EOR Screening Criteria Revisited—Part 1: Introduction to Screening Criteria and Enhanced Recovery Field Projects

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Summary

Screening criteria have been proposed for all enhanced oil recovery (EOR) methods. Data from EOR projects around the world have been examined and the optimum reservoir/oil characteristics for successful projects have been noted. The oil gravity ranges of the oils of current EOR methods have been compiled and the results are presented graphically. The proposed screening criteria are based on both field results and oil recovery mechanisms. The current state of the art for all methods is presented briefly, and relationships between them are described. Steamflooding is still the dominant EOR method. All chemical flooding has been declining, but polymers and gels are being used successfully for sweep improvement and water shutoff. Only C02 flooding activity has increased continuously.

Introduction

Oil-production from EOR projects continues to supply an increasing percentage of the world's oil. About **3%** of the worldwide production now comes from EOR. Even though EOR production in the U.S. appeared to peak in 1992, **Fig. 1** shows that the EOR percentage of the **U.S.** production is larger than ever, because conventional oil production in the U.S. has continued to fall. Therefore, the importance of choosing the "best" recovery method becomes increasingly important to petroleum engineers.

About 100 years ago, oil producers injected gas to restore pressure to their dying oil wells.' Because air was cheaper than gas, air was often injected to increase production from the older fields. For many years, operators had the choice of air or gas, and sometimes they injected both into the same reservoir.[2] Naturally, there were safety and other problems with air. However, not until about 1928 did natural gas become the injectant of choice for pressure maintenance.[3] Water injection was legalized in Pennsylvania in 1921 (it was done secretly before that)?

The choice of injectants has widened considerably since those early days, but the petroleum engineer still must choose an injection fluid and an overall process to try to recover the maximum amount of oil from the reservoir while still making a profit. Screening criteria have evolved through the years to help the petroleum engineer make these decisions.[5-15] Some of the early work in this field was done by Geffen[5,6] before there was much field experience with most EOR methods. Many of his criteria have stood the test of time. Perhaps the best known, and most widely used, screening criteria appeared in the 1976 and 1984 Natl. Petroleum Council (NPC) reports.[7,8] We comment in Ref. 16 on some of the predictions based on these criteria. Ref. 9 is one paper that we are "revisiting." Although we retain the format of some of the tables in Ref. 9, all have been revised. We are basing our criteria in this paper on the results of much more field and laboratory information that has become available. Additional information (especially on the use of gelled polymers for water shutoff) is given in Ref. **17,** the original version of this paper.

In recent years, computer technology has improved the application of screening criteria through the use of artificial intelligence techniques, but the value of these programs depends on the accuracy of the input data used.[11-14] In this paper, we present screening criteria based on a combination of the reservoir and oil characteristics of successful projects plus our understanding of the optimum conditions needed for good oil displacement by the different EOR fluids. One goal is to provide realistic parameters that can be used in the newer computer-assisted tools for reservoir management.

EOR/Improved Oil Recovery (IOR)/Advanced Secondary Recovery (ASR)/Reservoir Management. In the past few years, the term IOR has been used increasingly instead of the traditional EOR, or the more restrictive "tertiary recovery." Most petroleum engineers understand the meaning of all the words and phrases, but our technical communications are improved if we use the terms with their intended technical meanings. We certainly endorse the wider use of IOR, but we cling to the technical meanings of EOR and tertiary recovery. Successful enhanced recovery projects are being conducted as tertiary, secondary, and even enhanced primary operations. The terms should continue to be used with their evolved historic meanings. Tertiary should not be used as a synonym for EOR because some EOR methods work quite well as either secondary or tertiary projects (e.g., CO_2 flooding), while others, such as steam- or polymer flooding, are most effective as enhanced secondary operations. To us, EOR simply means that something other than plain water or brine is being injected into the reservoir. We use the terms "enhanced secondary" or tertiary when necessary for clarity. Others may use the phrase ASR[18-22] for EOR in the secondary mode. We are convinced that engineers should consider this improved (enhanced or advanced) secondary option much more often in the future.

Classification of EOR Methods. Table 1 lists more than 20 EOR methods that experienced intensive laboratory and, in most cases, significant field testing. The methods use about 15 different substances (or specific mixtures) that must be purchased and injected into the reservoir, always at costs somewhat greater than for the injection of water. The economics of EOR are discussed more later, but experience shows that the best profits come only from those methods where several barrels of fluid (liquid or gas at reservoir pressure) can be injected per barrel of incremental oil produced.[23,24] This limits the main methods to either water (including heated, as steam, or as a dilute chemical solution) or one of the inexpensive gases. For some methods (e.g., micellar/polymer) there have been some technical successes but relatively few economic successes. These methods are included in our screening criteria because they are still being studied and applied in the field. If oil prices rise significantly, there is hope that these methods might become more profitable.

We provide screening criteria for the eight methods that are either the most important or still have some promise. These eight methods are shown in in Table 1, along with the number of the table in Ref. 16 for those methods that are examined in detail. These "current" EOR or IOR methods include the three gas (nitrogen, hydrocarbon, CO_2), three water [micellar/polymer plus alkaline/surfactant/polymer (ASP); polymer flooding; gel treatments] and the three thermal/mechanical (combustion, steam, surface mining) methods.

A convenient way to show these methods is to arrange them by oil gravity as shown in **Fig. 2.** This "at-a-glance" display also provides approximate oil gravity ranges for the field projects now under way. The size of the type in Fig. 2 is intended to show the relative importance of each of the EOR methods in terms of current incremental oil production.

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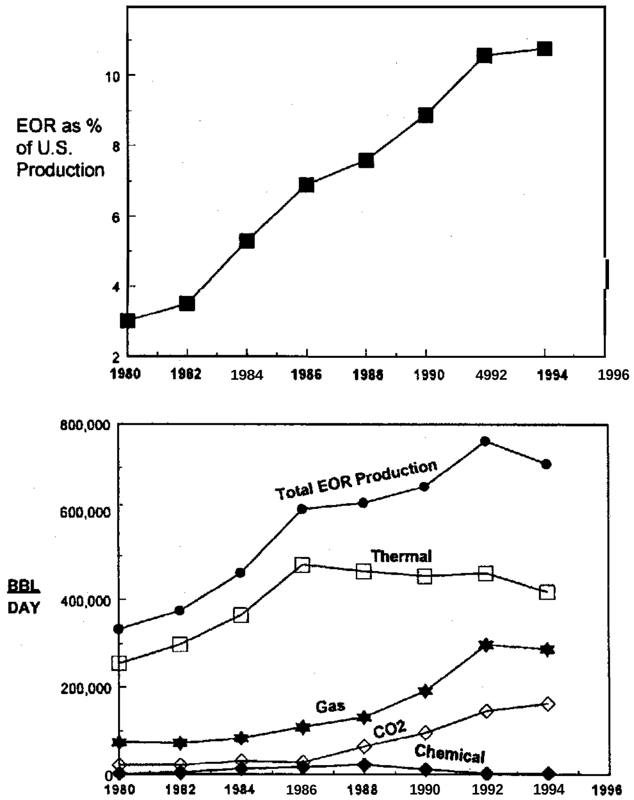

Fig. 1—EOR production in the U.S. (data from Ref. 25).

When examining the rationale for some of the screening parameters, it is instructive to consider the oil-displacement mechanisms for the EOR methods. **Table 2** shows that there are three main mechanisms for displacing additional oil with an injected fluid **(1)** solvent extraction to achieve (or approach) miscibility, **(2)** interfacial-tension (IFT) reduction, and **(3)** viscosity change of either the oil or water, and/or plus additional pressure added to the injection fluid. There is overlap of the mechanisms. For example, IFT is lowered as miscibility is approached in the "solvent" methods. The reservoir and injection conditions should be chosen to optimize the displacing mechanisms wherever possible (e.g., use a high enough pressure to achieve miscibility in solvent flooding and look for shallow reservoirs to reduce wellbore heat losses in steamflooding). Note that we have added "enhanced gravity drainage" by gas injection to Table **2.** Although not shown as a separate method in Table **1,** it is covered in **Table 3** as the immiscible-gas part of each of the three gas-injection methods.

TABLE 1—CURRENT AND PAST EOR METHODS

Method	Table Number (in Ref. 16)
Gas (and Hydrocarbon Solvent) Methods	
"Inert" gas injection	
Nitrogen injection	1
Flue-gas injection	1
Hydrocarbon-gas (and liquid) injection	2
High-pressure gas drive	
Enriched-gas drive	
Miscible solvent (LPG or propane) flooding	
CO_2 flooding	3
Improved Waterflooding Methods	
Alcohol-miscible solvent flooding	
Micellar/polymer (surfactant) flooding	4
Low IFT waterflooding	
Alkaline flooding	4
ASP flooding	4
Polymer flooding	5
Gels for water shutoff	
Microbial injection	
Thermal Methods	
In-situ combustion	6
Standard forward combustion	
Wet combustion	
02-enriched combustion	
Reverse combustion	
Steam and hot-water injection	7
Hot-waterflooding	
Steam stimulation	
Steamflooding	
Surface mining and extraction	—

Oil/Reservoir Characteristics of Successful Projects

The depth, and the corresponding oil gravity, of most of the EOR projects in the world are shown in **Figs. 3 and 4.** We have included projects for which data are available from a recent **paper.**[25] We are more familiar with the **U.S.** projects (Fig. **3.)** than those in other parts of the world (Fig. 4). In addition to the very broad distribution of the EOR projects, Fig. **3** shows the general trend, ranging from the many steam projects for the heavy oils at shallow depths in California to the very deep projects for the lightest oils that can be

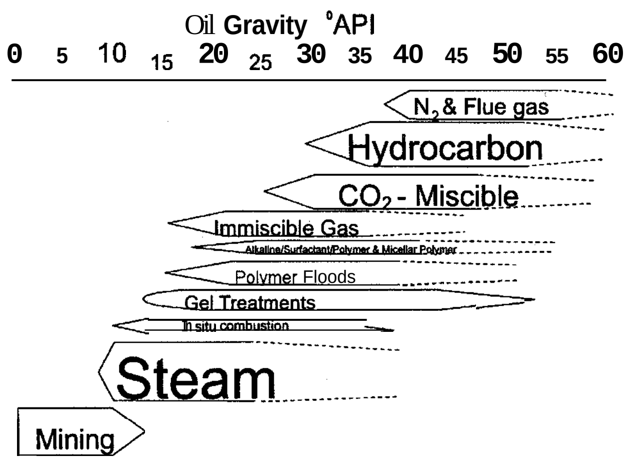

Fig. 2—Oil gravity range of oil that is most effective for EOR methods. Relative production (BID) is shown by size of type.

TABLE 2—CLASSIFICATION OF CURRENT ENHANCED RECOVERY METHODS*

Solvent extraction and/or "miscible-type" processes
Nitrogen and flue gas
Hydrocarbon-miscible methods
CO_2 flooding
"Solvent" extraction of mined, oil-bearing ore
IFT reduction processes
Micellar/polymer flooding (sometimes included in miscible-type flooding above)
ASP flooding
Viscosity reduction (of oil) or viscosity increase (of driving fluid) processes plus pressure
Steamflooding
Fireflooding
Polymer flooding
Enhanced gravity drainage by gas or steam injection

'Classified by the main mechanism of oil displacement (excluding gel treatments).

TABLE 3—SUMMARY OF SCREENING CRITERIA FOR EOR METHODS

Detail Table in Ref. 16	EOR Method	Oil Properties: Gravity (°API)	Oil Properties: Viscosity (cp)	Oil Properties: Composition	Reservoir Characteristics: Oil Saturation (% PV)	Formation Type	Net Thickness (ft)	Average Permeability (md)	Depth (ft)	Temperature (°F)
				Gas Injection Methods (Miscible)						
1	Nitrogen and flue gas	>35↗48↗	<0.4↘0.2↘	High percent of C_1 to C_7	>40↗75↗	Sandstone or carbonate	Thin unless dipping	NC	>6,000	NC
2	Hydrocarbon	>23↗41↗	<3↘0.5↘	High percent of C_2 to C_7	>30↗80↗	Sandstone or carbonate	Thin unless dipping	NC	>4,000	NC
3	CO_2	>22↗36↗ [a]	<10↘1.5↘	High percent of C_5 to C_{12}	>20↗55↗	Sandstone or carbonate	Wide range	NC	>2,500[a]	NC
1–3	Immiscible gases	>12	<600	NC	>35↗70↗	NC	NC if dipping and/or good vertical permeability	NC	>1,800	NC
				(Enhanced) Waterflooding						
4	Micellar/ Polymer, ASP, and Alkaline Flooding	>20↗35↗	<35↘13↘	Light, intermediate, some organic acids for alkaline floods	>35↗53↗	Sandstone preferred	NC	>10↗450↗	>9,000↘3,250	>200↘80
5	Polymer Flooding	>15	<150, >10	NC	>50↗80↗	Sandstone preferred	NC	>10↗800↗ [b]	<9,000	>200↘140
				Thermal/Mechanical						
6	Combustion	>10↗16→?	<5,000 ↓ 1,200	Some asphaltic components	>50↗72↗	High-porosity sand/ sandstone	>10	>50[c]	<11,500↘3,500	>100↗135
7	Steam	>8 to 13.5→?	<200,000 ↓ 4,700	NC	>40↗66↗	High-porosity sand/ sandstone	>20	>200↗2,540↗[d]	<4,500↘1,500	NC
—	Surface mining	7 to 11	Zero cold flow	NC	>8 wt% sand	Mineable tar sand	>10[e]	NC	>3:1 overburden to sand ratio	NC

NC = not critical.
Underlined values represent the approximate mean or average for current field projects.
[a]See Table 3 of Ref. 16.
[b]>3md from some carbonate reservoirs if the intent is to sweep only the fracture system.
[c]Transmissibility > 20 md-ft/cp
[d]Transmissibility > 50 md-ft/cp
[e]See depth.

miscibly displaced by *dry* gas or nitrogen at high pressures. The water-based methods use oils in the mid-gravity range, while the CO_2 projects cover a fairly broad range of oil gravities between 30 and 45°API. Fig. 3 confirms that all CO_2-miscible projects are at depths greater than 2,000 ft. Fig. 4 shows that the non-U.S. world distribution of projects is similar, but that there are more hydrocarbon and fewer CO_2 projects than in the U.S.

The incremental oil production from each EOR project is shown in **Figs. 5 and 6.** The dominance of steamflooding stands out clearly in these figures. Not only are there far more steamfloods, but the oil produced by steamflooding far exceeds that from all the other methods combined. Note that the largest EOR projects (in terms of oil production) are steamfloods, with the "off-scale" (Fig. **6)** Duri steamflood in Indonesia producing more than twice as much oil (245,000 B/D) as any other project in the world.

Suggested Criteria for EOR Methods

Oil and reservoir characteristics for successful EOR methods are given in Table 3. The table was compiled from field data for the projects shown in Figs. 3 through *6,* and from the known oil-displacement mechanisms for each of the methods. Very brief descriptions

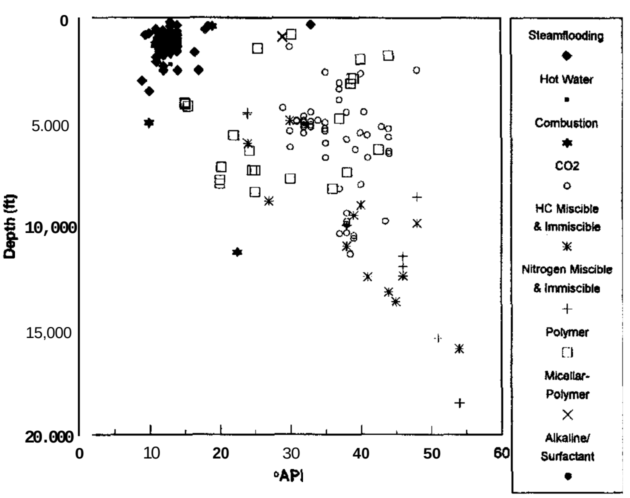

Fig. 3—Depth and oil gravity of producing EOR projects in the U.S. (data from Ref. 25).

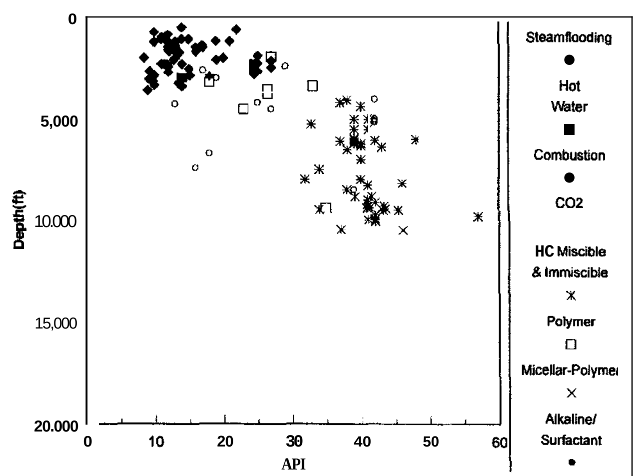

Fig. 4—Depth and oil gravity of producing EOR projects outside the U.S. (data from Ref. 25).

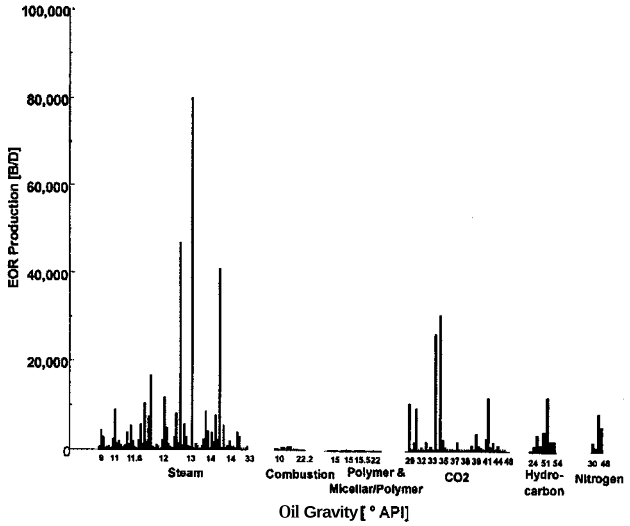

Fig. 5—EOR production vs. oil gravity in the U.S. (data from Ref. 24).

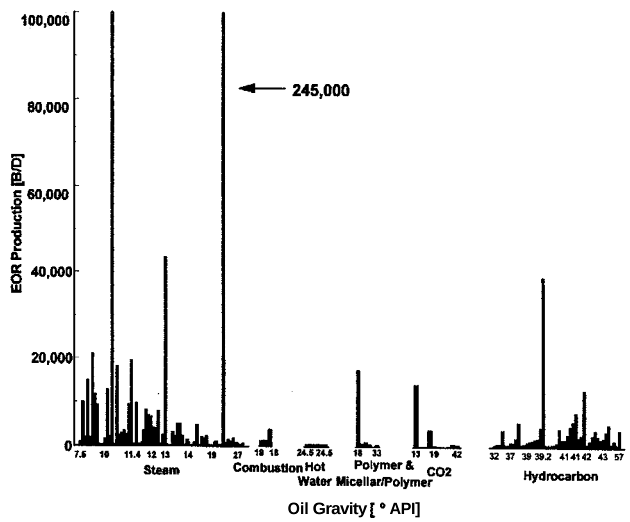

Fig. 6—EOR production vs. oil gravity outside the U.S. (data from Ref. 25).

of these mechanism are given in the "thumbnail sketches" of the methods in Tables 1 through 7 of Ref. 16.

Note that we have avoided notations such as $\geqq$ (equal to or greater than) because we want to emphasize that the suggested parameters are never absolute. They are intended to show approximate ranges of the criteria for good projects. In most cases, when we show such values as $>x$ or $<y$, there is not a specific upper (or lower) boundary to the parameter except for the limits of the oil and reservoir characteristics, as found in nature. For example, we show that nitrogen floods are recommended for oils lighter than 35°API, but this does not mean that the probability of doing miscible nitrogen floods drops to zero at 34°API. This obvious shortcoming of most screening criteria tables has been noted by authors who use artificial intelligence (AI) methods to select EOR processes for specific reservoirs.[11] To overcome the problems that arise with rigid boundaries in their "crisp" expert systems, some AI workers have used "fuzzy-logic"methods to obtain much more realistic results.[12]

In Table 3, we attempt to show that, for a given parameter, if $>x$ is feasible, $\gg x$ may be even better for a given process. By underlining a value, we indicate the average or mean of the parameter for that EOR method. For example, for the oil gravity in miscible nitrogen floods, $>35\nearrow\underline{48}\nearrow$ means that the process should work with oils greater than 35°API (if other criteria are met) and that higher-gravity oils ($\nearrow$) are better, and that the approximate mean or average of current miscible nitrogen projects is $\underline{48}$°API. The ascending arrow is meant to indicate that higher-gravity oils may be better yet.

In general, the upper and lower values in Table 3 ($>$ or $<$) have come from process-mechanism understanding (laboratory experiments), and they also include parameters of successful field projects. For example, even though we are unaware of any miscible CO_2 projects in reservoirs with oils of less than 29°API, we list 22°API as the lower limit because extensive laboratory work shows that the required pressure [i.e., minimum miscibility pressure (MMP), see Table 3 of Ref. 16] can be met in typical west Texas reservoirs with oils of that gravity. Also, we have lowered the oil gravity requirement to >12°API for immiscible CO_2 floods to include a successful 13°API project in Turkey (see Fig. 6).

Method/Criteria Descriptions

Gas-Injection Methods. Gas injection, the oldest EOR method, is a bright spot in EOR technology. Although most EOR production comes from steamflooding, Figs. 5 and 6 show that gas-injection methods are next in importance and appear to be growing throughout the world. Oil production from CO_2 flooding is the only EOR method that has continued to increase (Fig. 1) in the U.S. in spite of various declines in oil prices through the years, and more projects are planned. Hydrocarbon gas injection is second to steamflooding for the entire world. Thanks to efforts to reduce gas flaring, gas injection should continue to grow in importance as worldwide oil production expands. After years of extensive laboratory and field experience, the gas EOR methods are now well understood, and screening criteria can be recommended with more confidence than before. Although studied most extensively for CO_2, the concept of MMP explains the efficient oil displacements by N_2, hydrocarbons, and CO_2. As long as this MMP can be achieved in the reservoir, good oil recovery [greater than 90% original oil in place (OOIP) in the region swept] should result, although CO_2 displacements are usually more efficient than N_2 or CH_4. Even though the oil gravity/pressure/depth (MMP) requirements are different for the three gases, Table 3 shows that there is overlap of the criteria for the three methods. Thus, any of the methods will work in a high percentage of the deeper reservoirs, and the final choice often depends on the local availability and cost of the gas to be injected.

Nitrogen and Flue-Gas Injection. Other than compressed air, nitrogen and flue gas are the cheapest gases (especially in terms of volumes at reservoir temperatures and pressures) that can be injected. They are considered together because the pressures required (MMP) for good displacement are similar,[26] and it appears that they can be used interchangeably for oil recovery. Indeed, at least three of the current nitrogen projects[25] were operated successfully for years as flue-gas-injection projects.[24,27] However, corrosion was a problem (especially for flue gas from internal combustion engines), and all have switched to nitrogen injection with good results.

In addition to its low cost and widespread availability, nitrogen is the most inert of all injection gases. Unfortunately, it has the highest MMP, so miscible displacement is possible only in deep reservoirs with light oils.

Hydrocarbon Injection. As one of the oldest EOR methods, hydrocarbon injection was practiced for years before the MMP concept was well understood. When a surplus of a low-molecular-weight hydrocarbon existed in some fields, they were often injected to improve oil recovery. The three different methods were described by Stalkup[23] and are summarized very briefly in Table 2 of Ref. 16, including first-contact-miscible (LPG solvent), condensing (or enriched) gas drive and the vaporizing (or high-pressure) gas drive. In terms of the pressure required for efficient miscible displacement, we rank the hydrocarbon gases between the very high pressures required for nitrogen and the more modest range of pressures for CO_2 (see Table 3 of Ref. 16 for the reservoir depth requirement for different gravity oils). This ranking is correct for methane. However, if a shallower reservoir depth requires a lower pressure, it can be achieved by adding more enriching hydrocarbons (usually C_2 through C_4) if the economics are satisfactory.[28,29] This fine-tuning

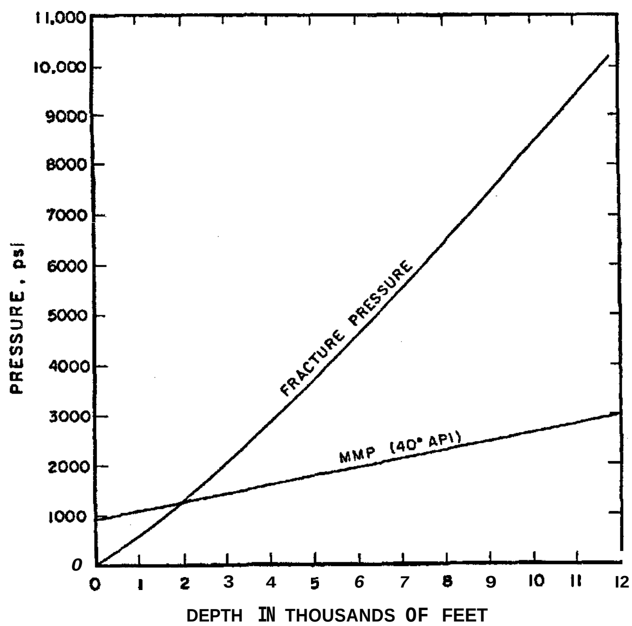

Fig. 7—Increase in CO_2 MMP and fracture pressure with depth for Permian Basin reservoirs. Increasing temperature with depth is incorporated in the MMP correlation show (from Ref. 33).

method is practiced most in Canada where cheap CO_2 is in short supply and hydrocarbon gases are available.

CO_2 Flooding. There may be more optimism for CO_2 flooding in the U.S. than for any of the other EOR methods. As noted before, it is the only method that has had a continuous increase in production since CO_2 flooding started more than **35** years ago. The technical and economic reasons for the success of CO_2 flooding have been explained before.[30] In the Permian Basin, a large pipeline supply of natural CO_2 is available at a low cost compared to methane, and the pipelines are being extended to more fields.[31,32] The screening criteria in Table **3** of this paper and Table **3** of Ref. 16 show that a fairly wide range of crude oils and reservoir depths can meet the requirements for miscible CO_2 flooding.

The density (and therefore the solubility of CO_2 in oil) decreases with temperature, **so** the MMP required for a given oil must increase with higher temperatures.[33] Since the reservoir temperature normally increases with depth, the MMP must also increase with depth, as shown in **Fig. 7** for a **40° API** oil in typical West Texas reservoirs. Fortunately, the pressure required to fracture reservoirs increases much faster than temperature with depth. Therefore, there **is** an MMP "window of opportunity," as shown in Fig. 7.[33] Oils heavier than 40° API would have an MMP/temperature/depth correlation above the line shown in Fig. 7; the pressures required are given in Table **3** of Ref 16. The MMP requirements for N_2 and CH_4 would have correlation lines with different slopes that are well above that shown only for CO_2 on Fig. 7.

The correlations in Fig. 7 and Table **3** of Ref. 16 come from many sources and are reviewed briefly in Refs. **30, 33,** and **34.** Most of the relationships among temperature, oil composition and pressure come from extensive work by various workers, primarily on oils from fields in the U.S.[35-38] The MMP screening criteria in Fig. 7 should work well for oils that have hydrocarbon distributions similar to the average mid-gravity crude oils of the U.S., especially those from the Permian basin of West Texas and Southeast New Mexico. However, if the oil differs significantly from the types of crudes for which the correlation was developed, additional laboratory tests may be required. Hagedorn and Orr[39] have shown that a high percentage of multiring aromatics will raise the MMP significantly because they are extracted **so** poorly by the CO_2 phase. **Table 4** gives conversions useful when reading CO_2-flooding literature.

TABLE 4—ADDITIONAL CONVERSION FACTORS USEFUL FOR READING CO_2-FLOODING LITERATURE

1 bbl = 42 U.S. gallons = 0.159 m^3
1 ft^3 = 0.0283 m^3
1,000 ft^3 (Mscf or Mcf) = 28.3 m^3
Standard conditions in U.S. oil industry (may vary in some states) = 1 atm and 60°F (1.013 bar, 14.7 psia)
CO_2 density at standard conditions = 0.001868 g/cm^3 or 1.87 kg/m^3 = 0.1166 lbm/ft^3
17,150 ft^3 of CO_2 at 60°F (1 atm) = (weighs) 1 ton U.S. (2,000 lbm)
1 ton U.S. = 2,000 lbm = 907 kg (1 kg = 2.2 lbm)
1 ton U.S. = 0.907 metric ton or tonne
1 tonne CO_2 = 18,904 scf at 60°F and 1 atm
1 Gt (gigatonne) = 1 billion metric tons
1 bbl oil (35°API) = 0.16982 ton U.S. = 0.16895 tonne
1 Mscf/bbl = 0.31324 tonne CO_2/tonne oil (35°API)
Some factors are rounded for convenience and quick estimates. Crude oil density typically ranges from 0.8 to 0.95 g/cm^3 or 800 to 950 kg/m^3.

Chemical and Polymer Flooding and Gel Treatment Methods. Figs. **3** through 6 show that there are relatively few chemical flooding projects (shown as polymer or micellar/polymer) in the world and that these projects contribute little to worldwide EOR production when compared to steamflooding and gas injection. For our screening criteria, we concentrate most on current technology that can be applied profitably today. Therefore, we have limited our criteria in Table **3** to these broad methods that are often included in the general term "chemical flooding." We are not aware of any pure alkaline floods at present. There are ASP projects that are hoped to be a low-cost improvement over micellar/polymer or surfactant flooding. Therefore, we have dropped the separate alkaline flooding category and combined it with the two main surfactant (IFT lowering) methods as shown in Table **3** of this paper and Table **4** of Ref. 16: micellar/polymer and ASP and alkaline flooding. There is still some excellent chemical flooding research and development work underway in laboratories around the world.

The polymer injection projects (especially in the U.S., see Fig. **3)** far outnumber the other chemical flooding methods. However, there has been some confusion between polymer flooding for enhanced oil recovery and the injection of gelling polymers for water shutoff in either injection or production wells. Therefore, they are considered separately in Table **3** of this paper and in Tables 8 and 9 of Ref. 17.

Wettability is another area of importance to waterflooding, and significant progress on understanding the influence of wettability on oil recovery is being made.[40,41] However, it would be premature to try to include wettability in our screening criteria at this time.

Micellar/Polymer, ASP, and Alkaline Flooding. The goal of the chemical methods **is** to reduce the IFT between oil and water, generally to displace discontinuous trapped oil (remaining oil saturation, S_{or}) that remains after a waterflood. Because it is approximately 10 times more difficult to replace trapped oil than continuous oil,[42] the surfactant slugs for these tertiary processes must be very efficient. The oil-displacement mechanics are well understood, and many formulations have been devised to give very high recoveries in laboratory experiments with actual reservoir rocks and fluids.

There have been some technical successes in the field[43,44]; however, there have been fewer economic successes because the cost of the injectant is too high. Therefore, there has been an effort to lower the injectant cost by adding more alkali and less surfactant or cosolvent to the formulations during the past few years.[24,45,46] These mixtures are often called ASP processes, and very large "slugs" can be injected because the cost is low compared with the classic micellar/polymer formulations. The alkali costs much less than the surfactant or cosolvent, and it helps to lower the IFT and reduce adsorption of the surfactant on the rock.[47,48] In one case, workers were able to reduce surfactant concentration by 10 times by adding low-cost alkali, and the formulation still provided very good oil recovery.[49] The ASP process has also been tested in the field.[50] A recent fieldwide project in Wyoming reports costs of U.S. $1.60 to $3.50/bbl of incremental oil produced.[51]

Polymer Floods and Gel Treatments. In the past, polymer floods and gel treatments were often lumped together as a single technology.[52] However, these processes have very different technical objectives, **so** we consider them separately. The distinction between a mobility-control process (e.g., a polymer flood) and a blocking treatment (e.g., involving crosslinked polymers or other gels) is an important concept to understand. For polymer floods and other mobility-control processes, the mobility-control agent should sweep evenly through the reservoir. In other words, the polymer should penetrate as far as possible into the low-permeability zones because that action provides the driving force for displacing and producing unswept oil. In contrast, for gel treatments, gel penetration should be minimized in less-permeable, oil-productive zones. Any gel that forms in the oil-productive zones reduces the oil-displacement efficiency and retards oil production.[53]

For existing gels and gelants that are used as blocking agents, the following behavior is observed during flow through porous media.[54–56] First, before gel aggregates grow to a size that approaches the size of pore throats, gelants flow through porous media like solutions without crosslinkers. Second, after gelation (or after gel aggregates grow to the size of pore throats), gel movement through porous rock is negligible. Third, in porous rock, the transition from a freely flowing gelant to an immobile gel occurs abruptly. After gel formation, crosslinked polymers, gels, gel aggregates, and the so-called "colloidal-dispersion gels" do not flow through porous rock like viscous polymer solutions.[55] Also, they do not enter and block the most-permeable strata first and then sequentially enter and block progressively less-permeable zones. Gelants and polymer solutions enter all zones simultaneously.[53] (Of course, the distance of polymer or gelant penetration depends directly on the permeability.) Understanding these concepts is particularly important for projects that were designed as polymer floods but that used hydrolyzed polyacrylamide (HPAM) crosslinked with aluminum citrate (i.e., the "colloidal-dispersion gels").[57] For these projects, an important question is, "Would the field response have been better if HPAM had been injected without aluminum citrate?"[55]

***Polymer** Flooding.* Over the past 35 years, a large number of polymer floods have been applied over a remarkably wide range of conditions[58,59]: reservoir temperatures from 46 to 235°F; average reservoir permeabilities from 0.6 to 15,000 md; oil viscosities from 0.01 to 1,494 cp; net pay from 4 to 432 ft; and resident brine salinities from 0.3 to 21.3% total dissolved solids (TDS). At project startup, the percent of OOIP ranged from 36 to 97.1%, and the producing water/oil ratio (WOR) ranged from 0 to 100. Narrower ranges of values for the relatively small number of current polymer floods are given in Table 5 of Ref. 16. During the 1980's, polymer floods were applied in sand or sandstone reservoirs about four times more frequently than in carbonate reservoirs.[59] In concept, a polymer flood could improve sweep efficiency during any waterflood. However, a number of technical and economic factors have limited the application of successful polymer floods. The cost effectiveness of polymers (i.e., the mobility reduction or viscosity provided per unit cost of polymer) is the main economic limitation. For example, if the cost of acrylamide/acrylate copolymers (HPAM) and xanthan polymers were substantially lower, higher polymer concentrations and larger polymer-bank sizes could be afforded in a given application. This, in turn, would lead to greater oil-recovery efficiencies, higher profits, and a wider range of potential applications.

Cost-effectiveness also impacts the permeability constraints for polymer flooding. For a given polymer, chemical retention increases and the rate of polymer propagation decreases with decreasing rock permeability. Current high-molecular-weight polymers often experience high retention and low propagation rates for rock permeabilities of less than 100 md.[60] This permeability constraint can be relaxed by use of polymers with lower molecular weights. However, the viscosity provided by a polymer decreases with decreasing molecular weight, so more polymer (and a higher cost per viscosity unit) is needed as the rock permeability and the maximum allowable polymer molecular weight decrease.

An important issue related to reservoir permeability is that of injectivity (injection rate per pressure drop). In wells that are not fractured, injection of viscous polymer solutions will necessarily decrease injectivity. To maintain the waterflood injection rates, the selected polymer-injection wells must allow higher injection pressures. This requirement becomes increasingly difficult to fulfill as the formation permeability decreases unless the wells are fractured. If injectors are fractured, the question is, "Will the increased injectivity from fracturing outweigh the increased risk of channeling?' (Later, we suggest that horizontal injection wells may alleviate injectivity limitations in some cases.)

Cost-effectiveness also affects the temperature constraints for polymer flooding. More than 95% of previous polymer floods were applied in reservoirs with temperatures of less than 200°F.[59] This fact reflects widespread doubt that HPAM and xanthan polymers are sufficiently stable at elevated temperatures. Literature reports[60] question whether these polymers are stable for field applications above 175°F. More stable polymers (e.g., scleroglucan and acrylamide copolymers and terpolymers) are available for high-temperature use, but the cost and cost-effectiveness of these polymers have limited their application to date.[60] Of course, significantly higher oil prices and/or breakthroughs in reducing polymer production costs could change this situation.

For many years, water salinity has been an important issue in polymer flooding.[60] In the range from 0 to 1% TDS, the viscosities of HPAM solutions decrease substantially with increased salinity. Thus, high-salinity HPAM solutions are relatively ineffective during polymer flooding. Differences of opinion existed concerning the viability of injecting low-salinity HPAM solutions into reservoirs with high-salinity waters. An important paper that addressed this issue was presented by Maitin.[61] In a well-documented field study, he demonstrated the conditions needed for low-salinity HPAM solutions to be effective in high-salinity reservoirs.

In reviewing literature reports of polymer floods, we often noted considerable uncertainty in assessing the benefits after a given project was completed. Most previous polymer floods used relatively small quantities of polymer (both in terms of polymer concentration and bank size).[59] Consequently, relatively small IOR values (1 to 5% OOIP) were often projected that resulted in small alterations of the oil-production decline curves and the WOR curves. Commonly, these small alterations were difficult to discern when comparing the actual polymer-flood response with the projected waterflood response.

In contrast, several polymer floods stand out that showed definitive responses, such as at the Marmul,[62] Oerrel,[61,63] Courtenay,[64] and Daqing[65] fields. Properties of these successful polymer floods are listed in Table 5 of Ref. 16 along with median values for all polymer floods that were applied during the 1980's. The four successful floods listed in this table had a number of features in common. These characteristics may be useful as screening criteria for today's economic environment. First, the floods were applied in high-permeability (> 0.87 darcy) sands and low-temperature (86 to 136°F) reservoirs. High oil saturations (71 to 92% OOIP) were present at project startup, and the oil/water viscosity ratios (15 to 114) at reservoir temperature were relatively high. The injected polymer solutions contained relatively high HPAM concentrations (900 to 1,500 ppm) in low-salinity waters, and large quantities of polymer (162 to 520 lbm polymer/acre-ft) were injected. Finally, the incremental oil recoveries (11 to 30% OOIP or 155 to 499 bbl oil/acre-ft) were high.

Gel Treatments. Gel treatments have been applied under conditions as diverse as those listed previously for polymer floods.[59,66] As mentioned earlier, the technical objective of a gel treatment should be very different from that of a polymer flood. In most cases, the objective of a gel treatment is to prevent channeling of fluid (usually water) without damaging hydrocarbon productivity. After extensive discussions with experts from the oil and service companies,[59,66] we developed criteria for selection of gel-treatment candidates for injection and production wells. These criteria and additional discussion of gel treatments are given in Refs. 17 and 66 through 70.

Thermal/Mechanical Methods for Heavier Oils and Tar Sands. Thermal methods account for the biggest share of the world's enhanced oil production. The largest EOR operations in many countries (e.g., Canada, Colombia, Germany, Indonesia, Trinidad, the U.S., and Venezuela) are either steamfloods or surface-mining operations. In the past, the production of bitumen from tar sands has not normally been included in EOR screening criteria or surveys, perhaps because the mining operations are not considered a part of reservoir engineering. However, the resource is so important that hydrocarbon recovery from tar sands should be included in listings of EOR or IOR processes. There is a very strong effort to try to recover these extremely viscous oils by in-situ methods[71] to avoid the cost of surface mining and to open vast deeper reserves. One method that shows promise uses horizontal wells in a variation of steamflooding known as steam-assisted gravity drainage (SAGD).[72-74] This mechanism is akin to the enhanced gravity drainage by immiscible gas injection mentioned previously and for which screening criteria are given in Table 3. In general, the screening criteria for SAGD and steamflooding are similar except that the depth, viscosity, and oil gravity ranges should be extended to include the tar sands.

Thermal EOR projects have been successful for more than 30 years, and the methods have been described in the literature.[75-77] Brief descriptions of the combustion and steamflooding methods are given in Tables 6 and 7 of Ref. 16. We comment here on only a few aspects that relate to screening criteria. In general, thermal methods have been used for those heavy-oil reservoirs that cannot be produced in any other way because the oil is too viscous to flow without the application of heat and pressure. To be produced at profitable rates, the sands must have a high permeability and oil saturations must be high at the start of the process. Therefore, the successful projects are almost always enhanced secondary (or even enhanced primary because primary production was essentially nil in many fields).

In-Situ Combustion. In-situ combustion seems like an ideal EOR method because of the following.

1. It utilizes the two cheapest and most plentiful of all EOR injectants: air and water.
2. For fuel, it bums about 10% of the least desirable fraction of the oil, and may upgrade the rest.
3. It works over a wider range of field conditions than steamflooding, especially in deep reservoirs.

This complicated process has been studied extensively[76] and tried in many different types of reservoirs.[78-80] However, at a recent symposium on in-situ combustion, Farouq Ali[81] claimed that "in-situ combustion remains the most tantalizing EOR method." At the same symposium, Sarathi and Olsen[82] showed that only one of eight cost-shared projects was an economic success, but that project provided valuable information on how to engineer a successful project. According to Turta,[83] air injection must start in the uppermost part of the reservoir, so that the combustion front can propagate downdip, preferably with a linedrive well configuration. Turta also described benefits of horizontal wells that have shown promising results in two Canadian combustion projects.

Efforts are continuing to improve the combustion process and to apply it to different types of fields. For example, oxygen-enriched fireflooding continues to look promising for reservoirs that require large volumes of gas at high flow rates where oxygen can be cheaper than air.[84] Newer materials and technology should help solve some of the field problems.[84] In another application, horizontal wells are being planned to improve light-oil, in-situ combustion projects (31 to 42°API) in North and South Dakota. Air injection has been under way since 1981. The operator hopes that horizontal wells will increase the recovery from the current 20 to 30% OOIP to 50% OOIP.[85] Deeper, light-oil reservoirs with significant dip are also targets for a new method of in-situ combustion that might be considered another variation of enhanced gravity drainage by nitrogen or flue gas.[86] In this process, air is injected in the formation, and the resulting combustion front moves downdip to displace the oil either miscibly or immiscibly by the flue gas produced from the combustion.[87] Combustion continues to have great promise for a much wider range of fields than the original heavy-oil targets, especially in deeper reservoirs. However, it is a complicated method with safety and corrosion problems that always need attention. These problems and their solutions were described in a recent review.[88]

Steamflooding. Steamflooding is the oldest commercial EOR method; the oil-displacement mechanisms are well understood. Much of the current emphasis is on improving the economics through better reservoir management.[89] As for screening criteria, the observations in our earlier paper[9] still apply: i.e., good projects require thick, shallow deposits with high oil saturations and good permeabilities. In times of low oil prices, the economics are very tight, especially because the heavy oil has less value than higher-gravity crudes. In recent years, the cogeneration of steam and electric power has been very beneficial to both the economics and environmental problems.[24,89]

Steamflooding was probably the first EOR method to take advantage of the benefits of horizontal wells.[90] References indicate that their use and other advanced engineering methods should make it possible to extend steamflooding to both lighter and heavier oils.[89] Laboratory tests show that steamflooding is an efficient mechanism for displacing light oils.[91] Several field tests have also been conducted in light-oil reservoirs, and a few have been successful.[92,93]

The Duri project in Indonesia is sometimes referred to as a light-oil project because its 22°API oil is outside Unitar's definition of heavy oil 10 to 20°API inclusive.[94] As the world's largest EOR project, the Duri steamflood is certainly successful (see Fig. 6). However, its starting oil saturation of 63% is near the average of the successful steamfloods in the world. Most of the other light-oil steamfloods had much lower oil saturations, so economic success was more difficult. In Table 3, we left a question mark for the upper limit to the oil gravity for steamflooding a medium-gravity oil that could be waterflooded as well as steamflooded. The steamflood should produce much more oil, but an effective waterflood will be cheaper. It will take a careful economic analysis of each potential light-oil steamflood to determine whether the additional oil will pay for the additional cost of the steamflood. It does appear that light-oil steamfloods should always be planned as enhanced secondary operations.

At the other end of the oil-gravity-steamflooding spectrum are the aforementioned SAGD projects in heavy-oil or tar sands. Although different techniques are under development, almost all these require one or more horizontal wells to inject the steam and withdraw the melted bitumen.[95] Normally, the steam is injected into the upper well of two parallel horizontal wells. With the application of hot steam and pressure, the tar melts and flows by gravity to the lower well, where it is pumped to the surface.

Mining and Extraction. Although not normally listed with EOR screening criteria, we include surface mining because the tar sands are such an important hydrocarbon resource and the production of synthetic crude from recovered bitumen keeps increasing.[96,97] In general, mining is used only when the oil is so viscous that it cannot be recovered by any other technique because the mining and upgrading of the bitumen are more costly than in-situ recovery methods. For this reason, the tar sands must have a high oil (bitumen) saturation and the ratio of overburden to tar sand must be low as shown in the screening criteria of Table 3. As mentioned in the previous section, there is an increased effort to produce these viscous hydrocarbons by in-situ methods, such as the SAGD process.

Conclusions

1. Screening criteria and brief descriptions are presented for the major EOR methods. The criteria are based on oil-displacement mechanisms and the results of EOR field projects. The depth, oil gravity, and oil production from hundreds of projects are displayed in graphs to show the wide distribution and relative importance of the methods. Steamflooding continues to be the dominant method, but hydrocarbon injection and CO_2 flooding are increasing.
2. If only oil gravity is considered, the results show that there is a wide choice of effective methods that range from miscible recovery of the lightest oil by nitrogen injection to steamflooding and surface mining for heavy oil and tar sands. However, there is often a wide overlap in choices.
3. With low oil prices, there is less chemical flooding of the intermediate-gravity oils that are normally waterflooded. Polymer flooding continues to show promise, especially if projects are started at high oil saturations.

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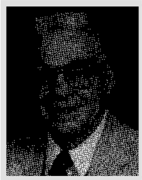
Metric Conversion Factors

atm	× 1.013 250*	E + 05	= Pa
°API	141.5/(131.5 + °API)		= g/cm^3
bar	× 1.0*	E + 05	= Pa
bbl	× 1.589 873	E − 01	= m^3
cp	× 1.0*	E − 03	= Pa · s
ft	× 3.048*	E − 01	= m
ft^3	× 2.831 685	E − 02	= m^3
°F	(°F − 32)/1.8		= °C
gal	× 3.785 412	E − 03	= m^3
lbm	× 4.535 924	E − 01	= kg
lbm mol	× 4.535 924	E − 01	= kmol
psi	× 6.894 757	E + 00	= kPa
ton	× 9.071 847	E − 01	= Mg
tonne	× 1.0*	E + 00	= Mg

*Conversion factor is exact.

SPERE

Joseph J. Taber was the first Director and is now Director Emeritus of the Petroleum Recovery Research Center (PRRC), a division of the New Mexico Inst. of Mining and Technology, where he continues his study of advanced recovery methods. He previously was a professor of petroleum engineering and chemistry at the U. of Pittsburgh and Senior Project Chemist with Gulf R&D Co., where he worked on new oil-recovery methods, especially horizontal wells for EOR and waterflooding. His recent work has dealt with C02 and EOR as they relate to environmental issues. He holds a BS degree from Muskingum (Ohio) College and a PhD degree from the U. of Pittsburgh. Taber was a 1989–90 Distinguished Lecturer on EOR and was named a Distinguished Member of SPE in 1994. **F. David Martin** is Manager and Chief Operating Officer of Strategic Technology Resources LLC, a technology-development company based in New Mexico. Martin has more than 35 years' petroleum industry experience. He worked at PRRC from 1976 to 1996, serving as Director during 1987–96. In that capacity, he supervised research on improved oil recovery, including CO_2 and chemical flooding. He holds a BS degree in chemical engineering from Texas Tech U. and an MS degree in petroleum engineering from New Mexico Tech. Martin has 16 patents and has written more than 50 technical papers related to petroleum production and of the chapter on "Reservoir Engineering" in the *Standard Handbook of Petroleum and Natural Gas Engineering.* Martin served as 1987–90 SPE Director for the Southwest Region and on several Society committees. **Randy Seright** is a Senior Engineer at the PRRC. He holds a PhD degree in chemical engineering from the U. of Wisconsin, Madison. Program Chairman for the 1998 SPE/DOE Improved Oil Recovery Symposium and a member of the Editorial Review Committee, Seright was a 1993–94 SPE Distinguished Lecturer and 1995 Program Chairman for the SPE International Symposium on Oilfield Chemistry.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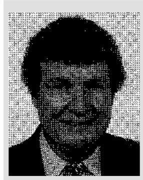
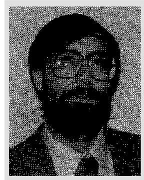

Martin


Seright