fluids in such reservoirs must be brine compatible. Continued laboratory and field research is needed to develop surfactants and other oil-recovery agents which are brine compatible.

In the present study, brine compatibility of injected fluids was assumed in the advancing technology cases. Data were not available in the OTA data base to assess the importance of this assumption, but it is known to be significant.

Development of Additional Processes Applicable to Carbonate Reservoirs

Although carbonate reservoirs represent approximately 28 percent of the initial oil in place in the United States,[41] the CO_2 miscible process is the only EOR process currently applied to such reservoirs, There is a possibility of using steam flooding in some carbonate reservoirs,[42] and other processes or process modifications should

[39] ERDA Workshops on Thermal Recovery of Crude Oil, University of Southern California, Mar. 29-30, 1977.

[40] *Technical Plan for a Supplementary Research Program To Support Development and Field Demonstration of Enhanced Oil Recovery*, for U.S. Energy Research & Development Administration, Washington, D. C., GURC Report No. 154, Mar. 17, 1977.

[41] *Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada as of December 31, 7975*, Joint publication by the American Gas Association, American Petroleum Institute, and Canadian Petroleum Association, Vol. 30, May 1976.

[42] *Enhanced Oil Recovery*, National Petroleum Council, December 1976.

be tested for carbonate reservoirs because of the possibility of CO_2 shortages and because of the high cost of delivering CO_2 to areas that might not be served by pipelines.

Operating Problems

Operating problems of EOR are more severe, less predictable, and certainly less easily controlled than operating problems one faces in a plant making a new chemical product, but the industrial sector is equipped to solve such problems. For example, steam is now generated from high-salinity brines, a process that once seemed to pose serious technical problems. Most such problems, however, must be solved within the next 6 to 8 years if the potential production represented by OTA's advancing technology case is to be achieved.

Some problems exist where Government assistance could be beneficial. Design of steam generators for steam-drive projects that will meet environmental pollution-control standards and use cheaper alternate fuels (heavy crudes, coal, etc.), as well as large-scale steam generation, are areas that have been recently highlighted.[43] Equipment for retrofitting existing generators to permit them to meet new standards and lower their unit pollution level is also needed.

Process Field Tests

The current ERDA field testing program is a vital step in accelerating EOR process commercialization, If the upper targets of any of the recent predictions of EOR potential are to be achieved, a significant increase is needed in the rate of technical progress. To achieve this, the level of field tests needs to be significantly increased. While OTA did not attempt to estimate the optimal number, a study by the Gulf Universities Research Consortium (GURC) estimated 100 as a target group.[44] It is important that ERDA-sponsored field tests be part of an EOR research strategy designed to complement industry's efforts and to provide information that can be generalized to a variety of classes of reservoirs, The status of current field tests taken from the Lewin ERDA report[45] is shown in table 25.

There are at least three levels of field tests: minitests, single- or multi pattern-pilot tests, and fieldwide commercial testing.

Single- and multipattern-pilot tests should be directed at determining potential economic success and to thoroughly defining the technical performance. To maximize the value of such field tests, extensive pre- and post-test well coring, logging, fluid analysis, and laboratory tests are required to understand the process well enough to provide a strong knowledge base for operating at full scale in test reservoirs. Data acquisition is expensive and time consuming, and the record indicates that too little data are being gathered. Government support for such activities may be required if the postulated rate of technological advance is to be achieved.

Special consideration should be given to testing more than one process in a reservoir and to undertaking processes in reservoirs that offer new ranges of application of the process.

There is some current concern about the relative merits of minitests (one to two well tests at small well spacing) compared with larger single- or multipattern-pilot tests. Both can be helpful. The minitest is faster, less expensive, and may be helpful in initial process or reservoir screening. However, its lower cost and greater simplicity do not substitute for the greater degree of understanding that can come from multi pattern tests.

The number of projects that should be undertaken for fieldwide commercial demonstration is not easily determined. A case can be made for at least one such test for every major process that has not yet reached commercialization. The options of cost sharing, risk sharing, and/or support through special price or tax provisions should all be considered. Considerations of the merits of such alternatives, the scale of operations, and the applicable processes were outside the scope of

[43] ERDA Workshops on Thermal Recovery of Crude Oil, University of Southern California, Mar. 29-30, 1977.

[44] *A Survey of Field Tests of Enhanced Recovery Methods for Crude Oil*, for FEA and the National Science Foundation, Washington, D. C., GURC Report No. 140-S, Nov. 11, 1974.

[45] *Research and Development in Enhanced Oil Recovery*, Lewin & Associates, Inc., Washington, D.C. Part 1, p. III-2, November 1976.

Table 25
Field Activity in Enhanced Oii Recovery

Technique	Number of EOR Proiects						Acreage under current development
	Technical pilots		Economic pilots		Fieldwide development		
	Total	Current	Total	Current	Total	Current	
Steam drive. ., ...	17	13	15	14	15	15	15,682
In situ combustion	17	3	6	5	19	10	4,548
CO_2 miscible and nonmiscible.	5	4	6	6	2	2	38,618
Surfactant/polymer.	12	10	7	7	2	2	1,418
polymer-augmented waterflooding	3	0	14	9	14	11	14,624
Caustic-augmented waterflooding	5	1	2	0	0	0	63
Hydrocarbon miscible . .	9	7	6	5	10	8	56,782
Totals.	68	44	57	47	62	48	131,735

"From *Research and Development in Enhanced Oil Recovery,* Final Report, Lewin & Associates, Inc., Washington, D. C., ERDA 77-20/1,2,3, December 1976.

this study. However, the issue **needs to be addressed within** the next year or two. This test program is a facet of the Government program that deserves a major emphasis.

Reservoir Characteristics

Uncertainty concerning the physical and chemical nature of an oil reservoir is one of the most severe technological barriers to EOR processes.[46] Not only are reservoirs significantly different among themselves, even within the same geological class, but the place-to-place variations in thickness, porosity, permeability, fluid saturation, and chemical nature can be discouragingly large. The present ability to describe, measure, and predict such variability is extremely limited. Knowledge to measure and predict this variability within a reservoir is vitally important for forecasting fluid movement and oil recovery efficiency. Research efforts have so far been directed toward studying portions of individual reservoirs intensively, with little attention given to generic solutions.

Any major governmental research effort to accelerate oil production from EOR processes should include development of methods to measure, describe, and predict variations in properties throughout a reservoir. Extensive field and laboratory studies are warranted.

Raw Materials Availability

Enhanced oil recovery processes use both natural and manufactured raw materials.. Short-term shortages of manufactured materials could exist for all EOR processes if a vigorous national program were launched to produce EOR oil.

The supply of two natural resources, fresh water and CO_2, may limit ultimate recovery from steam injection, surfactant/polymer, and CO_2 miscible processes. Local shortages may develop for adequate supplies of fresh or nearly fresh water in some areas in which polymer flooding or surfactant/polymer flooding is initiated. Most areas of known fresh water shortage either have or are developing criteria for allocation of the scarce supply among competing classes of use. A major technological challenge for EOR lies in development of economic means for using water with higher saline content for all processes in which water is needed. The problem seems to have been solved for steam generation. Brine of up to 20,000 ppm can be used successfully.

[46] *Technical plan for a Supplementary Research Program To Support Development and Field Demonstration of Enhanced Oil Recovery,* for U.S. Energy Research and Development Administration, Washington, D. C., GURC Report No. 154, Mar. 17, 1977.

Carbon dioxide availability is central to any major expansion of CO_2 flooding. As mentioned previously, the quantity needed (a total of 53 Tcf in the advancing technology-high-process performance case at world oil prices) is a volume almost three times the annual volume of natural gas consumed in the United States.

The economic potential of CO_2 flooding is so great that a Government effort to accelerate EOR production should include not only locating natural sources of carbon dioxide but also exploring ways to produce it economically from large-scale commercial sources. Locations of known, naturally occurring CO_2 sources are summarized in the recent NPC study of EOR.[47] The magnitude of the reserves of CO_2 at these locations is not known. ERDA is currently involved in a nationwide survey of CO_2 availability.

Human Resources

Shortages of technically trained people to operate EOR projects may exist temporarily if a major national EOR effort is undertaken. National projections of needs for technically trained people have not been highly accurate. Data are not readily available on industrial needs since many firms do not make formal, continuing, long-range personnel forecasts. The efforts of ERDA and other agencies in national manpower forecasting could be encouraged.

All EOR processes are extremely complex compared to conventional oil recovery operations. Because of this technical complexity, highly competent personnel must be directly involved in each EOR project on a continuous basis at the managerial, developmental, and field operations level. Without close monitoring by qualified technologists, the odds for success of EOR projects will be lower, There currently is a mild short-term shortage of persons to work on EOR projects. National forecasts[48] of the number of available college-age students (all disciplines) indicate a significant enrollment decline over the period of greatest potential EOR activity. The supply of technical people (engineering, science, and business) available for EOR operations will crucially depend upon the economic climate in other sectors of the economy. In a generally favorable economic climate, increasing competition for qualified personnel could develop.

Environmental Effects

For most EOR processes and in most geographical areas, accommodation to environmental protection regulations will not be a critically restrictive requirement. Details of environmental impacts and an estimate of their severity and magnitude are described in chapter VI of this report. The environmental effects that pose major technological problems include the need for emission controls in California thermal EOR projects, the possibility of fresh water shortages, and the need to protect ground water.

The need to develop an economically acceptable means of meeting the air pollution requirements for thermal processes has become critical in California. Further expansion of the thermal process in California awaits this development.

The requirements placed on EOR processes by the Safe Drinking Water Act (P.L. 93-593) are critical for their long-term development. Accommodation to the Safe Drinking Water Act is not so much a technological problem as it is a human and administrative matter. The need is one of establishing acceptable guidelines that will protect fresh water sources and still allow EOR processes to proceed. The record of compatibility of these two goals through the long period of secondary recovery in the United States suggests that this can be accomplished. This is discussed further in chapter VI.

The Rate of Technological Evolution

All estimates of potential recovery from application of EOR processes are based on a postulated rate of technological evolution. There is consensus among personnel in industry, Government, and academic institutions who are

[47] *Enhanced Oil Recovery,* National petroleum Council, December 1976.
[48] *Projection of [durational Statistics to 7985-86,* National Center for Educational Statistics, Publ. NCES 77/402, p. 32, 1977.

knowledgeable **in enhanced** oil recovery processes that much research and field testing is necessary to bring EOR technology to the point where commercialization is possible for all processes except steam displacement.

The suggested components of research and development programs to stimulate EOR production have received significant appraisal and modification within the last 4 years. Between 1973 and March 1977, the Gulf Universities Research Consortium (GURC) issued a series of five reports[49,50,51,52,53] detailing the need **for field tests, their number and character, and the basic research needs.** In addition, Lewin and Associates, Inc,[54] prepared a major study for ERDA which recommends specific research targets (process/reservoir type). Further details of the ERDA program are outlined **in the** ERDA Management Plan for EOR.[55]

The GURC and Lewin documents represent compilations of existing industrial viewpoints concerning research targets and types of programs that are appropriate. This gathered consensus has been supplemented by a **series of ERDA-sponsored workshops on ERDA research** targets[56,57] at which modifications to the program were suggested through public forums.

Although there is agreement concerning general research and development needs, there is a decided difference of opinion regarding the factors which will stimulate this needed research and development. The Lewin ERDA study[58] proposed an extensive Government research and development program, justified in part by results of an industry survey which indicated that research would not be greatly accelerated within the current set of constraints (economic, technical, and institutional). The National Petroleum Council's EOR study concluded that "Government policy with respect to oil price and other factors influencing EOR profitability is the dominant factor in establishing the level of R&D funding and the rate of evolution of technology. "

The OTA assessment did not attempt to resolve these positions because there appeared to be no meaningful way to predict what industry would do a) if the price of oil produced by some EOR processes was allowed to rise to free market prices as proposed by FEA, orb) if the price of all EOR oil were decontrolled. as proposed in the President's National Energy Plan.

The ERDA Programs

The Energy Research and" Development Administration has developed programs which are directed at stimulation of research and development of EOR processes. The general thrust of the ERDA programs, including field testing and continued industry/Government interaction, is good.

i'~P/armi ng *Criteria* ***Relative to*** **a** *National RDT&E Program* ***Directed to the*** *Enhanced Recovery of* ***Crude Oil and Natural*** *Gas,* **for U.S. Atomic** Energy **Commission,** Washington, **D. C.,** GURC **Report No. 130, Nov. 30, 1973.**

[50]*An I***investigation of** *Primary* ***Factors Affecting Federal*** *Participation* ***in R&D Pertaining to*** *the* ***Accelerated Production*** *of Crude* ***Oil,*** **for the National Science Foundation, Washing-' ton, D. C.,** GURC **Report #1 40, Sept. 15, 1974.**

51A *Survey* **Of** *Field* ***Tests*** *of* ***Enhanced Recovery Methods for Crude*** *Oil* **(supplement to** GURC **Report No. 140), for the National Science** Foundation and **the Federal Energy** Ad**ministration, Washington, D. C.,** GURC **Report No. 140-S, Nov. 11, 1974.**

[52]*Preliminary Field Test Recommendations* **and** *Prospective Crude* ***Oil Fields or Reservoirs*** **for High Priority** *Field* ***Testing,*** **for** U.S. **Energy Research and Development Administration, Washington, D. C.,** GURC **Report No. 148, Feb. 28, 1976.**

[53]*Technical* ***Plans for a Supplementary Research program to*** *Support Development* ***and Field Demonstration of Enhanced Oil Recovery,*** **for U.S. Energy Research and Development Administration, Washington, D. C.,** GURC **Report No. 154, Mar, 17, 1977.**

[54]*Research and* ***Development*** *in* ***Enhanced*** *Oil* ***Recovery,*** Lewin **& Associates, Inc., Washington,** D.C. **Part 1, p. III-2.**

[55]*Management Plan* ***for Enhanced*** *Oil* ***Recovery, ERDA,*** **Petroleum and Natural Gas Plan, ERDA 77-15/1, p.** II-1, **February 1977.**

[56]ERDA Workshops **on Thermal Recovery of** Crude Oil, **University of Southern California, Mar. 29-30, 1977.**

[57]EOR **Workshop on Carbon Dioxide, sponsored by ERDA, Houston, Texas, April 1977.**

[58]*Research* **and** ***Development in Enhanced*** *Oil* ***Recovery,*** Lewin **& Associates, Inc., Washington, D. C., Part 1, p. III-2.**

The ERDA management plan for EOR[59] is directed at maximizing production in the mid-1980's. However, short-term needs should not overshadow long-term national needs of increasing oil recovery. The OTA analysis indicates that a long-range program is needed to stimulate the development of processes, such as the surfactant/polymer process, which have the potential for greater oil recovery in the mid-1990's,

There does not seem to be adequate basic and applied research in the ongoing ERDA program. This has been recognized by ERDA, and an extensive research program has recently been outlined by GURC[60] for ERDA. This research program supplements the programs outlined in the ERDA management plan.[61]

The largest amount of basic and applied research has come from the integrated major oil companies and the service sector of the petroleum industry. The largest amount of expertise also resides in the industry. Basic and applied research done by industry and research institutions should be coordinated so that Government programs complement rather than duplicate programs underway in industry. This subject does not seem to be covered formally in the ERDA documents, and is particularly crucial since even under Government sponsorship a large portion of the basic and applied research is likely to be done in industry laboratories and oilfields.

The OTA assessment did not determine the level of ERDA or industry effort required to achieve the postulated technological advances or the cost of the necessary research and development. (Other studies have shown that the cost of research and development is on the order of a few cents per barrel of ultimate recovery.) However, the level of effort and funding in R&D must clearly be significantly increased over current levels by both industry and Government in order for the evolution of technology to approach the technological advances postulated in this assessment.

[59] *Management plan for Enhanced Oil Recovery,* ERDA, Petroleum and Natural Gas Plan, ERDA 77-1 5/1, p. 11-1, February 1977.

[60] *Technical Plans for a Supplementary Research Program to Support Development and Field Demonstration of Enhanced Oil Recovery,* for U.S. Energy Research and Development Administration, Washington, D. C., GURC Report No. 154, Mar. 17, 1977.

[61] *Management Plan for Enhanced Oil Recovery,* ERDA, Petroleum and Natural Gas Plan, ERDA 77-1 5/1, p. 11-1, February 1977.

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