A REVIEW OF SHALLOW-SHELF CARBONATE RESERVOIRS IN THE UNITED STATES

August 1992

Work Performed Under Contract DE-AC22--91BC14839

Prepared for
the U.S. Department of Energy
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DISCLAIMER

NOTICE

This report provides a technical review of shallow-shelf carbonate reservoirs in the United States based on publicly available information. The sources of information include; published technical papers and reports, trade journals, state agency reports and the Department of Energy and Commercial data bases. No proprietary or otherwise publicly unobtainable information are included in this document.

PURPOSE

The buried remnants of ancient ocean coastal regions hold significant amounts of the potentially recoverable oil of the United States. Many of these reservoirs, classed as shallow-shelf carbonates, share a geologic character and producing behavior that should respond to a focused research effort designed to reduce the technical and economic constraints on the recovery of their remaining oil.

The U.S. Department of Energy (DOE) is currently preparing to announce the opportunity for industry to participate with government in a series of research projects to contribute to this goal. This report provides background information regarding DOE's current understanding of the reservoir and geologic characteristics of shallow-shelf carbonates and the principal impediments to increased production from these reservoirs.

BACKGROUND

Increasing U.S. dependence on foreign oil and accelerating well abandonments in known, oil-rich reservoirs are major national concerns. DOE's National Energy Strategy (NES) responded to these concerns by recommending an integrated program of laboratory and field-based research on prioritized geologic classes of reservoirs to rapidly develop and demonstrate cost-effective advances in recovery technology. Under the NES mandate, the Oil Research Program Implementation Plan established the primary goals of improving the economic producibility of domestic oil and preserving access to those reservoirs containing the large volumes of oil at the greatest risk of being abandoned.

The plan establishes a program of highly targeted research, development, demonstration and technology transfer activities in collaboration with the industry, states, and the academic community. It focuses on the reduction of technical and economic constraints to production and also on the enormous potential of the resource remaining in known domestic reservoirs. The program balances three time-specific goals:

- In the near term (within 5 years), preserve access to reservoirs with high recovery potential that are rapidly approaching their economic limits and are in danger of being abandoned.

- In the mid term (within 10 years), develop, test and transfer the best, currently defined, advanced technologies to operators of the reservoirs with the greatest potential for incremental recovery.

- In the long term, develop sufficient fundamental understanding to define new recovery techniques for the oil left after application of the most advanced, currently defined, mid-term processes, and for major classes of reservoirs for which no advanced technologies are anticipated to be available.

In implementing its oil research program, DOE has used the information available in the Tertiary Oil Recovery Information System (TORIS) database to estimate the potential recovery from U.S. reservoirs under near- and mid-term technology scenarios. Reservoirs in TORIS were grouped into classes having common geologic characteristics and these classes were ranked according to selection criteria based on resource-in-place, recovery potential, and urgency due to the possible abandonment of this potential. Rankings were then developed to prioritize the classes for government research efforts.

To date, two classes have been identified by the DOE's prioritization efforts. Fluvial-dominated deltaic reservoirs were chosen as the first to be subjected to an intensive research and technology demonstration effort. This began with a solicitation for industry participation in government-funded research efforts, and in April 1992 the DOE selected 14 cost-shared field research projects stemming from industry proposals.

The DOE is preparing a second series of government-funded, cost-shared research projects to be focused on shallow-shelf carbonate reservoirs. These reservoirs contain a significant amount of potentially recoverable oil which is at risk of being irretrievably lost as older fields are abandoned. DOE plans to successively target as many as 10 classes of U.S. reservoirs, each grouped according to geologic similarities.

DESCRIPTION OF THE SHALLOW-SHELF CARBONATE RESOURCE

Location of Shallow-Shelf Carbonates

Carbonates are vitally important reservoirs worldwide, as evidenced by the massive reserves of the Middle East. In North America, despite the predominance of the Gulf Coast terrigenous tertiary province, about one-third of the major oil and gas fields have been estimated to be in carbonates.[1] This is confirmed by the TORIS database where approximately 33% of total light oil resources are found in carbonate reservoirs.

Of the 309 billion barrels of light oil original oil-in-place (OOIP) contained in reservoirs represented in TORIS, 68 billion barrels (22%) were originally contained in 382 shallow-shelf carbonate reservoirs, representing the largest share of OOIP attributed to any of the 22 geologic reservoir classes. *Open* shallow-shelf carbonate reservoirs comprise 64% (43.2 billion barrels) of the OOIP in shallow-shelf carbonate reservoirs, with *restricted* shallow-shelf carbonate reservoirs accounting for the remaining 36% (24.8 billion barrels). The distinction between these two types of shallow-shelf carbonate reservoirs is discussed further in subsequent sections of this report.

Nineteen billion barrels (28%) of the original resource in shallow-shelf carbonate reservoirs have already been produced (Figure 1), and an additional 3.7 billion barrels (5.8% of OOIP) are proved reserves which will be produced in the relatively near future. As much as 1.1 billion barrels of these reserves are expected to be incremental reserves resulting from established enhanced oil recovery projects. Of the remaining 45.3 billion barrels of oil-in-place, an estimated 13.6 billion barrels is unrecovered mobile oil which cannot be extracted through primary recovery processes or waterflooding due to large scale heterogeneities and unfavorable fluid characteristics within the reservoirs. This resource is the target of advanced secondary recovery (ASR) processes including geologically targeted infill drilling, polymer flooding and permeability profile modification. The remaining 31.7 billion barrels of oil are trapped within carbonate shelf reservoirs by surface tension or capillary forces and are immobile to waterflooding; this immobile oil is the target of "tertiary" or enhanced oil recovery (EOR) processes.

Figure 2 shows the distribution of TORIS shallow-shelf carbonate reservoirs, by geologic group or formation, as a percentage of total OOIP. Overall, West Texas and New Mexico (Permian Basin) carbonates account for over 70% of all TORIS shallow-shelf carbonate reservoirs' OOIP. The geographical distribution of shallow-shelf carbonate reservoirs covers 14 states (Figure 3). The two most important geologic groups, in terms of the number of reservoirs, are the Permian Basin carbonates (including the Ellenberger fractured dolomite) and the Williston Basin carbonates. The Texas Panhandle formation has a large OOIP contribution and is carried as a single reservoir unit by the Texas Railroad Commission, although much of the production is operated by independents as separate properties.

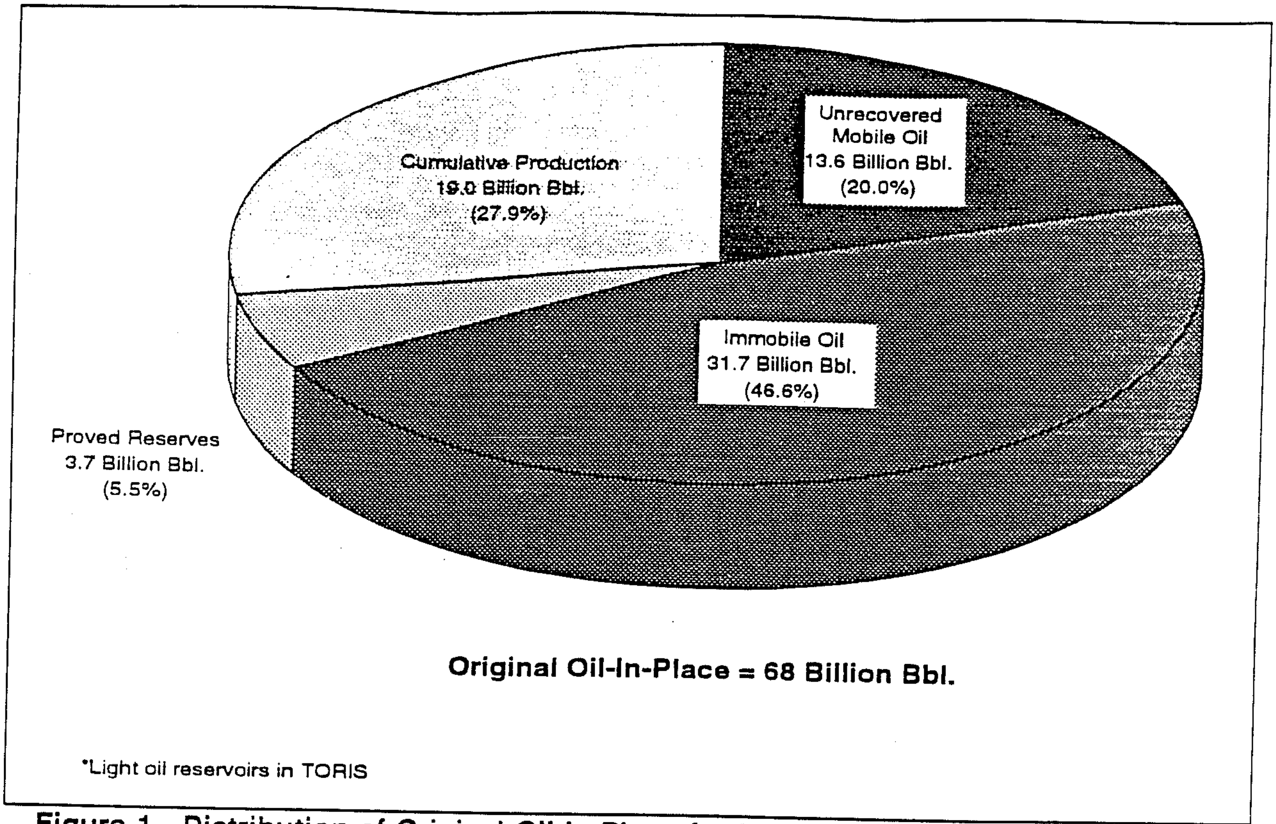


Figure 1—Distribution of Original Oil-In-Place for Identified Shallow-Shelf Carbonate Reservoirs

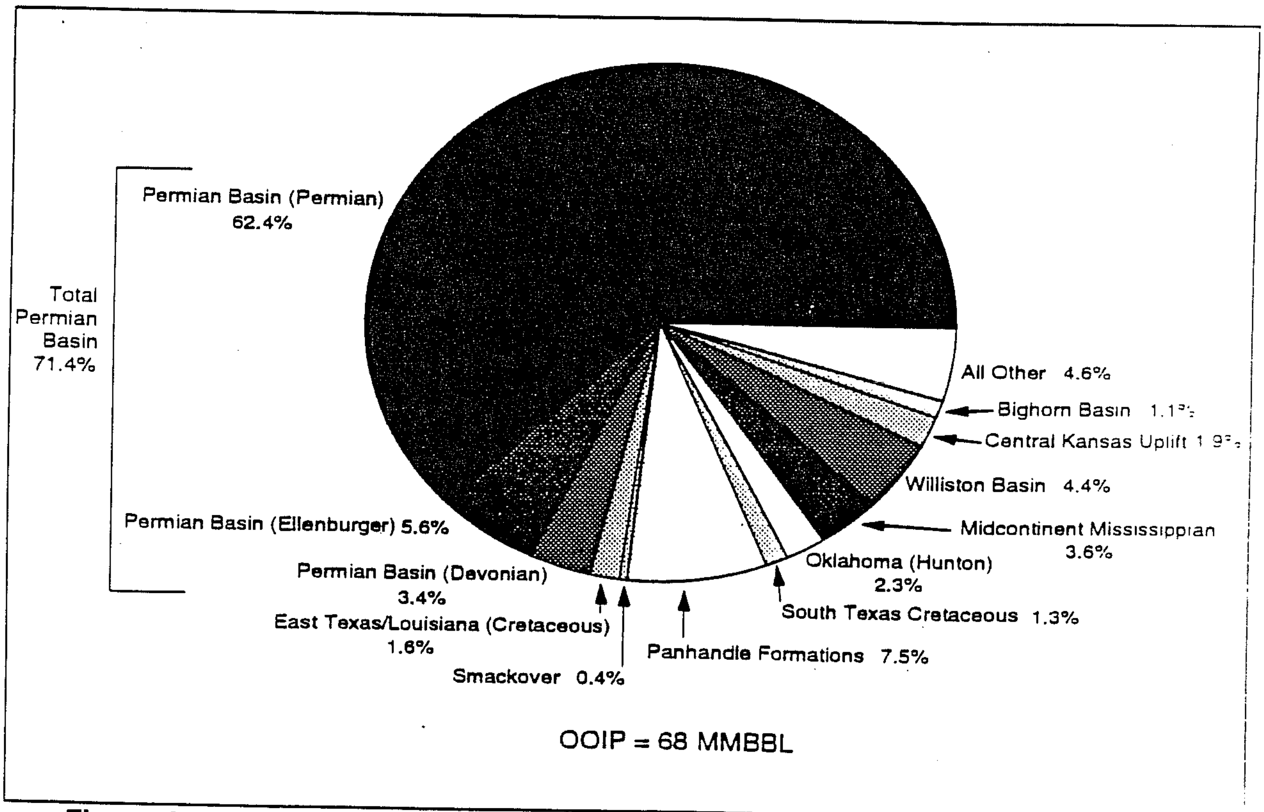


Figure 2—Distribution of Class II (Shallow-Shelf Carbonate) Reservoirs by OOIP

Deposition of Shallow-Shelf Carbonates

Figure 4 shows the distribution of carbonate depositional environments across a carbonate shelf. Shallow-shelf carbonates are deposited in a marine environment below the influence of tides. "Restricted" and "open" refer to depositional variables of water circulation, depth and salinity and are distinctions inferred from the rock record that may be subject to varying interpretations. The depositional environments are co-located and can be overlapping. Peritidal/subtidal sediments, similar to shallow-shelf (restricted) sediments, were also deposited in a subaqueous environment, but under the influence of tides. Peritidal facies can also be interlayered with shelf carbonates. For the purpose of defining a significant, genetically related group of reservoirs for directing research into optimal reservoir management, DOE has grouped shallow-shelf open and shallow-shelf restricted into a single class, shallow-shelf carbonate reservoirs.

Carbonate sediment is deposited with initially high porosity (reefs with more than 50%, sands with 40-80% and muds with 40-50%), although most of this porosity is occluded soon after deposition. On the carbonate shelf, the best reservoir facies include locally developed grainstones deposited on bars, reworked beaches and reefs. Shallow, open shelf facies consist of lime sand bodies, mudstones, bioherms and some clastics. Organic debris is generally supplied from marginal reefs developed at the shelf edge and patch reefs. Restricted shelf facies consist of bioclastic wackestones deposited in lagoons and bays, litho-bioclastic sands in tidal channels, lime mud tide flats and fine clastic units. Restricted and open areas may show clastic input, which will typically appear in well-segregated beds.

Four main groups of organisms play the main roles in carbonate sediment production.[2] They are: (1) those that rapidly form an integral framework during carbonate fixation — the reef formers such as coral; (2) those that disintegrate at death, or contribute whole skeletons to the sediment; (3) those that disintegrate upon death to form lime mud; and (4) those that trap fine-grained sediments to form mats. In addition to organic sediments, physiochemical precipitation of oolites is also a source of sedimentation. In the shallow marine environment of the shelf, energy from waves and tidal currents (in non-epicontinental seas) provide excellent particle size sorting, with little interparticle matrix.

Volumetrically, most of the sediments produced on the subtidal shelf are mud-dominated. The bulk of the mud comes from the disaggregation of calcareous green algae. Although the rate of carbonate production on the shelf may be high and perhaps equal to the shelf margin, the rate of accumulation is often an order of magnitude less on the shelf than on the margin because of the ease with which material goes into suspension and is transported shoreward as well as basinward during the times of storm activity. High rates of carbonate production on the shelf, combined with high rates of accumulation at the shelf margin, allow maintenance of a carbonate platform over long periods of geologic time, even during times of rapid sea-level rise.

Diagenesis

The diagenetic history of a carbonate shallow-shelf will be the result of a wide range of potential physical and chemical influences. These affect the porosity and permeability of carbonate rocks in funda-mental ways, sometimes obliterating and at other times enhancing depositional porosity and permeability, and can play an overriding role in determining reservoir quality. Diagenesis of platform sediments is highly influenced by climate and groundwater characteristics over geologic time. Important diagenetic processes within surficial and buried sediments along a typical platform include dolomitization, cementation, compaction, massive dissolution and other processes.

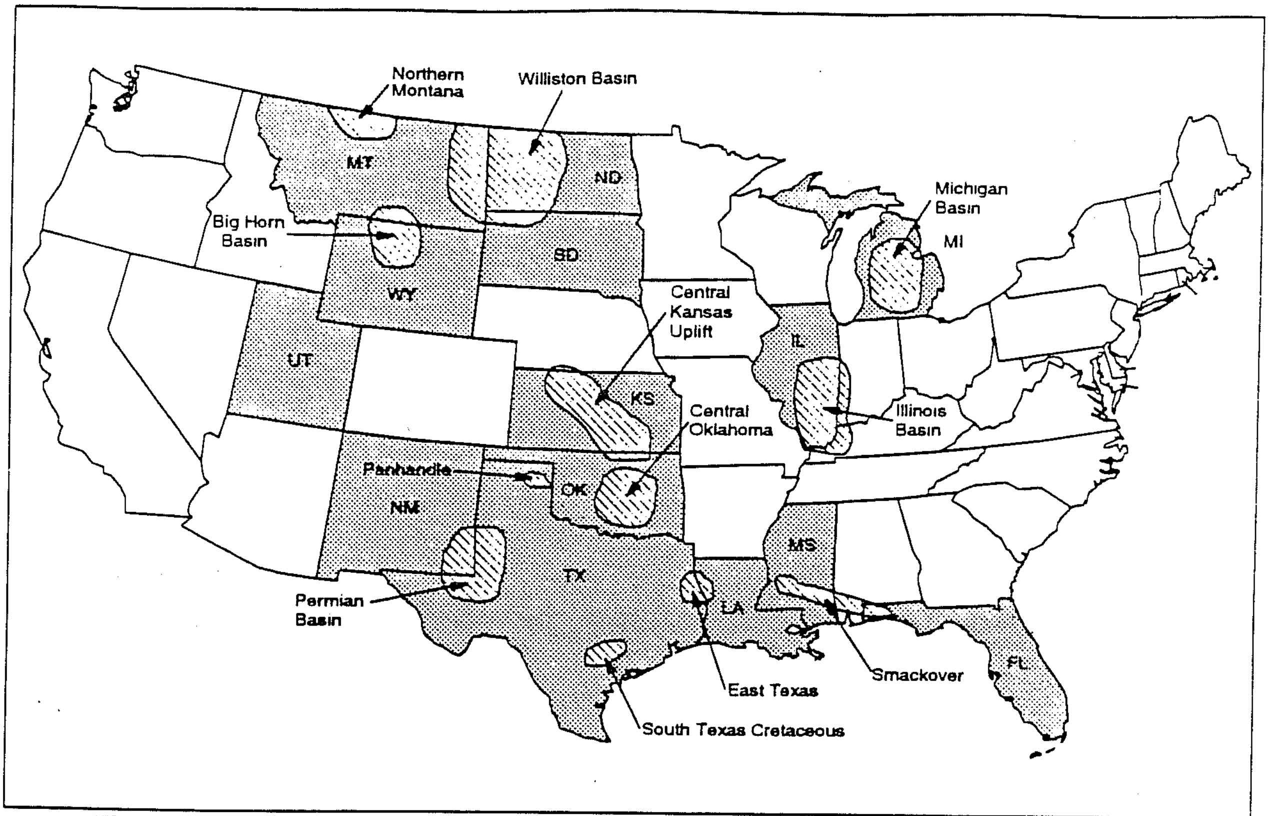


Figure 3—Location of TORIS Shallow-Shelf Carbonate Reservoirs (Light Oil)

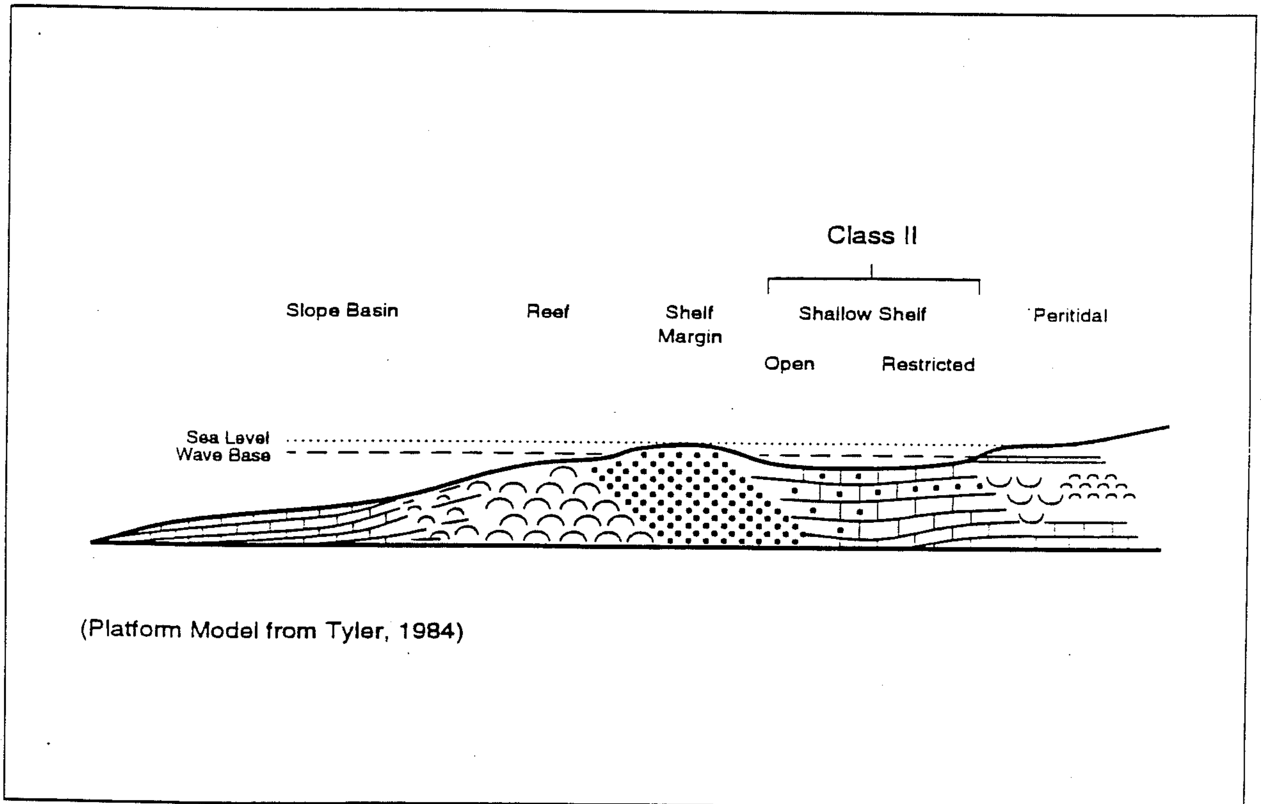


Figure 4—Carbonate Depositional Environments as Developed by the Reservoir Classification Working Group (1990)

Dolomitization, the replacement of calcium carbonate by magnesium carbonate, is a very important diagenetic process in shallow-shelf carbonate rocks. In fact, dolomitization is the most fundamental process in 61% of the shallow-shelf carbonate reservoirs in TORIS. Low-energy shelf mudstones buried as lime sediments will compact mechanically and chemically to form tight limestones that are often seals. The same muddy sediments, if dolomitized, will develop a well-interconnected intercrystalline porosity that will serve as an excellent reservoir. In addition, due to their higher density and chemical make-up, dolomites have a much greater resistance to compaction than other carbonates and thus will retain porosity and permeability to greater depths of burial.

Compaction and cementation are the dominant diagenetic processes in 15% of TORIS Class II reservoirs. Compaction occurs through dewatering, rotation, grain repacking, and grain deformation. Cementation is typically an early diagenetic process. The source of materials for burial cements can be difficult to determine; it may come from a local source such as a nearby styolite or may be transported laterally tens of kilometers to the site of precipitation.

Massive dissolution as a diagenetic process is a factor in 12% of TORIS shallow-shelf carbonate reservoirs. Carbonates exposed at the surface are susceptible to karsting processes that result in collapse breccias, connected vugs, cave fills and fracturing. This process is independent of lithology and often provides flow patterns for later dolomitizing solutions. The primary pore types in these reservoirs are fractures, interbreccia-block channels, large connected vugs, and caverns. Intercrystalline, intergranular and separate-vug pore types may also be present.

Heterogeneity

Although depositional facies of carbonate platforms from throughout geologic time share common characteristics, the variable nature of carbonate diagenesis both in time and space results in reservoirs with a high potential for heterogeneity within a given basin. For shallow-shelf carbonates, most major reservoirs do not exhibit significant structurally-induced heterogeneities at the intra-reservoir scale; however, depositional and diagenetic facies mapping represents an added order of complexity when mapping porosity and permeability trends away from points of subsurface control, especially in comparison to siliciclastic rocks. In carbonate rocks it is diagenesis that almost invariably determines which carbonate sediments will become seals and which will become reservoirs, and what the nature and quality of the final reservoirs will be.

Carbonate depositional systems, as shown by modern examples, are complex from the scale of a producing field right down to that of a pore throat.[3] This fact, coupled with the frequent control by facies over subsequent diagenesis, imparts great heterogeneity to carbonate reservoirs. Directly related to facies and diagenesis, permeability affects recovery efficiency and thereby links the depositional facies through sediment texture to reservoir performance.

Within carbonate depositional systems, individual facies can have both gradational or sharp lateral and vertical boundaries. Delineation of facies components provides the basis for establishing field-wide internal reservoir architectural style. In most cases, individual reservoirs produce from more than one facies because reservoir quality facies are often vertically stacked and laterally juxtaposed. Variation within an individual facies component produces reservoir heterogeneities at an intra-reservoir scale.

Description of Major Shallow-Shelf Carbonate Formations

Permian Basin area carbonates represent the largest resource group. This grouping includes the Permian aged carbonates (Queen, Grayburg, San Andres, Glorieta.

Clearfork, Wolfcamp, Wichita-Albany, Paddock, Yeso, Blinebry and Abo formations) as well as Silurian-Devonian aged carbonates and the deeper, older Ellenberger formation. The Permian Basin is a mature petroleum-producing province extending over about 80,000 square-miles of West Texas and southeastern New Mexico; its sedimentary rocks are more than 25,000 feet thick in its deepest parts. The basin is characterized by arches, platforms, basins and shelves formed during the later Paleozoic periods.

The Permian Basin was formed by tectonic activity that began during the early Pennsylvanian Period. The Delaware Basin, Central Basin Platform, Ozona Arch, and Midland Basin and surrounding Northwestern, Northern, and Eastern Shelves were established features by the end of the Pennsylvanian Period, and development of carbonate platforms was apparent by the early Leonardian (Figure 5). Relatively high-energy grainstone bars and reefs developed along the platform margins and restricted circulation of open-marine water to the platform interior, where low-energy carbonate and evaporite deposition dominated.

Ellenberger fractured dolomite fields are located throughout a large area of the Central Basin Platform and Midland Basin. In the outcrop in Central Texas, the Ellenberger Group consists of interbedded limestone and dolomite. In the subsurface, on the other hand, the Ellenberger is primarily dark-colored, finely crystalline dolomite having low permeability. Cores from Puckett field, Pecos County, indicate that the dolomite comprises a number of carbonate facies, including laminated mudstone, burrowed mudstone, birdseye mudstone, wispy-bedded mudstone, intra-clast packstone, algal boundstone, algal-head boundstone, and oolite grainstone.[4] Fractures and vugs are the major types of porosity in the Ellenberger. Solution-collapse breccias, which indicate periods of subaerial exposure, are commonly associated with the most porous and permeable zones. Addi-tional fracturing during burial extended and enhanced the permeability of the collapse zones.

Silurian-Devonian carbonates producing in the Permian Basin include the Fusselman Formation, a prolific producer in such fields as Dollarhide, Goldsmith, Justis, Good, and Midland Farm. Devonian-aged intervals also produce in the Denton, Lea, Dora Roberts, and Harper fields.

The Mission Canyon Formation of the Madison Group was deposited in the Williston Basin of North Dakota and Montana. In the Little Knife Field, the Mission Canyon as a whole is a shallowing-upward, regressive sequence characterized by a general upward change in lithology from carbonates to anhydrite.' It is analogous to the lime mud-to-sabkha cycle of Wilson.[5] Most of the carbonates are interpreted as subtidal, deposited in recognizable subenvironments. Reservoir development and hydrocarbon accumulation in Little Knife Field are primarily the result of structural flexure and stratigraphic entrapment coupled with diagenetic porosity development.

The Panhandle oil and gas field covers 200,000 acres and produces from several horizons.[6] These horizons are grouped as a single reservoir by the Texas Railroad Commission, and in TORIS. Production is from dolomite, limestone, sandstone and a granite wash. Portions of the productive strata are shallow-shelf carbonates, principally of Permian Wolfcamp age. The overriding geologic control on production is the structural drape across the Amarillo Uplift.[7]

FIELD IMPLEMENTATION OF IMPROVED RECOVERY PROJECTS IN SHALLOW-SHELF CARBONATE RESERVOIRS

Status of Existing EOR Projects

There are a total of 30 EOR projects currently underway in shallow-shelf carbonate reservoirs. Of these, 23 are

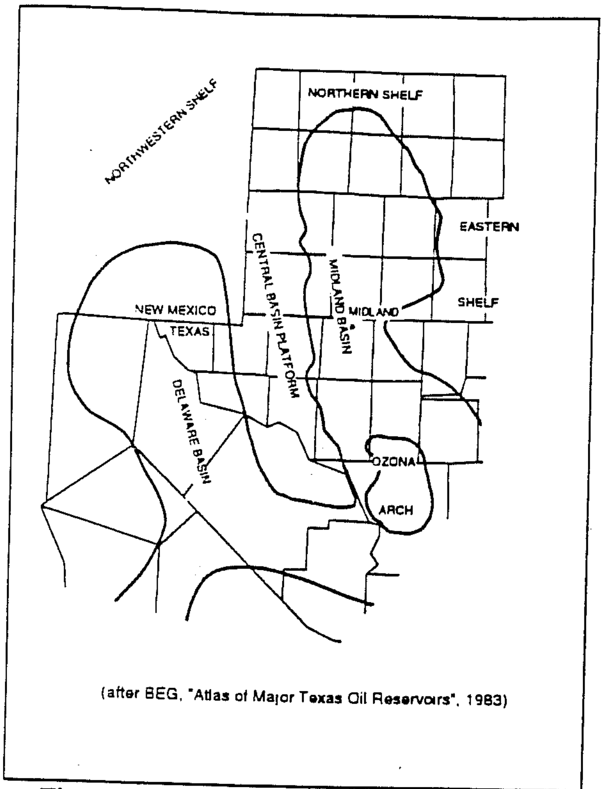


Figure 5—Index Map of the Permian Basin

carbon dioxide (CO_2) floods in the Permian Basin; 1 is a CO_2 flood in south central Wyoming and 6 are hydrocarbon miscible or nitrogen injection projects.[8] The large majority of these projects were initiated in the high oil price years of the early 1980s, although CO_2 injection projects in West Texas have continued to be initiated up to the present day. Three such shallow-shelf carbonate CO_2 injection projects (McElroy, Levelland and South Welch fields) are currently scheduled to begin during 1992-1994.

These 30 projects currently produce roughly 222,000 barrels of oil per day (BOPD), of which 97,000 BOPD, or 44%, is considered incremental EOR production. Over 80,000 BOPD of incremental oil is produced from miscible CO_2 projects in shallow-shelf carbonates, 55% of total U.S. carbon dioxide-injection-related incremental oil and just over 10% of total U.S. EOR production. Almost all of these projects are considered technical and economic successes.

Several factors influence the amount of incremental oil recovered from a reservoir relative to the amount of CO_2 injected. For example, the degree of reservoir heterogeneity will influence the ability of the CO_2 to contact and displace the remaining oil in a reservoir. More heterogenous reservoirs are more prone to CO_2 "fingering" through the oil, causing early CO_2 breakthrough and bypassing of significant volumes of oil. Water injection is typically alternated with CO_2 injection termed "water-alternating gas" (WAG) to help alleviate this problem. Further, the degree to which separation of fluids in a reservoir is caused by the effect of gravity on differences in density (gravity-induced flow of lighter CO_2 above the heavier oil) also influences miscible sweep efficiency. Other factors which affect the amount of incremental oil recovered in a CO_2 project include the amount of oil remaining after waterflooding, the efficiency with which the displaced oil can be captured by the producing wells, and the loss of displaced oil due to resaturation of low oil-saturation zones. In typical West Texas reservoirs, combined primary and secondary recoveries range from 25-40% of the OOIP. CO_2 projects typically are recovering an additional 8-15% of the original oil in place over a typical 15-20 year project life. CO_2 project performance is usually characterized by a 2-3 year delay in production response following the initiation of gas injection.

Successful CO_2-miscible injection projects can be expected to require 3 to 11 Mcf of CO_2 per barrel of recovered incremental oil (average of 6-8 Mcf/STB).[9,10] CO_2 cost is therefore critical to project economics. As injected CO_2 breaks through into producing wells, the gas-to-oil ratio in those wells rises. When the amount of CO_2 reaches a certain level, the gas must be treated to remove the CO_2, which in large projects can then be recycled or reinjected into the reservoir. A 60/40 ratio of purchased to recycled CO_2 is typical over the life of a project. CO_2 breakthrough typically occurs within the first 5 years of a flood, making a CO_2 recycling plant a consideration. These plants often have the highest capital cost in a project, but since the cost of recycled CO_2 is about 20 to 40% of purchased CO_2, they can be attractive. Efforts to delay breakthrough of CO_2 to producing wells by impeding fingering and gravity overriding not only improves sweep efficiency, they also can delay these plant costs. CO_2 projects are normally implemented in phases to permit the switching between CO_2 and water injection in various parts of the field, limiting capital exposure and optimizing economics.

Initial CO_2 flooding projects in the Permian Basin relied on CO_2 removed from natural gas produced from the Delaware and Val Verde Basins in Texas. Unfortunately, such a source is dependent on the operating capacity of the plants and if gas production is shut in or cut back, the volume of available CO_2 is diminished. Significant volumes of naturally occurring high-purity CO_2 exist, and these sources are likely to supply the bulk of future needs for CO_2 miscible flooding in shallow-shelf carbonate reservoirs. This is particularly so in the Permian Basin and, to a lesser degree, Wyoming, where a well developed infrastructure now exists for delivering CO_2 to oil fields with miscible recovery potential.

Roughly three quarters of the documented North American CO_2 reserves are in the Colorado-Utah-Wyoming-New Mexico area, occurring at depths ranging from 2200 feet (Bravo Dome) to 18,500 feet (La Barge Area). The three known high-purity natural sources of CO_2 for Permian Basin miscible flooding projects are: McElmo Dome, Bravo Dome, and Sheep Mountain. The McElmo Dome field is located in Dolores and Montezuma Counties of southwestern Colorado, the Bravo Dome CO_2 Unit encompasses over one million acres in portions of Union, Harding and Quay Counties, New Mexico, and the Sheep Mountain Field is located in Huerfano County, Colorado. Jackson Dome in central Mississippi (Rankin, Scott and Madison counties) is another natural source of CO_2 where development has taken place to supply CO_2 for miscible flooding. Also, the LaBarge Field in Western Wyoming is a large gas field with significant CO_2 content which is being tapped to supply injectant for Amoco's Lost Soldier field and Chevron's Rangley Field in Colorado.

As the potential for CO_2 miscible flooding in the Permian Basin was realized, three major trunklines (Cortez, Bravo, and Sheep Mountain) were constructed (Figure 6). Subsequently, additional lines to carry CO_2 to the rest of the Basin were constructed. These pipelines, the Central Basin Pipeline (operated by Enron) and the Big Three Pipeline (operated by Big Three Industries) became operational in 1985-86. The LaBarge and Baroil lines became operational in Wyoming in 1987 and 1986.

Overall, the CO_2 distribution system in the Permian Basin is well developed and currently operating below capacity. CO_2 can be delivered to practically any portion of the basin with a minimal amount of lateral line requirements. The proposed Este Pipeline to be built by Mobil in 1992-93 will enhance this coverage. Assuming the CO_2 production capacity exists or could be economically developed in the CO_2 fields, the pipeline system appears to be capable of supplying CO_2 to practically any potential project in the Permian Basin. Substantial CO_2 reserves exist in the LaBarge Field and consideration has been given to extending the CO_2 distribution system north to the Williston Basin where shallow-shelf carbonate reservoirs exist.

Potential Application of ASR Techniques

Of the advanced secondary recovery techniques, infill drilling has been the most widely applied in shallow-shelf carbonates

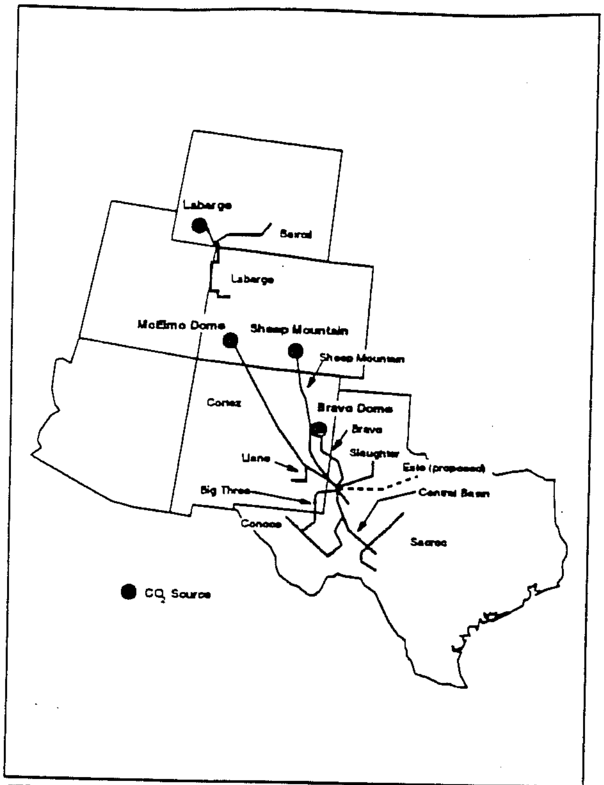


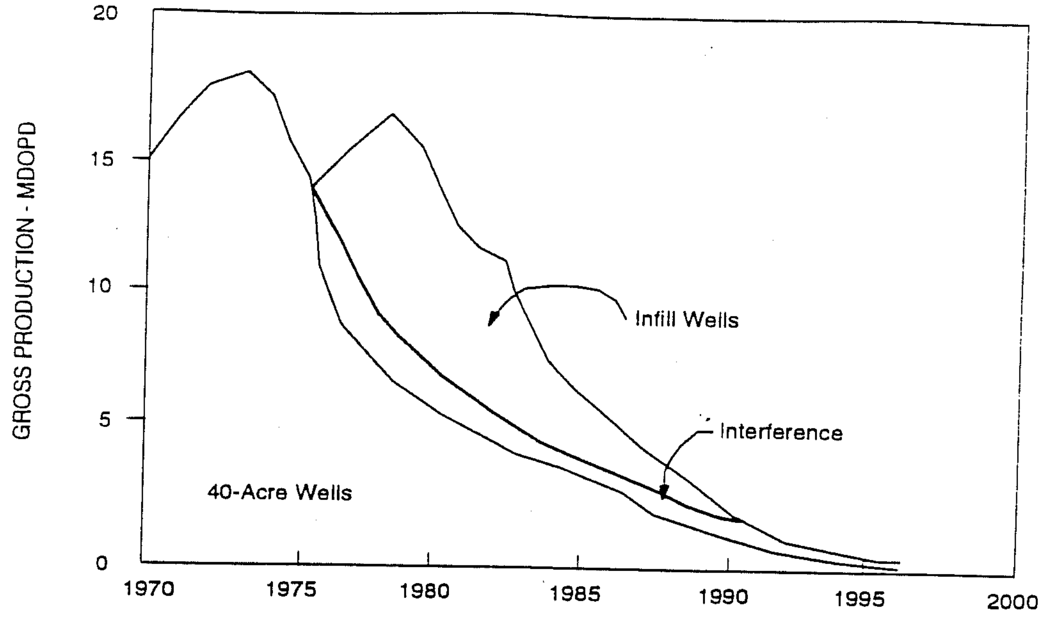
Figure 6—Major CO_2 Pipelines Servicing the Permian Basin and the Rocky Mountain States

and has the most potential for future reserve additions. A very large portion of the shallow-shelf carbonate fields in the TORIS database have been infill drilled to some degree. Infill drilling has been a component of most EOR projects in shallow-shelf carbonates, adding to the incremental production attributed to those projects. More than two-thirds of the calculated well spacings for shallow-shelf carbonate reservoirs in the TORIS database have well spacings of less than 40 acres per well.

Decreasing the distance between wells in a heterogeneous reservoir will increase overall recovery efficiency. This increase is due to the presence of static geological features which prevent the connection of movable oil with the wellbore in heterogeneous reservoirs (e.g., shale "baffles", horizontal permeability variations, sealing faults), and dynamic factors which are also the result of heterogeneity (e.g., vertical permeability contrasts leading to by-passed oil in adjacent layers at a well's economic limit and "corner effects" due to differences in mobility). Fieldwide decreases in well spacing via infill drilling programs serve to contact larger volumes of the reservoir, improving recovery where such static features are a factor. The efficiency of such a program is generally a function of the optimal placement of wells based on an understanding of the reservoir heterogeneities and flow paths. The dynamic factors are attacked through multiple completion strategies and profile modification during water injection programs, as well as infill drilling.

For example, the Means San Andres Unit in Andrews County Texas produces from a predominately dolomite shallow-shelf carbonate reservoir which is 200 to 300 ft thick.[11] Originally drilled to 40 acre spacing in the 1930's, selected areas of the field were infill drilled in the late 1970's to 20 acre and in a few areas 10 acre spacings. Actual and predicted production from the 40 acre wells are shown by the lower line in Figure 7. Total unit production is shown by the upper line. The area between these lines is production attributable to the infill wells and the area between the dashed line and the lower line is "interference" oil that would have been produced by the 40 acre spacing wells had the infill wells not been drilled. Increased recovery due to infill drilling was calculated to be 15.4 million barrels of oil, and is represented by the area between the dashed line and total unit production. Additional recovery from the 20 acre infills was determined to be from 5% to 8% of the OOIP. Subsequent infill drilling and pattern modification in the 1980's resulted in 10 acre spacing in most of the field. Additional recovery of 6.0 million barrels, or 2% to 3% of OOIP, has been attributed to this program.[12]

The results of similar studies on infill drilling programs carried out on other Texas carbonate and sandstone reservoirs, as well



(after Barber, A.H. Jr. et al., JPT August 1983)

Figure 7—Production Datagraph — Means San Andres Unit

as fields in Oklahoma and Illinois, were reported by Exxon in 1982.[13] They concluded that infill drilling resulted in per-well recovery improvements in fields with discontinuous reservoirs and that the optimal well density in any given field should be determined after evaluating field performance and geologic continuity. Published studies show reserve additions due to infill drilling (generally 40 to 20 or 80 to 40 acre spacing changes), range from 2 to 10% of OOIP and increase with increasing heterogeneity. Unlike EOR and polymer injection projects, no public data series exists specifically to track infill drilling, hence, only a few specified studies are cited.

TECHNICAL CHALLENGES OF SHALLOW-SHELF CARBONATES: A LITERATURE REVIEW

This section summarizes the most significant topics related to production of oil from shallow-shelf carbonate reservoirs and highlights issues of continuing importance. The discussions in this section are based on a review of the petroleum engineering and geological literature. Discussions related to the technical challenges in shallow-shelf carbonate fields are broken down into the five categories below:

1) The need for the development and use of proper mature-field reservoir management strategies to maximize recovery and efficiency in the face of reduced oil prices and increased operating and environmental costs.

2) Reservoir characterization problems associated with defining the geology of shallow-shelf carbonate reservoirs as inputs into the reservoir management process.

3) Problems associated with the reservoir engineering aspects of shallow-shelf carbonate reservoirs.

4) Operational problems related to the recovery processes utilized in shallow-shelf carbonate reservoirs (e.g., CO_2 flooding).

5) Operational problems related to the wellbores and facilities in shallow-shelf carbonate fields (e.g., artificial lift, field automation).

Reservoir Management Strategy

Proper reservoir management requires the integration of essentially all available data into the planning and implementation of projects, but the most significant requirement is an accurate geological and reservoir engineering characterization of the reservoir. This is especially the case when it comes to the justification of infill drilling projects in the highly complex shallow-shelf carbonate reservoirs.

A good example of the successful use of reservoir management strategies in shallow-shelf carbonate reservoirs is Exxon's work at the Jay/Little Escambia Creek Field in Florida and Alabama.[14,15] Exxon's approach to reservoir management strategy development and implementation is also well documented in the Blackjack Creek Field of Florida[16] and in the Means San Andres Unit in Texas.[17]

Reservoir Characterization

Proper reservoir characterization is essential to plan, implement, and optimize infill drilling, waterflood, or enhanced oil recovery projects in highly complex and discontinuous shallow-shelf carbonate reservoirs. Improved reservoir characterization has become more important over the years as conventional oil recovery practices (primary and conventional waterflooding) have tended to result in low overall recovery prompting the initiation of ASR and EOR projects. Project performance and recovery have been improved when detailed reservoir engineering and geological data have been integrated to accurately characterize the reservoir.

A significant number of shallow-shelf carbonate field performance problems represented in the literature are a direct result of a lack of understanding of the geologic complexities of these reservoirs. Through detailed analysis of the depositional and diagenetic histories of fields, operators have been able to arrive at a better understanding of reservoir performance. Detailed assessment of the geologic history of formations allows for the identification of porosity, permeability, and thickness trends which are typically correlatable with well productivity or injectivity variations.

Many shallow-shelf carbonate Permian Basin fields were originally developed on wide spacing which resulted in relatively ineffective primary and secondary recovery.[18] Early geologic models of producing formations typically resulted in the correlation of massive pay intervals over large areal extents. With the advent of modern logging tools, seismic methods, and increasingly sophisticated geologic models, more refined correlations have demonstrated that productive intervals were often, in fact, areally discontinuous. Increasingly detailed geological evaluation capabilities have also facilitated the recognition and delineation of depositionally related trends within reservoirs. By better understanding the relationship of the various depositionally or diagenetically controlled facies within reservoirs, geologists have been able to gain a clearer understanding of the relationship between the geology and production performance.[19] Through these methods, porosity, permeability, and net pay trends have been identified and mapped for entire fields or reservoirs. The correlation of these maps with production and injection history have often defined problem areas within fields which were ultimately corrected through infill drilling or recompletions. Such problem areas have included the identification of directional permeability trends, injection thief zones, and depositional or diagenetic facies related porosity or permeability trends.

A significant issue in the development and production of shallow-shelf carbonate reservoirs is the prediction of interwell trends that would be encountered through the reduction of well spacing. The poor performance of many of the waterfloods and some of the enhanced oil recovery projects in these reservoirs has often been related to the fact that the correlated pay zones were not as continuous as early interpretations had indicated. This recurrent problem led to the development of the continuous and discontinuous pay concept and the development of continuity relationships.[20,21] Continuity curves have primarily been developed and published for the heterogeneous shallow-shelf carbonate reservoirs of West Texas, and have been successfully utilized for the justification of infill drilling projects. Continuity relationships have been published for the following shallow-shelf carbonate fields: Wasson Denver Unit[22,23] Fullerton Clearfork Unit,[24] Means San Andres Unit,[25,26] Robertson Clearfork Unit,[27,28] Dune Field,[29] and Wentz Field.[30] The recovery from these waterfloods has been greatly improved through infill drilling and workover programs that were based upon such detailed geologic reservoir characterization.

Several additional advanced techniques have also been utilized to predict interwell trends in shallow-shelf carbonate reservoirs. Recent developments in the area of geostatistics have resulted in more sophisticated methods for characterizing and predicting interwell permeability and porosity trends. Stochastic and fractal methods have been developed to predict the distribution of porosity and permeability in reservoirs where the deterministic methods such as trend mapping and continuity relationships do not adequately describe the discontinuities. The use of these geostatistical approaches in reservoir simulations has resulted in accurate predictions of infill drilling performance in highly complex carbonate fields.[31]

Detailed outcrop studies provide another method for predicting porosity and permeability trends in the subsurface. Outcrops provide an opportunity that never exists in the subsurface; that is, the opportunity to obtain porosity and permeability values from rock samples at small lateral distances. Detailed porosity and permeability data obtainable from outcrops can be integrated with subsurface data from stratigraphically-equivalent reservoirs to develop an accurate picture of the reservoir trends. For example, the outcrops of the San Andres Formation found in West Texas and New Mexico have been extensively studied in order to gain a better understanding of the heterogeneities that exist in the analogous Permian Basin oil reservoirs.[32,33,34]

The borehole televiewer provides another method for defining certain heterogeneities in the reservoir. These tiny wireline-conveyed cameras can be utilized to view the open hole sections of newly drilled wells in order to identify fractures and injection thief zones that are sometimes undetectable utilizing standard well logging techniques.[35]

Seismic imaging methods are emerging as promising new tools which can be used to supplement stochastic and deterministic methods for bridging the data-gap between wells in shallow-shelf carbonate reservoirs. Reversed vertical seismic profiling, crosswell reflection imaging, and crosswell tomography are several new borehole seismic techniques which are being applied.[36] Mobil Exploration and Producing U.S. recently utilized 3-D seismic technology to better characterize the fractured Ellenberger formation in the 40-year-old Pegasus field, a shallow-shelf carbonate. This survey showed that the West Texas field still has producible oil in a series of mini-caverns.[37,38]

At the Means field, Exxon completed a major reinterpretation of the San Andres and Grayburg reservoirs using an extensive 2-D seismic dataset integrated with core descriptions and well log cross sections. The new stratigraphic model which resulted is being used to optimize CO_2 project completions by ensuring that all pay is opened in both producers and injectors based on correlative stratigraphic zones.[39]

Reservoir Engineering

Accurate reservoir characterization is essential for the design and economic justification of infill drilling, waterflood, and enhanced oil recovery projects. The most difficult question to answer in the justification process for an infill drilling project is: What is the optimum spacing? Often, this question is not answered until after the infill wells are drilled, but properly integrated engineering and geological characterization can help to prevent over-drilling.[40,41,42] The reservoir characterization process has been successfully employed for blanket infill drilling as well as geologically targeted infill drilling projects or remedial programs.[43,44] For enhanced oil recovery project justification, the best method for fully characterizing the reservoir and predicting the results of full field projects may be the use of pilot projects. Properly designed pilot projects facilitate the gathering of detailed geological and performance data which can then be used to design and justify large scale projects. The use of CO_2 pilot projects in the Levelland Field[45] and the Slaughter Field[46] are excellent examples of this process.

A significant problem that exists from a reservoir engineering perspective is the lack of adequate high-quality data to fully assess reserve potential. This is the case in many of the older Permian Basin fields, where well log and core data are of poor quality or non-existent. Many operators have solved this problem by acquiring large volumes of data during infill drilling programs, which facilitates evaluation of future projects and the optimization of current projects.[47,48,49,50] Specific data acquisition problems can also affect proper reservoir characterization, such as problems in obtaining accurate saturation values from cores[51,52] or well log identification of oil bearing zones in fields that have been waterflooded with fresh water.[53,54]

Other significant reservoir engineering problems in shallow-shelf carbonate reservoirs pertain to the numerical simulation of fields for the prediction of project performance. First and foremost is the problem of accurately describing a reservoir geologically in reservoir simulators.[55] Detailed geological work is required along with an iterative modification process during the history matching phase. Some specific problems relate to complex layering and vertical communication problems and the presence of an extensive gas cap.[56,57] Further, process specific reservoir simulation problems are often encountered, especially in the case of the simulation of CO_2 flooding.[58] A significant problem in CO_2 floods is the optimization of CO_2 slug volumes, which most often has been solved by the integration of pilot results into reservoir simulation.[59,60] If the dedication of time and expense for a full field reservoir simulation is not justified, simpler models can be applied to forecast performance.[61]

Operational Issues

Many of the operational issues associated with shallow-shelf carbonate fields result from the application of secondary and enhanced oil recovery processes. This is the case in the highly complex and discontinuous productive formations of West Texas, which have typically been waterflooded for many years and then have been drilled down to closer well spacings. In many cases miscible injection processes have subsequently been initiated.

As a direct result of the typically wide well spacing that existed when waterflooding commenced in shallow-shelf carbonate fields such as those in the Permian Basin, recurrent problems have been prevalent which have resulted in poor overall recovery. The highly heterogeneous nature of these fields are the primary reason for the poor waterflood sweep efficiency that is often experienced.[62,63] A common problem has been early water breakthrough as water channels through higher permeability zones between injectors and producers. Poor injection conformance is common in heterogeneous reservoirs such as these, and typically results in inadequate injection in some intervals within the pay column. Slow waterflood response has also been found to be related to the existence of permeability barriers which impede the flow of water from injectors to producers.[64] Recoveries have been greatly improved in these fields through infill drilling and pattern realignment projects which have been justified as a result of detailed reservoir characterization. In addition, less expensive remedial programs to isolate thief zones in injectors, to plug off high water producing zones in producers, or to increase injection into unswept zones have also helped to improve recovery.[65,66,67,68,69]

The problems associated with the operation of miscible or immiscible gas injection projects in the shallow-shelf carbonate reservoirs are also related to the heterogeneous nature of these fields and to the relationship between the injected gases and reservoir oil. Reservoir heterogeneities cause gas injection conformance problems much the same as in the case of water injection.[70] High permeability zones provide pathways for the injected gases to flow through and result in the premature production of excessive gas volumes. This results in poor miscible recovery performance and high gas treatment costs to remove gases such as carbon dioxide from the production stream. Mechanical workover programs and infill drilling have been utilized to help solve this problem, and chemical or foam diversion methods are being developed. Other process operational problems are related to the difference in density and viscosity between the injected gases and the reservoir oil. The most difficult problem to overcome is the viscous fingering of the gas through the oil saturated reservoir which results in nonuniform sweep of the oil.[71,72] This problem has not been completely solved for all cases, but mobility control additives have been developed and are under development. In addition, gravity segregation of the injected gases and reservoir oil can be a significant problem and must be considered in project design.

Many operational problems associated with shallow shelf carbonate reservoirs relate to the wellbores and surface facilities. One of the most significant problems in older fields is a higher percentage of inadequate original completions, where productive zones or injection intervals are partially completed or not completed at all.[73,74,75,76,77,78] This can result in poor injection conformance and inadequate reservoir sweep. These problems have been solved by redrilling wells, adding casing liner strings, or remedial work to perforate, re-perforate, stimulate, or isolate zones. The optimization of artificial lift methods presents many mechanical problems[79] as does the optimization of fracture stimulation design.[80,81,82,83] Another problem that often occurs in the producing wells in these fields is the build up of calcium carbonate scale, calcium sulfate scale, asphaltines, or paraffins, all of which tend to limit productivity. Scaling problems can be effectively reduced through the use of chemical scale inhibitors; asphaltine or paraffin build up can be removed by solvent treatments.[84] Surface facility problems primarily relate to the handling and treatment of production streams. The design of cost-effective treatment and disposal methods for produced waters and gases is a significant issue which will become an even greater concern as environmental legislation becomes tighter.[85,86,87,88,89]

Another important issue in mature fields is the automation of artificial lift and production equipment. Automation can increase efficiency and improve safety, while at the same time providing larger amounts of real-time data for effectively monitoring water injection and EOR projects.[90,81,92] Operator efforts to reduce costs and improve efficiency in mature shallow-shelf carbonate fields has even included such innovations as the use of interruptible power sources in waterflood operation.[93]

Reservoir Engineering

The environmental impacts associated with operations in shallow-shelf carbonate reservoirs are dictated in part by the local environmental characteristics, such as the location of aquifers and aquifer recharge areas, precipitation, climate, the proximity of surface water, the distance from urban areas, terrain, and the proximity of wetlands and other environmentally sensitive areas.

Portions of several of the shallow-shelf carbonate basins coincide with regions of major aquifers. These regions include the Williston Basin, the Illinois Basin, the Michigan Basin, the Texas Panhandle, South Texas, East Texas, the Smackover Trend, parts of the Central Kansas Uplift, parts of the Big Horn Basin region, parts of eastern Oklahoma, and parts of the Permian Basin. The most environmentally sensitive area of an aquifer is the recharge area, where the water supply in the aquifer is replenished. Impacts on recharge areas have a greater potential to affect major portions of the aquifer.[94]

Contamination of underground sources of drinking water is a potential risk from injection of produced waters. Since 98% of the wastes generated from exploration and production activities consists of produced water,[95] and since most of these waters are reinjected for enhanced recovery or disposal, potential contamination of drinking water is of particular concern in regions where there are major aquifers. Wells with casing leaks present a greater risk of contamination than wells which are structurally sound. External corrosion is the primary cause of casing leaks.[96]

The level of such risks can be categorized as significant, possible, and minor. Three regions exhibit *significant* potential for external casing corrosion to cause casing leaks: the Permian Basin, the Williston Basin, and the Central Kansas Uplift. In the Permian Basin, corrosion occurs at depths of 3,000 to 6,000 feet in the Clearfork, Coleman Junction, and Wolfcamp zones. Corrosion tends to be due to hydrogen sulfide and carbon dioxide in high salinity waters. The base of the usable quality water (3,000 milligrams per liter total dissolved solids) generally occurs at depths of less than 500 feet. In the Williston Basin, the Dakota saltwater sand is considered an aggressive leak zone at a depth of 4,400 feet. The highly corrosive salt water Dakota sand occurs throughout most of the Central Kansas Uplift at depths of 1,000 to 2,000 feet.[97]

Two regions have *possible* potential for external casing corrosion to cause casing leaks. These are the Big Horn Basin and the Texas Panhandle. In the Big Horn Basin, subsurface corrosive zones contain brines which typically have 5,000 milligrams per liter total dissolved solids.[98] These are much less corrosive than the zones mentioned above. In the Texas Panhandle region, casing corrosion has been minimized through the extensive use of cathodic well protection, which uses electric currents to charge the casing string, thereby reducing the potential for corrosion in long-life wells.

The Michigan and Illinois Basins, the Central Oklahoma Platform, and the Smackover region are all considered to have only *minor* potential for external casing corrosion causing casing leaks. In Illinois, oil production is from shallow (1,000 to 4,000 feet) oil sands and there are no aggressively corrosive salt water sands. In the Michigan

Basin, production is also from shallow depths, (3,000 to 6,000 feet) and there is an absence of corrosive zones. The Central Oklahoma Platform is considered to have minor corrosion potential due to the shallow production zones (4,000 feet), a historically low rate of casing leaks, and older reservoirs which are not extensively cathodically protected. The Smackover region is considered to have minor potential for corrosion due to low casing leak frequency and the limited need for cathodic protection in the region.

Advanced secondary and tertiary enhanced oil recovery increases the potential for environmental impacts from E&P operations due to an increased level of production activities and an extended duration of operations. However, most potential environmental impacts from enhanced recovery activities are of the same type as for conventional primary and secondary recovery. Enhanced recovery activities tend to take place in locations where the potential environmental impacts of concern have already been established by conventional activities. As such, they do not usually pose a significant additional impact risk. Potential environmental impacts due to enhanced recovery activities include: increased emissions of pollutants from added injection and production facilities; increased potential for pollution of surface waters and USDWs by injection fluids; expanded land use through more intensive field development; and extended duration of land use.

Environmental concerns related to miscible CO_2 flooding include transport of the CO_2 to the flooding site, groundwater contamination, air quality, and land use. Miscible fluid injection normally employs the same injection wells used in secondary operations. Because injection fluids are expensive, process economics dictate that injected and produced fluids be contained in a closed system whenever possible, thus minimizing the potential for environmental impacts.[99] Pilot studies may use CO_2 transported in tanker trucks or railroad cars, but larger or longer-term projects are usually supplied by pipeline, which would also have a land use impact.[100] CO_2 is generally considered to be environmentally benign; however, CO_2 is a greenhouse gas that is thought to contribute to global warming. Significant leaks of CO_2 during transportation or use could contribute to air quality concerns. CO_2 flooding may require significant volumes of water,[101,102] but since CO_2 injection candidates typically have previously been waterflooded, no additional potential for water-related environmental impacts would be anticipated.

Infill drilling is also an important technology for additional recovery in shallow-shelf carbonate reservoirs, and would generate additional volumes of drilling fluids and cuttings. Requirements for disposal of these wastes varies by state, but compliance with state requirements should obviate any potential environmental impacts.

Increased environmental compliance costs can be a major factor in project economics. Because increased costs of regulatory compliance cause projects to reach their economic limit sooner, environmental regulations contribute to premature well abandonments. New projects that formerly would have been economically viable, especially technology-intensive enhanced recovery projects, may fall below a hurdle rate when increased environmental compliance costs are considered. To the extent that these projects are not pursued because of environmental regulatory requirements, total domestic resource recovery potential will be reduced.

RESERVES POTENTIAL OF IDENTIFIED SHALLOW-SHELF CARBONATE RESERVOIRS

The analysis presented here is based on reservoir performance and economic modeling using the Tertiary Oil Recovery

Information System (TORIS). Adapted and validated by the National Petroleum Council (NPC) in 1984[103], TORIS is maintained and updated by the DOE's Bartlesville Project Office. It consists of comprehensive oil reservoir databases and detailed recovery process and economic models for predicting recovery potential under different price and technology assumptions. Two price/technology scenarios were used in this analysis: an *implemented technology* case, which assumes the more extensive application of currently available technology, and an *advanced technology* case, which assumes that the scope and application of existing technology is extended to overcome current limitations through research and development and technology transfer. These limitations, in the form of technical screening criteria, were originally defined by the NPC in 1984 and expanded by the DOE in 1990.[104]

The TORIS database contains information on reservoir and fluid properties, geology, and production for reservoirs accounting for about two-thirds of the total known onshore OOIP in the contiguous United States. Although the absolute numbers detailed in this report have not been extrapolated to national totals, the percentage estimates presented here for TORIS reservoirs are believed to be reasonable for the nation as a whole, particularly for larger reservoirs, where the TORIS database coverage approaches 100%.

TORIS technical screening, production, and economic models were used to estimate the magnitude of increased recovery potential over currently proved reserves resulting from the application of new EOR and ASR projects in existing reservoirs. This incremental recovery potential is projected over two price/technology scenarios: a "near-term" case which assumes low oil prices ($20/Bbl) and implemented technology, and a "mid-term" case based on higher oil prices ($32/Bbl) and advanced technology. These estimates are summarized in Table 1 and illustrated in Figure 8 .

There is significant potential, 2,361 million barrels, under the implemented technology and $20 oil price scenario. With advanced technology and a $32 oil price, this figure more than doubles to 5,183 million barrels. In each case, roughly 80% of the potential is from enhanced oil recovery using miscible CO_2 injection. About 10% to 20% of the potential lies with infill drilling, and a smaller contribution from polymer injection or infill drilling combined with polymer injection.

Under the near-term case, the potential reserves additions resulting from ASR processes are estimated to total 382 million barrels, with 289 million barrels produced from open shallow-shelf carbonate reservoirs and 92 million barrels produced from restricted shallow-shelf carbonate reservoirs. Within open shallow-shelf carbonates, almost 80% of ASR potential can be attributed to infill drilling. An additional 7% of the potential results from projects which combine infill drilling with other ASR processes. Polymer flooding accounts for 13% of potential incremental production and profile modification accounts for less than 1%. In restricted shallow-shelf carbonate reservoirs, infill drilling amounts to 41% of ASR incremental production with infill combination projects linked to an additional 25%. Polymer flooding results in 33% of incremental production and profile modification projects account for a fraction of 1%.

The higher oil prices and more advanced technology modeled in the mid-term case raises the total ASR potential to 1.178 billion barrels for the two groups of reservoirs. Open shallow-shelf carbonate reservoirs produce 929 million barrels of ASR potential and restricted shallow-shelf carbonate reservoirs produce 249 million barrels. Infill drilling alone and in combination with other processes accounts for 97% of the mid-term ASR potential of open shallow-shelf carbonate reservoirs. The remaining 3% of

Table 1—Shallow-Shelf Carbonate EOR and ASR Recovery Potential (Million Barrels)

	Near-Term Case (Implemented Technology @ $20/Bbl)	Mid-Term Case (Advanced Technology @ $32/Bbl)
Shallow-Shelf (Open)		
EOR	**1,224**	**2,526**
CO_2	1,224	2,526
ASR	**289**	**929**
Infill Drilling	230	850
Polymer	38	33
Profile Modification	< 1	< 1
Infill Combination*	21	46
Open Subtotal	**1,513**	**3,455**
Shallow-Shelf (Restricted)		
EOR	**756**	**1,479**
CO_2	756	1,465
Steam	---	14
ASR	**92**	**249**
Infill Drilling	38	140
Polymer	30	64
Profile Modification	< 1	< 1
Infill Combination*	23	45
Restricted Subtotal	**848**	**1,728**
TOTAL	**2,361**	**5,183**

* Infill drilling combined with polymer injection or profile modification

this potential results from polymer flooding projects. In restricted shallow-shelf carbonate reservoirs, 56% of the ASR potential is attributed to infill drilling and 18% is attributed to infill combination projects. Roughly one-quarter of ASR potential in restricted shelf reservoirs results from polymer flooding, and 0.1% stems from profile modification projects.

Enhanced oil recovery processes, dominated by CO_2 flooding, hold much greater promise for increased recovery, accounting for four-fifths of all incremental recovery potential in shallow-shelf carbonate reservoirs (open and restricted). (In a few

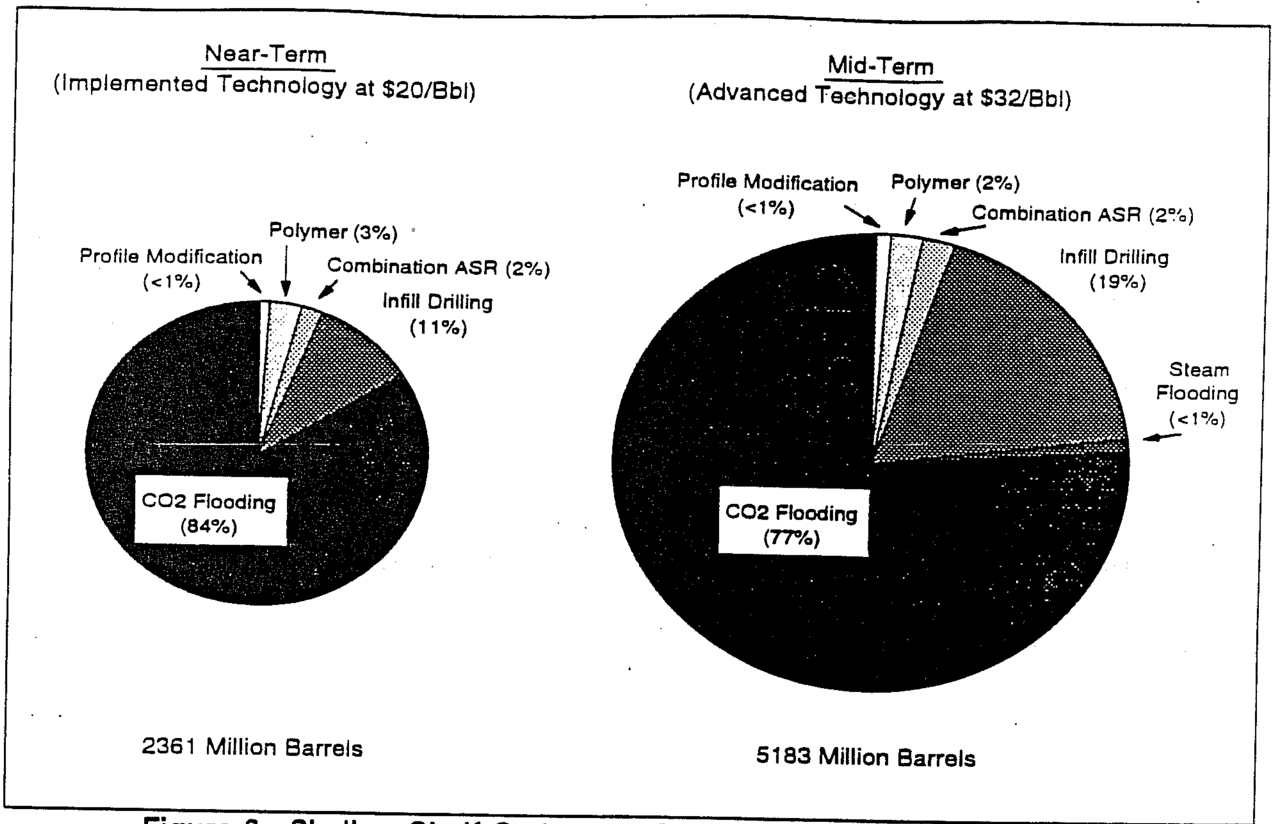


Figure 8—Shallow-Shelf Carbonate EOR and ASR Recovery Potential

cases, nitrogen flooding is considered to be the optimal economic choice for EOR; these reserves are added into the CO_2 total.) CO_2 miscible flooding produces all EOR potential reserve additions under the near-term case, amounting to almost 2 billion barrels (1.2 billion barrels in open shallow-shelf carbonate reservoirs and 756 million barrels in restricted shallow-shelf carbonate reservoirs). Under the mid-term case, the total is 4 billion barrels. CO_2 flooding accounts for all 2.5 billion barrels of potential EOR production from open shallow-shelf carbonate reservoirs and 1.5 billion barrels from restricted shallow-shelf carbonate reservoirs. About 14 million barrels (1% of the EOR total) has been attributed to steam flooding in the few shallow-shelf restricted reservoirs with relatively heavy oil.

The TORIS estimate of near-term EOR potential is concentrated in the Permian Basin of western Texas and eastern New Mexico where miscible CO_2 flooding projects hold significant promise for future oil recovery. Although shallow-shelf carbonate reservoirs in a total of nine states hold potential for recovery in the near term, more than 90% of this potential comes from Texas and New Mexico alone. Texas contains 1.76 billion barrels of EOR potential out of a total of 1.98 billion barrels. New Mexico accounts for a further 170 million barrels of EOR potential, leaving less than 50 million barrels of EOR potential in the other seven states. Similarly, New Mexico contains 210 million barrels and Texas 120 million barrels out of a total ASR potential of 380 million. The remaining seven states account for just over 40 million barrels of the near-term shallow-shelf carbonate ASR potential.

In the mid-term EOR case, Oklahoma recovery potential increases, concentrating the majority of mid-term potential in the three states of Texas, New Mexico, and Oklahoma. Together they account for 3.8 billion barrels of EOR recovery out of a nationwide total of 4.0 billion barrels. Among the other seven states, only Florida and Wyoming contain significant potential future recovery.

The potential benefits of EOR and ASR technologies are put at risk by the continued abandonment of marginally productive oil reservoirs over time. If reservoirs which have reached the end of their economic life under conventional primary and secondary recovery methods are abandoned before potentially profitable EOR or ASR projects are established, the cost of initiating such projects in the future becomes prohibitively expensive. Projections for the near-term price/technology case indicate that 24% of the incremental recovery potential of EOR and ASR processes could be lost by 1995 due to abandonment. An additional 5% could be lost by the year 2000 if no new technologies are applied. The potential losses due to abandonment under the mid-term price/technology case are even more dramatic. Twenty percent of the mid-term resource could be lost by 1995 and 44% could be lost by the year 2000. By the year 2000, a total of almost 2.3 billion barrels of potential could be lost (1.6 billion barrels in open shallow-shelf reservoirs and 690 million barrels in restricted shallow-shelf reservoirs). The primary objective of the near-term program is to delay these abandonments until the advanced technology becomes available.

It should be noted that the foregoing analyses estimate the potential for shallow-shelf carbonates to increase reserves. These results are not a forecast of the most likely future impacts but rather an upper boundary. For example, each of the following assumptions, if untrue, could cause the future potential to be less than stated:

- The results for the advanced technology case assume that R&D efforts by industry and government as described in the DOE plan will be fully successful in providing essential advances.
- The economic analyses assume that EOR projects will be initiated if an operator will accept a real rate of return in excess of 10% on his investment and will assume that prices remain stable, adjusting only for inflation.
- The analysis assumes that all operators have sufficient access to technological expertise, personnel, and capital to implement all the projects that meet the technical criteria.

In any case, it is clear that the amount of potentially recoverable oil endangered by abandonment establishes an urgency in ensuring application of *implemented* technologies to shallow-shelf carbonate reservoirs. The magnitude of the incremental recovery attributable to research-based *advanced* technology likewise establishes a substantial target for future R&D. Shallow-shelf carbonate reservoirs are clearly an important component of the nation's energy resource base.

SUMMARY

Shallow-shelf carbonate reservoirs are depositionally complex and their geologic history elucidates the reasons behind their heterogeneous and discontinuous nature. This complexity has driven the development of integrated reservoir management strategies to optimize secondary and tertiary recovery operations and has stimulated the development and use of detailed reservoir characterization techniques. An understanding of the relationship between the internal complexities and production performance of these reservoirs can help to solve the operational problems which often occur during primary, secondary and tertiary oil recovery operations. The maturity of shallow-shelf carbonate reservoirs magnifies the importance of artificial lift and operational issues. Finding ways to improve operating efficiency can mean the difference between continued production and abandonment.

The prevention of premature abandonment of shallow-shelf carbonate reservoirs is critical due to the enormous potential recovery by EOR and ASR techniques. Research and development, coupled with effective technology transfer, are key to "keeping the door open" for potential recovery from these reservoirs.

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September 4, 1992

PRE-SOLICITATION INFORMATION
FOR
PROGRAM OPPORTUNITY NOTICES NOS.
DE-PS22-93BC14806 AND DE-PS22-93BC14807
ENTITLED
"CLASS II OIL PROGRAM: NEAR and MID-TERM ACTIVITIES"

Prospective Offerors:

The DOE conducted a Pre-Solicitation "Public Meeting" on August 25, 1992 in Houston, TX. DOE's purpose for conducting this meeting was to present its plans for the support of Near-Term and Mid-Term Enhanced Oil Recovery Projects in domestic Shallow Shelf Carbonate Reservoirs (i.e. Class II Reservoirs). Additionally, the DOE afforded potential offerors an opportunity to ask questions, as well as to provide comments on the "draft" packet of information which was mailed on August 6, 1992.

Consistent with the commitment made by DOE at this meeting, the following items are being provided to all attendees (including all organizations/individuals contained on the DOE source list):

1) copies of the meeting agenda and subsequent DOE presentations (Attachment 1),

2) a list of meeting attendees (Attachment 2), and

3) a comprehensive list of shallow shelf carbonate reservoirs as contained in DOE's Tertiary Oil Recovery Information System (TORIS) (Attachment 3).

In an attempt to assist potential operators in the validation of a particular reservoir as shallow shelf carbonate, the DOE is providing two (2) additional items of information, including 1) a technical summary of shallow shelf carbonate reservoirs (Attachment 4), and 2) a topical bibliography (by subject matter) pertinent to Class II (Attachment 5).

As a final reminder, it should be noted that the planned release date for the two (2) subject Program Opportunity Notices is October 15, 1992.

Sincerely,

Dale A. Siciliano

Dale A. Siciliano
Contracting Officer