TECHNICAL AND ECONOMIC CRITERIA FOR SELECTING METHODS AND MATERIALS FOR ENHANCED OIL RECOVERY (or WHY CO_2 FILLS THE BILL IN THE PERMIAN BASIN OF NEW MEXICO AND TEXAS)

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ABSTRACT

Enhanced oil recovery may be defined as any combination of methods and materials which recovers oil more effectively than either plain waterflooding or gas injection. The three basic mechanisms which can be used (individually or in combination) to achieve increased recovery are to: (1) lower interfacial tension between oil and water; (2) use a solvent to extract oil; and (3) reduce viscosity contrast between the oil and displacing fluid by thinning the oil or thickening the displacing fluids. Many methods and materials have had extensive laboratory and field testing, and many combinations have been proved to be effective for displacing oil. However, economic and technical constraints limit current choices to 10 methods which use a total of only 8 individual compounds or general groups of chemical substances which include: light hydrocarbons, nitrogen, carbon dioxide, surfactant formulations (including co-solvents and salts), water-soluble polymers, alkaline materials, air, and water. Technical screening criteria for selecting the methods appropriate for Permian Basin reservoirs are described. Economic limitations are also discussed. The technical and economic logic behind the big push for CO_2 flooding in the Permian Basin are emphasized.

INTRODUCTION

Carbon dioxide flooding is currently one of the fastest-growing enhanced oil recovery methods. According to the recent National Petroleum Council (NPC) Report on EOR, oil production by CO_2-miscible flooding will even surpass thermal recovery in 20 years,[1] and most of this new oil will come from the Permian Basin. At the Interstate Oil Compact Commission (IOCC) Meeting* a year ago (Dec. 1983), Lowell Smith explained many of the factors which are contributing to this upsurge in activity.[2]

This paper also shows why carbon dioxide works so well in the Permian Basin. It includes a brief introduction to enhanced oil recovery, and a description of the methods and materials usually available. The technical and economic reasons for the match between the reservoirs of the Permian Basin and the carbon dioxide method for enhanced recovery will be described.

METHODS AND MATERIALS AVAILABLE FOR EOR

Figure 1 is a simplified sketch of the enhanced oil recovery process. In general, enhanced recovery can be defined as any method which recovers oil more

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effectively than plain waterflooding or gas injection. Many methods have been tried, and there are many substances which displace oil much better than water; at least nineteen different techniques have had both laboratory and field testing according to a recent reference.[3] However, Table 1 shows that there are only three basic mechanisms which can be used to recover oil more effectively than waterflooding or repressuring with gas. All of the ten methods in use today can be classified within these three basic mechanisms: solvent extraction, interfacial tension reduction, and viscosity change (either viscosity reduction of the oil or viscosity increase of the driving fluid).

However, even though a number of techniques and many materials have been tried, an examination of all methods shows that there are ten chemical substances or general classes of materials now being used for enhanced oil recovery. These materials are listed in Figure 2 along with the cost of each. Even though the cost of materials limits the number of possibilities for enhanced oil recovery, there are still many choices available. Petroleum engineers start their search for the best method to use in any reservoir by considering technical and then economic screening criteria.

TECHNICAL SCREENING CRITERIA

Screening criteria for enhanced oil recovery have been discussed by a number of authors,[1,3-15] and the criteria listed in the two reports on Enhanced Oil Recovery by the National Petroleum Council have been quoted widely.[1,4] Taber and Martin[3] have listed screening criteria which are very similar to those in the National Petroleum Council studies, and their Table 11 which has been reproduced here as Table 2, lists screening criteria for the eight methods which are used most widely today. Taber and Martin also give a thumbnail sketch of the eight methods; these sketches help to explain some of the technical reasons for the choice of parameters in the screening criteria. Two of their sketches are reproduced here, along with the screening criteria in Tables 3 and 4, for surfactant flooding and carbon dioxide flooding.

An examination of Tables 3 and 4 for just two methods, along with Table 2 for all eight methods, will show that it is difficult to keep track of so many different parameters if a number of reservoirs are to be compared. Therefore, Figures 3, 4 and 5 were prepared to show how different enhanced recovery methods can be compared graphically against certain features of the oil and reservoirs being considered.[3]

Characteristics of the crude oil to be recovered are critical in most enhanced recovery methods. For oil to be displaced, it must flow through small capillaries in the reservoir, and oil viscosity often limits the application of specific techniques. Figure 3 shows the ranges of viscosity over which different enhanced recovery methods work most effectively. An examination of Figure 3 shows that the three gas injection methods will work well with lighter oils, that is, oils having a low viscosity. A general trend between viscosity and API gravity is given in Figure 6.[16] .

Permeability requirements for enhanced recovery methods can be seen at a glance in Figure 4. Not only must the viscosity be low enough for the oil to flow at an economic rate, but for a given viscosity, the permeability must also be satisfactory. The only methods for which permeability is not a critical consideration are the three gas injection methods. This wide permeability range provides an advantage for carbon dioxide flooding compared to methods which must use water, such as surfactant/polymer flooding.

The reservoir depth required for enhanced recovery is another story. Figure 5 shows that all gas injection methods require reservoirs which are deep enough to contain the pressures needed to make the process work effectively. For carbon dioxide flooding, it will be shown later that there is a specific pressure (often called the minimum miscibility pressure, or MMP), which must be achieved before carbon dioxide can displace oil efficiently. Since this required pressure usually exceeds 1000 psi, the minimum depth to avoid fracture parrting is about 2000 feet, and for safety, preferred reservoirs are usually deeper. However, Figure 5 also indicates that shallow reservoirs can be considered for most of the other (non-gas) enhanced recovery methods as long as the other screening criteria are met.

COSTS OF INJECTED MATERIALS

The costs of injected materials, i.e. the liquids, gases and added chemicals, impose a very general economic screen on all enhanced recovery methods. A complete economic analysis is desired before an operator will decide on a particular process, and normally, a very detailed study will be carried out before the final decision is made. Figure 2 lists the costs to the purchaser for all substances usually available for injection into oil reservoirs. The figure shows a very wide range--from zero for air (no compression costs are included) to a high of $2.00/lb for water soluble polymers. Obviously, the costs of the bulk fluids left behind in the reservoir must be lower than the value of the crude oil itself. Therefore, the only substances which can be injected at 100%, (essentially in their "pure" form) are those which have not been processed and/or those which have no fuel value, e.g., air, water, nitrogen, and carbon dioxide.

Since many materials other than the four inexpensive ones are used in recovery methods, the cost per pound is only part of the consideration. Of greater importance is the net cost of a barrel of the fluid that is finally injected into the reservoir. This must include compression or processing costs for each barrel of fluid which replaces a barrel of oil in the reservoir. Costs in Figure 2 have been recalculated in Figure 7 on this basis. Figure 7 shows that the net cost of the materials, when based on their actual reservoir volume, changes significantly. Now, water is clearly the cheapest fluid (because of the cost of compressing the air), and nitrogen is somewhat cheaper than either carbon dioxide or methane when these gases are compressed to a reservoir pressure of 2000 psi. Also, the only chemical solutions that are significantly less costly than crude oil (and thus can be left behind in the reservoir in large quantities) are dilute concentrations of polymers or possibly surfactant plus polymer solutions, and low-cost solutions of alkaline chemicals.

As important as the cost, however, is the real value of the material for oil recovery. In other words, which fluids, including the solutions of chemicals, are most cost effective for recovering oil? A more detailed explanation of the technical screening criteria shows why carbon dioxide flooding is being used in the Permian Basin.

CO_2 IN THE PERMIAN BASIN

From the title of this paper, it should be clear that there is a good match between technical and economic screening criteria for CO_2 flooding and the characteristics of reservoirs in the Permian Basin. A brief examination of the mechanisms by which CO_2 recovers oil, and of the unique CO_2 supply system in the eastern Rockies will help to explain the reason for the high CO_2 flooding activity in the Permian Basin.

How CO_2 Recovers Oil

The displacement of oil from porous rocks by CO_2 under pressure is a complicated process which is still the target of much research in many laboratories. About 150 papers per year are currently being published on CO_2 lab and field studies, and although work remains to be done, much of the process is now understood. Table 5 lists five factors often cited in the literature as important to the oil recovery mechanism. There can be little doubt that each of these factors is at work at some point in every CO_2 flood, though some are more important than others. All of the effects listed in Table 5 are intensified at higher pressures, primarily because the amount of CO_2 which can be dissolved in the crude oil increases with pressure up to a point. Therefore, oil recovery with CO_2 always increases with higher flooding pressures until the maximum oil recovery is observed. Beyond this optimum pressure, additional pressure increments have little effect on oil recovery. The amount of oil that is recovered at this optimum pressure depends on the nature of the porous medium from which it is being displaced.

Figure 8 shows the amount of oil which can be expected to be recovered from different porous media at various pressures.[17] Note that maximum recovery is observed at the same pressure regardless of the type of rock or porous medium used. When oil is displaced from a very small diameter pipe or "slim tube" containing fine glass beads or uniform, fine-grained sand, extremely high recoveries of more than 95% are normally observed. The maximum oil recovery by CO_2 from a homogeneous sandstone will be somewhat less (75-80% from Berea), but the increase in recovery with added pressure will level off at the same pressure. For more heterogeneous rocks and CO_2 displacements in the field, oil recovery will be even less, but the pressure required for the optimum production will be the same for the same oil (if it is at the same temperature), in all cases. This required optimum pressure is called the minimum miscibility pressure or MMP, and it increases with the reservoir temperature and the molecular weight of the crude oil.

Even though the term, minimum miscibility pressure, is used commonly, the pressure is never really sufficient to achieve true miscibility between the crude oil and the injected CO_2, i.e., a CO_2-rich and an oil-rich phase will exist at any reasonable pressure which can be achieved in the lab or in the field. Figure 9 shows this two-phase region for Maljamar (New Mexico) crude oil and CO_2 at a pressure of 2500 psi,[18] well above the MMP of 1100 psi shown on Figure 8.

In Figure 9, 100% CO_2 is at the top of the ternary diagram and for plotting purposes, the crude is split arbitrarily into a heavy hydrocarbon fraction (C_{13}^+) and a light hydrocarbon fraction (C_1 - C_{12}) as shown.[18] Although this representation of the crude oil by only two pseudo-components is a gross simplification, it provides a means for locating all mixtures of the crude oil and CO_2 on the ternary diagram. The point is, with all crude oils (unless the oil is composed of only the C_{12}, or less, light hydrocarbons), the two-phase region such as that shown in Figure 9 will exist at all reasonable pressures. However, the extremely high recoveries observed in idealized porous media demand that a miscible displacement must be taking place. It will be shown in Figures 10 through 12 that a multiple contact miscibility is generated at the MMP by the extraction of the lighter components of crude oil.

Figure 10 shows how the volumes of the oil and CO_2 phases change as CO_2 is added to a fixed quantity of crude oil at increasing pressure.[19] At first, the CO_2 just dissolves in the oil at the lower pressures, thereby swelling its volume as shown and decreasing the oil viscosity. For the 95°F case, the high solubility of CO_2 in crude oil is evident; note that the oil swells to almost 1.7 times its original volume at 1000 psi. However, at this point, the oil volume starts to shrink, because at this pressure CO_2 is a good solvent for the lighter hydrocarbons, and it extracts them from the oil into the upper CO_2 phase. The CO_2 becomes an excellent extracting solvent when the pressure is high enough to compress the CO_2 until its density is similar to that of liquid CO_2 near its critical temperature of 88°F.[20]

Thus, the first three factors in Table 5, swelling of the crude oil, viscosity reduction, and interfacial tension reduction, all serve to aid oil recovery when CO_2 is injected at pressures below the MMP. Some immiscible CO_2 floods are now underway at these lower pressures, but the quantity of oil recovered will normally be lower than the maximum possible as shown on Figure 8. At or above the MMP, oil is displaced miscibly by CO_2 because the crude oil itself is miscible with the extracted hydrocarbons which now enrich the CO_2 phase. Figure 11 shows how this generated miscibility is developed in the transition zone between pure CO_2 and crude oil.[20] The generation of this multiple contact miscibility in Figure 11 is identical to the miscibility obtained in a high-pressure vaporizing gas drive process as described first by Hutchison and Braun.[21] In Figure 11, a straight (dilution) line connects the hypothetical Reservoir Oil A, with 100% CO_2 at the apex. As CO_2 is injected, it dissolves in the crude oil, as was shown in Figure 10, until it reaches its limit of solubility at L_1. At this point no more CO_2 will dissolve in the oil, and so two phases are present, the L_1 or liquid phase and the upper gaseous phase labeled U_1. The compositions of these two phases are connected by tie lines as shown in Figure 11. Note that the composition of the CO_2-rich phase, U_1, contains a rather high percentage of light hydrocarbons. This hydrocarbon-enriched CO_2 phase moves further into the reservoir and contacts new Reservoir Oil A on the baseline, as shown in Figure 11. This upper phase material moves on the composition line connecting U_1 and the Reservoir Oil A, until it reaches the composition at L_2 when it again splits into two phases. The upper phase this time is shown as U_2 which now contacts new reservoir oil, until it reaches the two-phase region very close to the critical plait point on the two-phase region. Thus, the CO_2 phase becomes richer and richer in light hydrocarbons until it finally becomes fully miscible with the crude oil itself at the plait point in Figure 11.

If the reservoir oil contained somewhat more of the heavy hydrocarbons as illustrated by Reservoir Oil B in Figure 11, this enrichment could not occur because the upper phase could not move to the right as it contacted more reservoir oil. Therefore, it is more difficult to achieve miscibility with heavy crude oils than with the lighter oils such as Reservoir Oil A. From Figure 11 it is clear that only those oils which lie to the right of the critical tie line (the dashed line tangent to the two-phase curve at the critical point P) can develop this multiple contact miscibility.

Figure 12 shows how higher pressures will move this critical tie line to the left to encompass crude oils with heavier hydrocarbons by shrinking the two-phase region.[18] Therefore, the MMP depends on the molecular weight (or API gravity of the crude oil) with heavier oils requiring higher pressures.

The general trend of the pressures required for maximum oil recovery at the MMP is given in Figure 13 which shows that about 95% of a light oil will be recovered at less than 1500 psi in a slim tube test. For a medium gravity oil the pressures can be as high as 3000 psi, and for heavy oils they can exceed

4000 psi. Note that the required pressure for miscibility at 165°F is higher in Figure 13 than the MMP values for the Maljamar crude in Figure 8. The displacements in Figure 8 were carried out at 90°F. These figures illustrate that higher pressures are required at higher temperatures in order to compress the CO_2 to the same density that it had at the lower temperatures.[19,20]

Effect of Contaminants on CO_2 Flooding

The general trend of contaminants on CO_2 flooding is shown in Figure 14. No specific flooding pressure is shown because the trends with the different contaminants will be the same for heavy or light oils. Note that the best recovery is observed for pure CO_2 or for CO_2 which has been contaminated with either hydrogen sulfide or sulfur dioxide. Although the latter two substances are very undesirable from the point of view of corrosion or safety, they do not hurt the actual oil recovery when present in significant amounts in the CO_2 stream. Indeed, the presence of SO_2 will actually lower the MMP so good oil recovery could be obtained at a lower injection pressure than with pure CO_2. Although multiple contact miscibility is possible with methane in a vaporizing gas drive, the required pressure is much higher than with CO_2. Therefore, when methane is a contaminant the pressure required for maximum oil production will increase depending on the amount of methane in the injected CO_2 as shown in Figure 14. Nitrogen is worse than methane for contaminating CO_2. Thus, if significant amounts of nitrogen are present in the injected CO_2, the MMP will be raised significantly. Figure 14 also shows that good recovery with pure nitrogen will require a much higher pressure, especially for the low-temperature reservoirs in the Permian Basin, than does pure CO_2.

Oil Reservoirs In The Permian Basin

From this analysis of the displacement mechanisms and the technical screening criteria for carbon dioxide flooding, the need for an oil of medium to high gravity and the reason for a required depth of 2000-3000 feet can be understood. Fortunately, a high percentage of reservoirs in the Permian Basin fall into these categories of gravity and depth.

A significant portion of the known oil in the United States is located in the Permian Basin. Table 6 shows that the Basin contains 18% of our Nation's known "oil reserves," i.e., oil which can be recovered by current primary and secondary technology. The rest of the oil, some 56 billion barrels is the target for EOR methods such as CO_2 flooding.[1,2]

Reference 22, entitled "Target Reservoirs for CO_2-Miscible Flooding - Task Two: Summary of Available Reservoir and Geological Data," includes selected reservoirs from the Permian Basin (Volume 1) and the Rocky Mountain States (Volume 2). Each volume consists of four parts (bound separately), and the title for each part is listed in Ref. 22 for convenience. The authors of the above study found a total of 577 reservoirs which met their general screening criteria of greater than 30° API for the oil and 2 md for the reservoir. (This is more restrictive than most CO_2 screening criteria[1,3], see Tables 2 and 4.) After eliminating many small reservoirs (a minimum of 20 producing wells were required to make the list), 358 target reservoirs remained. The Permian Basin contains 216 of these and they are grouped by geologic zone in Table 7.

A separate evaluation of the 50 major oil fields in the Permian Basin was also sponsored by the U.S. Dept. of Energy.[23] It was estimated that these fields contain 27.6 billion barrels of oil which are unrecoverable by non-EOR operating conditions. By applying the NPC screening criteria, the authors found that 16 of these large fields have good potential for CO_2 flooding and 11 have polymer flooding potential. No fields had good potential for surfactant flooding and, according to the screening criteria, none of five methods was suitable for 23 of the fields.[23]

As the title of Table 7 indicates, the 216 reservoirs are carbonates and all of the narrative in Ref. 22 implies that only carbonates were considered, even though the Yates and Queen sands are included in the Guadalupe Group (see Figure 15). When the latter formations were included, they were identified as sandstones in the detailed tables. In general however, the shallower sands were reserved for consideration as candidates for waterflooding EOR methods and only carbonates were screened for CO_2 flooding. The Permian Basin has a much higher percentage of carbonate reservoirs than most oil-producing areas in the U.S. These carbonate reservoirs may not meet the screening criteria for most of the chemical flooding methods, but they become top candidates for CO_2 flooding because the combination of depth and API gravity meet the CO_2 screening criteria. From Table 7, it can be estimated that 67% of the oil in the selected target reservoirs is found in the Grayburg and San Andres dolomites, and much of the current CO_2 activity is directed at these formations.

A correlation chart for lithologic sections of the Permian Basin divisions is given in Figure 15; the divisions and their boundaries are illustrated in Figure 16.

CO_2 Supply

Not only do these reservoirs meet the technical screening criteria for CO_2 flooding better than any other enhanced recovery process, but the area is close to large volumes of underground CO_2. Figure 17 is a rough sketch of the major CO_2 producing sources and the areas where CO_2 activity is the highest in the U.S., including three major CO_2 fields which are now supplying reservoirs of the Permian Basin. These are the McElmo Dome field in the Four Corners area, the Sheep Mountain field in southern Colorado, and the Bravo Dome in northeastern New Mexico. All of these produce CO_2 from underground sources, and the gas is almost pure carbon dioxide. Total CO_2 reserves exceed 20 trillion cubic feet, and all of the fields are now connected to the Permian Basin by modern pipelines which deliver carbon dioxide to the injection wells. The general routes of the pipelines are shown in Figure 18. It is the availability of carbon dioxide at a reasonable cost, through these modern pipelines, that helps CO_2 flooding meet the economic criteria in the Permian Basin. In other parts of the country there are studies and efforts to obtain carbon dioxide from above ground, man-made sources such as fertilizer plants, chemical plants and even the stack gases from major power plants. However, the costs for the CO_2 from these sources is too high to be a profitable venture unless very large credits for air pollution could be given to the CO_2 supplier.

Predicted Oil Recovery

An examination of Figure 8 would indicate that 10% recovery of the original oil in place in the Permian Basin should be a reasonable estimate for CO_2 flooding. This amount, 5.6 billion barrels, was predicted in Ref. 2 and it is in general agreement with the 3.1 billion barrels predicted by the NPC Report.[1] The latter used more specific screening criteria (reservoir temperature, °API, depth and other parameters) in its oil recovery predictions for actual reservoirs and a miscible flooding model calculation was performed on each reservoir which met all screening criteria. However, only reservoirs which contained more than 50 MM barrels of original oil in place were considered by the NPC.

Figure 19, which has been reproduced from the NPC Report[1] shows that the combination of reservoir characteristics and CO_2 availability in the Permian Basin has enabled the engineers working on the NPC Report to predict high ultimate recovery by CO_2-miscible flooding for this area. The predicted 3.1 billion barrels are greater than the amount expected from any other process or any other area except for the oil to be produced by thermal recovery. At a projected oil price of $30 per barrel, Figure 20 (also taken from the NPC Report) shows that miscible flooding will reach about 500,000 barrels per day in 20 years and actually exceed thermal oil recovery at some point just beyond the year 2005.

In conclusion, it has been shown that the unique combination of technical screening criteria, and the availability of the carbon dioxide to the reservoirs, especially carbonates, of west Texas and New Mexico, means that CO_2 flooding will be one of the best answers for achieving the maximum oil recovery in this region during the next two or three decades.

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Table 1
Classification of Enhanced Recovery by the Main Mechanism of Oil Displacement

Solvent Extraction or "Miscible-Type" Processes

Hydrocarbon Miscible Methods
Carbon Dioxide Flooding
Nitrogen and Flue Gas
Alcohol Flooding or Other Liquid Solvent Flooding
Solvent Extraction of Mined, Oil-Bearing Ore

Interfacial Tension Reduction Processes

Surfactant (Low Interfacial Tension) Waterflooding
Surfactant/Polymer (Micellar) Flooding (Sometimes Included in Miscible-Type Flooding Above)
Alkaline Flooding

Viscosity Reduction (of Oil) or Viscosity Increase (of Driving Fluid) Plus Pressure

Steamflooding
Fireflooding
Polymer Flooding

(After Ref. 3)

Table 2
Summary of Screening Criteria for Enhanced Recovery Methods

	Oil Properties			Reservoir Characteristics					
	Gravity °API	Viscosity (cp)	Composition	Oil Saturation	Formation Type	Net Thickness (ft)	Average Permeability (md)	Depth (ft)	Temperature (°F)
Gas Injection Methods									
Hydrocarbon	> 35	< 10	High % of $C_2 - C_7$	> 30% PV	Sandstone or Carbonate	Thin unless dipping	N.C.	>2000 (LPG) to >5000 (H.P. Gas)	N.C.
Nitrogen & Flue Gas	> 24 > 35 for N_2	< 10	High % of $C_1 - C_7$	> 30% PV	Sandstone or Carbonate	Thin unless dipping	N.C.	> 4500	N.C.
Carbon Dioxide	> 26	< 15	High % of $C_5 - C_{12}$	> 30% PV	Sandstone or Carbonate	Thin unless dipping	N.C.	> 2000	N.C.
Chemical Flooding									
Surfactant/Polymer	> 25	< 30	Light intermediates desired	> 30% PV	Sandstone preferred	> 10	> 20	< 8000	< 175
Polymer	> 25	< 150	N.C.	> 10% PV Mobile oil	Sandstone preferred; Carbonate possible	N.C.	> 10 (normally)	< 9000	< 200
Alkaline	13-35	< 200	Some Organic Acids	Above Waterflood Residual	Sandstone preferred	N.C.	> 20	< 9000	< 200
Thermal									
Combustion	< 40 (10-25 normally)	< 1000	Some Asphaltic Components	>40-50% PV	Sand or Sandstone with high porosity	> 10	> 100*	> 500	> 150 preferred
Steamflooding	< 25	> 20	N.C.	>40-50% PV	Sand or Sandstone with high porosity	> 20	> 200**	300-5000	N.C.

N.C. = Not Critical
*Transmissibility > 20 md ft/cp
**Transmissibility > 100 md ft/cp

(After Ref. 3)

Table 3
Surfactant Polymer Flooding

Description

Surfactant/polymer flooding, also called micellar/polymer or microemulsion flooding, consists of injecting a slug that contains water, surfactant, electrolyte (salt), usually a cosolvent (alcohol), and possibly a hydrocarbon (oil). The size of the slug is often 5-15% PV for a high surfactant concentration system and 15-50% PV for low concentrations. The surfactant slug is followed by polymer-thickened water. Concentrations of the polymer often ranges from 500-2000 mg/L; the volume of polymer solution injected may be 50% PV, more or less, depending on the process design.

Mechanisms

Surfactant/polymer flooding recovers oil by:
-- lowering the interfacial tension between oil and water
-- solubilization of oil
-- emulsification of oil and water
-- mobility enhancement

TECHNICAL SCREENING GUIDES

Crude Oil

Gravity	> 25° API
Viscosity	< 30 cp
Composition	Light intermediates are desirable

Reservoir

Oil Saturation	> 30% PV
Type of Formation	Sandstones preferred
Net Thickness	> 10 ft
Average Permeability	> 20 md
Depth	< about 8000 ft (see Temperature)
Temperature	< 175°F

Limitations

An areal sweep of more than 50% on waterflood is desired.
Relatively homogeneous formation is preferred.
High amounts of anhydrite, gypsum, or clays are undesirable.
Available systems provide optimum behavior over a very narrow set of conditions.
With commercially available surfactants, formation water chlorides should be < 20,000 ppm and divalent ions (Ca^{++} and Mg^{++}) < 500 ppm.

Problems

Complex and expensive system.
Possibility of chromatographic separation of chemicals.
High adsorption of surfactant.
Interactions between surfactant and polymer.
Degradation of chemicals at high temperature.

(After Ref. 3)

Table 4
Carbon Dioxide Flooding

Description

Carbon dioxide flooding is carried out by injecting large quantities of CO_2 (15% or more of the hydrocarbon PV) into the reservoir. Although CO_2 is not truly miscible with the crude oil, the CO_2 extracts the light-to-intermediate components from the oil, and, if the pressure is high enough, develops miscibility to displace the crude oil from the reservoir.

Mechanisms

CO_2 recovers crude oil by:
-- generation of miscibility
-- swelling the crude oil
-- lowering the viscosity of the oil
-- lowering the interfacial tension between the oil and the CO_2-oil phase in the near-miscible regions.

TECHNICAL SCREENING GUIDES

Crude Oil

Gravity	> 26° API (preferably > 30°)
Viscosity	< 15 cp (preferably < 10 cp)
Composition	High percentage of intermediate hydrocarbons (C_5 - C_{20}), especially C_5 - C_{12}

Reservoir

Oil Saturation	> than 30% PV
Type of Formation	Sandstone or carbonate with a minimum of fractures and high permeability streaks
Net Thickness	Relatively thin unless formation is steeply dipping
Average Permeability	Not critical if sufficient injection rates can be maintained
Depth	Deep enough to allow high enough pressure (> about 2000 ft), pressure required for optimum production (sometimes called minimum miscibility pressure) ranges from about 1200 psi for a high gravity (> 30° API) crude at low temperatures to over 4500 psi for heavy crudes at higher temperatures.
Temperature	Not critical but pressure required increases with temperature

Limitations

Very low viscosity of CO_2 results in poor mobility control.
Availability of CO_2.

Problems

Early breakthrough of CO_2 causes several problems: corrosion in the producing wells; the necessity of separating CO_2 from saleable hydrocarbons; repressuring of CO_2 for recyling; and a high requirement of CO_2 per incremental barrel produced.

(After Ref. 3)

Table 5
Factors Which Contribute to Oil Recovery by CO_2 Flooding

According to the literature, CO_2 recovers oil by:

- Swelling the crude oil.
- Reducing the oil viscosity.
- Reducing the gas-oil interfacial tension.
- Vaporizing lighter hydrocarbons in the crude oil.
- Generating miscibility by the multiple contact process if the pressure is high enough.

Table 6
Estimates of Oil Discovered and Produced in the U.S.A. and the Permian Basin

	Billions of Barrels		Permian Basin % of US Total
	USA	Permian Basin	
Total Oil Discovered	481	81	17
Produced to Date	130	20	15
Recoverable by Primary and Secondary (current reserves)	28	5	18
Total Oil Remaining	323	56	17

Source: Refs. 1 and 2

Table 7
Carbonate Reservoirs in West Texas and Southeast New Mexico

Geologic zone	Number of reservoirs Total	Number of reservoirs > 100 MMbbl cum. prod.	Initial stock tank oil in place, MMbbl	Cumulative production through 1979, MMbbl
Permian Guadalupe (Primarily Grayburg and San Andres)	86	46	37,238	7,822
Leonard	29	15	7,366	1,214
Wolfcamp	14	0	655	286
Subtotal	129	61	45,259	9,322
Pennsylvanian	42	9	5,897	2,426
Mississippian	1	0	286	4
Devonian	25	8	3,054	686
Silurian	8	1	289	111
Ordovician	11	3	685	338
TOTALS	216	82	55,470	12,887

Source: Ref. 22

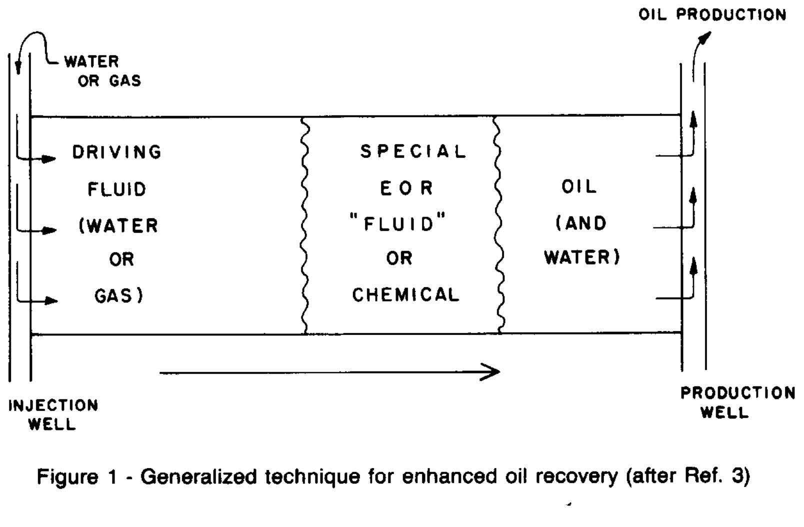

Figure 1 - Generalized technique for enhanced oil recovery (after Ref. 3)

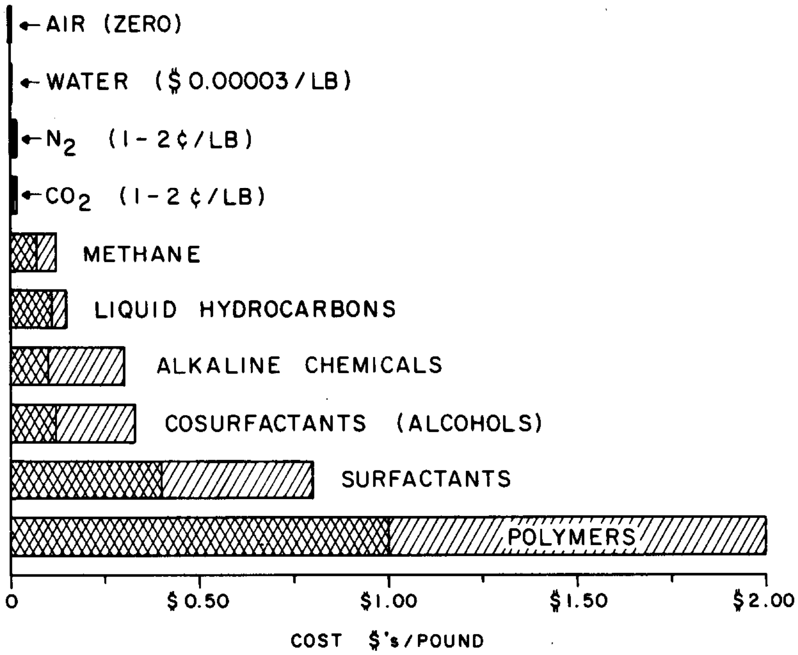

Figure 2 - Cost of materials used for EOR

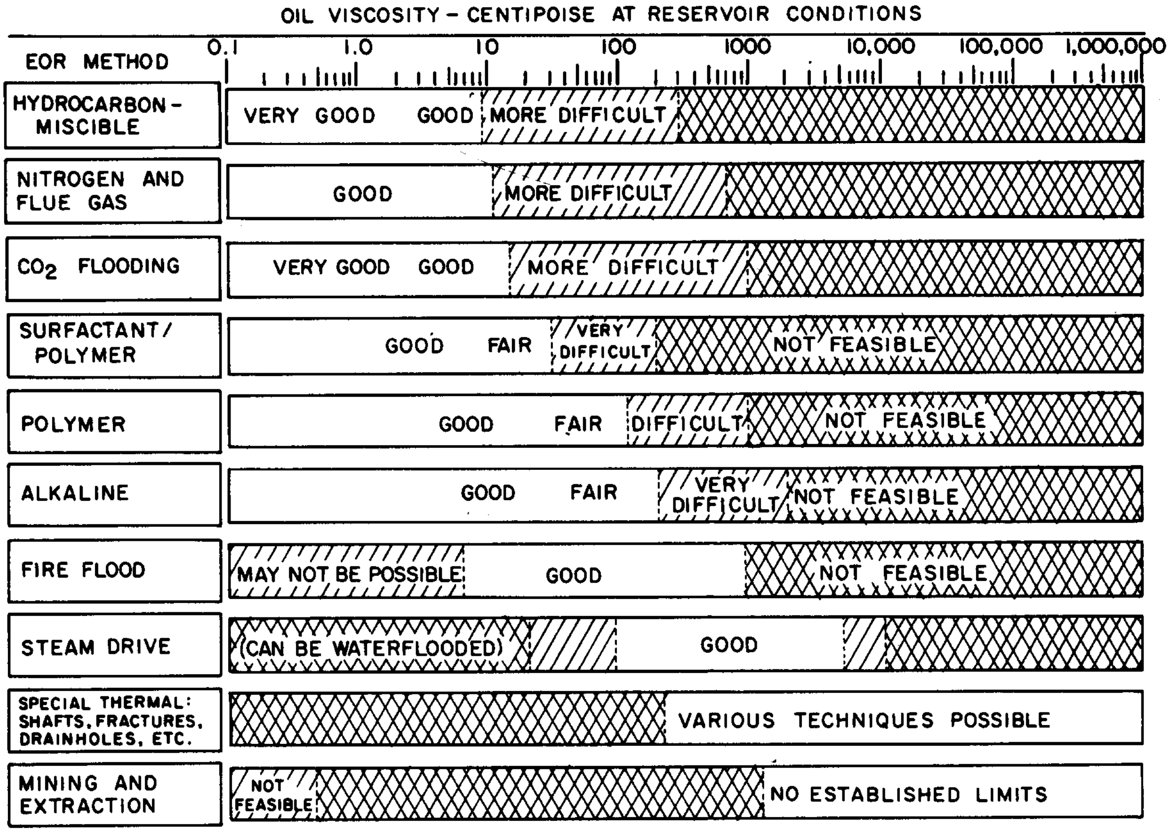

Figure 3 - Preferred oil viscosity ranges for enhanced recovery methods (after Ref. 3)

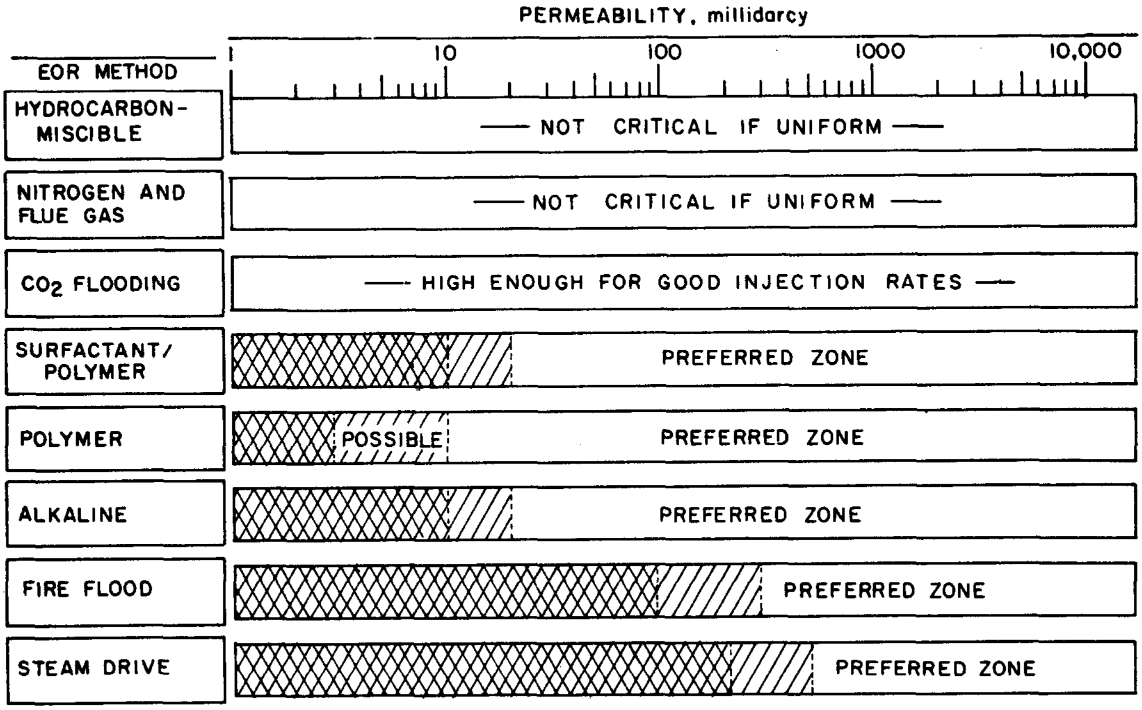

Figure 4 - Permeability guides for enhanced recovery methods (after Ref. 3)

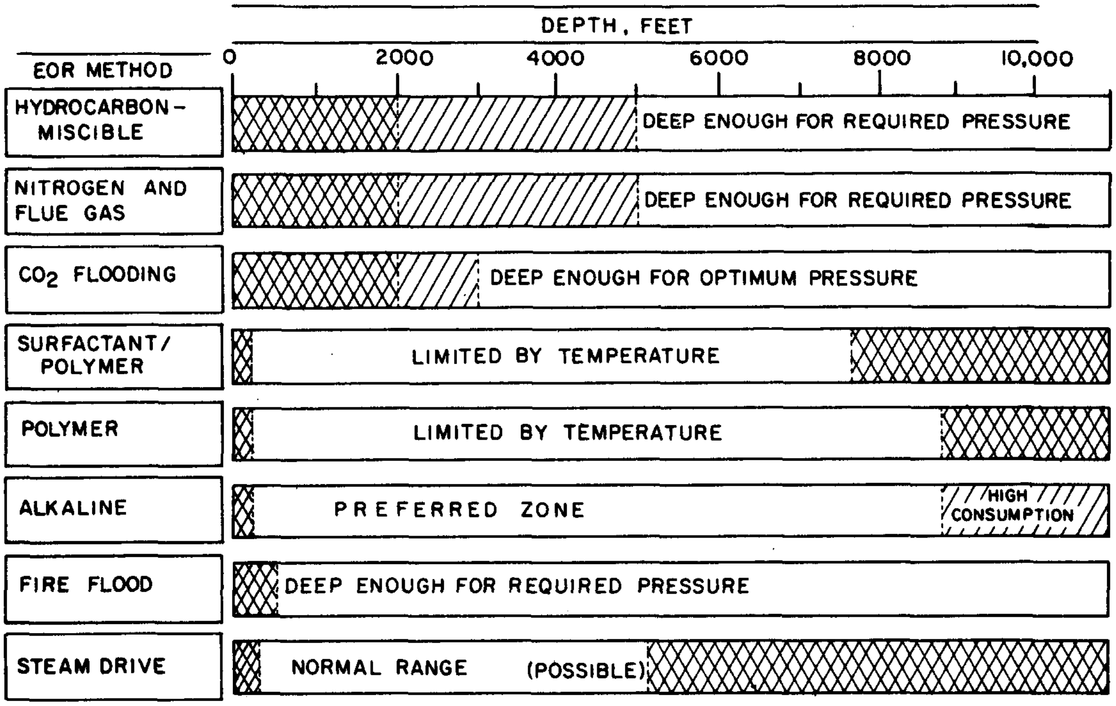

Figure 5 - Depth limitations for enhanced recovery methods (after Ref. 3)

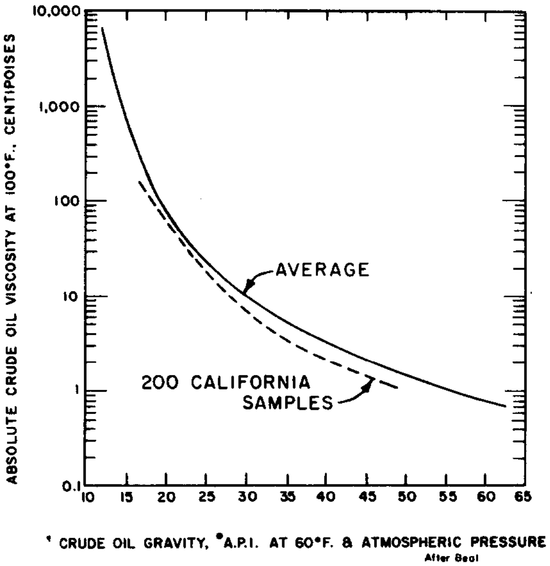

Figure 6 - General trend for viscosity of gas-free crude oil at 100°F and atmospheric pressure (after Ref. 6)

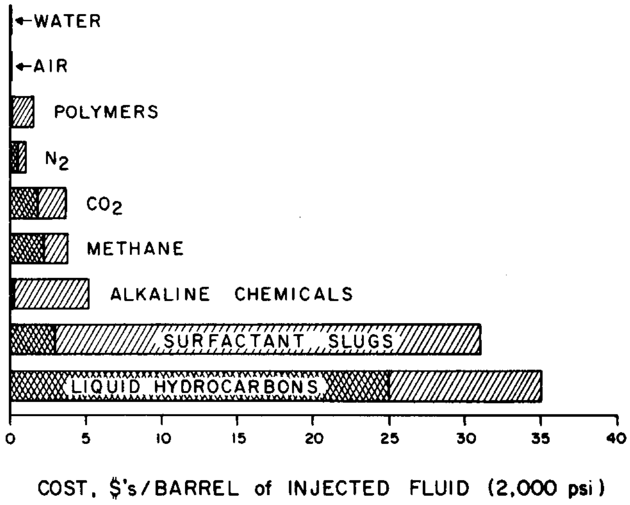

Figure 7 - Estimated cost of a barrel of "EOR Fluid" at reservoir conditions

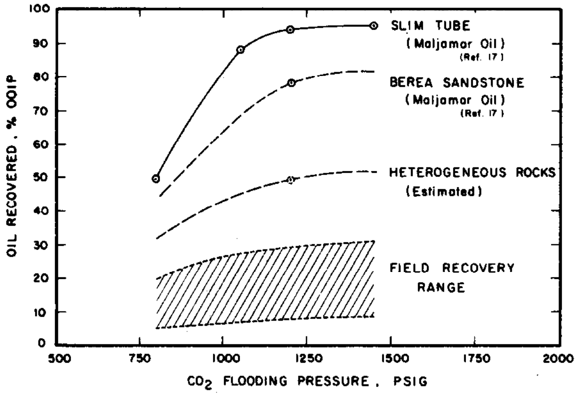

Figure 8 - Effect of pressure on oil recovery by CO_2

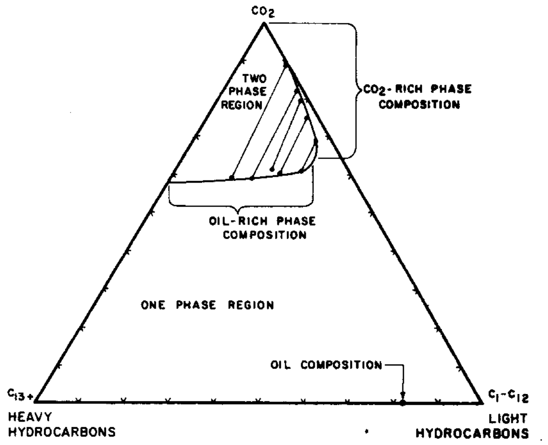

Figure 9 - Pseudoternary phase diagram at 2500 psia and 90°F for mixtures of CO_2 with a recombined Maljamar oil containing 650 sft^3 (standard cubic feet)/bbl solution gas (after Ref. 18)

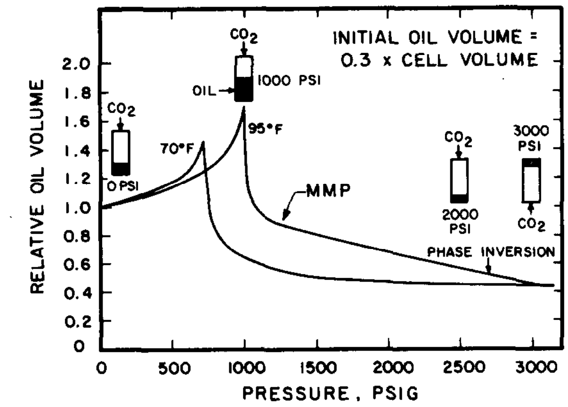

Figure 10 - Change in volume of Cabin Creek oil with the addition of CO_2 at increasing pressures (after Ref. 19)

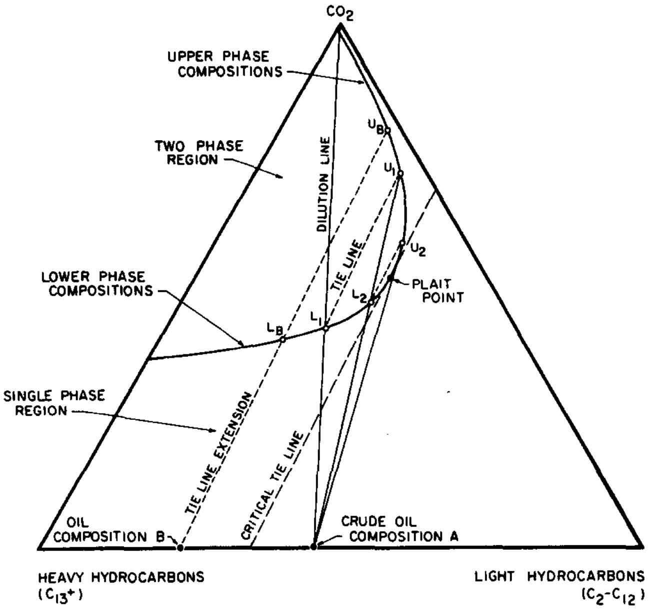

Figure 11 - Development of miscibility in CO_2 - crude oil systems (after Ref. 20)

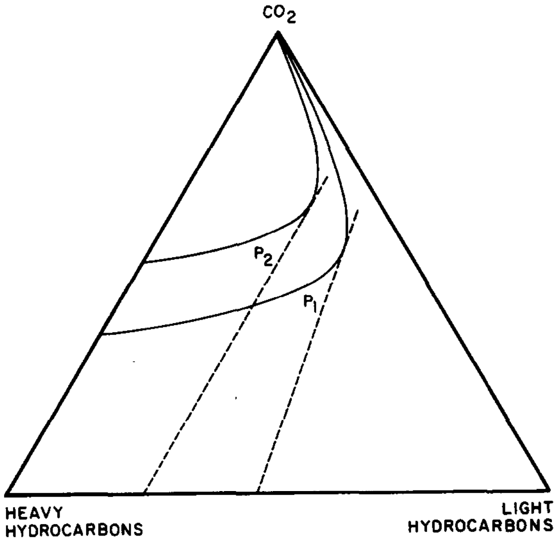

Figure 12 - Effect of pressure ($P_2 > P_1$) on size of two-phase region and position of critical tie line (after Ref. 18)

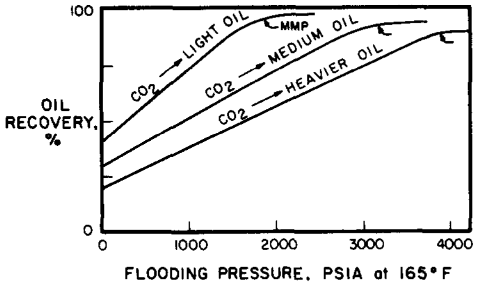

Figure 13 - Increase in pressure required for good CO_2 recovery of heavy oils

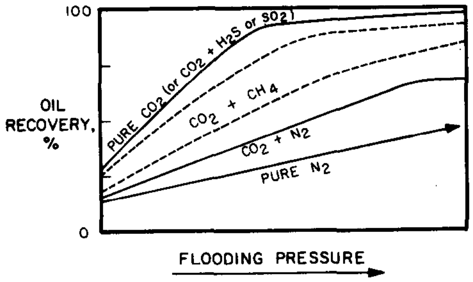

Figure 14 - General trend of *contaminants on CO_2 flooding*

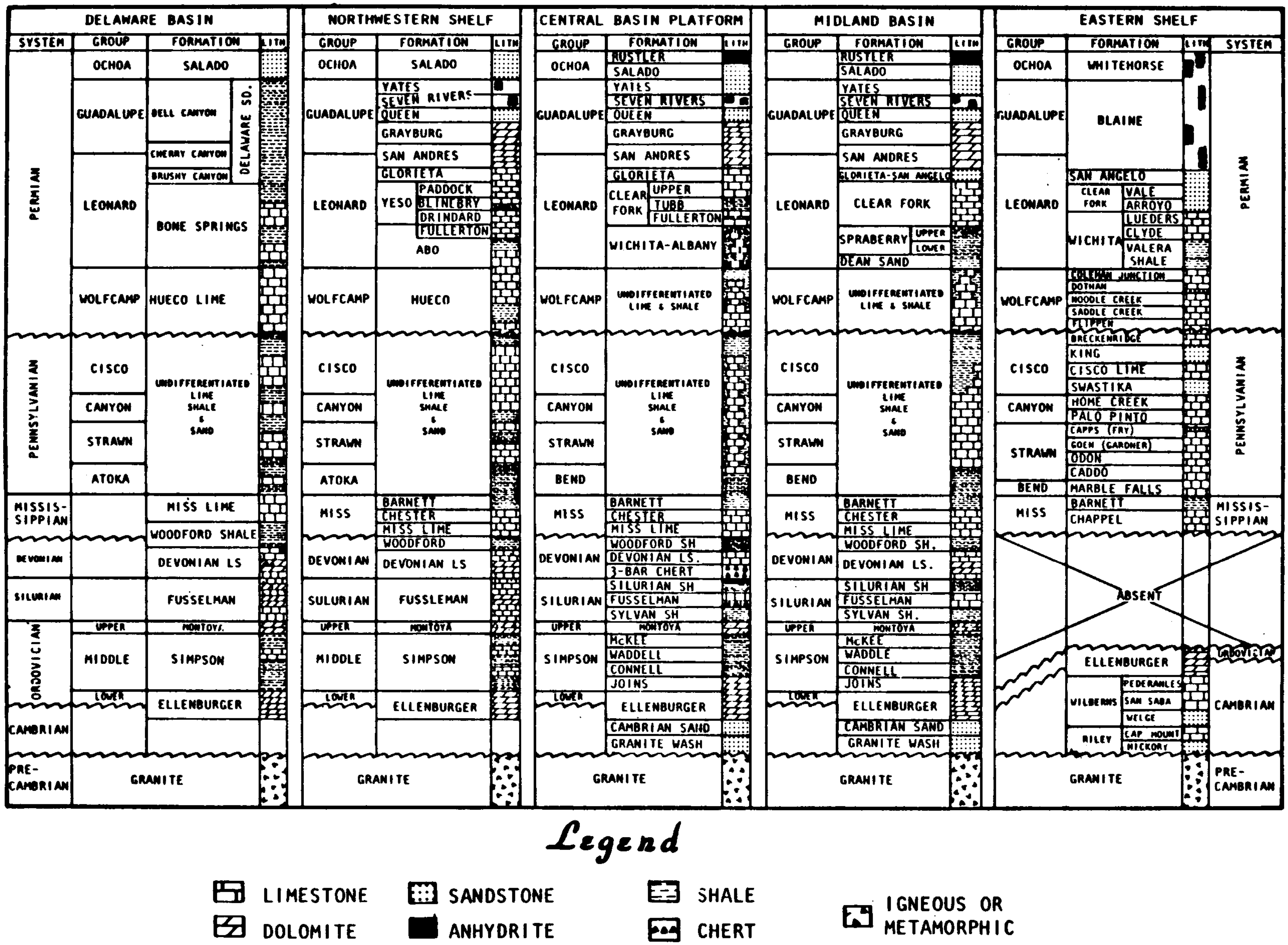

Figure 15 - Lithologic sections for Permian Basin Divisions (after Ref. 22)

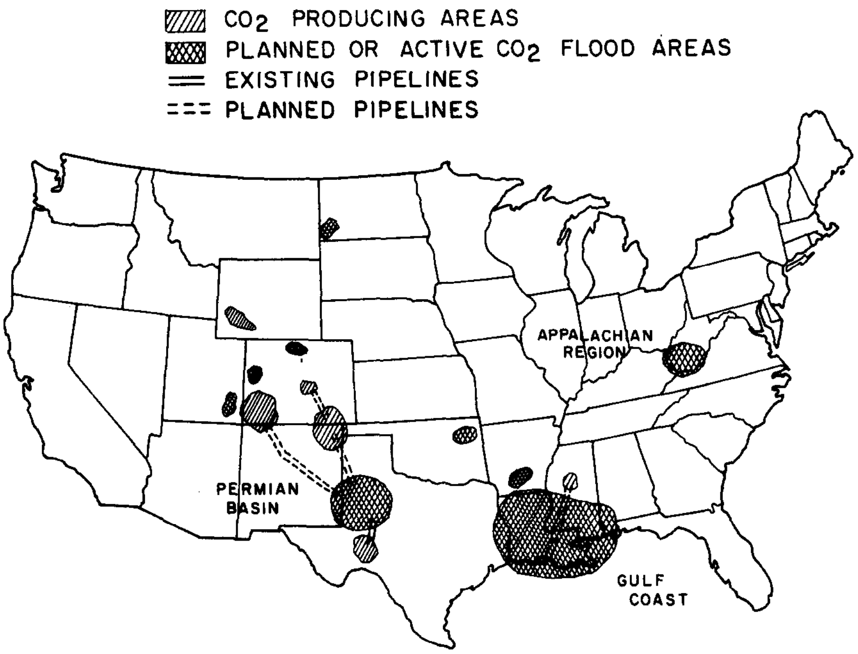

Figure 16 - Divisions and boundaries of the Permian Basin (after Ref. 22)

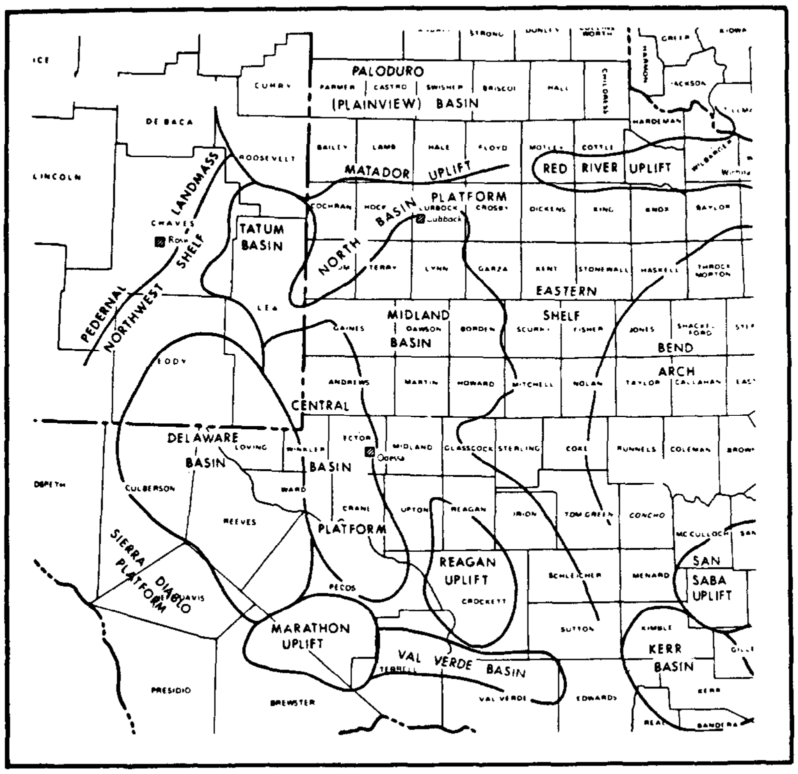

Figure 17 - Locations of natural CO_2 supplies and oil fields for which CO_2 floods are underway or planned

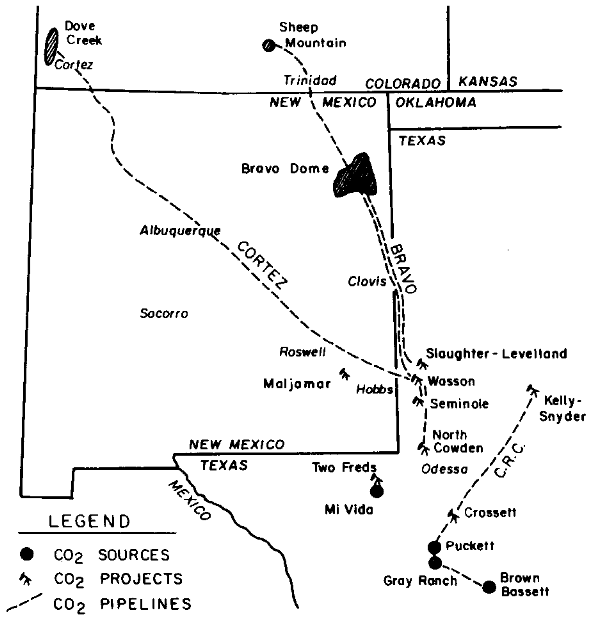

Figure 18 - CO_2 pipelines which supply the Permian Basin

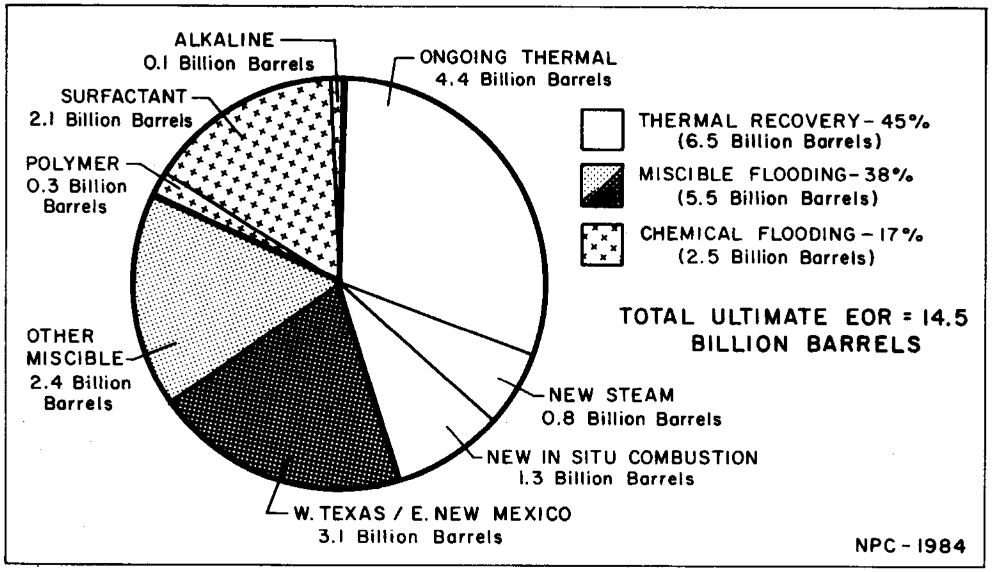

Figure 19 - Predicted recovery with present technology ($30/barrel and 10% minimum ROR) (after Ref. 1)

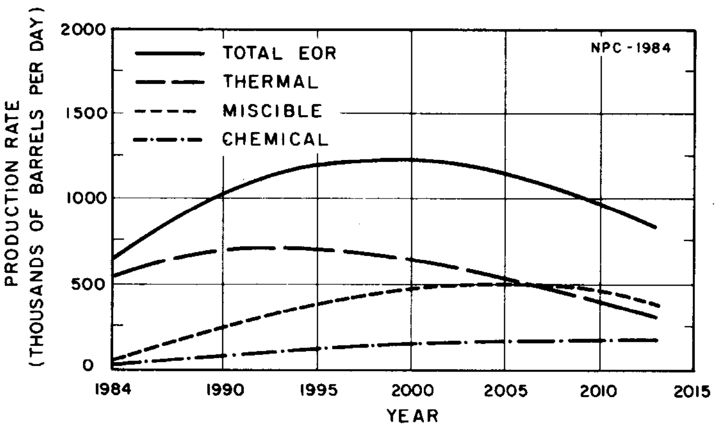

Figure 20 - NPC's predicted rate with present technology ($30/barrel and 10% minimum ROR) (after Ref. 1)