Enhanced Crude Oil Recovery Potential — An Estimate

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Introduction and Summary
Examination of published API data on domestic reserves of crude oil results in several interesting observations concerning the present status and future direction for the United States oil industry. Comparison of the low discovery rate of new reserves that the industry has experienced in the past — notwithstanding the discovery of Prudhoe Bay — with our present domestic demands for crude oil is striking. These discrepancies promise to have a dramatic effect on our domestic industry in years to come as the large fields discovered in the 1930's and 1940's are depleted. The foremost conclusion of this report, in common with that of many others, is that large, new domestic sources of crude oil need to be discovered and developed soon. Or, alternatively, an economically viable, massive substitute for domestic oil must be developed soon.

The second conclusion is that, contrary to many opinions, the cumulative oil reservoir recovery efficiency in the U.S. has been decreasing for a number of years, with the exception of a slight lift from the discovery of Prudhoe Bay. We can be certain that this is no way caused by poor or mediocre engineering, or by any arbitrary or poorly conceived decisions by management. The changes that have occurred in recovery efficiency with time are merely and exclusively caused by the sequence in which different types of oil fields were discovered in various locations in the U.S.

Study of the recovery-efficiency data has permitted us to reach some conclusions on the potential of tertiary recovery that we believe will be a shade better than those estimates that have been over-imbed with wishful thinking. The API data leave little doubt that there is and will be a very large amount of oil discovered that will not be produced with the technology we have developed to date. Thus, a third conclusion is that in addition to the need for large, new domestic sources of petroleum to be discovered, there is a potential for a sizable addition to domestic reserves if recovery efficiency can be increased. It becomes apparent, however, that the tertiary recovery potential cannot be quantified at this time, although targets can be spelled out. Were we faced with definitive success today in experimental and pilot operations, the time frame required for execution of the projects would make 1 million B/D by 1990 a difficult target.

Recovery Efficiency — Retrospective Analysis

Fig. 1 relates the 1973 estimates of ultimate recovery of crude oil reservoirs to their year of discovery; that is, reserves are attributed to the year in which the field was discovered even though development and additions to reserves from the field were continued in subsequent years.¹ The data are not complete for the last few years because development drilling and evaluation is still under way, but the trend is incontrovertible. Except for Prudhoe Bay, our discovery rate since 1958 has averaged less than 1 billion bbl/year; even with Prudhoe Bay averaged out over the past 8 years, the discovery

Examination of recovery efficiency and distribution of oil in place in the U.S. indicates reservoir recovery efficiency has been quite static for many years. Superficial changes in efficiency have resulted from the sequence in which reservoirs have been discovered and the methods used to book supplemental reserves. Development of tertiary recovery schemes is seen to have comparable importance to exploration in frontier areas.

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The rate is well under 2 billion bbl/year. The degree of success of exploration drilling also can be observed by reference to Fig. 2, which portrays the relation between exploration success and wells drilled. It is a cornerstone of our industry's future that this trend has to be dramatically reversed when new frontiers are made available to the driller.

Also shown in Fig. 1 is a curve indicating domestic consumption of crude oil, both domestically produced and imported. In recent years it has been hovering in the neighborhood of 5 to 6 billion bbl/year. Even more than the commonly shown figures comparing total domestic production with total domestic demand, these curves demonstrate the alarming disparity between the additions and withdrawals we have been making in our national oil bank account. Unless the success of exploration returns — and quickly — to that experienced during the glorious 1930's and 1940's we are probably on the road to closing out our nation's oil account for lack of funds.

Now, let us look at the recovery efficiency with the ultimate aim of determining if there is a significant amount of crude oil resources that we can view as a target for enhanced recovery. Recovery efficiency for discovered resources can be calculated from 1920 to the present using the API data. Pre-1920 discoveries are grouped together. Fig. 3 demonstrates that the recovery efficiency of our more recently discovered fields is less than the efficiency of that of earlier discoveries. Admittedly, the data for the last few years are open to question, since not all the fields discovered had supplemental projects installed at this time; as a result, not all the supplemental reserves were booked. On the other hand the supplemental targets are recognized and projects are implemented more quickly than in the past. It is also obvious that if only a small amount of primary is booked, then an even smaller amount of secondary can be booked. The trend is, again, incontrovertible.

In the face of our presently expanding technology concerning production and reservoir techniques, why is this reduction occurring? We will attempt to answer this by first breaking down the United States' reserves on a state-by-state basis. Borders between political units are not usually coincident with geological features, surface or subsurface, although there are marked exceptions. It is fortuitous, however, that in the U.S., state borders appear to circumscribe oil provinces. For discoveries thus far, four states have contributed 71 percent of our discovered ultimate recovery: Texas with 35 percent, California with 14 percent, Louisiana with 13 percent and Oklahoma with 9 percent. The ultimate recovery, broken down by states associated with discoveries in 10-year increments is shown graphically in Figs. 4A and 4B.

Before 1920, California, with the discoveries of the giant reservoirs in the Los Angeles Basin and the San Joaquin Valley, was the state in which most of the ultimate recovery was found. Other states, particularly the Appalachian states and Oklahoma, were at the time even more important than Texas and Louisiana. Starting in the 1920's and continuing through the 1950's, Texas rapidly replaced California as the leading oil state; subsequently, Louisiana came on and vied with Texas as the leading oil-finding state. At the end of the last decade, Alaska replaced Louisiana.

When we examine recovery efficiency on a state-by-
state basis in light of 1974 technology, we find rather striking differences. Fig. 5 shows how recovery efficiency has varied in 10-year increments in the chief producing states. Something different happened during the 1930’s in Texas and Louisiana, but not in Oklahoma and California.

The beautiful reservoirs (highly permeable and most with a strong natural water drive) were being discovered in East Texas and South Louisiana. The East Texas field is perhaps the epitome of this discovery cycle. Compared with the shallow, more viscous oil reservoirs discovered in the 1920’s and earlier (many by looking for the subterranean pool feeding the surface seeps), these reservoirs of East Texas and South Louisiana were bonanzas in every sense of the word. Later, during the 1940’s and 1950’s, the industry made its new discoveries by drilling deeper onshore or farther out into the deltas of the Gulf of Mexico; the sands were finer, the carbonates were tighter, and permeability and porosity were lower. A water drive, if any, was weaker. Recovery efficiency turned down again. The gradual, monotonous decline in recovery efficiency was interrupted in the late 1960’s with the discovery of the Prudhoe Bay accumulation — the largest in the U.S., and tentatively reported to have a modest water drive. Fig. 5 shows recovery efficiency both with and without Prudhoe Bay. Not only were the reservoirs discovered during the 1930’s efficient, they were big. In fact, of our 10 largest fields by remaining reserves, six were discovered in the 1930 to 1940 period and seven are deep in the heart of Texas.

On a cumulative basis, the trend is quite clear, as Fig. 6 demonstrates. Cumulative recovery increased significantly during the 1930’s, and has been going

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**Fig. 4A** — Recovery by states.

**Fig. 4B** — Recovery by states.

**Fig. 5** — Recovery efficiency by states.

**Fig. 6** — Cumulative recovery efficiency.

MAY, 1976
down in recent years with a bit of an inflection resulting from Prudhoe Bay.

A look at the microcosm of West Texas/Southwest New Mexico shows some of the detail of the nature of the historical oil-discovery cycle and the changes in recovery efficiency characteristic of the U.S.

Fig. 7 shows that three fields (oldies and goodies, to borrow a phrase from the recording industry) account for about 20 percent of the area's ultimate recovery. Yates field was discovered in 1926, Wasson field was discovered in 1936, and Kelly-Snyder field (Scurry County) was discovered in 1948.

Although there are some other sizable fields in the area, the industry has been ‘‘grubbin’ stumps’’ since 1950, waiting for something better to come along. Perhaps even the biggest stumps have been already grubbed. The few reservoirs that have been rooted out in West Texas in recent years are small and show fairly low recovery efficiencies. The original oil in place in this region is estimated at 89 billion bbl, or about 20 percent of that found in the nation. The ultimate recovery is estimated at 26 percent, compared with 32 percent for the nation. Surprisingly, this significantly lower efficiency is not caused by the carbonates, which we will see give almost average values after waterflooding, but results from the poor sandstones in the region.

Past Estimates of Recovery Efficiency and The Subsequent Effect of Waterflooding

The preceding analysis is ‘‘look-back data’’ as of Dec. 31, 1974. The recovery efficiency is that expected by the application of 1974 technology to the reservoir. But what if these reservoirs were evaluated with the technology of, say, the 1930's and 1940's; would the estimated recovery efficiencies be significantly lower? In other words, can we demonstrate a real increase in recovery efficiency of a particular reservoir or class of reservoirs with time? If we could, we could then say that developing technology did indeed increase recovery efficiency, and we might then be safe in projecting this increase forward in time. We are no Alley Oop, so we cannot transport ourselves backward in time and make a comparable evaluation ourselves. We will have to rely on the best estimates made by competent engineers at work on the problem in those days.

As recently as 1962, before the advent of the details of API statistical efforts, the Interstate Oil Compact Commission (IOCC) estimated original oil in place for reservoirs discovered before 1949 by using a figure of ‘‘3.57 barrels of oil discovered for each barrel of crude produced plus proved primary reserves.’’4 In other words, the best information available in 1962 indicate an average primary recovery efficiency of 28 percent when almost 75 percent of the nation’s total ultimate already had been discovered. The amount of crude produced by fluid injection by 1949 was negligible.

Let us compare the estimated primary recovery efficiency of 28 percent in 1949 with the API’s anticipate (proved and indicated) recovery efficiency of 32.9 percent at the end of 1974. Indeed, there is an improvement. It is important to assess whether this increase is to be attributed to gradually improving technology or to some other factor. We believe it is primarily attributable to the implementation of a single technique — waterflooding. The difference in recovery with and without waterflooding could have been added in one fell swoop. The IOCC did just that for the period 1948 to 1960. They had estimated a recovery efficiency varying from 31.5 to 32.8 percent over this period. The API statistics distribute this increase in recovery from waterflooding over several decades by adopting the procedure of booking waterflood and other supplement reserves only when the operation is actually implemented. Thus, the answer to our question is that gradual improvements in technology did not result in steady improvement in recovery efficiency.

The contribution to our ultimate recovery from the implementation of waterfloods can be calculated from these considerations as amounting to (4.9/32.9) X 100 percent of the total ultimate; or, an increase of 15 percent of the total ultimate. or, an increase of 21. billion bbl, 18 percent over primary.

Still another way to confirm this estimate is to add the total revisions made in the API estimated reserve between 1950 and 1974. These total revisions add up to 29.4 billion bbl. However, in addition to oil booked as a result of implementation of fluid injection operations revisions include those resulting from other information (other than changes in proved acreage), such as change

<table>
<thead>
<tr>
<th>TABLE 1 — CHANGING ESTIMATES OF RECOVERY EFFICIENCY</th>
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<tbody>
<tr>
<td>Date of API</td>
</tr>
<tr>
<td>-------------------</td>
</tr>
<tr>
<td>1968</td>
</tr>
<tr>
<td>1968</td>
</tr>
<tr>
<td>1970</td>
</tr>
<tr>
<td>1972</td>
</tr>
<tr>
<td>1974</td>
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<tr>
<td>(1974/1966)</td>
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Discoveries of 1960

<table>
<thead>
<tr>
<th>Date of API</th>
<th>Estimated Ultimate Oil in Place (thousands of barrels)</th>
<th>Estimated Oil in Place (thousands of barrels)</th>
<th>Recovery Efficiency (thousands of barrels)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1966</td>
<td>683</td>
<td>2,637</td>
<td>26.9</td>
</tr>
<tr>
<td>1968</td>
<td>732</td>
<td>2,615</td>
<td>28.0</td>
</tr>
<tr>
<td>1970</td>
<td>861</td>
<td>2,772</td>
<td>28.9</td>
</tr>
<tr>
<td>1972</td>
<td>874</td>
<td>2,963</td>
<td>29.5</td>
</tr>
<tr>
<td>1974</td>
<td>923</td>
<td>3,082</td>
<td>30.0</td>
</tr>
<tr>
<td>(1974/1966)</td>
<td>135 percent</td>
<td>121 percent</td>
<td>112 percent</td>
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</tbody>
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JOURNAL OF PETROLEUM TECHNOLOGY
in estimates of original oil in place, the effectiveness of the drive mechanism, etc. These revisions were always positive before 1950, so the 29.4 billion bbl probably includes more than just waterflood oil. (A couple of billion barrels certainly must be attributed to steam injection methods.) Thus, we are on quite firm ground in estimating waterflooding to have contributed an increased oil volume of between 20 and 25 billion bbl.

We should stop here for a moment and give credit to the old-time reservoir and petroleum engineers who made these early estimates, still valid today, with pencil, slide rule, and hand-cranked calculator. Their insight more than compensated for the primitive, but apparently more than adequate, tools at their disposal. We also must give credit to those operators in the Pennsylvania and New York oil fields who recognized the value of waterflooding 80 or so years ago. It was their misfortune that the State of Pennsylvania outlawed the operation of waterflooding, believing it would hurt the oil reservoirs. It was not until shortly after hard liquor was outlawed that waterflooding was legalized in 1921.

Extension of waterflooding to other regions was not rapid in the following decade, primarily because of the lack of economic incentive. However, in the 1930's, the Pete I unpleasant efforts were reported in many other states. A more thorough understanding of the process was developed after World War II, and the modern technology was subsequently developed. The greatest additions by waterflooding were achieved during the last decade.

When one studies the API statistical data for the past 10 years, it is also apparent that along with the steady increase in booked reserves owing to revisions and extensions, there has been a concomitant increase in the estimate of original oil discovered. Table 1 shows enhanced technological insight and additional production performance over a period of 8 years led to an improvement in estimated recovery efficiency for reservoirs discovered in prior years. In some cases, as for 1955, subsequent estimates of original oil in place have increased more than estimates of ultimate recovery, and look-back calculations of recovery efficiency decrease accordingly. This reveals an oversight in some prior attempts at demonstrating the effect of improved technology on recovery efficiency. The increase in the estimated ultimate recovery was perceived, but the change in the estimated original oil in place was not adequately assessed — and sometimes was neglected.

Technological developments have indeed permitted oil to be produced from deeper, higher pressure, a higher temperature reservoirs; in hostile, offshore, a frozen tundra environments; and from Hades-like gas environments. The accessibility to locations which oil has been discovered has been increased. Fracturing, acidization, and selective completions have stimulated producing wells and have accelerated recovery. The cost of produced oil has been kept low and production rates have been kept high enough to satisfy our nation's needs at low unit costs. It has been the achievements that, in no uncertain way, in times of war and of peace, have permitted our nation to reach and maintain its eminence. Although the continued implementation of supplementary recovery operations played an important role, we have not yet succeeded in introducing newer technology capable of further increasing recovery efficiency.

Total Volumetric Target for Tertiary Recovery
We have already shown that the rate of discovery has not kept pace with the rate at which we consume crude oil. We want to return to this point for a moment as a lead into the justification for the ensuing discussion of the need to increase recovery efficiency from known reservoirs, as well as to discover new resources in new frontiers.

One-half the crude oil discovered in the U.S. was discovered by 1936, and 75 percent was discovered by 1950, as shown in Fig. 8. We are living on these early discoveries. When discussion turns to the prospects for new frontiers, it is sobering to realize that the erstwhile new frontier now peaking out, the Gulf of Mexico, will contribute 6.3 billion bbl of estimated ultimate from current fields. This is a sizable volume of crude oil, but in terms of national consumption it is only a trifle more than a single year's supply. For comparison, an increase in recovery efficiency of only 1 percentage point would add a reserve of slightly more than 8 billion bbl. Of course, we hope the new frontier will exceed Prudhoe Bay and that recovery efficiency can be economically increased by more than a couple of percentage points; but until the barrels are in the pipeline, it is imperative that we look on this goal of increasing recovery efficiency with comparable enthusiasm.

Let us now shift our attention from recovered oil that left in the ground. That is our target for tertiary recovery. By breaking down these resources into regional groupings, we can see in Table 2 that there are...
really two types of reservoirs, as already noted: good ones and middling ones. It is not just that there is a natural water drive prevalent along the Gulf Coast; the quality of the sands, permeability, porosity, uniformity, and the low crude viscosity all aid and abet high recovery efficiency. In at least one of these giant fields, with a reported degree of uniformity better than some laboratory sand packs (a Dykstra-Parson coefficient of 0.2), the recovery is expected to reach some 80 percent.

**Some Tertiary Processes and Tertiary Targets**

Assuming an initial saturation of 65 percent, residual oil saturation in an average-performing Gulf Coast reservoir would be less than 30 percent at 100-percent sweep efficiency. If, because of the geometry of the reservoir and the placement of wells, the sweep is only 70 percent, the residual in the swept zone would be of the order of only 10 percent. Such low values have been confirmed.³ Three-fourths of the residual oil in such a reservoir is in the unswept portions of the reservoir. It is difficult to conceive how any tertiary process could get to this occluded oil, short of new drilling.

A first screening would say that a fraction in excess of one-half the Gulf Coast residual is not at high enough saturation for tertiary recovery processes that are currently under consideration. On the other hand, those Gulf Coast reservoirs with less than average performance (higher than average residuals) will still have characteristics (greater uniformity, freer of clays, and higher permeability) that are superior to those of most other oil provinces for chemical flooding. Chemical slugs introduced into these reservoirs will lead to more efficient displacement because the slugs have a greater opportunity to maintain their integrity and can attain higher velocities.⁷ On the other hand, Gogarty⁷ has indicated that in a good, clean Illinois Basin reservoir, a pattern spacing of 2.5 to 5.0 acres is required for efficient displacement of oil by a surfactant system. In the cited reference, infill wells apparently can be drilled to 1,000 ft for some $17,500. The resulting rate of return is indicated to be only 8 to 10 percent at an anticipated recovery efficiency of 242 bbl per net acre-foot ($\Delta S_p \phi = 0.031$) and a sales value of $13.50/bbl (Fig. 9). Taking into account the higher porosity for Gulf Coast sands (30 percent vs 19 percent) and an estimated lower residual (25 percent vs 40 percent), the recovery target would be about the same as in Illinois. Sand this was would not be sufficiently greater in the Gulf Coast to justify the obvious much higher cost of infill drilling in the marshes and bays of South Louisiana. In lieu of surfactant systems that can be propagated over larger well spacings or a much higher price than $13/bbl, a tertiary process other than chemical flooding appears to be needed as a general tool for the Gulf Coast reservoirs.

Let us look at what appears from Table 2 to be one of the largest single targets for tertiary recovery — the carbonates of West Texas. In textbooks, carbonate reservoirs usually get short shrift. The reason for this is the apparent complexity of the porous medium itself. Everyone has been to the beach as a child, and played with the sand and watched water drain out of sand piles. The concept of a sandstone reservoir is readily conveyed: fluid flow inside the sandstone can be easily conjured up in the mind’s eye. This, of course, is not the case for carbonates.

However, when one examines the performance of carbonate reservoirs, an unexpected consistency in their performance is observed. Fig. 10 is a plot from a current study being undertaken by the API Subcommittee

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**TABLE 2 — ESTIMATED UNRECOVERED OIL IN THE U.S.**

<table>
<thead>
<tr>
<th>Region and Reservoir Type</th>
<th>Original Oil in Place (billion barrels)</th>
<th>Estimated Ultimate Recovery (billion barrels)</th>
<th>Recovery (percent)</th>
<th>Estimated Residual (billion barrels)</th>
<th>Percent U.S.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Louisiana - south</td>
<td>30.96</td>
<td>16.13</td>
<td>52.1</td>
<td>14.83</td>
<td></td>
</tr>
<tr>
<td>Texas - east and</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Districts 2, 3, 5, and 6</td>
<td>35.17</td>
<td>19.32</td>
<td>54.9</td>
<td>15.85</td>
<td></td>
</tr>
<tr>
<td>Subtotal - Gulf Coast</td>
<td>66.13</td>
<td>35.45</td>
<td>53.6</td>
<td>30.68</td>
<td>10.4</td>
</tr>
<tr>
<td>Texas - south and west</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Districts with &lt; 30%</td>
<td>67.96</td>
<td>21.06</td>
<td>31.0</td>
<td>46.90</td>
<td></td>
</tr>
<tr>
<td>Districts with &gt; 30%</td>
<td>46.97</td>
<td>11.16</td>
<td>23.8</td>
<td>35.81</td>
<td></td>
</tr>
<tr>
<td>California</td>
<td>68.18</td>
<td>21.65</td>
<td>26.0</td>
<td>61.88</td>
<td></td>
</tr>
<tr>
<td>Oklahoma</td>
<td>37.66</td>
<td>12.44</td>
<td>33.0</td>
<td>25.21</td>
<td></td>
</tr>
<tr>
<td>Subtotal - except Gulf Coast</td>
<td>235.82</td>
<td>68.32</td>
<td>28.1</td>
<td>169.50</td>
<td>57.3</td>
</tr>
<tr>
<td>Remaining U.S.</td>
<td>138.77</td>
<td>43.24</td>
<td>31.2</td>
<td>95.53</td>
<td>32.3</td>
</tr>
<tr>
<td>Total U.S.</td>
<td>440.72</td>
<td>145.01</td>
<td>32.9</td>
<td>295.71</td>
<td>100</td>
</tr>
</tbody>
</table>

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Fig. 9 — Projected economics, 6,000-acre Maraflood performance development in Illinois; after-tax projections showing effect of recovery efficiency spacing and crude price on rate of return. (From Gogarty.⁷)

⁷Estimated residual in the half of the reservoirs amenable to tertiary recovery.
on Recovery Efficiency. It represents a plot of initial and recovered oil in barrels per net acre-foot for a group of randomly volunteered carbonate reservoirs from a number of operators in Texas. (We might add that the data from other solution gas driven carbonates will superimpose themselves on the Texas sample.) Such statistical consistency speaks for a rather consistent depletion mechanism being operative in carbonates. We interpret the apparent constancy of the recovery efficiency to signify a statistically average occluded pore volume fraction in carbonates. Swept pores have little oil left in them, and unswept pores have a lot (Fig. 11). If this is the correct picture, how do we get at the residual? Chemical flooding probably could reduce the low residual in the swept pores to zero, but would not have much chance of penetrating into the unswept pores. Moreover, the calcium and magnesium in the interstitial brines and at mineral surfaces in the carbonate reservoirs would wreak havoc with the delicately balanced multicomponent chemical slugs containing “Surfactant A + Surfactant B + cosurfactant + oil + salt + water + oxidation inhibitor + bactericide.” We do not doubt for a moment that such a formulation could be developed for carbonates; we do doubt its economic usefulness.

On the other hand, a miscible flood using carbon dioxide does have promise. Under high pressure, super-critical carbon dioxide is partially to completely miscible with many West Texas crude oils. Diffusion forces, aided by the low viscosity and density differences between the miscible fluids, would promote the penetration of the carbon dioxide into the formerly unswept pores. But we must not overlook the history of LPG flooding. Starting in 1956, with the threat of the Suez crisis hanging over the Western world, LPG flooding was latched onto as a great hope for increasing both recovery and production rates. Although crude oil was less than 10¢/gal at the time, LPG was only pennies per gallon and could be viewed in this context as a sacrificial reagent. Unfortunately, it was found that permeability variations within the reservoir and adverse mobility ratios, which could not be completely assessed in laboratory studies, mitigated economic recovery; the ratio of produced oil to injected LPG was too low even at the then relatively low cost of the LPG. (Today, of course, neither LPG nor natural gas can be thought of as cheap, sacrificial reagents.) These adverse parameters that obviously will appear in many carbonate reservoirs also will diminish the effectiveness of carbon dioxide.

Carbon dioxide, however, was introduced because it was a far cheaper reagent than LPG and it was anticipated that greater ratios of carbon dioxide to produced oil could be tolerated. Also, super-critical carbon dioxide may have a density between the densities of oil and water and, thus, gross gravity instability would be avoided. The viscosity, however, is very low and the potential for viscous fingering is still with us. In many cases, attempts are made to restrict the fingering of the carbon dioxide by the alternate injection of water. The goals appear to be the achievement of some degree of plugging of the more permeable paths and an improvement in sweep. The plugging presumably results from Jamin effects — the high energy required to force an alternating sequence of nonwetting and wetting phases through capillaries. Such effects, if they do occur, probably will be more pronounced in low-permeability paths than in the higher, already-depleted paths through the reservoir, even though the latter accept more of the injected fluid mixtures. But an even more significant drawback to the use of water to counteract the fingering of the carbon dioxide is the counter-effect it has on the basic goal of the process.

A tertiary carbon dioxide flood is, in mechanistic terms, a carbon dioxide flood of a water-filled reservoir, and much of what the carbon dioxide does is to displace the reservoir water. It would appear that it is behind this front that the carbon dioxide will begin to collect the distributed oil and, it is hoped, bank it up and get it moving. Alternating water with the carbon dioxide promises to break up any oil bank forming in back of the initial water-carbon dioxide interface. We believe some other process schemes will have to be developed to more efficiently reduce carbon dioxide fingering and circulation through the reservoir.

What can we say are the minimum requirements of carbon dioxide to recover a barrel of oil, and what is the cost? Merely to substitute for a barrel of stock-tank oil

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Fig. 10 — Texas carbonates, recovered oil vs original oil in place.

MAY, 1976
under anticipated subsurface conditions will require 2.5 to 3.0 Mscf. Losses caused by solution in reservoir-retained oil and water, and by incomplete stripping of carbon dioxide from produced fluids (the recovered carbon dioxide, at anticipated make-up costs, will be re-compressed and re-injected) could double this quantity.

Fig. 12 presents a location map of what we believe are the principal targets for carbon dioxide flooding in West Texas, and our arm’s-length estimate of the oil that might be recovered by successful application of the process. The total of 4 billion bbl is indeed impressive.

The recent disposition of merchant carbon dioxide supplies is shown in Fig. 13, and the cost of these supplies is shown in Fig. 14. The use is limited and the costs are quite high, but considering the use the buyer can afford the tariff. However, if carbon dioxide is used for tertiary recovery in West Texas, and if our estimates of consumption are in the ball park, then some 24 Mscf of carbon dioxide will be required. If we assume it will be used over a 20- to 25-year injection cycle, the demand, as shown in Fig. 15, jumps and eventually will reach more than 1 Tcf/year.

It is, of course, impossible for us to predict where such a supply of carbon dioxide would come from. Obviously, exploratory searches are under way to find it in the subsurface. One thing certain is that we cannot afford to burn oil just to produce carbon dioxide; burning a barrel of a typical crude will not produce much more than 6 Mscf. But even if the carbon dioxide is available free of charge, perhaps from the stacks of a coal gasification plant, compressing and transporting it over a distance of 500 miles, for example, puts a price tag on it of about $1/Mscf. Adding the mere operation of injecting 6 Mscf to recover a barrel of crude to the costs of the balance of the oilfield operation, recirculation of carbon dioxide, and fighting the corrosiveness of this acid gas, one could estimate an operating cost reaching $10/bbl. But if the carbon dioxide is not free (say it has to be manufactured by specialty manufacturing*), or if it is to be recovered from stack gases, or shipped 1,000 miles, or if direct consumption is greater than 6 Mscf, the direct operating costs to recover a barrel of oil could rise by a factor of two or more.

How much of the potential may we expect to realize? It is obvious that although the technology of oil displacement by carbon dioxide is still not ready to be wrapped up in a do-it-yourself treatise, there are other factors relating to reagent supply and costs, corrosion prevention, and pricing schedules that will have to be gelled and matched with each other before a significantly meaningful estimate of the total potential of tertiary recovery with carbon dioxide can be made. But estimating the total potential available is a relatively meaningless exercise. It is the estimate of the rate of supply—the barrels per day we may expect to be put into a pipeline some day in the future—that is important. We will return to this subject.

At this point, recall that another supplementary process, in addition to waterflooding, has been with us for some time. Modern work on the use of steam to recover

*Such as a modified PACE-SGP (Shell Development Co., licensor) facility.
petroleum was also initiated during the era of the Suez crisis. The art and science of steam soaking and steamflooding have been contributing an estimated 200,000 B/D to California's production total for most of the past decade. The added reserves are estimated to be between 1 and 2 billion bbl and may well be doubled in the future as the result of the greater value realized by heavy crude oil. The role that steam injection techniques has had in maintaining the health of at least one West Coast operation is shown in Fig. 16. Virtually all the oil produced by steam injection is from high-saturation, high-porosity, shallow reservoirs containing low API-gravity crudes.

But steam will displace light oils, too, even more effectively than heavy oils because of the volatility of the lighter oils and consequent distillation or stripping of the oil by the steam. Steam has a built-in, antibypassing capacity (built-in viscosity control, so to speak) until relatively grossly depleted intervals between wells are developed. Even then it continues to be effective, since heat can be transferred by conduction as well as convection.

The economic efficiency of steam drives are determined principally by injection rate, spacing, thickness, porosity, and oil saturation (Table 3).

What is an acceptable economic steam/oil ratio? In California operations, a value of 0.20 to 0.25 had been acceptable in the past, and in more current operations we would surmise that this ratio has been lowered toward a value of 0.15 because of the increased value of heavy crudes. Local costs, the need for drilling wells, water treating, etc., of course, will affect the acceptable ratio for any given operation. Considering the energy balance only, the ultimate steam/oil ratio when using your own crude is 0.065, since 65 bbl of oil in a highly efficient generator will convert about 1,000 bbl of water to steam. These numbers permit one to estimate that it takes the equivalent of about ½ bbl of crude to cover the costs of capital, operating expenses, and taxes for every barrel of produced crude at the 0.15 ratio.

This ratio could be conceivably reduced if fuels cheaper than crude could be used for generating steam. We would like to pass on the following thought. In some parts of the country, coal, lignite, and refinery bottoms, with rational controls on their utilization, could be significantly cheaper boiler fuels than produced crude or fuel oil. If, at such locations, the cheaper fuels were used, then the energy-basis steam/oil ratio could be lowered significantly below 0.065; additional targets for steam recovery might then be revealed. This could be the cheapest coal liquefaction process available to us.

The calculated values of steam/oil ratio in Fig. 17 are for a reservoir having a porosity of 20 percent and a recoverable oil saturation of 30 porosity percent using

**TABLE 3 — FACTORS DETERMINING STEAM/OIL RATIO**

\[
\frac{\text{Oil Produced}}{\text{Steam Injected}} = \left( \frac{h_t^2 \cdot \delta \cdot S_o \cdot \phi}{h_n \cdot l \cdot A'} \right)
\]

where

- \(h_t\) = formation thickness, gross
- \(h_n/h_t\) = net/gross
- \(\delta S_o\) = decrease in oil saturation
- \(\phi\) = porosity
- \(l\) = injection rate
- \(A'\) = area/injector

MAY, 1976
a recently published analysis. Calculations (Table 4) were made for 5- and 10-acre spacing and injection rates of 500 and 1,000 BWPD at pressures of 300 and 1,000 lb, and assume a total injection of 1 PV of water. These calculations do not include any beneficial effects of distillation.

The ratios are not economic if fuel oil is used to generate steam. If cheaper fuels could be used under the economic conditions noted, then economic recovery by steam injection from low-porosity, depleted, light oil reservoirs becomes a possibility—at least in some oil provinces. The process should be enhanced by distillation or by still-to-be-developed synergistic mechanisms (possibly concurrent gas or air injection, or use of only a fraction of a pore volume of steam as a precursor, because it appears that nothing else will bank up residual, disconnected oil as steam does), and then completing the displacement with water, polymers, and surfactants.

**Estimated Barrels per Day of Tertiary Oil — Circa 1990**

How do we go about estimating the barrels of tertiary oil that will be added to pipeline runs in the coming decades? Let us go back and look at the West Texas carbonate potential. We will assume a 20-year period is required to inject the primary amount of carbon dioxide; this is probably just enough time to pay out investment in facilities and inject the reagent. We will assume we get started in 1980, that there is a 5-year delay to production response, and that the oil production ensues over a 30-year period. Our 4-billion bbl target then would be produced between 1985 and 2015 at the rate of 365,000 B/D. This goal seems too optimistic since it would require the availability of 1 Tcf of carbon dioxide per year by 1980. We will discount it by 50 percent and set our goal on an average daily production of some 175,000 B/D during the last 15 or so years of this century.

The one chemical flood that has been announced is the Marathon operation, referred to earlier. Its inferred performance will average about 6,000 B/D over a period of some 15 years if the entire 6,000 acres in the Robinson field are developed. Were the Marathon experience to be duplicated 10 times each year during the next decade or so, a production rate from chemical flooding would reach 600,000 B/D by about 1990, and 750,000 B/D a few years later if still more opportunities can be found for development to be continued at that pace. However, the estimate is overly optimistic, since sufficient unrecovered low-viscosity oil to fulfill the estimate probably does not exist in reservoirs within about 1,000 ft. Significant price increases, as already indicated, would be required to extend the usefulness of the process to deeper reservoirs, or a significantly superior process would have to be developed. For the decade of the 1980’s, then, we would again discount the calculation by 50 percent, and look for the production of some 300,000 B/D by 1990. This would require the redevelopment of some 300,000 acres by chemical flooding operations.

Steamflooding will be extended to at least additional heavy oil targets in California, and we have already indicated this could result in an increase in reserves of as much as 2 billion bbl. Extended over a period of 25 years, an average enhanced production of some 200,000 B/D could be achieved. We will not discount this estimate. Adding the three together results in a total of 675,000 B/D by 1990. Allowing or hoping for further improvements in the technology of these processes, the extension of steamflooding to some light oil projects, new technology to be invented, and, eventually, the realization that energy will be relatively more costly to our nation than it has been historically, it is foreseeable that tertiary oil might get to 1 million B/D by 1990.

This will be a very welcome addition to our nation’s supplies. Pursuing these projects will be profitable ventures to those operators who have the amenable reservoirs, and who have had the necessary technology developed for them. This supply rate obviously will not alter the over-all energy deficiency that the country will be facing. By all accounts, the zenith of the age of petroleum in North America has been passed, and is currently being reached in the rest of the world outside communist areas, as shown by the supply projections delineated in Figs. 17 and 18. It is high time for us all to realize what the expectation for long-term petroleum supplies actually is. We must have a national energy policy that explores every possible way of continuing to make an economically useful supply of energy available to all of us.

We should heed the conservationists who have lob-

**TABLE 4 — CALCULATED STEAM/OIL RATIO**

<table>
<thead>
<tr>
<th>Pressure (psl)</th>
<th>Injection Rate (bpd)</th>
<th>5-Acre Spacing</th>
<th>10-Acre Spacing</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Steam/Oil Ratio</td>
<td>Steam/Oil Ratio</td>
</tr>
<tr>
<td>1,000</td>
<td>500</td>
<td>0.08/0.10</td>
<td>0.08/0.08</td>
</tr>
<tr>
<td></td>
<td>1,000</td>
<td>0.10/0.13</td>
<td>0.08/0.10</td>
</tr>
<tr>
<td>300</td>
<td>500</td>
<td>0.13/0.16</td>
<td>0.10/0.13</td>
</tr>
<tr>
<td></td>
<td>1,000</td>
<td>0.16/0.19</td>
<td>0.13/0.16</td>
</tr>
</tbody>
</table>

**Fig. 17** — Crude/LNG — historical development and projection of possible availability, world outside communist areas and North America.

**Fig. 18** — Crude/LNG — historical development and projections of possible availability, North America only.
bied (rightly so, in many instances) for the establishment of wild life and nature preserves. We must begin to lobby for the establishment of "people preserves" — American People — to be designated around every shale mine, coal strip, and oil derrick on our shores.

Acknowledgments

Appreciation is expressed to A. T. Guernsey for important suggestions on the presentation; to P. A. Payne for putting together some of the data on carbon dioxide; and to Shell Oil Co. for time to think and permission to publish this paper.

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APPENDIX

The possibility that discovered original oil in place has been incorrectly estimated will be examined briefly. Seventy-five percent of this oil was discovered before 1950, and some improvements in making such estimates have undoubtedly occurred. The annual API statistical efforts include a re-estimation in terms of the current technology at the time of reassessment, as well as both original oil in place and ultimate production.

One possible source of error in estimating the original oil in place (OOP) may not be fully accounted for; that is the effect of pressure on porosity. Porosity before 1950 would have been estimated from laboratory measurements at ambient conditions. However, it is well known that under subsurface conditions the porosity is less than that at 1 atm. The extent of the difference depends very much on the nature of the reservoir rock and its burial history. Most extreme differences will be found in unconsolidated sandstones.

Suppose the porosity was originally estimated from conventional core analysis to be 36 percent. Using logs, the water saturation was calculated to be 25 percent. From these values, oil properties, and maps that were constructed of the reservoir, the initial oil in place was determined by volumetric analysis. This value for original oil in place would be used in association with pressure analysis and decline curves to determine the recovery efficiency quoted today.

Modern technology — logs and stressed core analysis — has demonstrated that many of the early porosity values determined from core analysis are optimistic. If porosity values are later redetermined and found to be, say, 28 percent, using Archie's equation with some simplifying assumptions results in a water saturation value of 32 percent. Thus, our volumetric analysis would become

\[ \text{OOP}_{\text{actual}} = 0.71 \times \text{OOP}_{\text{early estimate}} \]

These numbers are only estimates of what could happen. How much of this kind of error is in the estimate of original oil in place and, therefore, also of recovery efficiency? Corrections of this type would be mainly applicable to sandstone reservoirs discovered before the 1960's. Even if the correction calculated above applied to one-half the oil discovered before 1950, the over-all effect on original oil in place would be a reduction of 10 percent, and estimated recovery efficiency would be boosted a few percentage points. The correction is viewed as an outside limit, and, even at that, it would not result in any significant change in the conclusions presented in this report.
Fig. 7 - Field measured and theoretical cumulative heat loss from formation.